OFFICE OF THE
PARLIAMENTARY
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BUDGET

Canada's Greenhouse Gas Emissions: Developments, Prospects and Reductions

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The mandate of the Parliamentary Budget Officer (PBO) is to provide independent analysis to Parliament on the state of the nation's finances, the Government's estimates and trends in the Canadian economy; and, upon request from a committee or parliamentarian, to estimate the financial cost of any proposal for matters over which Parliament has jurisdiction.

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Executive Summary

Prior to the global accord on climate change in Paris in December 2015, countries submitted statements that outlined actions they would undertake post-2020 to reduce greenhouse gas emissions aimed at limiting global warming to 2 degrees Celsius above pre-industrial levels. These actions would be the basis for achieving the long-term objective of the negotiations.

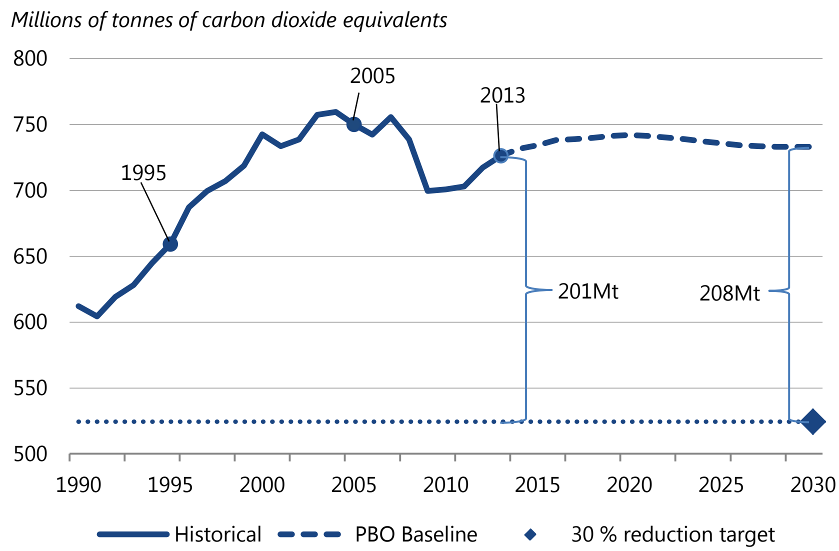
For its part, the Government of Canada announced plans in May 2015 to reduce the nation's greenhouse gas emissions (GHGs) by 30 per cent below 2005 levels by 2030.

This report outlines economic impacts and potential costs of reaching this target, as well as noting sources of downside cost risks. It does so by combining historical trends in intensity of emissions per GDP with the Parliamentary Budget Officer's projection of the Canadian economy to 2030. The purpose is to determine the magnitude of reductions that will be necessary.

It also discusses key issues around implementing emission reductions so as to help inform parliamentary debate. This report found:

- Based on historical trends, PBO projects that the level of emissions will increase only slightly by 2030 while intensity of emissions (i.e., emissions relative to GDP) will continue to decline. (Page 23, 24)
- To achieve the Government's target, Canadian emissions would have to fall by 208 million tonnes of CO_2 equivalent from projected 2030 levels if economic growth followed PBO projections (Summary Figure 1).[1] Based on Environment Canada (2016), if growth were faster and improvements in intensity of emissions slower, the needed emission reduction could reach 291 million tonnes. (Page 23)

Summary Figure 1 Greenhouse gas emission projection



Sources: Canada's National Inventory Report to UNFCCC (2015) and PBO projection.

Note: The PBO projection is based on extending past decreases in emission per unit of GDP on a sectoral basis.

- The 30 per cent target means removing more than the equivalent of all emissions from today’s cars and trucks (including off-road vehicles). The actions undertaken so far by various levels of government, though substantial, will not be sufficient to achieve the target. (Page 7)
- To appreciate the scale of the effort required for a 30 per cent reduction target, or 208-million-tonne reduction, some sources (e.g. NTREE, 2009) estimate that a price for abating carbon dioxide emissions of about $100 per tonne of CO_2 equivalent would be necessary. (Page 27)
- Technologies already available make it possible to ahieve the reduction target at prices starting below $100 per tonne (Summary Table 1; based on more detailed discussion in Appendix B. The left-most column gives an estimate of the price of carbon dioxide that would provide sufficient incentive for actions within the sector).

Summary Table 1 Abatement measures across sectors (in 2030, relative to baseline)

Cost per tCO_2e	Sector	Measures	Emission reduction (tCO_2e)
$10	Agriculture	Converting marginal agricultural lands	6
$25 to $50	Iron and steel	Improve energy efficiency and more use of direct reduction iron and electric arc furnaces	2
$30	Agriculture and waste	Capture methane emissions from landfills	12
$12 to $57	Electricity	Shift to renewables/wind, and carbon capture and storage	50
$60	Agriculture	Lower methane emissions from cattle	3.2
$15 to $75	Forestry	Selective harvesting, better use of harvested area, long-lived wood products	17
$43 to $100	Oil & gas extraction, refining, distribution	More use of low-emission sources of heating, carbon capture and storage	40
$60 to $100	Transportation	Greater use of hybrid technologies, lightweight materials	69
$65 to $100	Chemicals	Increased urea production, carbon capture and storage	3
$40 to $108	Cement manufacturing	Clinker substitution, fuel substitution, carbon capture and storage	5
		Total	**207**

Source: PBO estimates from Appendix B.

- Using carbon dioxide pricing (defined generally), the cost of meeting the target could be between 1 per cent and 3 per cent of gross domestic product by 2030 (based on NTREE, 2009). This would still leave incomes significantly higher than they are today, but lower than what they would have been in the absence of carbon pricing. (Page 27)
- Economic growth in the baseline means that average incomes as measured by real GDP per capita would increase by about 11.5 per cent from $55,500 in 2014 to about $61,800 in 2030, in 2014 dollars. However, the emission reductions – if done in an efficient manner (that is, where the cost is kept to a minimum[2]) – would instead cause a reduction in income per capita of between $600 and $1,900 by 2030. (Page 28)
- There are significant risks in a large-scale move to lower emissions. Two aspects where they are manifest are: (1) a patchwork of abatement programs across different sectors and regions may lead to unnecessarily high costs– indeed, measures such as the coal regulation and auto-efficiency standards have implicit carbon-prices associated with them and regional measures are not sufficiently coordinated; and (2) regional disparity in impacts may not be addressed, thereby undermining a consensus. (Page 29)

- Lowering emissions will likely require a variety of coordinated approaches and it will be complex. This stems from the highly diverse nature of the sources of emissions, and the need to avoid placing much of the burden on particular regions or sectors. However, not surprisingly, the bulk of the reductions will come from the three sectors that contribute most to current emissions – transportation, oil and gas production and distribution, and generation of electricity. (Page 34)
- Measures already undertaken such as the coal regulation that reduces coal-based emissions for electricity generation, and the increasing fuel-efficiency standards for light vehicles, will have a substantial impact on emissions. This means that not all measures are entirely new. Along with regional measures that are already in place, it creates a patchwork of policies where new measures (such as carbon pricing) will need to be carefully integrated to avoid high costs. For example, adding a carbon tax on fuels when vehicles are already subject to an increasing fuel-efficiency standard imposes an elevated cost on the transport sector. (Page 31)
- Canada's diverse regions are not necessarily an obstacle to implementing the abatement target, though they do make it a challenge. Standard abatement measures could have an uneven impact across regions. In Saskatchewan and Alberta, the emission intensity of GDP is about four times higher than elsewhere. The impact of abatement measures could be substantially larger in those regions. (Page 30)
- One measure that cuts across economic sectors is carbon capture and storage. A number of sectors would potentially benefit from its ongoing development and deployment; for example, electricity generation, cement, chemicals, and iron and steel. Over the long term it could account for a large share of emission reductions. Recent projects that implemented carbon capture and storage at industrial scale showed that the cost can be $57 or less per tonne of carbon dioxide. (Appendix A)

A general principle for keeping the cost of abating carbon dioxide emissions to a minimum is that each source of emissions should face the same cost everywhere. Carbon dioxide pricing is preferred by most economists since it faciliates that outcome.

When multiple instruments are used and some measures are already in place (e.g. carbon pricing with regulatory measures), keeping costs to a minimum would require harmonisation of the implicit or explicit costs of new measures with the cost per unit of carbon dioxide abated from existing measures.

This report assumes that there is a need to reduce emissions and discusses the measures to get there. The cost to Canada's economy of allowing a temperature increase of 2 degrees Celsius or more could be substantial – if not directly, then indirectly from elsewhere.

1. Introduction

Emission intensity has been falling sharply.

Canada's greenhouse gas (GHG) emissions have been falling relative to gross domestic product (GDP) for the past couple of decades. They dropped from 543 kilograms of carbon dioxide equivalent (CO_2e)[3] per thousand dollars of GDP in 1990, to 377 in 2013 (using 2014 dollars to measure GDP).[4]

That trend should continue into the future.

This trend occurred while GDP itself grew by a significant 71 per cent. Consequently, there was a net 18.5 per cent increase in the level of emissions over that period. For the future, that trend points to an ongoing reduction in intensity, along with a mild upward movement in the level of emissions.

Canada's emission target is 30 percent below 2005 by 2030.

Against this backdrop, Canada's announced target for emissions in 2030 has been to achieve a 30 per cent reduction from the level of 2005 (Box 1-1). To achieve that, an acceleration of the past trend will have to occur, given that the economy will continue to expand. A number of provincial governments such as Alberta, British Columbia, Quebec and Manitoba, have put in place moderate measures to limit emissions, while others have announced programs (Environment Canada, 2016).

Commitments thus far – federal and provincial – are not sufficient to achieve the reduction target.

Those announced measures, however, are unlikely to achieve that target (Boothe and Boudreault, 2015); they would likely represent a first step. At the federal government level, there are three areas where some steps have been taken, although further work would be needed to reach the 2030 target:

1. reducing emissions from coal use;
2. improving the fuel-efficiency of cars and trucks; and
3. undertaking detailed analysis and projection of the contribution of managed forests (under the rubrik of land-use, land-use change, and forestry) to removing GHGs from the atmosphere.

Coordination will be necessary.

The disparate federal and provincial measures will have to be made part of a broader agreement with a wider group of governments to reach the target.

Box 1-1 – Paris Climate Agreement (2015)

Prior to the Conference of the Parties (COP21) meeting in Paris, countries submitted statements of Independent Nationally Determined Contributions (INDC) that outlined actions they would undertake post-2020. These would be the basis for achieving the long-term objective of the negotiations.

Canada's was submitted on May 15, 2015 and included a target of 30 per cent below 2005 emissions by 2030. For Canada to meet its target, existing measures are not sufficient (Environment Canada, 2014).

If measures related to coal use and fuel-efficiency of vehicles are followed up and strengthened, they would make a significant contribution to achieving the target. Managed forests may also contribute substantially, but the Government has not released its estimates of the impact in 2030.

Other countries also outlined objectives for 2030. The United States, for example, is targeting between 26 and 28 per cent of 2005 emissions by 2030; in 2013, they were 9 per cent below 2005. However, measures that had been taken prior to the meeting largely put it on track to reach that objective.

Coal, for example, accounts for a little less than 40 per cent of electricity generation in the United States. Recent regulations by the U.S. Environmental Protection Agency will reduce it substantially (pending the outcome of legal challenges) in combination with low natural gas prices. Light-vehicle fuel-efficiency standards that are scheduled to keep increasing until 2025 will also contribute, and have the potential to cover the remainder of the U.S.'s commitment.

The outcome of the negotiations was to target a maximum rise in temperature of 2 degrees Celsius, so the 2030 target is effectively an interim one. Given the relatively high emissions per capita in both Canada and the United States, both will likely have to do more after 2030.

For example, if equal per-capita emissions (globally) by 2050 were to become an objective, both countries would need to reduce emissions on the order of 80 per cent below 2013 levels.

NRTEE (2009) underpins cost estimates herein.

This report is based on analysis by the former National Round Table on Environment and Economy (2009; though a range of estimates exist, that one is used as a reference point given its comprehensiveness). This report outlines economic impacts and potential costs of reaching the target, as well as noting sources of downside cost risks.

Declining emission intensity gives a projection of future emissions: a baseline.

It does so by combining historical trends in intensity of emissions with the Parliamentary Budget Officer's (PBO) projection of the Canadian economy to 2030. This is nominally a no-new-policy emissions baseline, but it minimally incorporates recent policy regarding coal use and vehicle fuel-efficiency standards. Its purpose is to determine the magnitude of reductions that will be necessary.

Higher emissions in a faster-growth alternative is not a cause for concern.

Environment Canada (2014b) created its own projection to 2020 and this was extended to 2030 in Environment Canada (2016). A brief comparison is made to that alternative. One lesson is that faster growth is beneficial, even if it leads to higher baseline level of emissions. This is because incomes will also be higher to deal with any increased need for abatement.

Report informs debate, but does not provide policy advice.

This report also discusses key issues around implementing emission reductions so as to help inform parliamentary debate. That is, it notes some risks and trade-offs, but does not attempt to provide policy recommendations. It is thus general to any target chosen, either for 2030, or for years further out.

The next section reviews trends across sectors and regions, which underpin projections made in the subsequent section. These projections make it possible to calculate the reduction necessary to achieve the targeted level of emissions. That is followed by a discussion at an aggregate level of the impact that reducing emissions will have on the Canadian economy.

To make the changes more concrete, the section that follows it outlines possible changes (by sector) that would achieve the target. Greater detail concerning those sectoral reductions is included in Appendix B.

Canada is in an international context, so some coordination with partners could lower risks.

Not included in this discussion is the potential for measures to impact on either Canada's imports or exports. Since the Canadian economy is dependent on trade – particularly with the United States – there would be some risk if Canadian efforts at emission reduction were to fall out of sync with those elsewhere. These issues are discussed a little further in Appendx C.

2. Current Context

Changing composition of the economy changes emissions intensity.

A number of factors contribute to emissions of GHGs in Canada. Many of these are linked to fossil fuel use since Canada has an abundance of such resources. The link, however, between GHG emissions and economic activity is not iron-clad. Some sectors use fossil fuels more intensively; those sectors do not necessarily grow at the same rate as the rest of the economy.

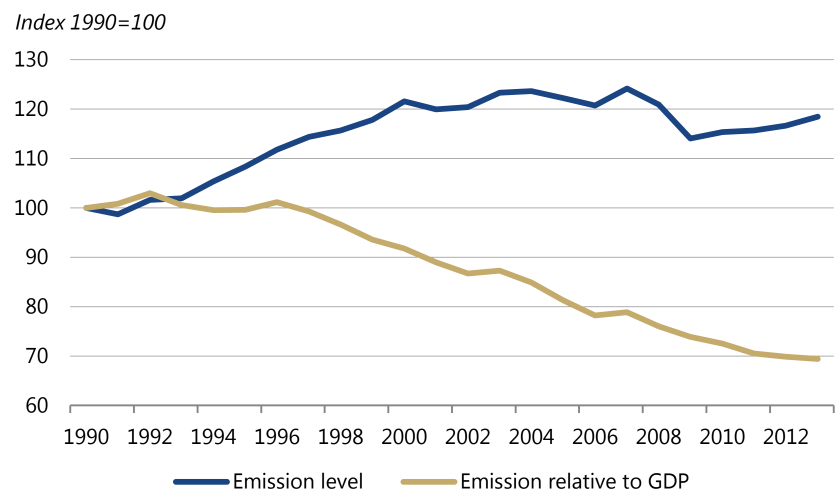
For example, services are less GHG-intensive.

That is, as an economy develops and the service sectors (where fewer GHGs are emitted) expand, the rate of emissions per unit of GDP (known as emission intensity) will naturally fall, when all else stays equal.

Decline in emission intensity has been fairly constant since the mid-1990s...

This and other factors caused emission intensity to decline by almost a third between 1990 and 2013 (Figure 2-1). This decline occurred at the fairly rapid rate of 1.6 per cent annually. Particularly striking is that, starting from 1995, emissions intensity fell at an almost uniform annual rate of 2.1 per cent until 2011.

Figure 2-1 **Canada's GHG emissions: Level and intensity**



Source: Canada's National Inventory Report to UNFCCC (2015).

...but economic growth out-paced improvements in intensity, so emissions increased.

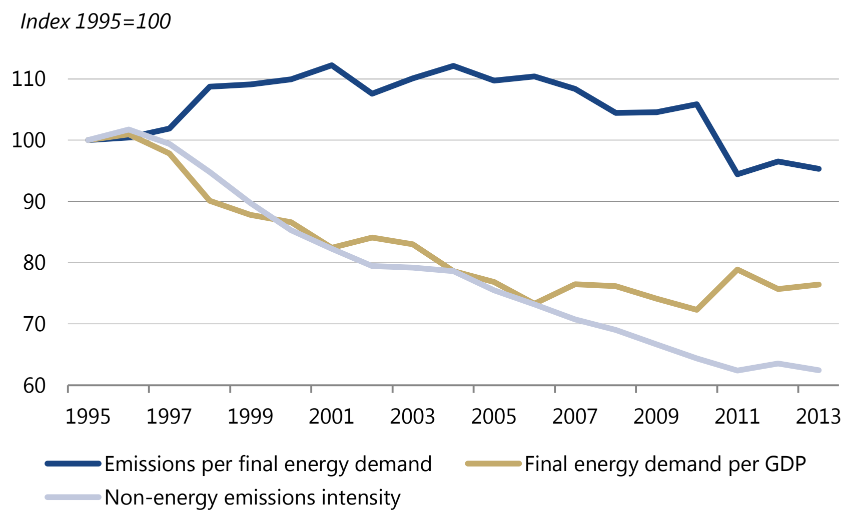
In contrast to the GDP intensity of emissions, the level of emissions rose from 1991 to 2007, then declined during the economic downturn by almost 9 per cent before resuming a gradual upward trend. This contrast between the level of emissions and their GDP intensity suggests a dichotomy between overall economic activity and emissions-generating activity. That is, a change in overall economic activity is a good predictor of a change in the level of emissions. However, technological change and economic transformation (from whatever source) that leads to a more GHG-efficient economy occur more purposefully and consistently.

Decomposing emission intensity

Looking at how emission-intensity changed will help with projections.

The changes in the emissions intensity illustrated in Figure 2-1 (gold line) can be decomposed into that from the energy needed to produce GDP, the emissions caused in producing each unit of energy, and the change in intensity in the non-energy sector. Showing how each has moved can help shed light on the underlying drivers of emissions intensity (Figure 2-2). Energy demand relative to GDP (gold line) had been falling until 2006, after which it became largely flat.

Figure 2-2 Decomposing emission intensity



Sources: Statistics Canada, Cansim Table 128-0016; National Energy Board database; and Canada's National Inventory Report to UNFCCC (2015).

Note: Final energy demand refers to end-user demand; including firms, consumers, and government. The decomposition shows how each component has moved relative to 1995. Combining (weighted) the blue, gold, and dotted lines gives the evolution of emission intensity of Figure 2-1 (gold line).

Either energy demand or the emission-intensity of energy have been falling.

On the other hand, the emission intensity of final energy demand (blue line) was mostly flat until 2006, after which it began to fall. These would suggest that the economy went through a transition in 2006 where it no longer became more energy efficient, but at the same time it turned toward less-emitting fuel sources.

But the link between them can be misleading.

However, this may be misleading. For example, if baseload electricity is produced with nuclear and hydro, and coal or natural gas are used to satisfy peak demand, then an economic downturn would reduce emissions at the same time that energy intensity became flat as a result of less expenditure on energy efficiency.

Policy changes were part of an existing trend.

This is consistent with the change after 2006. It is manifested in the decline in coal use, which then continued with policy decisions in Ontario to eliminate coal. Indeed, the economic downturn made it easier for Ontario to close its coal-based plants.

The downward trend has deep roots.

This suggests that the downward trend in emission intensity is caused by improvement in efficiency (generally defined) during times of economic growth, and then lower demand during times when growth slows. It gives the result that emissions intensity declined irrespective of the state of aggregate demand. The improvement in fossil-fuel efficiency can thus be seen as an underlying driver, that is only slowed when a substantial enough slowdown occurs.

Ongoing economic shifts cause continued decline in emission intensity.

Potential explanations for that trend can be given from a number of perspectives. These include a steady decline in the relative size of the sectors that cause emissions: between 1990 and 2006, iron and steel, chemicals, transport equipment and machinery all declined relative to the aggregate economy. In fact, manufacturing as a whole declined by some 2.3 percentage points of aggregate GDP. The decline was common across most OECD countries (see Figure C-4 in Appendix C).

As will continued competitive pressures.

In addition to these changes in the composition of the Canadian economy, each sector also individually increased its capacity to produce goods with fewer emissions. This occurred through efficiency gains as well as technological improvement. Competitive pressures continually lead to more efficient production processes that reduce material inputs, as well as improve final products.

Even productivity gains in other sectors will contibute to it.

Also important, however, are wage pressures from other sectors that can lead to value-added improving with only a small change in physical output. This is then observed as a decline in emissions intensity. This process was described some time ago in another context by Samuelson (1964) and Balassa (1964).

Steel production is a good illustration.

An illustration of it for emissions can be seen in steel production in Canada. Between 2001 and 2011, value-added per worker in iron and steel production increased by some 41 per cent. At the same time, the physical quantity of primary steel production actually decreased by 15 per cent.

The channel is wage competition.

Wage pressure from higher-productivity-growth sectors will lead to wage increases in all sectors, irrespective of gains in physical output (though wage disparity may increase). This is a process that will be ongoing and will be observed as a continual decline in emissions intensity at the sectoral level.

Oil and gas extraction has been expanding rapidly enough to affect the national trend.

The exception to the observation of declining emissions relative to aggregate GDP is the oil and gas extraction sector, which became a larger part of the Canadian economy. This also explains why the aggregate emissions intensity line in Figure 2-1 (gold line) began to flatten after 2011. Future growth in the oil and gas extraction sector should moderate unless prices return to levels well above $60 per barrel (for West-Texas Intermediate).[5]

Even non-energy sources of emissions had a steady decline.

The third component of the emission-intensity change decomposition (dotted line) evolved at a fairly constant rate. This is again consistent with a conjecture that these are emission sources that are becoming less significant parts of the economy.

Looking at sectors in more detail gives a picture that is less homogeneous: all sectors reduced emission intensity …

The source of changes in emissions can also be understood by looking at some underlying details (Figure 2-3 for the "emissions level" line, and Figure 2-5 for "emission relative to GDP"). The relative size of the pie charts in Figure 2-3 represents the relative levels of emissions, so the area of the pie chart for 2013 is almost a fifth larger than the area of the pie chart for 1990. This reflects the fact that emissions were almost a fifth higher in 2013.

… but only two reduced emission levels.

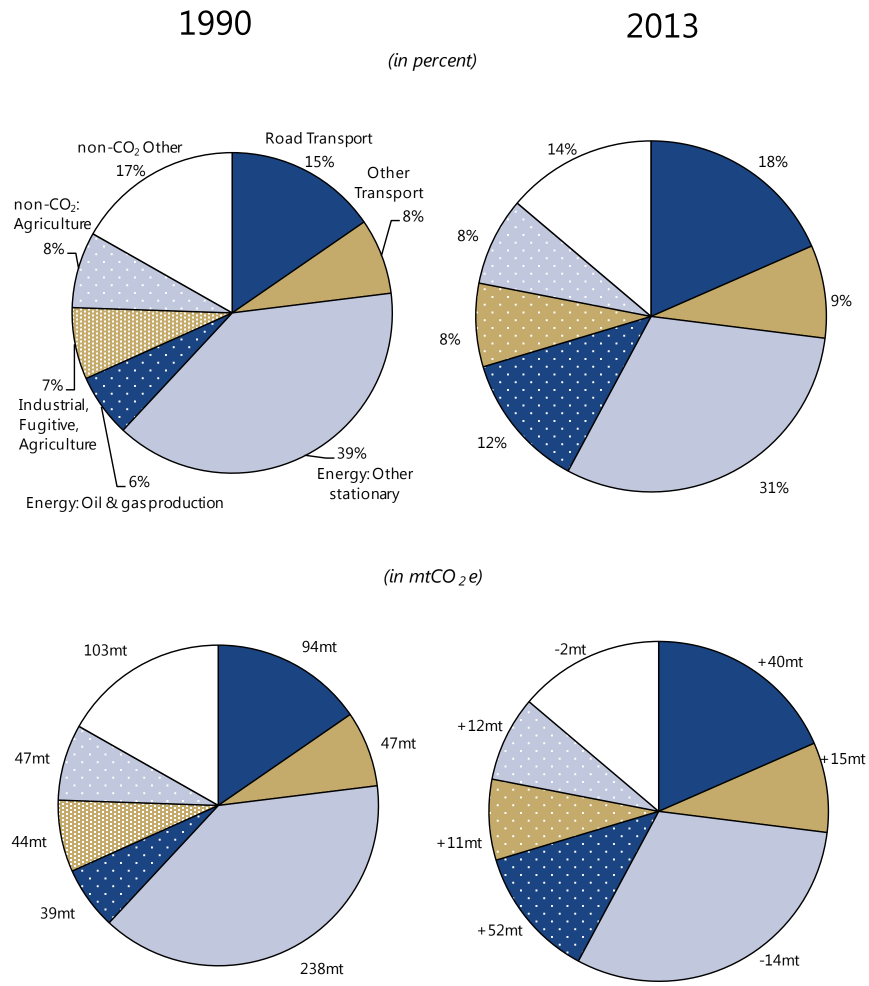
In two cases, the area of the pie segments are smaller in 2013, so emission levels in those sectors fell from those of 1990. In the first, Energy: Other stationary, the reduction is sharp given the economic growth that occurred. This sector includes fossil-fuel burning for electricity generation, manufacturing industries, agriculture and forest, buildings, and construction.

Emissions decreased more than energy use.

When this is combined with the increase in energy use that occurred during that period, it means that emissions per unit of energy consumed declined sharply. That is, the economy became more efficient in using the energy contained in fuels, and it was enough to offset growth.

The second area where emissions declined was from Non-CO_2 Other (other than agriculture). These are mainly process-related emissions that peaked in 1996 and have since been on a slow decline.

Figure 2-3 Decomposition and change in Canada's GHG emissions



Source: Canada's National Inventory Report to UNFCCC (2015).

Note: The first two pie charts show the change in each sector's proportion between 1990 and 2013. The second two show the change in each sector's level of emission. The energy and transport sectors (Road Transport; Other Transport; Energy: Other stationary; Energy: Oil & gas production) report only CO_2. Other GHG's from those sectors are reported in non-CO_2 Other. In 2013 emissions of GHGs were 18.5 per cent higher (113 $mtCO_2e$) than in 1990. This is reflected in the relative size of the pie (and segments) for those years.

In the other sectors, the level of emissions increased even though emissions intensity decreased. For example, non-energy related emissions in industrial processes, agriculture, and fugitive sources increased slightly.

Road transport and its energy source both substantially increased emissions.

Along with oil and gas extraction, road transport also experienced substantial increases in emissions. The next section outlines trends and the influences on its emissions. A more comprehensive discussion, with a different orientation, can be found in NRCAN (2013b).

Road transport and GHG emissions

Emissions from road transport are highly variable – even when incomes are increasing.

The emission intensity of road transport appears to have declined (Figure 2-5), whereas an increase in levels is shown in Figure 2-3. This suggests that emissions from driving and other forms of road transport increased with income, but on a less than one-to-one basis.

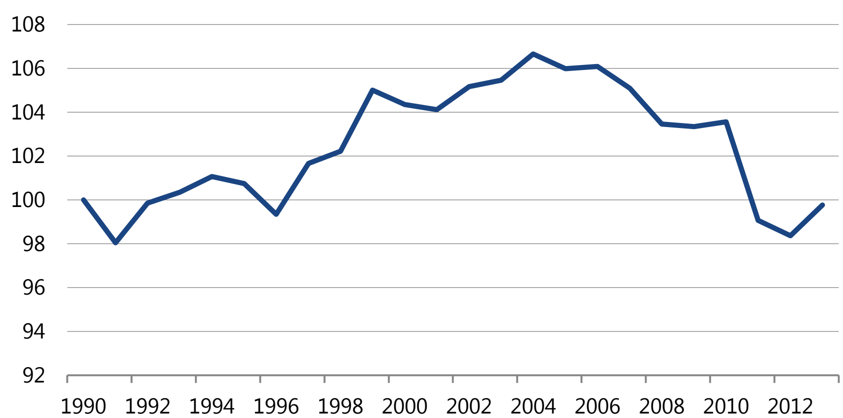
Looking at light-vehicles makes the flexibility of the fleet clearer.

So when income per capita increased at an annual rate of 1.3 per cent, emissions per person from road transport increased by 0.5 per cent per year. But when heavy trucks were distinguished from light-duty vehicles (Figure 2-4), by 2013 there was a notable return to 1990 levels of emissions per person from light vehicles. Again, since there was a substantial increase in income and travel, this suggests considerable change in behaviour in that sector since technology did not have sufficient time to react strongly.

Figure 2-4

Emissions per person from light-duty vehicles

Index 1990=100



Source: Canada's National Inventory Report to UNFCCC (2015).

Note: Light-duty vehicles include cars and small trucks – for use on roads – that run on gasoline, diesel, natural gas, or propane.

Oil prices played an important role in the change in emissions per person.

The responsiveness of light-vehicle transport to fuel prices is demonstrated by the decrease in emissions per person that started shortly after oil prices increased in 2000. From its peak in 2004, there was a decline of more than six percentage points in emissions per person. The evident delay may have been due to an initial perception that the price increases would not be permanent; oil prices have often experienced short-lived changes. The extent of the decline was also enhanced by the recession, but that did not begin in Canada until 2008, and growth recovered to above 3 per cent in 2010. For heavy-duty vehicles, the picture is clouded by globalisation and the increased use of just-in-time delivery. Between the mid-1990s and 2007 there was a 30 per cent increase in emissions as more products were moved by trucks (rail was only a little changed). But since 2007 they have remained unchanged, even as transport services have continued to increase.

Sectoral change

Intensity improvement is more than just each sector becoming more efficient...

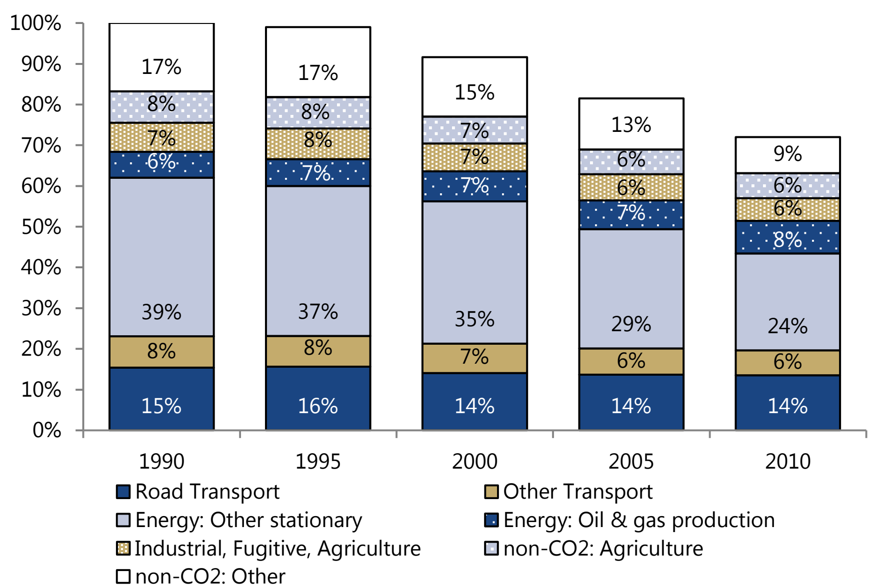
Returning to an issue outlined earlier, important from both Figures 2-1 and 2-3 is the evident consistency of the decline in emissions intensity. Figure 2-3, however, made it possible to observe that the reduction in emissions intensity is more than just the low-emission sectors of the economy becoming bigger than the high-emission sectors; for example, the services sector becoming larger than manufacturing.

The combination of changes gives a steady rate of change.

For the most part, there was a reduction on both the intensive margin (within sectors) and extensive margin (across sectors). What is again striking is that the improvement in efficiency apparently occurred at the same annual rate irrespective of the rate of economic growth; the slope of the emission intensity line in Figure 2-1 remained roughly constant. Even at the sectoral level there was a declining rate of emissions intensity that appears stable after 1995 (Figure 2-5).

Figure 2-5 Decomposition of Canada's GHG emissions intensity (GDP)

Index 1990=100



Source: Canada's National Inventory Report to UNFCCC (2015).

Note: This figure decomposes 5 dates of the "Emission relative to GDP" line of Figure 2-1. So, for Road Transport in 2010 emissions per unit of GDP were 2 percentage points lower than in 1990 (rounding obscures the magnitude). Only Oil and gas production showed an increase in emissions per unit of GDP. The segment Energy: Other stationary refers to Electricity and heat production, Petroleum refining, Manufacturing, Commercial and institutional, Residential, Agriculture, and Forestry.

3. Regional emissions

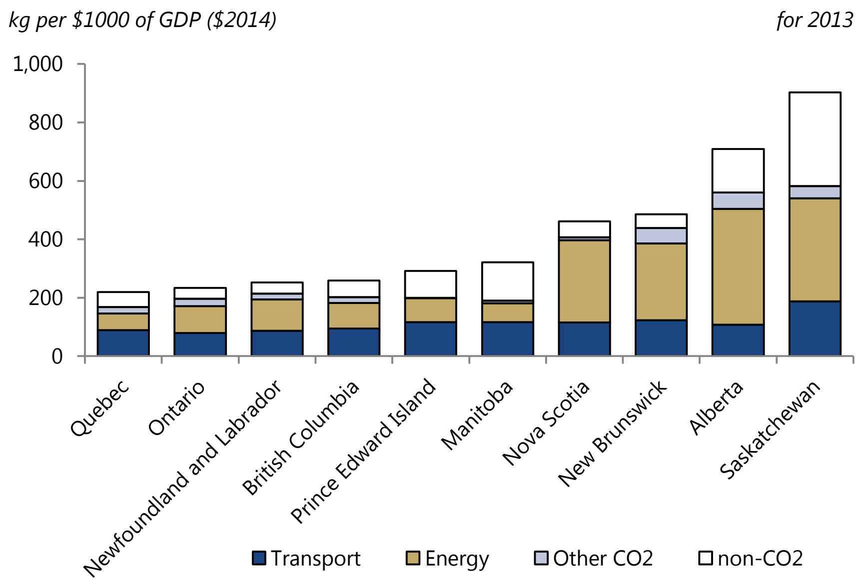
Canada has some unique challenges.

An important facet of Canada's GHG emissions is its regional diversity and strong regional governments. Canada's provinces are rich in natural resources which they control, but each has its own mix, with some being more carbon intensive than others. This contributes significantly to differences in emissions relative to GDP (and per person).

Regional emissions vary considerably… by a factor of 4.

At the low end is Quebec, where a heavy reliance on hydroelectric power leaves emissions at about 200 kilograms of CO_2e per thousand dollars of GDP. Saskatchewan is at the high end with more than four times as much (Figure 3-1).

Figure 3-1 GHG emissions intensity by source and region



Source: Canada's National Inventory Report to UNFCCC (2015).

Some sources of emissions are more-or-less similar across Canada, others are not.

There is considerable consistency across regions in emissions from Transport (except for Saskatchewan, where it is mainly due to heavy use of off-road transport equipment). But there is an outsized level of energy-related emissions in the four provinces with abundant fossil-fuel resources (right-most in the chart). Together, they account for only 25 percent of Canada's GDP, but some 52 percent of emissions (in 2013).

Common experiences provide lessons.

There are also some informative observations concerning regional effects that arise from experiences over recent decades. Particularly illustrative is the response that occurred across regions to the energy price hikes after 2000.

Prior to 2000, experiences were mixed.

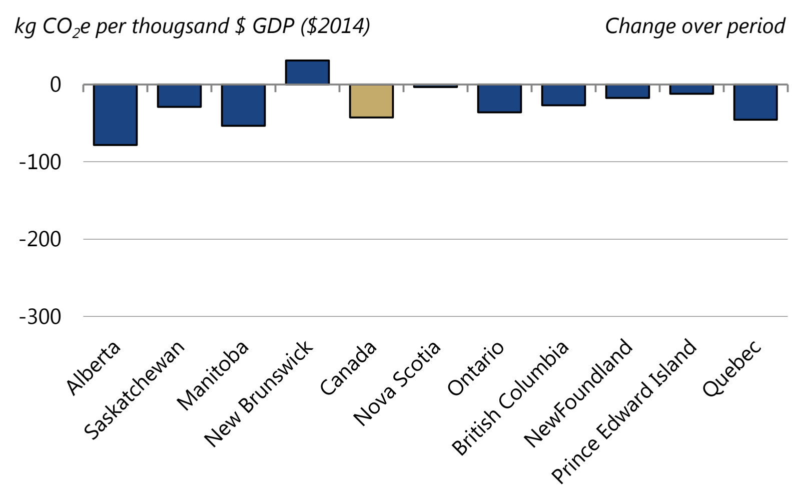
Consider the periods before and after 2000 (Figure 3-2). During the first, there was some reduction in most provinces, but it was uneven and in response to local events; there was no common driver. It ranged from a decrease of 78 kilograms per thousand dollars of GDP in Alberta to an increase of 31 kilograms in New Brunswick (Figure 3-2, Panel a).

After 2000, they were more consistent.

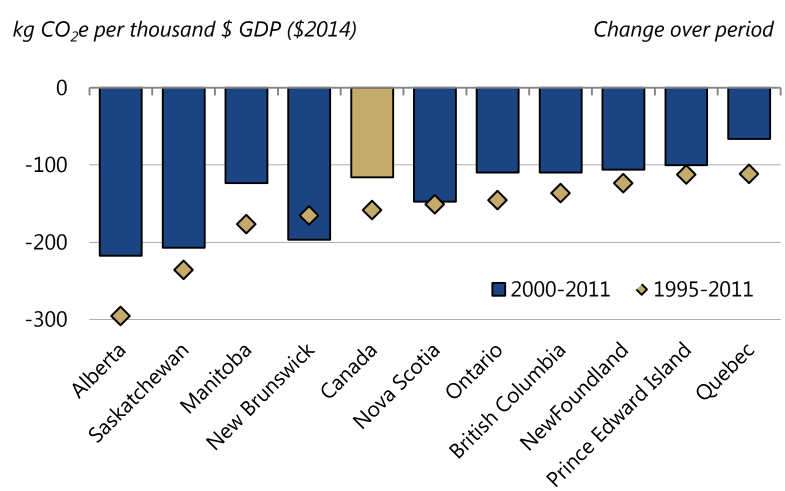
Then, even accounting for the longer period from 2000 to 2011, the changes were larger and more uniformly negative (Figure 3-2, Panel b). There appears to be a common driver.

Figure 3-2 Change in GHG emissions intensity by province

(a) 1995-2000



(b) 2000-2011



Source: Canada's National Inventory Report to UNFCCC (2015).

Oil prices rose after 2000.

One reason for that distinction across the periods is found in the change in cost for both natural gas and crude oil. Between 1995 and 2000, the nominal price of oil remained roughly steady at US$20 per barrel. But between 2000 and 2011, it more than tripled to an average of US$70, with spikes considerably higher.

As did natural gas prices.

Natural gas also rose sharply, with price spikes that more than doubled the cost to industries and households. But in the later period, prices averaged 50 per cent higher. This market-induced movement to conservation and energy efficiency improvements was common across all regions, irrespective of their prior level of emissions.

The largest decrease came from those with the highest intensity.

Thus Alberta and Saskatchewan achieved an intensity reduction that was larger than other provinces in spite of what appears to be a heavy reliance on GHG-emitting activity. Interestingly, Saskatchewan and Alberta both reduced the emissions intensity of their economies even while their production of fossil fuels increased. The fossil fuels they were producing were largely being sent to other regions, so expansion in other sectors dominated the oil sands emissions increase.

This illustrates the potential of emissions pricing to impact on emissions intensity.

Also implied from this illustration is that significant reductions in carbon dioxide emissions can be achieved through instruments such as pricing carbon dioxide emissions. That is, during 2000 to 2011, a price increase for oil and gas led to a change in behaviour by both firms and individuals. A given quantity of fuel will emit a fixed amount of carbon dioxide when burned. So a price on carbon dioxide corresponds to a price on the source fuel. As such, a price on carbon dioxide should similarly reduce fuel use.

4. Projecting GHG emissions

From 2013, 201 mtCO_2e would have to be abated to reach 30% target – could be higher by 2030.

Canada's emissions in 2013 were about 3.1 per cent below those of 2005. The objective outlined earlier of achieving a 30 per cent reduction from 2005 by 2030 would then require an additional abatement of 201 mtCO_2e from the 2013 level (not including potential removal of carbon dioxde from land use; see Endnote 1). However, since the economy will continue growing, emissions cannot be assumed to remain at 2013 levels into the future.

Projections are difficult to make since prices are inherently unpredictable.

One means of projecting future emissions is to derive demand for various fossil fuels from incomes and energy prices. This is made challenging by the inherent difficulties of projecting any price, including oil prices. Projections of energy prices and demand made just a couple of years ago have proven unreliable; indeed, they are inherently so because any information regarding future supply and demand is likely already reflected in today's prices.

Past trends in levels are of little help.

An alternative would be to project the level of emissions directly from past trends. This would be difficult to do, however, as there is no discernible trend rate of change in the level of emissions (the blue line in Figure 2-1).

But projections made from intensity trends by economic sector might provide a better footing.

However, emissions intensity (the gold line in Figure 2-1) fell at a fairly steady rate after 1995. This decline occurred with no specific policy in place to induce it (Section 2). Indeed, it began before the Kyoto Protocol was even signed at the end of 1997.

Emissions from oil and gas extraction might alter the trend.

The downward trend in the emissions intensity line of Figure 2-1 can be projected to continue, though a risk exists of oil-sands emissions rising sharply. However, this risk would be linked to prices for crude oil. Throughout November, 2015, the futures price of West-Texas Intermediate for delivery in 2020 averaged about US$58. In early 2016, even with a strong fall in the spot prices, it was still near US$50.

Current projections of future prices suggest a slowing but not stopping of oil sands development.

Since markets generally reflect available information, a futures contract is the best prediction of what the future price will be. Otherwise, knowledgeable investors who thought that the price would be higher would buy the contracts, driving up the price. Prices of crude oil at those levels will not stop the development of the oil sands. However, neither will they restore the rapid rate of expansion that resulted in a doubling of production between 2006 and 2014. CAPP (2015) also projected either a strong or mild rise in emissions from oil sands, depending on how strongly the price recovers; but, its projection of oil sands production were revised significantly downward over the previous 2 years.

Projection is based on each sector's 1995 to 2013 trend.

The PBO projection is made on the basis of sectoral trends in emission intensity between 1995 and 2013. It serves to draw attention to trends, and to provide a basis for discussion of possible changes to those trends. It thus motivates the discussion of sectoral actions, rather than providing detailed forecasts.

Building from sectoral detail will capture changing composition of sources.

An important aspect of building aggregate emissions from sectoral detail is that the changing composition of the economy will be reflected in the projection. Nonetheless, a drawback is that it makes the aggregate projection sensitive to the level of disaggregation, and even the historical period chosen.

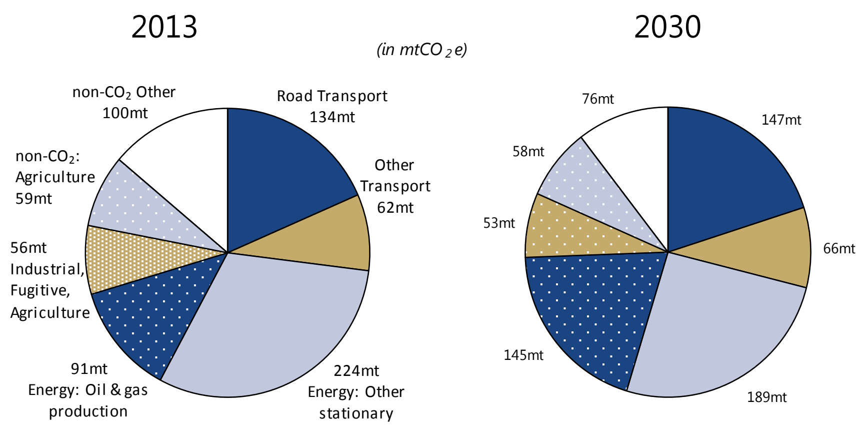
Improvement going forward is conservative by some measures.

Sectoral projections show that the rate of improvement in aggreate emissions intensity projected for 2014 to 2030 (1.6 per cent per year) is the same as that achieved between 1990 and 2013. And it is less than the rate of 1.9 per cent per year from 1995 to 2013 per cent.

Baseline is a no-new-policy projection.

Furthermore, a projection made on the basis of continuing 1995 to 2013 sectoral intensity trends represents a no-new-policy baseline, unless those trends are caused by policies that will expire.[6] Figure 2-3 outlined those sectoral trends, and Figure 4-1 illustrates their results.

Figure 4-1 Decomposition of projected change in GHG emissions



Sources: Canada’s National Inventory Report to UNFCCC (2015) and PBO projection.

Note: Efficiency gains refer to improvements in emissions per unit of GDP. The reduction in emissions per unit of GDP uses the historical rate of improvement from 1995 to 2013 at a sectoral level.

Road transport and oil sands-related activity are the main sources of ongoing emissions.

Emissions from road transport increase from 134 mtCO_2e to 147 as a result of increasing incomes and population, though there is some gain in fuel efficiency. Oil sands are also increasing in the baseline (again, no policies have been incorporated). Of the 91 mtCO_2e emissions for 2013 shown for oil and gas production, some 70 mt were from the oil sands.

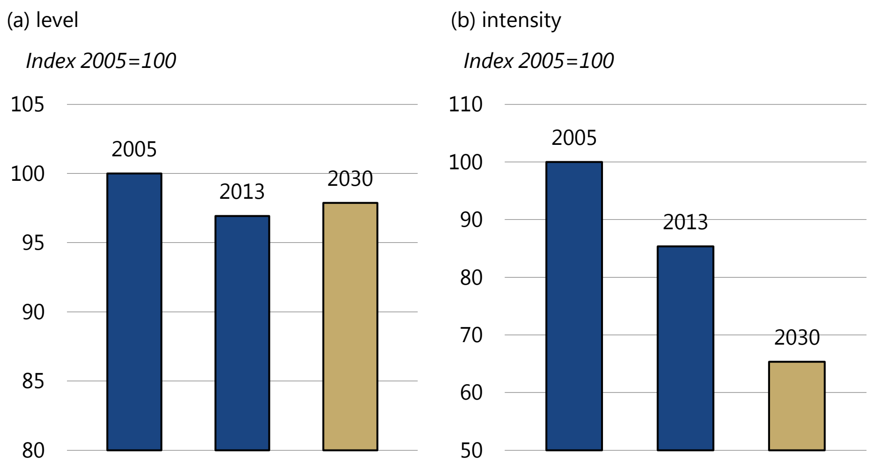
Expansion of oil sands is not out of line with other projections.

By 2030, oil sands would expand to roughly 123 mtCO_2e without additional policies. This is roughly in line with projections for oil sands in CAPP (2015) where production is projected to increase by between 56 per cent and 108 per cent from 2013.

The result is a small upward drift in emissions.

Most other sectors are decreasing their emissions. The overall rate of emissions intensity improvement that results is just under 1.6 per cent annually. When combined with GDP growth projected to be near 1.6 per cent, there is a small drift upwards in emission level (Figure 4-2); they would increase by about seven $mtCO_2e$.

Figure 4-2 Projection of emissions based on PBO growth baseline



Sources: Canada's National Inventory Report to UNFCCC (2015) and PBO projection.

Note: Efficiency gains refer to improvements in emissions per unit of GDP. The reduction in emissions per unit of GDP uses the historical rate of improvement from 1995 to 2013 at a sectoral level.

Continued emission intensity improvement stabilises aggregate emission levels when growth is moderate.

The two panels of Figure 4-2 link directly to Figure 2-1. Figure 4-2, Panel (a) extends the blue line "emissions level" to 2030, while Figure 4-2, Panel (b) extends the gold line "emission relative to GDP". This projection implies that in 2030, without explicit new policies, Canada's aggregate GHG emissions could be about where they were in 2013. Underlying this is the decline in emissions intensity (past and future) for all sectors except oil and gas extraction, where emissions intensity has been increasing because of the oil sands.

Other projections feature faster growth and slower intensity improvement.

The most direct comparison to the baseline projection is with that made by Environment Canada (2014b) in its annual *Canada's Emissions Trends to 2014*. There, projections to 2020 use a more rapid rate of GDP growth (2.2 per cent), combined with a slower emission intensity improvement (0.7 per cent) until 2020.

And significantly higher emissions in 2030.

Superceding that outlook, however, is a newly released projection to 2030 (see Environment Canada, 2016). It suggests in a central scenario that emissions could be 815 $mtCO_2e$, about 82 $mtCO_2e$ higher than PBO's. That projection is consistent with Environment Canada (2014), which also had emissions at 815 $mtCO_2e$ in 2030 – driven significantly by nominal oil prices projected to be over US$110 in 2020 and US$120 in 2030.

Slow intensity improvement is implied in the most recent projections.

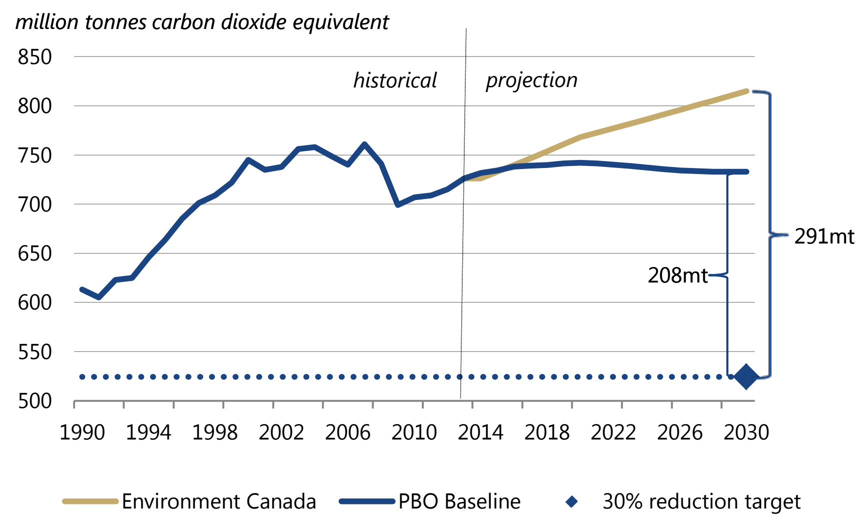
The economic growth underlying that projection, however, leads to a conclusion that emission intensity is improving at exceptionally slow rates relative to history (roughly 1.1 percent per year).

Achieving the 2030 target

Target abatement is 208 $mtCO_2e$, 291 with Environment Canada..

To achieve the targets announced in May 2015, Canadian emissions would have to decrease by 208 million tonnes of CO_2 equivalent from projected 2030 levels (Figure 4-3). For Environment Canada's projection, the emission reduction becomes 291 $mtCO_2e$ by 2030 (40 per cent more than PBO's).

Figure 4-3 Comparative projection and target: level



Sources: Canada's National Inventory Report to UNFCCC (2015); Environment Canada (2016); and PBO projection.

Note: The PBO projection is based on extending past decreases in emission per unit of GDP on a sectoral basis.

A significant difference across baselines is in GDP growth.

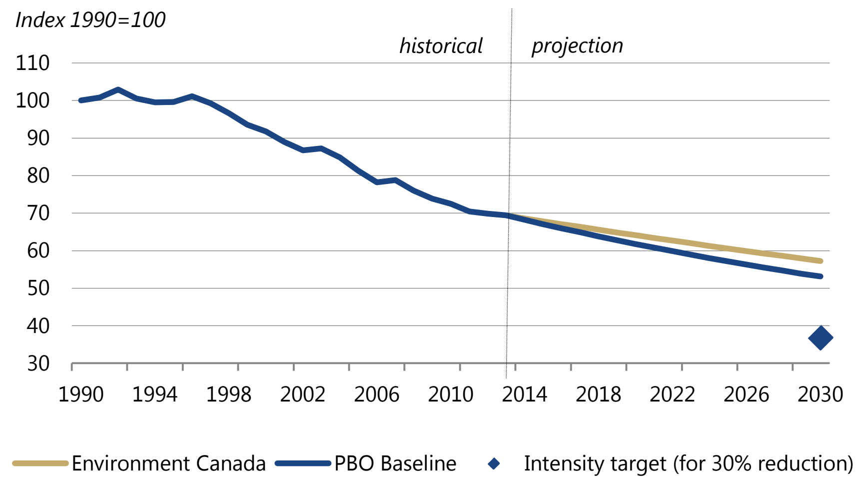
Environment Canada's projected emissions are higher than PBO's in part because GDP (per capita) in 2030 is 3.1 per cent higher than PBO's.

Intensity ends a little higher in Environment Canada's projection.

At the end of the projection, emissions intensity under the PBO's baseline are only 4 percentage points lower than Environment Canada's (Figure 4.4), even though the level of emissions is substantially higher. Much of the difference in emission levels is thus coming from faster GDP growth.

Figure 4-4

Comparative projection and target: intensity



Sources: Canada's National Inventory Report to UNFCCC (2015); Environment Canada (2014); PBO projection.

Note: The emissions intensity given for the 30% reduction target is what would have to be achieved under the PBO baseline. The target would be only a little lower with Environment Canada's projected growth and emission intensity to 2030.

But when higher emissions comes from higher growth, more income is available to deal with abatement.

The reduction in the level of carbon dioxide emissions is larger than that needed with the PBO baseline, so more aggressive actions to counter it would be called for. However, average GDP per capita in 2030 (in 2014 dollars) would be about $1,900 higher (+3.1 per cent) than in the PBO baseline, so more money is available to cope with it.

This is a proposition true for all environmental policy.

In fact, this is a general proposition regarding uncertainty in emission projections. When the source of uncertainty concerns projected growth, more rapid GDP growth will always lead to higher incomes, which will make it less burdensome to achieve an emissions target.

Slow emission intensity improvement makes abatement more difficult.

On the other hand, when the uncertainty is concerning projected emission intensity, then slower rates of intensity improvement will necessarily imply a larger loss of income to achieve the target. The slowdown in improvement in intensity after 2013 shown in Figure 4-4 suggests that neither projection is overly optimistic concerning future emissions: in both cases, the deflection in 2013 is caused by further oil sands development.

Other projections

Other projections have higher emissions, but the source is generally faster growth.

Other projections include OECD's (2014) annual real growth of 2.1 per cent between 2015 and 2030. In this case, Canada's emission level would increase by about 40 mtCO_2e (+5 per cent) even with the efficiency improvements conjectured above.[7,8] Chateau, Rebolledo and Dellink (2011) have an implicit emissions intensity improvement of 1.5 per cent per year. When that is combined with a 2.4 per cent average annual rate of economic growth, they project Canada's emissions to grow by 24 per cent between 2010 and 2030 (see Endnote 7).

NEB projection also implied rapid economic growth that led to emission growth.

The National Energy Board's Energy Outlook (2013) used an average annual economic growth of 2.1 per cent between 2010 and 2030. The resulting 25 per cent growth in primary fossil-fuel energy demand per cent implies that carbon dioxide emissions would increase by roughly 17 per cent (PBO inference[9]).

5. Cost of mitigating emissions

Explicit carbon dioxide pricing is generally the preferred instrument for most economist.

The emission target of 30 per cent below 2005 by 2030 would place emissions substantially below those projected in the baseline (Figure 4-3). The concept of "carbon dioxide pricing" has often been highlighted as a means that achieves reduction targets efficiently, that is, it imposes the lowest cost on the economy as a whole (see Endnote 2).

Carbon dioxide pricing has a number of forms...

There are two general approaches that explicitly price carbon dioxide: (1) direct tax on emissions of carbon dioxide, (2) cap-and-trade system. In addition, there are two other approaches that implicitly price emissions by providing incentives to reduce them: (3) regulatory requirements, and (4) technology subsidies.

...this report will not distinguish between them.

All four have advantages and disadvantages and must thus be considered carefully in designing the means to achieve emission objectives (see Appendix B). For the remainder of this paper, however, carbon dioxide pricing (when mentioned) will remain general and not specific to any of these instruments.

This report does not detail the cost of doing nothing ...

While the analysis here is broad in looking at the impact of achieving Canada's emission target, it will not analyze the cost of doing nothing. Such an omission is not to diminish the possiblity that the costs may be significant. Indeed, NRTEE (2011) estimated them to be as much as $5 billion per year by 2020, and increasing thereafter.

... which at best continues an uncontrolled experiment.

Instead, this report takes for granted that the case for reducing emissions has been made and discusses its implications. Perhaps the most compelling reason for undertaking actions to avoid significant temperature change (as scientists have argued would occur with unrestricted emissions) is to note from the scientific literature that it would engender an uncontrolled experiment that carries considerable risks, both environmental and economic.

The actual loss to the economy is different from the impact...

Carbon dioxide pricing would cause economic costs that will be measurable in lower GDP, but can be more formally charactized as *dead-weight losses*. These arise because changes in production processes and consumer purchases would have to occur to achieve the reduction.

...generally much smaller.

Only a small part of the economic changes are actually lost to the economy in a dead-weight loss. This is because, in the reallocation of resources within the economy, only things like long-term changes in the income of individuals (or profits of firms) endure.

When the impacts have passed, incomes will be a little lower.

In other words, not all individuals who had well-paying jobs in sectors affected by carbon dioxide pricing will be able to find similar-paying jobs: dead-weight losses imply lower income for some, but not less employment over the medium to long-term.

Full economic model can give an estimate of the cost after equilibrium is restored.

A framework that gives an estimate of the (dead-weight) cost of reducing emissions is a general equilibrium economic model. It accounts for the reactions in the economy to a change in prices. It also allows for a reallocation of resources to alternative activities – or even activities that support the reduction in emissions such as wind power.

NRTEE undertook a comprehensive study of the impact.

Such an estimate was given by the National Round Table on Environment and the Economy (NTREE, 2009). Though their objective was a larger decrease by 2050[10], their results show that a 30 per cent reduction would require a carbon dioxide price of $100 per tCO_2e (their Figure 14, adapted to 2014 dollars[11]). Numerous other estimates have been made of the economic impact of reducing emissions, but the comprehensiveness of their analysis allows it to serve as a reference for this report.

The estimated loss to the economy from that transition is about 1 per cent to 3 per cent of GDP (NRTEE, 2009). This loss is given as a range because a revenue-generating carbon dioxide price was used and the manner in which revenues are recycled changes the impact. Reducing existing taxes that are themselves distortionary can lead to a smaller loss.

But models present idealised outcomes that can only be considered reference points.

On the other hand, the estimate can be said to represent a minimum loss, since the framework assumes that the carbon dioxide price (irrespective of how it is recycled) is uniformly and perfectly applied across almost all sources of emissions. To the extent that other considerations such as the complexity of emissions sources (discussed below) must be dealt with in implementation, the loss could be bigger.

Incomes in the baseline are increasing…

The 1 per cent to 3 per cent economic cost to achieve the 30 per cent reduction is a decrease in the level of GDP relative to the baseline (Figure 5-1). Economic growth in the baseline means that by 2030, average incomes (as measured by GDP per capita) would reach $61,800 per person, about 11.5 per cent higher (measured in 2014 dollars) than the level of $55,500 in 2014.

… even with climate policies.

However, the emission reductions – when done in an efficient manner (that is, where the cost is kept to a minimum) – would instead cause income per capita to be between $600 and $1,900 lower. So by 2030, the potential loss would put incomes at between $59,900 and $61,200.

$100 carbon dioxide price equals 24 cents per litre of gasoline.

To appreciate the scale of the effort required for a 30 per cent, or 208-million-tonnes reduction, consider that a price of about $100 per tonne of CO_2e would increase the price of a litre of regular gasoline without ethanol by about 24 cents.

The initial disruption can be significant if done all at once.

If it had been applied to sources of emissions in 2013, it would have imposed a cost on them in 2013 of about $73 billion (a $100 price applied to all sources of emissions in 2013). This 'sticker' cost, however, is misleading since it represents an impact estimate where all else is held equal.

But responses will occur.

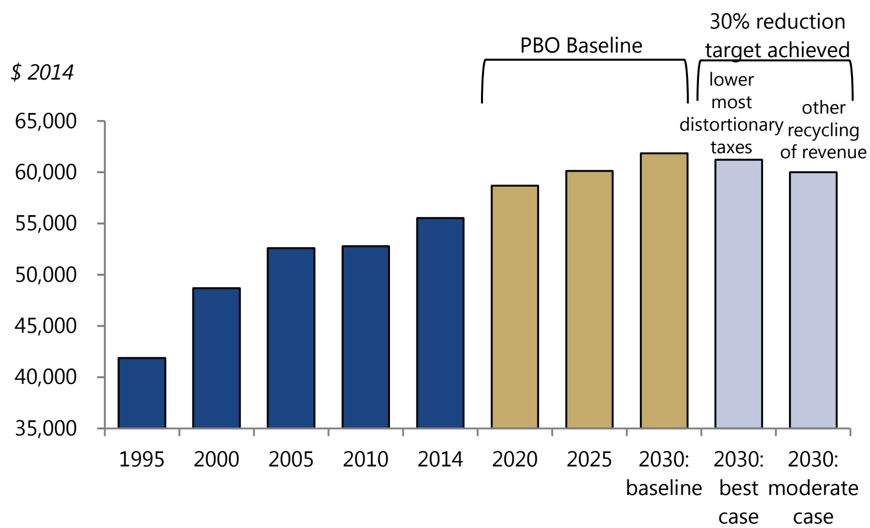
It is a cost in the sense that it represents an initial disruption to the Canadian economy, rather than an actual loss. Economies react to changes in prices as people alter their buying habits and firms change their processes and technologies.

Potential revenue from pricing carbon dioxide is substantial.

Again for perspective, a $100 tax per tonne of CO_2e would have amounted to a $53-billion source of revenue in 2013. This would have represented about 18 per cent of income taxes (personal and corporate) received by federal and provincial governments, or 11 per cent of all taxes (not including social contributions). Again, the ultimate impact of the policy will depend on how revenues are recycled.

Figure 5-1

Projected GDP per capita: baseline and scenarios with revenue recycling



Sources: PBO calculations from NRTEE (2009) and PBO projections.

Issues that can raise the economic cost

Estimated cost represents a back-drop for discussion.

The economic loss of 1 to 3 per cent of GDP is projected under ideal circumstances; that is, where the cost of abatement is uniform everywhere, and the implementation is gradual but certain. While these form the backdrop for analysis, there are caveats.

Complexity of emission sources

Number of sources and GHG gases muddy that back-drop.

A hallmark of the challenge to reduce GHG emissions is its complexity given the number and dispersion of emission sources. It is difficult to use a single instrument to achieve reductions over seven gases that are emitted from thousands, if not millions, of sources. When multiple instruments are being used simultaneously, there is a risk that they will not be sufficiently coordinated, which would increase the cost for the economy.

Mix of instruments creates a challenge to ensure costs is kept low.

With a mix of instruments, economists note that minimizing the impact on the economy calls for the cost of emission reduction from each source to be roughly similar per tonne. The reason for this is that only when all sources face the same cost is there some assurance that the cheapest will be used first and most often. A source that is initially cheap will be heavily used until its unit-cost approaches that of other sources.

Coordination will be key ...

Thus far, all four types of instruments outlined above are being used in Canada to varying degrees.

... especially since all instruments have a price for each tonne of abatement – some are implied.

To illustrate what is required, consider regulatory measures. The implicit cost to firms and individuals should be roughly equal to the explicit carbon dioxide price elsewhere. So if a regulatory measure were used for light vehicle transport, but a cap-and-trade system were used for electricity production, then the cost of meeting the regulation (implicit cost of reduced emissions) should be about the same as the cost of a permit (per tonne) in the electricity sector.

Regulatory measures need to be costed...

That is, the regulatory measure will increase the cost of a light vehicle by an estimable amount, which can then be used to derive a cost per tonne of carbon dioxide avoided. That implicit cost can then be compared to explicit costs elsewhere.

... to avoid imposing large costs.

This issue is of first order importance since reducing emissions from automobiles is potentially expensive (though less visible) under a regulatory regime, whereas emissions reduction in other sectors may not be. The upshot is that the choice of which activity to curtail and by how much should be largely left to firms and individuals who simply see a cost for each activity that causes emissions.

The EU ETS is not coordinated with other climate policies...

The European Union, with its Emissions Trading System (ETS), provides an example of a significant problem with coordination across instruments. Included within the scope of that trading system are a number of industrial sources that face a uniform cost of abatement, that is, the price of the emission permit. This has been hovering around five euros per tonne of carbon dioxide for at least the past two years after having started well above that in 2006.

...creating higher overall cost than is necessary.

A separate decision in many countries to reduce GHG emissions from electricity generation through subsidies and mandates led to a cost of electricity that varies widely. Each country implemented its own polices to achieve it, without coordination. Moreover, those policies were not linked to the ETS in a meaningful way. This led to strong outcomes, such as a cost of reducing GHG emissions from electricity in Germany that is an order of magnitude higher than in the other industries covered by the ETS.

When emission reductions of a significant magnitude are required (the 30 per cent reduction target noted earlier), the aggregate costs from a co-ordination failure can become quite large since the disruption to the economy will be extensive.

Regional diversity of emission sources

Canada's regional diversity could create a wide disparity in cost.

Another issue that could lead to substantially higher cost is the uneven impact that abatement will have across regions. In Saskatchewan and Alberta, where emission intensity is higher than elsewhere (Figure 3-1), a price of \$100 per tonne of CO_2e emission would represent some 10 per cent and 7 per cent, respectively, of provincial GDP (again, this is a "sticker price"). While in others, such as Ontario, it would represent 2 per cent.

Some provinces have electricity sectors that are already low-emission.

On the other hand, eliminating 200 kgCO_2e per thousand dollars of GDP from Quebec's emission intensity would be more challenging than removing the same amount from Saskatchewan's. The policy would have to make Quebec virtually carbon-free; Figure 3-1. This is because Quebec is already a low emitter since it generates electricity using hydro.

Most, if not all, options for dealing with regional issues involve some tradeoff.

Trying to avoid that outcome by having all provinces undertake similar *proportional* reductions would diminish that problem, but not eliminate it. The economic concept of an elasticity would still imply that a higher carbon dioxide price would be required in Quebec to get the same proportionate emission reduction as in Saskatchewan. Quebec's fuel prices are already higher, so even more would be needed. All options involved some tradeoff.

But there is a criteria for keeping costs low.

Economists recognise that to keep costs to a minimum the price per tonne of CO_2e abatement (implicit or explicit) should be similar everywhere. They also note measures that counteract uneven regional economic impacts without compromising the goal of keeping the aggregate economic cost as small as possible. Simple examples include (among others) tax rebates, subsidies for carbon dioxide abatement, or permit allocations within a cap-and-trade system, that is, "grandfathered" permits.

Buildling and maintaining a consensus is the central objective.

These "complementary" measures (that is, means of implementation) could partially address regional cost disparities that would undermine the consensus around lowering emissions, without compromising the cost-minimizing objective of equal carbon dioxide prices across the country.

Pre-existing polices

Climate policies are not working from a clean slate.

Another issue raised by economists is related to a concept known as the Theory of the Second Best which was introduced by the Canadian economists Lipsey and Lancaster in 1956. At its simplist, it notes that when an existing market disruption (i.e. distortion) is present, then trying to use a first-best policy to achieve goals cannot be assured of improving outcomes.

The risk for GHG emission abatement is that measures already implemented at both the federal level (fuel-efficiency standards and coal emission standards) and the provincial level (Alberta, British Columbia, Quebec, Manitoba, and those announced in Ontario and elsewhere) create that context.

Existing measures have a cost which must be accounted for...

For example, the regulatory policies create an implied price on emissions for transportation. Adding new measures to the mix could lead to using a first-best (national) carbon-pricing instrument that added to that price, rather than displaced it. In that case, adding a carbon price in the transport sector would result in its cost being significantly higher than in other sectors.

Timing of abatement

Since it is the stock of carbon dioxide in the atmosphere that matters, timing is important...

The costs of achieving a significant reduction in emissions also have another dimension that is independent of its complexity or distributional impacts. The timing of the reduction can matter a great deal for the magnitude of the impact that will be felt. Since significant infrastructure will have to be changed, a gradual process would avoid short-term resource constraints that could increase costs.

... for keeping costs low.

Moreover, a gradual replacement of fossil-fuel intensive capital will avoid stranding assets that may affect the viability of some firms. Set against that background is the fact that GHGs accumulate in the atmosphere and last a long time.

But acting early reduces cummulative emissions.

Over the next 15 years, the timing of the 30 per cent reduction could have a significant impact on Canada's cumulative emissions. For example, if the 30 per cent reduction target were attained immediately, Canada's contribution to the avoided stock of GHGs in the atmosphere by 2030 would be as if emissions had stopped entirely for five years.

So there is a tradeoff with regards to timing.

This is relative to the other extreme where the reduction was done entirely in the last year. There is thus an implied tradeoff between the timing of reduction, and the ultimate temperature change that may occur as a result of the stock.

Negative-cost abatement

Negative-cost abatement options means gains are possible from exploiting them.

An issue that comes up repeatedly in discussion of GHG abatement is the question of zero or negative-cost sources of emissions abatement. It typically refers to actions that can be undertaken that have no net cost (or produce net benefits) even though they were not being undertaken on their own.

They are formalised in the economic literature.

Formally they are known by economists as *market failures* because they reflect an outcome where the well-being of the community could be improved without having to economically harm anyone in doing so. A traditional literature divides them into categories such as environment externalities, public goods, decreasing-cost, and institutional barriers. Each of these can to varying degrees lead to outcomes that could be improved upon without adverse consequences.

Problems caused by lack of easy access to information often call for regulatory measures.

Another strand of that tradition looks at insufficient information, that is, a general lack of information, or information asymmetries such as where different parties in a market do not have access to available information. These latter sources of problems in markets are the basis of many of the claims of negative-cost GHG abatement.

McKinsey (2009), presented a series of cost estimates for abating global GHG emissions by sector (electricity, oil and gas extraction, buildings, etc). One criticism of that particular effort concerned the large amounts of negative-cost abatement opportunities that they report. They imply that there is a lot of free money that investors are failing to take up.

But zero-cost options are each unique and require careful study to get the right solution.

Such market failures are seen by economists as exceptions in competitive markets since the private sector excels at finding profit opportunities. Rodrick (2015) notes that without a good understanding of what is underlying them, there is a potential for the solution itself to do harm.

6. Mitigation opportunities

GHG abatement will be more complex than other environmental policy.

The earlier illustration of the diversity of emissions across regions and sectors suggests that attempts to reduce emissions will have highly varied impacts across the Canadian economy. Unlike other environmental issues – such as acid rain, or ozone-depleting chlorofluorocarbons (CFCs) – that were successfully dealt with in a straightforward way, GHG emissions come from many sources and are thus a more challenging problem to deal with.

Some appreciation of the needed changes can be gained through a sector-by-sector survey.

Those other issues either had a limited number of sources (sulphur-emitting coal plants in the case of acid rain), or had an available alternative technology (as with CFCs). A better understanding of what emissions reduction might involve can be gained by delving into major individual sources of emissions.

Projections made on the basis of specific industries will make the discussion clearer.

On a sectoral basis, these can be distinguished into nine sectors that account for some 91 per cent of Canada's emissions (Table 6-1: this disaggregation is different from that used earlier, but makes the discussion here more concrete).

Table 6-1 Emissions by major sectors in 2013

Sector	Emissions 2013		Emissions 2030
Electricity generation	12.1%	(88 mt)	*71 mt*
Transport services (less aircraft, rail, and pipeline)	25.2%	(178 mt)	*186 mt*
Oil & gas production, refining, and distribution	23.2%	(169 mt)	*208mt*
Agriculture and waste products	11.7%	(89 mt)	*81 mt*
Buildings (commercial and residential)	10.3%	(75 mt)	*61 mt*
Chemicals manufacturing	4.7%	(34 mt)	*31 mt*
Iron and steel manufacturing	1.8%	(13 mt)	*11 mt*
Cement manufacturing	1.4%	(10 mt)	*8 mt*
Land-use, land-use change and forestry	-2.0%	(-15 mt)	*0 mt*

Sources: Canada's National Inventory Report to UNFCCC (201 and; PBO projection.

Note: Land-use, land-use change and forestry was projected in Environment Canada (2014b) to be a net 'sink' of 19 $mtCO_2e$ for 2020, but new projections to 2030 are not yet available.

Technological possibilities can be noted in each sector.

The potential to achieve meaningful reductions in each of the sectors varies as a result of technological constraints, as well as economic ones. The discussion below highlights some of those means so as to gauge what can be done with available technologies.

This will provide some idea of what is possible at various costs.

Similar to an analysis presented in CCA (2015b), it is intended to underpin the quantitative assessment of costs discussed earlier that could occur in response to carbon dioxide pricing (implicit or explicit). This is summarized in Table 6-2; Appendix B provides a more detailed discussion.

Table 6-2 Abatement measures across sectors (in 2030, relative to baseline)

Cost per tCO_2e	Sector	Measures	Emission reduction (tCO_2e)
$10	Agriculture	Converting marginal agricultural lands	6
$25 to $50	Iron and steel	Improve energy efficiency and more use of direct reduction iron and electric arc furnaces	2
$30	Agriculture and waste	Capture methane emissions from landfills	12
$12 to $57	Electricity	Shift to renewables/wind, and carbon capture and storage	50
$60	Agriculture	Lower methane emissions from cattle	3.2
$15 to $75	Forestry	Selective harvesting, better use of harvested area, long-lived wood products	17
$43 to $100	Oil & gas extraction, refining, distribution	More use of low-emission sources of heating, carbon capture and storage	40
$60 to $100	Transportation	Greater use of hybrid technologies, lightweight materials	69
$65 to $100	Chemicals	Increased urea production, carbon capture and storage	3
$40 to $108	Cement manufacturing	Clinker substitution, fuel substitution, carbon capture and storage	5
		Total	**207**

Source: PBO estimates from Appendix B.

Note: Costs listed in left-hand column are those needed to create incentives in the private sector to undertake actions. Potential sinks from land-use, land-use change, and forestry have not been included.

Cost estimates are limited by available information.

A number of the options have an upper-range cost of abatement of $100 per tonne of CO_2 equivalent. To some extent, this reflects a level of ignorance, since low-cost options are difficult to confirm and counting on them would be imprudent. Moreover, since these estimates are based on what is currently technologically feasible, they represent a "partial" response in the sense that innovation by the private sector to find other alternatives and new technologies are not factored in.

Past experience shows that people react, which reduces costs.

Businesses will respond vigorously when the implicit or explicit price of emissions approaches $100 per tCO_2e. The currently low prices of sulphur dioxide permits in the United States attest to that; after their introduction, they eventually traded at one-tenth of the expected price. The means to achieve those reductions are outlined in Appendix B in a little more detail, but are briefly summarized here.

Electricity

Switching electricity generation to coal will not be enough

A primary means to reduce emissions is to move from coal to natural gas, as Ontario did in shutting down its coal plants. However, for Canada to achieve an aggregate 30 per cent reduction from 2005 this will not be sufficient. Natural gas produces 44 percent less carbon dioxide to generate electricity. New natural gas plants equipped with carbon capture and storage may become the standard in the future.

Alternatives exist.

Alternatives such as nuclear or wind power (with natural gas as backup) may also be implemented. Much coal-based electricity generation is currently in areas with geological formations suitable for carbon capture and storage. So coal could continue to be a source of electricity generation while reducing emissions. Carbon dioxide pricing would allow the market to determine which technology is best.

Transportation

Transportation can go a long way with hydrids and improving engine technology.

Improvements in internal combustion engines, and more widespread adoption of hybrid technologies, could improve automobile efficiency by 40 per cent. Such technologies cost less to implement than the equivalent of \$100 per tCO_2e emitted (24 cents per litre of regular gasoline without ethanol). Many of them are slated to come on line with increased future fuel-efficiency mandates already in place.[12,13]

Oil and gas production, refining, and distribution

Oil sands have been improving emission intensity with existing technologies ...

Technologies currently in development or partially deployed can significantly reduce emissions from oil sands. These include the use of Gas-Turbine Once-Through Steam Generators. Shell's Quest project will capture and store emissions, thereby making oil sands similar to conventional crude oil in emissions.

... and have options for future reductions.

Pricing carbon dioxide emissions at higher levels will make other projects to capture and store emissions feasible. Refining operations and natural gas distribution can also be made less carbon dioxide intensive; as has been occurring over the past 15 years or so.

Agriculture and waste products

Agriculture and waste can contribute, but moderately so.

Most non-energy emissions from agriculture in Canada are caused by cattle. Analysis suggests that some methane emission reduction can be achieved by changing their diet and selective breeding for more efficient digestion.

Changes in crop management can also achieve some reduction. Landfills can be designed to facilitate the capture of methane emissions, significantly reducing CO_2e given its potent warming potential. (A tonne of methane has the same warming potential over 100 years as 25 tonnes of carbon dioxide.)

Buildings

Solving a problem with market structure could help reduce emissions from buildilngs.

GHG abatement faces incentive problems, given some peculiarities in the structure of the housing market. Dealing with it will require the up-front cost of a building to reflect a balance between spending during construction for energy-efficiency, and spending on energy over a long horizon of 25 to 50 years.

Chemicals manufacturing and petrochemical use

Chemicals industry need to mainly deal with emissions from ammonia production.

Ammonia production is the main source of carbon dioxide from chemicals in Canada. Solutions exist to reduce emissions: one is to use it to make urea. Also, since a stream of fairly clean carbon dioxide is produced, it can be used in applications such as enhanced oil recovery. The United States also imports a large amount of urea from other countries, so there is some scope for expanding Canada's production and exports.

Iron and steel

Iron and steel production uses a number of technologies with varying emissions.

A range of options exists for reducing emissions based entirely on existing technologies. These include greater implementation of best-practices, as well as more use of combined Direct Reduction Iron/Electric Arc furnace (DRI/EAF) technologies.

So solutions should be with instruments that allow industry to decide.

Moreover, ongoing improvements in energy efficiency and reducing coal use further could induce reductions in emissions. While these trends have been occurring on their own in response to competitive pressures, they could be accelerated.

Cement manufacturing

Cement-based emissions can also be reduced through a number of channels.

The production of clinker is a primary source of carbon dioxide emissions in cement production. Partial substitution, as well as less use, would bring down process-related emissions. Estimates of the cost of reducing emissions from cement production range from low when additional clinker is substituted and fuel-switching is implemented, to high when carbon capture and storage are used.

Land-use, land-use change and forestry (LULUCF)

Some measures can also reduce emissions from forest lands and harvested products.

Recent research has outlined some actions that could be undertaken in the forestry sector (Symth, et al, 2014). The cost estimates range from a low of $10 per tCO_2e, when better resource management is implemented, to $75 when harvesting is more selective and the wood products are used more in longer-lived products (Lemprière, et al, 2015).

Canada can get some credit for forest regeneration.

Though Environment Canada (2014b) projected that LULUCF would result in a net decline for Canada of 19 $mtCO_2e$ in 2020, that was using a methodology different from what was in Canada's INDC to COP21 in Paris.

But estimates are not yet available.

Since the Government has not yet provided revised estimates, it has not been included as part of Canada's target. Nonetheless, human-induced changes in Canada's forests (net of natural disturbances), could continue to be a significant contributor to achieving the target.

7. Concluding observations

Coordination is key message.

A message that comes through this analysis is quite simple: emissions reduction will likely require a variety of coordinated approaches and be complex. This stems from the highly diverse nature of the sources of emissions, and the need to avoid placing much of the burden on particular regions or sectors.

Three sectors will make up the bulk of the reductions

However, not surprisingly, the bulk of the reductions will come from the three sectors that contribute most to current emissions (Table 6-1; electricity, oil and gas extraction, and transport). As ambitious as the 30 per cent reduction target is, it can be achieved with technology currently available.

Tradeoffs may be necessary to maintain consensus.

Some sectors will do more than others, and this will spill into some regions doing more. Measures to mitigate any disparities are available and can potentially be used to avoid hardships that could undermine an emissions-reduction consensus. Canada's diverse regions are not necessarily an obstacle to implementing the abatement target, though they do make it a challenge.

Cost will be significant...

Most of the emissions abatement needed to achieve the reductions can occur at prices (implicit or explicit) below \$100 per tCO_2e. This should not be dismissed as trivial, but it would also not substantially alter the Canadian economy.

...but achieving the objective does not necessitate a lifestyle change.

Perhaps one of the most telling foreseeable economic consequences from a push to lower emissions concerns the automobile. The mobile lifestyle to which consumers in Canada and many other countries have become accustomed is sometimes cited as being threatened by climate change-related policies. This is not necessarily the case when, as noted above, the abatement target can be reached by raising the price of all sources of emissions so that a litre of gasoline would go up by 24 cents. Economy-wide efficiency improvements would mostly offset the cost.

Carbon capture and storage can be a significant part of the solution.

A key area that has considerable potential is carbon capture and storage (Appendix A). It may be key to reductions in a few industries such as cement, chemicals and steel manufacturing, but its more widespread use in other industries such as electricity generation and oil and gas extraction holds greater potential.

Existing projects have revealed some of its cost (indirectly).

Moreover, the implicit price that can be calculated from existing projects that make use of it suggests that its price could be significantly less than \$100 per tonne of carbon dioxide (\$57 per tonne for the Boundary Dam project). If so, it would lower the overall impact on the economy by moderating increases in the price of electricity and other industries.

Appendix A: Carbon capture and storage

Carbon capture and storage (CCS) represent a grouping of technologies that deal with CO_2 emissions by means of end-of-pipe treatment.

Unlike other abatement technologies that reduce emissions by substituting away from sources of emissions – such as fossil fuels – CCS allows existing industries to continue operating with an add-on technology. It does so, for example, by capturing and compressing the flu-gas from coal or natural gas-burning power plants before it is released into the atmosphere.[14]

This approach has received greater attention during the past decade given its capacity for large scale storage. Indeed, looking past 2030 in both Canada and the United States, carbon capture and storage are very likely to be part of the solution since conversion of electricity generation from coal to natural gas will not be sufficient to achieve deep emission reductions.

Since viable technologies for Canada-wide grid-level electricity storage are not yet foreseen, wind-power generation cannot provide base-load capacity, even though it is a good source for low-carbon electricity.[15]

Moreover, using electricity generated from biomass coupled with carbon capture and storage has been cited as one of the few means that can potentially achieve large scale removal of carbon dioxide from the atmosphere. That is, carbon capture from coal burning avoids emissions. But since trees remove carbon dioxide, carbon capture with biomass could offset emissions that are more costly to abate in other parts of the economy.

In principle, biomass with carbon capture should receive credits for each tonne removed. This would then make it viable sooner than would otherwise be the case since it would potentially have three revenue streams: from electricity generation; from enhanced oil recovery, known as EOR; and from credits for carbon dioxide removed from the atmosphere.

The primary requirement for carbon capture and storage is a deep sedimentary basin (1-3 km below the surface) that is sufficiently porous. Canada's western regions sit atop such basins, perhaps not surprising since that is where oil and gas deposits are most often found (Figure A-1). The potential for carbon dioxide capture and storage is of a sufficient magnitude that up to one-half of Canada's emissions annually could be eliminated by 2050 through capture and storage.[16]

Figure A-1 Canadian sedimentary basins

Source: Integrated CO_2 Network.

The compressed carbon dioxide that is injected into the ground can be stored for the long term, or it can be used for enhanced oil recovery. (Depending on the basin, this can also result in long-term storage.)

This latter is a mature technology that has been in use for decades. Carbon dioxide, unlike water, dissolves in crude oil and makes it less viscous. This allows oil deposits that have otherwise been economically depleted to continue to be exploited in cases where the additional cost is low enough.

Transport and injection of carbon dioxide for EOR are currently done in the United States (and Canada) on a significant scale. As of 2005, some 2,500 km of pipeline were transporting about 50 mtCO_2e per year. The transport cost, when the pipeline is of sufficient diameter (50 cm or more, Coleman, *et al*, 2005) can be about US$2 per tonne over a distance of 250 km.

This would be a small fraction of the value of carbon dioxide if the abatement costs reached $50 per t$CO_2$e. Moreover, at $50, its volumetric value is $2.56 per 1000scf. This compares to natural gas, the wholesale value of which in 2015 averaged $4.05 per 1000scf (AECO price).

To get a sense of the economics of EOR, consider briefly a project that has been in operation since 2000: the Weyland oilfield (discussed in more detail below). Its characteristics, as outlined in Whittaker (2005), combined with a reported carbon dioxide price of US$20 per tonne, lead to the conclusion that it was based on an add-on cost of US$7 per barrel of oil produced (not including other costs associated with transporting and injecting the carbon dioxide).

When combined with the transport cost noted above, it sets a fairly low threshold for using EOR and helps explain its use even before oil prices began to rise after 2000.

While there are varying projections of the cost of carbon capture and storage,[17] only a few projects are actually implementing it. In Canada, which is currently a leader in this field, there are five projects of note that illustrate its economics (Table A-1). Four of them are either operating, or in the process of being commissioned. A fifth was cancelled, but underscores the wide range of the economics of carbon capture and storage.

Table A-1 Major carbon dioxide capture and storage projects

Project	Public funding	Implicit CO_2 price[1]	Status
Project Pioneer (Keephills 3)	\$342m (F) + \$436m (P)	\$95	Not completed
Quest (Scotford upgrader)	\$120m (F) + \$745m (P)	\$45	Due in 2015
Alberta Carbon Trunk Line	\$63m (F) + \$495m (P)	\$23	Due in 2015
Boundary Dam[2]	\$150m (F) + \$765m (P)	\$57	Completed
Weyburn-Midale[3]	\$40 (O)	\$0	Completed

Source: PBO calculation.

Notes:

1. The implicit price does not include the cost of capital for funds that would have to be invested without the subsidies.
2. For Boundary Dam, the funding does not include that given for refurbishing the power plant even though it is likely that the project would not have been undertaken without it. The \$57 estimate does not account for the \$25 it receives for each tCO_2e.
3. Weyburn-Midale did not require government funding to become operational. The reported explicit price of CO_2 that it pays is US\$20 per short ton.

Notation: (F) Federal; (P) Provincial; and (O) Other – academic and business groups wanting to study and monitor the activity.

The implicit price is calculated by taking the value of the subsidy over the life of the project (using a cost of capital) and dividing by the amount of carbon dioxide that will be captured. In the case of Boundary Dam, some accounting is made of operating costs. In the others it is imputed into the value of the subsidy.

This accounts for the private cost of CCS. The underlying argument is that the public funding caused the firm to undertake a project it would not have done on its own.

The implicit price is thus equivalent to an explicit carbon dioxide price (tax or tradable permit) that would also have tipped the balance in favour of the firm doing the project without the subsidy.

To get the estimate of actual cost of CCS, the calculation omits any payments received for the carbon dioxide. The Boundary Dam project is reported below both with and without the payments for carbon dioxide so as to gauge the cost of CCS on both electricity generation, as well as the cost that can be anticipated in future projects even without that income.

The cost of capital for firms having to raise funding has been assumed to be 5 per cent (3 per cent when adjusted for inflation) in both the fossil-energy-related industries and the electric power industries, based on a weighted average cost of capital.[18] In some cases, the result with a 7 per cent cost of capital is also reported.

A potentially important advantage of CCS coupled with coal-based electricity generation is that it would facilitate long-term planning since the operating cost would become predictable. That is, when the power station is near a coal mine, the extraction cost can be predicted relatively well. On the other hand, natural gas can be subject to wide swings in price that cannot easily be passed on to consumers in the short run. Stability is desirable in an industry where equipment has a 30- to 40-year operating horizon.

Boundary Dam

A recent project that has generated substantial discussion and media attention is the Boundary Dam complex in southern Saskatchewan. Its Unit 3 generator is a full-scale plant (160 MWh) that uses carbon dioxide capture to avoid emissions. The project was initiated in response to a regulatory change that requires new coal-based generating plants to emit no more than 0.420 tCO_2 per MWh.[19]

Since it is the first such plant in operation, assessing its financial status can help illustrate the viability of carbon capture and storage at industrial scale. Unfortunately, no complete accounting has been provided thus far. Nonetheless, some insights can be gleaned from available data.

To begin, such plants typically use a 30-year horizon, since that is the expected duration of the equipment in operation, although they often continue over longer horizons. A caveat in this particular case is that the contract to sell 1mt per year of carbon dioxide to a firm that uses it for EOR in southern Saskatchewan (Cenovus Energy, of Calgary, Alberta) does not run for the full 30 years.

Nonetheless, the analysis here will use the 30-year horizon on the assumption that: either another buyer will be found; or, the contract with Cenovus will be extended; or, there may be a broader policy introduced in the future to limit emissions by putting a significant price on carbon dioxide.

For the carbon capture and storage component of the project, the cost has come in at roughly $917 million; it had been budgeted for $800 million. This is partially covered by a $150-million grant from the federal government, with the rest coming from SaskPower. Glennie (2015; Table 3) provides a useful starting point by pulling together estimates of revenues and expenditures.

The conclusion there is that over the life of the project, it will generate a loss of around $1 billion. If that is correct, Saskatchewan ratepayers could face a substantial cost, more than three quarters of a billion dollars over 30 years. (The total federal government subsidy for all aspects of the project was $240 million.)

If the capital cost of $917 million was amortized over the 30-year horizon at an inflation-adjusted cost of capital of 3 per cent per year,[20] then net power generation of the plant (115MWh net of CCS) would require a sustained $47 per MWh price increase to cover the capital costs (in 2014 dollars). Using EIA (2015b), an estimate of the operating cost of the plant is $10 per MWh.

Since the emission rate of coal used at the plant is roughly 1 tCO_2 per MWh, this implies that a price of $57 per tonne of carbon dioxide would induce carbon capture and storage with that capital cost and without government subsidy.

In other words, facing a cost of about $57 per tonne of carbon dioxide emitted (and assuming no income from carbon dioxide sales), a firm would undertake carbon dioxide capture and storage, on its own, on the basis that:

- the $917 million cost of the CCS unit will be amortized over 30 years;
- the operating cost of the CCS unit will be $10 per MWh;
- the inflation-adjusted cost of capital was 3 per cent; and
- the net power generation capacity was 115 MWh.

Since there is a sale of carbon dioxide to Cenovus of $25 per tonne (see Banks and Bigland-Pritchard, 2015), in this particular case, a carbon dioxide price of $32 would achieve the same outcome. If the real cost of capital were 5 per cent, then the implicit cost would be $69 per MWh ($44 with the sale of CO_2).

Saskpower has stated that with learning-by-doing from the project, it could achieve a roughly $200-million cost saving on a similar plant. This would lower the implicit carbon dioxide price to $47 per tCO_2e without a resale value for the carbon dioxide.

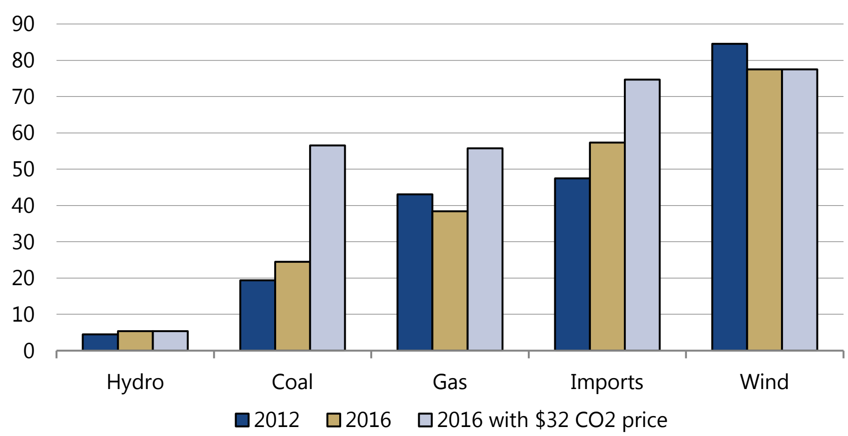
An alternative means to obtain that estimate concerns the amount of carbon dioxide to be captured and stored. Over 30 years, emission of some 30 $mtCO_2e$ will be avoided. A payment stream based on a carbon dioxide price of $57 per tCO_2e would be equivalent to a capital asset with a present value today of roughly $917 million when an inflation-adjusted rate of discount of 3 per cent is applied.

A broader perspective can be gained by looking at Saskpower's fuel costs (Figure A-2). Its projected cost for coal is significantly less than some alternatives. When a carbon dioxide price of $32 per tCO_2e is added (the price that is net of CO_2 sales), coal remains competitive.

The $32 price of emissions causes the fuel-cost for natural gas to increase by almost $17 per MWh, so coal and natural gas converge. However, the lower supply of carbon dioxide from burning natural gas may not trigger carbon capture and storage for natural gas, and the volatility of its price may be a factor in its use.

Figure A-2 **SaskPower electricity fuel-type cost**

dollars per megawatt hour



Sources: SaskPower Rate Application (2013) and PBO calculation.

Note: The cost of hydro power reflects a water charge that SaskPower pays to the province. The cost of wind power is calculated as an average. Thus newly installed wind would be lower. It also includes capital costs so the comparison is not straightforward. Natural gas prices are now projected to remain above 2012 levels – so the projected price with CCS would be higher. The price of natural gas with CCS is based on an estimated emission of 549 kilograms of CO_2e per MWh. Since imports are from neighbouring provinces that use coal and natural gas, the import price has been increased by the same amount as natural gas.

In sum, when coal is cheap enough and a sedimentary basin for storage is available, adding carbon capture and storage can keep coal competitive when emissions are priced, especially so if emissions from natural gas are also priced. Indeed, when low-grade coal is available locally (and has no alternative use), price stability and predictability would create a premium in coal's favour.

The $57 per tonne cost of carbon capture and storage is also noteworthy for the fact that it is in a *retro-fitted* plant. That is, the technology was integrated into the design of an installation that was being refurbished. In a *green-field* plant the design would have a clean start and would be able to more closely integrate all aspects of both the coal and carbon capture plants. This should result in substantial savings once the technology matures, though a first-of-its-kind risk to costs would exist (see Endnote 17 concerning Kemper County, Mississippi).

Some precaution with respect to long-term carbon dioxide storage would still argue in favour of wind energy. This is especially so since Saskatchewan's wind conditions permit a high utilization rate, although power storage would have to be dealt with to use wind for baseload demand.

However, eliminating emissions from coal-fired generation does not necessarily mean relatively high electricity costs when the coal is cheap enough.

Weyburn-Midale

The Weyburn project was completed in 2000 and extended to Midale in 2005. It involves transporting carbon dioxide 315 km via pipeline from a coal-gasification plant in North Dakota to two oilfields where production capacity had declined. The price of the carbon dioxide is reported to be US$20 per tonne. That cost must cover both compression and transport.

The project was undertaken with minimal subsidy (about $40 million) from research institutions and governments, and the capital cost was about $80 million. The demonstration effect is strong in terms of showing that even a relatively modest cost of carbon dioxide can still make CCS viable. The combined rate of injection into the two oilfields is just under 3mt per year.

One of the issues that detractors raise concerning the use of CCS in this case is that a substantial proportion of the carbon dioxide is ultimately released when the oil is extracted. Cenovus, the company operating Weyburn, has developed a process to re-capture that gas and again inject it back into the oil field. This would save US$20 per tonne of additional carbon dioxide.

To underscore the economics of EOR, consider that injection began in 2000. This was a time when prices for a barrel of oil were, and had been, largely below US$40 in today's dollars for West Texas Intermediate crude.

Quest project

The Quest project in northern Alberta is Shell Oil's effort to reduce carbon dioxide emissions from its Scotford upgrader plant. Subsidies from the federal and provincial governments amounted to $865 million for a plant that is slated to inject 1.1mt of carbon dioxide annually into deep aquifers, or into EOR.

That Shell Oil is going ahead with the project without an explicit sales value for the captured carbon dioxide implies that the government grants are sufficient to justify its cost.

Given those subsidies and the quantity of carbon dioxide being stored, with an operating life of 25 years, the implicit cost of the avoided carbon dioxide emissions would be \$45 per tCO_2, or \$55 per tCO_2 with a real cost of capital equal to 5 per cent.

Although, the design specification for the upgrader and storage wells called for an operating lifetime of more than 25 years, the grants from government only require that it operate for a 15 year horizon. If that period is used, then each tonne of CO_2e is instead worth \$65 per tCO_2e with a real cost of capital of 3 per cent. Using this shorter horizon, however, means that the plant could continue to operate for another 10 years by covering operating costs, which presumably are considerably less that \$65 per tCO_2e. In that case, the average cost should again be closer to \$45 per tCO_2e.

Alberta Carbon Trunk Line

The Alberta Carbon Trunk Line is a 240 km pipeline that carries carbon dioxide from an industrial area just northeast of Edmonton to an enhanced oil recovery site well south of the city. It was due to be fully operational during 2015. The sources of carbon dioxide are a fertilizer plant (chemical industry) and a bitumen upgrader (oil and gas extraction industry). Initially it will carry and inject about 1.6 $mtCO_2e$ per year.

The expectation is that it will increase to almost 15mt. The Alberta government is providing significant funding over a 10-year period, but the federal government is also contributing. With a project lifetime of 20 years, if storage remains at the lower range, the implicit cost of avoided emissions will be about \$23 per tCO_2e (\$28 if the real cost of capital were 5 per cent). That price would fall as the flow of carbon dioxide for storage increased.

Since no known funding was provided to the sources of the carbon dioxide, presumably the payments from enhanced oil recovery are sufficient to cover their costs, plus the additional capital investment that was needed beyond the government subsidies.

In other words, an implicit cost (whether tax or subsidy) of \$23 per tCO_2e should have been sufficient to trigger the private sector to undertake the project on its own. The Alberta government's proposed \$20 to \$30 per tonne carbon dioxide tax could be sufficient to keep the pipeline operating over the long term.

Since Weyburn had already showcased the viability of such projects, the demonstration value is small. But since Alberta will gain royalties on oil that would not have been otherwise extracted, the net cost to Alberta taxpayers may be small.

Project Pioneer

The final project discussed here is instructive for the fact that it was not completed. Project Pioneer was intended to capture carbon dioxide from coal burning at the Keephills 3 plant about 70 km west of Edmonton. A pipeline would have transported it 80 km to an injection point (for EOR). The completion date of the project meant that it wasn't subject to the coal emissions regulation.

The plan had called for 1 mtCO_2e to be sold annually for at least an initial 10-year period. The subsidies were granted for a project horizon of 15 years (10 operational, then monitoring) and amounted to an implicit cost of avoided carbon dioxide emissions of $95 per t$CO_2$e. When a sale value of the carbon dioxide of $30 per tonne is added, the implicit cost rises to $125.

At the time the project was cancelled in 2012, the explanation given was that the market for carbon dioxide was not sufficiently strong to make it viable. Clearly, the $125 was not sufficient by itself to justify the cost of capture and storage (TransAlta, 2013). This is in contrast to the Boundary Dam project, where $57 per t$CO_2$e was sufficient to proceed – but it was under the coal regulation.

Two apsects of the decision are noteworthy. The first is that the project only had a horizon of 10 years, which caused the capital cost to increase the unit cost of each tonne abated. The second is the decision to separate the main power generator (Keephills 3) from the carbon capture and storage facility. At Boundary Dam, the power draw for the latter is roughly 30 MWh, or about 207 KWh per tonne of carbon dioxide captured. At Project Pioneer, an entirely separate gas-fired unit was to be built to provide the power and steam for carbon capture and storage. This meant that almost $30 of natural gas would be used for each tonne of carbon dioxide captured and stored. That cost is substantially higher than the power cost at Boundary Dam.

The nominal lesson from this is that there is a wide range of costs that firms face in capturing and storing emissions, and that the context matters. Project Pioneer was intended to retrofit a relatively new technology onto a new coal-burning plant . The fact that the project was completely separated from the generating station added significantly to its cost, and its short operating horizon meant that its captial costs had to be amortized over a short horizon. If it had fallen within the coal emissions regulation, and been given the same funding, it would have had an incentive to fully integrate the carbon capture and storage facility into the power-generating unit. This could have led to a different outcome since it would have both reduced its cost, while allowing it to use a longer horizon over which to look at the business case for the plant.

Moreover, the upgrader that Shell is using in the Quest project is not capturing flu-gas from a coal burner. Instead, it is upgrading bitumen by adding hydrogen to it that is removed from methane; the carbon dioxide emission results from the carbon that is released during that process. The operating costs of capture and storage from that process are lower than the operating cost from capturing emissions from burning coal.

Appendix B: GHG emissions and abatement sources

Reducing GHG emissions requires incentives for individuals and businesses to change their behaviour. Those incentives can be in many forms, such as inducements through financial rewards or penalties, or more forcefully as requirements that are mandated. In each case, there is either an explicit, or implicit, price put on emissions.

The first section of this Appendix discusses alternatives for making emissions costly. The following section outlines potential actions in major sectors that could follow from that (explicit or implicit) pricing.

B.1 Pricing carbon dioxide (and other GHG gases)

Choices for pricing carbon dioxide emissions have many dimensions. An important one is the implication of how efficiently the objectives are reached (that is, causing as little mis-allocated capital and labour as possible). In general, options can be divided into those that have an explicit price on emissions, and those that have an implicit price:

Explicit pricing

1. tax on carbon dioxide,
   - Advantage: fixes a price that is equal and predictable everywhere
   - Disadvantage: leaves the amount of reduction variable
2. cap-and-trade system with carbon dioxide permits,
   - Advantage: determines a price that is equal and flexible everywhere; financial impact can be reduced by having permits that are 'grandfathered' to existing emitters
   - Disadvantage: price of permits can be volatile

Implicit pricing

1. regulatory requirements
   - Advantage: does not require ongoing revenue administration, easy to implement
   - Disadvantage: cost needs to be discerned and may be difficult to foresee
2. (technology) subsidies

- Advantage: create an explicit incentive for a technological result
- Disadvantage: cannot be widely applied and needs to be carefully administered.

The first two alternatives price carbon dioxide emissions but differ in one important aspect: taxes fix the price, but leave the quantity (objective) uncertain; whereas trading systems fix the quantity, but leave the price uncertain.

A common observation made about the trading system (2) is that it leaves prices unstable and fails to provide a long-term signal to market participants. However, rather than a short-coming of a trading system, this may be an advantage. To see why, consider what is driving the price changes.

If speculation were to be causing it, then the price instability would be a problem, although speculation is sometimes the result of a few individuals who are ahead of the market. However, if the price changes are linked to changes in technology and opportunities for abatement, then the instability is desirable.

That is, if the price moves substantially lower, it means that the market anticipates that the objective will be easily obtained. In that context, setting a high price (through a tax) runs the risk of *overpaying* for emissions reductions and overachieving. At the very least, hitting a target like a 30 per cent reduction would require occasional adjustment of a tax.

Good illustrations of this are seen in the sulphur trading system implemented in the United States during the 1980s to deal with acid rain. Prices were initially projected to be high, but then were almost a tenth of that when solutions to the problem became easier to achieve. The European Union's Emission Trading System also experienced a sharp decline in prices. However, the reason for it may have been an overallocation of permits, which may itself have been caused by the gains in reducing emissions from electricity generation.

While both taxes and trading systems can be used in a manner that reduces the burden on individual firms, trading systems facilitate that process. For example, permits that are 'grandfathered' to individual firms mean that the firm need only purchase those that it requires beyond its quota. It would buy them at market prices, and over time financial instruments would become available to hedge future changes in those prices.

On the other hand, taxes require firms to pay for each unit of emissions. Rebate systems for taxes could facilitate that, but would not be as easily targeted to specific industries, or even firms.

Hybrids of the two pricing mechanism are also possible. One simple example occurs where a permit system has an upper limit on its price, after which the government sells permits as needed at that fixed price. It then becomes the equivalent to a carbon dioxide tax. An important consideration, however, for any hybrid scheme includes the added complexity that it would engender.

Regulatory requirements have the advantage of simplicity with minimum opportunity for misallocation of capital and labour when the objectives are clear and well formulated. However, in cases where they are poorly implemented, the misallocation of resources can be larger than with either of the price two instruments.

Their usefulness is seen most clearly with auto-efficiency standards that required cars to achieve fuel-efficiency targets and that led to continued improvements in engine technologies and material weight. Since much innovation happened in response to changes in the standards, they are seen as having been a successful implementation of regulation to spur innovation (e.g. Bento, *et al*, 2015).

Another area where regulatory action might lead to cost-effective innovation is building standards. Builders have an explicitly short-term horizon to build and sell a structure, especially when the purchaser may be short-term constrained and thus willing to pay a long-term penalty.

This is particularly the case with younger individuals who foresee increases in income over the medium and long term. This is characterized as a market failure that could be efficiently corrected through building standards that incorporated long-term horizons for minimizing energy use and GHG emissions.

Subsidies for technological advance are perhaps the most controversial, given their potential for either misuse, or for inducing wasteful use of capital and labour (what is sometimes termed *rent-seeking behaviour*). They have been successfully used in a range of areas for achieving very specific goals, but are also often controversial for their use in non-carbon energy production.

Germany, for example, produces about a third of its electricity from non-carbon sources. But its residential electricity costs per kilowatt hour are four times those of Canada (IEA, 2015). The recent decline in the price of natural gas has called into question the necessity for such high electricity prices.

Nonetheless, well-focused subsidies have been successfully used in the past. Infrastructure projects, for example, are a subsidized service that in many cases would not otherwise be provided in sufficient quantity. Too few roads would be built if they were left entirely to the private sector.

B.2 Sectoral sources of abatement

Carbon dioxide pricing changes the choices that people and firms make. Some insights into those likely changes can be gleaned from technological possibilities as well as some changes in market structure.

This sub-section outlines some of those possibilities on the basis of existing technologies. It is not intended to be exhaustive; indeed, it cannot be since carbon dioxide pricing will almost certainly lead to new technologies and other changes that are difficult to foresee. The entrepreneurs who are particularly adept at implementing the needed changes will be those who profit by doing so.

Electricity

An important source of emissions is electricity generation. In 2013, it contributed about 12 per cent of Canada's total GHG emissions (88mt of carbon dioxide). Of this, about 9 percentage points (64mt) came from burning coal.

The baseline to 2030 incorporates a decline in those emissions of about 15mt annually. About 3mt came from the elimination of coal in Ontario in 2014. The remaining 12mt reduction represents increased use of renewables and natural gas, as has historically been the trend.

Canada's regulation concerning coal-fired electricity generation could have the effect of eventually reducing coal-based emissions by roughly 60 per cent (about 40 $mtCO_2e$ from 2013 levels). This is not explicitly included in the baseline since some flexibility in the regulation means that not all coal plants have to be converted by 2030. A simple switch by all plants to natural gas would reduce emissions by only 28 $mtCO_2e$.

A conversion to natural gas, however, would make it difficult to achieve the 2030 target. Other sectors would have to achieve the remaining 180 $mtCO_2e$ reduction, at potentially significantly higher cost. Alternatives would have to come into more widespread use, leaving natural gas to act as a backup. These include : (1) renewables, such as wind; (2) either coal or natural gas combined with carbon capture and storage; or (3) nuclear energy.

In fact, these are not mutually exclusive since wind requires backup or power storage. (Saskatchewan's existing wind turbines generate electricity at less than 50 per cent of capacity, Ontario's 25 per cent less.)[21] Storage is a technology in development, but is not yet proven to be cost-effective. Nuclear energy is a proven technology, but is primarily viable where the population density is high enough to support power generation on a gigawatt-hour scale.

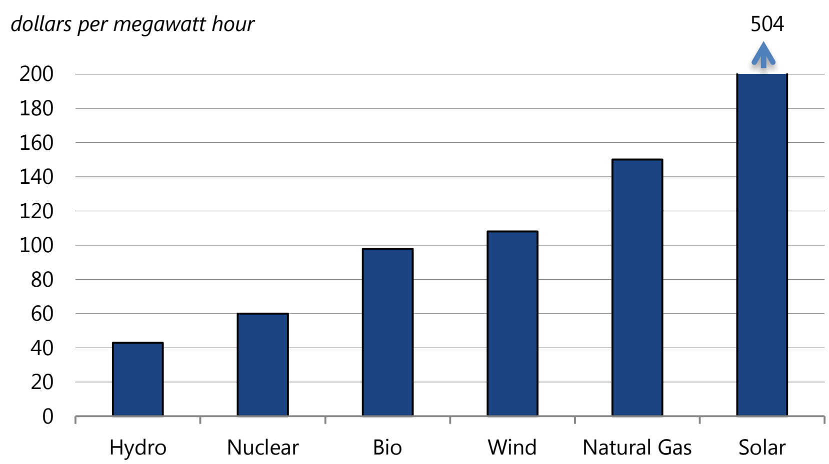
The cost of reducing or eliminating emissions from electricity can be gauged in part by the recent experience in Ontario. Nuclear energy and hydro now provide the lion's share of generated electricity; historically they have been low-cost. Natural gas had provided much of the remainder, but is now being overtaken by renewables (including sources embedded in the distribution system).

While natural gas is traditionally a low-cost source of electricity generation, its use to respond to demand (and supply) fluctuations has made it a high-cost source of electricity (Figure B-1).

This is because facilities need to be kept operational so as to respond on relatively short notice. From January to November 2015, on average, only 13 per cent of natural gas capacity was used (this may, in part, have been due to the rapid buildup of wind power). The cost to build and maintain the excess capacity is reflected in electricity costs and has been going up. Part of this cost may also reflect decisions to cancel natural-gas plants, which the Ontario's Auditor General noted resulted in significant penalties.

Figure B-1

Cost of producing electricity in Ontario by fuel-type



Source: Ontario's Long Term Energy Plan 2013: Cost of Electricity Service, LTEP 2013: Module 4.

Note: The cost of natural gas includes substantial reserve capacity intended to deal with short-term fluctuation in demand, making it considerably more expensive than would otherwise be the case. Coal is no longer used in Ontario. But Dewees (2012) estimates its cost at $100 per MWh when pollution control is installed, without carbon dioxide capture and storage.

The results illustrated here are based on actual outlays for 2013. As such, they may not reflect long-term costs such as those associated with refurbishment and retirement of facilities. In particular, hydro and nuclear energy have substantial additional costs when the long term is incorporated into operating costs. The cost of wind power that is illustrated does not reflect the diminishing cost of wind power-based generation.

Ontario began its wind program in 2006 with a feed-in tariff of $135 per MWh that was introduced in 2009. When a large response occurred from the private sector, it was subsequently limited to "small" operators whose capacity is less than 0.5 MWh. That is enough to power 100 homes based on average Ontario consumption and wind turbine operating rates in 2014.

The tariff was reduced by September 2014 to $128 per MWh. In Europe, 16 countries have a feed-in tariff that averages 77 euros per MWh. In each case, they have generated a vigorous market for construction and installation of turbines.

When the feed-in tariff is compared to fully priced coal ($100 per MWh as estimated by Dewees, 2012), the implicit carbon dioxide price is $28 per tonne. In other words, the Ontario government had implicitly put that price on carbon dioxide emissions.

That cost, however, may be somewhat pessimistic. New installations with capacity of more than 0.5 MWh capacity (most new turbines are substantially bigger) no longer qualify for the tariff. In fact, at the end of 2015, only half of Ontario's wind and solar capacity was under the feed-in tariff. The remaining half was covered by other Power Purchasing Agreements, where the price is lower.

In 2013, wind power became dispatchable in Ontario, meaning it no longer had to be purchased. However, there is still a partial payment to the generator, with caps on the amount of reduction they would have to accept.

On the other hand, using wind power requires some idle natural gas as backup. However, it is likely that natural gas would have operated in that capacity even without wind, once the decision to eliminate coal was taken. That back-up capacity adds to the overall cost of power.

Given the low usage rate of natural gas capacity (13 per cent through 2015), it would appear Ontario has more backup power than it needs, since its neighbours have spare hydro capacity that can respond to changes in demand. Even so, the relatively high cost of natural gas is, in part, related to some costly decisions concerning plant installations, as pointed out in the Ontario Auditor General's Annual Report for 2015.

There is, however, some debate concerning the contribution of wind power to Ontario's increases in electricity rates (Box B-1). Wind power has grown rapidly from little production in 2006 to 4 per cent of Ontario's grid-connect electricity production in the first half of 2015. Embedded systems produce an additional 3 per cent (and are also increasing rapidly), so that roughly 7 per cent of electric power is being produced through wind.[22]

Its continued rapid rate of growth – even without a feed-in tariff for wind farms – suggests that wind is profitable for its operators, at least at prices the wind-farm owners have negotiated outside the feed-in-tariff.

Indeed, a review by the U.S. Department of Energy in 2015 (Moné, *et al*, 2015) reported that the all-inclusive cost of producing electricity from wind had been falling rapidly. By 2014, it had reached an average of US$66 per MWh for a sample of 27 projects where the turbine's rated power averaged 1.91 MWh (roughly CAD$80 using a purchasing power parity exchange rate).

Box B-1 – Ontario's electricity prices

The sharp increases in electricity cost in Ontario over the past decade or so have caught the public's attention and have led to a debate over energy policy. Since those increases have coincided with a focus on renewable sources of electricity generation, they are of interest for possible lessons for the effects of meeting GHG-reduction objectives.

Dewees (2012) argues that Ontario's aging nuclear and hydroelectric base needed refurbishing and the costs going forward would inevitably rise. Indeed, MSP (2012; Figure 3-1) shows a large change in the fixed cost of nuclear in 2009, which has since remained elevated.

In the medium term, the Bruce nuclear facility will also need refurbishing starting in 2020. That would again increase electricity prices since the work will add about 1.2 cents per kilowatt hour to the power it produces.

On the other hand, McKitrick and Adams (2014) argue that the increases were linked to the push to renewable, particularly wind power. Since Ontario eliminated a relatively cheap source of electricity (coal) and replaced it with natural gas and a shift to renewables, such as wind, the link between wind and increasing cost seems reasonable.

However, they base that link on a statistical analysis of changes in electricity prices and the evolving composition of source fuel types. In particular, they find that the increase in wind power *capacity* has an outsized effect on fixed costs (*Global Adjustment*). There is no direct link between wind capacity and the Global Adjustment. But they assert an indirect one, given the observed statistical correlation. (For May 2015 to April 2016, wind power was expected to contribute 7 per cent of the supply of electricity, but 13 per cent of the Global Adjustment; Table 2 in OEB, 2015.)

Perhaps one means of gauging changes in Ontario's electricity prices is by comparing them to other nearby jurisdictions that have similar or diverse mixes of fuel types for producing electricity (Box table).

Box B-1 – Ontario's electricity prices (continued)

Box Table: Comparison of generation mix in 2014 and price for electricity

	Michigan	Pennsylvania	New York	Ontario
Natural Gas	12%	24%	40%	9%
Coal	50%	36%	3%	0%
Nuclear	30%	36%	31%	60%
Hydroelectric	2%	1%	19%	24%
Renewables	6%	3%	5%	7%
Average cost 2014 ($/MWh)	*US$110*	*US$98*	*US$155*	*$137 PPP$109*
Average cost 2006 ($/MWh)	*US$85*	*US$86*	*US$131*	*$86 PPP$71*

Sources: US Energy Information Administration : Electric Power Monthly table 5.06; IESO Monthly Market Report; Cansim Table 127-0008; Association of Major Power Consumers in Ontario

Notes: End-user price: all sectors. PPP (purchasing power parity) is the OECD GDP-based conversion that equates the value of a basket of goods in Canada with those in the United States. It omits the influences of day-to-day factors that cause the market exchange rate to fluctuate.

The cost of electricity generated in New York is substantially higher than in Ontario. Much of New York's high price is linked to the cost of distribution and transmission, which is rising due to its aging infrastructure. The cost of replacing that transmission system will continue to be felt over the next 15 years or so (Harris Williams & Co, 2010).

Other jurisdictions where there is aging infrastructure and whose replacement and maintenance has not been adequately funded will also begin to experience higher costs. The Ontario Auditor General's Annual Report for 2015 warns of such future cost increases.

The other states (Pennsylvania and Michigan) have costs comparable to, or higher than, Ontario's once the exchange rate is accounted for. Pennsylvania has only small amounts of renewables such as solar and wind (though wind has been doubling in generation capacity each year for the past few years). Coal is making up for the power that nuclear is providing in Ontario.

Going back to 2006, however, Ontario had lower cost electricity than all those states, significantly so when converting to comparable currencies. This is consistent with Dewees (2012) observation that electricity was under-priced in Ontario since it didn't account for the costs of maintaining the power generation system. Those costs have now become part of the pricing structure, and have been driving up prices to consumers and businesses.

The observation made in McKitrick and Adams (2014) may also be part of the explanation, but perhaps more through the rising cost of keeping (excessive) backup capacity in natural gas. The high cost of cancelled natural gas contracts – as noted by the Ontario Auditor General – also contributed.

Electricity generation in Alberta, Saskatchewan and Nova Scotia is reliant on burning inexpensive coal and natural gas, which has kept the cost of electricity for residential users comparatively cheap (below $100 per MWh in Alberta). Alberta currently has a carbon dioxide levy of $15 per tonne.

That Alberta has the third largest installed wind capacity (1.5 GWh; behind Ontario and Quebec) without subsidies in a region where cheap coal has always been available attests to its competitiveness. Natural gas prices have fluctuated significantly so a direct comparison is difficult to make. There is considerable scope for expanding wind capacity in Alberta, and proposed increases in the province's carbon tax should contribute.

However, all three provinces – particularly Alberta – are atop a sedimentary basin that is considered favourable to large-scale carbon capture and storage (see Casey, 2008; NRCan, 2013). Of particular relevance is the Boundary Dam project in Saskatchewan (see Appendix A).

In considering options for reducing emissions from electricity, Figures B-1 and A-2 are potentially misleading since they illustrate province-specific fuel-input costs at a particular instance in time. It is thus worth taking a broader look at future costs. The U.S. Energy Information Administration (2015b) in its Annual Energy Outlook provides a levelized cost of generating electricity from various sources (Table B-2).

Table B-2 Levelized project-life cost of electricity generation (2020)

Fuel source	Total levelized cost per MWh
Conventional coal	US$81
Conventional natural gas	US$75
Nuclear	US$95
Hydro-electric	US$84
Wind	US$74

Source: EIA (2015b).

Note: For plants that would be built to supply electricity to the grid in 2020. The original source included a US$15 per tCO_2e, from coal which has been removed. In the United States, the average cost of coal in 2014 was US$25 per MWh, which is about 50 per cent higher than the cost in Saskatechewan ($20 Canadian). The main source of the high cost of coal is for pollution control; the capital cost is four times that of natural gas. A 30-year horizon is used for capital costs.

The high cost of conventional coal comes from pollution control that is fully priced. One drawback of coal and natural gas is the potential variability of fuel costs over long horizons. EIA (2015b) projects that the cost of adding carbon capture and storage to natural gas makes it about US$27 per MWh more expensive, and coal US$44 (which is about the price at Boundary Dam with a purchasing power parity exchange rate, but more than what SaskPower expects to achieve with future projects).

Nuclear power is an energy source whose price of which is more stable, but given its large generating capacity, is more ideally suited to areas of higher population density. A typical 2.2 gigawatt nuclear plant can provide baseload power to roughly 3 million people. Much of its apparently high cost is the result of dealing with spent fuel and eventual decomissioning.

Given the current economics of wind power, and its lack of carbon dioxide emissions, it appears set to have an important role to play in future power generation. Other technologies will still be required for dealing with baseload given wind's intermittent generation and unproven power-storage technologies. But emissions would be substantially lower if natural gas were acting as a backup to wind power generation.

The upshot is that eliminating carbon dioxide emissions from electricity production would not necessarily entail the exclusion of coal or natural gas. A premium on those fuels could eliminate emissions through carbon capture and storage while raising the cost of the electricity they produce by less than $60 per MWh (6 cents per kilowatt-hour). Evidently, there are a number of available options open for low-emission electricity generation. This suggests that choosing 'the' winning technology will not be easy.

Allowing the market to make those choices by pricing carbon dioxide seems to be a least-cost solution. But the scale of investment needed for large-scale sources such as nuclear power may necessitate more government involvement to avoid market financing premiums that could render them non-viable. The estimate in Table B-2 is based partly on recent projects that are costing roughly US$10 billion for 2.2 GWh of electric power capacity.

For perspective, Canada's average residential electricity price (in purchasing power parity) was the lowest in 2013 among 28 countries reported in IEA (2015). Moving to carbon-free electricity generation should only mildly affect that ranking. For industry, Canada's average price ranked fourth cheapest, but 18 per cent more expensive than the United States.

Abatement projection

The PBO baseline did not fully address the potential reduction in emission that will result from the coal-plant regulations that became effective in July 2015. Those regulations require emission-efficiency improvements in new and refurbished plants to go below those of natural gas per MWh. The cost of switching to natural gas as coal plants reached the end of their originally-rated life-cycle would be a good estimate of a low cost of abatement with a proven technology.

In Saskatechewan, in 2012 this would have been roughly $23 per tCO_2e. If all coal plants are converted to natural gas, the reduction in emissions would be roughly 28 $mtCO_2e$. If, on the other hand, carbon capture and storage or other technologies are used, the cost would be higher, but the emission reduction would also be higher.

The revealed cost of carbon capture and storage is roughly \$57 per tCO_2e at Boundary Dam (partially offset by CO_2 sales). Consequently, a useful conjecture would be that most remaining coal-burning plants could, during refurbishment, implement carbon capture and storage at that price by 2030. This assumes that, learning-by-doing would balance any potential additional costs due to changed circumstances.

That estimate is underpinned by the EIA (2015b) projection that carbon capture and storage would add about US\$44 per MWh generated. **The avoided emissions would be about 50 $mtCO_2e$, assuming that either all coal-burning plants implement carbon capture, or are replaced by renewables** (with 10 per cent of emissions not avoided, as is the case at Boundary Dam).

This leaves a substantial level of emissions from natural gas-based generators (14 $mtCO_2e$) that are left unaffected by the existence of a conjectured price on CO_2e of \$57 (equivalent to almost six cents per kilowatt-hour). Since retrofitting carbon capture and storage is significantly more expensive than installation in a new plant, there is some justification for this.

Nonetheless, the possibility of installing additional wind or other non-emitting technologies under those circumstances balances any potential optimism in cost for achieving the 50 $mtCO_2e$ reduction through carbon capture and storage.

The lower range of the price in Table 6-2 is given by the feed-in-tariff price that Ontario used to get its wind program started.

Transportation

Emissions from transport services (excluding rail, air and pipeline) have consistently increased over time, from 122 $mtCO_2e$ in 1990 to 178 $mtCO_2e$ in 2013. In 2013, emissions from transport amounted to 25 per cent of all GHG emissions. For the baseline projection, transport will be a growing source of emissions, as it increases its share of overall emissions by about 1 percentage point.

A significant part of the past increase came from having more cars on the road. Today, there are eight cars and trucks on the road for every 10 adult Canadians under 75 years of age. But along with a steady increase in car ownership and driving, fuel efficiency also improved.

For example, between 2000 and 2008, the number of road vehicles in Canada increased by 18 per cent, while emissions from road transport grew only 13 per cent (Statistics Canada, Cansim Table 405-0004). This improvement was the result of technological advances. Engines provided more horsepower from a given engine size (power train improvements), and vehicles became lighter but safer (non-power train enhancements).

The upshot is that average emission-efficiency per vehicle improved by about 5 per cent. While some of that increase was predictable given that manufacturers have to compete globally for customers – and technological innovation is a main channel for that competition – the price of fuel also contributed to those improvements.

Between 2000 and 2008, the average retail fuel price rose by roughly 26 per cent and thus caused consumers to be more aware of vehicle fuel-economy. Indeed, emissions per person from light-vehicle transport started decreasing shortly after the price of crude oil began a sustained increase (Figure 2-4 in main text).

Surveys of the relationship between fuel use and its price generally find that the responsiveness is quite significant (see Goodwin, Dargay, and Hanly, 2004, for a review of elasticities). Those studies usually distinguish between a short-term response where people may drive less or otherwise make do with their existing vehicles by carpooling, and so on, and a long-term response where people change the means of travel by buying more fuel-efficient vehicles.

This latter long-term effect can be readily seen in the distinction between the Canadian and American car markets. In Canada, where the price of gasoline is generally higher than in the United States because of taxes, the top selling car is the Honda Civic. In the United Sates, the top selling car is the larger Toyota Camry. The difference cannot be explained by incomes alone.

The changes in fuel use between 2000 and 2008, when the price increased, imply a fuel-price responsiveness (elasticity) of about minus 0.2, which is consistent with what empirical studies generally find when looking at the short-term. The long-term responsiveness of fuel consumption, however, is about minus 0.5 to a retail price change. This means that a (sustained) 10 per cent increase in the retail price of fuel results in a 5 per cent decline in its use.

In spite of this strong link between fuel consumption and price, the link to income is even stronger and more robust. Travel has always increased with income and has often been found to have an elasticity of 1 over a sufficiently long period of time. So a 10 per cent increase in income results in a 10 per cent increase in travel.

This means that projections of future income growth would have strong predictable effects on emissions from transport unless measures to counter that influence were introduced. While the price of fuel would seem the obvious means to counter that effect, alternatives also exist (and have to some extent been implemented).

For perspective, between 1990 and 2013, there was a 39 per cent increase in emissions from transport in Canada at the same time that income per capita increased 34 per cent (both population and personal incomes rose). By 2030, a projected 11 per cent increase in incomes could lead to an 11 per cent increase in travel.

When combined with the population expansion, this could lead to an increase in emissions of about 30 mtCO_2e. The retail price of fuels would have to rise by about one-third above 2013 levels to keep aggregate transport emissions from increasing.

The needed reductions in emissions, however, are going to be helped by a policy development only partially in the baseline: the improvement in fuel-efficiency standards. In 2012, the United States revised its Corporate Average Fuel Economy (CAFE) standard. By 2016, new automobiles would have to be significantly more fuel efficient, and even more so by 2025.

In Canada, similarly enhanced standards would result in a 20 per cent improvement in fuel efficiency by 2016. Since Canada has also harmonized future standards with those of the United States, further gains in efficiency will occur even without explicit fuel-price changes.

Indeed, the fuel efficiency for cars is set to increase by almost 50 per cent by 2025, while that for trucks will increase by 25 per cent. This latter change partially offsets the potential loss of efficiency gains to bigger vehicles.

Nonetheless, there is some disagreement as to the effectiveness of the CAFE standards given unresolved issues with how the tests are administered and what the starting point is for each vehicle. There are also issues related to the malleability of the boundary between light trucks and cars.

Also significant are emissions from off-road vehicles, particularly nitrogen dioxide from large diesel engines. There are a number of technologies available to remove that potent greenhouse gas from the engine's exhaust (one technology is currently used in some diesel engines for passenger vehicles).

Abatement projection

IEA (2012) and McKinsey (2014) report that known potential improvements in internal combustion engines, and more widespread adoption of hybrid technologies, could improve future vehicle efficiency by 40 per cent. Since they also report that **those technologies cost less to implement than the equivalent of \$100 per tCO_2e emitted, the implication is that 40 per cent of future emissions (60 mtCO_2e) could be avoided with that carbon dioxide price**.

For reference, \$100 per tCO_2e emitted would increase the price of regular gasoline (without additives) by about 24 cents per litre. But some of those technologies become viable when the equivalent of $60 per tCO_2e is imposed on fuel costs (14 cents per litre of gasoline).

By comparison, the average tax and duties on a litre of regular gasoline amount to about 40 cents per litre (IEA, 2015). This is equivalent to a tax on carbon dioxide emissions of about $167 per tCO_2e. However, most of those taxes are unrelated to carbon dioxide emissions, so in principle they are not substitutable.

Moreover, the fuel-price equivalent of the cost of those technologies is blurred by the decline in the price of crude oil during 2014 and 2015. A price on carbon dioxide that was introduced on gasoline would have little impact if the price of crude oil remained significantly below US$50. This is because much of the lower emission intensity that was recorded from transportation in 2013 relative to 2005 was the result of higher oil prices.

Given the potential for the price of crude oil to remain depressed as efforts to abate emissions progress, estimates of explicit carbon taxes required to reduce emissions from transport are not reliable.

Oil & gas production, refining, and distribution

From 1990 to 2013, emissions from oil and gas extraction, refining and distribution increased from 104 $mtCO_2e$ to 169. Their share of overall emissions went from 17 per cent to 23 per cent. The main source of the increase was in oil and gas extraction, which was itself dominated by the oil sands. The baseline projection includes growth of oil sands emissions of about 74 per cent (52 $mtCO_2e$) between 2013 and 2030.

Methane emissions from extraction and distribution networks as well as petroleum refining operations are projected to remain constant since they have not changed much from 1995 even with large increases in production (Figure B-2).

Canada's petroleum and natural gas industries have been undergoing multiple transformations over the past 15 years. Movements in global demand and supply caused large gyrations in prices which then fed back into demand and supply.

Relative to 1995, the real price of crude oil (West Texas Intermediate) increased by 56 per cent by 2000. By 2008, it was five times higher before starting to decline again in the face of lower demand after the economic downturn and the development of shale-oil in the United States (itself a response to high oil prices).

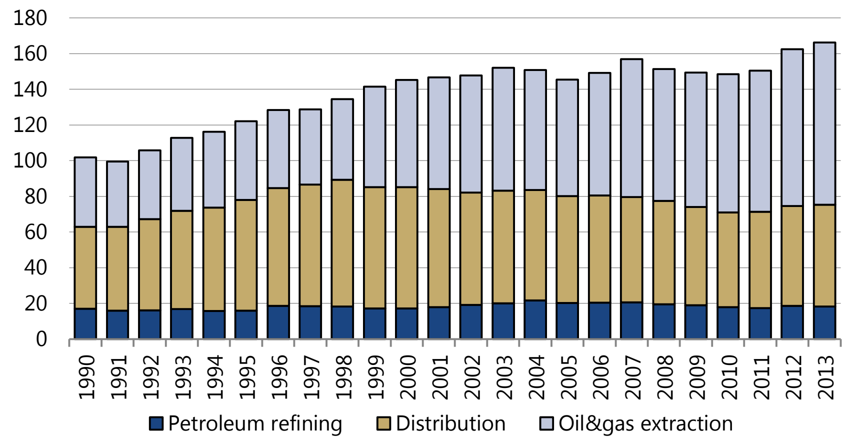
For natural gas, again relative to 1995, the real industrial product price in Canada was almost 70 per cent higher by 2000; by 2008, it was more than two times higher. After that, technological advances in gas extraction in the

United States (shale-gas) caused the price to fall significantly. Lower prices have prevailed since.

The strong run-up in oil prices led to much exploration and development of alternative energy sources. One beneficiary of that was the Canadian oil-sands sector where production increased nearly three-fold from 0.43 million barrels per day in 1995 to 1.21 million in 2008. By 2014, it had almost doubled again.

Figure B-2 GHG emissions from the oil & gas sector

million tonnes CO_2 equivalent



Source: Canada's National Inventory Report to UNFCCC (2015).

The main source of emissions from oil and gas extraction is in the process of converting bitumen in oil sands into a product that is sufficiently low in viscosity to be used by a refinery. This requires significant amounts of energy (heat) to generate steam that is injected into the ground or into a pool so the bitumen can be extracted.

When a fossil fuel is used, the CO_2e emissions can be significant per barrel of oil produced. For Canadian oil sands, there is a mix of energy sources that are used on a variety of different qualities of bitumen. This leads to CO_2e emissions per barrel of refined products (life-cycle) that are between 12 and 22 per cent higher than that of a conventional barrel of "Canadian Light" crude. On average, these emissions are about 66 kilograms of CO_2e per barrel.

Technologies currently in development or partially deployed can significantly reduce emissions. Some use solvent-assisted processes to extract oil from the source (which can reduce extraction emissions by one-third). Others replace steam altogether by injecting solvent. These have been tested and found to work at a sufficient level to be deployed. They nonetheless still require further development to ensure solvent recovery can be achieved so as to minimize environmental risks such as the contamination of ground water.

Further down the horizon are technologies that more efficiently heat the bitumen. These include microwave heating or copper wire heating where the energy source is non-fossil fuel based. Further upgrading of the bitumen prior to transport is also in development and would reduce the use of energy (and solvent) needed to move it through a pipeline. But some refineries that buy oil sands products prefer the raw product.

Alternative energy sources that do not involve burning natural gas are also possible and may become more viable with higher levels of carbon dioxide prices. The alternatives include installing modular/portable nuclear reactors, or even proceeding with some of the proposals that have been made and partially advanced for hydroelectric power.

To see the scope for these alternatives, consider that at present, roughly 66 kilograms of CO_2e[23] are emitted for each barrel produced. If we assume that this is all from a clean source such as natural gas, then it means that about 1,240 cubic feet of natural gas are used for each barrel at a fuel cost of about $5 per barrel when natural gas is $4 per thousand standard cubic foot (tcf, the AECO average price for 2015).

A carbon dioxide price of $100 per tCO_2e would lead to a price of natural gas that increased by $6.60 per tcf, so the fuel cost per barrel of oil would become $10.60. This means that electricity produced by natural gas for oil sands would become about $55 per MWh more expensive. These cost increases would make the alternatives of nuclear or hydroelectric sources of electricity considerably more attractive, and would make oil from the oil sands comparable in emissions to oil from conventional sources.

Even at lower carbon dioxide prices there is considerable prospect for reducing emissions by fuller use of existing technologies such as the Gas-Turbine Once-Through Steam Generators. These use natural gas to simultaneously produce electricity and steam for the extraction processes.

Carbon capture and storage will even play a role in reducing emissions. Using a price for CO_2e emissions of $45 per tonne (the estimated cost of CCS in the Quest project – Appendix A), the additional cost for oil sand production (above the cost that conventional oil would face) is less than $4 per barrel.

The other main source of emissions from the oil and gas sector is in the process of extraction and distribution of natural gas, and other products that cause methane emissions (fugitive emissions). They amounted to 59 $mtCO_2e$ in 2013, the majority of which came from either natural gas transportation or venting. This represented about 8 per cent of Canada's emissions. They can be difficult to eliminate since gas producers already try to avoid them; they have an incentive in the form of lost revenues.

Nonetheless, past responsiveness of such emissions to the real cost of natural gas suggests that there is some scope for lowering them. That is, the changing price of natural gas over the past 20 years has been associated with changes in the level of methane emissions.

They were first rising until 1998 as the real price of natural gas fell, then they were declining as the real price of natural gas subsequently rose. The straightforward explanation is that after 1998, the opportunity cost of the lost natural gas created sufficient incentive to improve the efficiency of the distribution system.

To put things into perspective, methane has a warming potential 25 times higher than carbon dioxide over 100 years (measuring each in tonnes). With a \$100 price per tCO_2e, the value of the lost natural gas would be roughly \$59 per 1000scf for the company (using 23.8 kilograms of natural gas per 1000scf).

Leakage rates have been measured at about 1 per cent in a few gas fields in the United States. If this were applied generally, it would mean that a price of \$100 per tCO_2e would add \$0.59 to the average cost of 1000scf of natural gas. It would provide a sizable incentive for gas companies to minimize leaks. This would complement existing abatement strategies (for example, OGP, 2000).

Abatement projection

Kilpatrick *et al* (2014) note that with a price around \$100 tCO_2e, a significant amount of CCS could be undertaken over 15 years. Combining their work with the discussion in Appendix A, and also allowing for some new technologies to be implemented as outlined in CCA (2015), **a price starting at \$45 per tonne and moving to \$100 will be sufficient to at least achieve a stabilization of emissions from oil sands at 2013 levels, and achieve an 11 $mtCO_2e$ reduction in other oil and gas activities, a 40 $mtCO_2e$ reduction from baseline**.

This also includes reductions in petroleum refining and natural gas extraction and distribution. Moreover, if the price of crude oil remained low over the period to 2030, much of the increased emissions from oil sands would not materialize and a smaller reduction from oil and gas would still be compatible with achieving the target.

Agriculture and waste treatment

Agriculture and waste treatment were the source of 75 $mtCO_2e$ in 1990 (12 per cent of overall emissions). This increased to 89 $mtCO_2e$ by 2013, but still represented 12 per cent of emissions. Agriculture was the larger of the two with roughly two-thirds of their emissions. By 2030, emissions from agriculture and waste treatement are projected to fall to 81 $mtCO_2e$.

The two sectors produce significant amounts of greenhouse gases in the form of methane. In the case of agriculture, apart from manure management, the source is mainly from livestock digesting grasses (through enteric fermentation). Decomposing grasses so the body can use them generates methane as an important byproduct. In terms of waste, methane comes mainly from landfills that contain decomposing organic material.

Since methane is a powerful greenhouse gas, agriculture alone contributed almost as much methane-based GHG emissions as the oil sands did in 2013 (indeed, when energy sources of emissions from agriculture are included, that sector surpasses the oil sands). Emissions of methane within agriculture and waste varied significantly over the years from 1990 to 2013, but ended only 6 per cent higher.

Most methane emissions from agriculture in Canada are caused by cattle. Large ruminants that graze, such as cattle, can eat substantial quantities of grasses (cellulosic material) through foraging each day. Smaller ruminants such as goats and sheep more efficiently digest smaller quantities of daily forage.

Methane emissions from cattle can be reduced by varying their diet to lower the quantity of grasses. This means mainly adding edible products such as vegetable oils, corn or barley that substitute for cellulosic material. At present, these are used primarily during the months before slaughter so as to increase the yield to the farmer from each animal. Estimates suggest that almost 20 per cent of methane emissions from cattle can be curtailed by doing so over an animal's life cycle.

However, this requires introducing food additives/substitutes that add to the cost of meats sold to consumers. It also may create a dilemma in terms of causing other agricultural activity to expand so that the higher quality feed can be produced. Some hormones that induce more rapid growth can lower emissions per animal, but in Canada there is less acceptability of this approach.

Still in experimental stages, however, are strategies that combine selective breeding with non-hormone food additives/substitutes. There is significant variation even within a herd in the amount of methane produced per animal, and that seems to be a characteristic that is passed down through subsequent generations. Exploiting that characteristic for selective breeding has been an active area of research for the past decade or so.

The U.S. Environmental Protection Agency estimates that feed supplements could, as a global average, cost about CAD$40 for each tonne of avoided carbon dioxide equivalent. Using the implied elasticity from that analysis, for Canada, this holds out the possibility of reducing about 0.3 megatonnes of emissions in total. Higher levels of abatement may be possible and are outlined in EPA (2013). But the caveats noted therein (page V-71) make it somewhat speculative to go beyond these modest estimates.

Moreover, differences in climatic conditions, etc., between Canada and the United States mean that the $40 cost estimate must be considered optimistic when applied to Canadian cattle production, although significant published research on substituting feed material has been conducted in Canada (e.g. Beauchemin and McGinn, 2005).

For crops, the emissions are mainly related to fertilizer use (N_2O) and soil carbon content (CO_2), though there is a very small contribution from soil methane content. Fertilizer use can be better managed in terms of more precise application. Reduced tillage along with reduced summer fallow can limit the release of carbon from soils.

However, Agriculture and Agri-Foods Canada (AAFC) estimates show that direct mitigation potential in the agriculture sector from adopting these practices is likely to be small and costly. The soil carbon sink is approaching equilibrium and there is limited scope for additional adoption of carbon sequestration practices such as no-till.

These practices were estimated to be viable under a voluntary offset system at a cost of $60 per tonne of CO_2e to achieve a 1.04-megatonne reduction, or $100 per tonne of CO_2e for a 1.30-megatonne reduction. But they are subject to optimistic assumptions regarding the amount of fertilizer that can be effectively reduced with precision techniques. These estimates are also dependent on the economic parameters used in the analysis, and do not reflect more recent trends.

For emissions from waste production, the primary action is to capture methane from landfills and either use it in manufacturing, or flare it so that its contribution to climate change is significantly reduced.[24] Capturing those emissions is facilitated by the design and construction of land-fill sites.

So, the initial reductions from any attempt to mitigate emissions may be modest but may grow over time as new landfill sites are developed with incentives to mitigate. EPA (2013) estimates that for Canada, about half of its baseline emissions (12 $mtCO_2e$) can be reduced by a carbon dioxide price of less than CAD$30.

Abatement projection

Summarizing the results from agriculture and waste production:

- Feed supplements, at a cost of CAD$40 for each tonne of avoided carbon dioxide equivalent, reduce roughly 0.3 megatonnes of emissions in total.
- Precise fertilizer application, combined with soil carbon sequestration, is estimated to achieve a 1.04-megatonne reduction at a cost of $60 per

tonne of CO_2e, or \$100 per tonne of CO_2e for a 1.30-megatonne reduction.

- For emissions from waste disposal, about 12 mtCO_2e can be reduced at a carbon dioxide price of less than CAD\$30.

Buildings

Heating homes and commercial buildings, and to a lesser degree cooking with natural gas, contribute significantly to GHG emissions. In 1990, they were the source of 12 per cent of Canada's emissions. By 2013, they had fallen to 10 per cent, although the level was unchanged at 75 mtCO_2e. By 2030, emissions are projected to fall to 61 mtCO_2e.

Buildings are a particularly important source of carbon dioxide emissions during winter when natural gas or fuel oil are used for space heating. In regions that use coal or natural gas to produce electricity, air conditioning and any other building-related uses of electricity also contribute to emissions. But they are not attributed to the emissions of buildings since they are counted as emissions from electricity generation.

One way of dealing with emissions from buildings is through better insulation, as well as higher quality doors and windows. The long life-cycle of buildings (50 years or more) however, means that measures taken now to reduce emissions in new buildings would be slow to show up in national data.

Moreover, since GHG abatement faces incentive problems given some peculiarities in the structure of the housing market, measures may have to be specifically adapted to the sector. One such issue is that the cost of housing is paid for up front, while the expenses of living in it occur over decades. Cash-constrained individuals often opt for a house or building that costs less to build up front, even if it will be more expensive over the long run.

The likelihood of selling the home may also factor in decisions regarding construction since recovering the cost may be uncertain. So insulation will only be installed to meet building regulations or market tolerance rather than to balance construction cost and heating over periods extending to 50 years. These kinds of market-related issues would be partially addressed if carbon pricing were introduced, but pricing would not address incentives related to upfront costs.

In fact, Canada does not have a mandatory building code at the national level. The National Research Council's National Energy Code for Buildings (2011) is a guideline since it is provinces and municipalities that regulate buildings. Even so, its objective seems to be a good use of available technologies rather than an explicit intertemporal accounting of long-term costs.

To illustrate, consider the cost for new structures of achieving the highest energy-efficiency standards ("green buildings"). It is estimated to be around 5 per cent of the construction cost (McGraw Hill, 2014; with variation around that depending on a number of factors).[25] The payback period is considered to be around eight years.

If the firm's real cost of capital is 5 per cent, it should undertake the investment if its investment horizon is more than 10 years. The implication is that getting to a "best" building standard for energy use only requires internalization of costs and benefits of energy use over an 11-year, or longer, horizon.

Of course, using a mandatory building code to address market peculiarities such as upfront costs will only tangentially address GHG emissions. Fully addressing emissions will still call for measures to discourage GHG-emitting sources of heating in favour of their non-GHG counterparts.

Indeed, the benefits of having building standards more fully address long-term costs from various sources have led some observers to suggest that there is a net gain from measures to reduce GHG emissions. But this confounds the two issues and potentially leaves GHG emissions only partially addressed.

For existing buildings, the issue is even less clear since the age of a structure matters for what can be done, and past government programs already provided incentives for retrofitting. For those buildings that are otherwise profitable for their owners to continue to operate, energy retrofits will be done at the same time as other work.

An example is the Empire State Building in New York. By 2010, a complete retrofit and remodel had been completed at a cost of $550 million. Of this, $106 million was for energy-related projects, which led to a reduction of energy use by 32 per cent, or $4.4 million per year. If the firm's real cost of capital were 3 per cent, it would take 44 years to recover the cost (longer with a higher cost of capital).

The full anticipation by the owner that the building had a long life-cycle ahead led to a complete internalization of long-term costs. Again, this occurred without a monetary incentive to reduce carbon dioxide (for example, emission pricing), so the emission reduction was a byproduct of the retrofit and not a business objective.

With respect to private homes, there are two sources for publications that deal with energy use: Statistics Canada (2013) and NRCan (2014). Their publications contain some information concerning the potential for carbon dioxide abatement when they are combined with the results of a program for energy retrofits enacted by the federal government between 2007 and 2010.

The program led to the retrofitting of some 640,000 Canadian homes to save an average of 20 percent on their energy bills. The cost to the government was $1,500 per home. At the time, there were roughly 13.5 million homes in Canada, so about 5 per cent of the total participated. With a typical year-round heating bill running about $1,200 per home, this represents a saving of about $240 per year. This money, however, would have leveraged expenditures by the household as well.

An estimate of the total amount spent can be made by noting that the average family was, at the time, able to borrow at roughly 6 per cent interest for a long-term loan (10 years). In that case, a potential savings of $240 per year would have induced them to spend an additional $1,800 for the retrofit. So the program should have led to 640,000 homeowners spending about $3,300 for energy-efficiency retrofits.

With the average annual natural gas consumption of each home at about 3,100 cubic metres, the 20 per cent reduction in fuel would potentially lower carbon dioxide emissions by 1.2 metric tonnes per year, and roughly double that in homes heated with fuel oil. Since just under two-thirds of Canadian homes are heated with GHG-emitting fuel, the overall effect of the program would have been to lower carbon dioxide emissions by roughly 0.5mt.

This effect was an additional benefit and not the main objective of the program; nonetheless, from the government's perspective, the cost per tonne of carbon dioxide abated was less than $100 in homes using natural gas, and about $50 in those using fuel oil.

Chemicals manufacturing, petrochemicals and fertiliser production

The chemicals industry represented almost 5 per cent of Canada's GHG emissions in 2013, about where it was in 1990. Roughly half of this was from energy use (mostly natural gas), while the other half was from processes and end-use disposal. For 2030, the industry's representation is projected to decline to just over 3 per cent.

A significant part of process-oriented emissions come from ammonia production, while some also come from nitric acid production. Ammonia production in Canada uses natural gas as a source of hydrogen and releases carbon dioxide as a byproduct. Under current technologies, this is a fixed relationship. So the stream of carbon dioxide would have to be dealt with directly to avoid emissions (although carbon-free technologies to produce ammonia are actively being researched). This process produces a concentrated steam of carbon dioxide.

Two technologies available to mitigate the release of carbon dioxide from ammonia production are to either use it to make urea, or to inject it into oil fields for enhanced recovery. In either case, the carbon dioxide is not released into the atmosphere.

Emissions that are instead caused by the energy needs of chemicals manufacturing are more costly to eliminate since the CO_2e stream is not concentrated, and thus would require more processing, or substitution to alternative sources.

Urea production has begun to expand considerably and between 2015 and 2018 a number of plants in the United States will come on line in response to low natural gas prices there and high urea prices. Still, since U.S. urea imports in 2012 were almost twice Canada's production, there is significant scope for expanding urea production in response to any program to reduce emissions in Canada (for example, carbon dioxide pricing).

Injection, on the other hand, is made a little more practical by the fact that natural gas is cheaper at its source since it avoids transport cost. That source is often closer to areas where crude oil has been extracted and enhanced recovery may be necessary. Indeed, one of the plants currently selling carbon dioxide for enhanced oil recovery in Alberta is a fertilizer plant (Agrium).

Abatement projection

At least two projects in Canada currently selling carbon dioxide for use in EOR illustrate that capture of carbon dioxide can be done at roughly $25 per t$CO_2e$. Prices above that level would have to be sufficient to cover transportation and injection.

Experience in the United States suggests that transporting carbon dioxide 250 kilometers can cost US$2 or less per tonne (Appendix A). So a price of $50 per t$CO_2e$ or higher would provide significant incentive for capture and long-distance transport with a sufficient network of pipelines. **A cost estimate beginning at $50 for carbon dioxide abatement from the chemicals industry would then move as high as $100 to achieve a substantial reduction of 3 mtCO_2e, which is mostly related to process emissions with minimal saving on energy emissions.** From the perspective of the chemicals industry, the implementation would have to be gradual to avoid stranded capital and potentially allow transport infrastructure to be built.

Iron and Steel

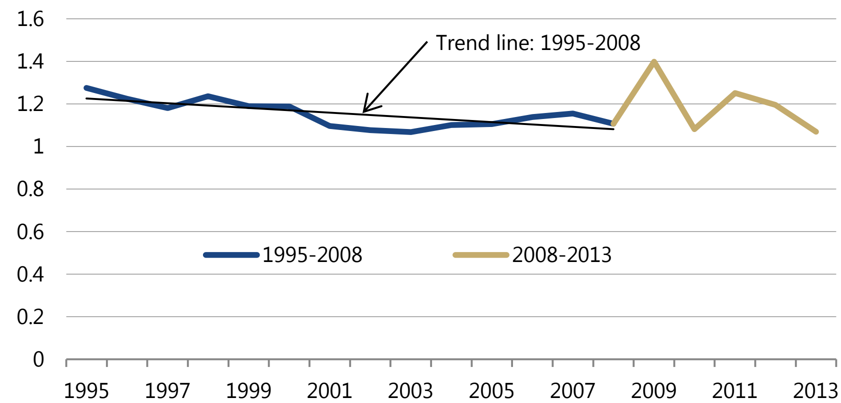
Emissions from the iron and steel industry have gradually declined during the past two decades. In 1990, they represented more than 2.5 per cent of Canada's CO_2e emissions; by 2013, this had fallen to about 1.8 per cent. This happened even with the substantial growth of the Canadian economy during that period. There are three reasons for that.

First, other products such as aluminium, graphite composites, plastics and so on continue to expand their applications. Secondly, steel is easily recycled, so the amount of iron ore needed each year will always be less than the demand for steel products; the larger the stock, the more that will be recycled each year. Finally, steel-making continues to evolve, with newer technologies being less emissions-intensive (Figure B-3).

Figure B-3

GHG emissions intensity in the iron and steel sector

tonne of CO_2 per tonne of steel (disposition)



Sources: Canada's National Inventory Report to UNFCCC (2015) and Statistics Canada NAICS 3311 data.

Note: The period after 2008 included a major slowdown in production and the closing of a large facility. The trend-line is thus reported for 1995 to 2008. The average emissions intensity reduction over that period was 1.1 per cent per year.

GHG emissions are produced in multiple stages in the process of making steel in integrated mills. In general terms, this includes cokemaking, ironmaking, steelmaking, finishing and steam production.

The process of converting iron ore to liquid iron in a blast furnace not only requires heat, whose carbon dioxide emissions can be minimised, but in removing the oxygen from iron oxides it requires carbon – obtained from coke. This carbon-based reduction of iron oxides to liquid iron releases carbon dioxide and carbon monoxide, along with other gases, in what is known as blast-furnace gas.

In the past, the heat for each stage was mostly produced by burning fossil fuels, except for the basic oxygen furnace which produces carbon dioxide by injecting oxygen into carbon-rich iron.

Over the past few decades, previously-known technologies were developed further and came into more widespread use by the industry. The initial impetus was the need for specialization in the North American steel industry.

Competition, particularly from Asia, intensified and there was a need for lower-cost production techniques in high-wage countries.

"Mini-mills" with their use of electric arc furnaces (EAF) could make smaller batches of commodity-grade steel that were more economic. Further development allowed them to become high-grade steel producers. Today it can even be used to provide some of the highest quality steel – that used for the exterior of an automobile's body (though this process is not yet used in Canada).

The additional benefit of EAF for today's environmental concern is that it produces significantly less carbon dioxide when the electricity used in the furnaces is generated from non-fossil fuel sources.

In Canada, the share of steel produced in this way gradually rose until 1997, after which it remained roughly stable. It is higher than in some countries, but significantly lower than in the United States. EAF was initially best applied to scrap metal, with some combination of iron ore when economic, or necessary.

It can, however, be made part of a steel production process that is significantly lower in carbon dioxide emissions when it is combined with a process called direct reduction iron (DRI). DRI takes iron ore and heats it to a temperature just high enough (above 800 degrees Celsius) that a reducing agent such as natural gas will strip away impurities and leave iron pellets of about 94 per cent purity. Today, DRI that is more than 90 per cent pure can be used in an EAF. It can also be used to generate a feedstock for blast furnaces that creates lower overall emissions even in integrated mills. Moreover, OECD (2012) illustrates that EAF combined with DRI produces steel at lower cost than blast furnace technologies.

However, the use of DRI/EAF technology is limited by the quality of the input ore since DRI cannot remove all impurities. It thus cannot replace all existing steel production in Canada. Nonetheless, a much higher proportion of steel is produced through DRI/EAF in countries such as the United States and India.

So expansion of the use of DRI (even for greater use in blast furnaces) in Canada is a forseeable consequence of carbon dioxide pricing, especially since past reviews have warned that the alternative of carbon capture and storage would double the cost of steel (Vanwortswinkel and Nijs, 2009).

Moreover, shifting to improved techniques without changing technologies can have a potentially large impact on emissions as well. NRCan (2007) reported that blast furnace-based steel-producing facilities could reduce fuel consumption by 12 per cent just by fully adopting existing technologies to improve their performance.[26]

IEA (2009) also highlights significant capacity to move to best practice. It notes costs starting at a low level below \$10 per tCO_2e, and moving as high as \$200 when very deep reductions are necessary.

Abatement projection

A simple continuation of past trends (Figure B-3) toward greater emissions efficiency is in the baseline, and leads to a 2mt decline by 2030. More involved measures such as increased use of DRI/EAF technologies and use of DRI with blast furnaces would be more costly, but could reduce emissions further. Based on the results of IEA (2009) analysis, this could be **an additional 2 $mtCO_2e$ at a carbon dioxide price of \$25**.

However, since Canada is already a mid-range emitter in steel production (Figure C-5 in Appendix C), it might be more costly than in some other countries to achieve a proportional reduction target, so a range of \$25 to \$50 would be more appropriate.

Given the intense international competition in steel production, the industry faces some risk if carbon pricing is done too quickly (stranded capital) and without sufficient international coordination (carbon leakage).

Cement manufacturing

Cement manufacturing caused a little less than 1.4 per cent of Canada's GHG emissions in 2013. Portland cement is the dominant product for making concrete in Canada, but other types of cement have in the past been used more commonly in other countries.

Its manufacture releases carbon dioxide from two primary sources: (1) about one-third from the heat from fuel combustion used to separate raw materials (primarily limestone and clay) into components; and, (2) the remaining two-thirds when the heated components separate and "clinker" is made.

Clinker is the substance that binds to form concrete when water is added to it and left standing. At a molecular level, the water is used to form polymers and the mix hardens. Portland cement is often composed of about 95 per cent clinker.

Until recently, the relationship between carbon dioxide emissions and cement production was relatively stable (Figure B-4). But increased experimentation and changes in fuel source led to some variation in emissions relative to the amount of cement produced. One such change has been to reduce the clinker used in cement.

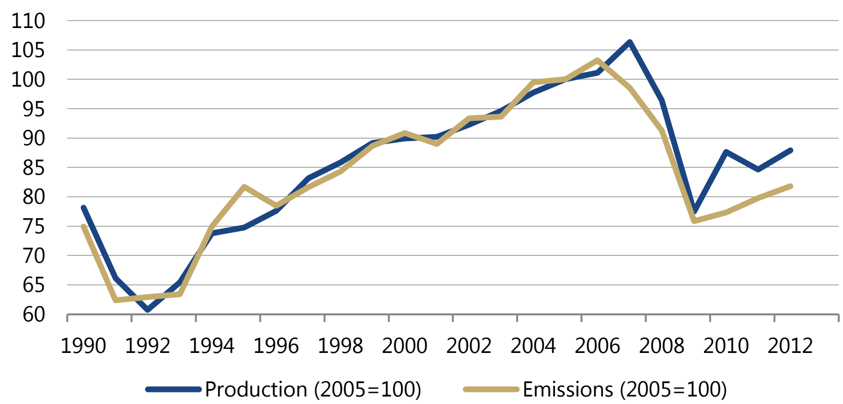
Other products, such as ash from coal burning, can serve the same purpose without compromising the structural integrity of the concrete products for which the cement is used, although large changes in the clinker component will change the property of the concrete. Indeed, since cement that is 95 per cent clinker is not always needed for concrete, greater variety of cement types, and lower *average* clinker content would indicate improved efficiency in the application of concrete.

Between 2000 and 2010, there was a 13.5 per cent decrease in the amount of clinker used in cement; it rose during 2011 and 2012, but the downward trend has since resumed. This has led to a reduction in emissions intensity that is particularly notable in recent years where emissions and production diverge. Between 2000 and 2006, the decrease in clinker was offset by an increase in coal use for heat.

Figure B-4

GHG emissions from cement production

Index 2005=100



Source: Nyboer and Bennett (2014).

Estimates of the cost of further bringing down emissions from cement production range from very low when additional clinker is substituted and fuel-switching is implemented, to high when CCS is used.

Ironically, clinker substitution requires the byproduct of GHG-emitting combustion (for example, slag from blast-furnaces producing iron and steel, or coal ash from large plants still using coal to produce electricity). Consequently, it is difficult to predict what will happen to the supply of clinker substitutes.

On the one hand, it could become more expensive as emissions abatement progresses and less coal-burning occurs. Alternatively, it could remain in plentiful supply if electricity generation or other processes adopt carbon capture and storage.

Abatement projection

Retrofitting cement plants with the capacity for carbon capture and storage has been estimated to cost roughly US$81 per tCO_2e (EIA, 2015). This could almost double the industrial price of Portland cement.

A high share of coal in providing heat for clinker production (Nyboer and Bennett, 2014) means that fuel substitution, even to natural gas, would significantly reduce emissions at a moderate cost. The shift to coal when natural gas became expensive gives some indication of the sensitivity to fuel-price change.

Carbon dioxide prices above $40 per tCO_2e would be sufficient to tip the balance permanently in favour of natural gas and further encourage clinker substitution. Thus, with carbon dioxide prices high enough to trigger carbon capture and storage (up to $108 per tCO_2e), **the reduction is expected to be about 5 $mtCO_2e$ from the baseline,** a combination of carbon capture and storage in new plants, along with fuel and clinker substitution.

Land-use, land-use change and forestry (LULUCF)

Emissions from forests, land-use, and changes in land-use are not included in commonly cited national emissions for most countries. So, for example, the 726 $mtCO_2e$ level of emissions for 2013 omits a decline of 15 $mtCO_2e$ from LULUCF.

However, in Canada’s proposed targets for COP21 in Paris, the contribution to carbon dioxide removal originating in LULUCF was to be included. Using a calculation known as “reference” to determine the value of the carbon dioxide decline, the net removal of carbon dioxide could be 19 mtCO2e for 2020 (Environment Canada, 2014b).

Nonetheless, in the proposal made to COP21, Canada stated its intension to calculate emissions on a “net-net” basis, which could make it an even bigger source of carbon dioxide removal. But, since the government has not published a projection of the value of the decline to 2030, it has not been included in either the baseline or as part of the abatement measures.

Canada’s forests are large and represent a stock of carbon that was captured in trees, other vegetation and soil over many years. Each year, wood harvesting results in carbon dioxide emissions. But at the same time, previously harvested areas are regenerating as forests, which remove carbon dioxide from the atmosphere.

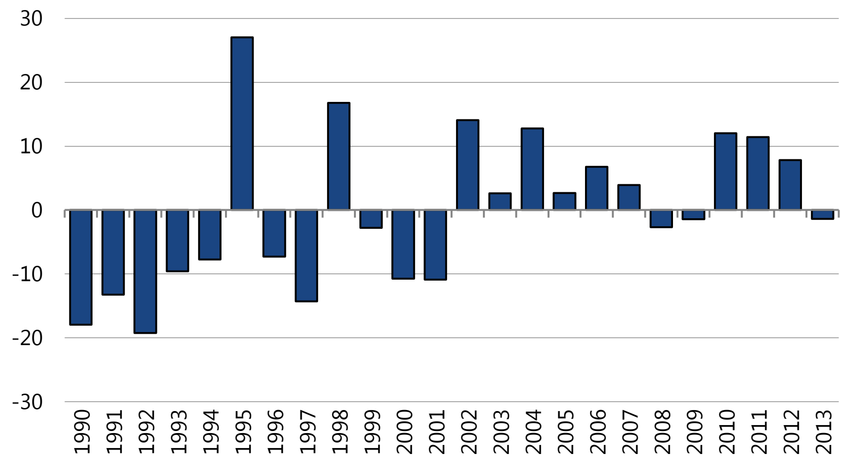
From year to year, there are considerable fluctuations in emissions from forests because of natural disturbance, especially wildfires, that are outside human control (Figure B-5; much of the fluctuation is caused by fires). Over a longer period, the destruction of forests by pests can cause substantial change in emissions, initially through decay, and then through regeneration.

For example, in 1990 the net decline in Canada’s managed forest offset some 18 per cent of all of Canada’s GHG emissions. Conversely, in 1995 very large forest fires meant that forest emissions were equivalent to a large percentage of national GHG emissions.

Since 2000, the mountain pine beetle infestation has also had an important impact. As a result, Canada's forests have been a GHG source in many of the years since. In 2010, emissions from LULUCF were a net source equivalent to 9 per cent of Canada's aggregate GHG emissions for that year.

Figure B-5 **Net emissions of CO_2e from LULUCF**

Per cent of national GHG emissions



Source: Canada's National Inventory Report to UNFCCC (2015).

Note: Much of the annual fluctuation is caused by variability of forest fires. Nonetheless, some years such as 1995 and 1998 are exceptional for the extent of the area affected by fire. Other years, such as 1992 and 2000 had relatively little area affected by fire, and insect infestations like the mountain pine beetle infestation in British Columbia were not yet important.

Abatement projection

Recent research has detailed various forest-related activities that could be counted towards Canada's (future) commitments (Smyth, *et al*, 2014). To 2030, they outline a cumulative potential of 254 mtCO_2e, or a simple **average 17 mtCO_2e per year**. The timing of those reductions is important, though, for the overall capacity of forests to absorb carbon dioxide.

The cost estimates range from a low of $10 per t$CO_2$e when better resource management is implemented, to $75 when harvesting is more selective and the wood products are used more in longer-lived products (Lemprière, *et al*, 2015).

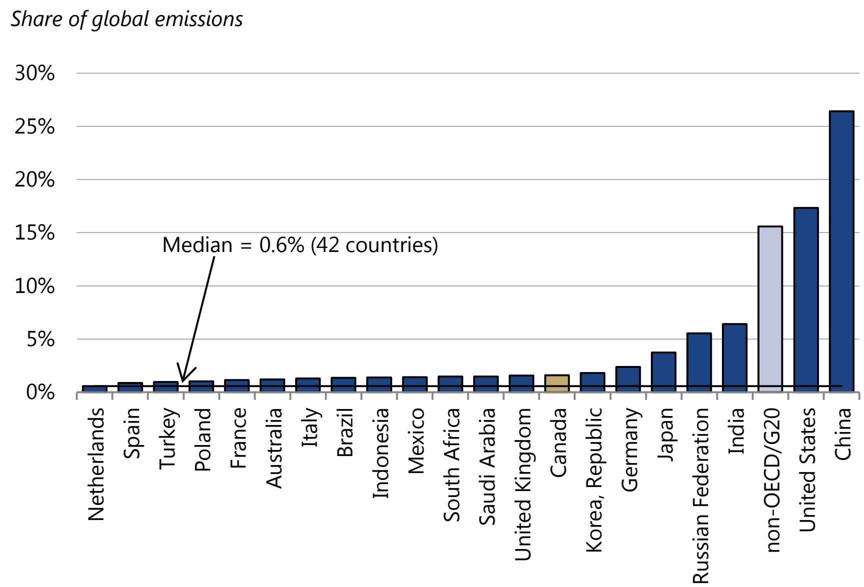
Again, not included in that estimate is the potential contribution of LULUCF on either a "reference" or "net-net" basis.

Appendix C: The global context for Canada

Canada contributed less than 2 per cent of global CO_2 emissions in 2010, making it a relatively small player on a world scale (Figure C-1). Nonetheless, even the United States, with 17 per cent of global emissions, is not the main source.

A significant unilateral reduction by the United States alone, or China alone, would not avoid a 2-degree Celsius temperature change. Any effort at emissions reduction must, therefore, include all countries to achieve meaningful results.

Figure C-1 Share of global emissions in 2010 (OECD, G20, All others)



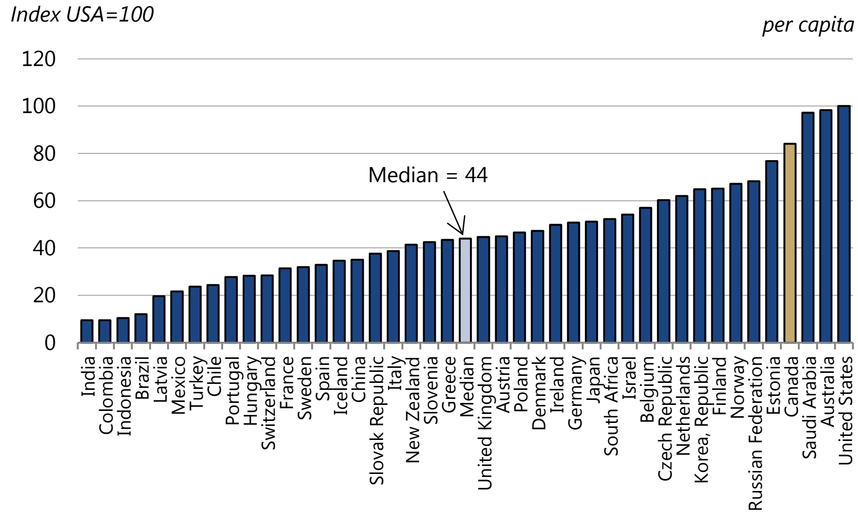
Source: World Bank World Development Indicators (2015).

Note: Other OECD countries are not shown because their emissions are less than 0.5 per cent of global emissions (Austria, Belgium, Switzerland, Chile, Columbia, Czech Republic, Denmark, Estonia, Finland, Greece, Hungary, Ireland, Iceland, Israel, Latvia, Norway, New Zealand, Portugal, Slovakia, Slovenia, Sweden). "non-OECD/G20" refers to all other countries not included in either OECD or G20.

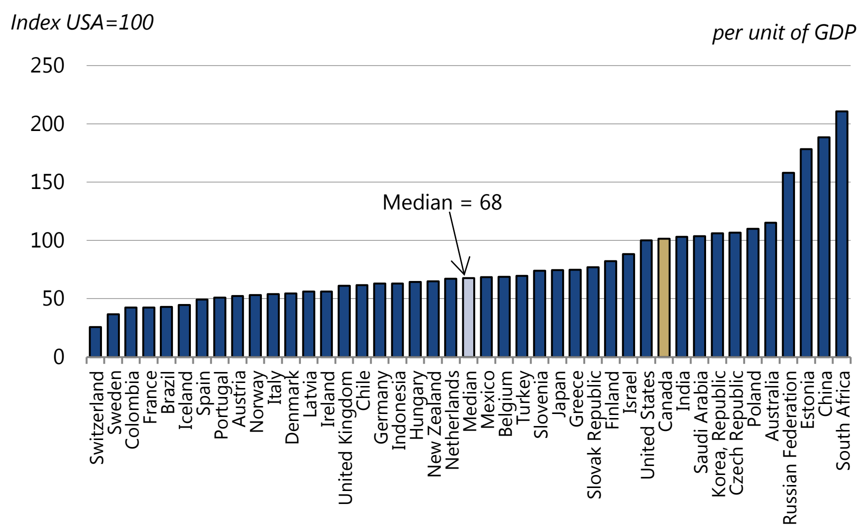
Even so, Canada's small contribution to aggregate global emissions masks its position as a substantial producer and user of fossil fuels. On both a per capita basis (Figure C-2a) and per unit of GDP basis (Figure C-2b), Canada's emissions rank above the median of OECD and G20 economies.

Figure C-2 Relative emissions in 2010 (OECD and G20, rel. to US)

(a) per capita



(b) per unit of GDP



Source: World Bank World Development Indicators (2015)

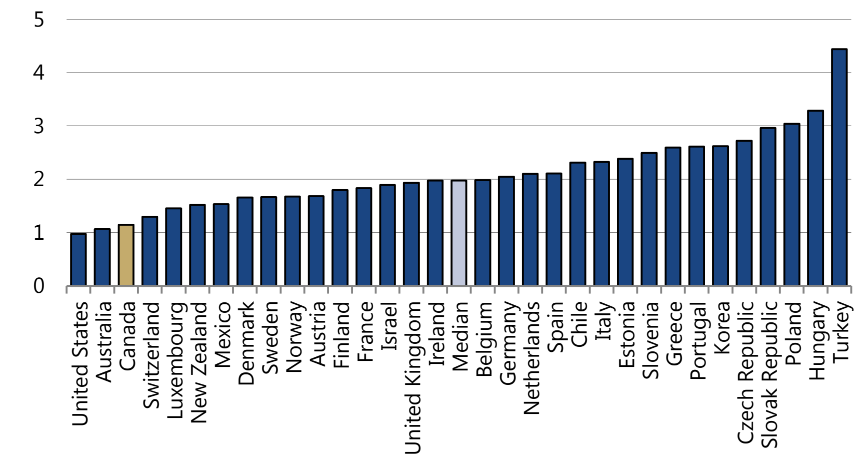
Note: Both charts rank countries by increasing emissions – in both cases relative to the United States. If Canada reduced emissions by 30 per cent and all other countries remained stationary, then Canada's ranking per capita would move down seven places to where the Czech Republic is in Panel (a). Also, measuring emissions per unit of GDP across countries can be misleading. Economies that are early in the development process will have a relatively small services sector, and thus systematically appear to be high-intensity emitters

One reason for that ranking of emissions-producing economies is the relative price across countries of sources of emissions. That is, countries are ordered in Figure C-2(a) by increasing levels of emission per capita. Those to the right are those where fossil fuels are less costly than elsewhere (Figure C-2(b) does the same ranking but with emissions per Gross Domestic Product for countries where data are available). This is indeed the case for crude oil, natural gas and coal (Figure C-3) in a sample of applications (gasoline, industry, and electricity production, respectively).

Figure C-3 Comparative prices for fossil fuels (2013)

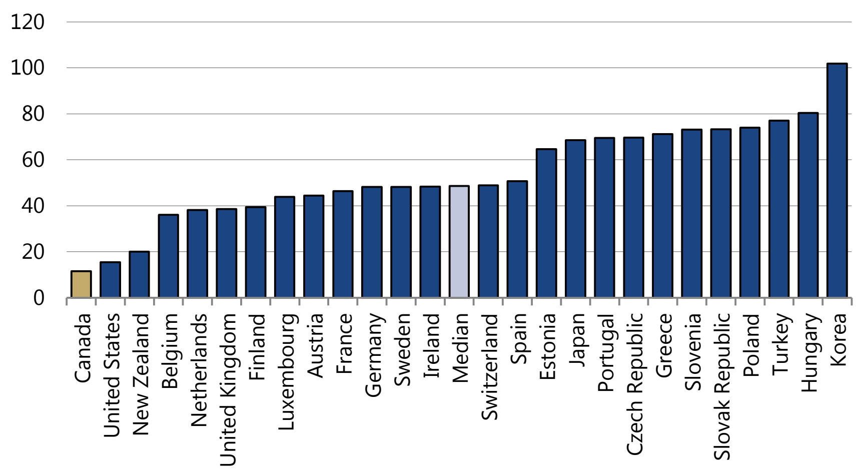
(a) 95 RON gasoline

US $ per litre (purchasing power parity)

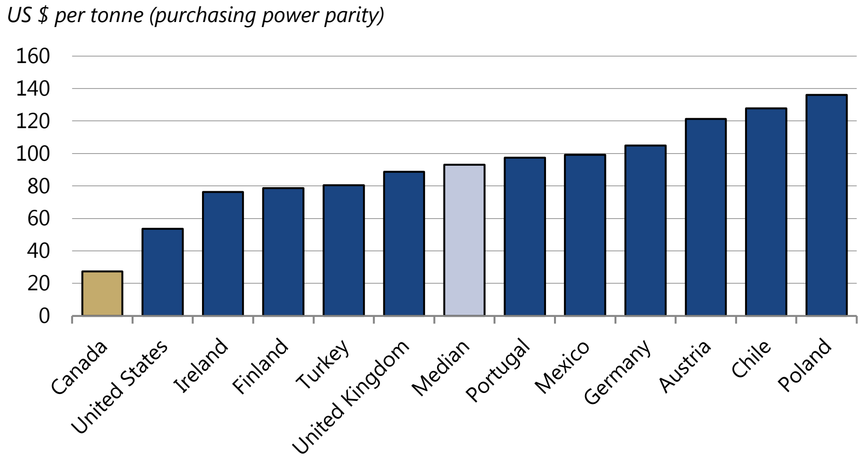


(b) natural gas for industry

US $ per MWh (GCV basis) (purchasing power parity)



(c) coal for electricity



Source: International Energy Agency (2015).

Note: GCV denotes Gross Calorific Value, so the quality of the fuel is accounted for. The source of the purchasing power parity series (PPP) is National Accounts of OECD Countries. For coal, the results change somewhat if account is taken of the quality of coal, but Canada and the United States remain the least-cost users of coal.

For gauging the relative cost across countries of reducing emissions, it would be useful to have a quantitative model that included considerable detail regarding sources of emissions and the many consequences that will occur within the economy, even outside the emission-causing sectors. However, even without such a model, some comparative analysis can be undertaken.

The charts in Figure C-3 make possible a general observation that, relative to most other industrialized countries, it should be less costly for Canada to reduce emissions. This can be demonstrated by supposing that the price in all countries were moved to that of the median country. Then in each country below the median, the price would increase and they would use less fuel. But the country at the median would be unchanged.

Indeed, if countries above the median were also adjusted – to lower prices – their fuel use would likely increase as it became cheaper.

This thought experiment can be extended from countries just below the median, to those countries with the lowest price. At each step, a lower price should result more fuel use, and the country with the lowest price should be among the biggest users of the fuel. Turning that around, when all countries are moved to the median price, the one with the lowest price before the change should experience the largest reduction in the use of the fuel because it will have the largest change in price.

This observation can also be used to comment on the likelihood that Canada will be able to purchase offsets from other countries if it does not meet its objective on its own. Since Canada is a relatively low-cost emitter, other countries will face higher costs domestically. In that case, Canada is more likely to be a net seller of offsets rather than a buyer.

That is, if another country has a price of $100 per tCO_2e to reduce emissions and Canada's price is $50, then it will be profitable for Canada to undertake additional abatement and sell the offsets. Of course, this observation gives some underlying economics, but the actual outcome of any regime would be highly dependent on its specific rules.

The diversity of emissions intensity (Figure C-2) suggests that attempts at scaling back emissions will have to be part of a collaborative effort with participation by all countries. Less than full participation could raise concerns that some countries are engaging in strategic behaviour to gain competitive advantage.

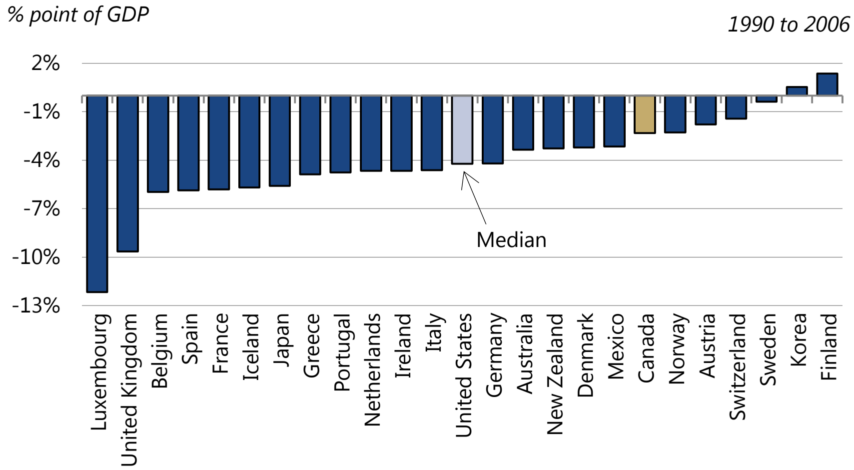
Canada's emissions from various manufacturing activities have been largely stable or declining. This observation is relevant to the concern that is often expressed regarding competitiveness of trade-exposed industries. The economic shift as services become an ever more dominant part of the economy has led to manufacturing's decline as a share of the economy in almost all advanced economies (measured in terms of value-added; Figure C-4).

This has happened more rapidly in some countries than in others; in fact, the decline in Canada has been slower than in most. Even industrial powerhouses such as Germany and free trade-based manufacturing beneficiaries such as Mexico experienced declines larger than Canada. A continued reduction in the size of manufacturing as a share of the economy should thus be distinguished from measures undertaken to limit GHG emissions.

Notice that even countries such as Denmark that successfully positioned themselves to manufacture equipment for renewable energy (wind power) did not escape the phenomenon. Denmark did, however, see a substantial decline in CO_2 emissions as a result of its shift to wind energy.

Figure C-4

Change in the size of the manufacturing sector



Source: OECD STAN database, version 3.

Note: The change in Luxembourg is exaggerated by the large influx of non-resident workers who are mostly employed in the services sectors.

The same observation can be applied to other emission-causing sectors of the economy.

Another concern regarding emissions abatement is with the potential for "carbon leakage". That is, if the cost of energy increased in Canada through carbon dioxide pricing, then economic production might move to other countries that were taking on less stringent reductions.

This is a realistic concern given the low transportation costs that now prevail globally. The United States imports substantial quantities of heavy goods such as cement, steel and fertilizer, so bulk and weight do not pose an obstacle to trade. Canada produces substantial quantities of all three goods, but competes with other producers for U.S. market share. Indeed, Canada itself imports substantial quantities of steel.

For Canada's electricity-generating sector, a reliance on hydro – and in Ontario on nuclear power as well – means that emissions per unit of electricity generated is relatively low (Figure C-5a). Similarly, the iron and steel sector (Figure C-5b), as well as the chemicals sector (Figure C.5c), is less carbon intensive in Canada than in a number of other countries.

For those industries, ensuring that Canada's competitors are also part of an abatement regime is an important objective since there are countries close to Canada's ranking and unilateral changes could have outsized effects.

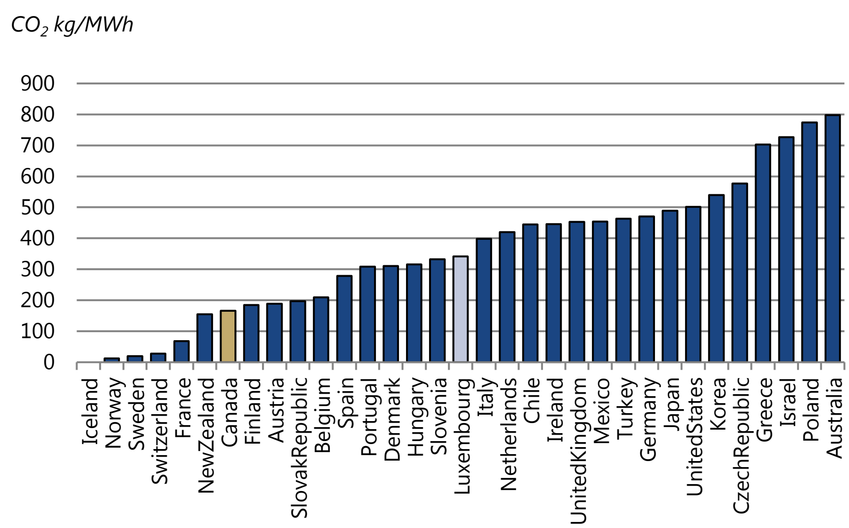
When the remaining manufacturing sectors, along with construction and mining are considered, the picture appears to change, and Canada is the highest emission-intensity country (Figure C-5d). That position, however, is significantly influenced by the inclusion of some parts of the oil sands extraction industry – the own-fuel combustion that occurs at the mine site.

This inclusion is mandated by the common reporting standards to the UN Framework Convention on Climate Change. When those emissions are removed, Canada's ranking moves toward the middle of the group (see the Canada2 bar in Figure C-5d).

These results underscore that Canada's economic sectors (other than oil and gas extraction and oil sands production) may be disadvantaged if emission reductions in similar industries are not undertaken by other countries with whom Canada competes for trade.

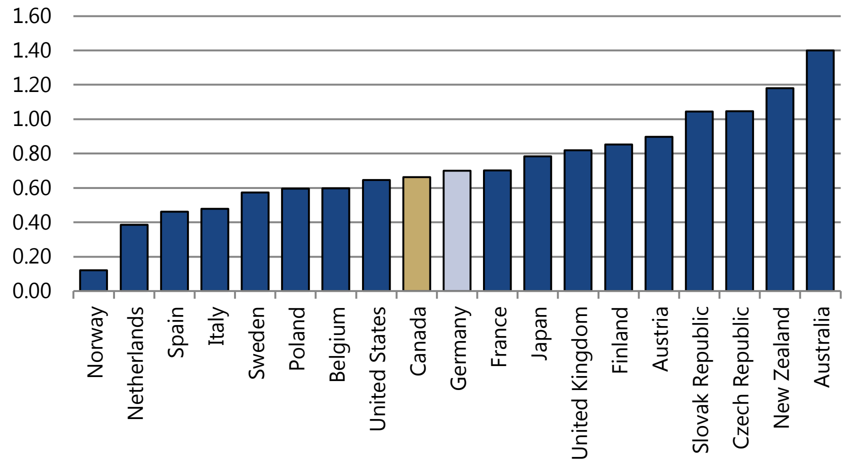
Figure C-5 Relative emissions intensity of electricity generation and manufacturing (2010)

(a) Electricity generation



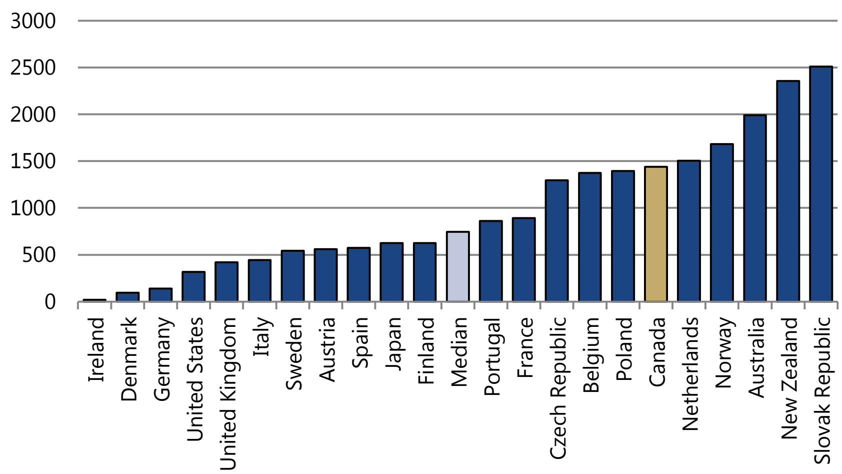
(b) Iron and Steel

CO_2 kg/kg Iron and Steel production



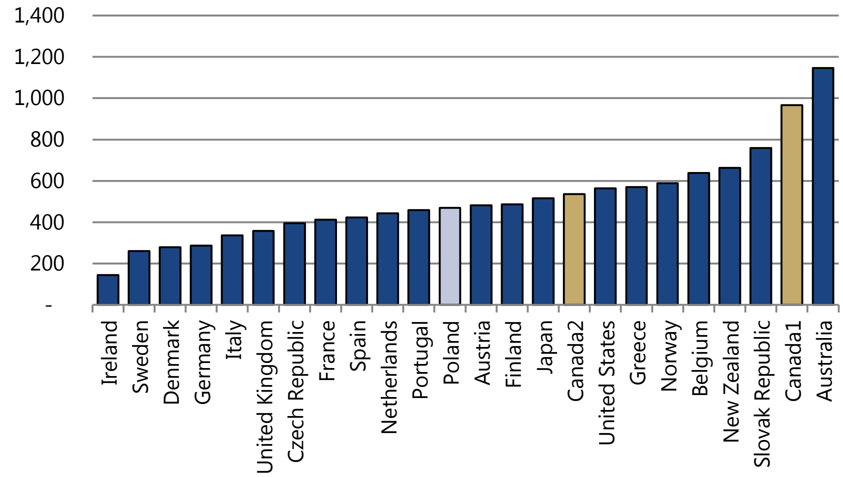
(c) Chemicals

CO_2 kg/thousand $ value-added



(d) Manufacturing, construction and mining

CO_2 kg/thousand $ value-added



Source: World Bank World Development Indicators; World Steel Association: Steel Statistical Yearbook 2013.

Note: Grey bars represent median. Manufacturing as reported with Canada1 includes own-fuel combustion in the oil sands. The bar labelled Canada2 excludes it. In both bars, purchased-fuel combustion and the on-site off-road vehicles used in some mining activities, such as oil sands, are excluded.

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Notes

1. This does not include the impacts on emissions from land-use, land-use change and forestry. They can be sources of removal of carbon dioxide from the atmosphere (i.e. sinks). Environment Canada (2014b) estimated that this would account for 19 million tonnes of carbon dioxide removed from the atmosphere in 2020 using a "reference" approach. Proposals by the federal government in May of 2015 would use a "net-net" approach which potentially make the carbon dioxide removal in 2030 larger, but the Government has not provided estimates of its magnitude.
2. Cost minimisation generally requires that policies achieve the criteria that all sources of emissions face the same cost (implicit or explicit) for each tonne of carbon dioxide, irrespective of the instrument used.
3. Henceforth GHG will be used interchangeably with carbon dioxide equivalent and a metric tonne will be denoted tCO_2e, million metric tonnes as mt. GHG's consist of carbon dioxide (CO_2), methane (NH_4), nitrous oxide (N_2O), hydro fluorocarbons (HFC), perfluorocarbons (PFC), sulfur hexafluoride (SF_6), and nitrogen triflouride (NF_3).
4. In the rest of this paper, emissions intensity will refer to emissions per unit of GDP.
5. Comments from senior executives of oil sands companies suggest that the extraction and processing costs are below $60 (Canadian dollars). See http://business.financialpost.com/news/energy/for-canadas-oil-industry-the-bad-news-just-keeps-coming.
6. An exception to this is the electricity sector, where a downward trend began in 1998. Using 1990 to 2013 for the projection gives a higher emission in 2030 than using 1998 to 2013. Some, though not all, of the recent coal regulations are thus implicitly incorporated into the projection.
7. The OECD projection, however, rests on a technical assumption regarding global economic (conditional) convergence that begins in 2016. That assumption carries with it unspecified policy and other changes that lead to more rapid technological change and productivity growth. While the assumption is useful in a multi-country long-term growth projection, it may not be useful for studies dealing with issues of short and medium-term horizons – such as GHG emissions over the next 15 years. Many long-term international projections use that same simplifying assumption.
8. The asserted independence between real GDP growth and improvements in emissions intensity is underpinned by the relatively constant decline in intensity seen in Figure 2-1 after 1995. It implies that sectoral reallocation and emission-improving technological change are largely independent of growth.

9. This inference was made by applying emission coefficients to their projected change in primary fossil fuel energy demand (mtCO_2 per petajoule): natural gas – 0.0504; refined petroleum products – 0.0675; and coal – 0.0903. In 2010, carbon dioxide accounted for 79 percent of Canada's GHG emissions in 2013. Note that in their projection, the decline in fossil-fuel intensity (in joules per GDP) to 2030 is almost half its average from 1996 to 2011.

10. Hughes and Chaudry (2011) noted that the implied rate of de-carbonisation of power generation was very high. The baseline projection here continues the 2.8 percent rate of emission intensity improvement in power generation that was seen from 1995 to 2011, but increases it to 8.7 percent (annually) when policies are introduced to achieve the 30% reduction target – so it goes from 88 mtCO_2e in 2013, to 27 mtCO_2e in 2030. This outcome requires carbon capture and storage even from natural gas-based generation if all coal is replaced by natural gas.

11. This inference is supported by NRTEE (2011b) where a reduction of 178 mtCO_2e within 15 years is shown to require a carbon dioxide price of $80.

12. The recently approved fuel-economy standard for light vehicles in the United States (to which Canada has harmonised) should increase fuel efficiency of the fleet by 40 percent by 2025 (from 2010 levels). This would lead to a substantial saving in fuel cost, but would increase the price of automobiles. On net, it may be balanced over the life of the vehicle. Nonetheless, some increase in fuel cost may be necessary to avoid a migration to heavier vehicles, whose fuel-efficiency standard will still be considerably lower than lighter passenger vehicles.

13. The average car costs more as a share of average annual income today than it did 45 years ago, yet car ownership increased substantially. Adding the cost of hybrid technology represents only a few years of the pace of price increases that have been occurring since 1970.

14. Natural gas is a 'cleaner' fuel for electricity generation since it only produces a little more than half the CO_2 emissions of coal for a given quantity of heat produced – and thus a given quantity of electricity generated. Even so, it produces sufficient carbon dioxide that attempts to aggressively deal with emissions would have to include reductions from natural gas-based sources.

15. The capacity sharing agreement between Ontario and Quebec is a good illustration of using hydro as a storage technology for wind power, but at present it represents less than 15 per cent of Ontario's grid-connected wind capacity – and is a seasonal agreement. Since Ontario's wind turbines sometimes operates at near-zero generation, to operate as base-load supplier, wind would have to have very large backup capacity.

16. Canadian ecoENERGY Carbon Capture and Storage Task Force (2008). www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/www/pdf/com/resoress/publications/fosfos/fosfos-eng.pdf

17. IPCC (2005) estimated that CCS would add between US$20 and US$50 per MWh to the cost of electricity generated using Pulverised Coal technology. Anderson and Newell (2004) estimated it to be between US$55 and US$68. EIA (2015b) estimates that a new plant starting operation in 2020 using Advanced Coal technology would add about US$39 per MWh to implement CCS (plus US$8 for operating cost). A project in Kemper County, Mississippi

that is to capture 3.5 mtCO_2e per year has gone over budget by substantialy more than twice its estimated cost and is years behind schedule. Its problems, however, appear more related to poor planning and implementation rather than the technology itself since structures have had to be torn down and rebuilt, causing long delays and cost-overuns.

18. Obtained from A. Damodaran at New York University Stern School of Business. Downloaded, December, 2015: http://people.stern.nyu.edu/adamodar/New_Home_Page/data.html

19. In fact, that standard is lower than the rate of emissions that result from using natural gas to generate electricity: 549 kilograms per MWh. So effectively, new natural gas plants would fail the standard.

20. See Saskpower Rate Application, 2013, for the reported long-term rate of interest paid on debt. This is also consistent with the real cost of capital reported in a survey of the power sector by the Stern School of Management: http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/wacc.htm. Moreover, electricity generators often last 50 years, which would give the same implicit carbon dioxide price even with a real rate of discount closer to 5 per cent.

21. On January 7th, 2016, Ontario's grid-connected wind-power generation fell below 100MWh for a significant part of the day. This from a generating capacity of more than 3,200MWh.

22. Embedded systems produce electricity locally and do not feed into the grid. Large windfarms and large solar panel farms are the source of electricity that is connected to the grid. Smaller systems often produce electricity for local use. Most solar panels are not connected to the grid.

23. Based on an average higher emission rate of 66 kgCO2e per barrel (well-to-wheel) of Canadian Oil Sands versus Canadian Light (Burkhard, *et al*, 2011).

24. One tonne of methane has 25 times the warming potential over a 100 year horizon as one tonne of carbon dioxide.

25. More efficient lighting (LEDs) is also included in the higher efficiency standards. They can significantly lower energy use for a house or building since they consume only a fraction of the power of incandescent lightbulbs (though LEDs provide no additional saving in commercial buildings since fluorescent lighting is already in widespread use there). They would, therefore, contribute indirectly to lowering emissions through lower electricity use. While the greater variety of LED lighting overcomes the main resistance consumers have had in the past to compact-fluorescent lighting, there remains the issue of higher upfront cost.

26. This does not necessarily mean that a "free lunch" is available to the industry. Fixed costs are large in the industry and remain a barrier over the short to medium term – especially in an uncertain industry where prices fluctuate significantly.