National Energy Board

Office national de l'énergie

CANADA'S ENERGY FUTURE 2018

AN ENERGY MARKET ASSESSMENT

ENERGY SUPPLY AND DEMAND PROJECTIONS TO 2040

Canada

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Letter from the Chair and CEO of the National Energy Board

I am pleased to introduce the 2018 edition of the National Energy Board's (NEB) *Energy Futures* series. Canada's *Energy Future 2018: Energy Supply and Demand Projections to 2040* (EF2018) carries on the tradition of energy outlooks that the NEB has been producing for over 50 years. EF2018 is the only publicly available long-term Canadian outlook that provides data and analysis on all energy commodities and all provinces and territories. This report provides Canadians a key reference point for discussing the country's energy future.

The pace of change in Canadian and global energy markets, policy, and technology trends suggests that the need for timely analysis is greater than ever. Over the course of preparing this report, there were numerous significant market and policy developments:

- In oil markets, higher than usual price discounts between Canadian and global benchmarks returned, and global crude benchmark prices reached their highest levels since 2014.
- On the natural gas side, a positive final investment decision on the LNG Canada liquefied natural gas export project was announced.
- On the policy front, there were numerous policy developments at the provincial level, mostly in relation to future carbon pricing.
- The renegotiation of NAFTA was finalized and the United States-Mexico-Canada Agreement (USMCA) was ratified.

One thing is for sure: the energy landscape will continue to change.

In this environment of change, how do we go about creating a meaningful long-term projection? We believe that currently there are three fundamental trends that provide the groundwork for the projections. First, continuous improvement in energy efficiency causes energy use and economic growth to further decouple. Second, falling costs of renewables such as wind and solar, leading to a more diverse energy mix. Third, the oil and gas sector has the ability to respond and remain competitive under challenging market conditions.

The day-to-day volatility of energy market prices, market sentiments, and policy direction are important. At the same time, the impacts of these dynamic factors on the energy outlook will be shaped by these long-term, fundamental trends.

Our Reference Case reflects the robustness of some key trends from previous energy outlooks.

EF2018 also focuses on several key uncertainties that have been significant in 2018. Energy prices have varied significantly, and our High Price and Low Price cases show large potential variation across these cases for oil and gas production. Our Technology Case explores the potential impacts of increased adoption of lower carbon technologies and strengthened climate policies across the world on the Canadian energy system.

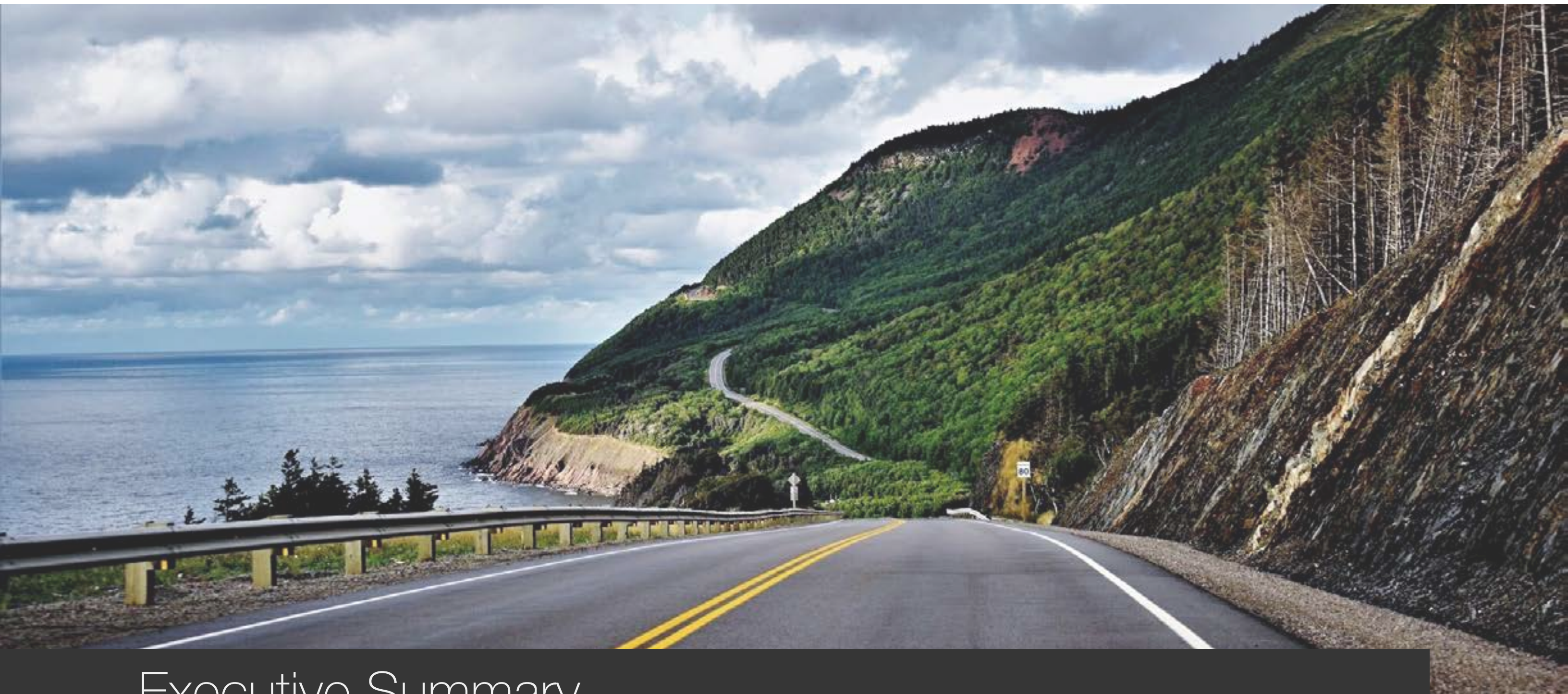
A thread that runs through all of the analysis is the existence of numerous challenges and opportunities, and the necessity for market players to innovate to successfully navigate this new environment. This report highlights numerous technological advancements, such as falling costs of renewables and improved efficiency of energy production and consumption. Innovation will also be important in policy design, market-based rules and regulations for incorporating new technologies, ways of communicating and engaging with stakeholders in energy matters, and sharing and improving Canadian energy information and analysis.

The *Energy Futures* reports are the flagship publication of the NEB's Energy System Information Program. The objective of the program is to publish products that are beneficial and informative for a diverse audience, and that reflect the diversity of relevant energy issues in Canada. We strive to increase the public's energy literacy in an engaging and transparent way. The NEB endeavors to play a leading role, along with other Government institutions, in providing Canadian energy data and analysis, and we are making great strides in that direction. Our *Energy Futures* reports are an example of providing fact-based data and analysis on the conversion, transportation, distribution, and consumption of energy products that serve the needs of Canadians, as well as what the future of energy might hold. These reports aim to provide a baseline for Canadians to have an informed discussion on current energy issues and policies.

I would like to thank the many stakeholders who engaged in helpful discussions on the future of energy in Canada during the creation of this report. This includes our federal government partners, provincial governments, and other energy experts across Canada. We have also benefitted greatly from discussions and collaboration with international experts from groups including the International Energy Agency, the U.S. Energy Information Administration, and participants of the Energy Modeling Forum.

We are proud of the contributions that EF2018 has provided to the Canadian energy conversation and we encourage Canadians to stay engaged in the energy dialogue.

C. Peter Watson, P. Eng. FCAE
Chair and CEO



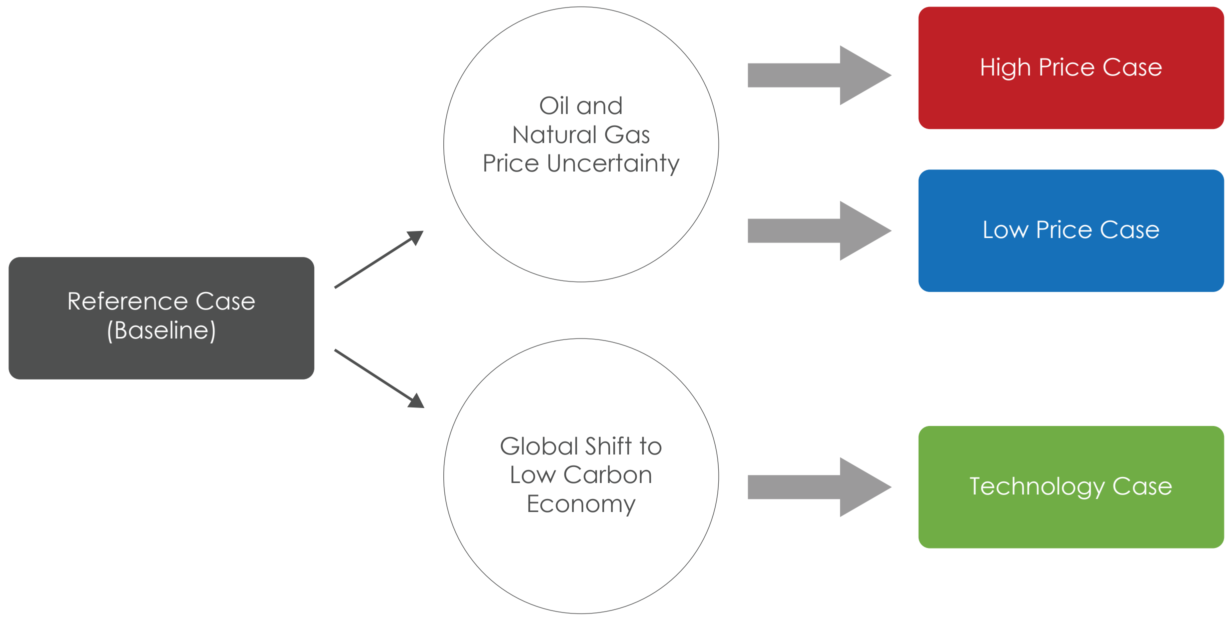
Executive Summary

The National Energy Board's (NEB) *Energy Futures* series explores how possible energy pathways might unfold for Canadians over the long term. The report employs economic and energy models to make projections based on a certain set of assumptions given what we know today about technology, energy and climate policies, human behaviour, and the structure of the economy. Readers of this analysis should consider the projections as a baseline to support ongoing discussions of Canada's energy future. This analysis is not a prediction of what will take place, nor does it aim to show how specific goals, such as Canada's climate targets, will be achieved.

Canada's Energy Future 2018: Supply and Demand Projections to 2040 (EF2018) considers four different Cases:

- The Reference Case is based on a current economic outlook, a moderate view of energy prices and technological improvements, and climate and energy policies announced at the time of analysis.
- The High and Low Price Cases consider the impact of uncertain commodity prices on the Canadian energy system.
- The Technology Case pushes past the policy and technology boundaries specific to the Reference Case and includes greater global climate policy action and low carbon technology adoption. It provides one potential view of what a faster transition enabled by stronger long-term carbon policy, faster uptake of technologies such as electric vehicles, and lower cost of renewables would mean for Canada's energy future.

Figure ES.1 Overview of Cases in Energy Futures 2018



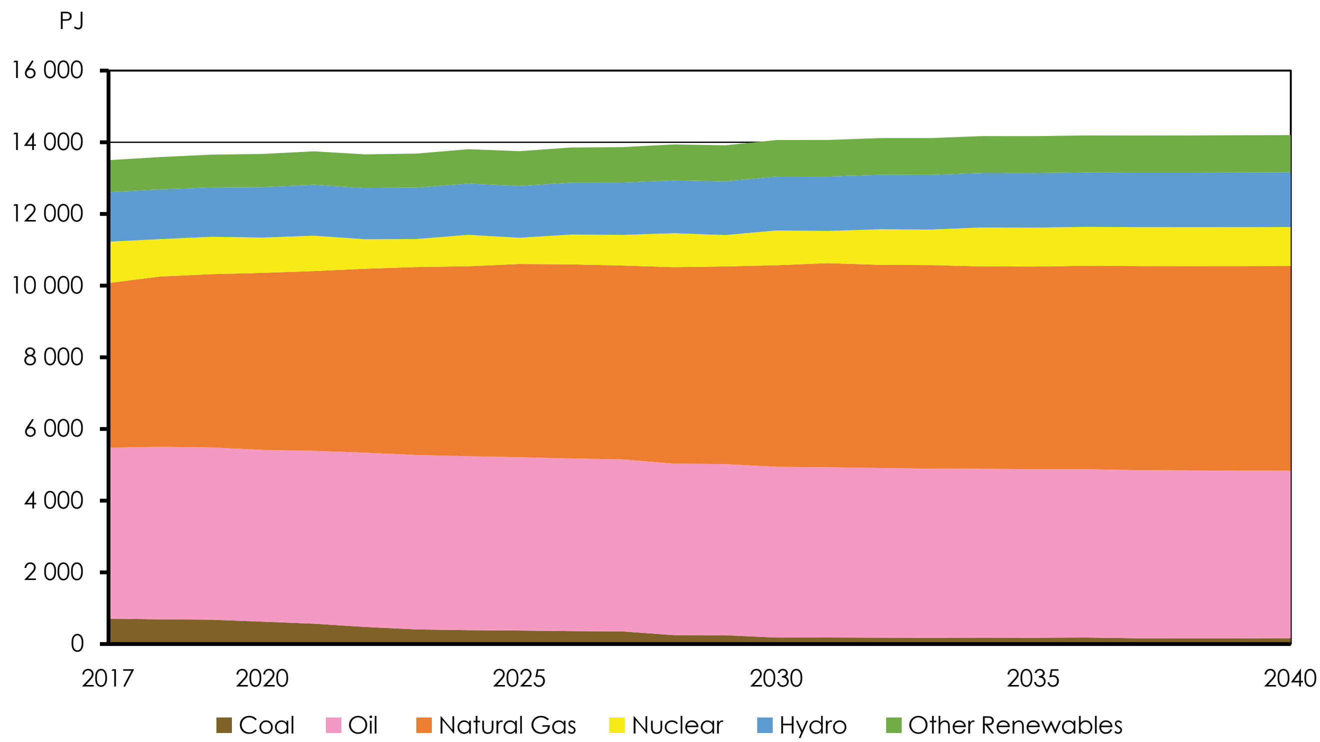
Key Findings (EF2018)

1. In the Reference Case, Canada's energy demand growth is slowing, while sources to meet these demands are becoming less carbon intensive.
2. In a scenario with greater adoption of new energy technologies, Canadians use over 15% less total energy and 30% less fossil fuels by 2040.
3. Energy use and economic growth continue to decouple.
4. Canada's energy mix continues to diversify, and its already low-emitting electricity mix adds more renewables.
5. Canadian oil and natural gas production increases in the Reference Case. Price and technology trends will be key factors influencing Canadian production in the future.

Key Finding 1: Canada's energy demand growth is slowing, while sources to meet these demands are becoming less carbon intensive.

In the Reference Case projection, energy use grows slowly, and by 2040 is 5% higher than current levels. Canadians use more natural gas and renewables, and less coal and refined petroleum products. On the supply side, Canada's electricity mix becomes even greener and crude oil and natural gas production grow from current levels. However, Canada's energy future is not predetermined, and EF2018's alternate cases explore how markets, policies, technologies, and innovation can alter these baseline trends.

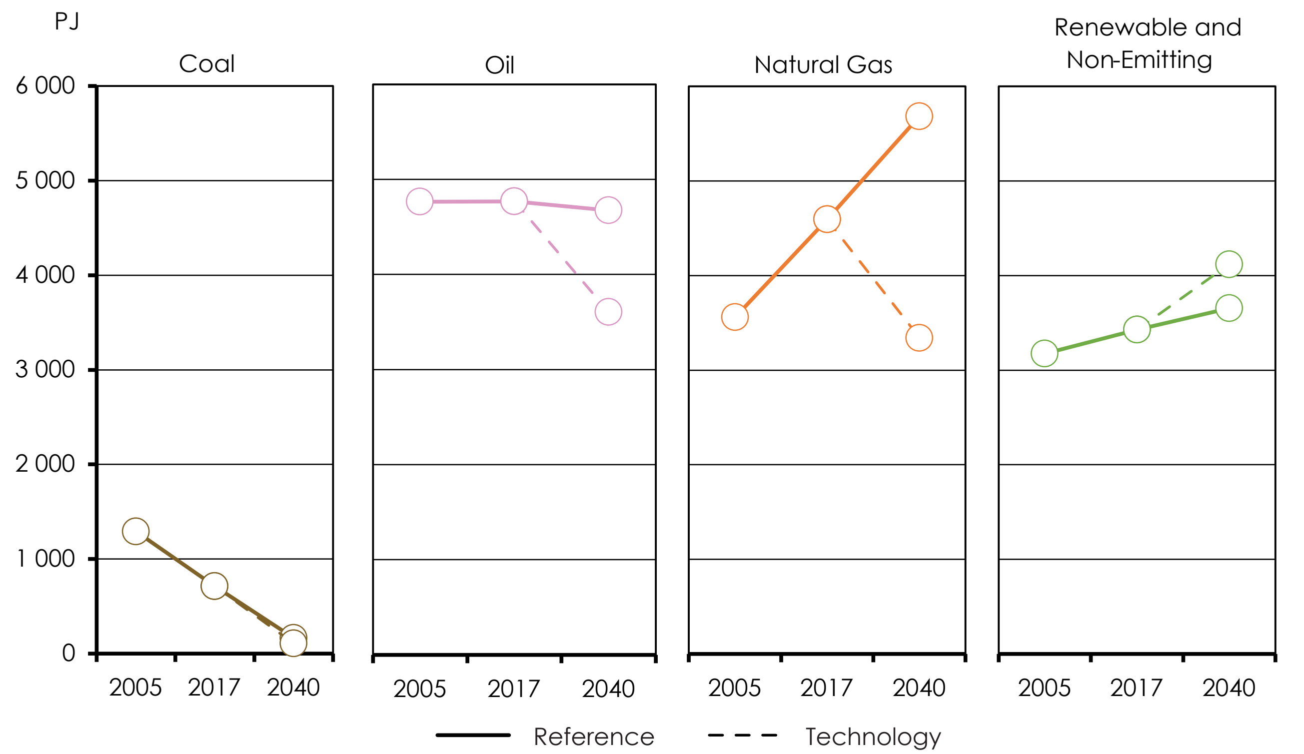
Figure ES.2: Total Canadian Energy Use by Fuel Type, 2017 to 2040, Reference Case



Key Finding 2: **Key Finding 2: In a scenario with greater adoption of new energy technologies, Canadians use over 15% less total energy and 30% less fossil fuels by 2040.**

The EF2018 Technology Case explores what a global shift in the implementation of innovative technologies and related policy assumptions might mean for Canada. Non-emitting sources and energy technologies get cheaper, improvements to equipment and buildings reduce energy requirements, and markets and infrastructure adapt to these changing trends. By 2040, energy efficiency, new technologies, and fuel switching combine to reduce Canadian energy use by over 15% from current levels. The fossil fuel portion of the fuel mix declines even faster, and is 30% lower than current levels by 2040, as the relative share of non-emitting energy grows.

Figure ES.3: Canadian Total Energy Demand by Fuel Type, Reference and Technology Cases

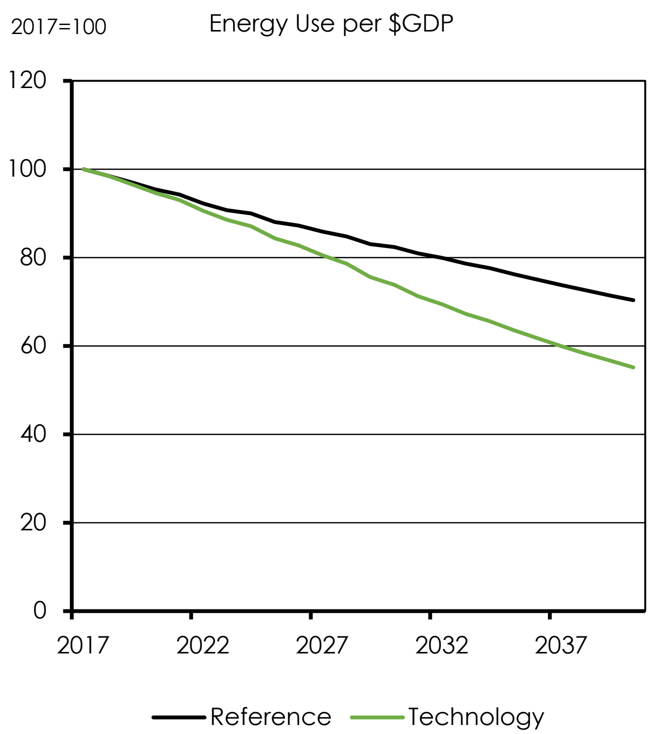


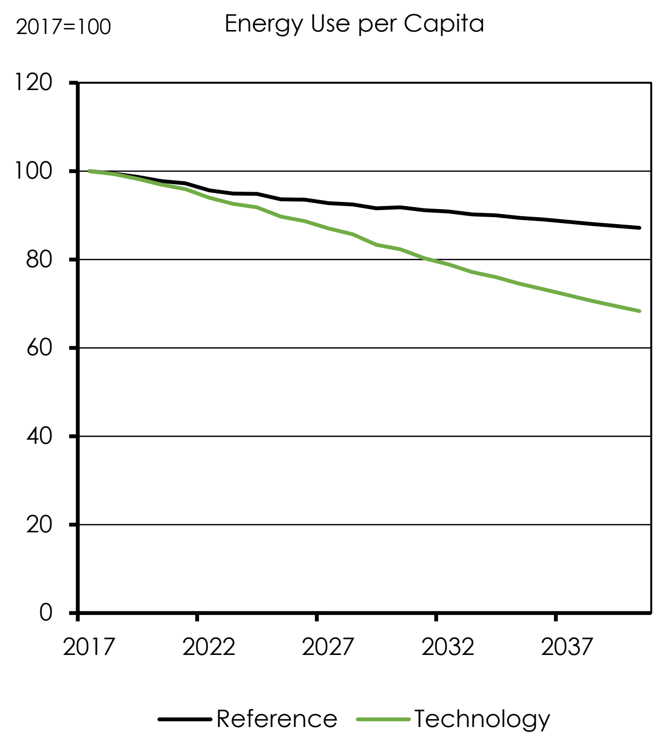
Key Finding 3: Energy use and economic growth continue to decouple.

In both the Reference and Technology Cases, gross domestic product (GDP) and population grow faster than energy demand, leading to reductions in energy intensity, measured in terms of total energy use per dollar of GDP and per capita. In the Reference Case, energy use per dollar of GDP is nearly 30% lower than current levels by 2040, while energy use per person is nearly 15% lower than current levels by 2040. This represents a moderate increase in the pace of decoupling compared to historical trends, and is related to a variety of factors including energy efficiency improvements, policies and regulation, and economic structural change.

In the Technology Case, these trends depart significantly from history. As the globe shifts towards a lower carbon future and other countries act on climate change in a similar fashion, economic growth in Canada is able to remain comparable to the Reference Case. Because energy use decreases in this case, energy intensity trends decline even further. By 2040, GDP energy intensity is nearly half the current levels, and energy use per capita is reduced by a third.

Figure ES.4: Energy Intensity Trends, Reference and Technology Cases, % of 2017 Level

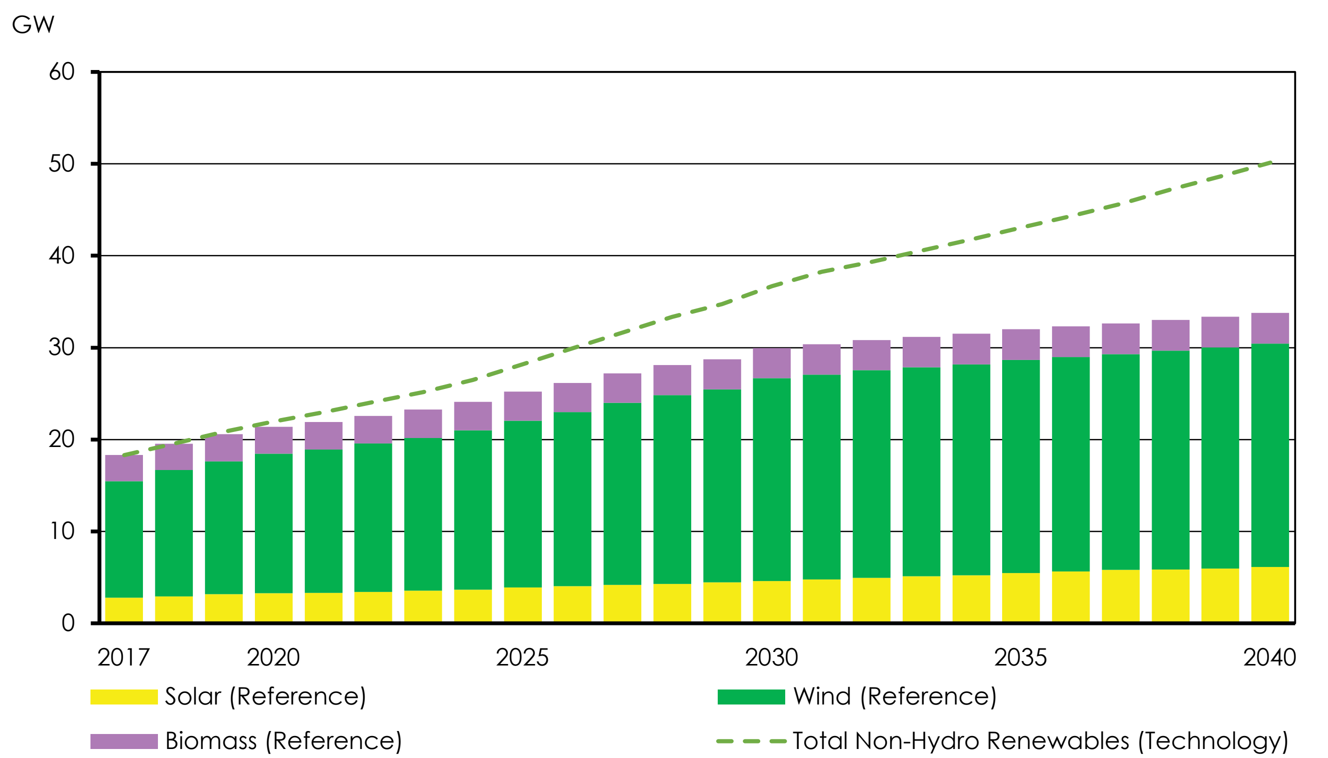




Key Finding 4: Canada's energy mix continues to diversify, and its already low-emitting electricity mix adds more renewables.

As emerging forms such as wind and solar increase, traditional forms of energy have limited growth or decline. In the Reference Case, wind capacity doubles and solar capacity nearly triples over the projection period. In the Technology Case, installed capacity of non-hydro renewables reaches over 50 gigawatts (GW) by 2040, 48% higher than the Reference Case. By 2040, the share of non-emitting electricity generation increases to nearly 84% in the Reference Case and 90% in the Technology Case, compared to approximately 80% currently.

Figure ES.5: Non-hydro Renewable Capacity, Reference and Technology Cases

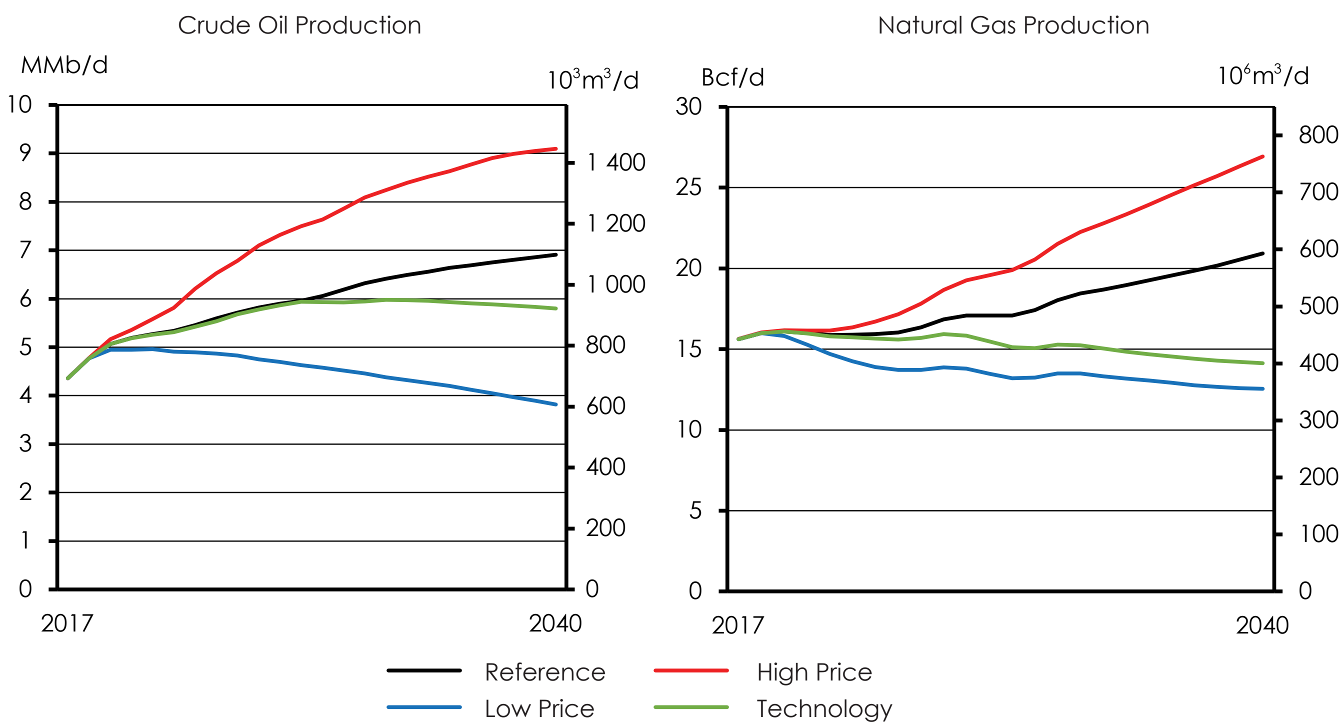


Key Finding 5: Canadian oil and natural gas production increases in the Reference Case. Price and technology trends will be key factors influencing Canadian production in the future.

Even though domestic use of oil products and natural gas grows slowly or declines, Canada has potential to increase energy production. In the Reference Case, oil and gas prices are sufficient for oil production to increase 58% by 2040, and gas production to increase by 33%.

This production growth depends on two key assumptions. First, EF2018 assumes that elevated price discounts for Canadian crude oil and natural gas benchmarks continue in the short to medium term, as production continues to outpace infrastructure capacity additions. Second, EF2018 assumes that export markets will be found to purchase the growing production that is surplus to Canadian needs. The High and Low Price Cases show the potential impact of long-term lower or higher prices, which create a large range around future production trends. The Technology Case assumes lower global fossil fuel demand, lower prices, and highlights the potential for improved technology to reduce emissions and help production remain competitive in this changing environment.

Figure ES.6: Crude Oil and Natural Gas Production by Case, 2017-2040



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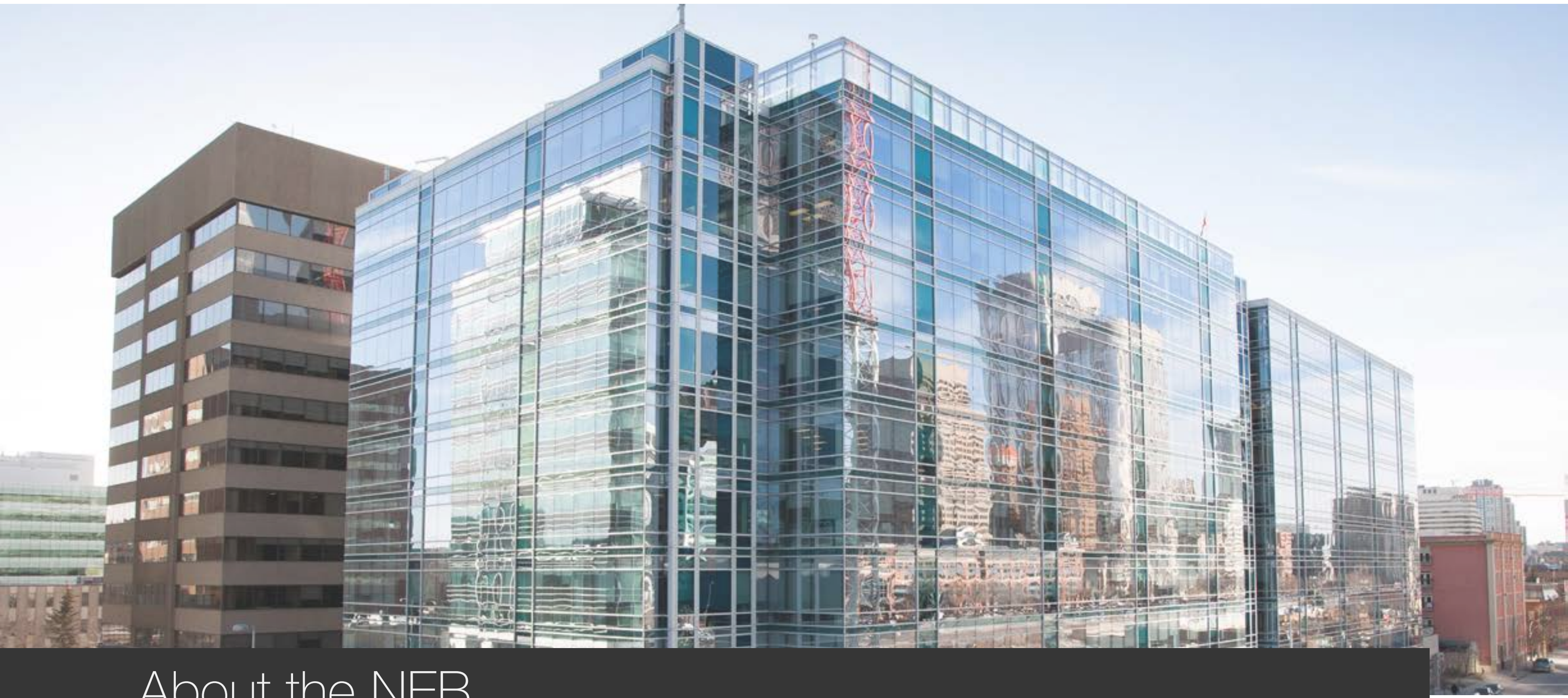


About the NEB

The National Energy Board (NEB or Board) is Canada's independent national energy regulator. The Board's main responsibilities include regulating:

- the construction, operation, and abandonment of pipelines that cross international borders or provincial/territorial boundaries;
- associated pipeline tolls and tariffs;
- the construction and operation of international power lines and designated interprovincial power lines;
- imports of natural gas and exports of crude oil, natural gas, natural gas liquids, refined petroleum products, and electricity; and
- oil and gas exploration and production activities in specified northern and offshore areas.

As part of our Energy System Information Program, the NEB is also charged with ensuring Canadians have access to and use energy information for knowledge, research and decision making, community-specific NEB-regulated infrastructure information, and opportunities to collaborate and provide feedback on NEB information products.

We study market trends, energy transportation, and emerging technologies to better understand the energy landscape in which we work; to provide Canadians with energy information of interest and relevance, and to identify and respond to emerging issues. We provide transparent information about pipeline safety performance, and use tools like interactive pipeline maps and visualizations of our data to make complex pipeline and energy market data user-friendly and accessible.

About this Report

The NEB's Energy System Information Program is closely linked to its regulatory responsibilities as defined in the National Energy Board Act. Under Part VI of the Act, the NEB regulates the export and import of natural gas as well as the export of natural gas liquids, crude oil and petroleum products, and electricity. The Act requires the Board to ensure that oil and gas exports are surplus to Canadian requirements. The NEB monitors energy markets and assesses Canadian energy requirements and trends to support its regulatory responsibilities. This report, *Canada's Energy Future 2018: Energy Supply and Demand Projections to 2040*, is the continuation of the *Energy Futures* series, and projects long-term Canadian energy supply and demand trends.

In developing this report, the NEB engaged various energy experts and stakeholders to gather input and feedback on the assumptions and preliminary projections. The NEB would like to thank all participants for their contributions to EF2018.

EF2018 was prepared by National Energy Board technical staff under the direction of Abha Bhargava (Abha.Bhargava@neb-one.gc.ca), Director, Energy Outlooks, Matthew Hansen (Matthew.Hansen@neb-one.gc.ca), Lead Technical Specialist – Energy Futures, and Andrea Oslanski (Andrea.Oslanski@neb-one.gc.ca), Project Manager – Energy Futures. Specific questions about the information in this report may be directed to: General Questions energyfutures@neb-one.gc.ca. Key Drivers and Macroeconomics: Matthew Hansen (Matthew.Hansen@neb-one.gc.ca), Lukas Hansen (Lukas.Hansen@neb-one.gc.ca) and Chris Doleman (Chris.Doleman@neb-one.gc.ca). Energy Demand: Matthew Hansen (Matthew.Hansen@neb-one.gc.ca), Chris Doleman (Chris.Doleman@neb-one.gc.ca), Ken Newel (Ken.Newel@neb-one.gc.ca), Lukas Hansen (Lukas.Hansen@neb-one.gc.ca). Crude Oil: Peter Budgell (Peter.Budgell@neb-one.gc.ca). Refinery Balances: Kinsey Nickerson (Kinsey.Nickerson@neb-one.gc.ca). Natural Gas and NGLs: (Melanie.Stogran@neb-one.gc.ca). Electricity: Michael Nadew (Michael.Nadew@neb-one.gc.ca) and Mantaj Hundal (Mantaj.Hundal@neb-one.gc.ca). Coal: Lukas Hansen (Lukas.Hansen@neb-one.gc.ca). Climate Policy: Chris Doleman (Chris.Doleman@neb-one.gc.ca), Kevin Caron (Kevin.Caron@neb-one.gc.ca), Ken Newel (Ken.Newel@neb-one.gc.ca).

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

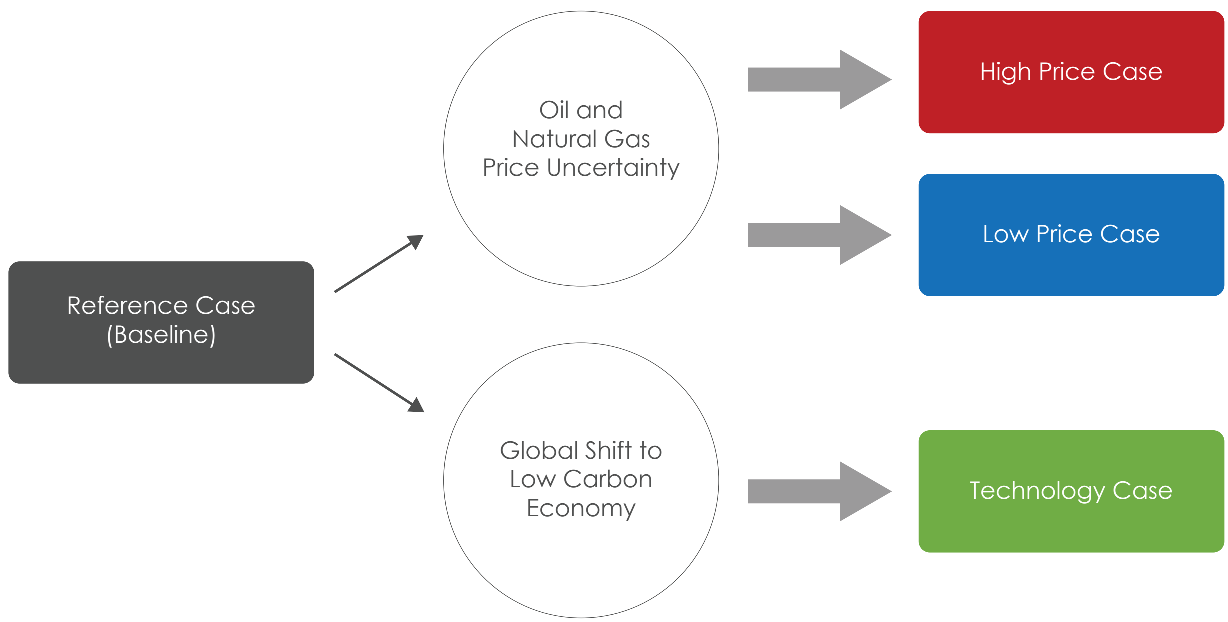
Chapter 1: Introduction

The NEB has been regularly producing long-term energy supply and demand projections since 1967. *The Energy Futures* series explores how possible energy futures might unfold for Canadians over the long term under a variety of scenarios. *Energy Futures* employs economic and energy models to make projections based on a certain set of assumptions given what we know today about technology, energy and climate policies, human behaviour and the structure of the economy. This analysis is not a prediction of what will take place, nor does it aim to show how specific goals, such as Canada's climate targets, will be achieved.

This report, *Canada's Energy Future 2018: Energy Supply and Demand Projections to 2040* (EF2018), is the latest edition of this series. EF2018 considers three core cases and one technology case:

- The Reference Case is based on a current economic outlook, a moderate view of energy prices and technological improvements, and climate and energy policies announced and sufficiently detailed for the modeling at the time of analysis.
- The High and Low Price Cases address the uncertainty of future crude oil and natural gas prices.
- The Technology Case pushes past the policy and technology boundaries specific to the Reference Case and includes greater global climate policy ambition and market outcomes. It provides one potential view of what a faster transition enabled by stronger long-term carbon policy, faster uptake of technologies such as electric vehicles, and lower cost of renewables would mean for Canada's energy future.

Figure 1.1 Overview of Cases in EF2018



Several assumptions underpin the Reference, High and Low Price Cases:

- Infrastructure and markets: In the short-to-medium term, pipeline capacity remains constant but gradually increases. In the long term, infrastructure is in place to move energy production and markets are found[1].
- Goals and targets: Unless provided with a definitive path for achieving them, climate and other related goals and targets are not explicitly modelled.
- Policies: Climate and other relevant policies with sufficient detail to model or make assumptions on are included. This includes various simplifying assumptions to reflect carbon pricing systems.
- Recent climate policy developments: Table A.1, found in Appendix A, describes many recent climate policy developments and indicates what policies are included in the EF2018 analysis.
- Technological change: These cases assume moderate improvement. This includes efficiency and costs reductions of renewables in line with current trends.

1 Note that this is a departure from *Energy Futures*' traditional assumption that all energy production will find markets and infrastructure will be built as needed. A more flexible assumption was required to accommodate the deep price discounts that currently exist for many Canadian oil and gas producers and are expected to persist over the short-to-medium term.

In addition to the Reference and High/Low Price Cases, EF2018 introduces the Technology Case that explores the Canadian energy outlook in a world where technology improvements, combined with increased global policy action on climate change, lead a shift towards a low carbon economy. This case is built by defining a global context, and then developing specific assumptions for Canada within that context on factors such as adoption of emerging technologies like electric vehicles. It is important to note that it is unclear which technologies will gain wider adoption in the future, and this scenario is just one example among many possible pathways. **It should be noted that this scenario is not a prediction or recommendation of certain policies, technologies, or outcomes**.

Over the projection period, it is likely that developments beyond the realm of normal expectations, such as geopolitical events or technological breakthroughs, will occur. Likewise, new information will become available and trends, policies, and technologies will continue to evolve. EF2018 makes several simplifying assumptions on current policies, as well as future technology trends. This report should not be taken as an official or definitive impact analysis of any specific policy initiative. Readers of this analysis should consider the projections a baseline to support ongoing discussions of Canada's energy future, not a prediction of what will take place in the future.

Chapter 2: Recent Context and Key Assumptions

The Canadian energy system is constantly evolving. Factors such as economics, infrastructure, and societal preferences influence the production, transportation, and consumption of energy in Canada. Technology, and climate policies and programs increasingly impact energy markets. This chapter provides an overview of recent energy market developments and climate policies. It also describes the key assumptions and recent developments underpinning the analysis in the report.

Crude Oil Markets

Current Context

Crude oil prices are a key driver of the Canadian energy system and are determined by global supply and demand. Canada is a major crude oil producer and prices are an important driver of future production growth. Increased Canadian oil production is largely due to technological improvements over the past decade. The prices of refined petroleum products (RPPs), such as gasoline and diesel, are related to crude oil prices and can influence energy demand.

From 2011 to mid-2014, global crude oil prices typically ranged between US$100 and US$120 per barrel (bbl). From June 2014, prices dropped steadily, with the Brent crude oil price falling to less than US$30/bbl in January 2016. In Canada, the price of Western Canadian Select (WCS) dropped to US$17/bbl. Global prices began to rebound in 2016, and by 2017, Brent prices reached US$65/bbl. The price rise and subsequent drop are evidence of an unbalanced global oil market. Years of rising demand and higher prices resulted in a global supply surplus, and record crude inventory builds.

Recent developments suggest a rebalancing of global oil markets. Sustained production cuts by the Organization of the Petroleum Exporting Countries (OPEC) and Russia, combined with unexpected supply outages, particularly in Venezuela, have reduced global oil supply. Global oil demand outpaced supply in 2017 and is expected to do the same in 2018[2]. Both United States (U.S.) and Organization for Economic Co-operation and Development (OECD) crude and product inventory stocks have been reduced and are currently near their five-year averages[3]. Also, spot prices have been higher than the futures prices for crude oil, a symptom that emerges when oil traders generally view a market as being undersupplied. Prices have increased over 2017 levels and hovered in a tight range around their 20-year average.[4]

Although global prices have risen, production in North America has outpaced incremental infrastructure, leading to discounted prices. U.S. production growth, particularly from the Permian Basin, has put pressure on pipeline capacity to remove oil from the region. This resulted in West Texas Intermediate (WTI) price discounts to Brent at Cushing, OK climbing to nearly US$10 in mid-2018.

In western Canada, production increased steadily while export capacity remained at 2016 levels or below[5] leading to large price discounts for Canadian crude benchmarks. From January to July 2018, WCS has averaged US$21.86 lower than WTI, an increase in the differential of 71% over the same period in 2017. While some discount should be expected based on quality and transportation costs to American refineries compared to other light crude streams, this normally ranges between US$10 and US$15. Western Canadian heavy oil production increased by 9.8% in 2017, and in the first half of 2018 was 8% higher year-over-year. Without incremental pipeline capacity available, some production has shifted to rail, which is more expensive. The WCS-WTI discount has settled over US$30 on some days. Figure 2.1 illustrates Brent, WTI, and WCS prices and differentials over the past five years. Western Canadian light oil benchmarks are also affected, with the Canadian Light Sweet (CLS) differential to WTI averaging US$7.62 per barrel in the first half of 2018, more than double the 2017 US$2.90 differential.

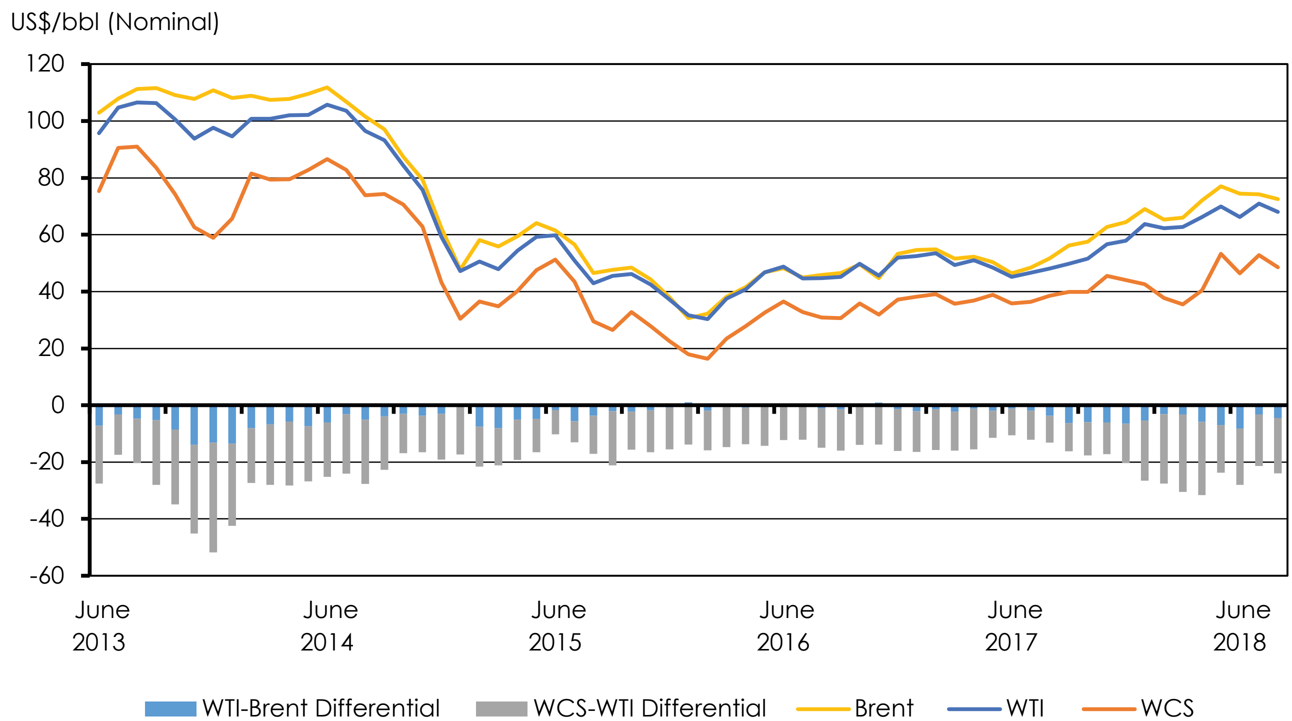
2 EIA STEO

3 EIA STEO

4 From April through June 2018, oil prices appeared to hover within a narrow range in the US$70s/bbl at a real price level that is close to the 20-year average of US$66. In July 2018, Brent averaged over US$74/bbl, a 53% increase over levels seen a year earlier.

5 The effective pipeline export capacity saw a temporary decrease when the Keystone Pipeline experienced an unexpected outage in November 2017.

Figure 2.1: Brent, WTI, and WCS Prices and Discounts, 2013-2018



Expected WCS-WTI Differential Impacts

Most of the Canadian production growth over the next several years comes from large-scale oil sands projects that were commissioned well in advance of the fall in oil prices. It is expected that western Canadian oil exports will surpass pipeline export capacity, in which case the WCS-WTI differential could average anywhere between US$18 and about US$30.

Factors Currently Affecting Crude Oil Markets:

- Global crude oil supply and demand.
- Incremental pipeline and rail capacity.
- Projects in progress (oil sands).
- IMO's 0.5% sulphur content regulation.

Canadian oil priced off WCS faces further downward pricing pressure from the International Maritime Organization (IMO) sulphur content regulations. The IMO's global limit of 0.5% sulphur content in fuel used by ships comes into force on 1 January 2020[6]. Canadian heavy crude will have increased competition for coker refinery capacity in the U.S. Gulf Coast resulting in lower WCS prices as Canadian heavy crude competes to maintain access to the fixed available refining capacity. While the degree and duration of the IMO impact on global refining and crude markets is uncertain, it will likely exert downward pressure on WCS prices for the duration of its influence.

6 The regulation is in place to reduce airborne emissions from ships.

International Maritime Organization Sulphur Regulations

The IMO is an agency belonging to the United Nations, whose mission is to regulate, among other things, emissions from the shipping industry. There are currently 174 countries who are members of the IMO.

The IMO's global limit of 0.5% sulphur content in fuel used by ships comes into force on 1 January 2020[a]. Compliance with the regulation is expected to be high, in the range of more than 70%[b]. The majority of compliance is expected to be through the use of fuel substitution, particularly toward more expensive low sulphur distillates[c]. This will reduce global demand for heavy sulphur fuel oil (HSFO) as early as June 2019. While HSFO makes up 4% of global oil demand as a bunker fuel for the shipping industry[d], it is a product of residual oil. Residual oil is an important revenue stream for refiners that process crude streams with higher sulphur content. The regulation is expected to change the economics of refining across the globe in the short term and alter the flow of crude and other products across it.

Notes:

a) The regulation is in place to reduce airborne emissions from ships.

b) CERI

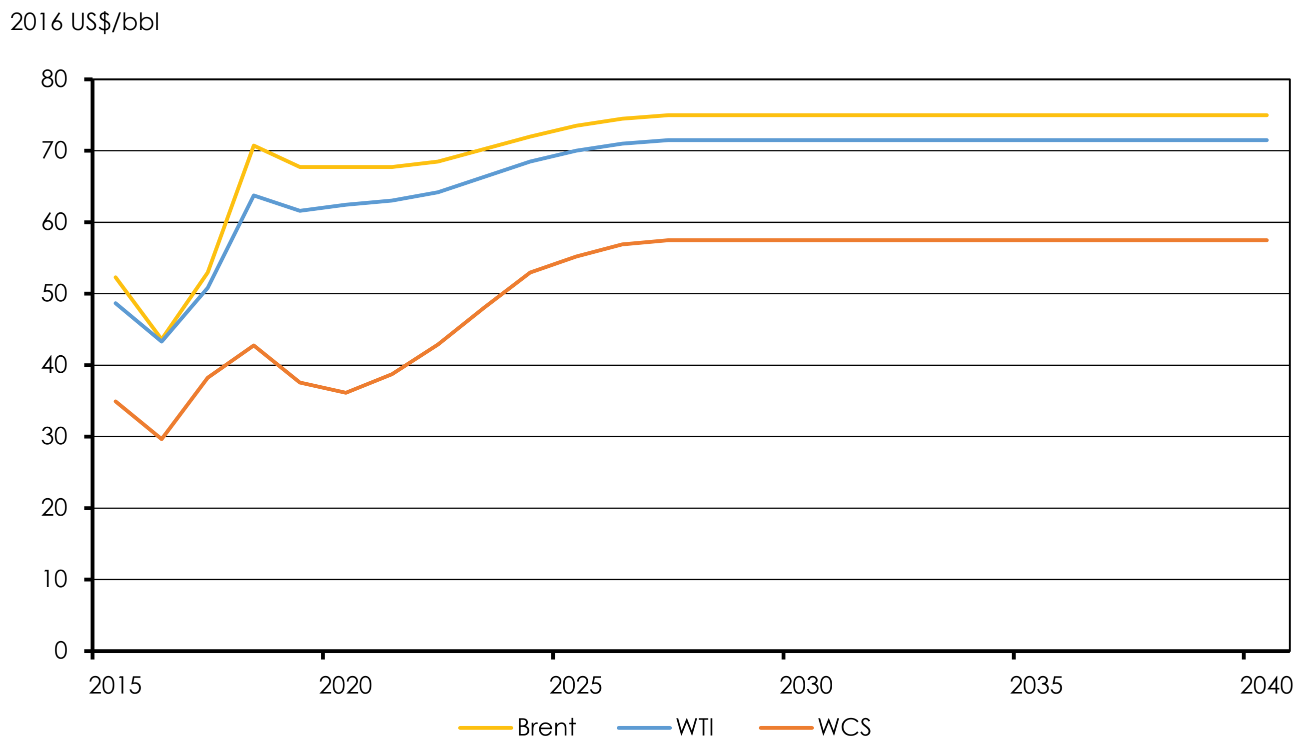
c) Forms of compliance expected to occur in order of likely occurrence include: producing heavy fuel oil from desulphurized residual oil, using LNG or Methanol as a marine fuel, blending HSFO with other distillates. While the degree to compliance is uncertain, it is expected that various measures are in place to ensure a high rate of compliance.

d) IEA, p. 105

EF2018 Crude Oil Price Assumptions

Figure 2.2 shows the Reference Case crude oil price assumptions for EF2018. Brent prices, in constant 2016 US$, are expected to decline in 2019 from current levels and remain at US$68/bbl for the next few years. In 2022, Brent is expected to start increasing and reach US$75/bbl by 2027, where it remains over the projection period. This medium-term price increase reflects the need to develop higher cost resources to replace continuously declining existing supplies and meet increasing global oil demand. The flat, long-term trajectory suggests that oil supply can then grow to meet modest global demand growth at a long-term US$75/bbl price level. The current Brent-WTI discount is assumed to decrease steadily from its current high levels, reaching US$3.50/bbl by 2024, roughly reflecting transportation costs from Cushing, OK to the Gulf Coast.

Figure 2.2: Brent, WTI and WCS Price Assumptions, Reference Case



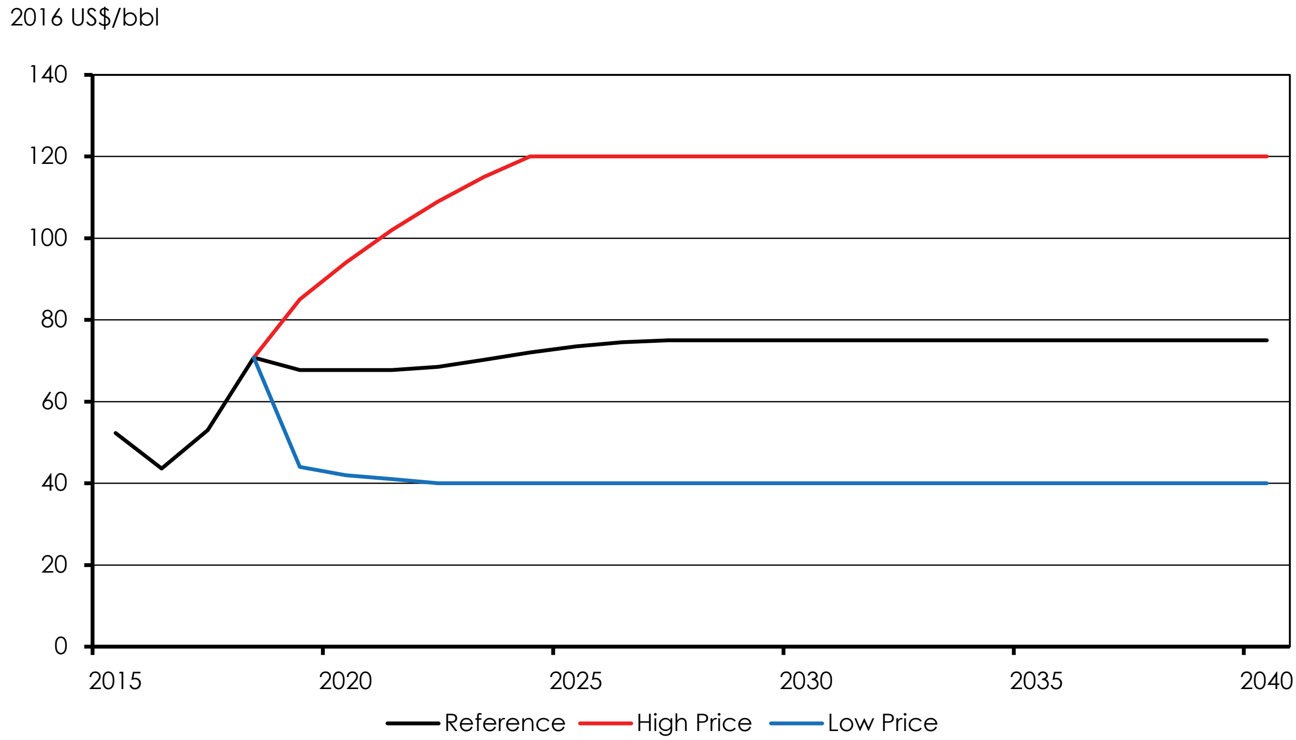
The combined effect of Canadian crude discounts and the IMO regulations are assumed to push the real WCS-WTI differential to US$26.30/bbl in 2020. As discounts are gradually alleviated, price discounts converge to a sustained value of US$14/bbl by 2027 that reflect quality differences and transportation costs to the Gulf Coast.

CLS is assumed to strengthen as WTI increases, but its discount will increase as production continues to outpace incremental pipeline capacity over the next year, reaching a high of US$7.69/bbl in 2019. The differential will narrow as capacity additions are assumed to come online gradually thereafter, reaching a long-term value of US$2.60/bbl with WTI in 2027[7], and an implied CLS value of almost US$69/bbl in the long term.

Figure 2.3 shows the Brent price assumptions for the Reference, High and Low Price Cases. The High Price Case presents a future where supply is not as robust and prices need to rise to levels around US$120/bbl to balance crude oil markets in the longer term. The Low Price Case reflects an environment where supply availability is more robust and begins to outpace demand growth, sending prices to $40/bbl in the long term.

7 Please see the EF online data appendices for CLS, as well as other benchmark prices.

Figure 2.3: Brent Price Assumptions, Reference, High Price and Low Price Cases

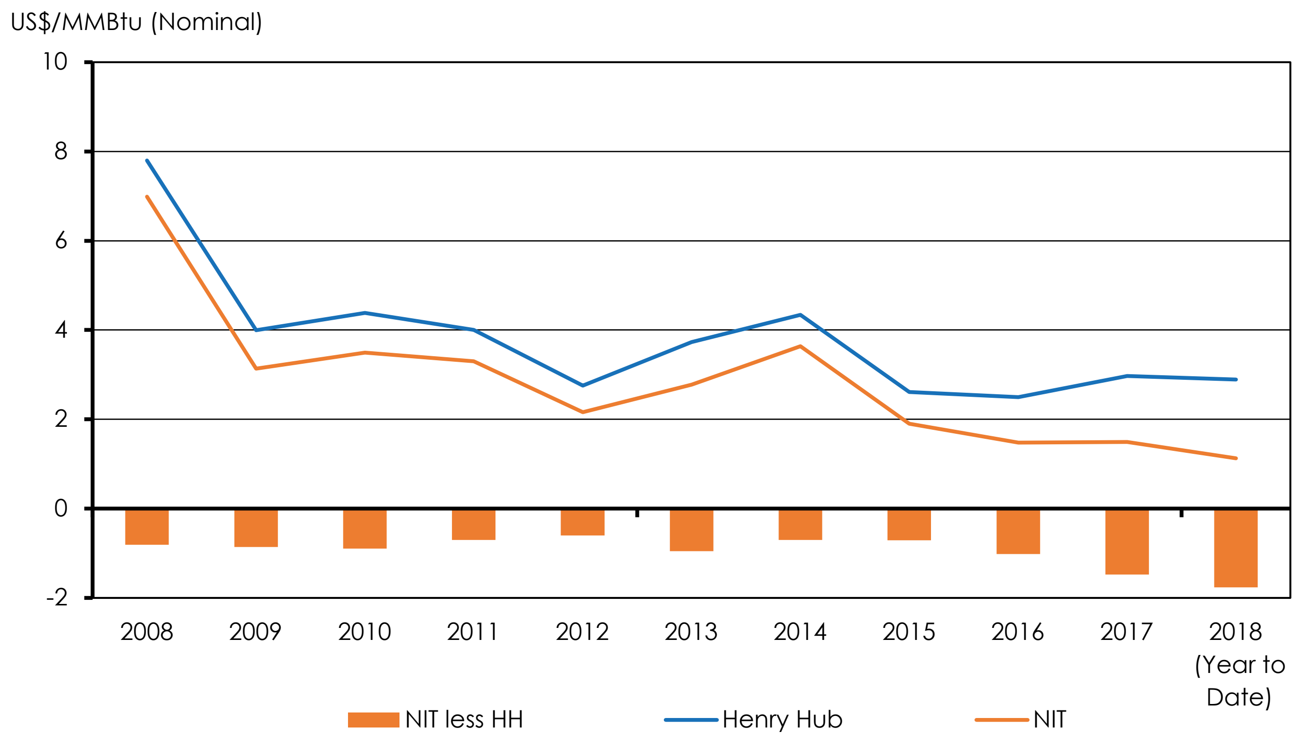


Natural Gas Markets

Current Context

North American natural gas prices have declined considerably over the past decade. Lower prices have been driven by large increases in production, made possible by horizontal drilling and multistage hydraulic fracturing. Henry Hub prices averaged US$7.80 per million British thermal units (MMBtu) in 2008, and declined by almost 50% by 2013. Over the past five years, prices have averaged just over US$3.00/MMBtu. From a low of US$2.49/MMBtu in 2016, prices have increased through 2017, and averaged US$2.89/MMBtu in the first half of 2018. Despite gains in U.S. production, much of which has been natural gas produced with oil, increased demand and increased liquefied natural gas (LNG) exports from the Gulf of Mexico contributed to moderately recovering prices. Figure 2.4 compares historical Alberta (Nova Inventory Transfer (NIT)) and Henry Hub prices for the past 10 years.

Figure 2.4: Henry Hub vs NIT Price, 2008-2018



From 2010 to 2013, Canadian natural gas prices averaged just under C$3/GJ. In 2014, prices briefly rebounded and have since continued to decline. Prices averaged C$1.50/GJ in 2017, and C$1.13/GJ in the first half of 2018. Canadian natural gas exports were formerly priced off Henry Hub, minus the cost of transport. However, rapidly rising U.S. production from the Marcellus Basin in Pennsylvania and Ohio now represents the competition for much of Canada's exports and Marcellus gas sells at a discount to Henry Hub. Canadian natural gas production is also being driven by the value of condensate and natural gas liquids (NGLs) that are co-produced with the gas. This means that some Canadian producers can accept a lower price for their natural gas because of the revenues earned from the accompanying condensate and NGLs. As production shifts westward in western Canada to access the sources richer in condensate and NGLs, pipeline capacity has not kept pace with production. Additional pipeline capacity is being constructed in those areas. The construction can cause interruptions to existing pipeline capacity resulting in periods when some gas in western Canada is sold at very low or even negative prices to find a market. From 2008 to 2015, the average NIT-Henry Hub differential was $0.78/MMBtu, but it averaged US$1.50/MMbtu in 2017 and over $1.75/MMBtu for the first six months of 2018. NIT even exhibited negative pricing on several days throughout 2017 and 2018.

Factors Currently Affecting Natural Gas Markets:

- Increased North American production.
- U.S. LNG exports.
- WCSB and export pipeline capacity.
- Oil sands demand for natural gas.
- Potential Canadian LNG exports.

As producers in western Canada seek new markets in the U.S. or to better compete in existing markets by lowering their costs, pipeline operators have been adjusting capacities on pipelines out of the region and making arrangements to lower transport costs. To access overseas natural gas markets, there are several proposed projects to export LNG from Canada's west coast, the economics of which have been improving over the past year.

EF2018 Natural Gas Assumptions

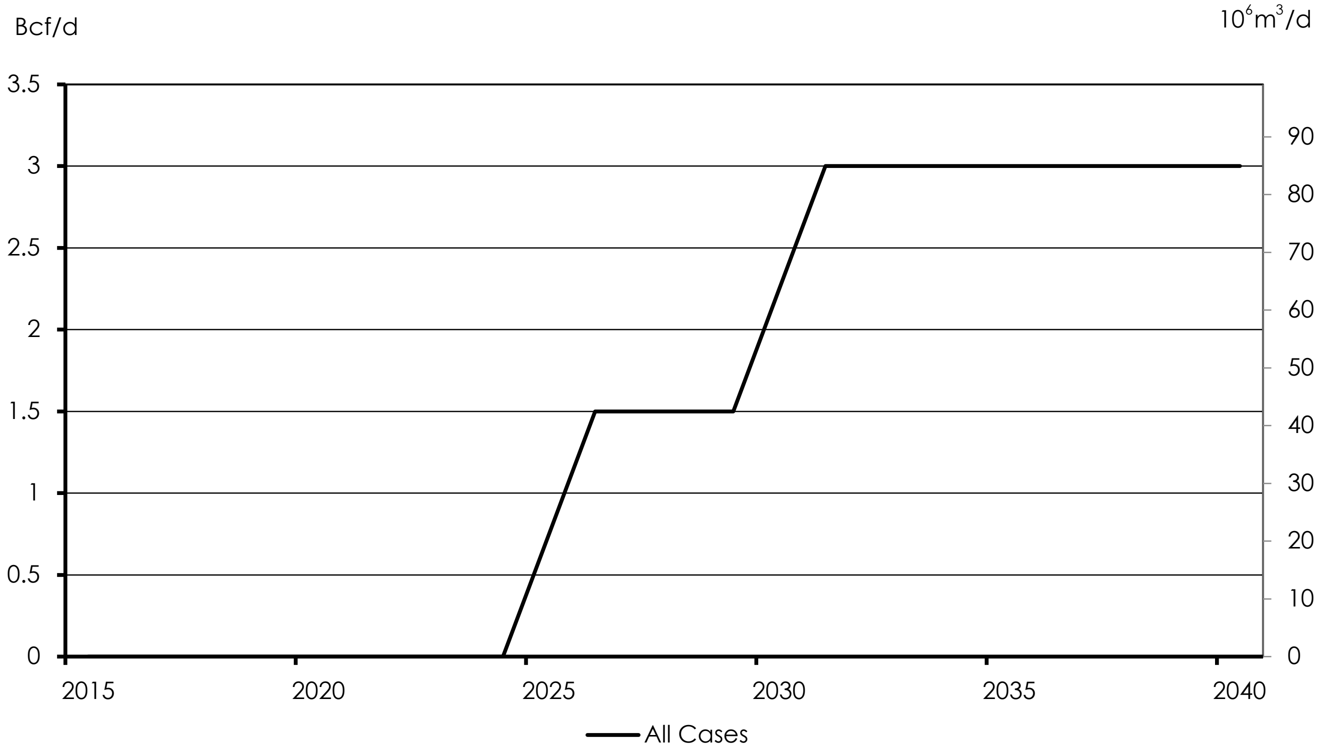
In the Reference Case, Henry Hub prices remain flat and stay under US$3.00/MMBtu until 2025 as the market continues to be in a state of over-supply. This is largely due to growing U.S. oil production and the natural gas production associated with it. The natural gas price is assumed to gradually increase thereafter as U.S. industrial demand and LNG exports outpace supply growth, reaching a long-term price of US$4.16/MMBtu in 2040.

The prospect of Canadian LNG export facilities also has important implications for energy supply and demand trends. The future of Canadian LNG exports has been uncertain. Globally, LNG trade is expected to increase as the demand for natural gas rises by over 45% in the next 25 years. Gas markets are expected to be well supplied in the near term and new exports will be required by the mid-2020s[8]. The demand increase could prove to be an opportunity for Canadian LNG export volumes.

All EF2018 Cases assume LNG exports from British Columbia (B.C.)'s coast beginning in 2025. LNG exports start at 0.75 billion cubic feet per day (Bcf/d) (21.3 million cubic metres per day (10^6m^3/d)) in 2025 and double in 2026 to reach 1.50 Bcf/d (42.5 10^6m^3/d). Phase II is assumed to come online in 2030, increasing total LNG exports to 2.25 Bcf/d (63.7 10^6m^3/d) in 2030 and 3.0 Bcf/d (85.0 10^6m^3/d) in 2031. Figure 2.5 shows the assumed LNG export volumes included in EF2018 analysis for all Cases. The Canadian LNG export volumes included in this analysis are an assumption of what might happen. They do not reflect volumes associated with a particular project or export license. On 2 October, LNG Canada announced a positive final investment decision for its proposed export project. The project will initially export 14 million tonnes per annum (mtpa) (the equivalent of ~1.8 Bcf/d or 51 10^6m^3/d) from two processing units and will have the capability to expand to four in the future. This decision came after the EF2018 analysis period was completed. At this point, the EF2018 LNG assumptions are considered applicable to any new large scale LNG facility, whether it turns out to be the LNG Canada project or a competitor. Additional details should become available once construction of a project is underway and these can be included in future editions of *Energy Futures*.

8 CERI: Competitive Analysis of Canadian LNG, 2018

Figure 2.5: LNG Exports, All Cases



EF2018 assumes that Canadian natural gas price discounts persist in the near term and are slowly alleviated by 2025 as infrastructure is built and markets for excess natural gas are found. Figure 2.6 shows the NIT-Henry Hub differential decreases from its current high of US$1.60/MMBtu to US$.90/MMBtu in 2025, bringing NIT to US$2.15/MMBtu (C$2.51/GJ). The NIT-Henry Hub differential increases again in 2027 as producers prepare their reserves and boost production for the upcoming phase of LNG exports, reaching US$1.05/MMBtu in 2029, and returning to its long-term levels of US$0.90/MMBtu. While the differential varies, NIT increases constantly over the Reference Case outlook, reaching a value of US$3.26/MMBtu (C$3.69/GJ) by 2040.

Figure 2.6: Henry Hub and NIT Price Assumptions, Reference Case

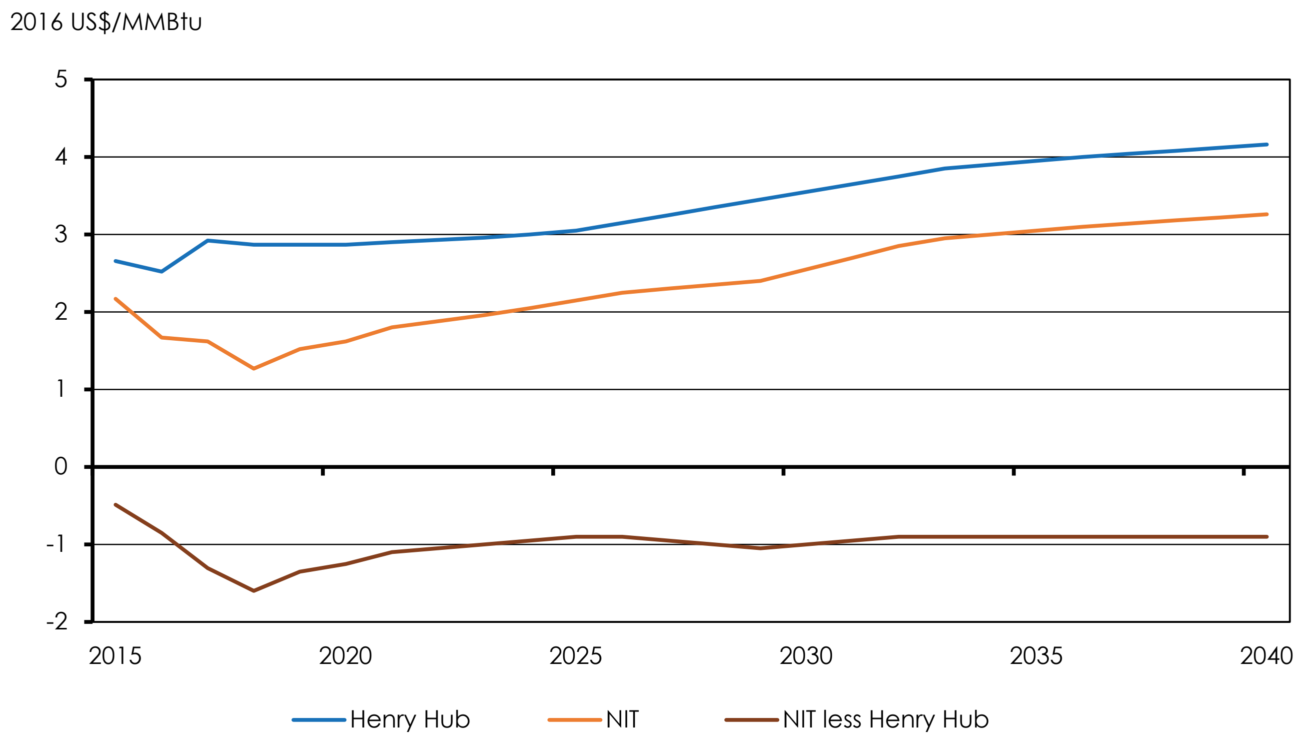
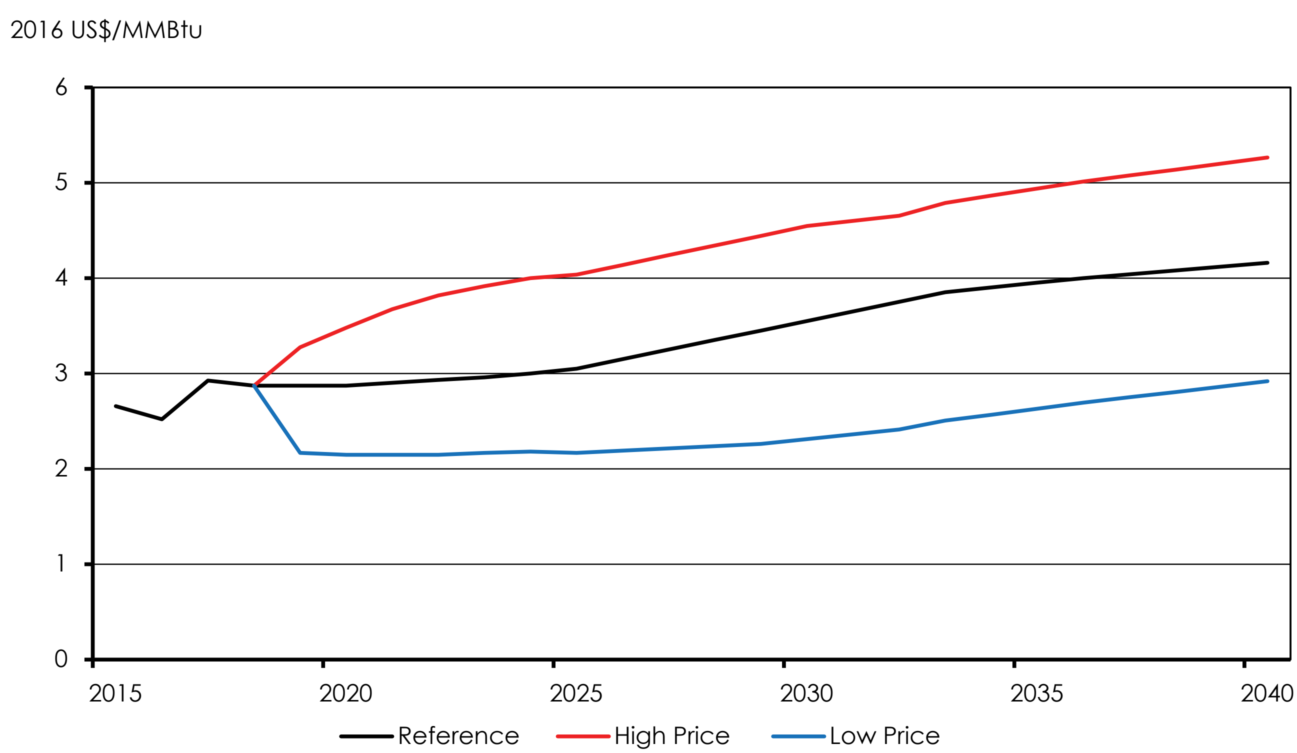


Figure 2.7 shows the Henry Hub natural gas price assumptions for the Reference, High Price, and Low Price Cases. In the High Price Case, Henry Hub rises to US$5.26/MMbtu by 2040. In the Low Price Case, Henry Hub declines to US$2.15/MMbtu by 2020, and gradually rises to US$2.92/MMbtu by 2040.

Figure 2.7: Henry Hub Price Assumptions, Reference, High Price and Low Price Cases



Climate Policy

Canadian climate policy has evolved rapidly since 2015. Over the past several years, all levels of government have made major policy announcements and continue to move forward with previously announced and implemented climate related plans.

EF2018 includes many recently announced and implemented climate policies. In order to determine whether a policy was included in the analysis, the following criteria were applied:

- The policy was publically announced prior to 1 August 2018.
- Sufficient details exist to model the policy.[9]
- Goals and targets, including Canada's international climate targets, are not explicitly modelled. Rather, policies that are announced, and in place, to address those targets are included in the modelling and analysis.

See Table A.1 in Appendix A for a list of some recent climate policies and how they are handled in EF2018.

Carbon Pricing

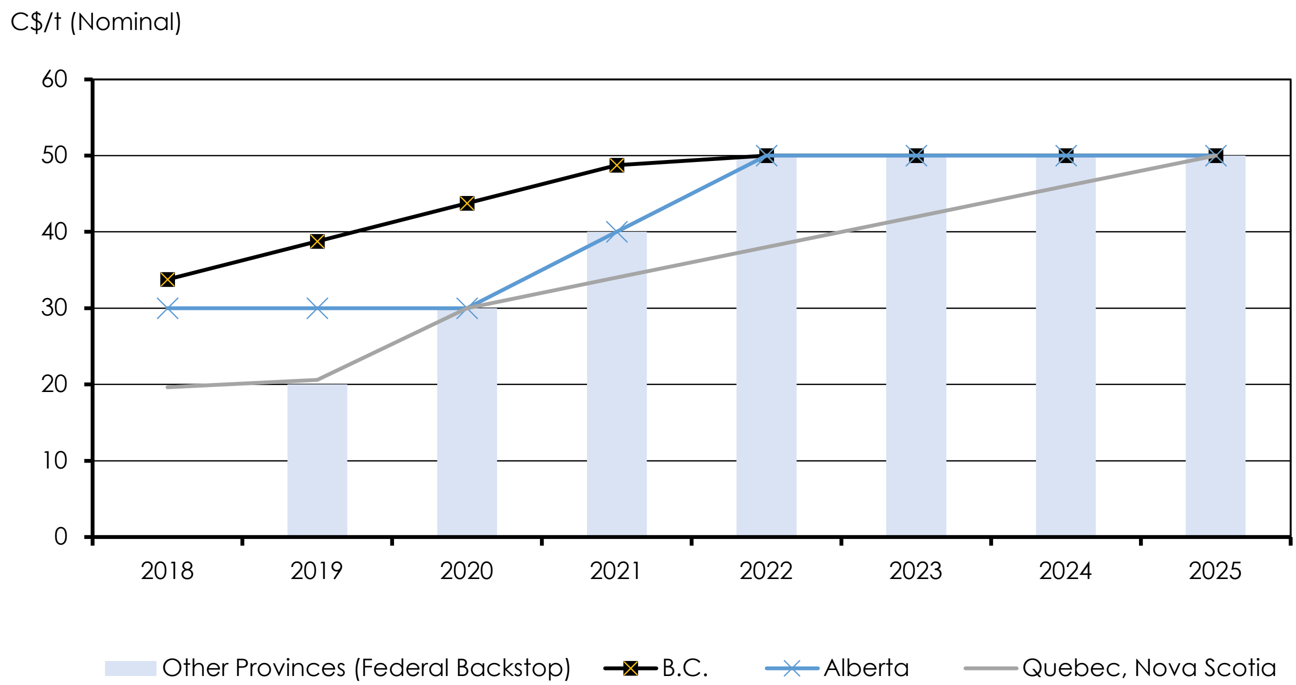
Carbon pricing systems continue to evolve in Canada, as various provinces and territories have announced their intentions for their own carbon pricing systems under the Pan-Canadian Framework. Figure 2.8 breaks down the EF2018 carbon price assumptions by province from 2018 to 2025. EF2018 assumes that the Federal backstop carbon price is binding in the Reference Case. For provinces that have not declared their own carbon pricing system, or have priced carbon at a level below the backstop schedule, the backstop schedule–beginning at $20 per tonne in 2019 and rising to $50 per tonne in 2022–is used.

For provinces that have chosen cap-and-trade systems, the future price of carbon will be determined by the supply and demand for emission permits. The outlook for this market price will be uncertain, similar to other market prices such as crude oil and natural gas. Like crude oil and natural gas prices, EF2018 makes simplifying assumptions for the future outlook of carbon pricing. For the two cap-and-trade provinces, Quebec and Nova Scotia, the carbon price is assumed to remain below the federal backstop in the early 2020s, before converging to $50 per tonne in 2025. Post-2025, carbon prices in all provinces and territories remain at $50/tonne in nominal terms[10].

9 For example, the proposed Clean Fuel Standard has been announced, but is not included as draft regulations are currently under development.

10 With Ontario's recent departure from the Western Climate Initiative, it is possible that emissions permits begin to trade at lower levels than are assumed here. Manitoba's recent announcement to cancel its $25 per tonne carbon price was made after this analysis was completed and is not reflected in EF2018. Manitoba carbon prices in 2018 and 2019 reflect the $25 per tonne carbon price, and follow the Federal Backstop afterwards.

Figure 2.8: Carbon Pricing by Province, 2018-2025



Carbon Pricing Exemptions and Allocations

Many carbon pricing systems have exemptions and/or permit allocations. One example is the output based allocation approach used f*or* large emitters in the Alberta and federal backstop systems. This system provides an allowable level of emissions for large emitters, and facilities pay for the emissions above that level or receive credits for their emissions below it. This system reduces the average carbon cost for these facilities, but maintains the incentive for emission reductions. In this analysis, emitters face the full carbon price at an end-user level to capture the incentive effect of the carbon price, while the impact of the output based allocations in reducing the overall cost to firms and income effects of the carbon prices is captured in the industrial macroeconomic projections. Other examples include emission units distributed free of charge to industrial emitters in Quebec to avoid carbon leakage in its cap-and-trade system, or point of sale rebates for heating oil in the Northwest Territories, as its residents already face heating costs higher than the national average.

While EF2018 attempts to include available details on current climate policies and carbon pricing systems, these systems are complex, continually being refined, and involve several uncertainties. The primary uncertainty is the federal government's jurisdiction to enforce the pan-Canadian benchmark for pricing carbon in the event that provinces that have not implemented their own plans that meet the minimum standards, or are actively opting out of implementing a carbon pricing plan. EF2018 makes many simplifying assumptions on Canadian climate policy implementation for the purposes of creating a reasonable outlook for future Canadian supply and demand trends. It should not be taken as direct analysis on any specific policy initiative.

Electricity

Current Context

Canada's energy system is entering a period of significant change, and the electricity sector is expected to play a key role in the transition to a cleaner economy[11]. In the federal government's Pan-Canadian Framework, four key areas of transition were identified: growth in renewables and low-emitting sources, increasing interconnections to allow the flow of clean power, modernizing the electricity system, and reducing diesel reliance in remote communities.

In spring 2016, the Alberta government unveiled a climate change and emissions strategy based on recommendations put forth by the Climate Leadership Panel. The Alberta government plans to phase out coal-fired electricity generation by 2030. However, this could take place earlier than planned through coal-to-gas conversions. In 2017, two operators announced their plans to retrofit existing coal units to natural gas-fired units as early as 2020. The strategy also calls for the development of 5 000 megawatts (MW) of renewables by 2030. To reach this target the Alberta Electricity System Operator's (AESO) launched the first Renewable Electricity Program (REP). This competitive process was a success; attracting 600 MW of new capacity with a record low bid price that averages $37/MW.h. In late 2016, the Alberta government announced its plan to transition from the province's energy-only electricity market to a capacity market framework. The AESO's ongoing Comprehensive Market Design work is expected to release rules on the capacity market by the end of the year, with a plan to award capacity contracts in 2020/21.

There are uncertainties regarding future carbon capture and storage (CCS) projects in Saskatchewan. Recently the province announced it will not be retrofitting Boundary Dam 4 and 5 with CCS. The two units will retire in accordance with federal regulations (2021 and 2024 respectively).

Ontario's nuclear refurbishment is proceeding, as the province plans to refurbish 10 units between 2016 and 2033. Work on the first unit (Darlington Unit 2) began in 2016. Refurbishment work on Darlington unit 3 and Bruce unit 6 are scheduled for 2020. Also, Ontario recently announced its plans to keep its Pickering nuclear plant open until 2024. Ontario is also considering a capacity auction framework under the Market Renewal initiative. In a capacity market, power suppliers will be paid a guaranteed fee for their commitment to make resources available when needed.

Factors Currently Affecting Electricity Markets:

- Moderate electricity demand growth in Canada and U.S.
- Federal and regional climate policies such as coal retirement and carbon pricing systems.
- Decline in cost for non-hydro renewables particularly for solar and wind technologies.

In late 2017, electricity was exchanged between Newfoundland and Nova Scotia for the first time through the Maritime Link transmission line. The new connection, which includes 170 kilometres (km) of subsea transmission cables, connects the Muskrat Falls generating station in Labrador to Nova Scotia. The majority of the energy from Muskrat Falls will serve both Newfoundland as well as provide contractual capacity and energy to Nova Scotia. Muskrat Falls is expected to come online in 2020.

11 Canada's Energy Transition: Getting to Our Energy Future, Together by Natural Resources Canada's Generation Energy Council Report

Short-term surplus capacity is a common theme in some Canadian regions as illustrated by record levels of electricity exports, wind curtailments, low hydro capacity factors and high reservoir levels in some regions. Quebec's reservoir reached historic levels of 140.5 TW.h and British Columbia's reservoirs recorded the third highest level in the past five years (14.5 TW.h). Ontario wind curtailments reached 26% (3.3 TW.h), the highest level in the past five years.

Remote communities primarily rely on expensive diesel-fired generation, while others rely on smaller local or regional electricity grids based on hydro or trucked-in liquefied natural gas (LNG). Many remote communities in northern Canada are exploring opportunities to reduce their reliance on diesel fuel, improve electricity reliability, and reduce emissions. Solar projects currently exist in many Northwest Territories communities although they tend to have limited functionality in the winter months due to reduced sunlight in the region. Despite this limitation, over 900 kilowatts (kW) of installed solar PV capacity helped offset an estimated 200 000 litres of diesel consumption in 2016.

Electricity Assumptions

EF2018 analysis reflects current utility and system operator expectations of future electricity developments in the respective regions, especially for major planned projects, and to guide assumptions on costs of generation for various types of electricity. Table 2.1 shows assumptions for natural gas, solar, and wind costs, including their capacity factors. The timing and magnitude of other forms of generation added over the projection period (such as hydroelectric and nuclear refurbishments) are based on current schedules and plans from utilities, companies, and system operators.

Table 2.1: Electricity Cost Assumptions, Natural Gas, Wind, and Solar

	Capital Cost (C$/kW)	Fixed Operating and Maintenance Costs (C$/kW)	Variable Operating and Maintenance Costs (C$/MW.h)	Capacity Factor
Gas (Combined Cycle)	1 400-1 850	20	5	70%
Gas Peaking	1 040-1 400	18	5	20%
Wind (2020)	1 541	24-55	0	35-50%
Wind (2030)	1 360	24-55	0	35-50%
Wind (2040)	1 200	24-55	0	35-50%
Solar (2020)	1 613	20-25	0	10-20%
Solar (2030)	1 307	20-25	0	10-20%
Solar (2040)	1 100	20-25	0	10-20%

Technology

Technology's influence on the energy system can range from marginal to transformative. Which emerging technologies will achieve widespread use is often difficult to predict. Likewise, the nature of future breakthroughs is unknown. The adoption rate of emerging technologies is a key uncertainty to the projections in EF2018.

The core Cases assume moderate technological progress, reflected by factors such as efficiency improvements and cost reductions for well-established technologies. However, there is a high degree of potential for further technological progress, especially as it relates to the increasing ambition of climate policies across the world and the transition to a low carbon economy. These types of changes pose several key uncertainties for Canada's energy system, and are explored in the EF2018 Technology Case. There is also potential for disruptive technologies to emerge, altering the ways Canadians use energy. They could result in both increases and decreases in energy usage for a variety of end-uses[12]. Additional context and assumptions for the Technology Case are covered in Chapter 4.

12 Examples include the rising consumption of electricity to produce crypto-currency, or the potential decreased cost of energy due to transport-as-a-service business models leading to increased energy use in the long term.

Chapter 3: Reference and High/Low Price Case Results

Overview

This chapter focuses on the results of the Reference, High and Low Price Cases. Chapter 4 describes the assumptions and results of the Technology Case.

Detailed data tables supporting the discussion in this Chapter are available in the EF online data appendices.

Macroeconomic Drivers

The economy is a key driver of the energy system. Economic growth, industrial output, inflation, exchange rates, and population growth all influence energy supply and demand trends. Macroeconomic projections for each of the Cases were provided by Stokes Economics. Stokes Economics developed unique projections of key macroeconomic indicators such as gross domestic product, exchange rate, and industry gross output for each of the Cases, based on the price assumptions and output of the NEB's supply and demand models.

Key economic variables are shown in Table 3.1. Economic growth averages 1.76% per year over the projection period in the Reference Case.

Table 3.1 - Economic Indicators, Reference, High Price and Low Price Cases

Economic Indicator	Compound Average Annual Growth Rate (unless otherwise noted)			
	1990-2016	Reference Case (2017-2040)	High Price Case (2017-2040)	Low Price Case (2017-2040)
Real Gross Domestic Product	2.28%	1.76%	1.84%	1.58%
Population	1.04%	0.82%	0.81%	0.81%
Inflation	1.92%	1.95%	1.97%	1.87%
Exchange Rate (average)	0.81 US/C$	0.82 US/C$	0.89 US/C$	0.75 US/C$

Compared to the past 26 years, the pace of economic growth is slower in the Reference Case. Economic growth in the High Price Case is higher than the Reference Case, largely due to an increase in the production of fossil fuels. Similarly, economic growth is lower in the Low Price Case due to lower production of fossil fuels.

Key Uncertainties

- **International demand for Canadian goods:** International demand for Canadian goods, the production of which can be energy intensive, impacts export-oriented industries. Faster or slower economic growth in the U.S., Canada's largest trading partner, would affect the economic and energy demand projections.
- **International trade and NAFTA:** The renegotiation of the North American Free Trade Agreement (NAFTA) with the U.S. and Mexico was ongoing at the time of EF2018 writing. EF2018 does not incorporate NAFTA's successor, the United States-Mexico-Canada Agreement, which was ratified at the end of September 2018. EF2018 is based on NAFTA-like conditions prevailing between the three countries in energy trade, energy demand and economic growth. At this time, these economic relationships continue to be the most reliable assumption for the purpose of the EF2018 report.
- **Large infrastructure projects:** Projects in the mining, oil, natural gas, and electricity sectors affect the macroeconomic projections in a number of provinces. The pace of these developments is uncertain and could lead to higher or lower economic growth, and impact energy trends.

Energy Demand

This section focuses mainly on end-use, or secondary energy demand. Secondary demand excludes energy used to generate electricity, which is accounted for in primary demand. Historical data is sourced primarily from Statistics Canada's Report on Energy Supply and Demand in Canada. That data is supplemented with additional details from various federal and provincial data sources.

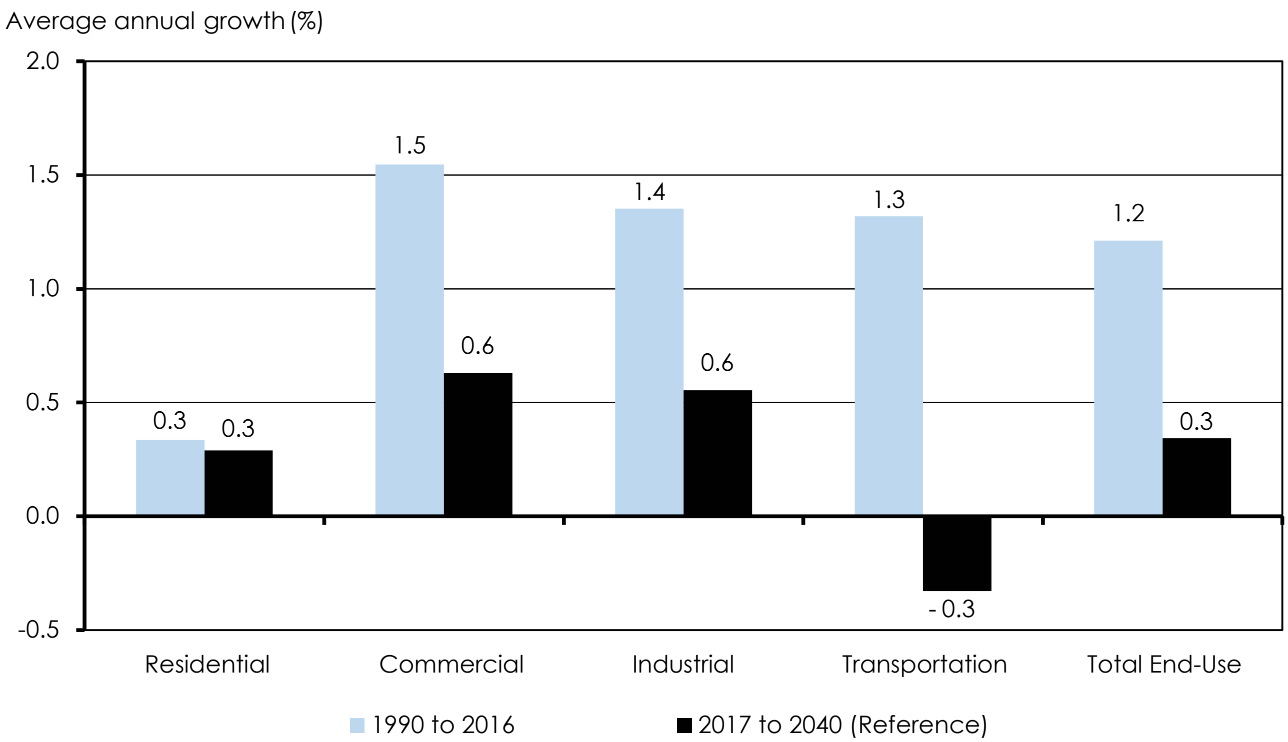
Figure 3.1 shows annual average growth rates of energy use by sector over the past 26 years, and from 2017 to 2040 in the Reference Case. Compared to the 1990-2016 period, when demand grew by an average of 1.2% per year, end-use energy demand growth in the Reference Case is considerably slower over the outlook period, averaging growth of 0.3% per year.

Key Trends: Energy Demand

- Energy use growing slower than history.
- Use of natural gas and renewables increases, coal and oil products decline.
- Energy use per $GDP and per person in Canada declines.

There are several reasons why energy use grows slower than history. Economic activity drives energy use, and as shown in Table 3.1, it is lower than historical levels. The historical trend of Canada becoming a less energy-intensive economy, as measured by energy consumed per unit of GDP, persists over the projection period. Energy efficiency continues to play a role in reducing energy demand growth because less energy is required for new buildings, devices, and equipment. Retail RPP prices, such as gasoline and diesel, continue to rise along with crude benchmark prices, dampening future demand growth. The Pan-Canadian approach for pricing carbon pollution has a downward impact on energy use trends for all fossil fuels. Several other policies, programs, and regulations affect energy use in the projection period.

Figure 3.1: Historical and Projected Average Annual Growth in End-Use Energy Demand by Sector, Reference Case



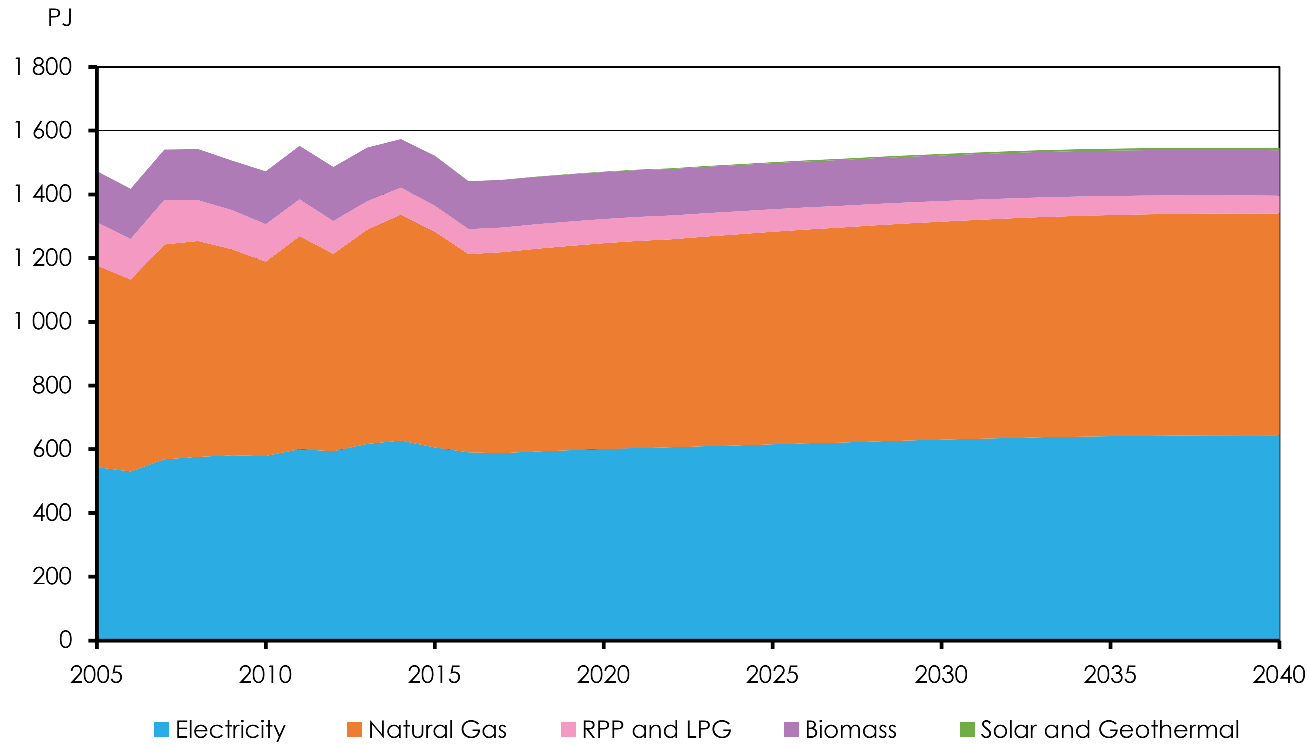
In the Reference Case, total end-use demand increases by 0.3% per year over the projection period, reaching 12 368 PJ by 2040. The price Cases see differences in demand, driven mainly by the energy needed to fuel variations in oil and gas production trends. In the High Price Case, end-use demand increases to 12 805 PJ by 2040; in the Low Price Case, it declines to 11 676 PJ by 2040.

Residential and Commercial

Residential energy use is the energy consumed by Canadian households. The commercial sector is a broad category that includes offices, stores, warehouses, government and institutional buildings, utilities and pipelines, communications, and other service industries. The residential sector made up 13% of total end-use demand in 2017, while the commercial sector consumed 12%.

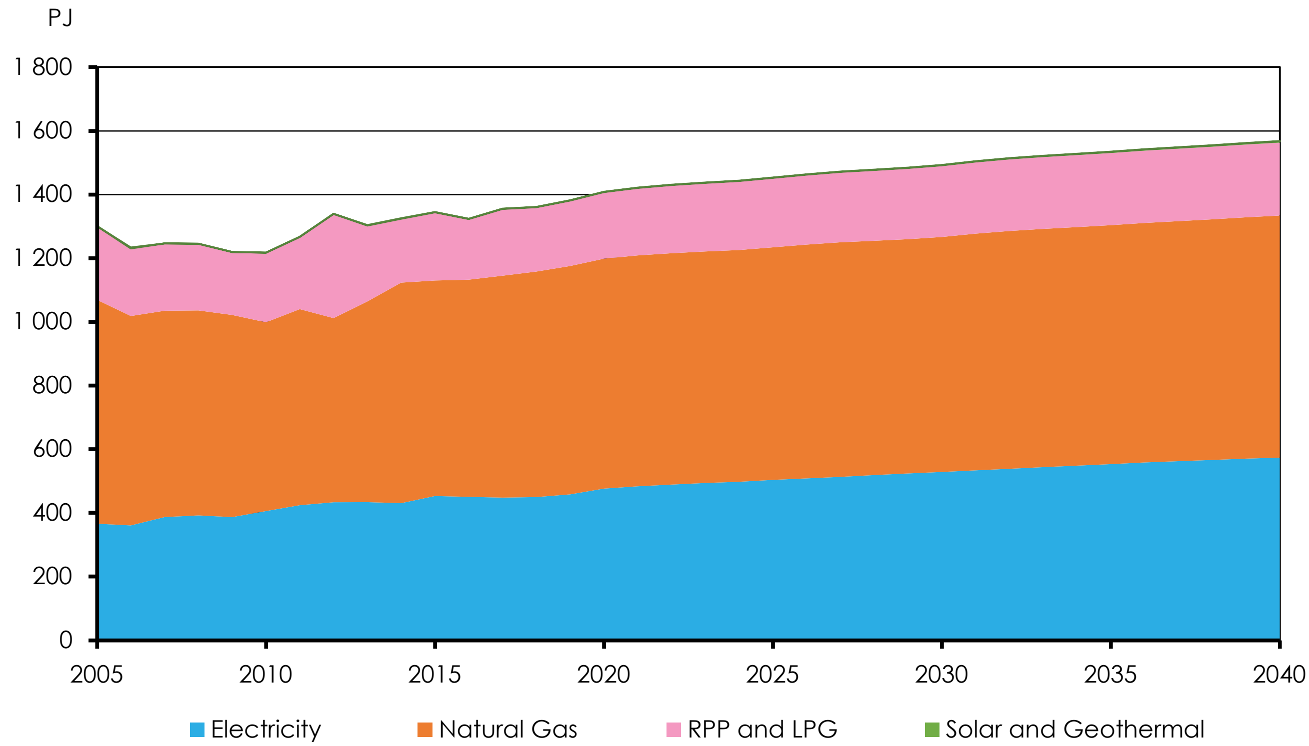
Figures 3.2 and 3.3 show annual average growth rates of energy use for the residential and commercial sectors over the projection period.

Figure 3.2: Canadian Energy Demand, Residential



In the Reference Case, energy use in the residential sector increases from 1 445 PJ in 2017 to 1 545 PJ in 2040. This corresponds to an average growth rate of 0.3% over the projection period, similar to the historical growth. In the Reference Case, energy use in the commercial sector grows 0.6% per year on average over the projection period, a significant reduction compared to the 1.5% growth observed historically.

Figure 3.3: Canadian Energy Demand, Commercial



Over the projection period, combined residential and commercial energy use per square foot of floor space decreases by 1.4% per year, compared to the historical decline of 1.1%. These efficiency gains further support the trend of declining energy use per household over the projection period. As a result, while population grows by 20% over the projection period, residential energy demand increases by only 6%.

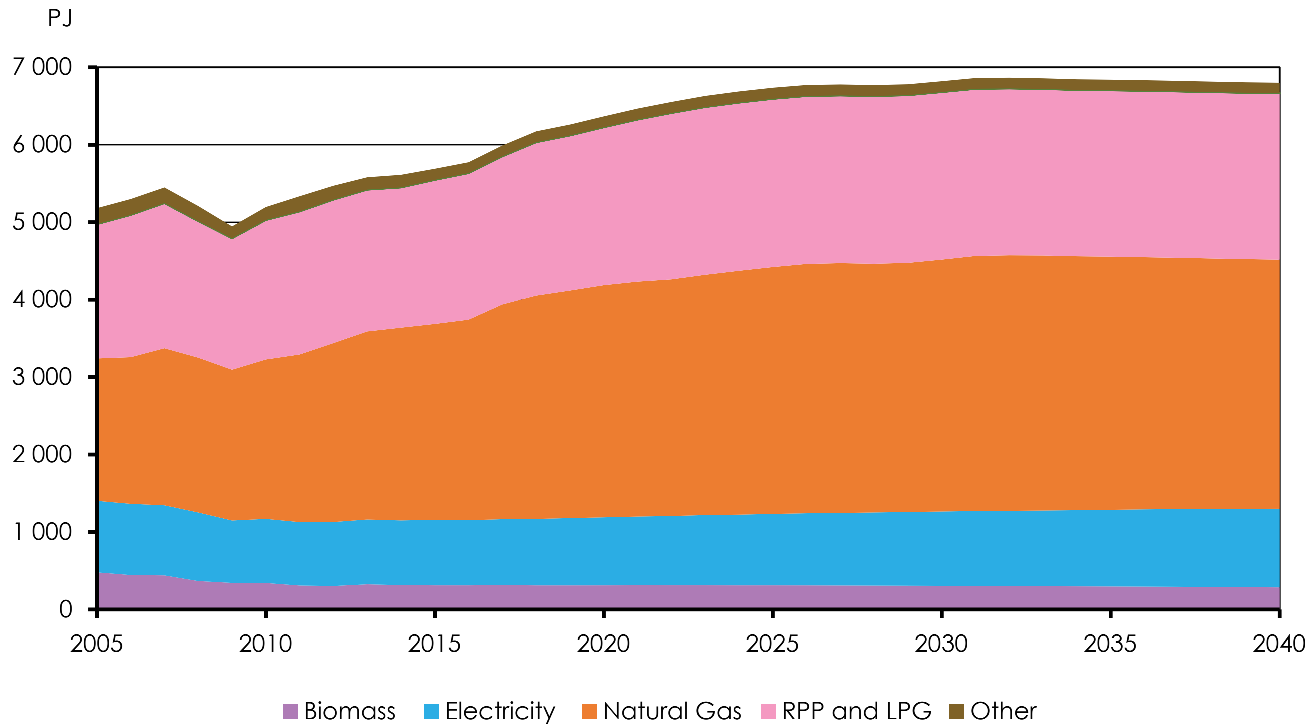
Industrial

The industrial sector includes manufacturing, forestry, fisheries, agriculture, construction, mining, and oil and natural gas extraction. The industrial sector made up 53% of total end-use demand in 2017. Additionally, natural gas demand makes up almost 44% of all industrial demand in 2017.

The economic outlooks of the various industries drive industrial energy demand projections. Industrial growth is linked to the demand for goods consumed domestically, but also those exported internationally due to Canada's trade-oriented economy.

In the Reference Case, industrial demand grows steadily in the early part of the projection, driven mainly by increases in oil sands production. As this production growth slows in the 2020s, industrial demand growth flattens out, reaching 6 802 PJ in 2040, or 0.6% per year on average over its 2017 level. Figure 3.4 shows industrial energy use trends by fuel in the Reference Case.

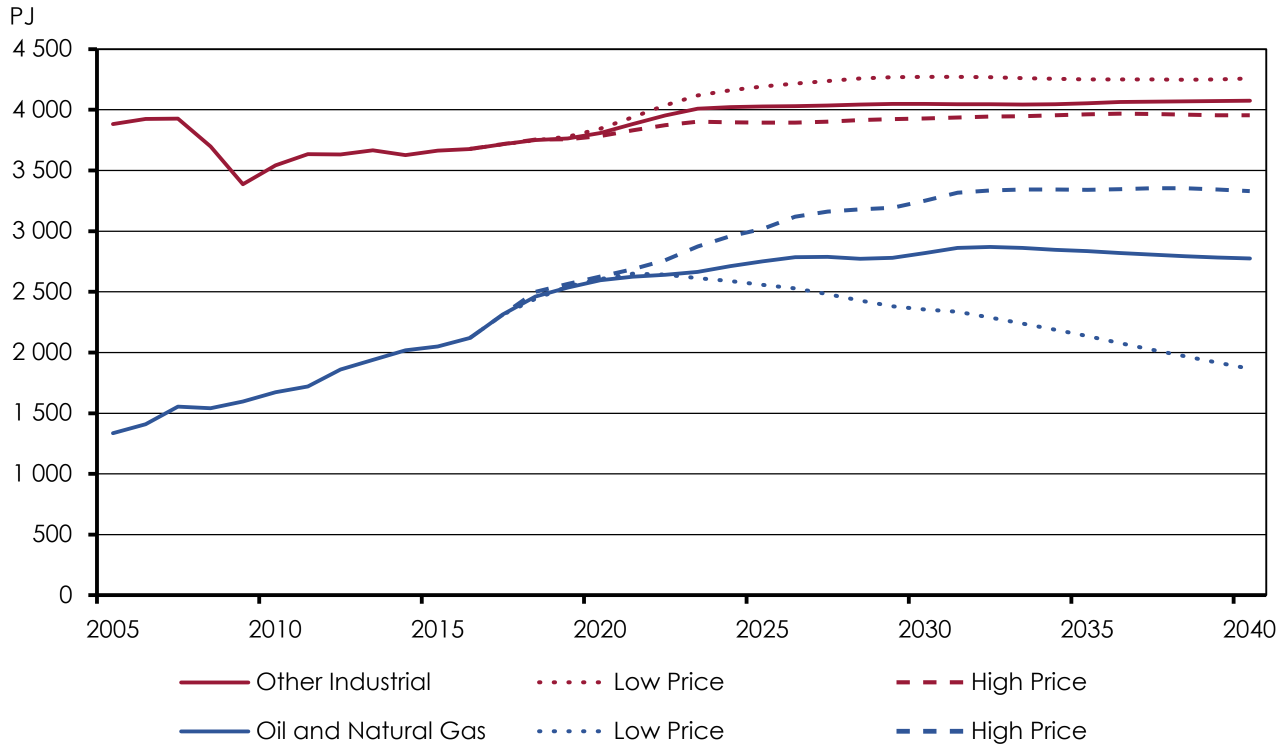
Figure 3.4: Industrial Energy Demand by Fuel, Reference Case



In 2040, Industrial demand in the High Price Case is over 6% higher than the Reference Case, while the Low Price Case is over 10% lower than the Reference Case. These differences are largely due to the changes in the oil and gas production trends between the Cases. In the High Price Case, energy demand for these sectors is 20% higher than the Reference Case in 2040. In the Low Price Case, it is 30% lower than the Reference Case in 2040.

Figure 3.5 emphasizes how energy demand in the oil and gas sector is quite responsive to the alternate price Cases. Energy use in the other industrial sectors is less responsive to the differences in oil and natural gas price. In the other industrial sectors, higher prices put downward pressure on demand, while lower prices lead to higher levels of energy use.

Figure 3.5: Oil and Natural Gas Sector and Other Industrial Energy Demand, All Cases

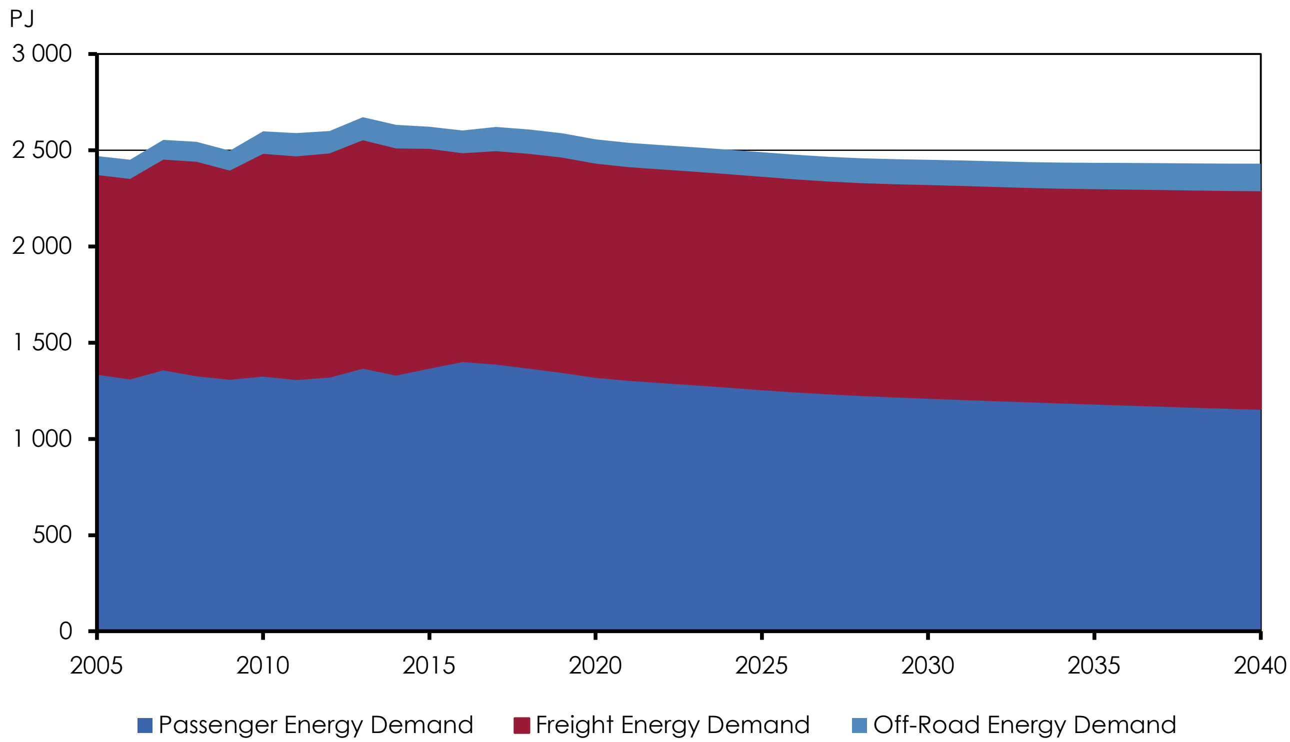


Transportation

The transportation sector includes passenger and freight on-road transportation, as well as air, rail, marine, and non-industrial off-road travel, such as recreational all-terrain vehicles and snowmobiles. The transportation sector made up 23% of total end-use demand in 2017. After increasing steadily for the past 26 years, transportation demand declines slowly over the projection period, from 2 620 PJ in 2017 to 2 430 PJ in 2040.

Figure 3.6 shows passenger and freight transportation demand projections to 2040. At 1 404 PJ, passenger transportation was 53% of total transportation demand in 2016 while freight made up 42% with 1 080 PJ and off-road made up 5% with 115 PJ. Passenger demand declines to 1 156 PJ in 2040. Freight transportation remains relatively flat throughout the outlook, increasing slightly to 1 130 PJ, leading the way for a convergence of passenger and freight shares of transport demand around 47%. Off-road travel demand increases to 143 PJ in 2040, where its share of transport demand rises to 6%.

Figure 3.6: Passenger and Freight Transportation Demand



In addition to the effect of rising transport costs emerging from higher carbon and energy prices, several other factors exert downward pressure on transport demand over the projection period. The primary reason is vehicle emissions standards. Canada enacted passenger vehicle GHG emission standards that extend from 2012 to 2025, and more recently GHG emission standards for medium and heavy-duty vehicles. Both standards mandate fuel economy improvements in vehicles sold in their respective periods, reducing fuel demand. Macroeconomic factors influencing transportation demand, such as GDP, population, and income, generally grow slower than historical levels, as discussed earlier. A modest uptake in electric vehicles (EVs) also contributes to demand reductions because of the relative efficiency of EVs to internal combustion engine (ICE) vehicles. The Technology Case, discussed in Chapter 4, provides an analysis of greater EV adoption.

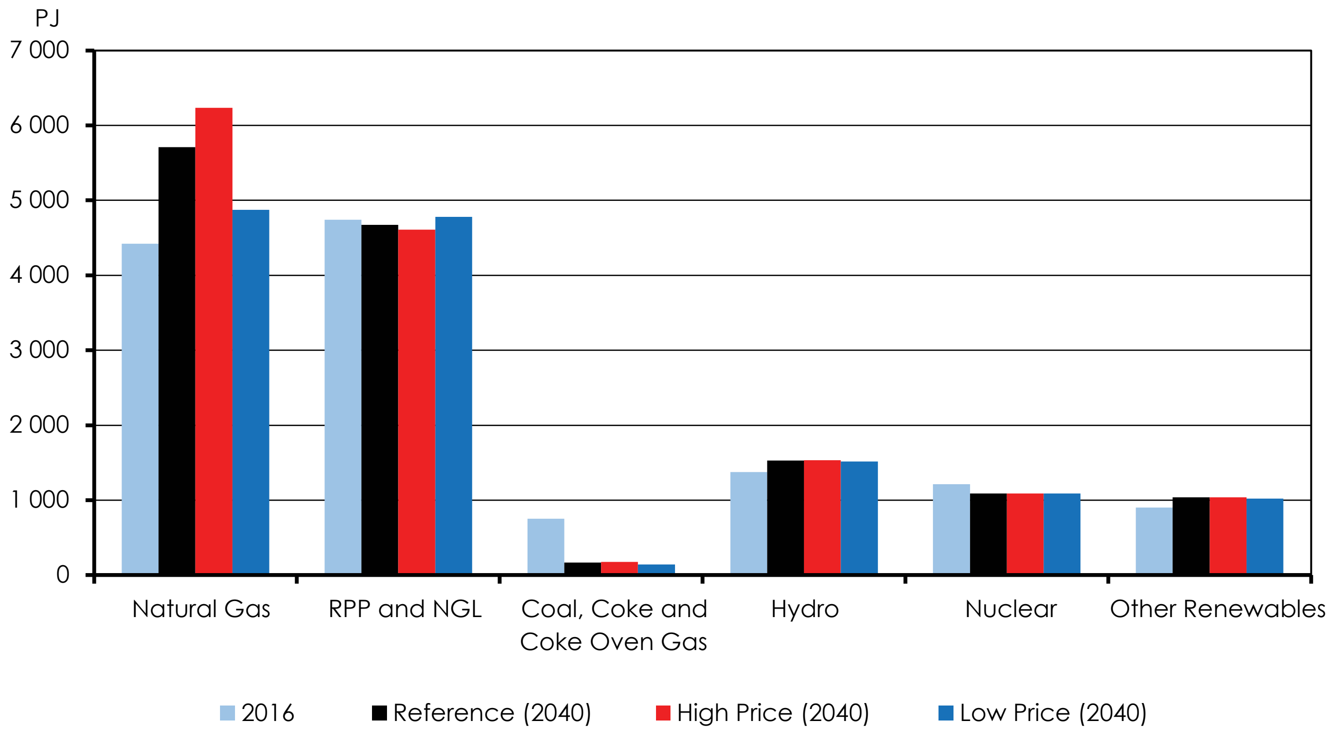
Primary Demand

In this analysis, primary demand is the total amount of energy used in Canada. In addition to end-use demand, it includes the energy required to generate electricity. Primary demand is calculated by adding the energy used to generate electricity to total end-use (or secondary) demand, and then subtracting the end-use demand for electricity.

In the Reference Case, primary energy demand increases at an average annual rate of 0.2% over the projection period, reaching 14 201 PJ in 2040.

As shown in Figure 3.7, the share of natural gas increases the most, a result of natural gas use for power generation and in oil sands production. Coal's share of primary demand falls considerably due to declining coal-fired power generation.

Figure 3.7: Primary Energy Demand, Reference, High Price and Low Price Cases



Differences in primary demand in the Reference and Price Cases are driven mainly by the natural gas used to fuel variable oil and gas production trends. In the High Price Case, increased oil and gas activity drives primary energy demand to 14 680 PJ, 3.3% above Reference Case levels. In the Low Price Case, lower activity reduces primary demand to 13 423 PJ, 8.6% lower than Reference Case levels. Energy intensity, measured as energy use per unit of economic activity, declines steadily in all three Cases.

Key Uncertainties

- **Technological influences:** The impacts of technology on the energy system can be substantial and often difficult to predict. EF2018 Reference Case assumes modest growth of emerging technologies. However, the Technology Case, discussed in Chapter 4, explores this uncertainty by analyzing the impact of a greater uptake of a selection of emerging technologies on the energy system.
- **Oil and natural gas industry transformations:** In recent years, the oil and natural gas industry has undergone rapid transformations in both the types of resources extracted and the technologies used to extract them. Depending on the future development of these resources and technologies, the energy used in this sector may be higher or lower than these projections. The most notable example of this would be the trend of the steam to oil ratio (SOR) for in situ oil sands development, which will have a substantial effect on future natural gas demand in Alberta.
- **The mining sector:** Mining introduces significant uncertainty to the energy demand projections. The development of a variety of announced projects can be uncertain due to market developments. Energy requirements for mines also vary on a project-by-project basis creating additional uncertainties, particularly for electricity demand in regions where mining is a significant portion of economic activity.
- **Climate policies:** Several measures are announced but are currently in initial stages of development, such as the proposed Canadian Clean Fuel Standard. These could impact energy trends as they are implemented. Likewise, small or large changes to existing policies, or changes in policy direction, could also impact the trends shown in the Reference Case projections. For example, there is potential for the Canada's projected automobile emission standards to change as it reviews its current light duty vehicle standards and the proposed heavy duty standards, which would impact transportation demand projections.

Crude Oil Production

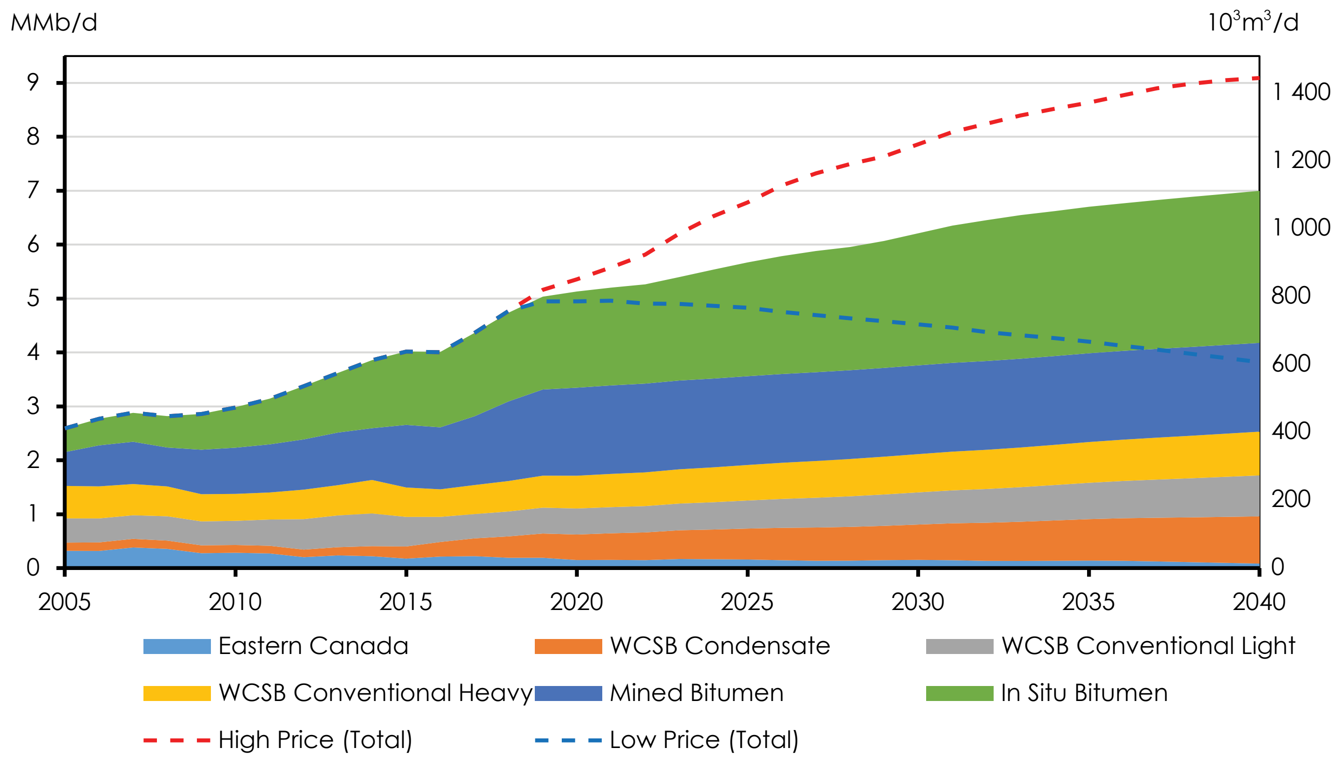
Canada produces crude oil for domestic refining as well as for exports. In 2017, Canadian crude oil production averaged over 4.4 million barrels per day (MMb/d) (693 thousand cubic metres per day ($10^3m^3/d$)). Over the first five months of 2018, this number rose by over 6% to 4.64 MMb/d (738 $10^3m^3/d$) as new oil sands facilities began producing for the first time and output from conventional oil plays continued increasing after two years of declines.

By 2040 Canadian crude oil production in the Reference Case is 6.9 MMb/d (1 098 $10^3m^3/d$). This is 58% higher than 2017 levels of 4.4 MMb/d (693 $10^3m^3/d$). Figure 3.8 shows crude oil production by type in the Reference Case and total production in High and Low Price Cases.

Key Trends: Crude Oil Production

- Crude oil production increases over 50% from 2017 by 2040.
- Growth in oil sands largely due to expansions of existing facilities.
- Global and benchmark prices, takeaway capacity, and technology are key uncertainties.

Figure 3.8: Total Canadian Crude Oil and Equivalent Production, Reference, High Price and Low Price Cases



In the High Price Case, total oil production reaches 9.1 MMb/d (1 446 $10^3m^3/d$) by 2040, 30% higher than in the Reference Case. Total oil production in the Low Price Case decreases over the projection period and at 3.8 MMb/d (607 $10^3m^3/d$) in 2040 is 45% lower than the Reference Case.

Crude Oil Ultimate Potential and Established Reserves

Table 3.2 shows Canada's remaining ultimate potential and established crude oil reserves. At 329 billion barrels (BBL) (52.3 billion cubic metres (10^9m^3)), Canada's remaining ultimate potential is considerable. Of this, 92% are found within the bitumen resources of the oil sands. The remaining share is from conventional, tight and shale oil deposits elsewhere in Canada, both onshore and offshore.

When a company can demonstrate that a resource can be recovered economically, that resource becomes a reserve. Canada's reserves are very large, at 170 BBL (27 10^9m^3). This is because so much of the resource is located within the oil sands, where the reservoir and extraction techniques are relatively well understood. Almost 55% of oil sands resources are considered reserves. The ratio of resources to reserves in the rest of Canada range from 32% in the western Canadian sedimentary basin (WCSB) to less than 1% in northern Canada.

Table 3.2 – Canada's Remaining Ultimate Potential and Established Crude Oil Reserves

	WCSB[a]	Eastern Canada	Northern Canada[b]	Oil Sands	Canada Total
	Remaining Ultimate Potential[c]				
10^6m^3	1 358	1 069	1 644	48 193	52 264
Billion Barrels	9	7	10	303	329
	Remaining Established Reserves[c]				
10^6m^3	440	260	8	26 284	26 992
Billion Barrels	3	2	0	165	170

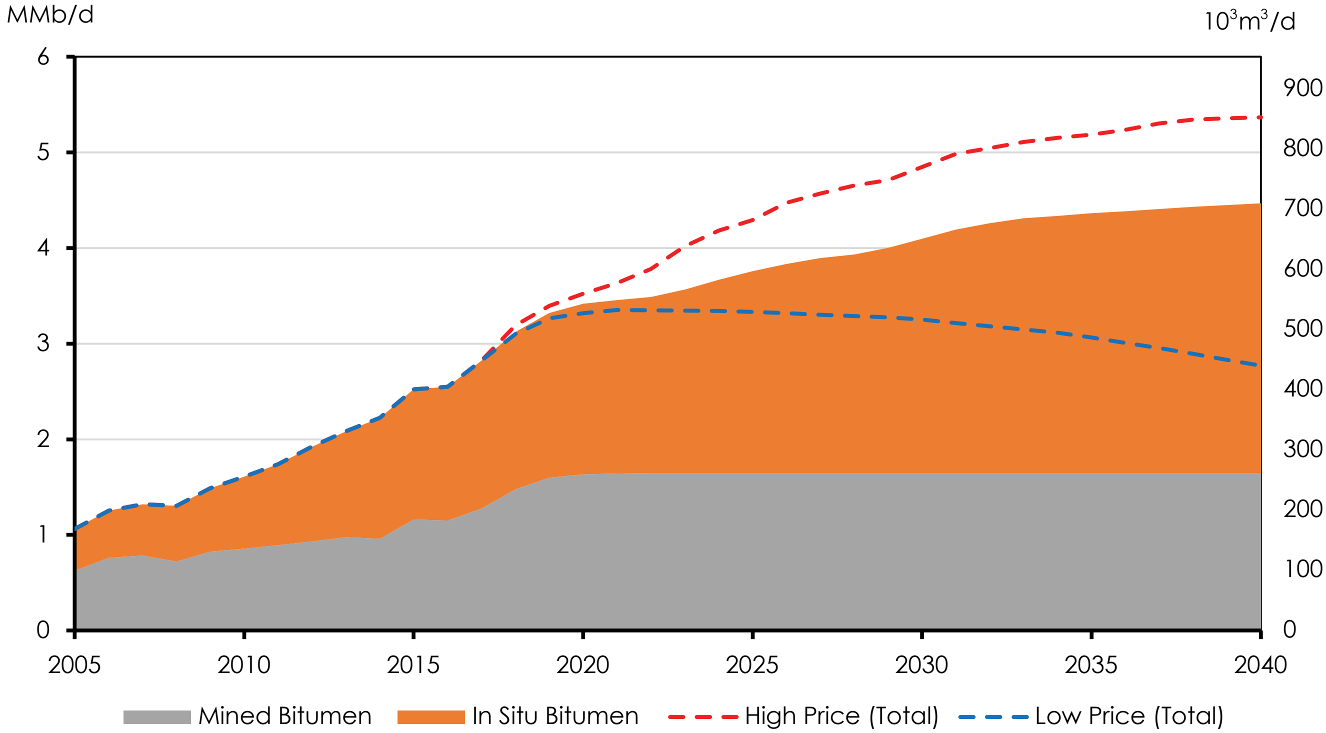
a - Includes B.C., Alberta, Saskatchewan and Manitoba. For the purposes of this table, all resources and reserves from the territories are included under northern Canada.
b - Includes onshore and offshore resources and reserves from Northwest Territories, Yukon and Nunavut.
c - Due to the lack of current data on reserves, some regions have been calculated based on prior year known values and cumulative production.

Oil Sands

Raw bitumen production hit a record high 2.8 MMb/d (449 10^3m^3/d) in 2017 as projects sanctioned before the 2014 to 2016 crude oil price decrease came online and other existing projects increased their output through technological and efficiency improvements. Figure 3.9 shows oil sands production for the Reference, High and Low Price Cases over the projection period. In the Reference Case, oil sands production reaches 4.5 MMb/d (710 10^3m^3/d) by 2040 which is 58% higher than current output.

Growth in oil sands production is largely due to expansions of existing in situ facilities with comparatively less coming from new projects. Overall in situ production increases 82% by 2040 compared to 2017. While there are no new mining projects assumed to be constructed over the projection period, expansions of producing mines are expected to lead to a 29% increase in mined bitumen output by 2040.

Figure 3.9: Oil Sands Production, Reference, High Price and Low Price Cases

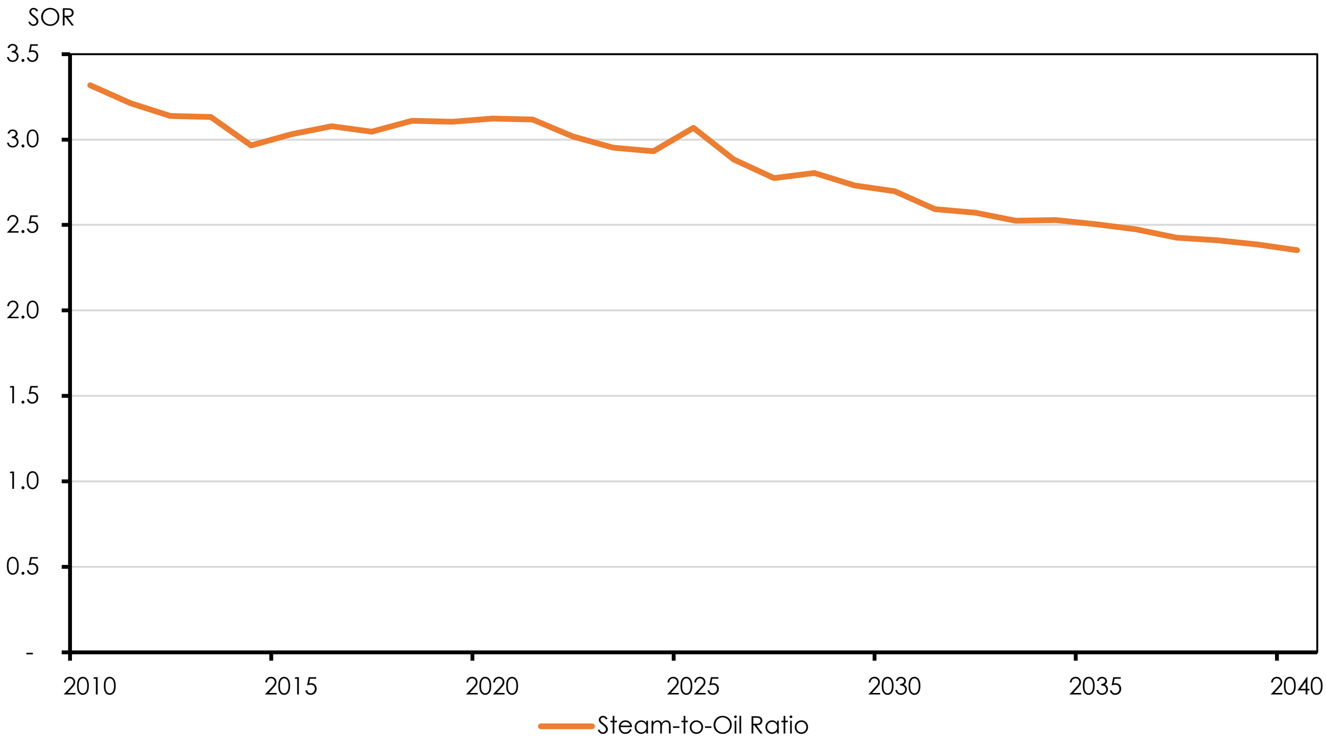


In the High Price Case, total bitumen production reaches 5.4 MMb/d (853 10^3m^3/d) by 2040. In situ production increases steadily and significantly in this Case, reaching 3.5 MMb/d (553 10^3m^3/d) by 2040, 125% higher than in 2017. As a result of cost inflation in the oil industry that would likely be associated with the high oil prices in this Case, no new mines are constructed. Mining production, however, does increase by 48% from 2017 levels through expansion of existing facilities. Total production in the Low Price Case increases in the near term, peaking at 3.4 MMb/d (533 10^3m^3/d) in 2021 as projects currently under construction are completed and brought online. Output in this Case falls thereafter as the low oil price is insufficient to incent companies to invest in new projects to offset declines in existing projects. Production by 2040 reaches 2.8 MMb/d (440 10^3m^3/d), nearly identical to 2017 levels.

Gradual technological and efficiency improvements are assumed to occur at both mining and in situ projects over the course of the projection. For the Reference, High, and Low Price Cases major breakthroughs, such as the employment of steam displacement or partial upgrading technologies, are not taken into account. Impacts of improved technology are explored in Chapter 4.

SOR represents the amount of steam required to produce one barrel of bitumen from an in situ well. SOR is a way to measure the environmental performance of oil sands projects. Figure 3.10 shows the average historical and projected SOR for all in situ projects in the Reference Case. Improvements in the way the steam is generated and the moderate adoption of steam displacement techniques over the course of the projection period lead to steady improvements in SOR. In the medium term there is a slight increase in SOR as new projects are brought online. By 2040 the industry average SOR is expected to fall 25% to 2.4.

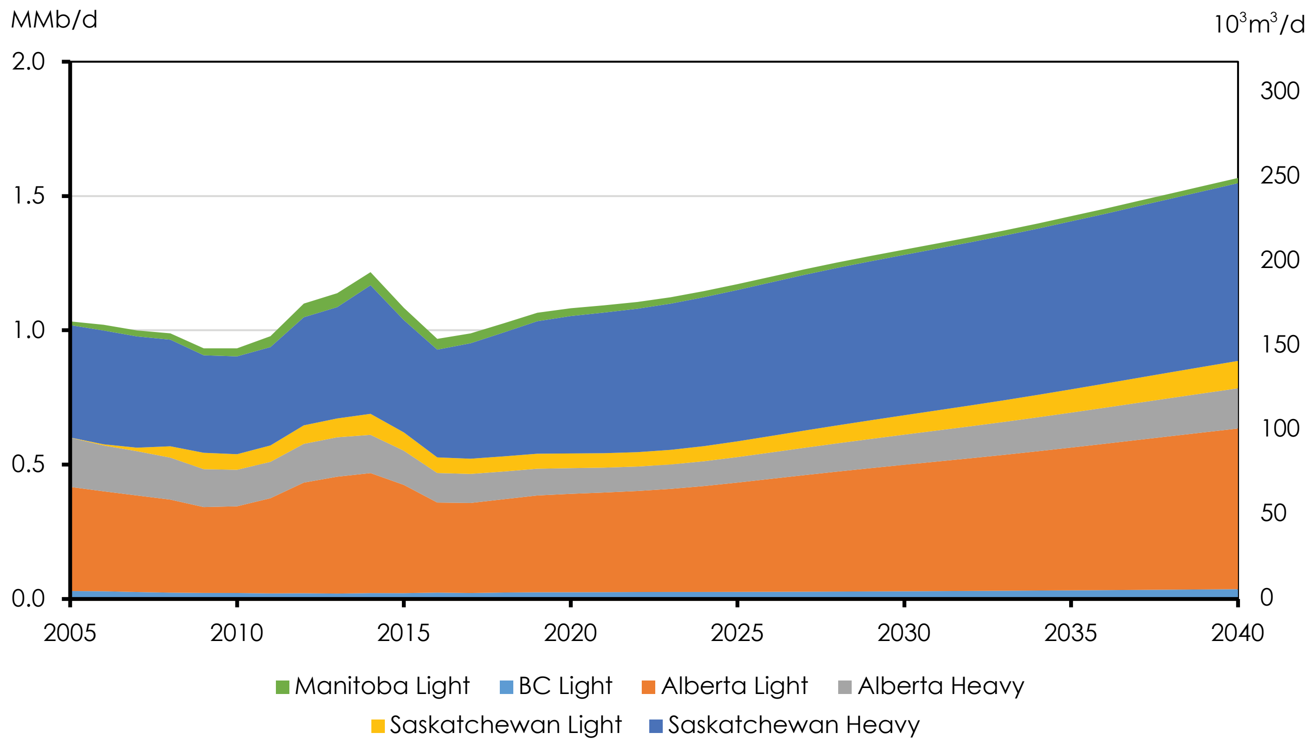
Figure 3.10: Steam to Oil Ratios, Reference Case



Western Canadian Conventional Crude Oil

Total production of conventional oil in western Canada was 0.99 MMb/d (157 $10^3m^3/d$) in 2017, accounting for 23% of all crude oil produced in Canada. Conventional production is classified as light or heavy, depending on the API gravity of the oil. In 2017, 54% of western Canadian conventional production was heavy, 46% was light. Figure 3.11 shows total conventional production in western Canada over the projection period.

Figure 3.11: Conventional Oil Production by Type, Reference Case



Alberta light and Saskatchewan heavy make up the majority of conventional production through the projection period in the Reference Case. At 0.60 MMb/d (95 $10^3m^3/d$), Alberta light accounts for 29% of total western conventional crude production by 2040. Saskatchewan heavy production, reaching 0.66 MMb/d (105 $10^3m^3/d$) by 2040, represents 32%. Figure 3.11 shows conventional oil production for the Reference Case over the projection period.

Heavy oil production growth in Saskatchewan is a result of the application of steam assisted gravity drainage (SAGD) production techniques to heavy oil fields. Similar to the oil sands, production from these thermal projects does not exhibit the steep decline rates typical of other conventional heavy oil wells. This contributes to the attractiveness of this type of production, leading to steady growth over the projection period.

After declining in 2016 due to low oil prices, production of light conventional oil, including condensate, rebounded to reach 0.77 MMb/d (126 $10^3m^3/d$) in 2017. Lower prices over the last three years lead to essentially flat production in the first five years of the projections. After 2022, production begins to rise and by 2040 is 1.2 MMb/d (193 $10^3m^3/d$) in the Reference Case.

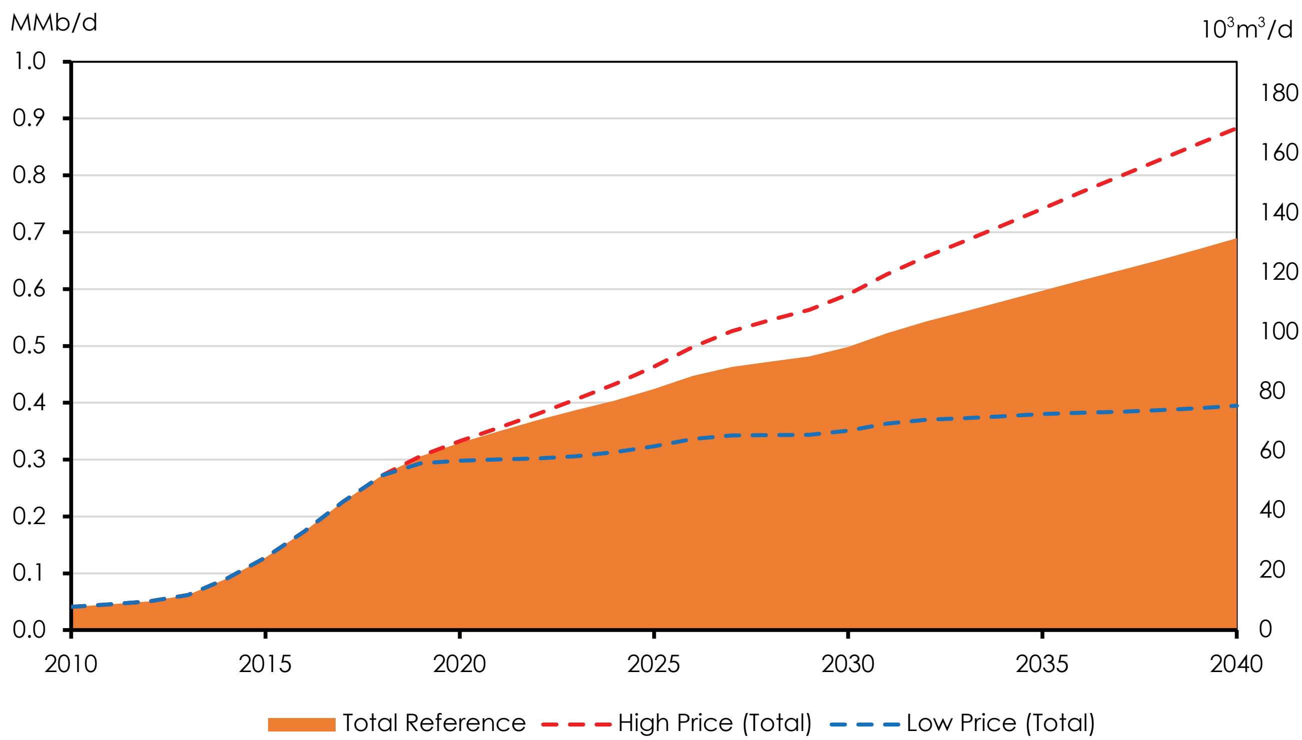
In the High Price Case, total conventional oil production, including condensate, reaches 3.4 MMb/d (533 $10^3m^3/d$) by 2040. In this case, higher crude oil prices are enough to more than offset field declines from existing wells. Conversely, in the Low Price Case cumulative production from existing wells declines faster than it can be replaced by newer wells and total production falls to 0.76 MMb/d (120 $10^3m^3/d$).

Condensate

Nearly all the condensate produced in Canada comes from B.C. and Alberta. Condensate comes primarily from natural gas wells and is removed from the gas stream either at the well head or at processing plants before the gas is sent to its intended market. Once removed, the condensate is used in a number of industrial processes, most notably as a diluent for bitumen and heavy oil.

Figure 3.12 shows condensate production projections in western Canada for the three Cases. Currently, the majority of condensate production comes from Alberta with the remainder coming from B.C. Operators' continued focus on liquids-rich natural gas plays like the Montney and Duvernay lead to substantial growth in condensate production in the projection period. Total production grows 205%, reaching 0.7 MMb/d (110 10^3m^3/d) by 2040. Alberta continues to produce the majority of condensate over the projection period. Higher natural gas drilling in the High Price Case leads to significantly higher condensate output and production climbs to 0.9 MMb/d (140 10^3m^3) by 2040, 291% higher than in 2017. In the Low Price Case, production grows 75% from current levels, reaching 0.4 MMb/d (63 10^3m^3/d) by 2040.

Figure 3.12: Western Canada Condensate Production, Reference, High Price and Low Price Cases



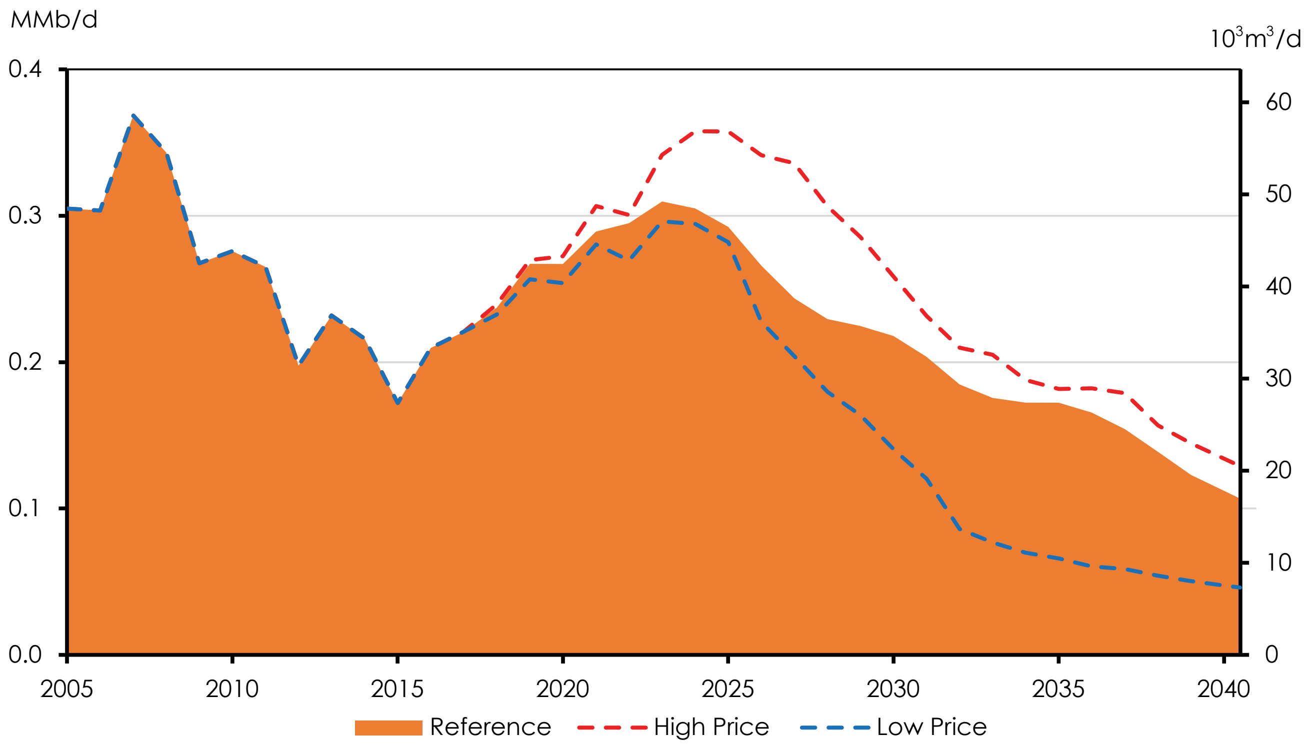
Newfoundland Offshore

Offshore production in the Reference Case increases in the near term as Hebron continues to ramp up and new wells from existing facilities are brought online. Production peaks at 309 Mb/d (49 10^3m^3/d) in 2023 and declines through the projection thereafter, reaching 107 Mb/d (17 10^3m^3/d) in 2040. A new offshore discovery is assumed to add production in 2028, with a second new discovery in 2034. Figure 3.13 shows Newfoundland's oil production in the Reference, High and Low Price Cases over the projection period.

Hebron is the only project in Newfoundland's offshore that produces heavy oil. Other projects produce either light or medium grade oil. The new discoveries included in the Reference and High Price cases are assumed to be light oil. Heavy oil currently makes up 21% of Newfoundland's production and this proportion reaches as high as 50% within the projection period.

In the High Price Case new offshore production facilities are assumed to be constructed, supported by the increased price of crude oil. There are five fields of various sizes, two in the 2020s and three in the 2030s. Production in the High Price Case peaks at 358 Mb/d (57 10^3m^3/d) in 2024 and falls steadily thereafter reaching 129 Mb/d (21 10^3m^3/d) in 2040. In the Low Price Case there are no new discoveries assumed and production reaches a high of 296 Mb/d (47 10^3m^3/d) in 2023 and falls to 56 Mb/d (7 10^3m^3/d) by 2040.

Figure 3.13: Newfoundland Oil Production, Reference, High Price and Low Price Cases



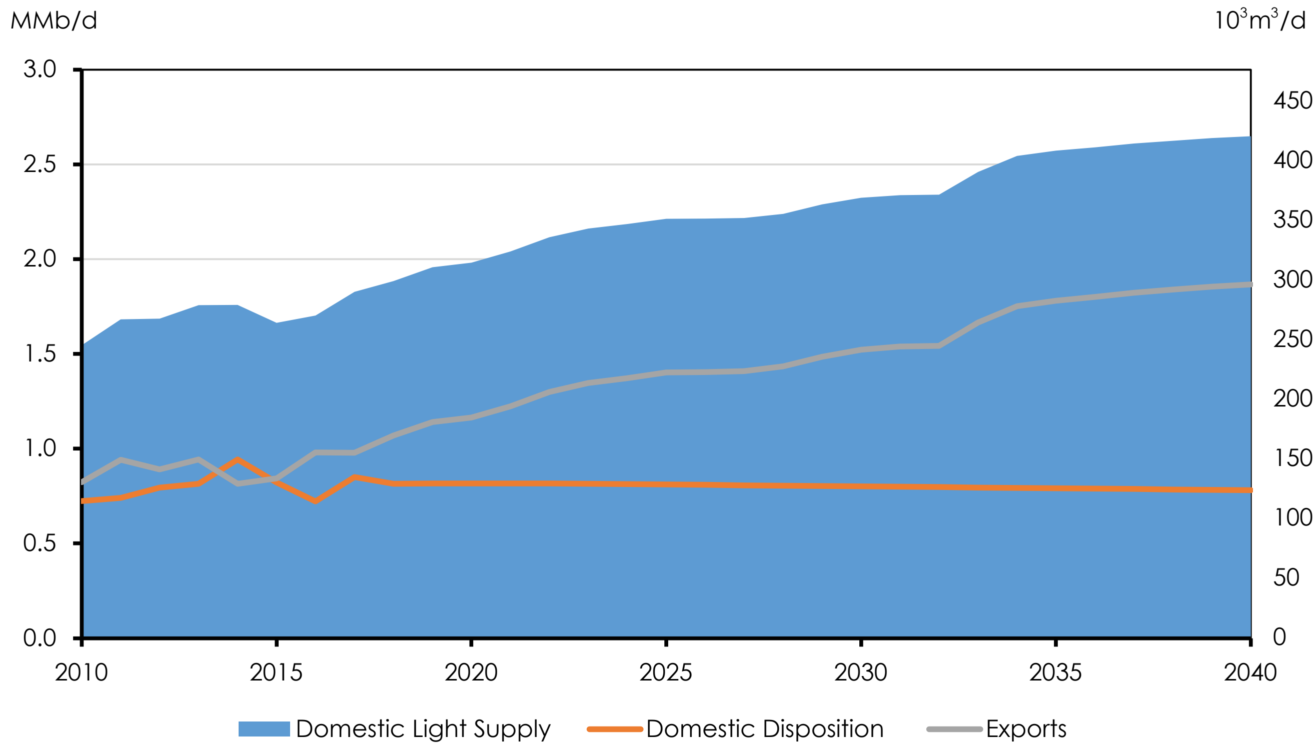
Crude Oil Supply and Demand Balance

All non-upgraded bitumen and nearly all conventional heavy oil must be blended with lighter hydrocarbons to reduce its viscosity and allow it to flow on pipelines. Bitumen that is transported by rail is generally blended as well, although sometimes at lower levels than for pipelines. The resulting blend of produced crude oil or bitumen, after accounting for production losses and any diluent recycling, is the net oil supply available for domestic and foreign markets.

Domestic disposition is the volume of Canadian crude oil that is required for feedstock at Canadian refineries. This volume is influenced by a number of factors such as refined product demand and the amount of foreign oil that is processed within Canada. Economics at any particular refinery dictate whether that facility uses Canadian or foreign oil to produce the refined petroleum products needed to meet Canadian demand.

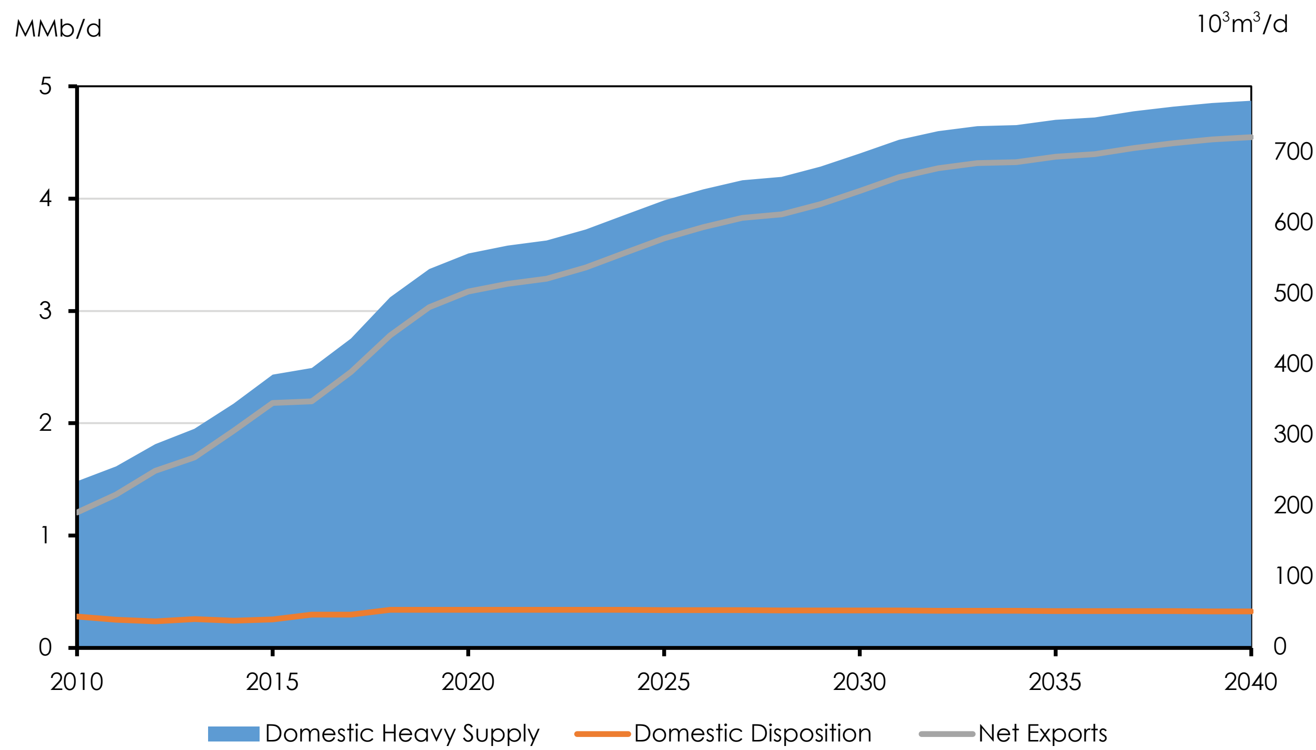
Exports of crude oil are the difference between the net available oil supply and the domestic disposition.

Figure 3.14: Supply and Demand Balance, Light Crude Oil, Reference Case



Exports of light crude oil grow throughout the projection period in the Reference Case, along with rising conventional light oil production. Figure 3.14 shows the supply and demand balance of light crude oil in the Reference Case over the project period. Exports reach 1.87 MMb/d (297 10^3m^3/d) in 2040. Exports increase sharply in 2033 as a number of in situ facilities are assumed to redirect their bitumen output to be processed through upgraders instead of being marketed as diluted bitumen.

Figure 3.15: Supply and Demand Balance, Heavy Crude Oil, Reference Case



Exports of heavy crude oil rise throughout the projection period in the Reference Case, reaching 4.55 MMb/d (723 10^3m^3/d) by 2040, 85% above 2017 levels. The increase is primarily because of increased blended bitumen production from new and expanded in situ projects and mining operations. Increases in conventional heavy oil also contribute to the increase. Figure 3.15 shows the supply and demand balance of heavy crude oil in the Reference Case over the projection period.

Key Uncertainties

- **Future oil prices:** Oil prices are a key driver of future Canadian oil production and a key uncertainty to the projections in EF2018. Oil prices could be higher or lower depending on demand and policy trends, technological developments, geopolitical events, and differentials between benchmark prices as discussed in Chapter 2.
- **Thermal recovery techniques:** The application of these techniques to Saskatchewan's heavy oil resources is a recent trend. Though promising, the impact of these techniques on future production growth is uncertain.
- **The pace of technological development in the oil sands:** EF2018 assumes gradual technological improvement in the sector and a more or less rapid technology development could impact the oil sands production projections. Potential advances that could change the supply projections include solvent-based processes, other steam-reduction technologies, and electrification.
- **Potential partial upgrading facilities:** The Alberta government has recently announced its intention to encourage construction of partial upgrading facilities in the province. This program could affect producers for a few reasons. Partially upgraded bitumen does not need to be mixed with diluent to flow in pipelines, which would reduce the costs of buying diluent like condensate. Without diluent, the total volume shipped would fall and ease congestion. Pipeline bottlenecks would improve and fewer barrels of oil would need to be shipped by rail, which is more expensive. Meanwhile, partially upgraded bitumen has a higher quality than non-upgraded bitumen. As such, it could receive a higher price, but it would have to compete with similar quality crudes for limited refining capacity, which potentially limits the benefits to producers.

Natural Gas Production

Canadian natural gas is produced for use domestically, as well as exported to the U.S. Canadian marketable natural gas production averaged 15.6 billion cubic feet per day (Bcf/d) or 442 million cubic metres per day ($10^6m^3/d$) in 2017 and 16.2 Bcf/d (460 $10^6m^3/d$) over the first half of 2018.

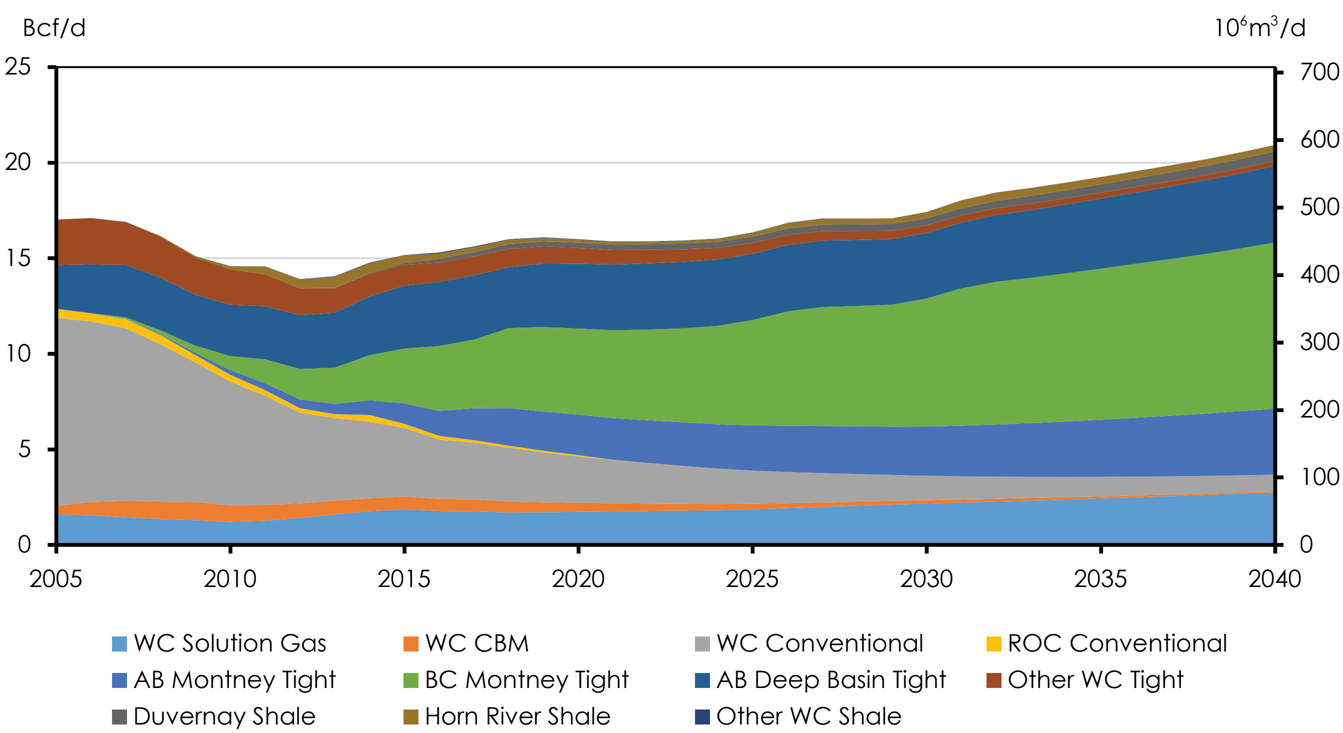
Natural gas production in the Reference Case declines early in the projection period, reaching a low of 15.9 Bcf/d (450 $10^6m^3/d$) in 2021. After 2021, production begins to increase as gradually higher prices encourage enough drilling to offset production declines from older wells, and development associated with assumed LNG exports support increased capital spending. This leads to more natural gas wells and production in the WCSB. By 2040, production increases to 20.9 Bcf/d (593 $10^6m^3/d$).

Figure 3.16 shows total Canadian natural gas production by type in the Reference Case. Production from the Montney Formation, a large resource located in northeast B.C. that extends into northwest Alberta, has grown significantly over the past five years. Production of tight gas from the Montney increased from no production prior to 2006 to 34% of total Canadian natural gas production in 2017, almost 5.3 Bcf/d (149 $10^6m^3/d$). The majority of production growth over the projection period comes from the Montney, with production reaching 12.1 Bcf/d (344 $10^6m^3/d$) in 2040, a 131% increase from 2017.

Key Trends: Natural Gas Production

- Natural gas production declines in the near term due to lower prices.
- Production increases in the long term with assumed price increases and LNG exports.
- Majority of the production growth comes from the Montney formation.

Figure 3.16: Natural Gas Production by Type, Reference Case



The Alberta Deep Basin–a tight gas play which runs along the Alberta foothills–produced 3.4 Bcf/d (95 10^6m^3/d) in 2017. Production grows modestly as natural gas and NGL prices increase, reaching 4.0 Bcf/d (114 10^6m^3/d) by 2040 in the Reference Case.

The Duvernay and Horn River shale gas plays currently produce small amounts of natural gas, and production from both grows modestly over the projection period. The Duvernay is an emerging shale play in Alberta that contains natural gas, NGLs, and crude oil. The Horn River play lacks NGLs, reducing its attractiveness compared to other areas. Combined, production from the two plays increases from 0.5 Bcf/d (14 10^6m^3/d) in 2017 to 0.9 Bcf/d (24 10^6m^3/d) by 2040 in the Reference Case.

Production from conventional and coalbed methane natural gas resources–which do not rely on horizontal drilling and multi-stage hydraulic fracturing–declines steadily over the projection period as new drilling targeting these resources is not economic given the natural gas price assumptions in EF2018. Western Canadian conventional non-tight production, which made up 61% of total production in 2007 and 23% in 2017, falls to 4% in 2040 in the Reference Case.

Solution gas is steady over the projection period, following the trends in projected conventional oil production. Solution gas accounted for 11% of total production in 2017, and increases to 13% in 2040, from 1.8 Bcf/d (50 10^6m^3/d) to 2.7 Bcf/d (78 10^6m^3/d) in 2040 in the Reference Case.

Figure 3.17: Natural Gas Production by Province, Reference Case

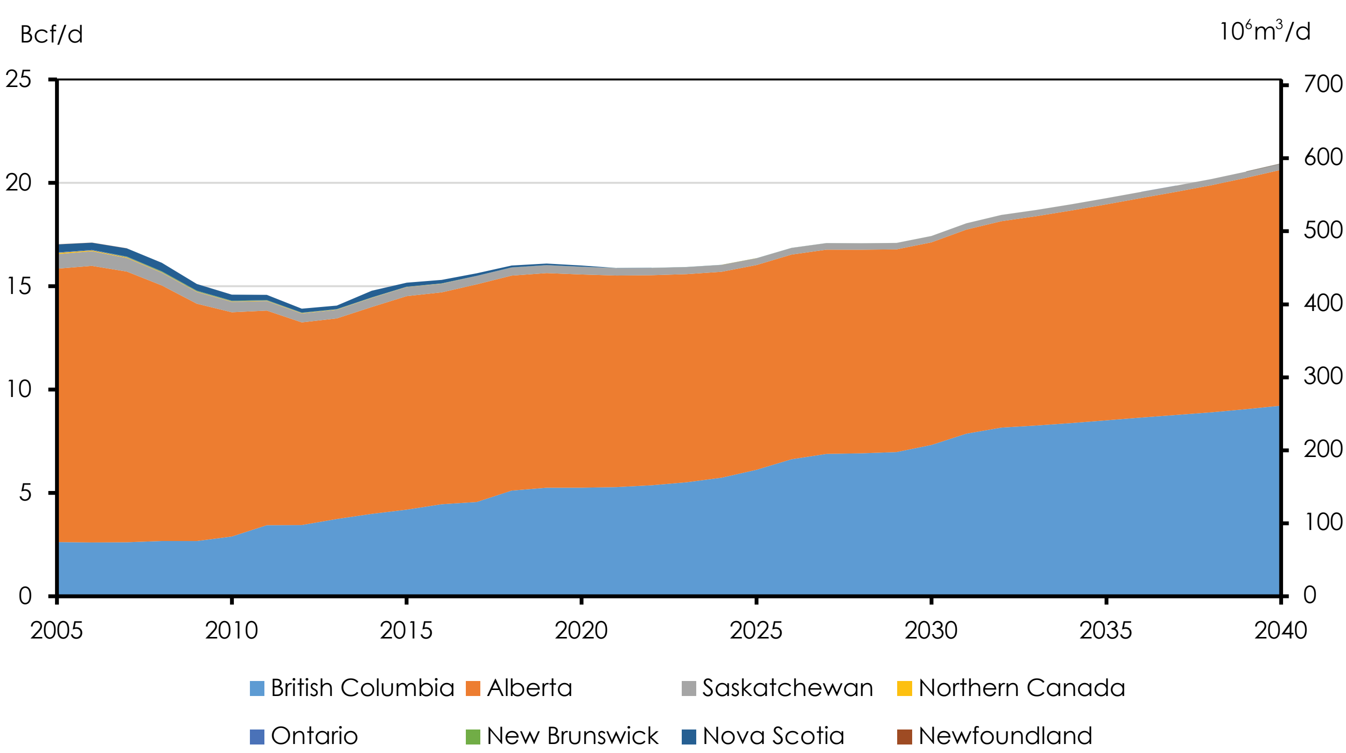
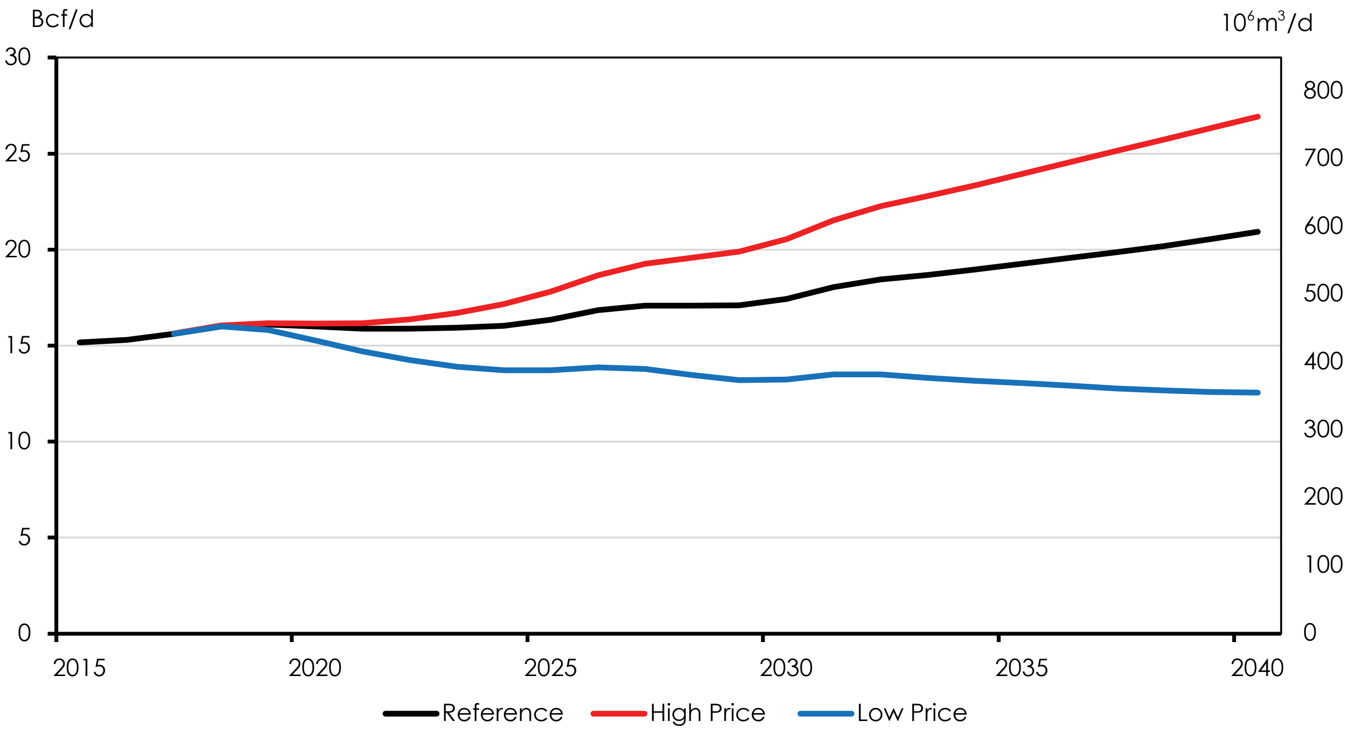


Figure 3.17 shows natural gas production by province in the Reference Case. Natural gas production in eastern Canada continues to decline over the projection period. Onshore natural gas production in New Brunswick falls to near zero by 2040. Offshore natural gas production in Nova Scotia declines steadily and is terminated in December 2020 as production ceases for both the Sable and Deep Panuke, whose declining production renders them uneconomic by that time.

Figure 3.18 shows total Canadian natural gas production in the Reference, High and Low Price Cases. Natural gas production in the High Price Case averages 26.7 Bcf/d (755 10^6m^3/d) in 2040, or 27% higher than the Reference Case. Western Canada's significant resource base, coupled with higher prices, encourages more drilling activity throughout the projection period. Canadian production in the Low Price Case declines until 2025 when assumed LNG exports reverse this trend. After 2025, production is relatively flat, reaching 12.6 Bcf/d (355 10^6m^3/d) by 2040, 40% lower than the Reference Case.

Figure 3.18: Canadian Natural Gas Production, Reference, High Price and Low Price Cases



LNG

As outlined in Chapter 2, the analysis in EF2018 assumes LNG exports start in 2025. Exploration and development spending associated with LNG exports support higher capital expenditure above what it would otherwise be. This leads to more natural gas wells and production in the WCSB. This LNG export assumption is the same for all cases[13].

Net Natural Gas Exports

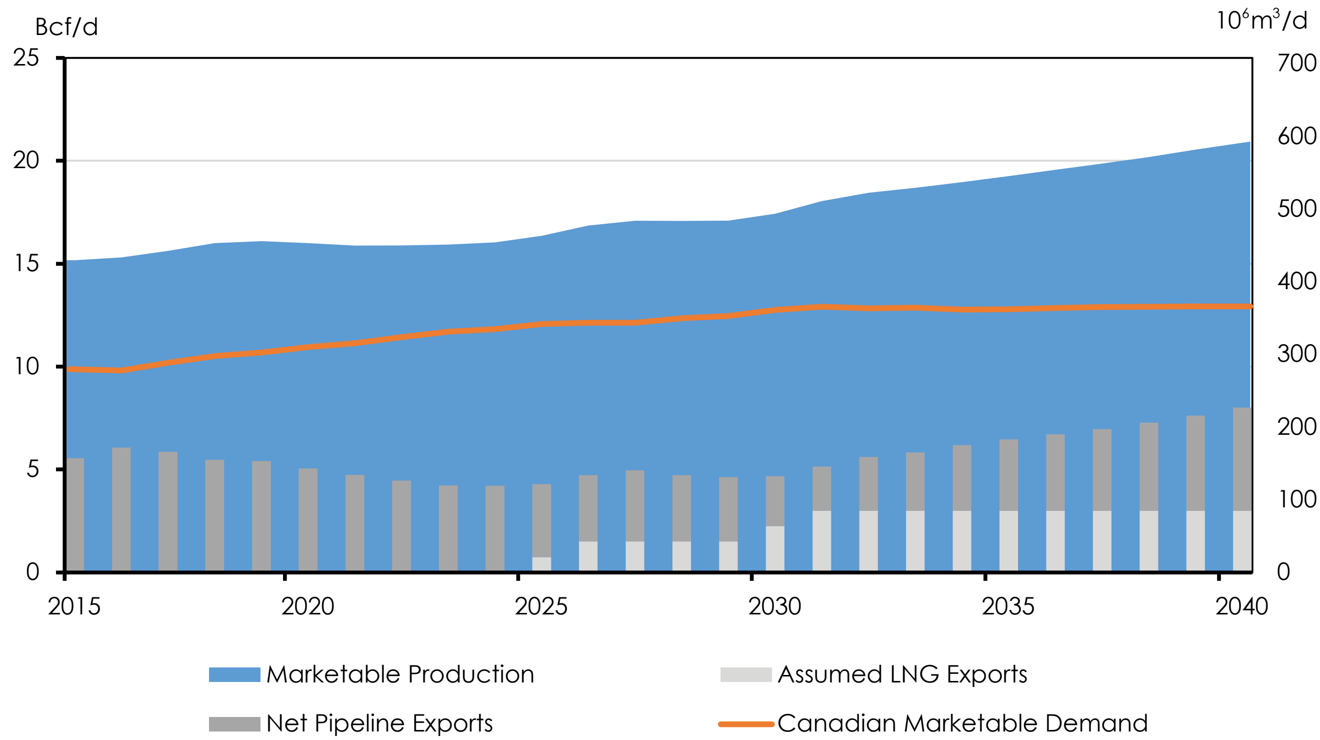
Natural gas exports have increased over the last few years, mostly due to exports into the western U.S. going from 7.4 Bcf/d (210 10^6m^3/d) in 2015 to 8.2 Bcf/d (233 10^6m^3/d) in 2017. Imports have remained modest over the last decade, hovering around 2 Bcf/d (55 10^6m^3/d). Imports could potentially rise as pipeline capacity increases out of the Appalachian Basin in the northeast U.S. into Dawn, Ontario. The difference between exports and imports is net exports, which has increased slightly over the last few years.

Projected net pipeline exports shown in Figure 3.19 is Canadian production less Canadian demand[14]. Near to mid-term Canadian natural gas demand growth leads to shrinking net exports. As production ramps up after 2023, production growth starts to outpace demand growth and net exports rise. LNG exports contribute to growth in net exports beginning in 2025.

13 For further analysis on how different LNG export assumptions might change the outlook, see the LNG Cases in EF 2016.

14 This value of natural gas demand is lower than the primary natural gas demand value discussed earlier because it does not include non-marketed natural gas used directly by those that produce it. Examples of this include flared gas, natural gas produced and consumed by in situ oil sands producers, and natural gas produced and consumed by offshore oil production.

Figure 3.19: Natural Gas Production, Demand, Assumed LNG Exports and Net Pipeline Exports



Key Uncertainties

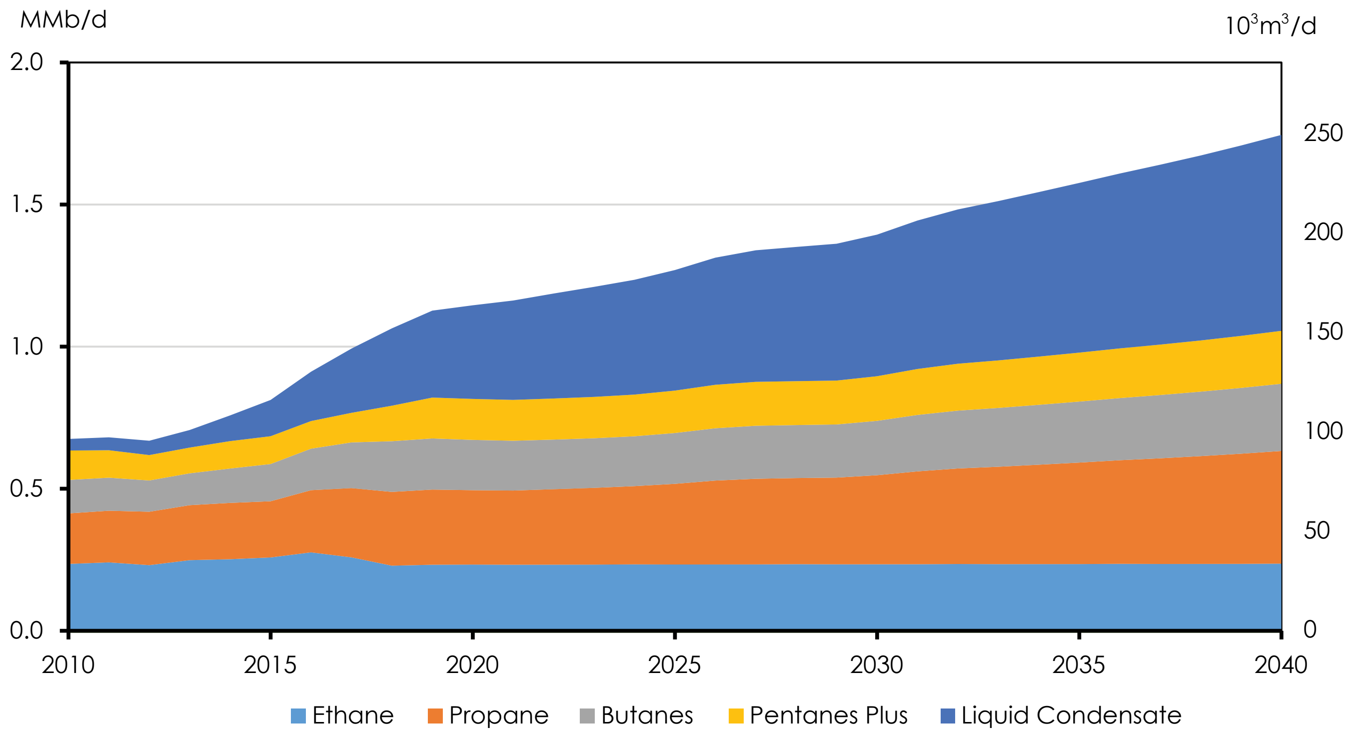
- **Future natural gas prices:** The High and Low Price Cases show how production could change given large price differences from the Reference Case. Prices could be different than assumed in any of these cases, which would lead to different production results.
- **Canadian natural gas discounts:** This analysis assumes that over the long term, all energy production will find markets and infrastructure will be built as needed. Extended differentials for Canadian natural gas relative to Henry Hub could reduce gas production in the longer term.
- **LNG exports:** It is possible that global market conditions and the costs of commissioning a new LNG export facility or phase may change in the future, influencing the future prospects of LNG exports in Canada.

Natural Gas Liquids Production

NGLs are predominantly produced from processing natural gas, but some are also produced as a by-product of oil refining or bitumen upgrading. Raw natural gas at a wellhead is comprised primarily of methane, but often contains other hydrocarbons and some contaminants. These other hydrocarbons may include ethane, propane, butanes, condensate and other pentanes. In 2017, 997 Mb/d (159 10^3m^3/d) of NGLs were produced in Canada.

Total NGL production levels off in the near term. Although gas production slightly declines, NGLs per unit of gas produced increases as producers increasingly target areas rich with NGLs, such as the Duvernay shale and Montney tight gas play. NGL production then increases steadily throughout the projections as natural gas production increases. Aggregate NGL production increases by 75% over the projection period, to 1.7 MMb/d (278 10^3m^3/d) in 2040. Figure 3.20 shows total NGL production in the Reference Case.

Figure 3.20: Natural Gas Liquids Production, Reference Case



Ethane, the majority of which is extracted at large natural gas processing facilities located on major natural gas pipelines in Alberta and B.C., made up 26% of NGL production in 2017, at 262 Mb/d (42 $10^3m^3/d$). Ethane production in the Reference Case increases slowly over the projection to 237 Mb/d (38 $10^3m^3/d$) in 2040, as its recovery from the natural gas stream is assumed to be related to the capacity of petrochemical facilities in Alberta that use it as a feedstock. The remainder of the ethane is reinjected back into the gas stream and sold as natural gas.

Propane production in the Reference Case follows the natural gas production projection. As natural gas production begins to increase, propane production begins to increase steadily, and reaches 397 Mb/d (63 $10^3m^3/d$) by 2040, 63% higher than 2017 levels of 244 Mb/d (39 $10^3m^3/d$).

Butanes production follows a similar pattern to natural gas production; 49% higher than 2017 levels by 2040, increasing from 161 Mb/d (26 $10^3m^3/d$) to 239 Mb/d (38 $10^3m^3/d$).

Production of pentanes plus is assumed to occur at natural gas processing plants, and does not include liquid condensate from the wellhead. Pentanes plus increases by 79%, from 104 Mb/d (17 $10^3m^3/d$) in 2017 to 186 Mb/d (30 $10^3m^3/d$) in 2040.

Liquid condensate is produced at the wellhead, and its demand is growing as oil sands production continues to grow. Condensate is added to bitumen to enable it to flow in pipelines and rail cars. Condensate demand has influenced gas drilling to focus on NGL-rich plays. Condensate production increased over 265% from 2013 to 2017. Of all the NGLs, condensate production grows the most over the projection period, increasing by 205%, from 226 Mb/d (36 $10^3m^3/d$) in 2017 to 689 Mb/d (110 $10^3m^3/d$) in 2040.

Petrochemicals

This term refers to chemical compounds that are generally made from oil and gas. Feedstocks derived from oil and gas are used in the production of a wide range of petrochemical product, including plastics and solvents. The six most basic petrochemicals are: ethylene, benzene, propylene, toluene, butadiene, and xylene. These are then used to make petrochemical derivatives which have a wide variety of uses.

There is potential for ethane and propane recovery to increase further if petrochemical production capacity, which uses these liquids as a feedstock, is added. The second phase of the Alberta Petrochemical Diversification Program (PDP II) could provide incentive to increase capacity. This program will provide up to a total of C$500 million of funding to selected applicants announced late 2018 or early 2019.

Key Uncertainties

- **Natural Gas**: NGLs are a by-product of natural gas production, and as such, any uncertainty discussed in the natural gas section is also an uncertainty for these NGL projections.
- **Oil Sands**: The rate of oil sands production growth, and proportion of bitumen that is partially or fully upgraded, will affect the demand for condensate required for diluent. Likewise, the use of solvents to reduce steam requirements in the oil sands could impact demand for propane and butanes and influence the degree they are targeted by future natural gas drilling.
- **LNG composition**: The composition of NGLs in LNG varies throughout the world and can be specified in the contracts underpinning a liquefaction facility, the energy content required by the LNG importer, and the gas composition of the feedstock gas used by the LNG exporter. EF2018 does not speculate on the specification of future LNG exports.
- **Petrochemical development**: There is potential for ethane and propane recovery to increase further if there is an increase in incremental petrochemical capacity requiring either as feedstock[15]. This potential looks most promising in Alberta due to the incentives included in its second phase of the PDP II.
- **Global Liquefied Petroleum Gas (LPG) export market**: Canada has approved several large-scale facilities to export LPG from B.C.'s coast and it is expected that propane will be the dominate liquid exported. However, these facilities would have the potential to ship butanes and future market developments could present a scenario where butanes is a viable export product. The composition of the LPG stream exported at these terminals could impact domestic NGL prices and the attractiveness of drilling for NGL-rich natural gas.

Electricity Generation

In 2016, installed electricity generation capacity in Canada reached nearly 146 GW. The electricity capacity mix varies significantly among provinces and territories, reflecting the type of energy available, economic viability, and policy choices. Hydroelectricity remains the dominant source of electricity, accounting for 55% of total capacity and 60% of total generation. Natural gas, nuclear, and coal are the most common sources of electricity generation after hydroelectricity, with non-hydro renewables such as wind, solar, and biomass making up the smallest portion of the capacity mix.

15 It is most likely than increased ethane feedstock demand would come through either the debottlenecking of an existing ethane cracker or construction of a new ethane cracker to produce polyethylene. A new cracker could increase ethane production in the range of 80 Mb/d. For propane, it is most likely that incremental feedstock demand would come through an increase in propane dehydrogenation capacity to produce polypropylene.

In 2016, Canadian electricity demand was 523.4 TW.h and accounted for 17% of total Canadian end-use energy demand. From 1990 to 2016, Canadian electricity demand increased by an average of 1% per year. In the Reference Case, electricity demand increases at an average annual rate of 0.8% over the projection period.

Key Trends: Electricity Generation

- Natural gas and renewable generation added, most nuclear will be refurbished.
- Coal largely phased out.
- Key uncertainties include falling costs of renewables, demand growth, and market developments.

The majority of additions to capacity in the Reference Case are natural gas, wind, and hydro facilities. Figure 3.21 shows the various capacity additions and retirements in the Reference Case. Table 3.3 provides capacity and generation levels and shares in 2017 and 2040.

Figure 3.21: Capacity Additions and Retirements by 2040, Reference Case

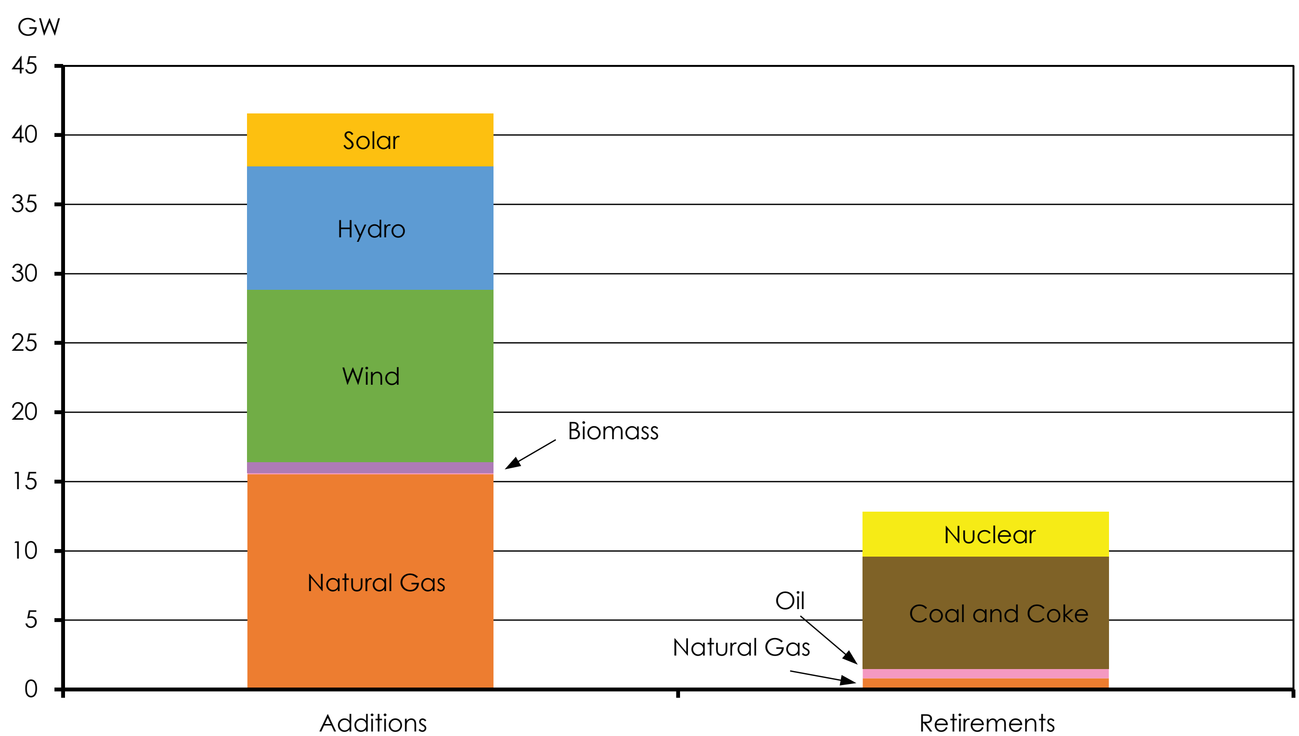


Table 3.3: Capacity and Generation, 2016 and 2040, Reference Case

	Capacity in GW and %		Generation in GW.h and %	
	2016	2040	2016	2040
Hydro	80.4	89.3	382.0	424.7
	55.1%	51.2%	59.5%	59.0%
Natural Gas	21.5	35.9	61.4	113.9
	14.7%	20.6%	9.6%	15.8%
Coal and Coke	9.5	1.4	57.8	2.1
	6.5%	0.8%	9.0%	0.3%
Nuclear	14.3	11.1	95.4	88.6
	9.8%	6.4%	14.9%	12.3%
Wind	11.9	24.3	30.3	68.6
	8.2%	13.9%	4.7%	9.5%
Solar	2.3	6.1	3.2	8.5
	1.6%	3.5%	0.5%	1.2%
Biomass	2.5	3.3	8.1	12.2
	1.7%	1.9%	1.3%	1.7%
Oil	3.5	2.9	3.5	1.2
	2.4%	1.7%	0.5%	0.2%

Outlook by Sources

Hydro

Hydroelectricity remains the dominant source of electricity supply in Canada over the projection period. Hydro has numerous benefits, including flexibility, relative affordability, and lack of GHG emissions at the operation stage. Certain hydro generating stations also have the ability to store water and change their output as needed. This benefit of hydro as a backup supply can also support the development of variable renewable energy resources like wind and solar.

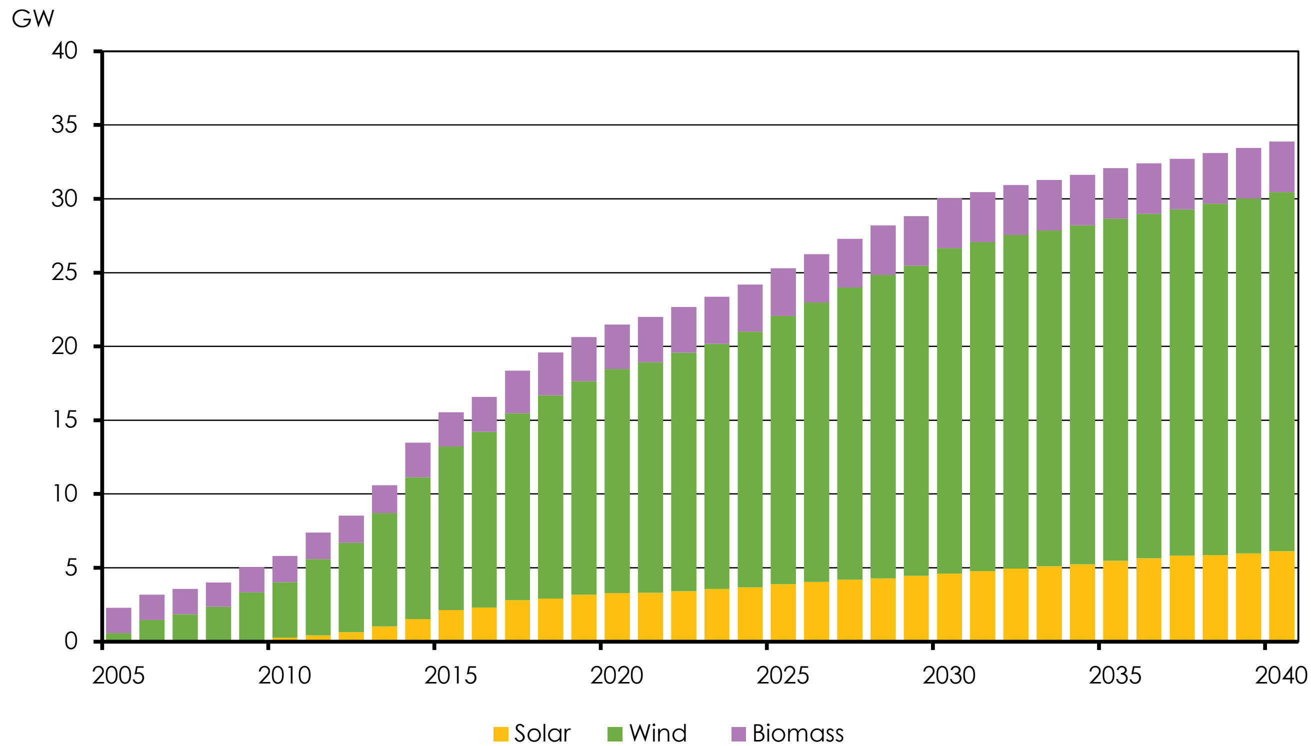
Hydroelectric generating capacity, including small hydro and run of river facilities, increases from 80 GW in 2016 to 89 GW in 2040. This capacity expansion stems from a number of large hydro projects either under construction or in the planning and development phase. Hydroelectric generation is expected to increase from 382 TW.h in 2016 to 425 TW.h in 2040. Over the projection period, hydroelectricity's share of generation stays steady at about 60%.

Non – Hydro Renewables

Canada has considerable non-hydro renewable resources including wind, biomass, solar, tidal, wave, and geothermal. Over the past few years, policy incentives and declining costs have spurred significant growth in the use of renewable generating technologies. In 2016, Canada had 17 GW of wind, solar, and biomass generating capacity, more than triple the amount in 2010. Most of Canada's installed wind capacity is located in Ontario, Quebec, and Alberta, while the majority of installed solar capacity is located in Ontario.

Non-hydro renewable capacity continues to grow in the Reference Case to nearly 34 GW by 2040, as shown in Figure 3.22. Wind capacity increases from 12 GW in 2016 to 24 GW in 2040, with the majority of new capacity additions coming from Alberta and Saskatchewan. Solar capacity nearly triples from 2.3 GW in 2016 to 6.3 GW in 2040, with most of the growth coming from Ontario and Alberta. Biomass capacity increases from 2.5 GW in 2016 to 3.3 GW in 2040, with growth in Alberta, Quebec, and northern territories.

Figure 3.22: Non-Hydro Renewable Capacity, Reference Case



In the Reference Case, generation from renewables is projected to increase from 42 TW.h in 2016 to 89 TW.h in 2040, representing 12% of all electricity generation.

Nuclear

Nuclear power accounted for 15% of Canada's electricity generation in 2016. Ontario's three nuclear power plants had a combined capacity of nearly 13 GW in 2016 and generated 58% of the province's electricity. New Brunswick's single nuclear power plant generated a third of the province's power in 2016[16].

Reference Case nuclear generation declines from 95 TW.h in 2016 to 89 TW.h in 2040. This is due to the shutdown of Ontario's Pickering Nuclear facility in 2024. Throughout the projection period, nuclear generation is lower than current levels due to outages of several nuclear units in Ontario while refurbishments take place.

Non-emitting generation sources (hydro, nuclear, and renewables) contribute 84% of generation by 2040, compared to about 80% in 2016. The increase is small because large amounts of natural gas-fired generation are added over the projection period.

Coal

Coal-fired generation accounted for 7% of the installed capacity in 2016 and generated 9% of all electricity in Canada. Currently four provinces operate coal power plants: Alberta, Saskatchewan, New Brunswick and Nova Scotia.

Federal regulations apply a strict emission performance standard to units that reach the end of their useful lives, essentially requiring them to be shut down or retrofitted with CCS technology. In 2015, Alberta announced plans to accelerate the phase out of its coal fleet, requiring traditional coal plants to be phased out by 2030. In 2016 the federal government announced its intention to amend its existing coal regulations to also phase out all traditional coal plants by 2030, rather than at the end of their economic lives.

16 For more information see Nuclear Energy in Canada.

Due to the above policies, coal capacity falls considerably over the projection period. EF2018 assumes equivalency agreements are reached in Saskatchewan, New Brunswick, and Nova Scotia allowing these provinces to maintain some of their traditional coal capacity in place beyond 2030. This capacity is used sparingly over the 2030 to 2040 time frame.

Natural Gas

Natural gas-fired capacity accounted for 15% of total capacity in 2016, with 22 GW installed. Natural gas is used to generate power across all regions of Canada except Prince Edward Island and Nunavut. The majority of natural gas-fired capacity is located in Alberta and Saskatchewan.

Natural gas-fired capacity increases steadily over the projection period. Relatively low fuel prices and capital costs make natural gas a likely option to replace retiring coal units. The increase in natural gas capacity is also linked to the growth of variable renewable energy. The intermittent nature of renewable electricity requires more reliable generation to complement it, and the ability of natural gas plants to quickly increase or decrease generation make it an attractive option. In the reference case, natural gas capacity increases from 22 GW in 2016 to 36 GW in 2040.

Oil

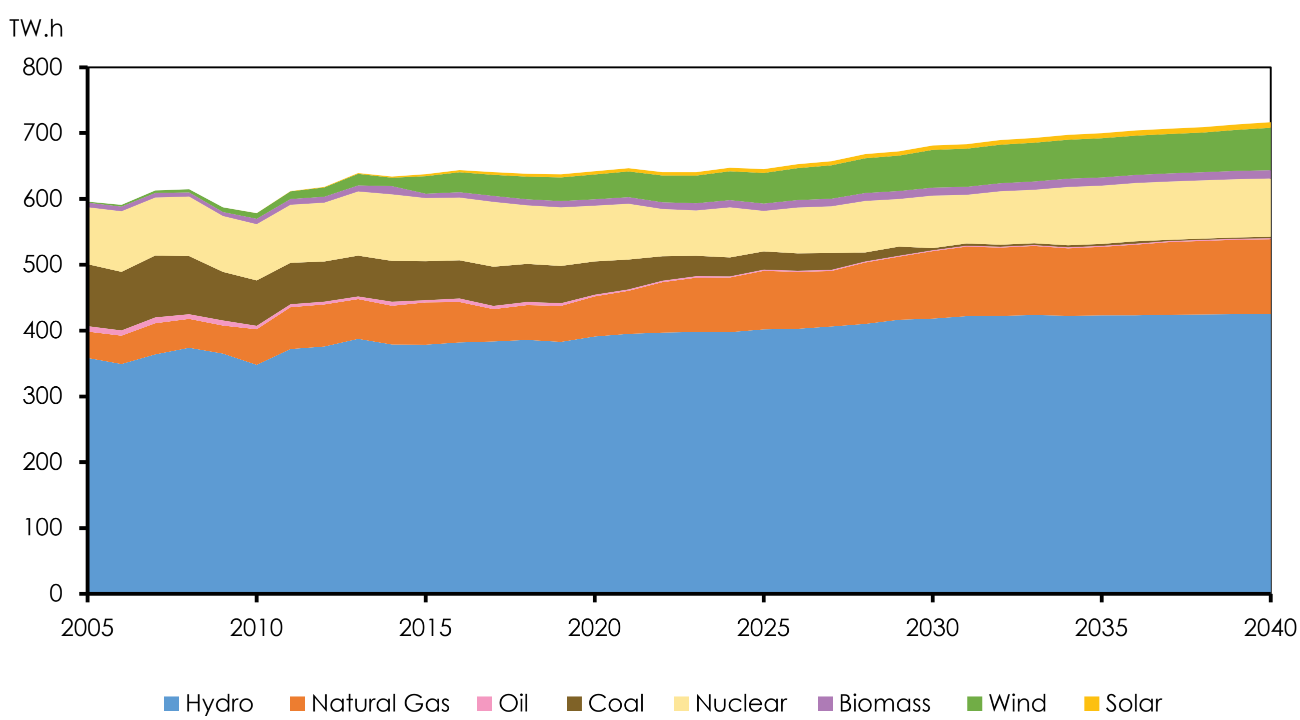
Oil-fired power plants accounted for 2% of Canada's total capacity in 2016, and are an important part of the supply mix in some smaller provinces and territories. Oil-fired power plants, which run mostly on diesel, are used to generate power during peak demand periods or in areas where other generation options are not widely available.

Total oil-fired capacity declines from 3.5 GW in 2016 to 3 GW in 2040. This reflects the retirements of aging units which are being replaced by renewable power, natural gas, or LNG-fired units when possible.

Total Generation

In the Reference Case, total Canadian electricity generation increases by over 78 TW.h from 2017 to 2040, an increase of about 12%. Hydro, other renewables, and natural gas lead this growth, while coal and nuclear generation decline. Figure 3.23 shows these trends by fuel type.

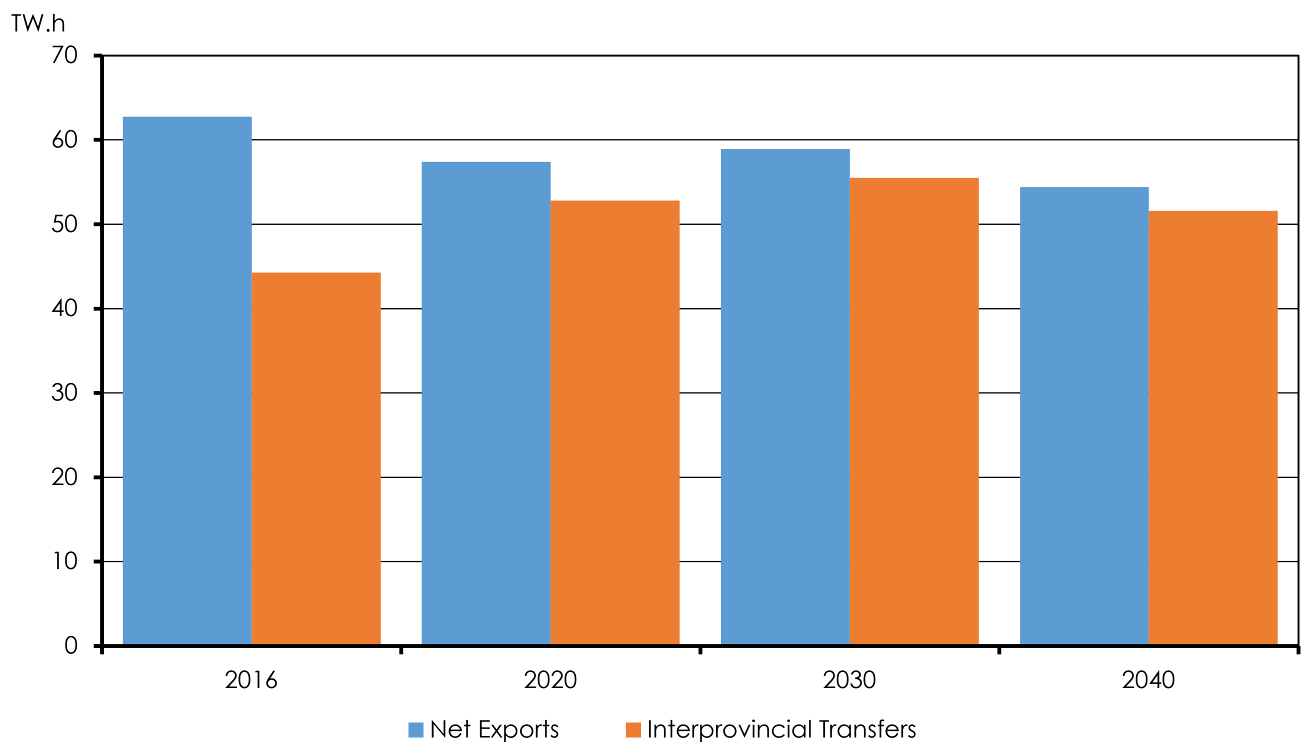
Figure 3.23: Generation by Fuel Type, Reference Case



Electricity Trade

Canada is a net exporter of electricity to the U.S., and large amounts of electricity are also traded between provinces, mainly in eastern Canada. By connecting the electricity grids of different regions, grid operators can take advantage of regional differences in periods of peak electricity demand. Differences in peak demand occur not only on the time of day, but also on the time of year. Seasonal peaks in Canada occur primarily during the winter when demand for heating is high, while peaks in the U.S. occur mostly in the summer to meet air conditioning demand. In the Reference Case, net electricity available for export grows moderately over the projection period, reaching 56 TW.h by 2040 (Figure 3.24). Interprovincial electricity transfers are projected to rise from 47 TW.h in 2005 to 52 TW.h in 2040. EF2018 assumes excess capacity from hydro projects in Labrador, Manitoba, Quebec, and B.C. is available for transfer to meet contractual agreements and open market opportunities.

Figure 3.24: Electricity Trade, Reference Case



Key Uncertainties

- **Future capital cost declines of generating facilities:** The capital costs associated with different generating technologies is an important factor in determining what type of facilities are built. This is especially true with less commercially mature technologies like wind, solar, and coal with CCS.
- **Electricity demand growth:** This is important in determining future electricity supply. As a result, the uncertainties identified in the energy demand section are uncertainties that also apply to the electricity supply projections.

- **Capacity market developments:** Recent capacity market developments in Ontario and Alberta were not modeled in EF2018. At the time of writing, the final structure of the new market from the two provinces has not been announced. However, EF2018 does model electricity build-outs in the same vein as a typical capacity market.
- **Future projects and developments:** Climate policies, fuel prices, electrification and power sector decarbonization in export markets could impact future projects and transmission intertie developments.

Coal

Total Canadian coal production declined for the third straight year in 2017 to 60.9 million tonnes. Production has generally been trending downward due to declining thermal use in Canada and reduced global prices.

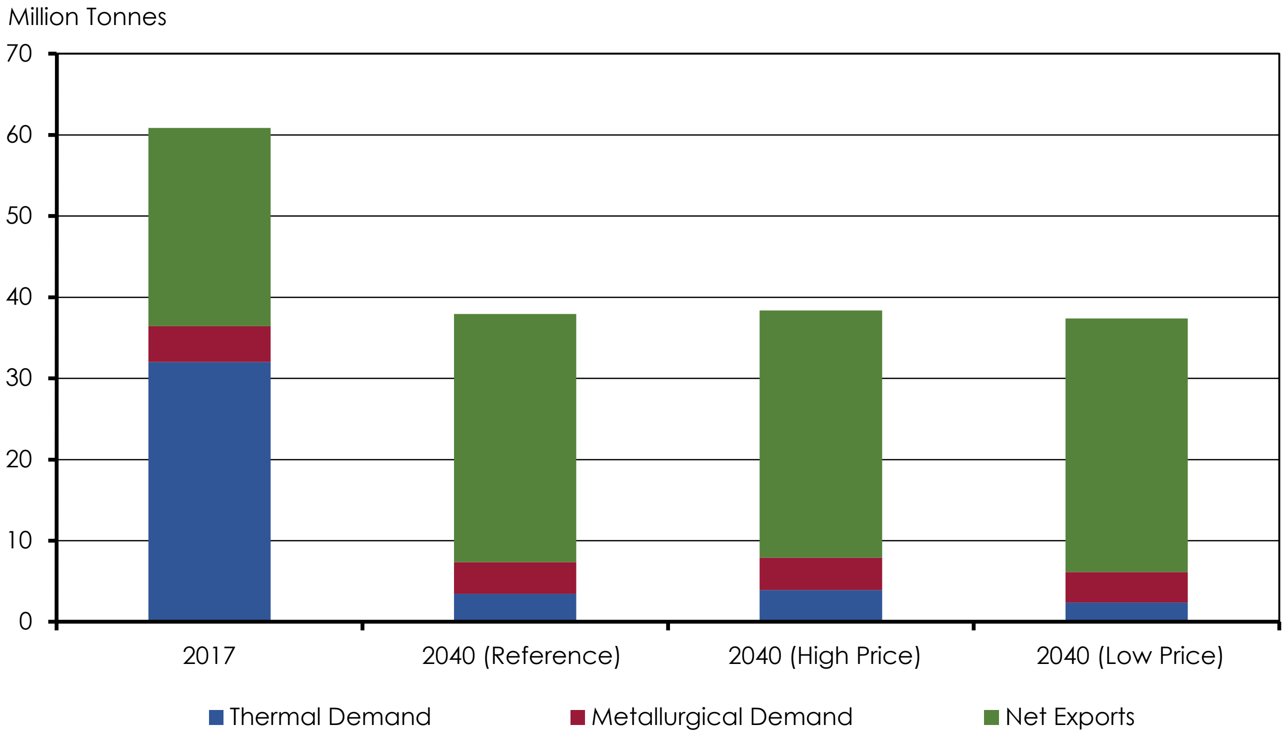
There are two main types of coal produced in Canada, thermal and metallurgical coal. Canadian thermal coal production is linked to the use of coal in the electricity sector, particularly in Alberta, Saskatchewan, and Nova Scotia. Metallurgical coal is primarily used for steel manufacturing domestically and internationally. Much of Canada's metallurgical coal production is exported and future production trends are linked to global metallurgical coal demand and prices.

Thermal coal accounted for 88% of total Canadian coal consumption in 2017. In the Reference Case, demand for thermal coal declines by 89% over the projection period, falling from 30.3 million tonnes in 2017 to 3.4 million tonnes in 2040. This declining trend is driven primarily by retirements of coal-fired generation capacity resulting from regulations to phase out traditional coal-fired power plants by 2030.

Domestic demand for metallurgical coal used in steel manufacturing declines from 4.4 million tonnes in 2017 to 3.9 million tonnes by 2040. Global demand for metallurgical coal grows moderately over the projection period, resulting in steady growth in net exports from Canada. Total metallurgical coal production in Canada increases from 29.5 million tonnes in 2017 to 30.5 million tonnes by 2040. Total production declines from 60.9 million tonnes in 2017 to 37.9 million tonnes in 2040.

Figure 3.25 shows Canadian production and consumption of coal in Canada in 2017 and 2040 in the Reference, High and Low Price Cases.

Figure 3.25: Canadian Coal Production and Disposition, Reference, High Price and Low Price Cases



Key Uncertainties

- **Prices:** Future price movements in the global coal markets are a key uncertainty for Canadian coal exports.
- **Climate policies:** Canadian climate policies, and the climate policies of coal importing countries, could have a significant impact on both Canadian thermal and metallurgical coal production.

GHG Emissions

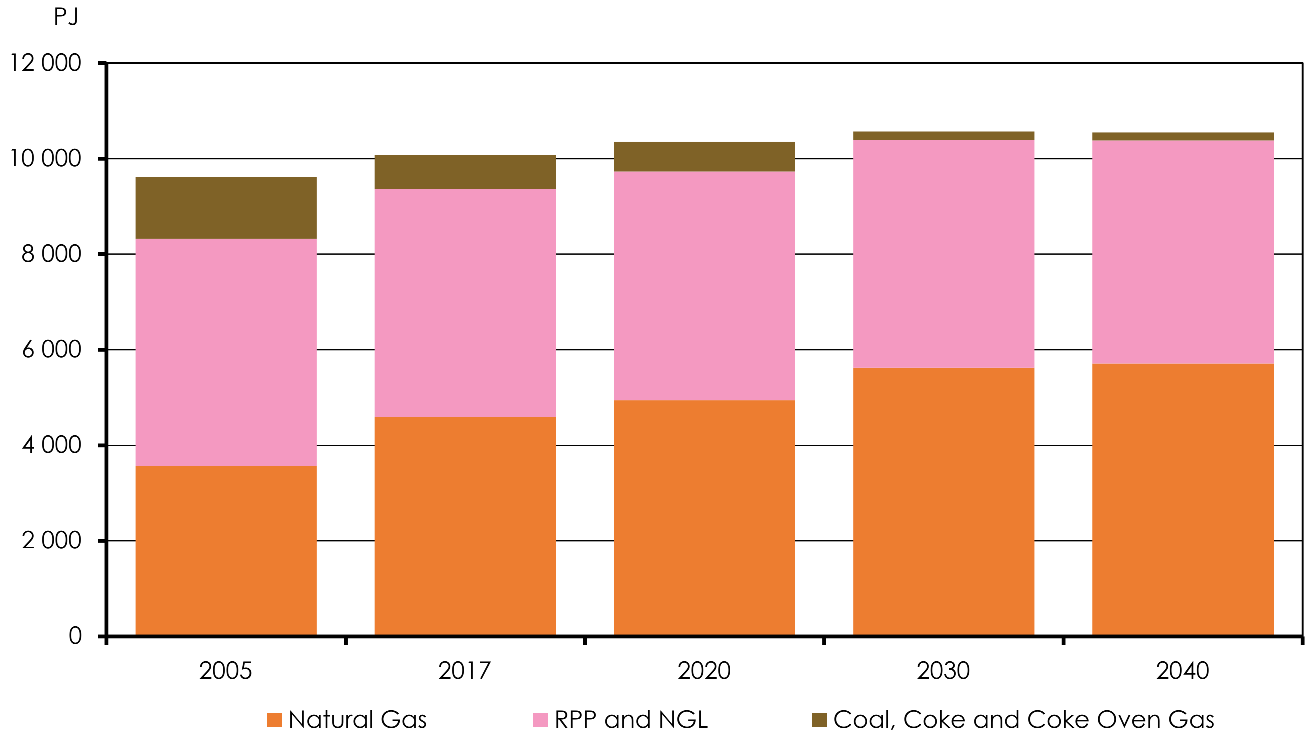
Currently, energy use and greenhouse gas (GHG) emissions in Canada are closely related. Environment and Climate Change Canada (ECCC) most recent official GHG projections are available through Canada's National Reports to the United Nations Framework Convention on Climate Change.[17]

The majority of GHGs emitted in Canada are a result of fossil fuel combustion. Fossil fuels provide the vast majority of energy used to heat homes and businesses, transport goods and people, and power industrial equipment. Emissions from fossil fuels, including those used for the production of energy, accounted for 81% of Canadian GHG emissions in 2016. The remaining emissions are from non-energy sources such as agricultural and industrial processes, and waste handling.

In the Reference Case, fossil fuel consumption increases early in the projection period and is relatively flat through the remainder of the outlook. Fossil fuel consumption in 2040 is 4.7% higher than in 2017, and 9.7% higher than in 2005. Figure 3.26 shows the total demand for fossil fuels in the Reference Case.

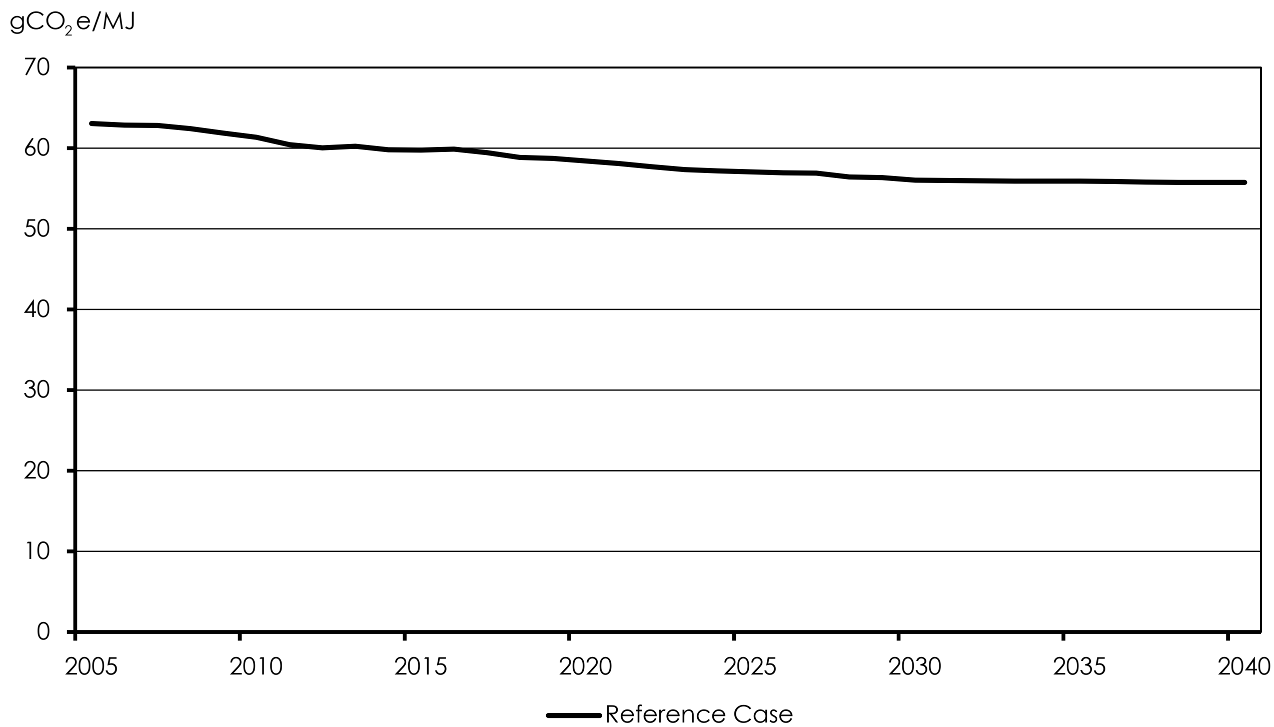
17 Data sets are also available through the Government of Canada's Open Government portal.

Figure 3.26: Total Demand for Fossil Fuels, Reference Case



While total fossil fuel consumption grows in the Reference Case, a changing fuel mix leads to declining GHGs per unit of fossil fuel energy used, as shown in Figure 3.27. Growth in natural gas, coupled with a steep drop in coal, results in GHG intensity declining by 6.3% from 2017 to 2040, or 11.6% from 2005 to 2040. Deployment of CCS technology in power and industrial facilities also reduces the GHG intensity of fossil fuel use. Accounting for reductions in non-combustion emissions, such as reducing methane leaks, as well as including emission credits purchased through international trading mechanisms (like Quebec's emission trading with California) could further decrease emission intensity.

Figure 3.27: Estimated Weighted-Average GHG Emission Intensity of Fossil Fuel Consumption, Reference Case



Key Uncertainties

- **Technology development:** Future adoption of low carbon technologies could alter the course of fossil fuel demands shown here. Increased deployment of technologies such as carbon capture, use and storage, could weaken the link between fossil fuel use and future emission trends.
- **Future climate policies:** The evolution of climate policies in Canada will be an important factor in fossil fuel combustion trends. Future developments in policies such as carbon pricing, energy and emission regulations, and support for emerging technologies could all alter these fossil fuel projections.

Chapter 4: Technology Case

EF2018's Technology Case explores how a global shift towards low carbon energy technologies could impact future Canadian energy supply and demand trends. Canada is a relatively energy intensive economy[18], and a major producer of many forms of energy. This potential shift is an important uncertainty for Canadian energy projections.

The Technology Case assumes that countries across the world increasingly adopt new technologies and increase their actions to combat climate change, as outlined in the IEA's World Energy Outlook 2017 "Sustainable Development Scenario". This global shift has implications for energy markets such as crude oil and natural gas. Canadian energy supply and demand trends are influenced by this global context, as well as specific assumptions on cost reductions and adoption for new technologies in Canada.

The Technology Case is designed to explore a key uncertainty for the future of Canada's energy system, a faster transition to a lower carbon economy driven by increasing global climate action and faster technological progress than assumed in the Reference Case. It is important to note that it is unclear which technologies will gain wider adoption in the future, and this case is just one example among many possible pathways. **This Case analysis is not a prediction or recommendation of certain policies, technologies, or outcomes**.

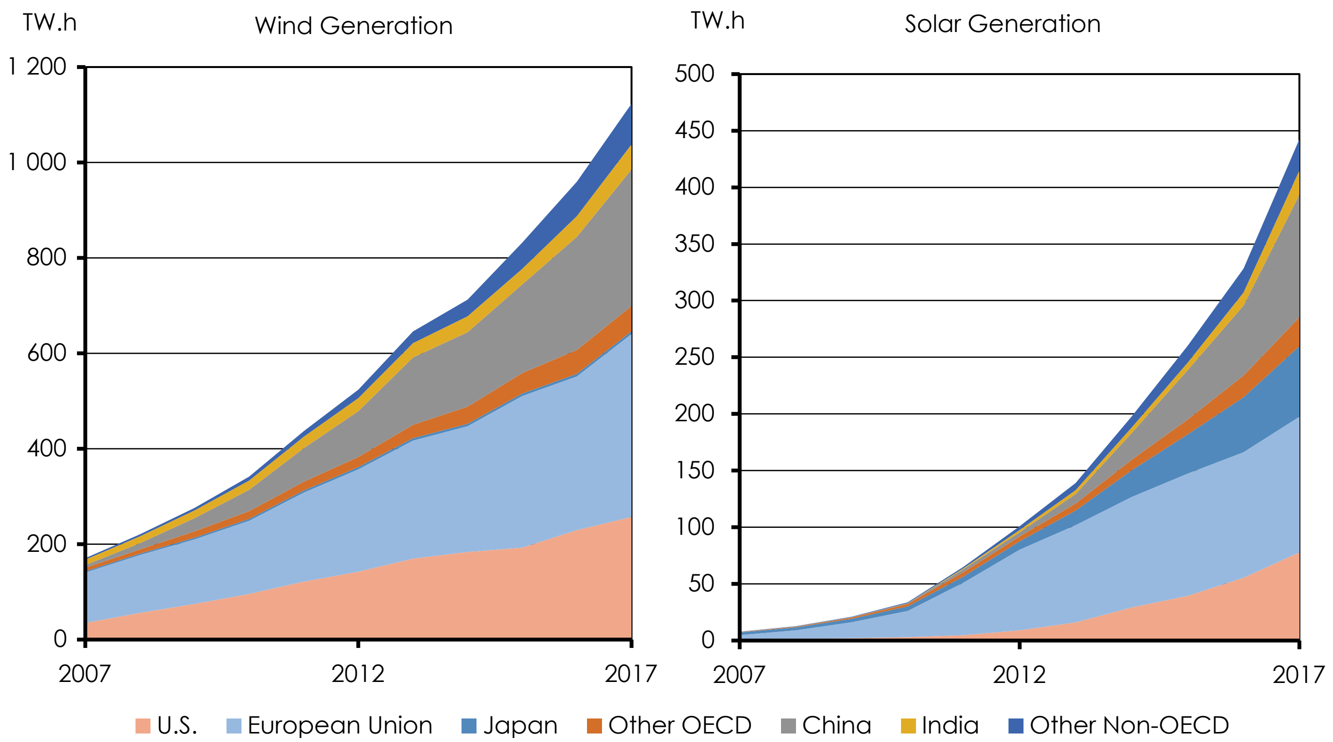
18 The World Bank ranks Canada the 39th most energy intensive country out of 237 countries with 7.3 MJ/$2011 purchasing power parity gross domestic product (PPP GDP).

Recent Context

Various technology, policy, and social trends over the past decade point to the potential for a global shift towards a lower carbon economy. This section outlines several examples of these trends.

Falling costs and increased deployment of renewable electricity sources, like wind and solar, have been an important technology change. Figure 4.1 shows global wind and solar generation. Over the last decade, wind and solar power have increased substantially, initially led by the European Union and the U.S., with recent growth in China and Japan. Many global forecasting agencies see this trend continuing[19].

Figure 4.1: Global Solar and Wind Generation by Country, 2007-2017



Source: BP Statistical Review of World Energy 2018

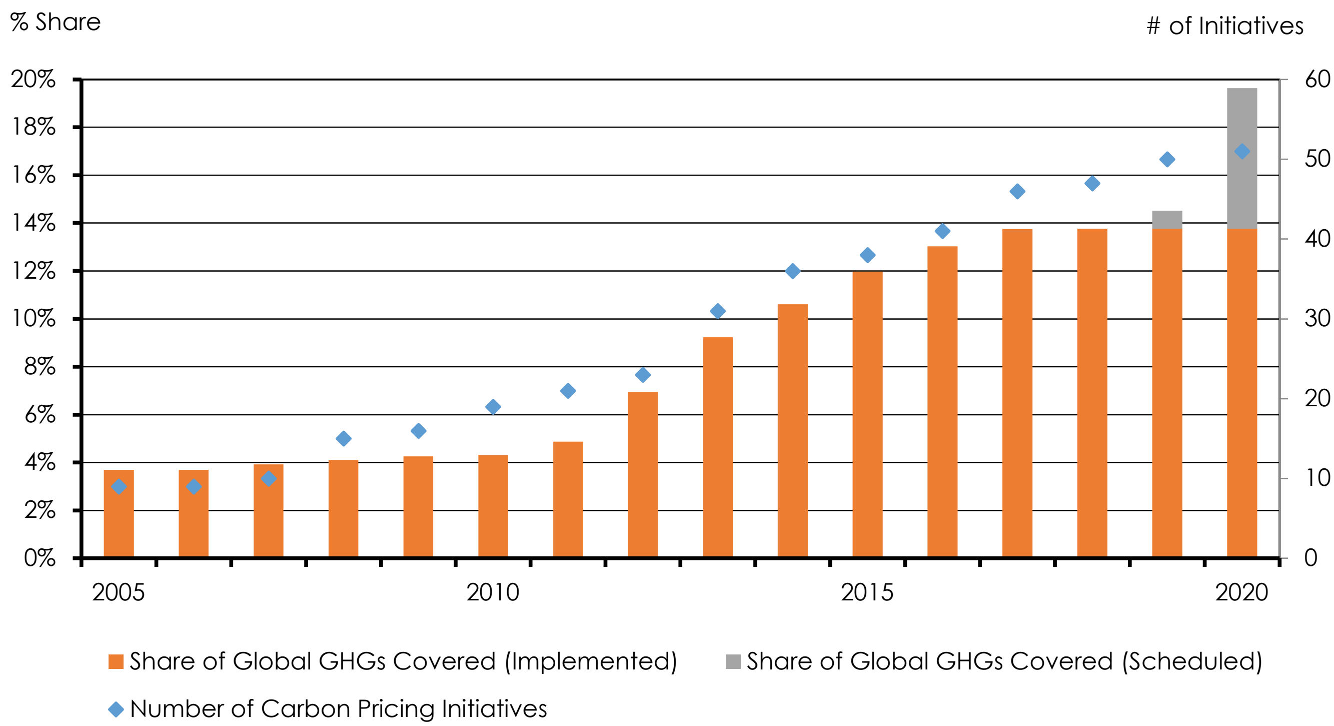
Technology and policy changes are transforming the transportation sector. Many forecasting agencies expect growth in refined oil products demand (gasoline) to slow or decline compared to historical trends. These changes are a key reason the concept of *peak demand*–the year at which global demand for oil will reach its maximum–is currently a key discussion point in oil markets. Reasons for this trend include increasing fuel economy, increased biofuel blending, and possible increase of EV adoption.

Emerging climate policies and future low carbon energy technologies are highly integrated. As an example of increasing momentum for policy action to reduce carbon emissions, Figure 4.2 shows that over the last decade the number of carbon pricing systems in the world increased from 10 to 46, while the coverage of those systems increased from 4% of global CO_2 emissions to 14%. Carbon pricing systems scheduled to come into effect soon, led by China's planned emission trading system, will bring this to over 50 systems covering nearly 20% of emissions by 2020[20].

19 Bloomberg New Energy Finance *New Energy Outlook, IEA World Energy Outlook 2017*, BP Energy Outlook 2018.

20 World Bank *State and Trends of Carbon Pricing 2018*.

Figure 4.2: Global Carbon Pricing Initiatives



Source: World Bank

In the Canadian context, Natural Resources Canada's "Generation Energy" initiative highlights the integration of technology and policy factors, as well as the many broad social issues involved in transforming energy systems. The *Generation Energy Council Report* distills possible initiatives into four key pathways: wasting less energy, switching to cleaner power, using more renewable fuels, and producing cleaner oil and gas. The milestones outlined in these pathways will have significant implications for how energy is produced and consumed in Canada.

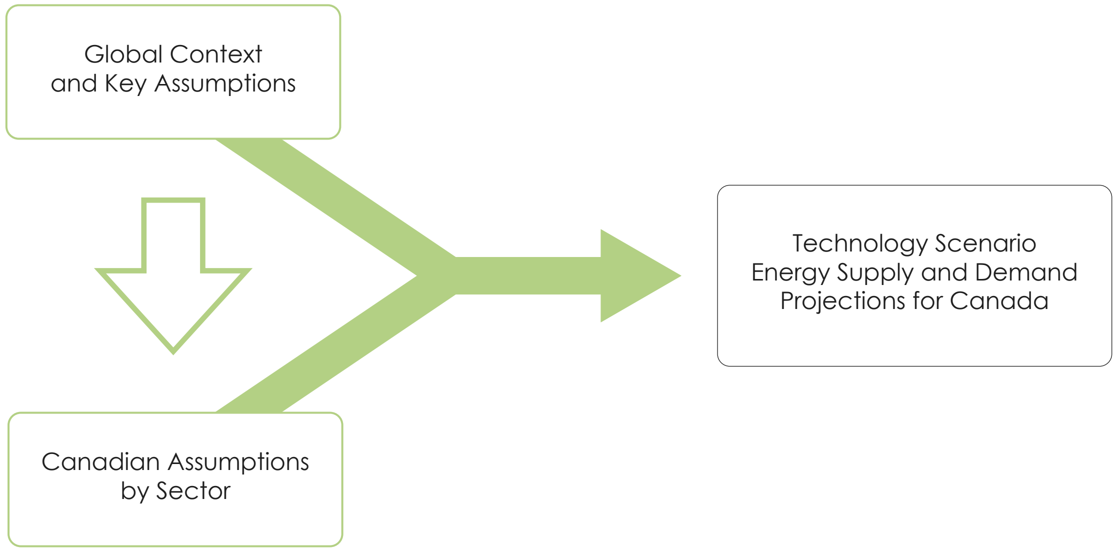
These trends suggest momentum towards a low carbon energy system. The Technology Case explores what continued momentum on this front might mean for future energy supply and demand in Canada.

Assumptions

The Technology Case is based on a set of global and Canadian assumptions around energy markets, energy and climate policy, and adoption of low carbon technologies. Figure 4.3 illustrates the overall approach to the Technology Case.

- **Global Assumptions**: Includes energy market price assumptions for global crude oil and North American natural gas, economy-wide carbon pricing, and other general policy trends. These global assumptions are aligned with the IEA's World Energy Outlook 2017 "Sustainable Development Scenario". This scenario, consistent with the Paris climate agreement targets, shows a steep decline in emissions from 2020 to 2040, putting the world on track to hold the increase of global average temperatures to below 2 degrees. It does so while also balancing other sustainable development goals, in particular, increasing access to modern energy sources and reducing local air pollution.
- **Canadian Assumptions:** Includes new technology cost reductions and adoption, energy efficiency improvements, use of alternative fuels, and Canadian benchmark oil and gas prices. These Canadian-specific assumptions are chosen to be consistent with the global context, but also reflect the specific nature of the Canadian energy system.

Figure 4.3: Technology Case Overview



The Technology Case Assumptions are also summarized in Appendix B.

The Technology Case and Paris Climate Agreement Goals

EF2018's global assumptions are aligned with the IEA's Sustainable Development Scenario, which reflect a world on track to meet commitments made under the Paris climate agreement. The assumptions and outcomes of the Technology Case are broadly consistent with the type of outcomes expected in such a transition: declining fossil fuels use, increasing use of non-emitting fuels, increased energy efficiency, and emergence of new technologies.

However, EF2018 and the Technology Case are strictly focused on Canada. Since climate change is a global issue, it is difficult to assess global climate implications without undertaking an integrated global climate modeling exercise.

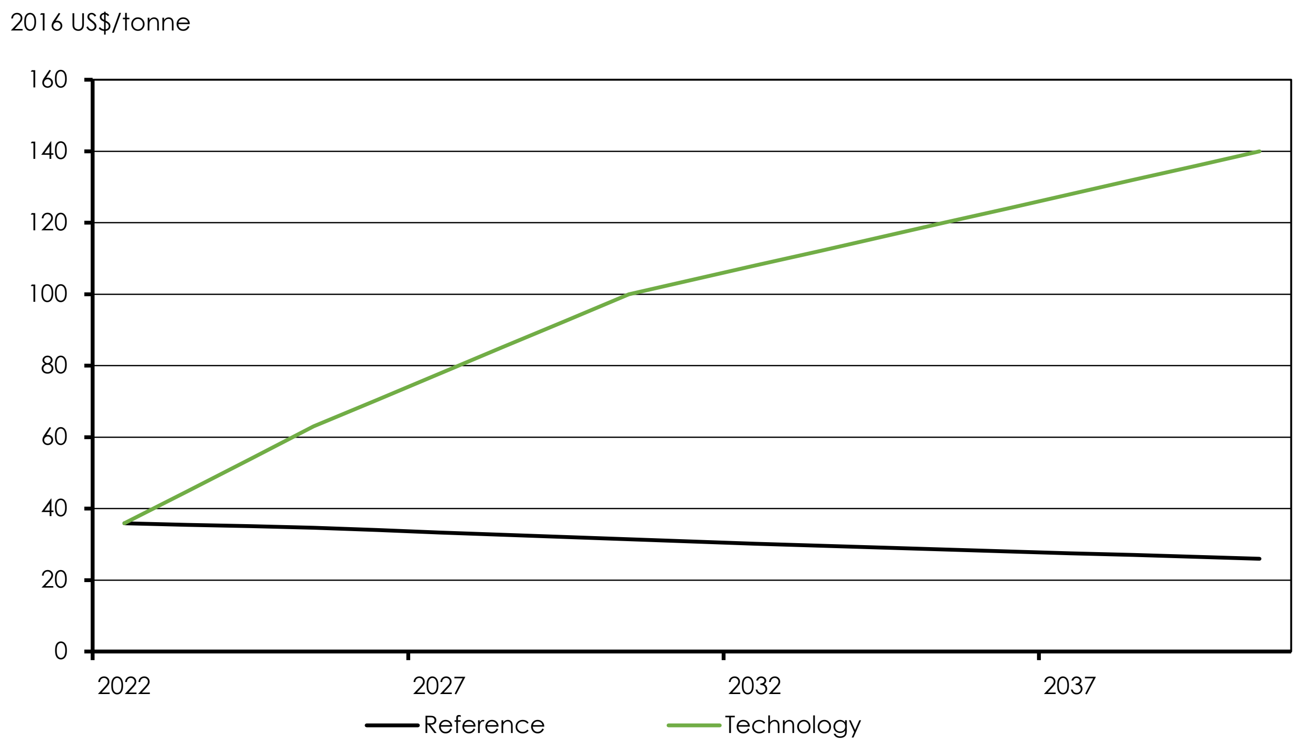
The Technology Case illustrates what a broad shift towards a low carbon energy system might look like for Canada. It is not a recommended pathway towards achieving Paris climate agreement goals, or Canada's own GHG emission targets. ECCC produces the official analysis of Canada's current emission outlook and performance against its climate commitments. Its most recent analysis can be found in Canada's 7th National Communication and 3rd Biennial Report.

Global Assumptions

Global Policy and Technology Trends

- **Carbon Pricing**: The IEA Sustainable Development Scenario shows a shift to a low carbon future that is driven by a broad set of policy assumptions, as well as the integration of a higher share of low carbon energy sources and technologies into the global energy mix. Carbon pricing provides a key driver for change across the economy. A rising carbon price is assumed for both OECD and non-OECD economies. Figure 4.4 shows the Technology Case assumption for Canada, aligned to the IEA's OECD carbon price increase.
- **Other actions**: In addition to carbon pricing, the IEA outlines several high-level policy initiatives by sector, including efficiency regulations, support for alternative fuels, emission standards and limits, and reduction of fossil fuel subsidies[21].

Figure 4.4: Economy-Wide Carbon Price, Reference and Technology Cases, 2022-2040

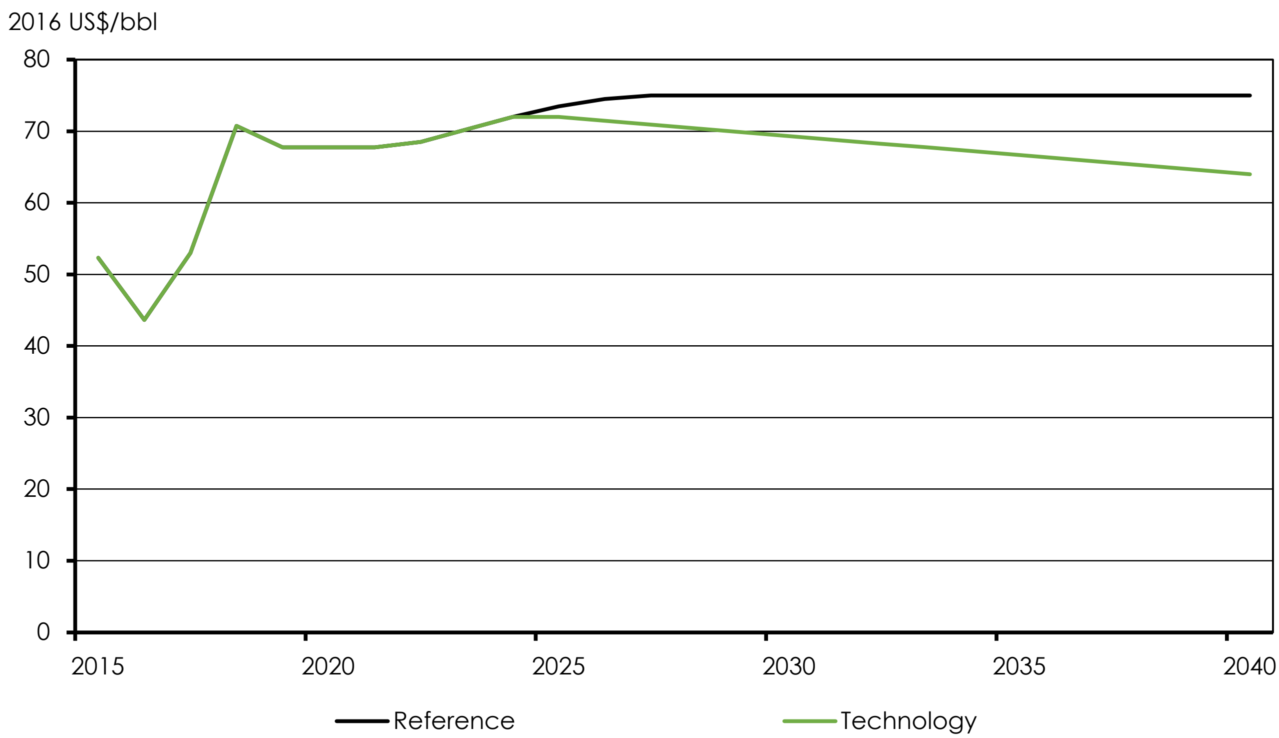


Global Crude Oil and Natural Gas Markets

- **Crude Oil Price**: The Technology Case Brent price assumption aligns to the IEA Sustainable Development Scenario global crude oil price. It begins to trend downward after 2025, consistent with a declining demand for global crude oil. It falls to US$69/bbl in 2030, $6 lower than the Reference Case, and US$64/bbl by 2040, $11/bbl lower than the Reference Case (Figure 4.5).

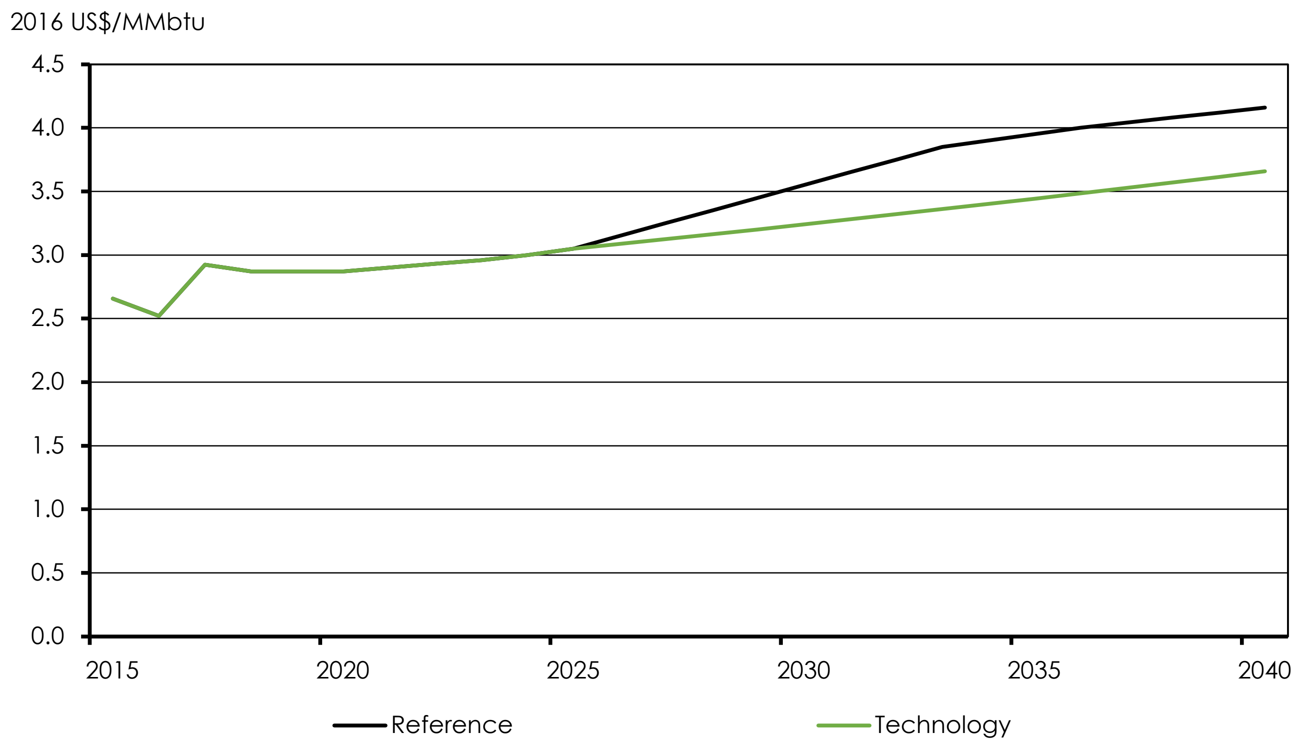
21 IEA *World Energy Outlook 2017*, Annex B

Figure 4.5: Brent Price Assumptions, Reference and Technology Cases



- **Natural Gas Price**: The natural gas price in the Technology Case aligns to the IEA Sustainable Development Scenario U.S. natural gas price. It increases from \$3.25/MMbtu in 2030 to \$3.66/MMbtu in 2040. This reflects growing demand for natural gas to replace coal for power generation. However, the IEA projects that global natural gas demand will grow at a slower rate in this case compared to other scenarios. The Technology Case reflects this dynamic; in 2030 it is \$0.30/MMBtu lower than the Reference Case and in 2040 is \$0.50/MMbtu lower than the Reference Case (Figure 4.6).

Figure 4.6: Henry Hub Price Assumptions, Reference and Technology Cases



Canadian Assumptions

Canadian Energy Markets

- **End-use Fuel Prices**: Canadian end-use prices are affected by the carbon price and benchmark crude oil and natural gas price trends. Lower crude oil and natural gas prices put downward pressure on prices for refined products and delivered natural gas. Increased carbon pricing puts upward pressure on prices, based on the relative carbon intensity of fuels. Table 4.1 provides example carbon prices of various fuels in energy equivalent and volumetric terms.

Table 4.1: Example Carbon Prices of Various Fuels in Energy Equivalent and Volumetric Terms

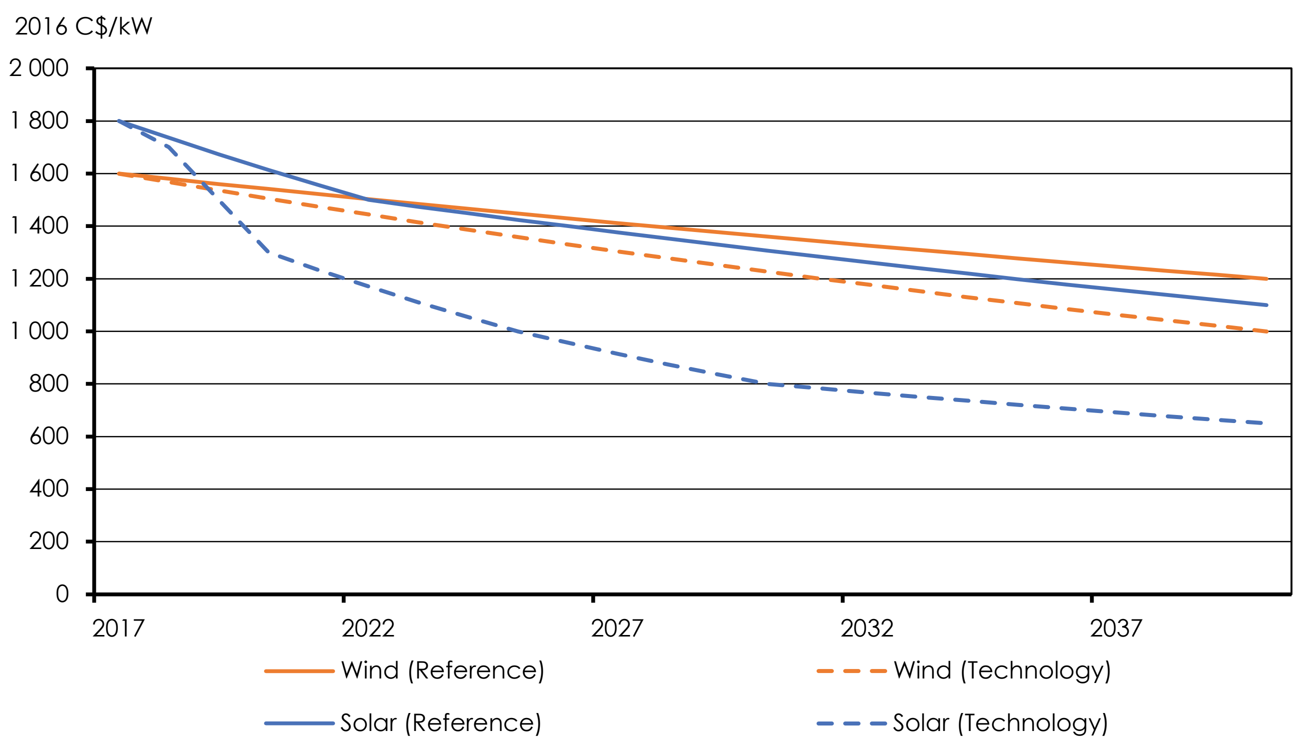
Carbon Price	$30/tonne		$50/tonne		$90/tonne		$140/tonne	
	Energy	Volume	Energy	Volume	Energy	Volume	Energy	Volume
Natural Gas	1.50 $/GJ	$1.58/Mcf	2.49 $/GJ	$2.63/Mcf	4.49 $/GJ	$4.74/Mcf	6.98 $/GJ	$7.38/Mcf
Gasoline	2.06 $/GJ	7.1¢/L	3.43 $/GJ	11.9¢/L	6.17 $/GJ	21.4¢/L	9.59 $/GJ	33.2¢/L
Diesel	2.22 $/GJ	8.6¢/L	3.70 $/GJ	14.3¢/L	6.67 $/GJ	25.8¢/L	10.37 $/GJ	40.1¢/L

- **Canadian Benchmark Prices**: The Technology Case assumes that the differentials between benchmark prices shown in Chapter 2 for the Reference Case are the same in the Technology Case. This implies a Technology WCS and CLS price $11/bbl lower than the Reference Case in 2040, and a NIT price $0.50/MMBtu lower in 2040. Given the global context, this is a very uncertain assumption. As the globe shifts towards a low carbon economy, market dynamics may evolve differently and lead to different relationships between the various benchmark prices in the short or long term.
- **LNG Export Assumptions**: The Technology Case assumes LNG export volumes are the same as the Reference Case. This is an area of uncertainty as well. Many dynamics will influence potential Canadian LNG exports, including economics, individual company investment decisions, and the role of natural gas globally in switching away from more carbon-intensive fuels like coal. LNG export assumptions are a key uncertainty in all EF2018 cases, and could be higher or lower than assumed both compared to the assumptions, and relative to each other.

Electricity Generation

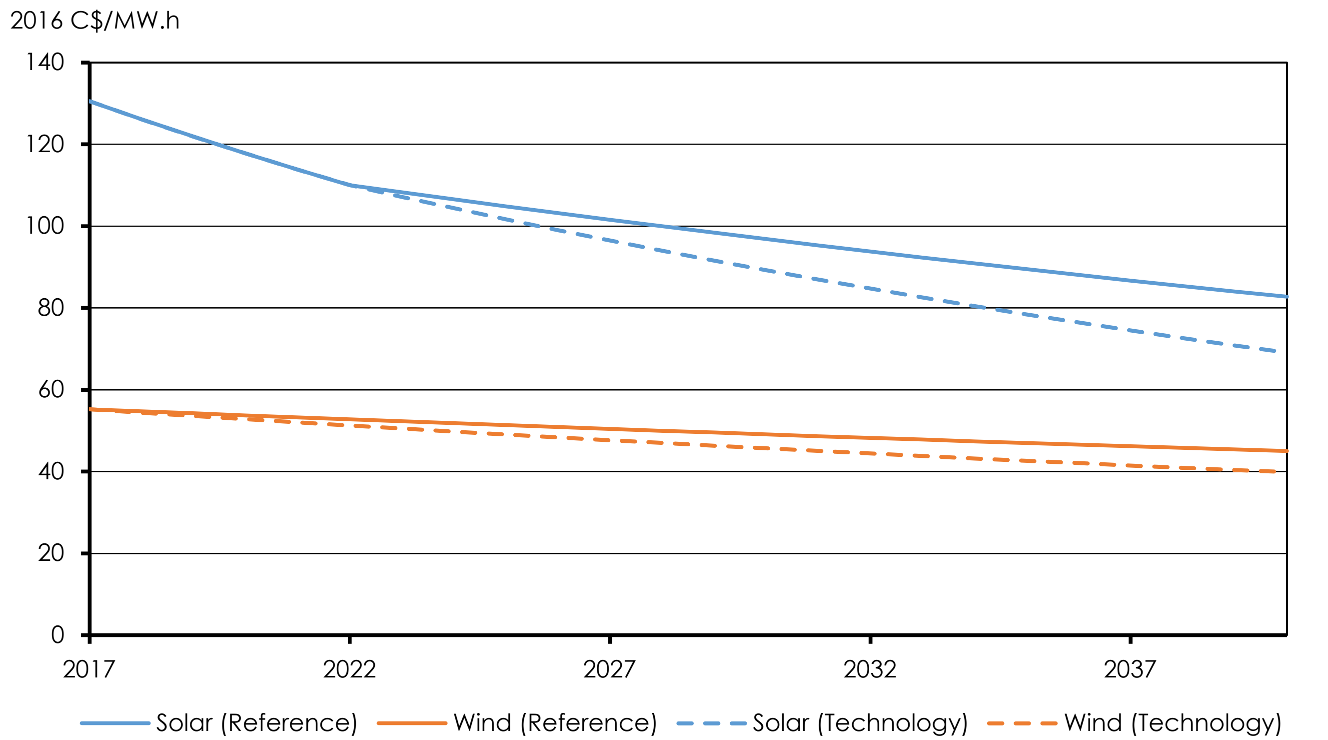
- **Solar and Wind Capital Cost Reductions**: Figure 4.7 compares wind and utility solar capital cost assumptions in the Reference and Technology Cases. In the Technology Case, wind costs decline nearly 40% compared to 2017 levels, while solar costs decline over 60%.

Figure 4.7: Wind and Solar Costs, Reference and Technology Cases, 2017-2040



- **Solar and Wind Levelized Cost Reductions**: Figure 4.8 compares levelized costs of wind and solar power, which is the cost per MW.h of generation. It shows that falling capital costs drive generation costs for these resources. Levelized costs include the amount of generation each kW of capacity produces, or the capacity factor. In Canada, wind power generally operates at a higher capacity factor than solar. This implies that wind, on average, has a lower cost per MW.h generated than solar, even with a higher capital cost.[22]

Figure 4.8: Wind vs Solar Levelized Cost, Technology Case, 2017-2040



- **Integrating Variable Renewables**: The Technology Case assumes enhanced integration of wind and solar power into electricity grids. This includes additional electricity transmission between Canadian provinces, and a greater use of demand management to match electricity demand loads to variable renewable generation.

22 The levelized costs are based on a solar capacity factor of 15% and a wind capacity factor of 40%. Costs and capacity factors will vary by location. This chart shows high level, average trends.

Variable Renewable Energy

Variable sources like wind and solar require additional efforts to integrate into the grid.

- **Flexible generation**: Generation sources like hydro and natural gas can be ramped up when solar and wind generation declines, or down when it increases.
- **Transmission**: Variable generation is location specific. Increased transmission from areas where wind generation is higher can help smooth out the variability of the resource, or connect the region to additional flexible generation. Recent analysis found transmission to be a key element of decarbonizing electricity grids for both Canada[a] and the U.S.[b]
- **Demand side management**: Electric loads can possibly be adjusted to better align with generation. As end uses become increasingly digitized, renewables could be better integrated for both large scale loads, and smaller scale integration at the household level.[c]
- **Storage**: Grid-scale storage includes many technologies like pumped hydro, batteries, compressed air and flywheels. Storage can help balance the electricity system by charging and discharging as wind and solar levels fluctuate. Recently, there is increasing interest in battery storage, given decreasing costs. The learning rate of battery storage–the percentage costs have fallen for every doubling of global battery storage capacity–has been at similar levels to solar PV.[d]

Notes:
a The Cost of Decarbonizing the Canadian Electricity System
b Future cost-competitive electricity systems and their impact on U.S. CO_2 emissions
c IEA, Digitalization and Energy 2017
d BNEF's New Energy Outlook 2018, CSIS Presentation

Oil and Gas Production

- **Global competition**: The global context of the Technology Case includes higher carbon prices and lower crude oil and natural gas prices compared to the Reference Case. This implies increased competitive pressures for producing these resources at a lower cost, as well as at reduced emission levels. Since this Case assumes the world is moving towards widespread action on climate change, current Canadian measures to avoid adverse competitiveness issues, or carbon leakage, are phased out by 2035. This includes the output based allocations (OBAs) used in the Alberta Carbon Competitiveness Incentive Regulation, as well as the federal backstop.
- **Solvent Technology for In Situ Production**: The Technology Case assumes widespread adoption of solvent technology for oil sands in situ production. Steam solvent technology is applied to all new production by 2025, as well as some existing reservoirs, resulting in a 25% reduction in SOR. By 2030, pure solvent technology reaches wide-scale commercial adoption, and all new production employs this technology, leading to an 80% reduction in SOR.

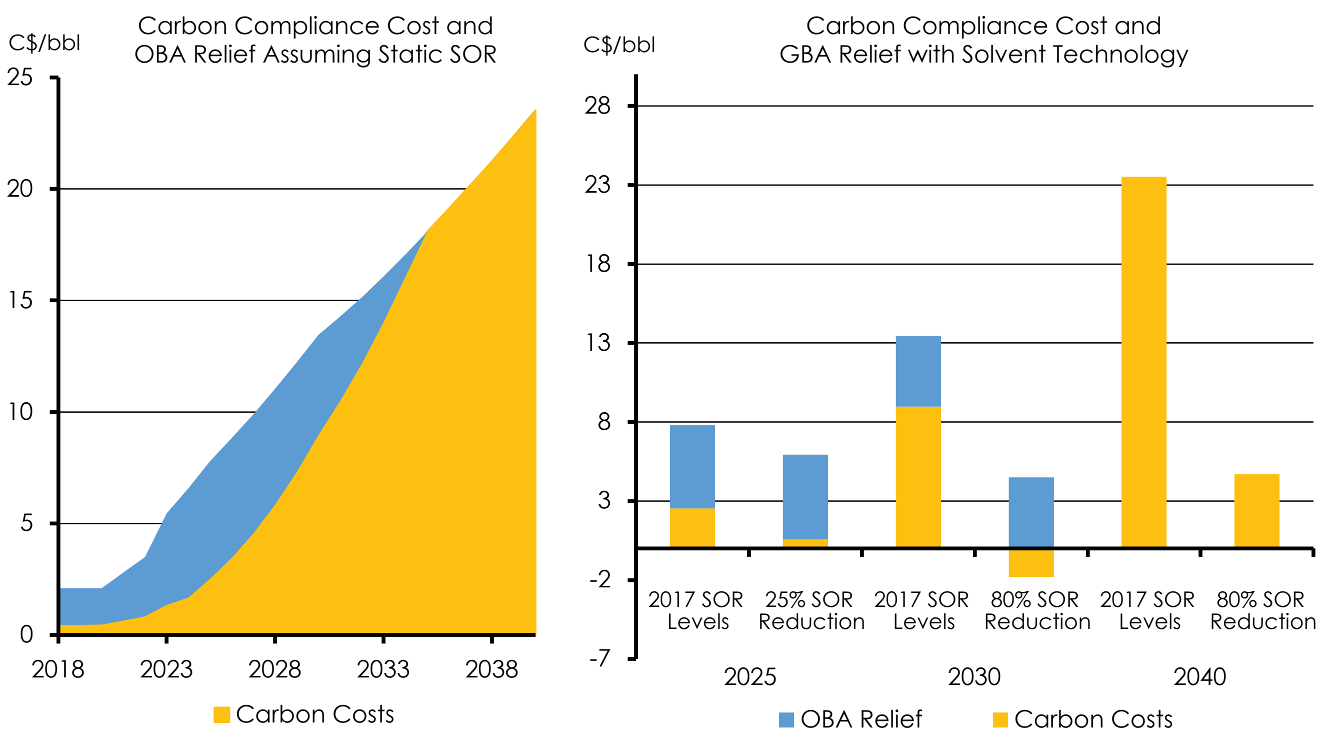
  Figure 4.9 illustrates this incentive to reduce the carbon emissions in the Technology Case. The first chart shows the theoretical carbon cost per barrel in the Technology Case assuming OBAs are phased out, carbon price rises, and emission intensity of production remains at 2016 levels. Given the oil prices shown earlier, these costs would become a major impediment to production economics. The second chart shows that 25% and 80% SOR reductions from steam and pure solvent technology, respectively, can reduce those costs significantly.

Solvent Technology

These technologies involve displacing the steam that is injected to produce oil with solvents, lowering natural gas requirements to generate the steam, and therefore the emissions intensity of production. Both steam and pure solvents are emerging technologies that have been under development for a number of years. An in situ project using steam-solvent technology can have higher upfront costs than a traditional in situ project as a result of additional facilities to store, treat, and recover solvents[a]. Greater bitumen recovery rates and lower steam requirements can offset those costs to varying extents depending on individual project characteristics. Pure solvents also offer the potential for capital cost reductions[b].

Notes:
a CERI Study 164
b Nsolv

Figure 4.9: Emission Cost Per Barrel Under Business As Usual, 25% Reduction, and 80% Reduction In Emission Intensities, Given Technology Case Carbon Costs



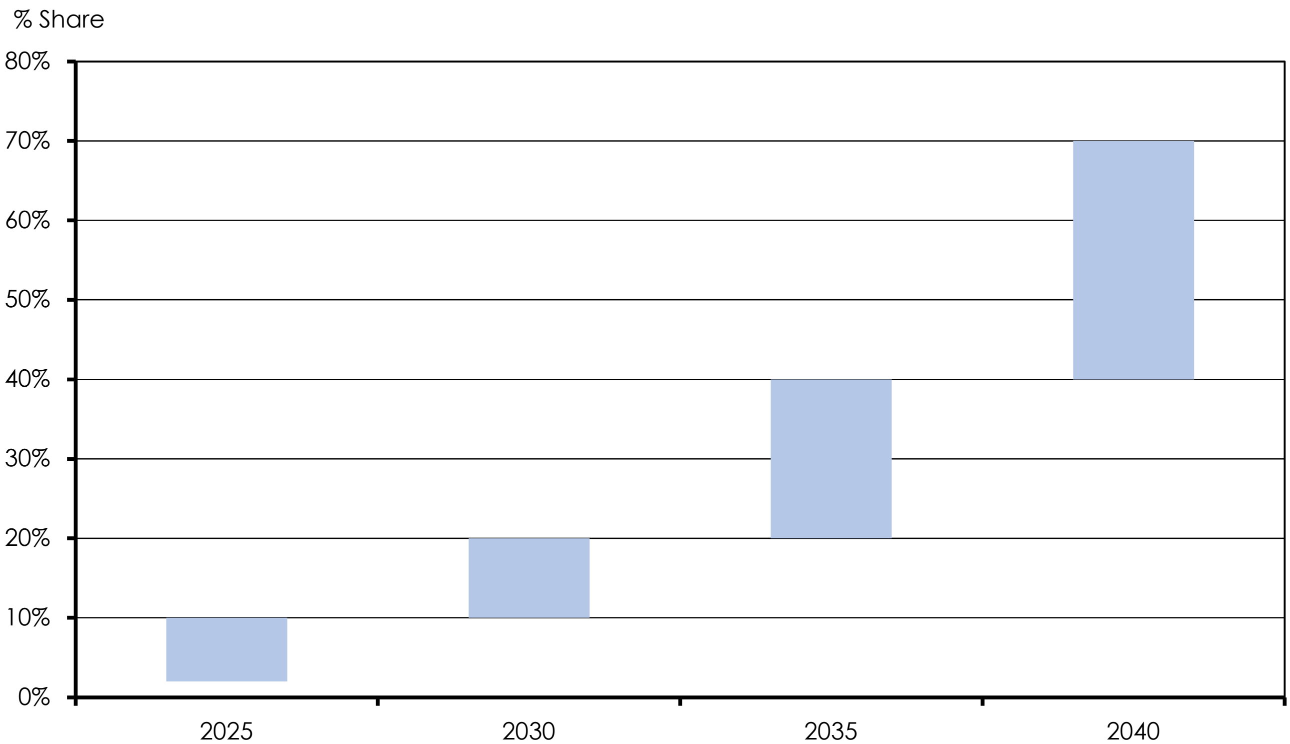
Residential and Commercial Energy Efficiency

- **Energy Efficiency Improvements**: The Technology Case assumes significant efficiency improvements across the buildings sector. Reducing energy and emissions intensity for buildings is an important part of many climate action plans, including the Pan-Canadian framework. The Technology Case assumes improvements to windows, building shells, and insulation reduce the energy required for heating and cooling. For remaining energy requirements, energy using devices (space and water heating, cooling, and appliances) become more efficient.
- **Increased Heat Pump Adoption**: Figure 4.10 illustrates the range of heat pump adoption across provinces in the Technology Case. Adoption of heat pumps increases from 10 to 20% of new, and replacement systems, by 2030; then it rapidly increases from 40 to 70% by 2040. The Technology Case assumes that technology improves for cold climate heat pumps, as well as reduced upfront costs. Analysis for the U.S. suggests heat pump costs could fall 10 to 20% by 2025-2030, and 20 to 30% by 2040. For areas that rely heavily on natural gas for heating, hybrid natural gas heat pump systems are an option. These systems rely on electric heat pumps producing heat when electricity prices are low, and high-efficiency natural gas during peak times when electricity prices are high.

Heat Pump Technology

Increased adoption of heat pumps for space heating and cooling, and heating water, could be an important component of decarbonizing Canada's building sector. Heat pumps have an advantage in that rather than creating heat, they exchange energy by extracting heat from an outside source and pumping it into a space. Heat pumps use approximately half the electricity compared to baseboard heating to generate the same amount of heat. They are not currently found more broadly because they are relatively more expensive compared to baseboard heating or natural gas furnaces, and have reduced efficiency during cold weather. Relatively low prices of natural gas compared to electricity can prevent electric heat pumps from yielding cost savings compared to high efficiency natural gas furnaces.

Figure 4.10: Range of Heat Pump Adoption Across Provinces, Technology Case

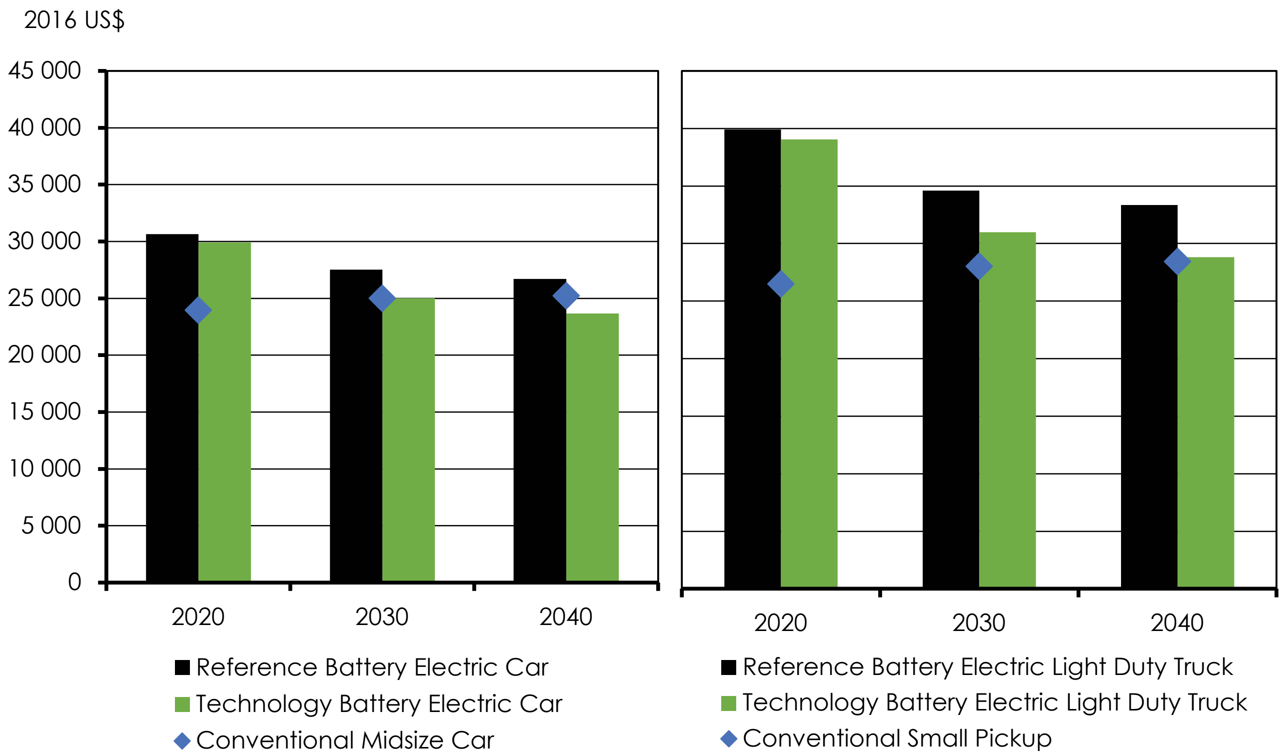


- **Process improvements and digitization**: Increased levels of digitization allow for less energy waste, optimizing energy use and energy costs (for example, load shifting when excess solar and/or wind power is available), and integration with other forms of energy demand, such as EV charging.

Transportation

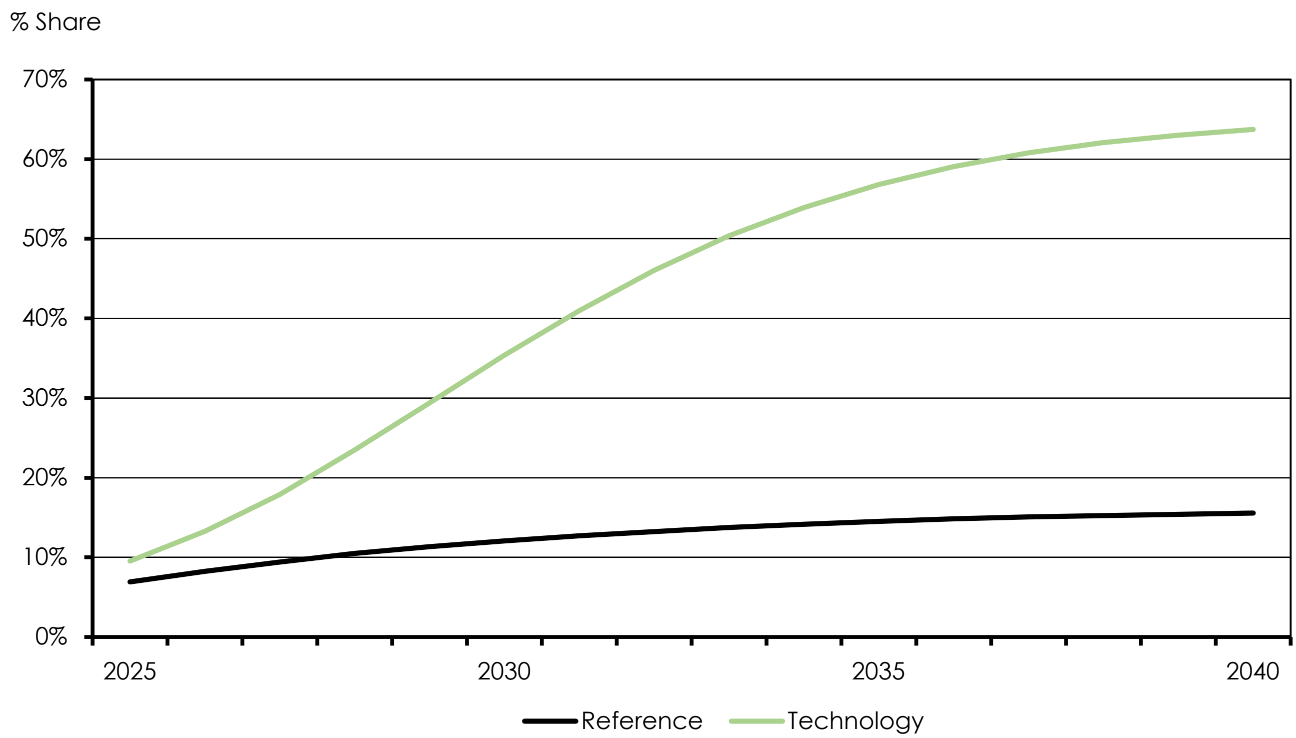
- **Electric Vehicles**: Figure 4.11 shows the assumed average cost for an EV in the Reference Case compared to a representative internal combustion engine (ICE) car and truck. On an average cost basis, EV purchase price reaches ICE levels by 2030 for cars and 2040 for trucks. Given the impact of end-use prices, and that the per-unit driving cost and maintenance cost of EVs are assumed to be lower than ICE, the economics begin to favour electricity in this time frame. In the 2030s, the Technology Case assumes charging infrastructure is well developed, leading to a rapid increase in the share of EVs in that decade. Increased ride sharing, mobility as a service, and potential autonomous vehicle technology could also favour electric vehicle adoption. Figure 4.12 shows average new sales of EVs in the Reference Case compared to the Technology Case.

Figure 4.11: Average Vehicle Purchase Price, Battery Electric Cars and Light Duty Trucks, Reference and Technology Cases



Source: EIA, NREL

Figure 4.12: Share of EVs in New Passenger Vehicles, Reference vs Technology Case, 2025-2040



- **Fuel Economy Improvements**: The Technology Case assumes ICE vehicles continue to improve and reduce their own variable costs, building upon the efficiency improvements from current vehicle emission standards. The Technology Case assumes fuel economy of gasoline and diesel cars and trucks improves by 1.5% per year in the longer term, beyond the expiration of current emission standards for light duty vehicles (2025) and heavy-duty trucks (2028).
- **Alternative Fuels**: Biofuel blending continues to grow, with ethanol and biodiesel blending reaching 10% by 2025. By 2040, gasoline and diesel are blended with 15% renewable fuels on average.[23]
- **Aviation**: Biofuels are currently being used for some air travel[24], and this increases in the Technology Case. Improved efficiency, as well as biofuel blending to 15% of jet fuel by 2040, reduce the emissions intensity of air travel.

23 Blend limits for ethanol and biodiesel are assumed to be consistent with Navius Analysis of the Proposed Canadian Clean Fuel Standard until 2025. Longer term increases of biodiesel blending beyond 10% reflect potential for increased use of next generation biofuels fuels such as hydrogenation derived and pyrolysis derived renewable diesel, or carbon-neutral liquid fuels derived from direct-air-capture technologies.

24 International Civil Aviation Organization, Map of Flights Using Alternative Jet Fuel.

Northern Territories and Remote Communities in the Technology Case

Northern Territories and remote communities have unique energy contexts with higher costs due to fuel transportation costs, colder climates, and reduced energy options, particularly for communities not connected to utility grids. Reducing reliance on diesel is a key complementary action in the Pan-Canadian Framework. The 2018 Energy and Mines Ministers Conference featured items on adopting renewables and reliability, as well as integrating new technology in remote communities.

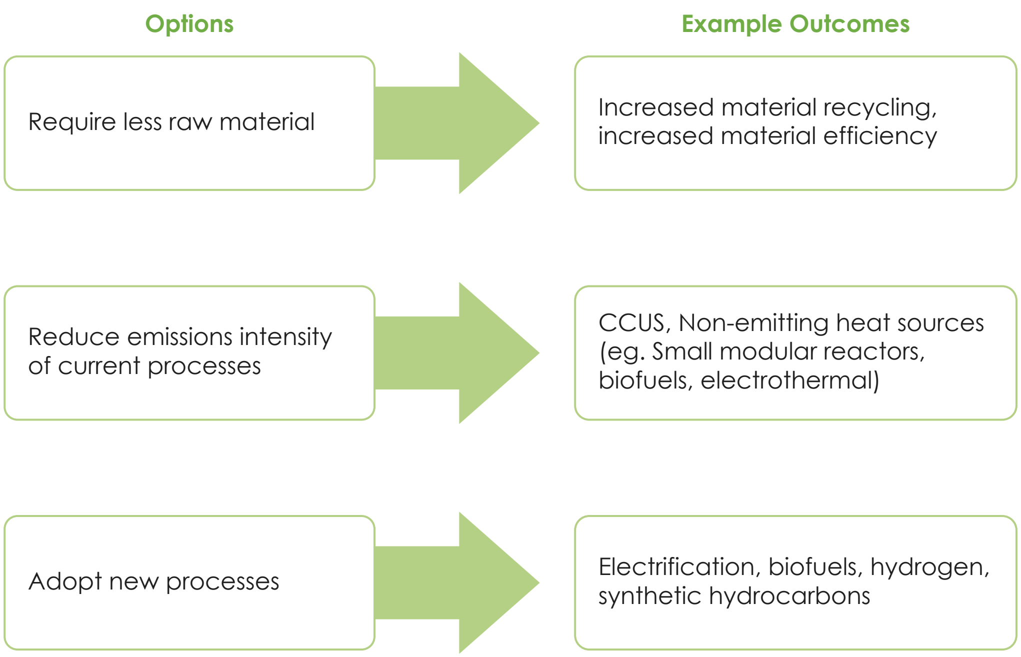
Given these unique energy issues, the Technology Case includes some specific assumptions for Northern Territories. The Technology Case assumes an increase in solar and wind power over the longer term, offsetting large amounts of diesel generation in the summer months. For space heating, current trends towards increasing biomass use are strengthened. On the energy use side, the Case assumes a lower adoption of EVs and heat pumps compared to the other provinces, but similar improvements in energy efficiency.

Industrial (Excluding Oil and Gas Production)

- **Options for Emission Reductions**: Canada's industrial sector is composed of many different industries that all have unique energy issues, varying energy mixes, and different technological options for reducing or eliminating GHG emissions. Figure 4.13 provides a high-level view of options for industrial decarbonization summarized by a recent study.[25] The future energy mix for industry will depend on factors such as ability to recycle raw materials, change process or fuels, or adopt new technologies such as CCS and carbon capture, use and storage (CCUS). The various economics involved in these decisions depend on the circumstances of the individual operation, company, and industry. For example, industries in western Canada have easier access to suitable locations for CCS based on storage availability, while abundant hydropower in Quebec could make it an attractive location to explore electrification of processes.

25 Bataille, et al includes an overview of technology and policy deep decarbonization pathway options for energy-intensive industry production. For additional information on reducing emissions in industry, see IEA's Energy Technology Perspectives.

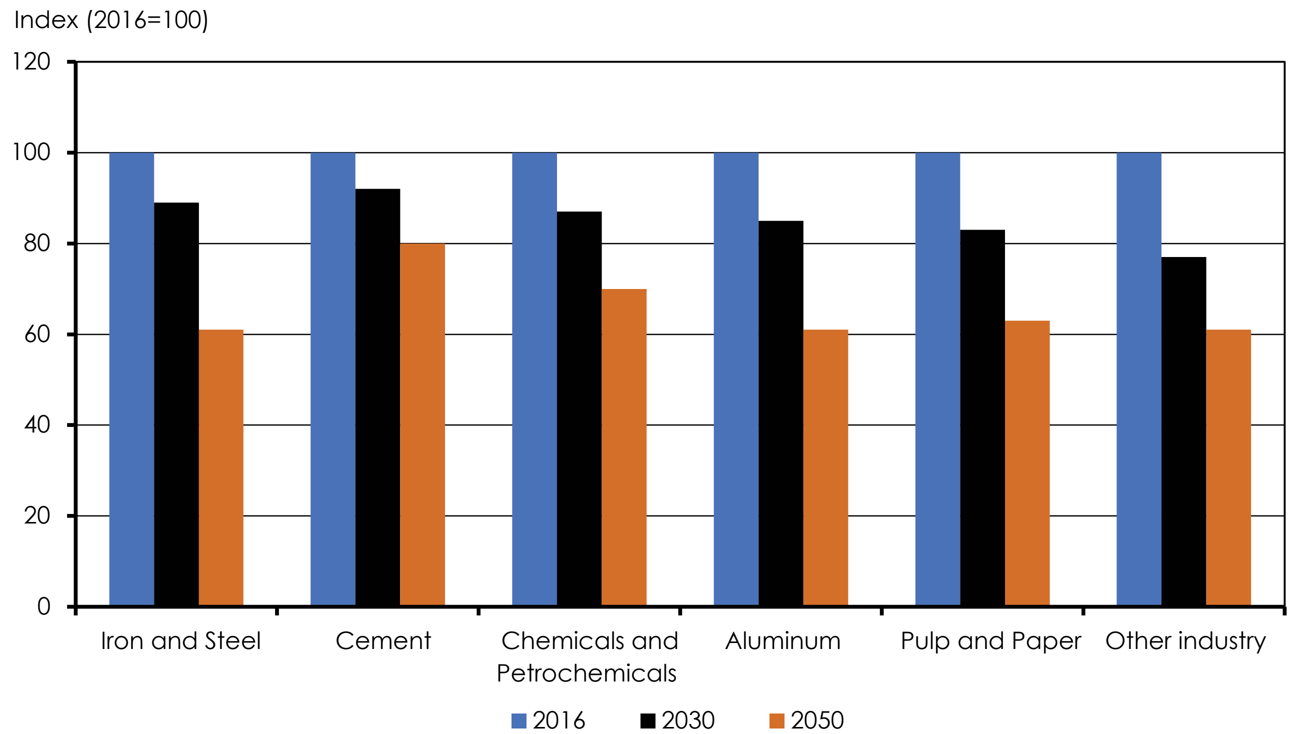
Figure 4.13: Energy-intensive Industry Decarbonisation Options



Source: Bataille, et al

- **Improved Energy Efficiency**: Energy efficiency and adopting best available technologies will also play a key role. Figure 4.14 shows recent IEA analysis for Canada, comparing energy intensity in 2016, 2030 and 2050. The IEA suggests in a high efficiency scenario, energy intensity of various industries could fall relative to 2016 levels, showing some variation depending on the industry. The Technology Case assumes that average process and device efficiency increases by 5 to 10% relative to the Reference Case in 2025, and 15 to 30% by 2040. Process changes, such as increased material recycling, are assumed to reduce energy demands.

Figure 4.14: Canadian Industry Energy Intensity Reductions Relative to 2016, IEA Energy Efficiency Scenario, 2030 and 2050

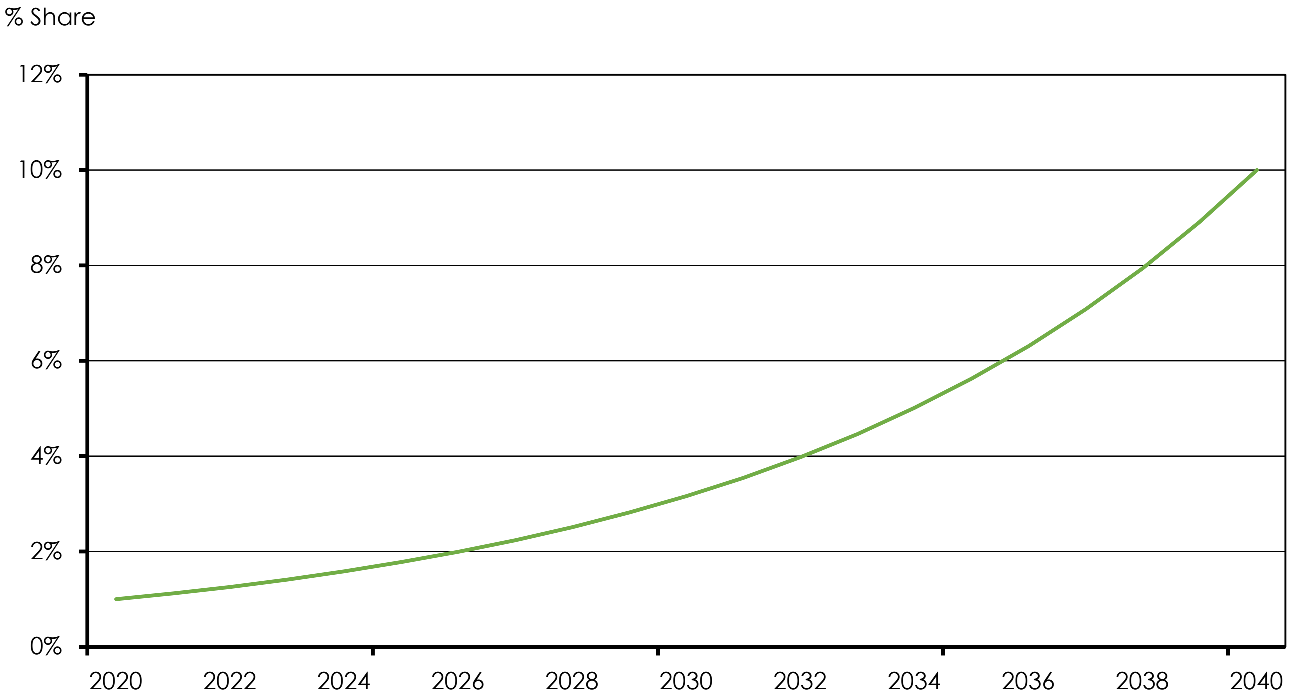


Source: IEA

Multi-sector Technologies

- **Renewable Natural Gas (RNG) Blending**: Costs of RNG vary by production type, and typically range between $8 and $20 per GJ. Although the lower end of that range is still higher than benchmark natural gas prices, as carbon costs rise and technology improves in the longer run, the relative economics of RNG could improve. The Technology Case assumes an average blending of RNG in Canada's marketable gas mix of nearly 2% by 2025, 3% by 2030, and 10% by 2040. Figure 4.15 shows the rate of RNG blending in the Technology Case.

Figure 4.15: Renewable Natural Gas Blending Rate, Technology Case



Renewable Natural Gas

RNG is carbon neutral methane gas derived from captured organic waste. It can be produced from agriculture, forestry, and municipal waste sources. Impurities are then removed to meet necessary specifications for transportation, distribution, and use. Canada has several existing RNG facilities, and some distributors offer RNG blending as a consumer service.

- **Carbon Capture Technology**: CCS and CCUS is another technology group that could gain significant momentum in a global shift towards a low carbon future. CCS and CCUS is often a critical component of energy scenarios that achieve low carbon futures. The Technology Case assumes technological progress and cost reductions for CCUS technology, with an additional 10 megatonne (MT) captured by 2030, and 45 MT by 2040.

Carbon Capture Use and Sequestration in Canada

Several commercial scale projects exist in Canada:

- Saskatchewan: The Boundary Dam power station began operations in 2014. The 115 MW coal-fired power plant is capable of capturing 1.3 MT of CO_2 per year. Most of the CO_2 from the facility is transported to nearby oil fields and used for enhanced oil recovery (EOR), while some is also stored underground in geological formations near the plant. In addition, Saskatchewan has also been importing CO_2 by pipeline for EOR from a coal gasification plant in North Dakota.
- Alberta: The Quest Project captures CO_2 from Shell's Scotford upgrader and transports it by pipeline for permanent storage underground. The project is designed to capture up to 1.1 MT of CO_2 per year or roughly 35% of the upgrader's emissions. Under development is the Alberta Carbon Trunk Line, a 240 km pipeline that will transport CO_2 from an industrial area north of Edmonton to EOR projects in central Alberta. Starting in 2018, the project will transport 1.7 MT CO_2 per year captured from two facilities, the Sturgeon Refinery and an Agrium fertilizer plant. The pipeline has a capacity of nearly 15 MT per year to allow for future CCS projects.

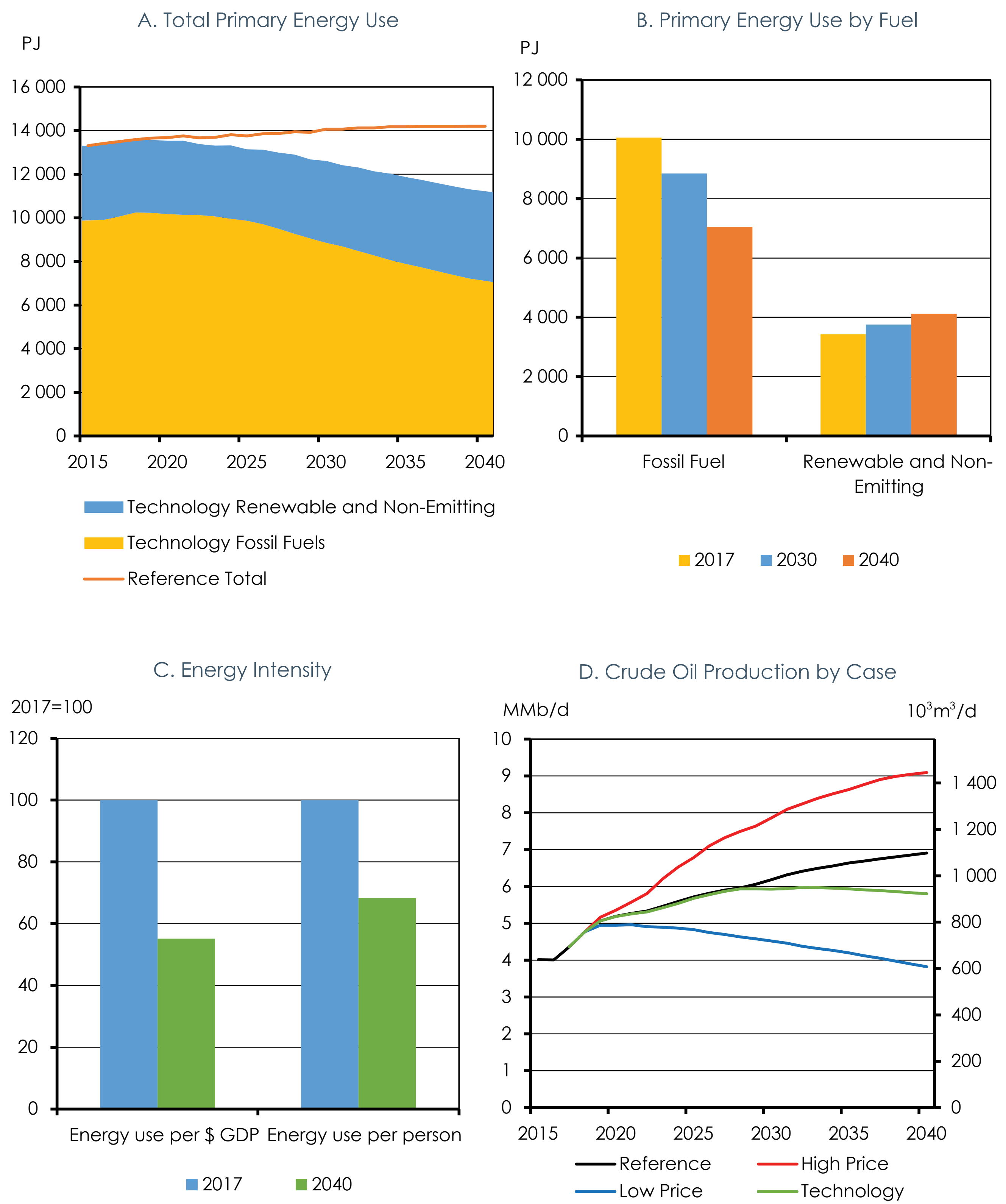
The momentum for this technology has also been varied. As discussed in Chapter 2, Saskatchewan announced in 2018 that it would no longer be going ahead with planned CCS projects in the near future. Internationally, the IEA's Tracking Clean Energy Progress lists CCUS in power and industry alike as "Not on Track." Research and development on CCS and CCUS is ongoing. For example, May 2018 saw the opening of the Alberta Carbon Conversion Technology Centre, a research facility located near Alberta's largest natural gas-fired power plant (Shepard Energy Centre), which will test capture and conversion technologies to turn emissions from the plant into useful products.

Results

The various energy market, policy, and technology assumptions that make up the Technology Case impact the energy supply and demand outlook in many ways. Figure 4.16 highlights four key shifts in the energy system:

1. **Total energy use declines:** Compared to 2017 levels, total Canadian energy consumption is over 15% lower in 2040 despite similar total GDP and population trends.
2. **The share of renewable and non-emitting energy increases:** Fossil fuel use falls faster than total energy demand, and by 2040 fossil fuel demand is 30% lower than 2017 levels. More efficient processes and technologies, as well as switching to renewable energy, cause this trend.
3. **By 2040, energy use per capita is reduced by one third, energy use per $ of GDP is nearly cut in half:** Economic and population growth become further decoupled from energy use, as Canadian homes and businesses use energy more efficiently.
4. **Prices and technologies will shape Canada's role in supplying oil and gas in a transitioning world:** Canadian oil and gas production will be influenced by their ability to reduce costs and emissions. Technologies such as solvent-based injection for oil sands production provide an opportunity to maintain production, while market prices are a key uncertainty.

Figure 4.16: Technology Case Key Results



Macroeconomic Drivers

Most macroeconomic drivers are similar between the Reference and Technology Case (Table 4.2). This is driven by improved technologies reducing energy use costs, but also several important assumptions. The Technology Case assumes global growth is the same as the Reference Case, including that of key trading partners. Revenues from the higher degree of carbon pricing in the case is recycled back into the economy through personal and corporate tax cuts. These factors result in small differences between macroeconomic trends between the Reference and Technology Cases at the national level.

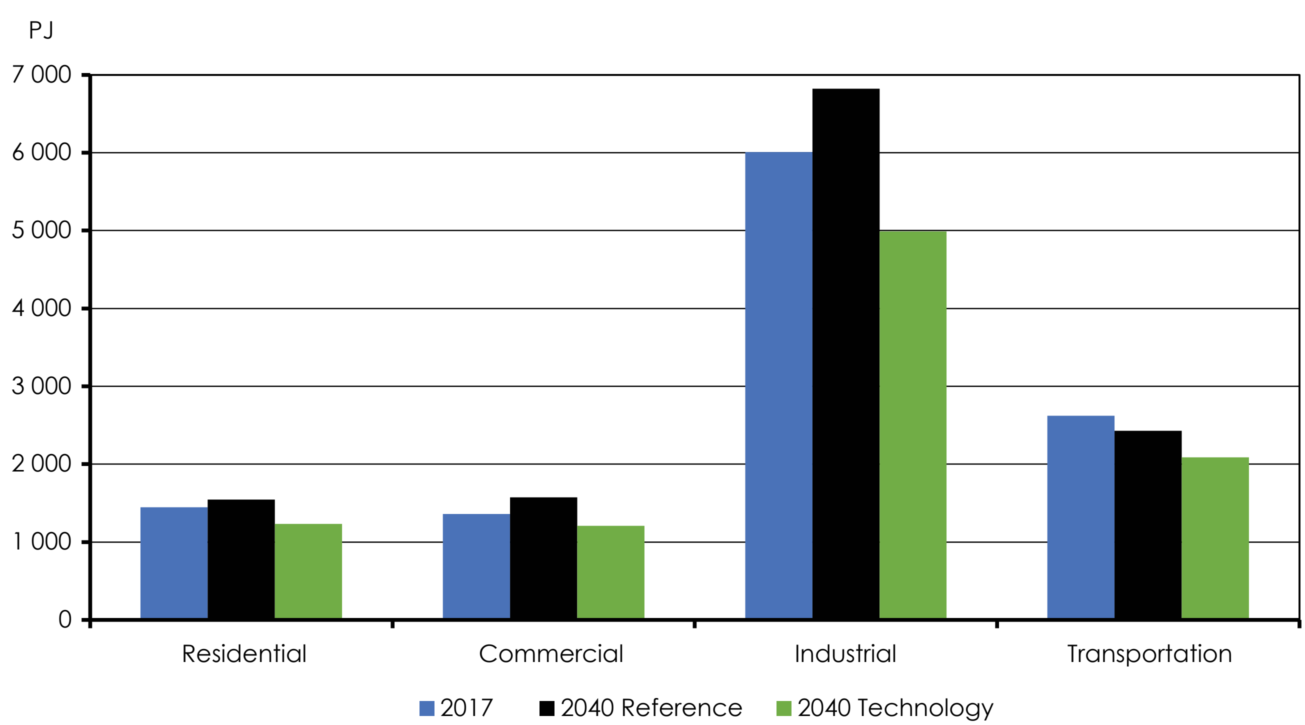
Table 4.2: Economic Indicators, Reference and Technology Cases (CAGR, 2017-2040, unless otherwise noted)

	Reference	Technology
Real GDP	1.8%	1.8%
Population	0.8%	0.8%
Residential Floorspace	1.4%	1.4%
Commercial Floorspace	1.9%	2.0%
Exchange Rate (US$/C$, Average)	$0.82	$0.80

End Use Energy Demand

Figure 4.17 compares Technology Case demands in 2040 to 2017 levels, as well as the Reference Case projections for 2040. In the Technology Case, end-use energy demand declines relative to 2017 levels in all sectors. Demands are also below Reference Case levels.

Figure 4.17: Technology Case Demands by Sector

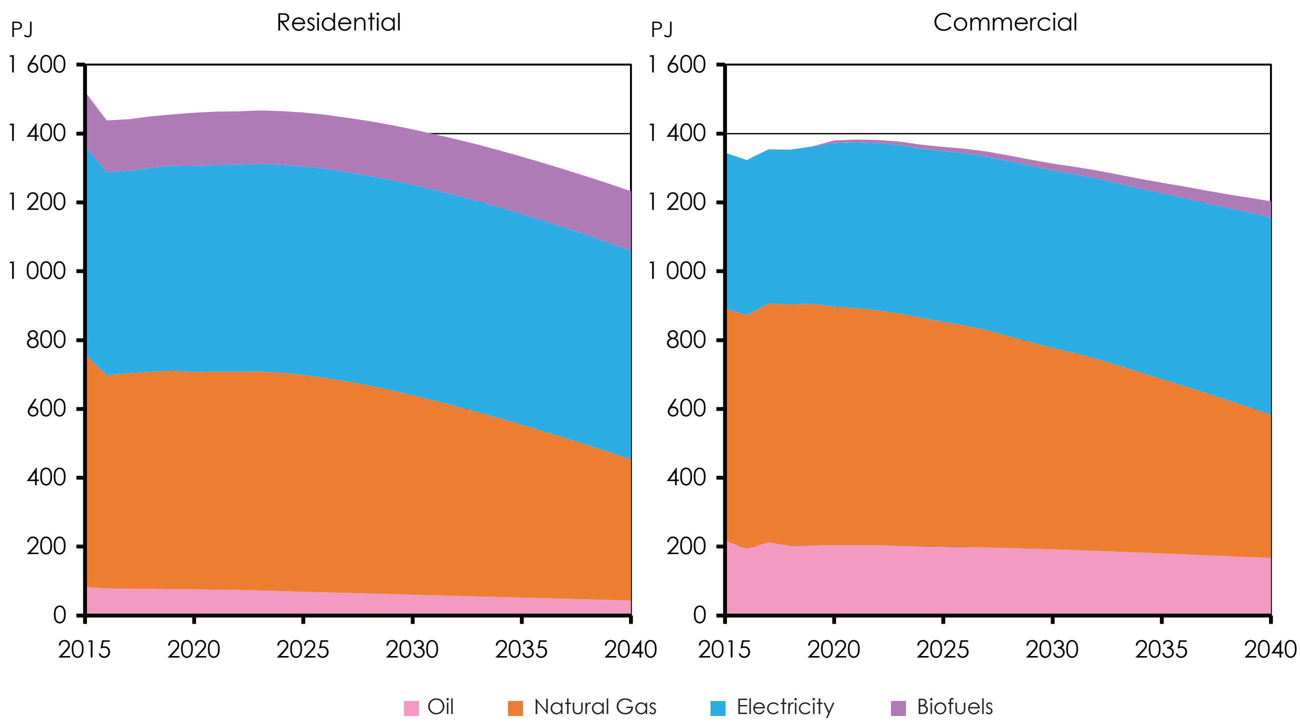


Residential and Commercial

Improving efficiency and increased electrification via high efficiency heat pumps leads to residential and commercial demands being 15% and 11% lower in 2040 than their 2017 levels, respectively. Figure 4.18 shows residential and commercial demand by energy source in the Technology Case.

When heat pumps replace natural gas heating, they lead to higher electricity use, although at lower levels than the natural gas they are displacing. However, when heat pumps replace electric baseboard heating or conventional air conditioning, this reduces electricity demand. Appliance efficiency improvements put further downward pressure on electricity requirements. Overall, despite electrification, annual electricity demands are similar to Reference Case levels. Given that demands for other heating fuels fall faster than electricity in the Technology Case, electricity makes up a growing share of residential and commercial building demands.

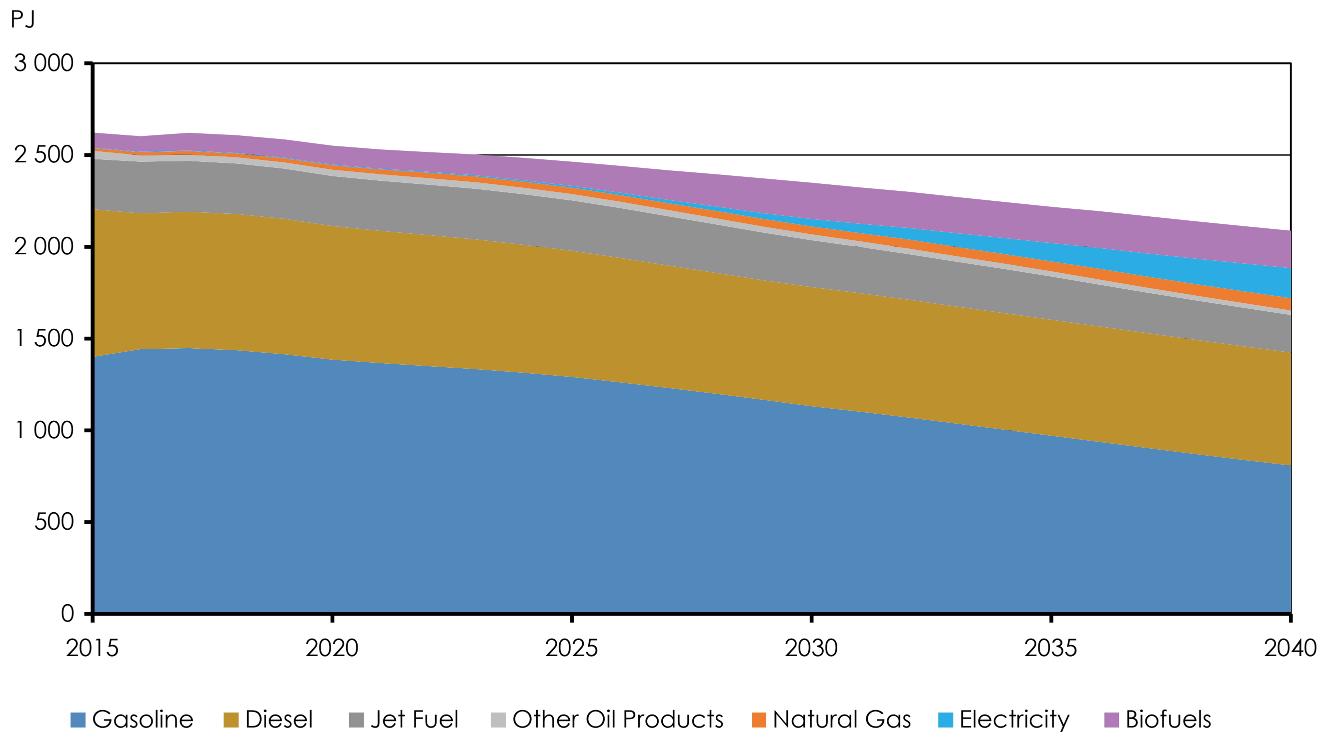
Figure 4.18: Residential and Commercial Demands by Energy Source, Technology Case



Transportation

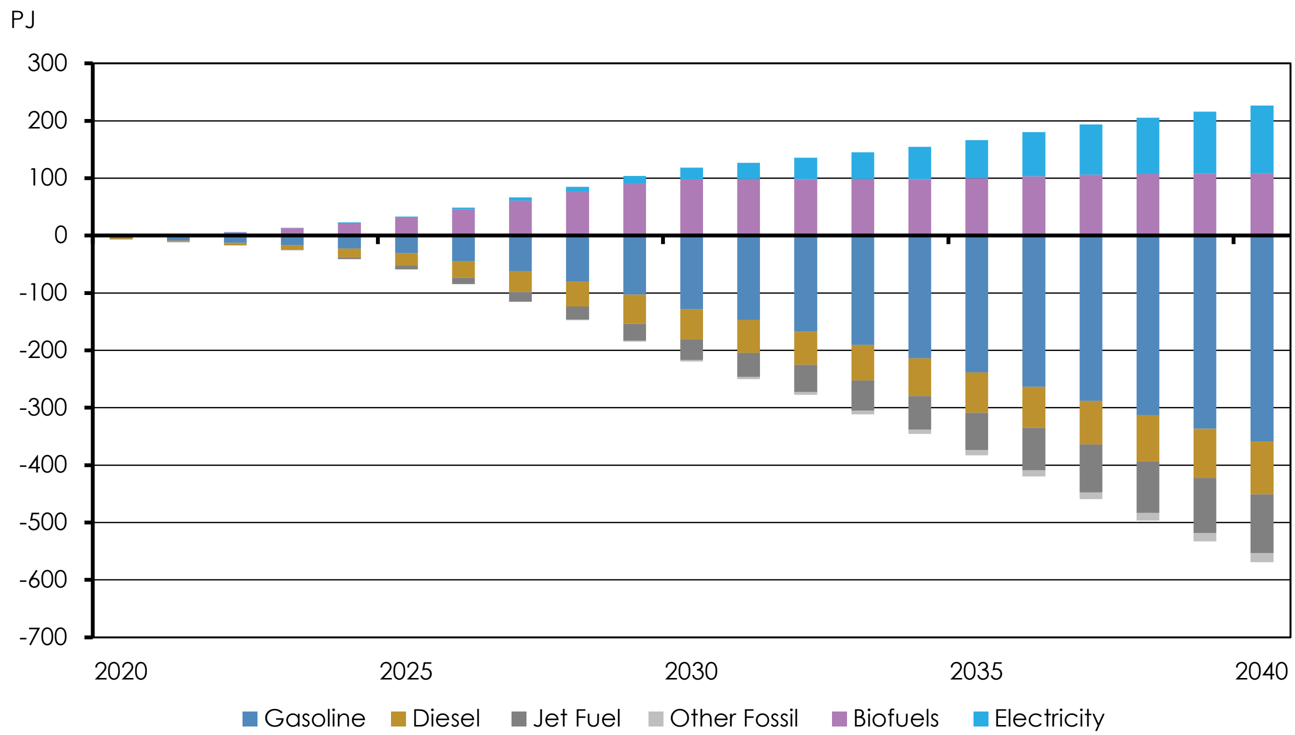
In the transportation sector, increased use of biofuels and electricity diversifies the fuel mix of the sector that has long been dominated by oil-based petroleum products. Energy efficiency improvements for all forms of travel also reduce energy requirements. Figure 4.19 illustrates the transportation sector energy mix in the Technology Case.

Figure 4.19: Transportation Demands by Fuel, Technology Case



Increased EV penetration adds approximately 120 PJ, or over 30 TW.h, of annual electricity use by 2040. This reduces a relatively higher amount of gasoline and diesel, as EVs typically use less energy per km travelled compared to conventional vehicles. Improved vehicle efficiency and biofuel blending further reduces demand for these fuels. Relative to the Reference Case by 2040, Figure 4.20 shows that the Technology Case adds nearly 230 PJ of electricity and biofuels, which is more than offset by a 570 PJ decrease in petroleum product demand.

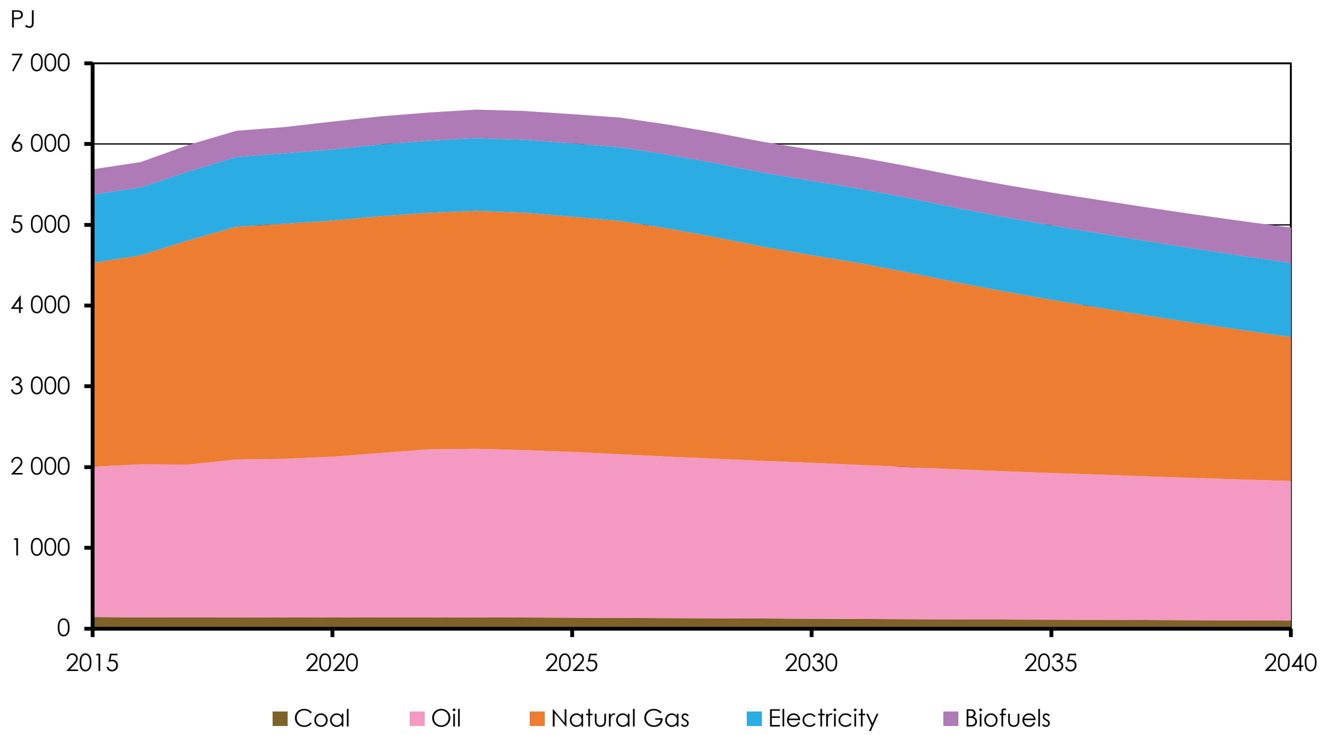
Figures 4.20: Difference in Transportation Demands by Fuels, Technology and Reference Cases



Industrial

Figure 4.21 shows industrial demand in the Technology Case by fuel. This reflects changes in energy use in both the oil and gas production sector as well as other industrial sectors. By 2040, industrial energy use is nearly 15% lower than 2017 levels, and 20% lower than the Reference Case. This is due to lower oil and gas production that is produced using less energy, as well as improved processes in other energy intensive industrial sectors.

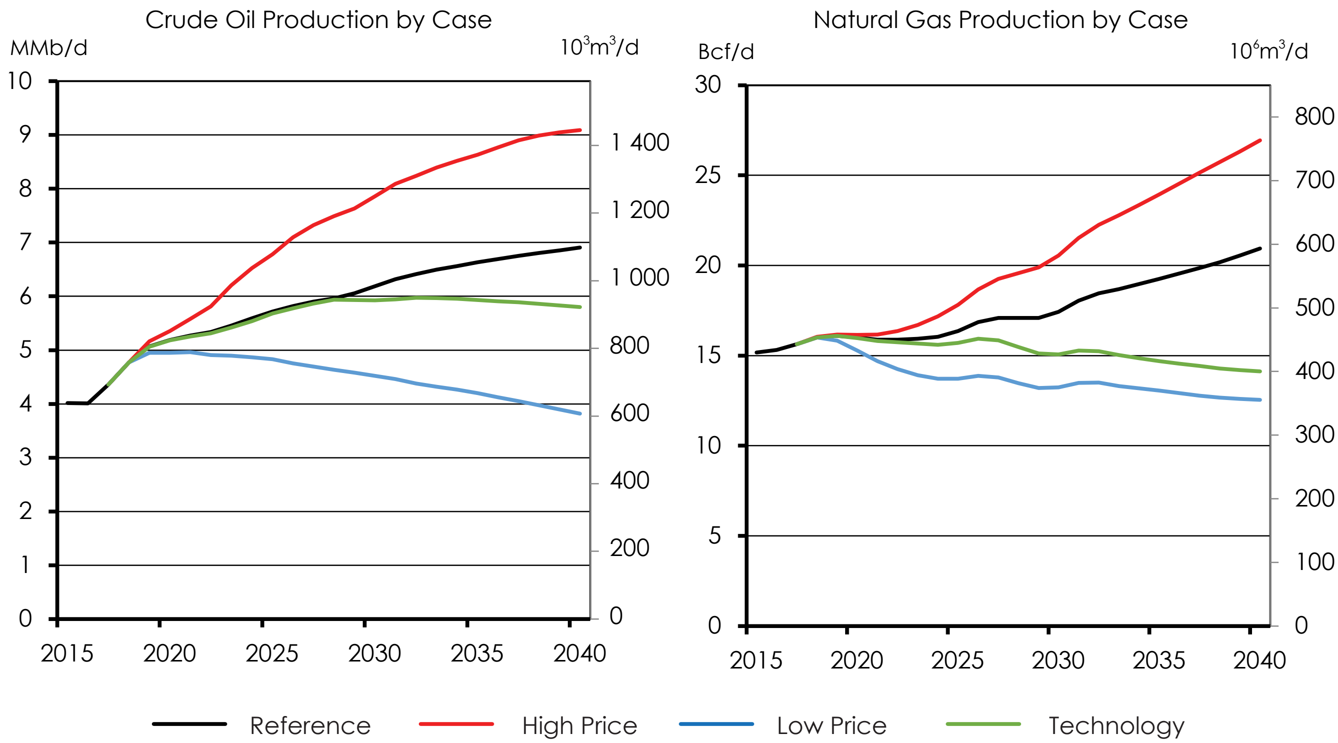
Figure 4.21: Industrial Demands by Fuel, Technology Case



Crude Oil and Natural Gas Production

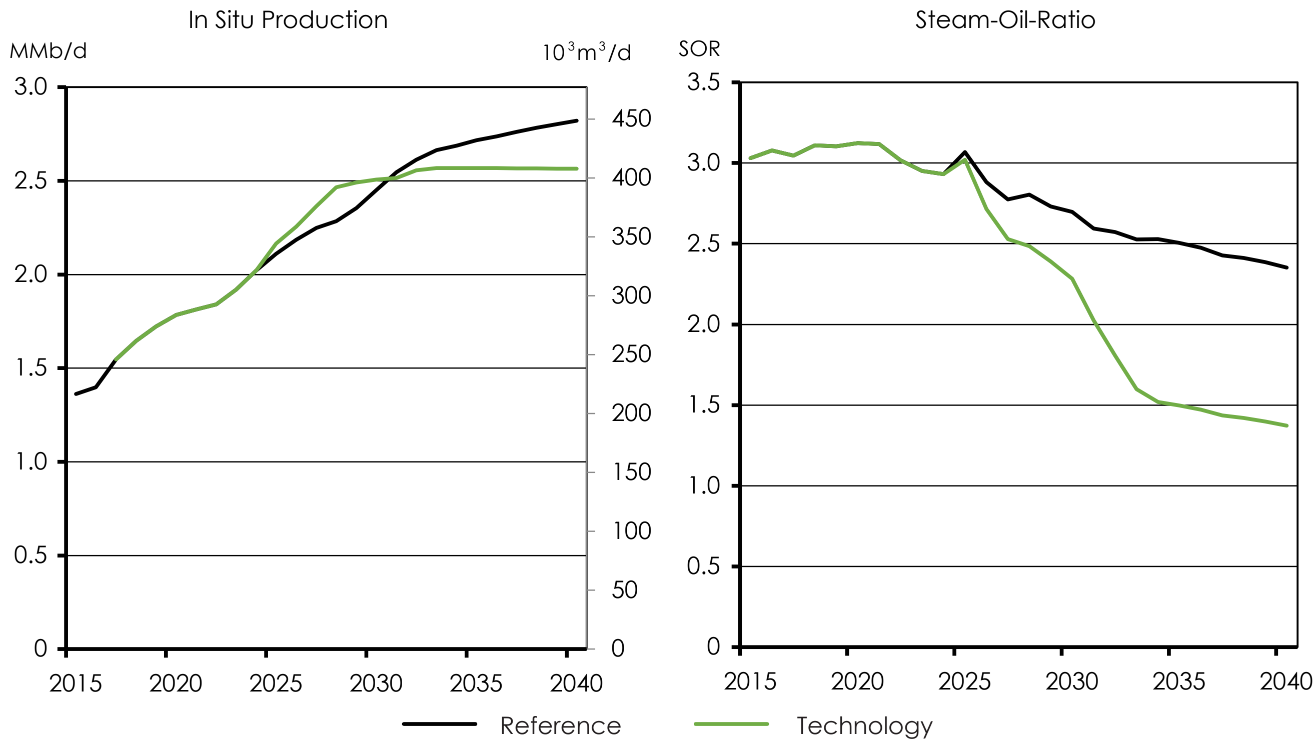
In the Technology Case, oil and natural gas producers face lower prices than in the Reference Case, reflecting slower growth in gas and declining demand for oil. Markets and infrastructure uncertainty are reflected in Canadian price discounts, which are the same as the Reference Case. In this smaller, and therefore increasingly competitive, global market for oil and gas, crude oil and natural gas production are lower than the Reference Case. By 2040, Technology Case crude oil production is 15% lower than Reference Case levels, and natural gas production is over 30% lower. However, production in the Technology Case is higher than the Low Price Case, highlighting the importance of market dynamics in future production trends.

Figure 4.22: Total Oil and Gas Production, All Cases



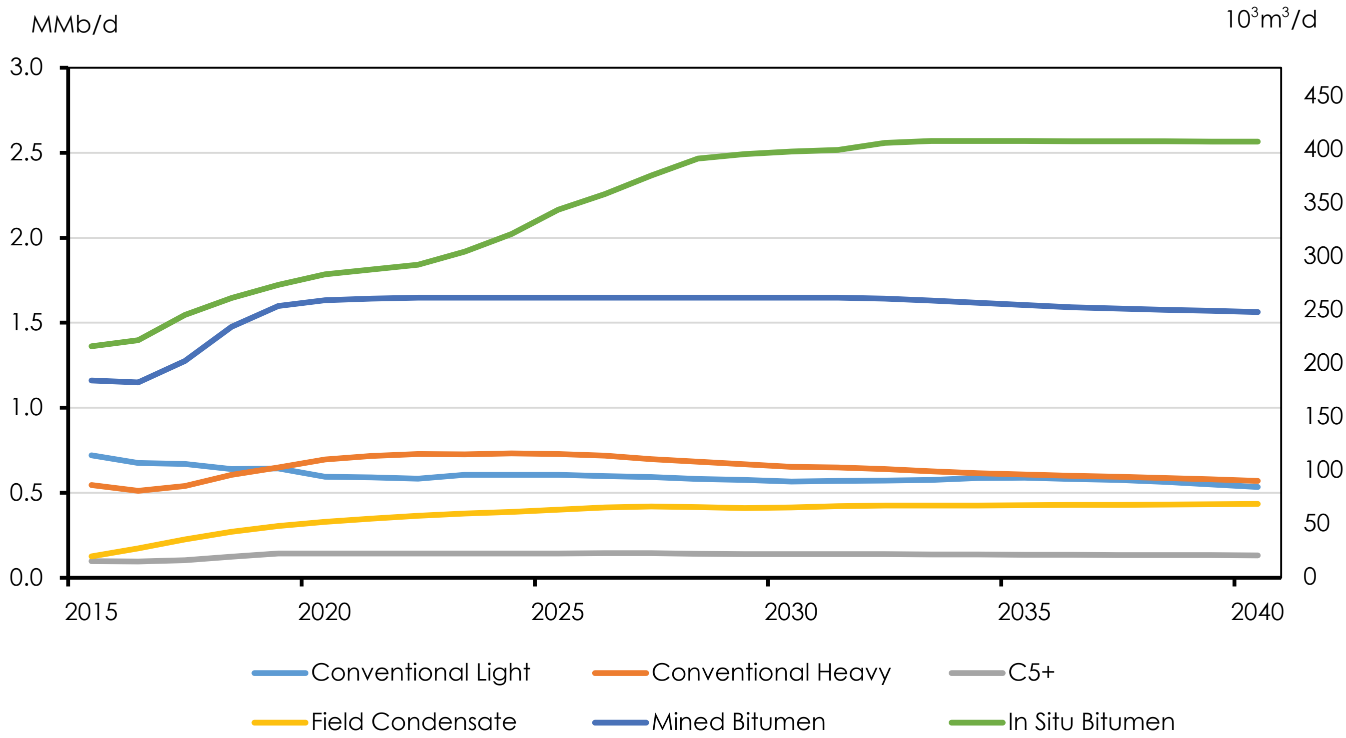
The key technology assumption of steam solvents being widely deployed by 2025 and pure solvents by 2030 has two main effects on oil sand producers. First, the technology creates a production uplift, so more oil is produced using the technology than standard steam injection, possibly up to 30%. Second, the technology reduces SORs. Figure 4.23 shows in situ production and SOR trends. In the medium term, technology improvements dominate market impacts, and Technology Case production is higher than the Reference Case until 2030. Over the longer term, lower prices and higher costs of carbon emissions cause Technology Case in situ production trends to flatten out. By 2040, in situ production in the Technology Case is nearly 10% lower than the Reference Case, but still higher than current levels.

Figure 4.23: In Situ Production and SOR Trends, Reference vs Technology



Another key factor is the relative lifetimes of oil sands projects versus other production types. Figure 4.24 shows production broken down by oil sands mining, in situ, and other production. Because of their long lifetimes, extremely low decline rates, and low per-barrel marginal costs of production, oil sands facilities continue to produce near current levels, with solvent-fueled technology leading to increases in production. Other forms of production, such as conventional and tight light oil, have shorter capital investment cycles, and are projected to be more responsive to global shifts in demand.

Figure 4.24: Oil Production by Type, Technology Case

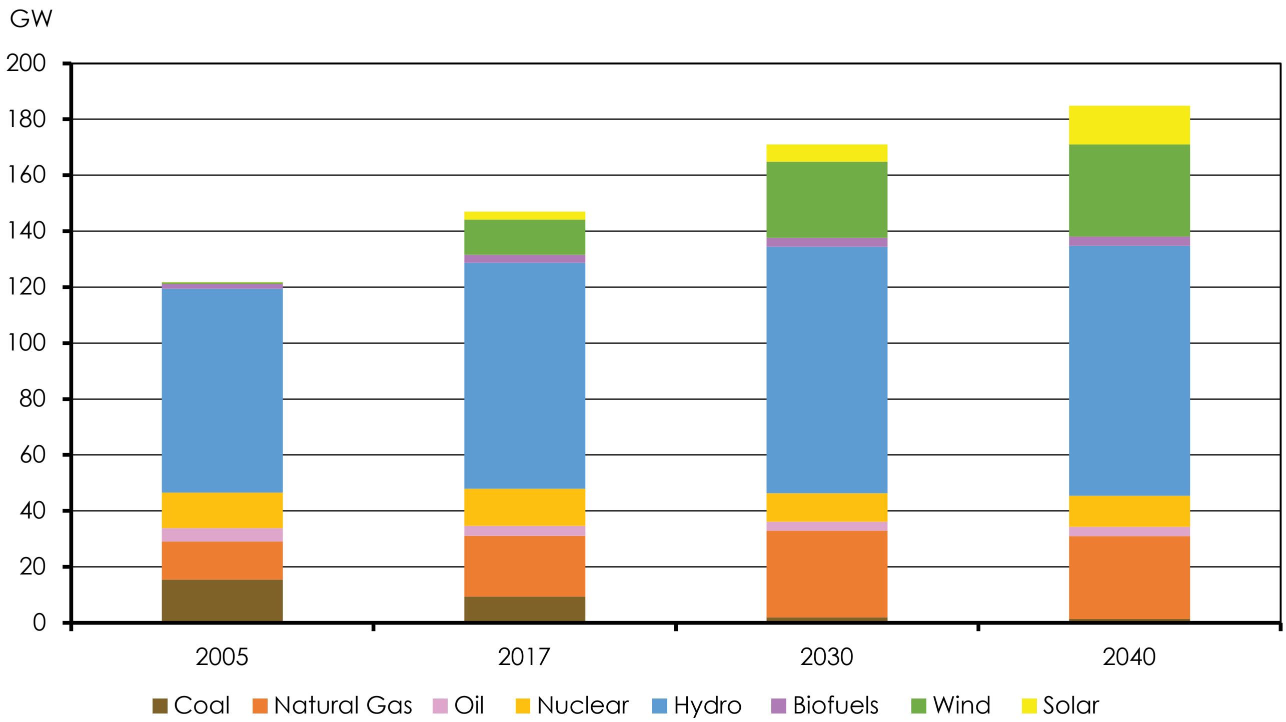


Electricity Generation

In the Technology Case, electricity generation is moderately higher than the Reference Case, reflecting improvements to energy efficiency roughly balancing additional electric demands from uses such as electric vehicles. In this case, Canada's already low-emitting grid reduces its emission intensity even further.

In the Technology Case, electric generating capacity is 26% higher than 2017 levels. Hydro still dominates Canada's capacity mix, and the combined capacity of wind and solar more than triples in the Technology Case, due to assumed lower costs and improved integration. In the Technology Case, wind and solar make up over 25% of Canada's capacity mix in 2040, compared to just over 10% in 2017. Figure 4.25 shows total electric capacity by fuel in 2005 and 2017 and in the Technology Case for 2030 and 2040.

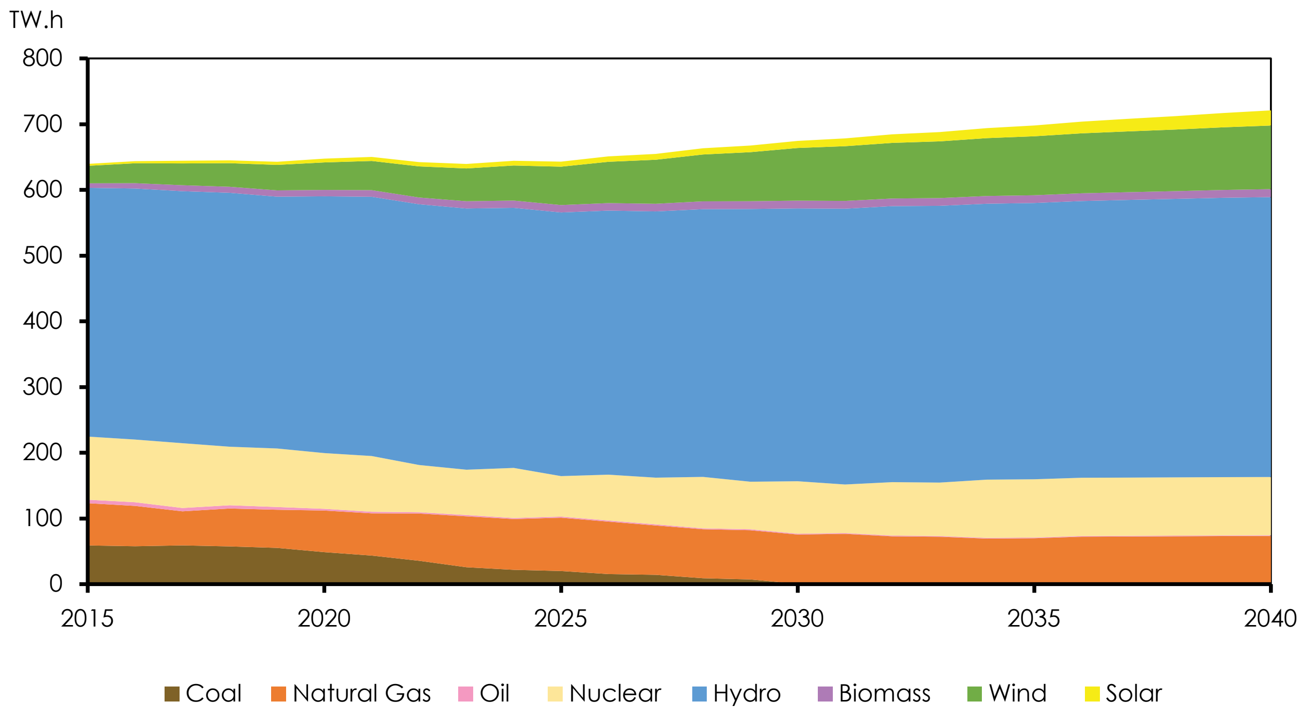
Figure 4.25: Capacity 2005, 2017, Technology Case 2030 and 2040



Electric generation is 12% higher than 2017 levels by 2040. Relative to the Reference Case, capacity grows more than generation in the Technology Case because most of the additions are wind and solar. Wind and solar tend to generate less per MW of capacity compared to other sources of electricity. While wind and solar make up 25% of capacity in 2040, these resources account for 17% of generation. Figure 4.26 shows electricity generation by source in the Technology Case.

Electricity generation varies significantly by province. For hydro generating provinces, the electricity mix is relatively similar to the Reference Case, with small levels of wind and solar added due to lower costs. For other provinces, wind and solar become an increasingly large part of the mix. These resources are backed up with natural gas as well as increased interchange and demand side management.

Figure 4.26: Electricity Generation by Fuel and Type, Technology Case 2040



Canada wide, the share of renewables and nuclear electricity generation reaches 90% by 2040. This compares to 84% in the Reference Case, and 82% in 2017. These annual figures can be misleading, as electric loads vary significantly during the day, as does available energy from variable sources like wind and solar. How these sources are matched with changes in electricity demands from end-users is an important uncertainty.

Primary Demand and GHG Emissions

The Technology Case implies a significant reduction in total primary energy demand, as well as a shift towards relatively more non-emitting energy. These changes will reduce Canada's GHG emission trajectory, as less fossil fuels are combusted and more carbon is captured and sequestered. Figure 4.27 shows total primary energy demand by fuel. In the near term, energy use peaks and then begins to decline, with energy demand in 2025 2 to 3% lower than 2017 levels. Post 2025, end-use electrification reduces direct fossil fuel use, improved efficiency reduces demands for all types of energy, and the electricity mix includes a greater share of renewable energy. Total primary energy use declines by over 1% per year from 2025 to 2040. By 2040, total demand is over 15% lower than 2017 levels, while fossil fuel use drops even faster to 30% below 2017 levels.

Figure 4.27: Primary Demand by Fuel

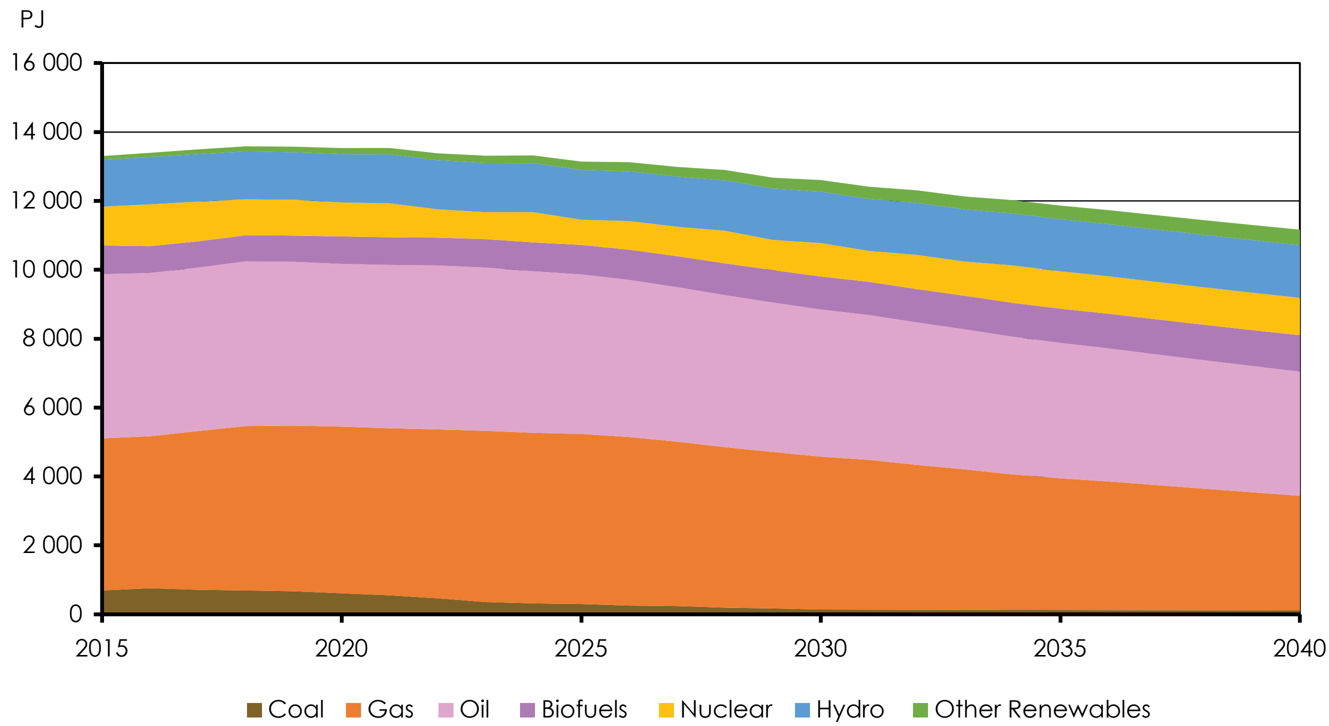
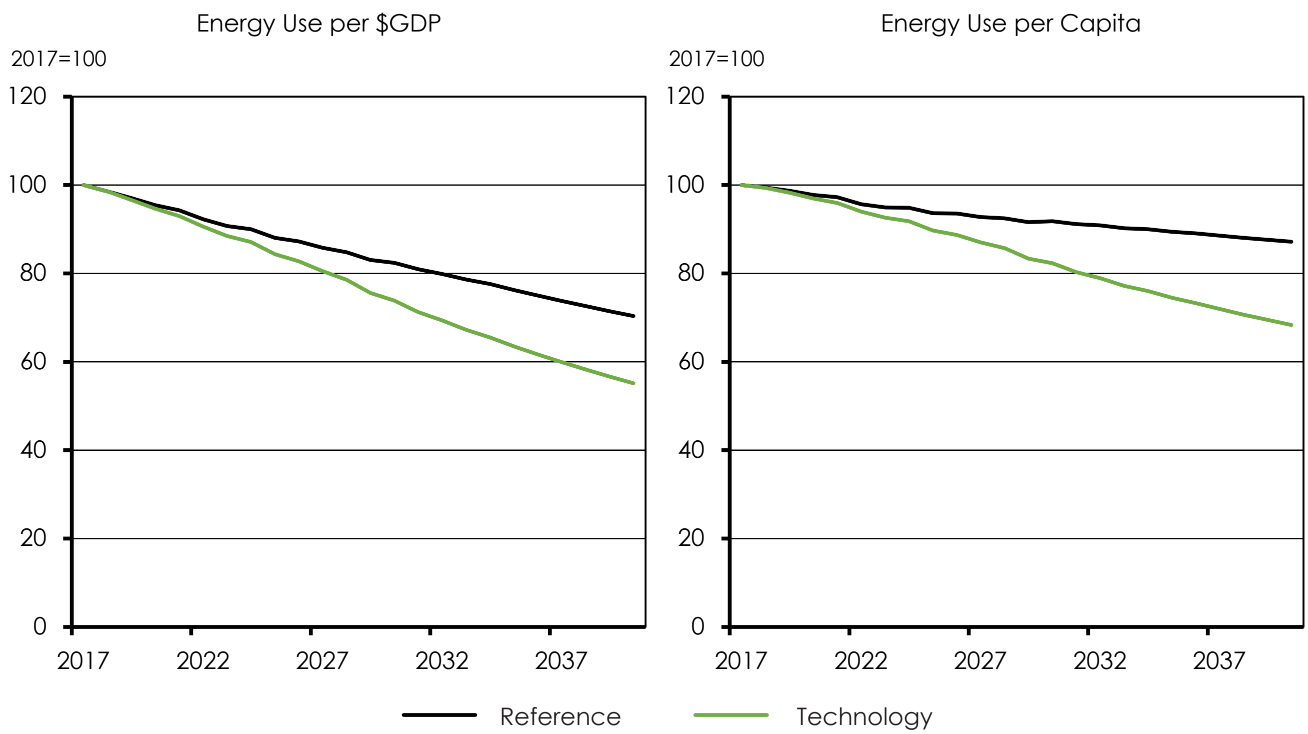


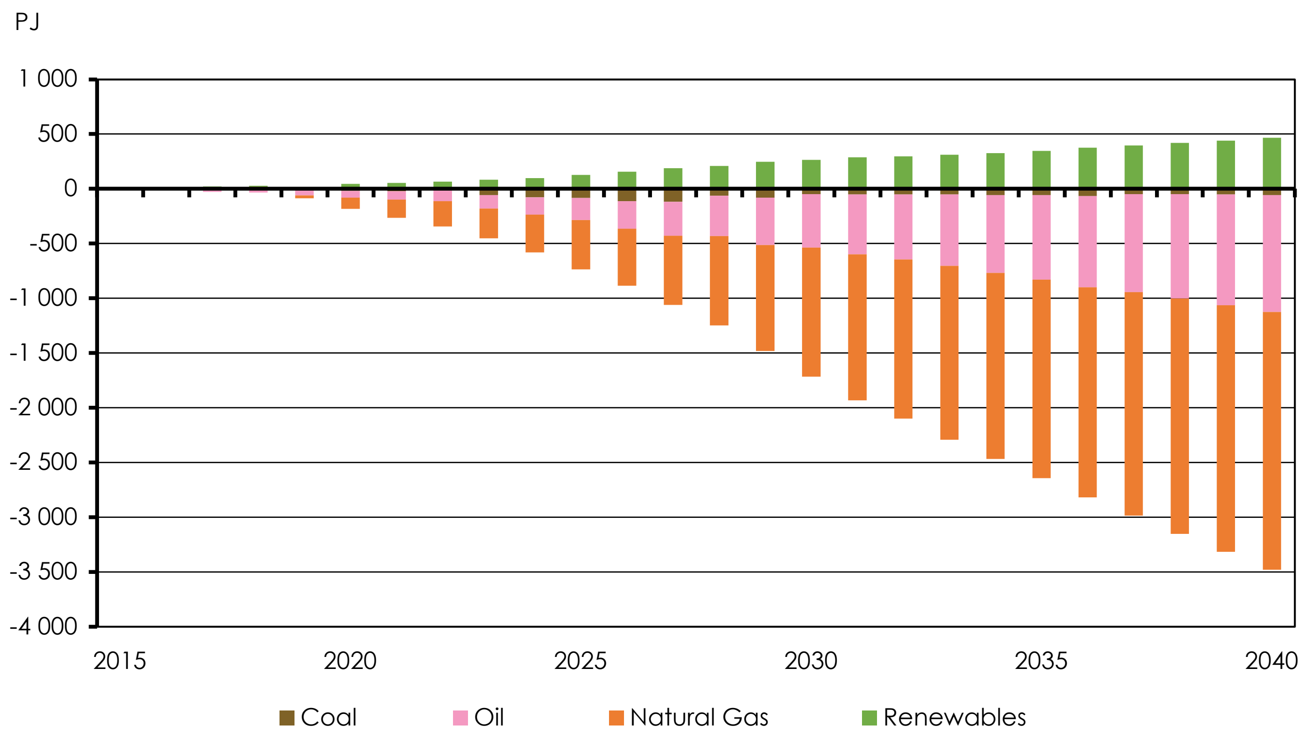
Figure 4.28 compares the total energy intensity of the economy between the Reference and Technology Cases, for both energy use per $ GDP and energy use per person. Energy use per $ GDP has generally declined in the last few decades, as economic growth has outpaced energy demand growth. Energy use per capita, on the other hand, has remained relatively flat. The Technology Case represents a further decoupling of energy use from GDP and population growth. This results in energy use per $ GDP declining 2.5% per year in the Technology Case, to be 45% lower than 2017 in 2040. Energy use per capita falls 1.6% per year in the Technology Case to be 30% lower than 2017 in 2040.

Figure 4.28: Energy Intensity Trends, Reference and Technology Cases, % of 2017 Level



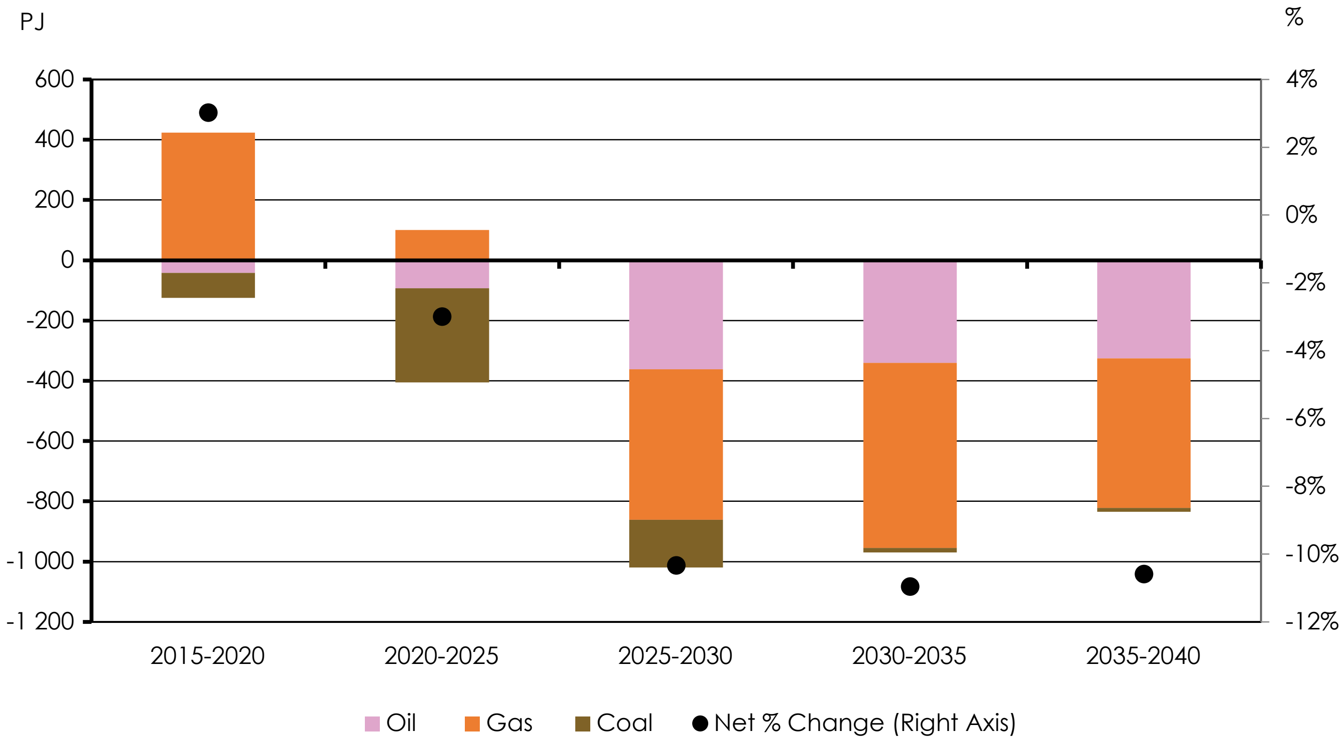
Compared to the Reference Case, the Technology Case uses more renewable energy and less fossil fuels (Figure 4.29). Renewable additions include wind and solar for electricity generation, increased biofuel blending in transportation, and increased use of RNG in the natural gas mix. Fossil fuel reductions are due to fuel switching towards biofuels or electricity at the end use level, relatively less natural gas used to generate electricity, and efficiency and process changes that require less energy, such as the adoption of solvent technology in the oil sands or heat pumps in buildings.

Figure 4.29: Change in Primary Energy Demand by Fuel Type, Reference vs Technology



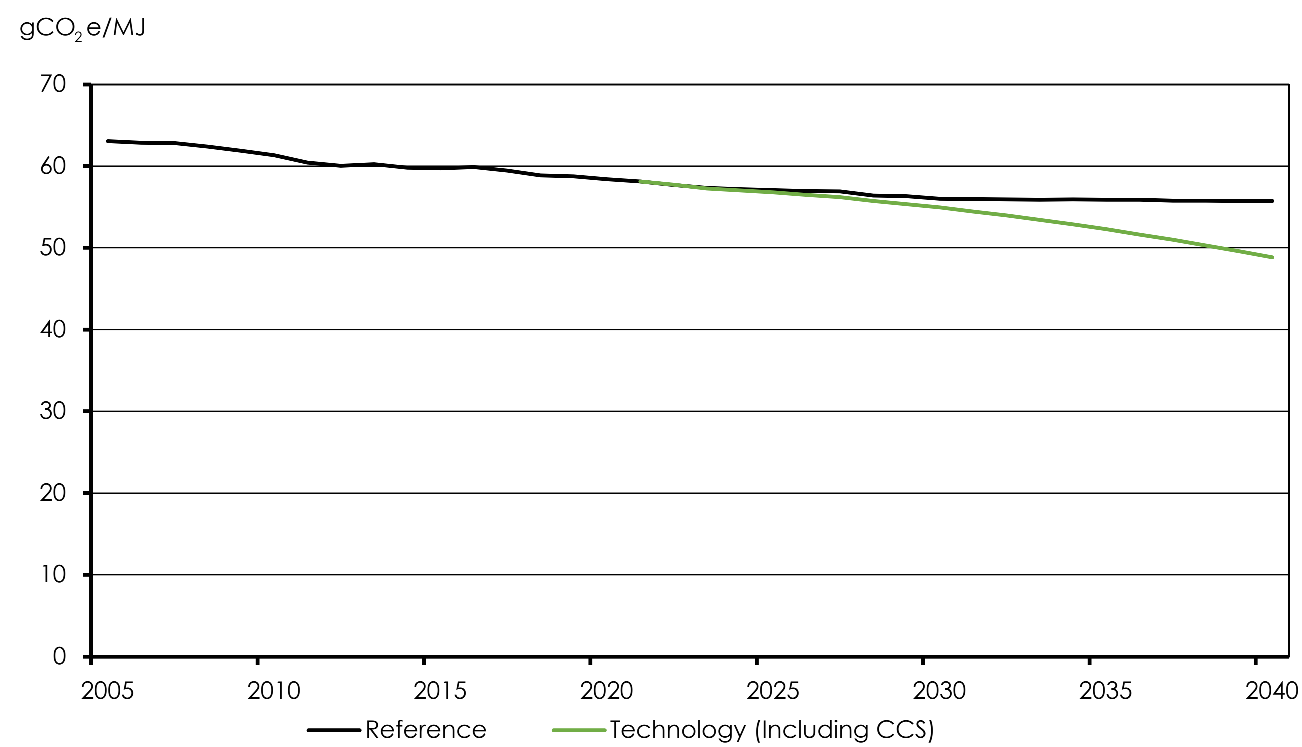
The Technology Case shows that in a transitioning global energy context, Canada's energy mix will transition as well. Figure 4.30 illustrates the change in coal, oil product, and natural gas demand in five year increments over the projection. The near term shows trends for increasing fossil fuel use in Canada reversing, largely driven by coal retirements and improved vehicle efficiency reducing oil product demand. Natural gas increases in the near term due to its role in oil production, heating, and replacing some of the initial coal retirements. In the longer term, new technologies and strengthening policies reduce demand for all three, such that every five years fossil fuel demand drops by about 10%.

Figure 4.30: Change in Fossil Fuel Demand Over Five Year Increments, Technology Case



The combination of reduced coal, as well as increased CCS, reduces the GHG intensity of the fossil fuel mix, putting further downward pressure on Canadian GHG emissions. Figure 4.31 compares estimated fossil fuel GHG emissions intensity for the Reference and Technology case.

Figure 4.31: Estimated Fossil Fuel GHG Emissions Intensity, Reference and Technology Cases

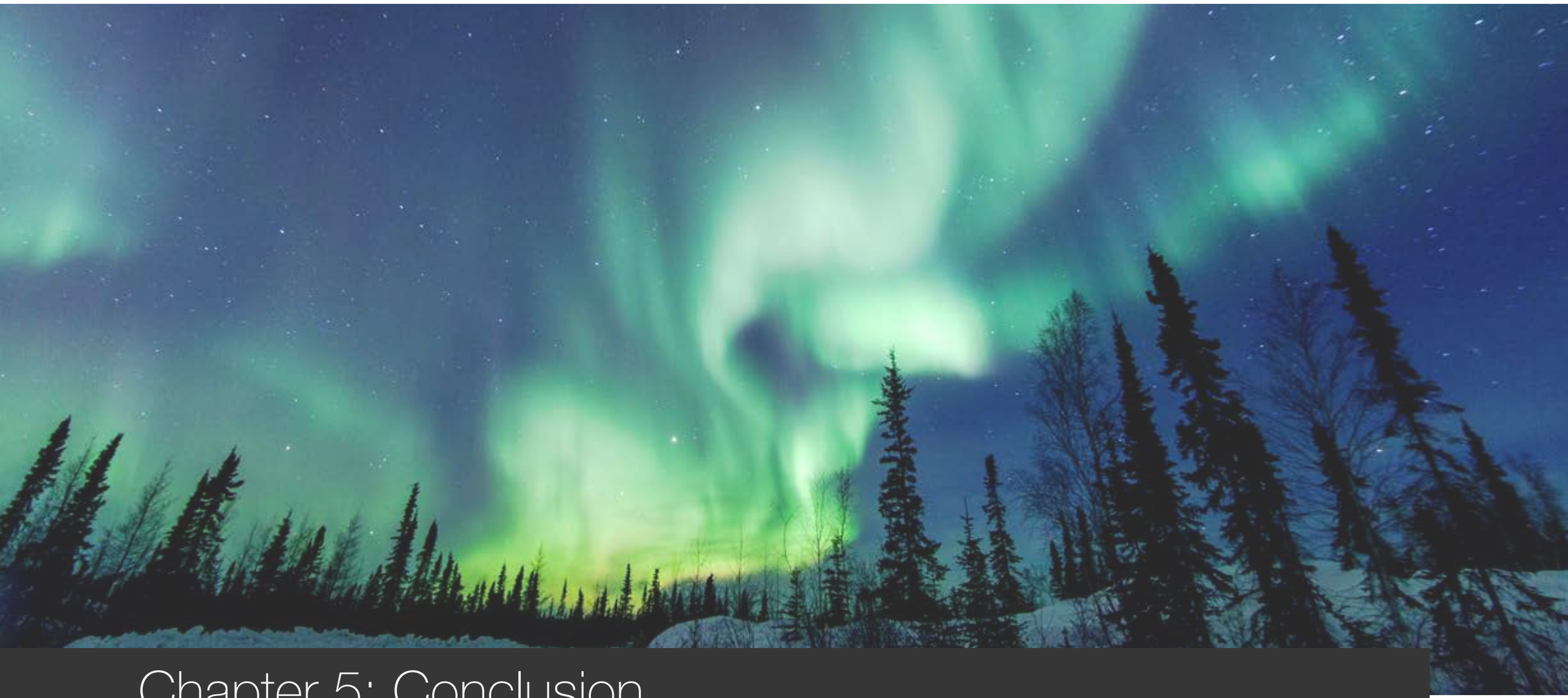


Key Uncertainties

The Technology Case provides one snapshot of what a global shift towards a low carbon economy might mean for Canada. Future development of both policies and technologies could lead to different outcomes than those presented in this analysis.

- **Global context**: How the global context affects global energy markets and investment is a key uncertainty that is important for the oil and gas projections. In the case of oil, others have suggested that falling global oil demand would mean a lower price than the Technology Case assumes. This could bring Canadian production trends closer to the Low Price Case.
- **Differentials and infrastructure**: Regional price differentials and infrastructure developments are generally assumed to be similar to Reference Case levels in the Technology Case. These are all highly uncertain areas however. Both oil and gas differentials could be different than assumed here, as could impact future project developments like LNG.
- **Lower technology costs**: The Technology Case assumes that costs of new technologies such as wind, solar, and batteries will continue to fall in the longer term. If these reductions do not occur, it is likely the adoption of these technologies will be lower.
- **Increased end-use electricity**: As part of the Technology Case, many end-use applications switch to electricity. Although the overall results of the Technology Case show similar electricity demand with the Reference Case as improved efficiency balances additional demand sources, there are many uncertainties with this result. First, depending on the distribution of electric loads throughout the day, or season, there may be additional challenges for the electric grid. Second, other scenarios see electricity increasing[26] as additional load requirements may not be offset by improved efficiency.
- **Technological innovation**: There are many details that are not covered in this analysis, which is based on relatively high level trends. As new technologies are adopted, the integration of energy supply and demand will likely become more and more important. Innovation will be necessary across the entire spectrum of the energy system–consuming and producing technologies, market and policy design, and public involvement in energy system issues–to ensure Canadians' energy needs are met in a reliable and affordable way.
- **Disruptive technologies**: The EF2018 Technology Case generally assumes gradual adoption of new technologies. Faster changes and disruptive technologies could alter the way Canadians use and produce energy, resulting in primary energy demand that is lower or higher in any of the cases presented in this report.

26 Examples include: CERI electrification study, NREL Electrification Futures demand side, DDPP, and Trottier.



Chapter 5: Conclusion

The projections in EF2018 show an evolving Canadian energy system. Canadians' use of energy is expected to be growing slowly, with energy and economic growth continuing to decouple. A global shift towards more low carbon technologies supported by strengthening climate policy, as outlined in the Technology Case, could put domestic fossil fuel use on a downward trajectory. Canada continues to have potential to increase production of many forms of energy, both renewable and from fossil fuel sources. Price and technology developments are the factors most likely to shape future production trends.

The pace and nature of this evolution will depend on many factors. Examples of these include: prices and market developments, emergence of new technologies, energy and climate policies at all levels of government, international policies and regulations, and the ongoing relationship between growing oil and natural gas production and capacity to transport these commodities to markets. Many key developments have occurred while this analysis was underway in 2018. Examples include the USMCA, the return of significant price discounts for Canadian heavy oil compared to global crude oil benchmarks, LNG Canada's final investment decision to build an export LNG terminal on Canada's west coast, and many important provincial policy decisions as part of the Pan-Canadian Climate Framework.

The projections in EF2018 are not a prediction of future Canadian energy trends. There are many reasons why future energy supply and demand may deviate from these projections. Energy systems are complex, involving a variety of uncertain factors interacting in sometimes unexpected ways. Alternatively, specific actions could be taken by governments, businesses, and citizens to change course from current trends to achieve outcomes not contemplated in this report. The projections contained in EF2018 provide a baseline to support ongoing discussion of Canada's energy future, including many of the key uncertainties and emerging trends.

Appendix A: Recent Climate Policy Developments

Table A.1 describes many recent climate policy developments and whether that policy is included in the analysis of EF2018. The following criteria were applied to determine whether a certain policy was included in the report:

- The policy was publically announced prior to 1 August 2018.
- Sufficient details exist to model the policy.
- Goals and targets, including Canada's international climate targets, are not explicitly modelled. Rather, policies that are announced, and in place, to address those targets are included in the modelling and analysis.

This Table is for background purposes and not intended to be an exhaustive list of all Canadian climate policy initiatives. For a detailed list of current policy initiatives, see Canada's 7th National Communication and 3rd Biennial Report, National Communication Table 1: Summary of Policies and Measures by Sector.

Table A.1 – Recent Major Climate Policy Announcements

Description	Details	EF2018
Pan-Canadian Framework on Clean Growth and Climate Change	In December 2016, Canada's First Ministers released the Pan-Canadian Framework on Clean Growth and Climate Change (Pan-Canadian Framework), which outlined the actions that will contribute to meeting or exceeding Canada's 2030 climate change target of a 30% reduction below 2005 GHG emission levels. Pillars of the Pan-Canadian Framework include: 1) pricing carbon pollution, 2) complementary actions to reduce emissions, 3) adaptation and climate resilience, 4) and clean technology, innovation, and jobs. The framework describes many new actions associated with the four pillars.	Several core elements of the Pan-Canadian Framework are included in EF2018, as described in the following sections.
Emission standards for heavy-duty vehicles (for post-2018 and beyond model years)	In July 2018, the federal government published final regulations on Amending the Heavy-duty Vehicle and Engine GHG Regulations. The regulations (Phase II) will introduce stronger standards for new vehicles and engines in model year 2021, and they will increase in stringency up to model year 2027. These standards improve a truck's overall fuel efficiency and reduce GHGs. The new regulations follow the 2014-2018 (Phase I) standard.	Post-2018 model year emissions standards for heavy-duty vehicles are included in EF2018.
Reducing methane emissions from the oil and gas sector	In April 2018, ECCC published federal methane regulations. The regulations will apply to oil and gas facilities responsible for the extraction, production and processing, and transportation of crude oil and natural gas, including pipelines. The first federal requirements come into force in 2020, with the rest of the requirements coming into force in 2023.	Regulation of methane emissions is included in EF2018.
Pan-Canadian Approach to Pricing Carbon Pollution	The federal government outlined its proposed approach to carbon pricing in Canada in October 2016. Jurisdictions have the flexibility to implement: 1) an explicit price-based system (a carbon tax like British Columbia's or a carbon levy and performance-based emissions system like in Alberta), or 2) a cap-and-trade system (e.g. Quebec). Revenues from carbon pricing remain in the jurisdiction of origin. In May 2017, the federal government released a technical paper on the implementation of a federal carbon pricing backstop. It provides details on how carbon will be priced in jurisdictions that do not have a carbon pricing system in place.	This initiative is included in EF2018. Carbon pricing assumptions are outlined in Chapter 2.

Federal phase-out of traditional coal-fired generation by 2030	In November 2016, the federal government announced it is amending the regulations applicable to coal-fired electricity generation to ensure that all traditional coal-fired units are phased out by no later than 2030. Alberta, Saskatchewan, New Brunswick, and Nova Scotia have coal-fired power plants that would be impacted by these regulations. Prior to this announcement, Alberta had already committed to phasing out pollution from coal-fired plants by 2030.	The phase-out of coal-fired generation is included in EF2018. Equivalency agreements with Saskatchewan and Nova Scotia were announced and in development, and are assumed in this analysis.
Federal clean fuel standard	The federal government announced a plan in November 2016 to work with provinces, territories, and stakeholders to develop a clean fuel standard. A clean fuel standard requires the lifecycle carbon footprint of fuels supplied to decline over time. A regulatory framework for the standard was published December 2017. Currently, proposed regulations for liquid fuels are to be published in spring 2019, final regulations in 2020, and requirements coming into force by 2022. Proposed regulations for gaseous and solid fuels are scheduled for fall 2020, final regulations in 2021 and requirements coming into force by 2023.	The clean fuel standard was under development at the time of analysis and is not included in EF2018.
Provincial and Territorial Carbon Pricing Initiatives	Many provinces and territories have developed their own approaches as part of the Pan-Canadian approach to pricing carbon pollution. Examples of developments in 2018 include: Manitoba's carbon price and output-based pricing system for large industrial emitters. Northwest Territories carbon tax with select exemptions (aviation fuel and heating fuel for most residents, businesses, and governments). Ontario's withdrawal from the WCI and proposal to reduce gasoline prices by ten cents per litre. British Columbia's increasing carbon tax. Nova Scotia's proposed cap-and-trade system.	High-level carbon pricing assumptions are outlined in Chapter 2. EF2018 assumes that the federal backstop applies to all provinces and territories that do not meet the benchmark in the Pan-Canadian approach. Province and Territory-specific exemptions and allocation systems are included.
Provincial and Territorial Renewable Electricity Initiatives	Various provincial and territorial initiatives to increase the amount of renewable electricity are in place. Recent examples include Alberta's Renewable Electricity Plan, which held its first round in 2017, and Saskatchewan's current request for proposal for wind and solar developments.	EF2018 electricity capacity expansion outlooks generally align to province and territory utility, government, and system operator expansion plans and expectations in the near-to-medium term. They include various renewable electricity initiatives that are sufficiently defined.
Provincial and Territorial Energy and Climate Strategies	Provincial and territorial governments have climate plans and strategies that guide policies related to energy and emission issues. Recent examples include: B.C. Climate Planning and Action Alberta Climate Leadership Plan Prairie Resilience: A Made-In-Saskatchewan Climate Change Strategy A Made-in-Manitoba Climate and Green Plan Ontario Climate Change Mitigation and Low Carbon Economy Act Quebec 2018-2023 Master Plan Transitioning to a Low-Carbon Economy: New Brunswick's Climate Change Action Plan Nova Scotia Taking Action on Climate Change Prince Edward Island Climate Change Action Plan Newfoundland and Labrador, Turn back the Tide: Taking Action on Climate Change Yukon Climate Change Action Plan Northwest Territories 2030 Energy Strategy Nunavut Climate Change Centre	EF2018 includes elements of these plans when there is enough information available to include in the modeling. Examples of included province-specific policies include Alberta's 100 MT limit on oil sands GHG emissions, and Quebec's zero-emission vehicle standard.

Appendix B: Summary of Technology Case Assumptions by Sector

Global Energy Market Dynamics	
Near term (2018-2025)	Longer term (2025-2040)
Global crude oil, North American natural gas, and OECD carbon pricing aligned with numbers from IEA's World Energy Outlook 2017 "Sustainable Development Scenario." Crude oil and natural gas benchmark prices similar to Reference Case levels. Carbon prices begin to diverge from the Reference Case in 2023.	Carbon prices reach $100/tonne by 2030, and $140/tonne by 2040. Brent crude oil is $6/bbl lower than the Reference Case in 2030 ($69/bbl), and $11/bbl lower in 2040 ($69/bbl). Henry Hub natural gas is $0.30/MMBtu lower than the Reference Case in 2030 ($3.25/MMBtu), and $0.50/MMBtu lower in 2040 ($3.66/MMBtu). (All prices in 2016 US$)
Canadian Energy Market Dynamics	
Near term (2018-2025)	Longer term (2025-2040)
End-use prices marginally higher given carbon pricing trends. Benchmark prices at or near Reference Case levels. LNG export assumptions at Reference Case levels and begin with 0.75 Bcf/d in 2025.	End-use prices for fossil fuels higher than Reference Case, varying by the CO_2 content of the fuel. Canadian differentials assumed to be the same as Reference Case, so lower benchmark prices imply lower Canadian prices. WCS and CLS are $11/bbl lower than Reference by 2040. NIT is $0.50/MMBtu lower than Reference by 2040 (prices in 2016 US$). LNG export assumptions at Reference Case levels, reaching 3 bcf/d by 2031.
Electricity Generation	
Near term (2018-2025)	Longer term (2025-2040)
Utility scale solar PV overnight capital costs are 30% lower than the Reference Case by 2025. Onshore wind costs are 6% lower than the Reference Case by 2025.	Utility scale solar PV overnight capital costs are 40% lower than the Reference Case by 2040. Onshore wind is 16% lower than the Reference Case by 2040. Increased interprovincial transmission capacity. Improved demand side management.
Oil and Gas Production	
Near term (2018-2025)	Longer term (2025-2040)
Steam solvent technology for in situ production achieves wide-scale commercial use, all new production by 2025 uses the technology. Steam-solvents applied to some existing reservoirs.	Pure solvent technology achieves commercialization and is applied to all new production by 2030. Output based allocations completely phased out by 2035. Energy intensity improvements for non-oil sands crude and natural gas production driven by carbon costs and increasingly competitive market.
Residential and Commercial Buildings	
Near term (2018-2025)	Longer term (2025-2040)
Building shell and process improvements reduce energy needs in new buildings. High efficiency natural gas heating becomes standard for regions dominated by natural gas heat. Heat pumps make up to 10% of new sales by 2025 in jurisdictions with a high share of electric heating, and 2 to 5% for jurisdictions dominated by natural gas.	Building shell improvements and process improvements reduce energy requirements significantly for new builds, as well as retrofits. Heat pump purchase costs are 20 to 30% lower than current levels, and make up 40 to 70% of new sales by 2040 in the provinces, some of which may be hybrid systems with high efficiency natural gas. Increased integration with electricity production and use for transportation to balance generation and loads.

Transportation	
Near term (2018-2025)	Longer term (2025-2040)
Average EV costs are 10% lower than the Reference Case, and 30% lower than current levels by 2025. Average ethanol blends in gasoline are 10% and 6% biodiesel by 2025. Vehicle emission standards remain at Reference Case levels. Efficiency improvements in aviation.	Average EV costs are 10 to 15% lower than the Reference Case, and 50 to 60% lower than current levels. EV penetration is on average 35% of new passenger vehicle sales in 2030, and averages nearly 65% by 2040. Conventional vehicle efficiency improves by 1 to 1.5% per year after current emission standards (2025 for passenger, 2028 for freight). Biofuel blends increase to 15% for gasoline and diesel by 2040. Aviation efficiency improves relative to the reference case, with 15% biofuel blending by 2040. Moderate electrification of heavy-duty freight sector towards the end of the projection, 5 to 8% of new sales by 2035-2040.
Other Industrial	
Near term (2018-2025)	Longer term (2025-2040)
Improvements in average new device and process by 5 to 10% compared to the Reference Case. Biofuel and natural gas blending as described in transportation/RNG sections.	Sector adopts best available technologies. Average device and process performance improves by 15 to 30% compared to the Reference Case by 2040 Improved processes, like material recycling, reduce energy requirements. Biofuel and natural gas blending as described in transportation/RNG sections.
Multi-sector Technologies	
Near term (2018-2025)	Longer term (2025-2040)
Renewable natural gas deployed, reaching 2% of mix by 2025. CCS begins to regain some momentum.	RNG blends reach nearly 4% by 2030, 10% by 2040. CCS capacity reaches 10 MT by 2030 and 45 MT by 2040, with additions across industry, power, and oil and gas production.
Northern Territories	
Near term (2018-2025)	Longer term (2025-2040)
Increased biofuel blending. Moderate increase in solar and wind electricity.	Efficiency improvements match other provinces. Biomass share of heating rises. Lower EV and heat pump adoption compared to other provinces, but same efficiency and biofuel blending rates. Solar (rooftop and community/utility) and wind capacity added to offset diesel generation. Increased use of natural gas delivered via LNG shipments offsets diesel usage.