Achieving Canada's climate targets and the impacts on Alberta's oil sands industry

by

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Abstract

This research project uses an energy-economy model to: (1) assess Canada's current climate policies in the medium-term; (2) develop a sector-specific regulatory package stringent enough to meet long-term climate targets; and (3) assess the implications of domestic and international climate efforts on Alberta's oil sands industry. The modelling results predict that Canada will fail to meet its medium-term climate targets under current and proposed policies. Long-term targets can be met with a sector-specific regulatory approach as promised by the Government of Canada. Lastly, Alberta's oil sands industry will be impacted by cost increases from domestic climate regulation and from oil price declines due to international climate efforts. Two oil price scenarios are explored. Under the high oil price scenario, expansion of the industry is predicted to remain profitable. However, under the low oil price scenario, expansion is predicted to be unprofitable and existing oil sands operations may be driven out of the market over the next two decades.

Keywords: Hybrid energy-economy models; oil sands; climate change policy; sector-specific climate regulation

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BAU	Business-as-usual
CAPP	Canadian Association of Petroleum Producers
CCS	Carbon Capture and Storage
CERI	Canadian Energy Resource Institute
CO_2	Carbon Dioxide
GEA	Global Energy Assessment
GHG	Greenhouse Gas
HVAC	Heating Ventilation Air Conditioning
IEA	International Energy Administration
IPCC	Intergovernmental Panel on Climate Change
NRTEE	National Round Table on the Environment and the Economy
SAGD	Steam-Assisted Gravity Drainage
SGER	Specified Gas Emitters Regulation
WTI	West Texas Intermediate
ZEV	Zero-Emission Vehicle

1. Introduction

On May 9, 2013, Hawaii's Mauna Loa measuring station registered a daily average atmospheric carbon dioxide (CO_2) concentration of 400 parts per million (ppm) for the first time since recording began in 1958 (NOAA, 2013). This concentration is about 50% higher than pre-Industrial Revolution levels in the mid-1700s. In fact, the last time concentrations were this high was in the Pliocene Epoch, about 4.5 million years ago, a time when global average temperatures were 3 to 4 ˚C warmer and sea levels 20 to 25 metres higher (NOAA, 2013; Yale, 2013; Dwyer & Chandler, 2008). The recently published Fifth Assessment Report by the Intergovernmental Panel on Climate Change (IPCC) states with over 95% confidence that higher, human-induced concentrations of greenhouse gases (GHG) such as CO_2 in the atmosphere are the principal cause for the warming experienced over the past century (IPCC, 2013). The IPCC warns that further increasing GHG emissions will have negative and irreversible consequences such as more intense and frequent heat waves, more extreme drought and crop failure events, mass species extinction, stronger storms, ocean acidification and sea level rise, displacing millions of people (IPCC, 2007).

To mitigate dangerous climate change, global leaders have committed to not let the global average temperature increase to exceed 2˚ C (Copenhagen Accord, 2009). Canada's current federal government under the leadership of Stephen Harper supports this objective and has promised significant GHG emission reductions to contribute to the international effort, with domestic emission reduction targets of 17% and 60–70% below 2005 levels by 2020 and 2050 respectively (Environment Canada, 2013; NRTEE, 2007). This is not the first time Canada has set reduction targets. Over the past two decades, Canada has repeatedly promised to decrease its emissions and set ambitious emission targets. Several governments introduced various climate policies. However, these policies have been largely ineffective as emissions have continued to increase, missing federal emission targets repeatedly (Jaccard, 2005).

An extensive literature exists on potential policy solutions to the climate change problem (Goulder & Parry, 2008; Aldy et al., 2010; Aldy & Stavins, 2011; Linares & Labandeira, 2010). Academics generally agree that market-based solutions, such as carbon taxes or cap-and-trade systems, are the most effective and economically efficient climate policies (Aldy & Stavins, 2011). However, the high-cost visibility to the general consumers of such market-based policies has made them politically unpopular (Linares & Labandeira, 2010).

Canada's current Conservative government has repeatedly rejected market-based policies, especially carbon taxes, in addressing the climate change issue. Instead, it has committed to decreasing GHG emissions with sector-specific regulations, an approach in which economic sectors are regulated individually or in groups (Environment Canada, 2012a).

Examples of sector-specific regulations include vehicle efficiency regulations that have existed for four decades. Recently, the Government of Canada matched tougher U.S. regulations on personal and freight vehicle efficiency as part of the government's commitment to address GHG emissions. The government also initiated a regulation that effectively requires new coal-fired electricity generation to be fitted with equipment that prevents most of the carbon emissions. These regulations cover sectors that account for approximately one-third of total nationwide emissions (Environment Canada, 2012a). Provincial governments have also implemented climate policies, such as Ontario's phase-out of coal-fired electric generation plants, Alberta's Specified Gas Emitters Regulation (SGER) for large emitters, Quebec’s cap-and-trade policy, and British Columbia's carbon tax on all provincial emissions from the combustion of fossil fuels. Canada's former minister of the environment, Peter Kent, stated in 2012 that current federal and provincial policies will achieve "half the GHG reductions required to meet Canada's GHG targets by 2020" (Environment Canada, 2012b).

Until it was eliminated in 2013, the National Round Table on the Environment and the Economy (NRTEE) provided independent analysis of climate policies and proposed policy packages for Canada to meet its 2020 and 2050 climate targets. Its reports focused on implementing a cap-and-trade system with additional GHG regulations on specific sectors (NRTEE, 2007; NRTEE 2009). The discontinuation of the

NRTEE did not allow a similar study based on the federal government's preferred sector-specific regulatory approach to be conducted. As such, there is a lack of independent analysis of how current climate policies may contribute to meeting medium (2020) and long-term (2050) emission targets. Furthermore, a gap exists in the literature on how Canada could meet its climate targets with the government's preferred approach of sector-specific regulation. In this study I seek to analyze current policies and, if necessary, recommend additional options to help the government meet its stated objectives.

In this study, I highlight the potential effects of emission targets and climate policy on Alberta's oil sands industry due to the industry's rapid growth in output and emissions. The oil sands are a mixture of bitumen (a dense form of petroleum), water, sand and clay. The process to liberate the oil requires a large amount of energy, which could come from any source, although natural gas is frequently used. Thus, producing oil from the oil sands is more energy-intensive and, depending on the technology, more emissions-intensive than producing conventional oil (IEA, 2010). Commercial extraction of Alberta's oil sands began in 1967, but technological challenges and high extraction costs constrained development for several decades. Since 2000, advances in extraction technology and higher world oil prices have improved the economic feasibility, and oil sands output has more than tripled since 2000. The industry plans to double production again over the next decade and triple it by 2030 (CAPP, 2013). Thus, GHG emissions from the oil sands are expected to increase fourfold between 2005 and 2030 (Environment Canada, 2013). The Canadian government has yet to show how the pursuit of expanding oil sands production is compatible with its domestic and international climate commitments.

Recent studies have assessed the level of oil sands development that would be compatible with national and international efforts to limit climate change impacts (Chan et al., 2012; IEA, 2010). These studies show how climate policies, consistent with the 2˚ C commitment, in Canada and other countries, have a profoundly negative impact on high-cost, high-emission oil producers like oil sands because these policy efforts would lead to higher production costs for emissions-intensive oil sands and lower global fossil energy prices. In this study I combine information from these global studies with a Canada-focused energy-economy model to understand the possible effectiveness of current and proposed policies in Canada, and, in particular, the implications for dramatic oil sands expansion.

In summary, my main research objectives for this project are:

- To assess whether or not Canada's current climate policies will meet the country's 2020 climate targets
- To develop a sector-specific regulatory approach that is sufficiently stringent to meet the country's 2020 and 2050 emission reduction targets
- To assess the possible impacts on oil sands expansion in a future carbon-constrained world, regulated by the above-mentioned sector-specific policies

The remainder of the report is organized into multiple chapters. Chapter 2 provides background information on the Canadian context to global climate change efforts, Alberta's oil sands industry, climate change policy tools, Canadian policy initiatives, and a short introduction to energy modelling. Chapter 3 introduces the CIMS model used in this project, explains in detail the methodology used to model Canada's current climate policies, describes a sector-specific regulatory framework for the long term, and assesses the economics of oil sands expansion in a future carbon-constrained world. Chapter 4 provides the modelling results and discusses their implications. Chapter 5 summarizes the key findings and recommends future study.

2. Background

The Government of Canada has committed to reduce its GHG emissions as part of an international effort to limit the impacts of anthropogenic climate change. It has promised to achieve these targets using a sector-specific regulatory approach, in which economic sectors are regulated individually. However, previous Canadian governments have repeatedly failed to meet their targets due to ineffective climate policies. This current Canadian government has shown strong support for expanding fossil fuel production, in particular the Alberta oil sands. The production of oil sands is emissions-intensive and increases the supply of fossil-based energy, which appears contradictory to meeting domestic and international climate targets.

2.1. Canadian context to climate change

Climate change as a global problem

Climate change, being global in nature, is an inherently difficult problem to address. Canada has committed to decreasing its emissions as part of an international effort to limit the impacts of climate change (Copenhagen Accord, 2009). Accounting for less than 2% of global emissions, Canada's effort will not, by itself, limit the impacts of climate change dramatically (Environment Canada, 2013). Furthermore, because the costs of decreasing emissions are incurred domestically and the benefits are shared globally, every country has an incentive to free-ride on other nations' efforts and a disincentive to act unilaterally. This is a global example of the classic tragedy of the commons. Collectively, all countries prefer to act to decrease emissions so as to limit the risk of dangerous climate change; when acting individually, however, countries still prefer to continue emitting unimpeded (Soroos, 1997; Helm, 2008). The issue is further complicated by a lack of global governance to enforce an agreement, disagreement on how much each country should contribute to the global effort, as well as on differing views on how best to achieve intergenerational equity when acting on the climate change threat (Gardiner & Hartzell-Nichols, 2012).

Canada's climate targets

In 2009, Canada committed to a GHG emission reduction target under the Copenhagen Accord (2009) as part of an international effort to limit the risk from climate change. The target is for GHG emission reductions of 17% below 2005 levels by 2020. This is in addition to the government's 2006 target of a 60–70% reduction below 2005 levels by 2050 (NRTEE, 2007). Canada's medium-term target is identical to that of the U.S. However, its long-term target is less ambitious than that of the U.S.'s 80% reduction target (Office of the President, 2013). Canada's emission targets represent limiting total annual GHG emissions to 612 Mt CO_2e by 2020 and 235 Mt CO_2e by 2050 (Environment Canada, 2013).

Canada's medium-term target is just six years away. In 2011, emissions were 702 Mt CO_2e, 5% below the 2005 level (Environment Canada, 2013). The decline has not been uniform and emissions have stabilized over the three years ending in 2011. Considering the slow capital stock turnover of energy-using equipment and infrastructure, this is problematic. Furthermore, economic recovery and increased production in the oil and gas sector, particularly in Alberta's oil sands industry, is expected to substantially increase emissions. Based on current policies, in 2013 Environment Canada predicted 2020 emissions of 734 Mt CO_2e, 20% above the official target. As such, it appears that additional policies will be required to meet the target. This study will explore policy options that would allow Canada to meet its medium- and long-term targets.

Since the elimination of the NRTEE, there is a lack of independent oversight on the effects of Canadian climate policies. Several jurisdictions have explored the role of such independent entities, which can work as examples for Canada, including:

- British Columbia used independent modellers to explore policy effectiveness in its 2007–2008 climate action plan,

- The U.S. Government uses the independent Energy Information Administration (EIA) to estimate effectiveness and costs of climate policy options,
- California uses the quasi-judicial California Air Resources Board (CARB) and the California Energy Commission to estimate the state's climate policy effectiveness (B.C. Government, 2008; CARB, 2013).

One goal of this study is to provide a similar independent assessment of the likely effect of current and proposed Canadian climate policy, and, if this assessment shows that the government is unlikely to achieve its emission reduction promises, to explore what extension and intensification of its regulatory approach would be required to address this failure.

2.2. Alberta's oil sands industry under climate constraints

Alberta's oil sands resource is vast, with an estimated reserve of 175 billion barrels, or 95% of Canada's total oil reserves. For extraction, the bitumen from oil sands has to be either mined and separated or heated and pumped. About 20% of the resource is close enough to the surface to be mined. The other 80% is too deep and must therefore be pumped or extracted from underground via in-situ production, most commonly with steam-assisted gravity drainage (SAGD). This process uses steam to make the bitumen flow. SAGD production is about three times more emissions-intensive than mining (Chan et al., 2012). The bitumen itself can be further upgraded to create a synthetic crude oil that has similar characteristics to light sweet oil. These extraction techniques and extra refining steps increase the fuel's energy intensity and emissions. The International Energy Agency (IEA, 2010) estimates that on average, Alberta's oil sands produce an extra 50 kilograms of CO_2e per barrel compared to conventional oils. The emission intensity of Alberta's oil sands is unlikely to decrease, since 75% of the forecasted production growth is through the more emissions-intensive in-situ projects (CAPP, 2013).

Carbon capture and storage (CCS) technology could be used to decrease GHG emissions in the extraction of oil from the oil sands. Furthermore, the Alberta and Williston basins are found to be suitable for carbon sequestration and cover most of

Alberta and southern Saskatchewan (Lutes, 2012). However, CCS has a cost, and so industry will not implement it without a requirement or incentive from government.

According to Environment Canada (2013) Alberta's bitumen production has tripled over the past decade to 1.8 million bbl/day in 2012, and is expected to double again in the next decade. Emissions from oil sands increased from 34 Mt CO_2e in 2005 to 55 Mt in 2012, representing 7.8% of Canada's emissions. These emissions are expected to increase in lockstep with forecasted oil sands production growth, and are forecasted to increase to 101 Mt CO_2e by 2020, which will represent 17% of total allowable emissions under the national GHG target in 2020. Emissions are projected to continue to increase past 2020, and will represent a larger share of the country's allowable emissions under its climate targets. This increase in emissions will make it difficult for Canada to meet its medium- and long-term climate targets.

The Canadian Energy Research Institute (CERI) estimates that under its reference scenario, oil production will increase to 5.4 million bbl/day, with associated emissions of 159 Mt CO_2e (CERI, 2012) by 2045. The Canadian Association of Petroleum Producers (CAPP), an industry group representing oil companies, forecasts production growing to 5.2 million bbl/day already by 2030—presumably causing an associated faster emission increase (CAPP, 2013).

Compared to conventional sources of oil, the oil sands are a more expensive resource to develop. Plant gate supply costs for new in-situ, stand-alone mining and integrated mining and upgrading projects are estimated at $45/bbl, $60/bbl and $90/bbl respectively (CERI, 2012).[1] CERI then provides the West Texas Intermediate (WTI) equivalent supply costs (which include the costs of transport, diluent mixing and the heavy-light differential) estimated at $65/bbl, $80/bbl and $90/bbl respectively

[1] Plant gate costs are based on a 30-year life cycle and with a real return on investment of 10%. Plant gate costs do not account for the heavy-light differential and transaction costs (transport and diluent mixing) and explain the lower cost for non-upgraded projects. However, the non-upgraded projects also receive lower prices.

(CERI, 2012).[2] In general, non-upgraded bitumen is harder to refine and therefore receives a lower price, while upgraded bitumen (also known as synthetic crude oil) is easier to refine and receives a slight premium over a benchmark such as WTI.

If the international community acts in concert to reduce global emissions in line with the international 2 ˚C commitment, Alberta's oil sands industry will be doubly impacted. First, the cost of producing bitumen is likely to increase from domestic climate policies aimed at achieving Canada's climate targets. Second, the demand for oil and therefore its price will decline, decreasing the profitability of oil sands projects.

Chan et al. (2012) used a global computable general equilibrium model, with a detailed representation of oil sands production processes and costs, to predict the output of Alberta's bitumen industry and other unconventional oils in a carbon-constrained world. Their analysis used more modest global emission reductions than the ~50% reduction below 2010 levels required to achieve the promised 2 ˚C target (Rogelj et al., 2011). The authors found that without climate policy, bitumen production would increase fourfold from 2010 to 2050. However, even with the more modest climate policy, both in Canada and globally, oil sands would be unable to grow and would eventually be driven down to low or even zero production due to increased costs of production and lower received prices for its oil product. Much of the global demand for oil would be met by cheaper and less emissions-intensive sources of conventional crude.

The International Energy Agency did a similar analysis in its World Energy Outlook, but in this case it fixed oil sands output to 2030 at the levels consistent with existing and already approved projects (IEA, 2010). The 2035 oil price the IEA uses for this study is still high by historic standards at $97/bbl (in 2010 dollars).

[2] WTI-equivalent costs equate the production costs of different-quality crudes to the oil benchmark West Texas Intermediate and include the heavy-light differential. The heavy-light differential is the difference in price between heavy and light oils. Heavy oils, such as diluted bitumen, are harder to refine and therefore receive a lower price compared to a light oil standard such as WTI. Upgraded oils are considered light oils and are easier to refine and historically receive a comparable price (or a slight premium) to the WTI sweet light oil benchmark. As such, the WTI-equivalent supply costs shows the price WTI must be for different quality oils to be economical.

Oil price determinants in a 2 ˚C world

The future price of oil will be paramount in determining what level of oil sands development will be economically feasible. If humanity acts in concert to reduce climate change, demand and therefore prices will generally fall for fossil fuels. Oil is used mostly in transportation, which is assumed to have higher marginal abatement costs than the electricity sector, which uses mostly coal and natural gas (Aldy et al., 2010). This suggests lower demand decline and thus less price decline for oil compared to other fossil fuels. On the other hand, as oil is used primarily in transportation, it is not as well suited for direct abatement from incorporating CCS technologies as are natural gas and coal. By incorporating CCS, natural gas and coal can reduce emissions without reducing demand for the commodities, while oil cannot. This second dynamic suggests that the demand and price decline for oil could be greater than for coal or natural gas.

The availability of transportation fuel alternatives is also paramount to the future price of oil. Abundant natural gas reserves and advances in biofuel production and electric vehicles, among others, hold much promise in offering reasonably cheap and, in some cases, environmentally better alternatives to oil. If these technologies and fuels can deliver on their promises, it would put further downward pressure on oil prices. In the absence of such alternatives, the world will have a much harder time decreasing its reliance on oil for the transportation sector (Chan et al., 2012).

Currently, oil is priced partially to accommodate the development of new supplies, with large investments in new and capital-intensive infrastructure (Hamilton, 2008). Arguably, the price also represents some scarcity, or Hotelling rent: an economic rent earned by a producer of a non-renewable resource in anticipation of higher prices in the future (Hotelling, 1931). If, however, future oil demand decreases so that existing infrastructure can meet demand, the price could fall to the operating costs of existing suppliers rather than to new supply costs. This seems to explain in part the low oil prices from 1986 to 2002, when reductions in demand from earlier oil price shocks and increases in supply kept the global oil market in a surplus position. Furthermore, in a world more and more constrained by climate concerns, the scarcity rent would disappear, as oil might be seen to have less value in future as humanity shifted to non-emitting transportation alternatives. A significantly lower oil price is therefore likely in a world in which the 2 ˚C promises of global political leaders are kept.

On the other hand, oil is a finite resource. How much longer reserves will last has evoked a large debate. The peak oil theory predicts conventional oil production peaking, causing prices to rise permanently to high levels (Hubbert, 1956). Recent research by the Global Energy Assessment (GEA, 2012) shows global conventional reserves at one trillion barrels, roughly equivalent to total cumulative oil production to date, at a full production cost of $5/bbl to $40/bbl. Including unconventional oils, the known and estimated reserve potential that is economically feasible at or below today's oil price (~$100/bbl) is more than five times larger than total cumulative oil production to date. The report also shows that when including gas-to-liquids conversion from the world’s ample natural gas reserves, the transport fossil fuel reserves increase dramatically again. The high transport fuel prices predicted by the peak oil theory do not appear to be of primary concern over the next several decades.

2.3. Climate change policy tools

Climate policies can be grouped into compulsory or non-compulsory policies. A spectrum exists from least compulsory polices, such as moral suasion and financial incentives or subsidies, to the most compulsory policies, such as traditional command and control regulation.

Non-compulsory policies

Non-compulsory policies are easy to implement as they do not force choices or costs on firms and consumers. Canada has historically relied on non-compulsory policies such as information campaigns and modest subsidies to address climate change. These policies have been proven to be largely ineffective in reducing GHG emissions (Goulder & Parry, 2008). Furthermore, subsidies are rarely economically efficient and are prone to free riding, a phenomenon in which a consumer or firm receives money, usually from public funds, to carry out an action that would have been implemented in the absence of these funds (Linares & Labandeira, 2010).

Compulsory policies

Command and control

Command and control regulations are the most compulsory of the policy options, as they force consumers, companies or entire industries to adopt a certain technology or to meet a certain efficiency or pollution standard. If non-compliance is encountered, sanctions are enforced. Due to a lack of flexibility in compliance, command and control regulations are noted to have low economic efficiency, as they tend not to exploit all lowest-cost GHG abatement options. However, more broadly applied regulations with certain flexibility conditions in meeting a given objective can decrease abatement costs and increase the economic efficiency with which a given objective is pursued.

Generally, command and control regulations do not promote, and sometimes actively deter, the innovation or adoption of more efficient and less-polluting technologies. This is especially true in fields with rapid rates of technological advances. For command and control regulation to be as effective as possible, it would have to be constantly updated, which allows us to question if public institutions are the most suited for this task (Jaffe & Stavins, 1994).

Tradable performance standards

Tradable performance standards blur the line between traditional command and control regulation and market-based policies. Similarly to traditional command and control regulation, tradable performance standards apply a certain standard that must be met, usually at the industry level. Firms can trade permits to comply with the standard, assuring that overall the industry meets the standard. This trading mechanism adds flexibility and therefore increases economic efficiency compared to traditional command and control regulations (Aldy & Stavins, 2011).

Carbon pricing: carbon tax and cap-and-trade

Carbon pricing represents the middle of the compulsoriness spectrum. It can be achieved by either a carbon tax or a cap-and-trade system. For the former policy, governments place a tax on carbon emissions. In the latter policy, governments set an emission limit (cap) and issue tradable emission permits that sum to this limit. Under both of these carbon-pricing policies, the firm or household has the incentive to decrease pollution to a level where any further reduction would cost more than simply paying the carbon price (paying the tax or purchasing a permit). Both systems leave it up to these agents to determine how to reduce emissions in the most cost-effective manner, increasing flexibility and thereby decreasing costs. Furthermore, a carbon price encourages innovation, as any innovation that reduces the cost of compliance provides a direct savings to the firm or household.

2.4. Sector-specific regulation

The Canadian government has ruled out a carbon tax and instead has committed to achieving the country's emission targets with sector-specific regulation (Environment Canada, 2012a). This approach imposes various command and control regulations and tradable performance standards on the various sectors of the economy. While regulations tend to be less economically efficient than market-based instruments, sector-specific regulations (and regulation in general) can be designed with economic efficiency in mind (Goulder & Parry, 2008). A sector-specific regulatory package that aims to equate marginal abatement costs across sectors may come close to realizing an economically efficient regulation.

Sector-specific regulation has one possible benefit in that it tends to recognize that different sectors have different priorities and constraints, enabling policy makers to tailor the policy to the unique constraints facing each economic sector. For example, sector-specific regulation, if designed appropriately, can better address the political constraints to climate policies in sectors most vulnerable to consumer or taxpayer reaction or to economic constraints in sectors exposed to foreign competition. California, with a population similar in size to Canada and with a larger economy, is relying mostly on such an approach by applying regulations in the personal transportation, buildings and electricity sectors, in conjunction with a cap-and-trade system for large industries emitting more than 25,000 t CO_2e/year (CARB, 2013).

2.5. Current climate policies in Canada

According to a recent Environment Canada (2012a) report, Canada's federal and provincial governments have implemented or are implementing 64 different GHG abatement policies. Most of these measures are of a non-compulsory nature that neither regulate technologies and fuels nor set a price on emissions. In this sense, they are similar to policies past Canadian federal and provincial governments have relied upon while continuously missing their emission reduction promises (Simpson et al., 2007). As non-compulsory policies are unlikely to cause profound changes in technology choice and behaviour, I focus here on compulsory policies (Goulder & Parry, 2008). A short description of the current compulsory policies in Canada is given below. Table 2.1. summarizes the policies.

Table 2.1. Summary of current compulsory climate policies in Canada

Policy	Jurisdiction	Sector	Policy Type
Performance standard on coal-fired electricity regulation	Federal	Electric utilities	Command and control/performance standard
Light-duty vehicle regulation (one and two)	Federal	Personal transport	Tradable performance standard
Heavy-duty vehicle regulation	Federal	Freight transport	Tradable performance standard
Ontario coal phase-out	Provincial	Electric utilities	Command and control
B.C. carbon tax	Provincial	All	Carbon tax
B.C. clean electricity regulation	Provincial	Electric utilities	Command and control
Alberta Specified Gas Emitters Regulation	Provincial	Large industrial emitters	Performance standard/carbon pricing/non-compulsory offsets
Quebec cap-and-trade	Provincial	First large emitters, later expanding to all sectors	Cap-and-trade

Federal policies

Federal performance standard for coal-fired electricity generation

Coal-fired electricity generation accounts for 73% of total electric utilities emissions and 13% of total nationwide emissions, while generating only 17% of all electricity (Canadian Senate, 2012). The government has introduced a regulation that requires coal-fired electricity generation plants built after 2015 to not emit more than 420 kg/CO_2e per megawatt hour (MWh), a level comparable to efficient natural gas combined cycle plants (Environment Canada, 2012c). In comparison, conventional coal-fired electricity plants generate between 750 and 1,200 kg CO_2e/MWh (GEA, 2012; IEA, 2010b). This, in effect, means that no new coal-fired plants will be built after 2015 unless they incorporate carbon capture and storage technologies (CCS) or co-fire significant quantities of biomass in their fuel mix. Existing plants are allowed to keep operating for their useful economic life, deemed by Environment Canada to be 50 years from the date of construction. Under this regulation, it is expected that about one-third of Canada's 51 currently operating coal power plants will need to be modified (with CCS) or shut down by 2025 (Environment Canada, 2012c).

If this regulation remains the only one affecting coal-fired power, it is possible that Canada will still have at least one coal-fired power plant operating with full emissions as late as 2060. Alberta's Keephills 3 coal-fired power plant commenced operation in 2011 (Trans Alta, 2012).

To increase flexibility of the policy and thus decrease costs, the federal government has agreed to negotiate equivalency agreements with several provinces. Nova Scotia has already agreed on an equivalency agreement (Environment Canada, 2012d). Saskatchewan and Alberta have expressed interest in exploring this possibility. As such, the final regulation may vary from one province to the other, but would presumably have the same emissions outcome as the initial federal proposal.

Light-duty vehicle regulation

The federal government has had vehicle efficiency regulation since the 1970s. To help combat climate change, the Canadian government recently strengthened these with Light-duty Vehicle Regulation One for model years 2012 to 2016 and Light-duty Vehicle Regulation Two for model years 2017 to 2025. The regulations focus on improving the fuel efficiency of the personal vehicle fleet. Under the former policy, the average fuel efficiency is expected to improve by 15% between 2010 and 2016. The latter policy requires more significant increases in fuel efficiency, with an average improvement of 5% per year from 2017 to 2025 for cars and of 3.5% per year from 2017 to 2021 and then 5% per year from 2022 to 2025 for light trucks. The regulations will improve the fleet-wide average fuel economy by an estimated 57% from 2010 to 2025 (Environment Canada, 2012e). By 2025, the Corporate Average Fuel Economy (CAFE) is expected to reach an equivalent of 4.3 l/100 km gasoline or 103 g CO_2e/km (if the regulation is met only by fuel economy improvements). The light-duty vehicle regulations basically copy U.S. regulations over the same model years, which were announced before those of the Canadian government.

Heavy-duty vehicle regulation

In spring 2013, the Canadian government announced additional regulation on heavy-duty freight transportation for model years 2014 to 2018. Fuel efficiency of new heavy-duty freight trucks is set to increase, on average, from 2.5 l/100 tonne-kilometre to 2.1 l/100 tonne-kilometre by the end of the regulatory period. For model year 2018, GHG emissions are to decrease by up to 23% per tonne-kilometre travelled compared to before the regulatory period (Environment Canada, 2013b).

Provincial policies

Ontario coal phase-out

Ontario has been actively pursuing a province-wide coal-fired electricity generation phase-out for over a decade due to climate and local air quality concerns. A complete phase-out was initially planned for 2007 and a new target was set for 2014. In 2012, the year with the last available information, coal-fired electricity accounted for less than 3% of Ontario's generation, a significant decrease from a level of 25% as recently as 2003. (Ontario Ministry of Energy, 2013).

B.C. carbon tax

British Columbia introduced a carbon tax in 2008. Initially, the tax started at \$10/t-CO_2e. Over the next four years the tax increased by \$5/t-CO_2e per year to its current level of \$30/t-CO_2e, reached in 2012 (B.C. Ministry of Finance, 2013). At this rate, the tax increases the cost of regular gasoline by 6.7 ¢/litre. The tax is designed to be revenue neutral. The revenue gained is offset by income tax cuts and tax rebates. Although the tax is generally perceived to be economy-wide, it is placed only on combusted sources of GHG emissions, which account for approximately 75% of B.C.'s total emissions. Emissions from other sources, such as venting of GHGs in the natural gas industry or fugitive emissions in the agricultural and waste sectors, are not covered. A recent report by Sustainable Prosperity (2013) found that the B.C. carbon tax was key in decreasing B.C'.s fuel consumption by 17% per capita compared to the rest of Canada.

B.C. clean electricity regulation

In 2010, the B.C. *Clean Energy Act* required that 93% of all new generation must be from net zero-emission sources (B.C. Legislature, 2010). This bill simply put in legislation what had already been a provincial government mandate since January 2007 for the public electric utility monopoly, BC Hydro. Fossil fuel-powered plants utilizing carbon capture and storage (CCS) are allowed, while nuclear power plants are not. Recently, the B.C. government declared burning natural gas to create electricity for the LNG industry to be included within the definition of clean energy, and therefore eligible for inclusion in the 93% of zero-emission sources.

Alberta Specific Gas Emitters Regulation

Since 2007, Alberta's Specific Gas Emitters Regulation (SGER) has required that large industrial emitters with annual emissions over 100,000t-CO_2e decrease their emission intensity 12% below a 2003–2005 reference level by 2012. Firms can comply in three different ways: through direct reductions; by purchasing offsets in Alberta; or by paying into a technology fund at a rate of \$15/t-CO_2e for non-compliant emissions. As the policy applies only to emission intensity rather than absolute emissions, only a small portion of the absolute emissions is effectively priced. With intensity improvements, total emissions from industry could increase significantly from increased output and not be priced. As such, the policy may have little effect in slowing the growth in emissions-intensive industries (Alberta Ministry of Environment and Sustainable Resource Development, 2012).

The average carbon price of the SGER can only be estimated, since some industry reductions are cost-effective and would occur anyway. The policy would have its highest average price of \$1.80/t-CO_2e (12% * \$15/t-CO_2e) if industries achieve no cost-effective intensity improvements (Pembina Institute, 2012). The policy's average price on carbon emissions could be zero if the required 12% intensity reduction is less than what would have happened through cost-effective technological changes. Given that industries have paid into the technology fund for excess emissions, the policy must have had some effect. However, the average carbon price would likely still be below \$1.80/t-CO_2e.

Quebec cap-and-trade system

In 2011 Quebec adopted the Quebec Cap-and-Trade System for Greenhouse Gas Emission Allowances, which became effective January 1, 2013. The first compliance period, lasting to late 2014, covers large emitters with emissions over 25,000 Mt CO_2e. Free emission allowances are awarded for companies based on past production volume and emission intensity. Extra permits could be purchased at a minimum price of \$10.75/t-CO_2e in 2013, increasing by 5% per year plus inflation to 2020 (Government of Quebec, 2014).

Starting in early 2015, businesses that distribute fossil fuels with associate emissions over 25,000 Mt CO_2e will be included in the policy, broadening the coverage of the policy significantly. About 80% of provincial emissions will then be covered by the policy. Furthermore, starting in 2015, the number of free emission permits allocated will decrease between 1% and 2% per year. The system is designed to allow Quebec to participate in evolving carbon markets; the Quebec cap-and-trade system is harmonized with California's cap-and-trade system and will allow their markets to link up (Government of Quebec, 2014). The initial cost impacts of Quebec's cap-and-trade system will be low, with a low average price on emissions. However, the province is implementing a compulsory policy that covers a large amount of provincial emissions and gradually increases the policy's effective carbon price, creating an incentive for future reductions. Furthermore, by harmonizing with California's system, Quebec is linking to one of the most significant climate policies in North America.

2.6. Introduction to energy-economy models

Policy makers seek to know how a certain climate policy may impact the economy, the environment and society at large. Energy-economy models can help with this question. They can be grouped based on their representation of (1) behavioural realism, (2) macroeconomic feedbacks and (3) technological explicitness.

Top-down models

Top-down models estimate aggregate relationships between inputs and outputs in the economy. Inputs are characterized by their costs and degree of substitutability with each other. Elasticity of substitution (ESUB) parameters reflect how the shares of inputs change as their relative prices change. ESUB parameters are estimated from a combination of observed past behaviour and expert judgment (Bataille et al., 2006). Some top-down models also include macroeconomic feedbacks, such as computable general equilibrium models (Bergman & Henrekson, 2003; Chapman, 2007). They may include endogenous or exogenous technical changes. The autonomous energy efficiency index (AEEI) parameter is an example of exogenous technical change, as the model user sets its value to determine the rate of energy efficiency improvements of the capital stock over a period of time, independent of price changes. One issue with top-down models is that they tend to lack technological detail.

Bottom-up models

Bottom-up models are technologically explicit, meaning that they include a variety of current and potential energy-related technologies that can be substituted for one another. Bottom-up models are often solved using optimization algorithms, designed to satisfy a certain goal, such as delivering energy at the lowest cost, under a few constraints like environmental performance and social viability (Chinneck, 2001). A weakness of many bottom-up models is their lack of representation of behaviour economic feedbacks and intersectoral linkages. For example, many bottom-up models may miss economic feedbacks such as the rebound effect, in which reduced energy costs due to efficiency result in a higher demand for certain energy services (Owen, 2010). Furthermore, bottom-up models often consider just financial costs. In reality, new technologies often have intangible costs that make them more or less desirable to firms and consumers. New technologies may not provide the same quality of service, may be more risky investments, or have longer payback periods. By overlooking these important implications, bottom-up models can overestimate the benefits or underestimate the costs of certain policies (Murphy & Jaccard, 2007).

Hybrid models

As the limitations of one model type tend to represent the strength of the other, significant efforts have been made in combining the technological explicitness of bottom-up models with the behavioural realism and economic feedbacks of top-down models. Such models are known as hybrid models (Jaccard, 2009).

Murphy and Jaccard (2011) compared the modelling results from a bottom-up model and a hybrid model for the same climate policies (McKinsey & Company, 2009). Their findings showed that the bottom-up model underestimated the cost of climate policy and overestimated the benefits of energy efficiency investments.

3. Methodology

In this section I describe the methodology of this project. In Section 3.1., I briefly discuss the CIMS model and how it relates to the project. In Section 3.2., I discuss the modelling methodology of current provincial and federal climate policies. In Section 3.3., I discuss the modelling methodology and assumptions of the study's domestic sector-specific regulatory package. In Section 3.4., I assess the impacts of the sector-specific regulatory package and international climate efforts on the oil sands.

3.1. Introduction to the CIMS model

The model I used for this project is the CIMS model, a hybrid energy-economy model that is technologically explicit, behaviourally realistic, and includes partial equilibrium feedbacks (Jaccard, 2009). CIMS is used and maintained primarily by the Energy and Materials Research Group (EMRG) at Simon Fraser University and the Navius Research consulting company. CIMS has been used widely in the analysis of both federal and provincial policy. For example, CIMS was used to assess the feasibility of federal climate goals and how to achieve them and to verify B.C.'s Climate Action Plan (NRTEE, 2007, 2009; B.C. Government, 2008).

CIMS simulates the evolution of the energy capital stock over time through retirement, retrofitting and new capital acquisitions. CIMS can be used to model the Canadian energy-economy system to 2050 in five-year intervals, under business-as-usual (BAU) and policy scenarios. The model includes a rich representation of technologies, much like a traditional bottom-up model. Technologies compete for market share, based on the relative life cycle costs of each technology, to satisfy demand for different energy services. The calculation of the life cycle costs for certain technologies includes financial and non-financial (or intangible) costs, such as consumers' preferences, risk aversion to new technologies and aversion to long payback periods. The inclusion of non-financial costs distinguishes CIMS from conventional bottom-up models. Equation 2.1 demonstrates how CIMS determines the technological market share of the capital stock.

Equation 3.1. How CIMS simulates the competition between energy service technologies

$$MS_j = \frac{\left[CC_j * \frac{r}{1-(1+r)^{-n_j}} + MC_j + EC_j + i_j \right]^{-v}}{\sum_{k=1}^{K} \left\{ \left[CC_k * \frac{r}{1-(1+r)^{-n_k}} + MC_k + EC_k + i_k \right]^{-v} \right\}},$$

MS_j represents the market share, CC_j is the capital costs for technology j, MC_j is its maintenance and operations costs, EC_j is the energy cost, r represents the time preference for decision makers for a certain energy demand, i_j represents all intangible costs, and the v parameter represents heterogeneity in the market in which different consumers and firms experience different life cycle costs. (Jaccard, 2009)

Although CIMS includes market feedbacks, the model does not have complete market equilibrium capabilities that top-down models such as computable general equilibrium models have. Thus, CIMS is a partial equilibrium model that balances only the demand and supply for energy services, including demands for mobility and some industrial production.

The primary limitation of CIMS for this exercise is the model's lack of an endogenous representation of the global oil market. As such, CIMS is unable to assess the price for petroleum products under global climate policies. This must be estimated from other global energy-economy models for the Canadian-focused policy analysis in this study.

Another limitation of CIMS is the lack of complete equilibrium capabilities. CIMS will under-represent, perhaps significantly, the macroeconomic effects of carbon prices on the Canadian economy. CIMS achieves emission reductions primarily from technology switching, as it does not adequately account for the structural changes to the economy (through trade and consumption) and the impacts on total output (through slower economic growth) that higher energy prices will cause. As such, the model may underestimate emission reductions from carbon pricing simulations compared to what is likely in the real world. To overcome this challenge, CIMS could be linked with a full computable general equilibrium model as in Peters et al. (2010).

Assumptions on activity levels in the CIMS model

The output of the model is highly dependent on assumptions of the future activity levels in the various economic sectors. This study uses activity forecasts from the NRTEE (2012). Table 3.1. summarizes the activity levels for several key sectors used in this exercise.

Table 3.1. Assumptions on Canada-wide activity levels in key sectors in CIMS

Sector (unit)	2010	2020	2035	2050
Residential (million households)	13.7	15.5	17.4	19.3
Commercial (million m^2 floor space)	730	899	1,141	1,324
Transportation Personal (billion pkt)	658	742	833	917
Transportation Freight (billion tkt)	874	1,126	1,407	1,610
Other Manufacturing (billion $ 2005 GDP)	151	223	291	332
Electricity (tWh)	552	656	772	861
Petroleum Crude Extraction (million bbl/day)	2.9	3.8	4.8	5.8

Source: NRTEE (2012). Pkt is person-kilometres travelled; tkt is tonne-kilometres travelled;
tWh is terrawatt hours

3.2. Modelling methodology for the BAU-POLICY simulation

To estimate the effectiveness of Canada's current climate policies, I designed the Business-as-Usual Policy (BAU-POLICY) simulation, which includes all current federal and provincial policy initiatives that are expected to result in considerable changes in GHG emissions. I compare this simulation with my Business-as-Usual (BAU) simulation, a hypothetical scenario in which no GHG policies would have been implemented in Canada. I explore the effectiveness of each policy included in the BAU-POLICY simulation to the 2020 emission targets. Cumulative impacts are explored to 2050. Following is a list of the policies included in the BAU-POLICY simulation:

- Federal performance standard for coal-fired electricity generation
- Federal Light-duty Vehicle Regulation One and Two
- Federal Heavy-duty Vehicle Regulation
- Ontario coal phase-out
- B.C. carbon tax
- B.C. clean electricity regulation
- Alberta Specified Gas Emitters Regulation
- Quebec cap-and-trade system

Although not a climate policy, I explore the GHG emissions impacts of Alberta's oil sands industry expansion, as well as the GHG emission impacts of three major pipeline proposals currently in the regulatory review process.[3]

Federal policy design

Federal performance standard for coal-fired electricity generation

As discussed in Section 2.1. the federal coal regulation seeks to prohibit the construction of new conventional coal-fired electricity plants after 2015. Existing plants, even ones constructed in the last decade, are allowed to keep operating until 50 years after construction. To model this policy in CIMS, I set the life expectancy of the historical stock (pre-2005 in CIMS) to be 45 years. The age of the historical stock is calibrated in CIMS to reflect the historical fleet. Similarly, I set the life expectancy of coal plants constructed between 2005 and 2015 to be 45 years.[4] I did not allow any new conventional coal plants to be built after 2015. As noted previously, several provinces that use coal-fired electricity generation have or are negotiating agreements on equivalency. However, they were not in place at the time of this analysis and thus are not included in this study, and they would have the same effect on emissions, in any case. The federal regulation is modelled in all provinces that use coal. The exception is Ontario, which is expected to have completed its coal phase-out by the time the regulation takes effect.

3 TransCanada Keystone XL, Enbridge Northern Gateway and Kinder Morgan Trans Mountain

4 The latest draft for the federal coal regulation states a "useful economic life" of coal plants as 50 years. I chose to model 45 years, as this was the original proposition.

Federal Light-duty Vehicle Regulation One and Two

I rely on an Environment Canada study (2012a) that has modelled this policy in detail, and match their forecasted emission reductions. Environment Canada found that the Light-duty Vehicle Regulation One, which requires manufacturers to increase the fuel efficiency of new vehicles, will result in annual emission reductions of 9–10 Mt CO_2e by 2020 compared to before the regulatory period. Additionally, Light-duty Vehicle Regulation Two for model years 2017–2020 will result in another 2–3 Mt CO_2e of emissions abatement. Combined, total abatement is estimated to be between 11–13 Mt CO_2e. In this study, I assumed a reduction of 12 Mt CO_2e by 2020 from 2005 levels. To achieve targeted abatement by 2020, I increased the market share of high-efficient gas and diesel, hybrid, plug-in hybrids (PHEV) and zero-emission vehicle (ZEV) technologies until the emission reductions reached 12 Mt CO_2e below 2005 levels by 2020 for this sector. As such, I adjusted the market share of more efficient and less emitting vehicles to match projected emission reductions from the Environment Canada forecast. By using this method, I do not constrain the model's ability to simulate different vehicle stock outcomes for different climate policies.

Federal Heavy-duty Vehicle Regulation

In modelling the federal regulation on heavy-duty freight transport, I faced similar constraints as for the light-duty vehicle regulations described above. Environment Canada (2012a) forecasts heavy-duty freight emissions under the regulation to increase from 56 Mt CO_2e in 2005 to 67 Mt in 2020. To match this in CIMS, I increased the market share of efficient technologies to achieve similar increases. Total activity in this sector is set to increase by 23% between 2005 and 2020 in CIMS.

Environment Canada (2012a) groups freight transport emissions differently than they currently are in CIMS. I chose to match absolute emission reductions, which results in a more stringent policy in CIMS compared to Environment Canada's forecast.

Provincial policy design

Ontario coal phase-out

In the Ontario region, I set coal generation for peak and shoulder load at zero as early as 2010, while coal for base generation was eliminated completely by 2015 for the simulation period. This is consistent with the recent and required decline of coal-fired electricity generation over this period (Ontario Ministry of Energy, 2013).

B.C. carbon tax

Because CIMS only operates in five-year increments, I set its B.C. carbon tax at \$20/t-CO_2e in 2010 and increased it to \$30/t-CO_2e in 2015, holding at this level thereafter. I placed the carbon tax only on fossil fuel combustion.

B.C. clean electricity regulation

B.C'.s clean electricity regulation states that 93% of new sources of electricity must emit no net GHG emissions. To simulate this regulation in CIMS, I made conventional fossil fuel generation unavailable after 2010. The representation of this regulation may need to be revised in future studies, as the B.C. government has declared that burning of natural gas for electricity used by the LNG industry would be in compliance with the law.

Alberta Specified Gas Emitters Regulation

Alberta's Specified Gas Emitters Regulation (SGER) is a complex policy in that it is intensity-based and applied only to large emitters above 100,000-t CO_2e/year. As the specifics of this policy are difficult to model in CIMS, I used estimated emission reductions reported by Alberta Ministry of Environment and Sustainable Resource Development (2012) as a guide in the setting of a low carbon tax on all Alberta industrial emissions. The level of the carbon tax required to achieve these reductions gives insights into the stringency and future effectiveness of the policy.

Alberta Ministry of Environment and Sustainable Resource Development states that 2011 reductions of the SGER were 6.5 Mt CO_2e. Of this total, 0.68 Mt CO_2e reductions came from improvements in operations, 3.86 Mt were from offsets purchased, and 1.96 Mt were from emission performance credits generated (Alberta Ministry of Environment and Sustainable Resource Development, 2012). To account for free riding, I consider the actual emission reductions achieved from the offsets and emission performance credits to be only 50% of their total claimed (Grosche & Vance, 2009). This gives an emission reduction of 3.6 Mt CO_2e. To model this policy, I apply an industry carbon tax from 2010 to 2020 at a level that achieves reductions of 4 Mt CO_2e by 2015. The rationale for keeping the tax constant is that I assume that the stringency of the policy will not change.

Quebec cap-and-trade system

I simulate Quebec's cap-and-trade system by applying a carbon price on all combusted emissions starting in 2015 and increasing gradually to 2020, that achieves emission reductions of 5%, or 4.5 Mt CO_2e, between 2015 and 2020. This reduction is within the range, albeit at the low end, of the planned reductions in free emission permits granted; Quebec plans to decrease free permits by 1–2% per year between 2015 and 2020 (Government of Quebec, 2014). I will apply a minimum price of \$12/t-CO_2e, as this is the floor price set for emission permits by the Government of Quebec.

Assumptions for oil sands growth

The rate of bitumen production is set exogenously in CIMS. As I noted in Section 2.2. oil sands production forecasts range widely. I took a median forecast based on the NRTEE (2012). However, this production forecast is considerably lower than forecasts by the petroleum industry and from other government agencies (CAPP, 2013; CERI, 2012).

Three major pipeline proposals are currently in some stage of the regulatory review process: Trans Canada's Keystone XL with a capacity of 830,000 bbl/day; Enbridge's Northern Gateway with a capacity of 525,000/bbl/day, and Kinder Morgan's Trans Mountain Expansion, with an additional capacity of 590,000 bbl/day (CERI, 2012). I assess the emission impacts of each level of pipeline development.

Without additional pipeline infrastructure, pipelines will be nearing capacity by 2015 to 2020, with a likely effect of slowing bitumen production (CERI, 2012). As recent growth in rail transport of diluted bitumen has shown, zero growth in pipeline capacity will not completely prevent growth in bitumen production. Nonetheless, when industry and government forecasts refer to a doubling or tripling oil sands production, all include the assumption that this will entail a significant increase in pipeline capacity, especially the construction of the three projects on which I have focused my analysis. Therefore, in my simulations I make the simplifying assumption that without the three pipelines, oil sands growth will not grow after 2015. The construction of Keystone XL will facilitate Alberta crude expansion by an assumed 750,000 bbl/day, 80,000 bbl/day less than the stated pipeline capacity. The other 80,000 bbl/day are assumed to be used to transport increasing production from North Dakota's Bakken Formation (CAPP, 2013). The Northern Gateway and Trans Mountain Expansion projects are assumed to increase bitumen production by their total stated capacity. All oil sands emissions will be modelled under Alberta's Specified Gas Emitters Regulation described above. Table 3.2. summarizes the capacity and the bitumen production growth facilitated by each of the three pipelines.

Table 3.2. Pipeline capacities and bitumen production facilitated

Pipeline	Total capacity (bbl/day)	Oil sands production modelled (bbl/day)
Keystone XL	830,000	750,000
Northern Gateway	525,000	525,000
Trans Mountain Expansion	590,000	590,000

Data obtained from CAPP, 2013

It should be noted that in this analysis, results for Alberta's crude extraction sector are reported in aggregate unless specifically mentioned otherwise. As such, production and emission values include both conventional oil and oil sands.

Additional policies if the 2020 climate target is not achieved

The BAU-POLICY simulations explore whether current policies achieve the country's 2020 target. If they fail to do so, I ran additional simulations with an economy-wide emissions price, simulating an economy-wide cap-and-trade system, added to the other policies until I found the price that achieved the targets. I call this policy the Business-as-usual Policy Plus Cap-and-Trade simulation (BAU-POLICY+C&T). Additional policies to meet the 2050 target are discussed in Section 3.3.

Excluded policies and infrastructure investments

In this exercise I include only compulsory policies that have been passed into law or proposed in detail by Canadian governments. Announced policies that have not been made public, such as the long-anticipated federal regulation on the oil and gas sector, are ignored. Similarly, I include only major industrial projects that are in the review process and have a high certainty of investment funding. Potential developments such as British Columbia's plans to develop its LNG industry, which will have significant GHG implications, are not included. Their implications for the 2020 and 2050 targets could be explored in future studies when more details become known.

3.3. Modelling methodology for the Sectoral-Reg+C&T approach

The Canadian government has repeatedly committed to its medium- and long-term climate targets and to its claim that it will achieve these with sector-specific regulation. However, with the exception of new coal plants and vehicles, it has yet to provide details, and eight years have now passed since it initially announced its commitment to using this approach to achieve its targets. At the request of the Canadian government, the NRTEE, an advisory body, produced two reports on how the 2050 target could be achieved. In one report, the NRTEE (2007) proposed an economy-wide cap-and-trade system. In the second report, it combined this with a package of sector-specific regulations in keeping with the policy prescriptions of the federal government. However, in 2012 the government eliminated the NRTEE. Since the NRTEE's two reports, there has been no independent or government attempt to show how its emission targets for 2020 and 2050 could be achieved, whether using carbon pricing policies (carbon tax, cap-and-trade) or its preferred regulatory approach. In this study, my goal is to provide an independent assessment of how it might achieve its goals.

The policy package I test is a mix of sector-specific regulation and market-based instruments. As such, it incorporates the government's favoured regulatory approach, but doesn't rely entirely on it. I refer to it as the Sectoral-Regulation Plus Cap-and-Trade approach (Sectoral-Reg+C&T). The details of this policy package are based on my own choices, as the government has not yet provided detailed information on how it plans to proceed. I apply command and control regulations and tradable performance standards to sectors most exposed to domestic consumers, and a cap-and-trade system to the industrial sectors. The former will be referred to as the domestic consumption sectors, while the latter will be referred to as the industry sectors. My goal is to create a balanced approach that considers the political and economic constraints to climate policy while also addressing the policy preferences of the Canadian government. The list below describes the various economic sectors in the domestic consumption and industry sectors.

Domestic consumption sectors:

- Personal Transport
- Electricity Generation
- Residential Buildings
- Commercial Buildings

Industry sectors:

- Freight Transport
- Chemical Products
- Industrial Minerals
- Metal Smelting
- Mineral Mining
- Paper Manufacturing
- Other Manufacturing
- Agriculture
- Waste
- Petroleum Refining
- Petroleum Crude Extraction
- Natural Gas Extraction
- Coal Mining

Modelling methodology of the domestic consumption sectors

I combine a mix of command and control regulations and tradable performance standards to the domestic consumption sectors. The choice of policy and its rationale for each sector are described below.

Zero-emission electricity regulation

I applied a 100% zero-emission electricity regulation similar to what currently exists in the province of B.C. (at a 93% level). Under this regulation, no new conventional fossil fuel-powered electricity plants can be built. Projects that integrate CCS are permitted, as I consider them zero emissions. I let existing fossil fuel electricity plants keep operating for their normal economic life.

Zero-emission residential and commercial building regulation

I applied to the residential and commercial building sectors a zero direct-emission heating, ventilating and air conditioning (HVAC) regulation. Similarly to the electricity sector, I allow only non-emitting technologies for new investments, such as electric baseboard heaters, electric heat pumps and electric air conditioners, among others. Existing capital keeps operating for its useful economic life. I chose to include the commercial sector in this group because I assume that small/retail businesses prefer regulation rather than joining a cap-and-trade system, which can have considerable transaction costs.

Zero-emission vehicle tradable performance standard

In the personal transportation sector, I set what I call a zero-emission vehicle (ZEV) tradable performance standard. I chose this approach as this sector faces multiple constraints. Policies can be highly visible to the general consumer, leading to push-back against policies that impose costs. This favours regulations, as the cost increase is less visible to consumers (Linares & Labandeira, 2010). The sector also faces relatively high abatement costs compared to some other regulated sectors. Policy makers are therefore also motivated to pursue market-oriented policies, since these can decrease, to some extent, the costs of abatement (Aldy et al., 2010). To balance these two considerations, I apply a tradable performance standard that does not impose an outright ban on traditional gasoline and diesel vehicle technologies, and allows trading between companies. The ZEV standard requires vehicle retailers to achieve an increasing market share of low-, ultra-low and zero-emission technologies until the chosen emission reduction target is met. Hybrid and plug-in hybrid vehicles are classified as low- and ultra low-emission vehicles. Electric, biofuel and fuel cell vehicles are classified as zero-emission vehicles. I chose an emission reduction target for this sector of 65% below today's level by 2050, which is equal to the national target for the entire economy.

Modelling methodology for the industry sectors

To businesses in the industry sectors I apply a cap-and-trade policy. The cap-and-trade system exposes the businesses to a price on GHG emissions, this being the emission permit trading price. The industry group as a whole is allowed to emit the difference between the domestic consumption sectors' emissions and the country's emission targets. The price starts at a low level in 2015 and is increased until emissions are constrained to the desired level.

I chose the cap-and-trade policy due to its economic efficiency from setting an equal price on GHG emissions across all industries. This could also have been achieved through a carbon tax. However, for this simulation (and for all other simulations in this study that require an efficient carbon policy), I opted for a cap-and-trade system because (1) Prime Minister Stephen Harper has publicly supported this approach in the past, and (2) other federal opposition parties consider a cap-and-trade as their preferred approach for pricing emissions.

Modelling assumptions for the Sectoral-Regulation Plus Cap-and-Trade

I made several important modelling assumptions for the Sectoral-Reg+C&T approach. In the industry cap-and-trade, Alberta crude extraction is not allowed to grow past 2015. The rationale for this is that Canada will not act alone in addressing the climate change issue, but rather work in concert with the international community. This will influence the viability of oil sands production, due to the decreased demand for petroleum in the future. In this project, I take a middle ground between Chan et al. (2012), who predict that under climate constraints, oil sands will be driven out of the market over the next few decades, and the IEA, who predict under their 450 ppm scenario that oil sands projects that are currently existing, under development, and already approved will be developed and remain operating until 2030 at least. I fix Alberta crude oil output at 2015 levels of 2.9 million bbl/day, and hold it at this level to 2050. Currently, oil sands represents almost 2 million bbl/day. A more thorough assessment of oil sands under climate constraints is undertaken in Section 3.4.

I chose to include the agriculture sector in the industry group as it is a large emitter in absolute terms. However, in my simulation I have created a subsidy to farmers. Farmers will be required to cover only half of their emissions in the cap-and-trade regulation, cutting the costs of emission compliance in half. The rationale is that emissions from agriculture are difficult to monitor, emission abatement opportunities from this sector are more limited, and co-operation will be required in the early stages of climate policy implementation

3.4. Modelling methodology for Alberta's oil sands industry under climate constraints

In a world that acts to limit climate change, Alberta's oil sands industry will face cost increases from domestic climate policy and receive a lower price for its fossil energy products. The domestic cost increases depend on the Sectoral-Reg+C&T industry cap-and-trade system described in Section 3.3. For the oil price, two scenarios are explored. The first is a high oil price scenario, which is based on a forecast by the IEA's World Energy Outlook (IEA, 2012). The second is a lower oil price scenario based on the rationale presented in Section 2.2. namely, that a falling global demand for oil will lead to a falling international oil price.

Cost increases from domestic policy

In my simulation, I regulate Alberta's bitumen industry under the cap-and-trade system in the Sectoral-Reg+C&T approach. Under the cap-and-trade system, emissions from the bitumen industry will represent a cost. To decrease this cost, the industry will have an incentive to decrease emissions. Emission reductions can come from improvements in operation, fuel switching and from CCS. I explore only emission abatements from CCS as this has a great potential.

The many different technologies involved in bitumen production—from mining and in-situ bitumen extraction to upgrading and others—have different capacities to incorporate CCS technologies into their operations. Bitumen upgrading is an ideal candidate for employing CCS technology due to high concentrations of CO_2 in the flue gas. Estimates for the cost of capture vary. Lutes (2012) assumes \$29/t-CO_2e capture costs for upgrading. Transportation and storage add to the costs. I assume a value of \$40/t-CO_2e avoided for CCS from bitumen upgrading, based on Chan et al. (2012). SAGD in-situ bitumen extraction has higher projected CCS costs because facilities are usually relatively small and dispersed. Furthermore, the flue gas concentration of CO_2 is relatively low, ranging from 3.5% to 9.2% (Ordorcia-Garcia et al., 2011). Lutes (2012) estimates the costs of CCS in SAGD operations to be \$235/t-CO_2e avoided, a value I use in this exercise. I consider mining unsuitable for CCS.

Emissions also vary among bitumen extraction technologies. Table 3.3. summarizes the emissions and the availability and the costs of CCS for various bitumen extraction technologies.

Table 3.3. Emission factors and CCS costs for different oil sands production technologies

Technology	CO_2e (t/bbl)	CCS available	CCS costs (\$/t)
Mining	0.029	No	NA
Upgrading	0.085	Yes	40
In-situ	0.091	Yes	235

From Chan et al. (2012) and Lutes (2012)

For my calculations I assume that a given CCS operation captures 90% of the potential GHG emissions. In addition, I assume an energy penalty of 10% for CCS in oil sands operations. This is based on research by Rubin et al. (2007), who find a 10% energy penalty for a 90% capture rate optimistic in power plants (I could not find specific estimates on the energy penalty for oil sands operations). Furthermore, I assume that no market value exists for the captured CO_2 from CCS in the long term.[5] I do not include learning rates. These could decrease the costs of CCS with increased time and experience of using this technology.

Equation 3.1 explains the per-barrel cost increases from climate policy if CCS emission reductions are cheaper than purchasing emission permits. The emissions in

[5] In the short- to medium-term, CCS may offset some of its costs through selling CO_2 for enhanced oil recovery (EOR) and other uses. However, in the long-term carbon-constrained world, the quantity of captured CO_2 will greatly increase, depressing prices.

this equation result in 110% of the emissions from Table 3.3. This is due to the energy penalty discussed above. If the permit price is lower than the CCS costs, cost increases to producers are represented by Equation 3.2. Whichever value is lowest I add to the costs of each barrel of bitumen produced.

Equation 3.2. Increase in cost from using CCS

Cost increase = (process emissions * CCS costs) + .1 (process emissions * emission permit)

Equation 3.3. Cost of purchasing emission permits

Cost increase = (process emissions * emission permit)

In my simulation I consider only abatement options from CCS. Some lower-cost abatement options likely exist that industry would implement first. Furthermore, I designed the Sectoral-Reg+C&T simulation's cap-and-trade system to auction 100% of the permits. Cap-and-trade systems that issue free permits may reduce compliance costs to industry. As such, my assumptions and policy design may result in higher cost increases for the petroleum industry than would occur in real-world conditions.

Bitumen production costs

I took an approximate value based on three production cost estimates of new oil sands projects from the Canadian Energy Resource Institute (CERI, 2012), the Alberta Energy Resource Conservation Board (ERCB, 2011), and the National Energy Board (NEB, 2011). The cost estimates are based on producing a product equivalent to West Texas Intermediate. This equates different qualities of oil to a common commodity. As such, the heavy-light discount for non-upgraded products is included. Transportation and diluent costs are included as well. The costs are based on 30-year life cycle and include a real return on investment of 10%. Table 3.4. summarizes the different supply cost estimates.

Table 3.4. Various WTI-equivalent supply costs forecasts of new projects

Technology	CERI ($/bbl)	ERCB ($/bbl)	NEB ($/bbl)	Approximate median ($/bbl)
SAGD	65	47–57	50–60	57
Mining	82	63–81	65–75	75
Mining + Upgrading	91	88–102	85–95	91

Source: CERI, 2012; NEB, 2011; ERCB, 2011

The Canadian Energy Resource Institute includes the compliance cost of Alberta's Specified Gas Emitters Regulation, while the other reports do not. The SGER compliance costs are likely to be small and will disappear if the industry joins an absolute emissions cap-and-trade system. To account for this, I subtract the SGER compliance costs from the production costs forecast. The WTI-equivalent supply costs I use in this study are $56/bbl for SAGD, $74/bbl for mining, and $90/bbl for integrated mining and upgrading projects. Table 3.5. summarizes the costs of production. Costs are in constant 2010 Canadian dollars.

Table 3.5. Bitumen supply costs of new projects

Technology	Approximate media WTI-equivalent supply costs ($/bbl)	Current SGER emission charges ($/bbl)	Supply costs for study (WTI-equivalent $/bbl)
SAGD	57	0.60	56
Mining	74	0.40	74
Mining + Upgrading	91	0.65	90

Source: CERI, 2012; NEB, 2011; ERCB, 2011

Operating costs of existing oil sands projects

The impacts of a carbon-constrained world will be different for new versus existing oil sands projects, as the latter need only cover operating costs to stay solvent. Based on Levi (2009), I assume $35/bbl as the operating cost for existing oil sands operations. I assume the same WTI-equivalent operating costs for the three production types investigated: SAGD, mining and integrated mining and upgrading.[6] I will add compliance costs, determined by the Sectoral-Reg+C&T simulation's cap-and-trade, to existing projects as I do for new oil sands projects. As such, Equations 3.1. and 3.2. also determine the increases to the operating costs of existing oil sands projects.

World oil price in a future 2 ˚C world

I take future oil demand and oil price forecasts from global energy-economy modellers who test alternative targets for carbon pollution. In this analysis, the high oil price scenario is based on the 450 ppm scenario of the IEA's World Energy Outlook 2012 (IEA, 2012), which simulates a carbon emissions path with a significant likelihood of achieving the 2 ˚C limit. However, it only simulates to the year 2035, by which time the carbon price in the industrialized world must be \$90–120/t-CO_2e. The IEA predicts the price of oil to decrease linearly from \$112/bbl in 2012 to \$97/bbl in 2035 due to a demand decrease of 3.7% between 2010 and 2035. Assuming this trend is linearly continued to 2050, a price of \$87/bbl is calculated. The price is in constant 2010 U.S. dollars. It is possible that the oil price would fall to a much lower level in a world with forceful climate policies, especially since the relationship between demand changes and price tends to be non-linear, with small downward declines in demand capable of causing substantial decreases in price, as occurred in the global oil market in the period 1982–1988.

Thus, I also assess the economic impacts on oil sands production under a much lower oil price scenario, in which prices fall linearly from \$100/bbl in 2015 to \$40/bbl in 2025, and then stay at this level. The \$40/bbl level is based on the GEA (2012), which shows that plentiful oil and oil-equivalent supplies that would satisfy total cumulative consumption can be extracted below this price. This is similar to the world oil market experience through most of the 1960–1972 and 1986–2002 periods of surplus low-cost oil production capacity.

6 Non-upgraded projects will have lower operating costs than integrated mining and upgrading projects, but will also receive a lower value for the oil. The WTI-equivalent costs capture this dynamic and equate costs to the value of the product.

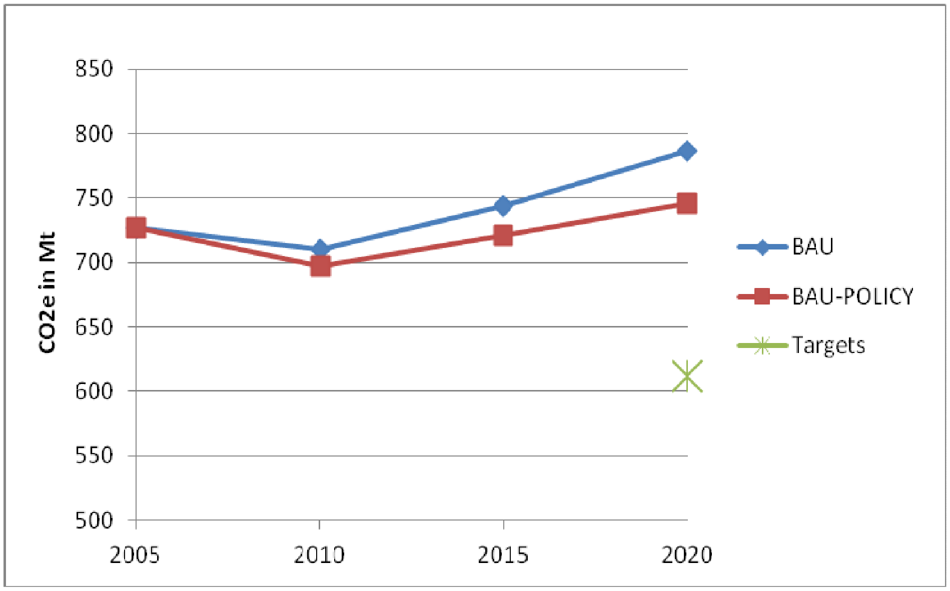
4. Results and Discussion

4.1. GHG mitigation from the BAU-POLICY simulation

Under the current policy simulation (BAU-POLICY), which estimates the ongoing effect of current federal and provincial climate policies, GHG emissions in Canada will drop from the BAU case. Emissions will reach 744 Mt CO_2e by 2020, 132 Mt above the climate targets. This is a decrease of 64 Mt CO_2e from the BAU simulation and 33% of the necessary reduction to achieve the country's targets. The estimated emissions in 2020 are 12 Mt CO_2e higher than recently predicted by Environment Canada (2013). It should be noted, however, that the Environment Canada report includes the Land Use, Land-Use-Change and Forestry sector—a sector I do not include in this simulation—which absorbs 28 Mt CO_2e of total emissions. Excluding this sector, emissions total 762 Mt CO_2e in 2020 for the Environment Canada study, 18 Mt more than my forecast using CIMS. Figure 4.1. shows the trend in emissions to 2020.

While emissions are lower with the BAU-POLICY compared to the BAU simulation, total emissions fail to decline from their 2005 level. Emissions in 2020 will be 2% higher rather than 17% below, as required under the Copenhagen commitment.

Figure 4.1. GHG emissions for the BAU and the BAU-POLICY simulation to 2020



By 2050, emissions under the BAU-POLICY simulation will increase to 778 Mt CO_2e, 90 Mt below the BAU simulation. Although this is a larger absolute reduction from the BAU case than in 2020, the level of emissions exceeding the target increases to 543 Mt CO_2e. This is a result of increasing emissions and a significantly more stringent emission target of 235 Mt CO_2e in 2050. Table 4.1. summarizes Canada's emission trends to 2020 and 2050.

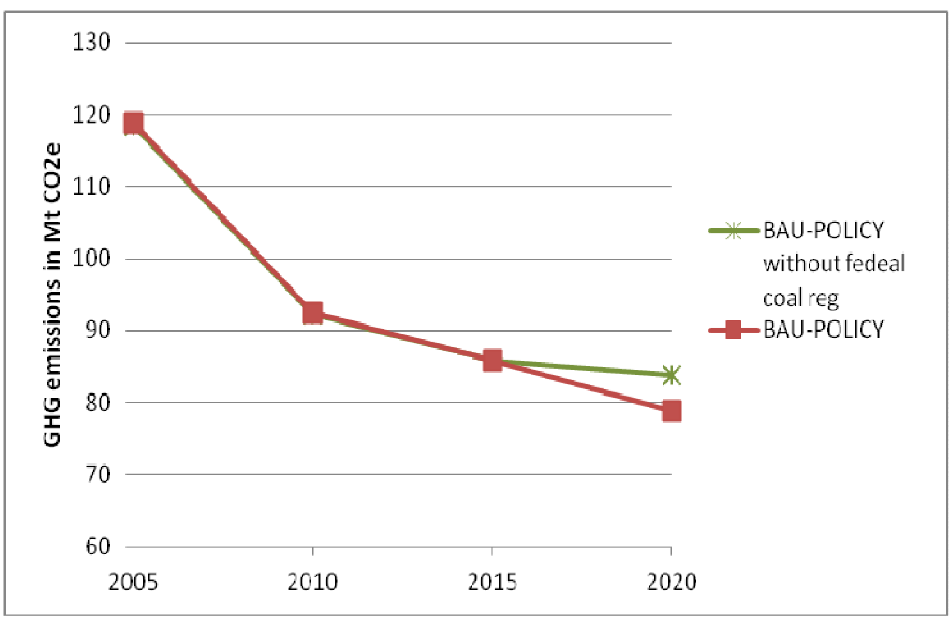
Table 4.1. GHG emissions by simulation (Mt CO_2e)

Simulation/Year	2005	2010	2020	2035	2050
BAU	735	727	808	836	868
BAU-POLICY	729	697	744	762	778
Emission Targets	731		612		235
Difference between BAU-POLICY and targets	NA		134		543

Federal emission performance standard on coal-fired electricity generation

To estimate the emission abatement from the federal coal regulation, I first modelled the BAU-POLICY to include all policies that impact the electricity sector. In this simulation, GHG emissions from the electricity sector decline from 119 Mt CO_2e in 2005 to 79 Mt by 2020. I then modelled the BAU-POLICY simulation without the federal coal regulation. Emissions decrease to 84 Mt CO_2e. As such, the federal coal regulation results in an incremental decrease of 5 Mt CO_2e by 2020. This is equivalent to the Environment Canada forecasts for this policy (Environment Canada, 2012a). The majority of the emission reductions relative to BAU in the electricity sector are not from the federal coal regulation. They are almost exclusively caused by provincial policies like Ontario's coal phase-out and British Columbia's clean electricity standard. Coal is a cheap source of energy. Without these provincial policies, new coal plants would likely have been built before the federal regulation becomes effective, and emissions in Canada would be much higher. Figure 4.2. summarizes the effects of the federal coal regulation to 2020.

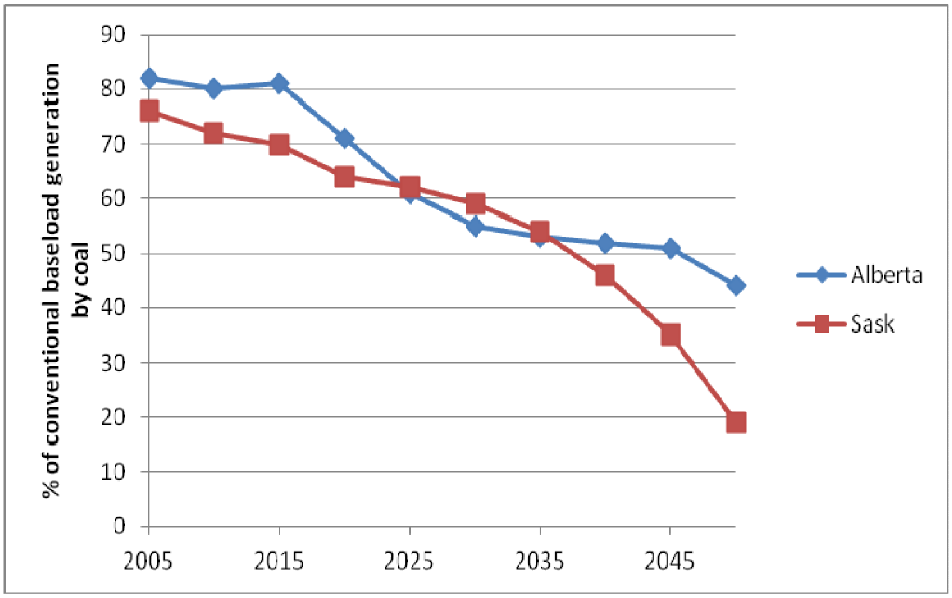
Figure 4.2. BAU-POLICY electricity sector emissions with and without federal coal regulation



As the federal coal regulation becomes effective in 2015, the policy contributes only in a limited measure to the country's 2020 targets. However, the policy becomes more significant over the longer term. Without any additional policies on the electricity sector, 2050 GHG emissions will decrease from the BAU simulation of 65 Mt CO_2e to 49 Mt due to this policy. It must be noted that it is difficult to determine attribution to emission reductions to the federal coal regulation, as several other policies, such as Ontario's coal phase-out and B.C.'s clean electricity regulation, were implemented earlier, and thus make the federal regulation superfluous in these provinces.

The longevity of coal plants, set by Environment Canada (2012a) at 50 years, portrays the slow capital turnover rate of electricity generation technologies. As such, under a policy that restricts new construction rather than phasing out existing conventional coal technologies, the importance of conventional coal-fired electricity will decline only gradually over the next four decades. Figure 4.3 shows the baseload contribution of coal-fired generation in Alberta and Saskatchewan, the two provinces with the highest reliance on coal. Under the federal coal performance standard, and assuming no additional policies will be enacted on the electricity sector, Alberta and Saskatchewan will still rely on conventional coal to satisfy 44% and 19% respectively of their baseload generation by 2050.

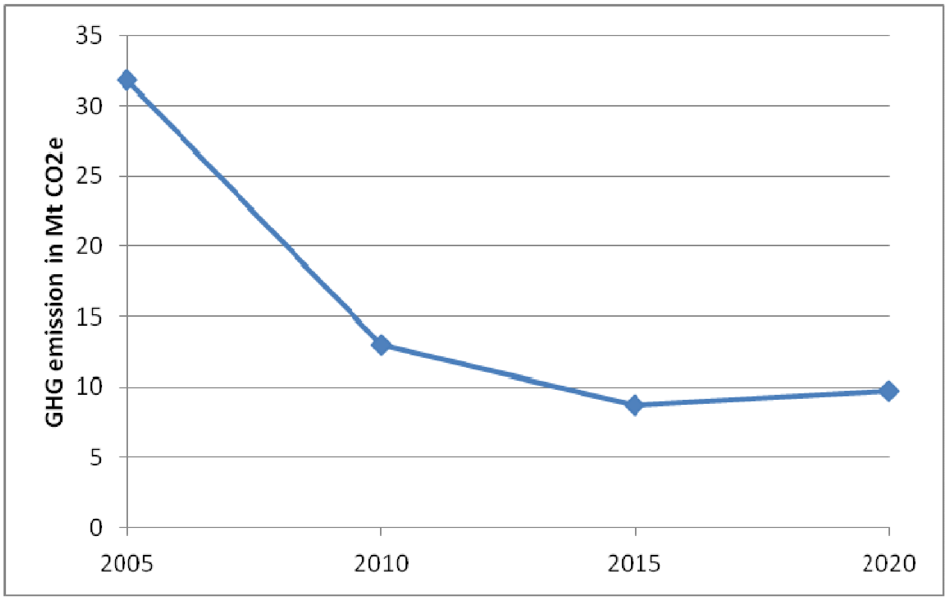
Figure 4.3. ***Percentage contribution by conventional coal-fired electricity generation to baseload in Alberta and Saskatchewan in the BAU-POLICY simulation***



Ontario coal phase-out

Ontario's coal phase-out reduces emissions in the electricity sector by 22 Mt CO_2e by 2020. This accounts for 34% of Canada's total emission reductions, significantly more than any other climate policy. Figure 4.4. shows Ontario's emissions between 2005 and 2020. Emissions drop dramatically over the period, showing only a small increase toward 2020 as new natural gas plants are installed along with renewables to meet growing electricity demand.

Figure 4.4. GHG emissions from Ontario's electricity sector



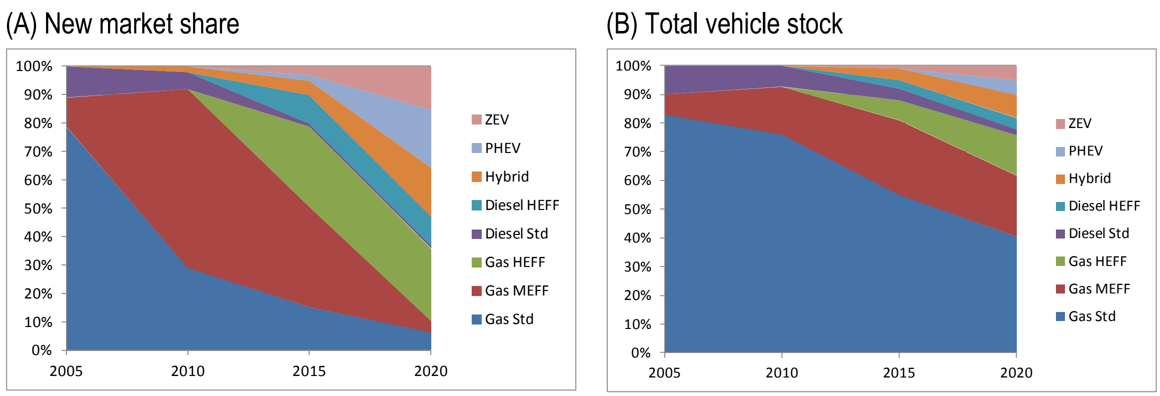
The stark contrast between a policy that prohibits the construction of new coal generation compared to one that actively phases out coal plants is evident when one compares Figure 4.4. with Figure 4.2., which showed the impacts of the federal coal-fired electricity regulation.

Federal light-duty vehicle regulation

Emissions from the personal transport sector will decrease from 92 Mt CO_2e in 2005 to 80 Mt in 2020. This drop will occur even though total person-kilometres travelled will continue to increase (NRCan, 2010). This is made possible by increasing the average fuel economy of the vehicle fleet and by a gradual shift to lower-emission vehicles.

I matched the 12 Mt CO_2e reduction forecasted for the federal light-duty vehicle regulations by Environment Canada (2012a) by decreasing the market share of less-efficient technologies and increasing the market share of more-efficient ones. Figure 4.5. (A) shows one plausible market share makeup that satisfies the regulation and is the one I used in the BAU-POLICY simulation. The figure shows that under the federal light-duty vehicle regulation, the new market share of standard efficiency gasoline technologies quickly drops and is replaced by medium- and high-efficient gasoline vehicles. Lower-emitting vehicles—such as hybrids, PHEVs and ZEVs—also become increasingly important as the regulatory period progresses and account for 50% of the new vehicle share by 2020.

Figure 4.5. New (A) and total (B) market share of personal vehicle technologies under the BAU-POLICY simulation



Note: All percentages are share of vehicle kilometres travelled, not actual market share of technologies. Gas Std is standard-efficiency gasoline; Gas MEFF is gasoline medium efficiency; Gas HEFF is gasoline high efficiency; Hybrid is hybrid with gasoline engine; PHEV is plug-in hybrid with gasoline, and ZEV is a zero-emission vehicle such as electric, fuel cell or biofuel.

Due to the 16-year average life expectancy of vehicles, the total market share lags changes in new market shares. By 2020, the total vehicle stock will be split between vehicles manufactured before and during the period covered by the light-duty vehicle regulation. Figure 4.5. (B) summarizes the total existing vehicle stock over the period from 2005 to 2020. The figure shows that standard-efficiency gasoline vehicles drop to 41% of the total vehicle stock, while medium-efficiency gasoline vehicles rise to a 20% market share. Newer technologies, such as hybrid, PHEV and EV, which increasingly become a more important part of the new market share in the later period, play only a minor role in the total vehicle stock by the end of the decade. In 2020, the combined stock of these technologies will be only 18%.

The federal light-duty vehicle regulation applies only to new vehicles. As such, it will take the total vehicle stock longer to achieve the regulation's demanded efficiency improvement, which is a 50% improvement for new vehicles by 2025. Considering a vehicle operating life of 16 years, and assuming no additional policies are passed, the vehicle stock will achieve only the 50% efficiency improvements by 2041. The federal light-duty vehicle regulations implemented by the Canadian government last year are presented as helping to meet the 2020 climate targets. While they do contribute, the full effect of the policies won't be felt for more than two decades after 2020.

It must be noted that these modelling results may overestimate the effectiveness of the policies. By regulating the fuel efficiency of new vehicles, thereby increasing purchase costs, the policy could incentivize vehicle owners to extend the life of older, less-efficient vehicles beyond the lifespan I set for my simulations.

Federal heavy-duty vehicle regulation

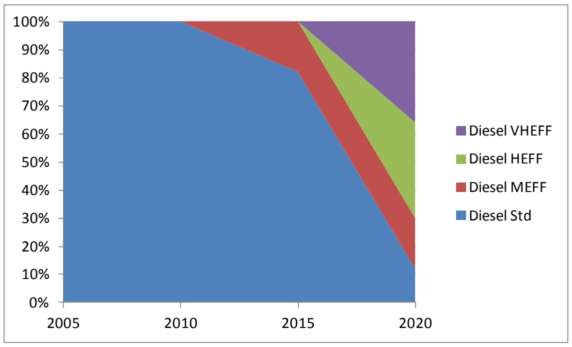
My simulation of the federal heavy-duty vehicle regulation in the BAU-POLICY simulation shows that emissions increase from 100 Mt CO_2e in 2005 to 113 Mt in 2020. Activity is set to increase by 23% over this period. The requirement for more-efficient technologies helps to decrease emission intensity, but fails to prevent rising total emissions due to increased transport of freight. The regulation decreases emissions 3 Mt CO_2e below the BAU simulation.

To match the Environment Canada (2012) forecast for this policy, I increase the market share of the most efficient technologies available after 2015. Figure 4.6. (A) presents one plausible market share makeup and is the one I chose in my BAU-POLICY simulation. The figure shows that as the regulation takes effect, the new market share of standard-efficiency diesel technologies quickly drops from 82% in 2015 to 12% by 2020. As the regulatory period progresses, the new market share quickly transitions to high- and very high-efficiency diesel engines. By 2020, these more-efficient technologies make up 70% of the new market.

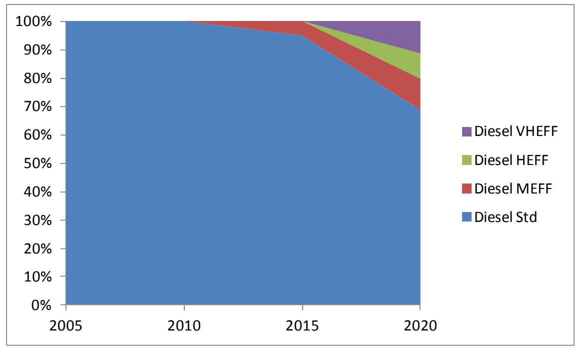
But as Figure 4.6. (B) shows, standard-efficiency diesel vehicles are still 68% of the total vehicle stock in 2020. Medium-efficiency diesel market share rises to 11% of the market during the regulatory period. High- and very high-efficiency diesel vehicles, technologies that dominate the new market share in the later period, contribute a combined 20% to the market by 2020. Again, the limited time during which the policy is effective and the slow capital stock turnover explain the regulation's limited effect to 2020.

Figure 4.6 New (A) and total (B) market share of freight transport vehicle technologies under the BAU-POLICY simulation

(A) New market share



(B) Total vehicle share



Note: All graphs for the freight transport sector are share of tonne-kilometre-travelled (as modelled in CIMS) and not actual percentage of vehicles. Diesel VHEFF is very high-efficient diesel; Diesel HEFF is high-efficient diesel; Diesel MEFF is medium-efficient diesel, and Diesel Std is standard-efficient diesel.

B.C. carbon tax

The B.C. carbon tax, modelled in the BAU-POLICY simulation at $20/t in 2010 and $30/t from 2015 to 2020, achieves emission reductions of 7 Mt CO_2e by 2020 compared to my BAU simulation. Province-wide emissions decrease 9% from BAU levels to 67 Mt CO_2e. Table 4.2. summarizes the emission reductions.

Table 4.2. B.C. emissions and carbon tax reductions (Mt CO_2e)

Policy/year	2005	2010	2015	2020
BAU	65	62	66	74
B.C. with carbon tax	65	62	60	67
Carbon tax reductions	0.0	-1	-6	-7
Percentage reduction	NA	-1%	9%	9%

Note: numbers do not add due to rounding.

Alberta Specified Gas Emitters Regulation

My modelling results show a decrease of 4 Mt CO_2e by 2015 and 5 Mt CO_2e by 2020 below the BAU case, with a carbon emissions price on industry of \$3/t-CO_2e. This represents just over 1% of the total provincial emissions by 2020. As Table 4.3. shows, this implies no significant changes in the operations and emissions of large emitters. The simulation produced no reductions in the share of coal-generated electricity.

Table 4.3. Alberta emissions and SGER reductions (Mt CO_2e)

Policy/year	2010	2015	2020
Alberta BAU	251	285	311
Alberta with SGER	249	281	306
SGER reductions	2	4	5
Percentage reduction from BAU	0.7%	1.2%	1.6%

Comparing the Alberta SGER to the B.C. carbon tax shows the former to be considerably less effective. The SGER is expected to achieve reductions of 1.6% below provincial BAU emissions in 2020. The B.C. carbon tax, on the other hand, achieves 9%.

I made assumptions about the SGER that probably suggest a greater impact than the policy has had and will have if kept in the future. The carbon tax level of \$3/t-CO_2e that I applied across Alberta industrial emissions is higher than the SGER's maximum average price of \$1.80/t-CO_2e. As noted in my initial explanation, the SGER's average effective price could be \$0/t-CO_2e if industries achieve cost-effective intensity improvements greater than 12%. This would make the policy non-binding and achievable in the business-as-usual scenario.

Quebec cap-and-trade system

To model Quebec's cap-and-trade system, I applied to all GHG emissions from combustion sources a carbon price from 2015 to 2020 that achieves emission reductions of 4.5 Mt CO_2e or 5% over the period. To achieve this I require a carbon price starting at \$12/t-CO_2e and increasing to \$15/t-CO_2e by 2020. The permit price is only slightly higher than the minimum floor price set for this policy.

The 5% reduction is within range, albeit at the low end, of the planned reductions in emission permits granted; Quebec plans to decrease the number of permits by 1–2% per year between 2015 and 2020 (Government of Quebec, 2014). Should Quebec decrease emission permits at the higher end of its forecast, the price of the emission permits will be higher. Quebec's cap-and-trade system starts modestly, but it is set up to be an effective policy for reducing emissions over the longer term.

I do not consider the purchase of permits from other jurisdictions linked with the system (such as California) where reductions may be cheaper.

Emissions from Alberta's petroleum extraction sector under various levels of pipeline development

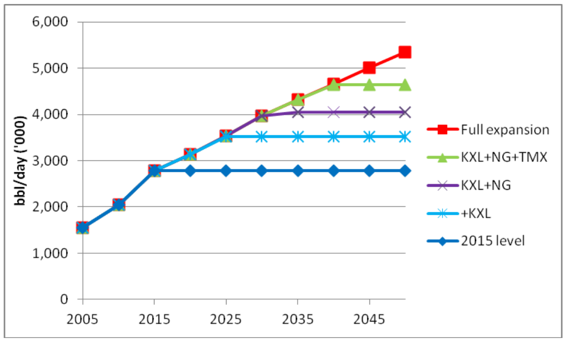
Emissions from Alberta's petroleum extraction sector rise rapidly in the BAU-POLICY forecast.[7] With my forecasted expansion, reaching 5.3 million bbl/day by 2050, and with just the current SGER policy, emissions from crude oil extraction (mostly oil sands) will increase to 193 Mt CO_2e. This represents a near fourfold increase from 2005 levels of 49 Mt CO_2e.

While there has been considerable debate in Canada and the U.S. about the exact relationship between pipeline expansion, oil sands production expansion and increasing GHG emissions, energy economists generally assume that all parts of a production and transport system for a product are critical. Currently three major pipeline proposals are at some stage of the regulatory process, which together will transport an additional 1,865,000 bbl/day. In Figure 4.7. (A), I relate the pipeline capacities to production growth in Alberta's petroleum extraction sector, and in Figure 4.7. (B), I relate the pipeline capacities to emission growth with current policies (i.e., SGER).

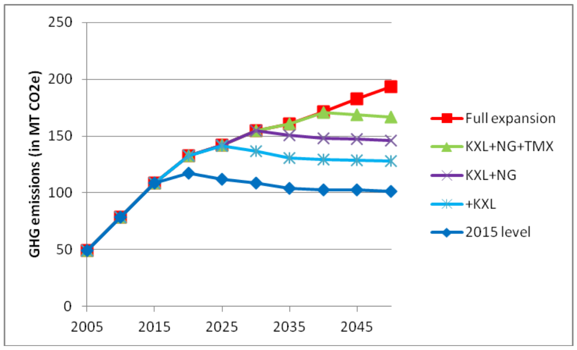
[7] The petroleum crude extraction sector includes extraction and upgrading emissions. It does not include refining or transport emissions.

Figure 4.7. Alberta petroleum extraction (A) and emissions (B) facilitated by pipeline development

(A) Crude extraction



(B) Emissions



This assumes that oil sands production tracks pipeline development. +KXL describes currently existing plus Keystone XL. NG is Northern Gateway; TMX is Trans Mountain Expansion.

My results show a slight decline in emissions even if pipeline capacity, and therefore oil extraction, is held constant. This is because of efficiency improvements in operations over time. However, as production increases, emission intensity tends to increase. Emission intensity increases by 35% between 2005 and 2020. This is due to increasing production from more emissions-intensive sources, such as in-situ SAGD production, and decreasing production of less emissions-intensive conventional oils. This causes emissions to grow faster than crude production. Table 4.4. describes the average emission intensity per barrel of oil through time.

Table 4.4. Emission intensity of Alberta's crude extraction sector under full expansion (t-CO_2e/bbl)

2005	2020	2035	2050
0.09	0.12	0.11	0.10

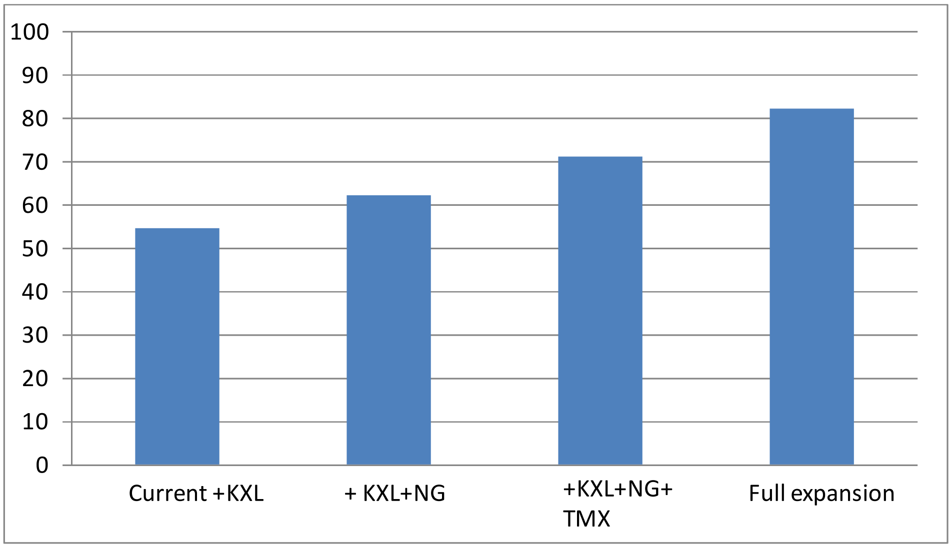
Emissions from Alberta's petroleum extraction sector represent a large and growing share of Canada's future allowed emissions under the country's climate targets. My calculations show that constructing any one of the three pipelines will allow Alberta's crude sector to grow to 3.1 million bbl/day by 2020. Emissions will increase by 240% from 2005 levels.

By 2020, oil sands will account for 90% of total crude production in Alberta. Emissions from the oil sands will increase to 127 Mt CO_2e. This represents 21% of the total allowable Canadian emissions of 612 Mt CO_2e by 2020 under the Copenhagen Accord, up sharply from the sector's 7.8% share of Canadian emissions in 2012 (Environment Canada, 2013).

I assume that for the 2050 target, the long-lived and capital-intensive nature of oil sands infrastructure will assure that most of the infrastructure, whether currently in operation, under construction or already planned, will operate beyond the middle of the century. CERI (2012) predicts that no major currently existing pipeline transporting bitumen will be decommissioned by 2045.

Thus, if oil sands production tracks the capacity additions of the three proposed pipelines, and if that production process has roughly the same emission intensity as I use in my study, then emissions will rise to 165 Mt CO_2e by 2050, accounting for 70% of total allowable emissions under Canada's current target. This is comparable to an analysis by CERI (2012) in which, under their reference case scenario, oil sands emissions are forecasted at 159 Mt CO_2e by 2045. This trend emphasizes how sharply rising output and emissions from this industry are incompatible with stringent federal emission targets. Figure 4.8. shows the percentage of allowable Canadian emissions accounted for by different levels of development in Alberta's petroleum extraction sector.

Figure 4.8. Percentage of total Canadian allowable emissions (235 Mt CO_2e) by Alberta's petroleum extraction sector in 2050



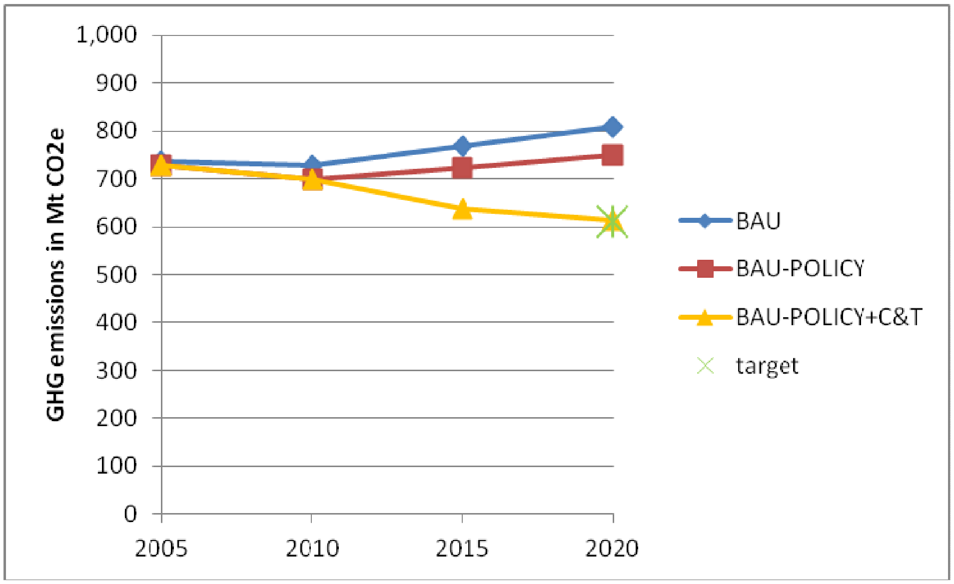
This assumes that oil sands production tracks pipeline development. Current +KXL describes currently existing plus Keystone XL. NG is Northern Gateway; TMX is Trans Mountain Expansion; Full expansion is the expansion forecast set in CIMS.

Additional policies to achieve 2020 climate target: BAU-POLICY plus cap-and-trade

The simulation of current government policies (BAU-POLICY), while showing 64 Mt CO_2e of decreased emissions from the BAU simulation, falls far short of achieving the 2020 target. Additional measures must be taken for the government of Canada to keep its commitment.

My next simulation therefore added to the BAU-POLICY an economy-wide cap-and-trade system, which limits the total emission permits in the country to the government's promise for 2020. I refer to it as the BAU-POLICY+C&T. This is similar to the approach taken by California, which implemented several sectoral regulations (vehicles, fuels, electricity) from 2007 to 2012, but then added a cap-and-trade system that is slated to become economy-wide in 2015. In the Canadian case, the cap-and-trade policy must achieve an additional reduction of 132 Mt CO_2e when added to the effect of the existing regulations. To achieve this magnitude of reduction in such a short time, the price of the tradable permits (the carbon price) in my simulations starts at \$50/t-CO_2e in 2015 and must increase rapidly to \$225/t-CO_2e by 2020. The high level and rapid increase of the carbon price gives an idea of the stringency of the policy required to meet the government's commitment, given that it has done little in the past seven years since first setting targets for 2020. Figure 4.9. shows the emission trend with all current policies and the above-mentioned cap-and-trade system superimposed. Table 4.5. summarizes the findings.

Figure 4.9. GHG emissions from BAU, BAU-POLICY and BAU-POLICY+C&T



BAU is business as usual; BAU-POLICY is current policy simulation, and BAU+C&T is current policy scenario with additional cap-and-trade.

Table 4.5. GHG emissions from BAU, BAU-POLICY and BAU-POLICY+C&T (emissions in Mt CO_2e)

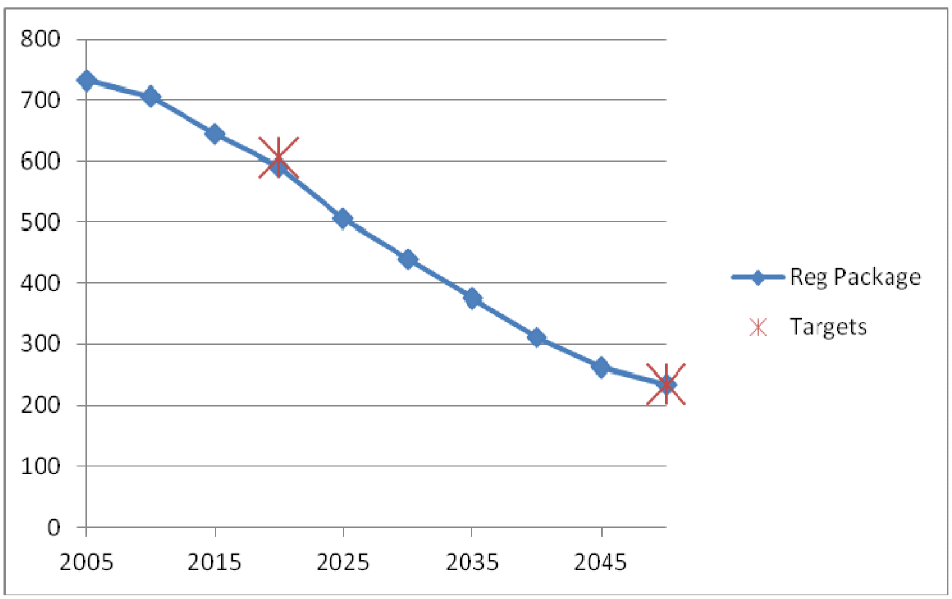
Policy simulation/year	2005	2010	2015	2020
Targets	726			612
BAU	735	727	769	808
BAU-POLICY	727	697	723	744
BAU-POLICY + Cap-and-Trade	727	697	637	613
C&T emission charge ($/t)	0	0	50	225

4.2. Sectoral-Regulation Plus Cap-and-Trade approach to achieve climate targets

GHG mitigation potential of the proposed Sectoral-Reg+C&T approach

I designed the proposed Sectoral-Reg+C&T approach to achieve the 2050 emission target of 235 Mt CO_2e. As it turns out, the government's 2020 target is roughly consistent with the emissions path that would achieve its 2050 target, which is similar to the findings of the NRTEE (2007) when simulating a set of policies and a trajectory of emissions to achieve the government's 2050 promise. Figure 4.10. summarizes my simulated emissions path for the 2050 target.

Figure 4.10 GHG emissions under the proposed Sectoral-Reg+C&T approach



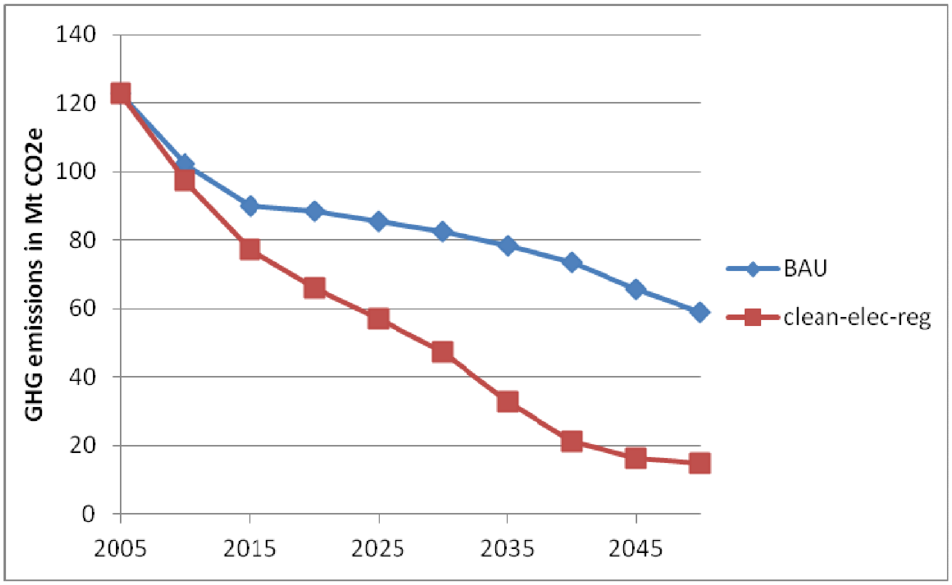
Domestic consumption sector regulations

Clean electricity standard

I set a zero-emission electricity regulation by 2015 that affects only new capital stock. I do not regulate existing plants. GHG emissions drop from a level of 123 Mt CO_2e to 15 Mt in 2050, a reduction of 88% over the study period. Emissions in

2050 are from GHG-emitting legacy plants not yet retired and from residual emissions that are not captured by the CCS process. Figure 4.11. summarizes the clean electricity standard compared to the BAU simulation.

Figure 4.11. Electricity sector emissions under the clean electricity regulation



Provinces throughout Canada have very different resource endowments, which determine how they respond over time to the zero-emission regulation. These responses, described below, are summarized in Figure 4.12.

- B.C. continues its heavy reliance on hydropower. New investments are made primarily in smaller-scale hydro developments. Wind increases its market share to 10% by 2050.
- Alberta, with its significant coal endowment and history of coal-fired electricity generation, makes the most use of coal with CCS, which grows to 40% of generation by 2050. Conventional coal sees a gradual phase-out to 2050. A combination of renewable technologies increase their combined market share to 39% by 2040.
- Saskatchewan takes advantage of small hydro resources in the province's north, which surpass conventional coal (decreasing its market share to 18% by 2050) as the province's largest electricity source between 2030 and 2035. Wind and coal with CCS increase their market shares to 16% each by 2050.

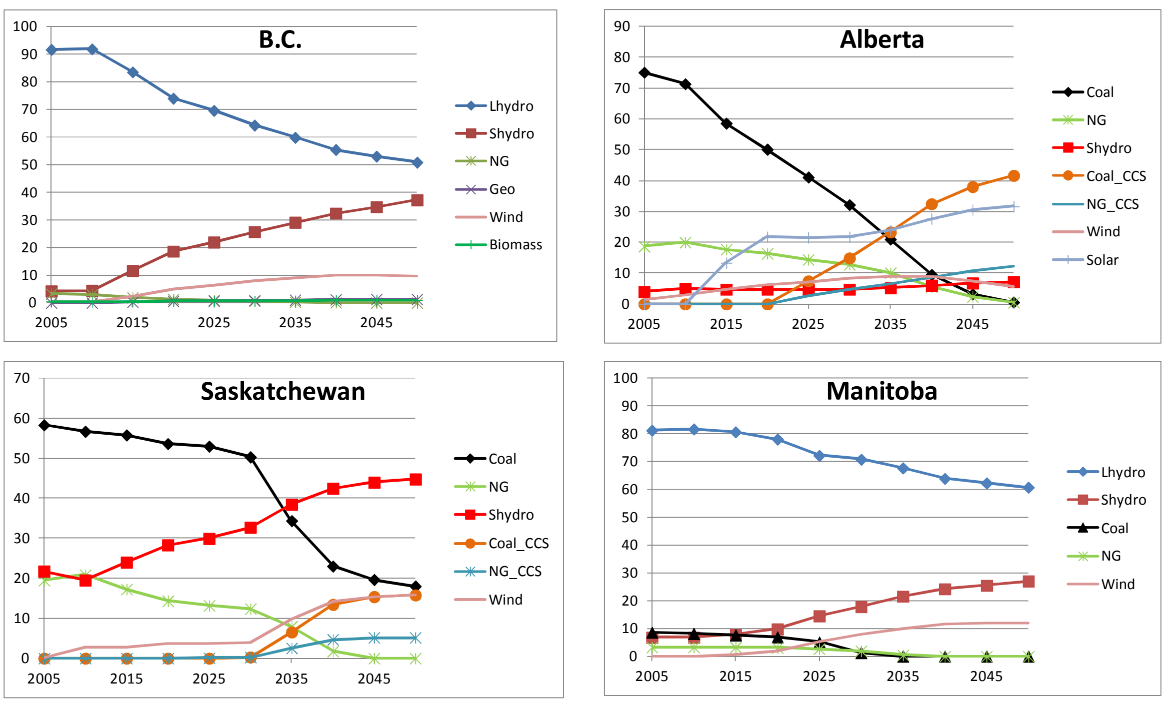
- Manitoba continues its heavy reliance on hydro, with new generation coming primarily from smaller projects. Wind grows its market share to 12% by 2050. Its small use of conventional coal is completely phased out by 2030.

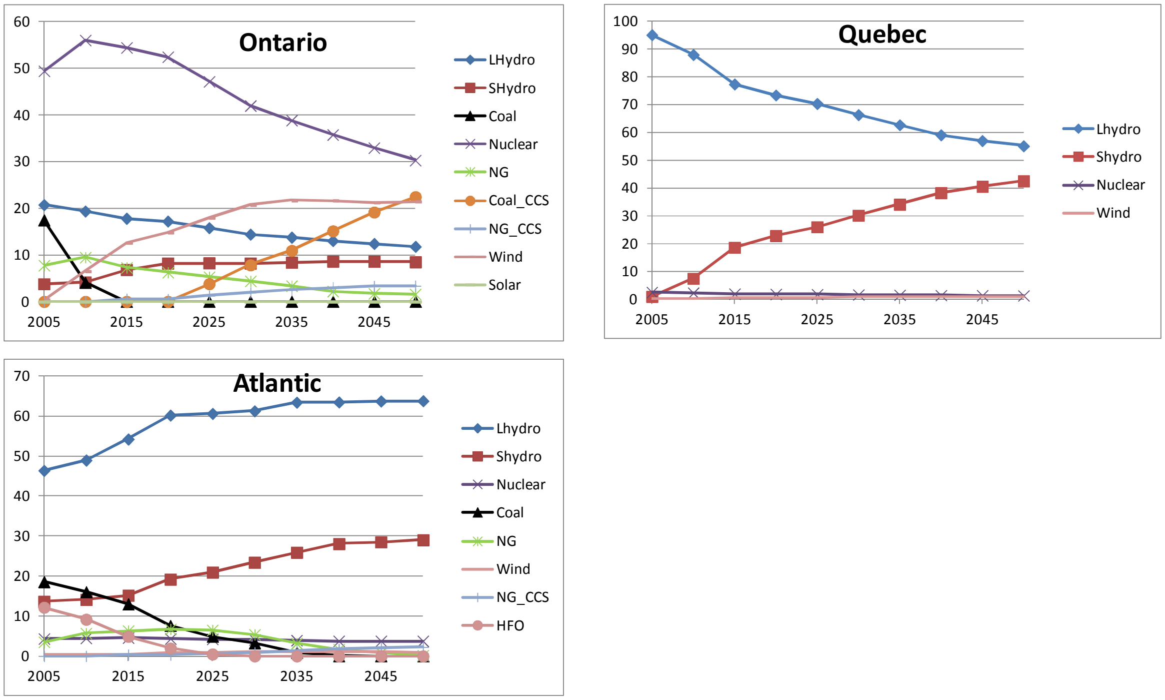
- Ontario is predicted to have the most diverse energy system. Nuclear will continue to be the largest source of power, though its market share drops from 55% in 2015 to 30% in 2050. After 2020, coal with CCS gains in market share and accounts for 20% by 2050. Natural gas grows from 2005 to 2015 and then falls. Wind grows to 21% by 2050, the largest share in any province.

- Quebec continues its heavy reliance on hydro power, with new generation coming from smaller plants.

- Atlantic Canada continues its reliance on hydro power. New generation comes mostly from small hydro projects which, combined with the hydro legacy, contribute around 93% of electricity by 2050. Nuclear stays relatively constant. Wind is the dominant renewable, though its contribution is limited. Conventional coal is phased out by 2035.

Figure 4.12. Total generation by source (%)





Lhydro is large hydro; Shydro is small hydro; NG is natural gas; NG_CCS is natural gas with CCS; Coal_CCS is coal with CCS; GEO is geothermal power, and HFO is heavy fuel oil.

Although in-depth cost analysis is not the goal of this study, the price impacts of the clean electricity standard are briefly explored due to the increasing importance of electricity in a future carbon-constrained world. The proposed regulation will affect electricity prices differently for each province. The weighted average industrial electricity rate across the country is expected to increase from 3.8¢/kWh to 6.5¢/kWh (in constant $2005) between 2010 and 2050, an increase of 72%. This is less than a 2% increase per year over the time period. Provinces most endowed with hydro power, such as Quebec, Manitoba and B.C., will continue to provide relatively cheap electricity, with prices below the national average. Residential rates will be higher.

Alberta sees the largest increase in industrial electricity rates, with these climbing 90% over the study period. Alberta is expected to be more reliant on new, somewhat more expensive technologies, such as coal with CCS and renewables. It should be noted that some studies such as Lutes (2012) estimate smaller price increases for Alberta under similar policies.

The increase in the electricity price is not caused solely by the clean electricity regulation. Climate regulation in other sectors will cause increasing electrification of the economy. Consumers and industry will switch to electricity as a clean secondary source of energy whose production emissions are in decline in response to policy. Widespread adoption of electric vehicles, electric heat pumps in buildings, and other applications will increase electricity demand and therefore bring upward pressure on the electricity price. However, the cost increase is kept in check as coal with CCS acts as backstop technology and therefore represents a price ceiling. Table 4.6. summarizes electricity prices to 2050 for each province.

I expect natural gas with CCS to be similarly competitive to coal with CCS and to contribute to putting a price ceiling on electricity. In my simulation natural gas with CCS gained only modest market shares, ranging from 5–10% in four provinces by 2050.

Table 4.6. Industrial electricity costs throughout Canada under clean electricity regulation (2005c/kWh)

	2010	2020	2035	2050
Canada	4	5	6	6
B.C.	3	4	5	5
Alberta	5	6	7	9
Sask.	6	7	8	10
Manitoba	3	3	4	4
Ontario	3	4	5	6
Quebec	3	4	5	5
Atlantic	7	8	9	11

Canadian industrial electricity rate is weighted to the generation of each province.

Zero-emission residential and commercial HVAC regulation

I implemented my zero-emissions HVAC regulation for the residential and commercial sector starting in 2015. This regulation requires all new capital acquisitions to be of zero-emission technologies, while existing capital is allowed to operate for the reminder of its useful economic life.

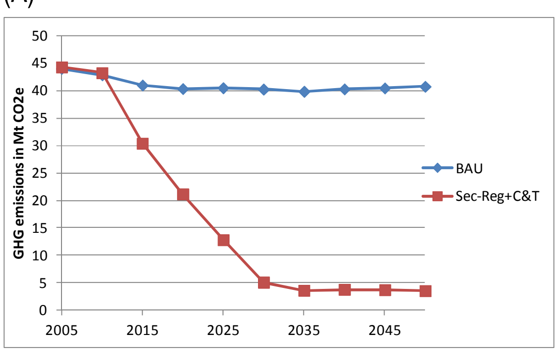
In the residential sector, emissions decrease from 44 Mt CO_2e in 2005 to 4 Mt in 2050. Emission reductions are primarily achieved by fuel switching from natural gas to electricity. By 2050 heating services are almost entirely dominated by electric heat pumps, which account for 96% of new investments by 2050. Earlier in the regulatory period, air-source heat pumps dominate, while ground-source heat pumps increase their market share later.

In the commercial sector, emissions decrease from 35 Mt CO_2e in 2005 to 2 Mt in 2050. As opposed to the residential sector, the commercial sector is expected to experience significant emission growth. As such, the decrease in emissions in the commercial sector is even greater from the BAU simulation; emissions are expected to decrease by 96%. Similar to the residential sector, HVAC technologies transition to electric heat pumps. Various electric heat pump technologies account for 95% of the new market share for heating and air conditioning services by 2050. Figure 4.13. (A) and (B) summarize the results of the zero-emission building regulations.

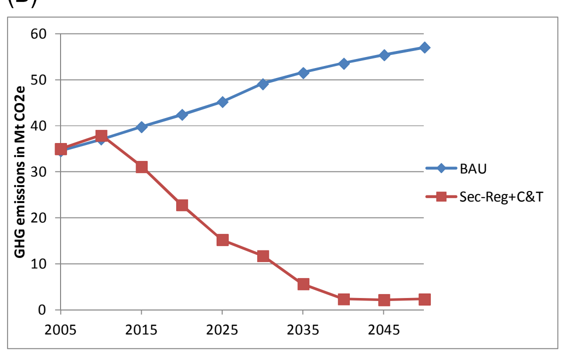
While I did not allow for it in my regulation, having some level of cogeneration for electricity production and heating services in dense urban centres would likely be advantageous. Cogeneration would increase the flexibility of the policy, decreasing the costs while having limited GHG impacts.

Figure 4.13. Emissions from (A) residential and (B) commercial buildings under the zero-emission buildings regulation

(A)



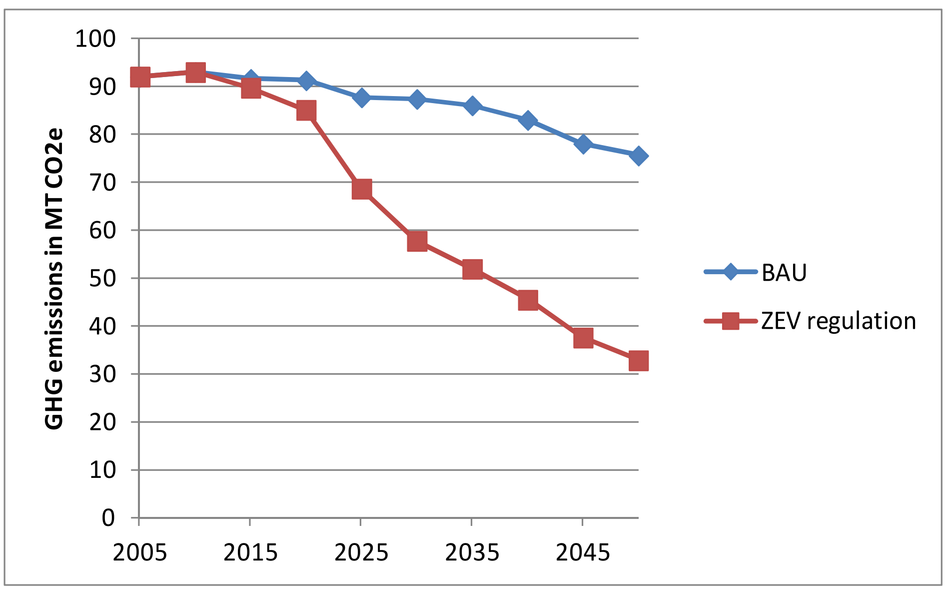
(B)



Zero-emission vehicle tradable performance standard (ZEV)

I regulate the personal transportation sector with a tradable performance standard that becomes effective in 2015. Emissions in this sector drop from 93 Mt CO_2e in 2010 to 33 Mt by 2050, which is the 65% reduction target I chose for this policy. It should be noted that this covers tailpipe emissions only. Increased emissions from electricity generation for charging PHEV and EV, or increased emissions from the production of biofuels are not considered under the personal transport sector. However, these emissions are accounted for and regulated in their respective sectors. The 65% reduction is less than the reductions in the other domestic consumption sectors, which is likely good from an economic efficiency perspective, as emission reductions in the personal transport sector have somewhat higher marginal abatement costs compared to the other sectors. Figure 4.14. summarizes the emissions of the personal transportation sector throughout the study period.

Figure 4.14. Emissions from the personal transportation sector under the ZEV standard and BAU (Mt CO_2e)

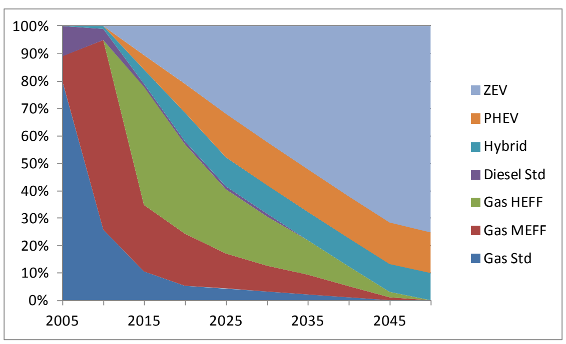


To achieve the required 65% reduction, low- and ultra low-emission vehicles grow by 1% per year each, with a 5% start in 2015. Low-emission vehicles will represent 10% of the vehicle fleet by 2020 and will stay at that level. Ultra low-emission vehicles will represent 15% of the vehicle fleet by 2025 and stay at that level. Zero-emission vehicles, such as electric vehicles, biofuel vehicles and hydrogen fuel cell vehicles, must grow by 2% per year and continue growing their market shares to the end of the forecast period, reaching 75% of new market share by 2050. In this analysis, electric vehicles accounted for the majority of the vehicle market share. Figure 4.15. (A) summarizes the new market share of different technologies.

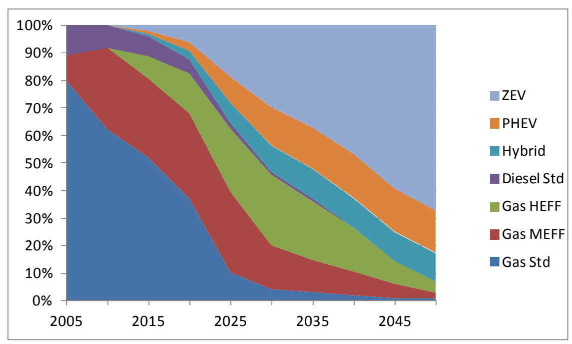
As noted previously, total vehicle stock lags the new market share. Under this policy, standard- and medium-efficiency gasoline vehicles will still be the most common technology until 2025. Traditional gasoline-powered ICE vehicles still make up 34% of the market by 2035. By 2050, however, low-, ultra-low and ZEV vehicles comprise 10%, 15% and 66% of the market respectively. Figure 4.15. (B) summarizes the total vehicle stock.

Figure 4.15. New (A) and total (B) market share of vehicle technologies satisfying the ZEV standard

(A) New market share



(B) Total vehicle stock



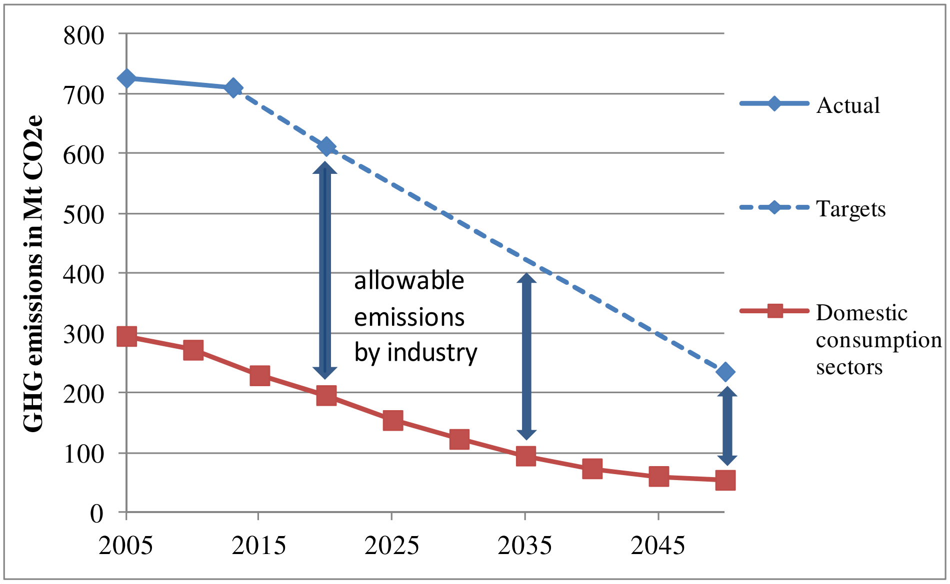
All percentages are share of vehicle kilometres travelled, not actual market share of technologies. Gas Std is standard-efficiency gasoline; Gas MEFF is gasoline medium efficiency; Gas HEFF is gasoline high efficiency; Hybrid is hybrid with gasoline engine; PHEV is plug-in hybrid with gasoline, and ZEV is a zero-emission vehicle such as electric, fuel cell or biofuel.

Industry sector cap-and-trade

I group all remaining sectors in the industry sector cap-and-trade. I allowed these sectors to only emit the difference between the domestic consumption sectors' emissions and the country's emission targets. With 2020 and 2050 targets of 612 Mt

CO_2e and 235 Mt CO_2e respectively, the industry sector will only be allowed to emit 417 Mt CO_2e falling to 181 Mt CO_2e over that same period. See the summary in Figure 4.16.

Figure 4.16. Allowable emissions from industry sectors to 2050



An increasingly stringent cap will cause a rising permit price in the cap-and-trade system. In my simulation, the price starts at \$50/t-CO_2e in 2015 and must increase rapidly to 2025 and then more gradually to reach \$500/t-CO_2e after 2040.[8] This carbon price is higher than the highest-price policy scenario modelled by the NRTEE (2007), which started in 2010 and required a carbon price of \$350/t-CO_2e to achieve the same targets. This difference appears to illustrate the extra costs of not acting in time and the inefficiencies of not using an economy-wide carbon pricing mechanism, since the model and the time frame are otherwise quite similar.

One factor that helps explain the very high carbon price in my study is the CIMS model's lack of full macroeconomic equilibrium capabilities, as discussed in Section 3.1. When the CIMS model is used in isolation, emission reductions must be achieved almost entirely by technological change. In reality, high carbon prices would also decrease

[8] This is under the additional assumptions of limited crude extraction in Alberta. With higher crude production from increasing oil sands production, the permit price would be higher.

emissions through structural changes in the economy (to less emissions-intensive economic sectors) and by impacting total economic output (through slower economic growth). Thus, in reality, the emission cap may be achieved with a lower permit price than I computed. Constant output is not necessarily a limitation of CIMS, but rather an assumption I made in this exercise. Linking CIMS with a macroeconomic general equilibrium would help solve this issue and likely give more accurate carbon pricing values (Peters et al., 2010). The industrial restructuring and slower economic growth will be challenging, especially for emissions-intensive sectors and the regions that rely on them. Table 4.7. summarizes the simulated carbon permit price over the time period.

Table 4.7. ***Industry permit price in Sectoral-Reg+C&T approach (\$/t-CO_2e)***

	2010	2015	2020	2025	2030	2035	2040	2045	2050
Carbon Charge	0	50	125	300	400	450	500	500	500

Under the combination of sector-specific regulations and an industrial cap-and-trade program, the country achieves the government's promise for 2050 emissions of 235 Mt CO_2e. Appendix A gives the emission levels for all sectors under this policy package.

Sectoral-Reg+C&T compared to an economy-wide cap-and-trade approach (Total-C&T)

I also simulated a single economy-wide cap-and-trade system to achieve the targets (Total-C&T). I start the carbon price at the same level of \$50/t-CO_2e in 2015. However, the permit price does not need to increase as rapidly under the Total-C&T system compared to the industry cap-and-trade in the Sectoral-Reg+C&T approach. The Total-C&T carbon price reaches a peak of \$400/t by 2040. This is 20% lower than the marginal emission price in the Sectoral-Reg+C&T approach. In the Total-C&T approach, the industry sectors make smaller contributions compared to the Sectoral-Reg+C&T approach. Furthermore, in the Sectoral-Reg+C&T approach, the residential and commercial sectors decrease emissions more, while personal transportation and electricity decrease emissions less than would occur in an economically efficient system.

This shows that the proposed Sectoral-Reg+C&T approach is not likely as economically efficient—not all sectors make the emission reductions as would occur under the Total-C&T approach. However, there is only a 20% difference in the marginal carbon price between the two. Other studies predict a greater price increase for regulation compared to market-based policy approaches (Rudd, 2012). As such, the proposed Sectoral-Reg+C&T approach appears to be a reasonably cost-efficient approach. This is because the reductions in the domestic consumption sectors are similar in both the Sectoral-Reg+C&T and Total-C&T approach; industry sectors have to abate similar levels of emissions, causing a similar permit price. Table 4.8. compares the permit price for the Sectoral-Reg+C&T and the Total-C&T approach required to achieve the 2050 target.

Table 4.8. Emission permit price in Sectoral-Reg+C&T and the Total-C&T approach (\$/t CO_2e)

Simulation	2010	2015	2020	2025	2030	2035	2040	2045	2050
Sectoral-Reg+C&T	0	50	125	300	400	450	500	500	500
Total-C&T	0	50	125	250	350	400	400	400	400

4.3. Alberta's oil sands industry under climate constraints

This section assesses the prospects for oil sands growth under the Sectoral-Reg+C&T approach to achieving Canada’s commitments in concert with a successful global effort to keep temperature increases to below a 2 ˚C increase.

Oil sands cost increases under the Sectoral-Reg+C&T approach

The extra costs for the bitumen industry under the Sectoral-Reg+C&T simulation's cap-and-trade system vary by time period and technology. In general, the costs rise with increasing CO_2 permit costs unless substantial emissions are abated with CCS. Cost increases by 2040, the year the price of emission permits peak at \$500/t-CO_2, will be \$26/bbl for SAGD in-situ, \$15/bbl for stand-alone mining and \$22/bbl for integrated mining and upgrading. Considering that the oil sands are already at the upper end of the global oil supply cost curve (IEA, 2010), these extra costs could present an insurmountable challenge for the industry.

Emission compliance and CCS costs will increase to 31%, 16% and 20% of total life cycle costs for new SAGD in-situ, stand-alone mining, and mining and upgrading projects respectively. Chan et al. (2012) found that adding CCS increased production costs by 23% for integrated mining and upgrading projects, in line with my findings. This is a dramatic increase from a less than 1% cost increase under Alberta's current SGER regulation (CERI, 2012). The cost increases are summarized in Table 4.9.

Table 4.9. Cost increases for bitumen extraction technologies under the Sectoral-Reg+C&T approach ($/bbl)

Technology	2010	2015	2020	2025	2030	2035	2040	2045	2050
Emission Permit ($/t)	0	50	125	300	400	450	500	500	500
In Situ	0	5	13	24	25	25	26	26	26
Mining	0	1	4	9	12	13	15	15	15
Mining + Upgrading	0	5	8	15	18	20	22	22	22

I only consider abatement options from CCS. However, the petroleum industry will have lower cost abatement options than CCS, and will implement these first. This will decrease the extra costs compared to my analysis. Lutes (2012) found that under a wide range of climate policies, the petroleum extraction industry abated almost all of its GHG emissions through CCS. Lower cost options such as fuel switching to electricity did exist, but overall such reductions were minimal compared to CCS. As such, the extra costs to the industry may be lower than anticipated by my analysis, but the difference will likely not be large.

Oil sands supply costs in a future climate-constrained world

When the high and rising emission permit prices are added to production costs, SAGD break-even costs increase from $56/bbl in 2010 to $82/bbl by 2040, and mining costs from $74/bbl in 2010 to $88 in 2040, while integrated mining and upgrading cost increases from $91/bbl in 2010 to $113/bbl in 2040. Table 4.10. summarizes these costs for future oil sands investments.

Table 4.10. WTI-equivalent supply costs of new bitumen projects under the Sectoral-Reg+C&T approach ($/bbl)

	2010	2020	2035	2040	2050
SAGD	56	69	82	82	82
Mining	74	78	87	88	88
Mining + Upgrading	91	99	111	113	113

The operating costs of existing oil sands operations without climate constraints are $35/bbl WTI-equivalent. This increases dramatically under climate constraints. SAGD operating costs increase to $61/bbl in 2040, mining to $50/bbl, and integrated mining and upgrading projects to $57/bbl, as shown in Table 411.

Table 4.11. Operating costs of existing oil sands operations under the Sectoral-Reg+C&T approach ($/bbl)

	2010	2020	2035	2040	2050
SAGD	35	48	60	61	61
Mining	35	39	48	50	50
Mining + Upgrading	35	43	55	57	57

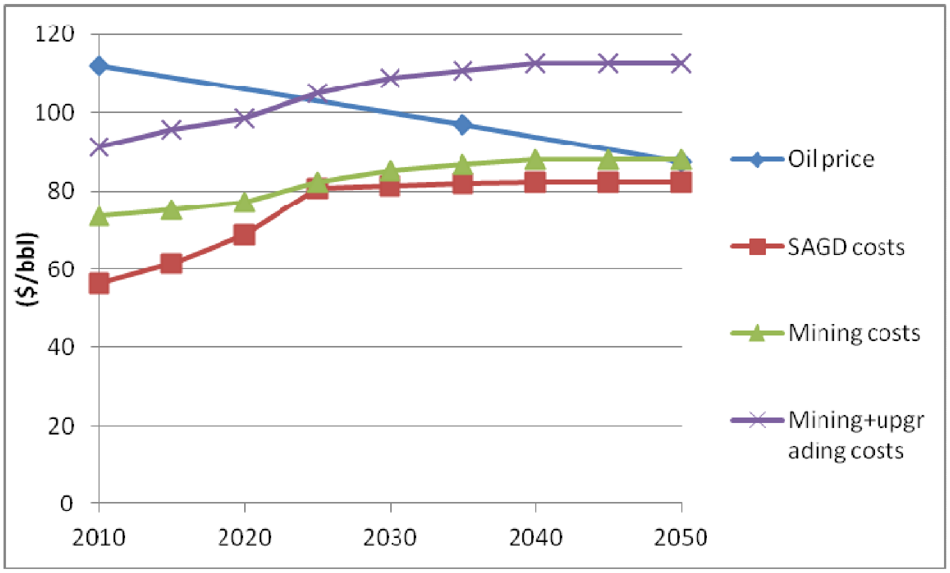
New oil sands operations with climate constraint: high oil price scenario

Under the high oil price scenario, based on the IEA's 450 ppm scenario, oil prices average $100/bbl over the 2015–2045 period.[9] Since the average costs for SAGD, mining, and integrated mining and upgrading are $78/bbl, $84/bbl and $107/bbl respectively, the first two remain profitable, while new integrated mining and upgrading

[9] I use a 30-year period, as the project life cycle costs are calculated on this time frame based on data from CERI (2012).

projects do not appear profitable.[10] The costs exceed the forecasted oil price starting between 2020 and 2025. Figure 4.17. and Table 4.12. summarize these findings.

Figure 4.17. New oil sands production costs; high oil price scenario



Prices and costs are in $/bbl WTI equivalent.

Table 4.12. New oil sands production costs and oil price from 2015–2045; high oil price scenario

	Costs WTI-equivalent ($/bbl)	Price received ($/bbl)	Profit ($/bbl)
SAGD	78	100	22
Mining	84	100	16
Mining + Upgrading	107	100	-7

Considering that significant amounts of oil sands products are exported, one must also consider the GHG regulation in export markets. Without GHG regulations in export markets, non-upgraded bitumen will have an advantage over upgraded synthetic crude oil; upgrading and refining emissions will occur in export markets where they are

[10] The calculations include a 10% real return on investment. Integrated mining and upgrading projects could be economical, though at much lower returns and higher risks to investors.

free. If significant GHG regulations exist in the export markets, then the value of non-upgraded bitumen compared to upgraded bitumen would be less, if not inverted.

Existing oil sands operation with climate constraint: high oil price scenario

Operating costs of existing oil sands projects will increase to $61/bbl, $48/bbl and $57/bbl for SAGD, mining, and integrated mining and upgrading projects by 2040. Expenditures on permits and CCS will represent 43%, 29% and 38% of total operating costs respectively. Operating costs stay well below the price of oil, suggesting that oil sands facilities will continue to operate under the proposed Sectoral-Reg+C&T approach and oil prices as forecasted by the IEA's 450 ppm scenario (IEA, 2012).

My high oil price scenario gives a similar oil price as forecasted by Chan et al. (2012) under their world policy scenario. Under this policy and the resulting oil price, Chan et al. found that the oil sands industry will be driven out of the market. The authors conclude that investing in oil sands projects is financially unwise, or that investors are counting on the failure of global leaders to implement policies to achieve their promises. My results tell a different story. With the oil price staying around the $90–100/bbl mark to 2050, oil sands will be profitable and oil sands expansion is economically attractive, even with the added costs of domestic policy. However, Chan's study used less ambitious global emission targets than the 2 ˚C scenario assessed in this study. This could mean even lower world oil prices.

New oil sands operations with climate constraint: low oil price scenario

Under my lower oil price scenario, which sees oil prices dropping to $40/bbl by 2025, the average received oil price over the 2015–2045 period is $53/bbl. This is below the average costs of new projects for all production methods over this period, meaning that new oil sands projects would not be economically feasible. Table 4.13. summarizes these findings.

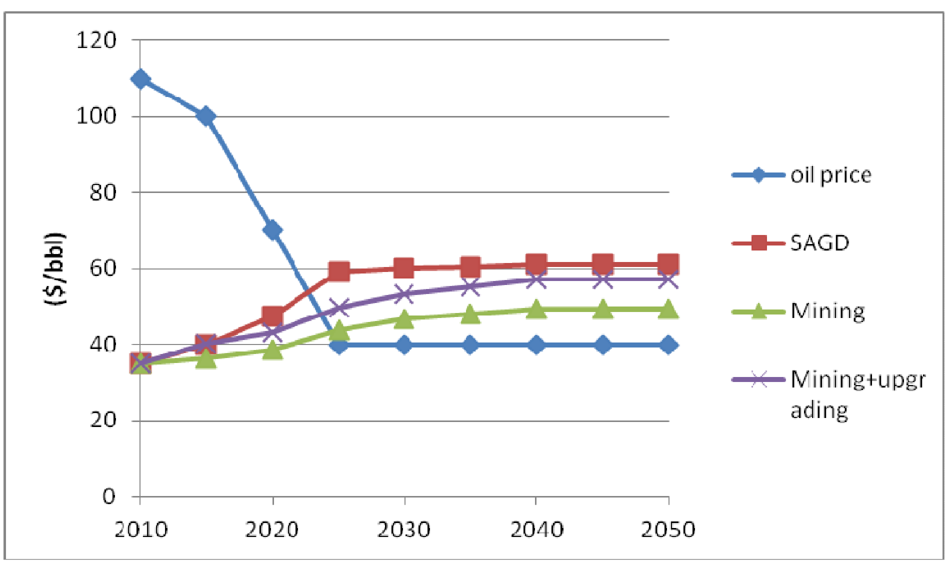
Table 4.13. New production costs and oil price from 2015–2045; low oil price scenario

	Costs ($/bbl WTI-equivalent)	Price received ($/bbl)	Profit ($/bbl)
SAGD	78	53	-25
Mining	84	53	-31
Mining + Upgrading	107	53	-54

Existing oil sands operations with climate constraint: low oil price scenario

Existing oil sands projects will keep operating as long as their operating costs are lower than the oil price. Under the Sectoral-Reg+C&T approach and the lower oil price scenario, operating costs exceed the price of oil once it gets down toward $40 between 2020 and 2025. This suggests that existing oil sands operations will be driven out of the market at that time. Under this scenario, global oil demand declines so that demand is met by cheaper and less emissions-intensive sources of crude, just as simulated by Chan et al (2012). SAGD is the first to be driven out of the market due to high emission compliance costs, while stand-alone mining is most resilient to climate change policy. Figure 4.18. summarizes the findings.

Figure 4.18. Existing oil sands projects under the low oil price scenario



My chosen cap-and-trade design—based on 100% auctioning and with no revenue recycling to firms—may place higher financial burdens on emissions-intensive industries, such as Alberta's bitumen industry, than some other policy options that better protect GHG-intensive industries (Peters, 2012). The allocation of costs is a policy choice. Implementing a policy that would include significant grandfathering of emission permits and revenue recycling to companies would make compliance for emission intensive industries cheaper, thereby increase the resilience of the oil sands industry to climate policy. However, this will occur at an added costs to the economy. Jorgenson et al. (2013) found that the most economically beneficial way to recycle revenue from carbon pricing is to reduce taxes on capital.

5. Conclusion

5.1. Summary of major findings

GHG emission potential from current policies (BAU-POLICY)

According to my BAU-POLICY simulation using the CIMS model, I estimate that Canada will fail to meet its climate target, set under the Copenhagen Accord. Emissions in 2020 will be 2% above 2005 rather than 17% below, as promised by the Canadian government. Current policies decrease emissions by 64 Mt CO_2e below BAU. The most significant abatement action in Canada is the Ontario government's policy to phase out its use of coal for electricity generation, which results in a reduction of 22 Mt CO_2e by 2020. The federal coal phase-out regulation has minimal impact on emissions by 2020, as it does not encourage early plant retirement, and its restriction on the construction of conventional coal plants is made superfluous in many parts of the country due to previously existing provincial policies, such as Ontario's coal phase-out and B.C.'s clean electricity regulation.

Expansion of Alberta's petroleum extraction sector is the principal reason why Canada's emissions will be higher in 2020 than in 2005. Under the modelled expansion plans, emissions from Alberta's petroleum extraction sector will increase by 240% from 2005. Emissions from the oil sands will reach 127 Mt CO_2e, accounting for 21% of nationwide emissions allowable under the 2020 climate targets, up from the sector's contribution of 7.8% in 2012. This increase highlights the discrepancy between nationally ambitious emission targets and rapidly increasing emissions in a single industry. This trend gets more dramatic over the long term. If three pipelines currently under review are built, Alberta's oil sands expansion will be facilitated to a level of 4.6 million bbl/day, resulting in emissions of 165 Mt CO_2e per year. To meet the national targets for 2050, this leaves just 70 Mt CO_2e for the rest of the Canadian economy.

To achieve the government's 2020 emission promise, forceful measures must be taken immediately to decrease emissions by an additional 132 Mt CO_2e. The only way this can be achieved is by adding to all other climate policies an economy-wide price signal that would result from an absolute cap on emissions. I refer to this simulation as BAU-POLICY+C&T. The price of tradable emissions would start at \$50/t-CO_2e in 2015 and increases rapidly to \$225/t-CO_2e by 2020.

In my BAU-POLICY simulation I made assumptions that both overstate and understate the expected results for the various policies. For example, I overestimated the carbon price for Alberta's SGER policy, and for the federal efficiency regulations on personal and freight transportation I did not account for the likely incentive to keep older vehicles longer. Furthermore, the rate and ultimate scale of oil sands expansion I forecasted in CIMS is less than what other reports suggest (CERI, 2012; CAPP, 2013). On the other hand, I did not include the macroeconomic feedbacks from higher energy prices, which would increase abatement from the policies due to structural shifts in the economy to less emissions-intensive economic sectors and from decreasing economic growth.

Proposed Sectoral-Regulation Plus Cap-and-Trade to climate targets

I designed this simulation to achieve the Canadian government's climate targets with a policy package that matches, though not entirely, its preference for a regulatory approach. Regulations are imposed on sectors more exposed to the general consumers, while industrial emissions are covered by a cap-and-trade regime. The Sectoral-Reg+C&T approach, which would start in 2015, is designed to increase political acceptability in sectors where climate policy initiatives are relatively more constrained by political roadblocks while focusing on economic efficiency in sectors where business competitiveness is deemed paramount.

I chose to regulate three sectors by command and control regulations that prohibit investments in new GHG-emitting technologies. The result is that emissions decrease by 88%, 91% and 94% for the electricity, residential and commercial sectors. Electricity rates are expected to increase by 72% between 2010 and 2050, though results vary by province. This price increase is less than 2% per year. I implemented a

ZEV tradable performance standard in the personal transportation sector in order to balance the sector's high visibility to the consumer with its high abatement costs. The new market share of zero-emission vehicles must increase to 75% to achieve my chosen 65% reduction target by 2050.

I designed the policy package so that the industry sector would achieve reductions equal to the difference between the domestic consumption sectors' emissions and the national climate targets. This is achieved with a cap-and-trade system in which the emission cap must decrease over time to 181 Mt CO_2e by 2050. For this to happen, I estimate that the price of emission permits will increase to a peak value of \$500/t-CO_2e by 2040.

Critics will argue that the proposed Sectoral-Reg+C&T approach with a mix of policies across various sectors is more economically costly than necessary. Emission permits are 20% more expensive than under a nation-wide cap-and-trade policy. Nevertheless, the Sectoral-Reg+C&T approach assures that all regions and sectors contribute to the climate efforts. By balancing political acceptability and economic efficiency where they matter most, and by incorporating design elements favoured by the current Canadian government, my proposed Sectoral-Reg+C&T approach is effective enough to meet the country's climate targets while still being relatively efficient.

Alberta's oil sands industry in a future climate-constrained world

While oil sands production is projected by industry to increase from today's level of 1.8 million bbl/day to 5.8 million bbl/day by 2035, the industry faces the global effort to limit climate change. Domestic climate policy will increase the cost of oil sands production, while global climate efforts will decrease the demand and therefore the price for petroleum products.

Under my initial high oil price scenario, based on the World Energy Outlook of the IEA, and under my Sectoral-Reg+C&T policy, new SAGD and stand-alone mining projects are predicted to still be profitable investments. These findings differ from those of Chan et al. (2012), who found that under a similar oil price, oil sands will be driven out of the market. My analysis shows that this would only occur with a significantly lower oil price.

Under my low oil price scenario, in which the price falls to \$40/bbl by 2025 because of excess oil supply as demand falls, oil sands operations will be strongly affected. No new projects are viable. Furthermore, operating costs of existing projects may well exceed the price of oil sometime after 2020. Oil prices low enough to drive out projects currently under construction or already existing are not unreasonable to expect if world leaders are serious about their promise to constrain global temperature increases.

5.2. Recommendations for future studies

Better balance marginal abatement costs in Sectoral-Reg+C&T approach

In the design of my proposed Sectoral-Reg+C&T approach, I did not balance the marginal abatement costs across the domestic consumption sectors (personal transport, electricity, and residential and commercial). This balance is difficult to achieve, as regulations rarely consider the complex interconnections of the various economic sectors. Future research could try to balance the abatement costs of the regulation within these sectors and equate it to the expected marginal abatement costs of the industry sector cap-and-trade system. This would further increase the economic efficiency of the chosen Sectoral-Reg+C&T approach without unduly sacrificing political acceptability or moving further away from the government's favoured approach.

Surveying global modellers to determine future oil price

I modelled only energy-economy effects in Canada and therefore cannot assess the effect of global climate efforts on sources of energy whose prices are determined by global supply and demand. As such, this study would benefit from gaining a better understanding on the impacts of global climate efforts on world oil prices. One way to gain this understanding is by surveying more studies from global energy-economy models that estimate the price of oil under various global climate efforts. Better estimates of the future price of oil will improve our understanding of the role that the oil sands can play in delivering energy to a future world that acts to limit the impacts of climate change to a 2 ˚C increase.

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Appendices

Appendix A.

GHG emissions by sector under the hybrid policy regulatory approach (Mt CO_2e)

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Residential	44	43	30	21	13	5	4	4	4	4
Commercial	35	38	31	23	15	12	6	2	2	2
Transportation Personal	92	93	90	85	69	58	52	45	38	33
Transportation Freight	100	99	85	73	63	53	47	38	24	18
Chemical Products	12	11	10	10	7	6	6	5	5	6
Industrial Minerals	15	16	16	16	13	11	9	7	5	4
Iron and Steel	15	10	12	12	9	7	6	5	5	4
Metal Smelting	11	11	10	9	8	7	6	5	4	4
Mineral Mining	6	4	5	4	4	4	4	4	4	4
Paper Manufacturing	7	6	5	4	2	1	1	1	1	1
Other Manufacturing	20	16	12	8	6	4	4	3	3	3
Agriculture	76	72	72	73	74	77	77	77	76	76
Waste	23	24	4	4	4	5	5	5	5	5
Electricity	123	97	77	66	57	48	33	21	16	15
Petroleum Refining	21	21	20	19	16	13	10	7	4	3
Petroleum Crude Extraction	65	90	112	117	105	94	76	54	39	31
Natural Gas Extraction	65	53	46	40	34	31	29	26	23	20
Coal Mining	2	2	2	2	2	2	2	2	2	2
Ethanol	0	0	0	0	0	0	0	0	0	0
Biodiesel	0	0	0	0	0	0	0	0	0	0

Appendix B.

GHG emissions by sector under an economy-wide carbon price (Mt CO_2e)

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Residential	44	42	34	27	19	12	9	8	6	6
Commercial	35	36	33	27	20	16	10	7	6	6
Transportation Personal	92	92	88	84	68	51	40	28	17	14
Transportation Freight	100	97	85	75	67	61	58	52	39	32
Chemical Products	12	11	11	10	7	6	6	6	6	6
Industrial Minerals	15	16	16	16	13	11	9	7	5	4
Iron and Steel	15	10	12	12	9	7	6	5	5	5
Metal Smelting	11	11	10	9	8	7	6	5	4	4
Mineral Mining	6	4	5	4	4	4	4	4	4	4
Paper Manufacturing	7	6	5	3	2	1	1	1	1	1
Other Manufacturing	20	15	12	8	6	4	4	3	3	3
Agriculture	76	72	71	71	73	76	78	80	77	77
Waste	23	22	4	4	4	5	5	5	5	5
Electricity	118	88	56	45	31	24	17	13	11	10
Petroleum Refining	21	21	20	19	16	13	10	7	5	4
Petroleum Crude Extraction	65	89	111	130	120	113	97	76	58	47
Natural Gas Extraction	65	52	46	40	35	31	29	26	23	20
Coal Mining	2	2	2	2	2	2	2	2	2	2
Ethanol	0	0	0	0	0	0	0	0	0	0
Biodiesel	0	0	0	0	0	0	0	0	0	0