



Canada's Energy Outlook

CURRENT REALITIES AND IMPLICATIONS FOR A CARBON-CONSTRAINED FUTURE

By J. David Hughes
MAY 2018



CCPA
CANADIAN CENTRE
for POLICY ALTERNATIVES
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**PARKLAND
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**CORPORATE
MAPPING PROJECT**

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By J. David Hughes

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Summary

This section presents a brief overview of the report that follows. An extended executive summary is available online and for download at energyoutlook.ca.

Canadians enjoy a high standard of living underpinned by a reliable and secure supply of energy. Like many other countries, however, Canada is currently faced with some difficult decisions given the realities of climate change and the need to reduce emissions, as well as the finite nature of its fossil fuel supply. Even considering Canada's position as the second-largest hydropower producer in the world, 63% of its primary energy comes from fossil fuels. On an end-use, delivered energy basis, 76% is provided by fossil fuels, with only 17% provided by electricity.

Canada is also a signatory to the Paris Agreement, and aspires to reduce emissions 30% from 2005 levels by 2030 and 80% by 2050. Given the current status of Canada's energy supply, these are very aggressive targets.

This report analyses Canada's energy system and assesses future options to maintain energy security and meet climate commitments as a foundation for planning a viable long-term energy strategy. The report is divided into four parts:

PART 1 examines the evolution of Canada's energy system in the global context in order to develop an understanding of where our energy comes from, trends in production and consumption, and the scale of the problem in maintaining future energy supply while minimizing environmental impacts. It looks at oil, gas, coal, hydro, nuclear and non-hydro renewables. It also looks at emissions and the correlation between economic activity and energy consumption, as well as trends in energy- and emissions-intensity.

PART 2 examines Canada's remaining non-renewable energy resources. Existing oil and gas resources are assessed in terms of pay type, future viability, resource estimates and National Energy Board (NEB) projections of future production. It also examines jobs and government revenues from non-renewable resource extraction and the decline in royalty and corporate tax payments despite increasing production.

PART 3 examines electricity capacity and generation by fuel as well as NEB projections of future generation through 2040. Given that electricity is the principal output provided by renewable sources, particular attention is devoted to generation from solar, wind, biomass and tidal energy. The implications of Canada's mid-century scenarios for emissions reduction in terms of new capacity required and cost are also reviewed for each carbon-free generation source. This section also looks at renewable heating and liquid fuel sources including biomass, geothermal energy and biofuels.

PART 4 summarizes key considerations for an energy strategy and the projections provided in Canada's pan-Canadian framework and mid-century strategy scenarios to reduce emissions by 30% and 80% from 2005 levels, respectively. It also reviews the implications of NEB projections of future energy production on Canada's emissions-reduction targets. The low likelihood of success given the implications of the scenarios and projections is highlighted, along with key focus areas that will increase the chances of success in both emissions reduction and future energy security.

Introduction

Canada is near the top of the list of developed countries in terms of quality of life. It is also near the top of the list in terms of energy consumption, which is highly correlated with gross domestic product (GDP). The average Canadian consumes 5.1 times as much energy as the average world citizen and 23% more than the average American. Although Canada generates much more of its electricity from hydroelectric sources than most other countries, it is still dependent on fossil fuels for 63% of its primary energy consumption (the world average is 85%).¹ Fossil fuels are projected by the U.S. Energy Information Administration (EIA) to comprise 78% of a much larger global energy requirement by 2040.²

Although Canada is self-sufficient in terms of fossil fuel and is a net exporter of oil, gas and coal at present, it is a mature oil and gas exploration region, having been in production since the 1940s. Conventional oil production peaked in the 1970s and natural gas production has been in decline since 2001. This means that growth in production will be primarily from unconventional resources, principally the oil sands, tight gas, shale gas and tight oil. These sources have greater environmental impacts than conventional oil and gas.

Notwithstanding global concerns about climate change due to fossil fuel emissions, and the finite nature of fossil fuels, Canada has embarked on a de facto strategy of exporting its oil and gas resources as quickly as possible. The Canadian Energy Strategy assembled by the provincial premiers in July 2015 provides some laudable aspirations and recommendations for further research, but actions taken since its adoption have done little to change the status quo. Fossil fuels are likely to be needed by Canadians at some level for the foreseeable future, yet their production and use counters efforts to reduce emissions given Canada's commitments as a signatory to the Paris Agreement.

This report provides an objective analysis of Canada's energy system as a foundation for developing a sustainable long-term energy strategy. It looks at the evolution of Canada's energy supply in the global context, the availability of domestic non-renewable and renewable energy resources, future production forecasts and their implications for carbon emissions, and Canada's announced emissions-reduction strategies. Finally, it provides recommendations for a sustainable long-term Canadian energy strategy.

¹ BP Statistical Review of World Energy, 2017, <http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html>.

² U.S. Energy Information Administration, International Energy Outlook 2016, reference case, <https://www.eia.gov/outlooks/ieo/>.

1. Canadian energy consumption in the global context

In developing an energy strategy, it is first important to understand where Canadian energy comes from and how Canada compares to other countries in terms of total production and consumption by type of fuel. Primary energy consumption includes energy at the source before conversion to end-use forms such as electricity and refined petroleum products. Delivered energy (sometimes called secondary energy) is energy consumed at the point of use, and excludes losses such as those in converting fossil fuels to end-use electricity. A typical coal plant, for example, may have a conversion efficiency of just 33%, so 67% of the energy in the coal is lost in the conversion process.

The following section looks at primary and delivered energy consumption by fuel source and country, to put Canada in perspective as to the absolute level of consumption and the trends in consumption over the past few decades. It also looks at electricity generation and consumption, given that electricity is a particularly useful form of end-use energy and is the primary form of energy generated by renewables, which will be increasingly important in lowering greenhouse gas emissions in the future. The contribution of non-renewable energy production to government revenues in terms of royalties, corporate taxes, GDP and jobs is also examined.

1.1 Primary energy

Figure 1 (next page) illustrates per capita primary energy consumption for selected countries and geopolitical groupings in the world.³ Canada is one of the highest per capita energy consumers, at 5.1 times the world average, and is considerably higher than the US. Developed countries, represented by the Organization for Economic Cooperation and Development (OECD), consume 3.4 times as much energy per capita as the rest of the world, and Canadians consume more than twice as much energy as the average citizen in the OECD. A major issue for the future is the aspiration of the developing world to consume energy at the rates of developed countries (non-OECD countries comprise 83% of world population). It is also interesting to note that developed nations like Germany, France, the United Kingdom and Japan consume energy at less than half the rate of Canadians.

³ BP Statistical Review of World Energy, 2017. Note that the "oil equivalent" basis converts primarily electricity sources like hydro, nuclear, wind, solar and geothermal to "oil equivalent" at an electricity conversion efficiency of 38% to calculate the amount of oil that would have to be burned to generate that amount of end use electric energy, <http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html>.

Figure 1: Per capita primary energy consumption by country and fuel source in 2016.⁴

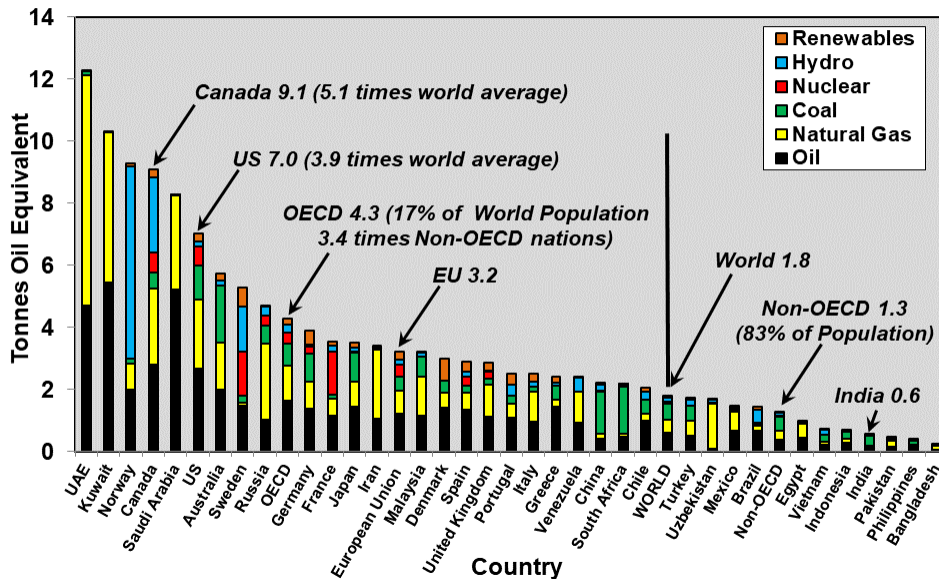
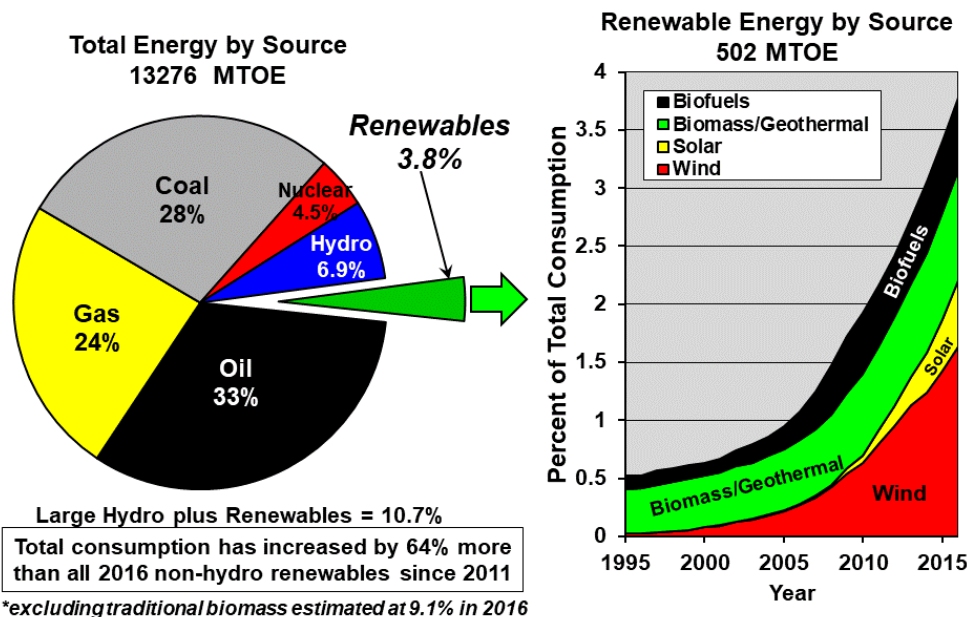


Figure 2 illustrates global energy consumption by fuel source in 2016. Fossil fuels accounted for 86%, with oil, coal and gas comprising 33%, 28% and 24%, respectively. Hydroelectric provided a further 6.9% followed by nuclear at 4.5%. Non-hydro renewable energy provided just 3.8%, even though it has grown exponentially in recent years. Notwithstanding the need to reduce global emissions from burning fossil fuels, they are likely to be part of the energy mix for the foreseeable future, given their utility and the scaling issues of non-hydro renewable energy.

Figure 2: World primary energy consumption by fuel source in 2016, illustrating the evolution of non-hydro renewable energy from 1995 to 2016.

MTOE stands for "million tonnes oil equivalent."⁵



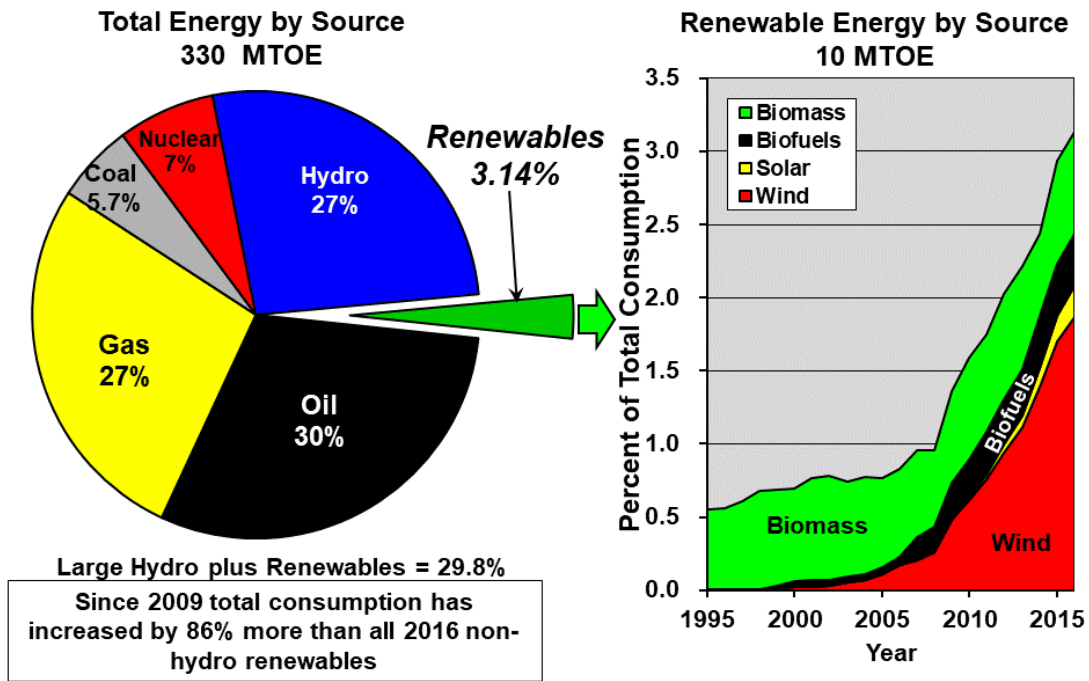
⁴ Data from BP Statistical Review 2017 and World Bank population statistics for 2016

⁵ Data from BP Statistical Review of World Energy, 2017; traditional biomass from REN21, 2017

Figure 3 illustrates Canadian energy consumption by fuel source in 2016. Although Canada has a far lower dependence on coal than the world as a whole, its dependence on oil and gas is the same, at 57%. Hydroelectricity is a major source of renewable energy in Canada, at 27% of primary energy consumption, compared to less than 7% in the world as a whole. Non-hydro renewable energy comprised 3.1% of Canadian consumption in 2016, two-thirds of which came from solar and wind.

Figure 3: Canada primary energy consumption by fuel source in 2016, illustrating the evolution of non-hydro renewable energy from 1995 to 2016.

*MTOE stands for "million tonnes oil equivalent."*⁶



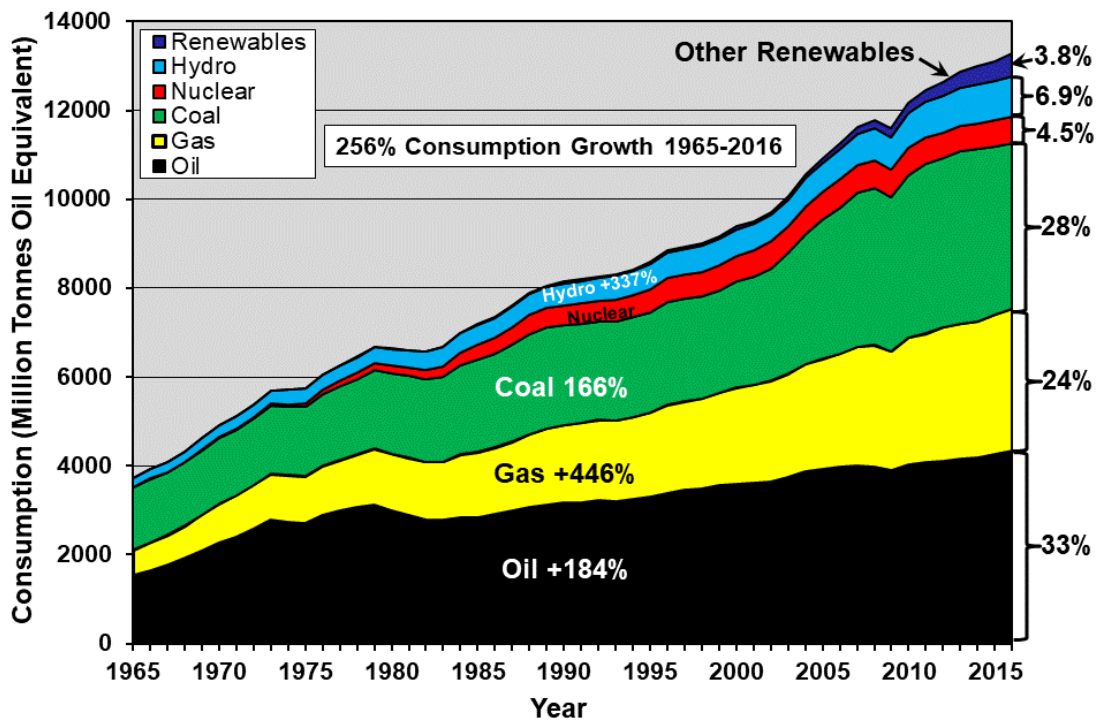
⁶ Data from BP Statistical Review of World Energy, 2017

1.1.1 Trends in consumption

Energy consumption has grown rapidly in tandem with population growth and growth in per capita consumption. Globally, energy consumption has increased by more than three-fold in the past 50 years (see Figure 4). Notwithstanding the exponential growth in non-hydro renewable energy, which, along with nuclear energy and hydropower, provided 15.2% of the 2016 total, fossil fuel use tripled over this period and now provides 85% of primary energy consumption. Natural gas consumption grew more than five-fold while oil and coal nearly tripled. This suggests that even with rapid growth in renewable energy sources like wind and solar, the world will remain highly dependent on non-renewable fossil fuels for many years into the future.

Figure 4: World primary energy consumption by fuel from 1965 to 2016.

Fossil fuels comprised 85% of 2016 consumption. "Other Renewables" include wind, solar, biomass, geothermal and biofuels.⁷

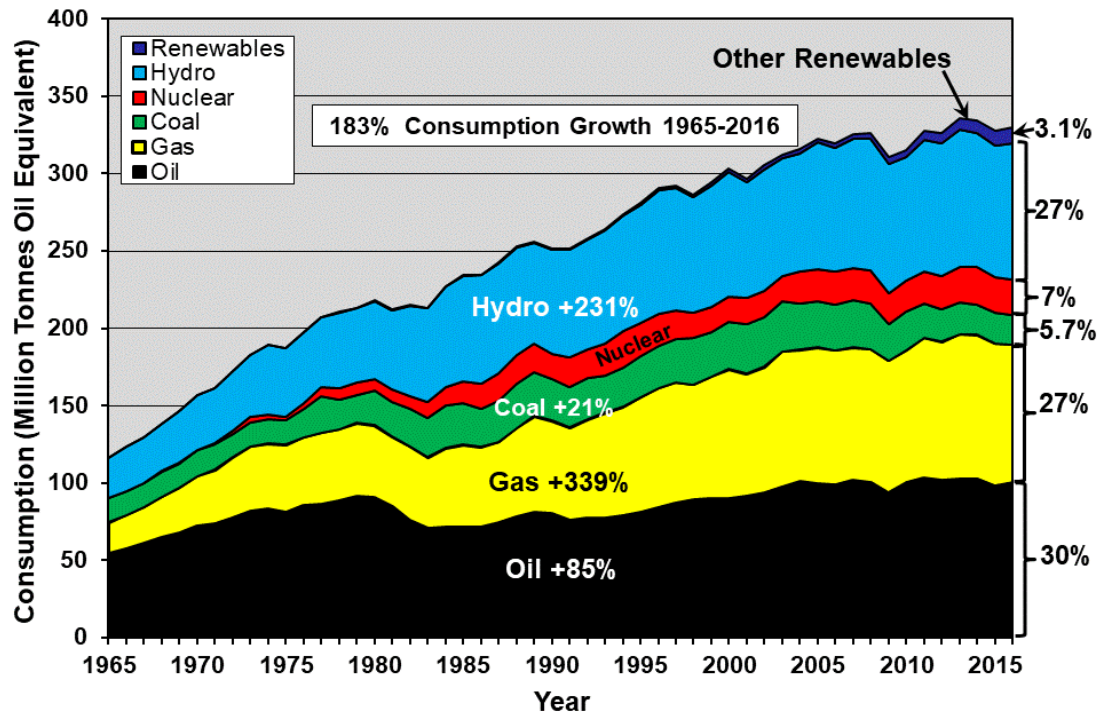


⁷ BP Statistical Review, 2017

Canadian consumption over the same 50-year period increased by 183%, or nearly triple, and fossil fuels comprised 63% of the total in 2016 (see Figure 5). Natural gas consumption grew more than four-fold and oil nearly doubled. Coal consumption increased by 37% overall, but has declined substantially in recent years with the coal phase-out in Ontario. Non-hydro renewables, which include solar, wind, biomass and biofuels, contributed just 3.1% of 2016 consumption. Notwithstanding the need to reduce carbon emissions, fossil fuels, particularly oil and gas, are likely to be a significant part of Canada's energy mix for many years to come.

Figure 5: Canada primary energy consumption by fuel from 1965 to 2016.

Fossil fuels comprised 63% of the total in 2016. Oil and gas, at 57% of 2016 consumption, are equal to the world average, except that Canada uses a higher proportion of natural gas and a lower proportion of oil. "Other Renewables" include wind, solar, biomass, geothermal and biofuels.⁸



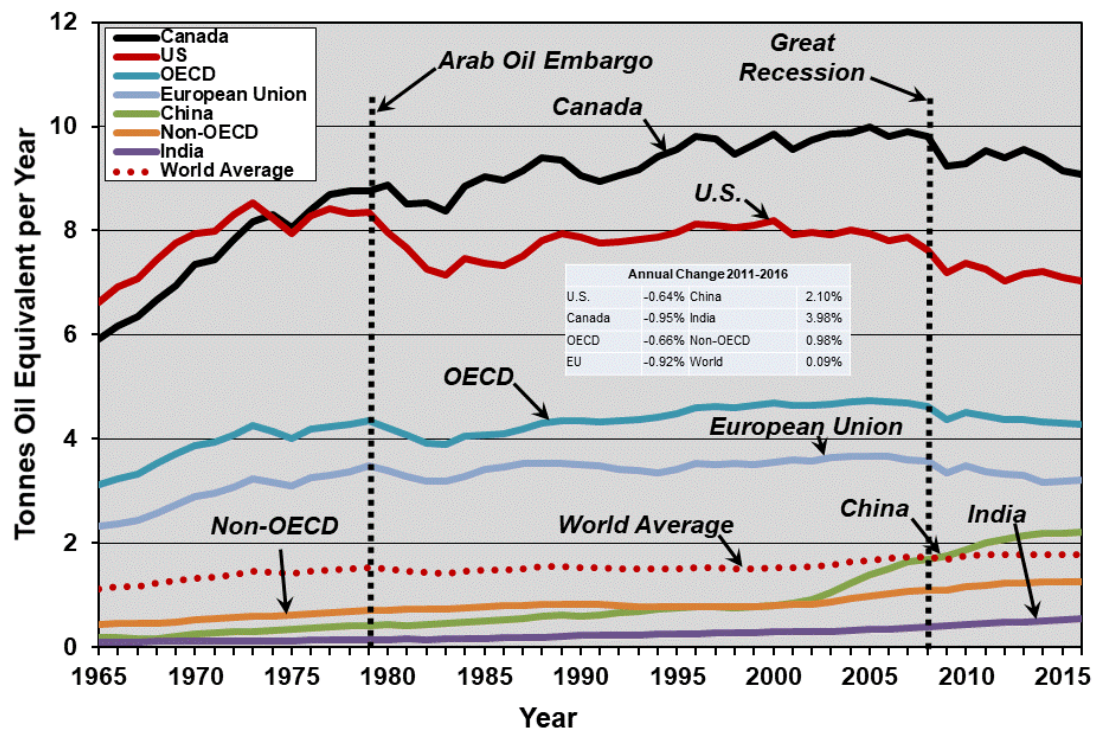
⁸ BP Statistical Review, 2017

Figure 6 illustrates the change in per capita consumption of energy in Canada and other countries over the past 50 years. Canadian consumption has been one of the world's highest over this period at more than double the average of developed nations in the OECD and European Union, and five times the world average. Although Canadian consumption on a per capita basis has grown 54% since 1965, it has been declining over the past five years at an average rate of .95% per year. Similarly, other developed countries are also declining: the OECD at .66% per year, the US at .64% per year and the European Union at .92% per year. The impact of oil supply restrictions on per capita consumption during the Arab Oil Embargo beginning in 1979 and the Great Recession of 2008, which mainly affected the developed world, are also shown in Figure 6.

In contrast to the slight decline in per capita energy consumption in the developed world, the developing world is growing at high rates. Non-OECD countries, comprising 83% of the world's population, have grown .98% per year over the past five years. China has grown 2.1% per year and now exceeds the world average. India has grown 3.98% per year while the world as a whole has increased .09% per year.

Figure 6: Per capita primary energy consumption by country from 1965 to 2016.

Developed countries far exceed the consumption levels of developing countries. Developing countries, however, are growing quickly in contrast to developed countries, which are in slight decline. The Arab Oil Embargo and Great Recession, which impacted per capita consumption in developed countries, are also shown.⁹

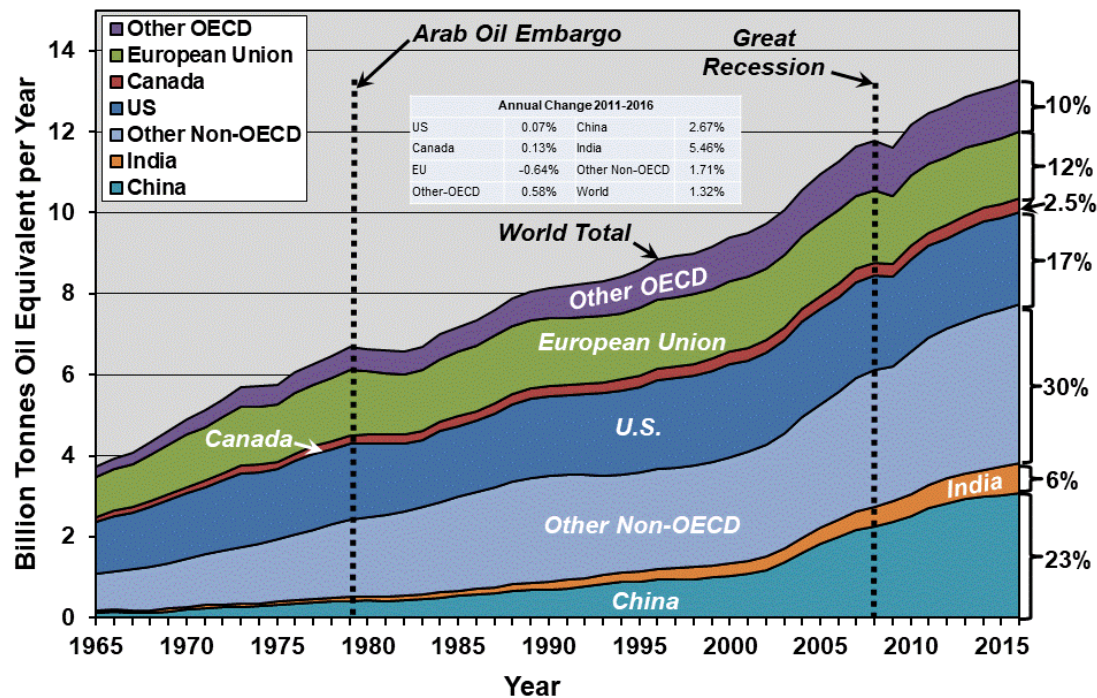


⁹ Data from BP Statistical Review 2017 and World Bank population statistics

Total energy consumption by country over the past 50 years is illustrated in Figure 7. Total consumption growth rates are higher than those for per capita consumption, as they reflect both changes in per capita consumption and population growth. The developing world (represented by non-OECD countries), with 83% of world population, consumed as recently as 2005 less than half of the world's energy, but now consumes 59% and has grown at 1.71% per year over the past five years. China alone consumes nearly a quarter of the world's energy (for comparison, the US consumes 17%), and has grown 2.67% per year over this period. Canada consumed 2.5% of the world's energy in 2016, and has increased at .13% per year over the past five years. The developed world outside of Canada, the US and the European Union has increased its consumption by .58% per year, while the European Union has been declining at .64% per year over this period. Energy consumption in the world as a whole has increased 1.32% per year over the past five years.

Figure 7: Total energy consumption by country from 1965 to 2016.

Developing countries, which comprise 83% of world population, have increased consumption rapidly and now account for 59% of world consumption. Developing countries also have far higher consumption growth rates than the developed world. Total world energy demand has grown at an average 1.32% per year over the past five years. Although growth has slowed in developed nations (and has declined in the European Union), it continues to grow at rates of nearly 3% per year in China and over 5% per year in India.¹⁰



Given world growth rates and forecasts of continued population growth, it is clear that the world will demand more and more energy over the coming years, much of it from fossil fuels. Whether supply can meet demand is another matter, given the fact that fossil fuels are finite, non-renewable resources. Although it is generally accepted that there are far more fossil fuel resources than humanity can afford to burn given climate change, they are increasingly found in lower-quality deposits that are more difficult to access for economic, environmental and geopolitical reasons.

¹⁰ Data from BP Statistical Review 2017

1.1.2 Trends in consumption by fuel

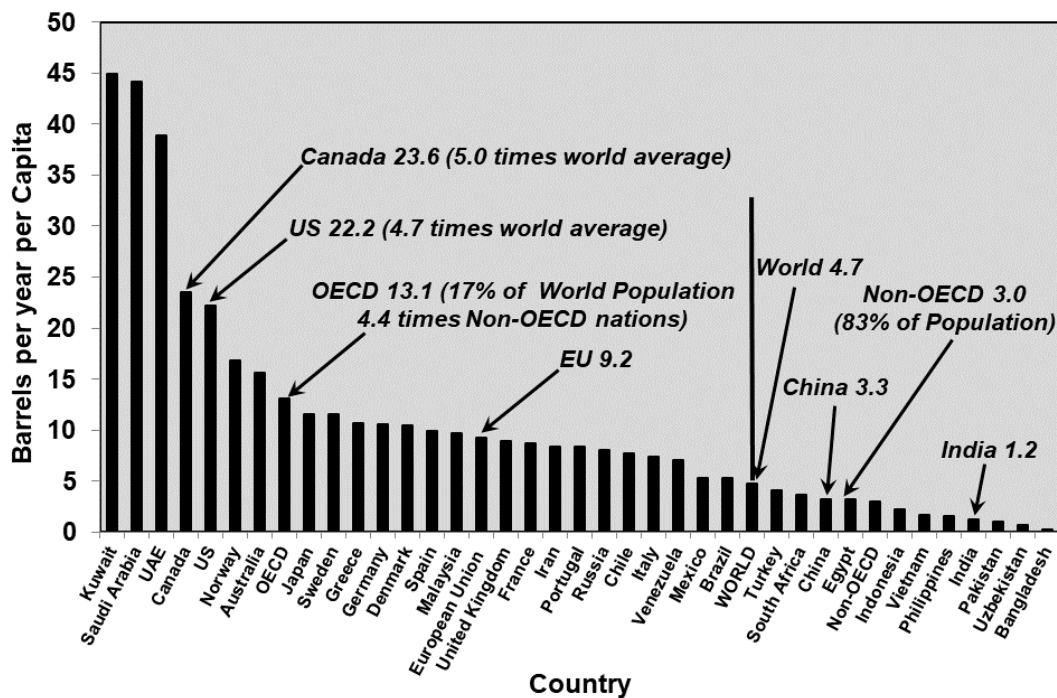
The following section examines consumption trends for all energy inputs into the Canadian energy system, in relationship to other countries, in order to assess their relative importance and potential contribution in the future.

1.1.2.1 OIL

Oil is the number one energy input into both the world and Canadian economies, and is the premier fuel for transportation. Figure 8 illustrates per capita consumption by country in 2016. Canada is among the highest oil consuming countries in the world, at 23.6 barrels per person per year, which is 6% more than the average American and five times the world average. There is a great inequity in oil consumption between the developed and developing worlds, with OECD countries, which represent just 17% of world population, consuming 4.4 times as much oil as non-OECD countries. Canadians consume seven times as much oil as the average person in China and 19 times the average person in India. Industrialized countries like Germany and other countries in the European Union consume per capita less than half the oil of Canadians.

Figure 8: Per capita oil consumption by country in 2016.

Canadians are among the highest consumers in the world at five times the world average.¹¹

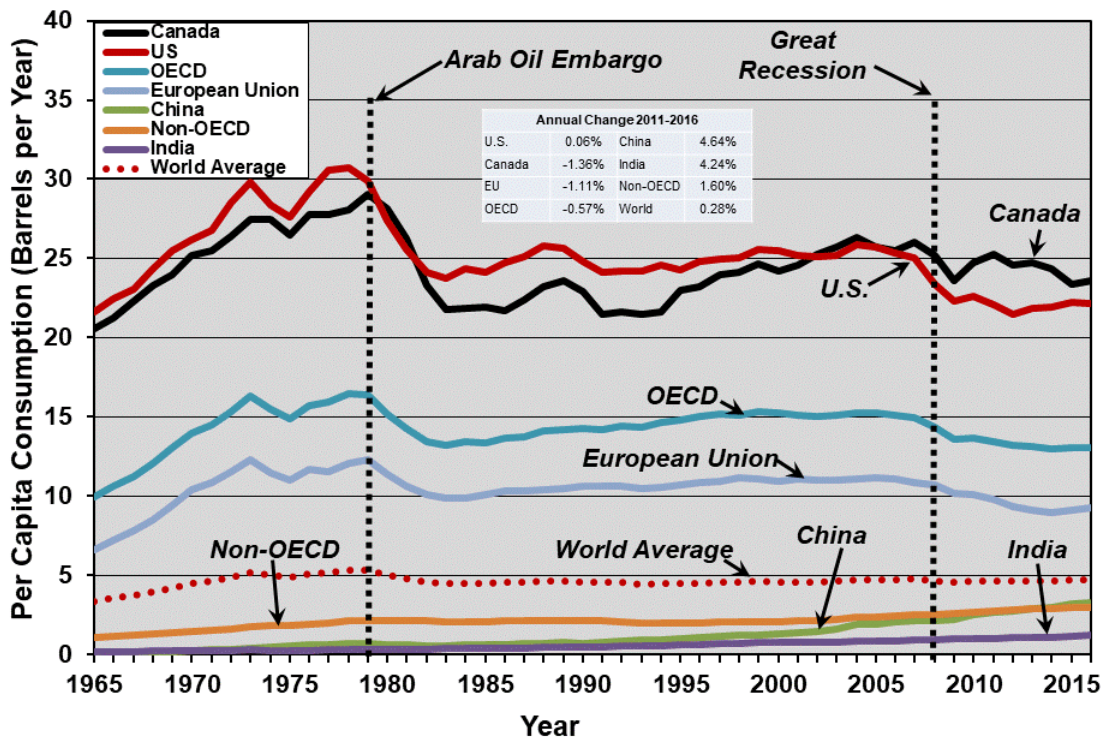


¹¹ Data from BP Statistical Review 2017 and World Bank population statistics for 2016

Figure 9 illustrates trends in per capita oil consumption over the past 50 years for Canada and other countries. Per capita consumption in most developed countries and in the world as a whole peaked in 1979 at the time of the Arab Oil Embargo. Although consumption grew slowly again in the 1980s and 1990s, it has been declining in the developed world over the last five years (with the exception of the US), primarily as a result of the Great Recession that began in 2008. In contrast, per capita oil consumption in the developing world has grown rapidly in recent years, offsetting declines in the developed world, such that the world as a whole has been growing at an average annual rate of .28% over the past five years.

Figure 9: Per capita oil consumption by country from 1965 to 2016.

Consumption peaked in 1979 overall and, with the exception of the US, has been declining recently in the developed world. Rapid consumption growth in the developing world has, however, offset these declines, and the world as a whole has been slowly increasing its per capita oil consumption over the past five years.¹²

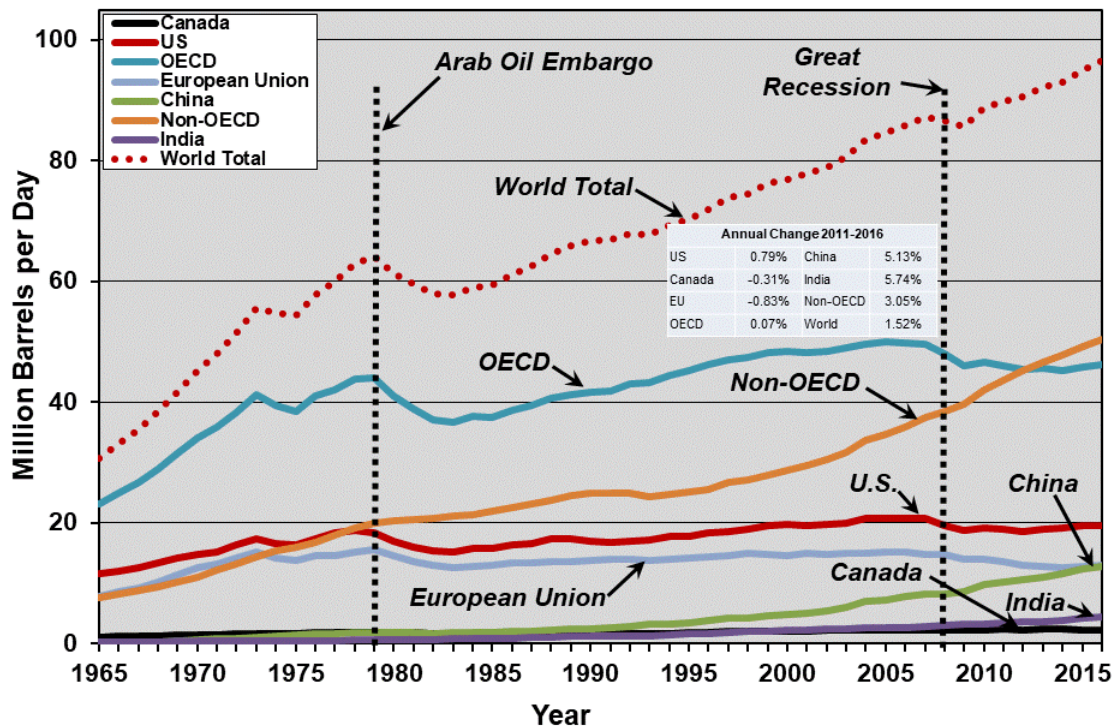


¹² Data from BP Statistical Review 2017 and World Bank population statistics for 2016

Figure 10 illustrates total oil consumption by country over the past 50 years. Given population growth, consumption has been increasing globally at an average rate of 1.52% per year over the past five years. Although oil consumption growth has been almost flat in developed OECD countries (.07% per year increase), and declining in the European Union and Canada (.83% and .31% per year decreases, respectively), it has been growing rapidly in the developing world, with non-OECD countries up an average of 3.05% per year, and China and India up 5.13% and 5.74% per year, respectively. Non-OECD countries now consume more oil than OECD countries.

Figure 10: Total oil consumption by country from 1965 to 2016.

World consumption has grown at 1.52% per year over the past five years. Consumption is flat in developed (OECD) countries but is growing rapidly in developing (non-OECD) countries. Non-OECD countries now consume more oil in total than OECD countries.¹³

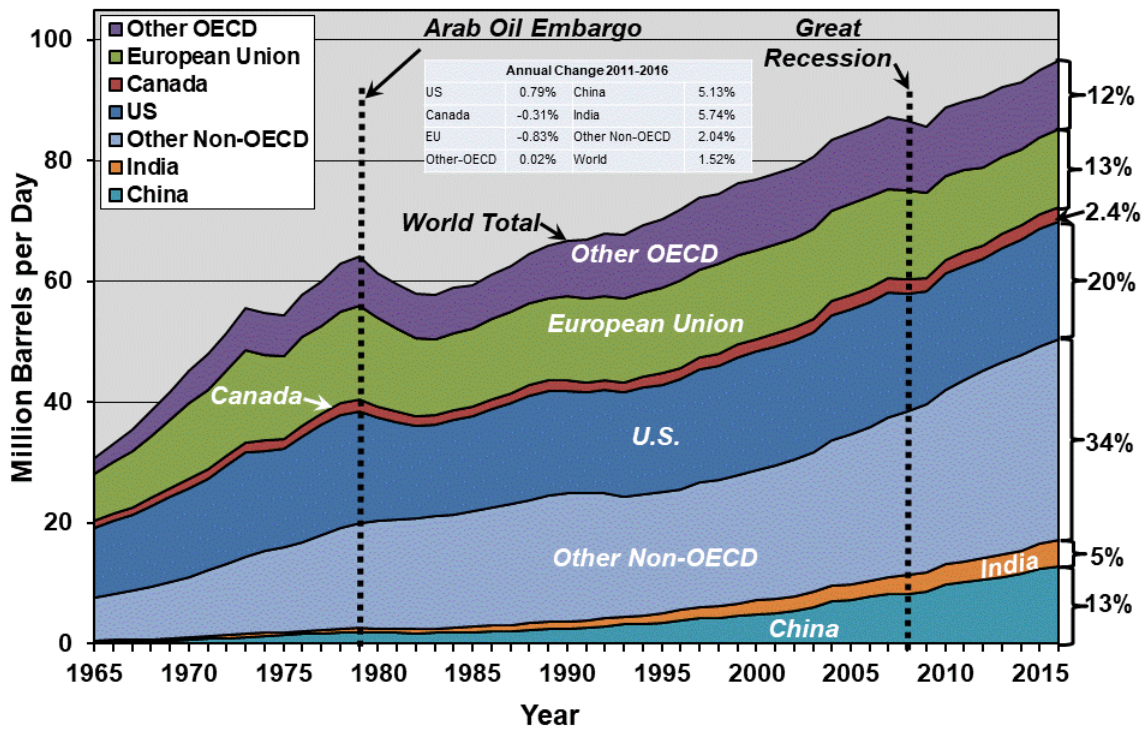


¹³ Data from BP Statistical Review 2017

Figure 11 shows a stacked chart of total oil consumption by country over the past 50 years. Most future growth in oil consumption is likely to come from developing countries, which are growing from low per capita consumption levels. Oil consumption in the developed world is already very high on a per capita basis and hence oil prices tend to have a proportionately larger impact on dampening consumption there than in the developing world. Notwithstanding its high per capita consumption, Canada accounts for just 2.4% of global oil consumption, given its relatively small population.

Figure 11: Total oil consumption by country from 1965 to 2016.

The developing world represented by non-OECD countries is growing rapidly, more than offsetting declines in most of the developed world.¹⁴



1.1.2.2 NATURAL GAS

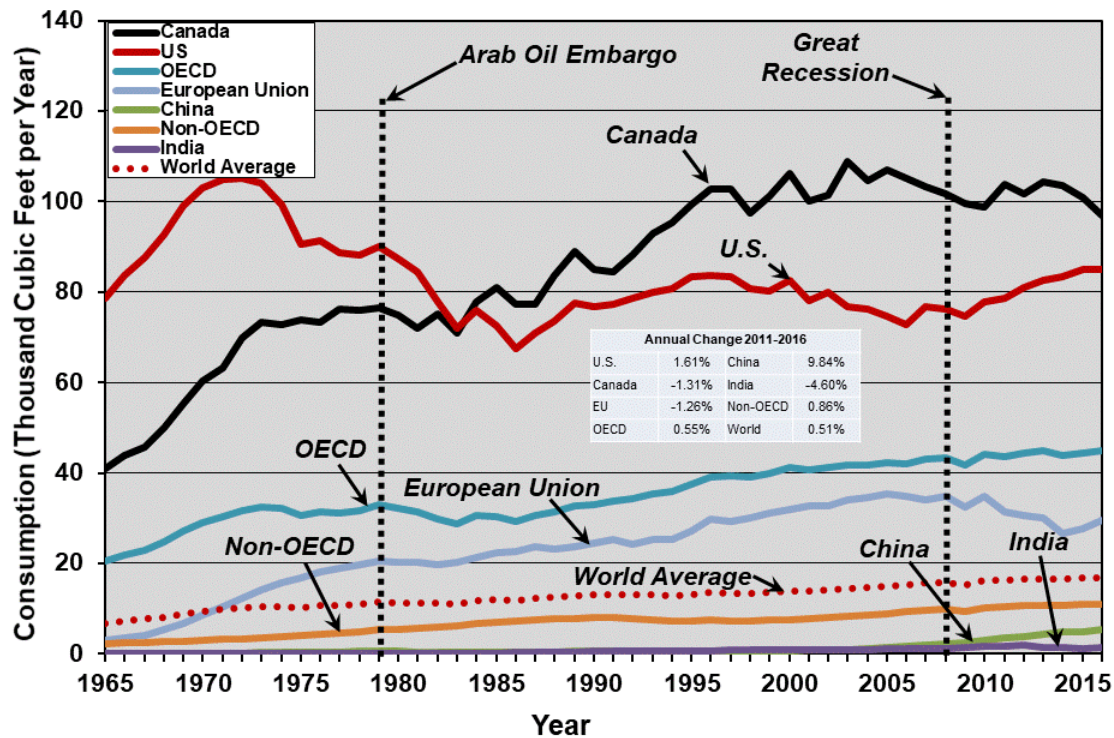
Natural gas is the third-largest energy source globally and the second-largest source in Canada. It is the fastest growing fossil fuel, having increased more than four-fold globally over the past 50 years. As with oil, Canada is one of the highest per capita consumers of gas in the world, at 5.8 times the world average in 2016, when Canadian consumption was 14% higher than US consumption. Canadians consumed 18 times as much natural gas as the average person in China and 73 times that of the average person in India in 2016. Industrialized countries represented by the OECD consume on average less than half the natural gas of Canada per capita, and countries in the European Union consume less than a third.

¹⁴ Data from BP Statistical Review 2017

Figure 12 illustrates trends in per capita consumption by country over the past 50 years. Natural gas consumption in the world as a whole has been growing more slowly than oil on a per capita basis over the past five years, at .51% per year. Natural gas consumption in the industrialized countries represented by the OECD, however, grew faster than oil consumption over this period (.55% per year), but in developing countries grew more slowly (.86% per year for gas versus 1.6% per year for oil). Per capita consumption of natural gas in Canada and the European Union fell over this period, at 1.31% and 1.26% per year, respectively. US per capita consumption peaked in 1972, although it has been growing at 1.61% per year over the past five years due to the shale revolution and the switch from coal to gas for electricity generation. China has grown very rapidly over the past five years, at 9.84% per year, but this growth has been offset by India, which declined 4.6% per year over the same period.

Figure 12: Per capita natural gas consumption by country from 1965 to 2016.

Although per capita consumption has been growing rapidly in China, global gas consumption has lagged oil consumption growth over the past five years.¹⁵

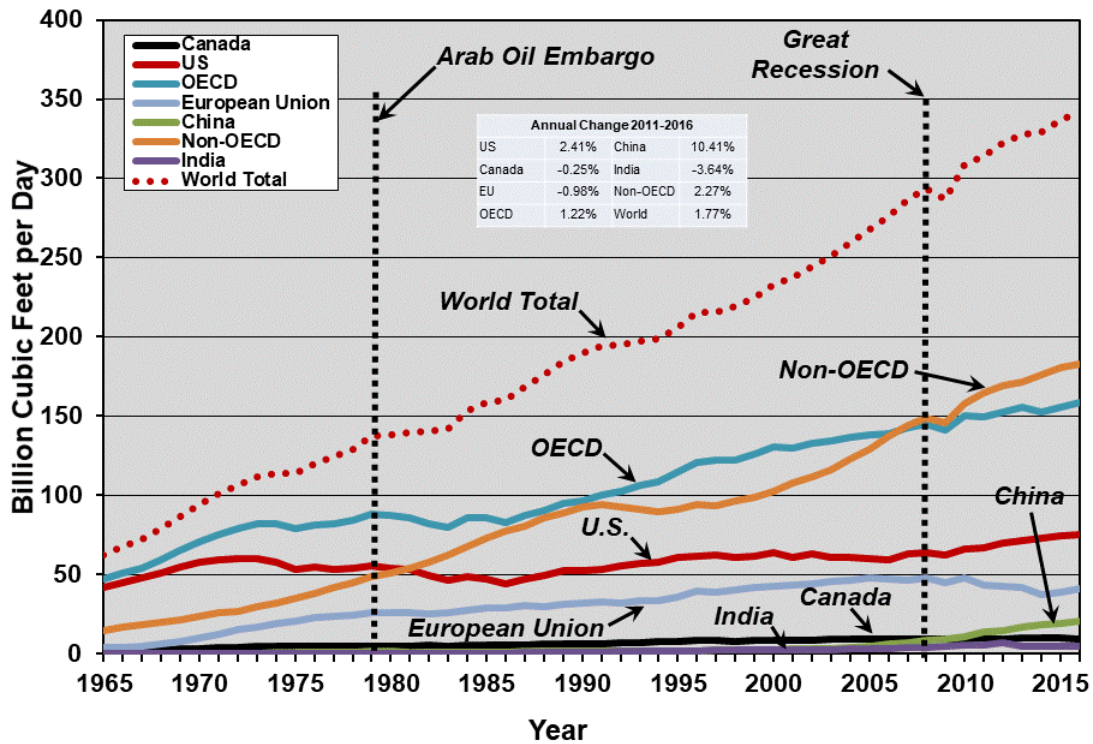


¹⁵ Data from BP Statistical Review of World Energy, 2017

Figure 13 illustrates total natural gas consumption by country over the past 50 years. Given population growth, total consumption has been growing globally at an average rate of 1.77% per year over the past five years. Total consumption has increased in developed countries represented by the OECD at 1.22% per year over this period, and at 2.27% per year in non-OECD countries. China increased at 10.41% per year whereas India declined at 3.64% per year. The non-OECD countries now collectively consume more gas than the OECD countries. Canadian consumption over the past five years has been declining at .25% per year, and the European Union has been declining at .98% per year.

Figure 13: Total natural gas consumption by country from 1965 to 2016.

Consumption has increased in developed (OECD) countries but has grown much more rapidly in developing (non-OECD) countries. Non-OECD countries now consume more natural gas in total than OECD countries.¹⁶

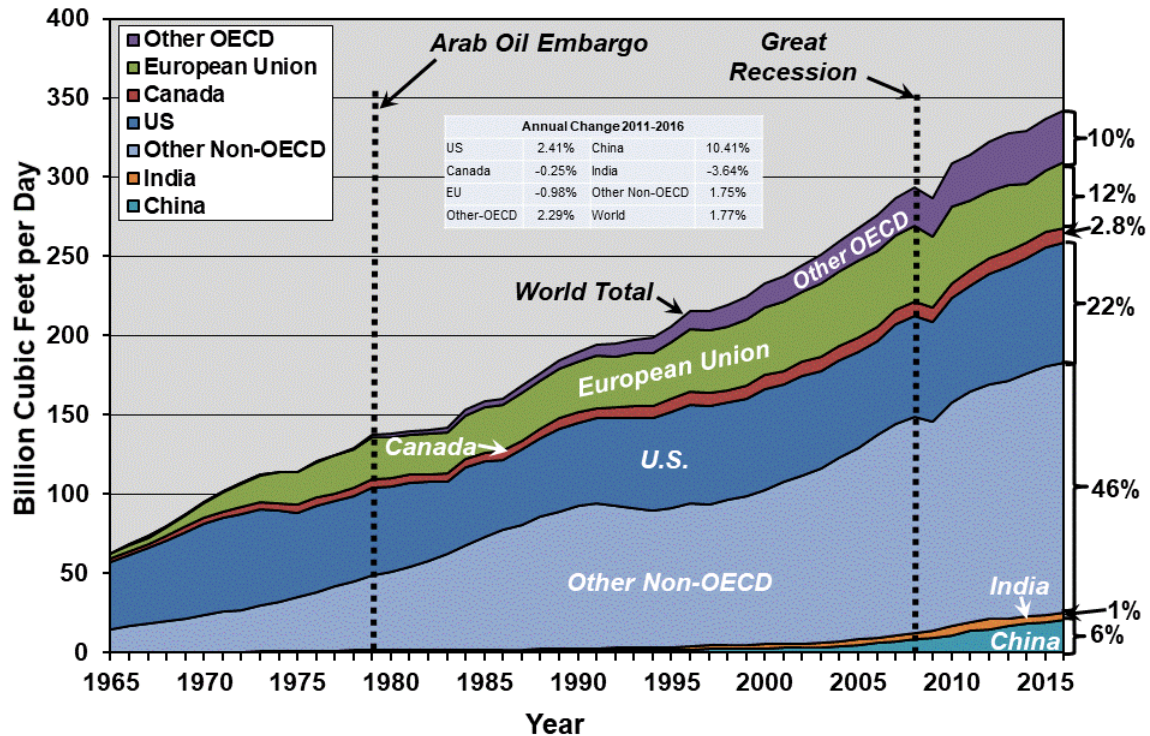


¹⁶ Data from BP Statistical Review 2017

Figure 14 shows a stacked chart of total gas consumption by country over the past 50 years, illustrating the proportions of gas consumed. As with oil, consumption of natural gas in the developed world is already very high on a per capita basis, and although there is scope for some further growth given the shift from coal for electricity, far more growth will occur in the developing world. Notwithstanding its per capita consumption of gas, which is among the highest in the world, Canada accounts for just 2.8% of total global gas consumption, given its relatively small population.

Figure 14: Total natural gas consumption by country from 1965 to 2016.

The developing world represented by non-OECD countries is growing rapidly and natural gas has been by far the highest-growth fossil fuel over the past 50 years.¹⁷



1.1.2.3 COAL

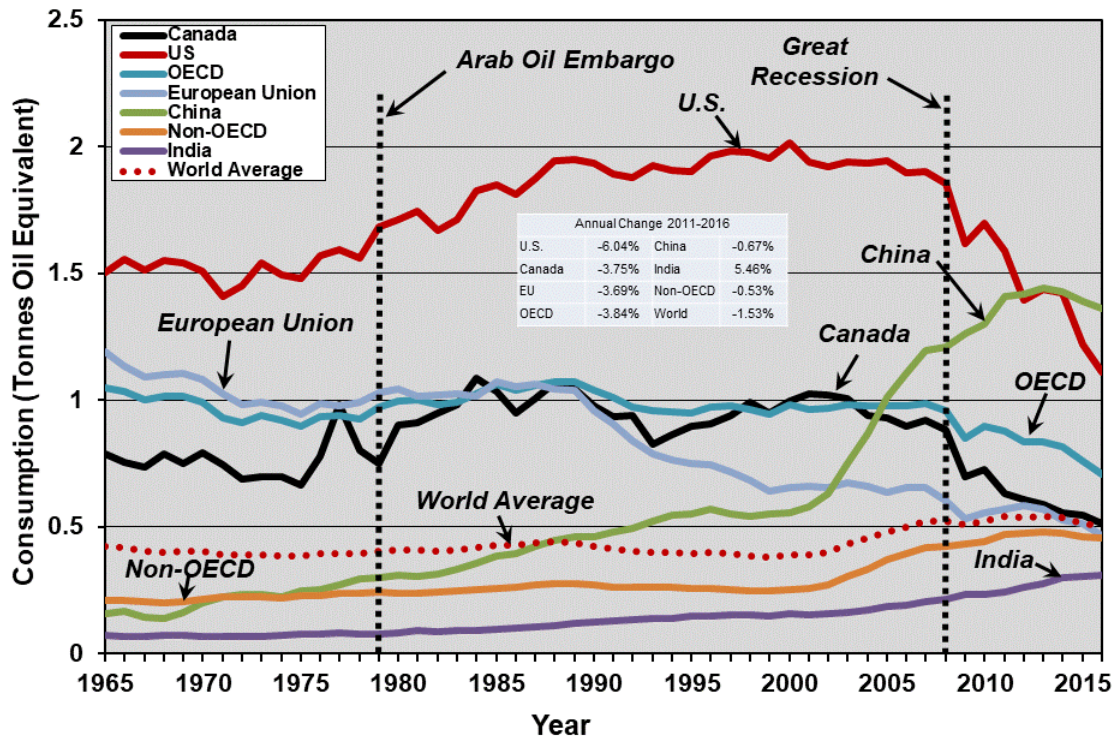
Coal is the second-largest energy source globally and the fifth-largest in Canada. Coal use has been falling rapidly in the industrialized world and growing slowly in the developing world, with world coal consumption peaking in 2014 and falling 4.4% since then. Although US consumption has been falling rapidly in recent years, in 2016 the US still consumed on a per capita basis 81% as much coal as China, which is the largest consumer of coal in the world. On a per capita basis, Canadians consume 54% less coal than Americans but 2% more than the world average. Coal is a major component of electricity generation in Alberta, Saskatchewan and Nova Scotia, but most domestic use will be phased out by 2030 under current climate legislation.

¹⁷ Data from BP Statistical Review 2017

Figure 15 illustrates trends in per capita coal consumption by country over the past 50 years. Over the past five years, coal use on a per capita basis has fallen at 1.53% per year globally, 3.84% per year in OECD countries and .53% per year in non-OECD countries. India is an exception—per capita coal use has been growing there at 5.46% per year over this period. China consumes half of the world's coal production. Although per capita consumption of coal in China has more than doubled since 2000, it has declined at .67% per year over the past five years. On a per capita basis, US consumption of coal peaked in 2000 and Canadian consumption peaked in 1984.

Figure 15: Per capita coal consumption by country from 1965 to 2016.

Per capita consumption has fallen rapidly in the developed world over the past five years and at 1.53% per year globally.¹⁸

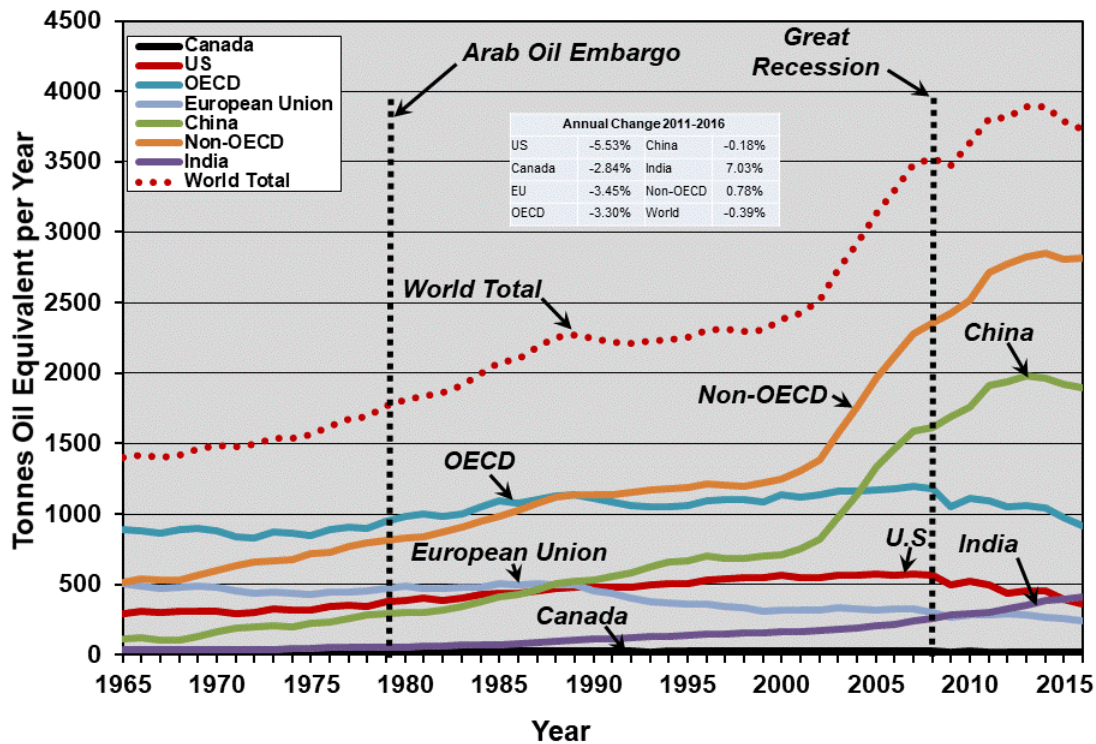


¹⁸ Data from BP Statistical Review 2017 and World Bank population statistics

Figure 16 illustrates total coal consumption by country over the past 50 years. Although total consumption has nearly tripled since 1965, consumption over the past five years has been declining globally at an average rate of .39% per year, declining at 3.3% per year in OECD countries and growing at .78% per year in non-OECD countries. Coal consumption in the world as a whole has increased by 56% since 2000, mostly due to growth in India and China. Canada and the US have decreased coal consumption by 2.84% and 5.53% per year, respectively, over the past five years.

Figure 16: Total coal consumption by country from 1965 to 2016.

Consumption has declined rapidly over the past five years in developed (OECD) countries, but it continues to grow in developing (non-OECD) countries. Non-OECD countries now consume nearly three-quarters of the world's coal production.¹⁹

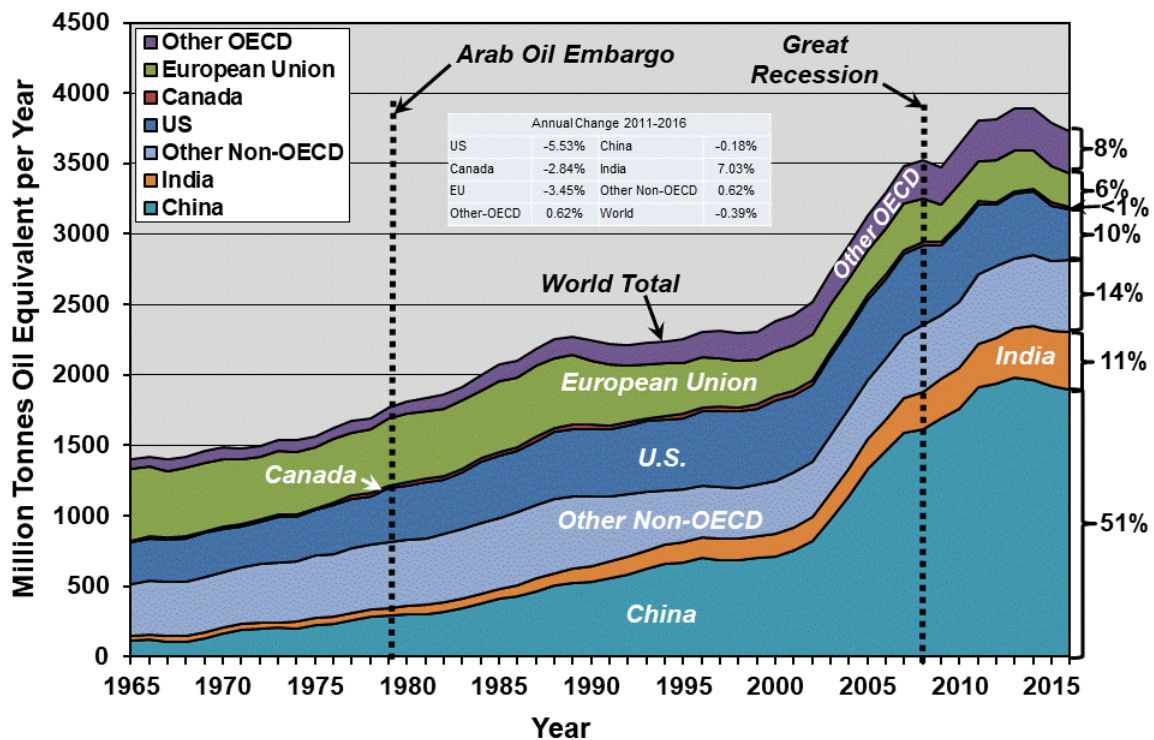


¹⁹ Data from BP Statistical Review 2017

Figure 17 shows a stacked chart of total coal consumption by country over the past 50 years, illustrating the proportions of coal consumed. Future growth in coal consumption, if any, is likely to be confined mainly to the developing world, given concerns with greenhouse gas emissions and the ability of natural gas and renewables to replace coal for electricity generation. However, coal will remain a major input into the steel-making industry (Canada is a major exporter of metallurgical coal). Canada accounted for just .51% of current global coal consumption in 2016, given its abundant hydro resources and relatively small population. As the second-largest source of energy in the world, coal will be a significant challenge to replace.

Figure 17: Total coal consumption by country from 1965 to 2016.

Coal consumption peaked globally in 2014, although it continues to grow in developing (non-OECD) countries, which now consume 76% of all coal production, with China alone consuming half.²⁰



1.1.2.4 NUCLEAR

Nuclear is the fifth-largest energy source globally and the fourth-largest in Canada. Nuclear power generation peaked globally in 2006 and has declined 7% as of 2016. Nuclear use has been falling in the industrialized world as a result of reactor shutdowns following the Fukushima accident in Japan, and an aging nuclear reactor fleet requiring the decommissioning of the oldest units. Nuclear energy is predominantly generated in the industrialized world, with OECD countries accounting for 75% of total generation, but it is growing rapidly in the developing world, particularly China. The US and the European Union together generated two-thirds of global nuclear power in 2016. Canada is a major consumer of nuclear energy—consuming more than the US and the European Union on a per capita basis. Canadian nuclear generation has been growing in the last few years with the refurbishment of some plants in Ontario and New Brunswick, although peak production occurred in 1994 when the Darlington plant came online and it has declined slightly since then (4%). Canadian mines supplied about 16% of the world's

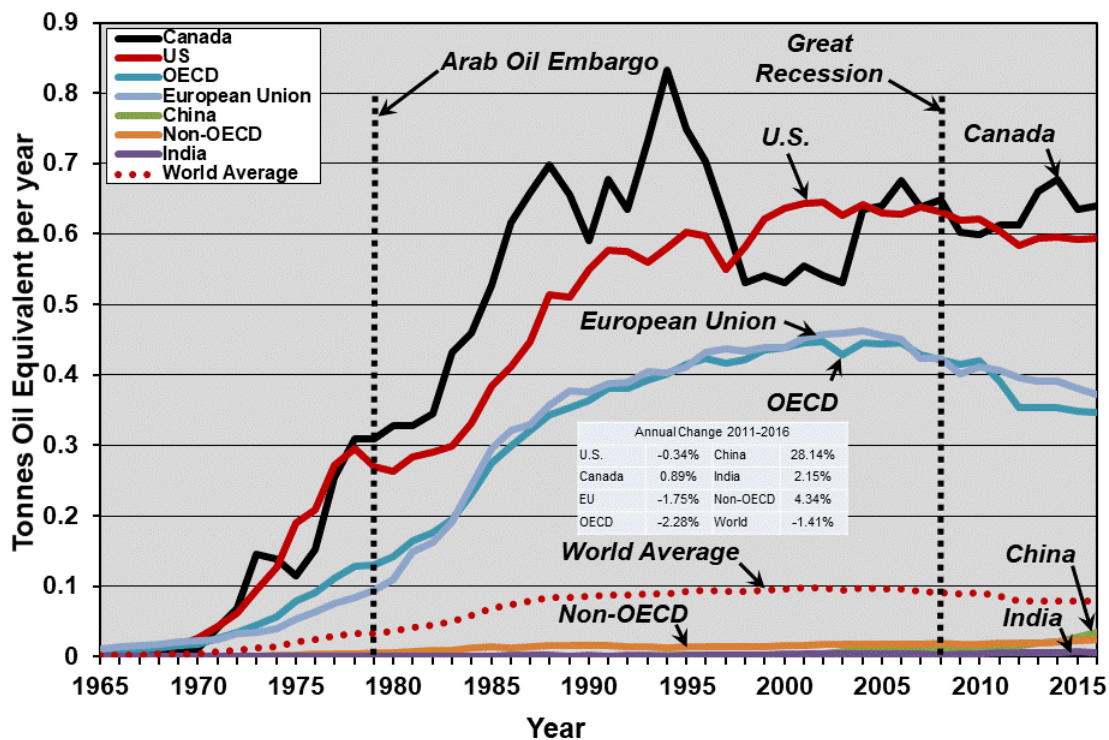
²⁰ Data from BP Statistical Review 2017

uranium in 2014 and Canada has 9% of the world's identified recoverable uranium resources. Canadian reactors burned about 3.3% of the world's uranium supply in 2015.²¹

Figure 18 illustrates trends in per capita nuclear energy consumption by country over the past 50 years. Globally, per capita consumption peaked in 2002 and has fallen by 18% as of 2016. There were 447 operable reactors in the world and 56 under construction as of August 2017.²² China alone has 20 reactors under construction, followed by Russia with seven, India with six and the US with two (two construction projects in the US were shut down in July 2017). Many existing reactors will be coming offline over the next 10 to 15 years, having reached their design lifetimes, hence it is expected that new reactors under construction will just maintain, not significantly increase, global nuclear generation. Some 66 reactors were retired between 1996 and 2013, and the rate of retirements will increase in the future owing to the age of the existing fleet. There are an additional 162 “planned” and 349 “proposed” nuclear reactors globally, but how many of these will be built is questionable given capital costs and anti-nuclear sentiment in the wake of the Fukushima disaster. In Canada, there are 19 operating reactors, none under construction and two listed as “planned.” Canada's nuclear fleet is aging and there will be more retirements over the coming years (Canada's nuclear industry is discussed in more detail in a later section).

Figure 18: Per capita nuclear energy consumption by country from 1965 to 2016.

Per capita consumption peaked in Canada in 1994 and in the world as a whole in 2002. Although nuclear energy consumption is falling in the industrialized world, it is growing rapidly in the developing world, particularly in China.²³



²¹ Joint Report by the OECD Nuclear Energy Agency and the International Atomic Energy Agency, 2016, Uranium 2016: Resources, Production and Demand, <https://www.oecd-nea.org/ndd/pubs/2016/7301-uranium-2016.pdf>

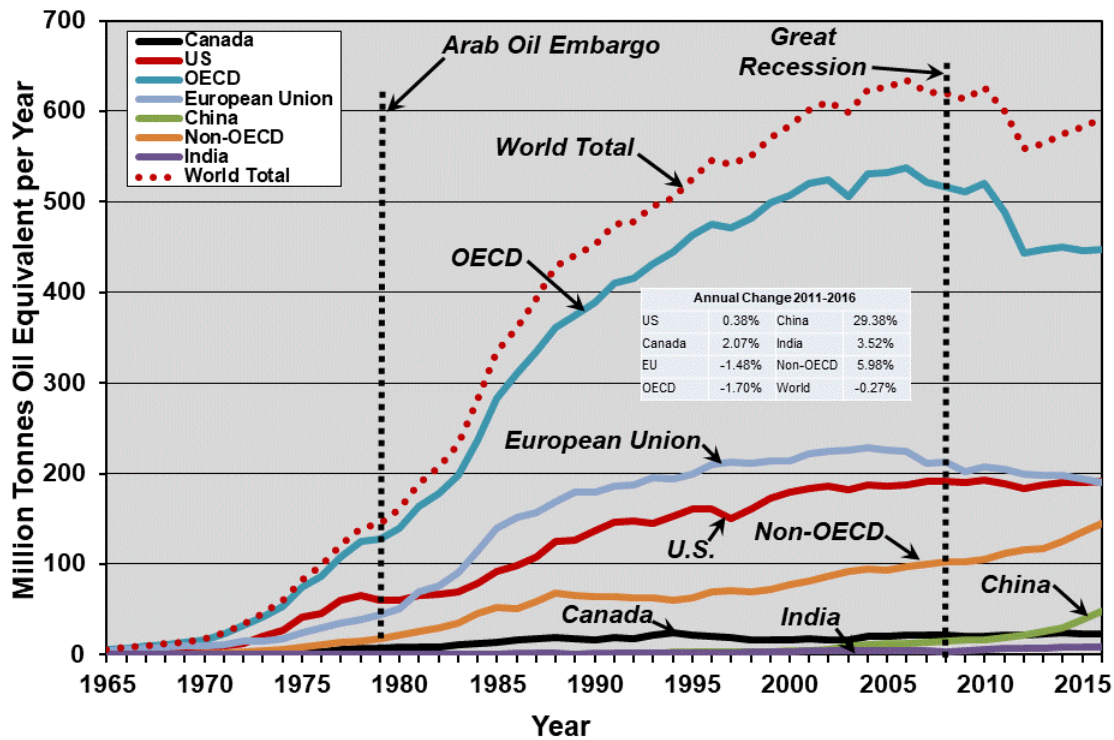
²² World Nuclear Association, August 2017, World Nuclear Power Reactors and Uranium Requirements, <http://www.world-nuclear.org/info/Facts-and-Figures/World-Nuclear-Power-Reactors-and-Uranium-Requirements/> Note that two US reactor construction projects were shut down in late July, 2017, which reduces the actual number under construction to 56, rather than 58 as noted in this reference.

²³ Data from BP Statistical Review 2017 and World Bank population statistics

Figure 19 illustrates total nuclear energy consumption by country over the past 50 years. Global nuclear generation has declined slightly (.27% per year) over the past five years and has grown since 2013 after a sharp drop following the Fukushima disaster. Developed (OECD) countries collectively declined at 1.7% per year over the past five years, although Canada (2.07% per year) and the US (.38% per year) grew slightly. The developing world is the main catalyst for future nuclear generation growth, with non-OECD countries increasing at 6% per year over the past five years and China averaging a 29% per year increase.

Figure 19: Total nuclear energy consumption by country from 1965 to 2016.

Consumption has declined in developed countries (represented by the OECD) and grown rapidly in developing (non-OECD) countries, although non-OECD countries still consume a small proportion of global nuclear energy. Canadian consumption has grown somewhat in the last five years with the refurbishment of some reactors.²⁴

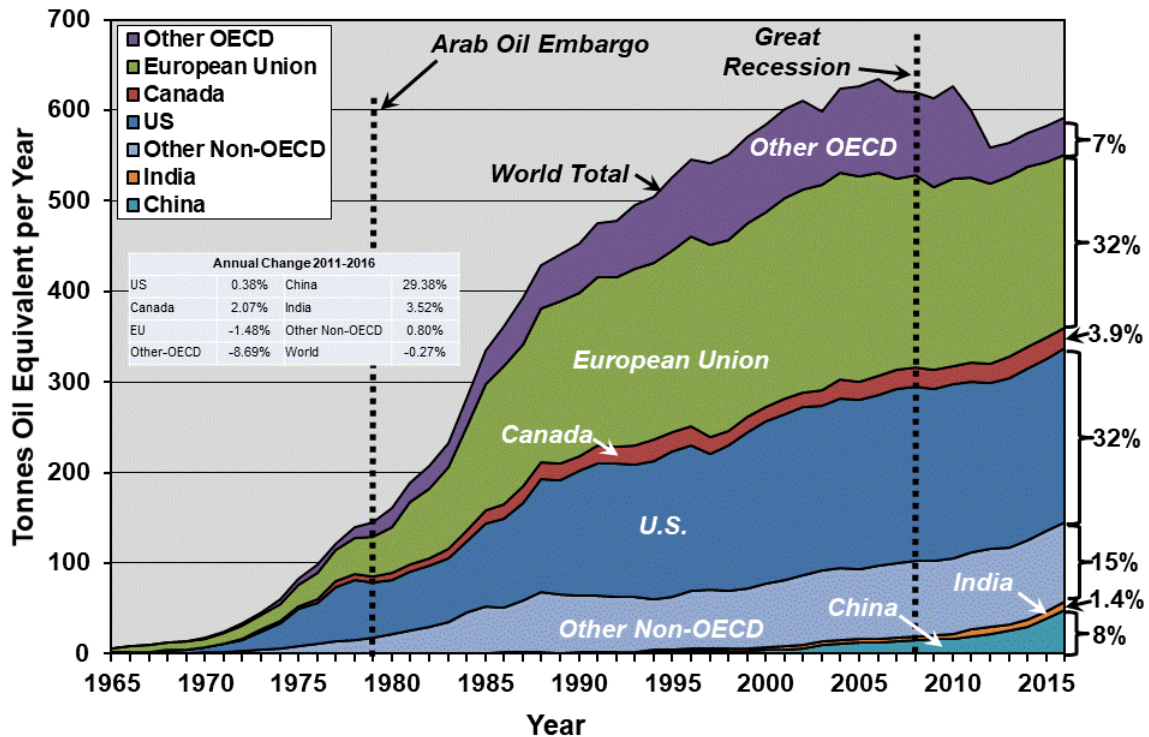


²⁴ Data from BP Statistical Review 2017

Figure 20 shows a stacked chart of total nuclear generation by country over the past 50 years, illustrating the proportions of nuclear energy consumed. Nuclear energy is predominantly a developed-world energy source, although it is growing rapidly in the developing world. The shutdown of reactors in Japan after the Fukushima disaster is the main cause of the post-2011 decline in global nuclear generation. The planned shutdown of reactors in Germany by 2022 will further stall global growth. Canada generated 3.9% of the world's nuclear power in 2016.

Figure 20: Total nuclear consumption by country from 1965 to 2016.

The developed world represented by OECD countries is by far the largest consumer of nuclear energy at 75% of 2016 generation, but the developing world, in particular China, is growing fast.²⁵



1.1.2.5 HYDRO

Hydropower from large facilities is the fourth-largest energy source globally and the third-largest in Canada. Although hydropower production has been relatively flat in the industrialized world over the past two decades, it is growing rapidly in the developing world. Since 2000, developing (non-OECD) countries have produced more hydropower than OECD countries, and now produce two-thirds of the world's hydropower.

Canada has vast hydropower resources compared to most countries, and was the second-largest hydropower producer in the world in 2016. On an oil-equivalent basis, hydro provided 27% of Canada's primary energy in 2016, compared to 6.9% for the world as a whole. Canadians consumed on a per capita basis 20 times as much hydropower as the world average in 2016. This was exceeded only by Norwegians, who consumed 51 times the world average. By contrast, Americans consumed 1.5 times the world average and, despite the development of the massive Three Gorges Dam and being the world's largest hydropower

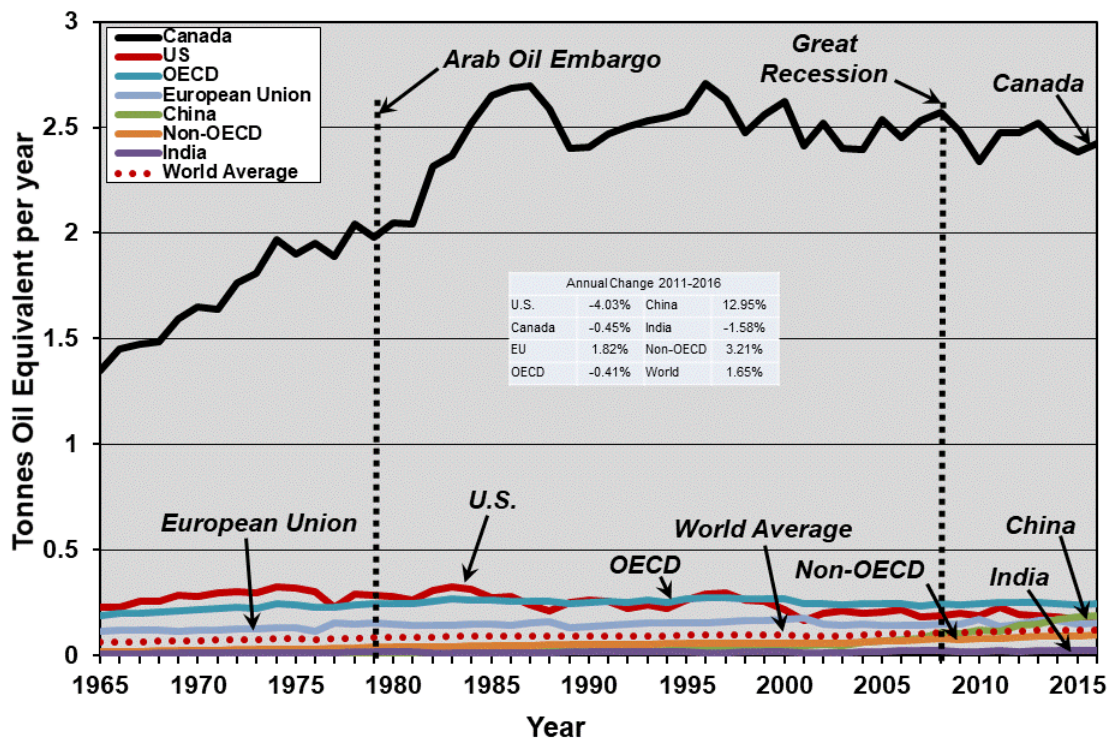
²⁵ Data from BP Statistical Review 2017

producer, the Chinese consumed just 1.6 times the world average. On an oil-equivalent basis, hydropower provided 2.6% and 8.6% of total primary energy consumption in the US and China in 2016, respectively.

Figure 21 illustrates trends in per capita hydropower consumption by country over the past 50 years. Hydro has been increasing globally at 1.65% per year over the past five years. This growth is mainly in the developing world, with an average increase of 3.21% per year in non-OECD countries, compared to a decline of 0.41% per year in OECD countries. Canadian consumption of hydro grew very rapidly from the mid-1960s to the 1980s with the completion of large dams in BC, Manitoba, Ontario and Quebec. Per capita consumption in Canada has been falling over the past five years given the slow rate of increase in the completion of major new hydro projects and the increase in Canadian population.

Figure 21: Per capita hydropower consumption by country from 1965 to 2016.

Per capita consumption has been declining in the developed world (represented by OECD countries) over the past five years, but has been growing rapidly in the developing world, particularly China.²⁶

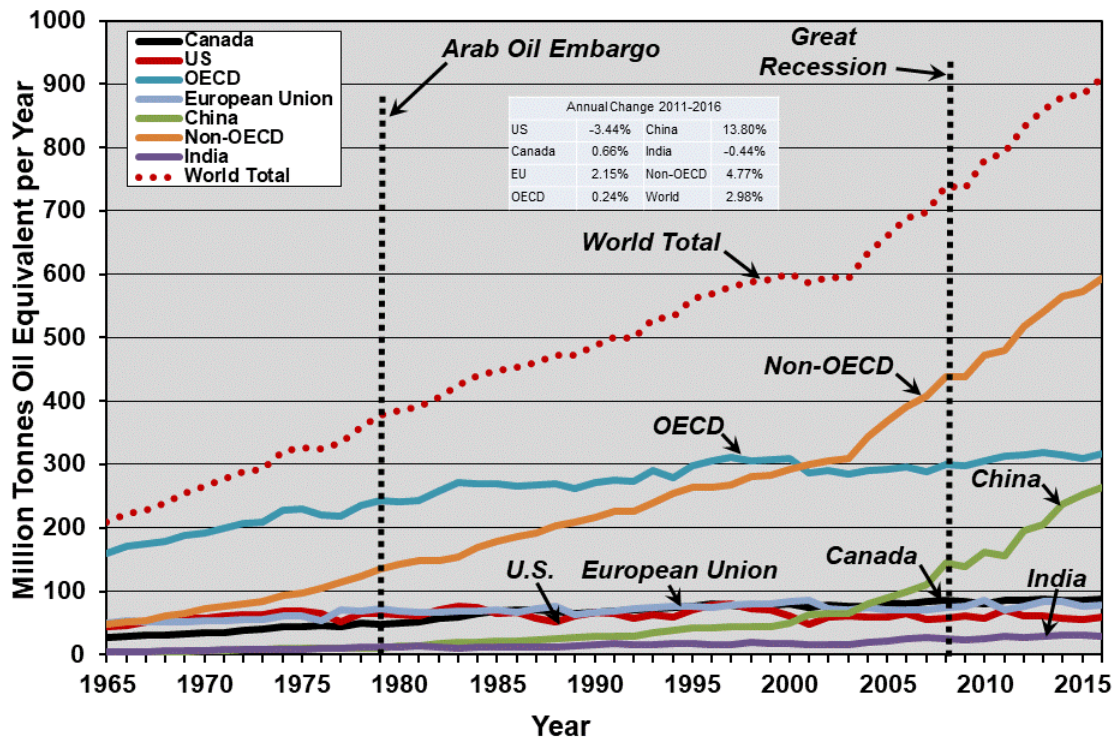


²⁶ Data from BP Statistical Review 2017 and World Bank population statistics

Figure 22 illustrates total hydropower consumption by country over the past 50 years. Given population growth, consumption has been growing globally at an average rate of 2.98% per year over the past five years, and hydropower consumption in the world as a whole has increased by 87% since 1990. In developing (non-OECD) countries, hydropower consumption has grown by 175% since 1990. It has increased more than nine-fold in China, compared to growth of just 17% in OECD countries and a decline of 10% in the US Hydropower has increased by 31% in Canada since 1990 (as of 2016).

Figure 22: Total hydro consumption by country from 1965 to 2016.

Consumption has been flat in developed (OECD) countries since 1995, compared to strong growth in non-OECD countries.²⁷

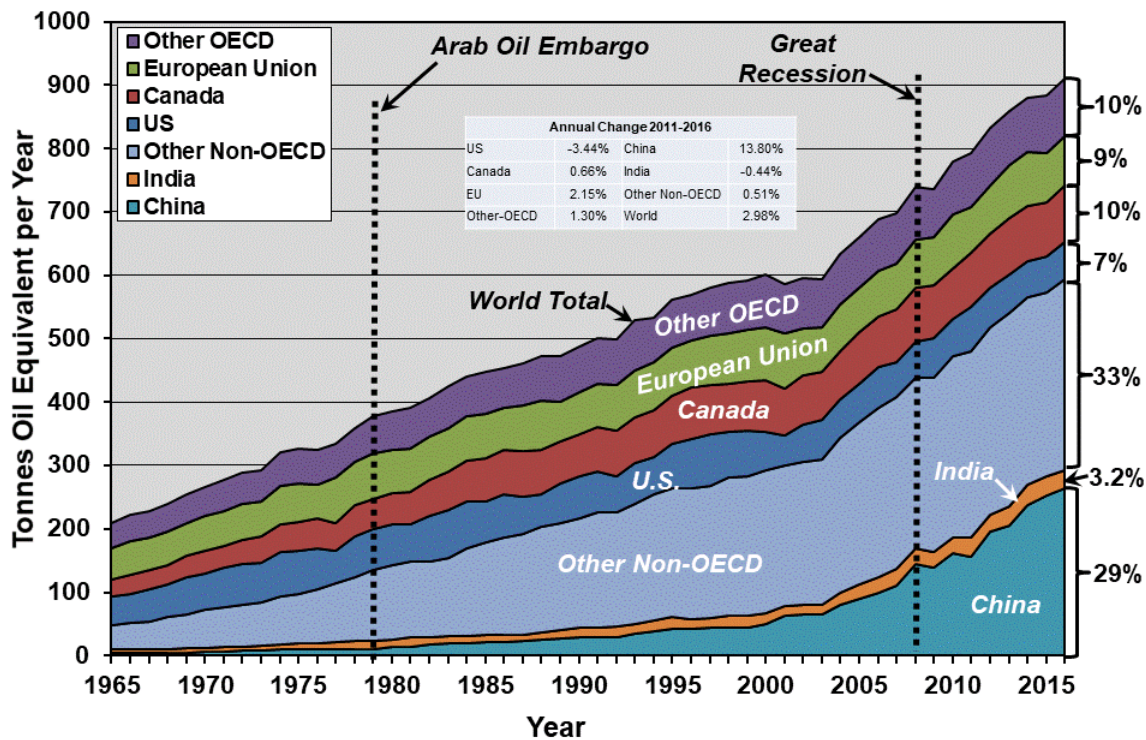


²⁷ Data from BP Statistical Review 2017

Figure 23 shows a stacked chart of total hydro consumption by country over the past 50 years, illustrating the proportions of hydro consumed. The developing world consumed 65% of global hydropower output in 2016. The importance of hydro to Canada can be seen in the fact that it produced 10% of total global hydropower and 28% of OECD hydropower in 2016. Future growth in hydropower is likely to be confined mainly to the developing world. Although there are still some sites remaining in the developed world, particularly in Canada, decommissioning of dams has begun in the US, and there is a growing amount of public opposition to major new projects given their environmental impacts.

Figure 23: Total hydro consumption by country from 1965 to 2016.

The developing world (represented by non-OECD countries) is growing rapidly and now consumes 65% of all hydro production, with China alone consuming more than a quarter of global hydro output in 2016. Canada produces 10% of global hydro output yet comprises just 0.5% of the world's population.²⁸



1.1.2.6 NON-HYDRO RENEWABLES

Non-hydro renewables refer to fuel sources other than hydropower that are renewable and provide electricity, heat and transport fuel. They include solar, wind, geothermal, biomass and biofuels. They do not include traditional biomass used for cooking and heating primarily in the developing world, which was estimated to account for 9.1% of global energy consumption in 2010 according to the UN's REN21.²⁹ The consumption of traditional biomass is not included in the charts in this report owing to the paucity of accurate consumption data. Forecasters at the UN's IRENA expect traditional biomass to be largely phased out over the next two decades.³⁰

²⁸ Data from BP Statistical Review 2017

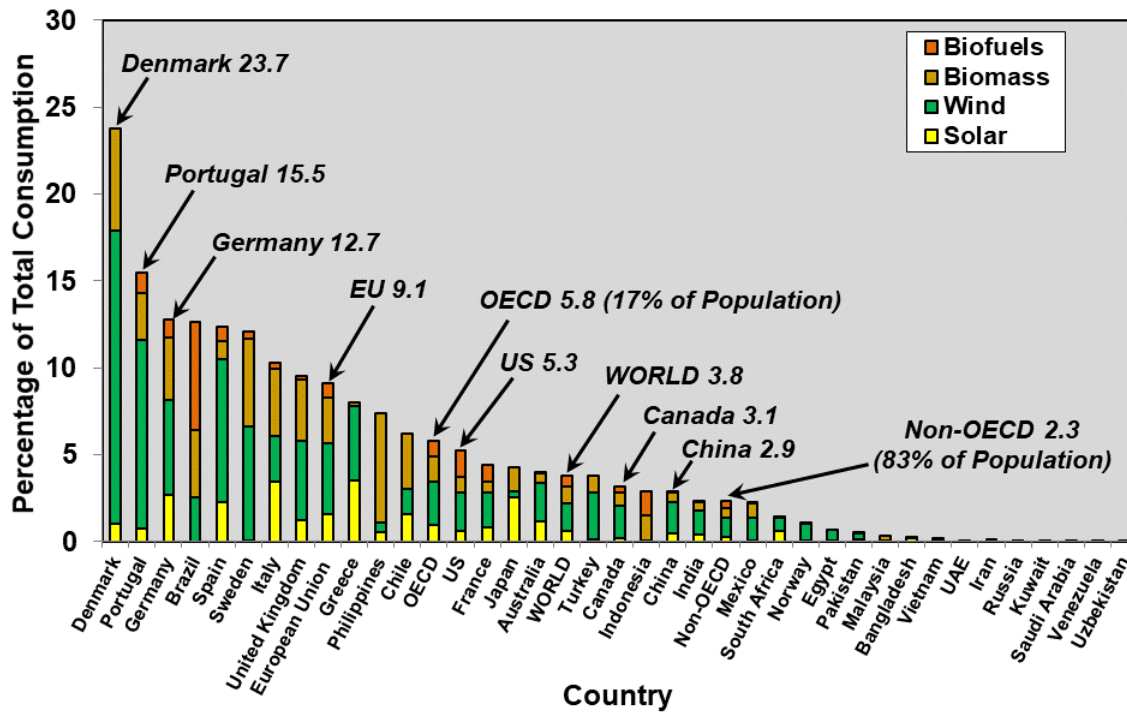
²⁹ REN21, 2017, Renewables 2017 Global Status Report, http://www.ren21.net/wp-content/uploads/2017/06/17-8399_GSR_2017_Full_Report_0621_Opt.pdf

³⁰ UN IRENA, June 2014, Remap 2030, A Renewable Energy Roadmap, see page 23, http://www.irena.org/remap/REmap_Report_June_2014.pdf

Non-hydro renewable energy has been growing exponentially in recent years but from a very small base, such that just 3.8% of global energy consumption was from non-hydro renewables in 2016. Deployment of non-hydro renewables has been much more pervasive in the developed world than in the developing world. Figure 24 illustrates the percentage of primary energy consumption obtained from non-hydro renewables by country in 2016. Denmark obtained nearly a quarter of its primary energy from them, followed by Portugal (16%), Germany (13%), Brazil (13%) and Spain (12%). Canada, at 3.1%, is below the world average and considerably below the US which is at 5.3%.

Figure 24: Percentage of primary energy provided by non-hydro renewables by country in 2016.

Globally, 3.8% of total consumption was provided by non-hydro renewables, although Denmark obtained nearly a quarter of its primary energy from non-hydro renewables in 2016, and the European Union as a whole obtained 9.1%. Canada obtained 3.1% from non-hydro renewables in 2016.³¹

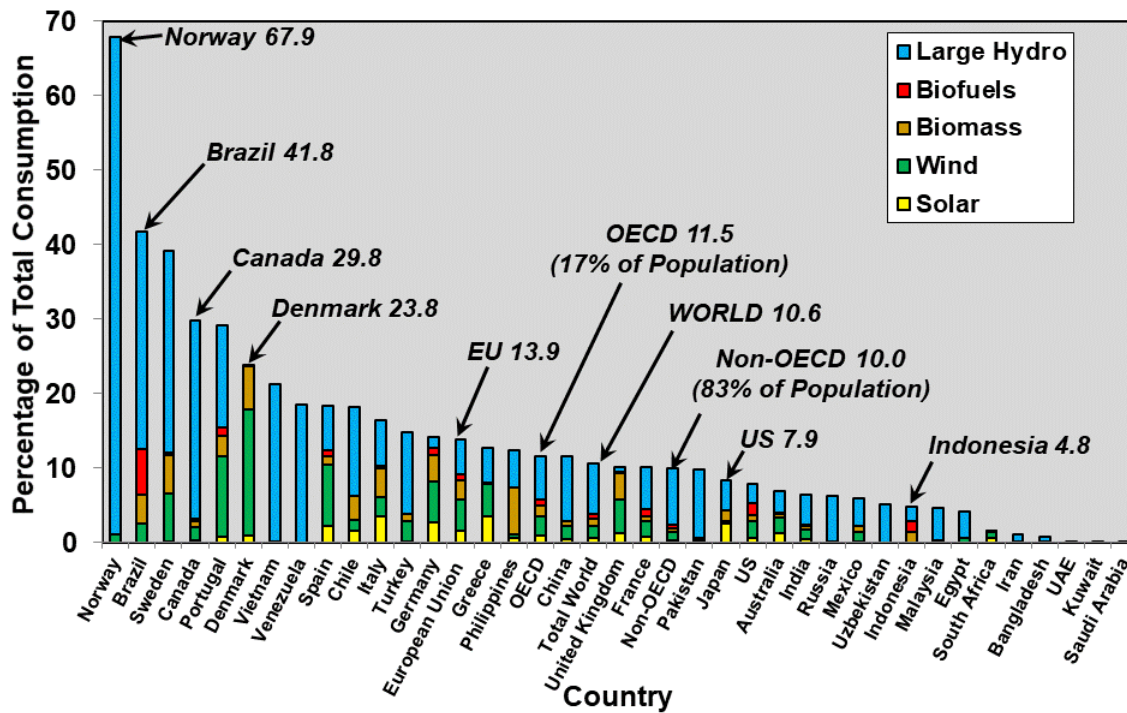


³¹ Data from BP Statistical Review 2017

In terms of total renewable energy, hydropower generated twice as much primary energy in 2016 as all other forms of renewable energy combined (excluding traditional biomass). Figure 25 illustrates total renewable energy consumption including hydropower by country in 2016. In this case Denmark, the world's largest consumer of non-hydro renewable energy, ranks behind Canada, which generated 29.8% of its primary energy from renewable sources. Norway, a very small consumer of non-hydro renewable energy, obtained two-thirds of its primary energy from renewables in 2016 if hydropower is included. Large hydro projects are much more prevalent in the developing world than non-hydro renewable projects, hence when hydro is included the developing world (represented by non-OECD countries) obtained nearly as much primary energy (10%) from renewables as the developed countries (11.5%) in 2016.

Figure 25: Percentage of primary energy by country provided by all forms of renewable energy (including hydro) in 2016.

Globally, 10.6% was provided by renewables, and Canada obtained nearly 30% of its primary energy from renewables thanks to its large hydropower resource.³²

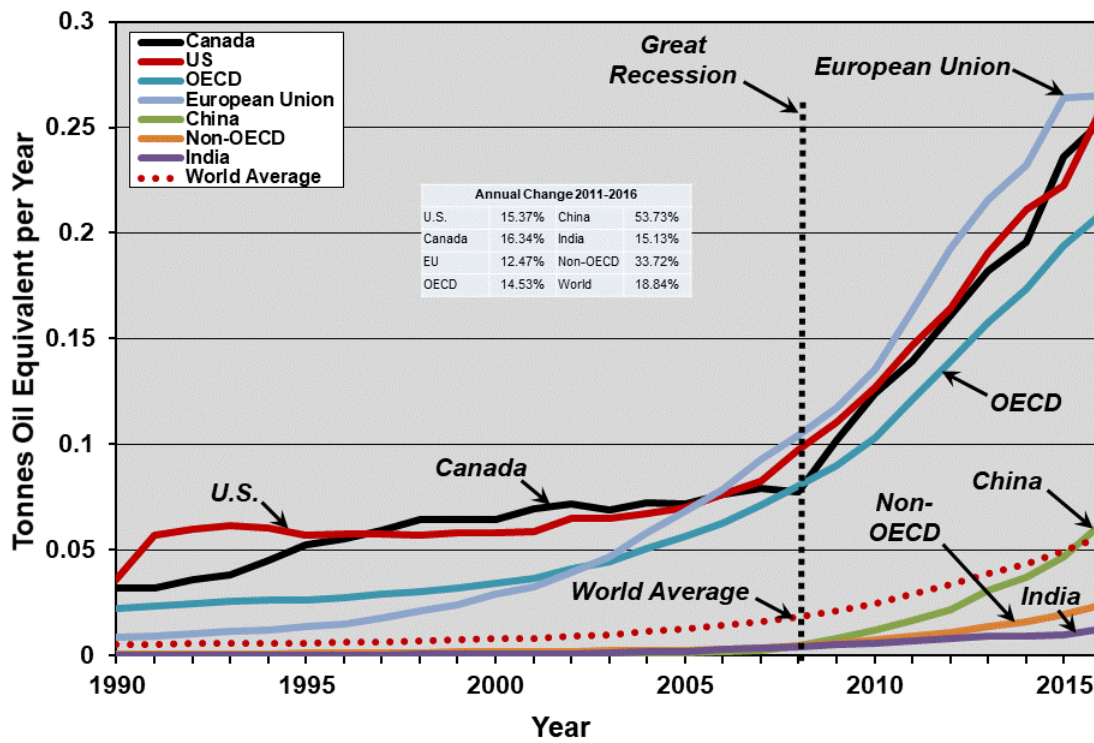


³² Data from BP Statistical Review 2017

Figure 26 illustrates trends in per capita non-hydro renewable consumption by country over the past 26 years. Per capita consumption of non-hydro renewable energy has increased dramatically in most countries, but overall consumption is far higher on a per capita basis in the developed world than in the developing world. The highest growth rates, however, are in the developing world, with non-OECD countries growing at 33.7% per year over the past five years versus OECD countries at 14.5%. China and India increased at 54% per year and 15% per year, respectively, over this timeframe. Of OECD countries, the US and Canada exceeded average growth at 15.4% per year and 16.3% per year, respectively. Global growth over the past five years was 18.8% per year, making non-hydro renewables by far the fastest growing energy source. However, as they are growing from a very small base they remain a small portion of total energy supply.

Figure 26: Per capita non-hydro renewable consumption by country from 1990 to 2016.

Although consumption has grown rapidly in all parts of the world, rates of non-hydro renewable consumption are much higher in the developed world than in the developing world.³³

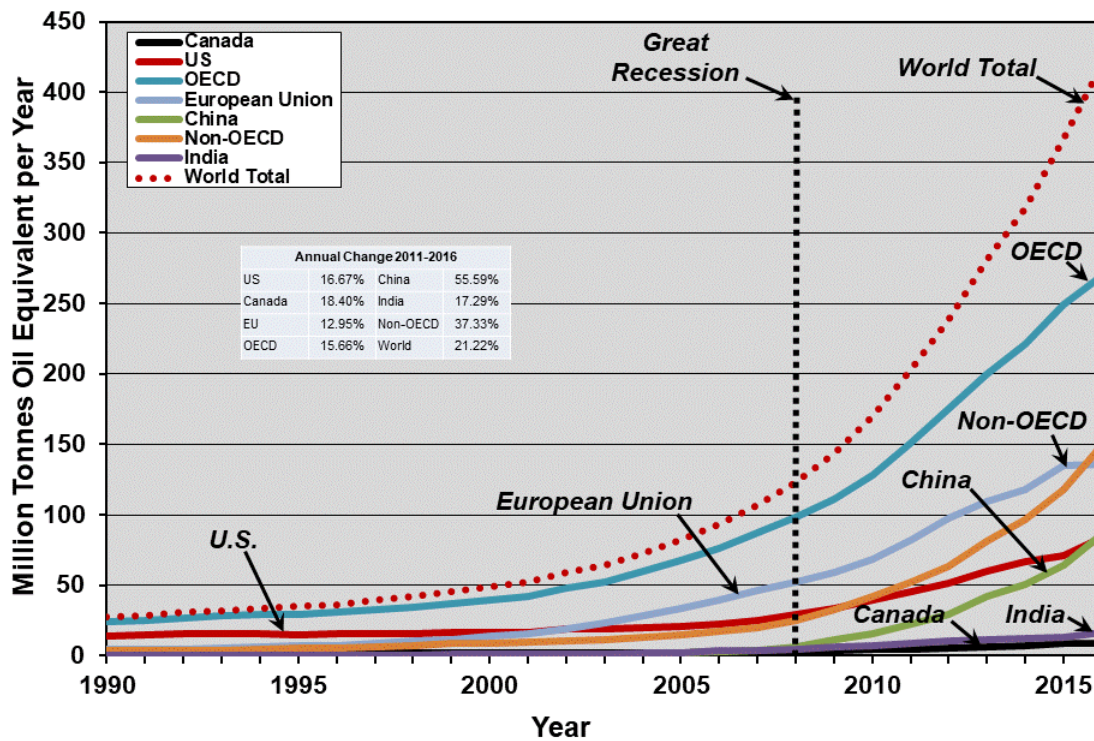


³³ Data from BP Statistical Review 2017 and World Bank population statistics

Figure 27 illustrates total non-hydro renewable consumption by country over the past 26 years. Given population growth, consumption has been growing globally at 21.2% per year over the past five years. Total consumption in the developed world (represented by OECD countries) has been growing at 15.7% per year. Despite representing just 17% of the world's population, developed countries consumed nearly twice as much non-hydro renewable energy as the developing world. As observed above with per capita consumption, however, growth in consumption of non-hydro renewables is much higher in non-OECD countries, at 37.3% per year over the past five years. Canada, at 18.4% per year, exceeded the non-hydro renewable growth rate in the developed world, but was below the world average. If hydropower is included, however, Canada has a very large component of renewable energy compared to the world average, as noted above.

Figure 27: Total non-hydro renewable consumption by country from 1990 to 2016.

Consumption has grown rapidly, particularly in the past decade. The developed world (represented by OECD countries) consumes nearly twice as much non-hydro renewable energy as the developing (non-OECD) countries.³⁴

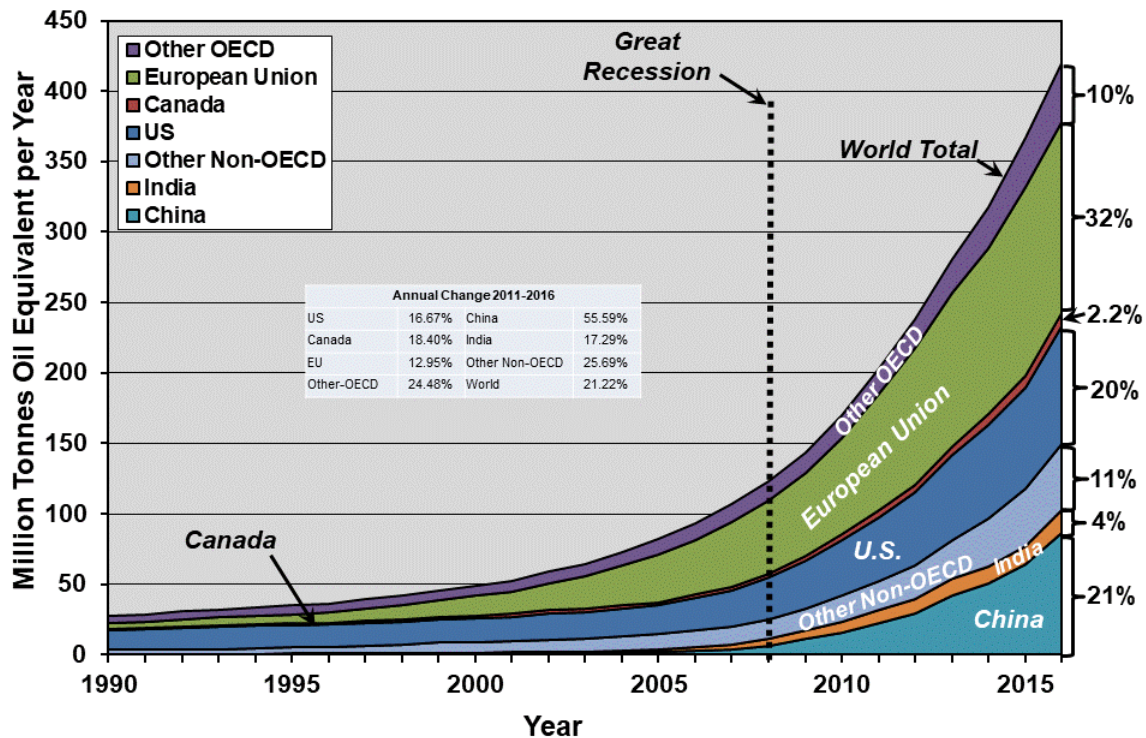


³⁴ Data from BP Statistical Review 2017

Figure 28 shows a stacked chart of total non-hydro renewable consumption by country over the past 26 years, illustrating the proportions consumed. Total consumption has tripled globally since 2009. The European Union consumed 37% of global non-hydro renewable energy in 2016, and OECD countries collectively consumed two-thirds, making non-hydro renewable energy a rich country's game—so far. However, consumption in non-OECD countries is growing at faster rates than in OECD countries, with most more than doubling since 2009, and China increasing eight-fold since then. Canadian consumption of non-hydro renewable energy has increased by 168% since 2009, and accounted for 2.2% of global non-hydro renewable consumption in 2016.

Figure 28: Total non-hydro renewable consumption by country from 1990 to 2016.

Although the developing world (represented by non-OECD countries) is growing rapidly, it consumes only about a third as much non-hydro renewable energy as OECD countries.³⁵



1.2 Delivered energy by fuel and sector

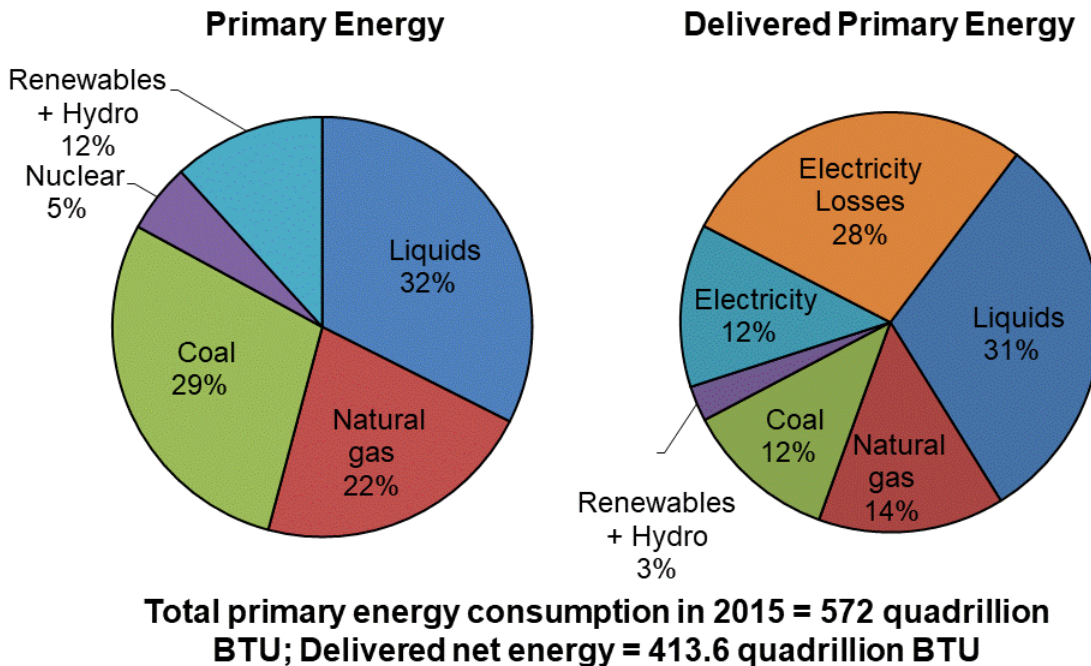
Primary energy undergoes losses as it is converted to a form suitable for end use, which is termed “delivered energy.” Principal among these are losses in the conversion of fossil fuels to electricity, but other losses are incurred, for example, in the conversion of crude oil or bitumen to refined petroleum products, and the clean-up and distribution of natural gas from well head to burner tip. Losses in the conversion of coal and natural gas to electricity amount to 55–70% and 45–65%, respectively, of the energy in the input fuel, depending on the technology used. Some losses are also incurred in the transmission of electricity to the point of end use. Electricity is an extremely versatile form of energy, however, and underpins modern life. It is also the principal product of renewable technologies, which will be increasingly important in lowering the carbon footprint of the energy system.

³⁵ Data from BP Statistical Review 2017

Figure 29 illustrates the conversion of primary energy to delivered energy for the world in 2015. Some 40% of primary energy is used in electricity generation but only 12% of primary energy is consumed as electricity delivered to the point of end use—28% of primary energy is lost in the electric conversion process. The other 60% of primary energy is used in non-electric applications for heat and transport, and as feedstock for petrochemicals and other products.

Figure 29: Conversion of primary energy by fuel into end-use delivered energy for the world in 2015.

Energy losses amount to 28%, chiefly due to the generation of electricity by coal and natural gas. Data are from the US Energy Information Administration's 2016 International Energy Outlook.³⁶

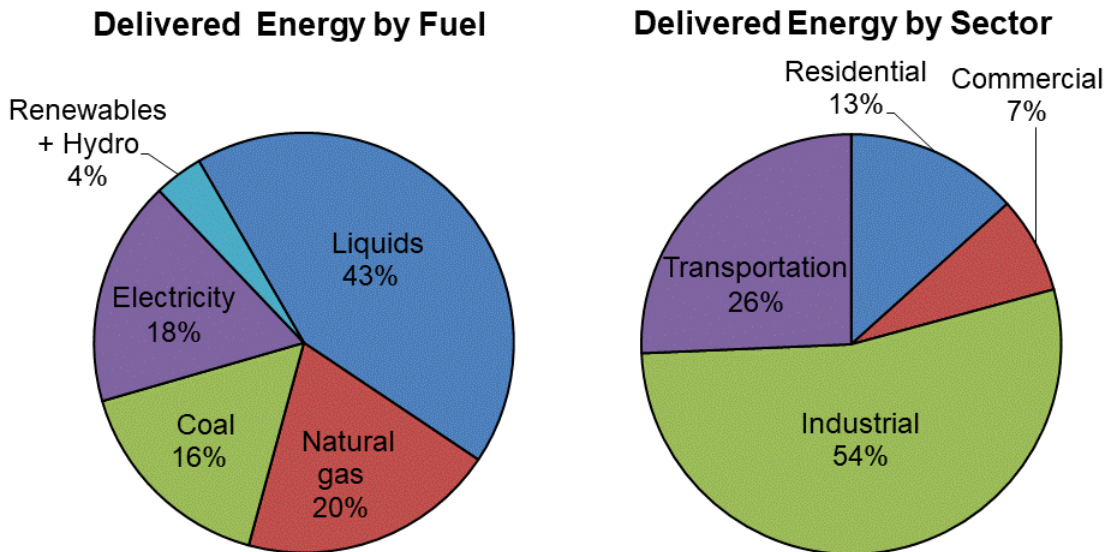


³⁶ U.S. Energy Information Administration, 2016, International Energy Outlook, <https://www.eia.gov/outlooks/ieo/>. Liquids are mainly oil but include a small component of biofuels and natural gas liquids such as condensate.

Figure 30 illustrates global consumption of delivered energy by fuel and end-use sector in 2015. Electricity amounts to just 18% of delivered energy consumption. Some 78% of delivered energy is fossil fuels used in non-electric applications such as heat, transportation, petrochemical feedstocks and other industrial processes. The industrial sector alone consumes over half of delivered energy and the transportation sector consumes a quarter, with the balance used in the residential and commercial sectors.

Figure 30: Delivered energy consumption by fuel and end-use sector for the world in 2015.

Fossil fuels used for non-electric uses make up 78% of end-use consumption. Data are from the US Energy Information Administration's 2016 International Energy Outlook.³⁷



Total primary energy consumption in 2015 = 572 quadrillion BTU; Delivered net energy = 413.6 quadrillion BTU

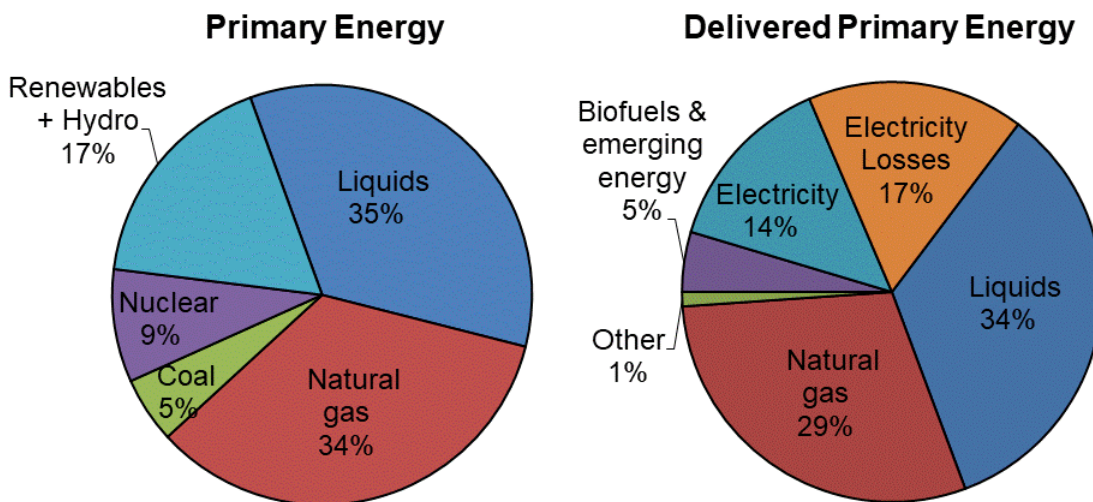
The sheer magnitude of non-electric fossil fuel energy consumption points to the challenge of converting to a world largely run on renewable energy, which would require a much higher level of electrification of all end-use sectors. Electricity is, however, a much more efficient source of energy for some applications, such as transportation, given the superior efficiency of electric motors (80–90% versus 20–40% for internal combustion engines), and a significant proportion of the energy the industrial sector uses is for the production of oil and gas. Hence increased electrification can result in a reduction in end-use energy consumption without impacting consumers. Nonetheless, the scale-up in electrification required to move to a mostly renewable future is daunting, as it would require a several-fold increase in electricity generation (this problem and scenarios for electrification included in Canada's "Mid-Century Long-Term Low-Greenhouse Gas Development Strategy" are discussed in a later section).

³⁷ U.S. Energy Information Administration, 2016, International Energy Outlook, <https://www.eia.gov/outlooks/ieo/>

Figure 31 illustrates the conversion of primary energy to delivered energy for Canada in 2016. Canada generates a large proportion of its electricity from hydropower, hence energy losses from conversion to electricity are considerably lower than for the world as a whole: 17% versus 28% of primary energy consumption. Furthermore, electricity comprises a higher percentage of delivered primary energy in Canada compared to the world: 14% versus 12%. Some 69% of delivered primary energy in Canada was used in non-electric applications for heat and transport, and as feedstock for petrochemicals and other products in 2016.

Figure 31: Conversion of primary energy by fuel into end-use delivered energy for Canada in 2016.

Energy losses amount to 17%, chiefly due to generation of electricity by coal and natural gas. Data are from the National Energy Board's Energy Futures report.³⁸ "Renewables" include landfill gas.



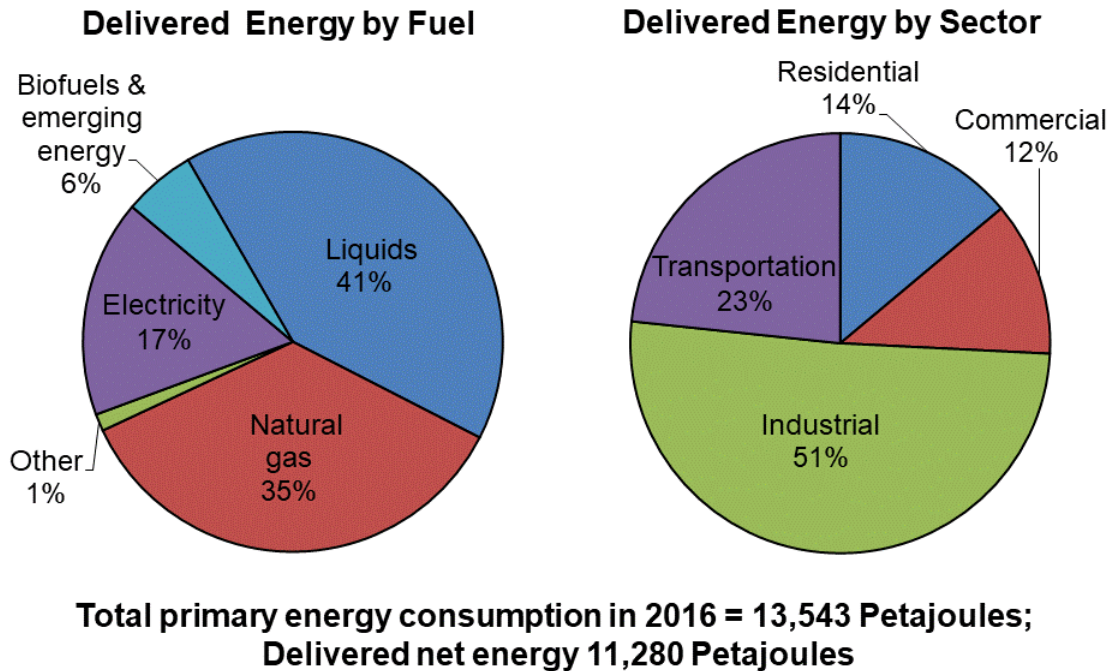
**Total primary energy consumption in 2016 = 13,543 Petajoules;
Delivered net energy 11,280 Petajoules**

³⁸ National Energy Board, October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ptr/2017/2017nrgptr-eng.pdf>, Appendices, <https://apps.neb-one.gc.ca/ptrppndc/dflt.aspx?GoCTemplateCulture=en-CA>

Figure 32 illustrates Canadian consumption of delivered energy by fuel and end-use sector in 2016. Electricity comprised just 17% of Canadian delivered energy consumption in 2016 (comparable with the world as a whole at 18%). Some 76% of delivered energy was fossil fuels used in non-electric applications such as heat, transportation and petrochemical feedstocks. The industrial sector alone consumed half of delivered energy and the transportation sector consumed a quarter, with the balance used in the residential and commercial sectors.

Figure 32: Delivered energy consumption in Canada by fuel and end-use sector in 2016.

Fossil fuels used for non-electric uses make up 76% of end-use consumption. Data are from the National Energy Board's Energy Futures report.³⁹ "Renewables" include landfill gas.



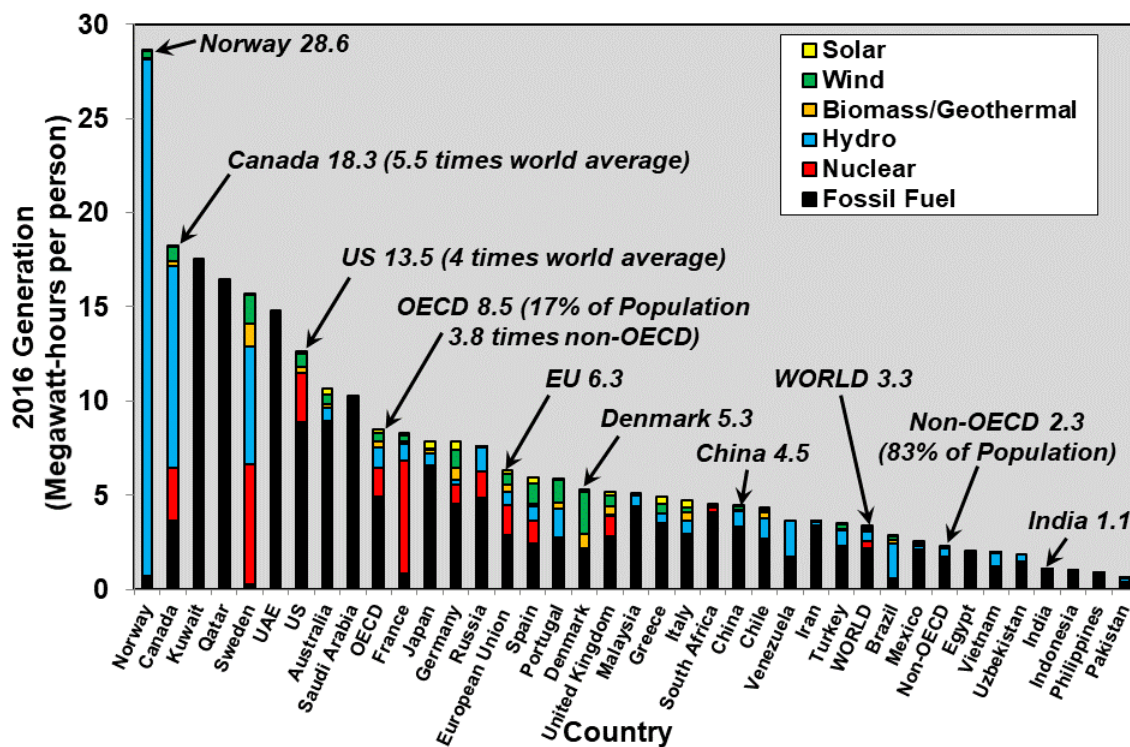
³⁹ National Energy Board, October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ft/2017/2017nrgfr-eng.pdf>, Appendices, <https://apps.neb-one.gc.ca/ftppndc/dflt.aspx?GoCTemplateCulture=en-CA>

1.3 Electricity generation and consumption

Electricity deserves a closer examination, given that renewable energy sources such as wind and solar produce electricity directly. For there to be a much higher penetration rate of renewables into the world's overall energy system, a much greater proportion of end-use consumption will need to be converted to electricity.

Figure 33 illustrates per capita generation of electricity by country and fuel in 2016. As with energy in general, the industrialized world consumes a great deal more electricity than the developing world. OECD countries, which constitute 17% of the world's population, generate nearly four times as much electricity per capita as non-OECD countries. India generates one third of the per capita electricity of the world average, and less than one quarter that of China. Norway is one of the highest per capita generators of electricity in the world with its extensive hydropower resources, much of which is exported to other European countries. Americans generate four times the world average, mostly from fossil fuels and nuclear power, and Canadians generate more than five times the world average, much of it from hydropower, of which a significant proportion is exported, particularly from Quebec.

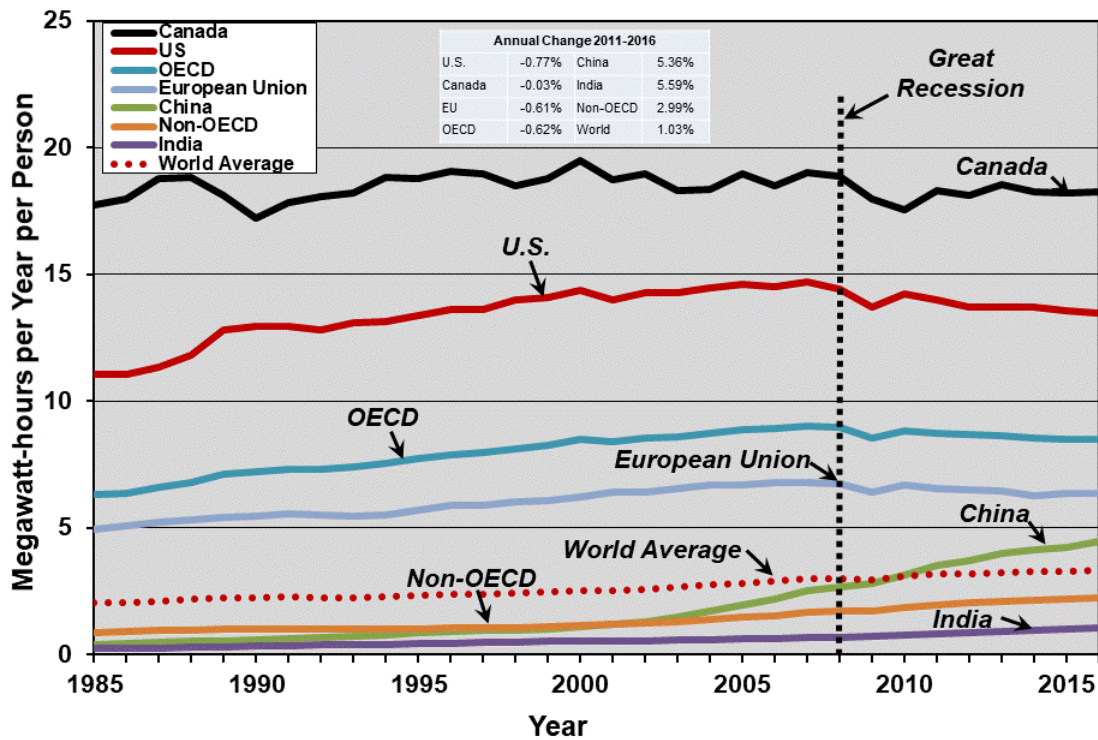
Figure 33: Per capita generation of electricity by country and fuel in 2016.⁴⁰



⁴⁰ Data from BP Statistical Review 2017 and World Bank population data

Figure 34 illustrates trends in per capita generation of electricity by country over the past 31 years. Globally, per capita generation has been rising at 1% per year over the past five years. Per capita generation in OECD countries, however, although at much higher levels than in developing countries, has fallen 6% from its peak in 2007. Per capita generation also peaked in the US in 2007 and is down 8.5%. In Canada, per capita generation peaked in 2000 and is down 6.2% as of 2016. In contrast, the developing world has grown rapidly, with China up 5.4% per year over the past five years, India up 5.6% per year and non-OECD countries as a whole up 3% per year. Per capita generation is likely to continue to grow very strongly in the developing world. The decline in the industrialized world contradicts the trend that would seem necessary to replace many of the current non-electric end uses of energy with renewables.

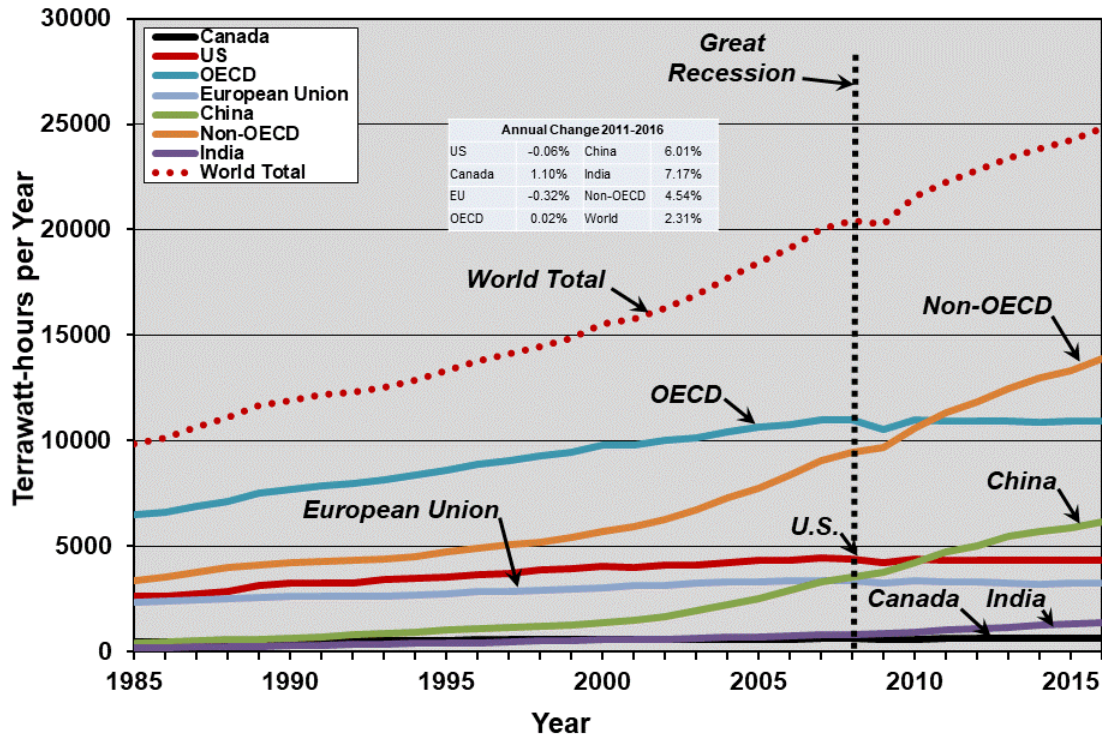
Figure 34: Per capita generation of electricity by country from 1985 to 2016.⁴¹



⁴¹ Data from BP Statistical Review 2017 and World Bank population statistics

Figure 35 illustrates total electricity generation by country over the past 31 years. World generation has grown at 2.3% per year over the past five years, with the developed world essentially flat and the developing world (represented by non-OECD countries) growing at 4.5% per year. Electricity generation in China has more than quadrupled since 2000, and in India it has more than doubled. US generation is down 2% since peaking in 2007, and Canadian generation has been growing at 1.1% per year over the past five years.

Figure 35: Total electricity generation by country from 1985 to 2016.⁴²

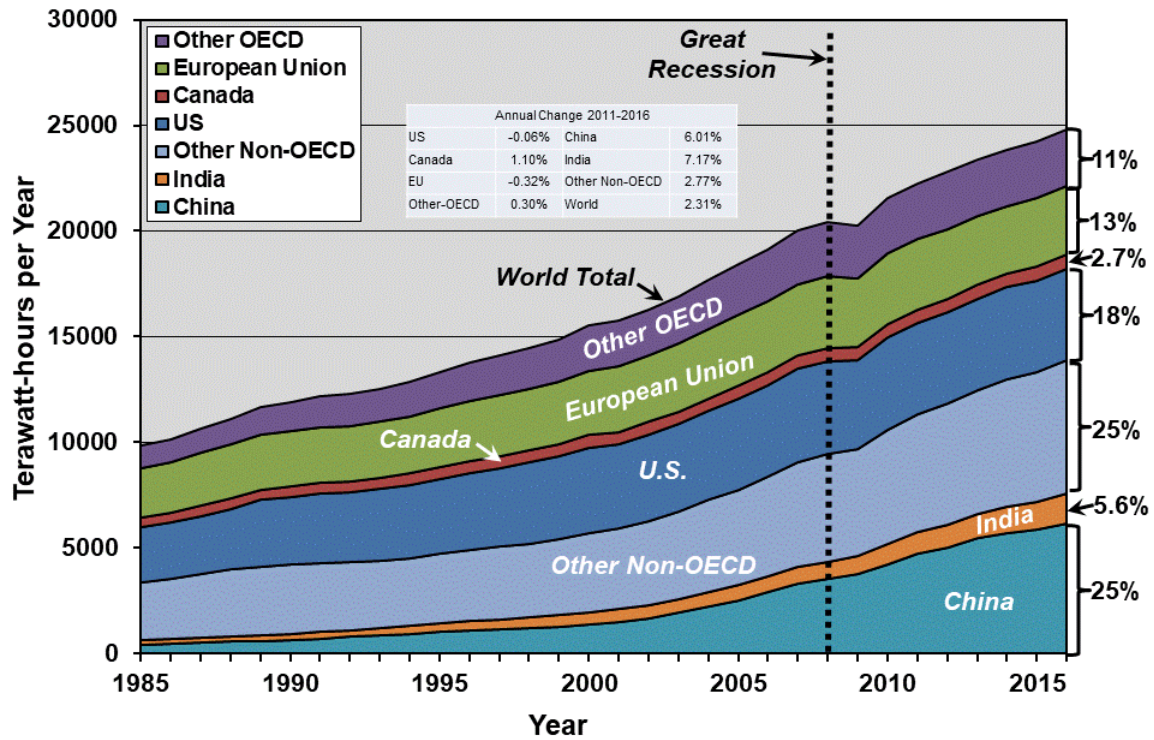


⁴² Data from BP Statistical Review 2017

Figure 36 shows a stacked chart of total electricity generation by country over the past 31 years, illustrating the proportions consumed. Total generation has doubled globally since 1992. China is now the largest consumer of electricity in the world at 25%, followed by the US at 18% and the European Union at 13%. Canadian consumption has been relatively stable for the past 10 years, and accounted for 2.7% of global electricity generation in 2016.

Figure 36: Total electricity generation by country from 1985 to 2016.

World generation has doubled since 1990 and China became the largest consumer of electricity in the world in 2011.⁴³



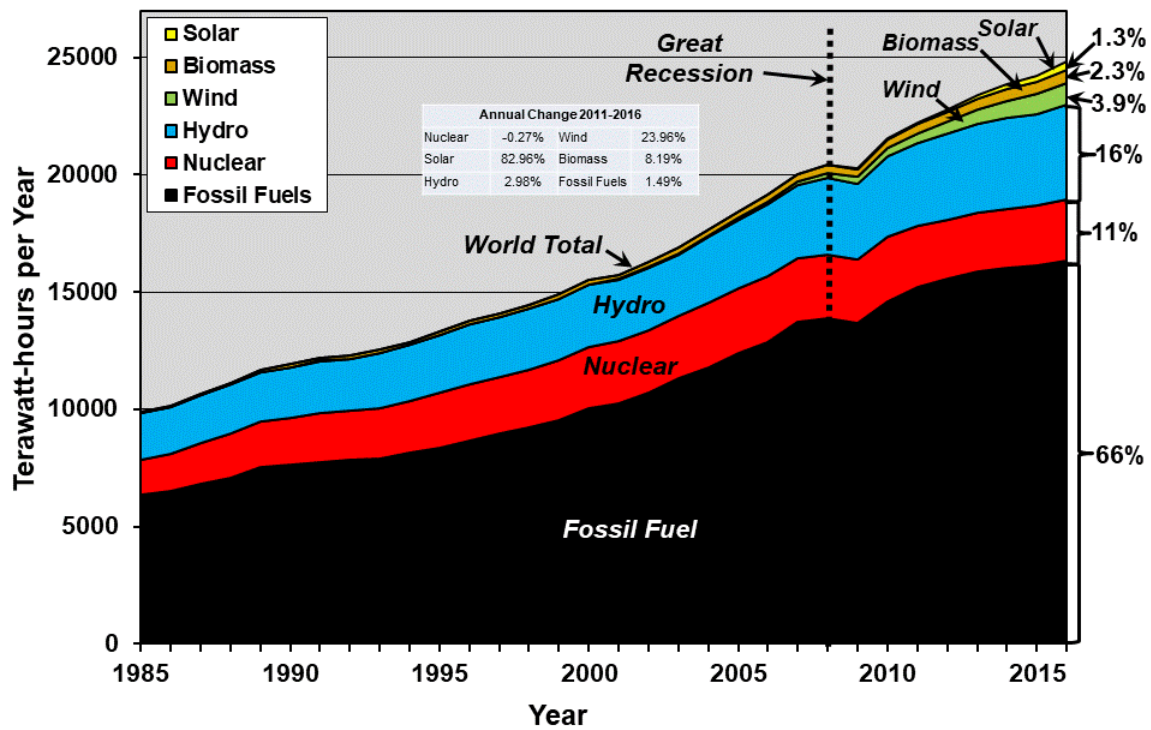
⁴³ Data from BP Statistical Review 2017

1.3.1 Electricity generation by fuel

Figure 37 illustrates electricity generation by fuel. Fossil fuels, primarily coal and natural gas, provided two-thirds of global electricity generation in 2016, followed by large hydro and nuclear, at 16% and 11%, respectively. Non-hydro renewables—wind, solar and biomass—provided just 7.5%, although they are growing rapidly, with solar averaging 83% per year growth over the past five years and wind 24% per year. Fossil fuel and hydro generation has grown also, but at much slower rates, averaging 1.5% per year and 3% per year over this period. Nuclear has been slowly declining.

Figure 37: World electricity generation by fuel from 1985 to 2016.

*Fossil fuels remain dominant—although non-hydro renewables are growing rapidly, but from a small base.*⁴⁴

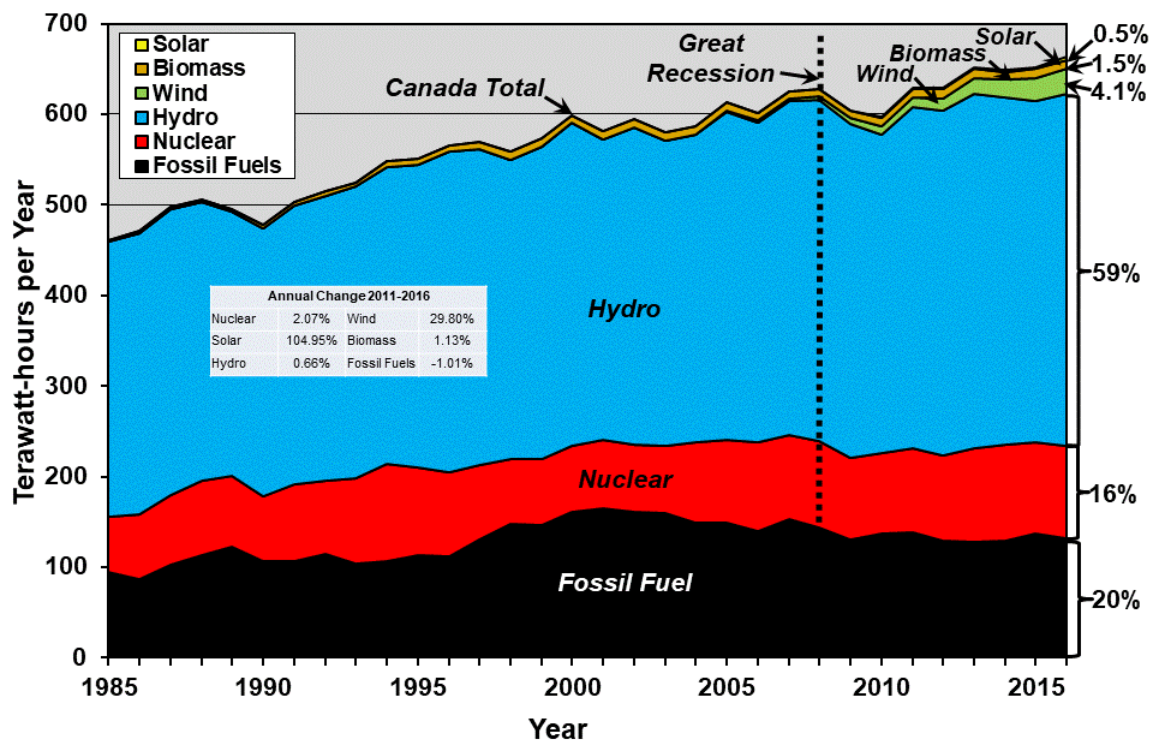


⁴⁴ Data from BP Statistical Review 2017

Canada's electricity system is dominated by large hydro, making it one of the cleanest in the world from a carbon emissions point of view (see Figure 38). Fossil fuel use for electricity generation in Canada has been declining at an average rate of 1% per year over the past five years. Nuclear power generation has increased somewhat in recent years with the refurbishment of some reactors, although the all-time peak was in 1994. Some 65% of Canadian nuclear generation capacity comes from reactors that are more than 30 years old, and 14% from reactors more than 40 years old, meaning more refurbishments and/or replacements will be needed in coming years to maintain nuclear generation capacity.⁴⁵ Although non-hydro renewables such as wind and solar have been growing very rapidly in recent years, they made up just 6.1% of generation in 2016.

Figure 38: Canadian electricity generation by fuel from 1985 to 2016.

Large hydro is dominant although non-hydro renewables have grown significantly in recent years. Fossil fuel generation peaked in 2001 and had declined 20% by 2016.⁴⁶



⁴⁵ International Atomic Energy Association, Power Reactor Information System, accessed October 10, 2016, <https://www.iaea.org/PRIS/CountryStatistics/CountryDetails.aspx?current=CA>

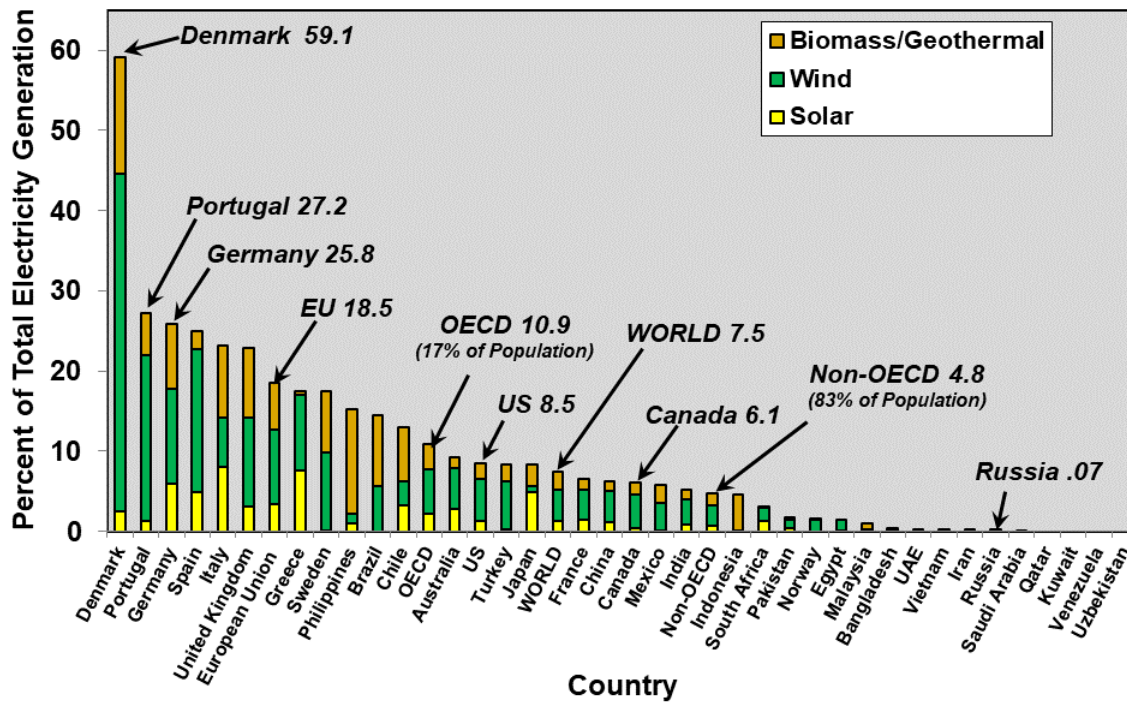
⁴⁶ Data from BP Statistical Review 2017

1.3.2 Electricity generation by renewables

In terms of electricity generation from non-hydro renewables, Canada, at 6.1%, remained below the world average of 7.5% in 2016, and far below countries like Denmark, at 59.1% (see Figure 39). Non-hydro renewables have potential for considerable upward scaling, but as they are being scaled from a small base significant penetration will take some time. Non-hydro renewables also have issues such as intermittency, seasonal fluctuations and the need for more transmission infrastructure, which must be planned for as they are scaled upward.

Figure 39: Non-hydro renewable electricity generation by country in 2016.

Canada is below the world average and far below countries such as Denmark, Portugal, Spain and Germany.⁴⁷

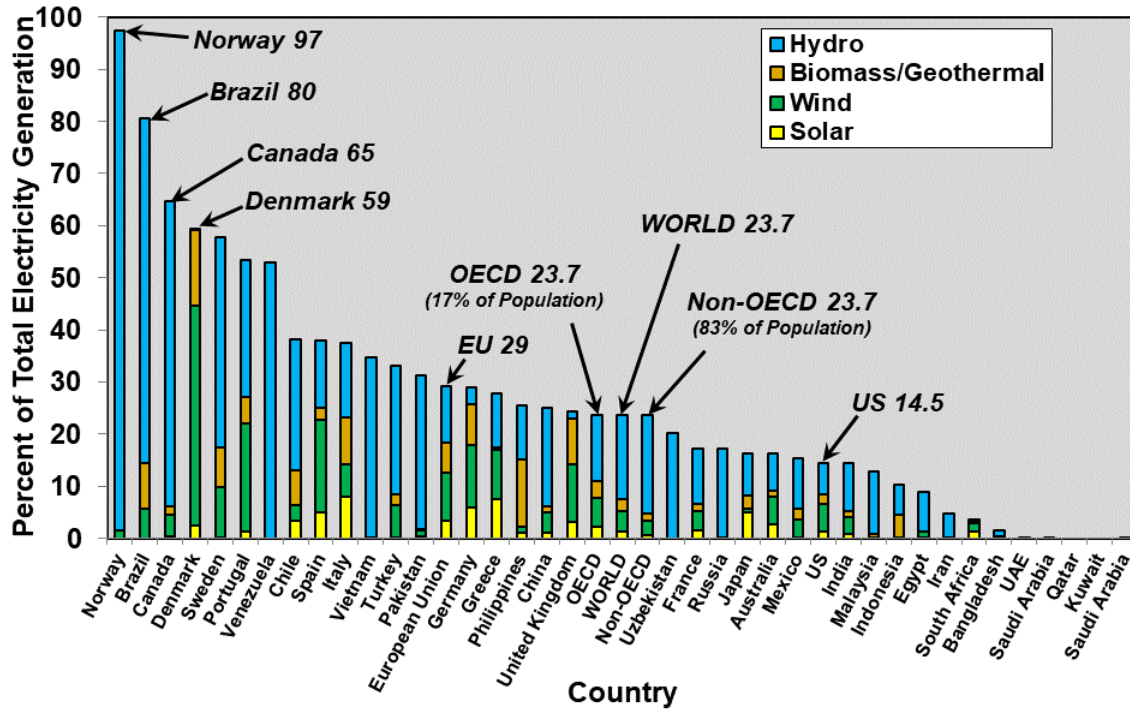


⁴⁷ Data from BP Statistical Review 2017

If large hydro is included, Canada has one of the cleanest electricity systems in the world, with 65% of electricity generated by renewable sources—nearly triple the world average (see Figure 40). Large hydro has significant environmental impacts, however, and many of the prime sites close to demand loads have already been developed. Large hydro generates more than twice as much electricity globally as non-hydro renewables combined, and in Canada generates 10 times as much.

Figure 40: Electricity generation from all renewable sources by country in 2016.

Canada is near the top in this comparison. Large hydro generates more than twice as much electricity globally as non-hydro renewables combined.⁴⁸



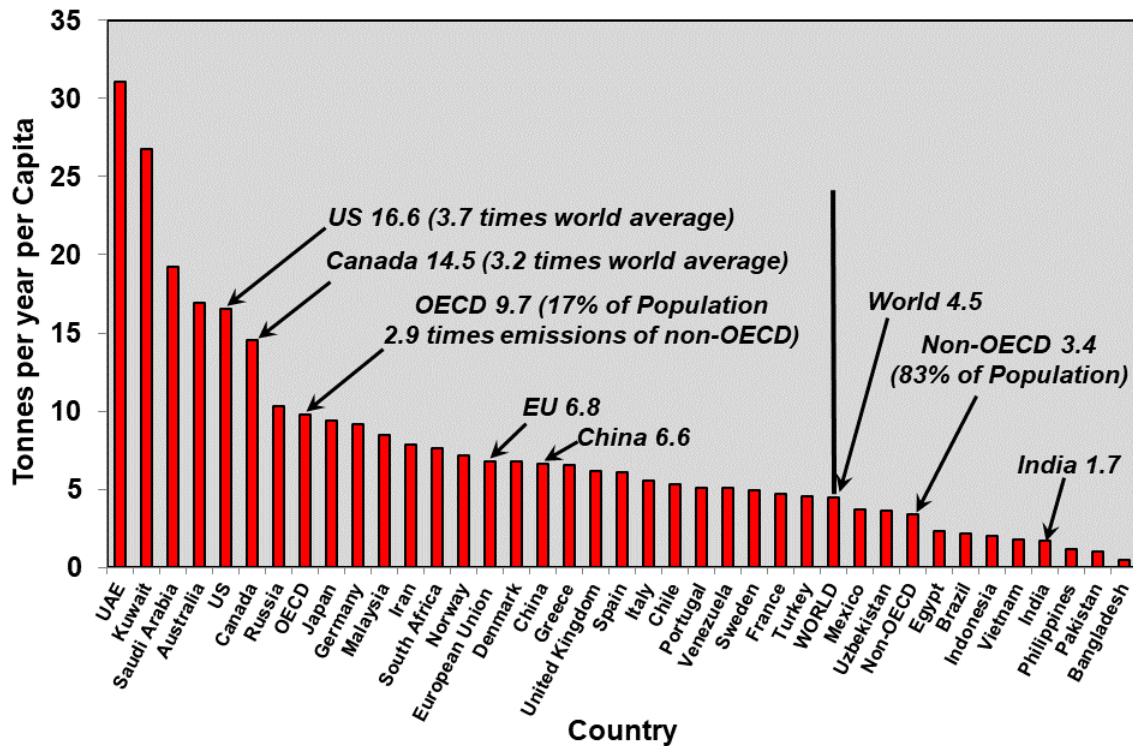
⁴⁸ Data from BP Statistical Review 2017

1.4 Greenhouse gas emissions

Carbon dioxide emissions from the combustion of fossil fuels are the major greenhouse gas concern for global warming, given carbon dioxide's longevity in the atmosphere. Although there are several even more potent greenhouse gases, such as methane, they typically have much shorter residence times in the atmosphere (and non-fossil fuel activities such as livestock and land disturbance also release considerable amounts of greenhouse gas). Carbon dioxide emissions from fossil fuels have tripled globally since 1965, although there has been very little growth since 2013.

Figure 41 illustrates per capita emissions of carbon dioxide by country in 2016. Canadians emit more than triple the world average, despite the fact that Canada's electricity sector has a high proportion of carbon-free generation. This is primarily a result of emissions in the transportation, building and industrial sectors. The US, at 3.7 times the world average, is higher than Canada mainly due to the carbon intensity of its electrical sector. The European Union has on average less than half of the per capita emissions of Canada. Industrialized countries represented by the OECD have nearly triple the per capita carbon dioxide footprint of developing countries. Looking at the two largest developing countries, China has nearly quadruple the per capita emissions footprint of India (China is now close to the per capita emissions of the European Union).

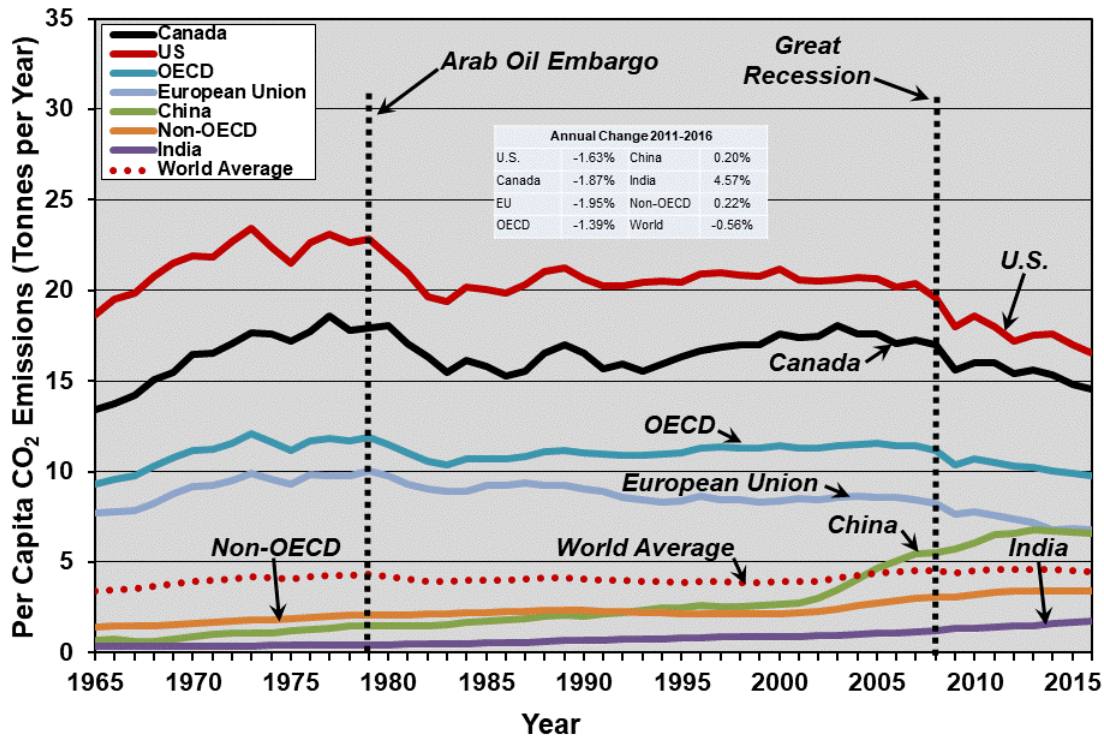
Figure 41: Per capita carbon dioxide emissions by country in 2016.⁴⁹



⁴⁹ Data from BP Statistical Review 2017 and World Bank population statistics for 2016

Figure 42 illustrates trends in per capita carbon dioxide emissions by country over the past 50 years. Per capita emissions in the industrialized world, although much higher than in the developing world, have been declining over the past decade. Canada's per capita emissions have declined at an average annual rate of 1.87% over the past five years, and the US has been declining at 1.63% per year. By contrast, China's emissions have increased at .2% per year and India's have increased at 4.57% per year over the same period. The world as a whole has declined at .56% per year on a per capita basis over the past five years.

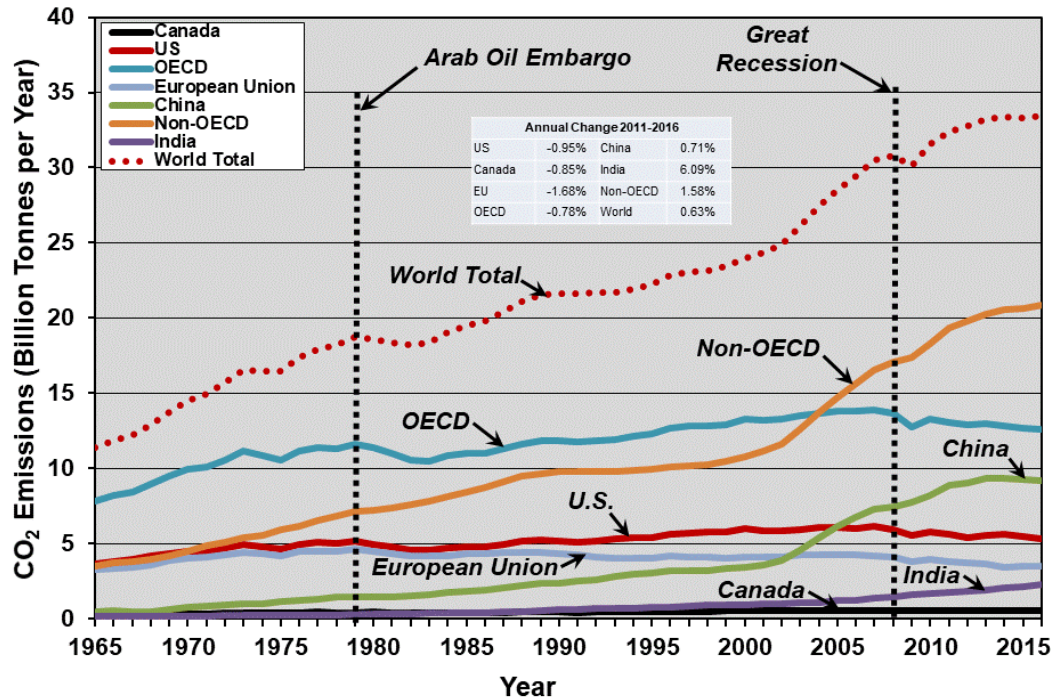
Figure 42: Per capita carbon dioxide emissions by country from 1965 to 2016.⁵⁰



⁵⁰ Data from BP Statistical Review 2017 and World Bank population statistics

Figure 43 illustrates total carbon dioxide emissions by country over the past 50 years. Coupled with population growth, world emissions have grown at .63% per year over the past five years but have been essentially flat since 2013. Total emissions in Canada have declined at an annual rate of 0.85% over this period and the US has declined by .95% per year. Overall emissions have declined in industrialized (OECD) countries at .78% per year and have grown at 1.58% per year in the developing world. Non-OECD emissions have exceeded OECD emissions since 2004. Annual emissions in China and India have grown at .71% per year and 6.09% per year, respectively, over the past five years (although China's emissions have declined slightly since 2014).

Figure 43: Total carbon dioxide emissions by country from 1965 to 2016.⁵¹

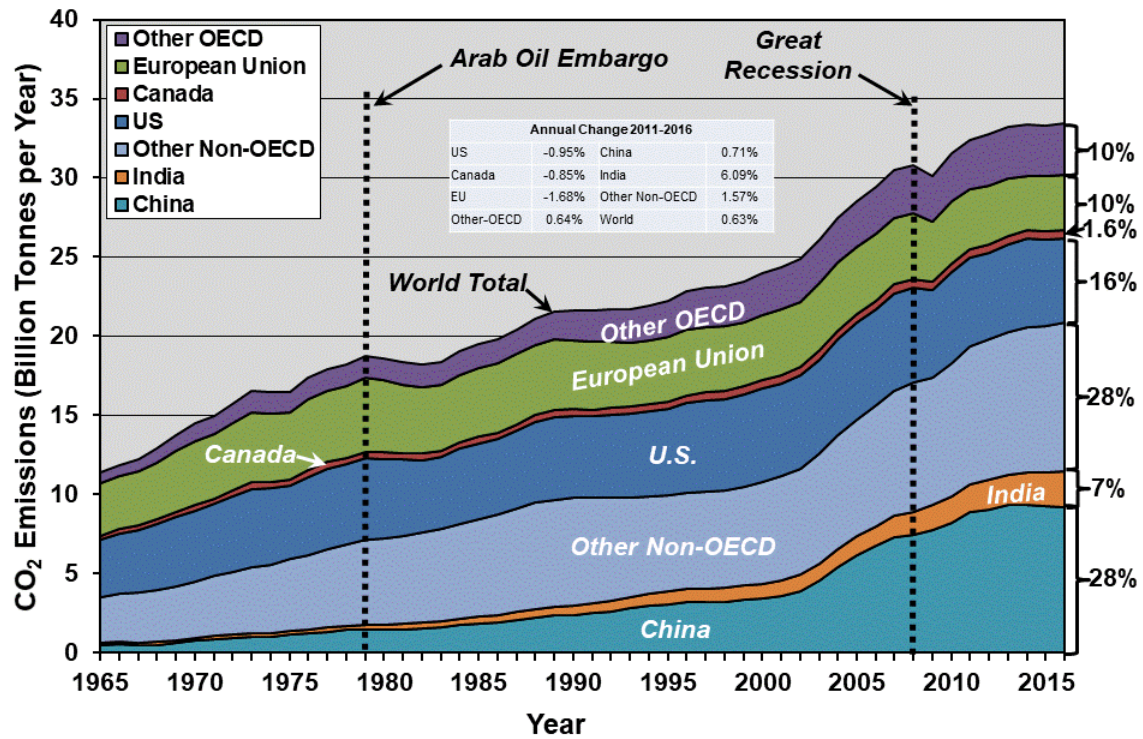


⁵¹ Data from BP Statistical Review 2017

Figure 44 shows a stacked chart of total carbon dioxide emissions by country over the past 50 years, illustrating the proportions of the global total emitted by each country. Emissions have tripled globally since 1965 and have increased by 39% since 2000. The developing world now accounts for 63% of global emissions and China, the world's largest emitter, accounts for 28%. Canada accounts for just 1.6% of global emissions given its relatively small population, even though its emissions on a per capita basis are very high.

Figure 44: Total carbon dioxide emissions by country from 1965 to 2016.

World emissions have tripled since 1965 and China is now the largest emitter in the world.⁵²



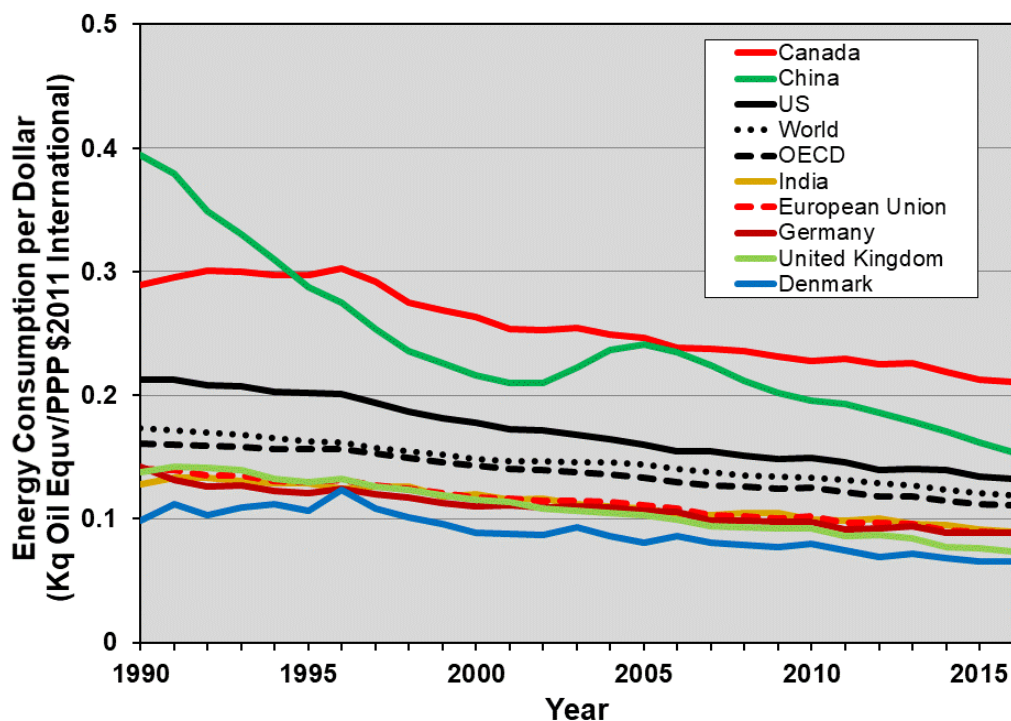
⁵² Data from BP Statistical Review 2017

1.5 Energy and the economy

Economic activity and energy consumption have historically been closely linked, although energy intensity—the amount of energy used per dollar of gross domestic product (GDP)—has decreased over time. Figure 45 illustrates the energy intensity trends for developed and developing countries over the past 25 years. Although Canadian energy intensity has improved, it is still one of the highest in the world, higher even than China, which relies extensively on coal for electricity generation. The energy intensity of European countries, and especially Denmark with its high proportion of renewable energy, is less than half that of Canada, reflecting greater efficiency in the coupling of energy to the economy.⁵³

Figure 45: Energy intensity by country from 1990 to 2016.

GDP is expressed as purchasing power parity (PPP) in constant 2011 international dollars (an international dollar has the same purchasing power over GDP as the US dollar has in the United States).⁵⁴



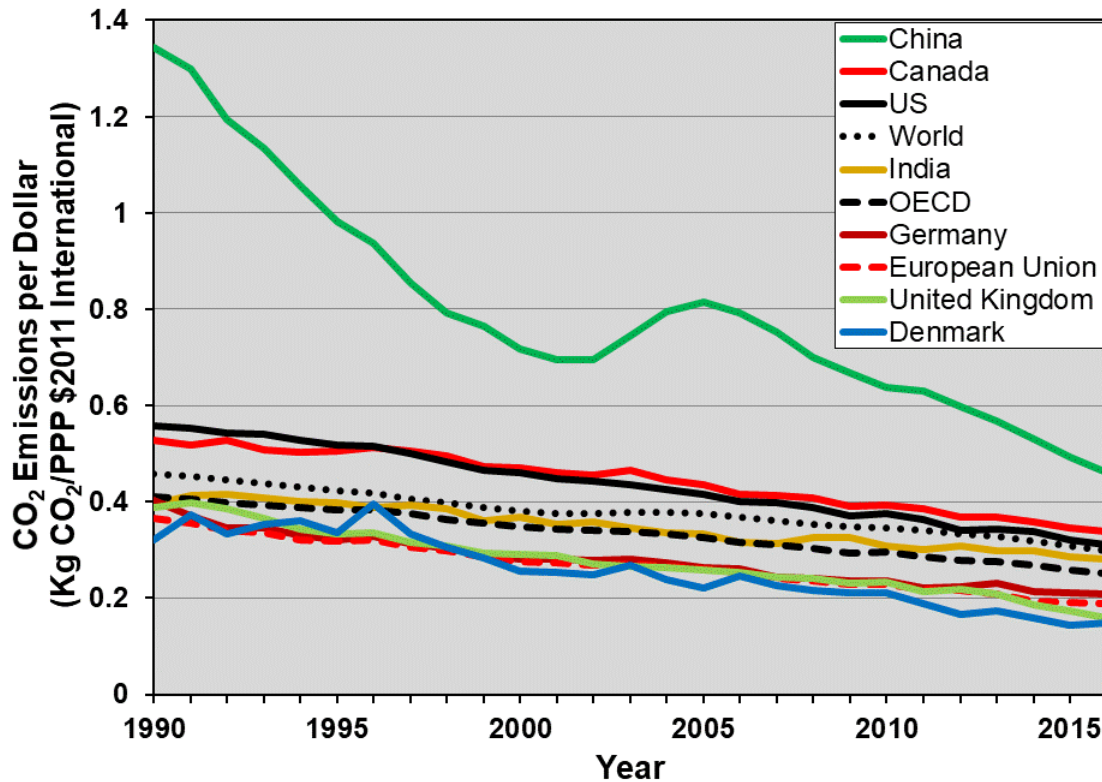
⁵³ World Bank, Data Bank of World Development Indicators, retrieved August 18, 2017, <http://databank.worldbank.org/data/reports.aspx?source=2&country=CAN>; Energy consumption from BP Statistical Review of World Energy 2017.

⁵⁴ GDP data from World Bank, 2017; Energy consumption data from BP Statistical Review, 2017

Greenhouse gas emissions intensity—the amount of greenhouse gas emitted per dollar of GDP— has also decreased over time with the improvement in energy intensity and efficiency. Figure 46 illustrates carbon dioxide emissions from fossil fuels per dollar of GDP. In this case Canada fares much better than China, given that a large proportion of Canada's electricity is generated by carbon-free sources, but it still ranks above the world average and is much higher than European nations. Denmark, with among the world's highest per capita consumption of renewable energy, has less than half the emissions intensity of Canada.⁵⁵

Figure 46: Carbon dioxide emissions intensity from fossil fuel combustion by country from 1990 to 2016.

GDP is expressed as purchasing power parity (PPP) in constant 2011 international dollars (an international dollar has the same purchasing power over GDP as the US dollar has in the United States).⁵⁶



The decrease in both energy- and emissions-intensity is sometimes cited as reason to believe that energy and emissions are becoming “de-coupled” from the economy, and the world can enjoy continued economic growth while at the same time reducing energy consumption and emissions. Although improvements in efficiency will allow further decreases in energy intensity, it is unlikely to ever become completely decoupled from the economy. Emissions intensity will benefit from both efficiency gains and the increased use of renewable energy. However, as renewable energy is being scaled from a very small base, hydrocarbons will likely remain a significant source of energy for decades to come.

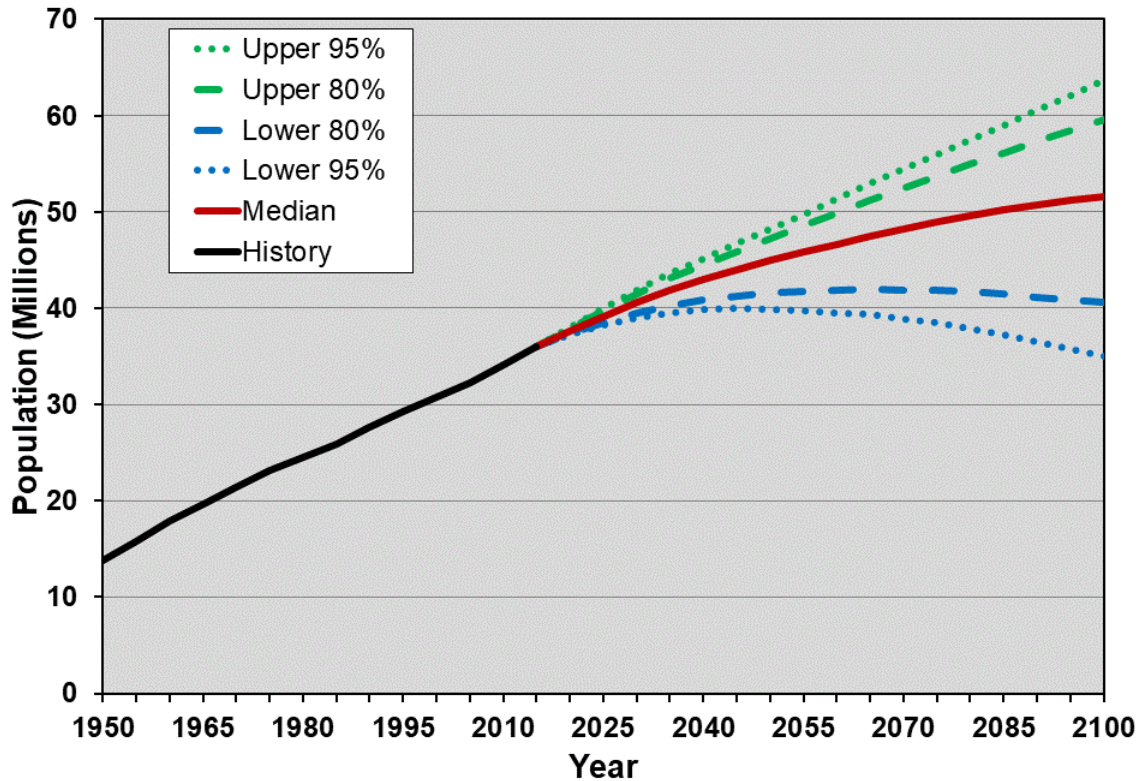
⁵⁵ World Bank, Data Bank of World Development Indicators, retrieved October 20, 2016, <http://databank.worldbank.org/data/reports.aspx?source=2&country=CAN>; Carbon dioxide emissions from BP Statistical Review of World Energy 2016.

⁵⁶ GDP data from World Bank, 2017; CO₂ emissions data from BP Statistical Review, 2017

Another factor that energy- and emissions-intensity statistics mask is the total impact of energy consumption and emissions given that GDP per person is growing along with population. According to the United Nations, the world has a median expectancy of reaching 11.1 billion people by 2100, from 7.5 billion at present, and Canada can expect to grow from 36.6 million at present to more than 51 million in 2100 (see Figure 47).⁵⁷

Figure 47: United Nations history and projections of population in Canada through to the year 2100.

*The median estimate would see Canadian population reach more than 51 million by 2100 from 36 million at present.*⁵⁸



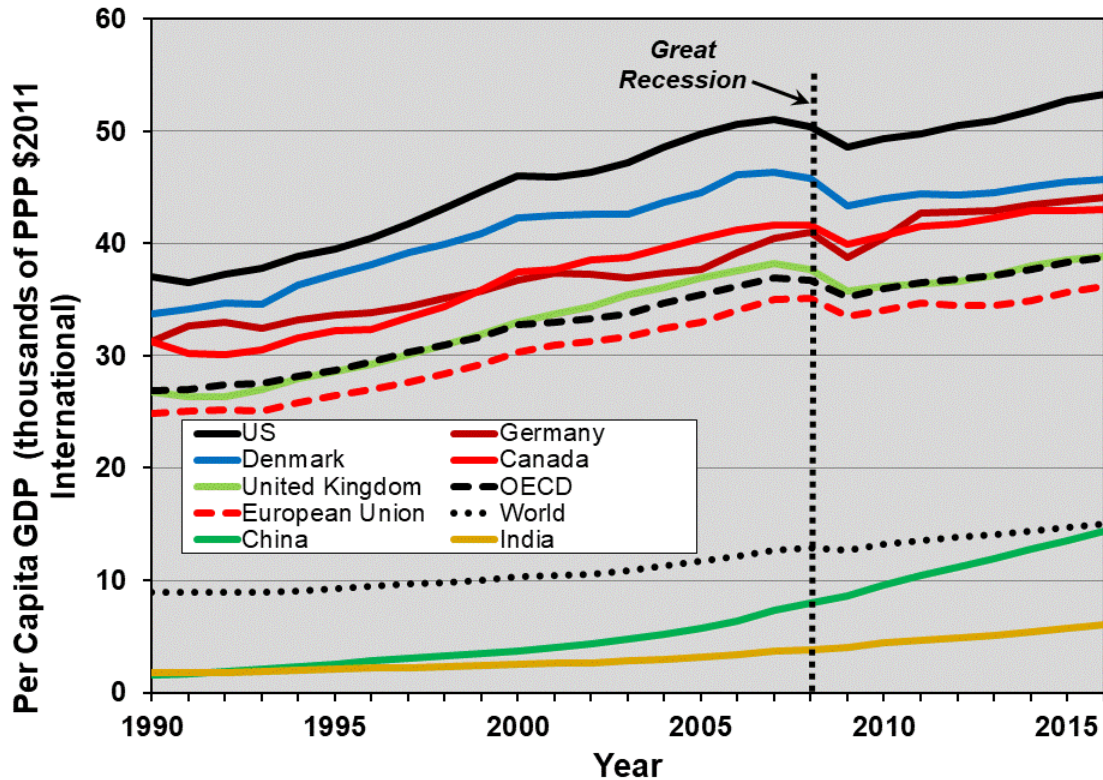
⁵⁷ United Nations, 2017, Probabilistic Population Projections based on the World Population Prospects: The 2017 Revision. Population Division, DESA. <http://esa.un.org/unpd/ppp/>

⁵⁸ Data from U.N. World Population Prospects: The 2017 Revision

GDP per capita and population growth serve to keep energy consumption and emissions rising, despite declining energy- and emissions-intensity. Figure 48 illustrates the growth in per capita GDP over the past 25 years. There is a great inequity between developed and developing countries. Per capita GDP in the US, for example, is three and a half times the world average, and nearly four times that of China and nine times that of India. The developing world, however, aspires to developed-world levels of consumption, and GDP per capita in countries like China is growing at much higher rates than in the developed world.⁵⁹

Figure 48: GDP per capita by country from 1990 to 2016.

GDP is expressed as purchasing power parity (PPP) in constant 2011 international dollars (an international dollar has the same purchasing power over GDP as the US dollar has in the United States).⁶⁰



⁵⁹ World Bank, Data Bank of World Development Indicators, retrieved August 18, 2017
<http://databank.worldbank.org/data/reports.aspx?source=2&country=CAN>

⁶⁰ Per capita GDP data from World Bank, 2017

Table 1 illustrates the impact of growth in GDP per capita and population on energy consumption and emissions over the past five years. World energy consumption is up by 1.32% per year and emissions are up by .63% per year. Developed countries are growing at low rates or declining in terms of energy consumption and emissions. Canada, for example, is growing at just 0.13% per year in energy consumption and declining at 0.85% per year in emissions. The developing world, however, is growing aggressively, with China and India up 2.7% and 5.5% per year in energy consumption and .71% per year and 6.1% per year in emissions, respectively. Given the fact that the developing world constitutes more than 80% of the world's population, aspirations for much higher economic prosperity coupled with population growth represent major challenges in curtailing global emissions and meeting future energy requirements.

Table 1: Average annual percentage change in energy consumption, emissions and GDP by country from 2011 to 2016.

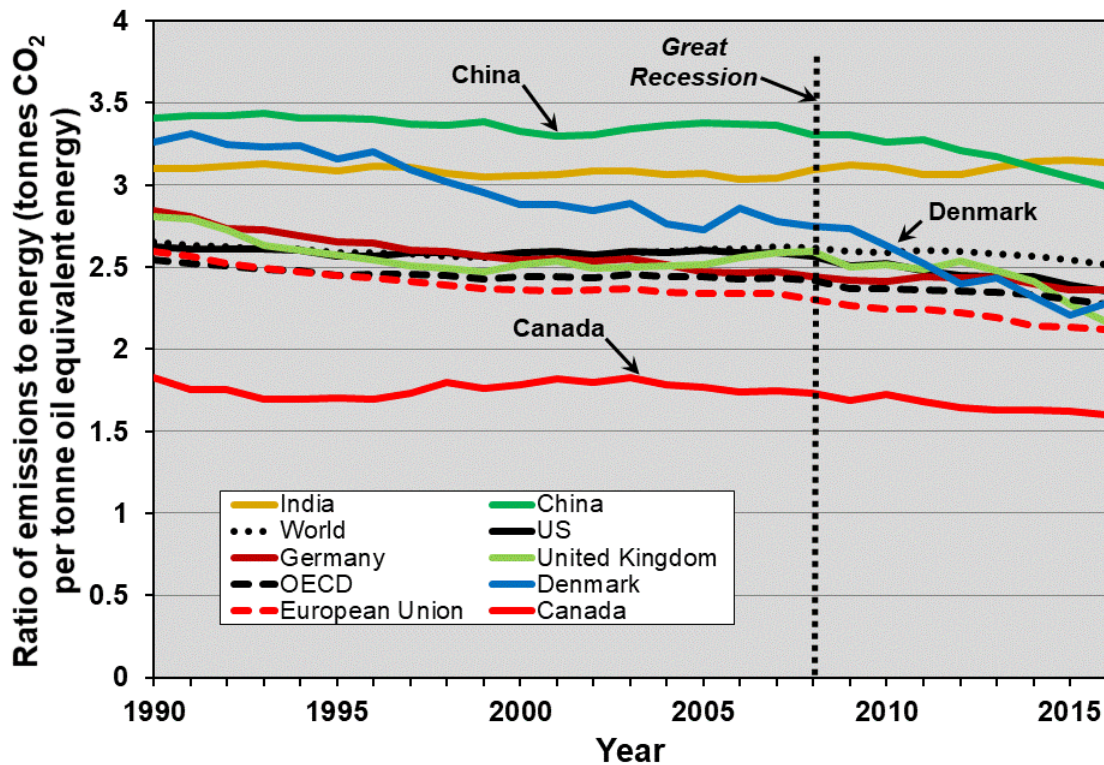
Although energy intensity is down 1.89% per year for the world over this period, energy consumption is rising at 1.32% per year. Similarly, emissions intensity for the world is down 2.48% per year, but total emissions are rising at .63% per year.

	Energy intensity	Energy per capita	Total energy	Emissions intensity	Emissions per capita	Total emissions	GDP per capita
US	-1.91%	-0.64%	0.07%	-2.83%	-1.63%	-0.95%	1.40%
Canada	-1.62%	-0.95%	0.13%	-2.51%	-1.87%	-0.85%	0.73%
Denmark	-2.50%	-1.99%	-1.47%	-4.16%	-3.70%	-3.23%	0.58%
Germany	-0.56%	0.07%	0.66%	-1.19%	-0.59%	-0.01%	0.65%
United Kingdom	-2.91%	-1.76%	-1.07%	-5.15%	-4.15%	-3.56%	1.34%
China	-4.04%	2.13%	2.70%	-5.43%	0.20%	0.71%	7.74%
India	-1.75%	3.98%	5.46%	-1.30%	4.57%	6.09%	6.28%
World	-1.89%	0.09%	1.32%	-2.48%	-0.56%	0.63%	2.19%
OECD	-1.74%	-0.66%	-0.03%	-2.43%	-1.39%	-0.78%	1.18%
European Union	-1.71%	-0.92%	-0.64%	-2.69%	-1.95%	-1.68%	0.86%

Given the importance of energy to GDP, and energy's linkage to emissions, another measure of the degree to which energy is being decarbonized is the emissions per unit of energy production. Figure 49 illustrates fossil fuel carbon dioxide emissions per unit of energy consumption. Progress towards decarbonization has been very slow, with the exception of countries like Denmark, which has rapidly ramped up renewable energy. Nonetheless, Canada, with its large component of renewable hydropower and nuclear, has a lower carbon dioxide per unit of energy consumption footprint than the world average—and even lower than Denmark's. Although Canada's footprint by this measure is declining, it is doing so very slowly.

Figure 49: Carbon dioxide emissions from fossil fuel combustion per unit of energy produced from 1990 to 2016 (tonnes carbon dioxide per tonne of oil-equivalent energy).

In tonnes of CO₂ per tonne of oil-equivalent energy. CO₂ emissions noted here are from fossil fuels only.⁶¹



⁶¹ Data from BP Statistical Review 2017

2. Non-renewable energy supply, resources and revenue

The previous section outlined the big picture of where Canada stands in terms of energy consumption and emissions with respect to the rest of the world. Canadians enjoy a high standard of living compared to much of the world, but this is fuelled by high levels of energy consumption, a major portion of which is from fossil fuels. Canada has been touted as an “energy superpower” by the former Harper government, and the Alberta government clamours for expanded oil and gas production and new pipelines to “tidewater” for more oil and gas exports to boost the economy. The Trudeau government has subscribed to this rhetoric with its approval of new pipelines and liquefied natural gas export terminals. Fossil fuels, however, are finite, non-renewable resources, and despite the urgent need to reduce emissions, they will likely be needed in the long term at some level. The following section examines Canada’s energy supply from non-renewable resources, from both a historical and future sustainability perspective.

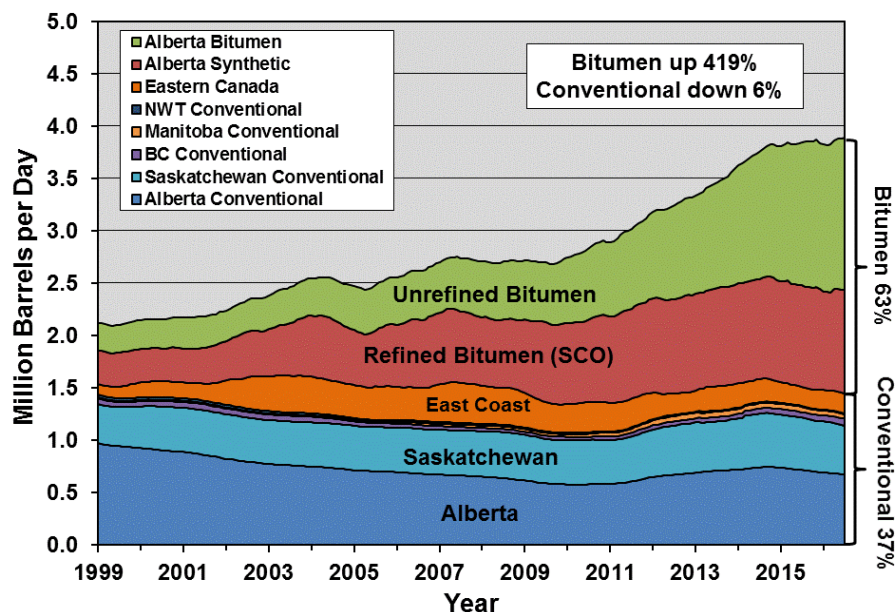
2.1 Oil and gas

Canada is a mature oil and gas exploration region with the exception of the Far North and parts of the East and West coasts offshore. The four western provinces comprise the majority of production, along with some declining offshore production from Newfoundland in Eastern Canada. There has been a moratorium on exploration off the West Coast for several decades and exploration in the Arctic has been minimal since the 1970s.

Figure 50 illustrates Canadian oil production over the past 17 years. Conventional oil production has declined overall, but strong growth in “unconventional” bitumen production has resulted in overall production of nearly four million barrels per day, 63% of which was bitumen in mid-2016.

Figure 50: Marketable oil production in Canada by province and oil type from 1999 to 2016.

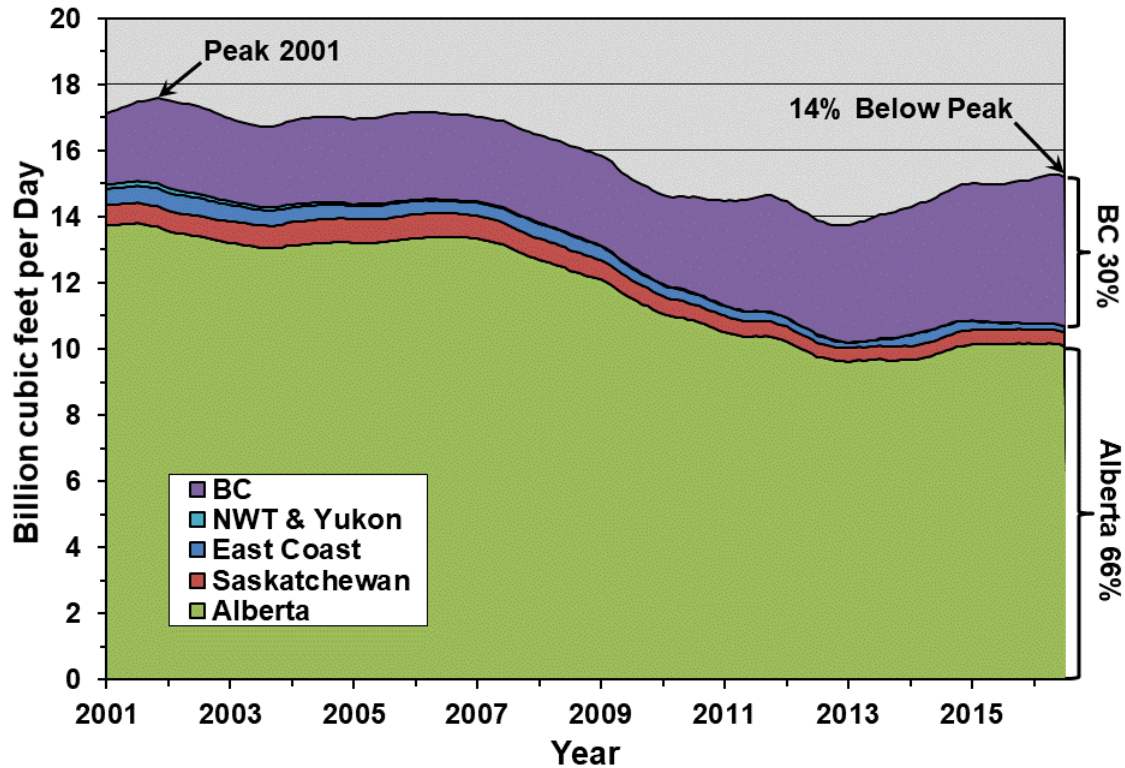
The majority of bitumen production is in Alberta.⁶²



⁶² Data from National Energy Board, 1988–2016, crude oil, C5+ and condensate; 12 month centred moving average

Figure 51 illustrates Canadian natural gas production over the past 15 years. Natural gas production peaked in 2001 and is now down 14% from peak. Alberta comprised two-thirds of Canadian gas production in 2016. Recent growth in gas production has been mainly confined to British Columbia, which is also the major hope for future growth. Exports to the US, which once comprised more than half of Canadian production, have been declining as US shale gas production increases.

Figure 51: Marketable natural gas production by province from 2001 to 2016.⁶³

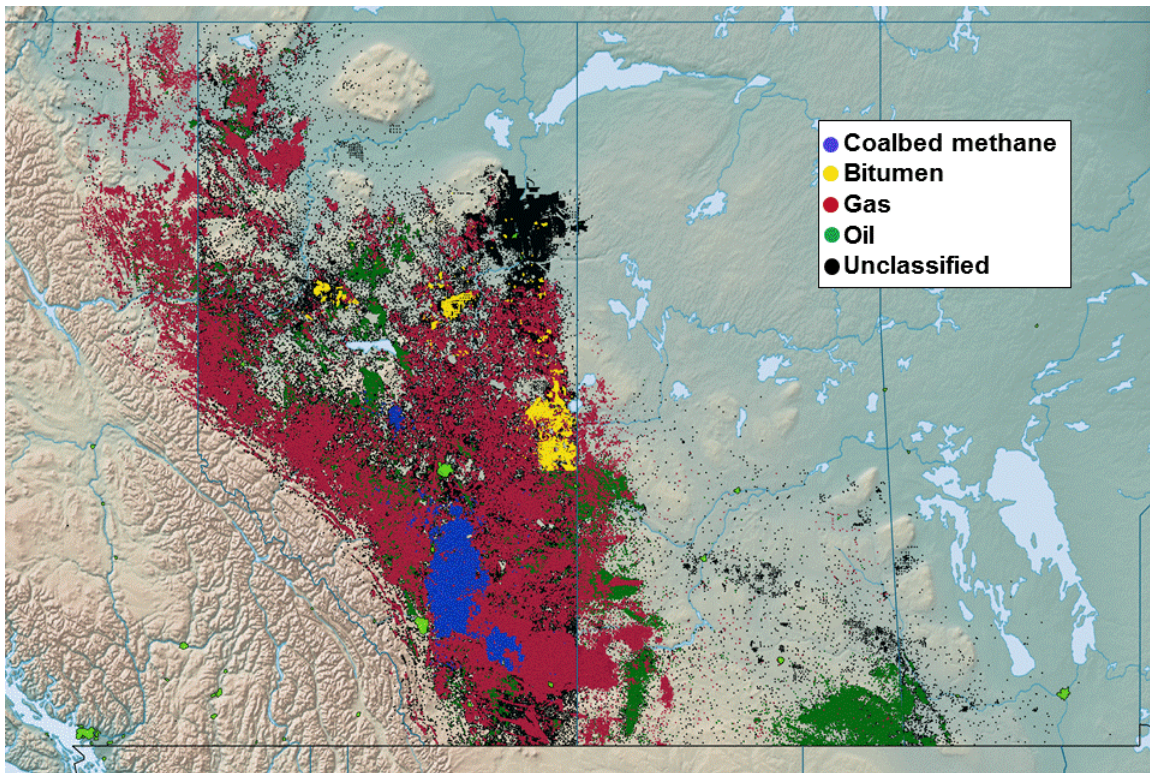


Western Canada is a mature petroleum exploration region, with more than 800,000 wells drilled since the discovery of oil in the early part of the last century. Table 2 (next page) provides the distribution of wells by type and province, and Figure 52 illustrates well distribution in Western Canada. Of the total, some 491,000 wells are producing or have produced bitumen, oil or gas. Other wells produce water used in secondary and/or tertiary oil recovery operations and hydraulic fracturing, or are used for injection of fluids (mainly water but also solvents, carbon dioxide, acid gas and waste), and a great many wells (labelled N/A in Table 2 and unclassified in Figure 52) are stratigraphic tests delimiting the extent of resources in the oil sands and elsewhere. The distribution of well types mimics the fundamental nature of the geology: BC is gas prone, due to the higher thermal maturity of its reservoir rocks; Alberta is both oil and gas prone; Saskatchewan is primarily oil prone, as thermal maturity decreases eastward; and Manitoba is almost exclusively oil prone. Some 77% of all wells have been drilled in Alberta, 18% in Saskatchewan, 3.2% in BC and 1.3% in Manitoba.

⁶³ Data from National Energy Board, 1988–2016, 12 month centred moving average

Table 2: Distribution of wells by type and province associated with the oil and gas industry as of late 2015.

Well type	BC	Alberta	Saskatchewan	Manitoba	Total	Per cent
Gas	17,301	186,201	35,501	1	239,004	29.1%
Oil	3,323	91,718	90,104	7,758	192,903	23.4%
Bitumen	0	23,243	0	0	23,243	2.8%
Cyclic-steam	0	9,063	990	0	10,053	1.2%
SAGD	0	3,422	0	0	3,422	0.4%
CBM	0	22,295	0	0	22,295	2.7%
Water	1,011	1,624	834	18	3,487	0.4%
Injection	8	15,758	7,941	588	24,295	3.0%
Other	0	1,387	12,523	1,906	15,816	1.9%
N/A	4,951	282,751	49	431	288,182	35.0%
Total	26,594	637,462	147,942	10,702	822,700	100.0%

Figure 52: Distribution of wells associated with the oil and gas industry in Western Canada by well type as of late 2015.⁶⁴⁶⁴ Data from Drillinginfo, December 2015

Wells are categorized by current status in Table 3. Of the more than 800,000 wells drilled, just 235,876 (28.7%) are currently active. The remainder have been plugged and abandoned, are inactive or suspended, or were never used for oil and gas production (e.g., injection wells and stratigraphic tests).

Table 3: Western Canadian wells associated with oil and gas production by well status and province.

Well status	BC	Alberta	Saskatchewan	Manitoba	Total	Per cent
Active	9,716	168,496	52,700	4,964	235,876	28.7%
Inactive	3,926	294,603	15,594	1,649	315,772	38.4%
Suspended	5,972	64,766	21,164	6	91,908	11.2%
Abandoned	4,797	74,564	42,307	1,898	123,566	15.0%
Other	2,183	35,033	16,177	2,185	55,578	6.8%
Total	26,594	637,462	147,942	10,702	822,700	100.0%

The advent of horizontal drilling in conjunction with high-volume hydraulic fracturing (fracking) has opened up previously inaccessible shale and tight reservoirs, resulting in a turnaround in US oil and gas production. Fracking has also been widely applied in Canada. Although they are more costly, fracked wells are generally more productive, requiring fewer wells to maintain production. Horizontal drilling has proved very effective in draining the last of the oil and gas from old reservoirs developed mainly with vertical drilling, and in accessing previously uneconomic reservoirs. Table 4 provides the distribution of wells by drill type and province. Although horizontal wells make up only 11% of the total, they are now responsible for the majority of production. Figure 53, for example, illustrates the takeover of horizontal drilling for natural gas production in Western Canada—from nothing in the early 1990s to 59% of production in 2014. In BC, where new production is coming from shale and tight reservoirs, 82% of production comes from horizontal wells. In terms of oil production, the takeover by horizontal drilling is even more remarkable. Figure 54 illustrates oil production by drill type. In 2015, 74% of production came from horizontal wells.

Table 4: Western Canadian wells associated with oil and gas production by drill type and province.

The “undifferentiated” wells in Alberta are primarily vertical.

Drill type	BC	Alberta	Saskatchewan	Manitoba	Total	Per cent
Vertical	15,592	n/a	109,593	6,858	132,043	16.0%
Horizontal	7,805	49,311	27,481	3,736	88,333	10.7%
Directional	3,197	n/a	10,868	108	14,173	1.7%
Undifferentiated	0	588,151	0	0	588,151	71.5%
Total	26,594	637,462	147,942	10,702	822,700	100.0%

Figure 53: Raw gas production in Western Canada by drill type from 1965 to 2015.

Horizontal drilling now accounts for 59% of production. Note that raw gas production is higher than marketable gas production due to losses in processing, etc.⁶⁵

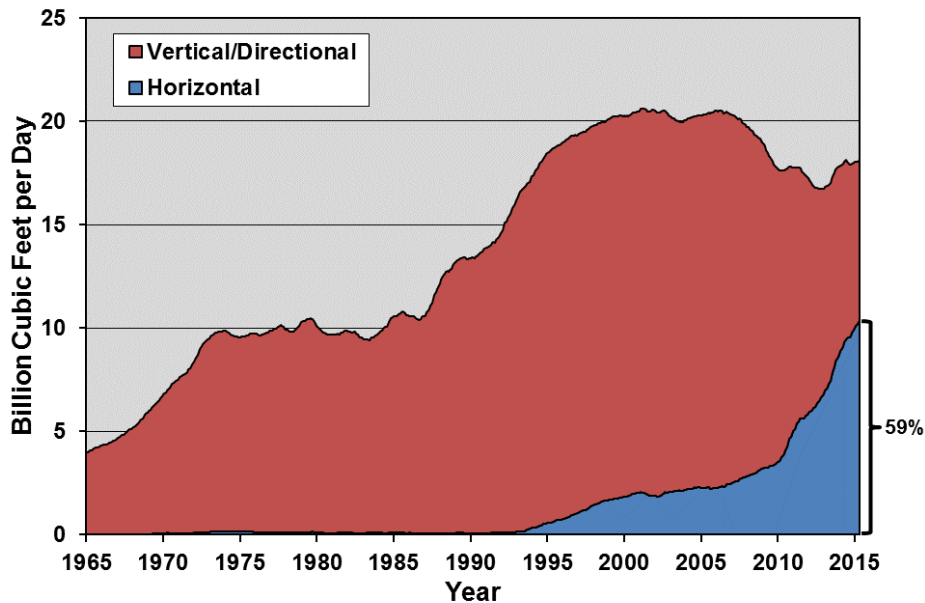
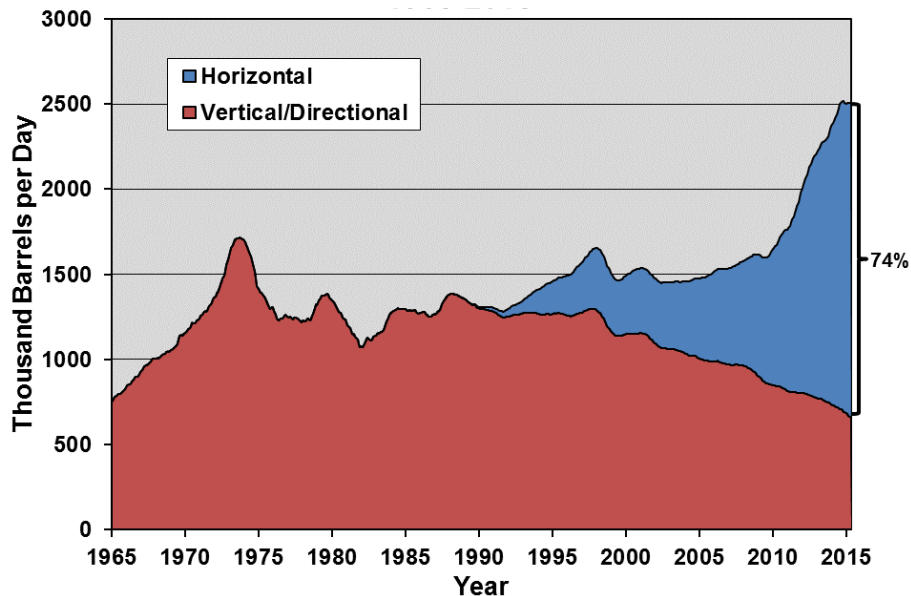


Figure 54: Oil production by drill type in Western Canada from 1965 to 2015.

Horizontal drilling now accounts for 74% of production.⁶⁶



Horizontal wells require variable levels of fracking, depending on the nature of the reservoir. In the Horn River basin of northeast BC, for example, more than 25 million gallons of water have been used to frack individual wells, whereas in BC's Montney tight gas play an average well uses about 4 million gallons. The environmental ramifications of this include sourcing the water for the fracking operation, potential

⁶⁵ Data from Drillinginfo, December 2015; 12 month centred moving average

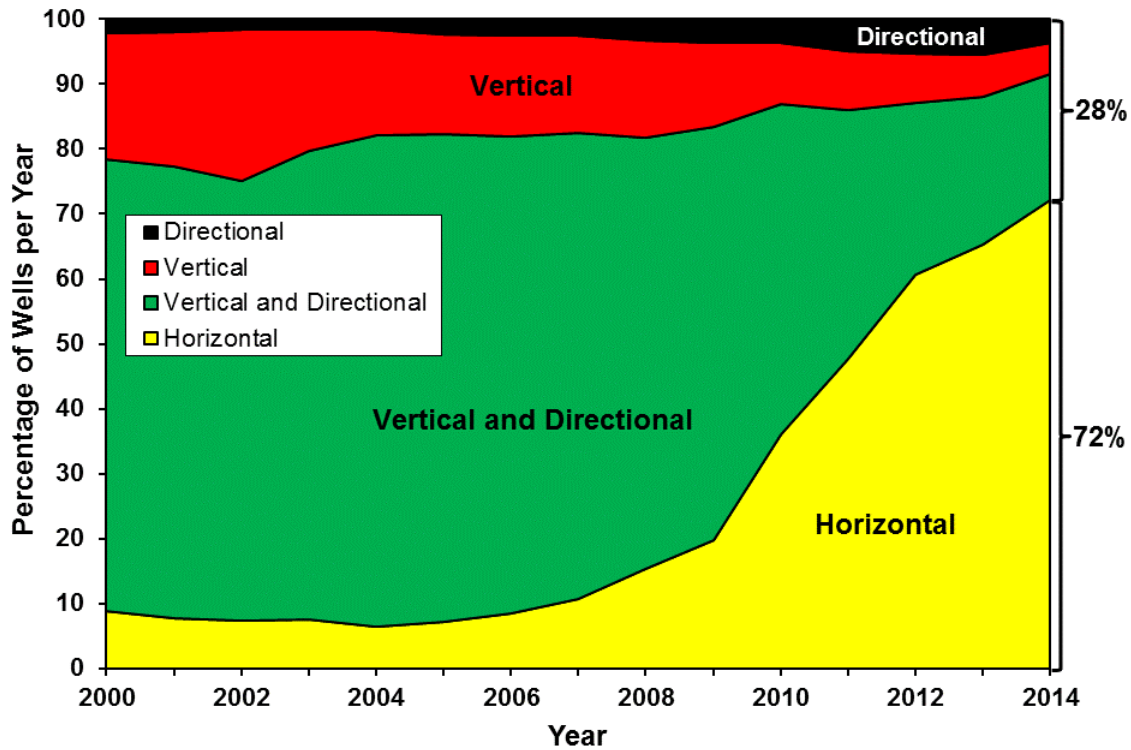
⁶⁶ Data from Drillinginfo, December 2015; 12 month centred moving average

contamination of aquifers through casing failure and from produced frack water, and induced seismicity from both the fracking operation and the disposal of frack water in injection wells.

Notwithstanding the potential environmental impacts, Figure 55 illustrates drilling activity trends by drill type. Horizontal wells made up 72% of all wells drilled in 2014, up from 10% as recently as 2006, and are likely to increase further.

Figure 55: Drilling in Western Canada by well type from 2000 to 2014.

Horizontal drilling made up 72% of the total in 2014. Data are wells with first production in each year.⁶⁷



⁶⁷ Data from Drillinginfo, December 2015;

The importance of horizontal drilling and hydraulic fracturing (fracking) to oil and gas production in Western Canada is summarized in Table 5. Even though horizontal wells make up only 20% of producing wells and 11% of all wells, they produced 75% of the oil and 58% of the gas in Canada as of August 2015. In British Columbia horizontal wells produced 83% of the gas and in Alberta they produced 76% of the oil. New oil developments in Saskatchewan and Manitoba are highly dependent on horizontal drilling and fracking.

Table 5: Oil and gas production from wells by province and well type as of August 2015.

Also shown are the number of producing wells and total well count by type. Horizontal drilling now accounts for the majority of Canada's oil and gas production.

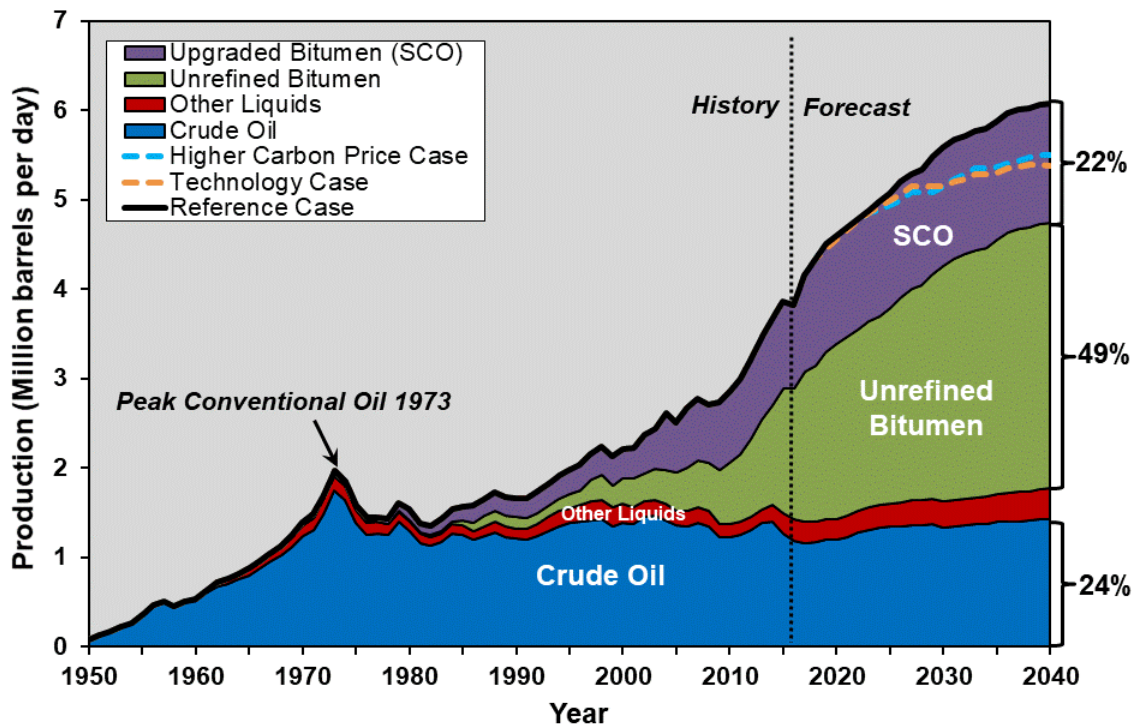
PRODUCTION						
Province	Total		Vertical/directional		Horizontal	
	Oil (kbd)	Gas (bcf/d)	Oil	Gas	Oil	Gas
BC	30.9	4.6	34.6%	16.7%	65.3%	83.4%
Alberta	1,952.4	11.9	23.7%	51.0%	76.3%	49.0%
Saskatchewan	482.3	0.6	30.4%	55.5%	69.6%	44.5%
Manitoba	41.5	0.0	23.7%	25.5%	76.3%	74.5%
Total	2,507.0	17.1	25.1%	42.0%	74.9%	58.1%
Province	Producing wells			All wells		
	Total	Vertical/directional	Horizontal	Total	Vertical/directional	Horizontal
BC	9,047	49.3%	50.7%	26,594	70.7%	29.3%
Alberta	163,014	86.3%	13.7%	637,462	92.3%	7.7%
Saskatchewan	46,001	66.4%	33.6%	147,942	81.4%	18.6%
Manitoba	4,167	44.3%	55.7%	10,702	65.1%	34.9%
Total	222,229	79.9%	20.1%	822,700	89.3%	10.7%

The trend of increasing application of horizontal drilling will continue, given that the bulk of remaining oil is contained in tight reservoirs requiring fracking, and in bitumen deposits accessible only by in situ methods such as steam-assisted gravity drainage (SAGD). Similarly, the bulk of remaining gas is contained in shale and tight reservoirs in western Alberta and northeast BC. Notwithstanding pushback from environmental groups against fracking, this technology will be needed to access most of the remaining oil and gas resources in Western Canada.

2.1.1 Conventional oil

Conventional oil production peaked in Canada in 1973 and production has remained flat since the mid-1990s. Figure 56 illustrates Canadian oil production by type since 1950, including the latest National Energy Board projections through 2040. Given the mature state of exploration, there is little prospect for major new discoveries of conventional light and heavy oil in Western Canada. Although conventional oil production will continue with some new discoveries along with production from known fields through primary, secondary and tertiary recovery methods, the only prospect for a significant ramp-up in Canadian oil production is from the oil sands.

Figure 56: Canadian oil production by type since 1950 with the latest National Energy Board projections (higher carbon price case, technology case and reference case) through 2040.⁶⁸

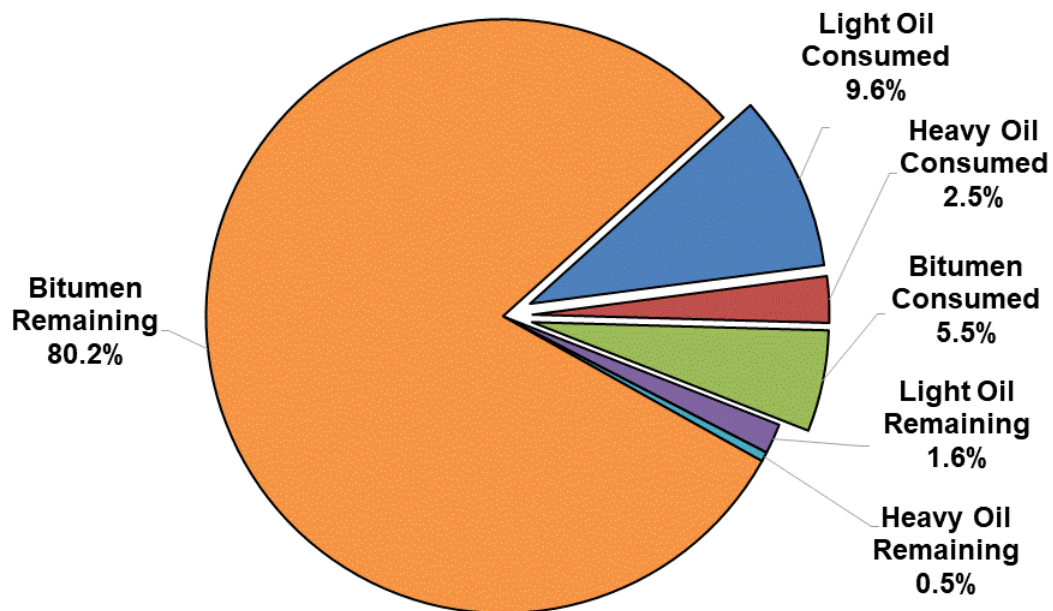


⁶⁸ 1950-2004 data are from the Canadian Association of Petroleum Producers Statistical Handbook retrieved December 3 2016. 2005-2040 data are from the National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/fttrpndc/dflt.aspx?GoCTemplateCulture=en-CA>. ("Other liquids" include condensate and C5+.) The NEB's "reference" case projection is illustrated along with totals for its "higher carbon price" and "technology" cases. The reference case is based on the current economic outlook, a moderate view of energy prices, and climate and energy policies that have been announced at the time of analysis. The higher carbon price case assumes the Canadian price for carbon increases steadily by \$5 per tonne per year after reaching \$50 per tonne in 2022, to \$90/tonne in 2030 and \$140/tonne in 2040. The technology case considers, in addition to higher carbon prices, the impact on the Canadian energy system of greater adoption of select emerging production and consumption energy technologies.

Figure 57 illustrates Canadian oil reserves at the end of 2015, according to the National Energy Board. Of an original reserve endowment of 206.1 billion barrels, 86% is bitumen and 14% is conventional oil. Some 85% of conventional oil reserves have been consumed, which means that 97.4% of Canada's remaining reserves of 169.8 billion barrels are bitumen. Bitumen from the oil sands represents a large potential resource, but compared to conventional oil its production requires large energy inputs with associated emissions, and imported diluents to move it through pipelines (a 30% blend of diluent with the bitumen is needed). Bitumen also commands a lower price than conventional oil due to its inferior quality. Under Alberta's recently announced cap, oil sands emissions will rise to 19.3% of all Canadian emissions by 2030 if commitments under the Paris Agreement signed at COP21 are kept (oil sands emissions were 10.9% of Canadian emissions in 2015). The sections that follow examine conventional oil and bitumen in more detail.

Figure 57: Canadian oil reserves at the end of 2016 according to the National Energy Board.⁶⁹

Of the original endowment of 206 billion barrels, 17.6% has been consumed, including 85% of conventional oil reserves. Oil sands constitute 97.4% of remaining reserves.

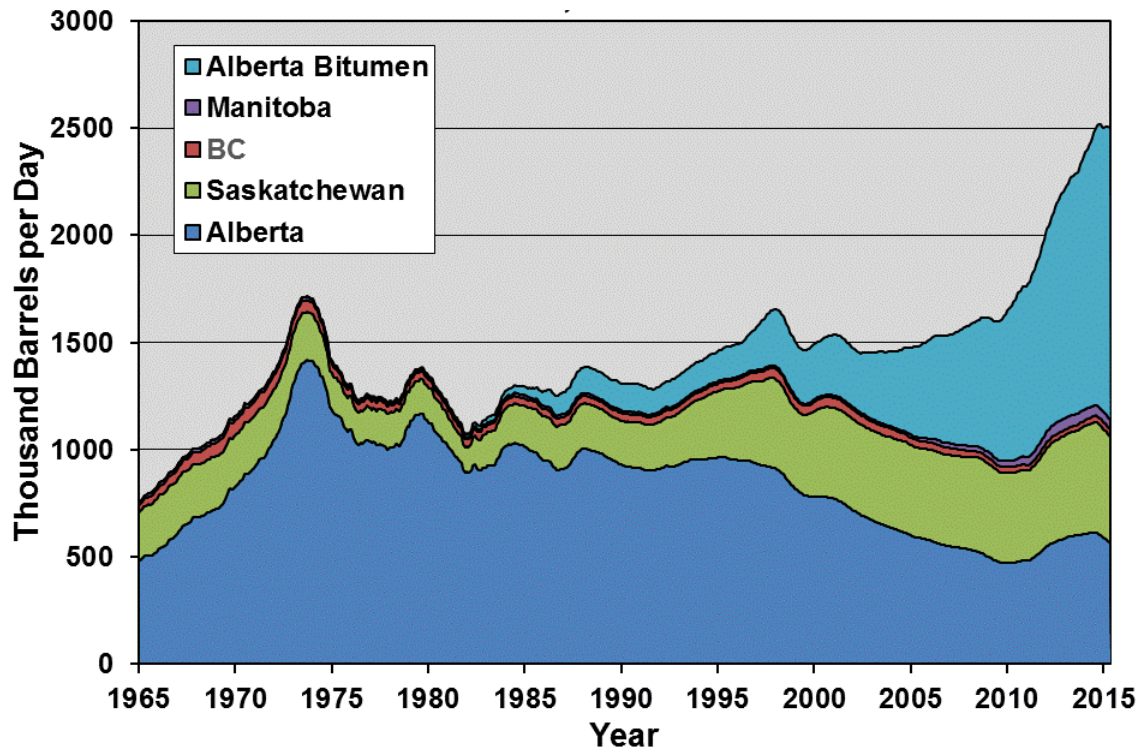


⁶⁹ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA> (these were received via email from NEB November 2, 2017 as corrections to data originally posted in the report).

Conventional oil production in Western Canada peaked in 1973, as illustrated in Figure 58. Although Alberta has produced the majority of Canada's oil, Saskatchewan has been increasing in part due to the development of the northern extension of the Bakken field of North Dakota through the application of horizontal fracturing technology, and now accounts for nearly half of conventional oil production in Western Canada.

Figure 58: Conventional oil and bitumen production from wells (i.e., does not include mined bitumen) by province in Western Canada from 1965 to 2015.

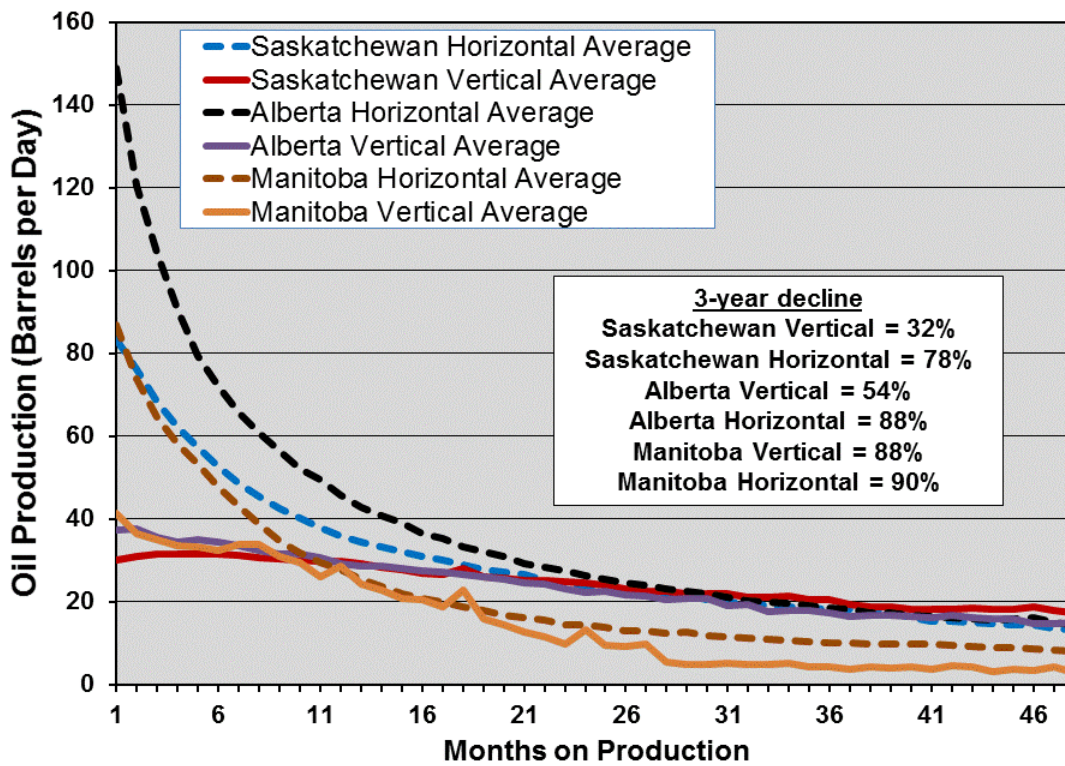
Peak conventional production occurred in 1973.⁷⁰



⁷⁰ Data from Drillinginfo, December 2015; 12 month centred moving average

Oil wells, especially horizontal ones, decline in production rapidly over their first few years, necessitating more drilling to maintain production. Figure 59 illustrates the average production rates over time of conventional oil wells (not including bitumen wells or liquids production from gas or other wells). Production decline in the first three years averages between 78% and 90% for horizontal wells and between 32% and 88% for vertical wells. As decline is hyperbolic, with the steepest decline in the first few years, overall field declines from a mix of old and new wells typically ranges between 25% and 35% per year, meaning that this much production must be replaced each year through more drilling to keep production flat. On average, Manitoba oil wells are less productive than those in Alberta and Saskatchewan (BC's oil production is relatively minor—see Figure 58). Production from oil wells in even the best shale plays, such as the Bakken in southeast Saskatchewan and southwest Manitoba, is typically far less than that from wells in the “sweet spots” of US tight oil plays like the Bakken or Eagle Ford.

Figure 59: Average production decline profiles for oil wells in Alberta, Saskatchewan and Manitoba.⁷¹

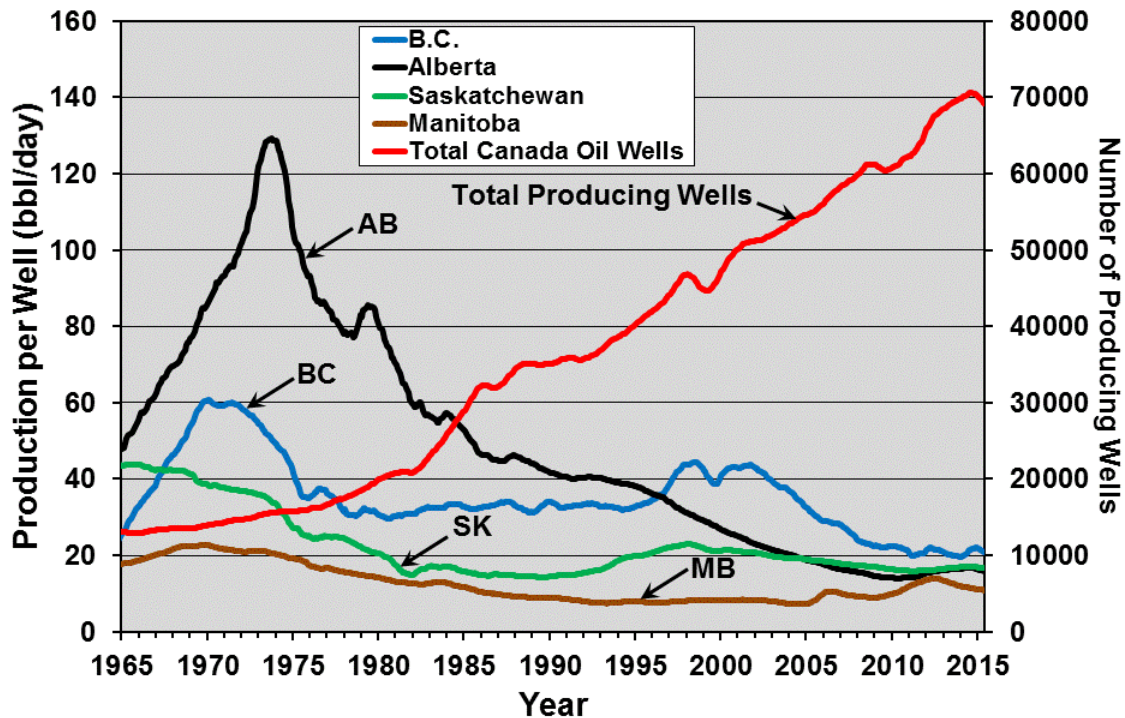


⁷¹ Data from Drillinginfo, December 2015

Given the steep drop in production of the average oil well in the first few years after it is drilled, and the rapidly escalating number of wells, the average productivity of wells has declined over time. Figure 60 illustrates average oil well productivity since 1965. Peak production per well occurred in the late 1960s and 1970s for all provinces. More and more wells and infrastructure are required to maintain production as fields are exhausted. This trend of declining productivity will continue.

Figure 60: Average production per conventional oil well by province from 1965 to 2015, and total number of producing oil wells.

Does not include bitumen production from bitumen, cyclic-steam and SAGD wells or liquids from gas wells.⁷²



Oil reserves are defined as discovered resources that are technically and economically recoverable. They are usually expressed in probabilistic terms: “proven”, “probable” and “possible”.⁷³ The National Energy Board (NEB) provides no such subdivisions, however, providing instead only “reserve” and “resource” breakdowns. In the NEB’s parlance, “resources” include both “discovered resources” (which include “reserves”) and “undiscovered resources” that may be proven to exist in the future with more exploration. Since the NEB does not provide the backup information required under regulations such as National Instrument 51-101, under which Canadian reserve and resource reporting is regulated, its estimates of reserves and resources should be viewed as approximate and likely subject to downward revisions if measured under current regulatory requirements.

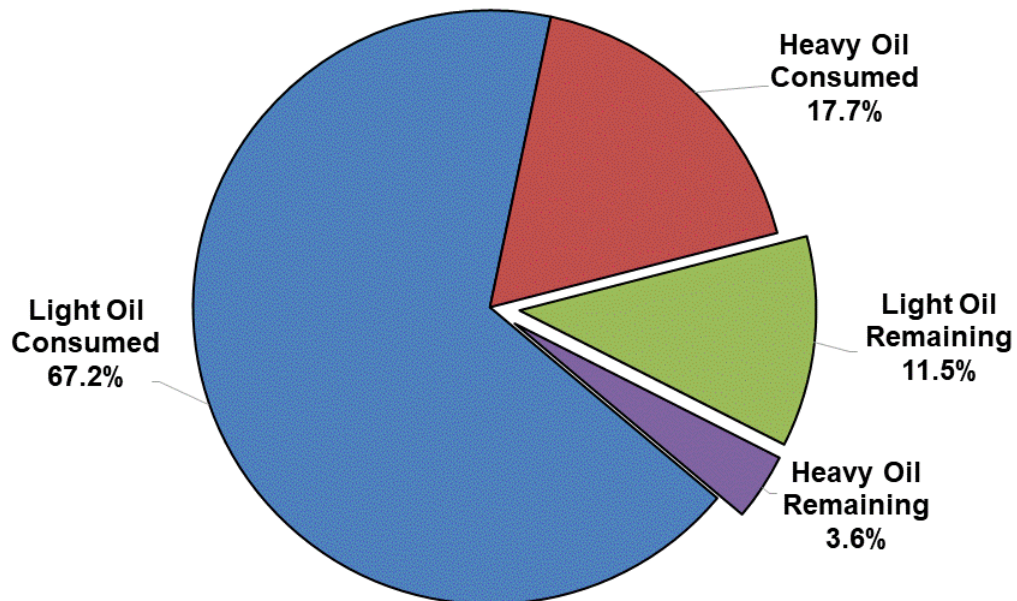
⁷² Data from Drillinginfo, December 2015; 12 month centred moving average

⁷³ Society of Petroleum Engineers, 2011, Guidelines for Application of the Petroleum Resources Management System http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf. In Canada reserve and resource reporting is regulated under National Instrument 51-101 which is guided by technical standards in the Canadian Oil and Gas Evaluation Handbook updated periodically by the Canadian branch of the Society of Petroleum Engineers.

Figure 61 illustrates Canada's conventional reserves at the beginning of 2015 according to the NEB. Of the 29.4-billion barrel endowment, 85% has been consumed, leaving just 4.5 billion barrels remaining (Canada consumed .55 billion barrels of conventional oil in 2015, so conventional oil reserves represent 8.2 years of current consumption).

Figure 61: Canadian conventional oil reserves at the end of 2016 according to the NEB.

Of the original endowment of 29.4 billion barrels, 85% has been consumed.⁷⁴ Remaining light oil reserves are 3.4 billion barrels and remaining heavy oil reserves are 1.1 billion barrels.

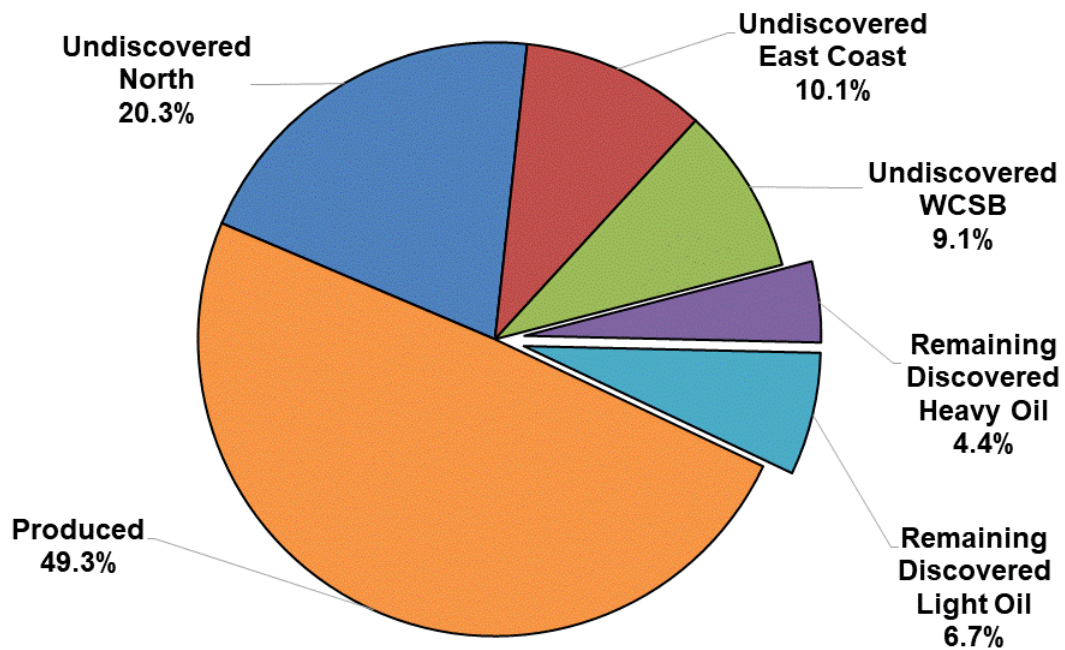


⁷⁴ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA>

Figure 62 illustrates Canada's conventional oil "resources", including undiscovered resources thought to exist off the East Coast and the Arctic Coast, according to the NEB. Undiscovered resources have a low certainty of existence compared to reserves and include no assurance that they are technically and economically feasible to develop. Furthermore, there are additional environmental concerns with developing oil resources in the Arctic given its remoteness and susceptibility to spills. Of the 50.6-billion barrel original endowment of conventional oil resources, 49.3% have been consumed, 39.5% have yet to be discovered and 11.1% are discovered resources that have not yet been produced.

Figure 62: Canadian conventional oil resources at the end of 2016 according to the National Energy Board.

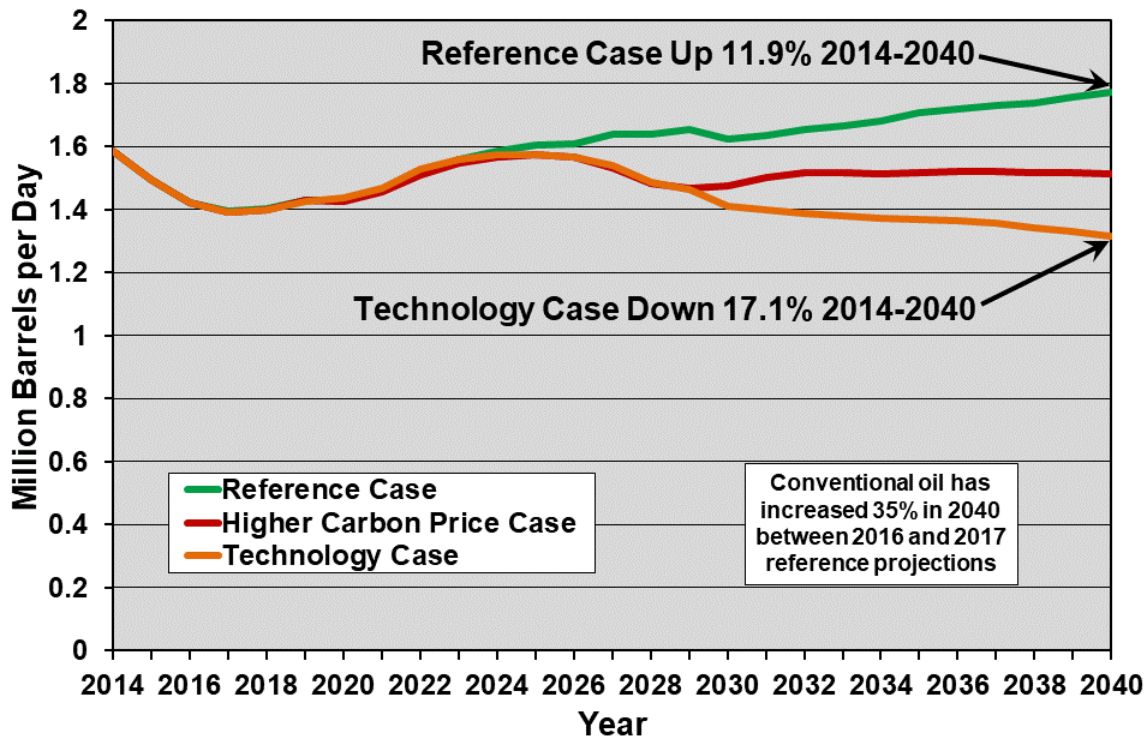
Of the hoped for 50.6-billion barrel endowment, 49.3% has been consumed, 39.5% has yet to be discovered and 11.1% are discovered resources that have not yet been produced.⁷⁵



⁷⁵ Data from NEB Energy Future, October 2017

Although there is hope that relatively new plays made possible by horizontal drilling and fracking technology (like the Montney and Duvernay in Alberta and BC and the Bakken in Saskatchewan and Manitoba) will replace declining production in older plays, their collective production amounted to less than 12% of Canadian conventional production as of late 2015. The NEB's projections range from a 12% growth to a 17% decline in conventional oil production from 2014 levels by 2040, as illustrated in Figure 63.⁷⁶ Clearly there is no bonanza ahead for conventional oil production in Canada. The only hope for substantially increased production, as previously stated, lies in the oil sands.

Figure 63: National Energy Board projections of conventional oil production by scenario over the 2014–2040 period, from its latest outlook.⁷⁷



The NEB's reference case estimate in Figure 63 would see 14.1 billion barrels of conventional oil recovered between 2017 and 2040. This would require the recovery of 100% of Canada's remaining discovered resources, 100% of the undiscovered resources in Western Canada, and 25% of the undiscovered resources off the East Coast and in the Arctic. This seems a highly optimistic assessment of what is possible, and would leave Canada with very little remaining conventional oil by 2040 (and located in vulnerable Arctic and offshore locations).

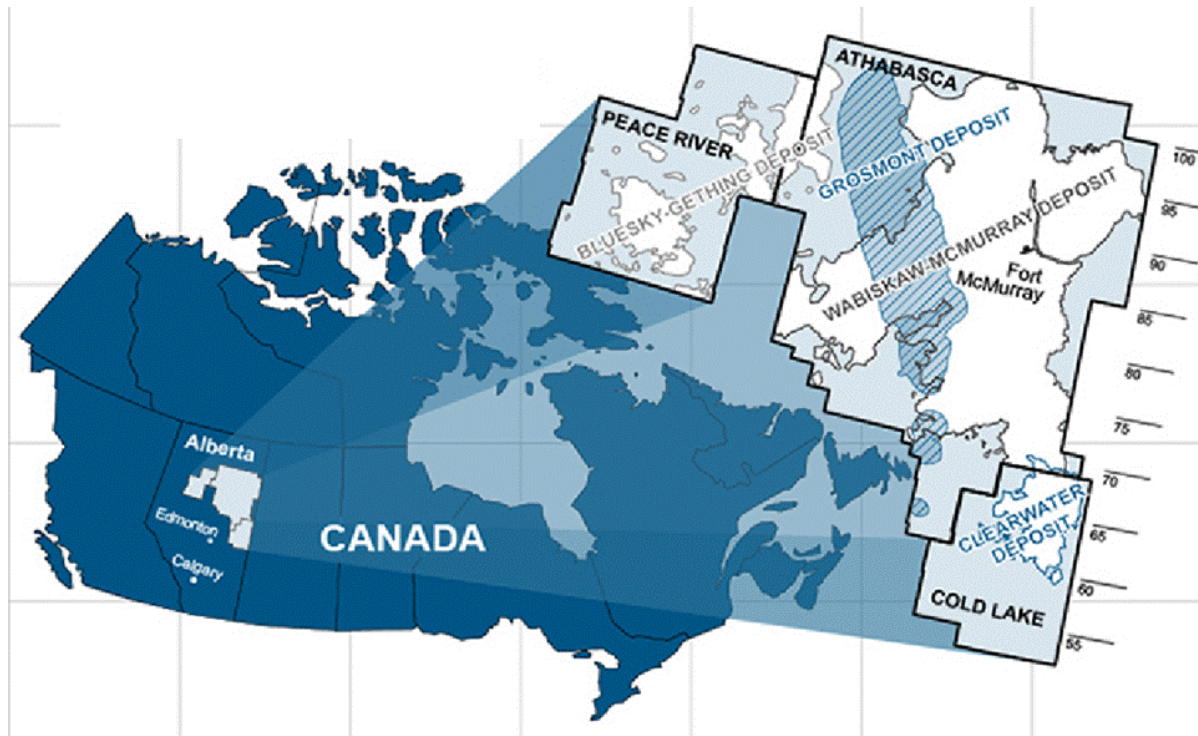
⁷⁶ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA>

⁷⁷ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA> (conventional includes NGLs)

2.1.2 Bitumen production

Bitumen represents by far the largest remaining portion of Canada's oil resources. It is recovered by surface mining as well as drilling where deposits are too deep to be mined. Oil sands deposits are widespread in northern Alberta, as illustrated in Figure 64. However, the mineable portion is exclusively within the Athabasca region and largely confined to the Wabiskaw-McMurray deposit. Elsewhere bitumen is recovered from greater depths by in situ methods using conventional wells and thermally heated cyclic-steam and steam-assisted gravity drainage (SAGD) wells.

Figure 64: Distribution of oil sands regions in northern Alberta.⁷⁸

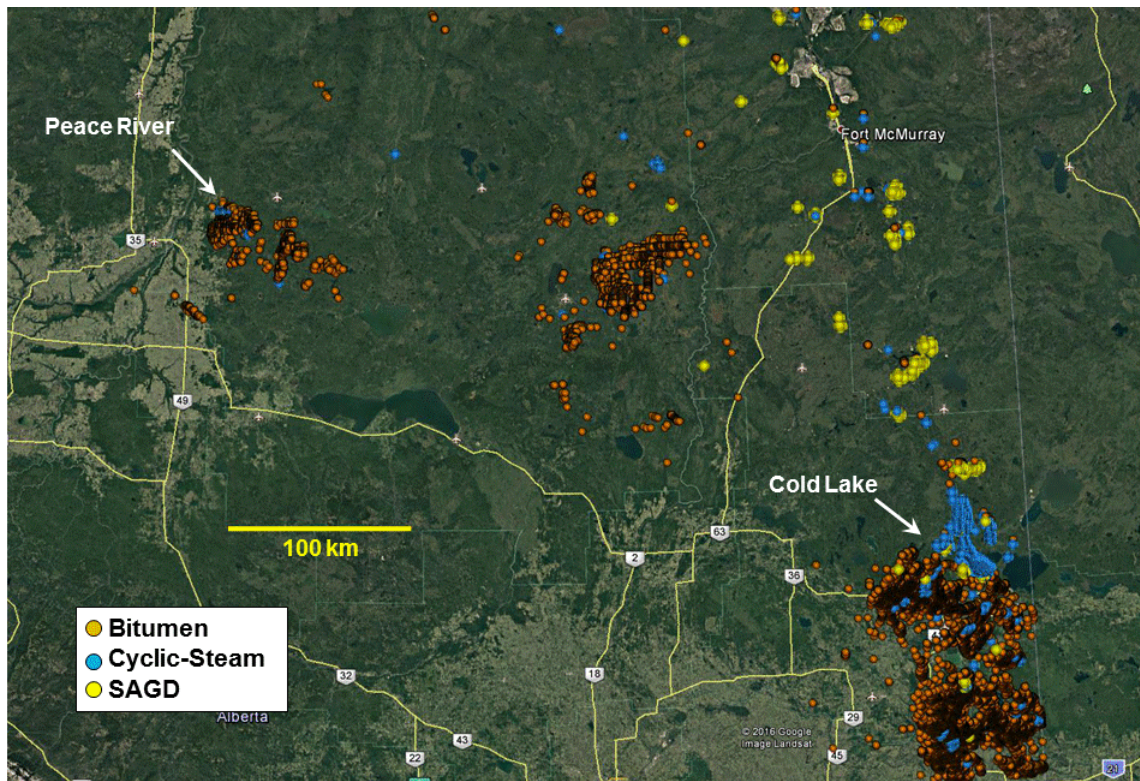


⁷⁸ Alberta Energy Regulator, 2016, Report data for ST-98 2016 reserves report.
https://www2.aer.ca/t/Production/views/CrudeBitumenFigureR3_1Albertasoilsandsareasandselectdeposits/FigureR3_1Albertasoilsandsareasandselectdeposits?embed=y&showShareOptions=true&display_count=no

Figure 65 illustrates the geographical distribution of wells recovering bitumen in northern Alberta. Bitumen in the Cold Lake and Peace River regions is mainly recovered by cyclic-steam wells as well as by bitumen wells without thermal stimulation. In the Athabasca region production is mainly from SAGD wells as well as surface mining.

Figure 65: Distribution of bitumen wells by type in northern Alberta.

Non-thermal bitumen wells are in orange, cyclic-steam wells are in blue and steam-assisted gravity drainage (SAGD) wells are in yellow. Note that most of these are multi-well pads.⁷⁹

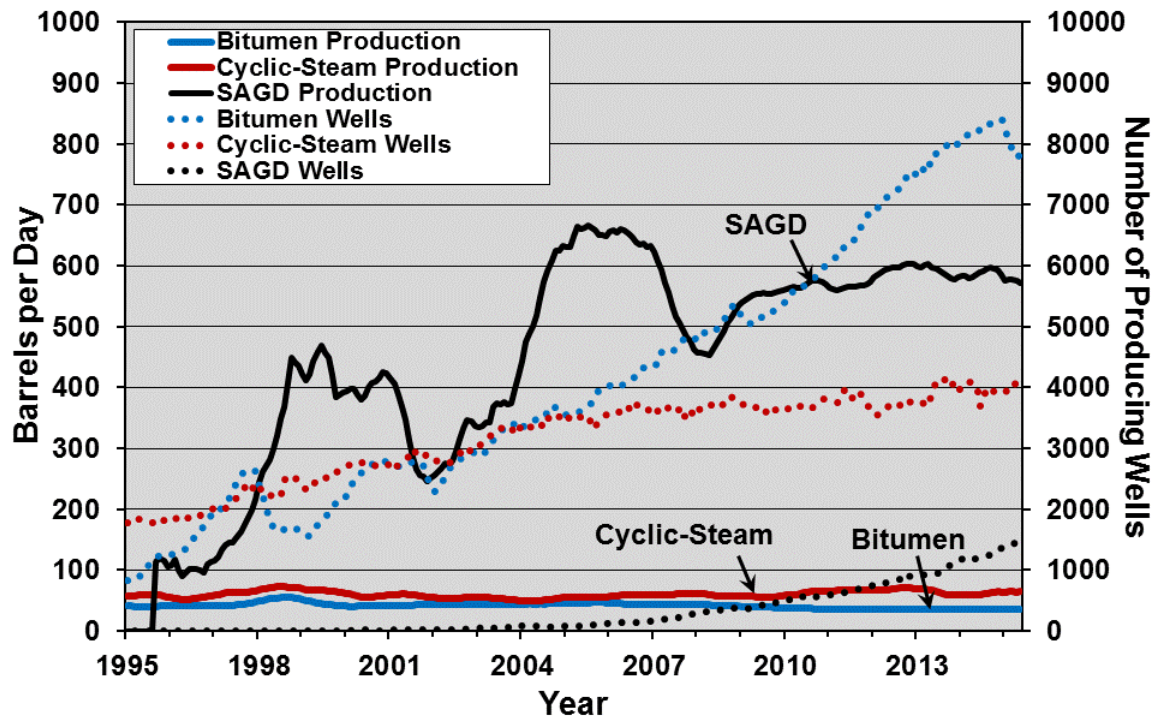


The development of SAGD technology in the 1990s marked a major improvement in the ability to recover in situ bitumen. SAGD uses horizontal well pairs, one well for steam injection to heat the reservoir and a second for bitumen recovery. Cyclic-steam wells, on the other hand, alternate periods of steam injection with production, while bitumen wells use no thermal heating to produce bitumen (bitumen and cyclic-steam wells may be vertical or horizontal).

⁷⁹ Data from Drillinginfo, December 2015

The difference in average well productivity for these different technologies is striking, as illustrated in Figure 66. SAGD wells averaged 572 barrels per day in 2015 compared to 64 barrels per day for cyclic-steam wells and 35 barrels per day for bitumen wells. The per-well upfront cost of a SAGD project is higher, however, given the need for a steam generation plant, pipelines to distribute the steam and collect the bitumen, and the drilling of horizontal well pairs.

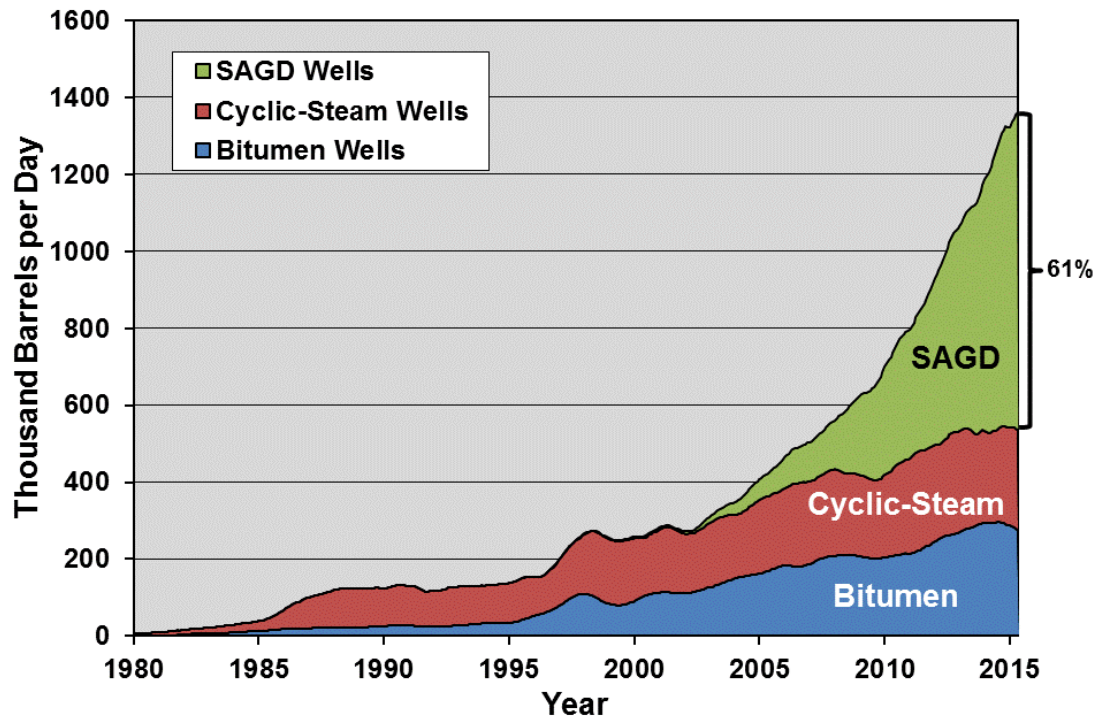
Figure 66: Average bitumen production per well for different technologies and number of producing bitumen wells in Alberta.⁸⁰



⁸⁰ Data from Drillinginfo, December 2015; production is 12 month centred moving average

Given the superior productivity of SAGD wells, it is no surprise that SAGD produced 61% of in situ bitumen in 2015 with just 1,450 producing wells, compared to 19% from 4,200 cyclic-steam wells and 20% from 7,800 bitumen wells, as illustrated in Figure 67. Cenovus has a good field tour guide for its Foster Creek project, the first application of SAGD on a commercial scale, which illustrates that the life of a SAGD well at full production is five to 10 years, with a wind-down phase of an additional six or more years before the well must be abandoned.⁸¹

Figure 67: Bitumen production by well type from 1980 to 2015.⁸²



⁸¹ Cenovus Field Tour Guide, accessed September 2016, <https://www.cenovus.com/invest/docs/FC-Field-Tour-Handout.pdf>

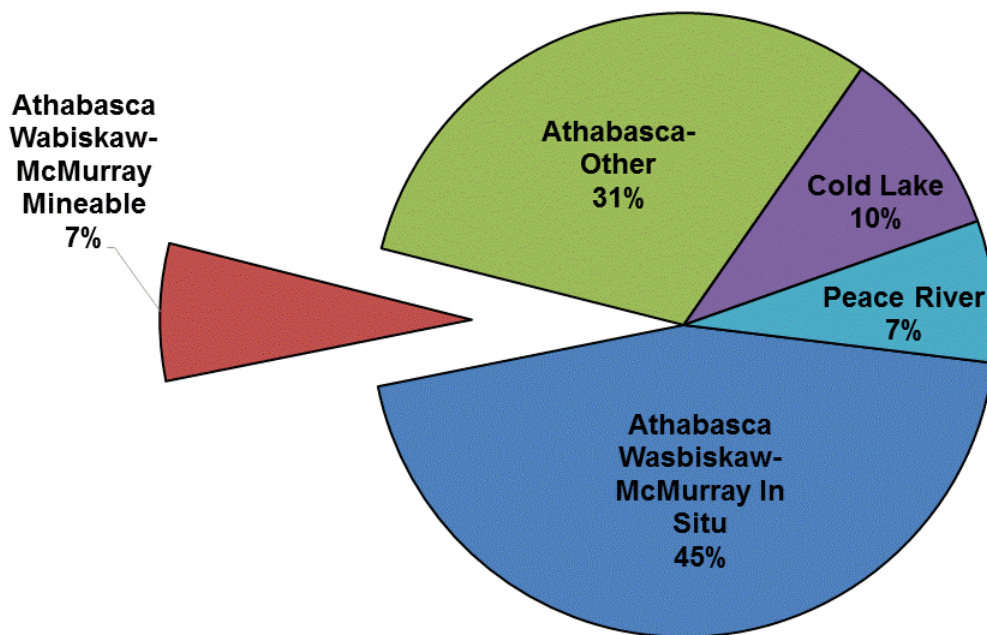
⁸² Data from Drillinginfo, December 2015; 12 month centred moving average

2.1.2.1 BITUMEN RESERVES

The Alberta Energy Regulator (AER) produces an in-depth review of bitumen resources and production each year. In its 2016 edition, the AER reports an “initial in-place” bitumen resource of 1,845 billion barrels, of which 83% is in the Athabasca region and 93% is too deep to be mined. The distribution by region is illustrated in Figure 68. In 2015, 82% of bitumen was recovered from the Athabasca region, 16% from the Cold Lake region and 2% from the Peace River region.

Figure 68: Initial in-place bitumen resources by region according to the Alberta Energy Regulator.⁸³

Athabasca area contains 83% and the Wabiskaw-McMurray Formation in the Athabasca area contains 52%. Just 7% is potentially surface mineable.



The AER's resource assessments are accepted by the NEB and are used here, but like the NEB's estimates they don't conform to Canadian regulatory standards under National Instrument 51-101. The AER reports that 11.4 billion barrels of bitumen have been recovered as of the end of 2015, with a further 23.9 billion barrels of “reserves under active development.” These “reserves” are not categorized by probability, as required, but otherwise qualify as “reserves” under NI 51-101. The AER reports an additional bitumen resource of 141.5 billion barrels to make up its total “remaining established reserves” of 165.4 billion barrels. The latter are more correctly termed “contingent resources” under NI 51-101, as they are not under development as is required to be termed “reserves,” nor have they been definitively proven to be commercially extractable based on the information provided by the AER.

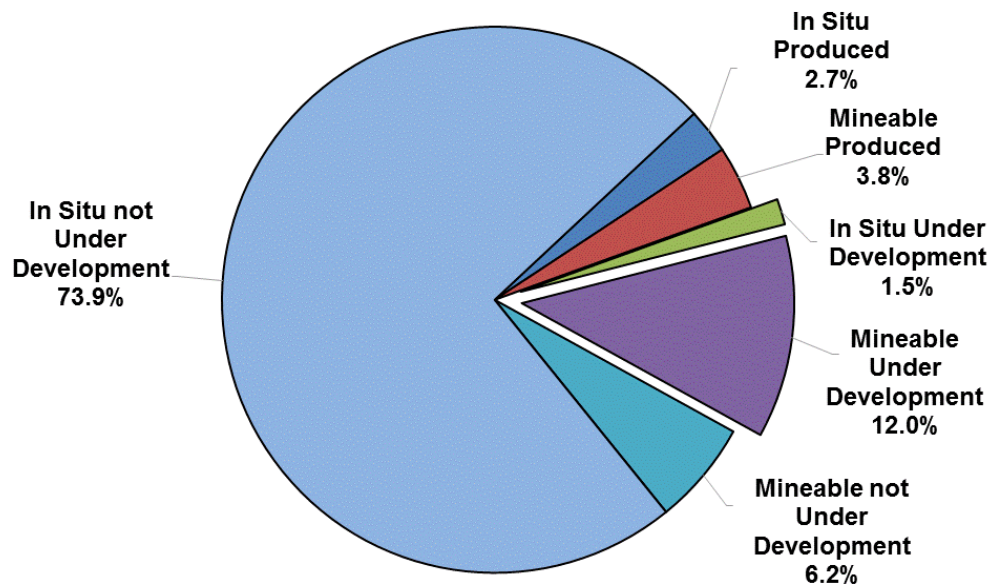
⁸³ Alberta Energy Regulator, 2016, Report data for ST-98 2016 reserves report. http://www1.aer.ca/st98/tables/crude_bitumen/table_R3_6.html

Figure 69 illustrates the AER's "initial established reserves" of bitumen in 2015. Although 81% of the remaining portion of these reserves is too deep for surface mining, the subset "reserves under active development" is predominantly surface mineable. One of the reasons for this is the amount of energy required for in situ development, which increases operating costs even though initial start-up costs are lower for in situ extraction compared to mining.

Figure 69: Initial established reserves of bitumen by recovery method and development in 2015 according to the Alberta Energy Regulator.⁸⁴

Under development (Billion barrels): Mineable = 21.2; In situ = 2.7; Total = 23.9.

Not under development: Mineable = 10.9; In situ = 130.6; Total = 141.5.



2.1.2.2 LIMITATIONS ON LONG-TERM BITUMEN PRODUCTION

Given that bitumen represents Canada's main hope for growing and even maintaining crude oil production in the long term, it is useful to consider constraints to its development. These include the following:

- Oil sands have higher emissions per unit of production than conventional oil, and Canada has committed to emissions reductions of 30% below 2005 levels by 2030. Alberta has imposed a cap on oil sands emissions of 100 megatonnes per year, some 47% above 2014 levels, which will cap production at some point. More stringent emissions reductions through the periodic reviews required under the Paris Agreement will add further pressure to reduce oil sands production, given that it is one of the largest sources of Canadian emissions.
- Oil sands have a lower energy return on energy investment (EROI) than most other oil sources owing to the large inputs of energy required, which accounts for their higher emissions.⁸⁵ The highest EROI is from mining, but the majority of the reserve is only recoverable using in situ methods, hence the average EROI will decline overtime as mineable reserves are exhausted. When EROI approaches a breakeven point it makes no energetic sense to pursue further extraction.

⁸⁴ Alberta Energy Regulator, 2016, Report data for ST-98 2016 reserves report.

http://www1.aer.ca/st98/tables/crude_bitumen/table_R3_1.html

⁸⁵ Energy return on energy investment, or EROI, is the ratio of all energy inputs required for production compared to the amount of energy contained in the produced oil.

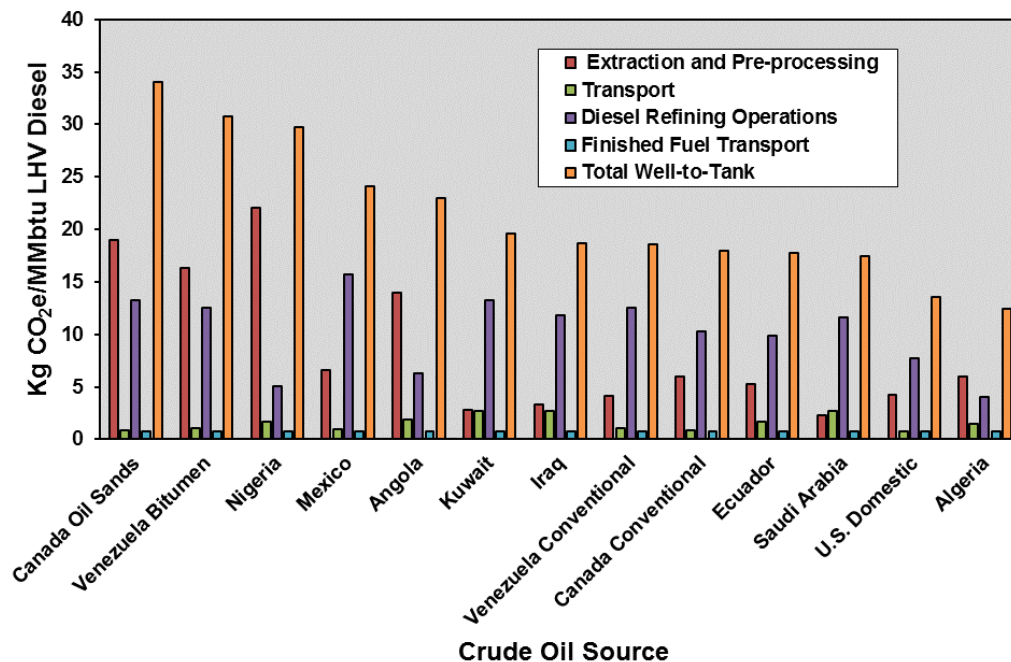
- Companies, when given the choice, develop the highest-quality, cheapest resources first, to maximize return on investment. These are the thickest, highest-quality parts of the deposits with the highest EROI and lowest emissions per unit of production. Notwithstanding the large “established reserves” purported by the AER, the questions remain: What portion of these resources are recoverable at a net energy (and financial) profit, and what are the emissions consequences of recovering lower and lower quality portions of the resource in the future?

Each of these is dealt with in more detail below.

2.1.2.2.1 Life cycle assessment of emissions

There are many life-cycle assessments of greenhouse gas emissions for various crude oil sources. Virtually all of these show that oil sands emissions are considerably higher than most other conventional crude oil sources. For example, according to a 2009 study done by the U.S. Department of Energy's National Energy Technology Laboratory, oil sands emissions are roughly twice that of conventional Canadian oil on a well-to-tank basis,⁸⁶ as illustrated in Figure 70.

Figure 70: Well-to-tank emissions for various crude oil sources to produce diesel fuel (Kg CO₂e/MMBtu = kilograms of carbon dioxide per million British Thermal Units).⁸⁷



A more comprehensive life-cycle assessment that also includes emissions from the combustion of refined products is presented in Table 6. Well-to-wheels emissions for oil sands synthetic crude oil range from 36% to 56% higher than the best-performing crude oil, and from 19% to 37% higher than conventional Canadian oil from Saskatchewan. Given that the tank-to-wheels portion of emissions is quite similar for most oils, the bulk of the variation is in the well-to-tank portion of the supply chain. Oil sands synthetic

⁸⁶ “Well-to-tank” emissions include extraction and preprocessing, transport to refinery, refining, and transport to point of use. “Tank-to-wheels” emissions include the combustion of the refined product as motor fuel or other end uses. “Well-to-wheels” emissions include the full lifecycle from extraction to final end use.

⁸⁷ NETL 2009, An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions. <http://ethanolrfa.org/wp-content/uploads/2015/09/An-Evaluation-of-the-Extraction-Transport-and-Refining-of-Imported-Crude-Oils-and-the-Impact-on-Life-Cycle-Greenhouse-Gas-Emissions-.pdf>

crude oil emissions on a well-to-tank basis are 179% to 297% higher than the best-performing crude oil, and from 93% to 161% higher than conventional Canadian oil from Saskatchewan.

Table 6: Carbon dioxide emissions for representative crude oils on a well-to-tank and tank-to-wheels basis (kgCO₂e/barrel = kilograms of carbon dioxide equivalent per barrel of oil).

Well-to-tank emissions of oil sands such as Suncor Synthetic H are 297% higher than the best-performing oil (Kazakhstan Conventional–Tengiz) and 161% higher than Canadian conventional oil from Midale, Saskatchewan.⁸⁸

Crude Oil Source (kgCO ₂ e/barrel)	Well to tank	Tank to wheels	Well to wheels	Well to tank %	Tank to wheels %
China Conventional Heavy Oil (Bozhong)	342.7	390.4	733.1	46.7%	53.2%
Nigeria High Flaring (Obagi)	262.7	442.5	705.2	37.3%	62.7%
Canada Oil Sands Mining and Upgrading (Suncor Synthetic H)	254.6	441.2	695.8	36.6%	63.4%
US California Heavy Oil with Steam (Midway-Sunset)	289.8	404.2	694	41.8%	58.2%
Canada Oil Sands Mining and Upgrading (Syn crude Synthetic)	251.8	428.9	680.7	37.0%	63.0%
Indonesia Heavy Oil with Steam (Duri)	279.2	375.8	655	42.6%	57.4%
Nigeria High Flaring (Bonny)	194.2	442.5	636.7	30.5%	69.5%
Venezuela Orinoco Heavy Oil (Hamaca)	199.8	433.4	633.2	31.6%	68.4%
US California Heavy Oil with Steam (South Belridge)	214.1	409.2	623.3	34.3%	65.6%
Canada Oil Sands Mining and Upgrading (Suncor Synthetic A)	179.1	427.4	606.5	29.5%	70.5%
US California Conventional Heavy Oil (Wilmington-Duffy)	147.5	410.1	557.6	26.5%	73.6%
Canada Oil Sands In situ (Cold Lake Dilbit)	189.1	355.5	544.6	34.7%	65.3%
UK Offshore (Brent)	135.1	408.6	543.7	24.9%	75.2%
US Conventional with High Gas (Alaska North Slope)	119.7	421.6	541.3	22.1%	77.9%
Brazil Deep Offshore (Lula)	97.4	431	528.4	18.4%	81.6%
Iraq Conventional (Zubair)	106.8	418.6	525.4	20.3%	79.7%
Brazil Conventional Heavy Oil (Frade)	121.8	394	515.8	23.6%	76.4%
Russia Deep Offshore (Chayvo)	96.3	417.8	514.1	18.7%	81.3%
Canada Conventional High Water (Midale)	97.6	411.8	509.4	19.2%	80.8%
Angola Conventional (Girassol)	73.4	430.5	503.9	14.6%	85.4%
US Average Crude Oil Refined (2005)	91.2	409.9	501.1	18.2%	81.8%
Angola Conventional Heavy Oil (Kuito)	69.6	425.7	495.3	14.0%	85.9%
UK Offshore (Forties)	84.4	406.5	490.9	17.2%	82.8%
US GOM Deep Offshore (Mars)	67	422.6	489.6	13.7%	86.3%
US Tight Oil (Bakken)	79.9	408.6	488.5	16.4%	83.6%
Canada Offshore (Hibernia)	55.1	421.9	477	11.6%	88.4%
Kuwait Conventional (Ratawi)	60.8	414	474.8	12.8%	87.2%
US GOM Deep Offshore (Thunder Horse)	58.7	413.6	472.3	12.4%	87.6%
Azerbaijan Conventional (Azeri)	50.2	419.5	469.7	10.7%	89.3%
Nigeria Conventional (Agbami)	68.9	388.7	457.6	15.1%	84.9%
US Tight Oil (Eagle Ford)	49	408.6	457.6	10.7%	89.3%
Norway Offshore (Ekofisk)	39.5	411.8	451.3	8.8%	91.3%
Kazakhstan Conventional (Tengiz)	64.1	382.1	446.2	14.4%	85.6%

⁸⁸ ARC Financial, 2016, Crude Oil Investing in a Carbon Constrained World - see Table 3, based on data from the Oil-Climate Index by the Carnegie Endowment for International Peace, NETL (for US average - see previous footnote), and IHS (for Eagle Ford tight oil), http://www.arcfinancial.com/assets/693/Crude_Oil_Investing_in_a_Carbon_Constrained_World.pdf

Oil sands operators have made considerable improvements in emissions per barrel of bitumen over recent years. They have also added cogeneration plants, which use some process gas (but mainly increasing amounts of purchased gas, according to the AER) to generate electricity needed for production as well as to feed some electricity into the Alberta grid, displacing coal generation and hence improving emissions performance. These improvements are likely reaching the law of diminishing returns, however, and emissions performance can be expected to worsen as lower-quality portions of the bitumen resource are accessed.

2.1.2.2 Energy return on energy investment

Energy return on energy investment (EROI) is reported to be about 17:1 for global oil and 11:1 for US oil, on average.⁸⁹ Oil sands EROIs for the bulk of the recoverable resource are considerably below this given the large inputs of energy required, mainly in the form of natural gas. In situ oil sands EROIs average about 4:1 (81% of remaining recoverable bitumen), whereas mining operations with upgrading average about 8:1 (see Table 7). This only considers the purchased gas from external sources required to fuel the process. It does not consider the energy needed to build the facilities, power the mining equipment and pumps, produce and transport the diluent needed to move bitumen through pipelines, etc., and therefore must be considered an upper limit of actual EROI if all energy inputs were accounted for. Brandt et al (2013) have produced a thorough analysis of net energy returns for oil sands that came up with similar values.⁹⁰ They point out, however, that if the energy inputs used in the calculation include transport and refining to the point of use (well-to-tank), the EROI of bitumen produced by in situ methods is closer to 2:1.

Table 7: Energy return on energy investment (EROI) of oil sands given extraction method and upgrading based on inputs of purchased gas only.

(Considerable amounts of produced and process gas are also used, but these sources amount to “self-fuelling” and are therefore not considered in the calculations.) Estimates of purchased gas used per barrel are from the Alberta Energy Regulator (mcf/bbl = thousand cubic feet of gas per barrel of oil).⁹¹

Extraction method	Purchased gas consumption (mcf/bbl)			EROI		
	Min	Max	Mean	Max	Min	Mean
Mining bitumen only	0.4	0.6	0.5	14.50	9.66	11.60
Mining with upgrading	0.6	0.8	0.7	9.66	7.25	8.28
In situ bitumen only	1	2	1.5	5.80	2.90	3.87
In situ with upgrading	1.2	2.2	1.7	4.83	2.64	3.41

Thus, oil sands are a low-quality source of oil, both energetically and in terms of emissions, compared to conventional crude. New greenfield oil sands SAGD projects without upgrading will not be built unless oil prices reach \$US85 per barrel, according to a recent analysis by the Petroleum Technology Alliance of Canada (PTAC).⁹² Prices needed for new greenfield standalone mining projects are even higher, at

⁸⁹ Murphy DJ. 2014 The implications of the declining energy return on investment of oil production. *Phil. Trans. R. Soc. A* 372: 20130126. <http://dx.doi.org/10.1098/rsta.2013.0126>

⁹⁰ Brandt et al., 2013, The energy efficiency of oil sands extraction: Energy return ratios from 1970 to 2010, *Energy Volume 55*, 15 June 2013, Pages 693–702.

⁹¹ Alberta Energy Regulator, 2016, ST-98, In situ and standalone mine purchased gas requirements http://www1.aer.ca/ST98/tables/supply_cost/table_1_4.html. The estimate of upgrading purchased gas requirement (.2 mcf/bbl) is from Alberta Energy Regulator, 2011, ST-98, Table 3-10.

⁹² Petroleum Technology Alliance of Canada, March 31, 2015, Needs Assessment for Partial and Field Upgrading, 15p; the \$US85/barrel price estimate for SAGD and the \$US105.50 estimate for standalone mining includes the cost of diluent and

\$US105.50 per barrel. PTAC points out that greenfield mining projects with upgrading require prices that are only marginally higher than mining projects without upgrading (\$US109.50 per barrel). This is due in part to the fact that upgraded bitumen (synthetic crude oil) does not require a 30% blend of diluent to move it through pipelines, which is a considerable cost savings. Nonetheless, new bitumen projects are unlikely unless the price of oil goes higher (WTI oil price was \$US60 per barrel as of this writing⁹³). Existing projects will continue to operate, however, as upfront capital expenditures have already been made and operating costs vary between \$C19.31 and \$C32.75 per barrel, depending on extraction method and degree of upgrading.⁹⁴

2.1.2.2.3 High-grading the bitumen resource

As pointed out previously, the term “reserves” has a specific meaning under Canadian security regulations in that they must be technically and economically recoverable. It is by no means assured that what the Alberta Energy Regulator terms “initial established reserves” meets this test. In fact, up until 1999, prominent compilers of global oil reserve statistics, such as BP and the *Oil & Gas Journal*, carried much smaller numbers on their books for the oil sands. In 1999, with a stroke of the pen, reported oil sands reserves went from 43.1 billion barrels in the previous year to 175.2 billion barrels, as BP accepted the AER’s number.⁹⁵ The *BP Statistical Review of World Energy* is a widely used handbook on global energy reserves, however, the company is careful to include a disclaimer:

The data series for proved oil and gas reserves in *BP Statistical Review of World Energy June 2016* does not necessarily meet the definitions, guidelines and practices used for determining proved reserves at company level, for instance, as published by the US Securities and Exchange Commission, nor does it necessarily represent BP’s view of proved reserves by country.

Given that companies target the highest-quality portion of oil sands deposits first, and there has been abundant exploration to identify these areas, it remains to be seen how much of the AER’s “initial established reserves” can actually be recovered at a financial and a net-energy profit.

transportation to move the bitumen to market in the US. The supply cost of in situ SAGD bitumen at the well is estimated at \$CA50.90/barrel, and the supply cost of standalone mining at the mine mouth is estimated at \$CA71.10/barrel by PTAC.

⁹³ West Texas Intermediate (WTI) is a North American benchmark oil price.

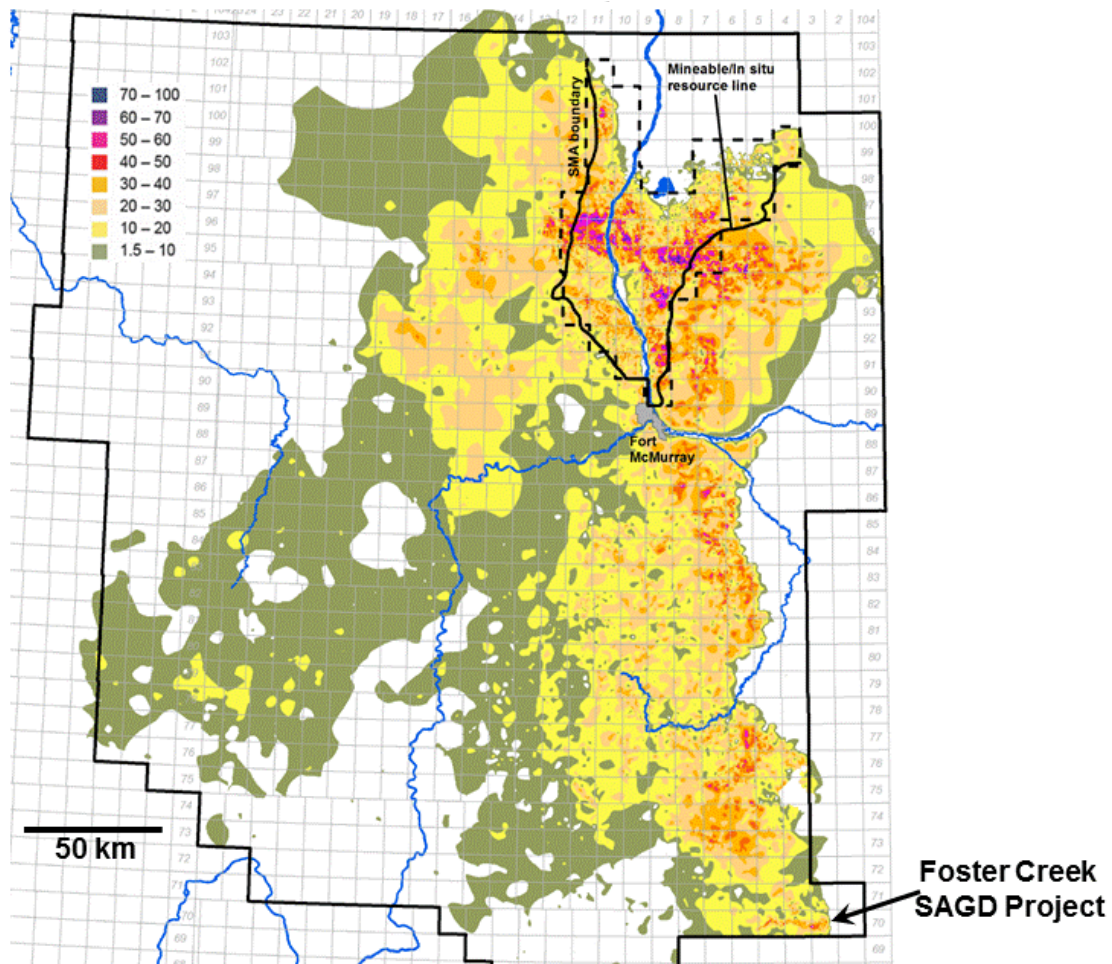
⁹⁴ PTAC op. cit.

⁹⁵ BP Statistical Review of World Energy data workbook, 2016, <http://www.bp.com/content/dam/bp/excel/energy-economics/statistical-review-2016/bp-statistical-review-of-world-energy-2016-workbook.xlsx>

Figure 71 illustrates the distribution of the oil sands resource in the Athabasca Wabiskaw-McMurray deposit, which contains 52% of the “initial established reserves” and all of the mineable oil sands. As can be seen, pay thickness is highly variable, with the thickest parts falling into the surface mineable area. Although pay thickness as depicted in this figure is a primary indicator of economic viability, the actual economics depend on the nature of the distribution of this pay, as several pay intervals have been aggregated in some areas to make this map. Other oil sands deposits show similar variability.

Figure 71: Pay thickness in the Athabasca Wabiskaw-McMurray deposit, which contains 52% of the oil sand's “initial established reserves.”⁹⁶

“SMA” indicates the general boundaries of the surface mineable area, with the solid black line indicating a more accurate delineation of the mineable/in situ boundary.

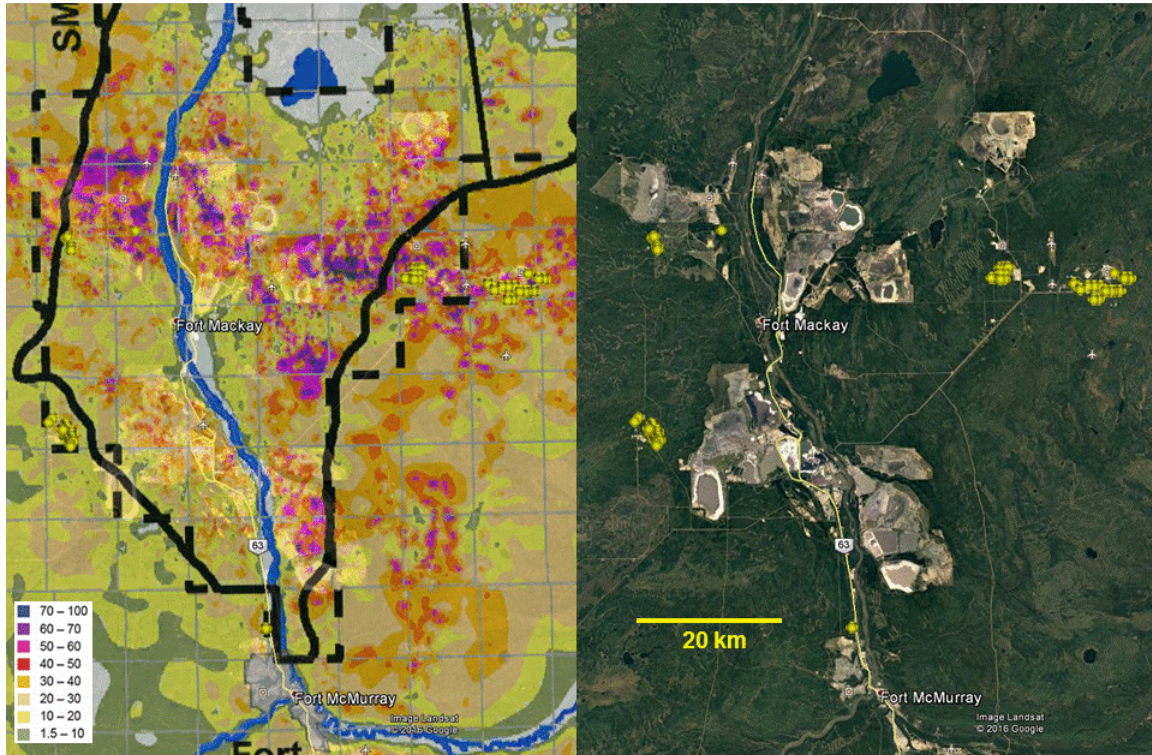


⁹⁶ Alberta Energy Regulator, 2016, ST-98, Figure R-3.6, https://www2.aer.ca/t/Production/views/CrudeBitumenFigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit/FigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit?embed=y&showShareOptions=true&display_count=no

Figure 72 illustrates surface mineable development with an overlay of bitumen pay thickness, showing that the thickest, most attractive portions of the resource are already being developed. Although there are still some attractive areas yet to be developed, more than half of the thickest surface mineable pay is under development.

Figure 72: Overlay of the Athabasca Wabiskaw-McMurray deposit pay thickness on a satellite image of surface mining development in the surface mineable area north of Fort McMurray.⁹⁷

The left- and right-hand images cover exactly the same area. The solid line marks the approximate boundary of mineable and in situ resources. See Figure 71 for location. SAGD wells are indicated in yellow (these are multi-well pads).



⁹⁷ Alberta Energy Regulator, 2016, ST-98, Figure R-3.6, https://www2.aer.ca/t/Production/views/CrudeBitumenFigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit/FigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit?embed=y&:showShareOptions=true&:display_count=no, Satellite image from Google Earth. Data from DrillingInfo, December 2015.

Figure 73 illustrates a similar overlay for Cenovus Energy's Foster Creek in situ SAGD project. As with surface mineable resources, Foster Creek is understandably focused on the thickest parts of the deposit, which is restricted to a relatively small part of the total area underlain by bitumen in this area.

Figure 73: Overlay of Athabasca Wabiskaw-McMurray deposit pay thickness on satellite image of the Cenovus Foster Creek project, which is the first commercial SAGD operation.⁹⁸

The upper and lower images cover exactly the same area and contours of pay thickness are shown on both images. See Figure 71 for location. SAGD wells are indicated in yellow (these are multi-well pads). The economic pay thickness is relatively restricted in this area and is being fully exploited.

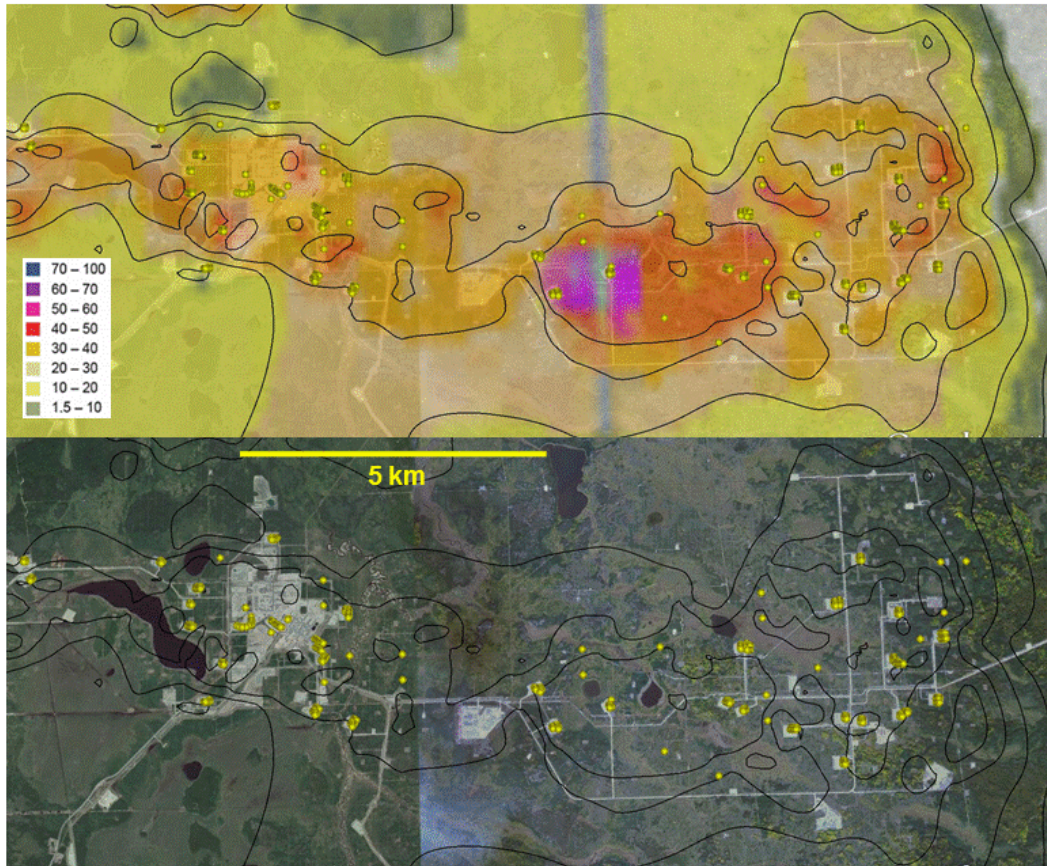


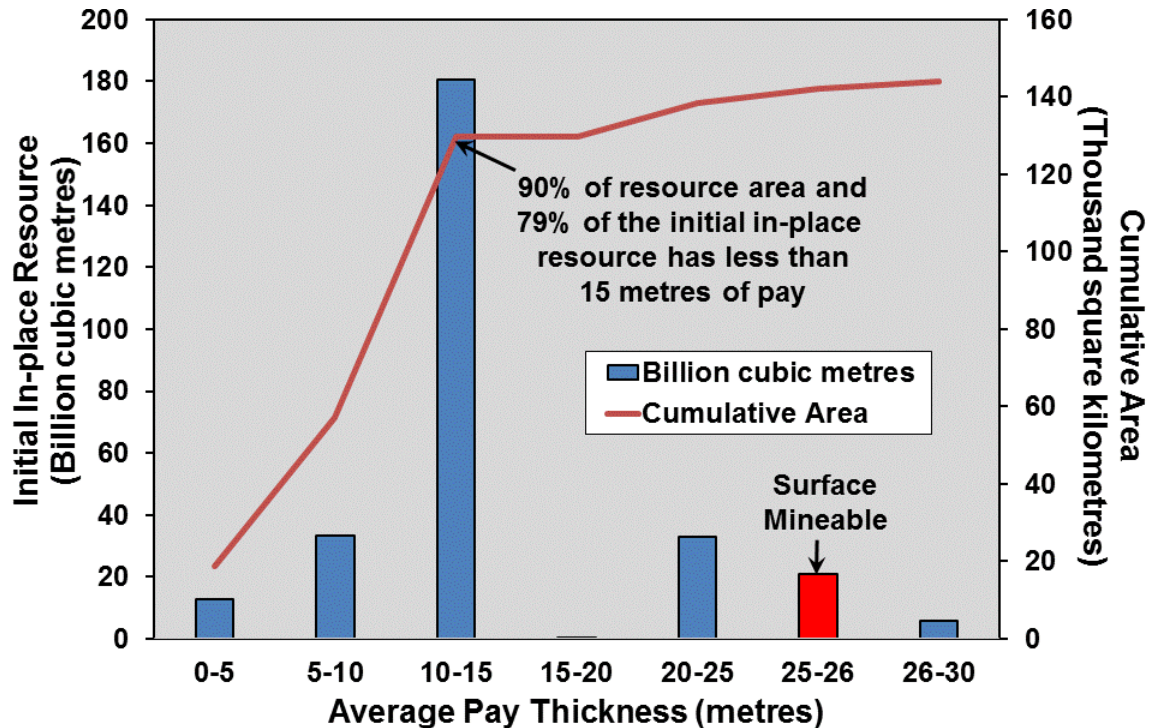
Figure 74 (next page) illustrates the distribution of the initial in-place resources by pay thickness (the in-place resource distribution by deposit is illustrated in Figure 68).⁹⁹ Some 90% of the overall resource area and 79% of the in-place resource has a pay thickness of less than 15 metres. Although resources shallow enough for surface mining average about 26 metres thick, existing mines have focused on only the thickest subset of this, in the 30–70 metre range (see Figure 72). In situ projects such as Foster Creek have focused on portions of the deposit with pay in the 20–50 metre range on the AER's map (see Figure 73).

⁹⁸ Alberta Energy Regulator, 2016, ST-98, Figure R-3.6, https://www2.aer.ca/t/Production/views/CrudeBitumenFigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit/FigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit?embed=y&showShareOptions=true&display_count=no, Satellite image from Google Earth. Data from Drillinginfo, December 2015.

⁹⁹ Note that the Alberta Energy Regulator states “the deposit is treated as a single bitumen zone and the pay is accumulated over the entire geological interval.”, hence the thicknesses on the AER pay thickness map in Figures 70–72 could include zones not considered for extraction based on a full economic evaluation and hence may overstate the actual economic pay thickness. See AER ST-98-2016 “Pay thickness discussion”, http://www1.aer.ca/st98/data/crude_bitumen/BitumenPayThicknessDiscussion.pdf

Figure 74: Initial in-place oil sands resources by pay thickness.¹⁰⁰

Also shown is the cumulative area underlain by bitumen in each pay thickness class. Some 90% of the resource area and 79% of the in-place resources have a pay thickness of less than 15 metres, but most extraction is currently from areas with pay thicknesses of greater than 20 metres.



Although oil sands resources are reported to be vast, the thickest and highest-quality portion of them are being developed now and are being sold off mostly for export at low prices that bring in little benefit in terms of royalties and taxes compared to earlier years. Oil sands reserves that are recoverable at a financial and net-energy profit are likely considerably smaller than the AER's "initial established reserve" estimates (which do not conform to the regulatory protocols of National Instrument 51-101). Furthermore, emissions are growing as production rises, making Canada's greenhouse gas commitments ever more difficult to achieve. What will be left when the highest-quality resources are gone will be the thinner, higher-cost, more energy- and emissions-intensive resources, which will require ever higher prices to break even and make Canada's climate commitments even more difficult to meet.

2.1.2.2.4 Bitumen production outlook

The National Energy Board's *Energy Futures* report makes three projections of bitumen production through 2040 with different assumptions of price and market accessibility.¹⁰¹ In addition, the Alberta government has announced a Climate Leadership Plan that will cap emissions from the oil sands at 100 megatonnes (Mt) per year.¹⁰²

¹⁰⁰ Alberta Energy Regulator, 2016, ST-98, Table R-3.7, http://www1.aer.ca/st98/tables/crude_bitumen/table_R3_7.html

¹⁰¹ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA>

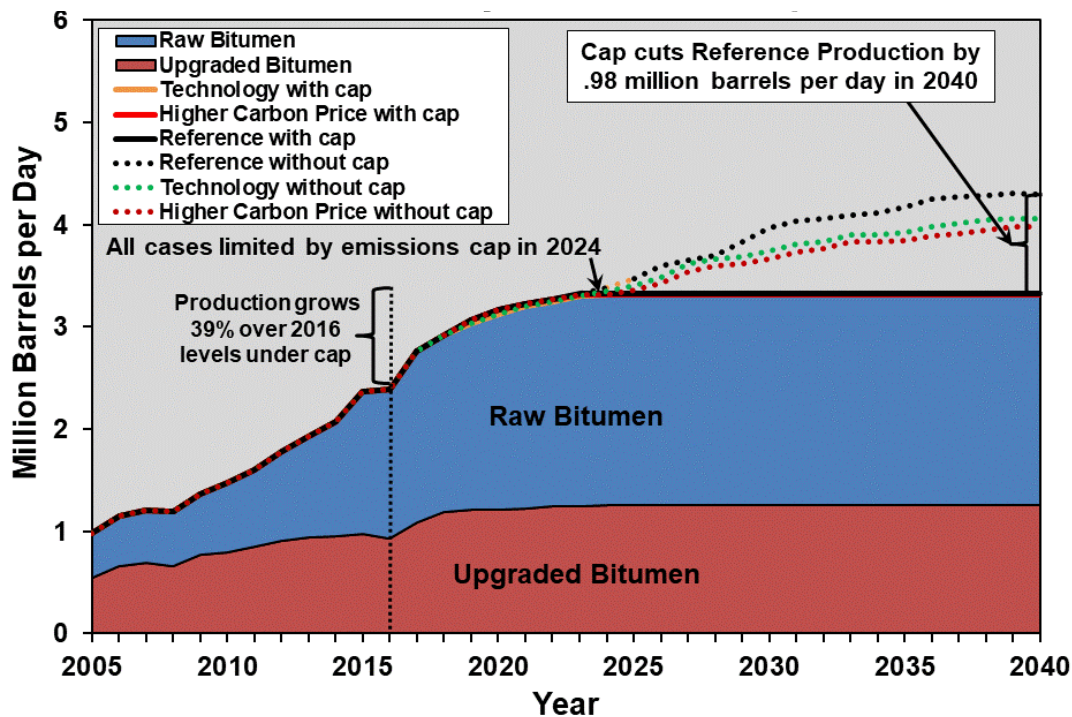
¹⁰² Alberta Government, November 2015, Climate Leadership Report to Minister, <http://www.alberta.ca/documents/climate/climate-leadership-report-to-minister.pdf>.

Environment and Climate Change Canada's latest report to the United Nations on Canada's greenhouse gas emissions contains estimates for the oil sands.¹⁰³ These are subdivided into extraction by "mining" and "in situ" methods, as well as "upgrading" to synthetic oil. Collectively these summed to 71 Mt in 2015, the most recent year for which data are available. This means that a 100-Mt cap will allow a 41% growth in emissions above the 2015 level. To evaluate the impact of the emissions cap on the NEB's bitumen production projections, the average emissions per unit of production from the most recent four years were used to calculate future emissions for the NEB projections. Figure 75 illustrates the production implications.¹⁰⁴

Bitumen production in all three NEB production cases is constrained by the cap, beginning in 2024, at a production rate of between 3.3 and 3.4 million barrels per day (mbd), or 39% above 2016 levels. Bitumen production would be constrained by .98 mbd in 2040 in the NEB reference case with the cap. Given the current low oil price environment, and the previously discussed thresholds needed for new projects, new greenfield oil sands projects are unlikely unless prices move higher, hence even increasing oil sands production to the cap remains uncertain. This could change relatively quickly, however, given changes in the global supply/demand balance and remembering that the price was over \$US100 per barrel as recently as 2014.

Figure 75: Marketable bitumen production in the National Energy Board's production scenarios through 2040.

Raw bitumen is converted into upgraded bitumen with a volume loss of 14%, so the volumes here reflect delivered quantities. Production in the reference case can grow 39% over 2016 levels before being limited by the emissions cap.¹⁰⁵



¹⁰³ Environment Canada, April 2017, National Inventory Report 1990-2015: Greenhouse Gas Sources and Sinks in Canada, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/hrv-2017-nir-26may17.zip

¹⁰⁴ For more detail on the assumptions used in determining production under the Alberta oil sands emissions cap see: David Hughes, 2017, Will the Trans Mountain pipeline and Tidewater Access raise Prices and Save Canada's oil industry?, Canadian Centre for Policy Alternatives. <https://www.policyalternatives.ca/sites/default/files/uploads/publications/2017/05/Trans%20Mountain%20Pipeline%20and%20Tidewater%20Access%20FINAL.pdf>

¹⁰⁵ Data from NEB Energy Futures 2017; emissions from ECCC NIR report 2017

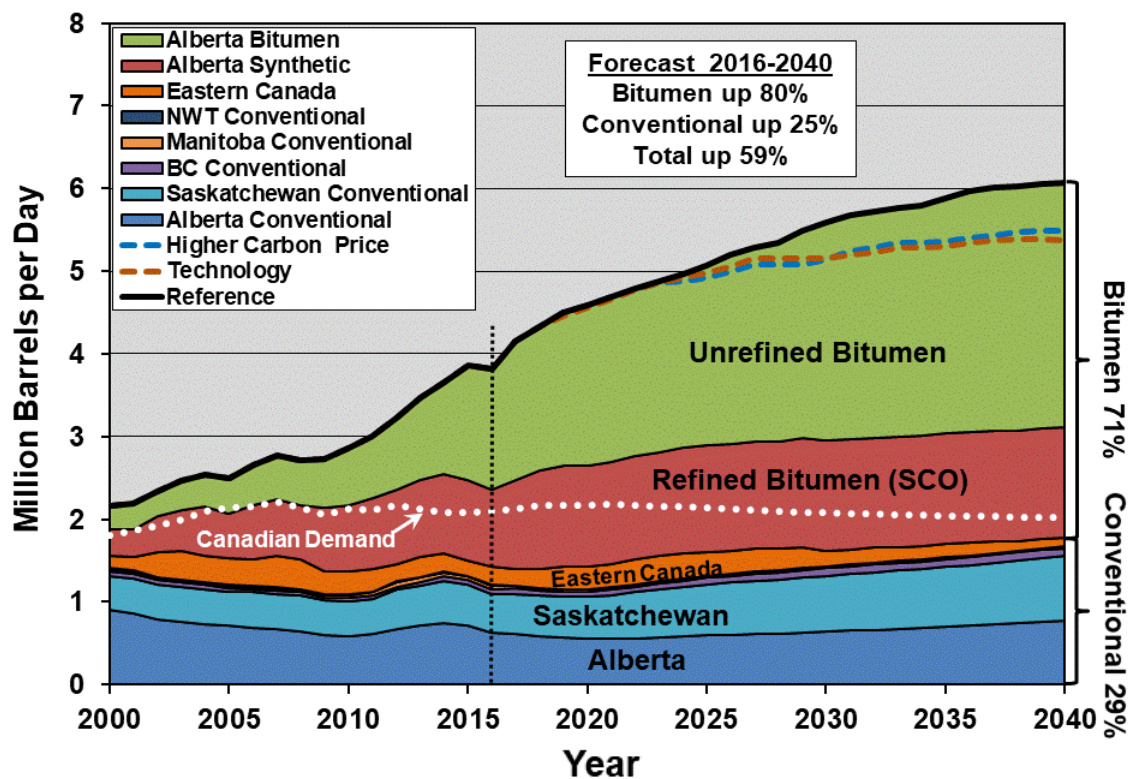
Under the emissions cap, the NEB reference case production scenario would see the extraction of 46% of remaining mineable bitumen reserves, and 15% of remaining in situ reserves, from 2016 to 2040. Given the uncertainties of the NEB's estimates, and the fact that the highest-quality and most economic resources are extracted first, this is a significant inroad on the best part of the bitumen resource—particularly the mineable portion, which has the lowest emissions and highest EROI. The cap allows for aggressive growth in production, which will make meeting Canada's emissions-reduction commitments under the Paris Agreement extremely difficult to achieve given that oil sands emissions will grow from 9.8% of Canada's emissions in 2015 to 19.3% in 2030 if the Paris Agreement commitment is met.¹⁰⁶

2.1.3 Overall oil production outlook

Figure 76 illustrates the NEB's reference case forecast for Canadian oil production through 2040, not including Alberta's oil sands emissions cap. Bitumen production nearly doubles whereas conventional production increases by 25% from 2016 levels. According to this forecast, 71% of Canadian oil production will be bitumen by 2040.

Figure 76: The National Energy Board's "reference" case projection of Canadian oil production through 2040 by province and oil type.¹⁰⁷

Also shown are the overall "higher carbon price" and "technology" production cases as well as Canadian demand, which is projected to peak in 2021 and decline by 7% through 2040.



¹⁰⁶ The Paris Agreement commits Canada to a 30% reduction of greenhouse gas emissions below 2005 levels by 2030. This amounts to a reduction to 517 Mt/year in 2030. See Environment Canada, 2016, Canada's Emission Projections in 2020 and 2030 (Mt CO₂ eq), <https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=8BAAFCC5-1>

¹⁰⁷ Data from National Energy Board 2000–2005; National Energy Board Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ft/2017/2017nrgfr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftppndc/dflt.aspx?GoCTemplateCulture=en-CA> (data and reference case demand); Emissions from Environment Canada, National Inventory Report, released April, 2016. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2016-nir-14apr16.zip (conventional includes NGLs).

The implications of this forecast for conventional oil, along with two other NEB projection variants, are summarized in Table 8. By 2040 conventional oil production will consume more than triple the currently known reserves, and consume between 55% and 60% of all discovered and undiscovered resources, a significant proportion of which has not been demonstrated to be economically or technically recoverable, and would require extraction of undiscovered resources in the Arctic and on the East Coast. Table 8 also shows cumulative carbon dioxide emissions from upstream emissions in producing this oil, assuming average 2011–2015 emission levels in the future. Under the Paris Agreement commitments, conventional oil production would comprise between 5.5% and 6.3% of all Canadian emissions in 2030.

Table 8: Conventional oil production and emissions according to the National Energy Board's scenarios, from 2016 to 2040 (Gbbbls = billion barrels).¹⁰⁸

The emissions production rate in 2030 would constitute 5.5% to 6.3% of allowable emissions under the Paris Agreement in 2030.

	Reference	Higher carbon price	Technology
Total conventional oil production (Gbbbls)	14.10	13.14	12.58
% of conventional reserves produced	316%	294%	282%
% of discovered and undiscovered conventional resources produced	55.0%	51.3%	49.1%
Emissions of conventional oil 2017–2040 (MtCO ₂)	789	734	703
% of 2030 emissions under Canada's Paris Agreement target	6.4%	5.8%	5.6%

¹⁰⁸ Production forecasts from: National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/fttrppndc/dflt.aspx?GoCTemplateCulture=en-CA>. Emissions are from Environment Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip.

Bitumen production, according to these production projections, would consume 14.3% to 15.4% of in situ bitumen reserves and 46% of mineable bitumen reserves by 2040 (Table 9). Doing so would see upstream oil sands emissions rise to between 21.4% and 22.8% of all Canadian emissions in 2030, up from 9.8% in 2015, if the Paris Agreement target is met. Coupled with upstream emissions from the production of conventional oil, oil production would constitute between 27.2% and 29.2% of allowable 2030 Canadian emissions under the Paris Agreement.

Table 9: Production and emissions for three National Energy Board production projections from 2016 to 2040 (Gbbbls = billion barrels).¹⁰⁹

The emissions production rate in 2030 would constitute 18.8% to 24.3% of allowable emissions under the Paris Agreement in 2030.

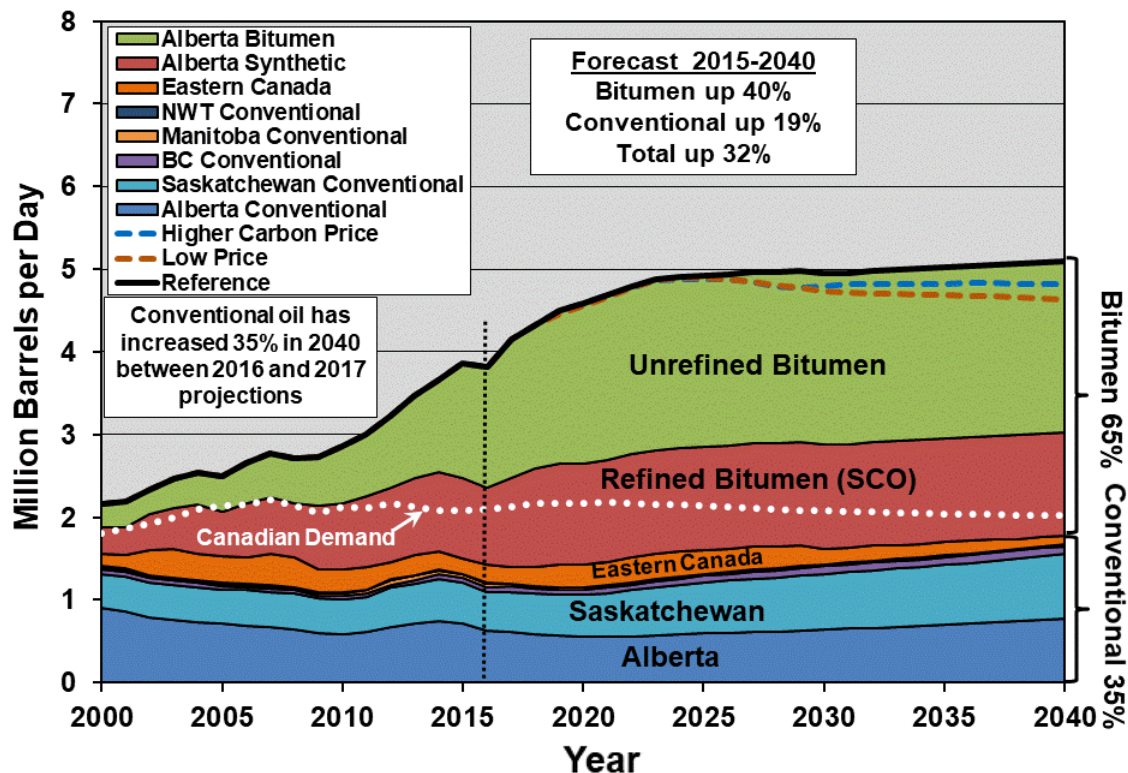
Bitumen production and emissions without emissions cap, 2016–2040			
	Reference	Higher carbon price	Technology
Mined bitumen production (Gbbbls)	14.74	14.74	14.74
% of mineable reserves produced	46.0%	46.0%	46.0%
In situ bitumen production (Gbbbls)	20.58	19.02	19.43
% of in situ reserves produced	15.4%	14.3%	14.6%
Upgraded bitumen (Gbbbls)	11.26	11.26	11.26
Total diluent required (Gbbbls)	6.39	5.92	6.05
Imported diluent required (Gbbbls)	3.91	3.64	3.75
Total bitumen shipped including imported diluent (Gbbbls)	50.58	47.79	47.74
Emissions of oil sands (MtCO ₂)	2,729.52	2,623.85	2,651.34
% of 2030 emissions under Canada's Paris Agreement target	22.8%	21.4%	21.7%

¹⁰⁹ Production forecasts from: National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/fttrpndc/dflt.aspx?GoCTemplateCulture=en-CA> retrieved Oct 29, 2017. Emissions are from Environment Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip.

Total Canadian oil production under Alberta's emissions cap in the NEB's reference case is illustrated in Figure 77. In this case, oil production would rise until the cap constrained oil sands production in 2024, and then grow gradually through 2040 to just over five mbd, mainly through the growth in conventional oil production. In the NEB's higher carbon price and technology cases, however, Canadian oil production would peak in 2025 at 4.9 mbd. Production in 2040 would be 65% bitumen in the reference case, and total oil production would be roughly double Canadian domestic demand, meaning Canada would remain a significant net oil exporter over the 2016–2040 period.

Figure 77: The National Energy Board's reference case projection of Canadian oil production through 2040 under Alberta's 100-megatonne per year emissions cap by province and oil type.¹¹⁰

Also shown are the overall higher carbon price and technology production cases, and Canadian demand under the reference case, which is projected to decline slightly from 2021 through 2040.



Under Alberta's oil sands emissions cap, bitumen production, given the NEB's forecasts, would consume 12–13% of in situ reserves and 45–46% of mineable reserves over the 2016–2040 period (Table 8). Doing so would see the oil sands rise to 19.3% of all Canadian emissions in 2030, up from 9.8% in 2015, under the Paris Agreement. Coupled with upstream emissions from conventional oil production, total oil production under the cap would constitute 27–29% of all Canadian emissions in 2030 if the Paris Agreement target is met.

¹¹⁰ Data from National Energy Board, 2000–2005; National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ft/2017/2017nrgfr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftppndc/dflt.aspx?GoCTemplateCulture=en-CA> retrieved Oct 29, 2017 (for 2005–2040 data and reference case demand). Emissions are from Environment Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip (conventional includes NGLs).

As indicated in Table 10, in response to the cap, overall bitumen production would be reduced by between 2.6 and 4 billion barrels over the 2016–2040 period in the NEB's reference and higher carbon price cases, respectively. This amounts to a cutback in the production of bitumen over this period of 8–12%, depending on the scenario, and a reduction in cumulative emissions of 7.4–10.9%. Under the NEB's reference case, the cap would result in a reduction of 12% in bitumen production and an emissions reduction of 10.9% over the 2016–2040 period.

Table 10: Production and emissions for three National Energy Board production cases from 2016 to 2040 under the 100-megatonne per year Alberta emissions cap (Gbbls = billion barrels; MtCO₂eq = megatonnes of carbon dioxide equivalent).

The production and emissions implications of the cap compared to no cap are also illustrated.¹¹¹

	Reference	Higher carbon price	Technology
Mined bitumen (Gbbls)	14.55	14.72	14.63
% of mineable reserves	45.36%	45.89%	45.60%
In situ bitumen (Gbbls)	16.68	16.45	16.52
% of in situ reserves	12.51%	12.34%	12.39%
Upgraded bitumen (Gbbls)	11.17	11.30	11.23
Total diluent required (Gbbls)	5.47	5.41	5.43
Imported diluent required (Gbbls)	2.91	3.05	3.04
Total bitumen shipped including imported diluent (Gbbls)	32.33	32.38	32.37
Emissions of oil sands (MtCO ₂ eq)	2,431.11	2,430.83	2,427.11
Bitumen production difference due to cap (Gbbls)	4.02	2.55	2.96
% production difference due to cap	12.03%	7.98%	9.18%
Emissions difference due to cap (MtCO ₂ eq)	298.40	193.02	224.23
% oil sands emissions difference due to cap	10.93%	7.36%	8.46%
% of 2030 emissions under Canada's Paris Agreement target	19.30%	19.30%	19.30%

2.1.4 Pipeline requirements under the cap

The issue of building more export pipelines to move increasing production of western Canadian oil has been a major point of contention between environmental groups and citizens, the oil and gas industry, and governments. Industry and the Alberta and Saskatchewan governments claim that new capacity is needed to get oil to “tidewater” in order to capture a significant “price premium,” given that exports now are largely to a “single customer,” the US. Other studies have shown that there is sufficient export capacity under Alberta's emissions cap if rail is considered, that there will be little or no price premium for tidewater access, and that increasing oil sands emissions by 41% over 2015 levels, as allowed under the cap, will make meeting the 2030 target Canada committed to under the Paris Agreement virtually impossible.^{112,113} The issue of pipeline capacity is briefly reviewed below for the three National Energy Board production cases.

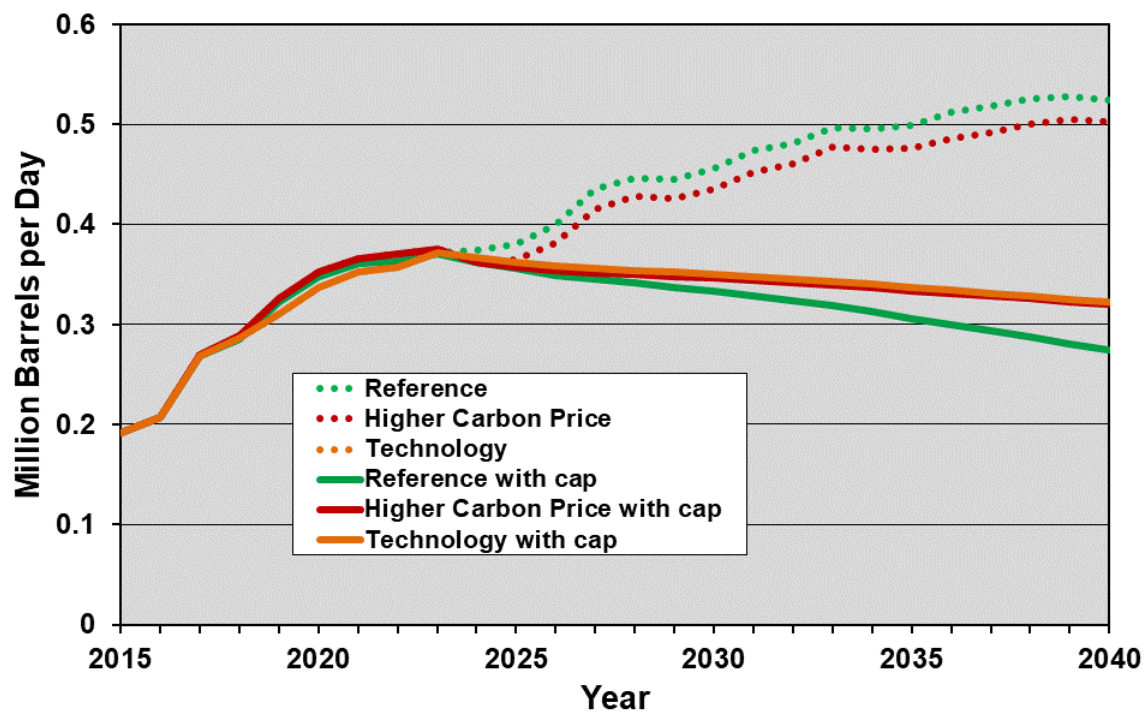
¹¹¹ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA> retrieved Oct 29, 2017. Emissions are from Environment Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip.

¹¹² Hughes, J.D., 2016, Can Canada Expand Oil and Gas Production, Build Pipelines and Keep Its Climate Change Commitments?, Canadian Centre for Policy Alternatives, 38p,

One of the issues with exported raw bitumen, as opposed to upgraded synthetic oil, is that it must be diluted with lighter hydrocarbons to lower the viscosity enough for it to flow through pipelines. The preferred diluent is condensate and other light natural gas liquids, which are needed at a blending rate of 30% by volume to create “dilbit” (synthetic crude oil can also be used as a diluent but at a higher blending ratio—typically 50%). As the NEB has pointed out, the need for diluent to blend with bitumen production for export has already exceeded Canada’s domestic production capacity, hence increased bitumen production will require diluents to be purchased on international markets and imported. The volumes of imported diluent needed are substantial, ranging from 2.9 to 3.1 billion barrels over the 2016–2040 period with the emissions cap in the NEB’s projections (Table 10). The need to purchase diluent and ship it in and out of Alberta further impacts the economics of bitumen. The need for diluent also means that pipelines have to be sized 30% larger to transport a given volume of product than if they carried synthetic or conventional oil alone, to accommodate the diluent. Figure 78 illustrates the imported diluent required for the three NEB production cases with and without the Alberta oil sands emissions cap. Under the cap, between 371 and 376 thousand barrels per day (kbd) of imported diluent will be needed at peak requirements in 2023.

Figure 78: Rates of imported diluent required in three National Energy Board production cases with and without the 100-megatonne per year Alberta oil sands emissions cap.¹¹⁴

This assumes that domestically produced diluents will be used first before importing.



Although some of Western Canada’s oil production will be consumed by domestic refineries, most will be exported to the US and Eastern Canada. The Canadian Association of Petroleum Producers (CAPP) expects refinery consumption to rise from 602 kbd in 2016 to 671 kbd in 2020, with the completion of the

https://www.policyalternatives.ca/sites/default/files/uploads/publications/National%20Office%2C%20BC%20Office/2016/06/Can_Canada_Expand_Oil_and_Gas_Production.pdf

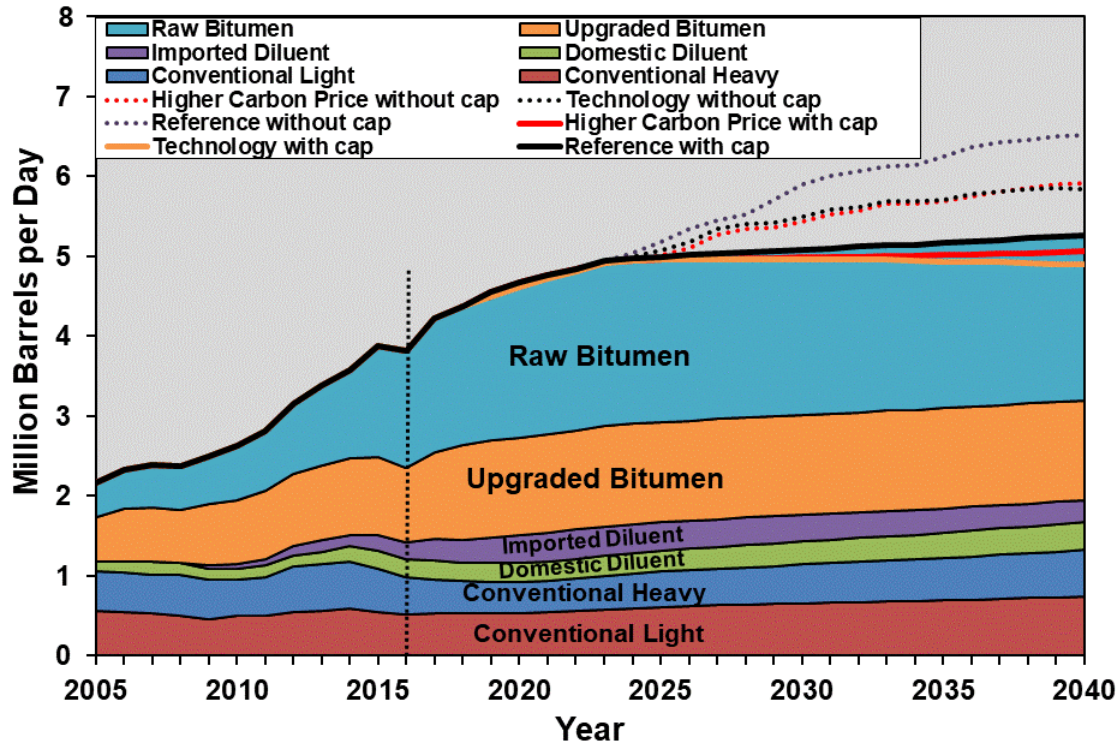
¹¹³ Hughes, J.D., 2017, Will the Trans Mountain Pipeline and Tidewater Access Boost Prices and Save Canada’s Oil Industry?, Canadian Centre for Policy Alternatives, 42p,

<https://www.policyalternatives.ca/sites/default/files/uploads/publications/2017/05/Trans%20Mountain%20Pipeline%20and%20Tidewater%20Access%20FINAL.pdf>

¹¹⁴ Data from National Energy Board, Canada’s Energy Future 2017, and author calculations

Sturgeon refinery in Alberta and other increases.¹¹⁵ Figure 79 illustrates western Canadian supply for refinery consumption and export under the emissions cap, including bitumen, conventional oil production and imported diluent.

Figure 79: Western Canadian oil supply with and without the Alberta emissions cap in three National Energy Board scenarios.¹¹⁶



Existing export pipeline and rail capacities from Western Canada are given in Table 11, along with three proposed pipelines: Line 3 restoration, Keystone XL and Trans Mountain expansion. Nameplate export capacity from existing pipelines is 4,236 kbd, however, effective capacity is usually less, owing to outages for maintenance and other logistical issues. Assuming a 95% availability yields an existing effective pipeline capacity of 3,974 kbd. Refinery consumption adds a further 671 kbd of supply handling capability. Rail loading capacity of 754 kbd is also available and is typically used for incremental volumes not shipped by pipelines. Although rail is flexible, given that railways exist to most North American refineries and offshore export points, it is significantly more expensive than pipelines for shipping dilbit. If bitumen is shipped in undiluted form, however, rail can ship 42% more product per unit volume than pipelines, eliminating the need for imported diluent and increasing safety in the event of an accident, given that undiluted bitumen doesn't flow like dilbit. This confers significant cost savings and makes rail more competitive with pipelines, while reducing risk at the same time. Rail capacity is also cheaper to build than pipelines, and can be used for other purposes in the event that it is not needed for oil transport. Adding rail capacity to export pipelines and refinery consumption yields an effective ability to handle western Canadian supply of 5,399 kbd, which is more than sufficient to meet the export needs of any of the NEB's production scenarios under the Alberta emissions cap.

¹¹⁵ CAPP, 2016, Crude Oil Forecast, Markets and Transportation, <http://www.capp.ca/-/media/capp/customer-portal/publications/284950.pdf>

¹¹⁶ Author calculations from National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/fttrppndc/dflt.aspx?GoCTemplateCulture=en-CA>

Table 11: Pipeline and rail export capacity and refinery consumption in Western Canada. Net capacity discounts nameplate capacity by 5%, allowing for maintenance and outages.

All capacities come from the Canadian Association of Petroleum Producers¹¹⁷ except for the Rangeland-Milk River pipeline, which is from Alberta Energy.¹¹⁸

Pipeline	Nameplate capacity	Net capacity at 95%	Source
Existing pipelines			
Enbridge Mainline	2,851	2,708	CAPP 2016
Kinder Morgan Trans Mountain*	300	235	CAPP 2016
Spectra Express	280	266	CAPP 2016
TransCanada Keystone	591	561	CAPP 2016
Rangeland-Milk River	214	203	AE 2009
Total existing capacity	4,236	3,974	
Western refinery receipts and rail capacity			
Refinery consumption ¹¹⁹	671	671	CAPP 2016
Rail export capacity	754	754	CAPP 2016
Grand total	5,661	5,399	
Proposed pipelines likely to be built under the Trump administration			
Line 3 replacement	370	352	CAPP 2016
TransCanada Keystone XL	830	789	CAPP 2016
Existing plus likely capacity	6,861	6,539	
Proposed Canadian "tidewater" pipelines¹²⁰			
KM Trans Mountain expansion	590	561	CAPP 2016
Total	7,451	7,100	

* Parkland's Burnaby refinery needs subtracted from Trans Mountain export capacity (50 kbd)

¹¹⁷ CAPP, 2016, Crude Oil Forecast, Markets and Transportation, <http://www.capp.ca/~media/capp/customer-portal/publications/284950.pdf>

¹¹⁸ Alberta Energy, 2009, BRIK Infrastructure and Bitumen Supply Availability, http://www.energy.alberta.ca/oilsands/pdfs/brik_availability_infrastructure_to_industry.pdf

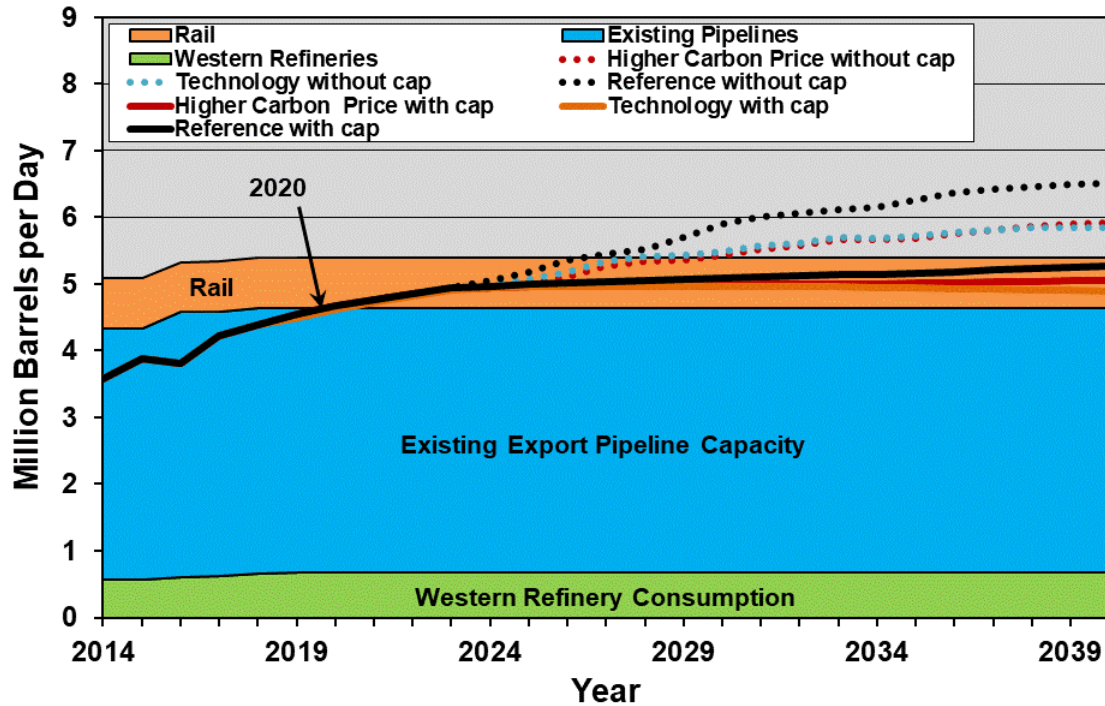
¹¹⁹ Refinery consumption as of 2019 according to Canadian Association of Petroleum Producers, 2016 CAPP Crude Oil Forecast, Markets & Transportation (Calgary: CAPP, 2016). If built, TMEP would be completed by this date.

¹²⁰ "Tidewater" refers to ocean access and the capability to transport oil to overseas markets via tankers.

Figure 80 illustrates existing capacity compared to production, assuming pipelines can only operate at 95% of rated capacity. Existing pipeline capacity would be full by 2020 in all of the NEB's scenarios. Oil moved by rail amounted to 93 kbd in July 2017, or about 2% of western Canadian supply.¹²¹

Figure 80: Western Canadian supply with and without the Alberta emissions cap compared to existing export pipeline, rail and refining capacity.

The National Energy Board's reference, higher carbon price and technology supply forecasts are shown. Pipelines are assumed to run at 95% of nameplate capacity. Pipeline capacity in all cases would be full by 2020, but if rail is included, existing capacity can handle all cases under the oil sands emissions cap.¹²²



The election of Donald Trump in the US has changed the political landscape for pipelines. The Obama administration cancelled the Keystone XL pipeline in November 2015, which would have added 830 kbd of export capacity. The Trump administration has reversed this decision and approved the Keystone XL pipeline. Furthermore, the Trudeau government approved the Line 3 restoration project in November 2016, which will add an additional 370 kbd of capacity, for a total of 1,200 kbd over and above existing capacity. Given the political support on both sides of the border, it seems likely that these pipelines will be built.

In addition, two tidewater pipelines have been proposed, the Trans Mountain expansion to the West Coast and Energy East to the East Coast (the Energy East pipeline has since been cancelled). The rationale for these pipelines was that a price premium would be obtained by selling oil on international markets. In fact, although a price differential did exist between the international price of oil (the Brent benchmark) and the North American price (the West Texas Intermediate or WTI benchmark) in the 2011–2014 timeframe when these pipelines were proposed, this differential has since been largely eliminated. The differential was caused by insufficient pipeline capacity from Cushing, Oklahoma, where the WTI benchmark is set, to the US Gulf Coast, where international prices can be accessed. This bottleneck was eliminated with the

¹²¹ National Energy Board, 2017, retrieved November 14, 2017, <https://www.neb-one.gc.ca/nrg/ststsc/crdlndptrlmprdct/stt/cndncrdlxprtsrl-eng.html>

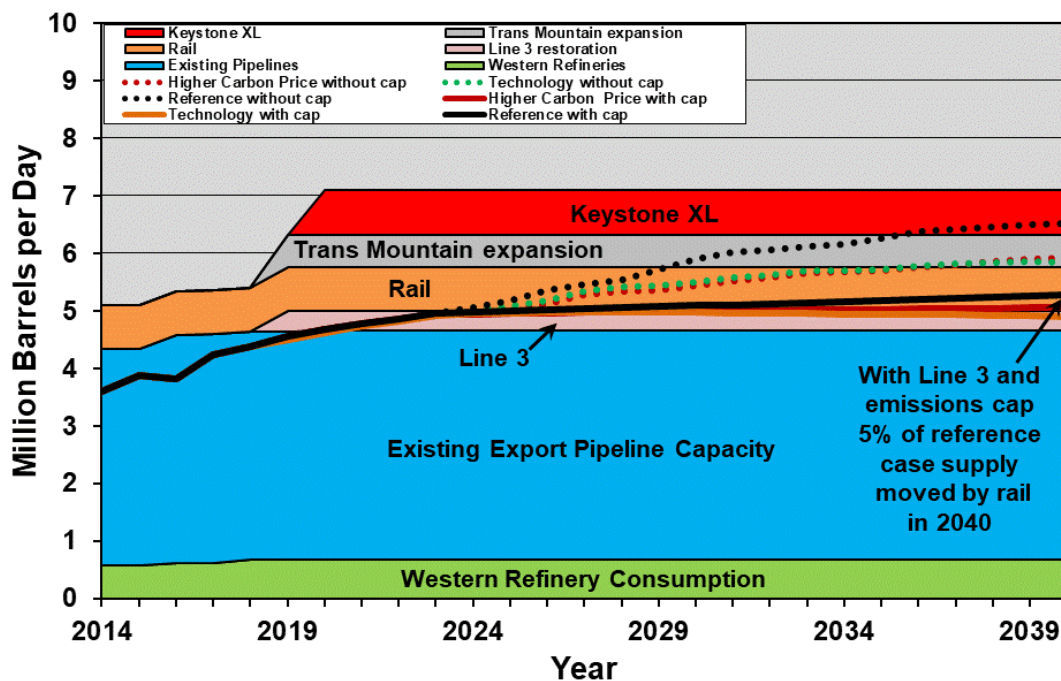
¹²² Data from CAPP Oil Forecast 2016; National Energy Board, Canada's Energy Future 2017

construction of new pipelines and the differential averaged just 82 cents per barrel in 2016.¹²³ Although this differential increased to \$3.49 per barrel in 2017, it is still far below the \$18 differential that existed in 2013 when these tidewater pipelines were proposed.

Figure 81 illustrates export pipeline capacity, refinery consumption and rail capacity compared to the western Canadian oil supply assuming the Line 3 restoration project, currently under construction, is completed, and the full capacity of the Keystone pipeline is restored (the capacity of the existing Keystone pipeline was reduced by 20% following a spill in November 2017). Under the emissions cap, pipeline capacity would be sufficient until 2025 and about 5% of 2040 production would have to be shipped by rail in 2040 in the NEB's reference scenario.¹²⁴ In the NEB's technology scenario, no rail would be needed. Also shown is the additional surplus capacity the Trans Mountain expansion and Keystone XL pipelines would represent. The Trans Mountain expansion project is facing legal challenges as of this writing; the Keystone XL project, however, has received approval from the Trudeau government, the Trump administration and the State of Nebraska, and appears likely to go ahead.

Figure 81: Western Canadian supply with and without the Alberta emissions cap compared to existing export pipeline, rail and refining capacity if the Line 3 restoration project is completed.

With the emissions cap, pipeline capacity would be sufficient until 2025 and about 5% of 2040 production would have to be shipped by rail in 2040. The completion of either Keystone XL or the Trans Mountain expansion would provide sufficient pipeline capacity without rail in all three of the National Energy Board's scenarios under the emissions cap.¹²⁵



¹²³ Hughes, J.D., 2017, Will the Trans Mountain pipeline and Tidewater Access raise Prices and Save Canada's oil industry?, Canadian Centre for Policy Alternatives. <https://www.policyalternatives.ca/sites/default/files/uploads/publications/2017/05/Trans%20Mountain%20Pipeline%20and%20Tidewater%20Access%20FINAL.pdf>

¹²⁴ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA> retrieved Oct 29, 2017. Emissions are from Environment and Climate Change Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip.

¹²⁵ Data from CAPP Oil Forecast 2016; National Energy Board, Canada's Energy Future 2017; and author's calculations.

Table 12 summarizes export capacity in the three NEB scenarios for western Canadian supply with the oil sands emissions cap, assuming various combinations of pipeline and rail. Existing pipeline capacity with the Line 3 restoration project would be sufficient for peak western Canadian supply only in the NEB's technology scenario. If rail is included, however, there would be a surplus capacity of between 8% and 14% at peak supply, with 5.4% carried by rail in 2040 in the NEB's reference scenario. If the Keystone XL and Trans Mountain expansion projects are also built, there would be a surplus of pipeline-only capacity of between 17% and 22% at peak supply. If rail is added to this latter case, surplus export capacity at peak supply would be between 26% and 30%.

Table 12: Pipeline and rail export capacity (including refinery consumption) compared to western Canadian supply at peak rates in three National Energy Board production cases, with various combinations of existing and proposed pipelines and rail (through 2040).

With rail, existing pipeline capacity and the completion of the Line 3 restoration project there would be between 8.4% and 13.8% surplus capacity at peak supply. Pipelines are assumed to run at 95% of nameplate capacity. (mbd = million barrels per day)

	Maximum WCSB supply with 100-Mt cap (mbd)	Year of maximum WCSB supply	Surplus capacity with existing pipelines and Line 3 (%)	Surplus capacity with existing pipelines, and Line 3 plus rail (%)	Surplus capacity with existing pipelines, Line 3, Trans Mountain expansion and Keystone XL (%)	Surplus capacity with existing pipelines, Line 3, Trans Mountain expansion and Keystone XL, plus rail (%)
NEB reference scenario	5.27	2040	-5.46%	8.36%	16.97%	25.79%
NEB higher carbon price scenario	5.06	2040	-1.26%	12.02%	20.28%	28.74%
NEB technology scenario	4.96	2027	0.74%	13.75%	21.85%	30.15%

The Trans Mountain expansion project from Edmonton to Burnaby has been vigorously opposed by environmental groups, First Nations and municipal governments. The principal argument the federal government has used for approving this project, that new pipeline access to tidewater will confer a significant price premium for western Canadian oil, has been shown to be false.^{126,127,128} If the Alberta oil sands emissions cap is observed, new pipelines would not be needed if small amounts of rail transport are included. Even with the emissions cap, oil production emissions alone will grow to 25% of Canada's allowable commitments under the Paris Agreement in 2030, which will make meeting these commitments very difficult or impossible.¹²⁹ Without the cap, additional export pipelines would be needed, but would render Canada's commitments under the Paris Agreement even less achievable.

¹²⁶ Oil Change International, March 2016, TAR SANDS: THE MYTH OF TIDEWATER ACCESS, <http://priceofoil.org/content/uploads/2016/05/Tidewater-2016-v2.pdf>

¹²⁷ Jeff Rubin, Globe and Mail, November 1, 2016, New pipelines? The oil sands may have trouble filling the ones it has, <http://www.theglobeandmail.com/report-on-business/rob-commentary/new-pipelines-the-oil-sands-mayhave-trouble-filling-the-ones-it-has/article32601876/>

¹²⁸ Hughes, J.D., 2017, Will the Trans Mountain pipeline and Tidewater Access raise Prices and Save Canada's oil industry?, Canadian Centre for Policy Alternatives

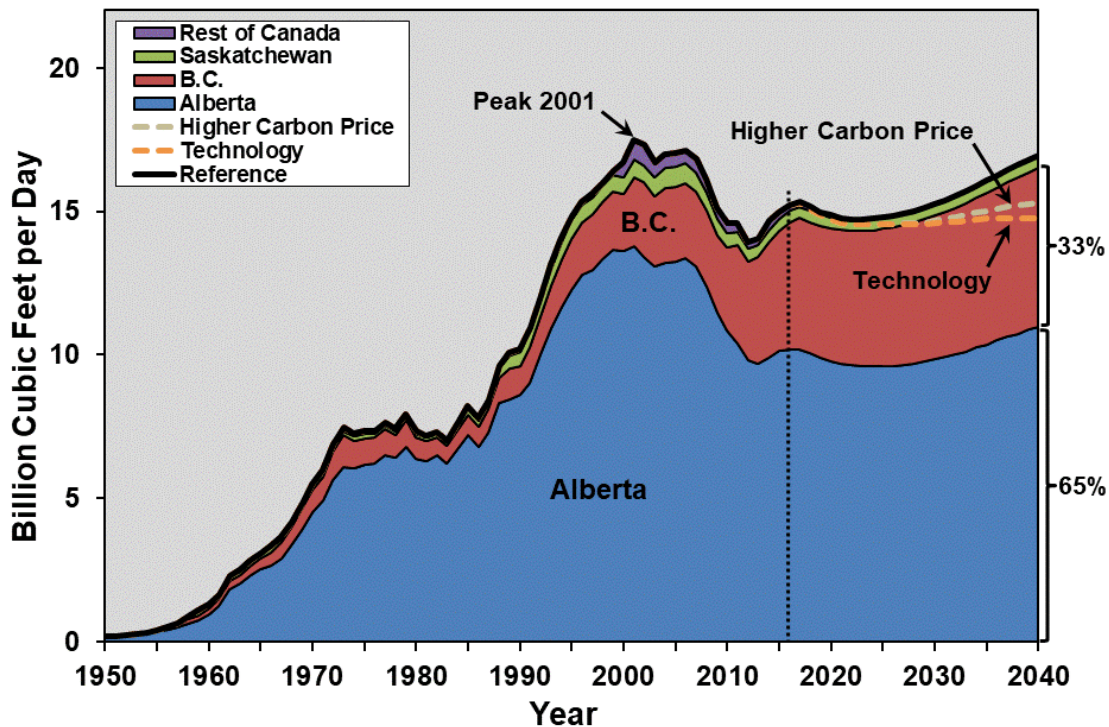
¹²⁹ Hughes, J.D., 2016, Can Canada Expand Oil and Gas Production, Build Pipelines and Keep Its Climate Change Commitments?, Canadian Centre for Policy Alternatives, 38p, https://www.policyalternatives.ca/sites/default/files/uploads/publications/National%20Office%2C%20BC%20Office/2016/06/Can_Canada_Expand_Oil_and_Gas_Production.pdf

2.1.5 Natural gas

Natural gas production in Canada peaked in 2001 and is now down 14% from its peak (see Figure 51), despite record drilling rates in 2006 and record high prices in 2008. Although Alberta has been by far the most important contributor to the Canadian gas supply, BC has become a major supply source and is forecast to provide one-third of the Canadian supply in 2040, mainly through the development of extensive shale and tight gas resources made accessible with horizontal drilling and hydraulic fracturing technology (fracking). Figure 82 illustrates historical production and the NEB's reference case forecast by province. Under the reference scenario, Canadian production in 2040 is projected to be roughly what it was in 2001.

Figure 82: Historical natural gas production by province from 1950 to 2016, and the National Energy Board's reference case forecast to 2040.

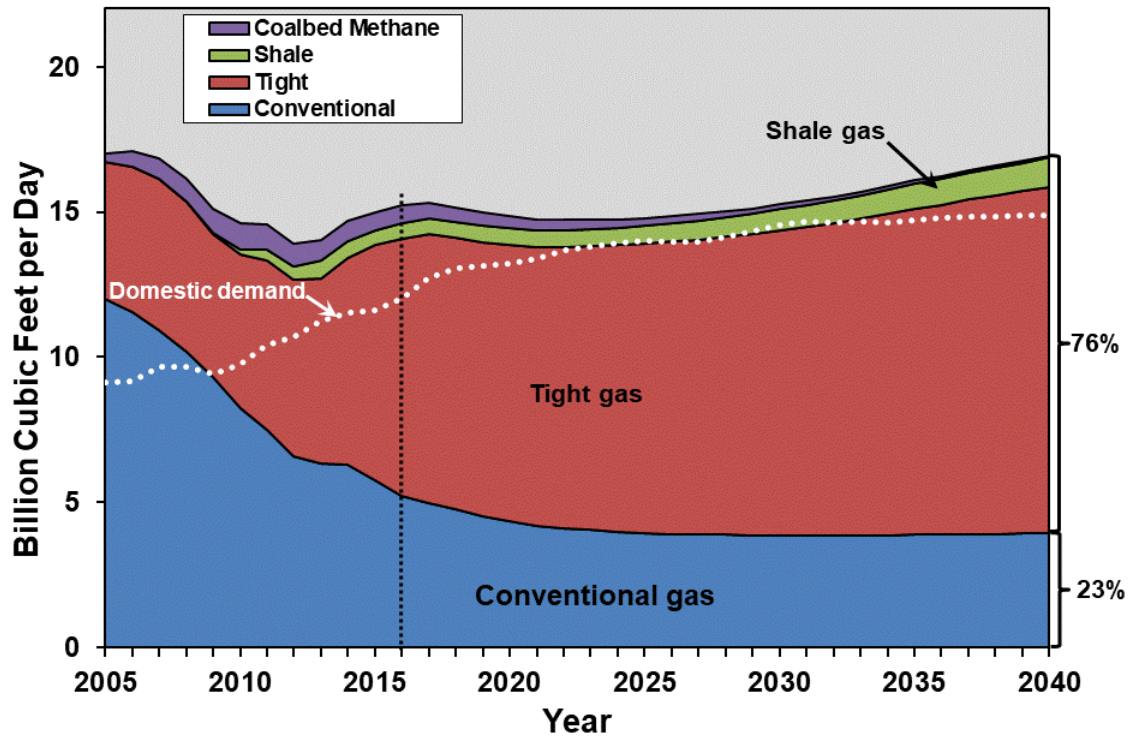
Peak production occurred in 2001 and is currently down 14% below peak (see Figure 51). Also shown are the NEB's higher carbon price and technology production scenarios.¹³⁰



¹³⁰ 1950–1999 data from CAPP; 2000–2004 data from National Energy Board, Energy Future 2016; 2005–2040 data from National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/fttrpndc/dflr.aspx?GoCTemplateCulture=en-CA> retrieved Oct 29, 2017.

Figure 83 illustrates current and future production by play type as well as projected gas consumption in the NEB's reference scenario. Although conventional gas dominated Canadian production in the past, future production will predominantly come from unconventional tight and shale gas sources. Canada has historically been a major exporter of natural gas, however, future NEB projections suggest that the production surplus compared to domestic demand will narrow to less than 10% beginning in 2021.

Figure 83: Natural gas production by play type from 2005 to 2040 in the National Energy Board's reference case scenario, and domestic demand.¹³¹

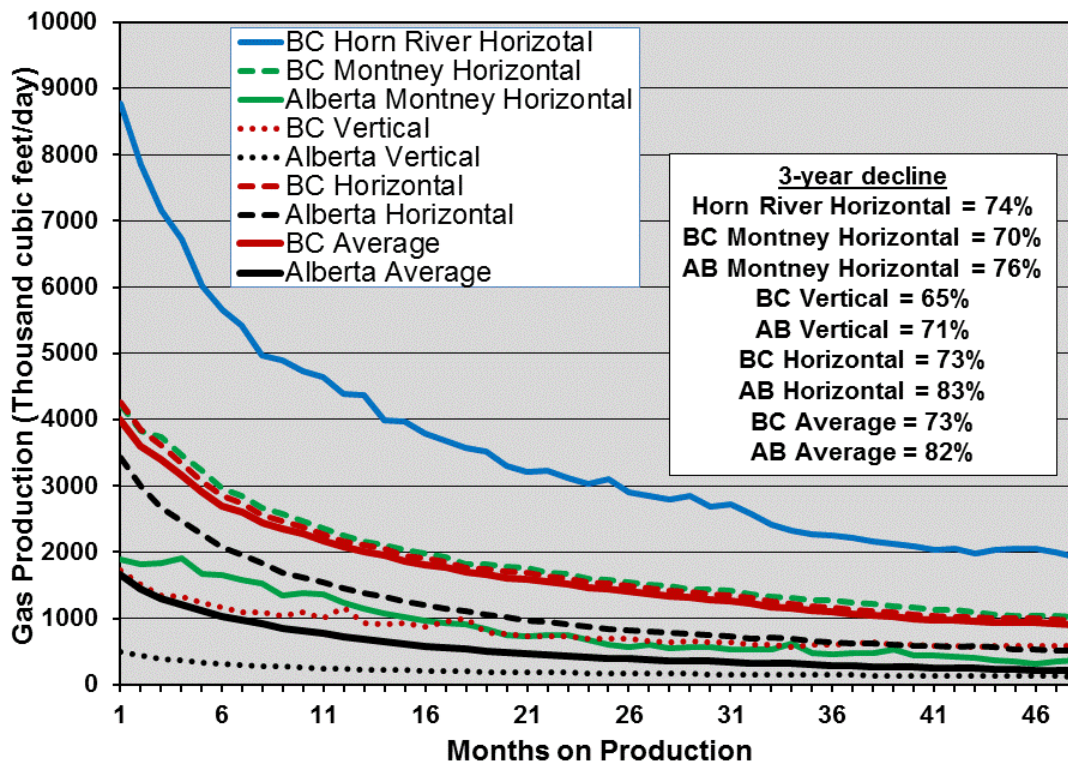


¹³¹ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA> retrieved Oct 29, 2017.

As with oil, gas wells decline in production rapidly over the first few years, necessitating more drilling to maintain production. The decline in natural gas prices since 2008 has resulted in a decline in drilling rates, which is responsible for much of the decline in Canadian production. This decline was offset in part by increasing numbers of horizontal fracked wells, which opened up new resources in the Montney and Horn River plays of western Alberta and northeast BC. Figure 84 illustrates the average production rates over time of gas wells (it does not include gas production that may come from oil or bitumen wells). As can be seen, horizontal wells are much more productive than vertical wells. The Horn River shale wells in northeast BC are very productive—equivalent to the best US shale gas plays—but they are also very expensive. Horn River wells average 25 million gallons of injected fracking fluid, compared to four million for the Montney.¹³² Production declines in the first three years average between 70% and 83% for horizontal wells and between 65% and 71% for vertical wells. As decline is hyperbolic, with the steepest decline in the first few years, overall field decline from a mix of old and new wells typically ranges between 25% and 40% per year, requiring replacement each year through more drilling to keep production flat.

Figure 84: Average production decline profiles for horizontal and vertical wells in Alberta and BC

Includes gas wells only—not oil or bitumen wells, which also may produce some gas.¹³³

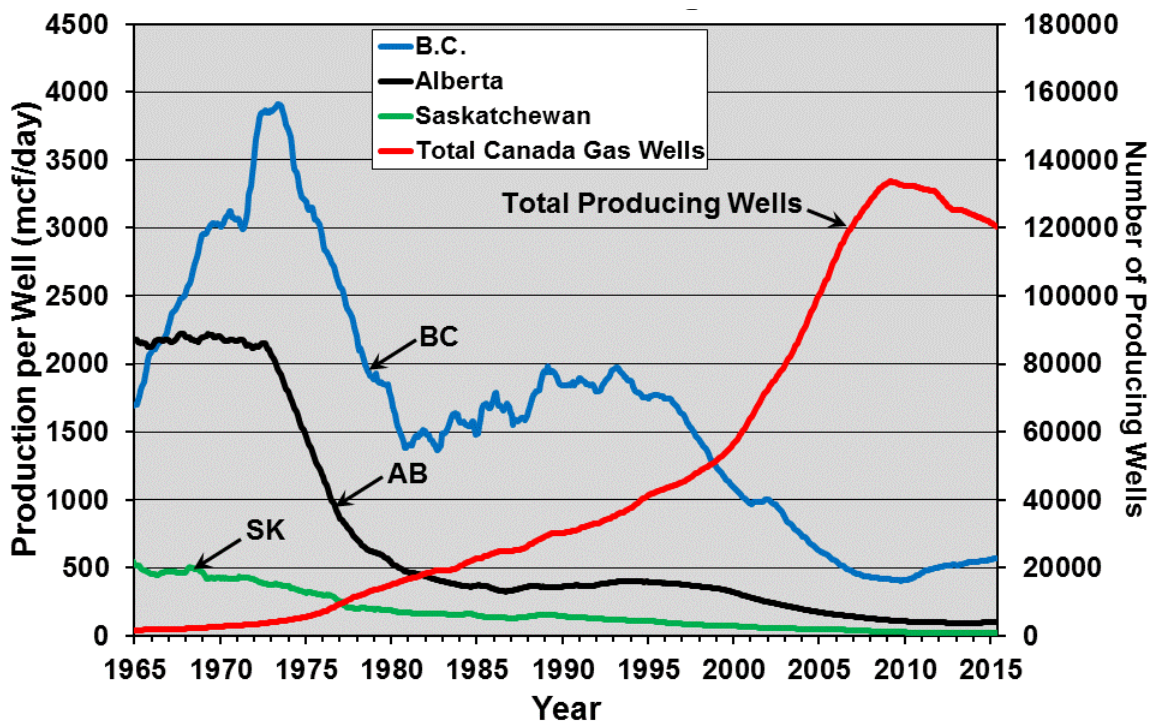


¹³² Hughes, J.D., 2015, A Clear Look at BC LNG, https://www.policyalternatives.ca/sites/default/files/uploads/publications/BC%20Office/2015/05/CCPA-BC-Clear-Look-LNG-final_O_O.pdf

¹³³ Data from Drillinginfo, December 2015

Given the steep drop in production of the average natural gas well in the first years after it is drilled and the rapidly escalating number of wells, the average productivity of wells has declined over time. Figure 85 illustrates average natural gas production per well by province since 1965. Peak production per well occurred in the late 1960s and early 1970s in all provinces. More and more wells and infrastructure are required to maintain production as wells decline and fields are exhausted. This trend of declining average production will continue despite the generally higher productivity of new horizontal wells, given the large number of lower-producing legacy wells that are responsible for the bulk of production. The total number of producing wells peaked at just over 133,000 in late 2009 and has declined since as older wells become uneconomic and are shut in.

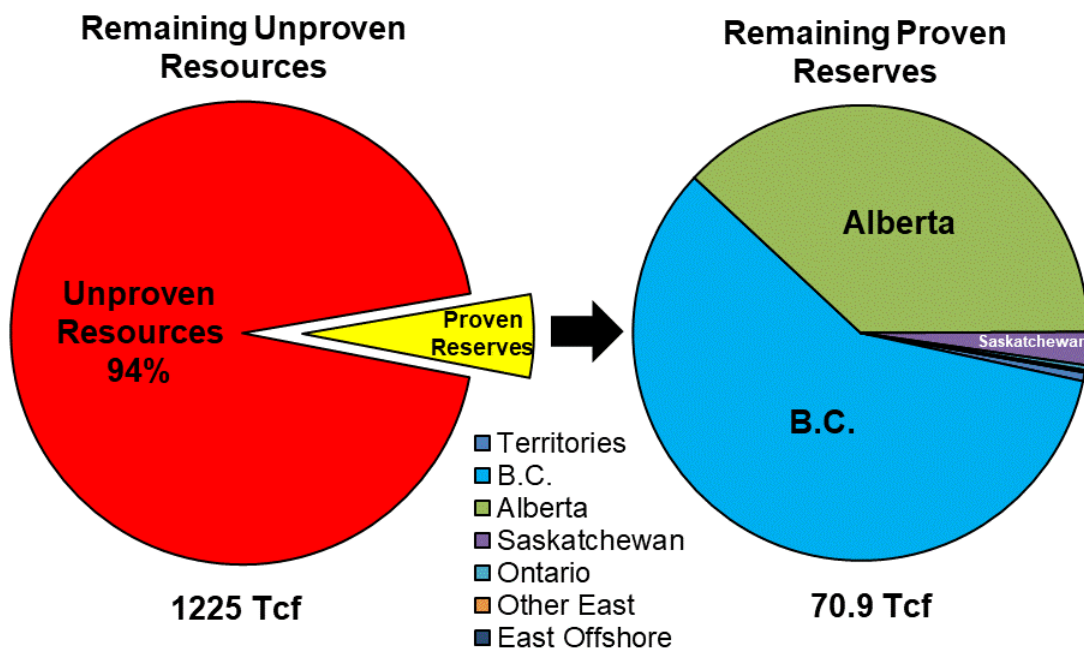
Figure 85: Average production (mcf = thousand cubic feet) per natural gas well by province from 1965 to 2015, and total number of producing natural gas wells (includes gas wells only—not oil or bitumen wells, which also may produce some gas).¹³⁴



¹³⁴ Data from Drillinginfo, December 2015; 12 month centred moving average

Natural gas reserves are defined as discovered resources that are technically and economically recoverable. They are usually expressed in probabilistic terms: “proven,” “probable” and “possible.”¹³⁵ The NEB does not provide estimates of natural gas reserves in its *Energy Futures* reports as it does for oil. Instead, it provides only estimates of “marketable resources” calculated by methodology that does not conform to the requirements of regulations such as National Instrument 51-101, under which Canadian reserve and resource reporting is regulated. Given the assumptions and limited data used as a basis for its estimates, the NEB’s reported marketable resources should be viewed as approximate and likely highly optimistic. However, the provinces do apply stringent criteria to estimate natural gas “reserves.” These are compared to the NEB’s resource estimates in Figure 86.

Figure 86: Marketable natural gas resources as of year-end 2015 estimated by the National Energy Board¹³⁶ compared to reserves estimated by the provinces and compiled by the Canadian Association of Petroleum Producers¹³⁷ (tcf = trillion cubic feet).



Reserves are typically replaced over time with more drilling, but this cannot continue indefinitely as natural gas is a non-renewable resource. The NEB’s reference case forecast calls for the production of 135 trillion cubic feet (tcf) over the 2017–2040 period, which is nearly double Canada’s currently known reserves of 70.9 tcf.

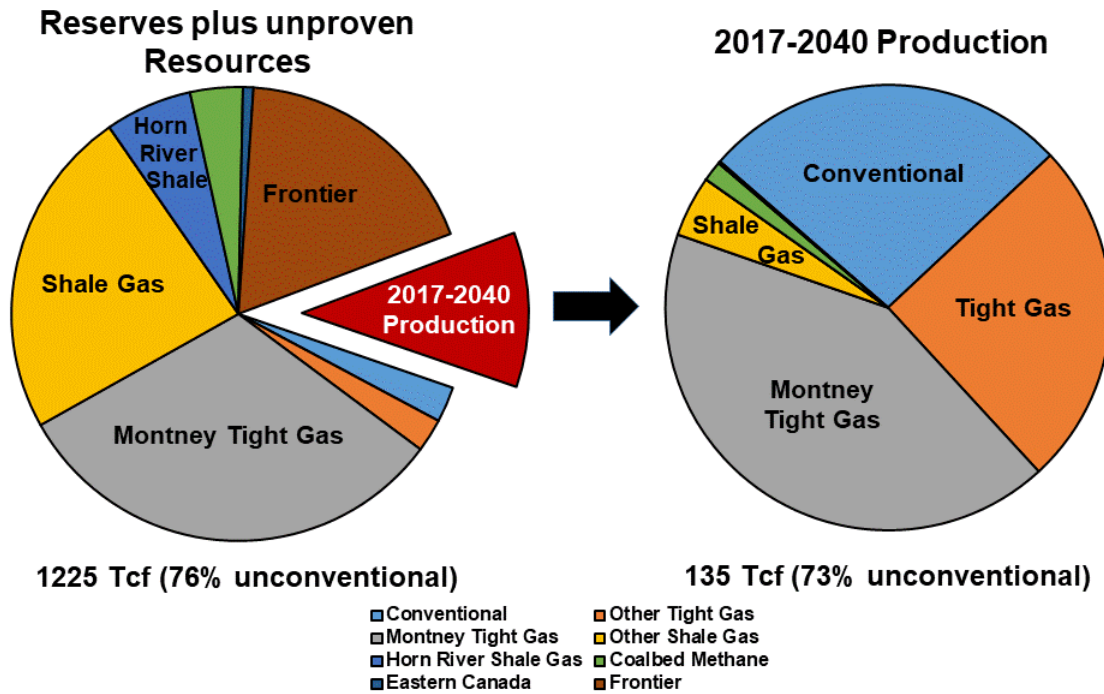
¹³⁵ Society of Petroleum Engineers, 2011, Guidelines for Application of the Petroleum Resources Management System http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf. In Canada reserve and resource reporting is regulated under National Instrument 51-101 which is guided by technical standards in the Canadian Oil and Gas Evaluation Handbook updated periodically by the Canadian branch of the Society of Petroleum Engineers.

¹³⁶ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/fttrpndc/dflt.aspx?GoCTemplateCulture=en-CA>

¹³⁷ Canadian Association of Petroleum Producers Statistical Handbook, retrieved November 5, 2017, <http://www.capp.ca/publications-and-statistics/statistics/statistical-handbook>

The NEB's estimates of marketable resources by source in its reference case are illustrated in Figure 87, along with forecast production under this scenario. Unconventional resources made possible by the application of horizontal drilling and fracking constitute 76% of remaining resources, and 73% of 2017–2040 production.

Figure 87: Remaining Canadian marketable natural gas resources by type after 2017–2040 production is removed (tcf = trillion cubic feet), according to the National Energy Board (left), along with cumulative production over the same period (right).¹³⁸

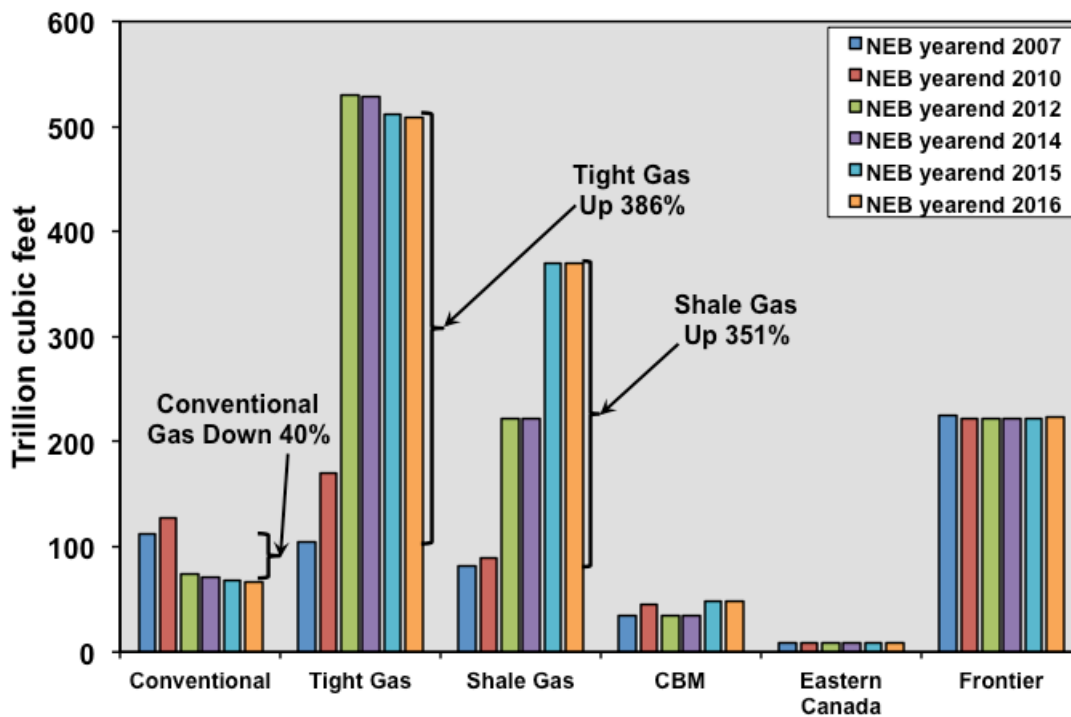


¹³⁸ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/fttrpndc/dflt.aspx?GoCTemplateCulture=en-CA>

As Canada is now mainly dependent on unconventional sources of natural gas for future supply, and the recovery of that gas depends on hydraulic fracturing technology, which has been found to have serious environmental impacts in some jurisdictions,¹³⁹ it is prudent to assess the uncertainty of the NEB's estimates, given their importance for future energy security. Figure 88 illustrates the growth of NEB estimates of marketable resources by source from 2007 to 2017. Virtually all of the increases have been in unconventional tight gas and shale gas—conventional gas resources have declined by nearly half since 2010 and frontier resources have remained constant. Coalbed methane, which in 1999 the NEB believed would be able to provide up to 80% of Canadian production by 2025, has increased little and is projected to be a very minor portion of supply through 2040.¹⁴⁰

Figure 88: NEB estimates of “marketable” natural gas resources from year-end 2007 through to year-end 2016.

Virtually all growth stems from vast increases in estimates of unconventional tight gas and shale gas resources.¹⁴¹



¹³⁹ U.S. Environmental Protection Agency, 2016, EPA's Study of Hydraulic Fracturing for Oil and Gas and Its Potential Impact on Drinking Water Resources, <https://www.epa.gov/hfstudy>

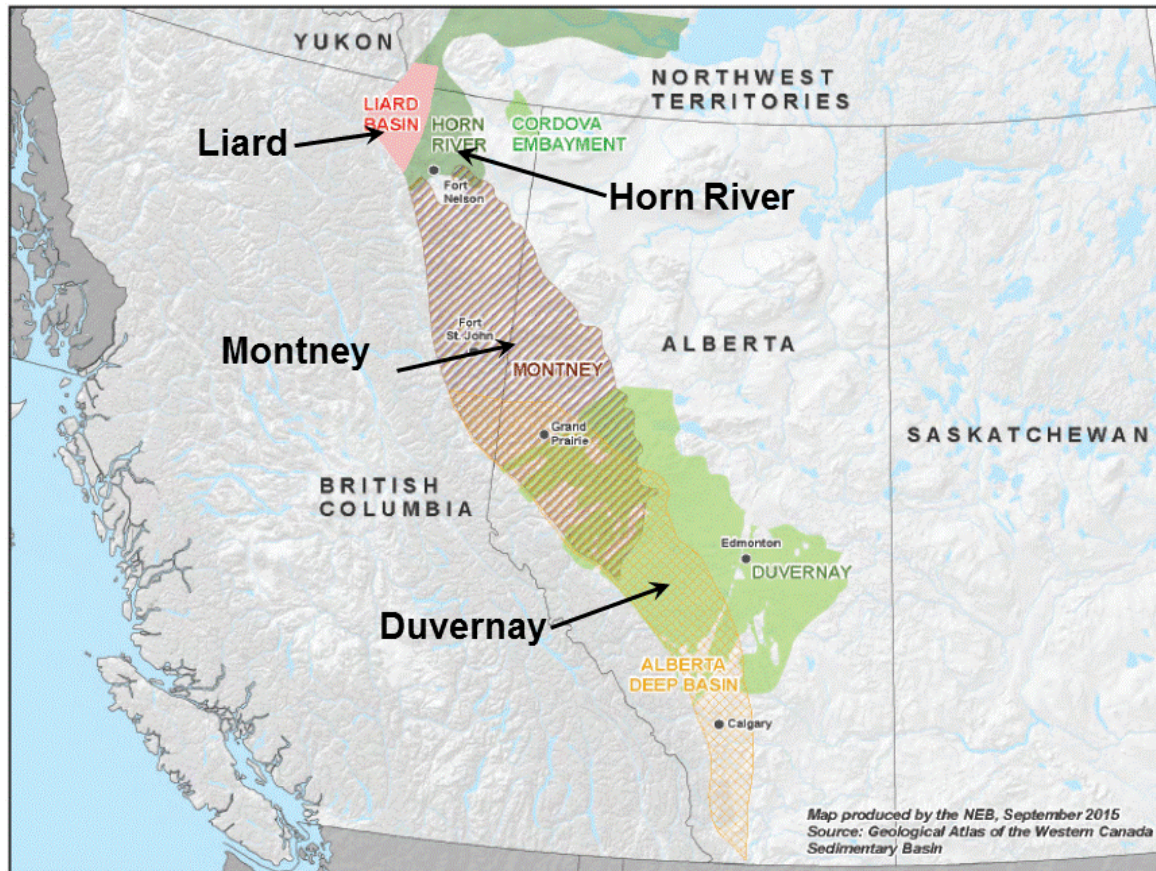
¹⁴⁰ National Energy Board, 1999, Canadian Energy - Supply and Demand to 2025 (released in 1999), see Figure 5.6 on page 49.

¹⁴¹ Data from National Energy Board, 2009, 2011, 2013, 2016, 2017

The NEB has more than quadrupled its estimates of tight gas and shale gas since 2007, based primarily on three studies of resources in northwest Alberta and northeast BC: the Horn River shale play,¹⁴² the Montney tight gas play¹⁴³ and the Liard Basin shale play.¹⁴⁴ Together, these plays made up 74% of the NEB's remaining marketable resource estimates for Western Canada at year-end 2015 (see Figure 89). A fourth study, of the unconventional Duvernay play, has recently been released but has not yet increased the NEB's marketable gas estimates.¹⁴⁵

Figure 89: Location of Montney, Horn River and Liard plays, which constitute 74% of the National Energy Board's estimate of remaining "marketable" natural gas resources.¹⁴⁶

The Duvernay is an emerging play that produces both gas and oil.



¹⁴² National Energy Board, 2011, Ultimate Potential for Unconventional Natural Gas in Northeast British Columbia's Horn River Basin, <https://www.neb-one.gc.ca/nrg/sttstc/ntrlg/rprt/archive/ncnvtntlntrlgshrnrvrbsnhnrnr2011/ncnvtntlntrlgshrnrvrbsnhnrnr2011-eng.pdf>

¹⁴³ National Energy Board, 2013, The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta - Energy Briefing Note, <http://www.neb-one.gc.ca/nrg/sttstc/ntrlg/rprt/ltmptntlmntnyfrmtn2013/ltmptntlmntnyfrmtn2013-eng.html>

¹⁴⁴ National Energy Board, 2016, The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin of British Columbia, the Northwest Territories, and Yukon - Energy Briefing Note, <https://www.neb-one.gc.ca/nrg/sttstc/ntrlg/rprt/ltmptntlbcnwtkn2016/index-eng.html>

¹⁴⁵ National Energy Board, Duvernay Resource Assessment Energy Briefing Note September 2017, <https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmpdct/rprt/2017dvrn/2017dvrn-eng.pdf>

¹⁴⁶ National Energy Board, January 2016, Canada's Energy Future 2016 - Energy Supply and Demand Projections to 2040, <https://www.neb-one.gc.ca/nrg/ntgrtd/ft/2016/2016nrgft-eng.pdf>

Table 13 illustrates the well count, cumulative production and year-end 2015 NEB marketable resource estimates for the Montney, Horn River and Liard tight gas and shale gas plays. Of these, the Montney has the most drilling, with 6,800 wells drilled, of which 4,200 are still producing. It has produced nearly seven tcf to date, or less than 2% of the NEB's recoverable estimate of 445 tcf. The NEB estimate is based on a probabilistic assessment of variables such as thickness, depth, organic content, pressure, temperature, porosity and recovery factors over very broad areas, and hence yields a very large number—larger than the Marcellus, the largest shale gas play in the US, which has had considerably more exploration and production effort. The Montney study has a high level of uncertainty as to how much of this resource will ever be recovered. Its authors note that “no study has been undertaken to determine the economics for marketable resources.”¹⁴⁷

Table 13: Well count, cumulative production and the National Energy Board's year-end 2015 “marketable” resource estimates for the Montney, Horn River and Liard tight gas and shale gas plays, which account for 74% of its estimates of Western Canada's remaining gas resources.¹⁴⁸

Also shown are the uncertainty ratings for the NEB's estimates (tcf = trillion cubic feet).

Play	Province	Well type	Total wells	Producing wells	Total producing wells	Cumulative production (tcf)	Total cumulative production (tcf)	NEB estimate gas (tcf)	Uncertainty
Montney (tight gas)	Alberta	Vertical	1,646	618	4,181	1.67	6.86	177	High
		Horizontal	1,587	1,141		0.89			
	BC	Vertical	1,231	499		0.73		268	
		Horizontal	2,325	1,923		3.57			
Horn River (shale gas)	BC	All	313	186	186	0.88	0.88	77	Very high
Liard (shale gas)	BC	All	4	3	3	0.01	0.01	167	Extremely high
	Yukon	All	-	-		0.00		8	
	NWT	All	-	-		0.00		44	
Total		All	7,106	4,370	4,370	7.76	7.76	741	Very high

The Horn River shale gas play was the first unconventional play assessed by the NEB, in a 2011 report. This play has had relatively little exploration, with 313 wells drilled, of which 186 are still producing. The Horn River play is more remote and wells are more expensive than in the Montney, as they are deeper and use much larger volumes of injected water, proppants and chemicals. The Horn River wells are, however, much more productive on average than the Montney wells (see Figure 83), and are among the most prolific shale gas wells in Canada and the US. The NEB's assessment of Horn River marketable resources used the same probabilistic methods outlined above for the Montney, however, given the fact that there is much less drilling information for the play, the uncertainty as to how much of this resource will ever be recovered

¹⁴⁷ National Energy Board, 2013, The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta - Energy Briefing Note, <http://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/lmtptntlmntnyfrmtn2013/lmtptntlmntnyfrmtn2013-eng.html>

¹⁴⁸ Total and producing well counts and well type are from Drillinginfo and are current to August 2015. “Marketable” resource estimates are current to year-end 2015 and are from the NEB October 2016 Energy Future update.

must be rated as very high. For example, the Horn River study used recovery factors of 15% to 25%¹⁴⁹ of in-place resources, compared with estimates from more mature shale plays in the US of 1.7% to 11.2%.¹⁵⁰ Using an average recovery factor of 6% instead of 18% (the average used in the NEB's "medium" estimate) would alone reduce the marketable resource estimate by two-thirds (from 77 tcf to 25.4 tcf). As with the Montney study, the Horn River study adds the disclaimer that "no study has been undertaken to determine the economics for marketable resources,"¹⁵¹ hence the marketable resource assessment should be viewed as highly optimistic.

The Liard shale play study is the most recent NEB assessment of an unconventional natural gas resource.¹⁵² The Liard Basin is located in northern BC and parts of the southern Yukon and Northwest Territories, as shown in Figure 88. There are four modern shale gas wells located in the BC portion of the basin, of which three are producing. Estimates of in-place resources used a probabilistic methodology comparable to the earlier Horn River and Montney studies, however, the marketable estimate used the estimated ultimate recovery (EUR) of an "index" well. Presumably it was assumed that all wells drilled within the play area would be successful (with modest reductions in deformed portions), and would have EURs comparable to the index well after adjustments for variables like depth and pressure.

The production data for the four available wells are given in Table 14 (next page). The EURs are estimated at between 2.2 and 10.3 billion cubic feet (bcf), with a mean EUR of 6.25 bcf (an EUR of 6.25 bcf is a very good well by comparison to most shale plays). The NEB chose the best well, C-45-K, for its "index" well and assumed it would have an EUR of 15.8 bcf, or nearly three times the average of the four available wells and 53% higher than actual production data for C-45-K suggest, and hence its estimate is extremely optimistic.

The NEB estimates recovery factors of 19.7% of in-place resources in its "expected" case for the BC portion of the basin, compared to estimates of 1.7% to 11.2%¹⁵³ in mature US shale plays. Using the average EUR of the four available wells (rather than an overestimate of the best one) would reduce the recovery factor to 7.8% and the estimated marketable resource by 60%. This, coupled with the relatively small amount of data available for the probabilistic part of the assessment, means that the NEB's marketable resource estimate for the Liard Basin should be viewed as extremely optimistic. As with the Montney and Horn River studies, the NEB adds the disclaimer that "no study has been undertaken to determine the economics for marketable resources."¹⁵⁴

¹⁴⁹ National Energy Board, 2011, Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin, see page 6-7, <https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/archive/ncvntnlIntrlgshrnrvrbsnhrrvr2011/ncvntnlIntrlgshrnrvrbsnhrrvr2011-eng.pdf>

¹⁵⁰ Oil and Gas Journal, November 3, 2014, New well-productivity data provide US shale potential insights, <http://www.ogj.com/articles/print/volume-112/issue-11/drilling-production/new-well-productivity-data-provide-us-shale-potential-insights.html>

¹⁵¹ Supra note 149

¹⁵² National Energy Board, 2016, The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin of British Columbia, the Northwest Territories, and Yukon - Energy Briefing Note, <https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmptntlbcnwtkn2016/index-eng.html>

¹⁵³ Oil and Gas Journal, November 3, 2014, New well-productivity data provide US shale potential insights, <http://www.ogj.com/articles/print/volume-112/issue-11/drilling-production/new-well-productivity-data-provide-us-shale-potential-insights.html>

¹⁵⁴ Supra note 152

Table 14: Producing shale gas wells in the Liard Basin using the National Energy Board's assessment.

Estimated ultimate recoverable gas (EUR) is shown for each well along with the NEB's assumed EUR for its "index" well used to estimate marketable resources.

Well	C-45-K	C-86-F	D-28-B	B-20-I
First production	2/1/2011	12/1/2011	9/1/2009	11/1/2013
Months of production	55	44	52	15
Total depth (feet)	15,567	14,514	12,963	15,414
Status	active	active	suspended	active
Drill type	H	V	V	H
Cumulative gas (bcf)	6.8	3.8	1.4	0.6
Peak gas (mcf/d)	18,818	6,178	3,508	3,843
Latest gas (mcf/d)	1,263	1,945	724	587
EUR 50 years (bcf)	10.3	9.1	3.4	2.2
BC C-45-K well EUR assumption (bcf)	15.8 (.85 km lateral)			
BC index well EUR assumption (bcf)	32.5 (1.75 km lateral)			

With its three unconventional gas resource studies, the NEB increased Canada's remaining marketable gas resources by 60% (741 tcf). This compares to just 68 tcf of remaining conventional resources, which Canada has relied on for the past 70 years. Other resources are mainly offshore, on the East Coast and in the Arctic. Given the highly to extremely optimistic nature of the three NEB studies outlined above, it is a mistake to weight these unconventional resources too heavily when planning future Canadian supply.

2.2 Coal

Coal has been a major source of electricity generation in Alberta, Saskatchewan, Ontario and Nova Scotia for many decades. Metallurgical coal for steel-making also supports a large export industry from mines in the foothills and front ranges of Alberta and BC. Emphasis on reducing the carbon emissions from coal-fired power generation has resulted in a coal phase-out in Ontario, which was completed in 2014, and a pledge by Alberta to shutter the last of its coal plants by 2030. Saskatchewan, which has employed carbon capture and storage (CCS) technology to reduce emissions,¹⁵⁵ and Nova Scotia are likely to continue to use coal at some level beyond 2030.

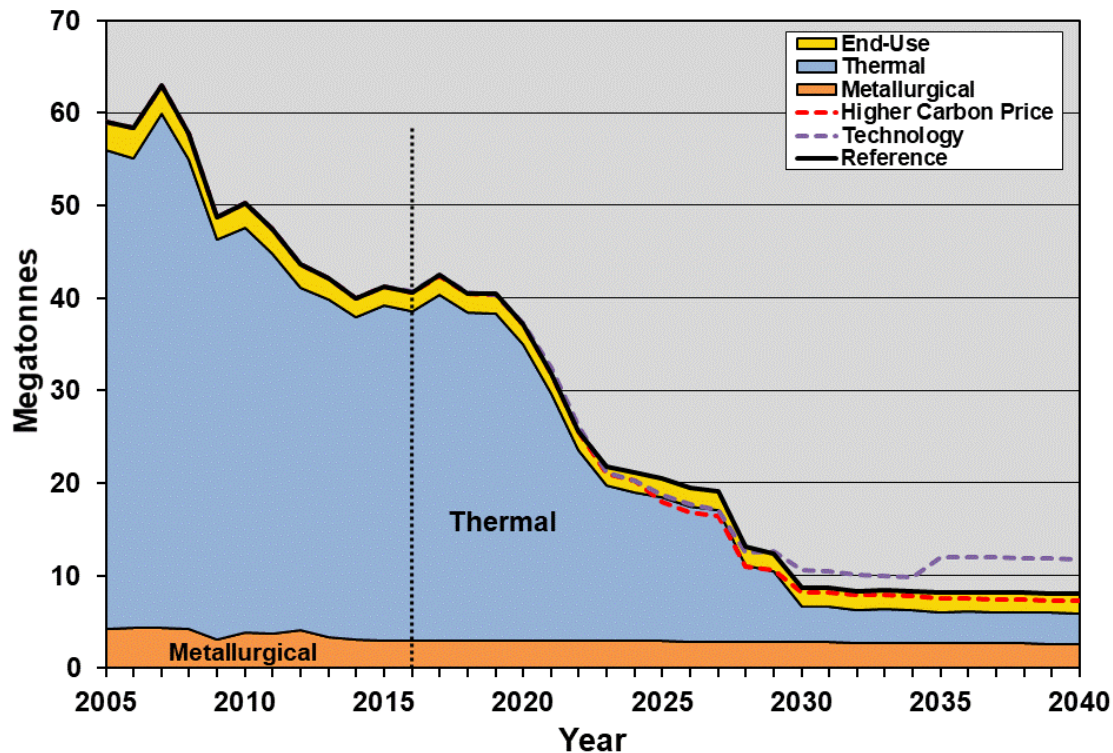
Although a large proportion of coal burned in the world is used for electricity generation, metallurgical (or "coking") coal is essential in the steel-making industry and has few economical substitutes. Coal is classified by rank or thermal maturity, which is a function of the temperature and time it has been exposed to over its geological history. Lower-rank subbituminous and lignite coals, along with non-coking bituminous coals, are used exclusively for thermal applications. They are widespread in the plains and foothills of Alberta and BC, in southern Saskatchewan and in Nova Scotia, with smaller deposits in the

¹⁵⁵ Global CCS Institute, Boundary Dam Carbon Capture and Storage Project, retrieved 21 February 2017, <https://www.globalccsinstitute.com/projects/boundary-dam-carbon-capture-and-storage-project>

interior of BC, on Vancouver Island and in the James Bay region of Ontario. Higher-rank metallurgical coal is limited to the foothills and front ranges of BC and Alberta.¹⁵⁶

Figure 90 illustrates coal consumption in Canada and the NEB's projections through 2040. The shutdown of coal-fired electricity generation in Ontario has resulted in a major drop from 2005 levels, and the planned coal phase-out in Alberta by 2030 will result in a further major drop by 2030. Metallurgical coal for steel plants in Eastern Canada, which is mainly imported from the US, will continue to be used, along with some thermal coal for power generation and non-power end-use applications.

Figure 90: Coal consumption in Canada by type from 2005 to 2040, the National Energy Board's reference case is illustrated, along with its higher carbon price and technology case projection through 2040.¹⁵⁷



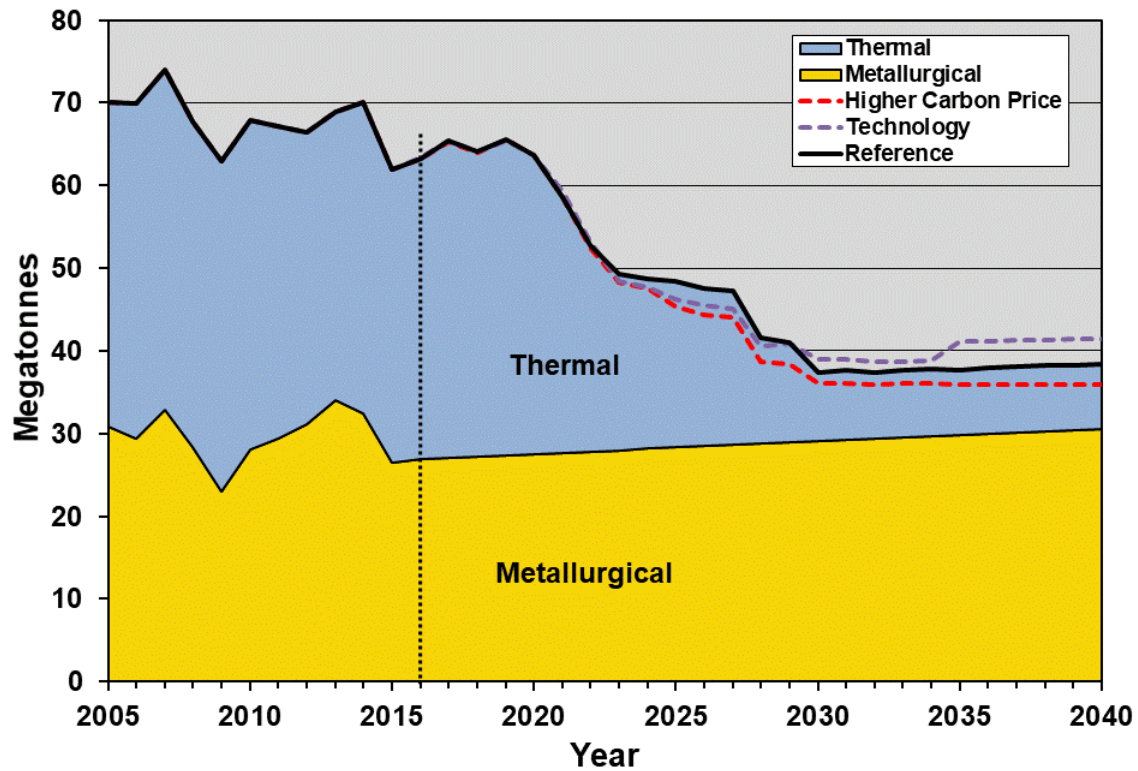
¹⁵⁶ For a detailed look at the distribution and characteristics of coal in Canada, see Smith, G.G., 1989, Coal Resources of Canada, Geological Survey of Canada Paper 89-4.

¹⁵⁷ National Energy Board Energy Future, October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ft/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftppndc/dflt.aspx?GoCTemplateCulture=en-CA>

Canadian coal production, along with the NEB's projections, is illustrated in Figure 91. Metallurgical coal production in Western Canada for export is expected to continue at slightly increasing levels through 2040, whereas thermal coal production is expected to fall by 77% (from 2016 levels) by 2030, due to the closure of coal-fired power plants in Alberta.

Figure 91: Canadian coal production by type from 2005 to 2040.

The National Energy Board's reference case is illustrated along with its higher carbon price and technology case projections through 2040.¹⁵⁸



¹⁵⁸ Data from NEB Energy Future 2017

Figure 92 illustrates the NEB's projections of coal imports and exports through 2040. Canada will continue to export some thermal coal through 2040, and will export gradually increasing amounts of metallurgical coal from Western Canada. Thermal coal imports have been radically reduced with the closure of coal-fired power plants in Ontario but will continue to supply plants in New Brunswick and Nova Scotia. Metallurgical coal imports will also continue to supply steel mills in Eastern Canada.

Figure 92: Canadian coal imports and exports by type from 2005 to 2040.

The National Energy Board's reference case projection is illustrated through 2040. The NEB's higher carbon price and technology projections are not shown here, as they are not significantly different from the reference case.¹⁵⁹

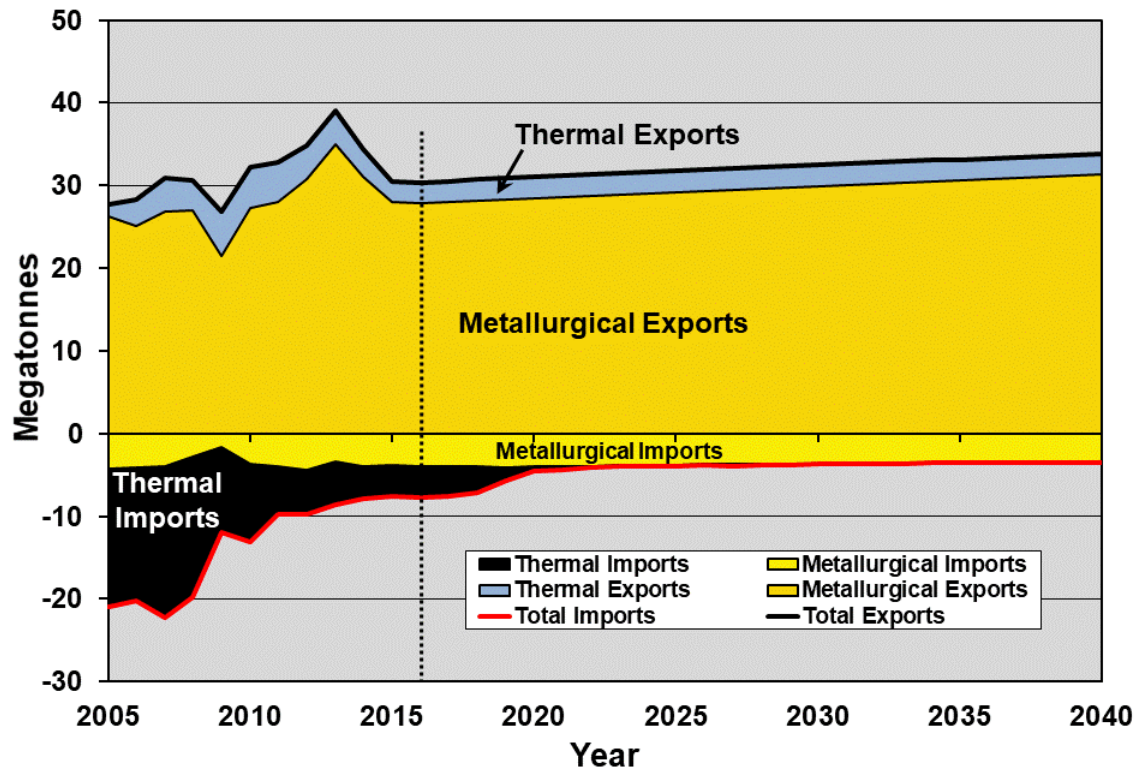


Table 15 illustrates remaining Canadian coal reserves and resources as of 2014. At 2015 production levels, reserves would last for 155 years for metallurgical coal and 70 years for thermal coal. At 2030 production levels metallurgical and thermal coal reserves would last for 142 and 675 years, respectively. The resources in Table 15 should be viewed as highly speculative.

Table 15: Canadian coal reserves and resources as of 2014 according to the World Energy Council.¹⁶⁰

Hard coal roughly equates to metallurgical coal, and subbituminous/lignite to thermal coal.

2014 reserves (billion tonnes)			2014 resources (billion tonnes)		
Hard coal	Subbituminous/ lignite	Total	Hard coal	Subbituminous/ lignite	Total
4.35	2.24	6.58	183.26	118.27	301.53

¹⁵⁹ Data from NEB Energy Future 2017 Reference Case

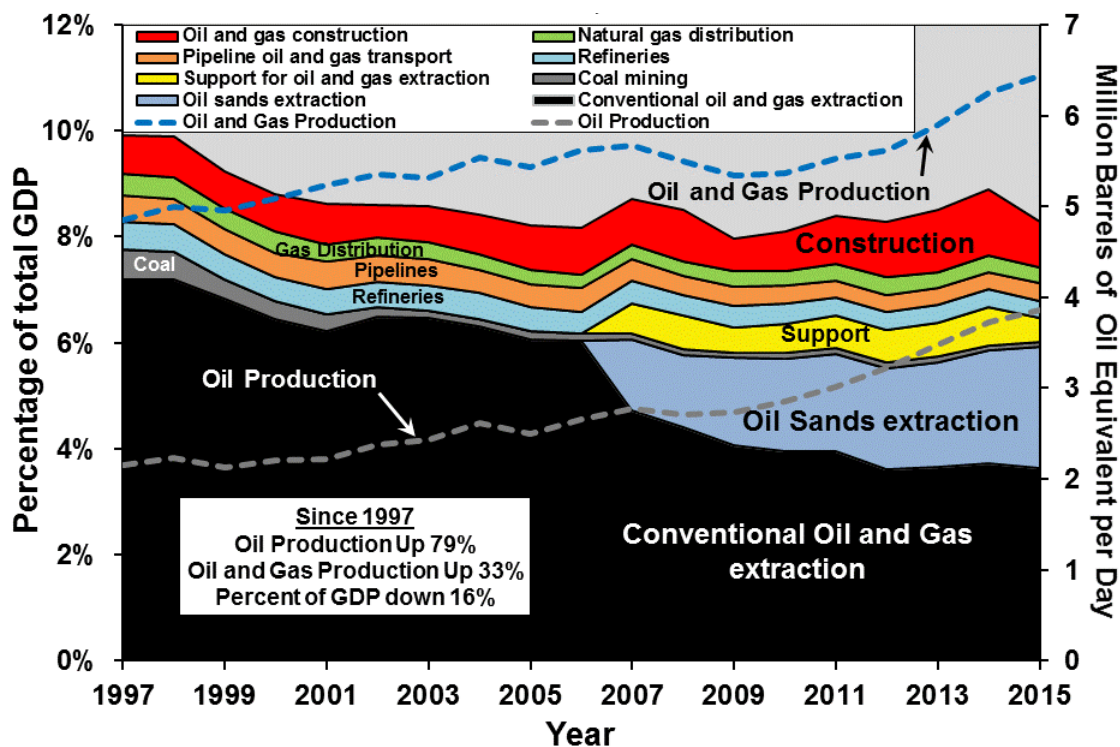
¹⁶⁰ World Energy Council, 2016, World Energy Resources 2016, https://www.worldenergy.org/wp-content/uploads/2016/10/World-Energy-Resources_Report_2016.pdf

2.3 Government revenue from oil, gas and coal production

Canada is touted as a “petrostate”¹⁶¹ by some, although in fact the percentage of Canada’s GDP generated by fossil fuel extraction, processing and related construction has declined from 10% to 8.3% over the past two decades—despite the fact that oil production has gone up by 79% and combined oil and gas production by 33% over this period. Figure 93 illustrates the percentage of Canada’s GDP generated by fossil fuel production, distribution and construction.

Figure 93: Gross domestic product (GDP) generated by the fossil fuel industry in Canada as a percentage of total GDP from 1997 to 2015.¹⁶²

Oil and gas production during this period is also shown.¹⁶³ GDP from fossil fuels as a percentage of total GDP has fallen by 16% while production has grown substantially.



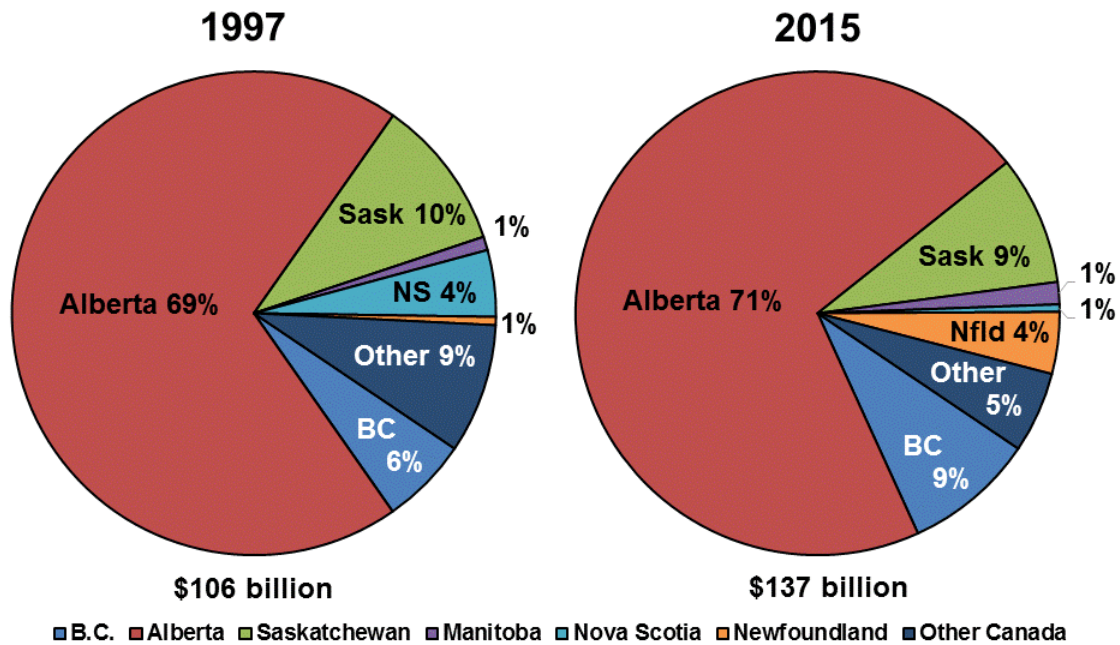
¹⁶¹ Bloomberg, June 17, 2016, Canada Flirts With the Petrostate Trap, <https://www.bloomberg.com/view/articles/2016-06-17/canada-flirts-with-the-petrostate-trap>

¹⁶² Statistics Canada CANSIM Table 379-0030, <http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=3790030&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid>

¹⁶³ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftrpndc/dflt.aspx?GoCTemplateCulture=en-CA>

More than two-thirds of GDP from fossil fuel production, distribution and construction is generated in Alberta, as illustrated in Figure 94. BC has increased its share since 1997, Nova Scotia has reduced its share, and Newfoundland has increased its share markedly.

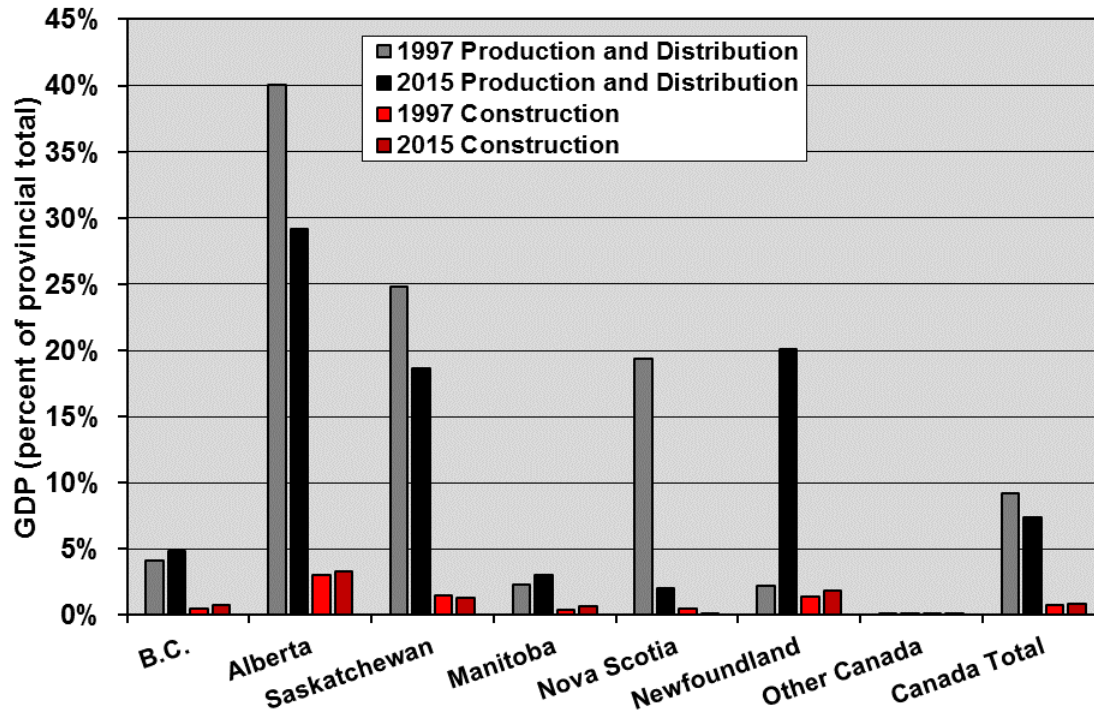
Figure 94: Canadian gross domestic product (GDP) from fossil fuel production, distribution and construction by province in 1997 and 2015.¹⁶⁴



¹⁶⁴ Data from Statistics Canada CANSIM Table 379-0030, <http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=3790030&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid=> (totals are in chained 2007 dollars)

On a provincial basis, the percentage of GDP attributable to the production and distribution portion of the fossil fuel industry has declined since 1997 in Alberta, Saskatchewan and Nova Scotia, and in Canada overall (see Figure 95). GDP from production and distribution has increased slightly in BC and Manitoba and markedly in Newfoundland, where offshore oil production was just beginning in 1997. Construction of oil and gas production infrastructure has increased GDP in BC, Alberta and Newfoundland as well as in Canada overall, although construction is only about a tenth of the GDP generated by production and distribution.

Figure 95: Gross domestic product (GDP) as a percentage of provincial totals for production and distribution and for construction.¹⁶⁵

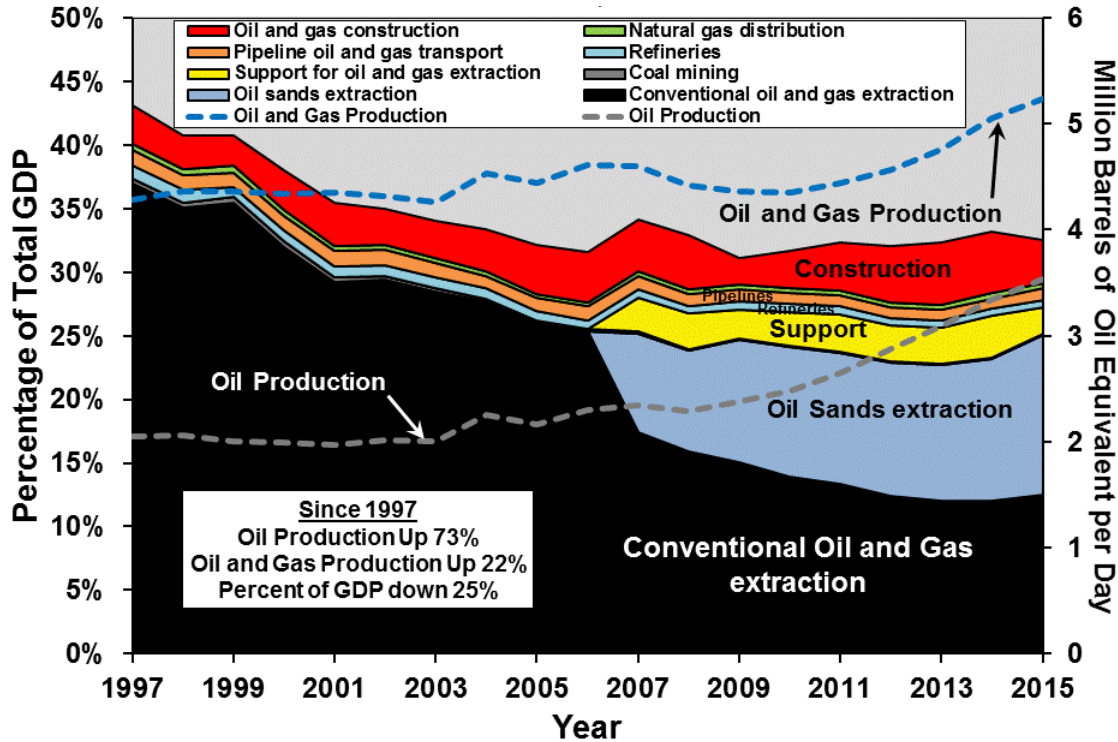


¹⁶⁵ Op. cit.

Figure 96 illustrates the GDP share of components of the fossil fuel supply chain in Alberta, which accounts for 70% of Canadian fossil fuel GDP. Although oil production has gone up 75% in Alberta since 1997, and combined oil and gas production has gone up 22%, the proportion of provincial GDP generated by fossil fuel has declined by 25%.

Figure 96: Alberta gross domestic product (GDP) generated from fossil fuel production, distribution and construction as a percentage of total provincial GDP.¹⁶⁶

Although this portion of GDP has grown slightly in real terms, GDP from the rest of the economy has grown faster, resulting in a declining share from fossil fuel despite increasing fossil fuel production. (Note that the oil sands were not distinguished separately until 2007.)



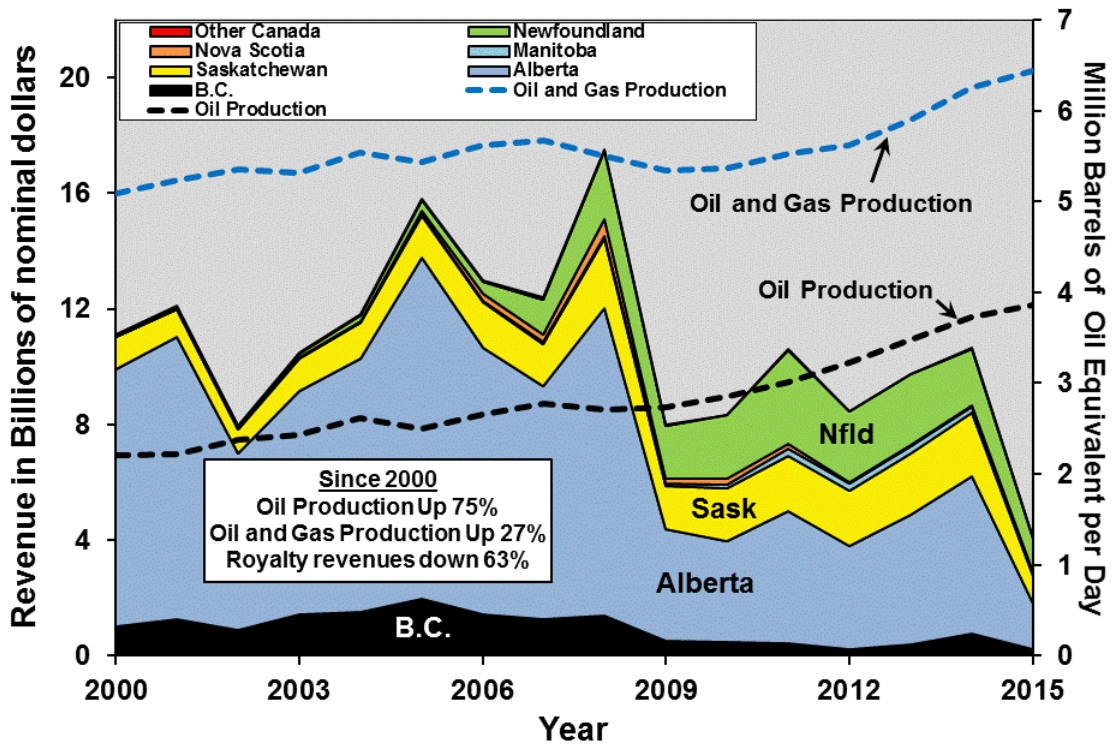
GDP, which is a broad measure of economic activity, includes much more than the actual monetary return to Canada from the sale of its non-renewable energy assets, which is primarily represented by royalties. Royalties are ongoing payments per unit of production to governments representing the owners of the resources—the Canadian public. Royalty take is a function of commodity prices and the policies of governments, which may vary the way in which royalties are calculated and offer incentives and rebates that reduce the amount of revenues received. More ephemeral income comes from land sales and bonus bids when Crown land is first leased or sold to energy companies. Ongoing lease rentals and corporate income taxes paid by companies developing the resources provide some additional revenue, however, royalties provide the lion's share of benefit to the public owners of the resource.

¹⁶⁶ Op. Cit.

Figure 97 illustrates royalty revenue received in Canada by province from 2000 to 2015. Royalty revenue peaked in 2008 with the spike in oil and gas prices and has collapsed since then. Royalty revenue has declined by 63% since 2000, despite oil production growth of 75% and combined oil and gas production growth of 27%. Canada's non-renewable energy resources are clearly being sold off for ever-decreasing benefit.

Figure 97: Royalties paid by province from 2000 to 2015.¹⁶⁷

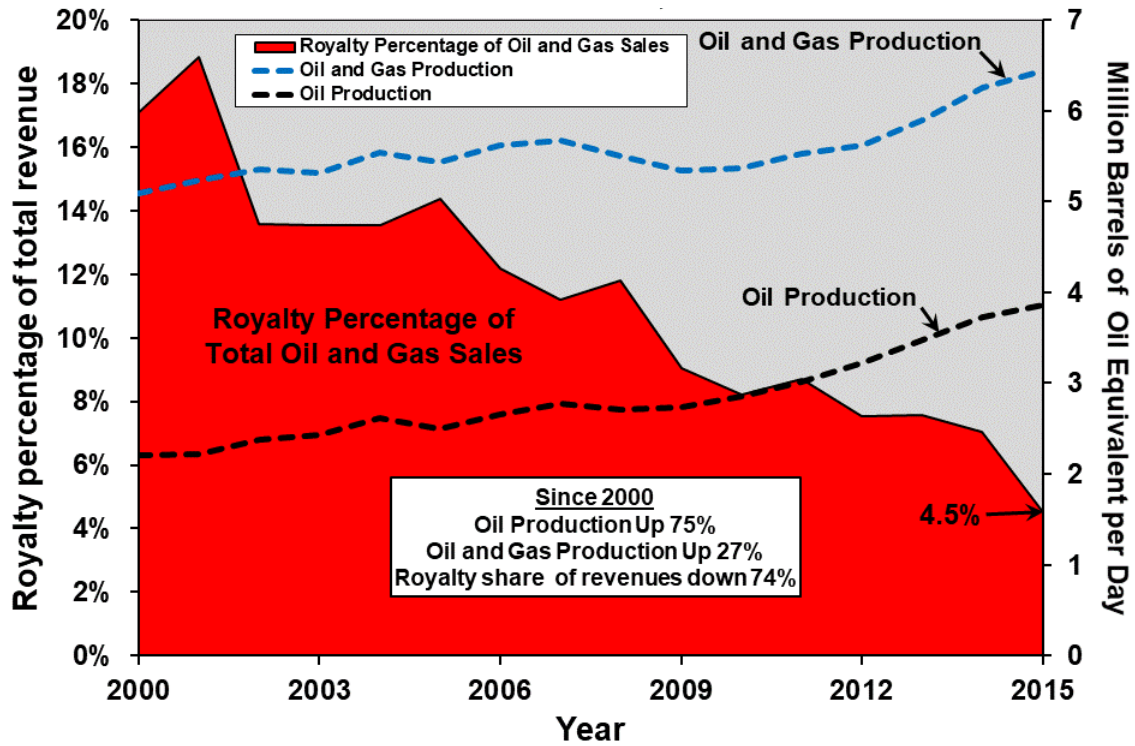
Royalties are down 63% since 2000, despite a 75% growth in oil production and a 27% growth in combined oil and gas production.



¹⁶⁷ CAPP Statistical Handbook, retrieved February 24, 2017, Tables O4-03B through O4-16B; Production data from NEB 2016

A clearer view on the ever-decreasing royalty take from Canada's non-renewable energy assets is illustrated in Figure 98, using data from the Canadian Association of Petroleum Producers (CAPP).¹⁶⁸ Royalties ranged between 13% and 17% of the sales revenue from oil and gas between 1990 and 2000. Since 2000, they have declined to 4.5% of sales revenue, a decrease of 74%, while at the same time oil and gas production grew by 27%. This decline continued through the oil and gas price spike in 2008, indicating that this trend is independent of price.

Figure 98: Revenue from royalties in Canada as a percentage of total revenue from oil and gas sales from 2000 to 2015.¹⁶⁹



¹⁶⁸ CAPP Statistical Handbook, retrieved February 24, 2017, Tables O4-02B and O4-25B.

¹⁶⁹ Data from CAPP Statistical Handbook, Tables O4-25B and O4-02B; Production data from NEB 2016

In Alberta, home to 70% of Canada's fossil fuel-generated GDP, government resource revenue has declined 90% from 1980 levels, despite a doubling in oil and gas production, as illustrated in Figure 99. In 1980, 80% of Alberta government revenue came from fossil fuel production compared to just 3.3% in 2016 (see Figure 100).

Figure 99: Revenue from oil, gas and coal in Alberta from 1970 to 2016.¹⁷⁰

Oil and gas production has doubled from 1980, however, revenues are down 90% as of 2016.

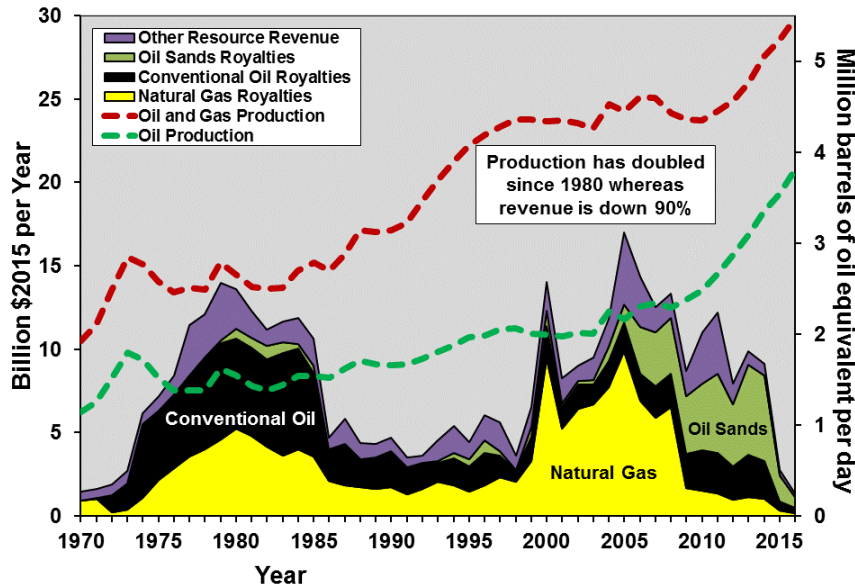
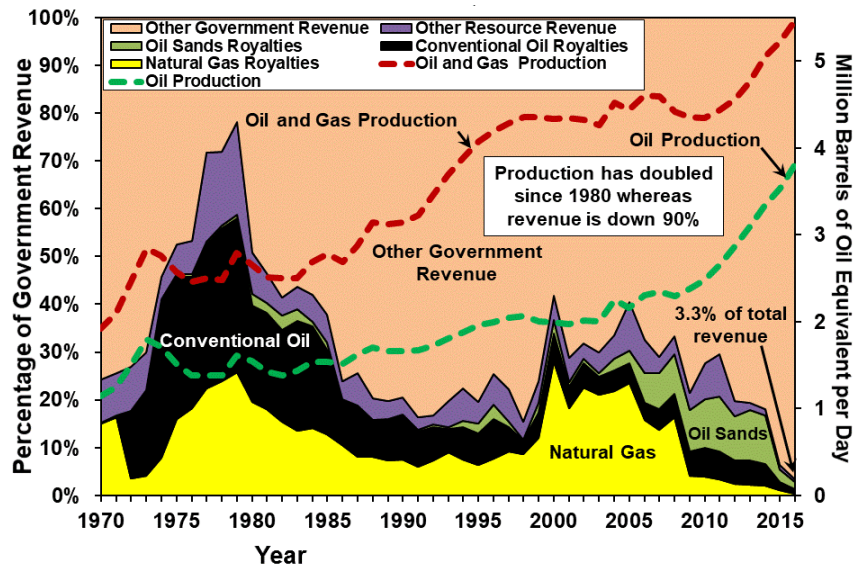


Figure 100: Non-renewable energy resource revenue in Alberta as a percentage of total government revenue from 1970 to 2016.¹⁷¹



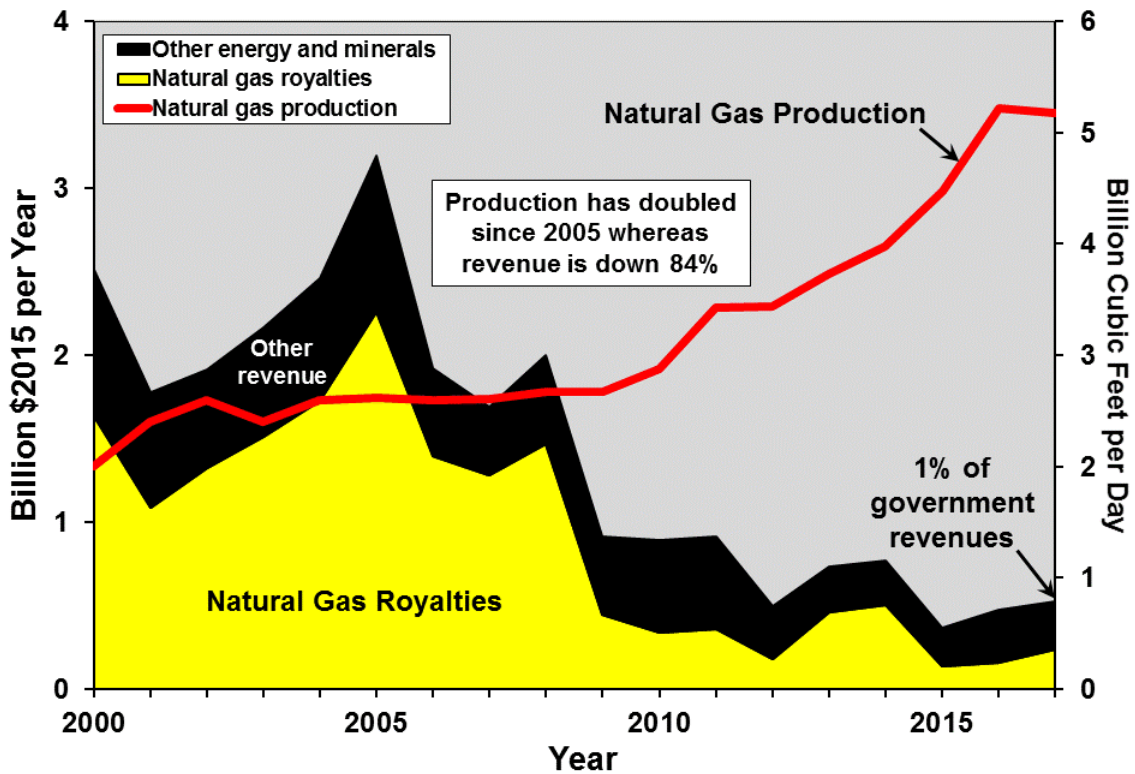
¹⁷⁰ Alberta Energy revenue workbook, August 2016, accessed February 15, 2017, <http://www.energy.alberta.ca/Org/docs/RevenueWorkbook.xls>; Oil and gas production from NEB Energy Futures update 2016 and from CAPP; Other resource revenue includes rental fees, lease sales and coal royalties

¹⁷¹ Data from Alberta Energy, July 2017, and Alberta 2017 budget estimates; Production data from CAPP and NEB; Other resource revenue includes rental fees, lease sales and coal royalties

BC energy resource revenues to government have followed a similar pattern. Revenues generated from oil, gas and coal have declined by 84% since 2005, while over the same period natural gas production has doubled (see Figure 101). Non-renewable resource revenues made up just 1% of total government revenue in BC in 2017.

Figure 101: BC government revenues from fossil fuels from 2000 to 2017.¹⁷²

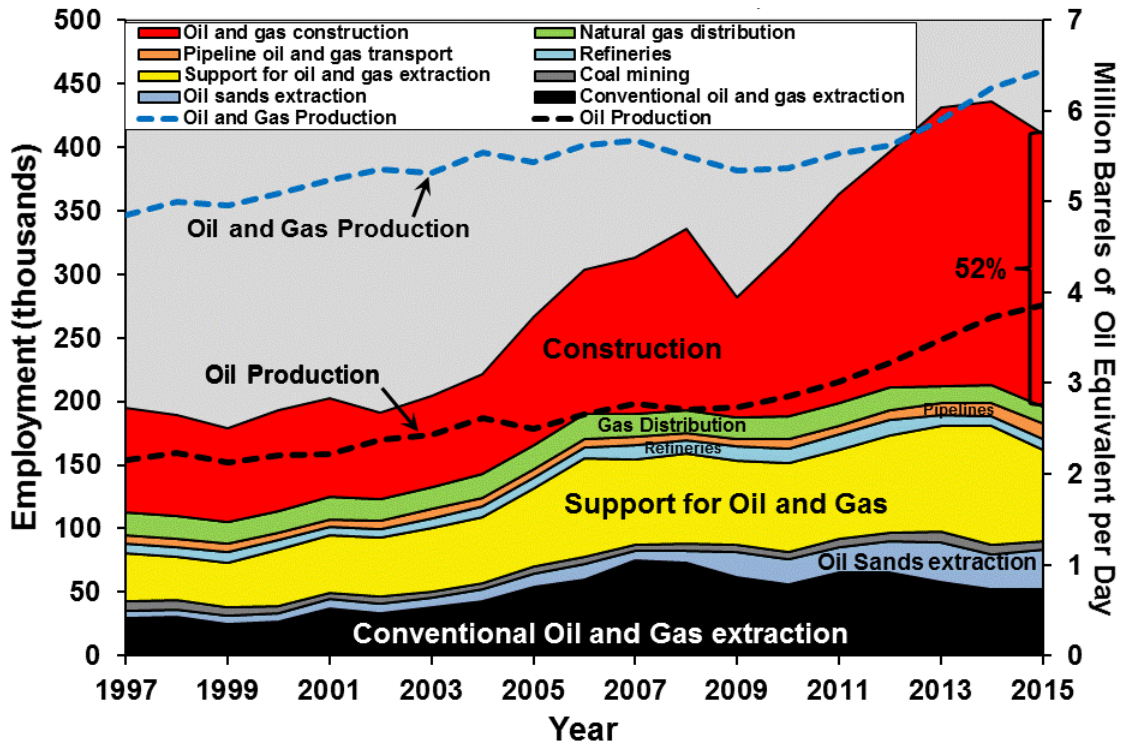
Crown lease revenue, which was estimated to be \$353 million in 2017, has been excluded as it includes revenue from forestry and mining.



¹⁷² BC Budget documents from 2000 through 2017, retrieved February 10-March 1, 2017, <http://www.bcbudget.gov.bc.ca/default.htm> (note: 2016 and 2017 are estimates); Production data from NEB update, 2016; Crown lease revenue data excluded as it includes mining and forestry

Employment is often touted as a reason for continuing to ramp up oil and gas production. Figure 102 illustrates employment in the production, distribution and construction segments of the fossil fuel industry since 1997. Despite growing production, jobs in the extraction and distribution portions of the industry have been relatively flat since 2006 and declined in 2015 with the downturn in oil price. The exception is construction, mainly in the oil sands, which in 2015 comprised 52% of all jobs. Construction jobs are short-term, however, unlike jobs in the production and distribution parts of the industry. With the completion of projects currently under construction, many of these jobs will disappear.

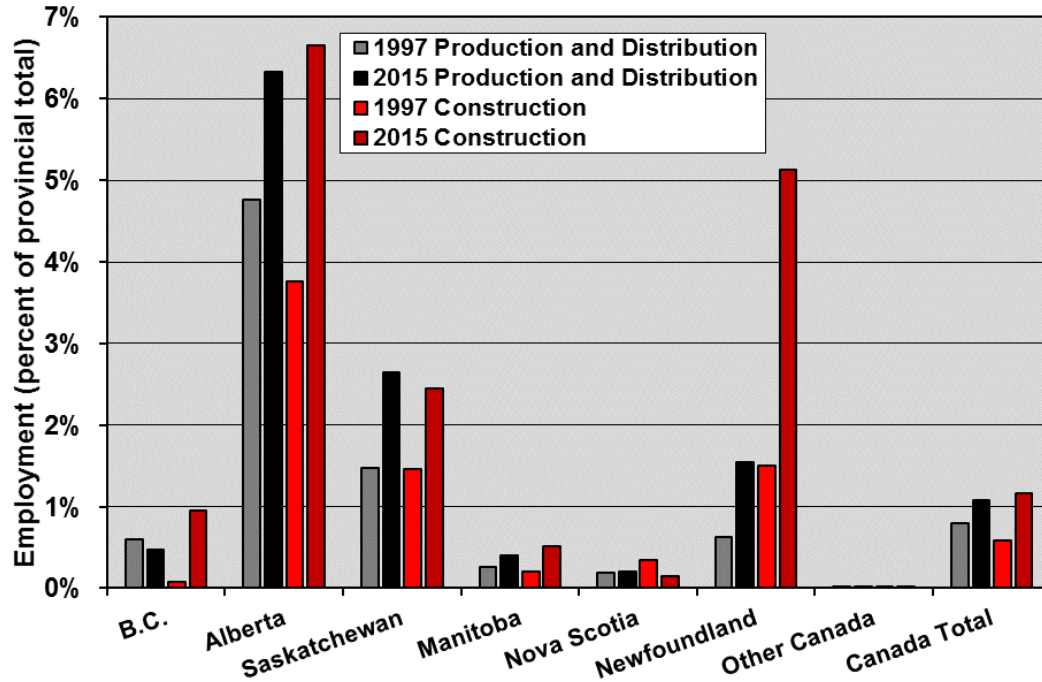
Figure 102: Employment in fossil fuel production, distribution and construction in Canada from 1997 to 2015.¹⁷³



¹⁷³ Statistics Canada CANSIM Table 383-0031, <http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=3830031&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid=>; production data from NEB.

Jobs in the industry as a proportion of total employment by province are illustrated in Figure 103. Overall in Canada, production and distribution amounted to just over 1% of total employment in 2015, and construction accounted for an additional 1.17%. Jobs in production and distribution increased in most provinces except BC, compared to 1997, and construction provided even more jobs than production and distribution in BC, Alberta and Newfoundland. At some point construction will be largely completed and jobs provided by the industry will contract to the basic production and distribution functions.

Figure 103: Employment in fossil fuel production, distribution and construction by province in 1997 and in 2015.¹⁷⁴

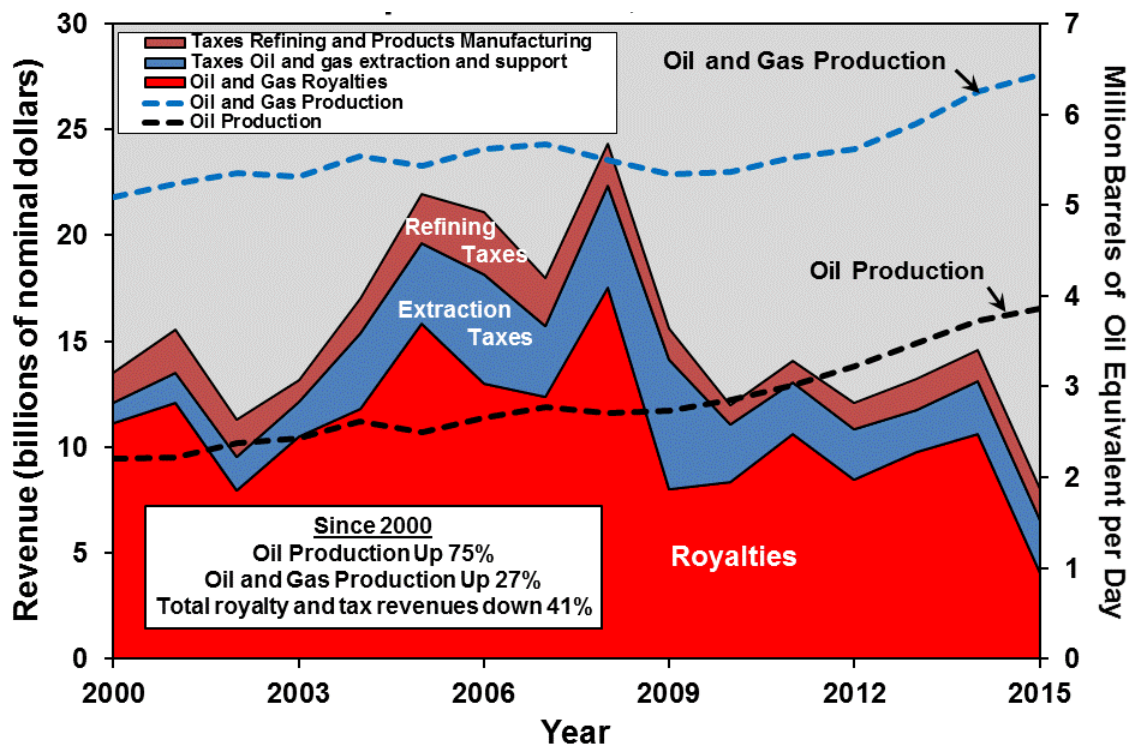


¹⁷⁴ Statistics Canada CANSIM Table 383-0031, <http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=3830031&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid=>

A final source of government revenue from fossil fuel extraction is corporate income tax paid by the corporations extracting the resources. Corporate tax revenue comprised an average of 30% of total government revenues from fossil fuel production between 1997 and 2015, with royalties providing the balance, as illustrated in Figure 104. Corporate income tax revenue peaked in 2006 and has declined by 51% since then, along with a 69% decline in royalty revenues. These declines occurred despite a 45% growth in oil production and a 15% growth in combined oil and gas production since 2006. The oft-cited claim that growing oil and gas production is vital to Canada's economic well-being and its ability to protect the environment has become progressively less true over the past decade.

Figure 104: Corporate income tax and royalties received by governments from 2000 to 2015.¹⁷⁵

Also shown is oil and gas production.



An argument can be made that the personal income taxes paid by employees in the sector should also be included as government revenue attributable to fossil fuel production. However, personal income taxes would be paid whether employees worked in the sector or not (i.e., they would not be unemployed). Natural Resources Canada suggests that such "indirect taxes" amount to about 45% of corporate taxes paid.¹⁷⁶

¹⁷⁵ Data from CAPP Statistical Handbook, retrieved February 24, 2017, Tables O4-02B; Statcan Table 180-0003; Production data from NEB, 2016

¹⁷⁶ NRCAN, 2016, Energy Fact Book 2016-2017,

https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/EnergyFactBook_2016_17_En.pdf

3. Electricity: capacity, generation and renewable fuels

Electricity is an energy carrier that provided only about 17% of the total delivered energy for end uses in Canada in 2017 (see Figure 105). The balance was provided by oil (40%); natural gas (36%); biomass, solid waste, coal and coke for thermal uses; and biofuels for transportation (7%). In its reference scenario, the NEB's projects that in 2040, oil and gas will still make up 75% of delivered energy, with electricity's share up slightly to 19% (see Figure 106). The industrial sector is the largest consumer of energy followed by the transportation, residential and commercial sectors.

Figure 105: Delivered energy by fuel type and sector in Canada in 2017 (PJ = petajoules).¹⁷⁷

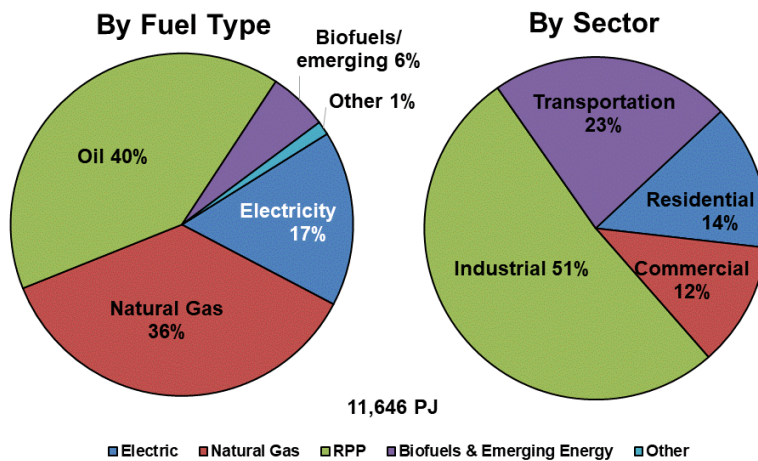
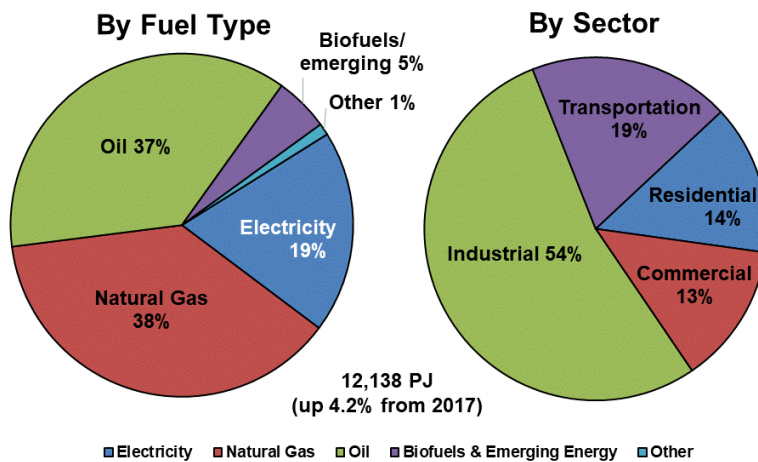


Figure 106: Delivered energy by fuel type and sector in Canada in 2040 (PJ = petajoules).¹⁷⁸



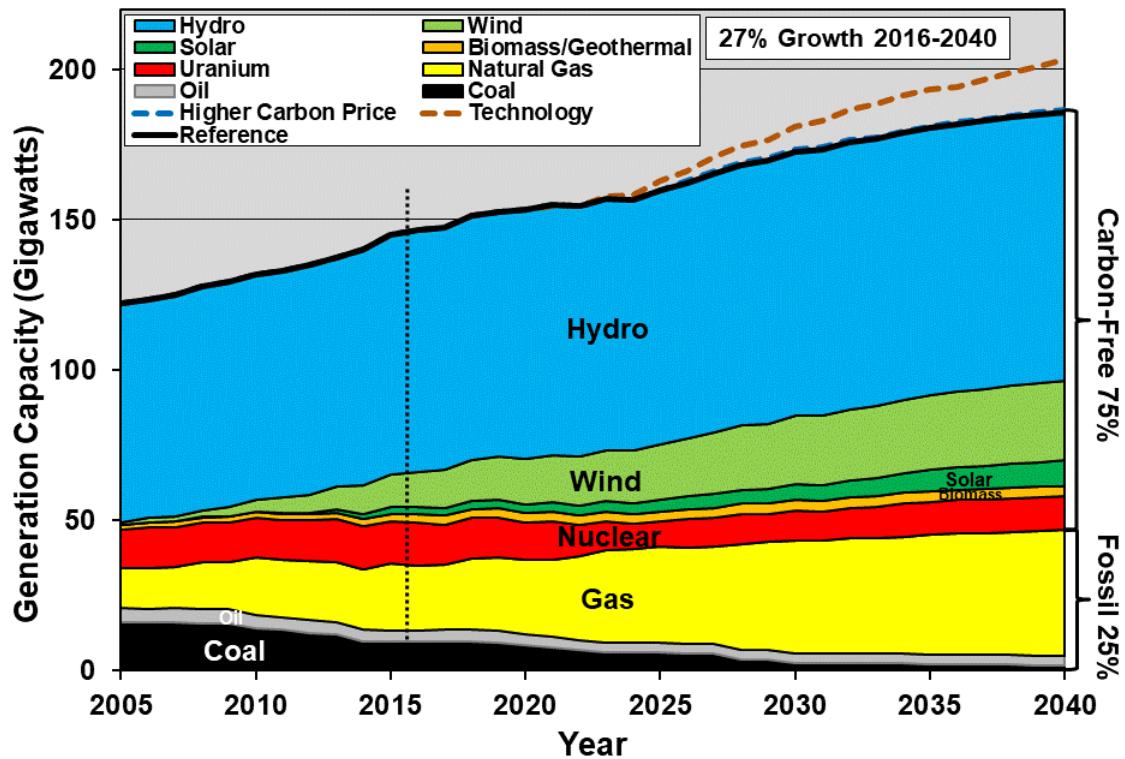
¹⁷⁷ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ft/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftppndc/dflt.aspx?GoCTemplateCulture=en-CA>

¹⁷⁸ Op. cit.

The NEB's projection of electricity generating capacity under its reference case is illustrated in Figure 107, forecasting a 27% growth over 2016 levels by 2040. Wind, solar and natural gas are projected to increase substantially at the expense of coal, with the phase-out in Alberta and curtailment at the federal level, and nuclear. Large hydro, as outlined earlier, will remain the major source of generation capacity. Taken together, Canada's electricity generation capacity would be 75% carbon-free in 2040, about the same as it was in 2016.

Figure 107: Electricity generation capacity in Canada from 2005 to 2040 according to the National Energy Board's reference case projection.

Also shown are the total capacities in the NEB's higher carbon price and technology scenarios.¹⁷⁹



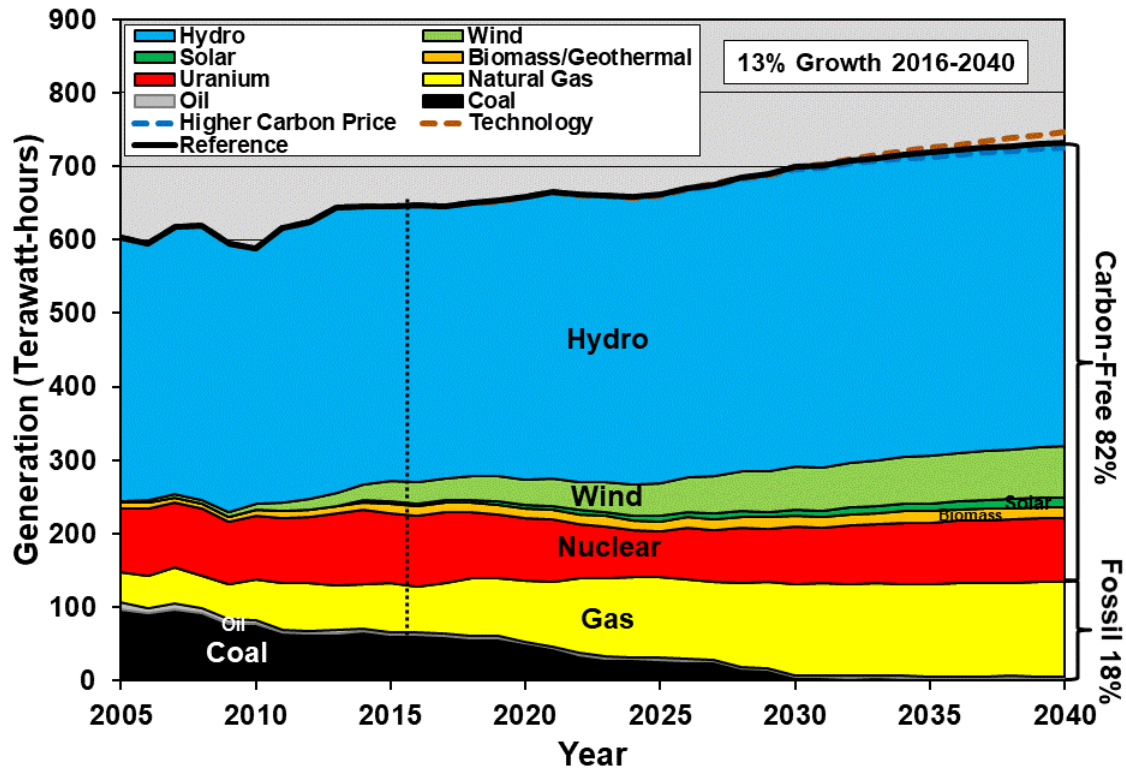
Actual electricity generation depends on the characteristics of the generation source. Nuclear, coal and combined-cycle gas typically are “base load” sources, as they can’t be easily ramped up and down to meet changing electricity demand. Gas turbines can be ramped up and down to meet variations in demand and hence can meet “peaking load,” although they are less efficient than combined-cycle natural gas. Hydro is a versatile source that can meet both base load and peaking load applications. Wind and solar are intermittent sources dependent on the vagaries of wind speed and solar insolation. Their output is prioritized (i.e., used first), but as they are unpredictable they must be backed up by a dispatchable generation source like natural gas or hydro.

¹⁷⁹ Op. cit.

Figure 108 illustrates the NEB's reference case projection for actual generation through 2040. Despite capacity additions of 27% over 2016 levels, actual generation grows only 13%, due to the addition of sources with lower capacity factors, such as solar and wind. In total, generation would be 82% carbon-free in 2040 according to this projection, about the same as it was in 2016.

Figure 108: Electricity generation in Canada from 2005 to 2040 according to the National Energy Board's reference case projection.

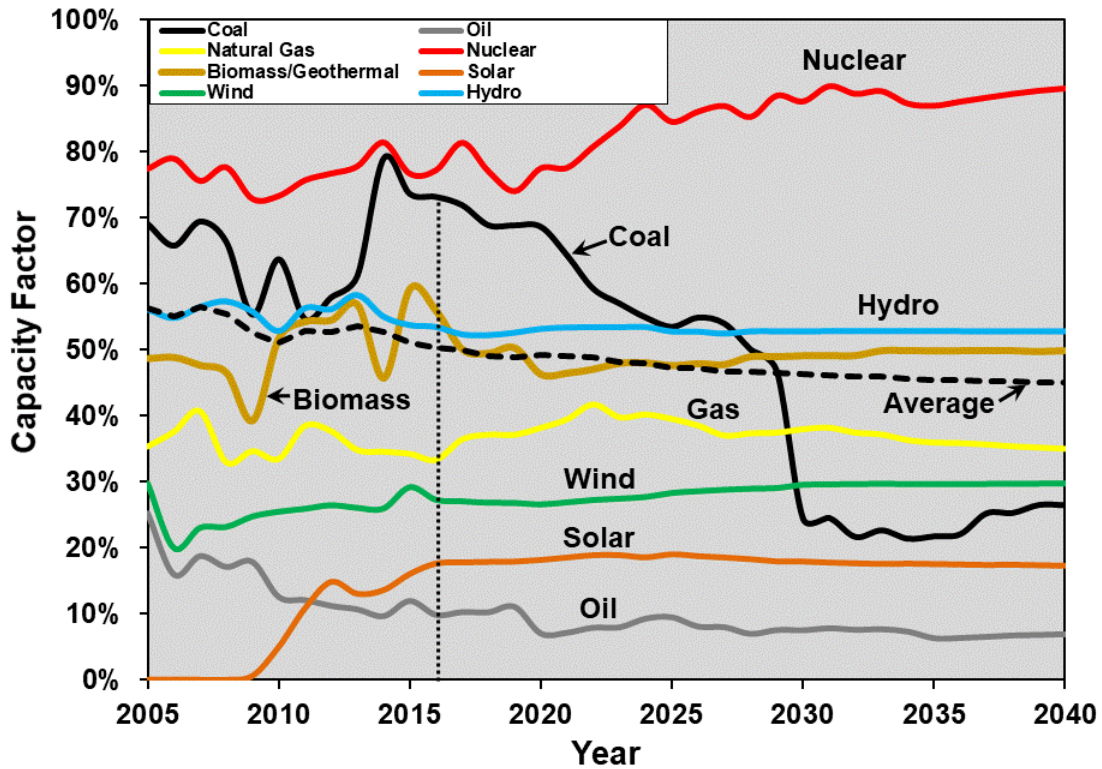
Also shown is the total generation in the NEB's higher carbon price and technology scenarios, which are little different from the reference case.¹⁸⁰



¹⁸⁰ Op. cit.

The ratio of generation capacity to actual generation is termed “capacity factor.” Base load sources like hydro, nuclear, coal and combined-cycle natural gas can generally run at capacity factors of more than 50%, and nuclear typically runs at 80% or more. The trade-off between coal and combined-cycle natural gas has historically depended on fuel price, and in future carbon pricing will likely reduce the use (and hence capacity factor) of any remaining coal plants after the phase-out. Gas turbines are only used when needed to meet peak demand as they are less efficient and therefore more expensive compared to combined-cycle natural gas. Wind and solar, due to their intermittency, have much lower capacity factors. In a very good location wind may have a capacity factor of 30–35%, and solar in a good location at the latitude of Southern Canada may have a capacity factor of 15–20% (higher in the summer and lower in winter). Therefore, for a given amount of generation, several times the amount of solar and wind capacity must be installed compared to dispatchable sources like hydro or natural gas. Figure 109 illustrates the capacity factors of various generation sources assumed in the NEB’s reference case through 2040.

Figure 109: Capacity factors for various electricity generation sources in the National Energy Board’s reference case from 2005 to 2040.¹⁸¹

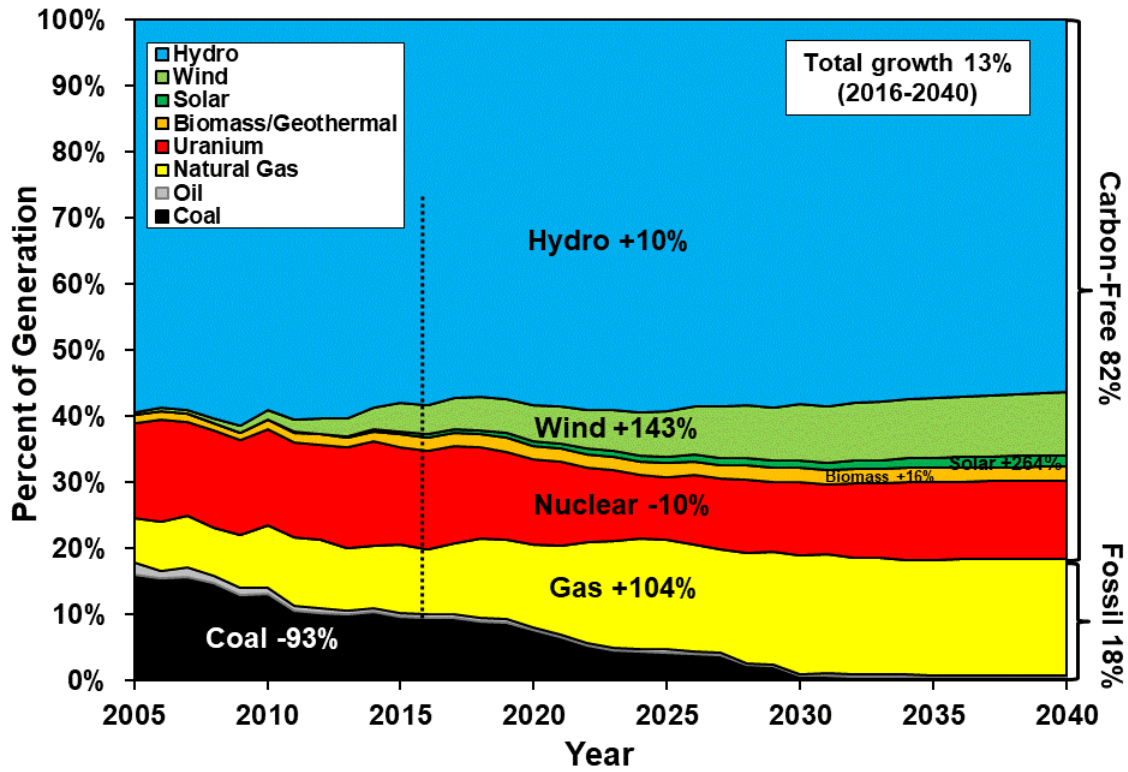


¹⁸¹ Op. cit.

Figure 110 illustrates the percentage share of Canadian generation through 2040 in the NEB's reference case. The share of fossil fuel generation declines slightly from 2015 to 2040 and overall generation increases by 13%. Wind, solar and biomass increase substantially but are offset by a decline in nuclear generation. Fossil fuel generation is projected to decline only slightly despite the phase-out of coal, which is offset by the increase in gas-fired generation.

Figure 110: Electricity generation in Canada from 2005 to 2040 as a percentage of total generation according to the National Energy Board's reference case projection.¹⁸²

Hydro and carbon-free energy sources maintain their share through 2040, although overall generation increases by 13%. The percentage change of each generation source from 2016 to 2040 is also shown.



¹⁸² Op. cit.

The breakdown in electricity generation capacity, actual generation and capacity factor by source for Canada in 2015 is given in Table 16. Of carbon-free emissions sources, large hydro provides roughly 59%, followed by nuclear at 15%. Although wind and solar make up 6% of capacity, they generate less than 3% of total generation due to their low capacity factors. Carbon-emitting thermal sources made up 22% of 2015 generation.

Table 16: Canada's electricity generation capacity, actual generation and capacity factor by source in 2015.¹⁸³

Also shown is the National Energy Board's reference case change in generation from 2016 to 2040.

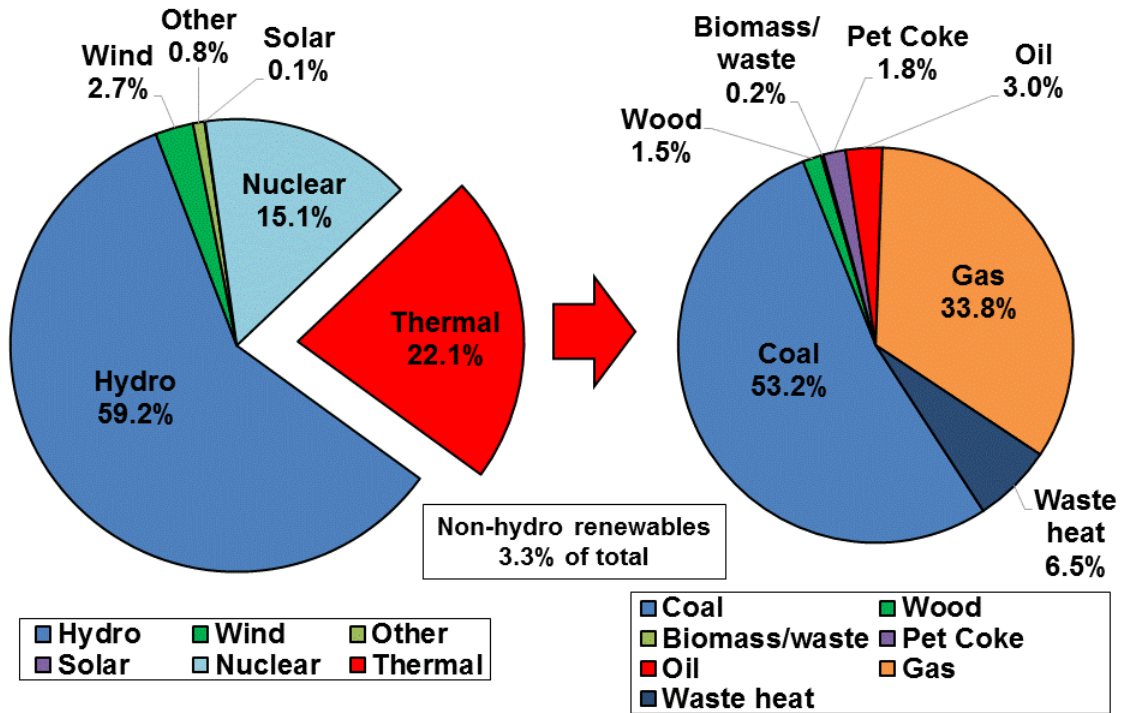
Source	Capacity		Generation		Capacity factor	2016–2040 generation change
	Gigawatts	%	TWh	%	%	
Hydro	79.23	58.57%	373.84	59.18%	53.86%	12.50%
Wind	7.64	5.65%	17.11	2.71%	25.57%	101.74%
Solar	0.19	0.14%	0.34	0.05%	20.27%	108.34%
Nuclear	14.03	10.37%	95.68	15.15%	77.84%	-27.39%
Thermal	34.15	25.25%	139.46	22.08%	46.62%	40.90%
Total	135.27	100.00%	631.68	100.00%	53.31%	13.70%

¹⁸³ Statcan CANSIM tables 127-0007 and 127-0009 accessed March 8, 2017. Note that there are discrepancies between Statcan data for solar compared to other sources. IRENA reports 2015 capacity as 2.44 GW vs .19 GW for Statcan. In 2014 both IRENA and NRCAN report 1.84 GW vs .19 GW for Statcan. For 2014 generation Statcan reports .33 TWh vs 1.78 TWh for IRENA and NRCAN. BP reports 1.9 TWh in 2015 vs .34 TWh for Statcan. If alternate data are used solar would be 0.3% of total generation and 1.8% of capacity. Wind capacity for 2015 is also understated by Statcan at 7.64 GW vs 11.2 GW for IRENA and the Canadian Wind Energy Association.

A detailed breakdown of thermal generation sources in 2015 is illustrated in Figure 111. Wood, other biomass and waste are renewable, and are by definition carbon-free (although they emit carbon when burned, in theory regrowth will remove these emissions); they amounted to 1.7% of thermal generation and less than .5% of total generation in 2015.

Figure 111: Canada's electricity generation by source in 2015, illustrating a breakdown of thermal generation sources.¹⁸⁴

Pet coke is petroleum coke derived from upgrading operations, and waste heat is energy captured from industrial operations.



¹⁸⁴ Statcan 2017, CANSIM Tables 127-0006 and 127-0007 accessed March 10, 2017.

Environment and Climate Change Canada (ECCC) has developed a “Mid-Century Long-Term Low-Greenhouse Gas Development Strategy” (mid-century strategy),¹⁸⁵ which presents six scenarios for meeting a goal of approximately 80% emissions reduction by 2050. Three of these were developed by ECCC using its Global Change Assessment Model (GCAM), two by the Trottier Energy Futures Project¹⁸⁶ and one by the Deep Decarbonization Pathways Project (DDPP).¹⁸⁷ All of these scenarios call for greatly increased generation of electricity, ranging from 86% to 245% above 2015 levels. Table 17 illustrates these scenarios compared to the NEB’s reference case projection through 2040.

New generation capacity required in these scenarios for growth in electricity generation is explored for each energy source in the following section. One thing that is clear, however, is that the NEB’s projections of modest growth in electricity generation and essentially the same proportion of delivered energy supplied by electricity in 2040 as today are unlikely to result in the emissions reductions needed when compared to the scenarios in ECCC’s mid-century strategy.

Table 17: Generation of electricity in Environment and Climate Change Canada’s mid-century strategy scenarios compared to current generation and to the National Energy Board’s reference case 2040 projection.

Also shown is the percentage of final delivered energy supplied by electricity in 2050.¹⁸⁸

Scenario	TWh	% growth from 2015 levels	% of delivered energy
NEB 2015 Generation	646	-	16.8%
DDPP 2050	1477	129%	48.5%
Trottier Current Tech 2050	2257	249%	65.3%
Trottier New Tech 2050	1622	151%	58.4%
ECCC High Nuclear 2050	1648	155%	57.0%
ECCC High Hydro 2050	1648	155%	57.0%
ECCC High Demand Response 2050	1215	88%	33.1%
NEB Reference in 2040	732	13%	19.1%

¹⁸⁵ Environment and Climate Change Canada, 2016, Canada’s Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

¹⁸⁶ Trottier Energy Futures Project Final Report, 2016, https://www.cae-acg.ca/wp-content/uploads/2013/04/3_TAFP_Final-Report_160425.pdf

¹⁸⁷ Bataille, C. et al. 2015, Pathways to Deep Decarbonization in Canada. Retrieved from http://deepdecarbonization.org/wp-content/uploads/2015/09/DDPP_CAN.pdf

¹⁸⁸ Environment and Climate Change Canada, 2016, Canada’s Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, see Figures 2 and 7, http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

3.1 Nuclear

Canada has 19 operating reactors, which amounted to 14% of Canada's total generating capacity and 15% of actual generation in 2015 (see Table 16). Four reactors in Ontario and Quebec are being decommissioned and two, Pickering A2 and A3, are idle and listed as permanently shut down.¹⁸⁹ Table 18 illustrates the operating reactors, their capacity and their currently planned closure dates.

Table 18: Nuclear reactors currently operating in Canada, their capacity and planned closure date.

The date of the plants' first power, and the date of commissioning of refurbished plants is also shown.¹⁹⁰ (OPG = Ontario Power Generation; MWe net = net generation capacity in megawatts)

Reactor	MWe net	Operator	First power	Refurbishment first power	Planned close, or licensed to
Pickering A1	515	OPG	1971	2005	2022
Pickering A4	515	OPG	1972	2003	2018
Pickering B5	516	OPG	1982		2018
Pickering B6	516	OPG	1983		2019
Pickering B7	516	OPG	1984		2018
Pickering B8	516	OPG	1986		2018
Bruce A1	750	Bruce Power	1977	2012	2035
Bruce A2	750	Bruce Power	1976	2012	2035
Bruce A3	750	Bruce Power	1977	2004	2036
Bruce A4	750	Bruce Power	1978	2003	2036
Bruce B5	825	Bruce Power	1984		2024 ^a
Bruce B6	825	Bruce Power	1984		2024 ^a
Bruce B7	825	Bruce Power	1986		2026 ^a
Bruce B8	825	Bruce Power	1987		2027 ^a
Darlington 1	881	OPG	1990		2025
Darlington 2	881	OPG	1990		2025
Darlington 3	881	OPG	1992		2025
Darlington 4	881	OPG	1993		2025
Point Lepreau 1	635	NB Power	1982	2012	2037
Total	13,553	<i>a - closure date assuming a 40-year life without refurbishment</i>			

¹⁸⁹ IAEA, 2017, Power Reactor Information System, <https://www.iaea.org/PRIS/CountryStatistics/CountryDetails.aspx?current=CA>

¹⁹⁰ World Nuclear Association, November, 2016, Nuclear Power in Canada, <http://www.world-nuclear.org/information-library/country-profiles/countries-a-f/canada-nuclear-power.aspx>

The World Nuclear Association provides a good overview of nuclear power in Canada, including its recent history and future outlook.¹⁹¹ Given the closure and/or “licensed to” dates in Table 18, which would see all plants closed by 2037, major investments in refurbishing existing reactors and/or building new ones will be required just to maintain output or stem the decline. Table 19 illustrates the nuclear capacity lost with the closure of reactors according to the schedule in Table 18. By 2025, 61% of capacity would be lost and by 2037 all plants would be closed.

Table 19: Decline in nuclear generating capacity through 2040 given the World Nuclear Association's closure dates given in Table 18.

Closure date	Number closed	Capacity lost MWe net	% of total	Total % lost
2018–2019	5	2,579	19.0%	19.0%
2020–2025	7	5,689	42.0%	61.0%
2026–2030	2	1,650	12.2%	73.2%
2031–2035	2	1,500	11.1%	84.2%
2035–2040	3	2,135	15.8%	100.0%
Total	19	13,553	100.0%	100.0%

Clearly this is unlikely to happen, but it points out the vulnerability of Canada's aging fleet of reactors. Ontario Power Generation (OPG) has announced plans to refurbish the four Darlington reactors at a cost of \$12.8 billion over the next decade, extending their life by perhaps another 20 years when complete in 2026.¹⁹² As part of this plan, OPG plans to keep the Pickering reactors running until 2024, which is six years beyond their current closure date, when they will be decommissioned. Refurbishments of the four Bruce B reactors have been announced by Bruce Power over the 2020–2033 period, along with further work on the Bruce A3 and A4 reactors, at a cost of \$13 billion.^{193,194} If the Darlington and Bruce B refurbishments go ahead as announced, that would extend 50% of existing capacity beyond the current 2037 closure dates for all plants. If the life of the older Bruce A3 and A4 reactors is also significantly extended, that would preserve 61% of existing capacity.

Even with the expenditure of \$26 billion on refurbishments of the Bruce and Darlington reactors, Canadian nuclear power is set to decline by about 39% over the next two decades unless new reactors are constructed. The NEB's reference case projection of a 10% decline in nuclear power from 2016 levels by 2040 shown in Figure 109 is therefore optimistic, as it would require four new 1,000-megawatt reactors to be built.

Globally, 447 reactors are operational, with 99 in the US and 58 in France, the top two nuclear-powered countries.¹⁹⁵ Permanently shut down reactors total 160 worldwide, with 34 of those in the US and 12 in France. Some 56 reactors are under construction, with 20 of those in China, seven in Russia and six in India. Although they are currently the top two users of nuclear power, the US and France have just three reactors under construction between them (two for the US and one for France). Given that two-thirds of the world's nuclear reactors were built prior to 1990, it remains to be seen if new construction can keep up with retirements as older plants reach the end of their design life. Construction of nuclear power plants is

¹⁹¹ Op. cit.

¹⁹² Ontario Power Generation, press release January 11, 2016, http://www.opg.com/news-and-media/news-releases/Documents/20160111_DarlingtonRefurb.pdf

¹⁹³ CBC, December 3, 2015, <http://www.cbc.ca/news/canada/toronto/bruce-power-1.3348633>

¹⁹⁴ Bruce Power, March, 2017, BPRIA backgrounder refurbishment schedule, <http://www.brucepower.com/bpria-backgrounder/refurbishment-schedule/>

¹⁹⁵ World Nuclear Association, August 2017, World Nuclear Power Reactors and Uranium Requirements, <http://www.world-nuclear.org/info/Facts-and-Figures/World-Nuclear-Power-Reactors-and-Uranium-Requirements/> Note that two US reactor construction projects were shut down in late July, 2017, which reduces the actual number under construction to 56, rather than 58 as noted in this reference.

also expensive compared to other forms of generation, costing over five times more than gas, three times more than onshore wind and two times more than utility-scale solar (see Table 20). Cost overruns in construction are also common, and decommissioning costs are 10% to 15% of the original construction cost.

Table 20: Power plant capital costs for construction, and fixed and variable operating and maintenance (O&M) costs.¹⁹⁶

All figures are in 2016 US dollars.

Power plant type	Plant size capacity (MW)	Overnight capital cost (\$US2016/KW)	Fixed O&M (\$/KW-year)	Variable O&M (\$/MWh)
Ultra supercritical coal	650	3,636	42	4.6
Ultra supercritical coal with ccs	650	5,084	70	7.1
Natural gas combined cycle	702	978	11	3.5
Natural gas combustion turbine	100	1,101	18	3.5
Advanced nuclear	2,234	5,945	100	2.3
Biomass fluidized bed	50	4,985	110	4.2
Onshore wind (wn)	100	1,877	40	0
Photovoltaic – fixed	20	2,671	23	0
Photovoltaic – tracking	20	2,644	24	0
Photovoltaic – tracking	150	2,534	22	0
Battery storage	4	2,813	40	8

Aside from the expense of construction, nuclear power poses the additional problem of long-term disposal of high- and low-level radioactive wastes. Despite decades of research and some promising repositories, permanent disposal at scale has not yet been achieved. Repositories such as Yucca Mountain in Nevada have been ruled out after many years and billions of dollars of investment. The additional risk of infrequent but very costly accidents such as Fukushima and Chernobyl have caused countries such as Germany to phase out nuclear power, and Japan has vastly curtailed nuclear generation.

¹⁹⁶ EIA, November 2016, Capital Cost Estimates for Utility Scale Electricity Generating Plants, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

Notwithstanding these environmental and cost issues, ECCC's mid-century strategy requires growth of up to 733% in nuclear generation by 2050 from 2015 levels (see Table 21), when nuclear power would make up to 48% of total generation. The lowest nuclear scenario (DDPP) would see a decline of 15% in generation by 2050, but would still require construction of three new reactors to replace decommissioned reactors. This would be at a cost of US\$17.8 billion, assuming advanced nuclear reactors at a cost of US\$5,945 per kilowatt and a capacity factor of 77.8% (see Table 20). In the high nuclear case, 108 new reactors at a cost of US\$642 billion would be required. In all scenarios, the refurbishment of eight existing reactors at a cost of \$26 billion is assumed to maintain nuclear generation at 39% below existing levels through 2050.

Table 21: Generation of electricity by nuclear power in Environment and Climate Change Canada's mid-century strategy scenarios compared to current generation and to the National Energy Board's reference case 2040 projection.

Also shown is the percentage of 2050 generation from nuclear power, the number of new reactors required and their estimated cost assuming "advanced nuclear reactors" per Table 20.¹⁹⁷

Scenario	TWh	% growth from 2015 levels	% of total generation	New 1GW reactors needed	New reactor cost (US2016\$B)
NEB 2015 Generation	96	-	14.8%	-	-
DDPP 2050	81	-15%	5.5%	3	17.8
Current Tech Trottier 2050	797	733%	35.4%	108	642.1
New Tech Trottier 2050	656	586%	40.6%	87	517.2
High Nuclear 2050	797	733%	48.4%	108	642.1
High Hydro 2050	281	194%	17.1%	32	190.2
High Demand Response 2050	163	70%	13.4%	15	89.2
NEB Reference in 2040	87	-9%	11.9%	4	23.8

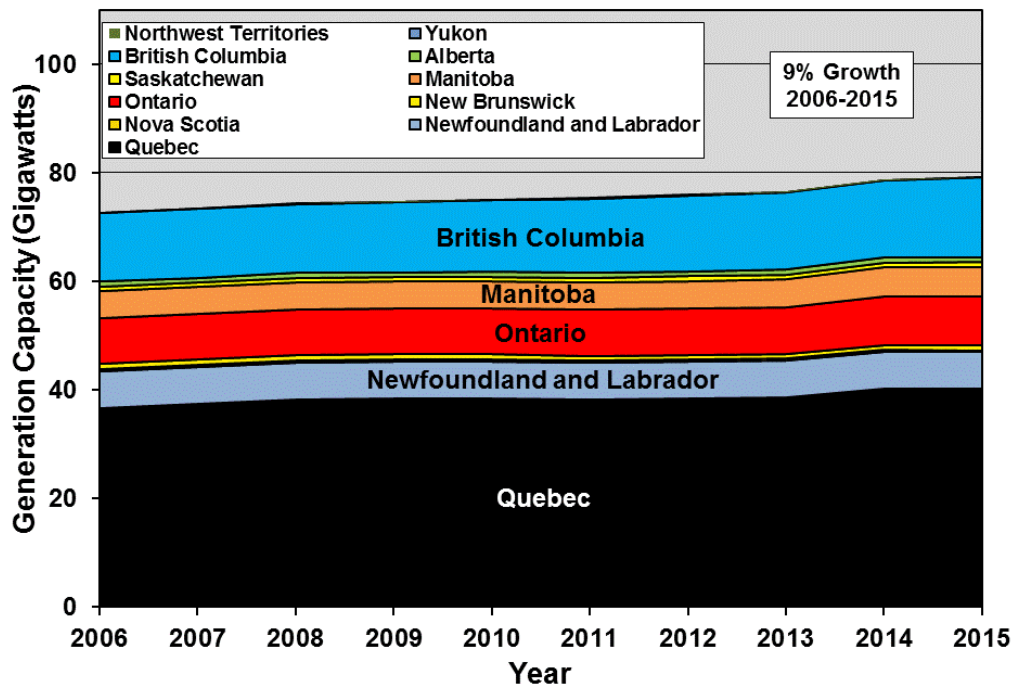
¹⁹⁷ Environment and Climate Change Canada, 2016, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, see Figures 2 and 7, http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

3.2 Hydro

Hydro comprises 58% of Canada's electricity generating capacity and 59% of total generation (Table 16). Some 55% of Canada's 79 gigawatts of hydro capacity is contained in 22 facilities rated at more than one gigawatt each, although there are 576 hydro facilities rated at more than 0.8 megawatts.¹⁹⁸ Generation capacity has increased by 9% over the 2006–2015 period, as illustrated in Figure 112. Quebec has 51% of total capacity followed by BC (18%) and Ontario (11%).

Figure 112: Hydroelectricity generation capacity in Canada by province from 2006 to 2015.¹⁹⁹

Total capacity increased by 9% over this period.



Hydro is a reliable, renewable and carbon-free source of electricity (if emissions from the construction of dams and the flooding of reservoirs, which occur in the early years of projects, are not considered). Hydro also provides dispatchable power, meaning it can be ramped up and down to follow demand. This makes hydro a better match for intermittent renewable energy sources like wind and solar than primarily base load generation from nuclear, coal and combined-cycle gas, which are best suited to constant output.

¹⁹⁸ NRCAN, 2016, Energy Fact Book 2016–2017,

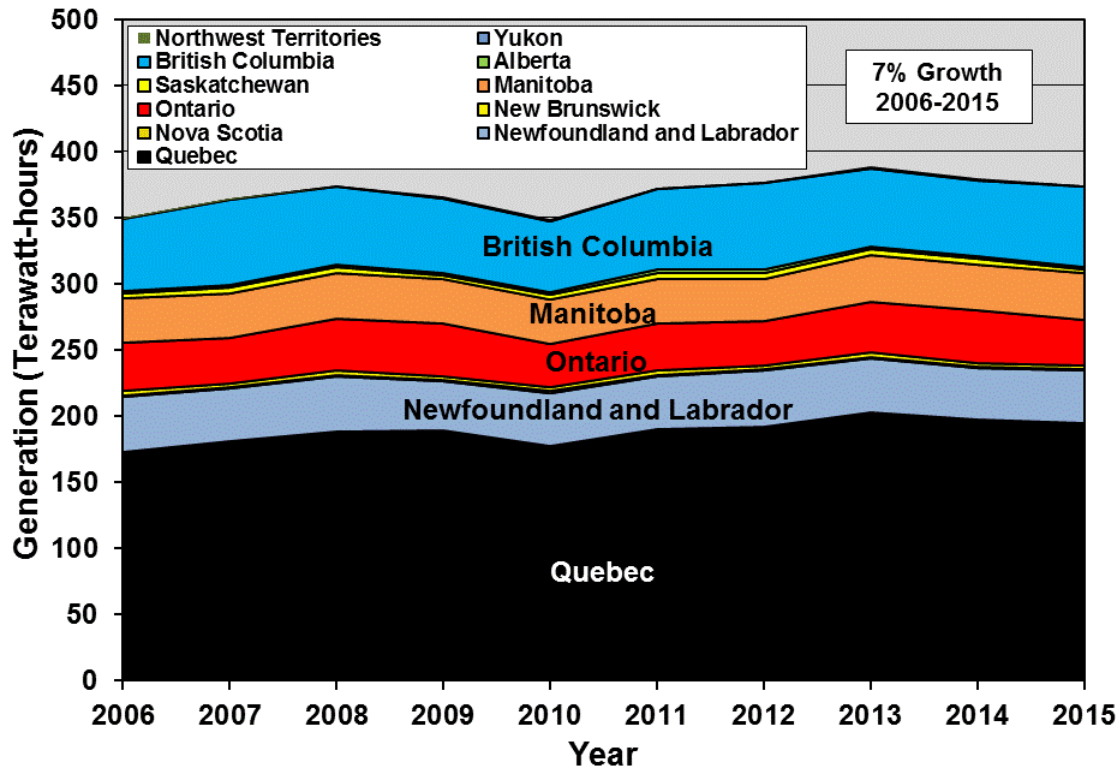
https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/EnergyFactBook_2016_17_En.pdf

¹⁹⁹ Statistics Canada, 2017, CANSIM Table 127-0009, retrieved March 8 2017.

Actual generation from hydro facilities depends on seasonal variations in rainfall and water supply, and variations in demand. Climate change may impose additional constraints on water supply and variability. The average capacity factor for hydro in Canada is 54% of maximum rated output (see Table 16). Figure 113 illustrates hydro generation by province, which has increased overall by 7% from 2006 through 2015.

Figure 113: Hydroelectricity generation in Canada by province from 2006 to 2015.²⁰⁰

Total generation increased by 7% over the period.



²⁰⁰ Statistics Canada, 2017, CANSIM Table 127-0007, retrieved March 8 2017.

Five additional projects were under development in 2016, which would add 4.6 gigawatts, or 5.8%, to total hydro capacity by 2024 (see Table 22).²⁰¹ The NEB's reference case projects a growth in hydro generation of 10.4% over 2015 levels by 2040, which would require eight new hydro projects of the size of the Site C dam in BC.

Table 22: Hydro projects under construction in Canada as of 2016.

Project	Province	Capacity (MW)	Expected in-service date
Site C	BC	1,100	2024
La Romaine Complex	Quebec	1,550	2017–2020
Muskrat Falls	Newfoundland–Labrador	824	2018
Keeyask	Manitoba	695	2021
Lower Mattagami Complex	Ontario	438	2016
Total		4,607	

Development of new large hydro projects is controversial, as evidenced by protests of the Site C project in BC and Muskrat Falls in Labrador. Site C's critics cite, among other things, the following:

- Flooding of high-value agricultural land.
- Disruption of traditional land use and values of First Nations.
- Downstream impacts, including to the Peace River delta.
- Impacts on wildlife and fish.
- Emissions of methane from flooded land.
- Emissions during the construction process.

Similarly, there have been protests against less invasive “run-of-river” hydro projects in BC as they involved roads and transmission lines constructed in pristine wilderness in addition to the actual hydro infrastructure itself. These projects are also high-cost, with Site C amounting to \$8.335 billion,²⁰² or \$7,577 (US\$5,683) per kilowatt, which is at the high end of the cost scale, roughly the same as nuclear (see Table 19). Site C is forecast to produce 5,100 GWh per year, meaning that it will have a capacity factor of 53%—much higher than renewables like wind and solar but lower than nuclear.

Although many of the best hydropower sites in Canada within proximity to large population centres have been developed, the question remains: How much undeveloped hydropower capacity exists in Canada? The Canadian Hydropower Association claims there are 160 gigawatts (GW) in addition to the 80 GW already developed, but offers no evidence to support this claim.²⁰³ Canada's National Research Council (NRC) prepared a report in 2014 on the total hydrokinetic energy of all Canadian rivers, which projected very large numbers, but noted “that most locations would potentially be infeasible for energy extraction for a host of reasons.”²⁰⁴ The NRC estimated a mean hydrokinetic energy potential of 344 GW with a 95% probability interval of 29 GW to 5,530 GW. When asked what proportion of this potential would be technically feasible to develop, an NRC representative replied, “to my knowledge the practical or technical resource remains undetermined.”²⁰⁵

²⁰¹ NRCan, 2016, Energy Fact Book 2016–2017,

https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/EnergyFactBook_2016_17_En.pdf

²⁰² BC Hydro, Site C Fact Sheet, March 2017, https://www.sitecproject.com/sites/default/files/site-c-fact-sheet-march-2017_2.pdf

²⁰³ Canadian Hydropower Association, retrieved April 6, 2017, cites a 2007 report it commissioned that is not publicly available hence cannot be evaluated, <https://canadahydro.ca/hydropower-potential/>

²⁰⁴ National Research Council, 2014, Assessment of Canada's Hydrokinetic Power Potential, Phase III Report, Resource Estimation, see page 39.

²⁰⁵ Personal communication, Andrew Cornett, National Research Council, March 28, 2017.

In 2015, Canada ranked a distant second in the world to China in terms of total hydropower generation (374 TWh versus 1,163 TWh).²⁰⁶ It seems unlikely that Canada will significantly ramp up large-scale hydropower generation beyond projects under construction over the next few decades, given environmental considerations and opposition along with cost.

Notwithstanding this, the ECCC projects in its mid-century strategy scenarios that hydropower capacity will have to increase on average by 107% by 2050. Table 23 illustrates new hydro capacity required for each scenario.

Table 23: Projected increases in hydropower by scenario in Environment and Climate Change Canada's mid-century strategy²⁰⁷ and under the National Energy Board's reference scenario.²⁰⁸

Also shown is total cost (assuming US2016\$5,683 per kilowatt of capacity, which is the estimated construction cost of Site C), and number of new Site C-sized dams required (given Site C capacity of 1.1 GW).

Scenario	TWh	% growth from 2015 levels	% of total generation	New capacity needed (GW)	New dam cost (US2016\$B)	New Site C-sized dams required
NEB 2015 Generation	374		57.9%			
DDPP 2050	786	110%	53.2%	102	576.8	92
Current Tech Trottier 2050	828	121%	36.7%	111	630.8	101
New Tech Trottier 2050	824	120%	50.8%	111	630.8	101
High Nuclear 2050	526	41%	31.9%	36	204.6	33
High Hydro 2050	967	158%	58.7%	130	738.8	118
High Demand Response 2050	865	131%	71.1%	108	613.8	98
NEB Reference in 2040	413	10.4%	56.4%	8.3	47.0	8

Developing this much additional hydropower in just 33 years would require up to 118 new dams the size of Site C at a cost of up to US\$739 billion. This would likely involve multiple dams on the last remaining undammed rivers, including the Fraser, Skeena, Mackenzie and Yukon, as well as major investments in new transmission lines. The environmental costs of doing this would be substantial, to put it mildly.

²⁰⁶ BP Statistical Review of World Energy 2017.

²⁰⁷ National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/fttrpndc/dflt.aspx?GoCTemplateCulture=en-CA>

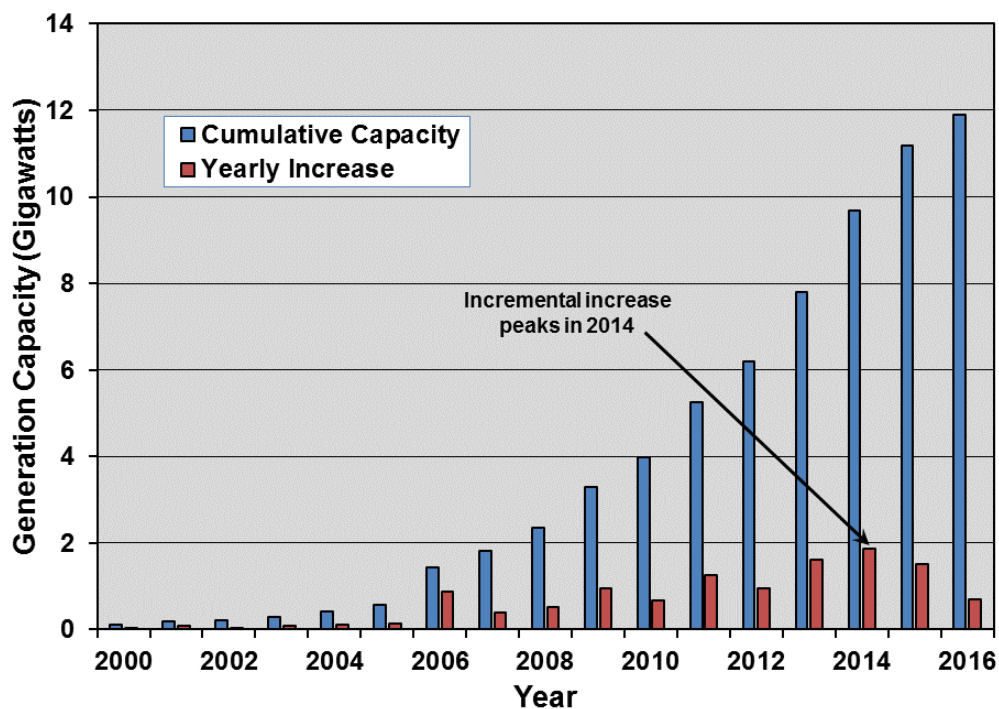
²⁰⁸ Environment and Climate Change Canada, 2016, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, see Figures 2 and 7, http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

3.3 Wind

Wind electricity generation capacity has grown from less than one gigawatt in 2005 to nearly 12 gigawatts in 2016 (see Figure 114) according to the Canadian Wind Energy Association (CANWEA).²⁰⁹ This represents about 9% of 2016 Canadian capacity, although Statistics Canada reported that wind was just 5.65% of Canadian capacity in 2015 (see Table 16—CANWEA notes all wind projects and is believed to be more complete and accurate than Statistics Canada). Yearly additions of wind capacity have declined since peaking in 2014. At the time of writing, an additional 22 wind projects worth US\$4.8 billion were either under construction, under review, approved or planned. If completed, these would add 2.6 gigawatts, increasing Canada's capacity by 22% to 14.5 gigawatts.²¹⁰

Figure 114: Incremental and cumulative wind generation capacity in Canada from 2000 to 2016.

*Yearly growth in capacity peaked in 2014.*²¹¹



Ontario, with its aggressive policy to phase out coal, comprised 40% of total wind capacity in 2016, followed by Quebec and Alberta (see Figure 115, next page). Together these three provinces comprise 82% of Canadian wind power capacity. Figure 116 illustrates the location of the 217 wind generating stations in Canada by rated capacity.

²⁰⁹ Canadian Wind Energy Association, 2017, List of Wind Farms in Canada (as of December 31, 2016), http://canwea.ca/wp-content/uploads/2013/12/Installedcap_PublicWebsite-Dec-31-2016_dk.pdf

²¹⁰ Natural Resources Canada, The Atlas of Canada - Clean Energy Resources and Projects (CERP), retrieved May 28 2017, <http://atlas.gc.ca/cerp-rpep/en/>

²¹¹ Data from Canadian Wind Energy Association, 2017

Figure 115: Wind generation capacity in Canada in 2016 by province.²¹²

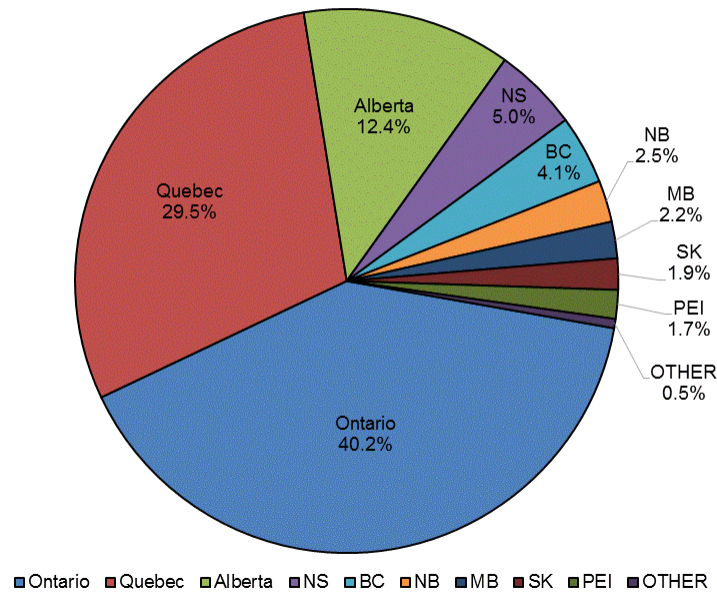
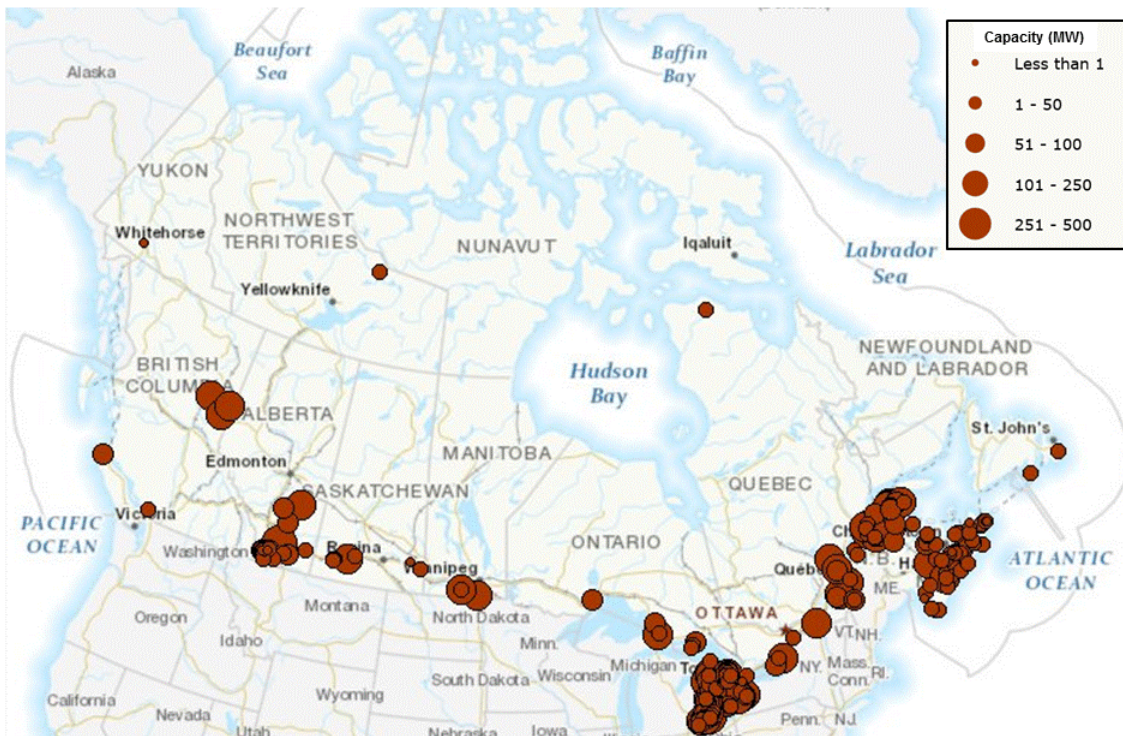


Figure 116: Wind generating stations in Canada as of early 2016, showing capacity (11,058 megawatts in total).²¹³

There are 217 stations shown.



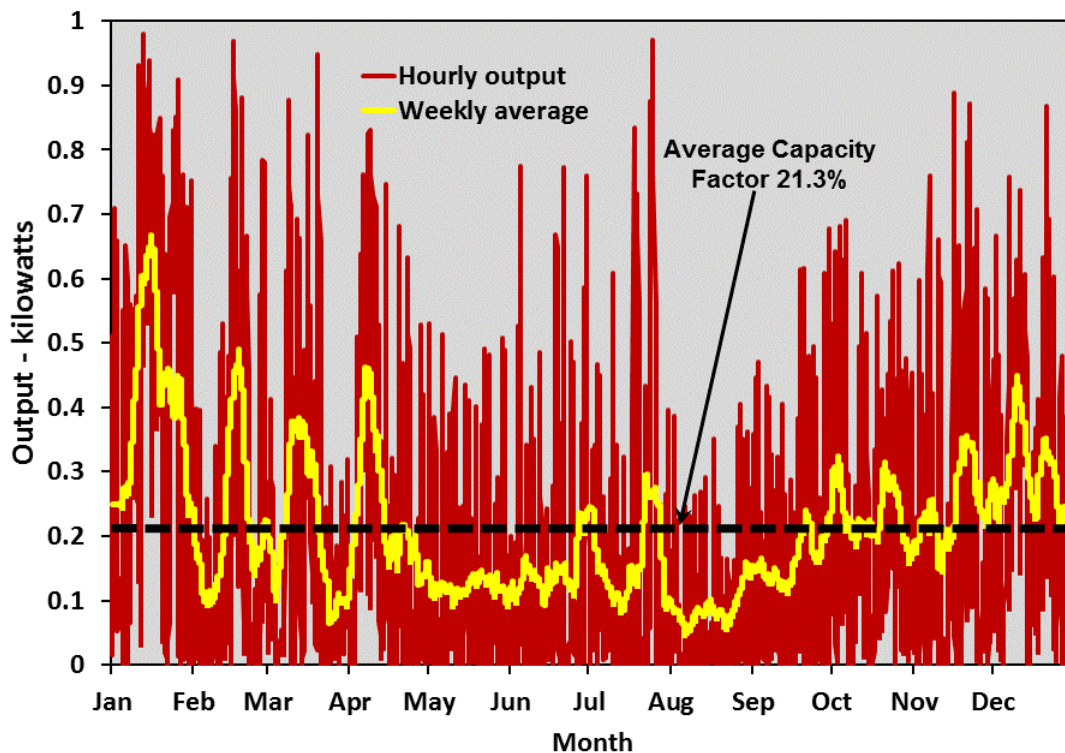
²¹² Canadian Wind Energy Association, 2017, List of Wind Farms in Canada (as of December 31, 2016), http://canwea.ca/wp-content/uploads/2013/12/Installedcap_PublicWebsite-Dec-31-2016_dk.pdf

²¹³ Natural Resources Canada Atlas of Canada, retrieved June 10, 2017, <http://atlas.gc.ca/cerp-rpep/en/>

A major issue with renewable sources such as wind and solar is that they are intermittent, and vary in output on an hourly (or even shorter) basis as well as seasonally. To maintain a stable grid, “dispatchable” sources of generation that can be rapidly ramped up and down must be available to provide backup power when the wind is not blowing and the sun is not shining. Figure 117 illustrates this issue for a theoretical windmill located at Calgary, Alberta, using 2014 climate data. At this location, the average capacity factor for the year is 21.3%, but is higher in winter than summer months. Hydropower is an ideal dispatchable renewable resource to back up this intermittency, where available, but simple cycle turbines burning gas are also commonly used. These can be rapidly ramped up and down to match wind generation’s intermittency, unlike more efficient combined-cycle gas generators, which are less suited to rapid changes in output.

Figure 117: Generation from one kilowatt of wind capacity from a tower 60 metres high located at Calgary, Alberta, in 2014.²¹⁴

Hourly and weekly generation is indicated. The overall average generation is 21.3% of rated nameplate capacity, but this is highly variable.²¹⁵



Capacity factor varies with the wind resource. In a high-quality onshore location, capacity factors can be 30% or higher. Using Statistics Canada data, the average capacity factor of wind in Canada from 2011 to 2015 was 22.7%.²¹⁶ The UN’s International Renewable Energy Agency (IRENA) also provides data on wind generation and capacity for Canada, which yield a capacity factor of 26.5% in 2014.²¹⁷ In Alberta, where a high-quality wind resource exists in the southwestern part of the province, Statistics Canada data yield an average capacity factor of 34.4% over the period from 2011 to 2015.

²¹⁴ Data from NASA MERRA-2 database with bias-correction from Staffell and Pfenninger, 2016 – Vestas V80-2000

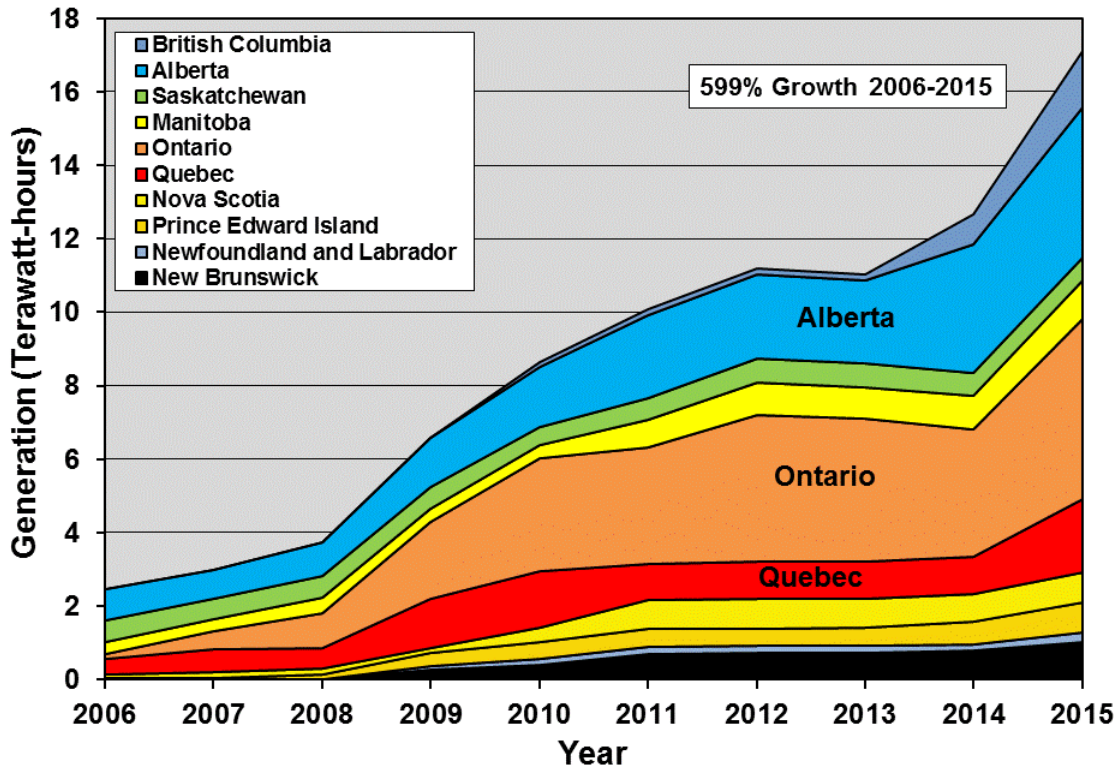
²¹⁵ Stefan Pfenninger and Iain Staffell, retrieved March 5, 2017, climate data sources NASA MERRA reanalysis and CM-SAF’s SARAH dataset, <https://www.renewables.ninja/#>

²¹⁶ Statistics Canada, CANSIM Tables 127-0007 and 127-0009 retrieved February 5, 2017.

²¹⁷ IRENA, Featured dashboard Capacity and Generation, retrieved April 15, 2017, <http://resourceirena.irena.org/gateway/dashboard/?topic=4&subTopic=54>

Figure 118 illustrates wind generation by province over the period from 2006 to 2015 using Statistics Canada data, which amounted to 2.7% of total Canadian generation in 2015. Total generation is likely somewhat higher than this given Statistics Canada's underestimation of total wind capacity (IRENA, for example, reports 22.5 TWh in 2014 versus 12.7 TWh from Statistics Canada; in 2015 the NEB reports 28 TWh versus 17.1 TWh from Statistics Canada).

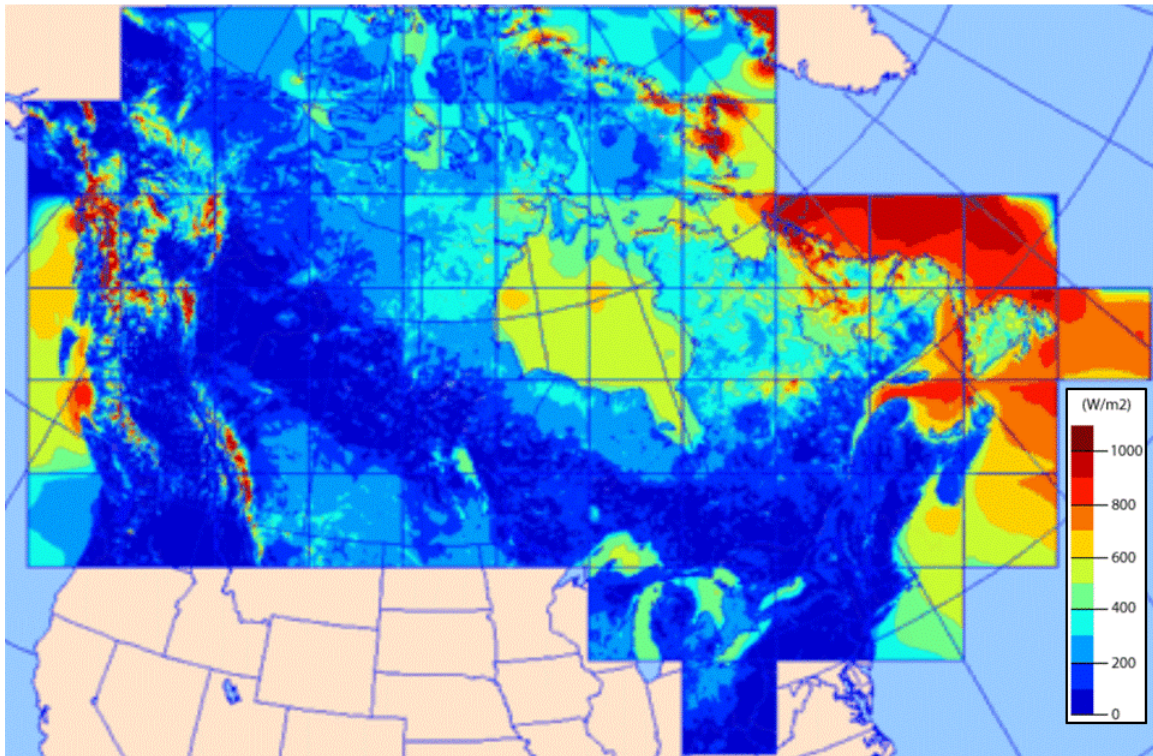
Figure 118: Wind generation by province from 2006 to 2015.²¹⁸



²¹⁸ Statistics Canada, CANSIM Table 127-0007 retrieved February 5, 2017.

The distribution of the potential wind resource in Canada is illustrated in Figure 119. The highest-quality resources are generally offshore, although these are costly to access and usually remote from demand centres, thus requiring costly new transmissions lines. Relatively high-quality resources are located in the prairies of southern Alberta, Saskatchewan and Manitoba, and along the Rocky Mountains of southern and central Alberta, as well as in localized high-potential resources in BC.

Figure 119: Mean wind energy potential in Canada at 50 metres above the land surface on an annual basis.²¹⁹



CANWEA commissioned a 2016 study to look at different scenarios of ramping up wind energy in Canada in terms of feasibility, new transmission lines required, emissions saved, US exports, etc. The study looked at four scenarios of up to 35% wind generation for Canada, all of which it found feasible. The 35% scenario would involve increasing wind capacity by five-fold to 65.2 gigawatts from current levels of 11.9 gigawatts, and would require wind to generate 50% of the electricity in Alberta, Saskatchewan and the Maritimes, which have the best wind resources. This would also require a significant number of new transmission lines and increased power exports to the US, which is highly integrated with the Canadian grid. The study assumed capacity factors of more than 35%, which are considerably higher than those observed from current installed wind capacity.²²⁰ The study also assumed existing levels of electricity consumption will persist in the future, not the much higher levels projected by government plans to meet international emissions-reduction commitments in ECCC's mid-century strategy.

²¹⁹ Environment and Climate Change Canada, Canadian Wind Energy Atlas, retrieved June 10, 2017, <http://www.windatlas.ca/>

²²⁰ CANWEA, 2016, Pan-Canadian Wind Integration Study (PCWIS), see Figure 1-3, <http://canwea.ca/wind-integration-study/full-report/>

ECCC's mid-century strategy scenarios for wind are given in Table 24. Up to an 18-fold increase in wind generation is called for at a cost of up to US\$366 billion. In the highest wind scenario (called "Current Tech Trottier"), 24% of Canada's electricity would be generated by wind. By comparison, CANWEA's 35% wind scenario of 212.7 TWh would only provide 9.4% of the expanded electricity requirement in ECCC's Current Tech Trottier scenario. Although the CANWEA study did not identify technical limits to its 35% scenario, the feasibility of the higher levels required by some of ECCC's scenarios remains to be proven.

Table 24: Wind generation by scenario in Environment and Climate Change Canada's mid-century strategy.²²¹

Also shown are the percentage of electricity generation by wind, the new capacity required (assuming an overall capacity factor of 30%) and the cost (assuming US2016\$1,877/kilowatt), excluding the cost of new transmission lines. The number of additional two-megawatt windmills needed is also shown.

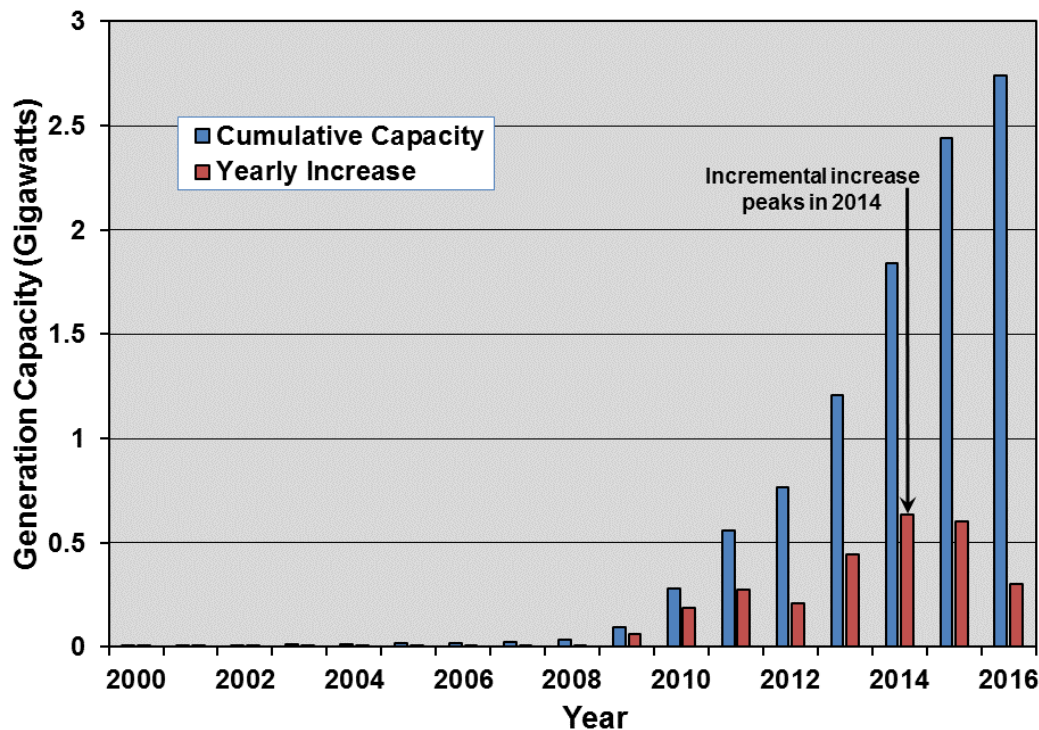
Scenario	TWh	% growth from 2015 levels	% of total generation	# of new 2MW wind mills needed	Cost of new wind mills (US2016\$B)
NEB 2015 Generation	28	0%	4.4%		
DDPP 2050	251	787%	17.0%	42,385	159.1
Current Tech Trottier 2050	540	1808%	23.9%	97,409	365.7
New Tech Trottier 2050	129	356%	8.0%	19,195	72.1
High Nuclear 2050	154	444%	9.3%	23,913	89.8
High Hydro 2050	228	705%	13.8%	37,992	142.6
High Demand Response 2050	32	13%	2.6%	701	2.6
NEB Reference in 2040	69	145%	9.5%	7,813	29.3

²²¹ Environment and Climate Change Canada, 2016, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, see Figures 2 and 7, http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

3.4 Solar

Solar electricity generation capacity has grown from less than one-tenth of a gigawatt in 2009 to 2.7 gigawatts in 2016 (see Figure 120). This represents about 2% of 2016 Canadian capacity, although Statistics Canada reported that solar was just .14% of Canadian capacity in 2015 (see Table 16). Data in Figure 119 are from Natural Resources Canada and IRENA, which are believed to be more complete and accurate than data from Statistics Canada. Natural Resources Canada reports 134 grid-scale solar generating stations with a total capacity of 1.58 gigawatts, including two with 100 megawatts each.²²² These stations do not include distributed solar at the household-scale, which contributes an additional 1.1 gigawatts of capacity. Yearly additions of solar capacity have declined since peaking in 2014.

Figure 120: Solar generation capacity in Canada from 2000 to 2016.²²³



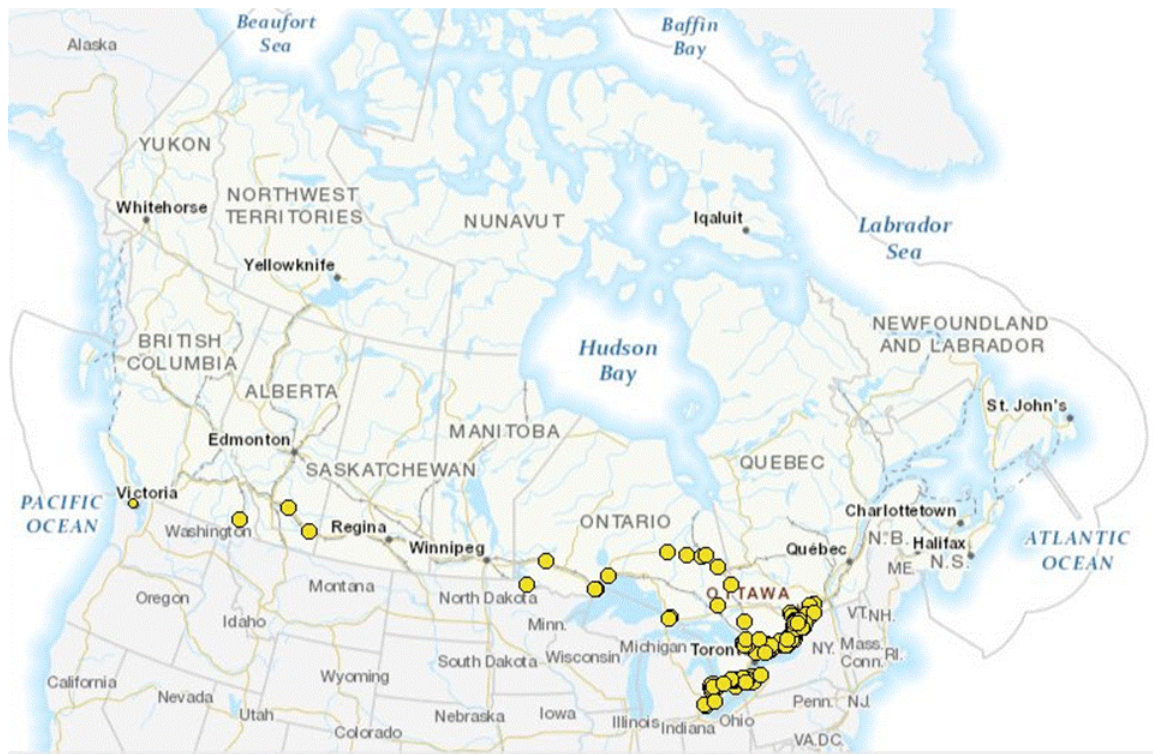
²²² Natural Resources Canada, The Atlas of Canada - Clean Energy Resources and Projects (CERP), retrieved May 28 2017, <http://atlas.gc.ca/cerp-rpep/en/>

²²³ Data for 2015 and 2016 from IRENA Featured dashboard Capacity and Generation, retrieved April 15, 2017, <http://resourceirena.irena.org/gateway/dashboard/?topic=4&subTopic=54>; 2000-2014 data from NRCan National Survey Report of PV Power Applications in Canada 2014, http://www.cansia.ca/uploads/7/2/5/1/72513707/national_survey_report_of_pv_power_applications_in_canada_2014.pdf. Note there is an order of magnitude difference between IRENA and NRCan capacity and Statscan which is an order of magnitude smaller, both in capacity and generation.

Figure 121 illustrates the distribution of grid-scale solar generating stations in Canada. With the exception of two stations each in Alberta and BC, all of the capacity is located in Ontario. This is due to the favourable fiscal environment in Ontario given its aggressive policies to promote renewable energy and phase out coal.

Figure 121: Location of grid-scale solar generating stations in Canada.²²⁴

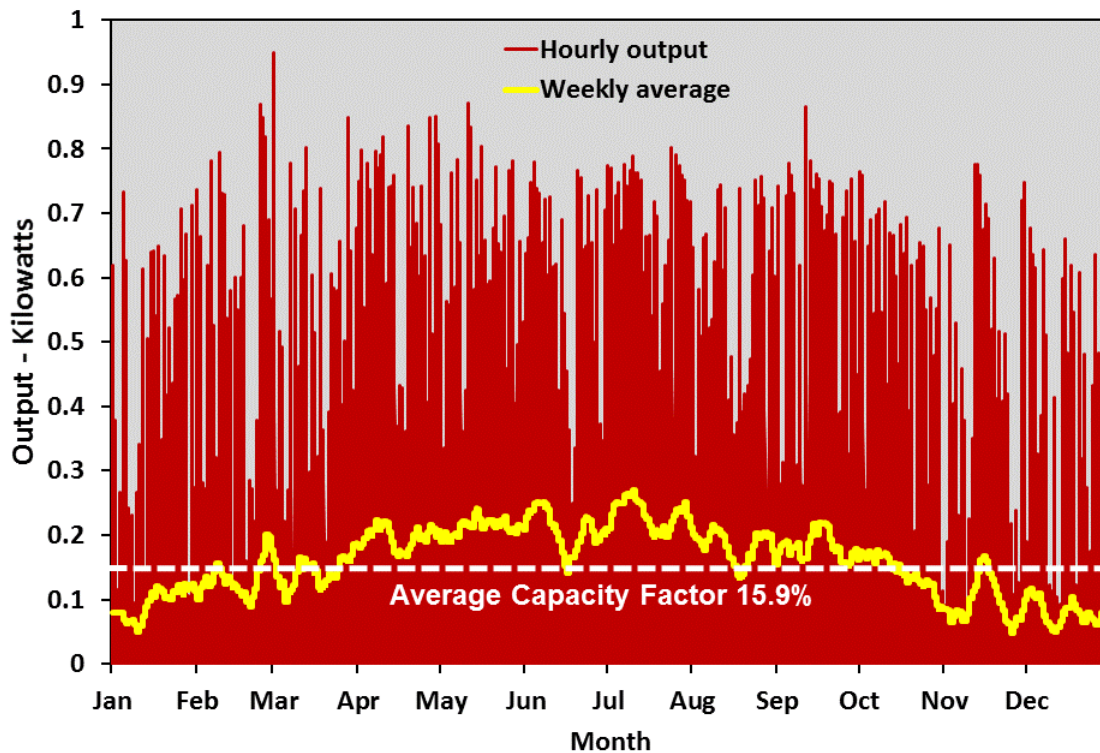
There are 134 stations with capacities of greater than .75 megawatts for a total of 1.58 gigawatts. Not shown is the distribution of household-scale solar capacity, which adds another 1.1 gigawatts of capacity.



²²⁴ Natural Resources Canada, Atlas of Canada, retrieved May 31, 2017, <http://atlas.gc.ca/cerp-rpep/en/>

As discussed above with respect to wind, a major issue with renewable sources such as solar is that it is intermittent, and varies in output on an hourly (or even shorter) basis given cloud cover and day/night cycles. It also varies seasonally, with the highest output in summer months. To maintain a stable grid, “dispatchable” sources of generation that can be rapidly ramped up and down must be available to provide backup power when the sun is not shining. Figure 122 illustrates this issue for a theoretical one-kilowatt photovoltaic array located at Calgary, Alberta, using 2014 climate data. At this location, the average capacity factor for the year is 15.9%, but is above 20% in the summer and below 10% in the winter. Capacity factor also varies with the solar resource. In a high-quality location, capacity factors may approach 20% on average, although according to IRENA data, the capacity factor from all Canadian solar generation averaged just 12.5% from 2013 to 2014. As discussed earlier, hydropower is an ideal dispatchable renewable resource to back up this intermittency where available, but simple cycle turbines burning gas are also commonly used. Various methods of storage, including pumped hydro, thermal, compressed air and mass-scale batteries are also being deployed, but so far these have not been able to displace the need for dispatchable power sources like natural gas in most locations.

Figure 122: Output from a theoretical one-kilowatt photovoltaic array located at Calgary, Alberta, illustrating intermittency and average output on a weekly basis in 2014.²²⁵

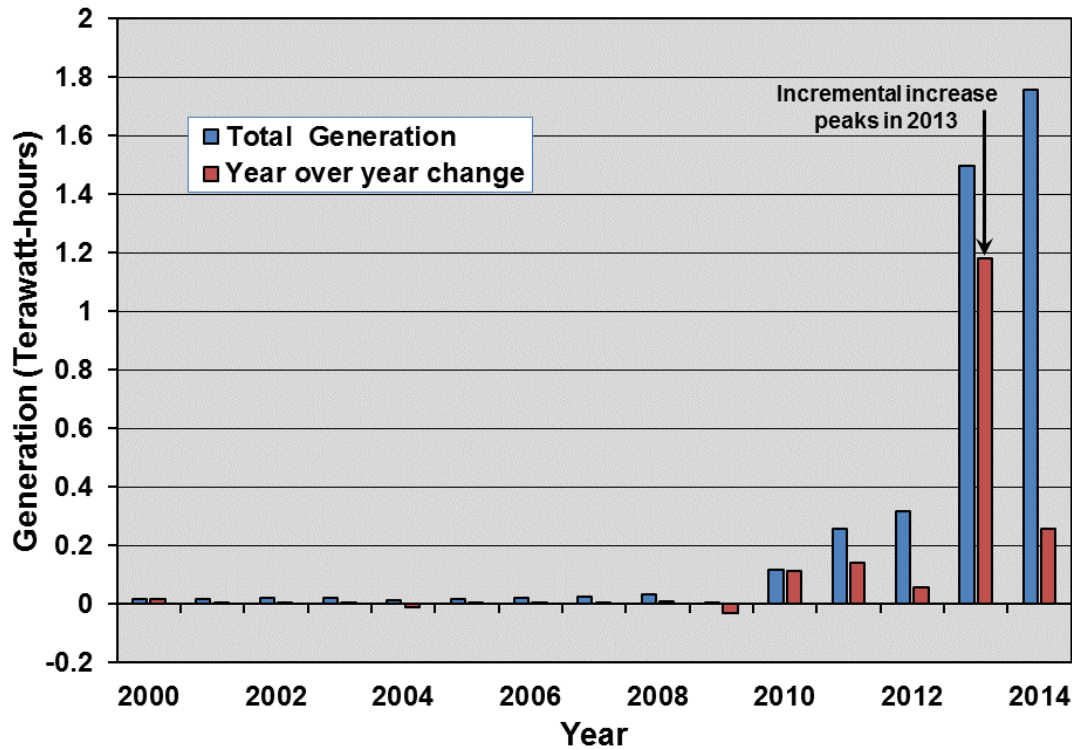


²²⁵ Stefan Pfenninger and Iain Staffell, retrieved March 5, 2017, climate data sources NASA MERRA reanalysis and CM-SAF's SARA dataset, <https://www.renewables.ninja/#>

Figure 123 illustrates solar generation over the period from 2006 to 2014 using IRENA data, which are believed to be more complete than Statistics Canada data. Using NEB data, which are higher still, solar generated three terawatt hours in 2015, or about 0.5% of total Canadian generation in that year²²⁶ (versus 0.05%, an order of magnitude less, reported by Statistics Canada in Table 16).

Figure 123: Electricity generation from solar power in Canada from 2000 to 2014, based on data from the International Renewable Energy Agency.²²⁷

The National Energy Board reports generation of three TWh in 2015, which represents a large increase over 2014.

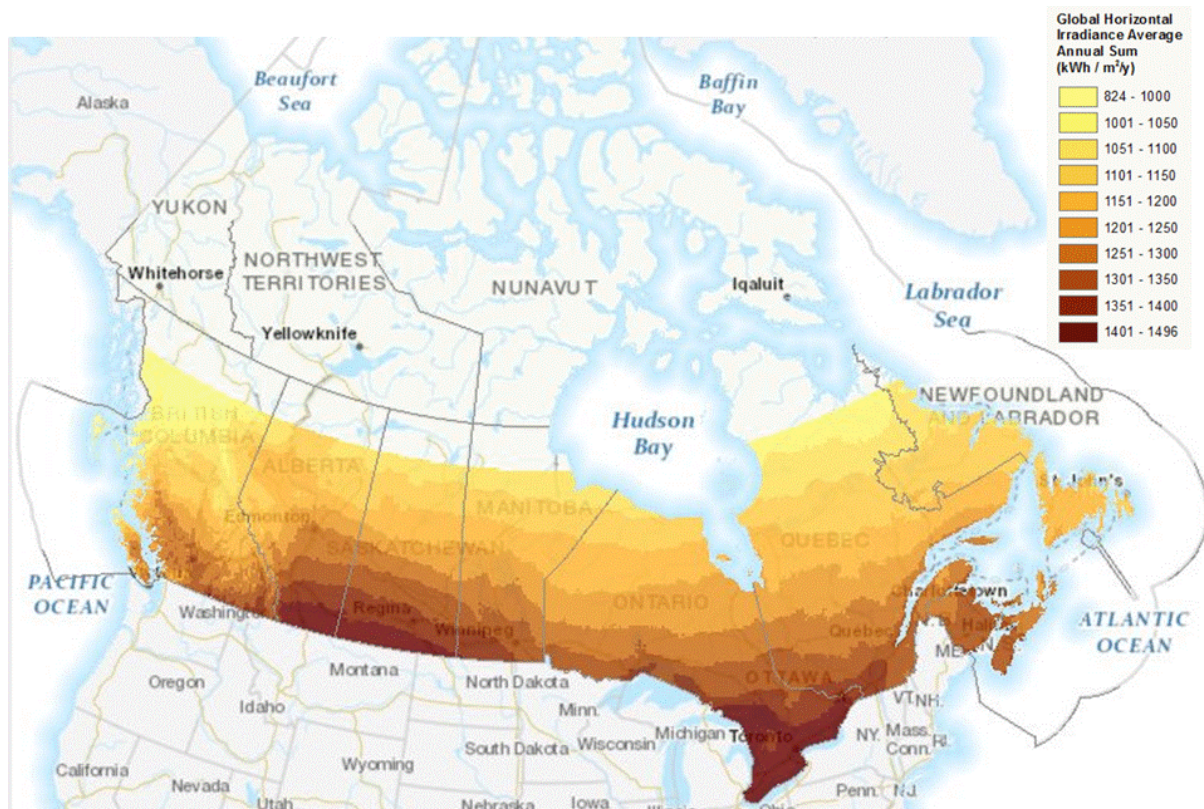


²²⁶ National Energy Board, October 2016, Canada's Energy Future 2016: Update - Energy Supply and Demand Projections to 2040, Appendices, <https://www.neb-one.gc.ca/nrg/ntgrtd/ft/2016updt/index-eng.html>

²²⁷ IRENA Featured dashboard Capacity and Generation, retrieved April 15, 2017, <http://resourceirena.irena.org/gateway/dashboard/?topic=4&subTopic=54>

The distribution of the potential solar resource in Canada is illustrated in Figure 124. The highest-quality resources are located in southern Alberta and Saskatchewan and the Niagara Peninsula of Ontario, although other areas have potential. Climactic factors, such as persistent cloudy conditions in winter months on the Pacific Coast, can severely degrade output when it might be needed most. Unlike wind, however, solar is more conducive to implementation on a distributed basis at the household level, offering opportunities to reduce overall load on the grid even where commercial-scale projects may not make economic sense.

Figure 124: Solar potential in Canada.²²⁸



²²⁸ Natural Resources Canada, Atlas of Canada, retrieved May 31, 2017, <http://atlas.gc.ca/cerp-rpep/en/>

ECCC's mid-century strategy scenarios for solar are given in Table 25. Up to a 32-fold increase in solar generation is called for at a cost of up to US\$185 billion. In the highest-solar scenario (called "High Hydro"), 6% of Canada's electricity would be generated by solar. In the lowest scenario ("High Demand Response"), even though solar generation would remain at current levels, its percentage of total generation would drop to 0.2% given the increase in electricity demand.

Table 25: Solar generation by scenario in Environment and Climate Change Canada's mid-century strategy.²²⁹

Also shown are the percentage of electricity generation from solar, the new capacity required (assuming an overall capacity factor of 15%) and the cost (assuming US2016\$2,534/kilowatt), excluding the cost of other infrastructure such as new transmission lines.

Scenario	TWh	% growth from 2015 levels	% of total generation	New capacity needed (GW)	Solar cost (US2016\$B)
NEB 2015 Generation	3.0	0%	0.5%		
DDPP 2050	74.0	2367%	5.0%	54.0	137.0
Current Tech Trottier 2050	24.5	715%	1.1%	16.3	41.4
New Tech Trottier 2050	3.0	0%	0.2%	0.0	0.0
High Nuclear 2050	18.0	500%	1.1%	11.4	28.9
High Hydro 2050	99.0	3199%	6.0%	73.1	185.1
High Demand Response 2050	3.0	0%	0.2%	0.0	0.0
NEB Reference in 2040	13.0	333%	1.8%	7.6	19.2

3.5 Biomass

There are 136 biomass-generating stations in Canada with a combined capacity of 2,843 megawatts.²³⁰ Although many of these stations are small (70 have capacities of less than 10 megawatts), four are greater than 100 megawatts, with the largest being Atikokan-G1 at 205 megawatts, operated by Ontario Power Generation. These plants burn wood and agricultural waste, municipal waste and biogas, and provided 1.9% of Canada's electricity in 2015.²³¹ Biomass has an advantage over intermittent sources such as wind and solar as it is "dispatchable" and can operate at much higher capacity factors.

Figure 125 (next page) illustrates the distribution of these generating stations and Figure 126 illustrates the proportion of capacity by fuel type. As of mid-2017 there were six new stations either planned or under construction, which will add an additional 695 megawatts of capacity. These include the Fort St. James Green Energy Project in BC, which will become the largest biomass plant in Canada at 235 megawatts.

²²⁹ Environment and Climate Change Canada, 2016, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, see Figures 2 and 7, http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

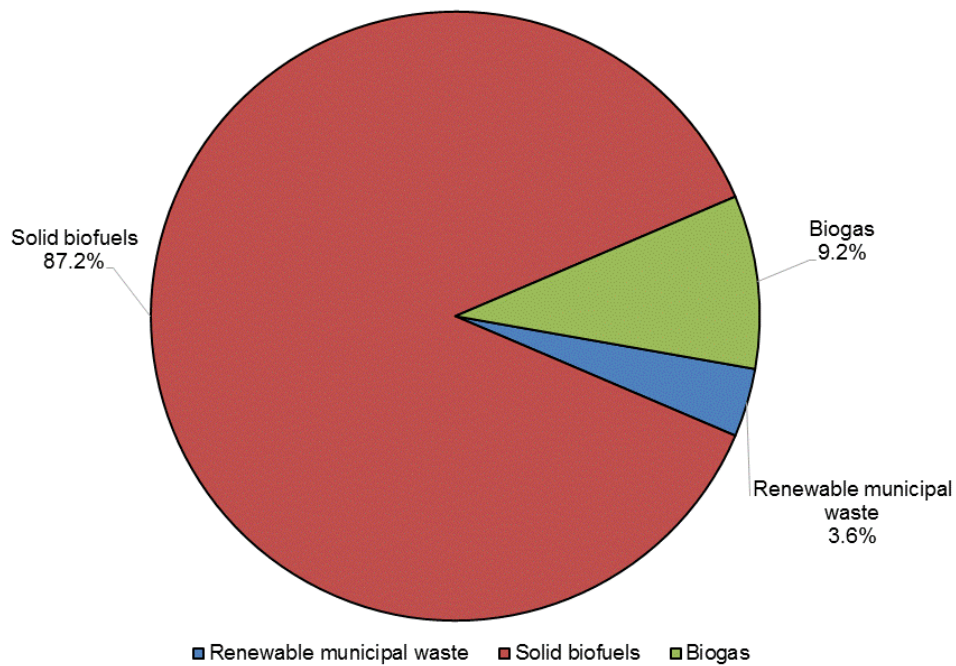
²³⁰ Natural Resources Canada, The Atlas of Canada - Clean Energy Resources and Projects (CERP), retrieved May 28 2017, <http://atlas.gc.ca/cepr-rpep/en/>

²³¹ National Energy Board, October 2016, Canada's Energy Future 2016: Update - Energy Supply and Demand Projections to 2040, Appendices, <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2016updt/index-eng.html>

Figure 125: Biomass generating stations in Canada, showing generating capacity.²³²



Figure 126: Biomass generation capacity in Canada in 2016 by fuel type.²³³



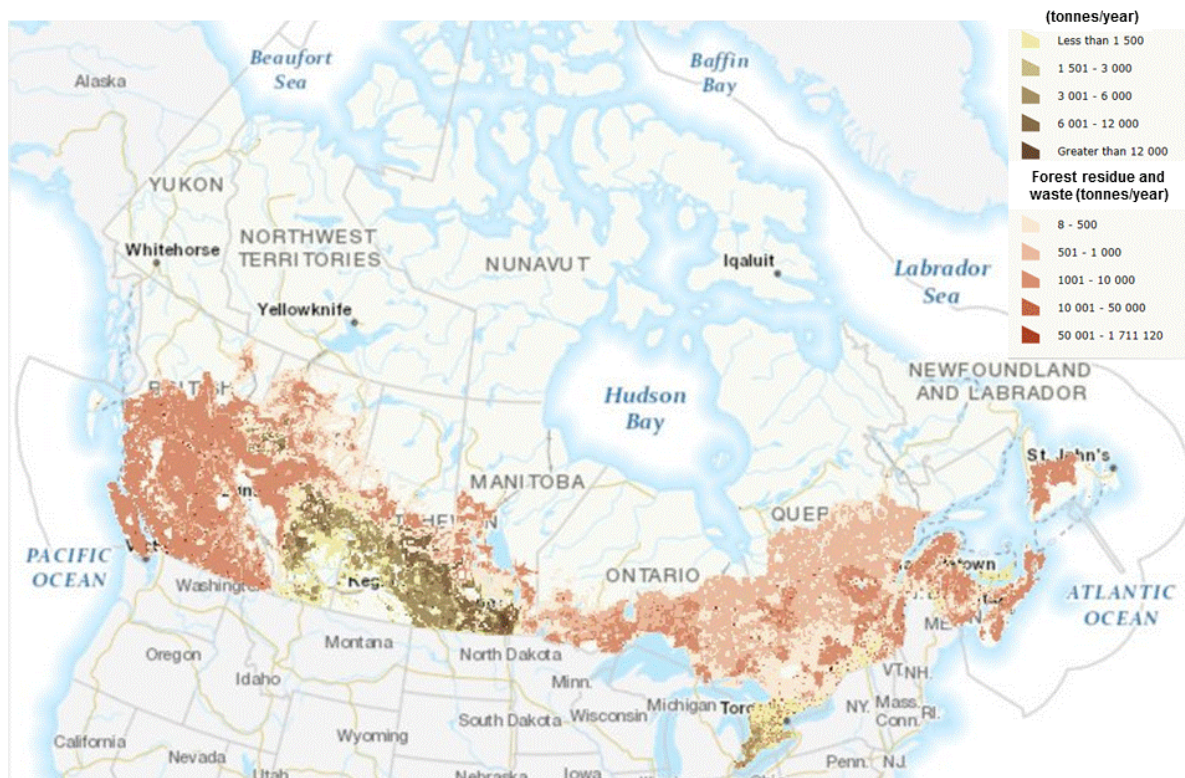
²³² Natural Resources Canada, The Atlas of Canada - Clean Energy Resources and Projects (CERP), retrieved May 28 2017, <http://atlas.gc.ca/cerp-rpep/en/>

²³³ IRENA Featured dashboard Capacity and Generation, retrieved April 15, 2017, <http://resourceirena.irena.org/gateway/dashboard/?topic=4&subTopic=54;>

Biomass is considered part of the solution to greenhouse gas emissions as in theory all of the carbon dioxide released when it is burned is removed from the atmosphere as the biomass grows back. Increasing amounts of biomass are therefore included in many climate models that minimize future emissions, often in conjunction with carbon capture and storage. However, a closer look reveals that emissions from burning biomass are comparable to those from burning coal, with some biomass fuels, such as agricultural waste, being worse than coal.²³⁴ Therefore, over the short term, biomass may exacerbate greenhouse gas emissions until the fuel regrows, which, depending on the fuel, could take 30 years or more.

Figure 127 illustrates the distribution of biomass potential in Canada from forest residue and waste and from cereal straw. Other potential sources include municipal solid waste and biogas from agricultural sources and landfills.

Figure 127: Distribution of biomass potential in Canada from forest residue and waste and from cereal straw²³⁵



²³⁴ Intergovernmental Panel on Climate Change, Emission Factors for Greenhouse Gas Inventories, April 4, 2014, https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

²³⁵ Natural Resources Canada, Atlas of Canada, retrieved May 31, 2017, <http://atlas.gc.ca/cepr-rpep/en/>

ECCC's mid-century strategy scenarios for biomass are given in Table 26. Up to a 9-fold increase in biomass generation is called for at a cost of up to US\$105 billion, although two scenarios do not consider future expansion of biomass. In the highest-biomass scenario ("High Nuclear"), 7.2% of Canada's electricity would be generated by biomass in 2050. In the lowest scenario ("New Tech Trottier"), even though biomass generation would remain at current levels, its percentage of total generation would drop to 0.7% from the current 1.9%, given the increase in electricity demand.

Table 26: Biomass generation by scenario in Environment and Climate Change Canada's mid-century strategy.²³⁶

Also shown is the percentage of electricity generation from biomass, the new capacity required (assuming an overall capacity factor of 58%) and cost (assuming US2016\$4,985/kilowatt), excluding the cost of other infrastructure, such as new transmission lines.

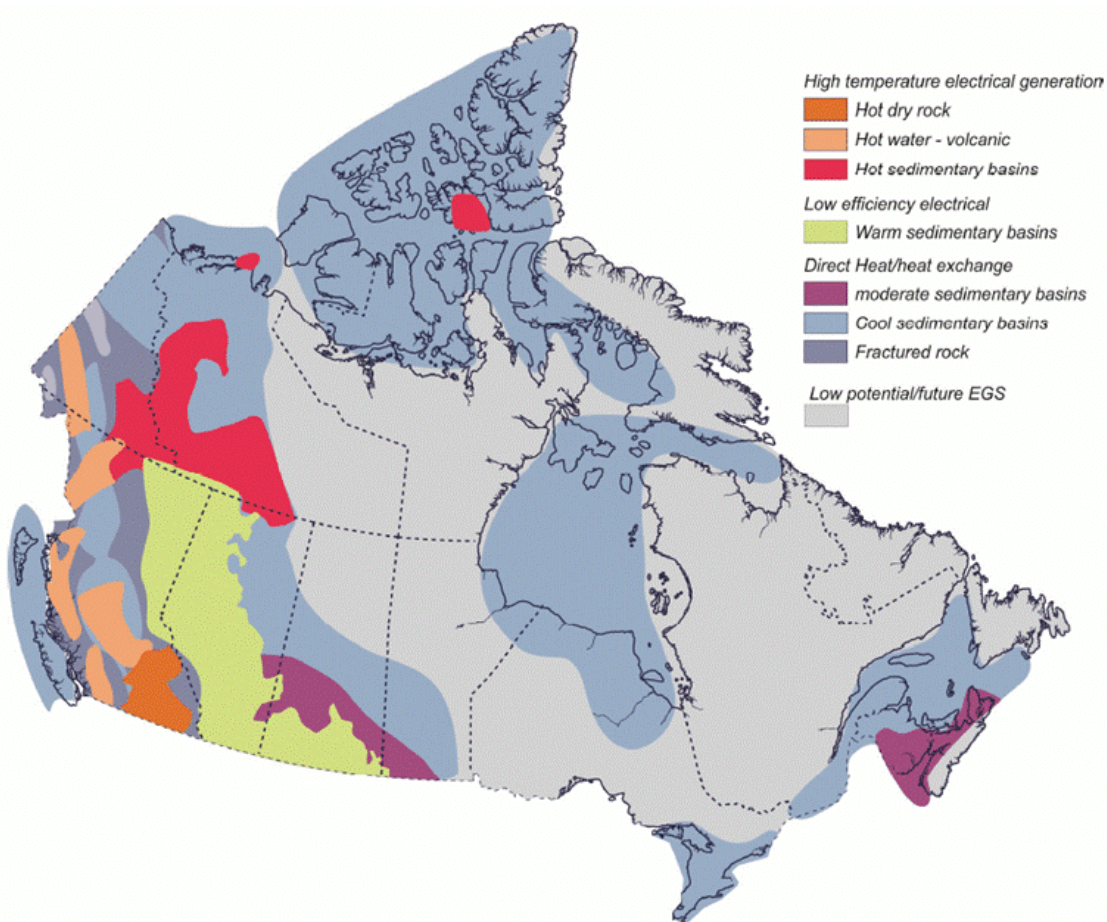
Scenario	TWh	% growth from 2015 levels	% of total generation	New capacity needed (GW)	Biomass cost (US2016\$B)
NEB 2015 Generation	12.5	0%	1.9%		
DDPP 2050	12.2	-3%	0.8%	-0.1	-0.3
Current Tech Trottier 2050	20.4	63%	0.9%	1.6	7.8
New Tech Trottier 2050	12.2	-3%	0.7%	-0.1	-0.3
High Nuclear 2050	118.3	845%	7.2%	21.0	104.5
High Hydro 2050	57.1	356%	3.5%	8.8	44.0
High Demand Response 2050	16.3	30%	1.3%	0.8	3.8
NEB Reference in 2040	15.3	23%	2.1%	0.6	2.8

²³⁶ Environment and Climate Change Canada, 2016, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, see Figures 2 and 7, http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

3.6 Geothermal energy

Grasby et al.²³⁷ provide a comprehensive review of geothermal resources in Canada, including a map of potential, which is illustrated in Figure 128. Most of the potential for high-efficiency electricity generation is located in high-temperature gradient parts of BC and the southern Yukon and Northwest Territories, with potential for low-efficiency generation in the cooler sedimentary rocks of Alberta, northeast BC and southern Saskatchewan. Despite considerable exploration in BC, mainly in the 1970s and 1980s, there are no geothermal generation stations in Canada, although Natural Resources Canada lists two announced projects—South Meager Creek in southwest BC and Mount Layton in northwest BC.²³⁸ Exploration for geothermal resources for electricity generation is both high-cost and high-risk, which has limited its development.²³⁹ Given the history of geothermal exploration in Canada to date, it seems unlikely that it will provide major amounts of electricity in the near or medium term.

Figure 128: Geothermal potential in Canada, categorized by end use.²⁴⁰



²³⁷ S. E. Grasby et al., 2012, Geothermal Resource Potential of Canada, Geological Survey of Canada Open File 6914, http://publications.gc.ca/collections/collection_2013/rncan-nrcan/M183-2-6914-eng.pdf

²³⁸ Natural Resources Canada, Atlas of Canada, retrieved June 26, 2017, <http://atlas.gc.ca/ceep-rpep/en/>

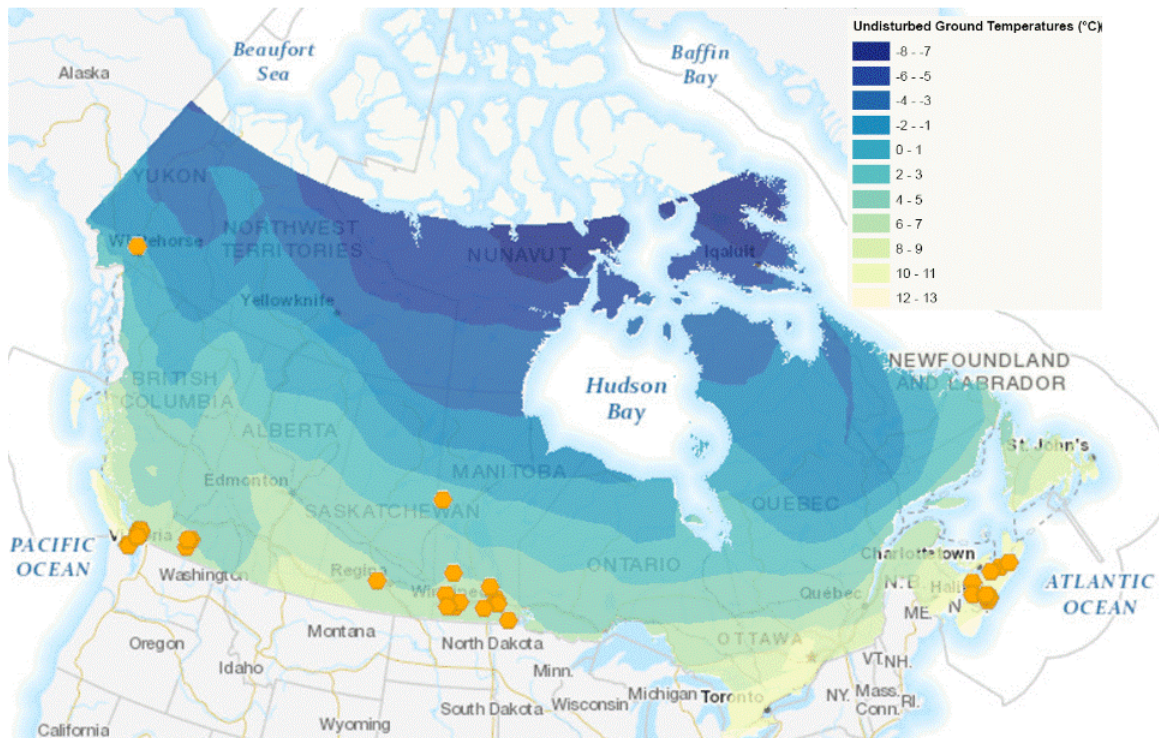
²³⁹ Business in Vancouver, "Geothermal generating little heat in energy sector", July 28, 2014, <https://www.biv.com/article/2014/7/geothermal-generating-little-heat-in-energy-sector/>; see also Ross Beaty, "Geothermal, Solar, Wind, Run of River Energy with Ross Beaty", September 12, 2015, <https://www.youtube.com/watch?v=HoknsUdu6Y>

²⁴⁰ S. E. Grasby et al., 2012, Geothermal Resource Potential of Canada, Geological Survey of Canada Open File 6914, http://publications.gc.ca/collections/collection_2013/rncan-nrcan/M183-2-6914-eng.pdf

Using geothermal energy for heating is likely to be a much larger contributor to displacing fossil fuel energy than using it for electricity generation. There are many geothermal heating projects in Canada, with more planned. Figure 129 illustrates the near-surface geothermal heating potential in Canada and the distribution of major projects. There is also a large potential for using ground source heat pumps on a smaller distributed scale to displace fossil fuels for heating residential buildings.

Figure 129: Near-surface geothermal heating potential in Canada.²⁴¹

Also shown are major geothermal heating projects.



3.7 Tidal power

Tidal power is still in its early stages of development worldwide. It suffers intermittency on a twice-daily basis as well as seasonal fluctuations in tidal height, but unlike solar and wind, its intermittency and power generation levels are highly predictable. In Canada, there has been some development in the Bay of Fundy in Nova Scotia, which has one of the highest tidal ranges in the world. A 20-megawatt tidal generating station (Annapolis Tidal) has been in operation since 1984 and a smaller station (Cape Sharp Tidal Venture), at up to four megawatts, has recently been commissioned.²⁴² The FORCE tidal demonstration project is also under construction there. Although there is considerable potential for tidal power in coastal regions, so far production has been very limited and it is unlikely to become a significant source of electricity in the near or medium term.

²⁴¹ Natural Resources Canada, Atlas of Canada, retrieved May 31, 2017, <http://atlas.gc.ca/cerp-rpep/en/>

²⁴² Op cit., see also "Tidal Energy Project in the Bay of Fundy" <http://www.nrcan.gc.ca/energy/funding/current-funding-programs/cef/4955>

3.8 Biomass and biofuels

In addition to electricity generation, biomass is also used for heating in many large- and household-scale applications, as well as in the production of liquid fuels, which can be used directly (biodiesel) or blended with gasoline (ethanol).

There are 270 large-scale biomass heating facilities in Canada, as illustrated in Figure 130. The biomass feedstocks most commonly used are wood chips and sawdust (often generated by onsite milling operations), followed by wood pellets, crop residue, construction and demolition waste, and other sources (see Table 27). Canada is a major producer of wood pellets at 44 plants. In 2017, 79% of estimated production of 2.2 million tonnes of wood pellets will be exported, mainly to Europe (74% of exports go to the United Kingdom).²⁴³ In addition, many rural households rely on wood for heat.

Figure 130: Location of the 270 large-scale biomass heating facilities in Canada.²⁴⁴

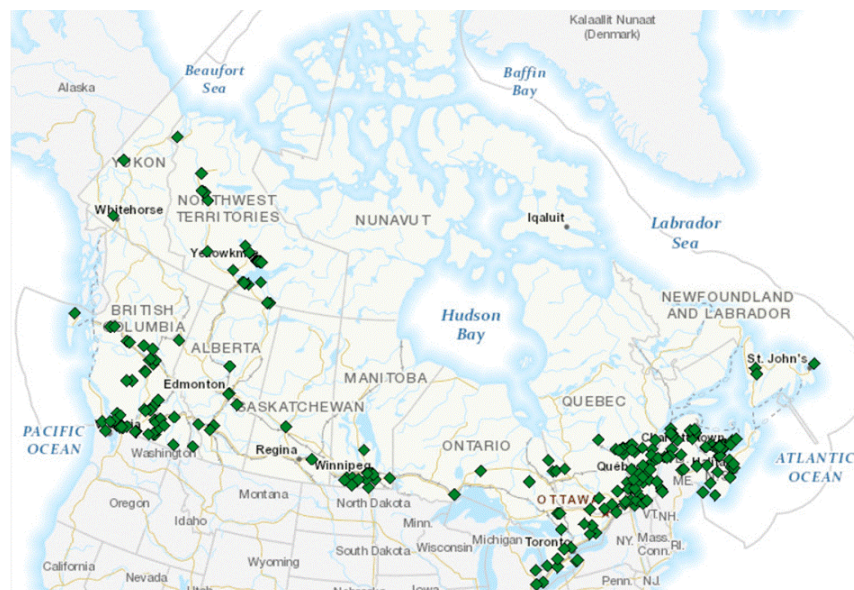


Table 27: Fuel sources for large-scale biomass heating facilities in Canada.

Biomass fuel	Number of facilities
Woodchips/sawdust	126
Wood pellets	95
Crop residue	11
Construction & demolition wood	11
Bark/hogfuel	6
Whole logs	1
Other	20
Total	270

Canada has a federal mandate for 5% bioethanol in gasoline (although some provinces are higher, for example Manitoba at 8.5%) and 2% biodiesel in diesel fuel and heating oil. Canada does not have sufficient

²⁴³ U.S. Department of Agriculture, 2016, Gain Report, Global Agriculture Information Report, https://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Ottawa_Canada_8-9-2016.pdf

²⁴⁴ Data from NRCan Atlas of Canada, retrieved June 29, 2017, <http://atlas.gc.ca/cepr-rpep/en>

production capacity from its 14 refineries to meet its bioethanol requirements, and therefore is a net importer of 36% of its consumption. Canada is self-sufficient in its biodiesel requirements, although there are significant imports and exports depending on the location of its 10 biodiesel production plants. Most ethanol is made from corn and wheat, whereas biodiesel is made from used cooking oil, canola oil, soybean oil and animal fats, in descending order of consumption. Given the inputs of fossil fuels to biofuel production in the form of transport fuel, fertilizers and power, and the resulting low energy return on investment (EROI is less than 1.6 for corn-based ethanol and 1.3 for biodiesel),²⁴⁵ biofuels are a marginal replacement for fossil fuels at best.

Biomass and biofuels are touted as a major component of managing greenhouse gas emissions given that they regrow after use and sequester their emissions. However, when initially burned biomass has greenhouse gas emissions comparable to coal, and biofuels are comparable to their fossil fuel counterparts (see Table 28). In the case of forest products, it may take several decades for regrowth to sequester the emissions from combustion, so in the short term their use exacerbates the emissions problem. Agricultural byproducts can be recycled more quickly, but are also useful nutrient sources for future crops if they are composted instead, thus avoiding the need for fossil fuel-based fertilizers.

Table 28: Emission factors (carbon dioxide, methane and nitrous oxide) for biomass fuels compared to fossil fuels.²⁴⁶

(MMbtu = million british thermal units)

Fuel	CO ₂ kg/MMbtu	CH ₄ kg/MMbtu	N ₂ O kg/MMbtu
Agricultural biomass byproducts	118.17	32	4.2
Solid biomass byproducts	105.51	32	4.2
Wood and wood residuals	93.80	7.2	3.6
Biodiesel (100%)	73.84	1.1	0.11
Ethanol (100%)	68.44	1.1	0.11
Biomass gas	52.07	3.2	0.63
Natural gas	53.06	1.0	0.10
Anthracite coal	103.69	11	1.6
Bituminous coal	93.28	11	1.6
Sub-bituminous coal	97.17	11	1.6
Lignite coal	97.72	11	1.6
Municipal solid waste	90.70	32	4.2

Biomass and biofuels are an important niche source of energy, but are unlikely to be scalable to displace a major portion of existing fossil fuel use. The issue of the minimal net energy yield from biofuels is also an important consideration that limits their contribution to greenhouse gas reduction, given the energy that must be used to produce them and the fact that their emissions are comparable to fossil fuel when burned.

Nonetheless, ECC's mid-century strategy calls for a large scale-up of "renewable fuels" in its scenarios. Biodiesel and ethanol production provide 1.3% and 3.8%, respectively, of current diesel and gasoline consumption.²⁴⁷ Canada is not self-sufficient in ethanol and must import some of its requirements.

²⁴⁵ Hall et al., 2014, EROI of different fuels and the implications for society, Energy Policy,

<http://www.sciencedirect.com/science/article/pii/S0301421513003856>

²⁴⁶ Intergovernmental Panel on Climate Change, 2014, Emission Factors for Greenhouse Gas Inventories,

https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

²⁴⁷ U.S. Department of Agriculture, 2016, Gain Report, Global Agriculture Information Report,

https://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Ottawa_Canada_8-9-2016.pdf

Depending on the scenario, a two-fold to 10-fold scale-up in the use of so-called renewable fuels is called for by 2050—mainly ethanol and biodiesel to replace liquid fossil fuels.²⁴⁸

²⁴⁸ Environment and Climate Change Canada, 2016, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, see Figure 8, http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

4. Emissions-reduction targets and implications for an energy strategy

Canadian emissions by sector are illustrated in Figure 131. Upstream oil and gas production was the largest emissions source in 2015 at 26%, followed by transportation (24%), buildings (11.9%), electricity (10.9%), heavy industry (10.4%), agriculture (10.1%) and other (6.6%).²⁴⁹

In January 2017 Canada implemented a “Pan-Canadian Framework on Clean Growth and Climate Change” designed to “enable Canada to meet or exceed its target to reduce emissions to 30% below 2005 levels by 2030” as a signatory to the Paris Agreement.²⁵⁰ Canada also submitted the aforementioned mid-century strategy to the United Nations Framework Convention on Climate Change (UNFCCC) in November 2016, which presents several scenarios to reduce emissions by approximately 80% by 2050 (these scenarios were reviewed by generation source in the previous discussion of electricity).

Figure 131: Greenhouse gas emissions by sector in Canada from 1990 to 2015.²⁵¹

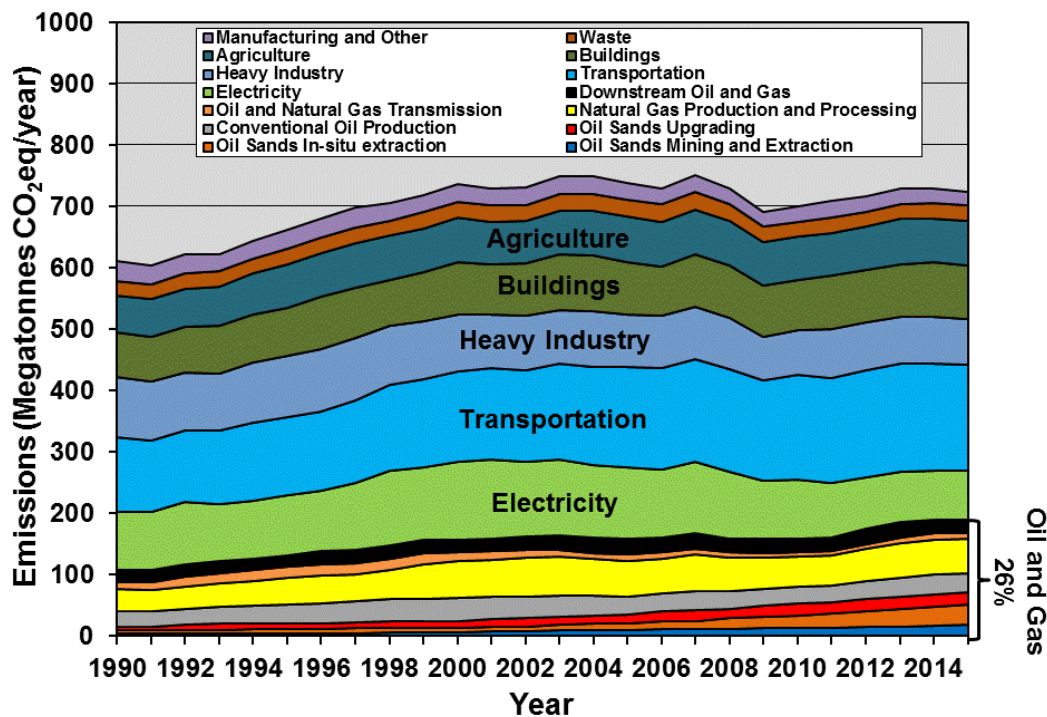


Figure 132 illustrates these emissions-reduction goals compared to planned growth in oil and gas production given the National Energy Board’s “reference case” production forecast, and including the 100-megatonne per year emissions cap on oil sands under Alberta’s Climate Leadership Plan. Oil sands production would grow until 2024 before being constrained by the cap.

²⁴⁹ Environment and Climate Change Canada, April 2017, National Inventory Report, Volume 3, see Table A10-2, page 44, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip

²⁵⁰ Environment and Climate Change Canada, Pan-Canadian Framework on Clean Growth and Climate Change, January 2017, <https://www.canada.ca/en/services/environment/weather/climatechange/pan-canadian-framework.html>

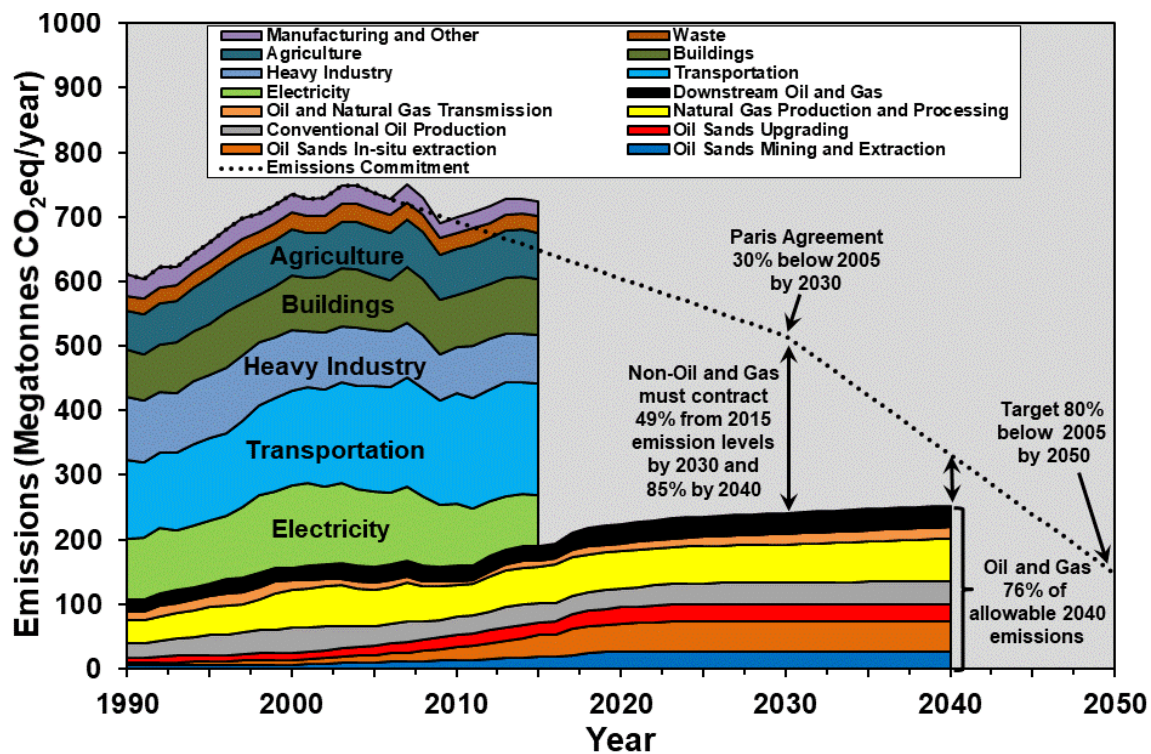
²⁵¹ Data from ECCC National Inventory Report 2017

The magnitude of emissions reductions required to meet these aspirational targets is daunting. In the NEB's reference scenario, including the Alberta oil sands emissions cap, oil and gas production would constitute 76% of all Canadian emissions in 2040, requiring emissions from the rest of the economy to contract by 85% from 2015 levels at that time. By 2050, if oil and gas production remained constant at 2040 levels, emissions from the rest of the economy would have to contract by more than 100%. Given the options to reduce and replace energy use in non-oil and gas sectors of the economy, which in 2015 were responsible for 74% of Canada's emissions, negative emissions are likely impossible by 2050, even with massive adoption of technologies like carbon capture and storage that have yet to be proven at scale.

Under the NEB's higher carbon price and technology scenarios, upstream oil and gas would, under Alberta's oil sands emissions cap, still constitute 70–72% of allowable emissions in 2040, and emissions from the rest of the economy would have to contract by 82–83% from 2015 levels (and contract by more than 100% by 2050).

Figure 132: Canadian emissions by sector including a projection to 2040 for upstream oil and gas emissions, assuming Alberta's 100-megatonne cap on oil sands emissions and the National Energy Board's reference case production projection.

Emissions per unit of production are based on the latest Environment and Climate Change Canada emissions report and NEB production data averaged over the 2012–2015 period.²⁵²



²⁵² National Energy Board Energy Future October 2017, <https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf> appendices <https://apps.neb-one.gc.ca/ftrpndc/dflt.aspx?GoCTemplateCulture=en-CA> retrieved Oct 29, 2017. Emissions are from Environment and Climate Change Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip.

4.1 ECCC's Pan-Canadian Framework on Clean Growth and Climate Change

Environment and Climate Change Canada's pan-Canadian framework is the federal government's plan to reduce emissions by 30% from 2005 levels by 2030, as committed to when Canada signed the Paris Agreement in late 2015. Under its reference case, which includes emissions-reduction measures announced up to November 2016, ECCC projects that emissions will fall from 2005 levels by only 0.7% by 2030, and will be 21.4% above 1990 levels, with emissions in the oil and gas sector rising by 46.5% (see Table 29).²⁵³

Table 29: Emissions by sector in Canada projected by Environment and Climate Change Canada's reference case to 2020 and 2030.

Sector	Historical		2016 projection		Change	
	1990	2005	2020	2030	1990–2030	2005–2030
Oil and gas	108	159	201	233	115.7%	46.5%
Electricity	94	118	64	34	-63.8%	-71.2%
Transportation	122	171	168	157	28.7%	-8.2%
Heavy industry	97	88	85	97	0.0%	10.2%
Buildings	73	85	89	94	28.8%	10.6%
Agriculture	60	70	72	74	23.3%	5.7%
Waste and others	57	56	51	53	-7.0%	-5.4%
Total	611	747	731	742	21.4%	-0.7%

The pan-Canadian framework provides few specifics on how much emissions will be reduced by each of its measures and in which sectors, and it appears to have double-counted the impact of certain mitigation strategies. For example, in its 2016 reference case projection (see Table 29), ECCC indicates that greenhouse gas emissions measures in place as of November 2016 were included,²⁵⁴ yet the pan-Canadian framework claims further reductions of 89 megatonnes per year from “announced measures as of November 1, 2016,” as well as “international cap and trade credits.”²⁵⁵ There is no mention of the split between “announced measures” and “international cap and trade credits,” which amount to buying credits rather than reducing emissions. The pan-Canadian framework claims a further 86 megatonnes of reductions will be achieved from the phasing out of coal-fired power (although all but eight megatonnes of coal phase-out are already accounted for in the ECCC projection in Table 29), along with buildings, transportation and industry (the ECCC projection included extensive measures implemented at the provincial and federal levels as of November 2016).

The probability of the pan-Canadian framework's success is difficult to evaluate without specifics on how much emissions can be cut by sector using new incentives, funding and technologies, and therefore it is largely an aspirational document. In contrast, ECCC's mid-century strategy offers specifics for a number of scenarios to reduce emissions by approximately 80% below 2005 levels by 2050, which can be used to assess their potential viability and cost.

²⁵³ Environment and Climate Change Canada, 2017, Canada's 2016 greenhouse gas emissions Reference case, <https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=1F24D9EE-1>; note that ECCC revised 2005 emissions downward to 738 megatonnes which makes its reference case projection in 2030 actually higher than 2005, not lower as indicated in Table 29 and the text above.

²⁵⁴ Environment and Climate Change Canada, 2017, Canada's 2016 greenhouse gas emissions Reference case, see Table A30, <https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=1F24D9EE-1>

²⁵⁵ Environment and Climate Change Canada, 2017, Pan-Canadian Framework on Clean Growth and Climate Change, see page 44, <https://www.canada.ca/content/dam/themes/environment/documents/weather1/20170125-en.pdf>

4.2 ECCC's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy

Environment and Climate Change Canada's mid-century strategy provides several scenarios to reduce emissions by 67% to 89% below 2005 levels by 2050, all of which project some reduction in overall energy consumption by 2050.²⁵⁶ Target emissions in 2050 and percentage reduction by scenario are given in Table 30.

Table 30: Target 2050 emissions and emissions reductions by scenario in Environment and Climate Change Canada's mid-century strategy.²⁵⁷

Scenario	CO ₂ eq emissions in 2050 (megatonnes per year)	% CO ₂ eq reduction by 2050 from 2005 without emissions credits	% CO ₂ eq reduction by 2050 from 2005 with emissions credits
DDPP 2050	78	89.4%	89.4%
Trottier Current Tech 2050	244	66.9%	66.9%
Trottier New Tech 2050	244	66.9%	66.9%
ECCC High Nuclear 2050	147.4	65.0%	80.0%
ECCC High Hydro 2050	147.4	65.0%	80.0%
ECCC High Demand Response 2050	147.4	65.0%	80.0%

²⁵⁶ Environment and Climate Change Canada, 2016, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

²⁵⁷ Environment and Climate Change Canada, 2016, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, see pages 21-22 and Figure 7 page 34, note that target emissions are calculated based on ECCC's revised estimate of 2005 emissions of 738 megatonnes http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

Scenarios in the mid-century strategy call for a major increase in electrification, from 17% of delivered energy in 2015 to as much as 65% in 2050. In all of the scenarios electricity, as a portion of total delivered energy, at least doubles and in some cases more than triples, as illustrated in Table 31. Consumption of natural gas and oil as a proportion of total delivered energy are projected to decrease markedly. By contrast, the National Energy Board's projection to 2040 forecasts an increase in energy consumption with oil and gas as a proportion of total consumption comparable to 2015 levels, and electricity increasing only slightly to 19% of delivered energy in 2040. The "other" category in the following tables includes biofuels, biomass, geothermal and hydrogen. The DDPP 2050 scenario also assumes that most coal and natural gas consumption would incorporate carbon capture and storage.

Table 31: Delivered energy supplied by fuel according to the National Energy Board reference scenario in 2015 and 2040, and in the six 2050 scenarios in Environment and Climate Change Canada's mid-century strategy.²⁵⁸

RPP=refined petroleum products

Scenario and % of supply	Natural gas	RPP	Electricity	Other
NEB Reference 2015	35.2%	41.0%	16.8%	6.9%
DDPP 2050	17.6%	13.0%	48.1%	21.3%
Current Tech Trottier 2050	6.7%	15.3%	65.3%	12.8%
New Tech Trottier 2050	5.4%	16.5%	58.3%	19.8%
ECCC High Nuclear 2050	12.5%	20.5%	57.2%	9.9%
ECCC High Hydro 2050	12.5%	20.5%	57.2%	9.9%
ECCC High Demand Response 2050	20.9%	0.0%	33.2%	45.8%
NEB Reference in 2040	37.8%	36.9%	19.1%	6.2%

The change in delivered energy consumption by fuel compared to 2015 levels in the NEB 2040 reference forecast and the 2050 levels in the various scenarios of the mid-century strategy is given in Table 32. In all scenarios, except the NEB reference case, consumption of oil and gas decreases radically, and electricity generation in most scenarios more than doubles from 2015 levels.

Table 32: Change in delivered energy supplied by fuel in 2050 compared to 2015 consumption in the scenarios in Environment and Climate Change Canada's mid-century strategy.

*Also shown is the National Energy Board's reference case projection to 2040.*²⁵⁹

(RPP=refined petroleum products)

Scenario and % change from 2015	Natural gas	RPP	Electricity	Other	Total
DDPP 2050	-57.1%	-72.9%	139.0%	153.5%	-14.9%
Current Tech Trottier 2050	-87.9%	-76.4%	141.0%	13.2%	-36.7%
New Tech Trottier 2050	-88.4%	-69.9%	153.3%	106.8%	-25.5%
ECCC High Nuclear 2050	-73.3%	-62.6%	149.2%	3.4%	-25.3%
ECCC High Hydro 2050	-73.3%	-62.6%	149.2%	3.4%	-25.3%
ECCC High Demand Response 2050	-44.0%	-100.0%	80.5%	498.1%	-6.8%
NEB Reference in 2040	16.6%	-2.3%	23.6%	-2.8%	8.7%

Table 33 illustrates the change in electricity generation by renewable and nuclear sources through 2050

²⁵⁸ National Energy Board Energy Future 2017 for 2015 delivered energy by fuel and 2040 reference case forecast; and Environment and Climate Change Canada, 2016, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, see Figure 7 http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

²⁵⁹ Ibid.

compared to 2015 levels for scenarios in the mid-century strategy. The scale-up in nuclear power in most scenarios required to meet emissions-reduction targets strains credibility. The slow growth in nuclear energy worldwide, given retirements of aging reactors, along with unresolved issues such as waste disposal, make it hard to believe that Canada's nuclear capacity will be scaled up by two-fold to eight-fold by 2050, as called for in five of the six scenarios. As discussed in the nuclear section above, Canada will have no nuclear capacity after 2036 without the expenditure of \$26 billion to extend the lives of eight Bruce and Darlington reactors. In the "Current Tech Trottier" and "ECCC High Nuclear" scenarios, Canada would require 108 new one-gigawatt reactors by 2050 (see nuclear section above for a more detailed discussion).

Table 33: Change in electricity generation provided by renewable and nuclear sources by 2050 compared to 2015 in Environment and Climate Change Canada's mid-century strategy scenarios.

Also shown is the National Energy Board's reference case projection to 2040.²⁶⁰

Scenario and % change from 2015	Nuclear	Hydro	Wind	Solar	Biomass
DDPP 2050	-18.1%	103.9%	779.1%	2361.6%	0.0%
Current Tech Trottier 2050	706.6%	114.8%	1791.7%	713.8%	67.7%
New Tech Trottier 2050	563.9%	113.7%	352.4%	0.0%	0.0%
ECCC High Nuclear 2050	706.6%	36.5%	439.2%	498.6%	872.5%
ECCC High Hydro 2050	184.4%	150.7%	698.3%	3192.3%	369.5%
ECCC High Demand Response 2050	65.0%	124.3%	12.0%	0.0%	34.1%
NEB Reference in 2040	-9.1%	10.4%	145.1%	332.6%	22.6%

Similarly, the scale-up in large hydro required by Canada's mid-century scenarios also strains credibility. Between 33 and 101 new "Site C"-sized dams (1.1 gigawatts) would be required, as discussed in the hydropower section above. Even the NEB's much more modest hydro expansion would require eight major new dams by 2040. Given the protests, backlash and cost-overruns associated with two hydro dams currently under construction—Site C and Muskrat Falls—it would be challenging to build eight new dams by 2050, let alone 101 dams.

²⁶⁰ National Energy Board Energy Future 2017 for 2015 delivered energy by fuel and 2040 reference scenario forecast; and Environment and Climate Change Canada, 2016, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, see Figure 2 http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

Table 34 gives estimated costs for new renewable, hydro and nuclear generation capacity by 2050 in the mid-century strategy's scenarios. Between US\$710 billion and US\$1,688 billion are required, based on 2016 capital costs (see Table 20), which corresponds to \$C30–70 billion each year between 2017 and 2050 (cost calculations for each electricity generation source can be found in previous sections). Somewhere between 67–99% of these costs are directed at nuclear and large hydro in ECCC's mid-century scenarios. The spending rates range from four to ten times higher than that required for the NEB's much more modest reference case scenario through 2040, which would see a considerable increase in emissions.

Table 34: Investment required to generate 2050 levels of electricity for renewable and nuclear sources in Environment and Climate Change Canada's mid-century strategy scenarios (and 2040 in the case of the National Energy Board's reference case forecast).

Also shown is the average expenditure per year required over the 2017–2050 period in Canadian dollars.

Scenario and 2016–2050 cost (\$US2016 billion)	TWh	Nuclear	Hydro	Wind	Solar	Biomass	Total	\$Cbillion/year 2017–2050
NEB 2015 Generation	646							
DDPP 2050	1,477	17.8	576.8	158.9	136.9	0.0	890.5	37.0
Current Tech Trottier 2050	2,257	642.1	630.8	365.5	41.4	8.1	1,687.9	70.1
New Tech Trottier 2050	1,622	517.2	630.8	71.9	0.0	0.0	1,219.9	50.6
ECCC High Nuclear 2050	1,648	642.1	204.6	89.6	28.9	104.8	1,070.0	44.4
ECCC High Hydro 2050	1,648	190.2	738.8	142.4	185.1	44.4	1,301.0	54.0
ECCC High Demand Response 2050	1,215	89.2	613.8	2.5	0.0	4.1	709.5	29.5
NEB Reference in 2040	732	23.8	47.0	29.3	19.2	2.8	122.1	7.3

The NEB's reference case forecast to 2040 calls for little change in the basic energy mix and significant increases in emissions from oil and gas production, such that by 2040 76% of Canada's emissions would come from upstream oil and gas production in a scenario where emissions-reduction targets were met, even with Alberta's oil sands emissions cap (see Figure 131). Canada's mid-century strategy scenarios, on the other hand, strain credibility with their call for major scale-ups in large hydro and nuclear. Even given this credibility problem, the scenarios still call for reduced but significant amounts of oil and gas consumption.

4.3 Key considerations for a long-term energy plan

The following are key findings of this report that should be considered in formulating a long-term energy plan to maintain long-term energy security for Canadians and minimize environmental impacts:

- Canada has very high per capita energy consumption—more than five times the world average. Primary energy consumption is based 65% on fossil fuels and 7% on nuclear energy. Delivered energy consumption is 83% non-electric, and 92% of non-electric delivered energy is fossil fuels.
- Although the “energy intensity” of the economy is decreasing somewhat, gross domestic product (GDP) remains highly correlated with energy consumption. Canada's energy consumption per dollar of GDP is nearly double the world average and considerably higher than even China's (the next-highest) and the US's (the third-highest). Greenhouse gas emissions per unit of energy consumed are flat to slightly declining.
- Canada's electricity consumption is among the highest in the world—more than five times the world average on a per capita basis. Although Canada is the second-largest generator of

- hydropower in the world, it is considerably below the world average in per capita generation of non-hydro renewable energy from solar, wind, biomass and geothermal sources.
- Canada's nuclear fleet is aging and capacity will be reduced to zero by 2037 without refurbishing eight reactors at Bruce and Darlington at a cost of \$26 billion. Even with refurbishment of these reactors, there will be a 39% reduction from 2015 levels of nuclear capacity by 2037, if new reactors are not built. Aside from the largely unresolved issue of long-term storage of nuclear wastes, the cost of a major nuclear scale-up is very high. The National Energy Board's reference case would require construction of four new reactors, in addition to the refurbishments, although overall nuclear output would still decline 9% from 2015 levels by 2040.
 - Canada's per capita emissions of greenhouse gases are among the highest in the world—3.2 times the world average, more than double that of China (the world's highest total emitter) and eight times that of India.
 - Although on paper Canada has the third-largest resource of oil in the world, in practice 97.4% of proven reserves are low-quality oil sands that are energy- and emissions-intensive to extract and costly to refine. Some 80% of the remaining recoverable resources in the oil sands are too deep for mining and thus require even more energy- and emissions-intensive in situ methods to extract. Furthermore, industry invariably extracts the highest-quality, most economic resources first, which means that much of Canada's remaining oil resource will cost more to extract than current operations and will produce higher levels of emissions.
 - The NEB has more than tripled its estimates of marketable natural gas in Canada since 2010 based on a series of brief studies with speculative assumptions. Although estimates of conventional gas have declined, estimates of tight gas and shale gas have vastly increased, due to the assumed widespread viability of horizontal drilling in combination with high-volume hydraulic fracturing (fracking). As with oil, the gas industry extracts the highest-quality, most economic resources first. Hence, even if these resources prove to be extractable, which is by no means assured, the bulk of them are in lower-quality parts of the resource, which will require higher prices to extract and mean higher environmental impacts given the number of wells required to produce them.
 - The revenues in terms of royalties and corporate taxes from oil and gas extraction have plummeted and are now relatively minor in terms of total government revenue. Even though oil and gas production has grown by 27% since 2000, royalty revenue is down by 63%. Royalties as a share of total oil and gas sales have declined from nearly 18% in 2000 to 4.5% in 2015. In Alberta, Canada's largest oil and gas producer, production has doubled since 1980 and royalty revenues are down 90% in real terms—resource revenue constituted 80% of Alberta government revenue in 1980 and just 3.3% in 2016. In BC, Canada's second-largest gas producer, resource revenue from natural gas, coal and minerals is down 84% since 2005 while gas production has doubled.
 - Corporate taxes paid for oil and gas extraction and refining are down more than 50% since 2006 despite growing production, and amounted to less than \$4 billion in 2015, which is less than the royalty revenue in that year. Employment in oil and gas extraction amounted to less than 3% of total Canadian employment in 2015, and more than half of that was in construction, which is temporary. The highest provincial employment in the oil and gas sector in 2015 was in Alberta at 13%, more than half of which were temporary construction jobs. Claims of higher employment and revenues relate to "spin-off" jobs not directly related to the oil and gas industry, and assume that these workers would not otherwise be employed.
 - Greenhouse gas emissions from oil and gas extraction amounted to 26% of Canada's total in 2015 and will rise to 76% by 2040, given the NEB's reference case production projection and Alberta's 100-megatonne oil sands emissions cap, under a scenario where Canada's emissions-reduction

targets are achieved. This would require emissions from the rest of the Canadian economy to contract by 85% in 23 years.

- Environment and Climate Change Canada's pan-Canadian framework for emissions reduction by 2030 is an aspirational document with little quantitative information on how much individual measures will cut emissions. ECC's mid-century strategy for emissions reduction contains several scenarios that would require an increase in annual spending on new energy infrastructure of four to ten times the amount in the NEB's reference case, 67–99% of which would be spent on new hydropower and nuclear plants. Development of up to 101 new "Site C" sized dams and 108 new reactors, as called for in some of these scenarios, indicates the scale of the problem in reducing emissions by 80% (and several of the scenarios require substantial purchases of international emissions credits, which were not included in cost estimates). Construction of new dams and reactors on this scale is highly unlikely given cost and public opposition to the environmental impacts.
- Renewable energy from solar and wind can be scaled up many-fold but there are limits due to intermittency and seasonal variations in output. Even the most aggressive scenarios in Canada's mid-century strategy don't see wind growing to more than 24% of total generation and solar to more than 6% (which would require an 18-fold increase in wind and a 32-fold increase in solar from current levels).
- Renewable energy from biomass can be scaled up also, bearing in mind that when initially burned it releases greenhouse gas emissions comparable to coal, and it takes decades to neutralize these emissions through regrowth. Biofuels have a low energy return on investment (EROI) and therefore do little to reduce overall emissions impact.
- Renewable energy from geothermal sources could be a major source of heat, displacing fossil fuels for heating buildings, but is unlikely to be scalable to replace much electricity generation by 2050.
- In terms of fossil fuels, Canada is a well-explored and intensively developed petroleum province. These fuels remain a reliable backup to other energy sources should the scale of alternatives prove to be unachievable. These resources are non-renewable and finite, and production of oil and gas is the largest source of Canadian emissions, yet current policy is to extract them as fast as possible and sell them at rock-bottom prices with diminishing returns for the Canadian economy. This compromises emissions-reduction commitments and imposes long-term risks for Canadian energy security.

Conclusions and recommendations for a Canadian energy strategy

Although Canadian provincial premiers produced an energy strategy in 2015, it is largely an aspirational document that highlights the need for more research and discussion on “energy efficiency,” “delivering energy,” “the transition to a lower carbon economy” and “technology and innovation.” It does not adequately deal with core aspects of Canada’s energy system and the scaling issues in addressing future energy security while meeting emissions-reduction targets.²⁶¹

Based on the present analysis and commitments to reduce emissions, recommendations for a more sustainable Canadian energy strategy are as follows:

- A major focus on reducing consumption. Implement energy conservation and efficiency measures and incentives to the maximum extent possible. This includes aggressive infrastructure improvements, building retrofits, enhanced building codes, mass transit and higher efficiency in all end uses. Reducing consumption will maximize the effectiveness of investments in renewable energy, and will minimize overall expenditures on new energy supply and the inevitable economic costs and environmental impacts of developing it.
- A major focus on renewable energy with incentives, but with an understanding of its limitations in being able to provide a complete switch-out for fossil fuels at the current levels of consumption. This includes the intermittency of solar and wind and backup requirements, and the ecological and economic consequences of new large hydro dams. Geothermal energy for space-heating to displace fossil fuels should also be an important focus.
- Phasing out fossil fuel subsidies to provide incentives for reducing consumption and ramping up renewables. Fossil fuel subsidies were reported by the International Monetary Fund to be \$US1,283 per person in Canada in 2015 (mainly due to the external costs of climate change, local air pollution and congestion, but also pre-tax subsidies, foregone consumption tax revenue, accidents and road damage).²⁶² This amounts to \$US88 per tonne of carbon dioxide or \$US324 per tonne of carbon emitted (without a phase-out, total subsidies would amount to \$US1.151 trillion or \$C1.457 trillion over the 2016–2040 period). A carbon tax considerably higher than what is currently implemented would provide a mechanism to more accurately cost the environmental impacts from fossil fuel combustion.
- A recognition that Canada is a well-explored petroleum province and that remaining recoverable oil and gas resources are finite. The resources that remain consist mainly of energy-intensive oil sands and unconventional gas, the extraction of which is responsible for a major portion of Canada’s greenhouse gas emissions and other significant environmental impacts.
- A realization that ramping up oil and gas production is a non-starter if Canada wants to meet its emissions-reduction targets. Increasing production while attempting to meet emissions-reduction targets are conflicting goals, and the reality of having to limit production growth must be faced.

²⁶¹ Canadian Premiers, Canadian Energy Strategy, July 2015, http://www.pmprovinceterritoires.ca/phocadownload/publications/canadian_energy_strategy_eng_fnl.pdf

²⁶² International Monetary Fund, IMF Survey: Counting the Cost of Energy Subsidies, July, 2017, <https://www.imf.org/en/News/Articles/2015/09/28/04/53/sonew070215a>

- A realization that the nature of oil and gas production is to high-grade the most economic resources first and leave the lower-quality, higher-emissions and higher-environmental-impact resources for last. Canada's oil and gas resources remain a valuable backstop should renewable sources prove to be insufficient. Selling off the best of Canada's remaining non-renewable resources at low prices, with minimal and declining returns to the public, compromises future energy security.
- A realization that although oil and gas production is important to the Canadian economy, it is a relatively small component. Oil and gas will be required at some level by Canadians for the foreseeable future, so the industry is not going away, but plans to aggressively ramp up production for export are misguided and severely compromise emissions-reduction objectives and long-term energy security. They amount to selling off the highest-quality portion of remaining resources at rock-bottom prices.
- A realization that radically increasing hydropower, which would require building dozens more large-scale hydropower dams, as assumed in some of the scenarios in Canada's mid-century strategy, is unlikely to happen, for ecological and economic reasons.
- A realization that ramping up nuclear energy generation by several-fold, as assumed in some of the scenarios in Canada's mid-century strategy, is also unlikely to happen for economic, environmental and fuel-supply reasons.
- A realization that the low net-energy gains of biofuels as a replacement for fossil fuels make them a marginal substitute, and that the initial emissions of biomass burning are equivalent to burning coal.

Canada faces some very difficult choices in maintaining energy security while meeting emissions-reduction targets. Current strategies are highly unlikely to deliver. This report is offered as an objective analysis of Canada's energy system to assist in the development of a more viable and sustainable long-term energy strategy.

Canada faces some very difficult choices in maintaining energy security while meeting emissions-reduction targets. Current scenarios, such as those in Environment and Climate Change Canada's mid-century strategy, are highly unlikely to deliver. In developing a viable plan, all energy options must be assessed in terms of availability, scalability, cost, environmental impacts and alternatives. This report provides an objective assessment of Canada's energy options as a foundation for the development of a viable and sustainable long-term energy strategy.

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