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Canadian Energy Outlook

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About the Institut de l'énergie Trottier (IET)
The *Institut de l'énergie* Trottier (IET) was created in 2013 thanks to a generous donation from the Trottier Family Foundation. Its mission is to train a new generation of engineers and scientists with a systemic and trans-disciplinary understanding of energy issues, to support the search for sustainable solutions to help achieve the necessary transition, to disseminate knowledge, and to contribute to discussions of energy issues. Based at Polytechnique Montréal, the IET team includes professor-researchers from HEC, Polytechnique and Université de Montréal. This diversity of expertise allows IET to assemble work teams that are trans-disciplinary, an aspect that is vital to a systemic understanding of energy issues in the context of combating climate change.

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The e3c Hub is a multidisciplinary research, transfer and training center of HEC Montréal, specializing in environment, energy and circular economy. Its mission is to contribute to a transition towards a sustainable society and economy, in conjunction with various stakeholders. To do this, the e3c Hub conducts research, runs a scientific program, and designs and organizes training courses and summer schools.

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ESMIA offers a cutting-edge expertise in 3E (energy-economy-environment) integrated system modelling for the analysis of optimal energy and climate strategies. ESMIA puts forward a scientific approach guided by sophisticated mathematical models. The goal behind our implication is to offer solutions that allow achieving energy and climate goals without compromising economic growth. For 20 years, the ESMIA consultants provide a full range of services for the development of economy-wide energy system models for high-profile organizations worldwide. They also provide advisory services that focus on analyzing complex problems such as energy security, electrification, technology roadmap and energy transitions. ESMIA benefits for this purpose from its own integrated optimization model: The North American TIMES Energy Model (NATEM).

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1 INTRODUCTION

This Outlook is a modelling effort that analyses possible transformation pathways required to achieve net-zero GHG emissions in Canada, with a special focus on the energy system. Produced by independent researchers, this Canadian Energy Outlook 2021 (hereafter the CEO2021) builds on extensive techno-economic modelling to analyze the trends occurring across the country, the possible transformation of the energy sector over the next decades, the political choices that need to be made to reach national objectives, and the considerable gap between promises and targets. This analysis helps contrast the projected evolution of the energy system and GHG emissions with the measures implemented, to assess their coherence. The hypotheses and limits underlying this work, along with a brief discussion of the recent evolution of Canada's energy sector, form the core of this introductory chapter.

1.1 Updating the possible pathways

The provision of energy services in all sectors is essential to move people and goods, heat buildings and ensure the operation of society as a whole. Moreover, at around 81% of Canadian greenhouse gas (GHG) emissions, slightly over the world average, energy production, transport and consumption occupy a central place in climate mitigation efforts. Assessing the impacts of pathways to net-zero emissions societies thus requires a deep understanding of what the current and expected energy developments mean for Canada's future, to help enlighten policy and investment decisions in trying to reach net-zero objectives. As a result, energy outlooks, which test various futures in these respects, are an essential tool for supporting this task.

Since the publication of the 2018 edition of the Canadian Energy Outlook (Langlois-Bertrand *et al.*, 2018), Canada, like many other countries around the world, has pledged to transform its economy in order to reach net-zero levels of GHG emissions by 2050. All over the world, these announcements of net-zero targets have bolstered modelling efforts to help determine the implications of these targets for all human activities.

Net-zero emissions are defined in this Outlook as society-wide neutral GHG emissions for those falling under the jurisdiction of the Paris Agreement. Under this Agreement, each country is responsible for the total emissions generated directly on its territory, irrespective of the final beneficiary of the emissions. For example, the emissions generated during the extraction of lithium, its transformation and the production of the battery are assigned to the countries where each operation is performed, not to that of the final user. Therefore, as per this international treaty, net-zero requires whatever GHG emissions occur in a given society to be compensated by an equivalent amount of emissions captured from the atmosphere by the emitting society. Although some technical issues lead to variations in the specific accounting of these emissions—and, by extension, in the exact meaning of being "net-zero"—the general idea is that such a society would have no "net" impact on the atmosphere in terms of GHG emissions, thus limiting its contribution to global warming.

Like this Outlook, other modelling reports focusing on net-zero targets give primary importance to energy-related activities and fugitive emissions, and also discuss other sources of emissions, such as agriculture and industrial processes. In the last year or so, other Canada-wide modelling efforts are worth mentioning:

- Canada Energy Regulator's Canada's Energy Future 2020 (CER 2020), which focuses on the evolution of the energy sector up to 2050; CER's hypotheses form the basis for most Canada-wide modelling, including this Outlook.
- Environment and Climate Change Canada, in Canada's Greenhouse Gas and Air Pollutant Emissions Projections 2020 (ECCC 2020), projects the effects of current and announced policies on the evolution of GHG emissions until the next target year (2030).
- Through 60 wide-ranging scenarios up to 2050, the Canadian Institute for Climate Choices' Canada's Net Zero Future: Finding our way in the global transition (Dion 2021) explores possible pathways to net-zero in order to identify safe-bet and wild-card choices.
- Using an analytical approach that evaluates the relevance and technological readiness of technologies, the Transition Accelerator's Pathways to net zero: A decision support tool (Meadowcroft 2021) provides an alternative strategy for projecting decarbonization pathways.

This report's focus on Canada's situation makes it possible to provide an analysis tailored to the country's particular energy system and enables comparisons with how similar net-zero challenges are met around the world by identifying commonalities as well as distinct features. It complements the efforts summarized above by using a technologically deep modelling approach to explore a rich set of optimally costed scenarios. To do so, it adopts a traditional form: it projects Canada's energy production and consumption into the next decades according to these scenarios and its GHG emissions, including those outside of energy-related activities. Although based on the Canadian Energy Regulator's energy demand scenario as the reference scenario, it focuses more directly on the transformation that is taking place across Canada's energy sector, its impact on the general economy, and its dependence on various provincial and federal GHG emission reduction measures.

1.2 Objectives of this Outlook

Reaching net-zero emissions requires profound transformations to all sectors of activity, including a transition in the Canadian energy system. This outlook aims to promote a better understanding of what is happening today and, building from this, to examine how we can forge tomorrow's Canada. To this end, the explored scenarios produce results that are discussed with several overarching objectives in mind:

1. Identify possible pathways to reach net-zero targets with different timescales and different choices that can be made to reach those targets. These pathways cut across Canada's energy system as well as other activities specific to certain sectors such as industrial processes and agriculture. Analyzing how the different pathways affect them is essential to understand the implications of the energy transition that will extend over the decades to come, and to highlight some of the choices that Canadians contemplate and the potential they hold for improving their quality of life in conjunction with the transition.
2. Ensure a thorough discussion of cross-provincial variations within these pathways. Keeping provincial variation in mind is crucial for at least two reasons in this context:
    a. The importance of political efforts to bring about emission reductions varies quite substantially across provinces, based on differences in the structure of their economies, the size of the population and its spread among rural and urban regions, as well as the preferences, values and ideologies that prevail in their population and political class.
    b. Furthermore, these differences occur in the context of a federation, where a significant portion of jurisdiction for energy matters lies with the provinces. While this situation complicates national initiatives to coordinate emission reduction efforts and transform the economy, it also points to the possibility that thinking in national terms may lead to a more efficient distribution of the transition costs.
3. Provide an extended analysis of the main aspects of reaching net-zero, as opposed to merely reducing emissions. This includes key families of technologies to transform energy systems, the capture of some carbon emissions, and how to treat the special case of the industrial sector.

The CEO2021 is not a crystal ball: it does not predict the future. It instead explores cost-optimal pathways, as measured mainly from the energy system's perspective, in response to external constraints such as the carbon tax or GHG emission ceilings. Modelling leaves aside questions that are essential to a society, including equity, health, education and more.

1.3 Prospective scenarios to net-zero

Throughout this Outlook, we consider three GHG emission reduction scenarios leading to net-zero in different years, a reference scenario for the business-as-usual case, and an additional one that takes into account the impact of the recently announced carbon pricing schedule to 2030 (as described in Table 1.1), all analyzed through NATEM.[1]

These scenarios were chosen to contribute to the objectives set out in the previous section, by:

1. Outlining the feasibility and implications of net-zero (NZ) scenarios, with details of what form they would take and what technologies and uses they entail.
2. Allowing for better insights into the optimal pacing of mitigation options by having scenarios with progressive targets on GHG emissions.
3. Identifying highlights from the implications of pursuing an even more aggressive schedule than Canada's 2050 target, one which aims to reach net-zero by 2045.

Table 1.1 – Description of the reference and GHG reduction scenarios

Name	Description
REF	The reference scenario. This scenario presents results using no constraining GHG reduction targets. Macroeconomic assumptions (GDP, population, oil and gas export prices) are aligned with the Reference scenario used in Canada Energy Regulator's Energy Future 2020 outlook (CER 2020), imposing no additional constraints in terms of GHG emissions reductions, but including policies already in place.
CP30	This scenario takes REF and adds the carbon pricing increase schedule announced by the federal government in late 2020, with a price reaching \$170/tonne of CO_2e in 2030.[2] To accelerate the impact of carbon pricing, this scenario also lowers the hurdle rate with respect to standard practice.
NZ60	This scenario imposes a net-zero emissions target on total CO_2e by 2060, a 30% reduction by 2030, and an 80% reduction by 2050 (with respect to 2005). This reflects the prior Canadian targets, extended to reach net-zero in 2060. Macroeconomic assumptions for all NZ scenarios are aligned with the Evolving scenario used in the CER Energy Future 2020 outlook (CER 2020).
NZ50	This scenario imposes a net-zero emissions target on total CO_2-eq by 2050, and a 40% reduction target by 2030, with respect to 2005. This corresponds most closely to the current government's targets.
NZ45	This scenario imposes a net-zero emissions target on total CO_2-eq by 2045 and a 45% reduction target by 2030.

[1] NATEM stands for North American TIMES Energy Model, an energy systems optimization model implemented by ESMIA Consultants Inc. It makes use of The Integrated MARKAL-EFOM System (TIMES) model generator developed and distributed by the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency (IEA) and used by institutions in nearly 70 countries.

[2] Two adjustments were necessary to incorporate this schedule: first, a discount rate was used to transform prices proposed by the government in the schedule into their equivalent for the year when they are applied (for instance, \$170 announced this year is worth \$131 in constant dollars for 2030, when adjusted for inflation; second, this maximum price reached in 2030 is then adjusted for inflation for the remainder of the period, i.e. until 2060.

All scenarios are based on targets from a national perspective. The model allocates reductions optimally across provinces in order to reach these targets, based on costs and available technologies. As a result, provincial pathways differ in the pace and extent of the transformations of the various sectors, and the remaining net emissions in each province vary based on their specific constraints. As Part 2 of this report shows, the results clearly indicate the need for a substantial amount of emissions capture, negative-emission activities, and direct air capture technologies for emissions to be neutral from a national perspective and compensate for each province's remaining emissions.

Lastly, it is worth noting some of the main assumption categories used by the model:

a. Prices of imported and exported energy commodities: prices used for REF and CP30 are aligned with the CER Reference scenario; prices in NZ scenarios are taken from the CER Evolving scenario;
b. Demand projections for energy services: a starting point for energy services demand is built from the reference scenario, and NATEM has its own price elasticity mechanisms so that demands react to their own prices;
c. Technological developments: the model uses an emerging technology database based on the literature, where technologies are characterized according to their technology readiness level;
d. Evolution of technical and economic attributes of technologies over time: realistic assumptions about the evolution of technologies and their cost are made based on a review of the literature; mid-point assumptions are made where wide discrepancies exist in projections;
e. Climate change mitigation efforts in other countries: decreases in demand for exports result from price assumptions in the CER's Evolving scenario, reflecting a certain level of climate change action around the world.

A discussion of the impact of each of these assumptions and some of the associated uncertainties is presented where relevant, including in sensitivity analyses (mainly in Chapter 9).

1.4 Recent developments in Canada's energy sector

Before moving on to the next chapters, which provide a comprehensive description of the Canadian energy system and GHG profile, it is worth reviewing recent developments affecting energy issues and GHG reduction efforts. In 2020, the energy sector was affected by the broad-scale economic downturn resulting from the COVID-19 public health crisis. In particular, the Canadian oil industry described in Chapter 2 was impacted both by the spectacular drop in oil prices worldwide and by the price war between oil producing countries early in the year. Although the considerable uncertainty with respect to this sector prevents us from making a clear-cut prognostic, the impact of these two crises, combined with ever more ambitious GHG-reduction targets, may prevent this sector from ever returning to pre-crisis levels.

Despite the prominence of this global crisis in 2020, many other developments surrounding Canada's energy sector occurred since the publication of the first Canadian Energy Outlook less than three years ago. Notably, opposition to large fossil fuel infrastructure projects continued, with varying effects across the country; clashes on carbon pricing between provincial governments and their federal counterpart multiplied and even reached the Supreme Court, and elections altered the prominence of some opponents; and calls for action to slow down humans' influence on global warming intensified within Canada and around the world. This section provides an overview of these and other major developments that marked the last three years in the Canadian energy sector.

1.4.1 Oil and gas infrastructure

We begin with several developments related to energy infrastructure projects. The first is U.S. President Biden's fulfilment of a campaign promise to revoke the presidential permit for the Keystone XL pipeline project, effectively shutting it down. While some court challenges had continued for the Keystone XL pipeline in 2020, construction of the project had begun. The previous U.S. federal administration had given it presidential approval in January of 2020, and the Nebraska state Supreme Court had sided with regulators in an earlier challenge over the tracing of the route within the state. In March of 2020, the Alberta government had also announced a $1.5 billion investment in the project to ensure its construction went ahead, and guaranteed loans for a further $6 billion. Construction work went on from March in Alberta and in several U.S. states, as well as at the U.S.-Canada border.

The project, which has been in planning since 2008, has faced a long list of court challenges and political hurdles—including opposition from the Obama administration. It would have delivered 830,000 barrels a day of crude oil from Alberta to Nebraska, connecting with the U.S. pipeline network and ultimately reaching the Gulf Coast hub of refineries and export terminals. In February 2020, Enbridge's project to replace its existing Line 3 seemed destined for a different fate, clearing its last hurdle when the Minnesota Public Utilities Commission approved a revised environmental impact assessment for the project. While the construction continued after the decisions, opponents to the project reached the Minnesota Court of Appeals, arguing that Enbridge failed to show long-term need for the Line 3 project. A decision is expected in 2021.

In February of 2020 as well, Teck Resources announced its decision to withdraw its Frontier oil sands mine proposal, which was still waiting for federal approval. Evaluated at $20 billion, the project would have been the largest in the Canadian oil sands. The company explained its abandon citing the many uncertainties in the current Canadian context, which included economic factors linked to insufficient oil prices and political opposition.

The Government of Canada purchased the Trans Mountain pipeline in 2018 and approved its expansion project in 2019. Its construction is administered by a crown corporation. In 2019, the Government conducted a second round of consultations with Indigenous populations on the project, which then cleared a potential legal obstacle when the Supreme Court refused to hear a challenge from Indigenous and environmental groups in March 2020. Construction of the pipeline project, now evaluated at $12.6 billion, continued through 2020.

In British Columbia, protests intensified about the Coastal GasLink, a natural gas pipeline intended to transport natural gas to a liquefaction plant for West Coast exports. The pipeline's route goes through several First Nations peoples' traditional lands, and disagreements among the Wet'suwet'en people's hereditary chiefs and elected band councils persisted on whether to support the project. Arrests of protesters by the Royal Canadian Mounted Police in early 2020 led to protests across the country, mainly in the form of rail blockades, causing several weeks of disruption to both passenger and freight transport. After several meetings, government and Wet'suwet'en leaders reached a tentative agreement that requires approval by the nation's people, but which excluded the pipeline itself. Public consultation was postponed and discussions slowed down due to the COVID-19 outbreak, although talks are now ongoing and construction on the pipeline has begun.

In the midst of these protests, the GNL Québec project lost its main investor. The project aimed to transport natural gas from Western Canada to the Saguenay reion in Quebec for transformation and export to Europe and Asia. Berkshire Hathaway, which intended to provide the larger part of the project's funding, announced its decision to withdraw its participation, citing uncertainty in the Canadian political context. In March 2021, a report from the Bureau d'audiences publiques sur l'environnement concluded that social acceptance for the project could not be established or confirmed, and that economic and environmental risks outweigh its potential benefits (Bergeron et Pilotto 2021).

1.4.2 Electricity

Several developments also affected Infrastructure projects in the electricity sector. British Columbia's site C hydroelectric dam continued and remains on pace to begin operating in 2024 as scheduled. Although Hydro-Quebec had to temporarily halt construction work at the Romaine-4 powerplant in late 2019 due to safety concerns, construction is set to complete this last part of the Romaine hydroelectric complex in 2022. Hydro-Québec also announced an agreement to export 9.45 TWh of electricity to Massachusetts for 20 years. Opposition to the route for the line to supply the transmission capacity for the project remains, however. After New Hampshire rejected the initial project, an alternative route through Maine is also facing obstacles, with a referendum on the project planned for November 2021.[3]

In Newfoundland and Labrador, the Commission of Inquiry Respecting the Muskrat Falls Project released its final report in early 2020. The commission was tasked with investigating the reasons behind the major cost overruns and construction delays. The report found that the cost benefits for the project were influenced by questionable optimism and political pressure, as well as strategic misrepresentation. The report concluded that the Government of Newfoundland and Labrador had predetermined that the project would proceed, and as a result "failed in its duty to ensure that the best interest of the province's residents were safeguarded" (Commission of Inquiry Respecting the Muskrat Falls Project 2020).

Finally, in Ontario, the refurbishment of the Bruce nuclear powerplant formally began in early 2020. The operation is part of a major refurbishment project of ten units at two powerplants between 2016 and 2033. The year 2020 marks the beginning of the phase when the Bruce refurbishment took place in parallel to similar work at the Darlington powerplant. The province announced it will further its commitment to nuclear energy, having signed a memorandum of understanding with Saskatchewan and New Brunswick to develop small modular reactors.

[3] A previous referendum initiative, scheduled for November 2020, was deemed unconstitutional by the Maine Supreme Court due to its wording. A new initiative was later tabled to correct this issue.

1.4.3 Hydrogen

After many false starts, hydrogen seems to be picking up around the world as an essential part of the decarbonization of the economy. It is generally seen as a flexible carrier for storing electricity from variable low-carbon sources or as a clean fossil energy source when deriving from natural gas reforming coupled with GHG emissions captured and sequestered at the transformation site. In December 2020, the federal government released its Hydrogen Strategy for Canada (NRCAN 2020), which follows from the international Hydrogen Initiative. The latter had been created a year earlier by the Clean Energy Ministerial, a group of energy ministers from 19 countries, including Canada.[4]

Canada's hydrogen strategy builds on the creation of hubs across the country to support mature and emerging applications, coupled with efforts at revising regulations and policies to facilitate the use of this molecule as part of GHG reduction plans. A first hub[5] was created in April 2021 in Edmonton, with the support, among others, of the federal and Alberta governments and of the city of Edmonton. A number of other provinces, including Quebec and Newfoundland and Labrador, are working on their own hydrogen strategy, which should be unveiled in 2021 or early 2022.

1.4.4 Electoral and political developments

In another series of developments, elections modified the political landscape as concerns climate and energy policy. In the spring of 2019, Jason Kenney became Premier of Alberta and vowed to roll back several of the measures taken by the previous provincial government to promote renewable energy and manage the carbon footprint of the province's oil and gas sector. The new government abandoned a large part of the province's carbon pricing mechanism and challenged the federal carbon pricing system in court. The challenge was significant because it led to a first victory by a province on the constitutionality of the program, after both Ontario and Saskatchewan had lost their respective court cases. The Supreme Court however decided against the provinces on the matter in 2021, while across the country the federal pricing system had taken effect in 2019 (see Chapter 5).

In the fall of 2019, a national election led to a new mandate for the incumbent Prime Minister Justin Trudeau, in a campaign where climate issues were prominent. The federal Liberal government was elected with a minority status but did not see its main climate policies questioned, as all other parties in Parliament but the Conservative generally support the efforts. However, the government's support for pipeline projects was met with more resistance from opposition parties.

In other Canadian politics, the National Energy Board, the main regulatory agency overseeing interprovincial and international energy infrastructure, became the Canadian Energy Regulator. The change also expanded the board's jurisdiction over offshore projects and the impact assessment of energy infrastructure projects. The Canadian Centre for Energy Information[6] was also created to improve and streamline data available to researchers and policymakers on energy matters across the country.

[4] http://www.cleanenergyministerial.org
[5] https://erh2.ca
[6] https://energy-information.canada.ca/en

South of the border, the U.S. administration sued the state of California over its participation in the cap-and-trade system with Quebec, arguing that the state overstepped its constitutional authority and undermines the federal government's ability to negotiate treaties with foreign nations. California and Quebec have been participating in this system since 2013, which imposes carbon pricing on large industrial emitters as well as fuel distributors. California won the case in July of 2020.

Finally, calls for more serious actions to prevent global warming intensified. The Intergovernmental Panel on Climate Change released a Special Report on Global Warming of 1.5 C in October 2018, detailing how deep emission reductions were needed to meet the target, well beyond the Paris Agreement pledges. A series of school strikes were also held around the globe throughout the first half of 2019, the largest being in March and May and each gathering more than a million strikers. Broader climate protests were then held in September, with several million people marching worldwide to ask for more action on reducing GHG emissions, eliminating fossil fuels, and expanding the use of renewable energy. Lastly, in November 2019 more than 11,000 researchers from around the world signed a widely publicized letter in BioScience, warning of the "untold suffering" that will result from insufficient mitigation of global warming (Ripple *et al.* 2020).

The last year has also seen a considerable strengthening of Canada's climate goals. In November 2020, the Liberal government tabled a C-12 Bill that established a net-zero target for 2050, as well as a new governance model to increase transparency and accountability on the climate change file.[7] The bill was adopted at the end of June 2021.

At a meeting led by U.S. President Joseph Biden for Earth Day 2021, the Prime minister also announced that GHG reduction targets for 2030 will be increased from 30%, with respect to 2005 to 40%-45%, although these objectives have no legal standing as of this writing. The probability of these targets to survive a change in government has been considerably increased with the Conservative Party of Canada's publication of a new climate platform that supports carbon pricing and the decarbonization of Canada's economy.[8]

These developments affect different parts of the Canadian energy system. Part 1 of this Outlook provides a more detailed look at the various dimensions of this system, helping to further understand the impact—and in some cases, the causes—of these events.

[7] https://parl.ca/DocumentViewer/en/43-2/bill/C-12/first-reading

[8] Secure the environment. The Conservative Plan to Combat Climate Change, 16 pages. Online, https://cpcassets.conservative.ca/wp-content/uploads/2021/04/15104504/24068610becf2561.pdf

1.5 Limitations of and omissions from this Outlook

Modelling exercises such as those presented in this document have a number of limitations that derive from the simplifications required and the uncertainty inherent in forward-looking initiatives. Dealing with these limitations requires careful assumptions; beyond some of the main assumptions presented in section 1.2 above, a few key points are set out below.

In the 2018 edition of this Outlook, we covered only energy-related emissions, in effect excluding other important sources such as industrial processes and agriculture (outside of fuel consumption). While we treated this limitation with care in the previous edition, the inclusion of—and indeed, our main focus on—NZ scenarios forces us to broaden the coverage, especially given that these sources present significant challenges and that fewer technological options are available at the moment. As a result, even though our main focus remains the transformation of the Canadian energy system, emission coverage goes beyond energy. It should also be noted that we now include fugitive emissions from the energy production sector, which is another addition to the model compared with its 2018 version.

Some GHG emissions are still missing from the model: emissions from land-use, land-use changes and forestry (LULUCF) are not covered, although they are partly touched on through the use of "negative emissions", a concept used to describe the use of biomass coupled with carbon capture. Emissions from international aviation and marine bunkers are also excluded from the model. Moreover, ancillary costs for electricity grids with a very high level of variable generation (such as from wind and solar installations) are simplified through the use of a cost premium on these as well as on storage technologies.

The broadening of our emission coverage does not eliminate uncertainty about the likelihood of the advent of disruptive technologies that could be game changers in some sectors, affecting the pace of some of the results. This uncertainty is typical in this kind of modelling and must certainly be kept in mind when interpreting the results. Since technology pathways with a high degree of uncertainty, such as hydrogen applications or certain niche technologies, are difficult to model by nature, results are necessarily uncertain.

Focusing on energy issues, CEO2021 has also left aside the important issue of adaptation to climate change that will affect energy consumption/production and the choice of investments in infrastructure. Certainly, the energy transition is as much about technological and economic development as it is about reducing the risks and costs associated with accelerated climate change caused by rising GHG levels in the atmosphere.

Finally, it must be noted that, to a certain extent, our discussion downplays the issue of displaced emissions. Not all technologies required for the extensive transformation of energy services following the different scenarios will be produced in Canada, and, following the Paris Agreement, we do not evaluate the impact that this shift will have on global GHG emissions. Another example is emissions from oil refineries, which the optimization of the model may reduce by importing refined products instead, even though these emissions will still reach the atmosphere. Although we do not take this issue lightly, this shortcoming is inevitable given our Canadian focus, as well as beyond the scope of our analysis—like many others with a national focus.

Despite these caveats, modelling allows for the identification of general trends, which we believe to be fundamental in setting the bases for a discussion of net-zero pathways for the Canadian energy system. We return to these issues in Chapter 15 in light of our results.

1.6 Overview of the report

This Outlook is divided into three parts, each with its own contribution to the overall analysis of net-zero pathways. Part 1 (Chapters 2–5) presents a description of the current energy and GHG situation in Canada. More specifically, Chapter 2 provides a profile of energy production and trade in Canada; Chapter 3 discusses recent trends in consumption in different sectors; and Chapter 4 presents an assessment of the importance of energy in the Canadian economy. Since GHG emissions reduction scenarios require significant transformations to the way we use energy, these chapters provide details on the starting point. Chapter 5 then presents a profile of GHG emissions across the country, including beyond energy-related activities. It then provides an overview of current policies announced or in place for reducing emissions. These four chapters contain a thorough description of the energy system and GHG policy efforts across the country, with additional policy details provided in Appendix B.

Part 2 of this Outlook (Chapters 6–10) discusses the results obtained from the modelling. Contrasting the impacts of the different scenarios, Chapter 6 focuses on energy consumption, Chapter 7 on energy production, and Chapter 8 enlarges the discussion to the evolution of GHG emissions. Chapter 9 then delves further into key technological pathways and uncertainties that play an important role in net-zero futures, namely with regard to electricity generation, hydrogen, biomass and carbon capture and storage (CCS). Finally, Chapter 10 concludes Part 2 by presenting some of the notable variations across provinces in the topics covered elsewhere this section, to highlight differences in the challenges facing each province.

Part 3 (Chapters 11–14) provides additional perspectives to better understand the takeaways from the first two parts. Chapter 11 makes a comparison with other net-zero reports around the world to identify commonalities and distinctions in the expected role played by different technologies. Chapter 12 specifically addresses CCS and analyzes the limits and constraints to the use of various technologies to capture emissions with regard to their energy requirements. Chapter 13 focuses on industry, where transformations face a specific and complex set of challenges. Lastly, Chapter 14 provides additional modelling of the economic impacts of the transformations required by the results.

All three parts are essential in building coherent conclusions in Chapter 15, allowing for a thorough understanding of the challenges to come and the actions needed to effectively reach the desired objectives. This enables us to present policy recommendations to make the shift toward a net-zero future effective.

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2 ENERGY PRODUCTION, TRANSFORMATION AND TRADE

The Canadian energy system has several unique characteristics that make it stand out on the world scene, despite its relatively small population and economy. Some notable features of this system are presented in this chapter.

HIGHLIGHTS

- Canada is one of the world's largest energy producers and exporters, with significant fossil fuel and uranium ore extraction sectors.
- Eighty percent of Canada's electricity production is from low-carbon sources; however, its electricity energy mix varies significantly between provinces.
- Over the past 20 years, natural gas rose from almost 0% of Canada's total energy imports to 30.2% in 2019, while crude oil exports almost tripled.
- Wind and solar electricity generation have enabled private actors to penetrate a traditionally public sector.
- GHG reduction targets, global oil prices and energy access to markets are the dominant issues shaping current energy debates in Canada.
- Energy imports, including oil, gas and electricity, are mainly from the USA.
- Due to limited interprovincial electricity infrastructures and political relations, small quantities are exchanged between provinces; in contrast, efforts to decarbonize electricity generation in the US are attracting considerable interest from low-carbon Canadian utilities.

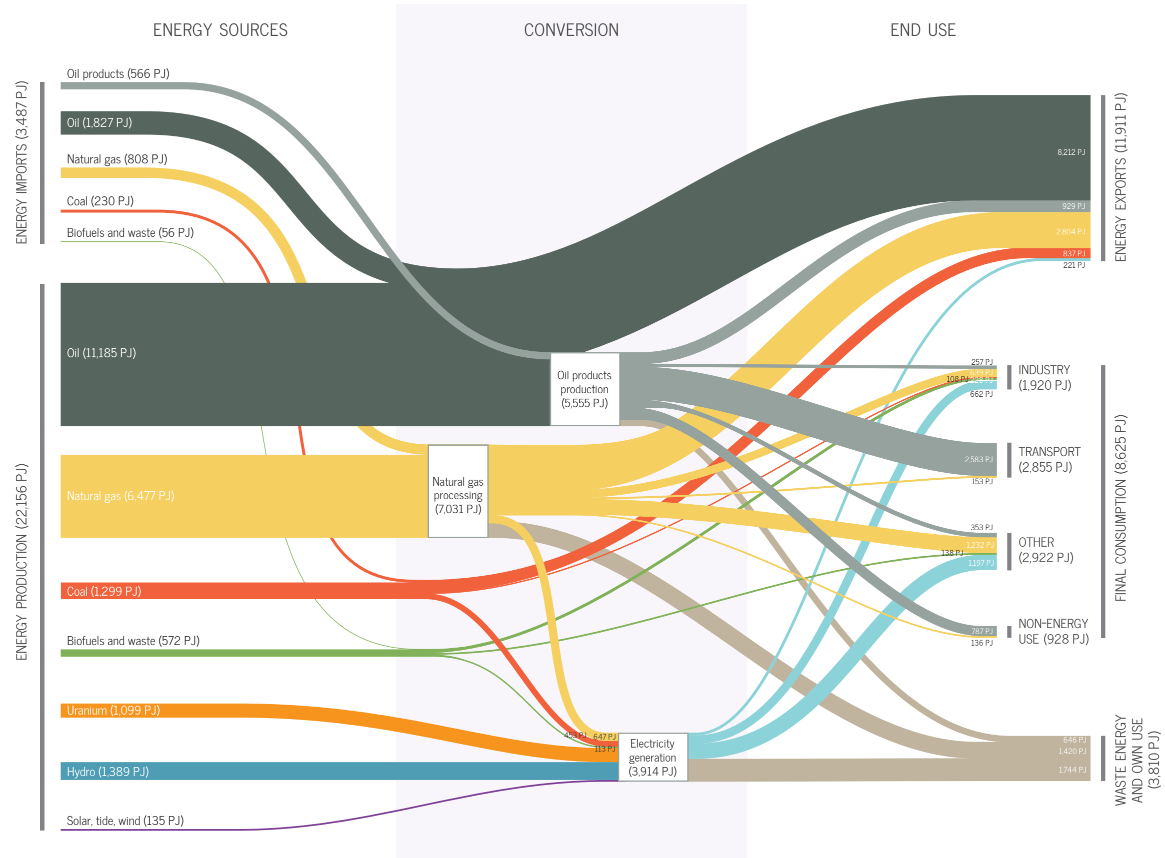
2.1 General characteristics

2.1.1 The energy system at a glance

The Canadian energy system, which main energy flows are illustrated in Figure 2.1, displays several characteristics that make it stand out from other countries. The abundance of domestic resources allowing Canada to be a major energy exporter explains not only the size and composition of its energy sector (presented in this Chapter) but also how and where energy is used across the country (the topic of Chapter 3).

However, presenting the energy system at the national scale hides the fact that production and use of energy vary greatly across provinces. If similarities across provinces can be observed mainly on the consumption side in sectors like transport or commercial and residential buildings, it is the opposite for the industrial sector, whose importance in energy consumption varies greatly on a provincial basis (Section 3.2), a difference attributable mostly to energy production activities.

Figure 2.1 – Supply, transformation and consumption of energy in Canada



Note: Energy flows of less than 50 PJ are not displayed. Totals may not add up due to rounding. Final consumption captured under "Other" includes residential, commercial and public services, agriculture and forestry, fishing and non-specified. Source: IEA 2021

2.1.2 Domestic resources

Canada disposes of an almost unique access to domestic energy resources, including fossil fuels, uranium mining and non-emitting electricity production. As Table 2.1 shows, Canada is in an enviable position with regard to crude oil (3rd in world reserves, 4th producer in the world), natural gas (4th producer in the world), uranium (3rd in world reserves) and hydroelectric power (3rd in the world in terms of electricity generated). When all energy sources are included, Canada is the planet's 6th largest energy producer and one of its main net exporters (NRCAN 2021). This position is supported by 282,000 direct jobs and generates more than 7.2% the country's GDP.

2.1.3 A largely decarbonized electricity production

In 2019, four-fifths (79.9%) of Canada's electricity derived from non-emitting sources, mainly hydroelectricity (59.4%), nuclear (15.1%) and wind (5.1%). This puts Canada in 6th position internationally for the share of renewables in its electricity generation. This position is even more remarkable as four of the five countries with a larger share are much smaller in terms of population and territory (Norway, New Zealand, Austria, and Denmark). Brazil, which uses a share of hydroelectricity similar to Canada's, is the sole exception.

2.1.4 Low interprovincial trade

Canada's federal system of government places jurisdiction for energy matters largely in the hands of the provinces. Historically, this has contributed to provincial clustering in energy matters, both in policy making and in the organization of energy systems. Most trade occurs North-South (between provinces and American states) rather than interprovincially, mainly for electricity, but also for oil and gas, even though in recent years the central provinces of Ontario and Quebec have shifted their main oil supply from overseas to Canadian and, to a lesser degree, American production.

Table 2.1 – Energy in Canada: world ranking for reserves/capacity, production and exports (2019)

Energy Resource	Proved Reserve/Capacity	Production	Exports
Crude Oil	3	4	4
Uranium	3	2	4
Hydroelectricity	3	3	-
Electricity (incl. hydro)	8	6	3
Coal	16	13	7
Natural Gas	17	4	6

Source: NRCAN 2021

2.2 Fossil fuels

Table 2.2 shows the evolution of production levels for fossil fuels. This production is mainly in the form of crude oil (54.8%) and natural gas (34.7%), with coal and natural gas liquids providing the remainder. Canada is the world's 4th largest producer of crude, although the production levels in the United States, Russia and Saudi Arabia are well above twice the Canadian levels. As for natural gas, while the United States and Russia each produce more than four times Canadian levels, Canada's production levels are comparable with the next top producers: Iran, Qatar and China.

While natural gas production levels have fluctuated over time, oil production levels have increased more or less continuously since 1999, with 2019 levels more than twice what they were 20 years earlier. Over the last year, price levels have dropped to a 20-year low, partly because of the pandemic but also owing to an increasingly aggressive play by the members of the Organization of Petroleum Exporting Countries (OPEC) and Russia to protect their market share and the ever more ambitious GHG reduction goals set by the world's leading countries. Although prices have strengthened somewhat since early 2021, global political tensions could have important implications for Canadian producers, who could struggle to maintain production levels in the face of uncertain price levels.

2.3 Uranium

In 2019, Canada produced 13% (around 7 kt) of the world's uranium output, putting it in second place on the world stage. Despite this position, production has dropped to half of what it was before low prices led to the suspension of uranium mining in several sites starting in 2016 and 2017. In absolute primary energy content, uranium production corresponded to 8,859 PJ of primary energy in 2018 (NRCAN 2021), which places it between Canada's natural gas and oil production (Table 2.2).

Table 2.2 – Fossil fuel production (PJ)

Fuel	1999	2004	2009	2014	2019
Crude oil	4,615	5,859	6,151	8,593	10,735
Natural gas	6,842	7,096	6,229	6,400	6,800
Coal	1,725	1,420	1,388	1,514	1,139
Gas plant natural gas liquids (NGL's)	662	651	631	660	919

Source: Statistics Canada 2021a

2.4 Oil products

Sixteen oil refineries are in operation Canada-wide (Table 2.3). Although there is some variation in the refineries' output, nationally the main refined products are gasoline (38% of total) and diesel fuel (27%), which are mainly used in the transport sector and distributed through a network of some 12,000 retail stations. The remaining 35% consists of a long list of refined products, including butane, light and heavy fuel oils, asphalt and feedstocks for the petrochemical industry, used for a variety of purposes (Statistics Canada 2021g). The most important of these is aviation turbo fuel at 6.2% of the total.

Regional factors and a fluctuating demand for refined petroleum products have meant that, even though overall production is sufficient to meet Canada's needs, trade remains significant to ensure a timely balance between demand and supply across the country. In 2019, exports were at 1,003 PJ, while imports stood at 693 PJ.

It is also worth noting that Western Canada's oil sands have increased their share in the supply to Canadian refineries over the past 20 years. In 1998, 13.8% of Canadian refinery supply derived from synthetic crude from the Canadian oil sands; by 2018 this share had risen to 28.1%. This growth has been at the expense of conventional light crude oil (-9.6 percentage points) and heavy crude oil (-6.5 percentage points) (Statistics Canada 2021b). This is the result of a 215% increase in Canadian oil production (overwhelmingly from the oil sands), associated with the difficulty of reaching international markets, coupled with low prices compared with other oil markets (Statistics Canada 2021b).

Table 2.3 – Refining capacity, by installation and province (2020)

Refinery installation	Province	Capacity (kb/day)	Total by province
Tidewater Midstream	British Columbia	12	67
Parkland	British Columbia	55	
North West Redwater	Alberta	80	509
Suncor	Alberta	142	
Imperial	Alberta	187	
Shell	Alberta	100	
Federated Co-op	Saskatchewan	130	130
Imperial (Sarnia)	Ontario	120	408
Imperial (Nanticoke)	Ontario	112	
Shell	Ontario	75	
Suncor	Ontario	85	
Petro-Canada Lubricants	Ontario	16	
Suncor	Quebec	137	402
Valero	Quebec	265	
Irving	New Brunswick	318	318
North Atlantic Refining	Newfoundland and Labrador	130	130
Total for Canada		**1,964**	**1,964**

Source: Statistics Canada 2021a

2.5 Electricity generation

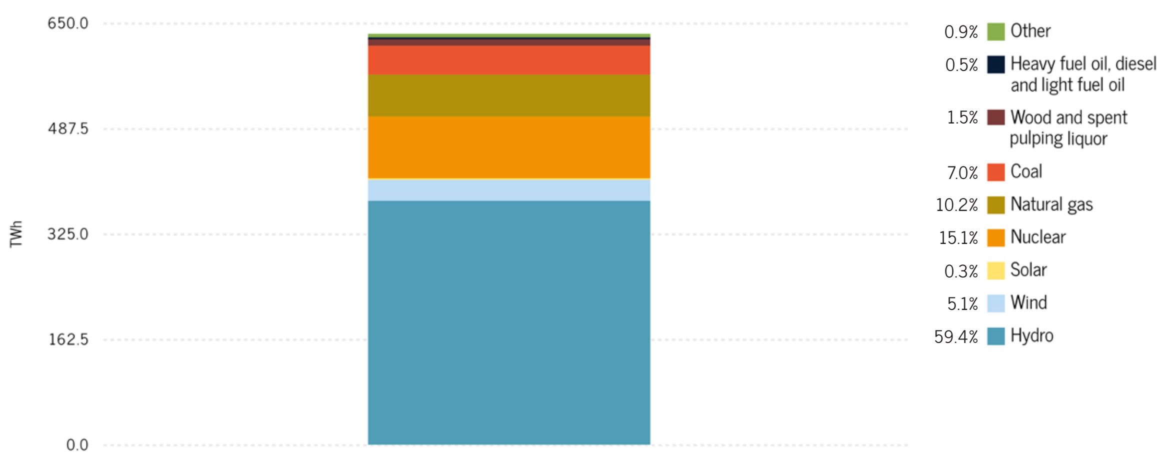
Hydroelectricity accounts for almost 60% of all the electricity generated across the country (Figure 2.2). When other renewable sources are added, the total share of renewable electricity generation is 64.8%. Almost all the rest is provided by nuclear (15.1%), natural gas (10.2%) and coal (7.0%).

Over the past decade, coal posted the largest decrease of all energy sources, dropping by 41.9% from 2009 to 2019 and losing a 5.9% share of total generation. This decline was mainly the result of Ontario's phase-out, which was completed in 2014. At the same time, the largest net increase in electricity production came from wind-based generation. The contribution of wind energy was multiplied by five and reached 5% of total generation in 2019 (from 1% of the total share in 2009). This rapid expansion was due to nation-wide support policies. Natural gas also increased its share of the total by 3.3 percentage points.

Table 2.4 shows the share of public utility ownership of installed capacity for different electricity sources. Between 2007 and 2017, the share of public ownership in the electricity sector fell from 73.5% to 64.3% overall. Although the increase in wind and solar energy installed capacity explains a large part of this change, it also stems from the diminishing role of public actors in thermal generation (apart from nuclear). Indeed, public utilities' share of installed thermal capacity decreased from 52.7% to 36.3% between 2007 and 2017, caused by the phase-out of coal and the growing role of private natural gas facilities.

In 2017, 64.3% of installed capacity was in public hands, largely owing to the dominance of public utilities, which own 87.5% of the total installed capacity in hydroelectricity, the main electricity source across the country, as well as 54.8 % of nuclear generation. Less than half of the installed capacity of all other sources is in the hands of public actors. Similarly, public utilities control only 10.6 % of wind energy installed capacity, which has been the fastest growing source in recent years.

Figure 2.2 – Electricity generation by source (utilities and industrial)



Source: Statistics Canada 2021d, 2021e

Table 2.4 – Share of public ownership in installed capacity by source (2017)

Source	Share of installed capacity owned by public utilities
Hydro	87.5%
Nuclear	54.8%
Thermal (outside of nuclear)	36.3%
Solar	32.9%
Wind	10.6%
Overall generation	64.3%

Source: Statistics Canada 2021f.

2.6 Biomass

Energy extracted from solid biomass (wood waste, pellets, etc.) serves essentially for heat production, with only a small share being used for electricity production. Liquid fuels (ethanol and biodiesel), also produced from biomass, are mainly mixed with their fossil counterparts to allow fuel distributors to meet provincial and federal mandates respecting gasoline and diesel blends, which vary from 2% to 10%. The Clean Fuel Standard currently developed by the federal government will amend these constraints on fuel distributors, as discussed in Chapter 5.

Although solid biomass is largely produced locally, more than 44% of biofuels used in Canada are imported (Table 2.5), almost all of which comes from the US.

Table 2.5 – Production and trade of biofuels in Canada (2018)

	Ethanol (million litres)	Biodiesel (million litres)
Production	1,900	400
Imports	1,232	548
Exports	0	301
Domestic consumption	3,132	647

Source: NRCAN 2021

2.7 Energy trade

Energy exports have increased by 67.8% over the past 20 years (by energy content). These exports, which are far more substantial in size than imports, also differ in their composition. At 60.7% of the total, crude oil exports dominate and have more than tripled over the past 20 years, while natural gas exports have recently decreased subsequent to a production boost in the United States. The evolution of these trends is highly uncertain for the near future. Notably, the drastic drop in crude prices following the COVID-19 crisis, and its effect on American tight oil production, could impact Canada's exports in ways that are difficult to foresee at this time.

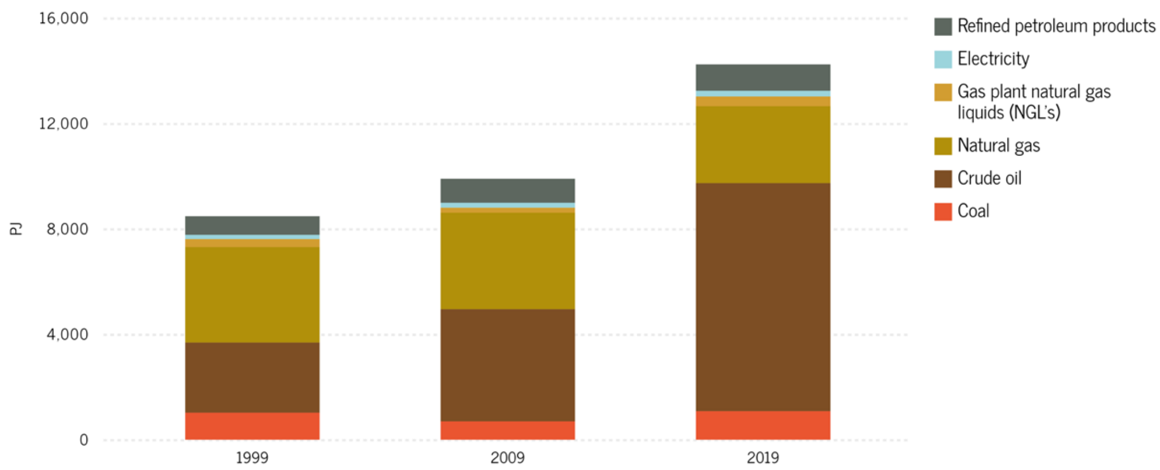
Figure 2.3 also highlights the small amount of electricity exports in comparison to fossil fuels, despite a 34.4% increase in the former since 1999, even when accounting for the sudden 2018 decrease following unusually high levels in 2016 and 2017. After a slump, coal exports have now returned to 1999 levels.

Despite Canada's sizeable energy production and exports, geographic constraints and variations in demand and costs mean that a substantial share of Canada's energy needs are met through imports. Historically, imports have primarily gone to the central and eastern provinces, but changes in recent years have seen production in the western provinces absorb a much larger share of oil used in Ontario, Quebec and the Atlantic provinces. This shift has considerably reduced the diversity of energy providers, especially as most of the recent imports have come from the United States (74% of energy imports in terms of value). In 2019, these imports amounted to 26% of Canadian consumption of crude-oil, 22% of natural gas consumption, 20% of coal consumption and 6% of petroleum products used in Canada (NRCAN 2021).

Natural gas has been the main driver of the 41.8% increase in imports since 1999, which have climbed from almost 0% to 30.2% of total imports. The import of refined petroleum products has significantly increased as well (+87.4%). Crude oil imports have fluctuated but have mainly remained stable during this period. However, coal's share decreased from 18.6% to 5.7% of total imports.

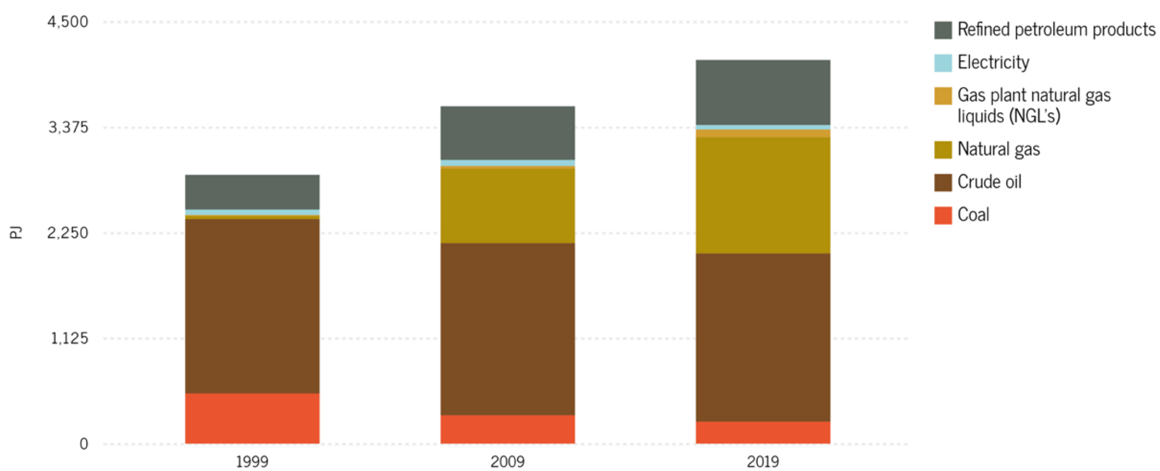
Finally, Table 2.5 provides trading numbers on biofuels. In spite of its land and agricultural sector, Canada is largely dependent on the US for 40 % of its needs. While no ethanol production is exported, geographical drivers for biodiesel demand have led to some trade as federal and provincial blending mandates are less demanding for this fuel.

Figure 2.3 – Energy exports



Source: Statistics Canada 2021a; NRCAN 2021

Figure 2.4 – Energy imports



Source: Statistics Canada 2021a; NRCAN 2021

2.8 Variation across provinces

Oil and gas production is very uneven in Canada with Alberta responsible for well above half of the country's production of these fuels over the past 20 years, its share reaching 80% in 2019. Saskatchewan and Newfoundland and Labrador have extracted most of the rest of crude oil (Table 2.6), while British Columbia has accounted for most of the natural gas production outside of Alberta (Table 2.7).

Alberta's oil production has more than doubled over the period, outpacing by far the production growth in other provinces. The situation is different for natural gas, where a decrease in Alberta's production was offset by British Columbia more than doubling its production, which went up to represent 27% of Canada's in 2019.

Some 85% of coal production takes place in Alberta and British Columbia (NRCAN 2021), although confidentiality issues prevent a more detailed breakdown. Natural gas liquids are primarily produced in Alberta and Ontario.

Provinces also show major variations in their electricity profiles (Figure 2.5). For instance, while hydroelectricity production dominates nationally, coal-fired generation is still important in a handful of provinces (Alberta, Saskatchewan, Nova Scotia and New Brunswick). At least some natural gas is used for electricity generation in all the provinces except Prince Edward Island, although the quantity of the electricity thus generated varies widely, ranging from 17 GWh in Manitoba to 38,930 GWh in Alberta. Furthermore, despite providing 15% of national electricity, nuclear power plants are in operation only in Ontario and New Brunswick.

Table 2.6 – Crude oil production, by province (PJ)

	1999	2004	2009	2014	2019	Share (2019)
Alberta	3,346	3,968	4,380	6,659	8,634	80.4%
Saskatchewan	839	967	965	x	1,123	10.5%
Newfoundland and Labrador	225	x	x	x	599	5.6%
British Columbia	101	106	76	x	254	2.4%
Other	103	818	729	1,934	126	1.2%
Canada	4,615	5,859	6,151	8,593	10,735	100%

Source: Statistics Canada 2021a

Table 2.7 – Natural gas production, by province (PJ)

	1999	2004	2009	2014	2019	Share (2019)
Alberta	5,622	5,415	4,600	4,488	4,722	69.4%
British Columbia	859	1,096	1,154	1,511	1,843	27.1%
Saskatchewan	306	356	291	225	198	2.9%
Other	56	229	184	175	38	0.6%
Canada	6,842	7,096	6,229	6,400	6,800	100.0%

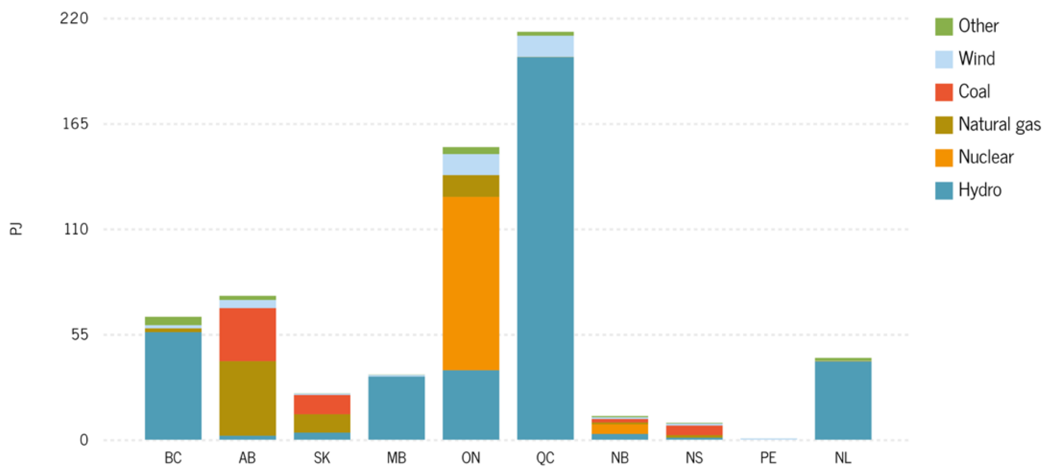
Source: Statistics Canada 2021a

Looking at interprovincial and international trade (Table 2.8), it appears that exports from Labrador to Quebec constitute the single largest provincial exchange, associated with the long-term contract on Churchill Falls. Quebec also makes the next largest interprovincial deliveries, mainly to Ontario and New Brunswick. As well, Quebec and Ontario export a large quantity of their production to the U.S., while British Columbia (and, to a lesser extent, Alberta) also trade significant quantities with northwestern U.S. jurisdictions. Relative to their size, Newfoundland and Labrador and New Brunswick are also important net exporters to the U.S.

It is also worth noting that while electricity exports to the United States were similar in 2019 and 2018, they fell by 15% between 2017 and 2018, after a temporary spike in 2016 and 2017. Changes in export levels from Manitoba and British Columbia account for most of this decrease.

Some provinces' large share of non-emitting generation capacity makes exports attractive to neighbouring jurisdictions wishing to rapidly decarbonize their electricity sector. This is especially the case for Minnesota (importing from Manitoba) and the New England states and New York for the central and eastern provinces. Hydro-Quebec, the province's public monopoly, has been the most active in developing these opportunities, securing an export contract with Massachusetts, as well as negotiating with New York. However, additional transmission lines are necessary for these expansions, which continue to face public opposition.

Figure 2.5 – Provincial electricity generation by source (2019)



Source: Statistics Canada 2021d, 2021e

Table 2.8 – Electricity, interprovincial transfers and U.S. trade (2019)

	Imports from U.S. (TWh)	Interprov. Receipts (TWh)	Total Receipts (TWh)	Exports to the U.S. (TWh)	Interprov. Deliveries (TWh)	Total Deliveries (TWh)	Exports to the U.S. ($1,000,000)
Quebec	115.4	32,375.7	32,491.0	25,918.6	9,929.9	35,848.5	1,033.9
Newfoundland and Labrador	1.1	178.0	179.1	1,127.1	30,182.2	31,309.4	30.1
Ontario	167.6	6,821.9	6,989.5	16,995.9	2,194.0	19,189.8	484.4
British Columbia	11,197.4	888.4	12,085.9	6,817.7	2,616.0	9,433.7	426.7
Manitoba	446.6	3.9	450.6	7,680.0	714.2	8,394.1	395.4
New Brunswick	114.6	3,873.3	3,988.0	1,377.5	2,033.1	3,410.6	116.9
Alberta	1,175.6	2,855.0	4,030.7	355.8	927.3	1,283.1	24.9
Saskatchewan	59.8	241.0	300.9	46.5	239.0	285.6	1.9
Prince Edward Island	..	1,144.2	1,144.2	..	277.3	277.3	..
Nova Scotia	55.8	731.9	787.7	29.9	0.5	30.3	0.9
Canada	**13,194.7**			**61,401.0**			**2,913.9**

Source: Statistics Canada 2021h

2.9 Takeaways

The previous sections show Canada's substantial and steady increase in oil production over the past 20 years, as well as the relative stability of natural gas production at the national level. A closer look at energy trade reveals that oil production chiefly focused on increasing exports, in contrast to natural gas, which has seen a decrease in net exports over the same period. Since Canada essentially has a single buyer for its oil and gas exports, its production levels and revenues are closely linked to the state of the market in the US. In particular, the major increase in tight oil and shale gas production south of the border has put significant pressure on the price of these commodities in Canada, largely contributing to the problems observed in the oil and gas sectors in the last few years.

It is also of note that oil and gas exports dwarf other sources. Uranium exports constitute large quantities in terms of energy content, but low prices on world markets have resulted in lower export revenues. Electricity exports also amount to significantly less value than oil and gas, although this is partly due to relatively small volumes.

Because of their resource endowment and geography, the provinces have drastically different production and trade profiles. Decarbonization efforts in bordering U.S. states have opened up opportunities for greater electricity exports, but obstacles to the building of additional transmission capacity have hampered the ability of Canadian utilities to take advantage of them.

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Statistics Canada 2021h. Table 25-10-0021-01: Supply and disposition of electric power, electric utilities and industry. Government of Canada: Statistics Canada.

3 ENERGY USE ACROSS CANADA

Canada is in eighth position globally in terms of overall energy consumption and uses more energy per capita than any other OECD country except Iceland. This consumption is also associated with a high energy intensity throughout the Canadian economy (discussed in Section 3.3).

A number of similarities in consumption profiles can be observed across the provinces, notably in the transport, commercial and residential sectors. However, final energy consumption in the industrial sector varies significantly from one province to another. These profiles are discussed in Section 3.2.

HIGHLIGHTS

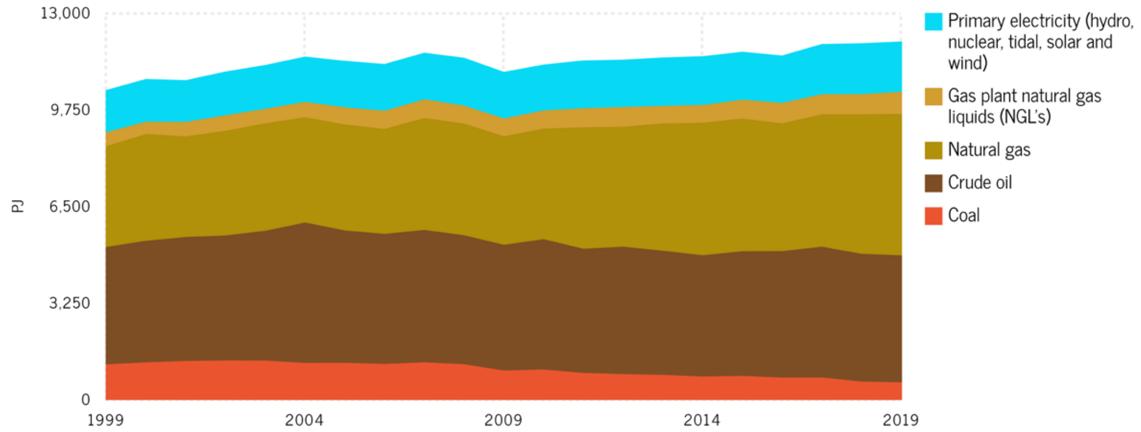
- Canada has one of the world's highest per capita energy consumption levels, with large provincial variations largely due to structural differences in industrial sectors.
- Contrary to almost all other sectors, energy consumption in the transport sector continues to increase, even on a per capita basis.
- Variations in consumption profiles across the provinces are not limited to industry: there are also important differences in freight transport and agriculture, as well as in space heating and transport choices.

3.1 Supply and consumption

Oil and natural gas constitute more than two-thirds of Canada's primary energy supply, with nuclear and hydraulic electricity, as well as coal, providing most of the rest (Figure 3.1). Over the past 20 years, the share of coal has decreased, mainly owing to its phase-out in Ontario's electricity generation, largely compensated by an increased use of natural gas, often directly resulting from coal's decline. Renewables outside of hydroelectricity, in particular wind and biofuels,[1] have played an increasing but still marginal role in the total supply.[2] These changes have been accompanied by an overall 20% increase in the supply, with fossil fuels retaining their share of the total.

Canadian transportation and industrial sectors each make up about one-third of the country's total final energy demand (Figure 3.2), with the building sector (residential, commercial and institutional) constituting most of the rest. The importance of energy production, mostly oil and gas, as well as refining is illustrated by the fact that 20.9% of the total net supply is used in producer consumption (where the energy producing industry uses its own produced fuel) and non-energy use (e.g., feedstocks used by the petrochemical industry). Given the high carbon intensity of their activities, energy producers' consumption occupies a key role in discussions on GHG emission reductions.

Figure 3.1 – Domestic primary energy supply, 1999-2019



Source: Statistics Canada 2021a

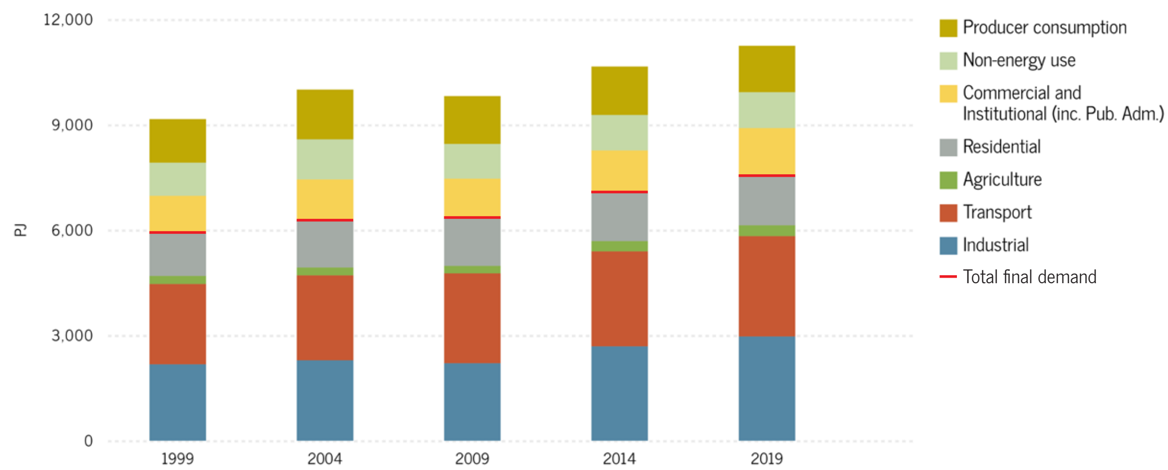
[1] Due to data availability issues, Figure 3.1 does not display biomass supply. Solid biomass (mainly wood products) supply was 487 PJ in 2017, while biofuels (ethanol and biodiesel) added another 48 PJ. Solid biomass production has remained fairly constant over the past 20 years, whereas biofuels production has increased steadily (NRCAN 2021).

[2] Data availability does not allow for the distinction of hydroelectricity and nuclear from other renewables on this chart. Chapter 2 provides more information on the breakdown of electricity production by source.

This section uses both a 20-year and a 10-year horizon to analyze long-term and shorter-term variations.[3] The industrial sector represents the largest share of energy use nationwide. Sub-sector variation is shown in Figure 3.3. Although the industrial sector as a whole saw its consumption increase by 24.7% from 1998 to 2018, this increase varies substantially based on the sub-sector. Notably, the mining sector (including oil and gas extraction) recorded a 224% increase over the entire period, reflecting its rapid expansion and the central role played by these activities in the economies of some provinces, as well as their overall weight in the national economy.

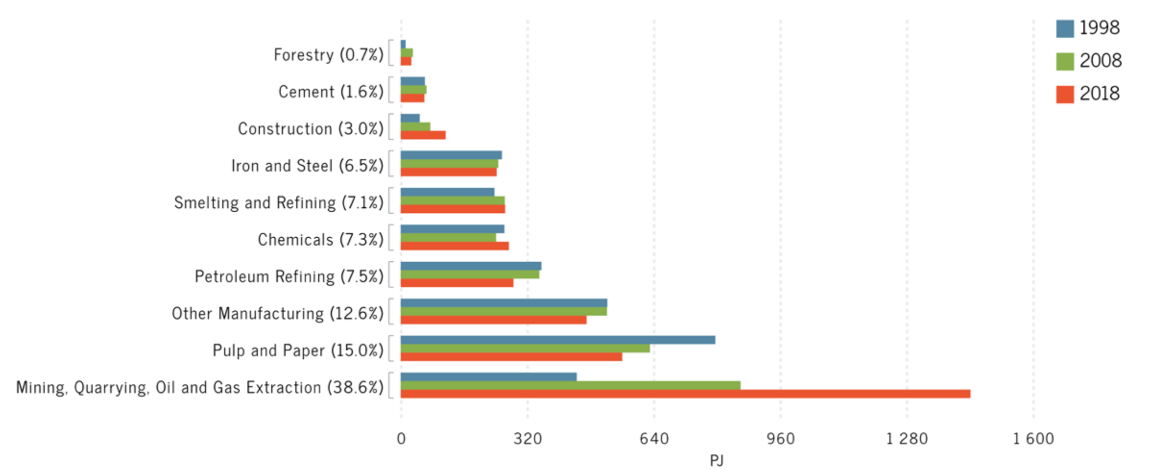
In contrast, decreases were observed in the pulp and paper (-29.6%), other manufacturing (-10.1%), petroleum refining (-19.9%), and iron and steel (-5.2%) sectors. While some of these reductions can be explained by efficiency improvements, a number of closures also had an impact.

Figure 3.2 – Net supply of energy (primary and secondary) by sector



Note: Due to statistical differences, sums may be different from totals. Source: Statistics Canada 2021a.

Figure 3.3 – Industrial energy use by industry (1998, 2008 and 2018)



Note: Percentages shown in the vertical axis represent the share of total energy used in the sector (total is not 100% due to rounding). Source: OEE 2021.

[3] Due to data availability, some charts and tables use 2018 as the year with most recent data, while others use 2019.

3.1.1 Transport

Consumption in the transport (Figure 3.4) sector is dominated by gasoline (57.0%), diesel (29.2%) and aviation turbo fuel (11.7%). Important differences emerge when distinguishing passenger from freight transport, both in the type of fuel used and in the energy intensity changes over the past two decades. While gasoline powered 73.5% of passenger transport, diesel remained marginal (3.9%). In contrast, diesel is the dominant fuel in freight transport (63.8%), compared with gasoline at 32.0%.

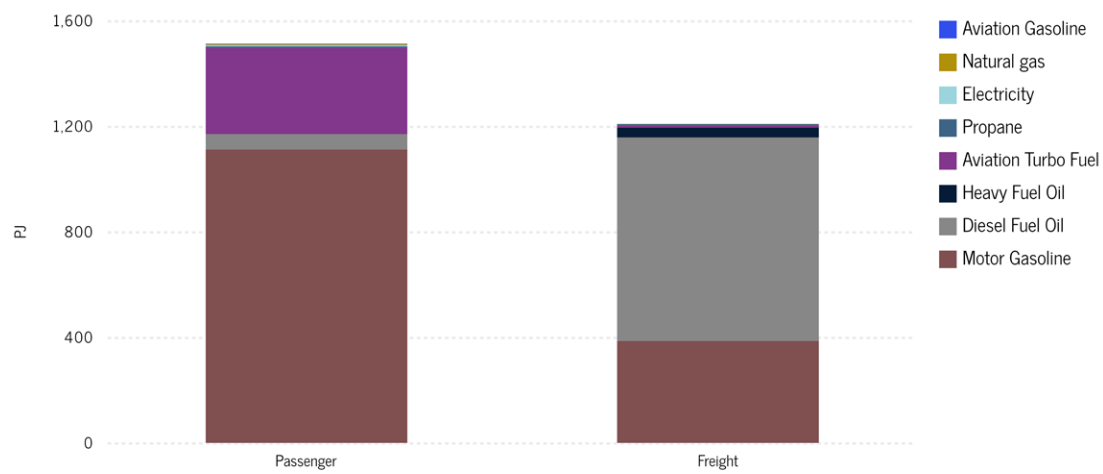
From 1998 to 2018, passenger transport increased by 48.8% or 21.0% on a per capita basis (Table 3.1), with growth being more rapid after 2008. During that same period, the increase in freight transport was 45.3% or 18.2% per capita. Despite a modest slow-down in growth in freight transport in the second half of the period examined, these increases continue to demonstrate how energy efficiency improvements in passenger transport are offset by increasing numbers of kilometres travelled by individuals, a situation that is even more drastic for freight transport where limited efficiency improvements have been realized. This is a consequence of historically low energy prices and Canada's geography.

Table 3.1 – Demand for transportation services

	1998	2008	2018
Passenger (in millions of passenger-km)	585,922	691,133	871,777
Freight (in millions of tonne-km)	716,273	870,105	1,041,012

Source: OEE 2021

Figure 3.4 – Energy use in transportation, by source (2018)



Note: Ethanol and biodiesel data was not available and is therefore excluded from totals. Source: OEE 2021.

3.1.2 Buildings

The profile of the building sector, which encompasses residential as well as commercial and institutional (C&I) consumption, is quite different.

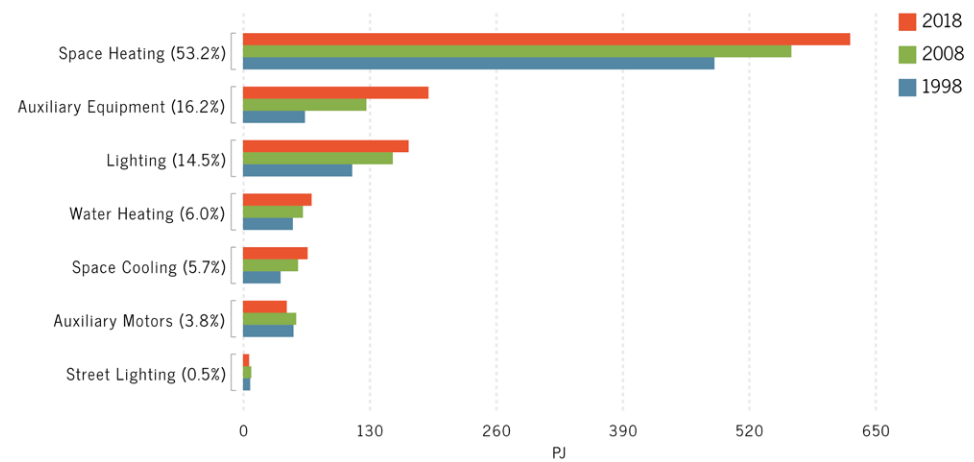
In the **C&I sector** (Figure 3.5), natural gas provides 49.0% of the energy used, with electricity in second place at 45.9%. Light fuel oil, kerosene, coal, propane, and other fuel provide the rest. Auxiliary equipment (16.2% of total consumption) is the fastest growing energy end-use (+199.1% from 1998 to 2018), while space heating remains by far the most important source of demand (53.2%). Lighting comes in third place (14.5%), with water heating, space cooling, auxiliary motors, and street lighting accounting for the rest of demand for the sector. While growth in floor space (+35.4% from 1998 to 2018) contributed to the increase in energy use, the importance of auxiliary equipment was also a significant driver, resulting in a 44.8% rise in total energy use for the sector from 1998 to 2018.

Residential energy use (Figure 3.6) presents a different profile despite some similarities with commercial space. Space heating is also the main driver of energy use (64.0%), with water heating (17.4%), appliances (13.0%), lighting (3.3%) and space cooling (2.3%) accounting for the rest. These percentages have largely remained stable over the past 20 years, although space cooling doubled its modest share of the total.

The period split highlights other important differences as well. Growth in energy use has been modest after 2008, following a period of much more rapid growth from 1998 to 2008 (+12.5%). This trend reflects improvements in energy efficiency for space heating in particular, as is indicated in Figure 3.6.

Figure 3.6 also shows that natural gas is the main source of energy for the two main end-uses (space and water heating), with electricity in second place. Wood also remains important in space heating (15.9%), while heating oil accounts for 5.1%, after more than halving its share from 1998 to 2018.

Figure 3.5 – Commercial and institutional energy use by end-use (1998, 2008 and 2018)



Note: Percentages shown in the vertical axis represent the share of total energy used in the sector (total is not 100% due to rounding). Source: OEE 2021.

3.1.3 Agriculture

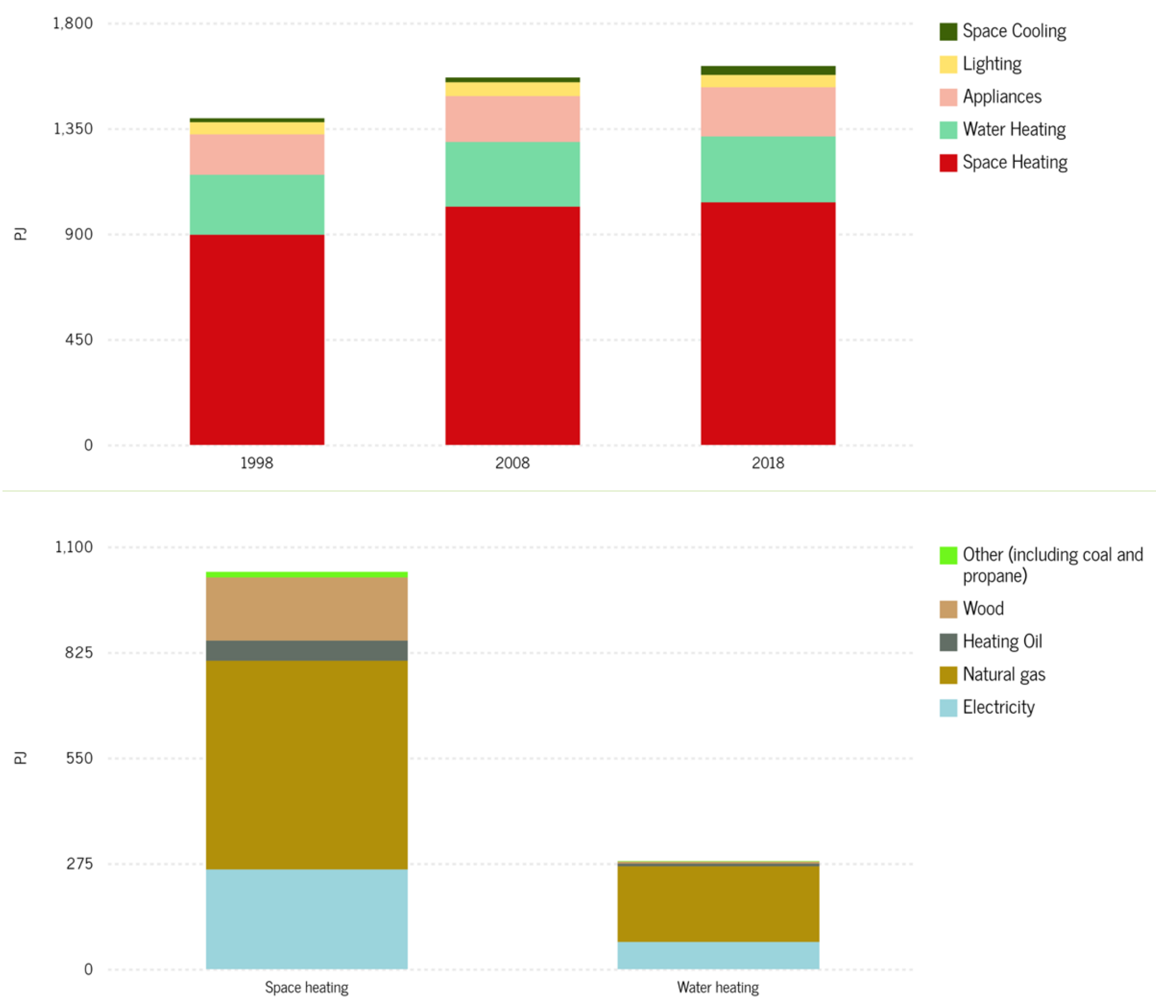
With the smallest share of total final demand, the agricultural sector chiefly consumes a mix of diesel (50.8%), gasoline (17.3%), natural gas (13.5%) and electricity (11.6%). A closer look at the sector shows why aggregate sectoral profiles must be treated with care: in late 2019, the CN Rail strike led to shortages of propane, threatening economic hardship and wasted crops for corn farmers in some parts of the country. For many, since propane is the only source of energy to dry crops for storage, this subsector has limited resilience in the event of a propane shortage. This example illustrates how the limited availability of energy substitutes for some specific end uses can gravely expose specific economic sectors, even if the source of energy used is a small share of their total needs.

3.2 Variation across provinces

Figure 3.7 presents energy mix variations across the provinces, in decreasing order of total final energy use.[4] Not surprisingly, for a country with a strong natural resource sector, the industrial fabric of each province contributes largely to the differences observed. For instance, Saskatchewan's total final energy use is more than half that of British Columbia, despite its population being less than a fourth of that of B.C.. Similarly, energy use in Alberta is substantially larger than in Quebec, even though its population is half the size.

It is also worth noting that when examining energy producers' consumption of their own fuel, as well as fuel used for nonenergy applications in the petrochemical industry—which are accounted for separately from final consumption in each sector—Alberta is the province with the largest energy use, well above that of Ontario. In Saskatchewan, energy producers' consumption adds around 25% to the total energy consumption of industry. Unfortunately, full data is not available on producer consumption and nonenergy use, which explains why it is omitted in Figure 3.7 and Figure 3.8.

Figure 3.6 – Residential energy use by end-use (1998, 2008 and 2018)



Sources of energy for space and water heating (2018)

Note: Total is not 100% due to rounding. Source: OEE 2021.

[4] Since the transport consumption breakdown is not available for 2019, the data is all taken from 2018 in the final energy consumption figures for the sake of consistency.

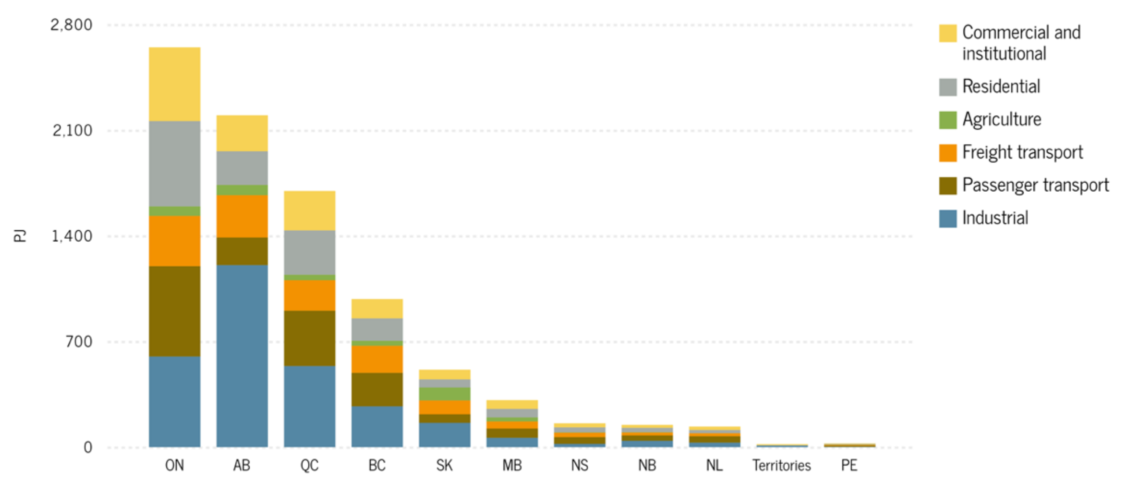
Looking at the provincial consumption profiles on a per capita basis (Figure 3.8), the industrial sectors in Alberta and Saskatchewan, which are driven by oil and gas production activities, stand out. It should be noted again that the omission of producer consumption leads to an underestimation of the total consumption in the industrial sector. Partial data shows that this underestimation is particularly severe in Alberta and Saskatchewan: for instance, Alberta's industrial sector consumption is more than twice what is shown in Figure 3.7.

Nevertheless, industry explains only part of the variations across provinces. Per capita consumption profiles outside of industry give a more accurate measure of the impact of other sectorial activities on energy consumption. In many provinces, agriculture can account for a significant share of the energy consumption. This is particularly the case for Saskatchewan, Manitoba and Prince Edward Island. Consumption for freight transport is also more significant in Alberta and Saskatchewan.

The remaining variation is found in the building sector (residential and commercial), where Alberta and Saskatchewan again show higher levels, as do Newfoundland and Labrador, and Manitoba to a lesser extent. Passenger transport is much more similar across the provinces, although the differences noted stem from the distance travelled, the lack of public transportation and the choice of vehicle, notably in Newfoundland and Labrador.

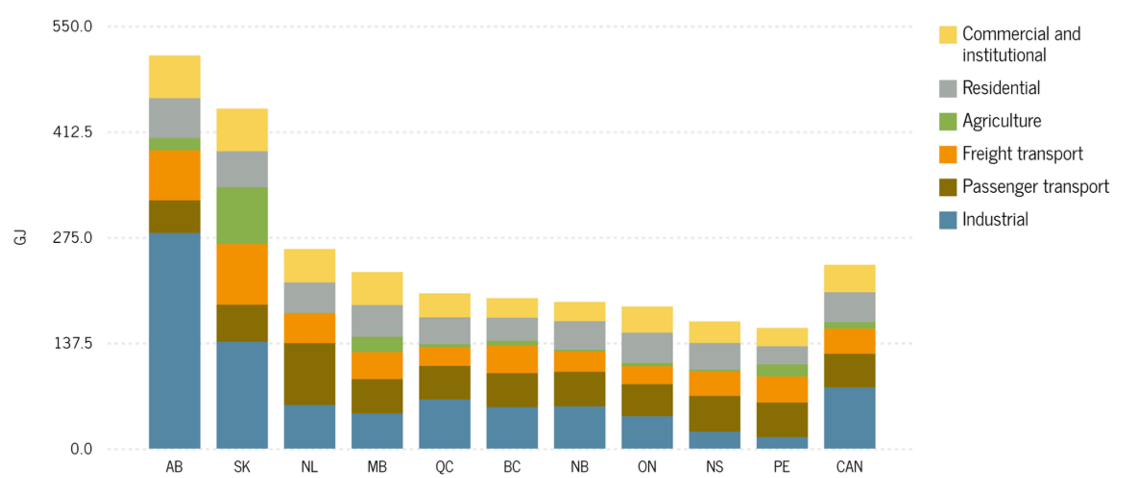
What these per capita consumption profiles thus show is that variations across the provinces go beyond the presence of certain industries: consumption in other sectors, notably agriculture and freight transport, is also significant. Moreover, choices made as to how everyday activities, such as passenger vehicle preferences or the source of space heating, are conducted are also responsible for variations.

Figure 3.7 – Total final energy consumption, by province and sector (2018)



Source: Statistics Canada 2021a

Figure 3.8 – Total per capita final energy consumption, by province and sector (2018)



Source: Statistics Canada 2021a, 2021b

3.3 Energy productivity

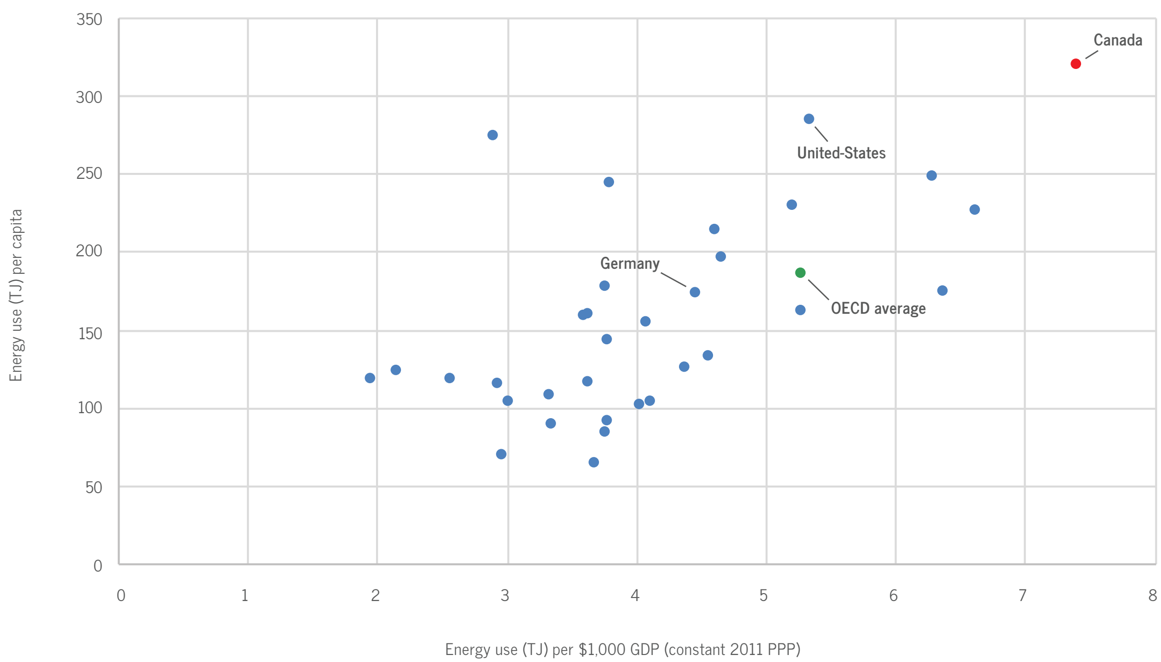
With the exception of Iceland, Canada surpasses all the other OECD countries in per capita energy use.[5] Its per capita consumption is almost twice as large as the OECD average. This position can partly be explained by the industrial and transportation sectors' profiles and the country's climate. What is particularly noteworthy is that energy intensity in Canada is also higher than in other comparable economies (Figure 3.9).

From 1995 to 2015, Canada was one of the top three worst performers on each of these indicators. This is particularly noteworthy given the significant decrease in energy intensity over the previous two decades (-34.1% between 1995 and 2015), showing that this decrease was not enough for Canada to catch up to other economies. Energy use per capita also stagnated over the same period (-4.4%), which suggests that efficiency improvements were barely sufficient to keep it from growing. Decreasing energy intensity implies that a smaller quantity of energy is needed to satisfy similar needs: therefore, this decrease and a stagnating energy use suggest a growth in the demand for energy services in the recent past.

It should be noted that this situation is partly caused by the historical structuring of the industrial sector, where many energy-intensive industries (aluminium smelters, pulp and paper mills, oil and gas extraction and transformation) result in a higher energy intensity for the economy overall. Over the last two decades, the rapid growth of the energy-intensive oil and gas sector provides a partial explanation for the variation in energy use in primary energy across the provinces, with oil-producing provinces well above the country's average. Alberta and Saskatchewan, the provinces with the largest oil production, post energy use levels per capita that are more than twice the Canadian average.

However, even low-consumption provinces (by Canadian standards) record very high per capita levels compared to most countries as even less energy-intensive sectors tend to have lower energy efficiency (by OECD standards).

Figure 3.9 – OECD members energy use and intensity (2015).



Note: Iceland, at 732 TJ energy use per capita and 17 TJ per $1,000 GDP, is omitted from this plot, to facilitate reading. Source: WDI 2021

[5] In Iceland, the expansion of energy-intensive industries like aluminum and the country's very small population explain its outlier energy use profile.

3.4 Takeaways

If all economic sectors have increased their energy use over the past 20 years, sectoral consumption profiles are quite different, both in their composition and in how they have evolved over that period. For example, **the oil and gas sector is responsible for most of the substantial consumption increase observed in industry**. Yet, in the past decade, many other sectors have either seen a decrease in their energy use or a slower growth rate compared with the previous decade. The latter is also true for transport sector consumption, which increased, but at a slower rate, in the past decade.

However, **the observed efficiency improvements is both unequal across sectors and insufficient to stop the overall rising energy demand altogether**. Increased demand (for transporting passengers or freight, or for larger space in buildings) has outpaced efficiency improvements.

Taking provincial variations into consideration, this suggests not only that **specific attention must be given to industry and transportation**, but also that **choices in other sectors should aim to reduce consumption consumption** as, if it is far from sufficient in itself, **energy productivity efforts are an essential part of the energy transition and GHG reductions**.

3.5 References

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4 ENERGY AND THE ECONOMY IN CANADA

As shown in Chapters 2 and 3, energy plays an important role in Canada's economy because of the country's high consumption levels and a substantial energy production sector. Acknowledging the major variations across the provinces' energy profiles is essential to understanding how regional constituencies affect action and policies targeting energy consumption and production. The energy sector's contribution to the economy, together with consumer preferences respecting energy expenses, produce a political economy of energy fraught with challenges inherent to low-carbon transformations.

HIGHLIGHTS

- Although oil and gas constitute the energy sector's largest contribution to Canada's GDP, they contribute far less in terms of employment owing to the high value of exports.
- Export revenues are subject to variations, largely due to the sector's vulnerability to changing market conditions in the United States.
- Investment in the renewables sector has a greater impact on job creation despite making a smaller contribution to GDP.
- Over the past decade, the increase in transport-related energy expenditures has led to higher-income households having a significantly higher carbon footprint than lower-income households, while these expenditures represent a heavier burden for the latter.

4.1 GDP, exports and employment

The economic importance of the energy sector is detailed in Table 4.1. Direct and indirect employments amount to 4.4% of the Canadian total, while contributing 10.2% of GDP. The energy sector is also responsible for 23% of merchandise exports. Overall, 81% of Canadian crude oil production, 43% of natural gas, 75% of uranium and 10% of electricity generated in Canada is exported. Although this production is delivered to a total of 141 countries, the bulk of Canada's energy exports are destined for a single market, the United States.

Oil and gas (including refined petroleum products) overwhelmingly constitute the largest share of Canada's total exports in terms of value, at $122 billion in 2019. Ninety-six percent of this total is shipped to the United States. While these exports are much less significant from the perspective of the United States' total consumption, Canadian production remains important for its neighbour since it amounts to 56% of the United States' crude oil imports, 98% of its natural gas imports, 21% of its uranium imports and 20% of its petroleum products imports. This trade relationship is also significant in the other direction; in value, 74% of Canada's total energy imports come from the U.S. (26% of the crude oil and 22% of the natural gas used in Canada) (NRCAN 2021). Overall, Canada's strong dependence on a single export market increases its exposure and reduces its control over the price of its energy exports.

Table 4.1 – Energy facts (2019)

Direct contribution to GDP	$154 billion (7.2%)
Indirect contribution to GDP	$65 billion (3.0%)
Total contribution to GDP	$219 billion (10.2%)
Direct jobs	282,000
Indirect jobs	550,500
Total jobs	832,500 (4.4% of total)
Exports	$134.3 billion (23% of goods exports)
Imports	$47.5 billion (8% of goods imports)

Source: NRCAN 2021

At 10.2% of the country's GDP, the energy sector's contribution to the economy is sizeable. However, this share is not matched by a similar contribution to employment, since only 4.4% of Canadian jobs are linked to the energy sector. In terms of direct contribution, this share is even more marginal; only 1.5% of jobs across the country are directly related to this sector.

With policy changes in Ontario respecting green energy production, clean energy investment (excluding investments in substantial hydroelectric power) fell from $US6.4 billion in 2014 to $US1.4 billion in 2019. Half of these annual investments were directed to onshore wind energy, while most of the rest went to solar PV. In 2018, clean energy's share of employment amounted to 120,650 jobs, accounting for 42% of total direct employment of the energy sector and 1.7% of GDP (NRCAN 2019; NRCAN 2021).

More details on energy sector contributions to employment, as well as an overview of other economic indicators, can be found in Energy in Canada: A Statistical Overview, a policy brief from the Ivey Energy Policy and Management Centre, Western University (Alahdad et al 2020).

Table 4.2 – Direct jobs and contributions to GDP from the energy sector

Jurisdiction	Direct jobs (2019)[a]	Direct contributions of energy to GDP ($ million, 2019)
Canada	282,000	154,000
Alberta	138,372	76,001
British Columbia	24,077	15,030
Manitoba	5,842	3,857
New Brunswick	3,932	1,802
Newfoundland and Labrador	6,683	7,571
Nova Scotia	2,471	872
Ontario	51,941	19,951
Prince Edward Island	210	79
Quebec	30,014	15,381
Saskatchewan	17,705	13,415
Northwest Territories	254	118
Nunavut	187	40
Yukon	105	39

a: Provincial and territorial figures do not precisely add up to the national total due to differences in data methodology. Source: NRCAN 2021

4.2 Research, development and demonstration (RD&D)

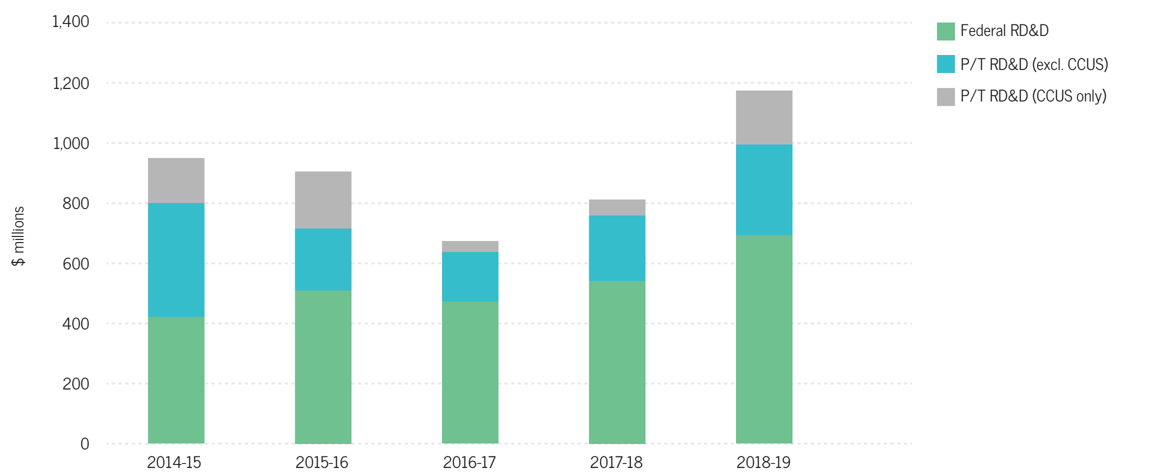
Federal RD&D spending targeting the energy sector has increased over the past four years, primarily through efforts tied to energy efficiency and carbon capture, utilization and storage (CCUS). These increases are consistent with Canada's commitments to double this spending through the Mission Innovation initiative, a global initiative aimed at accelerating global clean energy innovation (Canada 2020).

From 2014 to 2017, growth in overall public spending (Figure 4.1) at the federal level did not compensate the significant reductions in provincial spending on energy RD&D, which peaked in 2014 before falling to a low point in 2016-2017. Although part of this decrease can be attributed to the completion of Saskatchewan's Boundary Dam CCUS project in 2015, other provincial spending on energy RD&D also diminished. Since 2016-2017, the growth rate of federal spending has accelerated and provincial/territorial spending has also increased.

The increase since 2016-2017 can be broken down along areas of research (Table 4.3). Eighty-two percent of federal spending was devoted to clean energy, including the nuclear sector, and energy end-use. Energy end-use and energy efficiency have constituted the bulk of the increase over the past few years and has more than doubled since 2017-2018.

In contrast, the share of clean energy and end-use makes up only 49% of provincial spending; the main driver of growth for this spending has been for fossil fuels RD&D, which amounted to $91 million in 2017-2018. Finally, industrial actors devoted a larger share of RD&D to fossil fuels, reflecting the size of the Canadian oil and gas industry.

Figure 4.1 – Federal and Provincial/Territorial Public Expenditures on Energy RD&D



Source: NRCAN 2021

Table 4.3 – Expenditures on total energy RD&D by technology area ($ millions)

	Federal (2018/2019)	Provincial & Territorial (2018/2019)	Industry (2017)
Fossil fuels (incl. CCUS)	121	246	722
Renewable and clean energy (incl. nuclear)	243	172	511
Energy end-use (incl. energy efficiency)	315	62	263
Total	**678**	**481**	**1,496**

Source: NRCAN 2021

4.3 Household spending on energy services

Energy-related household expenditures (Table 4.4) can be broken down into the following two categories: direct energy expenditures, which include fuel and electricity purchased for transport or accommodation energy needs; and transport-related indirect energy expenditures, which represent all expenses associated with obtaining the transport services for which some of the direct expenditures are incurred. The latter includes average spending for purchasing private vehicles, their operating costs, and other means of motorized transport, such as public transit or air travel. The average Canadian household spent $4,580 on direct energy expenditures, and $11,022 on indirect transport-related expenditures, with important differences across quintiles. As for direct expenditures, the share of each fuel remains relatively similar across quintiles, although both electricity and vehicle fuel are more significant in the first quintile.

A few observations can be elicited from this profile. The first is that the share of direct energy expenditures is less significant for richer quintiles than for the first two. This indicates that energy-related expenses are less compressible than other expenditures and therefore represent a heavier burden for lower income households, a trend that has been consistent over the years.

Secondly, vehicle fuel expenses and transport-related indirect expenses are approximately three and five times higher in absolute value for the richest quintile with respect to the first. A variation of this magnitude cannot be explained solely by varying transport needs. It instead suggests that these needs are met by different means across quintiles; for instance through larger vehicles, more vehicles per household, more spending on air travel and less use of other collective transport.

Overall, both direct energy expenditures and indirect transport-related energy expenditures expand according to preferences and financial means, resulting in a significantly higher carbon footprint per household for top quintiles than the lower ones. However, these preferences remain unalterable below a certain income level: in other words, there is a limit to the compressibility of these expenses, which primarily affects lower-income households and their basic heating and transport needs.

Table 4.4 – Energy-related household expenditures by quintile of revenue (2019)

	Q1	Q2	Q3	Q4	Q5
Total household expenditures	**$ 37,534**	**$ 55,487**	**$ 79,357**	**$ 110,542**	**$ 185,422**
Share of direct energy expenditures	6.4%	6.2%	6.0%	5.0%	3.7%
Share of indirect transport-related energy expenditures	11.2%	12.0%	13.0%	12.1%	11.1%
Direct energy expenditures	**$ 2,397**	**$ 3,419**	**$ 4,756**	**$ 5,558**	**$ 6,768**
Principal accommodation energy needs	$ 1,187	$ 1,709	$ 2,104	$ 2,425	$ 3,083
Electricity	$ 831	$ 1,202	$ 1,413	$ 1,586	$ 1,937
Natural gas	$ 249	$ 369	$ 537	$ 682	$ 928
Other fuels	$ 107	$ 138	$ 154	$ 157	$ 218
Secondary accommodation (electricity and fuel)	$ 17	$ 27	$ 53	$ 56	$ 161
Fuel for personal transport	$ 1,193	$ 1,683	$ 2,599	$ 3,077	$ 3,524
Indirect transport-related energy expenditures	**$ 4,201**	**$ 6,632**	**$ 10,278**	**$ 13,387**	**$ 20,613**
Private vehicle purchases, leases and accessories	$ 1,848	$ 3,003	$ 5,341	$ 6,593	$ 10,579
Operating costs (registration, insurance, tires and repairs, parking, etc.)	$ 1,317	$ 2,296	$ 3,150	$ 4,114	$ 5,545
Collective transport	$ 906	$ 932	$ 1,191	$ 1,800	$ 2,565
Public transit	$ 228	$ 236	$ 273	$ 369	$ 396
Air travel	$ 441	$ 488	$ 661	$ 1,032	$ 1,731
Other (taxi, other passenger transport)	$ 237	$ 208	$ 257	$ 399	$ 438
Recreation vehicles (except bicycles)	$ 130	$ 401	$ 596	$ 880	$ 1,924

Source: Statistics Canada 2021

From 2010 to 2019, electricity expenses increased by 16%. Over the same period, expenses for the purchase of cars decreased by 28%, although this was more than compensated by a 69% increase in the truck category. This change in consumer preferences has to be taken into consideration in light of the increased demand for transport described in section 3.1. These preferences have led to both higher expenditures per household for individual vehicle purchases and lower fuel efficiency for the vehicle fleet. This has been accompanied by a steady increase in maintenance expenditures over the same period.

As for most other aspects covered in this chapter, provincial breakdowns show major distinctions across household consumption. The share of natural gas expenditures for principal residences is higher in Alberta (22%), Ontario (18%), Saskatchewan (15%), British Columbia (13%), and Manitoba (10%), compared to a maximum of 2% in the other five provinces.

In fact, natural gas in the residential sector remains marginal in Quebec, Newfoundland and Labrador, New Brunswick, Nova Scotia, and Prince Edward Island. While Quebec's commercial sector consumption of natural gas is substantial and almost as large as its electricity consumption, this is not the case for the Atlantic provinces, where there are very limited natural gas distribution networks.

While Quebec's residential heating needs are met by electricity, Newfoundland and Labrador, Nova Scotia, Prince Edward Island and, to a lesser extent, New Brunswick differ from the rest of Canada in their reliance on other fuels (notably heating oil and wood) to heat their homes. The role of these fuels remains marginal for all the other provinces (Statistics Canada 2021).

4.4 Takeaways

Although energy undeniably plays a major role in the Canadian economy, here again there are key variations to consider. Oil and gas contribute the energy sector's largest share to Canada's GDP, a consequence of the high value of exports as indicated earlier in the report. Partly due to this factor, the energy sector's contribution to the national economy is much less in terms of employment. The dependence on exports implies that oil and gas export revenues are more subject to variation, and their size underlines Canada's vulnerability to changing market conditions in the United States. Investment figures also suggest that investment has a higher impact on job creation in the renewables sector, despite a smaller contribution to GDP.

Household energy expenditures for energy services present two dynamics that have been prominent since 2010. Changing preferences for transport, the most expensive energy service, have led to an increase in this category of expenditures. Over the 2010-2019 period, this increase reflected purchases of more expensive vehicles and higher maintenance costs rather than higher spending on gasoline.

4.5 References

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5

POLICY FOCUS: ACCELERATING THE DEPLOYMENT OF GHG REDUCTION STRATEGIES

As in much of the rest of the world, Canada's provincial, territorial and federal governments have adopted various GHG emissions action plans and strategies. The description presented here reflects a diversity of approaches and ambitions, highlighting the challenge of establishing a coherent national program. With regard to the subnational level, this chapter is limited to a summary of targets and policies; Appendix B provides additional details for each province and territory.

HIGHLIGHTS

- Despite reductions in many sectors, Canada's overall GHG emissions have stagnated since 2005.
- Accounting for more than half the country's emissions, the transport sector and the oil and gas industry also represented the most rapid emission increases in absolute terms from 1990 to 2019.
- Most Canadian provinces have adopted GHG emission reduction targets. However:
  - Despite the proliferation of action plans and strategies, details on how targets will be reached—including costs, technologies, sectorial targets and pathways—are scant or entirely lacking;
  - For the most part, these strategies have so far failed to translate into reality.
- Strong disagreements with some provinces on carbon pricing reached the Supreme Court, which confirmed the constitutionality of the federal policy in 2021.
- Recent announcements by the federal government signal increasingly ambitious GHG emission reduction targets, including net-zero emissions by 2050 and a more than 40 % reduction with respect to 2005 by 2030. However:
  - Details are still lacking as to how these targets can be achieved;
  - Data relating to GHG emissions, and to associated energy production and consumption, are still lagging, limiting the capacity to evaluate progress and adjust the course of action.

5.1 GHG emissions in Canada

Although Canada's overall emissions increased by 22.8% from 1990 to 2005,[1] they have remained roughly stable from 2005 to 2019 (-1.1%). As Figure 5.1 shows, energy-related emissions make up 80.7% of total emissions, a share that has remained stable since 2005. Although emissions growth halted early in the 21st century, it has not budged since, despite reduction objectives and a significant number of policies to help achieve them, supported by considerable governmental expenditure. The rest of this section provides a more detailed portrait of emissions.

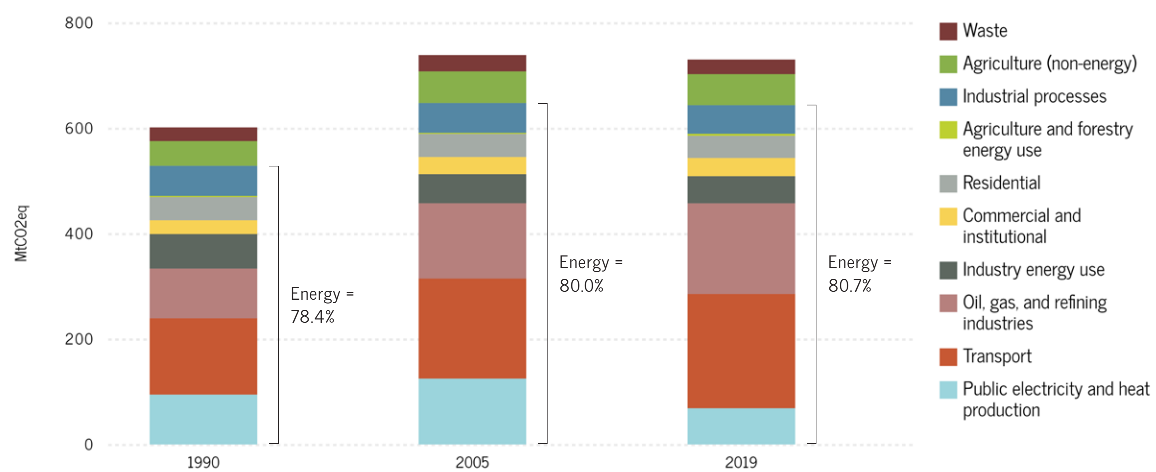
The plateau in total GHG emissions noted from 2005 to 2019 is associated with an overall decrease in emission intensity, as expressed by the following two metrics:

- Adjusted to population growth, per capita emissions were 15.2% lower in 2019 than in 2005;
- Over that same period, carbon intensity per constant dollar of GDP was reduced by almost 26.9%.

These metrics reflect transformations in the industrial sector, technological improvements, regulations, and more efficient equipment and practices (WDI 2021; ECCC 2021; Statistics Canada 2021).

A closer look at the main sources of emissions in 1990, 2005 and 2019 (Figure 5.1) reveals significant variations across categories. From 1990 to 2005, emissions increased in most sectors—with the notable exception of industries outside of oil and gas. Although the reasons for these increases differ considerably across the various categories, the main driver was a higher energy demand due to increased activities in each of the sectors.

Figure 5.1 – GHG Emissions in Canada by sector



Source: ECCC 2021

[1] The years 1990 and 2005 are used as two reference points in GHG emissions charts in this section as they are the two reference years most commonly used in developing GHG reduction targets. The most recent GHG emission data available for Canada at the time of writing is for 2019.

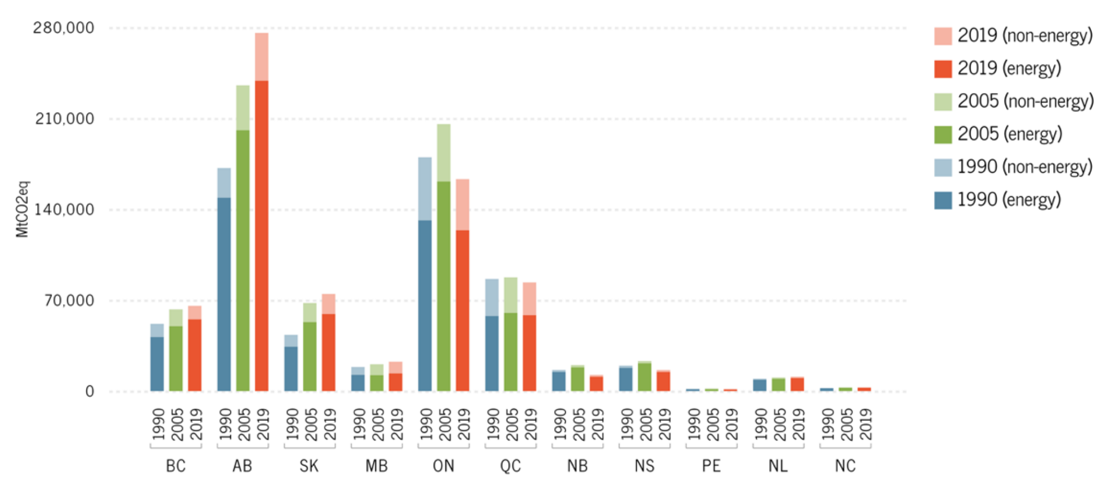
The period from 2005 to 2019 shows a different picture. Emissions from the building sector (residential, commercial and institutional) remained constant—growth was compensated by emission intensity reduction derived from efficiency gains, which include greater use of electricity—while emissions from electricity and heat production and industries outside of oil and gas fell significantly (-56.2Mt and -3.6Mt respectively). Fuel switching was responsible for most of the emissions reductions in the electricity sector as Ontario retired coal and replaced it with natural gas. The ongoing phase out of coal-fired power generation on a national scale should lead to more reductions over the next few years.

Conversely, the GHG share of the oil, gas and refining industries has grown systematically over the last 30 years, climbing from 15.7% in 1990 to 19.3% in 2005 and reaching 23.6% of the total in 2019. Despite technological improvements in oil sands production, which reduced emissions per barrel by 12% from 2005 to 2015 (NRCAN 2021a), this sector contributes close to one-third of energy-related emissions. A similar pattern is observed for the transport sector, whose share of emissions grew unabatedly from 24.1% in 1990 to 25.7% in 2005, and to 29.7% of the total in 2019. Together these two sectors are responsible for more than half the country's emissions; they also underwent the most rapid increase in absolute terms over the entire 1990-2019 period.

Breaking down total emissions by province (Figure 5.2) shows that all oil and gas producing provinces, including British Columbia, Alberta, Saskatchewan and Newfoundland and Labrador, showed a systematic growth in their total emissions over the 30-year period; apart from Manitoba, all the other provinces post lower emissions than in 1990. However, this reduction is only slight.

Owing to the importance of its oil and gas sector, Alberta has by far the largest emissions on a provincial basis. Saskatchewan's emissions are also much larger than its population or economic size would suggest. These two provinces also show the greatest increase in overall GHG emissions over both the 1990-2005 and the 2005-2019 periods, a direct result of increased oil and gas production.

Figure 5.2 – GHG Emissions by province

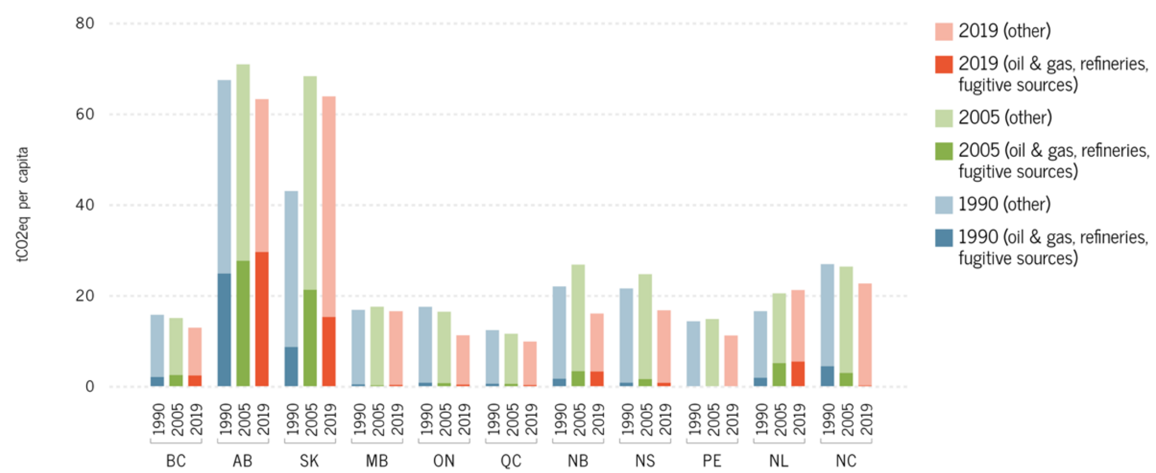


Source: ECCC 2021

These trends also led to a wide discrepancy in per capita emissions between Alberta and Saskatchewan on the one hand, and all other provinces on the other. This includes British Columbia, which showed a 18% decline in per capita emissions between 1990 and 2019, despite a growth in gas production-related emissions (Figure 5.3).

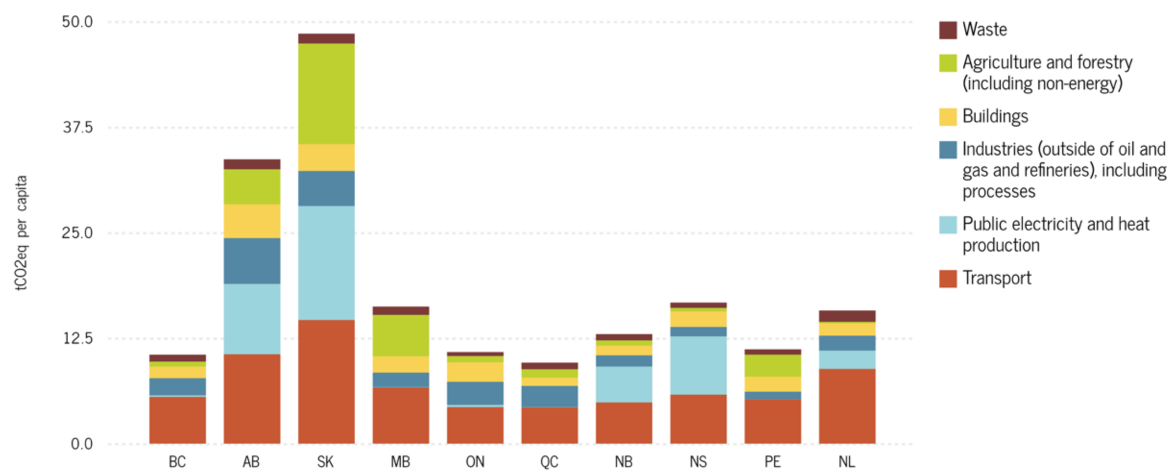
As Figure 5.3 indicates, a large part of the growth in Alberta and Saskatchewan is due to the importance of the oil and gas sector (including fugitive sources). However, larger per capita figures for the transport sector, a greater presence of fossil fuels in electricity generation, and the immense importance of the agriculture sector in the case of Saskatchewan, also contribute to this trend.

Figure 5.3 – Evolution of per capita GHG Emissions in Canada



Note: Due to data availability, 1990 figures use 1991 population data for Nunavut and Northwest Territories. Source: ECCC 2021; Statistics Canada 2021

Figure 5.4 – Per capita emissions outside of the oil and gas sector, by province (2019)



Note: Due to data availability, 1990 figures use 1991 population data for Nunavut and Northwest Territories. Source: ECCC 2021; Statistics Canada 2021

5.2 Carbon capture, utilization, and storage (CCUS)

As part of its strategy to reduce GHG emissions while maintaining a strong oil and gas production sector, Canada has become one of the few countries operating commercial scale CCUS operations, with two working installations today.

One of these is the Quest project in Alberta, where the capture operation is applied during the conversion of bitumen extracted from oil sands into higher grade oils. The other is the Boundary Dam coal-fired power station in Saskatchewan, where CO_2 produced at the combustion stage is captured.

Together, these projects provide essential information about real-life working conditions of CCUS technologies. The Quest project has been in operation since 2015. Its 2019 annual report indicates that the project stored 1,128 kt CO_2 that year, representing 78.8% of the carbon emitted from the syngas feed stream at the Shell Scotford Upgrader near Fort Saskatchewan. Taking into account the GHG emitted during the entire process—from capture to transport and storage and including imported electricity—the net CO_2 reduction amounts to 891 kt CO_2 (79% of the total CO_2 injected) for a net capture of 62% of carbon emissions.[2]

For its part, between April 2020 and April 2021, the Boundary Dam project captured some 745,000 tonne of CO_2 corresponding to about 75% of the GHG captured, well below its 90% target.[3] While the Quest Project aims at permanently storing CO_2, Boundary Dam uses CO_2 for oil recovery projects.

Even with massive subsidies, the financial viability of both projects is closely linked to carbon pricing and oil extraction operations for Boundary Dam and oil prices for Quest. For the time being, SaskPower has indicated that it would not retrofit any of its other power plants. The situation respecting enhanced oil recovery may evolve in the short term with the completion of the Alberta Carbon Trunk Line, a pipeline designed to carry CO_2 captured from the Heartland region of Alberta to an injection site 240 km to the south.

5.3 General overview of policies: targets and objectives

The federal and provincial governments have announced several targets and policies on energy, GHG emissions and carbon pricing. These policies include various incentives to change energy consumption patterns and behaviours, encourage or accelerate the adoption of certain technologies, increase the role of renewable sources in the energy mix, decrease GHG emissions, and put a price on carbon emissions. These policies share some commonalities, and several objectives complement one another.

Each section provides a summary of the targets and main incentives put forward by these governments and then moves on to review the main policy efforts to meet the targets.[4] Both the reference year and the time by which the target must be reached are indicated.

Although this presentation does not discriminate as to whether the target has been enshrined in legislation or regulation at this point, this distinction in the regulatory or legal status of the objectives is nevertheless important. The announcement of a target in a government press release or on the election campaign trail is not the same as the publication of an official strategic plan specifying the target and listing concrete measures to attain it. In turn, such announcements are also different from the passage of legislation or a regulation setting out how the government is moving forward on these measures.

This choice was made since this chapter is intended to provide a snapshot of 2021, and as such must reflect the state of affairs at the time of publication. However, it should be noted that scenarios exclude objectives or measures that are simply announced or are still in the earliest stages of design and implementation. Details on these exclusions can be found in later chapters.

It should also be noted that even legislated targets and action plans do not automatically result in the successful achievement of targets. Accordingly, a look at policy details and implementation so far is essential to provide a sense of the scale of the federal and provincial governments' efforts to achieve these targets. For a more quantitative impact of these measures, readers are referred to the reference scenario presented in the following chapters, which incorporates the bulk of these measures.

[2] Shell Canada Energy, *Quest Carbon Capture and Storage Project Annual Summary Report*, Alberta Department of Energy: 2019. https://open.alberta.ca/dataset/f74375f3-3c73-4b9c-af2b-ef44e59b7890/resource/ff260985-e616-4d2e-92e0-9b91f5590136/download/energy-quest-annual-summary-alberta-department-of-energy-2019.pdf

[3] SaksPower, BD3 Status Update: March 2021, April 14, 2021. https://www.saskpower.com/about-us/our-company/blog/2021/bd3-status-update-march-2021

[4] Appendix 8 provides more detail on policies in the provinces and territories.

5.4 Federal policies

Main targets and incentives

GHG emissions reduction

- -40–45% by 2030 (2005)
- Net-zero by 2050
- -40% by 2030 (2005) for government operations

Carbon pricing

- Federal tax on fuel emissions and output-based pricing for industrial emitters, unless provincial equivalent exists

Renewable energy targets

- 90% non-emitting electricity sources by 2030
- 100% clean power in government buildings by 2025

Coal phase-out

- Yes, by 2030 (with some exceptions due to equivalency agreements)

Low-emission vehicles incentives and renewable fuel mandates

- Cash rebates for low-emission vehicle purchase or leasing ($2,500-$5,000)
- Renewable fuel mandates (5% gasoline, 2% diesel)
- Clean Fuel Standard planned for 2022

Other

- Reduction of methane emissions by 40-45% by 2025

Shortly after Canada's Liberal government was elected in the fall of 2015, it signed the Paris Agreement and presented a series of plans to achieve GHG emission reduction targets. During its first mandate, the main medium-term target remained a 30% reduction in emissions over 2005 levels by 2030. Scenarios set out in communications to the United Nations Framework Convention on Climate Change then described a 2050 target of -80% as well. After a 2019 election campaign pledge to implement a 2050 net-zero target, the government presented its new climate policy strategy formalizing the target in December of 2020. Subsequently, at an international meeting led by US President Joseph Biden, the Canadian Prime Minister announced more aggressive GHG reduction objectives for 2030, mentioning a 40% to 45% reduction.

5.4.1 A price on carbon

Most of the pre-2020 announcements fall under the umbrella of the Pan-Canadian Framework on Clean Growth and Climate Change (PCF). The most high-profile measure under this framework is arguably the carbon pricing system legislated in the Greenhouse Gas Pollution Pricing Act, which imposes minimum requirements on provinces to implement an explicit price-based system (e.g., a carbon tax or levy) or a cap-and-trade system. If the federal government were to find a province's proposal that did not meet these minimum standards (both in coverage and in price levels), it committed to imposing a "backstop" option in the provinces that elected not to set up their own program or comply with the requirements.

Two elements comprise this "backstop" carbon-pricing system:

1. A charge on fossil fuels—paid by fuel producers and distributors, starting at \$20/tonne of CO_2e in 2019 and rising to \$50/tonne of CO_2e in 2022 by \$10 yearly increments;
2. An output-based pricing system, applied only to industrial facilities with high emissions levels (>50,000 tCO_2e).

The strategy the government presented in late 2020 included a new schedule for increases of \$15/year in the rate of the fuel levy, rising progressively to \$170/tonne in 2030.

In the output-based pricing system, the facilities covered are evaluated in relation to an emission standard for their activity sector. The federal government issues surplus credits to facilities emitting less than this standard, while those emitting above the standard are required to submit government-issued credits, submit eligible offset credits or pay a carbon charge (set at the same level as the above-described charge on fossil fuel).

Emission sources covered include fuel combustion, industrial processes, flaring, and some venting and fugitive sources, excluding methane venting and fugitive methane emissions from oil and gas facilities. Revenues from the proceeds are sent back to the jurisdiction of origin (Canada 2018a, 2018b, 2018c).

5.4.2 Transport sector: taxes, incentives and regulations

The Canadian government's approach to transport sector emissions is multifold. First, it imposes several taxes on fuel consumption, including a \$0.10 tax on gasoline and a \$0.04 tax on diesel. It also imposes an excise tax on the purchase of fuel-inefficient vehicles.

Second, it has launched a program to electrify the sector. One part of the program gives purchase incentives for battery-electric, hydrogen fuel cell, or longer-range plug-in hybrids (\$5,000), as well as for shorter-range plug-in hybrid purchases or leases (\$2,500). This initiative is in addition to the Zero Emission Vehicle Infrastructure Program, intended to deploy a network of zero-emission vehicle charging and refuelling stations.

The third transportation program is the development of the Clean Fuel Standard, which aims to reduce the carbon footprints of fuel suppliers by using a lifecycle approach. The measure is intended to avoid favouring specific fuels, as is the case for instance with current biofuels mandates. Regulations for the Clean Fuel Standard are scheduled to be completed in 2021 and come into force in 2022 for liquid fuels and by 2023 for classes of solid fuels.

5.4.3 Coal phase-out

In 2018, the Government of Canada also released regulations outlining a coal phase-out in the electricity sector by 2030. The phase-out is intended to help Canada reach its target of 90% emissions-free electricity generation by 2030. A Coal Transition Initiative, which has a \$35 million budget over five years, is used to help communities become less reliant on coal. Furthermore, GHG regulations for natural gas-fired electricity will be published to complement the coal phase-out.

5.4.4 "Green/Clean growth"

Under the PCF, the Low-carbon Economy Fund commits $2 billion to help support projects that generate green growth, reduce GHG emissions and help meet or exceed Canada's Paris Agreement commitments. The fund has two components: the Low Carbon Economy Leadership Fund, which provides $1.4 billion to provinces and territories to help them achieve their GHG reduction commitments; and the Low Carbon Economy Challenge, which uses the rest of the funds to finance innovations that "leverage Canadian ingenuity to reduce greenhouse gas emissions and generation clean growth in support of Canada's clean growth and climate action plan (the PCF)" (Canada 2020). Eligible applicants for the Low Carbon Economy Challenge include provinces and territories, municipalities, Indigenous communities and organizations, businesses, and not-for-profit organizations.

5.4.5 Exemplarity

Presented in 2017, the Greening Government Strategy sets targets for GHG emissions reductions for government operations at 40% by 2030 and 80% by 2050 (with 2005 as the baseline). The strategy's main tools to achieve these targets are repairs and retrofits to government buildings, as well as investments in transforming the government vehicle fleet to low-emission vehicles.

5.4.6 Methane

In addition, the government released regulations for methane emissions, with the aim of achieving 40%-45% reductions before 2025, as well as for outlining a new schedule for the reduction of HFCs. Equivalency agreements respecting these regulations have been reached with British Columbia, Alberta and Saskatchewan. The Canadian government also published its fourth Federal Sustainable Development Strategy (2019-2022), which established goals linked to the United Nations Sustainable Development Goals.

5.4.7 Implementation

A closer look at the implementation of these policies and announcements is essential to provide an assessment of the current state of affairs. First, as Table 5.1 shows, four provinces and the Northwest Territories have systems that fully comply with federal requirements; Ontario, Manitoba, the Yukon and Nunavut make full use of the federal "backstop," although Ontario will put its system for industrial emitters in place shortly. The remaining four provinces have a mixed system, with New Brunswick also planning to introduce its provincial system for industrial emitters shortly. Manitoba had proposed a provincial system for the fuel levy, which was shelved in 2020. Prince Edward Island has a provincial tax on fuel purchases, while the federal system applies to industrial emitters. Finally, Alberta has a provincial system for industrial emitters and the federal "backstop" applies as the carbon tax.

Two issues are worthy of note in assessing the impact of the federal carbon pricing policy. First, over the past two years, there have been three formal challenges to the constitutionality of the federal program. Saskatchewan and Ontario both lost in their respective courts, in contrast to Alberta, which won its challenge in early 2020. A further challenge by Manitoba was planned for 2020, but the Supreme Court settled the issue in its March 2021 decision (delayed due to COVID), essentially confirming the federal government's position.

The second carbon pricing issue relates to equivalency agreements between the federal government and provincial pricing policies. Quebec, notably, has so far successfully argued that its cap-and-trade program with California meets the federal requirements, a position with which the federal government has agreed. However, it is doubtful whether this equivalency will remain over the next decade if the price increase schedule proposed by the federal government is legislated (up to $170/tonne in 2030).

Prince Edward Island and New Brunswick have also signed equivalency agreements on carbon pricing. In both these cases, the province charges a tax that meets the federal requirements but decreases the provincial sales tax on fuel purchases to compensate for most of the financial impact on taxpayers. Although proponents of carbon pricing argue that this practice defeats the purpose of the tax by eliminating the financial incentive to reduce emissions, the federal government maintains that it sees benefits in tempering political opposition to carbon pricing.

In addition to carbon pricing, equivalency agreements on coal phase-out in the electricity sector have been reached in two out of the four provinces still using coal (Alberta, Saskatchewan, New Brunswick and Nova Scotia), exempting them from the regulations. Saskatchewan, which has a CCUS installation at a coal-fired powerplant, successfully made the case that this should be factored into its meeting of the coal phase-out commitment; Nova Scotia set lower emission caps for its electricity sector as a whole, also committing to 50% of electricity coming from a renewable source by 2020.

5.4.8 Upcoming policies

The October 2019 election resulted in a minority government led by the Liberals. Opposition to climate policy during the campaign was mainly voiced by Conservative candidates and leadership. This position changed in early 2021 when the Conservative leadership largely embraced the general concept of carbon pricing, although with terms and conditions that differ from the plan in place.[5] This new position provides some room to manoeuvre for the government to maintain the direction of the policies presented in its previous four-year mandate.

The presentation of the new climate strategy in late 2020, the government's introduction of Bill C-12 on net-zero governance,[6] and the 2021 budget formalized the 2050 net-zero target, although details were not yet available on how the plan will be implemented at the time of writing.

Table 5.1 – Carbon pricing system by province or territory

Jurisdiction	Prov./terr. pricing	Federal pricing	Mixed	Note
British Columbia	X			
Alberta			X	Federal "backstop" for the carbon tax, provincial system for industrial emitters
Saskatchewan			X	Federal "backstop" for the carbon tax, split system for industrial emitters
Manitoba		X		
Ontario		X		Federal system applies for the carbon tax; federal system applies to industrial emitters although it will be replaced by a provincial proposal shortly
Quebec	X			
New Brunswick			X	Provincial tax since April 2020; federal system applies to industrial emitters although it will be replaced by a provincial proposal shortly
Nova Scotia	X			
Prince Edward Island			X	Provincial tax, federal system for industrial emitters
Newfoundland and Labrador	X			
Yukon		X		
Northwest Territories	X			
Nunavut		X		

[5] *Secure the environment. The Conservative plan to combat climate change.* Conservative Party of Canada (2021). https://cpcassets.conservative.ca/wp-content/uploads/2021/04/15104504/24068610becf2561.pdf

[6] BILL C-12, *An Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050*, https://parl.ca/DocumentViewer/en/43-2/bill/C-12/first-reading

5.5 Policies in the highest GHG-emitting provinces

5.5.1 British Columbia

Main targets and incentives

GHG emissions reduction

- 16% by 2025 (2007)
- 40% by 2030 (2007)
- 60% by 2040 (2007)
- 80% by 2050 (2007)

Carbon pricing

- $40/tonne tax

Renewable energy targets

- 93% renewable electricity generation
- 15% of residential and industrial natural gas consumption derives from renewable gas

Coal phase-out

- N/A

Low-emission vehicles incentives and renewable fuel mandates

- Cash rebates up to $3,000 for the purchase of electric (including longer-range hybrid) and hydrogen fuel cells
- Share of zero-emission vehicles sales or leases, 10% by 2025, 30% by 2030 and 100% by 2040
- Renewable fuels mandates and carbon intensity targets for fuels sold

Other

- Carbon Neutral Government
- New buildings "net-zero ready" by 2032
- Reduction of methane emissions by 45% (2014)

British Columbia has its own carbon pricing system, first introduced in 2008 as a revenue-neutral tax on carbon emissions that reached $30/tonne in 2012. The rate has increased again by $5/tonne per year since 2018 to match federal requirements and the revenue-neutral condition has been eliminated. The rate applied for the carbon tax depends on the fuel's carbon content; an additional Motor Fuel Tax applies for gasoline and diesel.

Revised GHG targets were introduced in the 2018 Climate Change Accountability Act (40% by 2030, 60% by 2040, as well as a recommitment to 80% by 2050). In light of the results of a progress assessment in 2020, the province added a target of 16% reduction by 2025. The Zero-Emission Vehicles Act (2019) also set targets for the share of zero-emission light-duty vehicles sales or leases, which must reach 10% by 2025, 30% by 2030 and 100% by 2040. This is in addition to the Renewable and Low Carbon Fuel Requirements Regulation, which includes renewable fuels mandates as well as carbon intensity targets for fuels sold.

Most of these initiatives are part of the CleanBC strategy, released after the Climate Change Accountability Act as a set of measures to achieve the province's GHG emissions reduction targets. The strategy also requires that a minimum of 15% of residential and industrial natural gas consumption come from renewable gas. It has paid particular attention to the building sector, aiming to make every new building constructed in the province "net-zero energy ready" by 2032. In addition, regulations were enacted to reduce methane emissions from upstream oil and gas operations by 45%.

5.5.2 Alberta

Main targets and incentives

GHG emissions reduction

- None

Carbon pricing

- Federal "backstop" for the carbon tax, provincial system for industrial emitters

Renewable energy targets

- None

Coal phase-out

- By 2030

Low-emission vehicles incentives and renewable fuel mandates

- Renewable Fuels Standard (5% gasoline, 2% diesel)

Other

- GHG emissions cap of 100Mt for the oil and gas sector
- Reduction of 45% by 2025 for methane emissions in upstream oil and gas production (2014)

After the 2019 election, the new government announced early on that it would modify or eliminate several provisions following from the Climate Leadership Plan enacted by the previous government in 2015. These efforts began with the Carbon Tax Repeal Act, voiding the Climate Leadership Act and ending the Alberta Climate Leadership Adjustment Rebate. This triggered an announcement from the federal government that the federal carbon pollution pricing system would replace the Alberta carbon tax. Although the provincial government challenged the federal system in court, following Saskatchewan and Ontario, it lost after the Supreme Court's decision in March, 2021.

The provincial government also chose not to repeal the 100 Mt cap imposed on emissions from the oil and gas industry, underscoring that it is unlikely that the cap will be reached in the next several years. As a result, a significant increase in the province's overall emissions (and Canada's) is possible even while respecting the cap, which would largely offset efforts to reduce emissions through other measures.

In the electricity sector, Alberta remains the province with the highest share of coal in its electricity production. The government has planned a system of transition payments for facilities that were slated to be in operation beyond 2030.

As for cuts in methane emissions, conflicting regulations from both the Alberta and federal governments took effect on January 1, 2020; however, an equivalency agreement was subsequently reached in late 2020.

5.5.3 Saskatchewan

Main targets and incentives

GHG emissions reduction

- -40% by 2030 (2005) for SaskPower operations

Carbon pricing

- Federal "backstop" for carbon tax, split system (federal and provincial) for industrial emitters

Renewable energy targets

- 50% of electricity from renewable sources by 2030

Coal phase-out

- Exemption for Boundary Dam plant

Low-emission vehicles incentives and renewable fuel mandates

- 7.5% renewable content in gasoline, 2% in diesel

Other

- Reduction of 40%-45% in methane emissions in flared and vented methane emissions

In 2017, the province released its Prairie Resilience Action Plan, outlining its approach and strategy for reducing GHG emissions. This release was followed by the introduction of the Climate Resilience Measurement Framework in 2018, which set out a series of 25 targets for the province and municipalities to meet and manage. Saskatchewan remains the only province not to have signed on to the PCF.

Saskatchewan released a plan to price carbon pollution in 2018. Overall, the plan, which uses an output-based performance standards approach for some of its large industrial facilities, has resulted in only a partial attainment of the federal stringency requirements. The federal pricing system applies as an output-based pricing system for electricity generation and natural gas transmission pipelines that covers facilities from sectors emitting 50,000 tonnes or more of CO_2 equivalent annually, as well as a charge on fossil fuels, which is generally paid by registered distributors (fuel producers and distributors).

Saskatchewan is one of the four provinces that use coal for electricity generation. After the federal coal phase-out plan was announced, the province reached an agreement that allowed it to meet the federal emission requirement on an electricity system-wide basis in 2019. This agreement enabled the province to keep the station running at the Boundary Dam Carbon Capture Project beyond 2030. The project is a commercial-scale station that uses carbon capture, utilization and storage (CCUS) technology.

5.5.4 Ontario

Main targets and incentives

GHG emissions reduction

- -30% by 2030 (2005)

Carbon pricing

- Federal system applies for the carbon tax; federal system applies to industrial emitters but a provincial proposal will replace it shortly

Renewable energy targets

- N/A

Coal phase-out

- N/A

Low-emission vehicles incentives and renewable fuel mandates

- 10% renewable content in gasoline (to be increased to 15% in 2030), 4% in diesel

After its election in the spring of 2018, the new government led by Premier Doug Ford announced several changes to the climate policies put in place by successive Liberal governments from 2003 to 2018. The government introduced the Cap and Trade Cancellation Act in 2018, withdrawing the province from the cap-and-trade system it had joined with Quebec and California earlier that year, resulting in the application of the federal carbon pricing system instead. In 2020, the province received approval from the federal government for a carbon-pricing system for large industrial emitters, which functions as emissions performance standards. However, since its coverage was described as concerning by the federal Environment Minister, it will be reviewed in two years. At the time of writing, it had not yet been determined when the provincial system would take effect. The Green Energy and Green Economy Act was also repealed in 2018.

After the 2018 election, Ontario released its Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan, under which the province commits to a 30% reduction in GHG remissions from 2005 levels by 2030, in line with the federal target at the time. The plan includes emission performance standards for large emitters; the Ontario Carbon Trust, an emissions reduction fund to encourage private investment in clean technology solutions; and the Ontario Reverse Auction, which establishes an auction system that allows bidders to send proposals for emissions reduction projects and compete for contracts based on the lowest-cost GHG emission reductions.

Many of these changes arose from a concern about the impact on electricity costs, which have climbed rapidly in Ontario in recent years. The significant changes in policies to reduce GHG emissions (and to energy policy more generally) underscore the current government's different approach to these issues.

5.5.5 Quebec

Main targets and incentives

GHG emissions reduction

- -37.5% by 2030 (1990)
- Net-zero by 2050 (1990)

Carbon pricing

- Cap-and-trade system linked with California

Renewable energy targets

- +50% in bioenergy production by 2030
- +25% overall renewable energy output by 2030

Coal phase-out

- Elimination of the use of thermal coal by 2030

Low-emission vehicles incentives and renewable fuel mandates

- Zero-emission vehicle standard, increasing to 22% of new sales by 2025
- Cash rebates (up to $8,000) for the purchase of low-emission vehicles
- Renewable content in gasoline (15%) and diesel (10%) in 2030

Other

- No sales of new gasoline-powered vehicles from 2035
- -40% of consumption of oil products by 2030 (2016)
- +15% in energy efficiency
- -50% in space heating emissions by 2030 (1990)
- 55% of urban buses and 65% of school buses powered by electricity by 2030

In late 2020, the Quebec government introduced its *Plan pour une économie verte* (Plan for a green economy), which relies heavily on electrification. The plan includes various targets, including no sales of gasoline-powered vehicles from 2035, a 50% reduction in emissions from building space heating by 2030, and 10% renewable gas in the natural gas distribution network by 2030s. A large part of the efforts are to be achieved through investments from the *Fonds d'électrification et de changements climatiques* (Fund for electrification and climate changes), a fund dedicated to projects with GHG reduction potential financed mainly by proceeds from Quebec's participation in the Western Climate Initiative's cap-and-trade system with California since 2013. The system covers fossil fuel distributors and companies in the industrial and electricity sectors that emit more than 25,000 tonnes of CO_2e.

The province's *Politique énergétique 2030* (2030 Energy policy) includes several other 2030 targets. Established in 2016, the policy also created *Transition énergétique Québec* (Quebec energy transition), an agency tasked with developing cohesive action plans every five years to ensure progress toward the policy's objectives. Although the first plan was published in 2018, the 2020 strategy abolished the agency and the Conseil de gestion du Fonds vert (Green fund management board) (which provided oversights on climate-related expenses) and their responsibilities were transferred to existing ministries.

Quebec has introduced a zero-emissions vehicles mandate, enabling automakers to accumulate credits by selling zero-emission or low-emission vehicles, in order to meet progressively more stringent targets for the share of zero-emission or low-emission vehicles. This share is scheduled to reach 22% in 2025. A similar mandate for heavy-duty vehicles is planned but has yet to be formally announced. A second transport electrification policy offers cash rebates for the purchase of electric vehicles.

5.6 Policy overview in other provinces and in territories

5.6.1 Manitoba

Main targets and incentives

GHG emissions reduction

- 5-year rolling targets from recommendations of expert council (current target: -1Mt by 2023)

Carbon pricing

- Federal system applies

Renewable energy targets

- N/A

Coal phase-out

- N/A

Low-emission vehicles incentives and renewable fuel mandates

- Renewable content in gasoline (9.25%) and diesel (3.5%) (10% and 5% starting in 2022)

Other

- +11.25% energy efficiency in domestic natural gas consumption by 2032
- +22.5% energy efficiency in electricity consumption by 2032

5.6.2 New Brunswick

Main targets and incentives

GHG emissions reduction

- -10% 2020 (1990)
- -35% by 2030 (1990)
- -80% 2050 (2001)

Carbon pricing

- Provincial tax since April 2020; federal system applies to industrial emitters but provincial proposal will replace it shortly

Renewable energy targets

- 40% renewable sources for electricity sold in the province

Coal phase-out

- Yes

Low-emission vehicles incentives and renewable fuel mandates

- 20,000 electric vehicles by 2030

Other

- Carbon neutral government by 2030

5.6.3 Nova Scotia

Main targets and incentives

GHG emissions reduction

- -53% by 2030 (2005)
- Net-zero carbon footprint by 2050

Carbon pricing

- Provincial cap-and-trade system

Renewable energy targets

- 40% renewable electricity

Coal phase-out

- Equivalency agreement: keeps coal-fired plants while achieving deep reductions elsewhere in the electricity sector (phase-out by 2030 recently committed by current government)

Low-emission vehicles incentives and renewable fuel mandates

- None

5.6.4 Prince Edward Island

Main targets and incentives

GHG emissions reduction

- 1.2 Mt (~-40%) by 2030 (2005)
- Net-zero by 2040

Carbon pricing

- Provincial system for the carbon tax, federal system applies to industrial emitters

Renewable energy targets

- None

Coal phase-out

- N/A

Low-emission vehicles incentives and renewable fuel mandates

- Free electric vehicle registration

5.6.5 Newfoundland and Labrador

Main targets and incentives

GHG emissions reduction

- -30% by 2030 (2005)

Carbon pricing

- Provincial system

Renewable energy targets

- None

Coal phase-out

- N/A

Low-emission vehicles incentives and renewable fuel mandates

- None

5.6.6 Territories

Main targets and incentives

GHG emissions reduction

- Yukon: -30% (2010)
- Northwest Territories: -30% by 2030 (2005); -25% in emissions from diesel-generated electricity; -10% per capita transport emissions by 2030 (2016)

Carbon pricing

- Federal system in the Yukon and Nunavut, Northwest Territories specific carbon tax

Renewable energy targets

- Yukon: reduction in diesel use for electricity generation in communities not connected to the main electricity grid (-30% over 2010 levels); 40% of heating needs met by renewable sources by 2030
- Northwest Territories: 40% share in energy used for community heat

Coal phase-out

- N/A

Low-emission vehicles incentives and renewable fuel mandates

- None

5.7 Takeaways

This chapter covered the main policies put forward by the federal government and its counterparts in the provinces and territories. Two main takeaways emerge from this overview.

Recognition that efforts put in place so far have been grossly insufficient to meet GHG emissions reduction targets has been slow and uneven. Most provinces have put forward action plans and strategies focused on energy-related climate objectives and a majority have adopted medium-term targets for GHG emissions reductions. However, despite the policies implemented over the past decade, not one province has met a 2020 GHG emissions reduction target and those that promised or established targets for the coming decades are clearly unable to deliver. As a result, substantial policy adjustments are needed.

In fact, recognition of the need to change and intensify strategies to meet GHG targets has led to notable modifications in a few provinces. The British Columbia government used the limited impact of the province's carbon tax on emissions as a rationale to put forward several other policies; Nova Scotia and Prince Edward Island have both revised their medium-term GHG targets (2030) upward and have announced new actions to match these targets; and Quebec's approach has also been under revision at least since the passage of the zero-emission vehicle mandate as the first step in the transformation of the governance of GHG-related efforts. Faced with this challenge, Ontario, Manitoba and Alberta have moved in the opposite direction, instead emphasizing the high cost of meeting existing targets and lowering expectations and actions. At the federal level, Justin Trudeau's minority Liberal government expanded its commitment to intensify these strategies by presenting its new climate plan in the 2021 budget, raising its 2030 GHG reduction target to 40%-45% of 2005 levels, and releasing a schedule to increase the carbon tax rate to $170/tonne by 2030. This has resulted in significant changes to provincial energy and climate policies, as well as new targets for GHG emissions since our last report. Most importantly, these problems in moving forward to reach GHG targets highlights the need for strategic coherence among the various policies, as well as for ensuring that the policies are delivering the expected changes. Even though the variations among provincial energy and GHG profiles have to be dealt with by tailored policies, these policies also fall within the national efforts to meet the Paris Agreement targets, which in turn leads us to the second main takeaway.

The Supreme Court's decision in 2021 to uphold the federal carbon pricing system eliminated some of the uncertainty respecting the management of GHG-related efforts. It is however too soon to fully appreciate its impact. Even with the support of opposition parties on climate legislation, the current government remains in a minority position. Moreover, the Supreme Court decision does not resolve all federal-provincial tensions over climate policies. Despite its court victory, the federal government remains dependent on the provinces to achieve its most ambitious climate targets.

However, as the systematic failure of previous GHG reduction plans across Canada to achieve their stated targets shows, policy changes are not sufficient. Evidence from other countries that have managed to reduce their emissions much more significantly demonstrates that governance structures need to be put in place to ensure a continuous evaluation of the progress made towards the objectives and a swift response to this evaluation. At the moment, however, most of the focus across Canada has been on policies, which largely follows the approaches that have failed for the last three decades. The federal government has slowly started to build such a governance structure, resulting in the establishment of the following two organizations to help the government in this task: the Canadian Institute for Climate Choices, an independent research body tasked with helping to inform climate policy development; and the Net-Zero-Advisory Body, an independent group of experts mandated to engage with Canadians and provide advice to the Minister on pathways to achieve net-zero emissions by 2050, which is part of Bill C-12, currently under review.

The challenge of designing the right governance structure is made more difficult since the responsibility for delivering the reductions in line with Canada's 2030 and 2050 objectives, which remain out of reach with the measures announced so far, rests largely in the constitutional realm of the provinces. A successful approach to accommodate provincial variations on the net-zero pathway is still needed.

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[7] Appendix 8 presents all references for the policy and target overview, along with more detailed descriptions for the provinces and territories.

6

THE EVOLUTION OF ENERGY CONSUMPTION TOWARD NET-ZERO FUTURES

This chapter presents the first part of the results, focusing on energy demand and consumption, including a by-sector analysis and an examination of the specific case of space heating. Reducing fossil fuel sources in net-zero scenarios leads to a significant decline in energy demand, largely the result of technological transformations toward more productive energy sources, mainly electricity. Given the cost and availability of technological substitutes, the portrait across sectors is varied both in the mix used and in the pace of the transformation, which is more rapid in sectors with cheaper existing technologies.

HIGHLIGHTS

- Compared with simple reduction scenarios, the net-zero constraint profoundly changes the evolution of energy consumption.
- Net-zero scenarios lead to substantial transformations that mainly affect electricity, even before 2030 in some sectors.
- Net-zero reduction targets translate into reduced energy demand due in large part to energy efficiency and productivity gains (notably through electrification).
- Net-zero scenarios do not include any expansion of natural gas even over the medium term (2030), as it is largely incompatible with pathways aiming at net-zero by mid-century. Natural gas cannot be considered as a transition fuel.
- The transformation of the transport sector will be central to GHG emission reduction efforts.
- Replacement of fossil fuel powered systems by electricity for space heating constitutes a key contribution to GHG reductions.
- In all scenarios, bioenergy expands from now to 2030 (in large part because of liquid biofuels) and then grows more slowly afterward, partly due to limited availability.
- The industrial sector can reduce its emissions through the use of low-carbon energy sources for heat production even without changing its processes.
- Hydrogen remains a small share of the total even in 2060, in part due to current difficulties in assessing the exact technical role it can play.
- The proposed evolution of the federal carbon price up to 2030 is insufficient to reach the GHG reductions targeted.

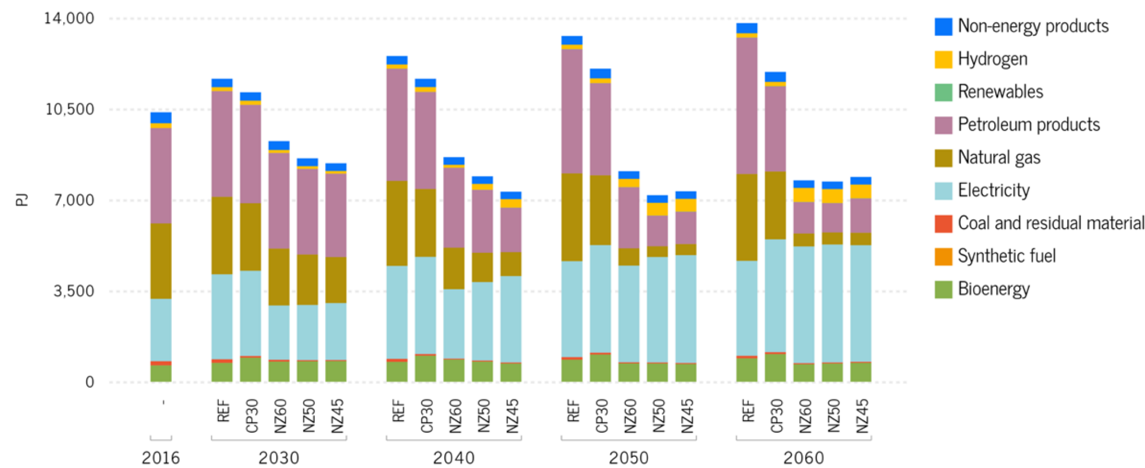
6.1 Energy demand by source

Figure 6.1 presents the evolution of the total final demand for energy for the five scenarios considered (presented in Chapter 1). REF shows a relatively uniform evolution in energy demand for all sources in response to the natural evolution in energy services associated with economic and population growth. Inclusion of the impact of the proposed carbon tax until 2030 (CF30) changes relatively little in the overall evolution of energy demand, which continues to increase with respect to 2016, albeit at a slower rate than for REF. However, on the shorter horizon, the energy mix shows a faster increase in electricity production than all other scenarios. Moreover, the carbon tax is adequate to stabilize demand of oil and gas at 2016 levels.

Direct constraints imposed in scenarios NZ60, NZ50 and NZ45 have a much larger impact on the diversity of energy sources and the total demand. In fact, between 2016 and 2030, an overall reduction in demand for all energy sources is observed in these three scenarios; in the subsequent decade, growth also appears much slower than for REF and CF30. While more detailed explanations for this trend are provided in the examination of sectorial energy consumption below, in broad terms, it can be linked to increased energy efficiency efforts, the accelerated shrinkage of the oil and gas sector, and the electrification of energy-intensive activities.

The share of fossil fuels, including natural gas, drops markedly for NZ scenarios, starting before 2030 and accelerating rapidly between 2030 and 2040. While the evolution of these three scenarios is very similar until 2030, the more aggressive ones move into electrification more quickly, while moving away from fossil fuels at the same time. A comparison with REF and CF30 suggests that some applications will remain particularly costly to fully decarbonize. In view of these results, policy and regulatory constraints are necessary to bring about the reductions needed to achieve net-zero targets.

Figure 6.1 – Final energy consumption by source



General observations:

- The decrease in total energy demand does not result in a corresponding reduction in the energy services provided. Instead, a large part of the demand for these services is met by more energy efficient technologies and sources, mainly electricity.
- Once net-zero is reached, increases in energy demand are possible without breaching carbon neutrality, as illustrated by the higher total demand in net-zero scenarios in 2060 compared with 2050. However, the growth in demand after net-zero is very slow.
- The proposed evolution of carbon prices up to 2030 is insufficient to reach the GHG reductions targeted.
- In the context of a 2050 NZ horizon, natural gas cannot be used as a transition energy.
- The almost identical total energy demand in 2060 for the three NZ scenarios suggests that there is limited risk in accelerating the electrification of the economy.
- In the NZ scenarios, around 22% of final energy demand for 2060 is satisfied by fossil fuels, representing, in absolute value, 25% of the total fossil fuel demand for 2016.

Interestingly, the final energy mix for NZ scenarios in 2060 is largely independent of the pathway selected. The final energy distribution is almost identical, with electricity meeting more than 55% of all energy needs and oil and gas still contributing 15% and 6% of the final energy demand in sectors for which low-carbon technologies are still uncertain. Respectively, these values correspond to only 32% and 16% of the quantities of oil and gas consumed in 2016.

6.1.1 Low-emitting energy sources and vectors

While potential hydrogen applications are broad, the considerable uncertainties that remain make this vector difficult to model. Within these limits and given its high cost compared to other options, hydrogen plays only a small role in the evolution of the energy mix and is confined to specific applications where it can be most useful, especially when electrification is available only at very high cost (see the sectoral discussion below). It should be noted that while hydrogen use increases by 50% in some net-zero scenarios before 2060, it will no longer be used in refining activities but in applications in industry and transport. Chapter 9 presents a sensitivity analysis that explores this energy vector more extensively.

In all scenarios, bioenergy continues to grow up to 2030. If this increase reaches 27% in NZ45, CP30 shows an even greater increase (47%), reflecting the relatively low cost of using bioenergy to rapidly decarbonize certain applications. Growth continues after 2030 in CP30 (70% for the entire 2030-2060 period with respect to 2016). Nonetheless, this picture is misleading in comparing overall biomass use throughout the economy, since NZ scenarios use a significant quantity of biomass as primary energy for hydrogen and electricity production with carbon capture (BECCS), which does not appear in final consumption numbers.

Taking this last point into account, in all three net-zero scenarios, availability remains the determining factor: after an initial increase, the total quantity of biomass available becomes an important constraint (Chapter 9 also presents a sensitivity analysis based on this factor). In any case, the potential of biofuels is limited in NZ scenarios because it results in residual emissions, which become more problematic as the net-zero point is approached.

6.1.2 An increased role for electricity

While the share of electricity in the energy basket remains relatively constant in REF and CP30, electricity becomes the dominant final energy source by 2050 in all NZ scenarios. This energy derives mainly from an expansion in renewable electricity generation, overwhelmingly produced from intermittent wind and solar (Figure 6.2), coupled with increased storage capacity.

The 50% increase in nuclear generation's share, in NZ scenarios, masks a more profound technology change: decommissioned larger plants are replaced with nuclear small modular reactors (SMR)—based on current costs estimates for this yet-to-be-developed technology. This represents an important difference from REF in the longer term, where no SMRs come into play after ageing plants close down. Electricity generation and other energy production are discussed at more length in Chapter 7.

Chapter 9 further examines these key vectors and sources (hydrogen, bioenergy and low-emission electricity) and analyzes their respective roles in net-zero pathways.

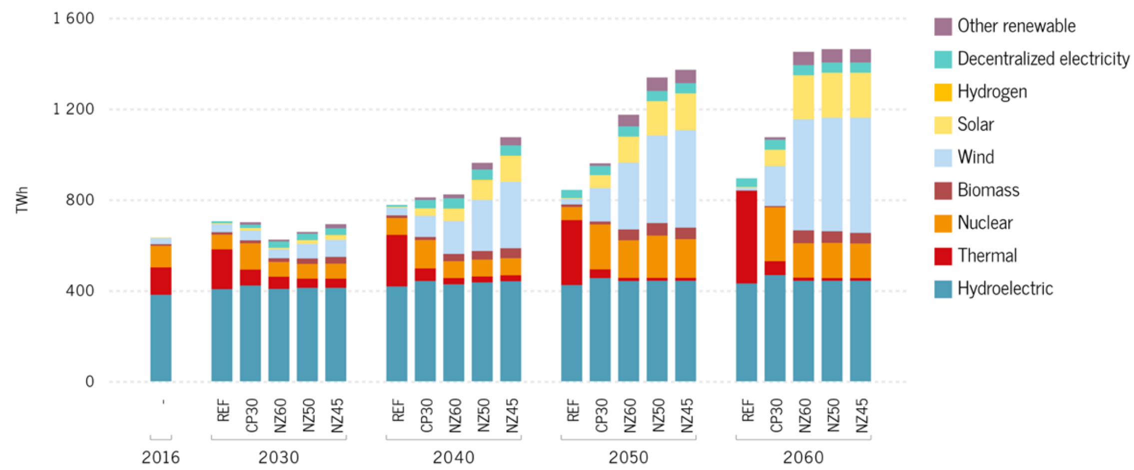
6.2 Energy demand by sector

The same data for energy demand can be plotted as a function of economic sector (Figure 6.3). Overall variation in energy demand by sector across net-zero scenarios is clearly linked to long-term goals, even in 2030, highlighting the importance of early reductions to reach stringent targets. On the longer term, this contrast between net-zero scenarios and the reference is steep, as the former primarily imply increased energy productivity. It is important to note again that this should not be interpreted as a proportional reduction in the provision of energy services, but rather as a demand met with higher efficiency low-carbon energy sources, notably electricity. For instance, this is the case for the dramatic expansion of heat pumps used for space heating in the building sector, which is much more efficient than the current mix of heating technologies.

Not surprisingly, the relative intersectoral evolution of this demand for REF and CP30 closely follows recent historical trends. In particular, there is a continuous growth in the relative (and absolute) importance of transport. Between 2016 and 2030, its share rises from 37% to 42% to 43% of energy demand for all scenarios, taking a slightly larger part in the NZ scenarios. This share increases to 46% for REF by 2060, while it plateaus at 39% for CP30 and drops as GHG reduction efforts are undertaken, to a low of 34% to 36% by 2040 for NZ45, by 2050 for NZ50, and by 2060 for NZ60. In the first two NZ scenarios, it is interesting to note that the share of energy demand begins to increase after hitting a low, around 34%, and rising back to 36% for NZ45 in 2060, to account for expected growth in demand for transport. This indicates that similar energy gains by electrification can be achieved as the demand for service grows in line with the population and GDP.

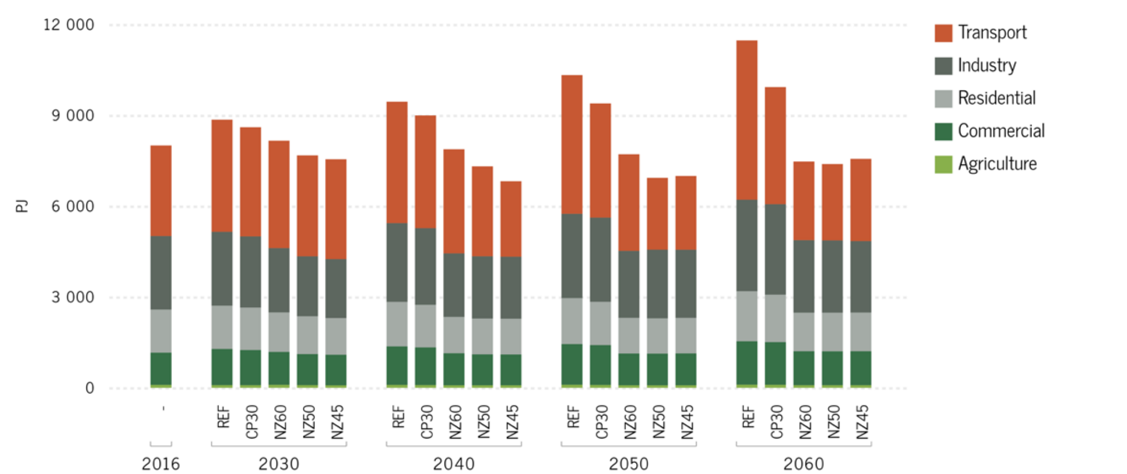
The evolution of energy profiles for each sector in light of these results is examined below.

Figure 6.2 – Electricity generated by source



Note: 1 TJ is equivalent to 0.278 GWh

Figure 6.3 – Final energy consumption by sector



6.2.1 The residential and commercial sectors

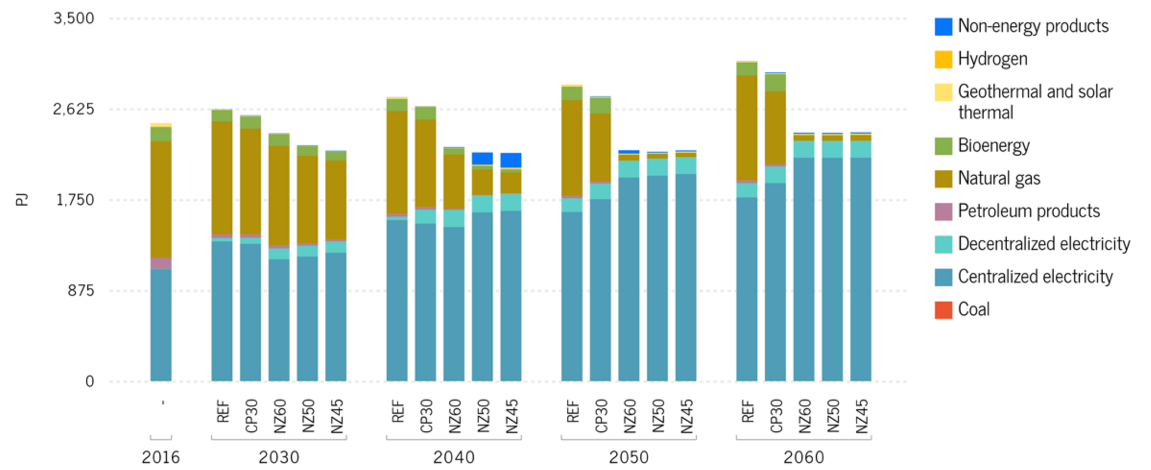
By 2030, the residential and commercial sectors (Figure 6.4) already show notable differences in the energy mix according to the various scenarios. These differences shrink over the following decade as all NZ scenarios rapidly decarbonize this sector, primarily through electrification with heat pumps, resulting in an overall increase in energy productivity. REF and CP30 show a very similar evolution over the next decades. The total energy demand in CP30, for example, is at most 4% lower than in REF over the whole period, with identical energy mix that shows a slightly faster reduction in fossil fuel usage at the expense of electrification by 2040, with a drop of 25% in gas. Yet, by 2060, it still represents 58% of 2016 demand.

However, by 2030, both NZ50 and NZ45 see the total energy demand drop by 13% to 15% with respect to REF. The same year, CP30 total energy demand is projected to fall by only 1% and that for NZ60 by 9%. By 2040, the three NZ scenarios show an increase in energy productivity of 18% to 20% with respect to the REF in the same year; all converge to 22% by 2050.

This increase in productivity is accompanied by a rapid decline in the use of fossil fuels, including natural gas, in favour of electricity in all scenarios. In 2030, natural gas demand drops by 3% to 5% for REF and CP30 with respect to 2016, and by 14% to 32% for NZ scenarios. This change is projected to accelerate over the following decade. Even for REF, demand falls by more than 10% by 2040 with respect to 2016; the reduction reaches 47%, 68%, and 70% for NZ60, NZ50 and NZ45 respectively. By 2050, natural gas represents only 8% to 4% of the 2016 demand for these scenarios.

The dominance of electricity in these sectors is unmistakable: in NZ scenarios, electricity accounts for more than 95% of total consumption in both 2050 and 2060, which requires the virtual elimination of both natural gas and biomass as energy sources for these sectors. Furthermore, results show only a small share for decentralized electricity in all scenarios, especially for net-zero scenarios.

Figure 6.4 – Final energy consumption in the residential and commercial sectors



General observations:

- The projections show that natural gas is not a transition energy for buildings since its total use declines in all scenarios and by as much as 50% to 70% by 2040 in NZ scenarios.
- Carbon pricing alone, as seen in CP30, is not sufficient even to initiate the transformation by 2030. In fact, this scenario does not significantly promote electrification due to insufficient price benefits associated with the upfront investment needed to replace fossil fuels with electricity.

6.2.2 The industrial and agricultural sectors

In net-zero scenarios, results for the industrial sector (Figure 6.5) also show an increase in the use of electricity and hydrogen at the expense of natural gas and, to a lesser extent, coal and coke in 2050 and 2060. Although the carbon pricing in CP30 is enough to bring similar changes for coal and coke, it does not significantly modify natural gas use with respect to REF, with a consumption only 15 % lower than REF between 2030 and 2060. While all NZ scenarios clearly present a lower overall demand than REF, illustrating the importance of direct and indirect energy efficiency (chiefly through electrification) in contributing to long-term GHG emission reduction efforts, they also point to the impacts of NZ targets on fossil fuel production, which contribute to an overall reduction in energy demand for the industrial sector.

In fact, projections for 2030 show lower energy consumption for all energy sources except biofuels in all NZ scenarios with respect to REF, including 15% lower electricity consumption and a 25% to 35% reduction in fossil fuel consumption. The rapid slowdown in the fossil fuel production sector is discussed in Chapter 7.

However, by 2040, differences in the various NZ scenarios indicate a broader transformation of the industrial sector, with increased use of electricity and hydrogen for NZ50 and NZ45, at the expense of natural gas with respect to NZ60. These differences shrink by 2050, with all NZ scenarios showing much similar energy consumption patterns for the industrial sector, dominated by electricity, bioenergy and hydrogen. While the share of these energies remains fairly constant over time for REF (around 53%) and CF30 (around 60 %, between 2030-2060), it climbs from a significant 55% in 2016 to 84% in NZ50 and NZ45 in 2050, remaining stable afterwards, and leaving 15% of fossil fuel usage.

Without going into more specific details, which are covered in Chapter 8, study of these trends suggests that some applications cannot easily be electrified with current technology because of both costs and the availability of technological substitutes.[1] Important gains in this sector will require breakthroughs in new technologies and processes for which costs cannot be easily evaluated. As discussed in the previous paragraph, owing to this mix, a significant quantity of emissions remains for the sector: optimization leads to a large compensation for these emissions through equipping plants with carbon capture technologies, although uncertainty about these technologies means they should be treated with care. Emission capture is discussed more extensively in Chapters 8 and 12.

[1] It should be noted here that this discussion pertains only to energy use in the industrial sector and excludes the evolution of industrial processes, which is discussed in Chapter 8.

Energy use in the agricultural sector, which includes heating and lighting but excludes transport and machinery (which are categorized under the transport sector), is almost completely electrified in all scenarios, including REF and CP30, by 2040, in line with heating production in other sectors (Figure 6.6). While both REF and CP30 project that electricity will represent 75% of all energy demand by 2040, oil disappears almost completely by 2030 for CP30, leaving natural gas to fulfil the remaining 25% of energy demand.

Interestingly, the optimal cost pathway suggests that natural gas usage for NZ60 could increase for a short period around 2030, to vanish by 2040. Nevertheless, by 2040, all NZ scenarios project that electricity will fulfil more than 85% of the energy demand, reaching 95% by 2050, with the remainder provided by fossil fuels. It should be noted that even with low-emission electricity as its main source of energy, the sector produces significant remaining emissions from non-energy sources. This point is discussed in Chapter 8.

General observations:

- The change in energy demand profile will impact energy production, contributing to a rapid decrease in fossil fuel demand in the industrial sector.
- Energy demand in the industrial sector is already dominated by electricity and bioenergy, which suggests that contrary to the building sector, there a few low-hanging fruits.
- The electrification of heating in agriculture, while cost competitive, may require specific programs and attention as heat is used for a number of different purposes, some of which, such as drying harvests, require considerable power. The use of locally produced bioenergy, which at this scale is not included in the model, could certainly complement electricity use in this sector.

Figure 6.5 – Final energy consumption in the industrial sector

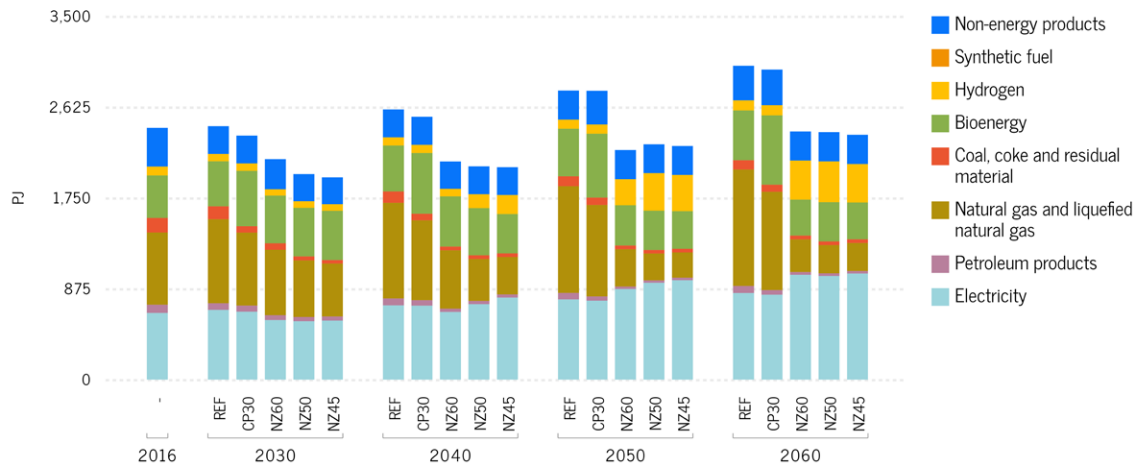
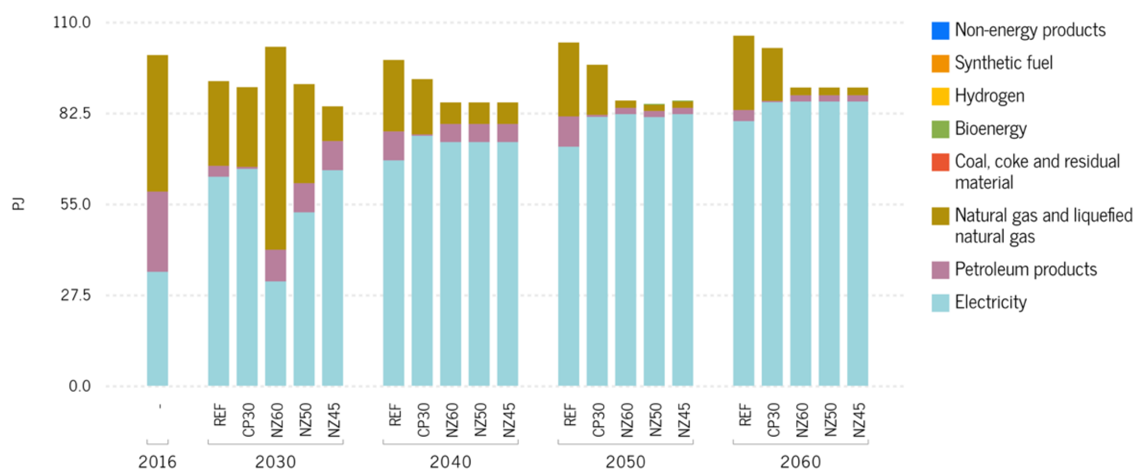


Figure 6.6 – Final energy consumption in the agricultural sector



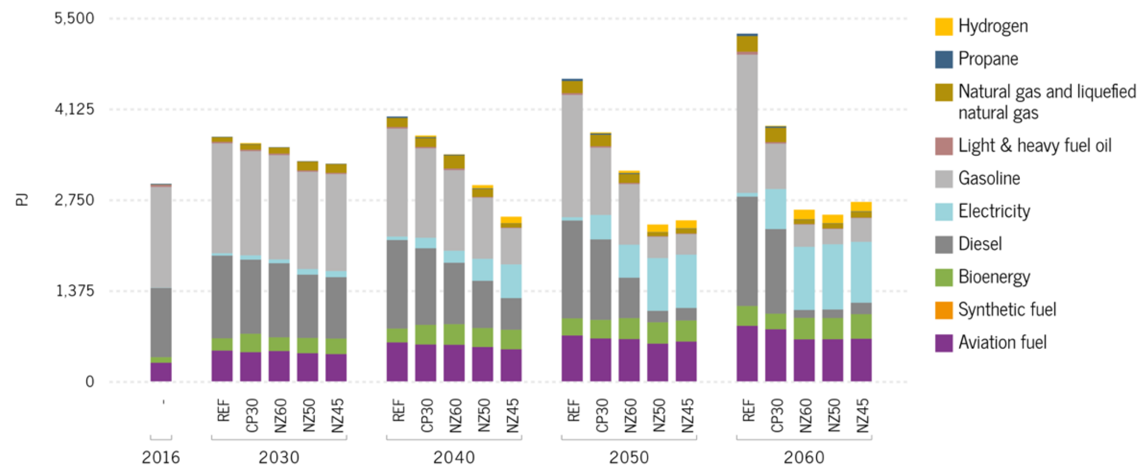
6.2.3 Transportation

The transportation sector shows the sharpest difference in energy demand between NZ scenarios and REF and CP30 (Figure 6.3). How this energy demand will be met varies across scenarios even on the 2050 horizon, suggesting a higher cost for some transformations and a more varied set of technologies to meet needs. Also to be taken into account are the considerable uncertainties about the technological solutions yet to be proposed (Figure 6.7).

REF is very conservative as concerns the transformation of the transport sector. The use of electricity remains marginal by mid-century and gasoline and diesel usage continues to trend upward until 2030. While CP30 is not sufficient to stop growth in diesel consumption, it favors a more important, but slow, electrification that leads to a 55% reduction in the use of gasoline by 2050, highlighting the high cost of deeply transforming the sector. This is a significant departure from the results in our previous Outlook, which showed a reduction in gasoline and diesel demand even in the business-as-usual scenario. This difference derives in large part from more conservative projections than in 2018 for efficiency improvements for gasoline and diesel engines, which result in a larger quantity of fuel needed to meet demand.

All scenarios show only a low penetration of electricity in the transportation sector by 2030 (less than 3% even in NZ45), but, for NZ trajectories, a rapid takeoff after that, with scenarios diverging much more from 2040 on. While the lower cost of bioenergy and blending mandates in place helps biofuels make a rapid and sizeable contribution to decarbonizing the sector before 2030 (+175% in NZ45 and NZ50, and +232% in CP30), biomass availability and the smaller GHG reductions on a life-cycle basis limit their increase over the longer term. Moreover, after 2030 most of the increase in the use of bioenergy is for biofuels for off-road transport, a category that includes agricultural vehicles and on-site transportation in the commercial and industrial sectors, where the cost of electrification is higher.

Figure 6.7 – Final energy consumption for the transport sector



The energy mix for the entire sector presented in Figure 6.7 hides important variations, depending on the vehicle category and the transport mode. In passenger transport, light trucks' share of the vehicle stock increases dramatically at the expense of cars. This leads to slower decarbonization of the sub-sector (Figure 6.8) since the electrification of light trucks takes off only after 2030 due to higher costs (while at least 35% of cars are electrified by 2030 in NZ45 and NZ50).

The technology mix is more varied in the transport of merchandise. While light and medium commercial transport similarly transform the passenger sector, heavy transport uses a more diverse set of technologies, including some hydrogen, natural gas plug-in hybrids, all-electric trucks, and—to a lesser extent—catenary lines and plug-in diesel-electric hybrids (Figure 6.8). The picture for merchandise transport is drastically different in REF and CP30, where the only change over time is a slow penetration of natural gas alongside diesel (Figure 6.9).

Other transport subsectors present different results. Aviation remains largely supplied by aviation fuel, with biofuels playing a very small role in net-zero scenarios, chiefly from 2050. Rail uses biofuels to help it decarbonize somewhat at first, but a larger share is then taken up by hydrogen as we near the net-zero target year. Hydrogen plays a key role in rail transport, accounting for more than 40% of total consumption in 2050 for NZ45 and NZ50. This growing role continues to increase rapidly beyond that horizon, with hydrogen becoming the main source in 2060 for all net-zero scenarios. Finally, maritime transport is decarbonized by increasing biofuels and hydrogen, and more importantly, by replacing gasoline and diesel with natural gas, with electricity unable to act as a viable substitute.

Figure 6.8 – Energy consumption by passenger transport mode

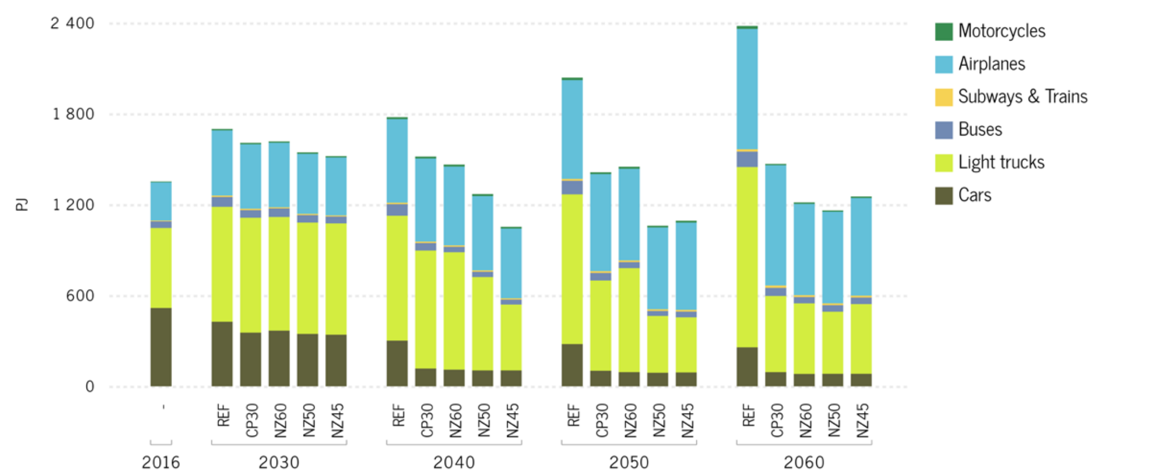
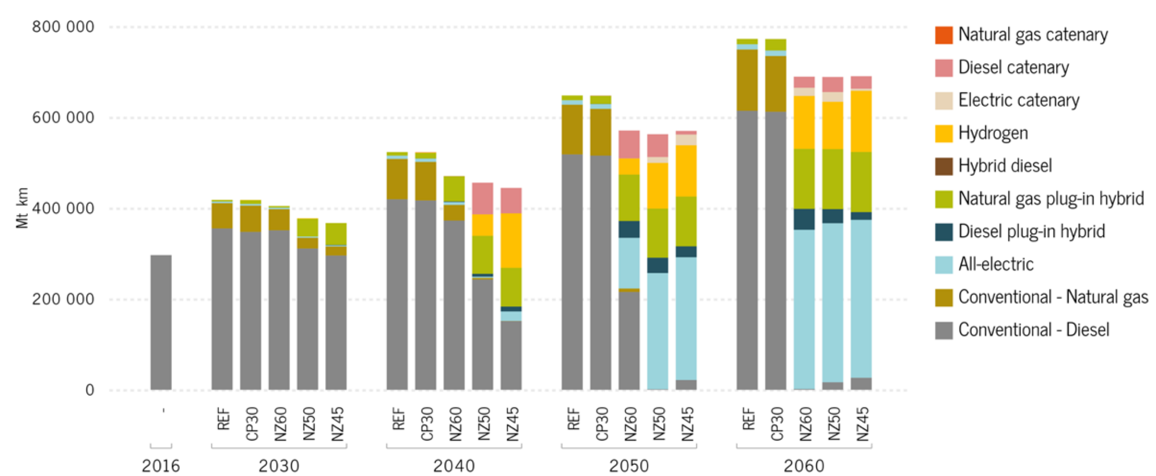


Figure 6.9 – Demand satisfaction by technology in heavy-duty merchandise transport

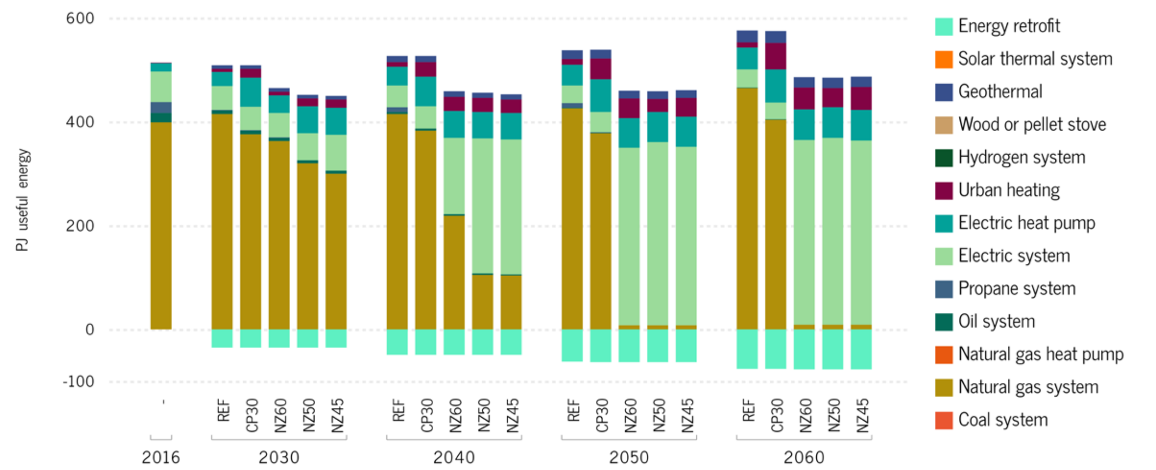


Overall, as in the previous edition of this Outlook, these results illustrate the crucial importance of the transport sector in GHG emissions reductions, together with the need for decisive policy action to help achieve substantial GHG reduction targets. The high costs lead to difficulties in transforming the sector since electrification remains expensive and biofuels offer only short-term and limited advantages in terms of GHG reductions. It is worth noting that these cost considerations primarily affect the pace of the transformation. In the case of road transport, the extensive penetration of electricity is found in all NZ scenarios once neutral emissions are reached. Accordingly, changes to the cost of these technologies in some transportation subsectors could accelerate this pace.

General observations:

- The electrification of the transport sector projected for NZ scenarios leads to a 50% reduction in total energy demand, which demonstrates the remarkable inefficiency of combustion engines, imposed by the laws of thermodynamics.
- The transformation of the transport sector depends on a number of competing electric-based technologies that have not yet reached the market. Because of the importance of standardization and the need for technology-specific infrastructures (recharging, catenaries, hydrogen), the relative weight of these technologies will be largely determined by political choices rather than cost.

Figure 6.10 – Space heating systems in the commercial sector



6.3 Heating

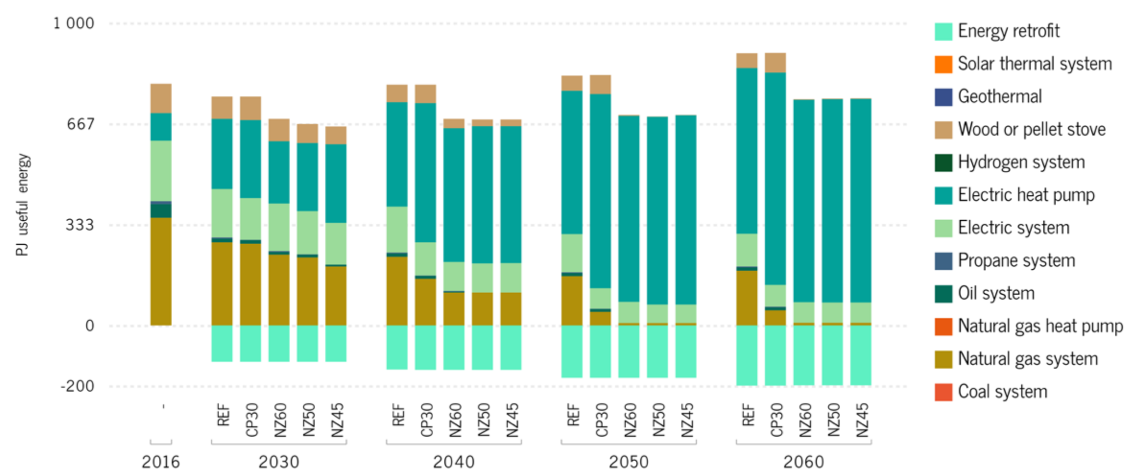
Given that space heating represents more than half the final energy demand in both the commercial and the residential sectors, it deserves special attention, particularly since it is currently largely ensured by natural gas systems (Figure 6 9 and Figure 6 10).

There is a striking similarity across all NZ scenarios, in which natural gas rapidly decreases its share especially after 2030 and all but disappears by 2050. In the residential sector, this transition involves a comprehensive shift to electric heat pumps. In the commercial sector, the mix is more diverse, although electric technologies also dominate, including in district heating. These developments are in sharp contrast to REF and CP30, where natural gas retains a dominant role, particularly in the commercial sector.

Another similarity across scenarios is the contribution of energy conservation measures, particularly better thermal envelope insulation. While this contribution is important (equivalent to some 13% of total demand in commercial buildings and 20% in residential dwellings), it is worth noting that it is the same in net-zero scenarios as in REF and CP30, since measures identified in the model are low cost even with respect to current energy prices and are identified in all optimized pathways. It is difficult to integrate a number of more expensive energy conservation measures in the model as electricity prices are expected to remain low, which explains why they do not appear in the modelling results.

Overall, the replacement of fossil fuel-powered systems (natural gas in most provinces, as well as oil products and biomass in some) by electricity in space heating is a key contribution to GHG reductions for the commercial and residential sectors, even with a short time horizon. This suggests that the building sector can be decarbonized at relatively lost cost with current technologies. As a result, it is clear that policy and regulatory incentives could rapidly ensure this evolution away from business as usual and could even be made to pursue more aggressive targets than the net-zero 2050 trajectory (NZ50) to achieve these reductions—particularly by encouraging a massive shift to electric heat pumps.

Figure 6.11 – Space heating systems in the residential sector



General observations:

- Electrification, especially through heat pumps, can provide the additional advantage of increased access to air conditioning, thus limiting health impacts during heat waves, which are expected to be more frequent.
- Some cooling fluids can be important contributors to global warming. Heat pumps in the NZ scenarios do not include the warming potential associated with leaks. Only strict regulation can ensure that heat pumps do not become a major source of GHGs.

6.4 Takeaways

In terms of overall final energy consumption, electricity becomes the dominant source after 2030 in all three net-zero scenarios, taking shares from natural gas and oil products, in sharp contrast to REF and CP30 and contributing to a significant increase in energy productivity. Moreover, **there is no expansion of natural gas—even before 2030—in CP30 and NZ scenarios, highlighting the incompatibility of the fuel as a transition energy source in pathways to reach neutral emissions by mid-century** or even simply decrease emissions.

In all five scenarios, biomass increases rapidly between now and 2030 due to lower cost compared with electric technologies in some sectors. However, growth is then curtailed by the availability of the resource as well as the remaining emissions associated with its use.

Hydrogen remains a small share of the total even in 2060, in part due to current problems in assessing the exact technical role it can play. The sensitivity analyses presented in Chapter 9 examine how this role could change.

After 2030, the main difference across scenarios is largely due to the degree of energy demand reduction over time (compared with REF), with net-zero scenarios showing the largest decreases in demand compared to the starting point of the period. A large part of this is due to gains in efficiency from electrification, as well as from lower overall demand associated with higher energy prices.

Overall, there are relatively few differences across net-zero scenarios apart from the pace of transformation. After net-zero is attained, the situation remains mostly stable. The discussion of remaining emissions, which is thus key to complete this picture, is presented in Chapter 8.

Policies should aggressively target sectors where pace is the only variation across scenarios and where technological uncertainties are the fewest. For instance, this is the case for the building sector, where the role of heat pumps in residential dwellings and electric systems in commercial space is similar across all scenarios, replacing natural gas. Therefore, it seems a safe bet to encourage the rapid adoption of these technologies at little risk and reasonable cost. A similar point can be made for the decarbonization of energy use in the agriculture sector.

Other sectors are much more difficult to decarbonize because of higher costs and the difficulty of substituting low-carbon technologies for other sources in some applications. Heavy commercial transport is one such case, where transformation is slow and more technologically eclectic. **Given the slow evolution toward a varied technology mix in this sector, different technologies are likely to be competitive alternatives to meet demand for this sub-sector. Choices will therefore likely need to be made about which path to favour and encourage.**

7

TRANSFORMING ENERGY PRODUCTION IN NET-ZERO PATHWAYS

Canada is a major energy producer and exporter. As such, its energy production will be deeply affected both by changes in demand and by constraints on GHG emissions. These changes will differ from one province to the other, in correlation with resource distribution, availability and the evolution of the import/export market, which is particularly important as more than half of Canada's primary energy production is destined for export. This chapter covers the evolution of primary energy production and the production of electricity for the country as a whole.

HIGHLIGHTS

- Energy production is significantly and rapidly transformed in all net-zero scenarios.
- All net-zero scenarios require an accelerated transformation of the economy away from the fossil fuel industry, even before 2030; not doing so will require ever-larger emission capture quantities to reach net-zero, making these paths more costly.
- Oil and gas production need to decrease significantly even before 2030 in order for production emissions to remain compatible with longer-term net-zero objectives
- The dramatic expansion of electricity generation required in net-zero scenarios is met in large part by variable solar and wind; the role of energy storage, particularly over the medium (weeks) and long (months) term, could greatly affect this expansion.
- Bioenergy production expands, especially to produce biofuels and generate electricity with emission capture (BECCS), although this expansion is limited by constraints on the availability of biomass and of competing non-energy applications.
- Energy exports are affected by the evolution of international markets and the pace required to reduce domestic production on the path to net-zero emissions.
- Imports are reduced as well; however, this reduction improves the trade balance.

7.1 Primary energy production

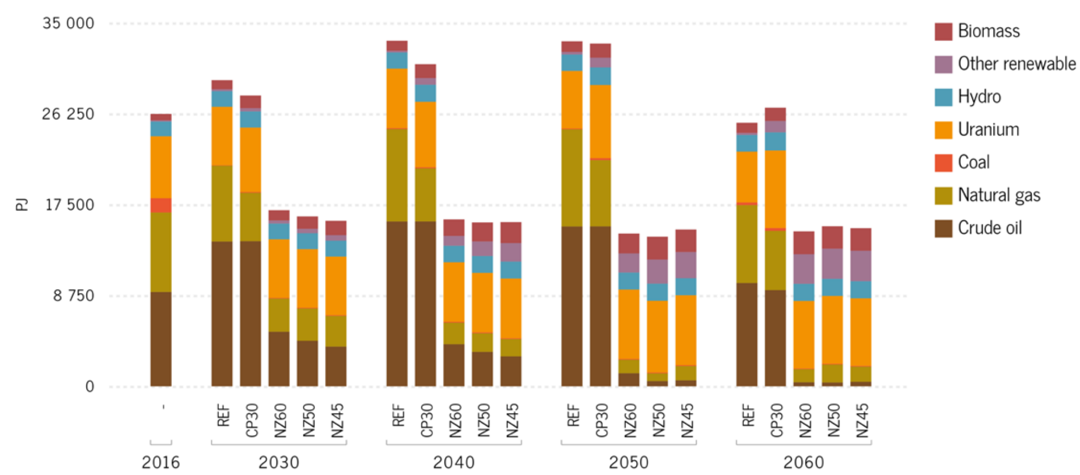
Figure 7.1 shows the predicted evolution of Canadian primary energy production as a function of the various scenarios. As mentioned earlier, these scenarios assume that the rest of the world will move at its own pace, irrespective of Canada's GHG targets. Oil and gas prices on the global market are therefore the same for all scenarios. This hypothesis is of course a simplification, as it is likely that Canada will act on its targets only if the rest of the world shows clear leadership, directly affecting energy prices on the global market.

Results show a sharp distinction between the NZ scenarios and both REF and CP30. In these latter scenarios, oil production increases by 50% by 2030, reaching a maximum in 2040 before returning to 2016 levels by 2060. For REF, natural gas production shrinks by 4% in 2030 and then slowly increases by 22% over the following 20 years, reaching a nadir in 2050, before returning to 2016 production levels in 2060. While both REF and CP30 project similar energy production levels, CP30 results in 40% less natural gas produced compared with REF starting in 2030. Oil production, however, remains practically unaffected by carbon pricing. As discussed in the next section, the evolution respecting REF and CP30 is essentially controlled by projected foreign demand.

Due to the schedule necessary to reach net-zero on the longer term, NZ60, NZ50 and NZ45 all require considerably smaller total energy production in 2030, the result of significantly reduced oil and natural gas production—respectively 61%, 59% and 58% less compared with REF. Unsurprisingly, this reduction is steeper with tighter net-zero schedules (NZ45 compared with NZ50, for instance).

This rapid decrease in oil and gas production over the next decade in the modelling, followed by a slower but continuous reduction on the longer term, is a result not only of the large quantity of emissions produced by the sector, but also of the lower direct cost for eliminating them in the short term, compared with decarbonization elsewhere. However, given the substantial indirect costs of such transformations, alternative scenarios were explored to look at the implications of a slower and less substantial reduction in this production (see section 7.1.1 below).

Figure 7.1 – Primary energy production



Biomass expands in all scenarios, particularly taking up a sizeable share in net-zero scenarios. The result is a 250% increase by the time net-zero is reached, an increase beyond this point being problematic given availability constraints. In terms of energy content, biomass production becomes more important than oil and gas combined in 2050, with a slightly larger share in NZ45. Renewables also increase in these scenarios in order to provide the necessary changes to electricity generation (see below).

In all scenarios, coal production is expected to fall to very low levels by 2030, becoming even more marginal. This includes a 95% reduction even in REF. As for uranium, which primarily targets export markets at the moment, if CP30 sees a small increase of 4% in production by 2030, all other scenarios anticipate an almost constant production level at first. By 2050, CP30 project an 18% growth as NZ scenarios see a 5% to 7% increase in production by 2050 to account for nuclear's expansion in electricity production. Since NATEM does not model the evolution of external demand, the quantity mined for exports remains the same across scenarios and over time and any growth is associated with larger internal consumption.

General observations:

- While oil and natural gas production dominates energy production in Canada today, all NZ scenarios show them decreasing by more than half within the next decade, suggesting a lower direct cost per tonne compared with many other areas throughout the economy.
- CP30 limits natural gas production in comparison with REF, suggesting that this production is more sensitive to carbon pricing.
- Based on projected energy prices discussed in Chapter 1, oil production increases by 60% in REF by 2040; current projections have it stagnating and decreasing sharply after 2050, returning to current levels. This is, of course, highly dependent on the evolution of world prices that will largely determine future Canadian production in the REF scenario.

7.1.1 The pace of oil and gas production changes

The rapid and substantial decrease of oil and gas production in NZ scenarios merits some discussion.

This decline stems from the generation of cost-optimal GHG-reduction pathways for Canada within the constraint of some external conditions. Three of these conditions particularly affect the evolution of Canada's oil and gas production sector. The first is that the oil and gas production is decoupled from domestic demand, which can be fulfilled by imports, if necessary, given that oil and gas prices are exogeneous to the model. In addition, following international agreements, only GHG emissions produced in the country are added to the balance; emissions generated abroad to satisfy internal services are not included, while emissions generated for the production of goods and services intended for export are fully allocated to Canada. Given that most of the oil and gas is exported, this accounting puts pressure mainly on energy production rather than on consumption. As international customers turn to other sources of supply, the net GHG decrease worldwide is therefore less than the decrease computed here and would then depend on the difference in production-related emissions between Canada's oil production and these suppliers.

Finally, only direct costs are taken into account since economic growth is exogenous to the model. However, given the oil and gas sector's share of the Canadian economy, a rapid decrease in these activities is bound to have an impact on this economic growth, unless policies are rapidly put in place to help manage this transition. We should note that if the rest of the planet, and the US in particular, moves as planned along a more aggressive GHG-reduction pathway, Canada will see its export market shrink rapidly, which would have an impact of a scale similar to what is projected here.

7.1.2 Sensitivity analysis: Effects of minimum oil and gas production levels

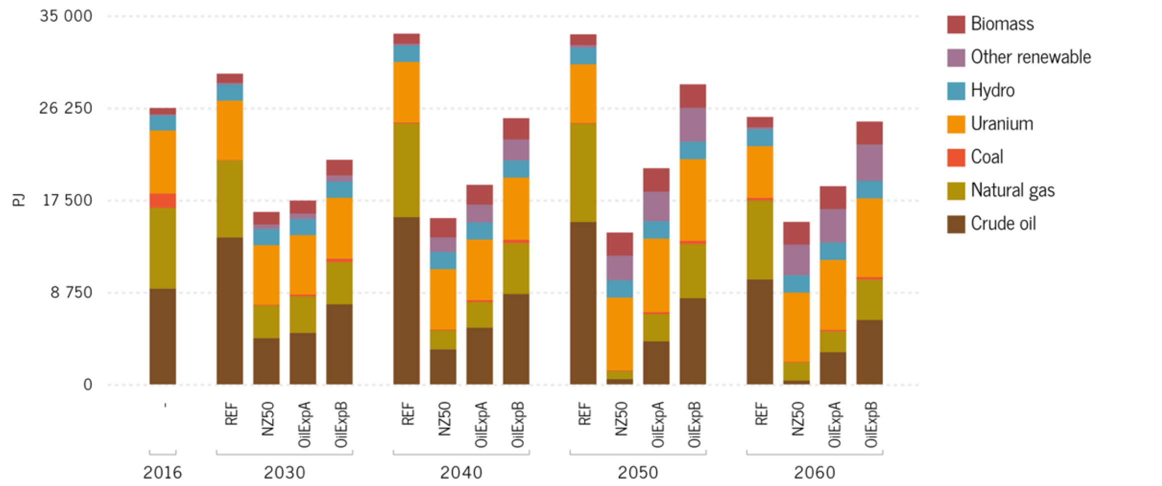
To help assess the effect of alternative pathways for the oil and gas sector, a sensitivity analysis was conducted where the reduction in energy production is externally controlled, using the following two additional scenarios to compare with NZ50:

- OilExpA: NZ50 targets but both oil production and natural gas production are maintained at a minimum of 25% of the reference scenario levels at all times
- OilExpB: NZ50 targets but both oil production and natural gas production are maintained at a minimum of 50% of the reference scenario levels at all times

In the main results for NZ50, oil and natural gas production decrease by 52% and 59% before 2030 with respect to 2016 (Figure 7.2). By 2050, these reductions reach 94% and 90% in comparison to the starting point. OilExpA sees oil production decrease by 46% (2030) and 55% (2050), while OilExpB maintains higher levels of production with reductions of only 16% (2030) and 10% (2050). These reductions for natural gas are 55% and 66% in OilExpA, and 48% and 33% in OilExpB. Production cuts are more substantial for natural gas than for oil in OilExpB, given the much larger expected increase in oil production in REF. While both OilExpA and OilExpB reach net-zero by 2050, it is interesting to note that the oil and gas production in neither scenario is limited by their respective imposed production floor.

While total oil and gas production is maintained at higher levels for OilExpA and OilExpB than in the less constrained NZ50, the impact of these two alternative scenarios on final consumption is notable but much less significant.

Figure 7.2 – Primary energy production with alternative oil & gas production constraints

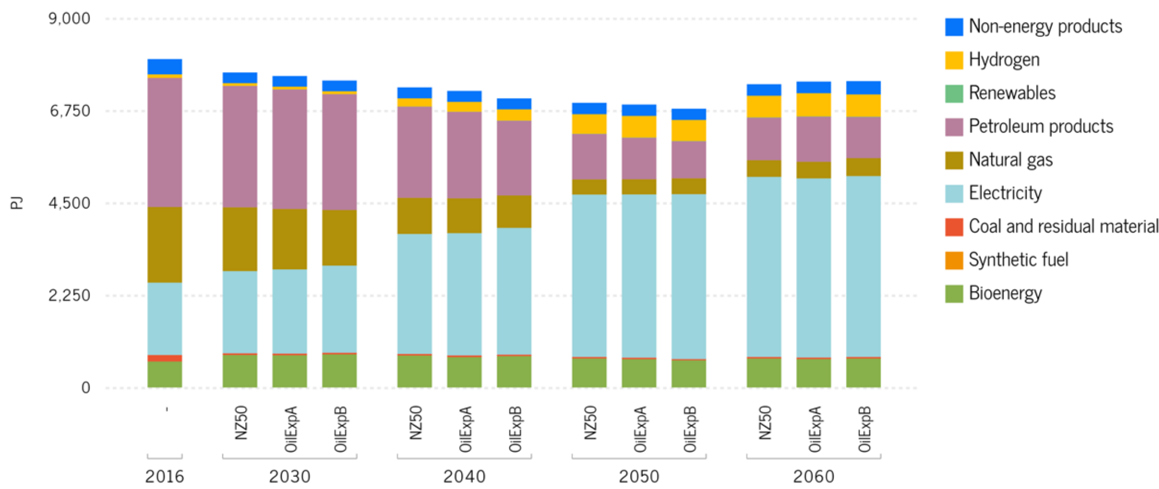


A second result from alternative scenarios is that final consumption of oil products and natural gas, excluding energy consumption for oil and gas production, is additionally reduced in both OilExpA and OilExpB, compared to NZ50 (Figure 7.3). In 2030, all fossil fuel consumption is significantly reduced: by 5% and 13% for natural gas and by 2% and 5% for oil in OilExpA and OilExpB respectively, as compared with NZ50. To compensate, all other sectors must therefore increase their electricity, biomass and hydrogen consumption by up to 2%, 6% and 8% in OilExpB, resulting, with the higher productivity of electricity, in an overall reduction of 2.5% in total energy demand.

In 2050, oil products are down by 8% (OilExpA) and 19% (OilExpB) compared with NZ50, but natural gas consumption is almost identical to NZ50. The main change in natural gas consumption therefore occurs in the shorter term, whereas oil products are affected in both the short and the longer term. Clearly, maintaining a higher level of oil and gas production, without full internal compensation in GHG means that, to achieve overall GHG reduction goals, all other economic sectors in Canada will have to transform much faster and more deeply. Thus, most of the additional production allowed in these scenarios will heighten dependence on export markets, if they still can absorb it, as internal consumption is more quickly moved to low-carbon energy sources.

To compensate for the lost emission cuts in OilExpA and OilExpB, other sectors must therefore decarbonize their activities more rapidly (see Appendix C for details on sectorial GHG emission reductions under those alternative scenarios). One example is the building sector, which is projected to lower its natural gas consumption by an additional 6% and 16% in OilExpA and OilExpB compared with NZ50 by 2030. This demand for buildings is met by a larger share of electricity (+10% and +14% in the two scenarios compared with NZ50), accelerating the electrification of the sector. Similar results are noted in the electricity sector, which must become net-negative by 2030 for OilExpB, and in the industrial sector, where natural gas consumption decreases by 11% and oil products by 10% in OilExpB compared with NZ50 by 2030. This demand is chiefly met by 4% more electricity.

Figure 7.3 – Final consumption by source with alternative oil & gas production constraints



Protecting oil and gas production mainly means accelerating the transformation of other sectors and, by 2050, there is relatively little difference in the energy basket for these sectors (Figure 7.3): oil products, although remaining only in very small quantity, are smaller in similar proportions than for 2030 (compared with NZ50), but natural gas consumption is identical to NZ50 in OilExpA and 10% higher in OilExpB.

Not surprisingly, even with the additional pressure of OilExpA and OilExpB, a more rapid transformation before 2030 remains too costly for the transport sector. Changes are thus modest: electricity, which represents only 2.5% of energy use in this sector by 2030 for NZ50, increases by 5% and 10% only in OilExpA and OilExpB by 2030, to match similar decreases (in relative size) in diesel and gasoline use.

The sum of these drivers—higher production levels for oil and gas and different sectoral consumption profiles—allows emissions to be reduced to the same extent but in different ways than in NZ50. When comparing alternative scenarios OilExpA and OilExpB with NZ50, the (direct) costs of reducing emissions increase more rapidly than for NZ50, as they are transferred from the oil and gas production sector to other parts of the economy, including other industries, buildings and transport, but also by a larger use of direct air capture (DAC) to compensate for the higher GHG emissions left from economic activities. By 2050, DAC is expected to almost triple, from 15 (NZ50) to 41 $MtCO_2e$ (OilExpB) captured annually.

General observations:

- Constraining a minimal level of production for oil and gas to slow its decrease helps maintain a strong export market (as long as external demand is there).
- However, this protection of oil and gas exports imposes more rapid and deeper reductions in Canada's consumption of oil and gas products in almost all sectors to reach the same GHG reduction targets
- This consumption evolves in each sector with more rapid electrification in the building sector, non-transport agriculture, transport and industry to meet energy demand with the smaller quantity of oil and gas, while exports of these fuels are increased.

7.2 Local consumption and export markets

Canada is a major energy exporter (Figure 7.4), directing close to 60% of the energy it currently produces to foreign markets, chiefly the United States. The transformation of world energy systems could therefore have a significant impact on this trade as most of the renewable energy that will be added over the next few decades is expected to take place at the expense of fossil fuels. However, shifts in domestic consumption, which will reduce oil and gas imports, especially in the East, could even have a significant positive impact on Canada's trade balance.

While world markets will have an impact on export opportunities for oil and gas, the rapid decrease in domestic production necessary in net-zero scenarios will affect these export levels as early as 2030. Figure 7.4 shows again the sharp distinction between net-zero scenarios and REF. It also highlights the limited impact of the additional constraints in the CP30 scenario on gas exports, which do not depart from REF. These trends remain over longer time horizons, although it should be noted that exports decrease after 2050 in REF and CP30 as a result of lower demand projections worldwide.

Of particular interest is the rapid expansion of liquefied natural gas (LNG), which increases similarly in all five scenarios in 2030 but less so after that in net-zero scenarios. LNG indeed becomes the main exported energy product in net-zero scenarios as early as 2030 (and even more so after that), almost matching current export levels for crude oil, up to a maximum of 51% of total exports in 2060 for CP30.

Imports are considerably lower than exports (Figure 7.5). Crude oil imports are relatively constant across scenarios in both 2030 and 2050. Natural gas imports are considerably lower in net-zero scenarios, especially on the longer term (-57% by 2050 for NZ50), resulting from the much lower consumption levels for the fuel.

Figure 7.4 – International exports

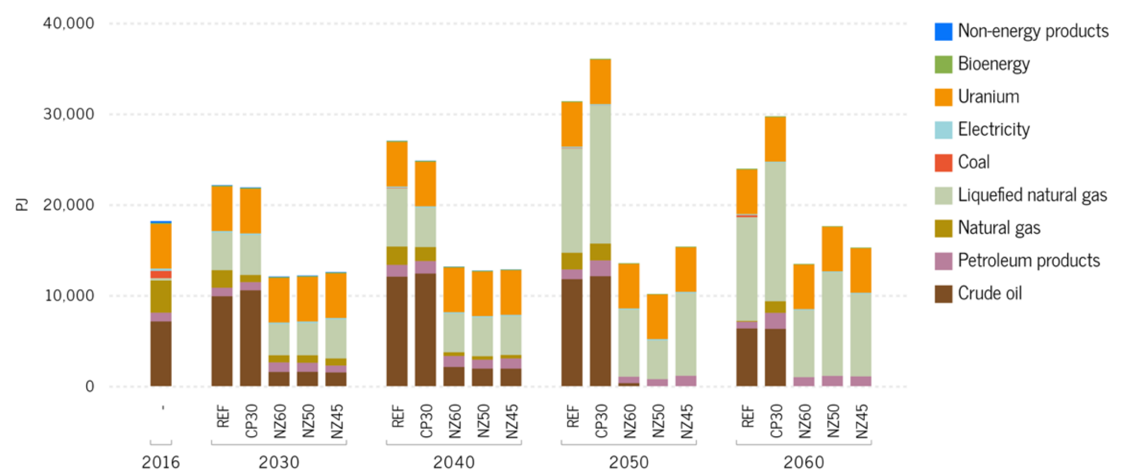
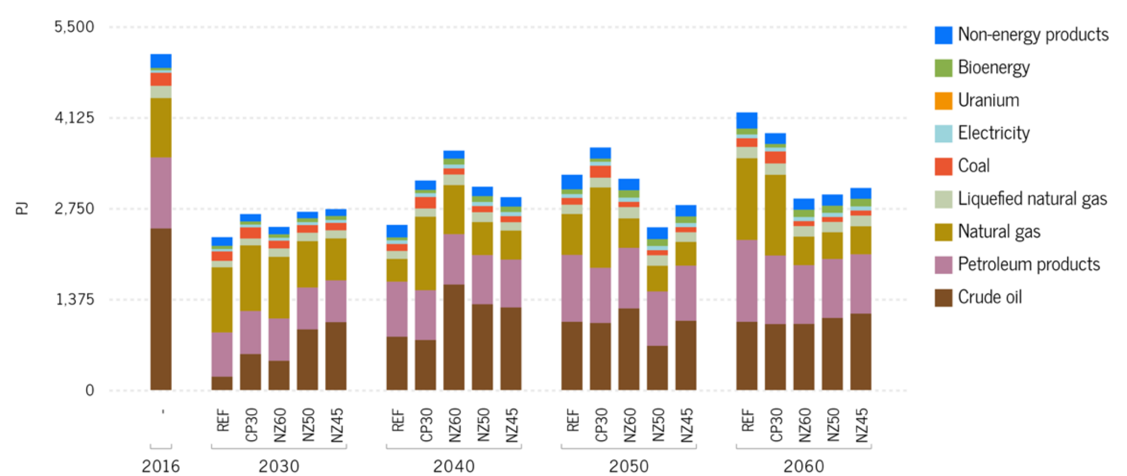


Figure 7.5 – International imports



While crude oil imports are lower in 2050, imports of oil products increase across scenarios. This suggests that some of the efforts to reduce Canadian GHG emissions in aggressive scenarios could consist in shifting oil refinery emissions elsewhere (overwhelmingly to the United States), a phenomenon that can also affect oil production and import levels. In other words, given the nature of the optimization model and the fact that it accounts only for domestic emissions, the results underestimate the extent to which the consumption of oil and petroleum products must be reduced in the short term in order to achieve net-zero by mid-century. This transfer is a consequence of international agreements that assign emissions to the primary producing territory and not the final user. See Chapter 1 for more discussion on this issue.

General observations:

- Given the importance of exports for the Canadian energy production sector today, the country's export profile changes abruptly in net-zero paths, in line with the changes to production described in the previous section.
- While the use of natural gas in Canada shrinks in all NZ scenarios, exports, especially LNG, expand slightly compared to 2016 levels.
- With the current GHG assignment for producing countries, oil imports could increase in NZ scenarios as compared to REF in order to reach domestic targets.

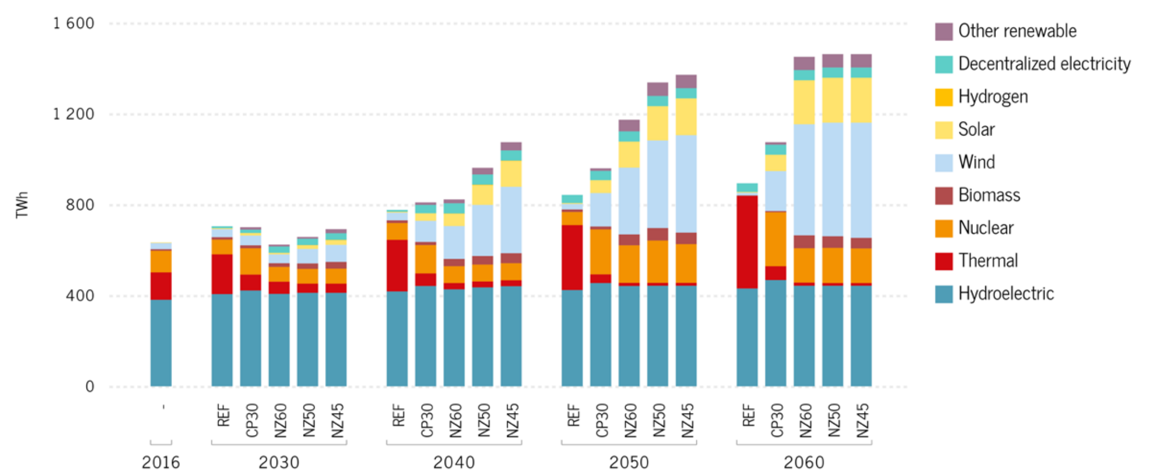
7.3 Electricity generation and installed capacity

As noted in Chapter 6, electricity plays a central role in the decarbonization pathways. While all scenarios project a similar level of electricity production by 2030, with more renewable and less fossil fuels in the NZ scenarios, pathways diverge significantly by 2040 to reconverge, in 2060, in three groups: REF, CP30 and NZ scenarios (Figure 7.6).

In fact, REF project a 20% increase in electricity production in 2040, supported by fossil thermal production and by renewables (wind and biomass) to a lesser extent. Over the following two decades, growth continues at the same rate, primarily supported by thermal production. CP30 sees a faster increase in electricity use with respect to 2016, on part with NZ60 until 2040: 10% in 2030 and 28% in 2040. By 2060, the demand for electricity is projected to be 70% higher than in 2016, an increase that is half that of NZ scenarios. The cost on carbon, however, contributes to decarbonize this sector. By 2030, fossil fuels generate only 10% of electricity and 4% in 2050; in absolute terms, this represents only a 70% drop in fossil fuel usage for electricity with respect to 2016. Growth in production is largely due to nuclear and wind, which are responsible for 21% and 15% of the total electricity production, in 2050.

While total electricity demand is relatively constant between 2016 and 2030, NZ scenarios all impose a stronger reduction on fossil fuel thermal generation, which represents between 6% and 9% of the total production in 2030, to fall to less than 3% in 2040. In absolute terms, due to the completion of a number of projects underway, most of the gap created by the quasi-elimination of fossil fuels in 2030 is filled by hydroelectric projects. In relative terms, wind grows by 50% to 174%, biomass by 100% to 300%, and solar by 100% to 500% for NZ scenarios in 2030.

Figure 7.6 – Electricity production



As electrification accelerates, electricity production grows proportionally with GHG reduction ambitions, a direct result of decarbonization efforts that favour electric technology substitutes in applications where fossil fuels would otherwise be used. In 2040, NZ60 sees a 30% increase with respect to 2016, while NZ50 and NZ45 require a 50% and even a 70% increase over 2016, reaching 85% to 116% in 2050 and 130% for all three NZ scenarios in 2060.

After 2030, most of this additional electricity comes from variable solar and wind energy, as well as from biomass. For example, in NZ50, wind is expected to produce 90% as much electricity as hydro in 2050, increasing by a factor 15 with respect to 2016. In the same scenario, biomass use will be multiplied by 7 and solar by almost 50. Starting well behind wind, they are projected to satisfy 4% and 11% of total electricity demand in NZ50 by 2050 (Figure 7.6).

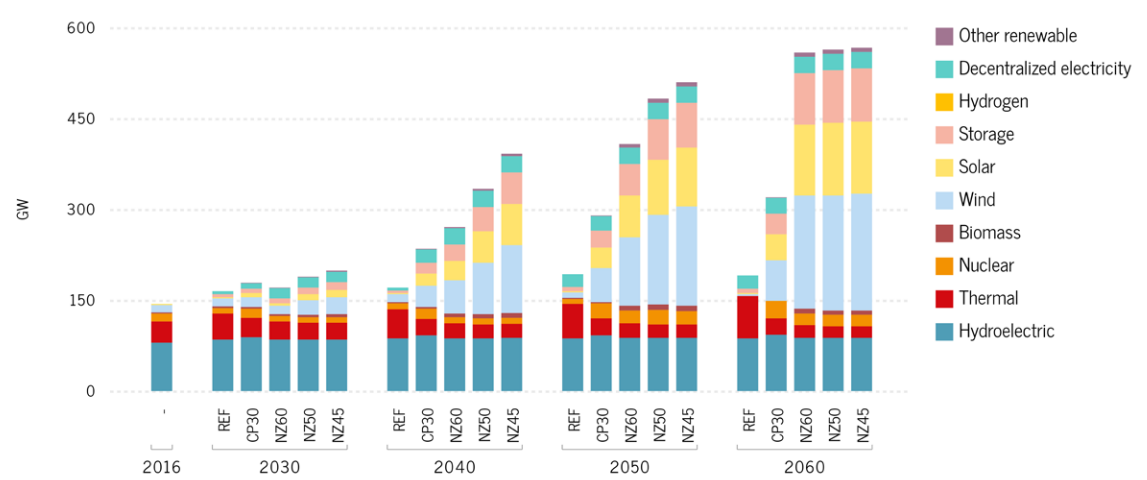
7.3.1 Hydroelectricity, nuclear and biomass

A few more points merit discussion. First, no new hydroelectric project is integrated in the modelling. Even though considerable potential resources remain in Canada, information is lacking as to the specific characteristics and prices of these various projects.

Second, nuclear energy production is transformed in all scenarios. Conventional nuclear electricity production is limited to current facilities in Ontario and New Brunswick and disappears after 2050 when they reach the end of their lifetime. This is true across all five scenarios. However, in NZ scenarios, SMRs appear in the results (after 2040), leading to a net expansion of nuclear electricity generation (+63% in NZ50 by 2060). This remains a small part of the total (slightly over 10% in 2060 for NZ scenarios) but provides part of the resilience needed to accommodate large shares of variable sources. Hydroelectricity, which does not change much across scenarios, also plays this role but to a much greater extent, due to the presence of large reservoirs in many regions of Canada. This development is based on price and characteristics according to pre-development estimates, which could change considerably in the next few years.

Third, net-zero scenarios also show some generation from thermal plants powered by bioenergy with carbon capture (BECCS), resulting in negative emissions. Accordingly, bioenergy accounts for a small share of the total in the electricity sector in net-zero scenarios (4% of total generation for NZ50 in 2050), but its role as a negative emission process is important. These carbon capture applications are crucial in compensating for remaining emissions when approaching the net-zero point, as discussed in Chapter 8.

Figure 7.7 – Electricity generation installed capacity



7.3.2 Generation capacity

As variable electricity production plays a growing role in the electricity system, it becomes important to also consider generation capacity, as the lower capacity factor of these technologies (averaging between 22% and 47%, depending on technology and site of deployment) implies that more installed capacity is required to deliver the same power.

For REF, as the share of thermal remains important, growth in capacity is largely proportional to electricity demand. This is also the case for CP30, where increased nuclear generation offers a high capacity factor and reduces the need for additional production capacity. There is a significant departure from this trend for NZ scenarios, which is notable as of 2040. For example, for NZ60, NZ50 and NZ45, the overall projected capacity in 2040 is 60%, 90% and 125% greater than for REF the same year, and 200% greater in 2060 for all three NZ scenarios. This overcapacity includes both production capacity (chiefly as wind and solar) and storage. The latter is projected to represent 10% to 13% of total capacity in NZ60 and NZ45 in 2040, rising to 15% for the three NZ scenarios in 2060. Although storage remains negligible in REF, as the cost of storage is expected to fall, it represents 7.5% of all capacity for CP30 in 2040 and rises to 10% in 2060.

As presented here, storage includes long-term (weeks), medium-term (days) and short-term (hours) energy storage. It could include battery, hydrogen and other types of storage. The exact proportion between these variable energy sources and these types of storage could vary as the generation capacity is determined by (i) the adequacy of variable energy production, which is not the same for wind and solar; and (ii) the cost of storage, which enables a more efficient match between production and demand. A precise modelling of these two considerations requires detailed data on energy consumption patterns in a changing energy system and electricity production, information that is not available at the present time.

General observations:

- Canada's large hydroelectricity installations are significant in helping it accommodate the more than tripling of electricity generation capacity from variable solar and wind in NZ scenarios, reducing the need for new storage and the overall cost of these technologies.
- In the absence of detailed assessments for new hydroelectric projects and in view of the low social acceptability for any large-scale hydroelectric developments, no new project is projected here. However, it is important to remember that Canada still has considerable potential for this energy source.
- Given the limitations to the building of new hydroelectric capacity and current technical constraints affecting other storage technologies, hydrogen and nuclear energy may play an important role. However, their respective role is difficult to ascertain precisely at this time, given the considerable unknowns as to costs, specifications, required infrastructures, safety concerns and social acceptability. It is likely that their contributions will depend on policy choices more than on simple costs.

7.4 Biomass

In biomass production (Figure 7.8 and Figure 7.9), the quantity of forestry residues remains significant over time, but the steep increase in overall biomass consumption (tripling in NZ45 and NZ50 by 2050) results in a smaller share for this feedstock at around half the total in net-zero scenarios. In particular, agricultural residues grow rapidly and reach more than 30% of the total in 2050 for all NZ scenarios. This increase is also found in REF and CP2030 before 2030, although the divergence with net-zero scenarios in this respect is important beyond that point. Dedicated culture, landfill biogas and municipal organic waste play a lesser but sizeable role from 2050.

While biomass as a primary energy source is currently used for industrial purposes, space heating, as well as biofuels and electricity production, all net-zero scenarios show that the increase in demand would be driven by a different relative importance of each (Figure 7.9). Although space heating from biomass all but disappears by 2050 in net-zero scenarios, the considerable expansion of primary biomass from 2040 results from an increase in electricity generation (41% of the total for NZ50 in 2050), hydrogen production (37%), biofuels production (13%), and renewable gas production (5% of the total). Biofuels production increases rapidly by 2030 in NZ scenarios, as in REF and CP30, but is more constrained in net-zero scenarios afterward, given the significant emissions associated with their consumption.

Figure 7.8 – Bioenergy sources by type

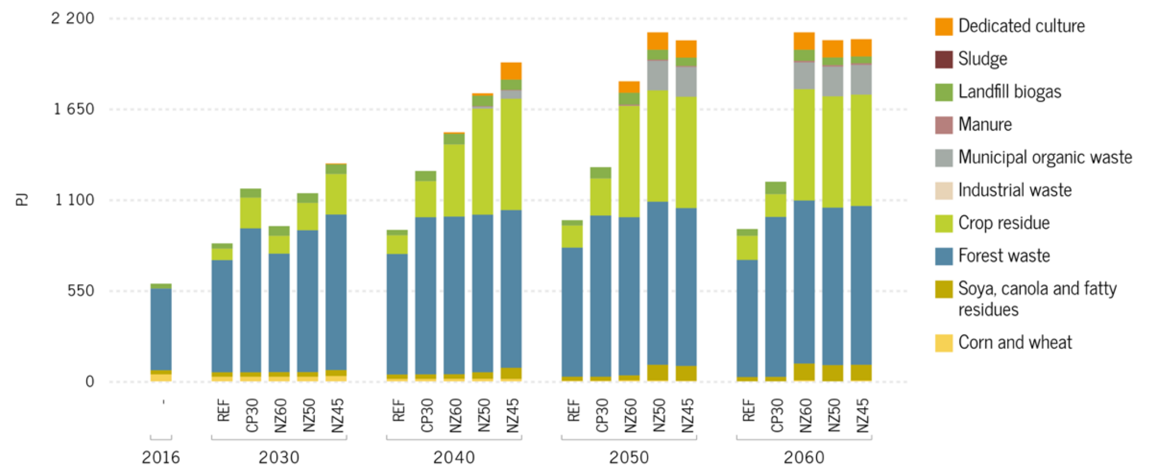
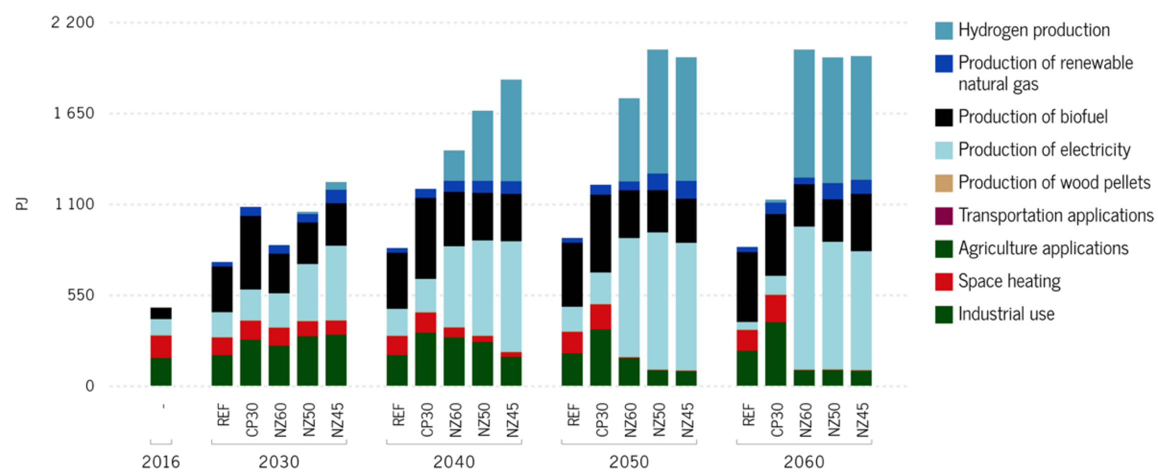


Figure 7.9 – Primary biomass uses



Overall, biomass expands extensively in all scenarios by 2030, primarily as a substitute for petroleum products in transport. This expansion is even more rapid in NZ scenarios than in REF. However, results indicate very considerable differences in the biomass mix after 2030 between REF and all other scenarios. Biofuels then become less important than BECCS in NZ scenarios, also leading to cessation in bioenergy-powered space heating and reducing industrial use to half what it is today. However, bioenergy's role is constrained by the availability of the resource. Chapter 9 presents a sensitivity analysis of this particular issue.

General observation:

- Bioenergy's growing role in all scenarios is not more of the same: the mix of sources for biomass changes significantly (with agricultural residues taking shares away from forest residues), as does its main applications, as biofuels and electricity production with carbon capture increase their use of this resource.

7.5 Takeaways

The importance of the energy production sector in the Canadian economy calls for careful consideration of the implications of net-zero pathways.

First, fossil fuel production is largely dependent on export markets, worldwide demand and pricing. However, irrespective of these markets, in a cost-optimal trajectory, **Canada must reduce its crude oil and natural gas production rapidly before 2030** to conform to net-zero targets. The sector's high emission intensity and limitations to fugitive emissions reductions techniques make it difficult to use an adequate quantity of negative emission technologies, such as direct air capture, at a reasonable cost and with realistic assumptions about CO_2 storage to compensate for a substantial emissions from the sector (see Chapters 8 and 12).

Short of such a reduction, reaching net-zero would require choices that involve reducing agricultural production or industrial processes. Reducing emissions by cutting production for the energy production sector is also cheaper in the short term than rapidly decarbonizing other sectors. However, this assessment must be carried out with care to ensure that the policy can help compensate for job losses in specific regions and export revenues that will be lost in the process. Sensitivity analyses exploring the consequences of maintaining higher levels of oil and gas production show how this transfers GHG reduction costs to other sectors, especially in the short term, increasing the challenge of reaching the emission targets.

It is crucial to note that if the rest of the world follows a trajectory similar to Canada's, with aggressive GHG reductions around the planet, international demand for oil and gas products will fall, directly affecting Canada's energy exports. In this context, given international pressure to address climate change, **expanding or even maintaining subsidies to this sector is unlikely to be a worthy investment. Instead, following international commitments, Canada should support an accelerated transformation of the economy away from this industry**, particularly in oil- and gas-producing provinces, which will significantly reduce the social costs of a worldwide transition away from fossil fuels. In other words, prevention is better—and cheaper—than cure.

Second, **a dramatic expansion of low-emission electricity production is expected in all net-zero scenarios, most of which will come from variable production technologies with careful consideration for grid resilience**. Given this very large share of wind and solar energy over the longer term, in addition to limited additional capacity to expand hydroelectric production, the role of nuclear energy through SMRs could grow and support the expansion of uranium mining to supply it. However, significant uncertainty remains about this technology. Storage (outside of hydroelectricity reservoirs) also expands. This is an area where the technical potential of hydrogen may be of interest when long-term storage is needed.

Third, **bioenergy is expected to rapidly play an expanded role**, especially in transportation. This role could be crucial to achieve reductions in the short term, while keeping costs in check and without impeding later transformations. However, beyond a certain point, the availability of biomass and the remaining emissions associated with it combine to limit its role in approaching net-zero emissions.

8

EVOLUTION OF GHG EMISSIONS IN NET-ZERO SCENARIOS

As discussed throughout this report, the challenge of reaching net-zero emissions requires not only reducing emissions to their lowest possible levels, but also compensating for remaining emissions that are too costly to eliminate. The latter includes specific applications where decarbonization is very costly or where technology is not yet available, but where demand is not projected to be eliminated. The discussion in this chapter thus focuses on the implications of the transformations needed to reach net-zero.

Unlike the previous edition of this Outlook, this edition addresses emissions from agriculture, waste and industrial processes, as well as fugitive emissions from the oil and gas production sector.

HIGHLIGHTS

- Current federal and provincial policies are grossly insufficient to turn the trend in GHG emissions.
- Even including a carbon price of $170/tonne by 2030, total emissions are projected to decrease by 9% between 2016 and 2030 (63 MtCO_2e); measured from the 2005 level (739 MtCO_2e vs. 705 MtCO_2e for 2016), this corresponds to a 13% reduction, considerably less than either the 40%-45% federal target, let alone the previous one of 30%.
- Reaching a 30% GHG reduction by 2030 will first and foremost require transformations on the industrial front rather than citizen actions, including the decarbonization of industrial processes, a significant reduction in oil and gas production, and aggressive reductions in fugitive emissions.
- Net-zero scenarios show a significant quantity of remaining emissions from all sectors combined (between 155 and 167 MtCO_2e annually), underscoring the essential role of carbon capture and storage (CCS), including direct air capture (DAC), to help compensate.
- Non-energy emissions (from industrial processes, agriculture and waste) occupy a much larger share of emissions around the net-zero point as they are difficult to reduce short of technological disruptions.
- In all net-zero scenarios, sectors decarbonize at very different speeds. The most challenging sector is transport, which will require considerable attention from decision makers and industry as many solutions are dependent on heavy infrastructure development.
- Sectors such as buildings and industrial combustion appear to be relatively low-hanging fruits and will mainly require regulations to force the acceleration of their transformation.
- The role of citizens' daily actions in reaching net-zero targets is very limited, affecting only a few sectors. It is therefore important for governments to focus their actions first and foremost on industry, and the energy and private sector in general.
- The projected cost of decarbonizing Canada's economy is falling rapidly as technologies progress faster than anticipated. While the marginal cost of the last ton for decarbonizing 65 % of Canada's economy by 2050 was projected to be above $1000 in the Canadian Energy Outlook 2018, current projections estimate the marginal cost of decarbonizing 80 % and 100 % of Canada's economy by 2050, is 400$ and 1100 $, respectively.

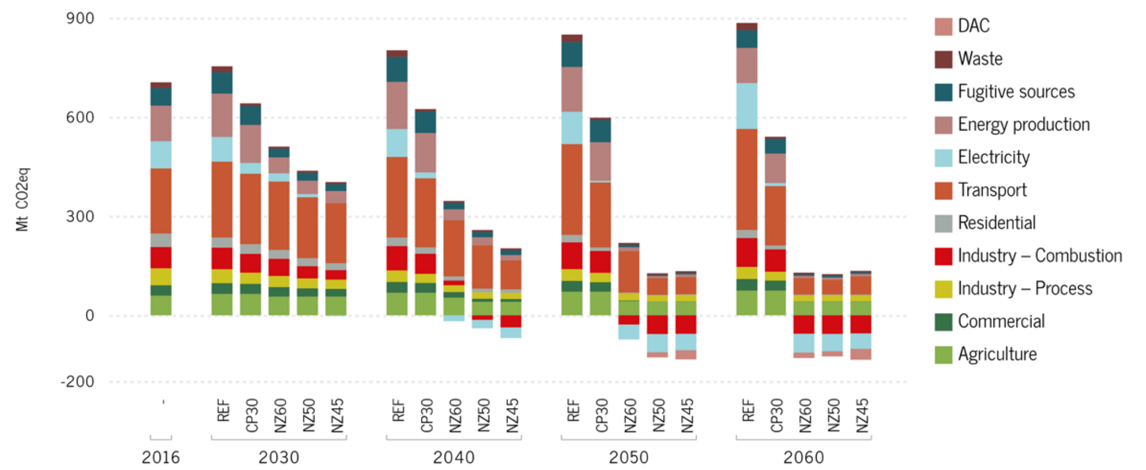
8.1 What does net-zero look like?

Despite the significant transformations to the energy systems reviewed in Chapters 6 and 7, a large volume of emissions remains across all scenarios when net-zero is reached. These emissions must be captured and sequestered—or compensated by the capture of emissions elsewhere (Figure 8.1). The distinction between the two references scenarios (REF and CP30) and net-zero scenarios (NZ60, NZ50 and NZ45) is also quite clear across the entire time period, showing an important divergence even before 2030. This chart also illustrates the extent of transformations required. In this section, key differences and common points are identified across scenarios, time and sectors.

8.1.1 Evolution of reference scenarios over time

With current policies, as defined in REF, emissions grow around 7% per decade, rising from 705 $MtCO_2e$ in 2016 to 850 $MtCO_2e$ in 2050, and 885 $MtCO_2e$ in 2060. Adding the proposed carbon pricing on a 2030 horizon leads to a 9% (641 $MtCO_2e$) reduction in 2030, far from the 30% target or the 40%-45% target. With respect to 2005 (739 $MtCO_2e$), this level corresponds to a 13% reduction by 2030, if we do not take into account the recent rise in GHG emissions (from 705 to 730 $MtCO_2e$) between 2016 and 2019). Adding the Clean Fuel Standard regulation,[1] published in December 2020 but not yet in force, to CP30 would produce a further 19 $MtCO_2e$ or 2.6% reduction by 2030, for a total of less than 12% overall GHG reduction with respect to 2016, and 16% with respect to 2005. By 2050, CP30 leads to a 15% decrease in GHG emissions with respect to 2016, reaching 23% over the following decade. Most of the difference in comparing CP30 with REF comes from lower emissions in power and energy production, as well as waste. This result shows that while the proposed carbon price increase helps overturn the recent trend in emissions when added to the rest of the policies already in place, it is not sufficient against demand drivers and deep reduction costs in most sectors.

Figure 8.1 – Total GHG emissions by sector



[1] Clean Fuel Regulations, Canada Gazette, Part I, Volume 154, Number 51, Dec. 19, 2020. https://canadagazette.gc.ca/rp-pr/p1/2020/2020-12-19/html/reg2-eng.html

While the three NZ scenarios (by design) introduce significant GHG emission reductions, it is interesting to look at the impact of using different horizons for this reduction. NZ50 and NZ45 bring an overall GHG reduction of 38% and 43% with respect to 2016, while NZ60 leads to a 28% reduction. Measured from 2005, these figures comply with the imposed reduction of 30% and 40% respectively for NZ60 and NZ50, and bring a substantial 54% for NZ45.

Even reaching 28% involves major sectoral transformations. Over the next 10 years, energy production, including fossil fuels and electricity, undergoes the most significant absolute reduction in GHG emissions in NZ60, with -60 and -58 $MtCO_2e$ respectively, corresponding to 55% and 70% reductions. This is followed by fugitive emissions (-50%, -27 $MtCO_2e$), which are also linked to fossil fuel production, and industrial processes (-34%, -18 $MtCO_2e$). Sectors such as industrial combustion and agriculture decrease by 20%, commercial buildings remain almost constant, while transport increases its emissions by 5%.

With more rapid reductions imposed by NZ50, these four sectors are transformed even more rapidly: reductions of 89% for electricity production, 62% for fossil fuel production, 58% for fugitive emissions, and 41% each for industrial process and combustion. Residential and commercial buildings accelerate their transformation, leading to 21% and 41% reductions in emissions respectively. Not surprisingly, transport (-8%) and agriculture (-5%) remain the toughest sectors to decarbonize. While there are some quantitative differences between NZ50 and NZ45, trends are very similar, with the notable fact that electricity production needs to incorporate biomass with carbon capture by 2030.

By 2040, electricity must deliver negative emissions in all NZ scenarios (18, 25 and 32 $MtCO_2e$, respectively). For NZ50 and NZ45, industrial combustion also contributes, sequestering an additional net amount of 14 and 36 $MtCO_2e$ and capturing even more. To compensate for the slow transition of the transport sector and, to a lesser degree, agriculture, all other sectors decrease their emissions by 60% or more in NZ50 and NZ45.

While the rate of GHG reduction varies from sector to sector, as a function of cost, almost all sectors are driven to zero or near zero emissions at the end of the periods, with three notable exceptions: transport, industrial processes and agriculture—in the latter two cases, essentially because of non-energy-related emissions. In a net-zero framework, these remaining emissions must be compensated by capture and sequestration elsewhere in the system. Overall, however, modelling suggests that it is preferable, from a cost-optimization perspective, to decarbonize maximally while taking advantage of specific and sectorial CO_2 capture and sequestration.

8.2 Emissions by sector

The main emissions remaining in net-zero scenarios come from transport, agriculture, industrial processes, energy (oil and gas) production and the fugitive emissions associated with it, and waste. However, beyond the end point of the modelling period, it is relevant to examine the evolution of the various sectors according to the scenarios considered.

8.2.1 Residential and commercial buildings

As discussed in Chapter 6, with heat pumps becoming more cost competitive, the residential sector (6% of current GHG emissions) is the only one to see its emissions decrease in all scenarios and in all time periods. While both REF and CP30 lead to a 25% reduction by 2030, the two trajectories then diverge, with a decrease of 45% for REF and 75% for CP30 by 2050. As expected, the decarbonization of this sector is accelerated in NZ scenarios, reaching between 33% and 50% by 2030. However, by 2040, all three NZ scenarios are much more aligned, with reductions of between 70% and 75%, before plateauing at 95% starting in 2050. This shows that the technology exists and is already largely competitive, although some planning is required to handle the increased electricity grid capacity. It also indicates that some efforts will be needed to obtain the final 5% reduction.

The transformation of the commercial sector, which currently represents 4% of GHG emissions, is much slower than for residential buildings. Both REF and CP30 project an almost flat curve in GHG emissions over the next 30 years (increase of 4% for REF and decrease of 9% for CP30), followed by a slight increase between 2050 and 2060 as energy efficiency measures are overtaken by economic and population growth. In contrast, models for NZ scenarios project rather a slower take on decarbonizing, with reductions of 8% (NZ60), 21% (NZ50) and 27% (NZ45) by 2030. This is followed by a rapid acceleration in GHG reductions. By 2040, the commercial sector should see its emissions reduced by 46%-74% in NZ scenarios, to reach 98% by 2050 in the two strictest scenarios (NZ50 and NZ45) and 94% in NZ60.

8.2.2 Transport

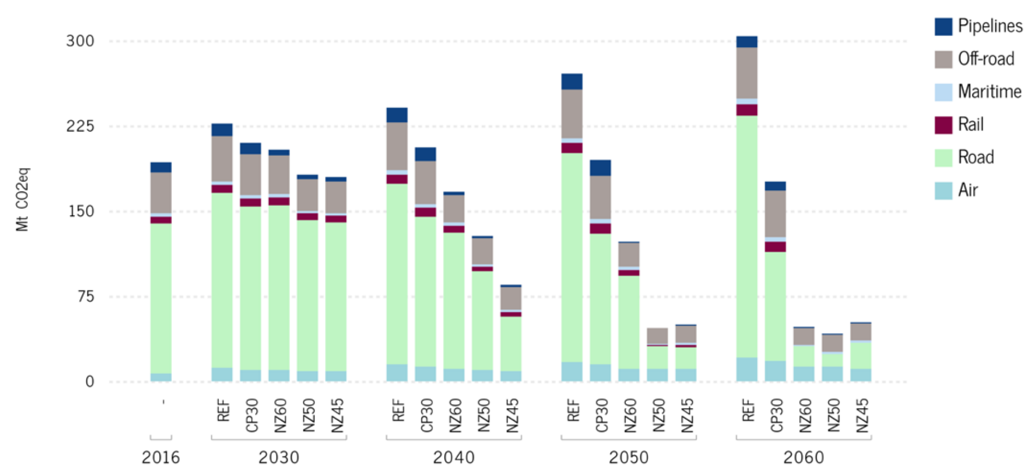
The sharp contrast between REF and net-zero scenarios in 2050 and 2060 illustrates the magnitude of the transformation needed in some sectors. This difference between scenarios is most notable in transport, which represents 28% of GHG emissions today. Unabated, emissions from this sector rise by 39% in 2050 and 55% by 2060. The introduction of a carbon price (CP30) barely manages to keep emissions at 2016 levels by 2050, bringing a 9% decrease over the following decade.

Even in NZ scenarios, this sector shows the highest emissions, representing 40% of total remaining emissions in NZ50 even though they are only 18% of what they would be in REF for 2050. Most of this reduction can be achieved in the largest source of transport emissions, that is, road transport, which in NZ50 drop to 11% of their value in the reference scenario (Figure 8.2). This is accomplished primarily through technological switching, mainly through electrification, as discussed in Chapter 6. Rail and off-road are also reduced significantly, while air transport is much more difficult to decarbonize and accounts for 23% of the total in NZ50.

Even for the most aggressive scenarios, decarbonization of the transport sector is slow. NZ50 and NZ45 project a reduction of only 6% and 8% by 2030, while NZ60 is in line with a 5% increase in GHG emissions. The slow transformation for NZ60 persists over the following decade, which sees a net reduction of only 14% with respect to 2016, while even with their aggressive targets, NZ50 and NZ45 are projected to achieve only 33% and 55% reductions in this sector.

These results underline the current lack of available commercial low-carbon solutions in most of the transport sector, with the exception of public transport and private cars, not including the popular SUVs.

Figure 8.2 – Emissions in the transport sector

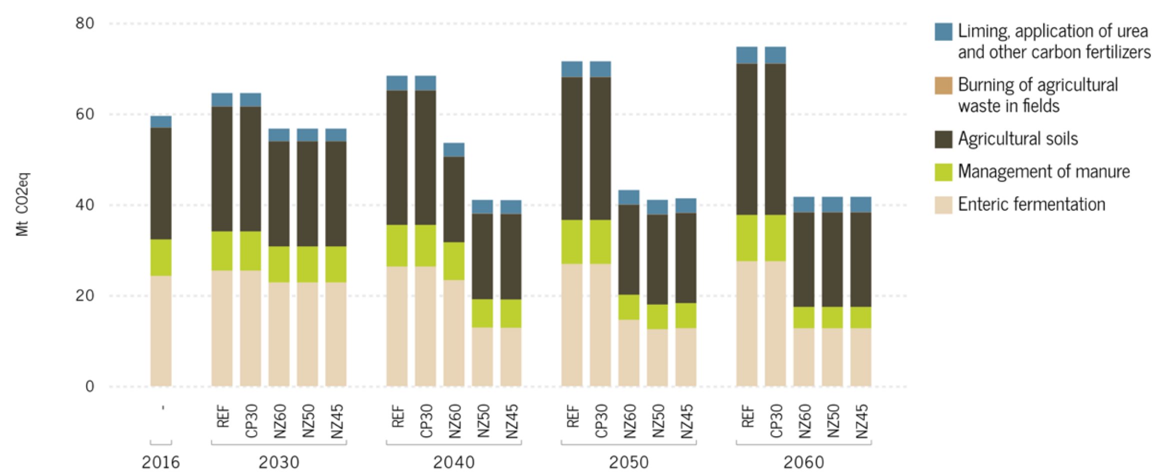


8.2.3 Agriculture

Although agriculture represents only 8.5% of current GHG emissions, it is projected to become the second largest source of remaining emissions (Figure 8.3), with around 41 $MtCO_2e$, close to a third of remaining emissions, in both 2050 and 2060 once net-zero is reached. These emissions are separate from those associated with energy consumption in the sector and which are almost all eliminated through electrification (see Chapter 6). In other words, agriculture remains the second most important source of emissions because of non-energy emissions, which are much more costly to eliminate without drastic reductions or the transformation of production practices. Net-zero scenarios still manage to eliminate some 40% of these emissions, compared with REF or CP30, which are identical for the whole period in large part because of reductions in enteric fermentation emissions (50% reduction in net-zero scenarios compared with current levels).

While approaches targeting the production strategies supported by changes in consumption will likely be needed, they do not fall within the scope of this report.

Figure 8.3 – Non-energy emissions in the agriculture sector



8.2.4 Industry – processes and combustion

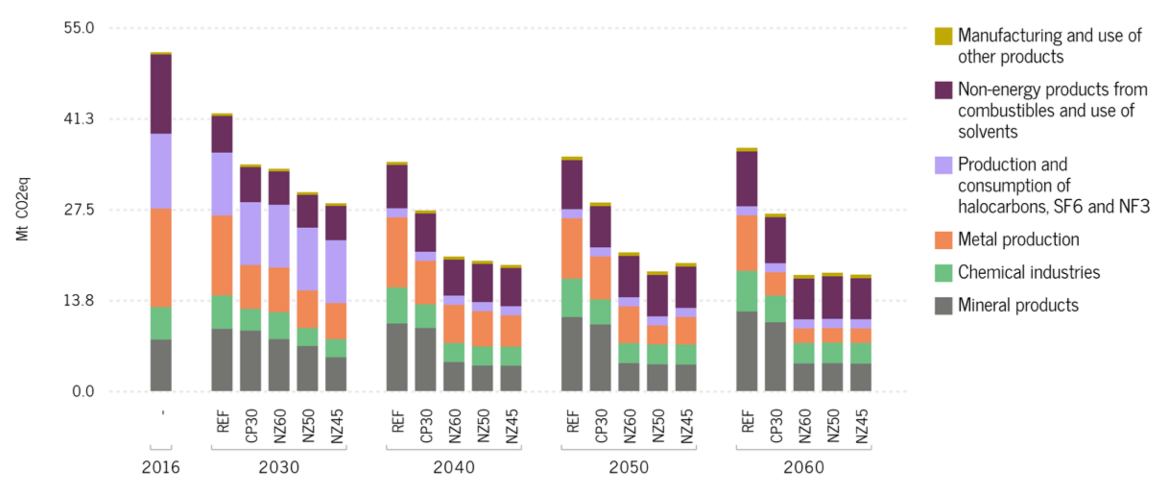
Industry (outside of energy production), which currently emits slightly over 16% of Canada's GHGs, is projected to rapidly decrease its process emissions in all scenarios, starting with a reduction in the production and consumption of cooling fluid (Figure 8.4). This leads to an 18% reduction in process emissions for REF in 2030, which reaches 30% by 2050 with the production of low-carbon aluminum. CP30 engenders a more significant transformation, with reductions of 33% by 2030, which peak at 47% in 2040 before GHG emissions increase again (REF) or stabilize (CP30) in the last 20 years of the model.

NZ scenarios bring further and faster reductions—34%, 41% and 45% by 2030. This last percentage climbs to around 60% in 2040, with a slower transformation afterward, to reach 67%-74% reduction in 2060, including some 5 MtCO_2e of carbon captured in 2050. At present, further reduction is limited by a lack of alternatives that tend to be very process specific, but that could emerge over the coming decades. We explore these issues in further detail in Chapter 13.

Over the 2050 and 2060 horizon, emissions linked to industry combustion continue to increase in REF and CP30, after a small 13% reduction by 2030 in the latter case. However, this sector plays a central role in NZ scenarios. By 2030, emissions from industry combustion fall by 20% (NZ60), 42% (NZ50) and 62% (NZ45), but become net negative in the latter two scenarios by 2040, with 121% and 156% reduction respectively, reaching almost 200% in all NZ scenarios by 2060. This is largely accomplished by capturing and sequestering emissions from biomass combustion used for heat or electricity production.

The important contribution of this sector early on in NZ pathways underlines not only the role that the private sector plays in producing emissions but also the role, which in Canada is much larger than that of citizens, it could play in contributing to the solution.

Figure 8.4 – Emissions from industrial processes



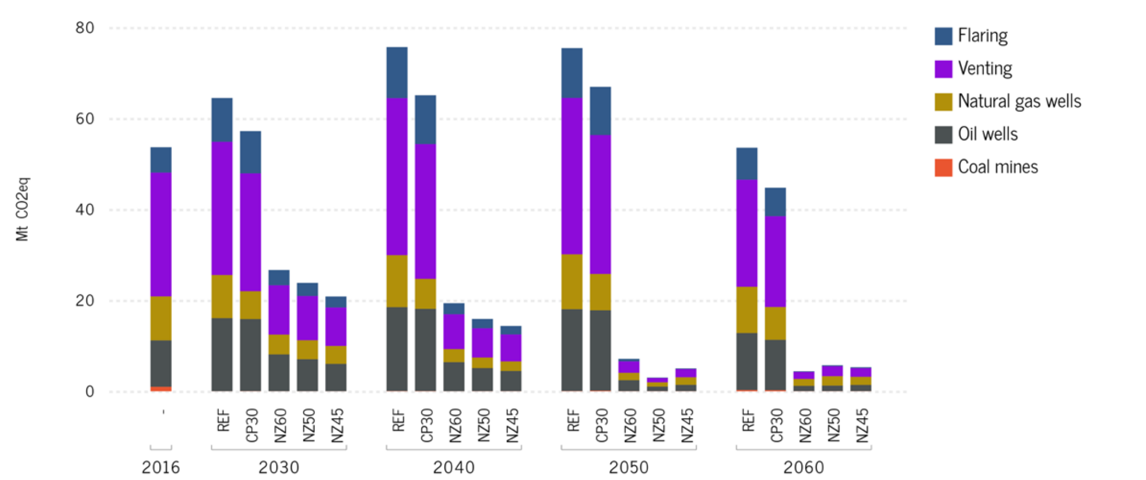
8.2.5 Energy production, including electricity

The energy production sector also requires a profound transformation. The transformation of electricity generation has previously been discussed in Chapter 7. After a 10% decline in emissions in 2030, REF projects a growth in emissions, based on the addition of thermal electricity production, starting in 2040 and rising to almost 70% by 2060 compared with today. CP30 shows a significant reduction by 2030 (60%), reaching 94% by 2050, before thermal production starts picking up to support the increased demand arising from economic and population growth. The significant difference between REF and CP30 supports the general observation that decarbonizing electricity is among the low-hanging fruits of any decarbonization pathway.

This is confirmed by NZ scenarios. By 2030, NZ60 and NZ50 project a 70% and a 90% reduction in total emissions, while NZ45 begins to include negative emissions (2 $MtCO_2e$). By 2040, all NZ scenarios project negative emissions for the electricity sector (respectively 122%, 130% and 140% lower than today), which are achieved by closing all fossil fuel thermal plants and strongly growing biomass electricity associated with CCS. As limits on biomass for energy use are reached, this saturates, resulting in floor levels of about 160% to 170% low than today's emissions in 2050-2060.

As indicated in Chapter 7, from an optimal cost perspective, the oil and gas sector is also a low-hanging fruit for decarbonizing Canada's economy. While emissions in this sector are higher than in 2016 for REF and CP30 for all decades but 2060 (where they fall by 1% and 17% respectively), they are projected to shrink by 55%-66% for NZ scenarios by 2030, reaching a floor of 89%-94% reductions in 2050. A substantial reduction from fugitive sources associated with the oil and gas sector also results, in part due to announced regulation and an overall reduction of activity in this sector (Figure 8.5). In 2050, this latter source also decreases by more than 95% in NZ scenarios, contributing a 72 $MtCO_2e$ reduction in NZ50 compared to REF in 2050.

Figure 8.5 – Fugitive sources of emissions



8.2.6 CCS and DAC: compensating remaining emissions

Figure 8.1 hints at the magnitude of GHG capture required by net-zero scenarios, but a closer look is required to understand the real extent of the capture required (Figure 8.6)

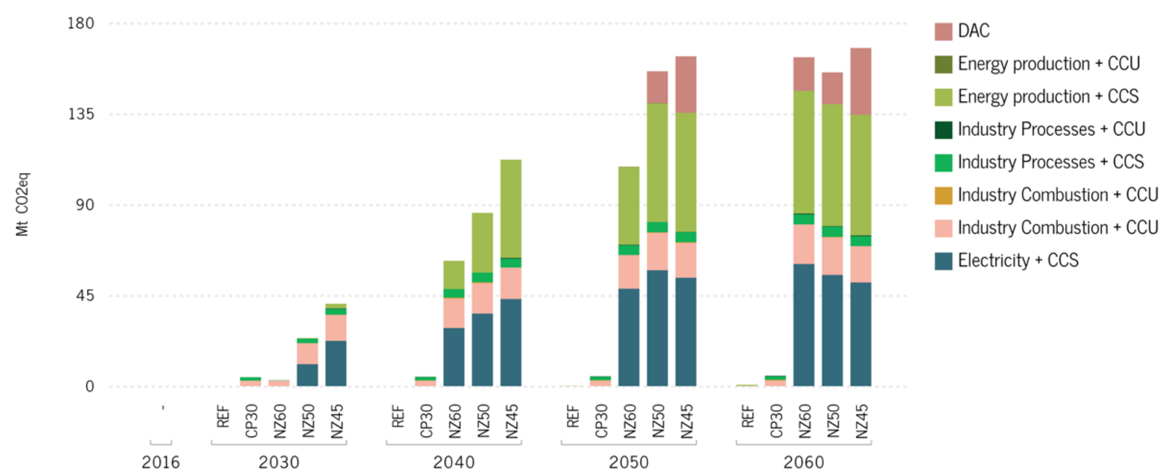
As discussed in the previous section, all net-zero scenarios show a rapid increase in capture from industrial applications as well as bioenergy with carbon capture (BECCS) power production, which is split more or less evenly between hydrogen production and electricity generation.

As a given scenario approaches net-zero, these applications are not sufficient to compensate fully for remaining emissions. As a result, direct-air capture is required (15 $MtCO_2e$ for NZ50 in 2050, and up to 33 $MtCO_2e$ in 2060 for NZ45). This brings the total emissions captured within a range of 155 to 167 $MtCO_2e$ once net-zero is reached in any scenario. To be clear: this is the capture necessary every year, which underscores the difficulty of maintaining net-zero emissions if no further reductions occur.

However, reference scenarios present almost no capture, with virtually none in REF and less than 5 $MtCO_2e$ in CP30, a result of the high cost of the different technologies and their applications. The role and challenge of CCS and DAC technologies is addressed in more detail in Chapter 9 and additional technical perspectives are presented in Chapter 12.

As mentioned above, agriculture and industrial process emissions highlight the importance of non-energy emissions, which are less than 20% of total emissions today but will grow in importance once we move closer to net-zero, becoming more than half of remaining emissions. This means that, aside from eliminating these activities altogether, negative emission technologies must be used to compensate (as discussed above). Although waste is the other source of non-energy emissions, a smaller quantity remains (around 5 $MtCO_2e$) once net-zero is reached, representing a 70% reduction compared with today.

Figure 8.6 – Captured emissions



As discussed in the previous paragraphs, the energy consumptions in industry and electricity production both become net negative sources with the help of carbon capture and negative emission technologies like BECCS. For instance, once net-zero is reached in NZ50, these two sectors amount to 88% of the negative emissions (with a slightly higher share for industry combustion) needed to compensate and reach net-zero, the rest being supplied by direct air capture. As a result, these activities are key in compensating for remaining emissions and helping reach net-zero without resorting to larger quantities of DAC.

General observations:

- The carbon pricing increase in CP30 does not have a major impact outside of energy and power production and is not sufficient to result in emission reductions.
- Reaching and maintaining net-zero requires an annual capture of between 155 and 167 $MtCO_2e$.
- Non-energy emissions become the majority of what remains once carbon neutrality is reached, a different challenge than reducing emissions from energy consumption since it necessitates disruptive technological innovation, which is difficult to predict.
- Most emissions in Canada are associated with industrial and commercial activities, which include natural resources extraction, production of goods and freight transport, contributing to 64% of Canada's emissions (72% when agriculture is also included). Transformation of these sectors is projected to be very cost competitive and can be considered as low-hanging fruit.

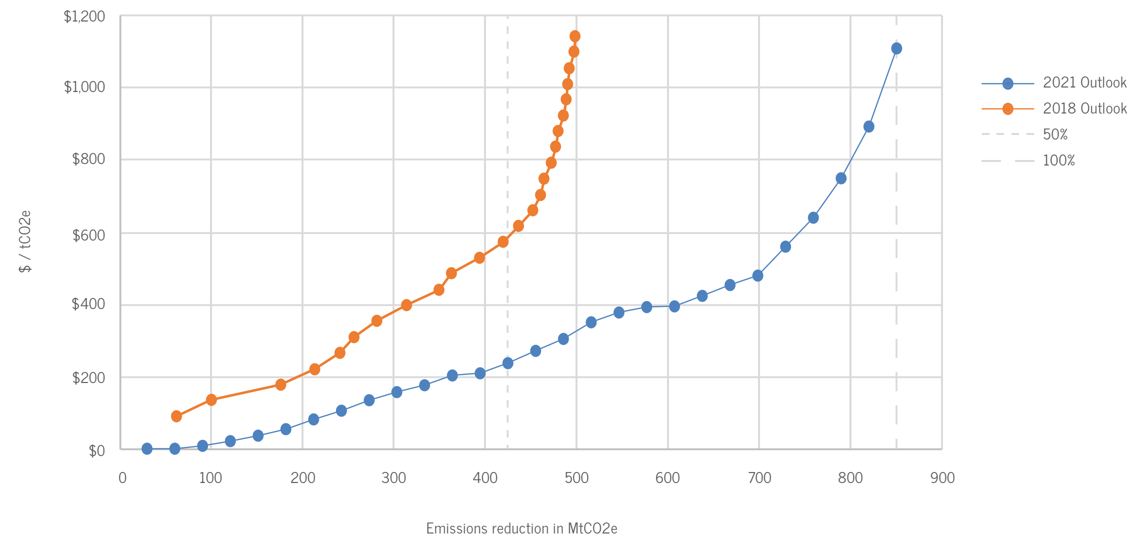
8.3 The cost of reducing emissions

A look at the marginal costs of reducing emissions over time helps illustrate how the challenge of deep reductions becomes more difficult—and thus costly—over time (Figure 8.7). The curve shows how costs rise more quickly for the latter set of emission reductions, reflecting the complexities of deep reductions, and the uncertainties respecting some technologies, including for carbon capture and negative emissions, as well as direct-air capture. Marginal costs once net-zero is attained reach \$1,100 for the last tonne of CO_2e eliminated. While this cost may seem high, it must be put in perspective.

First, for NZ50, which imposes the current federal target of 40% reduction by 2030 (compared with 2005 levels) and neutral emissions by 2050, the marginal cost remains under \$210/tCO_2e for achieving the -40% target. While marginal costs then go up in order to move beyond this reduction, the growth rate of this cost is not faster at first: at around -80% of 2005 emissions, the last tonne eliminated is still worth under \$500.

Second, it is worth comparing these results with earlier modelling efforts carried out for the Canadian Energy Outlook 2018. For the most stringent reduction scenario at the time (80P), the target was a reduction of 80% of energy-related emissions compared with 2005 levels by 2050 (around 65% reduction of total emissions). The marginal cost for the last tonne eliminated was then slightly above \$1,000/tCO_2e, significantly higher than numbers obtained this time. While a precise comparison is not possible given that the current model includes a more comprehensive coverage of emissions (as explained in Chapter 1), and the evolution of the reference scenario is also different, the order of magnitude is unmistakable. Technological developments since the previous Outlook, which help not only with providing emission reduction solutions, but also with reducing uncertainties about technological paths and their costs, have in less than three years resulted in a very significant marginal cost reduction. This is while the 80% reduction is achieved earlier than 2050 for NZ50 as compared to 80P.

Figure 8.7 – Marginal costs of reductions, NZ50 scenario compared with REF



The above helps illustrate that marginal costs are a rapidly moving target: as significant action is taken to reduce emissions, innovation leads to a decrease in the cost of further reductions. This is achieved as new technologies and applications are put in place. As a result, marginal costs on the longer term are then reduced; but more importantly, the higher levels estimated for the last tonne reduced becomes less relevant since it affects a smaller proportion of reductions. In Chapter 14, we return to the issue of the cost of transitioning to a net-zero economy to assess the overall costs and benefits of the transformations required before 2050.

8.4 Takeaways

REF and CP2030 are both very far from net-zero in 2050 and 2060, underscoring how the policies in place or announced are far from enough to steer society toward carbon neutrality. This demonstrates the urgent need for additional policies with clear and quantifiable indicators and objectives to correct the course, as discussed in the conclusion of this report. Part of this reflection must focus on the implications of net-zero emissions.

First, given the difficulties in foreseeing the necessary technological innovations required to reduce non-energy emissions from agriculture and industrial processes, achieving net-zero implies reducing energy-related emissions as much as possible. To be more precise: **energy-related emissions must present net negative emissions, achieved through all of drastic emission reductions, carbon capture applications, and the use of negative emission technologies**. This is a very tall order, but one which at least directs attention toward transformations that can be planned, some with technologies that already exist on a commercial scale or are reasonably well developed. There is no option to undershoot targets in this area because doing so will only add to the already sizeable emissions remaining from non-energy activities.

The above leads to the second point: relying on carbon capture is a central part of the scenarios to net-zero but **results from the optimization modelling should not obscure the significant uncertainties that remain about the true potential for capture to be efficient from a technical, economic and energy requirement perspective**. Experience so far with carbon capture in industrial applications shows a much lower share of emissions captured than theoretically feasible, as well as significant emissions resulting from energy use to operate the capture technologies. Experience with BECCS is even more limited, while no DAC technology is currently operated on a large scale, making it impossible to confirm costs for these processes. As a result, the quantity of emissions captured in the net-zero scenario results discussed above is likely to be an underestimation of what would be required to fully compensate remaining emissions.

Even disregarding these uncertainties about CCS, the amount of captured emissions (Figure 8.6) raises the issue of the implications of storing such large quantities every year, even after net-zero has been reached. While there is theoretically substantial storage capacity across the country, experience in storing quantities of this magnitude is lacking and some risk assessments suggest that large-scale storage should be considered with care. Opportunities for CO_2 reutilization that do not result in the eventual release of CO_2 are also very limited.

As a result, the need to capture and achieve storage to reach net-zero and the considerable uncertainties that remain about these processes pose a crucial conundrum: results from net-zero scenarios must be treated as optimistic at best with regard to the role of CCS, suggesting that the emission cuts required in all sectors (including in non-energy activities) are likely to be greater than discussed in Chapters 6 to 8 of this Outlook. And since life does not end at net-zero, the implications of these transformations and the storage needed as part of this management of remaining emissions extend well beyond 2050 and 2060.

9 KEY TECHNOLOGICAL PATHWAYS TO NET-ZERO

The results presented in Chapters 6 through 8 show both the variety in technologies required to reach net-zero objectives and the relative importance of each technological pathway in given sectors, based on a large number of assumptions respecting cost evolution and technical characteristics. Given the uncertainties inherent in forward-looking exercises of this kind, specific key assumptions about technological developments could have important implications for the results. This chapter delves further into four pathways identified in the modelling results to provide a more refined analysis of how these transitions could proceed should some assumptions turn out differently. More specifically, these four pathways explore the technological shifts associated with electrification, bioenergy, hydrogen and carbon capture.

Unlike the previous edition of this Outlook, this edition addresses emissions from agriculture, waste and industrial processes, as well as fugitive emissions from the oil and gas production sector.

HIGHLIGHTS

- Sensitivity analyses performed on key technological pathways show that the net-zero future is not determined and may take different forms.
- A significant quantity of electricity generation can be avoided through increased provincial interconnections, helping to reduce pressure on generation capacity to accommodate increased average and peak demand.
- Imposing constraints on storage and variable generation favours nuclear from a cost optimal allocation perspective, but uncertainties about SMRs and social acceptability means that these projections must be viewed with a critical eye.
- Social acceptability is also a major unknown when considering expanding hydroelectric generation, especially with extensive reservoirs.
- The assumed available quantities of biomass greatly affect the energy system, including the transport sector, electricity and hydrogen production in NZ scenarios, as biomass electricity generation coupled with carbon capture and sequestration (BECCS) provides a relatively cheap solution for negative emissions.
- More specifically, larger quantities of available biomass lead to more BECCS, reducing pressure for the use of DAC when approaching net-zero; the opposite is true for a future with less biomass available, underlining the need for the careful management of this resource
- The specific mix of technologies used to produce hydrogen—biomass with CCS or electrolysis—is strongly dependent on both the availability of biomass and the cost evolution of electrolysis.
- Increasing hydrogen penetration leads to increased use in most transport applications as well as some industrial sectors.
- The very large quantity of carbon capture, including through direct-air capture, required to reach net-zero can be achieved in various ways; the technological possibilities in capturing industry emissions are uneven across sectors.

9.1 The electrification of energy services

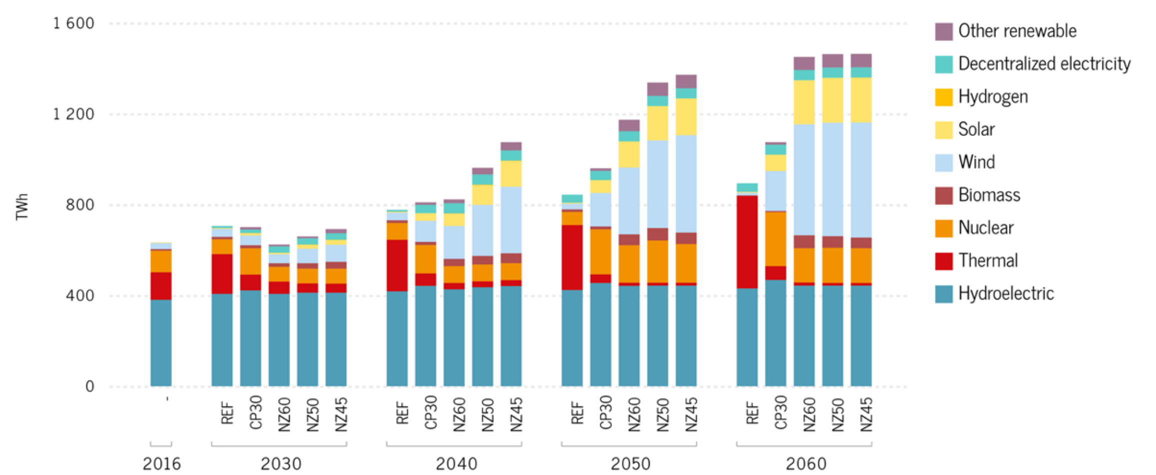
All net-zero scenarios point to two developments over the next few decades: first, the electricity sector itself will be fully decarbonized; second, electricity demand will grow sharply, especially in net-zero scenarios, to meet increased demand from activities formerly powered by fossil fuels. As a result, this sector needs to evolve significantly over the next decades.

9.1.1 Evolving toward a lower carbon mix

Canada's current electricity generation is dominated by hydro and nuclear generation, making it one of the OECD countries with the lowest GHG emissions per kWh generated. By 2040, thermal generation with fossil fuels, which accounts for only about 20% of the current mix, is reduced by half in absolute terms for CP30, and almost disappears in all net-zero reduction scenarios. The main difference across scenarios is the amount of demand for electricity, associated with the electrification of new sectors. In the various scenarios, demand increases more quickly in tighter schedules to reach net-zero, to then converges around similar levels once net-zero is reached (2060).

Figure 9.1 also shows that the replacement of fossil thermal production and the increase in total electricity demand are provided primarily by a balance of wind and nuclear for CP30, while across GHG reduction scenarios it is met overwhelmingly by wind, followed—to a substantially lesser extent—by solar. Hydroelectricity shrinks in terms of its role in the overall mix as its output remains more or less constant across time and scenarios. Nuclear also remains at similar levels although this hides a transformation in the technology used, with more SMRs as part of this generation starting in 2050.

Figure 9.1– Electricity generation



9.1.2 Sensitivity analysis

With a strong flexible base-load generation and considerable hydroelectric reservoirs, Canada will not be required to build up as much renewable capacity as other countries. However, uncertainties remain about (i) the technical and economic constraints of integrating such large shares of variable generation, (ii) the costs of battery storage capacity, and (iii) the development of nuclear SMRs, making relevant a sensitivity analysis based on parameters aiming to provide the planned increase in demand. Two alternative scenarios, both based on NZ50, are considered:

- IntA: maximum electricity generation from variable renewable sources capped at 30% of the total mix and limited storage capacity.
- IntB: maximum electricity generation from variable renewable sources capped at 30% of the total mix, limited storage capacity, investments in nuclear capped at NZ50 levels, and with firm/guaranteed capacity in each province that can be met through interconnections with neighbouring jurisdictions.

Both scenarios explore how the model accommodates a sizeable share of variable generation, but one that is more constrained in terms of its role in the overall mix. In IntA, more limited storage capacity can be compensated through any form of baseload generation, which tends to favour nuclear generation. In IntB, compensation must be accomplished through increased hydro generation and/or additional interprovincial exchanges rather than additional nuclear investment.

By design, both alternative scenarios show less variable electricity generation capacity installed over time. In IntA, this is compensated by more nuclear capacity; in IntB, by more hydro. In IntA, growth in nuclear stems from new SMRs, some existing conventional generation, and new advanced reactor powerplants, a result of more investment not allowed in IntB.

Electricity generation, which is determined by demand, presents an almost identical evolution over time for the three scenarios considered here. With electricity demand growing strongly after 2030, scenarios start diverging in terms of production and installed capacity, as seen from 2040. By 2050, electricity production remains dominated by hydroelectricity, which accounts for 33% of the total for NZ50 and IntA but reaches 39% in IntB. This increase in hydro production is accompanied by hydrogen, which represents 5% of electricity production against zero for the two other scenarios, and thermal, which increases from 1% to 2.4% by 2050 in this scenario. These increases are mainly at the expense of nuclear (7% vs. 14% in NZ50) and wind (25% vs. 29%). Since hydro expansion is constrained in IntA, changes with respect to NZ50 occur in the other energy production sources. In 2050, by construction, nuclear increases to 29%, a share similar to hydroelectricity, while wind and solar shrink but remain important at 18% and 7% of total production respectively.

Differences in production capacity are more dramatic since this capacity is determined by the energy source and its capacity factor, i.e., the fraction of peak power produced in a year, which varies according to production source. For example, while the total electricity production is multiplied by 2.1 between 2016 and 2050, to reach 1,341 TWh, production capacity is multiplied by 3.4, moving from 147 to 489 GW for NZ50. Favouring nuclear, with a capacity factor above 90%, IntA sees its capacity multiplied by only 2.7 (406 GW), while IntB, which preserves more variable sources, falls in-between at 448 GW. By 2050, nuclear capacity in IntA is projected to reach 50 GW, compared with 25 GW for NZ50 and 13 GW for IntB. This is sufficient to reduce the need for renewable capacity from 239 GW to 155 GW in IntA, with a collateral reduction in storage capacity from 68 to 45 GW. For IntB, hydro capacity increases from 89 to 107 GW, half at the expense of nuclear. While variable renewables capacity is also reduced by 63 GW with respect to NZ50, it is also partly compensated by 8 GW of hydrogen power capacity and a slight increase of 2 GW in fossil thermal.

Interprovincial exchanges are also used to balance demand and generation in IntB. Interprovincial electricity trade already rises by 15% in 2040 in IntB (compared with NZ50), while in 2050 and 2060 this figure is 42% and 63% of NZ50 levels respectively. This provides grid resilience without additional baseload generation capacity and in fact results in less generation overall, suggesting an improvement in overall grid efficiency.

These changes are also associated with different consumption profiles. Total final energy consumption in the sectors is similar across the three scenarios. However, electricity consumption is 6% less in IntB for 2050, while natural gas consumption is up in IntB (+23%), as is hydrogen use (+30%).

In the building sector, this results in three important changes in IntB, which uses more hydrogen (174PJ compared with 3PJ in NZ50 for 2050), natural gas (81PJ instead of 53PJ), and geothermal and concentrated solar (51PJ compared with 6PJ in NZ50). These changes become sizeable around 2040 and remain so afterward, with hydrogen use increasing chiefly in the commercial sector.

In the industry sector, 2050 sees slightly more electricity (+4%) and natural gas (+17%) in IntB than in IntA, but less bioenergy (-15%) and much less hydrogen (-22%). The transport sector sees IntA result in levels similar to NZ50, although while the total is similar for IntB, the latter uses less electricity (-7% compared with NZ50), gasoline (-9%), and bioenergy (-3%), while consuming more natural gas (+17%) and much more hydrogen (+50%). Nevertheless, after 2050, hydrogen levels converge across IntA, IntB and NZ50. These changes primarily affect merchandise transport.

Lastly, more emissions are captured through BECCS hydrogen production, given the higher use in IntB (12MtCO_2e in 2050 compared with NZ50). This requires biomass to be used here instead of BECCS electricity generation, compensating most of this change. In other words, more negative emissions result from the increase in BECCS hydrogen production, while BECCS electricity generation decreases by around 8MtCO_2e as a result. More capture also occurs in electricity generation in IntB, given the more significant use of natural gas, resulting in similar net emissions from power production across the three scenarios.

General observations:

- Strong dependence on variable energy sources for electricity requires a massive increase in capacity for production and storage to compensate for lower capacity factors and misalignments between production and consumption.
- Constraints on storage and variable generation favour nuclear from a cost optimal allocation perspective, but uncertainties about SMRs and social acceptability must be treated with care.
- A significant quantity of electricity generation and production capacity installed can be avoided through increased provincial interconnections.
- Favouring hydro generation and interprovincial connections over nuclear to balance variable renewables leads to different sectoral profiles where hydrogen use and natural gas are also increased.

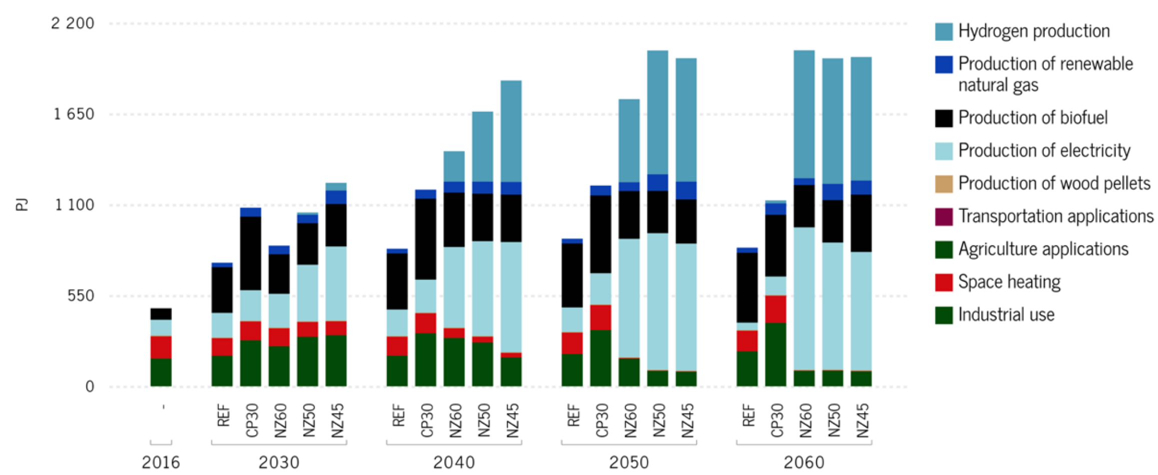
9.2 Bioenergy

9.2.1 Main applications

Biomass use increases significantly in all scenarios (Figure 9.2), including REF (+77% by 2060) and CP30 (+104%), even though this use is more modest than in net-zero scenarios where it more than quadruples. At first, biofuel production increases in all scenarios and rapidly reaches a limit in NZ scenarios, where increases after 2030 are very limited. Instead, the two main uses of the additional biomass consumption are BECCS for hydrogen and electricity production, which constitute at least 73% of the total in 2060. In the case of electricity, this means that even if little biomass is used for generation in proportion to the total, its role is key in net-zero trajectories because of the significant negative emissions that are obtained from biomass-fired plants with CCS.

In fact, given that the burning of transformed biomass results in GHG emissions and that other alternative low-carbon energy sources are available, its cost-optimal use is for guaranteeing net-zero targets. In the short term, biomass can provide an alternative to other fuels in sectors, mainly transport, that are costly to decarbonize. However, beyond the short term, the use of biomass remains primarily associated with the possibility of attaining power and hydrogen production with negative emissions (BECCS) in specific applications particularly tailored for its use, and where other technologies remain too costly or do not yet exist.

Figure 9.2 – Biomass consumption by application



9.2.2 Sensitivity analysis

The main constraint on the use of biomass with regard to BECCS after 2030 is availability. This availability is mapped by the model based on a review of the literature. As there is a considerable range in the numbers published around the average, and in order to explore the implications of this constraint, a sensitivity analysis respecting the NZ50 scenario was performed, using two alternative constraints:

- BioMin: biomass availability (e.g., forest and agriculture residues) for energy production is reduced by 50%.
- BioMax: biomass availability (e.g., forest and agriculture residues) for energy production is doubled.

The results show some changes in final consumption patterns. Overall, compared with NZ50, BioMin presents similar levels in 2030, but less consumption in 2050 (-11% compared with NZ50). In BioMax, consumption is 13% higher than in NZ50 for 2030, but does not increase further and even decreases by 5% from that level in 2050 and 2060. Although the opportunity to use more biomass in the short term helps reduce emissions, residual emissions from its burning become too significant to be sustainable as NZ targets approach.

When looking at consumption by sector, no changes are observed in buildings regardless of the scenario. In industry as well, changes are very limited, with around 8% less biomass used in BioMin, compared with NZ50 in 2050, being the most important change.

However, in the transport sector, the various scenarios introduced significant differences. Biomass consumption in BioMin is identical to NZ50 for 2030, but 10% less in 2050, again showing the importance of the availability constraint in BioMin on the longer term. In BioMax, changes are major: 50% more biomass is used in 2030 compared with NZ50, and 45% more in 2050.

Given this difference, a closer look is needed to determine where these changes operate. In passenger transport, BioMax shows 19% more biofuels in 2030 compared with NZ50 and results in almost five times as much biofuel in 2050. In other words, most of the change is over the longer term for passenger transport. In merchandise transport, BioMin is identical with NZ50 in 2030, but 20% less in 2050. However, BioMax shows a 38% increase over NZ50 in 2030 and a 100% higher value in 2050. Merchandise transport is much more affected than passenger transport by the opportunity to use more biofuels, in both the short and the long term.

Aviation sees a small decrease for BioMin in 2030 and levels 20% lower than NZ50 in 2050. BioMax levels are almost 10 times higher (2030) and 11 times higher (2050) than NZ50, but this remains a very small part of the total energy used by this sector (1% in 2030 and 5% in 2050).

The schedule for change is different in other transport sectors. Both rail and maritime transport use 40% more biomass in 2030 compared with NZ50, but levels are identical in 2050. A similar pattern is observed in off-road transport. This suggests that the additional biomass availability is useful in these sectors for short-term GHG reduction efforts but less so in the longer term.

A look at overall biomass use (Figure 9.3) provides a different angle on these increases. In 2030 and 2040, the increase in biomass use in BioMax is chiefly for biofuels and renewable natural gas (+80% and +200% over NZ50 in 2040, respectively). BioMin has the greatest impact in 2050 and 2060, reducing biofuels by 20% over NZ50 and renewable natural gas by 72%. As discussed above, BioMax sees both these applications decrease after 2040 as residual emissions from their burning become an important factor.

A final and crucial point is the impact of these alternative constraints on biomass availability on the negative emission activities, namely BECCS electricity and hydrogen production. Given the need for negative emissions in industry and in BECCS energy production to attain net-zero, the quantity of biomass available may play a key role both in the type of emission capture technologies used and in the requirements for DAC. BECCS electricity presents different levels than NZ50 from 2040 (less in BioMin and more in BioMax, as expected due to the availability constraint in each scenario), while BECCS hydrogen production is similar in all three scenarios. The different levels for BECCS electricity continue in 2050 when BECCS hydrogen production then also varies similarly, depending on BioMin or BioMax.

Overall then, changes to the structure of emissions are limited in the short term but become significant in 2050 (Figure 9.4). In BioMin, the need for DAC is increased as less BECCS is possible for negative emissions. In BioMax, no DAC is necessary and negative emissions are even more substantial (165 $MtCO_2e$ instead of 125 as in NZ50), allowing for more remaining emissions from other sectors (which come primarily from transport). The picture is similar for 2060.

General observations:

- The role of biomass availability in net-zero pathways is concentrated in the transport sector and in BECCS electricity and hydrogen production, with a direct impact on the possibility of negative emissions.
- In the transport sector, increasing biomass availability does not have a uniform impact over all subsectors: passenger transport is mainly affected in the longer term, while rail, maritime, and off-road transport are affected only in the short term; merchandise transport is affected at all times.
- More biomass leads to more BECCS, reducing pressure for the use of DAC when approaching net-zero; the opposite is true for a future with less biomass available, highlighting the need for careful management of this resource.
- From a system's point of view, more biomass availability favours an increased use of biofuels in transport, which then requires more CCS obtained by using more biomass for BECCS electricity.

Figure 9.3 – Biomass consumption by application (NZ50 and alternative scenarios)

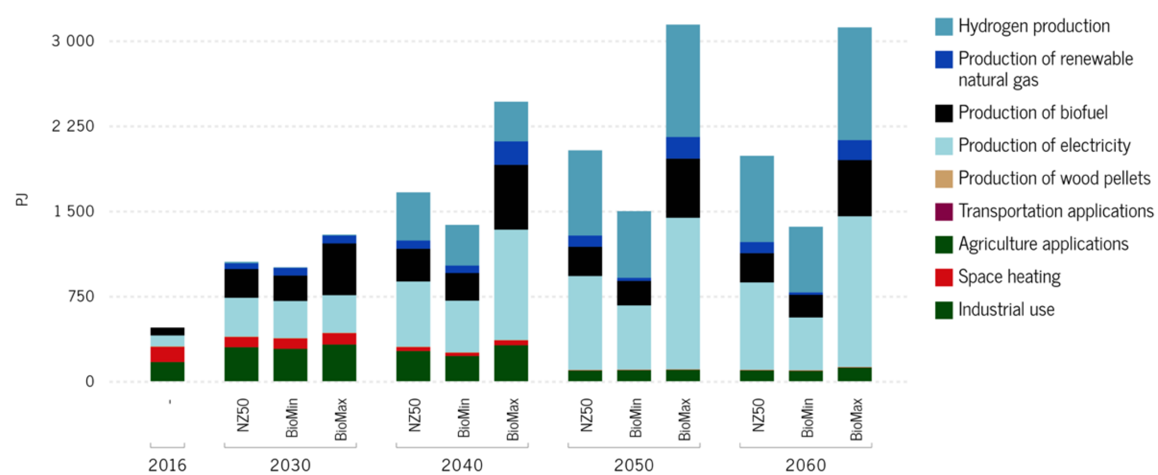
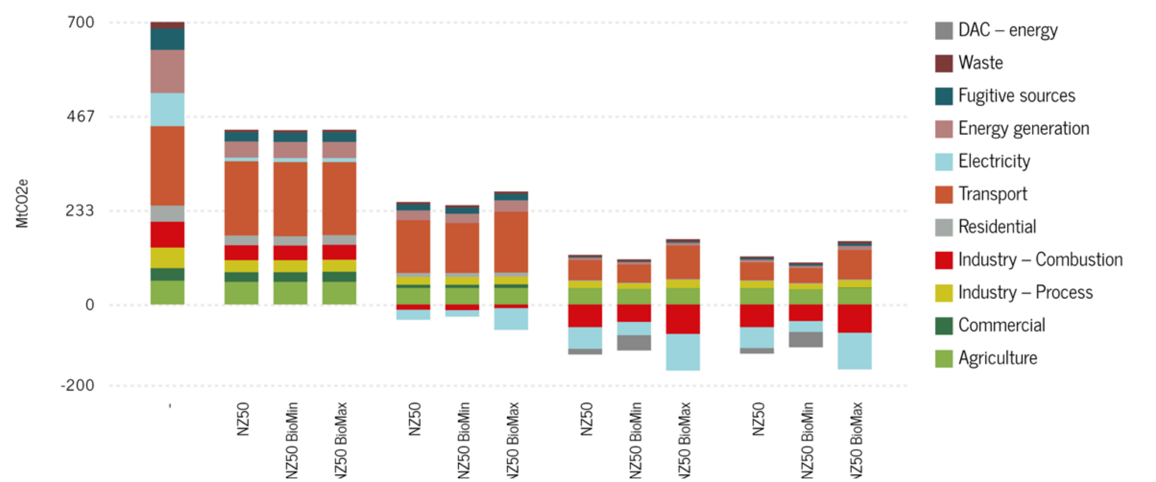


Figure 9.4 – Emissions by sector



Note: BECCS hydrogen production is included in industry-combustion on this chart

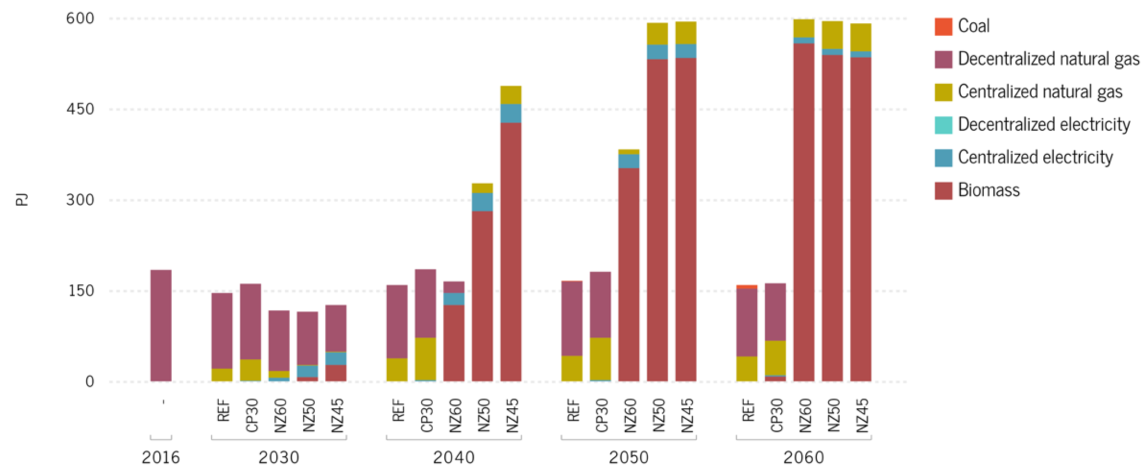
9.3 Hydrogen

9.3.1 Main applications and sources of production

Hydrogen use is limited across all net-zero scenarios, although this masks the replacement of hydrogen in the oil and gas production sector by uses elsewhere (see Chapter 6). Most of the new hydrogen use appears after 2040 in net-zero scenarios and is concentrated in industry and heavy-duty and rail transport.

The need for negative emission activities results in biomass gasification becoming the main source of hydrogen production, well ahead of electrolysis for example (Figure 9.5). Although natural gas reforming is virtually the only source of hydrogen today and remains the main source in the reference scenario, biomass takes off rapidly after 2030 to represent more than 90% of H_2 production in net-zero scenarios. This overall hydrogen production level is also much more substantial in these scenarios, almost four times what it is in REF and CP30.

Figure 9.5 – Main sources of hydrogen production



9.3.2 Sensitivity analysis

In these results, hydrogen remains marginal across the economy. Given that this vector is difficult to model with the major uncertainties that remain, and that hydrogen may provide advantages for a wide range of domain-specific applications, from long-term electricity storage to niche applications, a sensitivity analysis was performed to explore different variations of the NZ50 scenario in this respect. The two alternative scenarios are set out below:

- H2a: higher penetration of hydrogen in buildings (5% as a H_2-gas blend over the total), industry (30%) and transport (30%), as well as for synthetic fuel production (10% of all transportation fuels)
- H2b: higher penetration of hydrogen in buildings (5% as a H_2-gas blend over the total), industry (30%) and transport (30%) sectors, as well as for synthetic fuel production (10% of all transportation fuels), and with a minimum of 50% of hydrogen production derived from electrolysers

Both alternative scenarios impose a more significant penetration of hydrogen across sectors. However, while H2a does not constrain the source of hydrogen, H2b also forces electrolysis to become a dominant production method through large enough cost reductions (or any other driver).

As expected, the final consumption of hydrogen increases by similar amounts in both alternative scenarios compared to NZ50. For 2030, consumption quadruples over NZ50 levels, while in 2050 and 2060, levels are twice as high as NZ50 for both H2a and H2b.

In the building sector, a quadrupling of 2030 levels over NZ50 results in very small increases in absolute terms. These levels are also higher than in NZ50 in 2050 and 2060 for both H2a and H2b, although H2b presents lower levels than H2a. In industry consumption, H2a and H2b levels are similar across time and both are much higher than NZ50. The increase over NZ50 is around 200% for 2030, at from 3% to 10% of total energy consumption for the sector. For 2050, hydrogen consumption rises from 16% in NZ50 to 20% for H2a and H2B, a level that is similar in 2060 (from 17% to 20%).

The most significant changes occur in transport. Here again, H2a and H2b both present similar consumption levels across time, but the comparison with NZ50 yields very large increases. In 2030, where hydrogen is virtually inexistent in NZ50, levels in alternative scenarios reach over 170PJ, which is triple electricity's contribution for that year and almost 6% of total energy consumption. In 2050, hydrogen consumption in H2a and H2b is more than four times that of NZ50, at 22% of the total vs. 5%, similarly to 2060, as hydrogen consumption in the alternative scenarios approaches 600PJ or 24% of the total. Most of the increase for 2030 is for merchandise transport and synthetic aviation fuel, and to a lesser extent for hydrogen consumption in rail and maritime transport.

The increase in transport over the longer term is more substantial: synthetic fuels reach 40% of total consumption for aviation in 2050, while all transport subsectors see their use of hydrogen increase. In road transport as a whole, hydrogen fuels 40% of needs.

Hydrogen production explodes in 2030 compared with NZ50 (Figure 9.6). In H2a, less than half comes from biomass and the rest is mostly natural gas reforming, both with CCS. Electrolysis continues to be negligible for H2a over time and, while biomass increases, feedstock availability maintains the proportions of biomass and gas reforming up until 2060 at about 40% and 60% respectively .

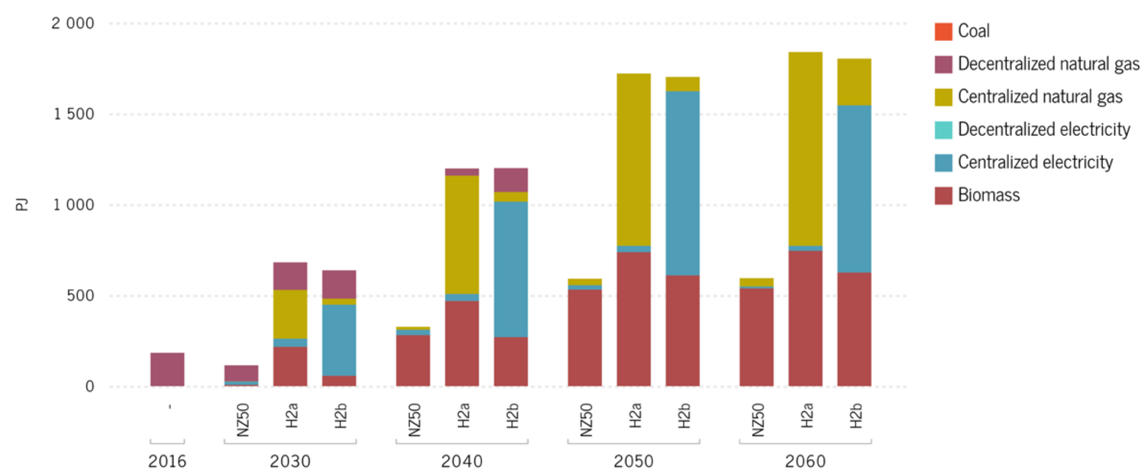
With a different pricing scenario for electrolysis, H2b results in this respect are completely different: while the total quantity produced is similar to that in H2a. As the consumption profiles discussed above would lead one to expect, electrolysis more or less replaces natural gas reforming's share (Figure 9.6). Accordingly, although hydrogen production increases by similar amounts in both alternative scenarios compared to NZ50, biomass availability prevents increases of BECCS hydrogen production much over NZ50 levels, resulting in almost all the rest being supplied either by natural gas reforming (H2a) or by electrolysis (H2b). This also implies that unless electrolysis costs are significantly brought down, natural gas reforming will remain cheaper and dominate hydrogen production in spite of emission-intensive gas reforming and the need for additional GHG sequestration.

Nevertheless, overall residual emissions (and, correspondingly, additional capture and sequestration efforts beyond CCS at the source for methane reforming) are lower in both alternative scenarios for 2050, at between 112 and 116 $MtCO_2e$ instead of NZ50's 125 $MtCO_2e$. Both scenarios resort to DAC in amounts similar to NZ50. Therefore, using more hydrogen throughout the economy does not result in more negative emissions from its production, which would allow more residual emissions from economic sectors: biomass availability prevents this development (see section 9.2). More hydrogen helps decarbonize efforts in applications where it is particularly difficult, as in some industrial and transport applications.

General observations:

- Increasing hydrogen penetration leads to increased use in most transport applications, as well as some industrial sectors.
- From a GHG emissions perspective, biomass availability (for BECCS production) and the cost of electrolysis will be determining factors in the emissions profile of hydrogen use, should this reach more substantial levels than NZ50 results suggest.

Figure 9.6 – Hydrogen production by source



9.4 Carbon capture

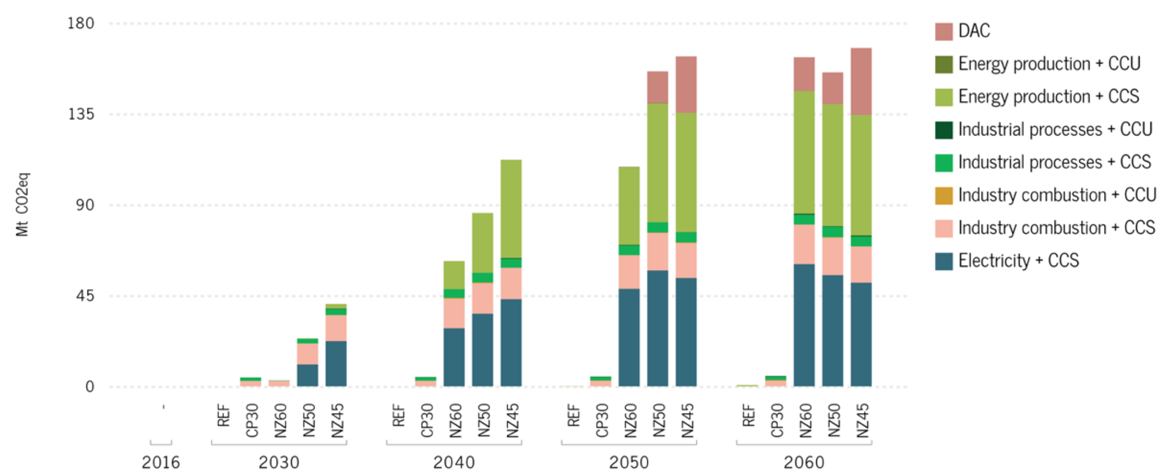
Achieving net-zero society-wide emissions is the result of both deep reductions across all sectors and the application of techniques to capture the equivalent of remaining emissions. The use of carbon capture in net-zero scenarios is largely unavoidable without reducing the provision of some services, mainly in agriculture and for industrial processes, as explained in Chapter 8.

Carbon capture can take different forms and be completed with various technologies and processes. A more detailed description of these technologies and processes is provided in Chapter 12. However, for the current discussion, three categories of applications are distinguished: the capture of emissions in industrial combustion and processes; capture in negative-emissions operations, which in the model means BECCS hydrogen production or electricity generation; and direct-air capture, which is meant to refer to the capture of emissions from the atmosphere with technologies other than natural processes like biomass photosynthesis. Each of these is addressed below.

While the total quantity of emissions captured in each scenario and at different points in time for each of the three categories varies according to the pace of emission reductions, all scenarios converge around the net-zero point between 155 and 167 $MtCO_2e$ captured (Figure 9.7). For capture in the industrial sector, the overwhelming share of captured emissions comes from combustion (around 77% for the sector), which highlights the difficulties of competitively transforming heat production with current technologies.

The importance of production facilities equipped with carbon capture varies across industrial sectors. Cement production makes up the largest share of the total, with 62% deriving from CCS-equipped plants by 2050 in NZ50. In contrast, only 30% of production from the pulp and paper sector comes from such plants and a similar share of chemical industries uses them. For the latter two industrial sectors, this means that, compared with cement, a much larger share of the emissions must be reduced through fuel switching.

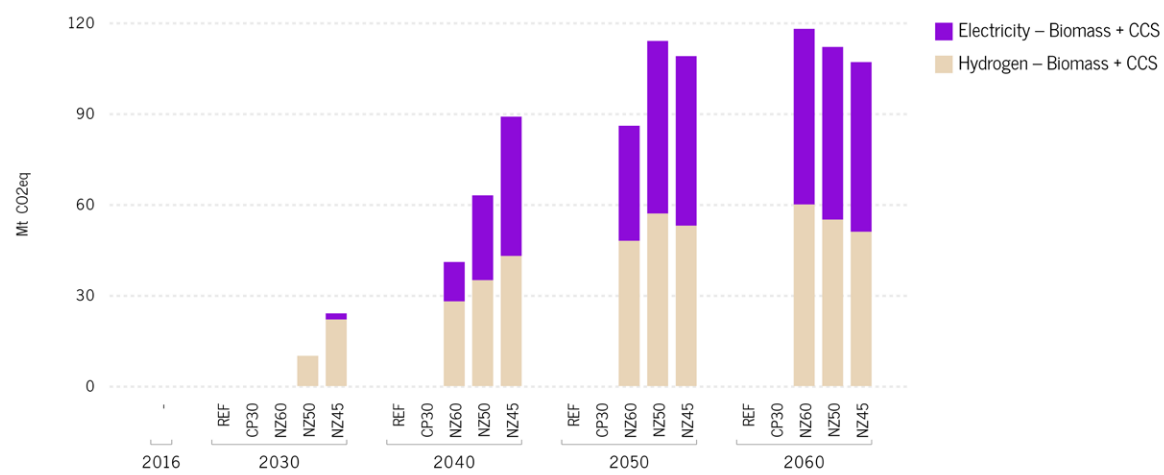
Figure 9.7 – Captured emissions



The next category of carbon capture application is bioenergy with carbon capture and storage (BECCS). More than 95% of capture in power and energy production comes from BECCS applications in electricity generation and hydrogen production (Figure 9.8), with the rest provided by natural gas powerplants with CCS installations. BECCS electricity generation already rapidly increases in NZ50 (11 $MtCO_2e$) and NZ45 (22 $MtCO_2e$) in 2030, but BECCS hydrogen production quickly catches up before constituting a roughly equal share by 2040 in these scenarios (around 57 $MtCO_2e$, similar to BECCS electricity). Part of this is the result of low hydrogen demand in the first decade due to the novelty of this vector, but once demand takes off, the possibility of achieving negative emissions makes it, along with BECCS electricity production, an important source to compensate remaining emissions elsewhere.

Therefore, although very little biomass is used for electricity production as a proportion of the total, significant negative emissions are obtained from biomass-fired plants with CCS. In fact, electricity production with carbon capture becomes the main use of biomass (827 TJ in NZ50 for 2050), a share roughly equal to that of the biomass used for hydrogen production (750 TJ), as noted in the previous sections.

Figure 9.8 – Bioenergy with carbon capture and storage (BECCS)



Finally, the results show that reaching net-zero requires direct-air capture. In reality, between 15 and 33 $MtCO_2e$ needs to be directly removed from the atmosphere to accommodate residual emissions in net-zero scenarios. While this is a small part of all emissions captured, the very limited experience with concrete DAC applications means that this result should be treated with care since considerable uncertainties remain given the cost of operating this technology. In fact, capture with DAC appears only near 2050 in the model, reflecting the associated high cost. It should be noted that for 2060, more DAC is used for NZ45 compared with NZ50, suggesting that technological innovation in carbon capture technology—for low-carbon technologies more generally—continues to evolve past the net-zero point, bringing more innovative solutions for emission control.

Figure 9.7 also shows that between storage and utilization in the industrial and energy production sectors, the main route for captured emissions (over 99%) is storage. DAC and BECCS electricity, shown on the chart, also result in a similar share of storage. On the one hand, this shows the limited reutilization potential of CO_2 in terms of cost, with storage being the cheaper option. On the other, it also illustrates the main constraint on reutilization, which more often than not results in the release of the captured emissions at some point downstream after the utilization of the captured CO_2.

General observations:

- The large quantity of carbon capture required to reach net-zero can be achieved in various ways and its use to capture industry emissions is uneven across sectors.
- DAC is essential in all net-zero scenarios, and the need to use it largely depends on the amount of residual emissions, as well as BECCS electricity generation and hydrogen production.

9.5 Takeaways

This Outlook analyses key technological pathways, mainly constrained by GHG emission targets. **By the nature of the exercise, these pathways are based on a large number of educated assumptions about the evolution of technologies and associated costs.** Yet over the last few years, many of the recent certainties about GHG emissions, including the role of nature-based solutions, have undergone massive re-evaluations. Similarly, technical developments have often been shown to be fickle: promising technologies fail to deliver on a large scale, while unexpected new approaches transform entire economic sectors. This chapter explores the impact of modifying some of these assumptions, which are by default built on what we know or expect, and the time to attempt to integrate some of these unexpected transformations in core energy transition issues.

Variable renewable electricity, provided by wind and solar generation, constitutes virtually all of the very significant increase in electricity generation needed to meet demand in the net-zero scenarios explored in this Outlook. Correctly modelling their integration is challenging and technical and economic uncertainties remain in relation to nuclear SMRs, utility-scale battery storage, and ancillary costs for grids with high levels of variable generation. Added to these are the uncertainties respecting social acceptability constraints on nuclear and large hydro development, as well as strategic considerations applicable to grid resilience and political orientation. Results from the sensitivity analysis show that **while total demand for electricity is not affected by the nature of the energy source, the evolution of these factors will affect the type of infrastructure needed**. For example, increased provincial exchanges of electricity provide an important way to reduce pressure on the grid in terms of the necessary capacity installed; similarly, less variable generation can be accommodated by more hydro and nuclear installations.

Biomass availability, which is the focus of much debate and many scientific studies, also turns out to be a major factor in shaping net-zero futures. **The sensitivity analysis conducted shows how useful bioenergy can be in efforts to reduce emissions, underlining how critical it is to very carefully manage this resource if its potential is to be tapped into.**

Uncertainties about the role that hydrogen will play in the future make it difficult to draw a bottom line today. Exploratory scenarios showed how hydrogen can play an increased role in different sectors without jeopardizing the achievement of net-zero emissions. However, negative emission production with BECCS remains constrained by biomass availability.

Finally, **with the current state of technologies, reaching and maintaining net-zero emissions will require significant amounts of carbon capture**. Here, both costs and technological uncertainties serve as an important warning that projections may be too optimistic, and that an even greater quantity of DAC and negative emissions energy production (which significantly is constrained by biomass availability) may be required to compensate for optimism on the share of emissions that can be captured in the various processes. This adds to the risks and current unknowns of continued large-scale storage. **While technological improvements may temper some of these risks over time, devoting at least as much effort to innovation in emission reductions as to capture seems essential.**

Naturally, the technological pathways discussed above do not exist in isolation: biomass availability not only increases the ability to deal with short-term reductions where technology remains expensive, but also results in the opportunity to produce more hydrogen with negative emissions, increasing its overall consumption. **More hydrogen helps decarbonize applications where electricity struggles and could provide an alternative in terms of storage.** The importance of social acceptability issues surrounding nuclear facilities and the construction of additional large-scale hydroelectric dams may also affect the prospects for a greater use of biomass. **Resolving these uncertainties will thus take time and strategic choices over which pathway(s) to focus on may be required before they are entirely eliminated.**

10 PROVINCIAL OVERVIEW

The Canadian provinces present a diversity of energy and GHG emissions profiles. This diversity is reflected in their economy, as well as in the cost and impact of achieving GHG reduction targets in each province. This chapter discusses key similarities and differences across provinces on the way to net-zero, highlighting variations in the challenges faced by each.

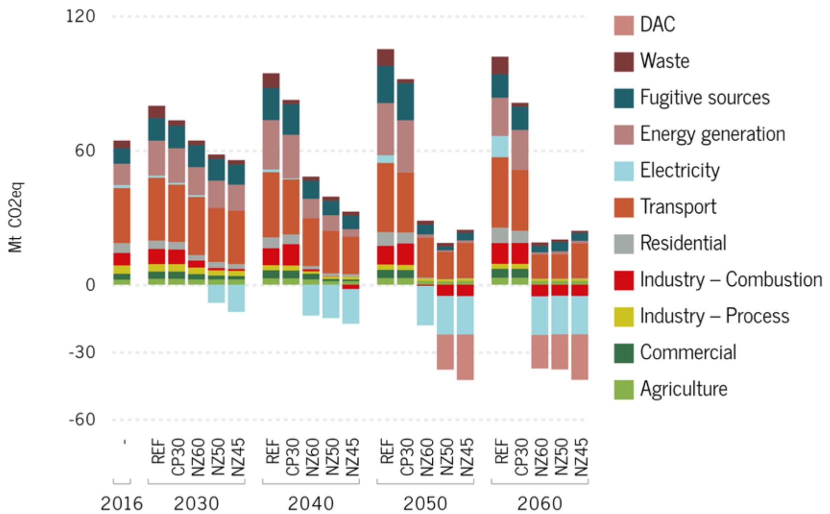
It is important to remember that in the modelling used in this Outlook, the GHG constraints are applied at the national level rather than by the provinces and territories in order to optimize total spending. Accordingly, some provinces and territories where decarbonization options are cheaper can move into net-negative emissions, while others can retain an overall higher fraction of their emissions.

HIGHLIGHTS

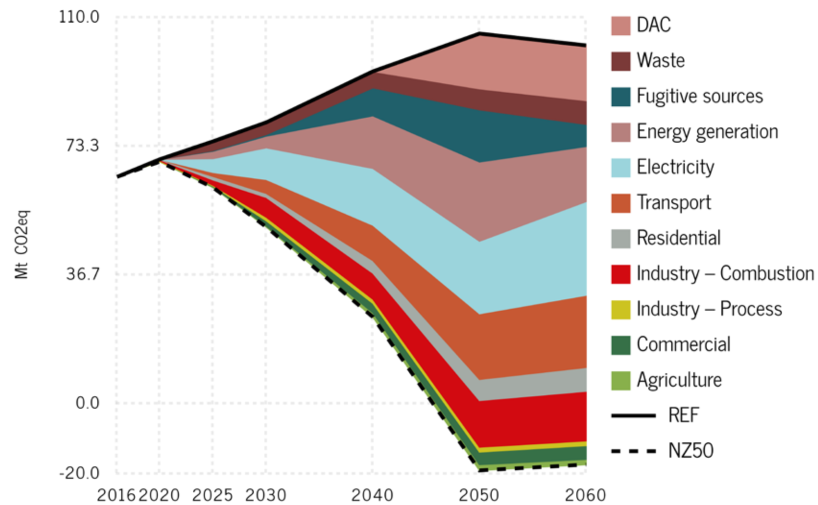
- Great provincial diversity in energy production and consumption leads to different challenges, for both the short and the longer term, in participating in the national effort to reach net-zero emissions at lowest cost. Some provinces end up with net positive emissions, while others find themselves in the opposite situation.
- Some specific applications, such as space heating in buildings, can be decarbonized early on across all provinces.
- Even though many solutions are local or remain in the hands of the provinces, transportation should be viewed from a national perspective.
- Provinces with a decarbonized electricity system and a small industrial sector must approach the costliest sectors (such as transport) early on; the opposite is true for provinces with emissions-intensive industries (such as oil and gas production) or carbon-intensive power generation since emissions reductions from these activities can all be achieved rapidly at relatively low cost.
- Provinces that currently have a highly emission-intensive electricity generation and little hydroelectric baseload generation face more significant grid infrastructure development challenges; a national plan to support cross-provincial interconnections would facilitate the required transformation of electricity generation, especially for these provinces.
- Because of the high cost of transporting biomass, the availability of feedstocks in each province plays a large role in determining whether the results include BECCS electricity and/or hydrogen production in a specific province—and, as a result, the quantity of negative emissions for the province.
- Using a national target allows taking advantage of some provinces' negative emissions to compensate for sectors more difficult to decarbonize in others.

10.1 British Columbia

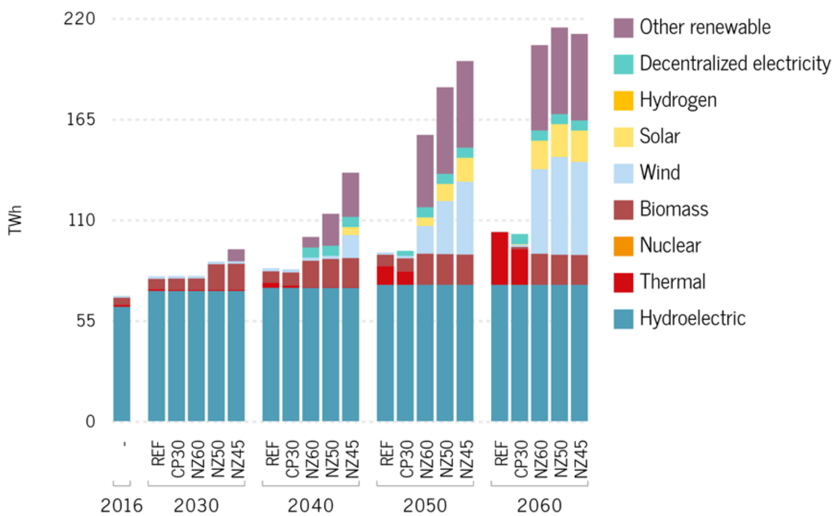
Figure 10.1 – British Columbia's energy profile



GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source

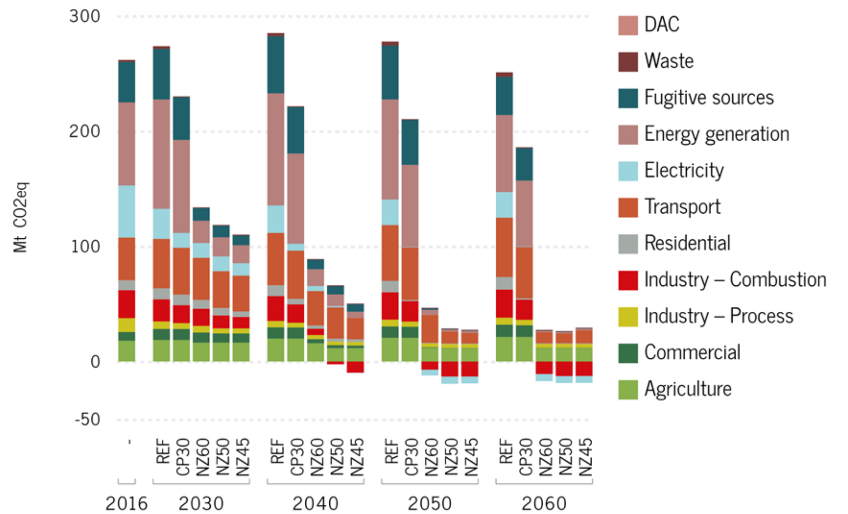
Biomass production by source

Key developments for British Columbia:

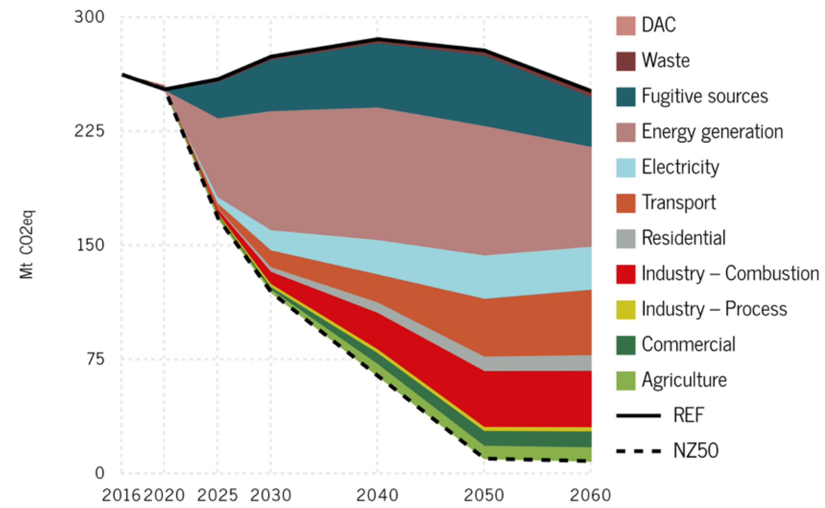
- The gas production sector puts significant pressure on GHG emissions. With the measures in place, emissions are projected to grow faster than the Canadian average: by 24% by 2030 and 63% by 2050, led by increases in gas production and transport.
- CP30 still means a continuous growth in emissions until 2050 (+43 %), but at a slightly slower rate than REF.
- Even net-zero scenarios decarbonize more slowly than the Canadian average on the short run: with reductions of 0% for NZ60, 22% for NZ50 and 32% for NZ45 by 2030. However, the rate picks up afterwards, as gas production drops and biomass-produced electricity with carbon capture and sequestration (BECCS) combine to produce a negative-emissions society by 2050 (-19 $MtCO_2e$) for NZ50.
- In net-zero scenarios, industrial combustion is the first sector to decarbonize throughout the 2020s (80% reduction in NZ50), followed by energy production and fugitive emissions after 2030.
- Residential and commercial buildings have mainly eliminated emissions by 2040; transport, however, takes longer and is limited to a reduction of a little over 50% by 2050.
- By 2050 or 2060, all net-zero scenarios result in more negative emissions than necessary to compensate for the province's remaining emissions: at that point, BC is therefore net negative in terms of GHG emissions.
- Electricity expands significantly more than the Canadian average for NZ scenarios. By 2030, it is expected to have grown by 16% to 37% for NZ60 to NZ45, and to be multiplied by 3 for all NZ scenarios by 2060.
- Electricity expands first through biomass, which allows the province to generate negative emissions through BECCS electricity production as early as the 2020s; BECCS hydrogen production starts from 2040; and a smaller share of BECCS is observed in industry after 2040 as well; a large quantity of DAC is also used from 2050 in net-zero scenarios, almost doubling BECCS negative emissions in NZ50 and NZ45.
- Wind energy appears later than in other provinces, amounting only to about half of new generation at or after the net-zero point; while there is some solar, most of the other half of new generation comes from geothermal (shown on the chart in the "other renewables" category.
- Electricity deliveries to Alberta increase five-fold in net-zero scenarios, while remaining much less than 10% of total generation for British Columbia
- Over time, biomass production comes overwhelmingly from forest residues (which doubles by 2030). Organic waste adds to this production later on (primarily from the 2040s), helping to generate a considerable amount of BECCS electricity, some BECCS hydrogen, very little biofuels, and biogas from the 2040s.

10.2 Alberta

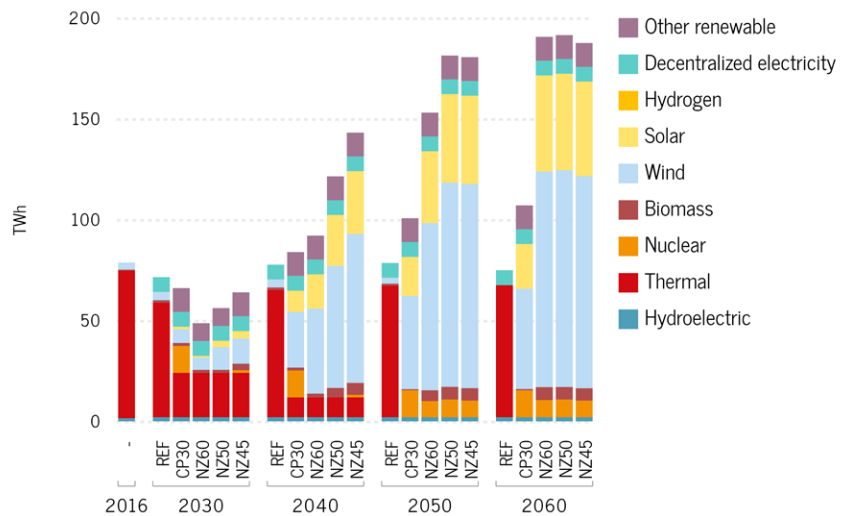
Figure 10.2 – Alberta's energy profile



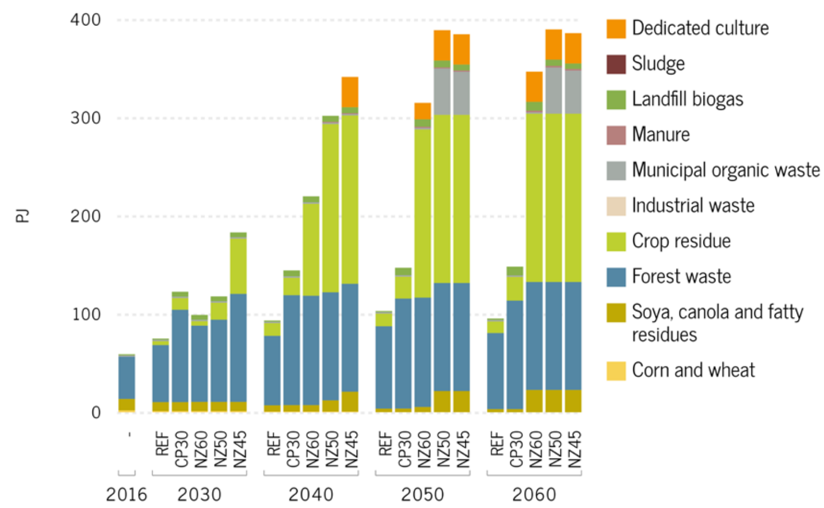
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



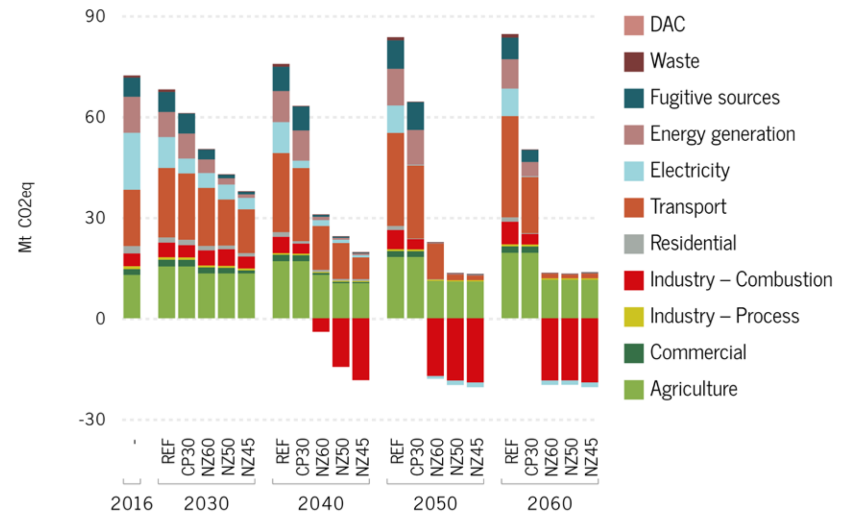
Biomass production by source

Key developments for Alberta:

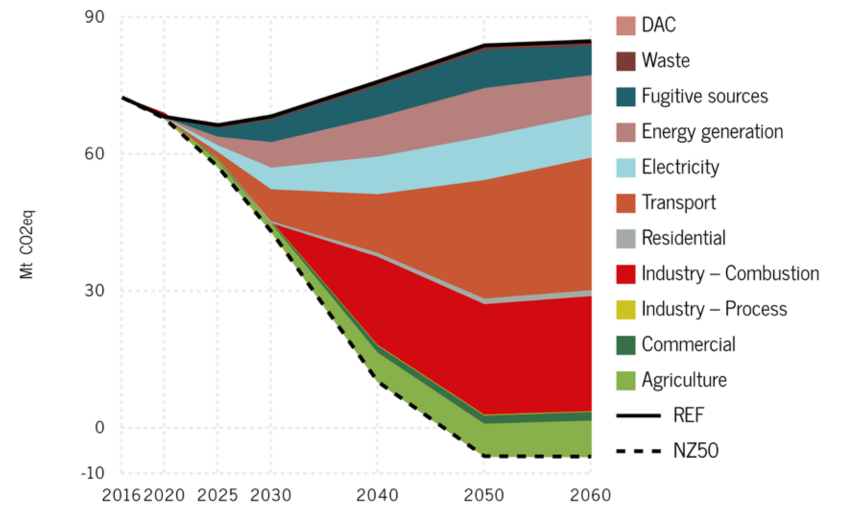
- With measures in place (REF), emissions are largely stable until 2060, peaking at +10 % in 2040. This is made possible by compensating the growth associated with oil and gas production with significant reductions in emissions from electricity production and industrial processes.
- The impact of the carbon tax (CP30) leads at first to a 12% reduction in GHGs by 2030, which slowly reaches 20% by 2060, on par with the national average.
- NZ scenarios see a rapid and significant decrease in oil and gas production, which provides a more rapid reduction in emissions (reductions of 48%, 55% and 58% for NZ60, NZ50 and NZ45, in 2030) than the Canadian average, although they do not quite reach zero by 2060, leaving 4% of 2016 emissions. Most other sectors all decarbonize slowly and at the national pace (see Chapter 7 for a discussion of the evolution of oil and gas production).
- Industry (outside of fossil fuels production) is decarbonized by 2040, while transport and agriculture also decrease by 2040, very significantly in the case of NZ45.
- Residential and commercial buildings have mainly eliminated emissions by 2040.
- The possibilities of using BECCS for negative emissions are much more limited in Alberta than in British Columbia: negative emissions appear in 2040 in NZ45 only, and then later for NZ50 and NZ60.
- Most of these come from BECCS used in industry, together with a small part from BECCS energy production; no DAC is used, and the province is net positive in terms of remaining emissions in 2050 and 2060.
- While electricity drops on the short term, in NZ scenarios, due to demand reduction from the oil and gas sector, its growth after 2030 follows the national average. By 2060, electricity production is 2.4 times greater than 2016 for the three NZ scenarios.
- Since Alberta has the most emission-intensive electricity production, the challenge of decarbonizing electricity is quite different from that in most other provinces: it is not sufficient to add low-carbon production, it is also necessary to transform the one in place. While decarbonizing this sector takes time, a good portion is achieved by 2030 and even more by 2040, chiefly through a significant expansion of wind, which represents up to 56% of all generation by 2050, and to a lesser extent solar and geothermal.
- After 2040, nuclear begins to replace a small fraction of base-load generation from natural gas powerplants (5% in 2050 and 2060), while wind continues to expand.
- Electricity receipts from other provinces, here virtually all from British Columbia, increase five-fold in net-zero scenarios, contributing the equivalent of around 6% of total generation.
- Biomass production expands significantly—more than six-fold in net-zero scenarios on the long term. The tighter the net-zero schedule, the faster the pace of this expansion, tripling in NZ45 by 2030. While forest residues increase, most of the expansion comes from agricultural residues (which overtake forest residues as the main source slightly after 2030) and organic waste adds to this production later on (chiefly from the 2040s), as is the case in British Columbia: this helps generate some BECCS hydrogen and electricity (more than half of the total), biofuels and biogas from the 2040s.

10.3 Saskatchewan

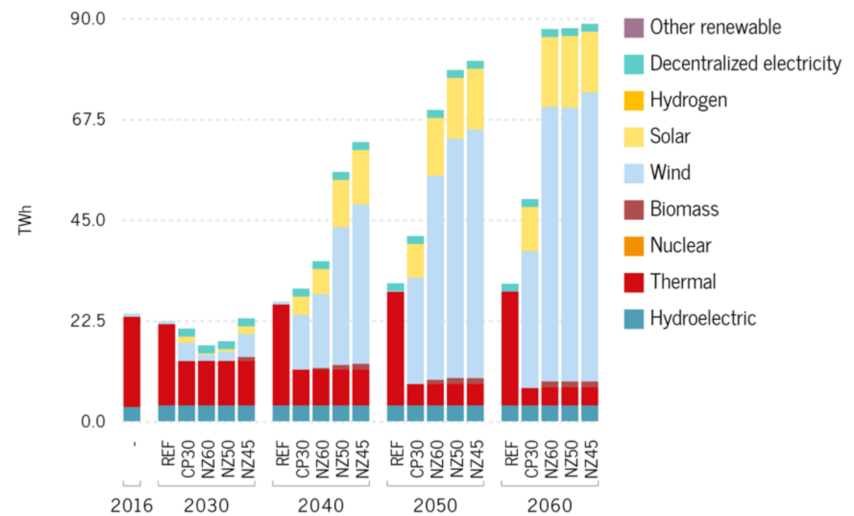
Figure 10.3 – Saskatchewan's energy profile



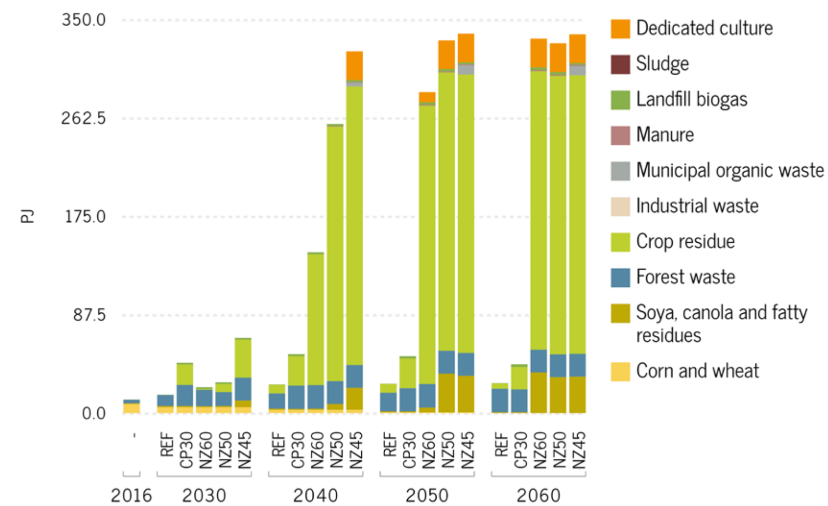
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



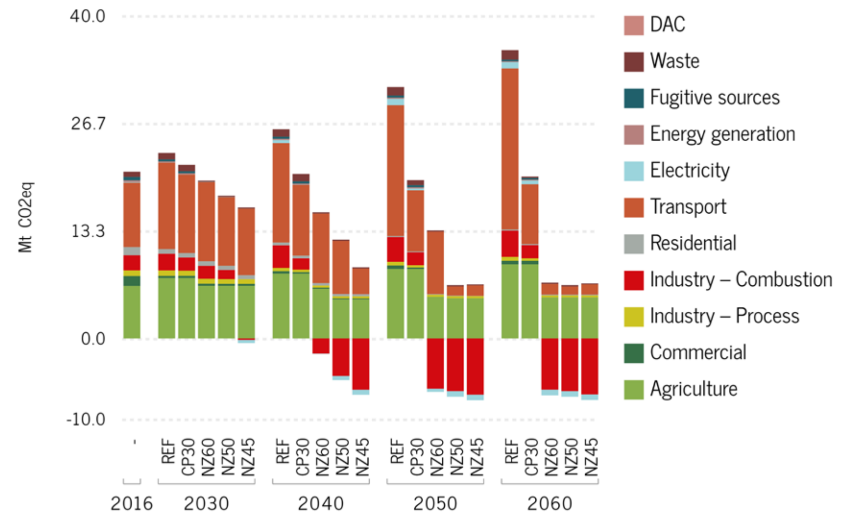
Biomass production by source

Key developments for Saskatchewan:

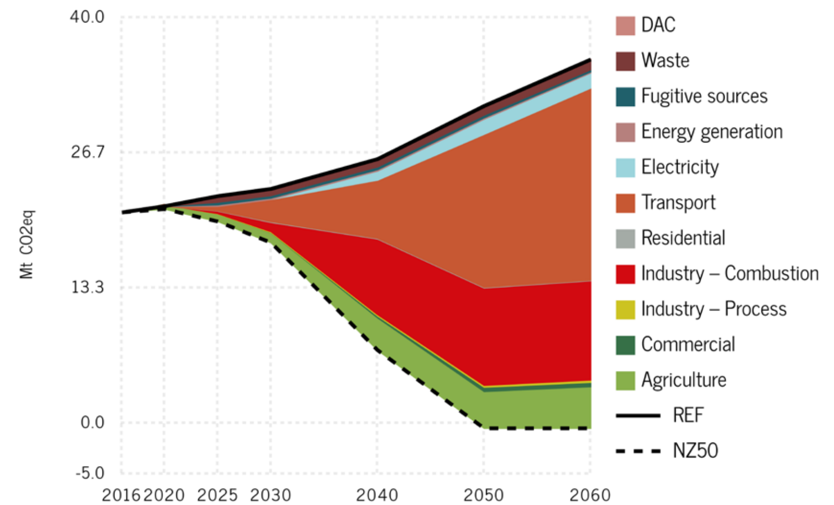
- In REF, emissions are projected to slowly rise by 16% in 2050-2060, after a small dip of 6% in 2030 associated with the transformation of electricity production.
- CP30 brings a slightly deeper GHG reduction by 2030 (16%); emissions then remain at the same level until 2050, after which they drop further, representing 70% of the 2016 level. Over that time, reductions in electricity production and building heating are compensated by growth in transport and fugitive emissions.
- With a rapid transformation of electricity production and the reduction in oil and gas production, NZ scenarios show deeper GHG reductions than the Canadian average: 50%, 57% and 62% for NZ60, NZ50 and NZ45 in 2030, reaching negative value (-7 $MtCO_2e$ through capture) by 2060. Most other sectors decarbonize slowly and at a largely comparable pace.
- Industry (outside of energy production) is decarbonized after 2030 and, with CCS, becomes a net absorber of emissions, capturing and sequestering up to 19 $MtCO_2e$ for NZ50 and NZ45 in 2050. Transport sees rapid reductions even before 2030 and is almost completely decarbonized by 2050, contrary to the national average.
- Once NZ is reached, agriculture is the source of the overwhelming majority of remaining emissions in Saskatchewan, with only modest reductions from 2016 levels and around 40% lower emissions in 2050 and 2060 in net-zero scenarios, compared with REF.
- In Saskatchewan, there is no DAC and very limited BECCS electricity production, but the very large increase in biomass use from agricultural residues allows for a significant BECCS production of hydrogen, along with some biofuels. The resulting negative emissions are significant enough to overcompensate remaining emissions from agriculture as the province is net negative in GHG emissions after net-zero is reached.
- Like Alberta, Saskatchewan has one of the most emission-intensive electricity generation profiles, a challenge that is quite different from that in most other provinces. While decarbonizing this sector takes time, a good portion is achieved by 2030 and even more by 2040, primarily through the significant expansion of wind, which represents up to 70% of all electricity generated by 2060, and to a lesser extent solar. Some thermal powerplants remain even in 2060 and electricity trade remains marginal, with the province's power mix able to meet demand within the province.
- Saskatchewan's biomass production comprises little forest residues compared with other provinces. The significant expansion from the 2020s—but especially after 2030—comes from the maximization of crop residues from agriculture. Compared with its western neighbours, these residues contribute to the production of biofuels and, to a much larger extent, hydrogen production, with virtually no biogas from municipal waste.

10.4 Manitoba

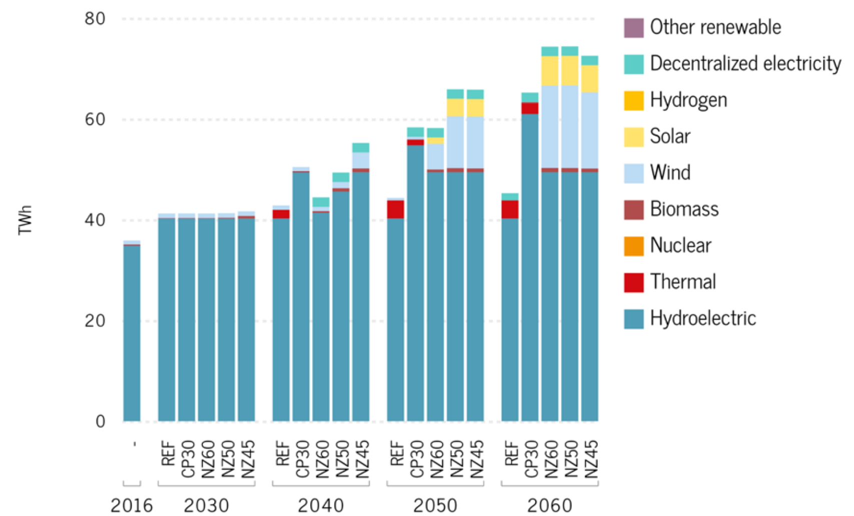
Figure 10.4 – Manitoba's energy profile



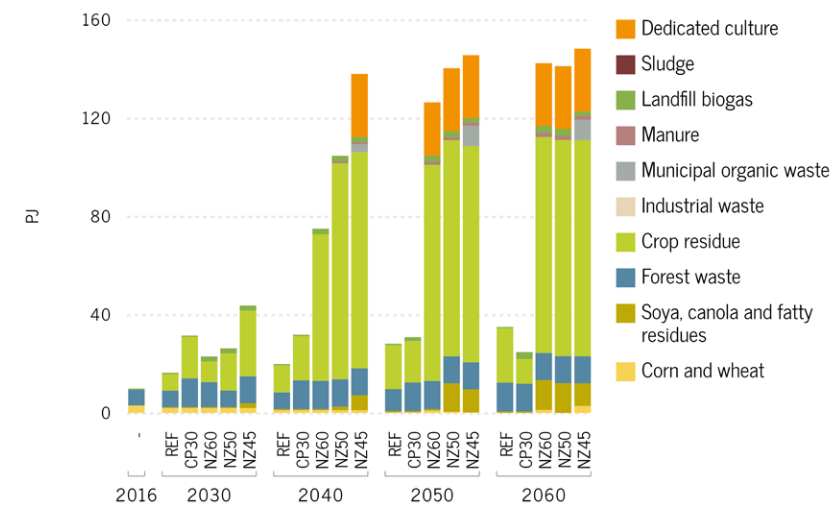
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



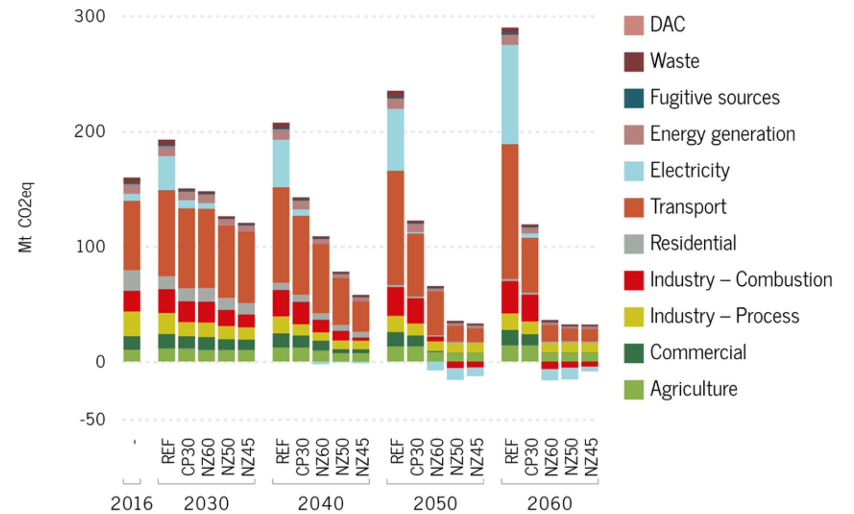
Biomass production by source

Key developments for Manitoba:

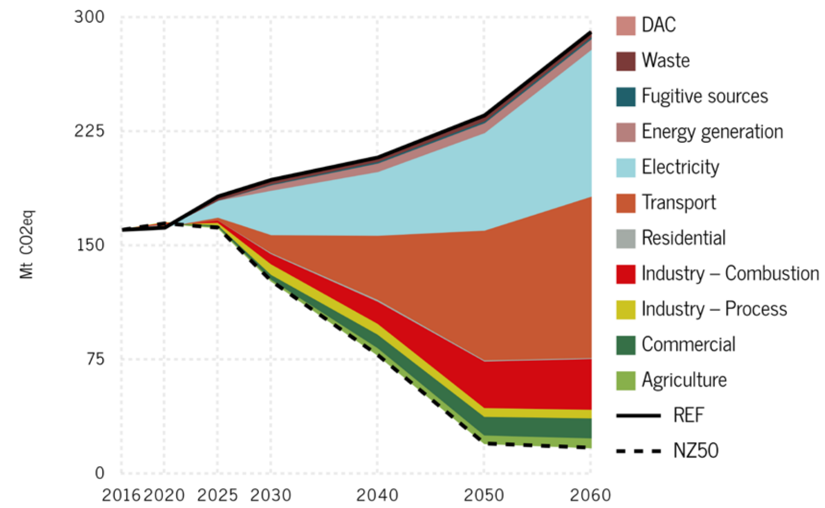
- Following current trends (REF), emissions are projected to grow by 72% by 2060, three times more than the national average (+25%), largely due to agriculture and transport.
- Within CP30, emissions are essentially constant over the next 40 years, with growth in agriculture compensated by reductions in building heating, even though this sector accounts for only 11% of emissions today.
- NZ scenarios lead to relatively slow reductions. By 2030, they range from 5% (NZ60) to 14% (NZ50) and 24% (NZ45). The transformation then accelerates and by 2050 both NZ50 and NZ45 show an overall small negative emission balance (about 1 $MtCO_2e$). Very little comes from BECCS electricity production and BECCS hydrogen production is instead the main source; no DAC is used, and the province is net negative in terms of remaining emissions in 2050 and 2060.
- Transport provides the majority of emission reductions, starting mainly after 2030. As in Saskatchewan, this results in very low emissions from this sector compared to REF (in 2060, they are around 95% less than REF in net-zero scenarios).
- Most of the remaining cuts in emissions derive from industry, while residential and commercial buildings are almost completely decarbonized by 2030.
- Electricity production is largely stable over the next decade and then grows continuously by about 100% by 2060, slightly below the national average. Manitoba's electricity sector is already decarbonized, using hydroelectricity to meet the overwhelming majority of its needs. Over time, in net-zero scenarios, some of the expansion comes from wind after 2030, as in most other provinces, but over 40% of the expansion is provided by additional hydroelectric capacity.
- This additional capacity, as well as a move away from electricity exports to the United States, helps the province deliver around 10% of its electricity production to other provinces after 2040.
- Biomass production follows a pattern similar to Saskatchewan's, with little forest residues compared with other provinces; the significant expansion from the 2020s—but especially after 2030—is due to the maximization of crop residues from agriculture. This goes to biofuels production and, to a much larger extent, hydrogen production, while some biogas from municipal waste is produced in NZ45.

10.5 Ontario

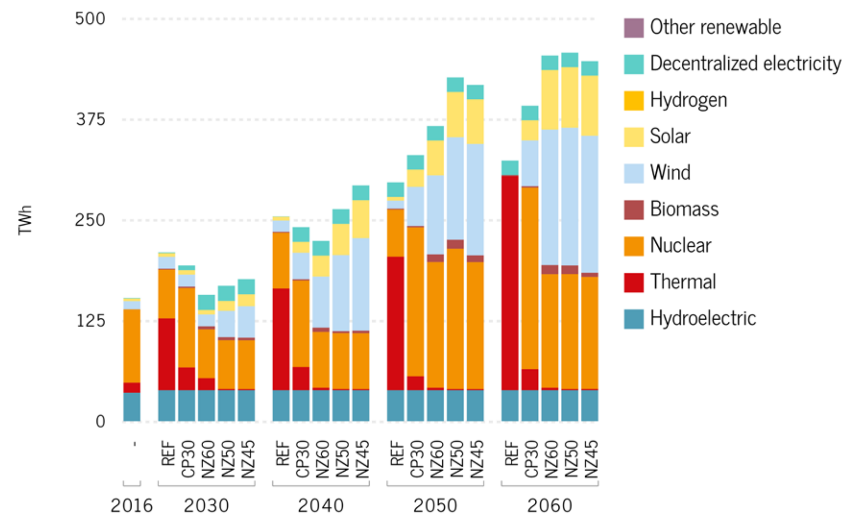
Figure 10.5 – Ontario's energy profile



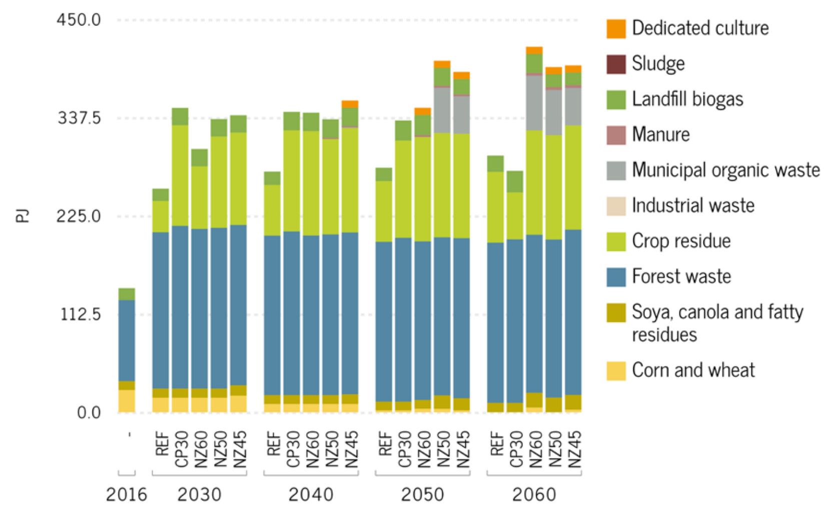
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



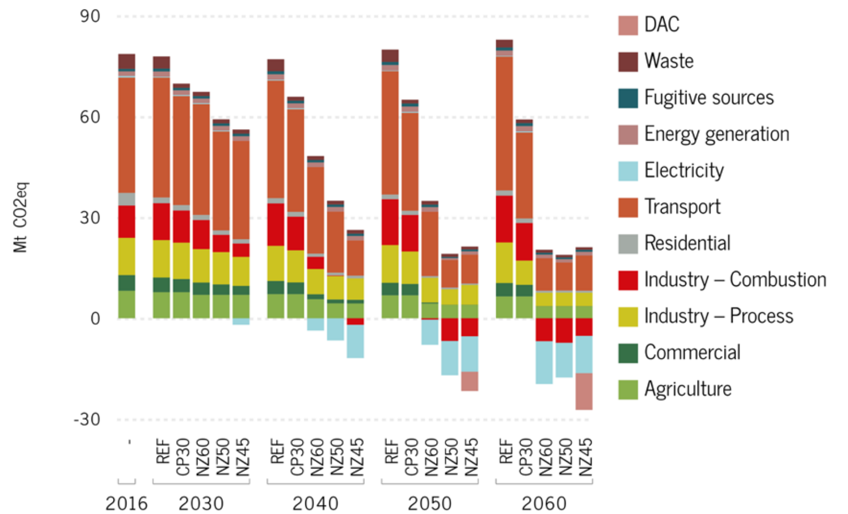
Biomass production by source

Key developments for Ontario:

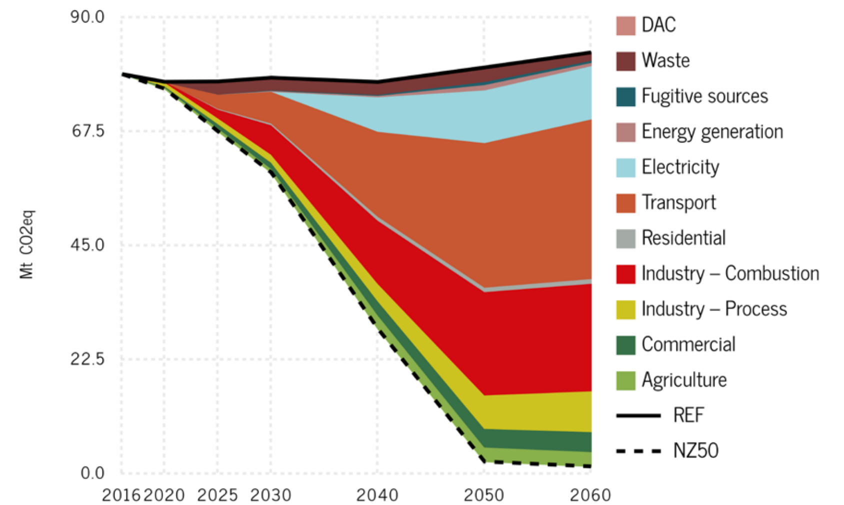
- Emissions in the REF scenario climb by 90% in 2060, much more than the Canadian average, driven mainly by transport and electricity production.
- The impact of carbon pricing is significant, especially as it leads to a substantial decarbonization of electricity, even though gas thermal increases in absolute value and notable reductions occur in transport. However, overall, CP30 leads to a 6% reduction with respect to 2016 by 2030 and 23% by 2050.
- More than CP30, net-zero scenarios move significantly away from REF right from the start, almost eliminating natural gas electricity production by 2030, whereas it expands seven-fold in REF.
- Electricity production also increases faster than the national average in NZ scenarios over all timeframes: by 3%, 10% to 15% in 2030 for NZ60, NZ50 and NZ45, reaching a factor of three in 2060. A small quantity is imported from other provinces, while exports move away from US markets to neighbouring provinces.
- Transport takes more time to decarbonize, only showing significant reductions starting in the 2030s. However, by 2050 and 2060 these reductions amount to 75%-85% compared with current levels, resulting in levels more than 90% lower than REF in 2060.
- Although process emissions decrease rapidly by 2030 (by 43% in CP30 to 50% in NZ45), industry begins reducing its combustion emissions only after 2030. Eventually, the sector moves into negative emissions territory in 2050 (-5 to -7 $MtCO_2e$ for the most aggressive scenarios). While some of these reductions come from BECCS electricity and hydrogen production, these levels of negative emissions remain small compared with remaining emissions, and the province has net positive emissions in 2050 and 2060 in net-zero scenarios. This is a result of the particular industrial profile and the size of the sector for the province, including significant process emissions (+16 to 23 $MtCO_2e$, depending on the scenario). Interestingly, NZ45 results in fewer negative emissions (mainly related to BECCS electricity generation) than NZ50 and NZ60.
- Ontario's electricity sector has a unique profile among the provinces due to its current large quantity of nuclear production; while this production decreases in both REF and net-zero scenarios, it increases again from the late 2030s in net-zero scenarios owing to the introduction of SMRs. CP30 is interesting in this respect and differs from all other scenarios: the carbon pricing and lowering of the hurdle rates are sufficient to keep existing generation running and SMR production is added from 2040, while wind and solar expansion follow the national pattern.
- Biomass production almost doubles in REF by 2040 and the increase is even more substantial in other scenarios. Although significant in absolute terms, these increases are smaller than in other provinces in relative terms. Forest residues increase from their current dominant share similarly in all five scenarios, while the rest of the expansion derives from crop residues and municipal waste from the late 2040s. In the short term, this primarily goes to biofuels production and industrial use in net-zero scenarios, while electricity production also appears before 2030. However, later on the profile of net-zero scenarios diverges from REF and CP30: after 2040, both biofuels production and industrial use shrink in net-zero scenarios, while electricity and hydrogen production expand to help with negative emissions.

10.6 Quebec

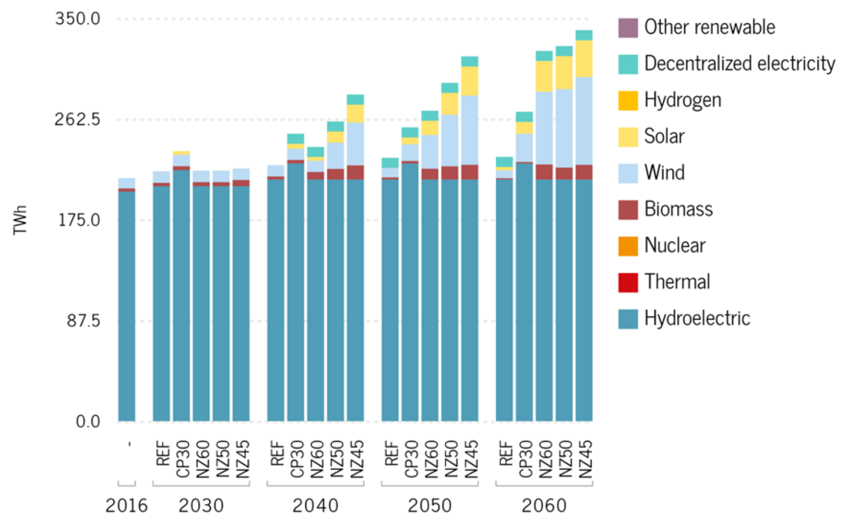
Figure 10.6 – Quebec's energy profile



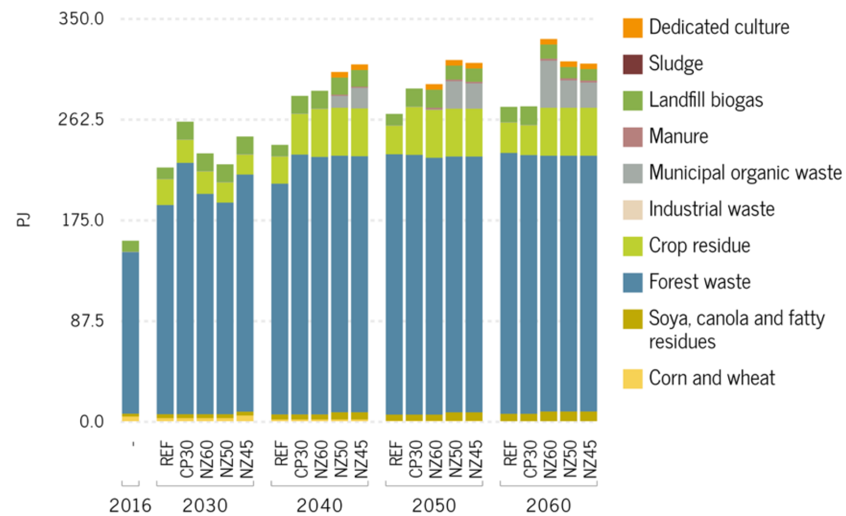
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



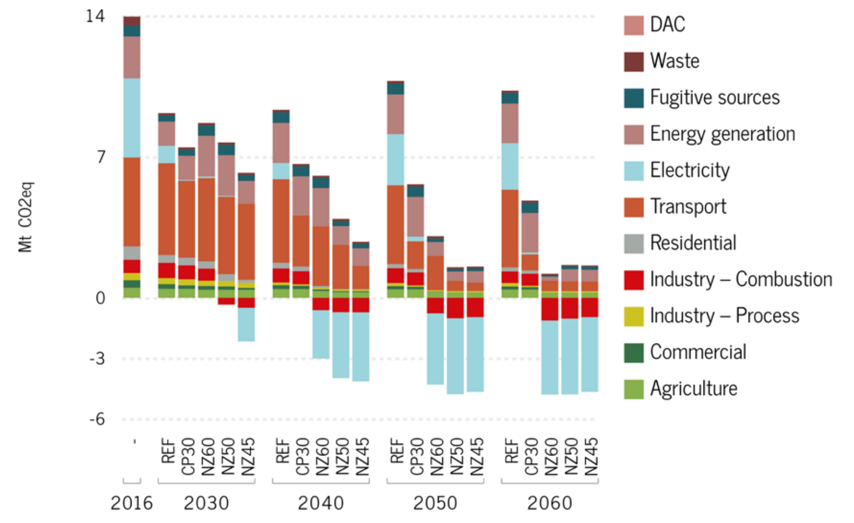
Biomass production by source

Key developments for Quebec:

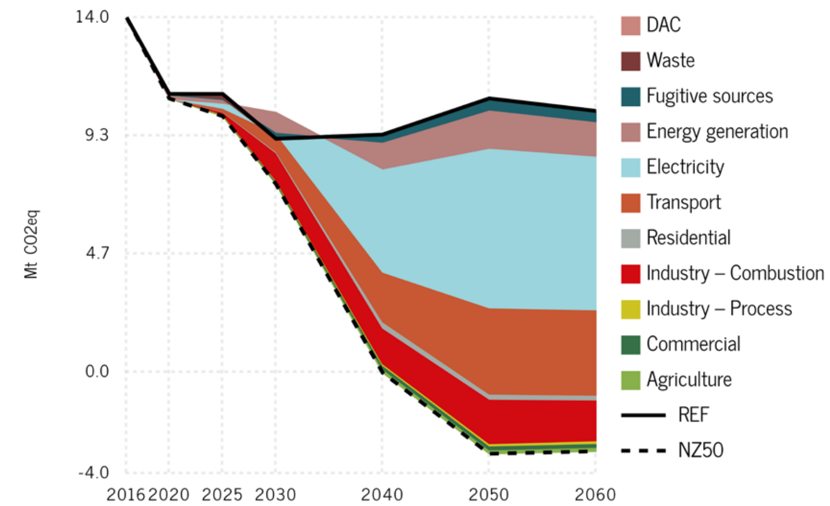
- Emissions in the REF scenario grow by 5% by 2060, well below the national average (+25%); growth in transport and industrial combustion are compensated by reductions in agriculture and building heating.
- CP30 shows a clear but limited departure from REF with emissions dropping by 11% in 2030, followed by a slow reduction to represent 75% of 2016 emissions in 2060. Over the entire period, the largest impact of carbon pricing is on waste and transport emissions.
- More than half of Quebec's emissions are produced by transport at the present time, with a power sector already completely decarbonized and virtually no production of fossil fuels. As a result, in NZ scenarios, early reductions come from the industrial sector (including from aluminum smelting) and transport, although reductions in the latter are more substantial after 2030.
- Some negative emissions are noted as soon as 2030 from electricity production in NZ45, and in all net-zero scenarios from the 2030s. When nearing their respective time point for net-zero emissions, NZ50 and NZ60 both show negative emissions, more or less breaking even with remaining emissions (mainly from transport and agriculture), while NZ45 uses DAC on the longer-term allowing it to make the province net negative in terms of emissions from the late 2050s.
- Quebec's electricity sector does not build more hydroelectric facilities, but wind and solar energy expand from 2040, along with some biomass, allowing the province's sector to attain negative emissions in the 2030s (even before, in the case of NZ45). Overall expansion in relative terms is smaller than in other provinces, reaching 40% at most in NZ45 in 2060 compared with today. It is also worth noting that production in REF remains constant over the entire time period.
- Meeting increasing electricity demand with a smaller expansion of the province's generation is managed through a different trade profile. Electricity receipts from other provinces increase by 50% in net-zero scenarios, much less than in REF (+143% compared with today). Moreover, exports to both other provinces and the United States diminish over time. The net result is fewer net exports to help meet peak demand over time without having to resort to additional production.
- Biomass production almost doubles in REF by 2040, while the increase is even more substantial in other scenarios. Although significant in absolute terms, these increases are smaller than in other provinces in relative terms, as is the case in Ontario. Forest residues similarly increase from their current dominant share in all five scenarios, while the rest of the expansion comes from crop residues and municipal waste from the late 2040s. However, the use of this production is somewhat different than in Ontario, with a smaller quantity going to biofuels production in the short term, but with an increase in industrial use in net-zero scenarios, similarly to Ontario. BECCS electricity production appears early (before 2030 in NZ45). Later on, net-zero scenarios present a profile that diverges away from REF and CP30: after 2040, both biofuels production and industrial use shrink in net-zero scenarios, while electricity and hydrogen production expand to help with negative emissions. Depending on the NZ scenario, Québec emissions by 2060 drop from neutral (+1 MtCO_2e) in NZ60 and NZ50 to slightly negative (-5 MtCO_2e) for NZ45.

10.7 New Brunswick

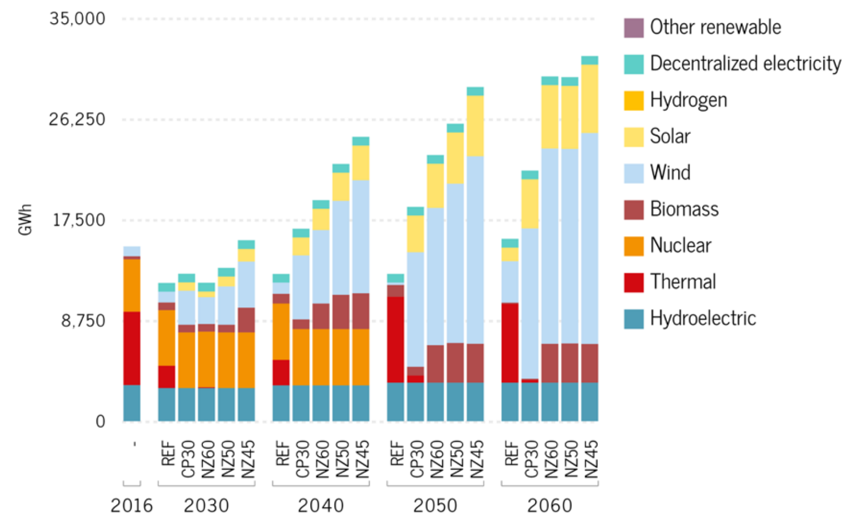
Figure 10.7 – New Brunswick's energy profile



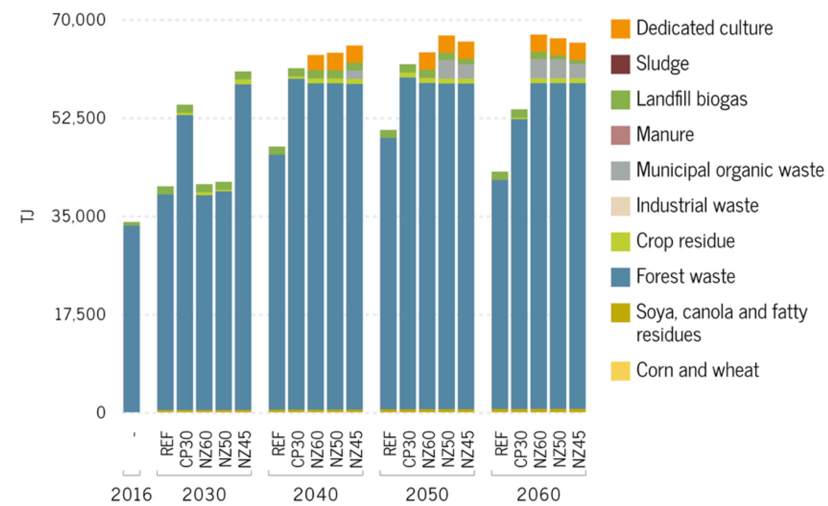
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



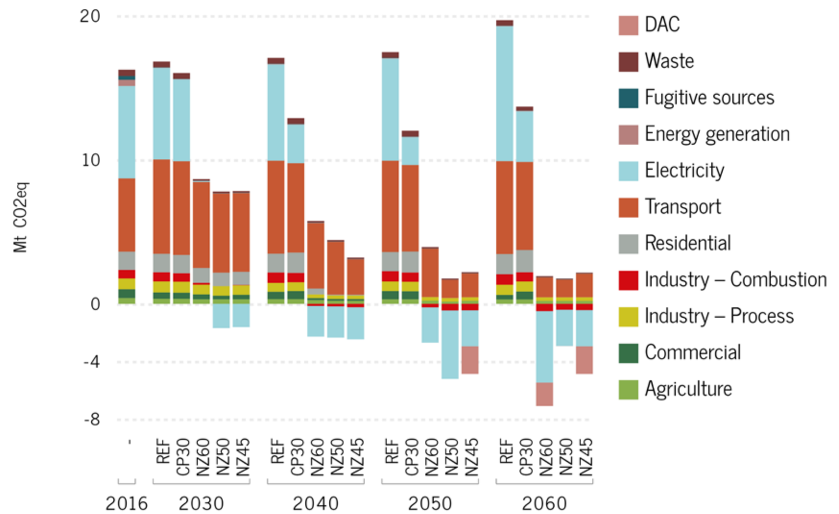
Biomass production by source

Key developments for New Brunswick:

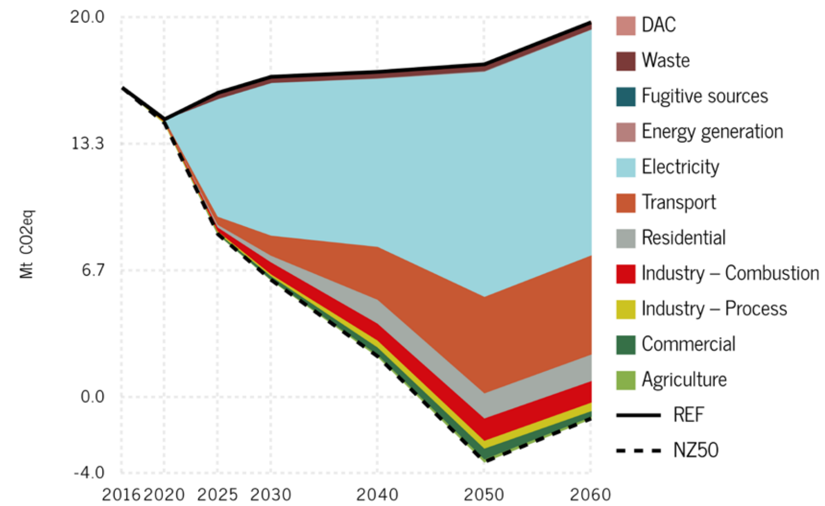
- In the REF scenario, emissions decrease from 2016, largely due to the transformation of electricity production. After a minimum in 2030 (-34% with respect to 2016), emissions increase by about 10% over the next 30 years. This substantial decline affects NZ scenarios for 2030 as the target is reached without much additional effort.
- For 2030, CP30 therefore shows a faster reduction in emissions than NZ60 and NZ50, at -46% with respect to 2016, reaching a reduction of 65% by 2060.
- Following a reduction in electricity production associated with the closure of a thermal plant after 2016, CP30 and NZ scenarios project a doubling of production by 2060, which is slightly below the national average.
- No nuclear SMRs appear in order to replace conventional nuclear generation, which is eliminated from 2040. Expansion thus comes from wind and solar, as well as some biomass used for BECCS generation.
- The results for New Brunswick are an intensified version of some trends observed across the provinces: while power production is responsible for 29% of the province's emissions today, it is almost all decarbonized in net-zero scenarios as well as CP30 by 2030, even contributing negative emissions in NZ45. This continues to evolve away from REF after 2030, holding steady in CP30 and with negative emissions in all net-zero scenarios from the 2030s. This trend helps make the province net negative (as early as 2040 in NZ45) by a significant margin, with almost 5 $MtCO_2e$ negative emissions and less than 2 $MtCO_2e$ remaining in NZs in 2060.
- Most of the transport decarbonization occurs from 2035, while emissions tied to oil and gas production remain significant due to the presence of the very large refining operations at the Irving facility (the largest in Canada); net-zero scenarios require a reduction in these activities.
- Some BECCS hydrogen production results in negative emissions, although in much smaller quantities than BECCS electricity generation.
- Biomass production almost doubles in net-zero scenarios and CP30 by 2040, a more sizeable increase than in REF, almost all from forest residues.

10.8 Nova Scotia

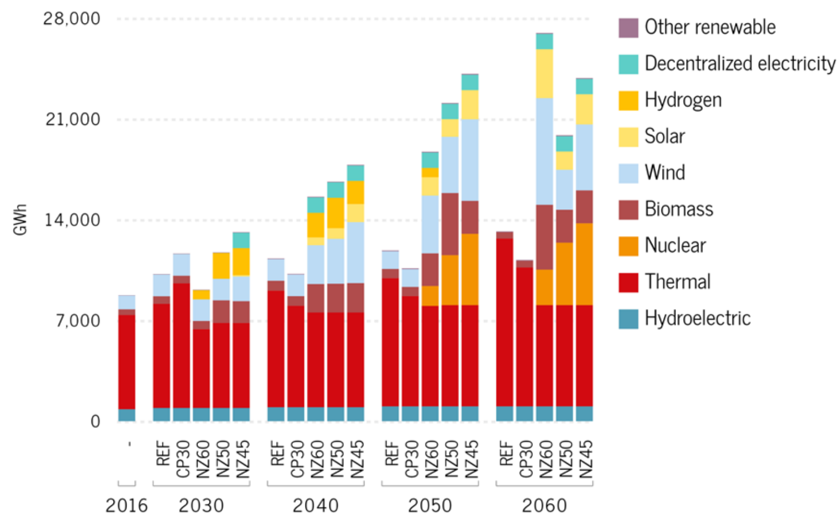
Figure 10.8 – Nova Scotia's energy profile



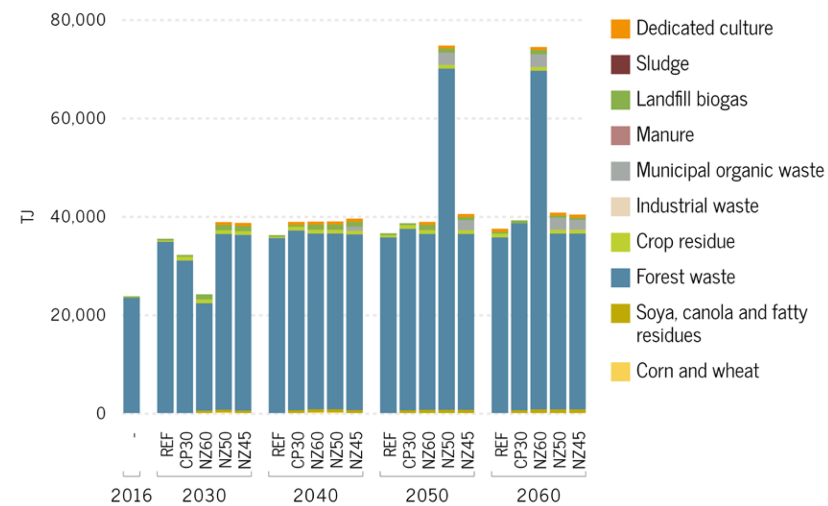
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



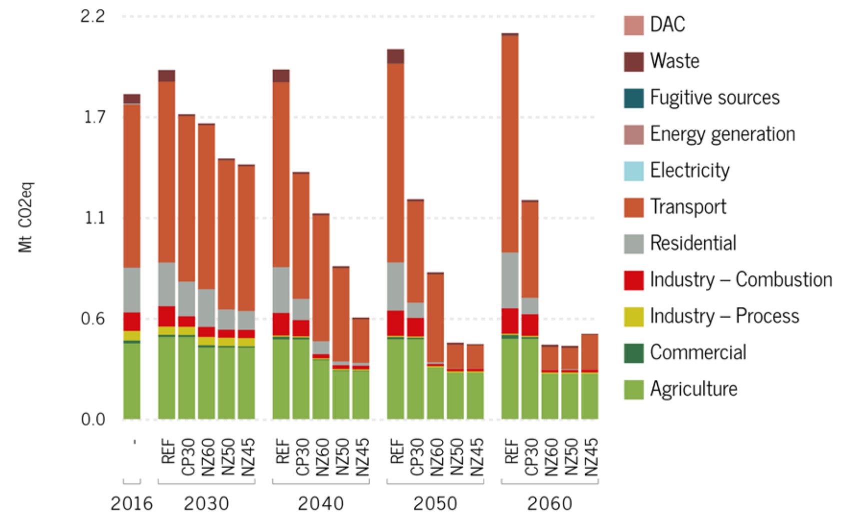
Biomass production by source

Key developments for Nova Scotia:

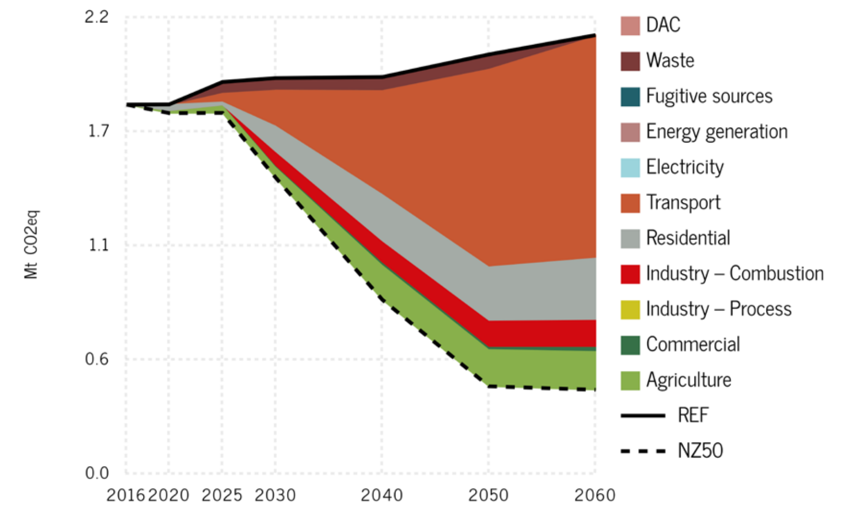
- Emissions in the REF scenario climb by 21% on the 2060 horizon, slightly below the national average. This growth is dominated by electricity production and transport.
- CP30 projects a barely 1% reduction in emissions by 2030, reaching 16% in 2060, again well below the national average. The main difference with respect to REF is in electricity production.
- For NZ scenarios, almost half of emissions are eliminated by 2030, increasing the production of BECCS electricity in Nova Scotia. It is interesting to note that thermal generation remains at levels similar to today even in net-zero scenarios. Therefore, the rapid and significant shift in emissions associated with the power sector in these scenarios is not through decarbonization, but from the use of BECCS, even though electricity production is multiplied by 2.3 to 3 by 2060. After this change in the first decade, the residential sector is next to provide emission reductions, between 2030 and 2040 in net-zero scenarios. Transport takes more time, as it does in most other provinces.
- The rapid shift from an emission-intensive sector to the opposite (in net terms) for power production also results in negative emissions, starting as early as the late 2020s in NZ45 and NZ50. This continues over the entire time horizon, although to different extents depending on the specific NZ scenario. Along with some DAC, the province is net negative by 2050 in NZ45 and NZ50 and by 2060 in NZ60 (between -3 and -5 $MtCO_2e$), once transport has reduced its emissions to their lowest level.
- Almost all BECCS is used for electricity generation, with only very little hydrogen production.
- Nuclear SMRs appear from 2040 in net-zero scenarios. Interestingly, while the size of this production at first seems to depend on the net-zero schedule (with NZ45 more aggressively developing this production compared with NZ50 or NZ60), these differentials remain over time until 2060.
- Biomass production, which increases more modestly in Nova Scotia compared with other provinces, is almost only due to the use of more forest residues. Production evolves rapidly in net-zero scenarios after 2040 and presents very different patterns depending on the scenario, suggesting the competitivity of other emission reduction opportunities elsewhere in the economy.

10.9 Prince Edward Island

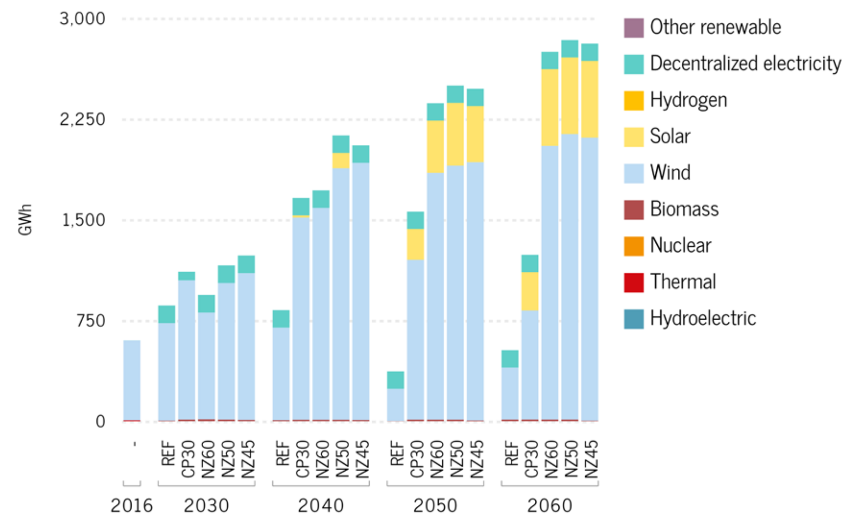
Figure 10.9 – Prince Edward Island's energy profile



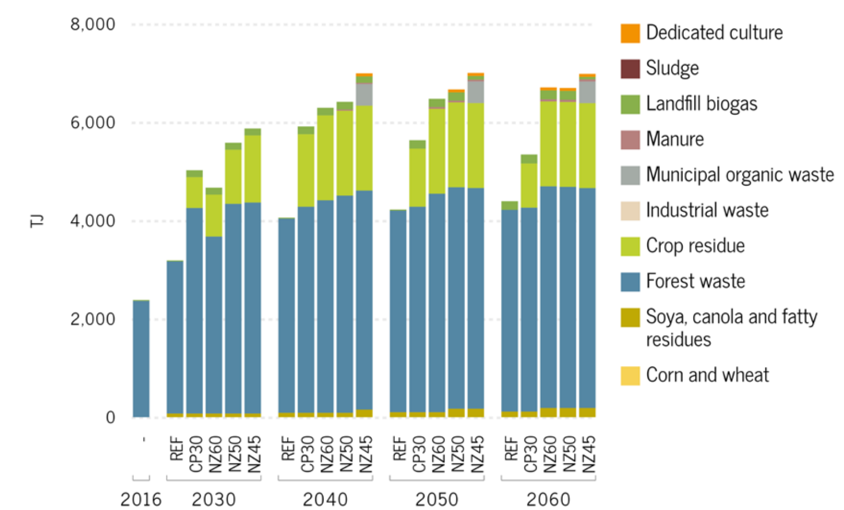
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



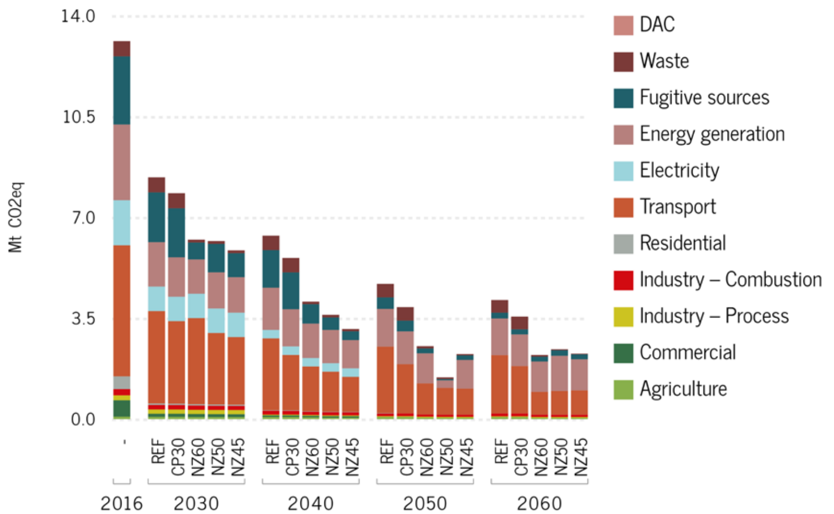
Biomass production by source

Key developments for Prince Edward Island:

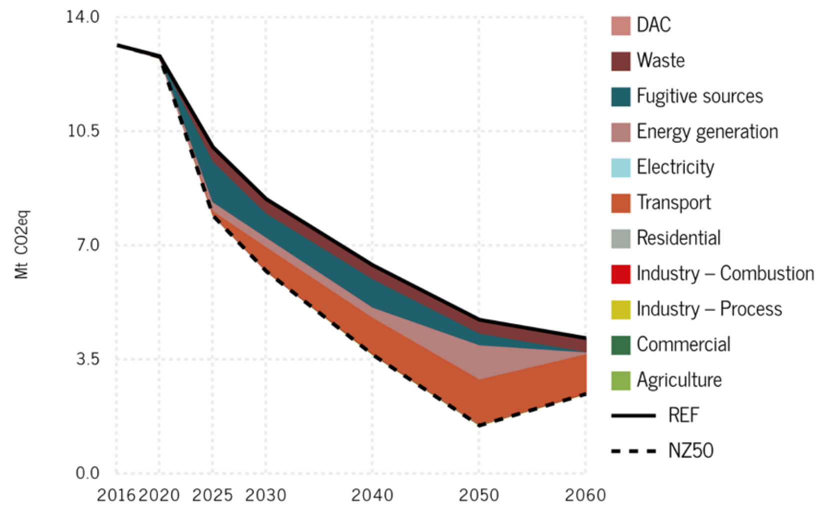
- REF projects a 20% growth in emissions by 2060, dominated by transport.
- CP30 induces a 6% reduction by 2030, and 32% by 2060. These are mainly due to reductions in transport and residential heating.
- Prince Edward Island's small industrial sector means that it contributes less to the province's emissions, while transport constitutes around half of total emissions, with agriculture and the residential sector producing most of the rest. The residential sector is the first to initiate reductions in the 2020s in net-zero scenarios, with industry following suit. Transport is much slower for emission reductions, which are nevertheless more rapid in the most aggressive net-zero scenarios (NZ45).
- BECCS is barely used for electricity production in some net-zero scenarios and no hydrogen is produced in the province. As a result, Prince Edward Island generates no negative emissions, making it net positive from 2050 although the remaining emissions are small in absolute terms.
- Almost all power is produced from wind today; this source triples its generation by 2050 in net-zero scenarios, adding solar as well. Imports from neighbouring provinces, which help PEI for the provision of baseload generation, are enough to accommodate the increase in wind generation in the short term (from the 2020s, storage appears to help in this respect). However, after 2030 these electricity receipts increase, eventually reaching around 60% higher levels compared with today.
- Forest residues increase by more than 80% in net-zero scenarios, much more (and more rapidly) than in REF. Crop residues and municipal waste add to this mix. Given almost no BECCS production, biomass is used instead for biofuels production, along with some biogas on the longer term.

10.10 Newfoundland and Labrador

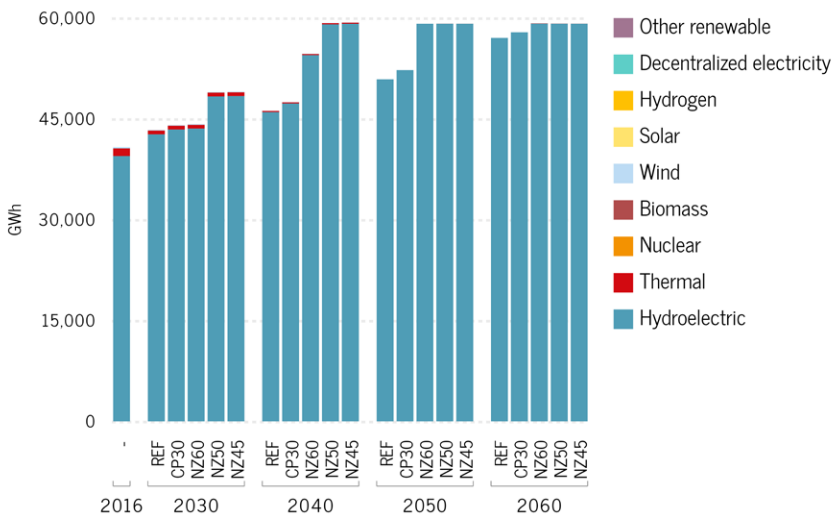
Figure 10.10 – Newfoundland and Labrador's energy profile



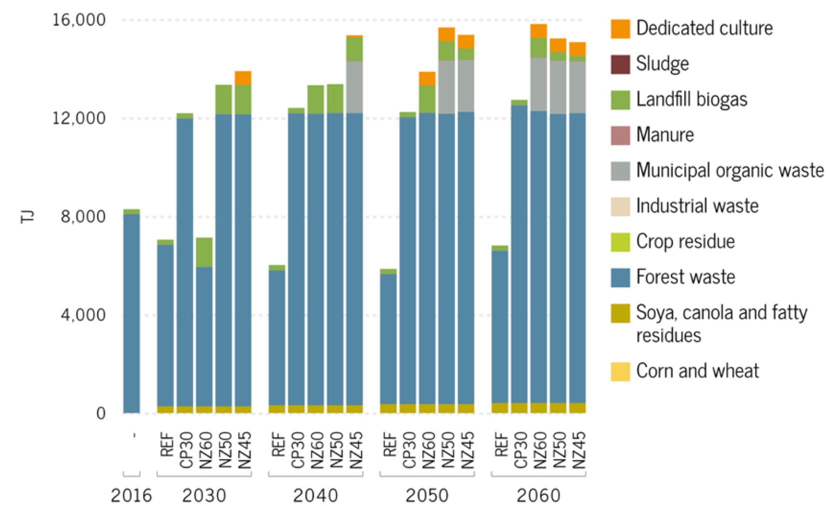
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



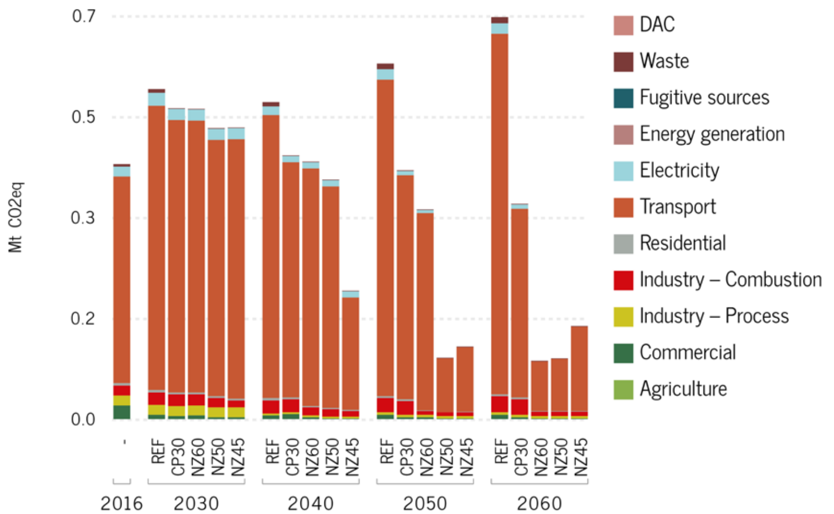
Biomass production by source

Key developments for Newfoundland and Labrador:

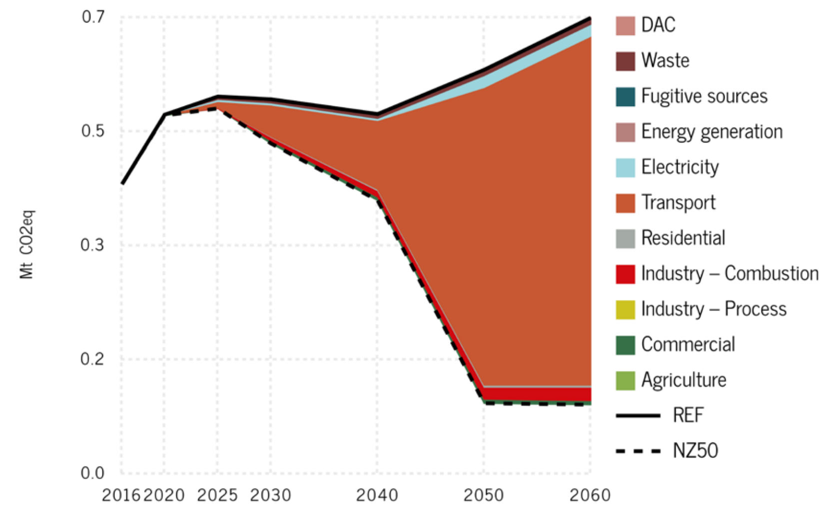
- Emissions in the REF scenario decrease rapidly between 2016 and 2030 (-36%) due to reductions in oil production and the halving of the remaining electric thermal production. This trend continues, with overall reductions of 68% by 2060, as the remaining buildings are fully decarbonized and transport emissions are cut by 55%.
- Because of the large reductions projected for REF, the relative effect of CP30 is slight. Nevertheless, with respect to 2016, emissions fall by 40%, with reduction reaching 73% in 2060, simply accelerating the trend in all sectors.
- By 2060, all NZ scenarios converge with net-positive emissions for the province (around 2 $MtCO_2e$), following reductions of 82% with respect to 2016.
- Similarly to Prince Edward Island, the small size of Newfoundland and Labrador's industrial sector means it contributes less to the province's emissions, while transport constitutes a large share of emissions and the residential sector produces some as well. However, similarities end here, given the province's oil sector, which produces a third of emissions today. Emissions from this sector are the first to decline from the 2020s (including in REF). Buildings, including commercial, also decarbonize quickly and almost eliminate their emissions by 2030 as they switch away from heating oil.
- Transport emissions, chiefly from personal vehicles, are cut by close to half their current levels by 2030 in NZ45 and NZ50, a trend that continues on the longer term. Contrary to other provinces, this also occurs in REF and CP30, and even though remaining emissions are higher than in NZs, they are less than half today's levels by 2050 or 2060. This highlights how the province is facing very few low-hanging fruits to help its emission reduction efforts, short of eliminating oil production, and without the possibility to achieve reductions in the power sector.
- BECCS is scarcely used for electricity production in some net-zero scenarios and the province produces no hydrogen. As a result, very few negative emissions are generated, making the province net positive from 2050.
- Power is produced almost exclusively from hydroelectricity after 2030, with a very small quantity of biomass used as well for BECCS generation. Hydroelectric generation rises over time, more rapidly in net-zero scenarios (+50% in 2060) but also in REF (+17%) and CP30 (+20%). A large share of this increase is exported to other provinces.
- All scenarios except REF show a doubling of biomass production from forest residues, with net-zero scenarios adding municipal waste used for biogas from 2040. Given almost no BECCS production, almost all biomass is used for biofuels production.

10.11 Yukon

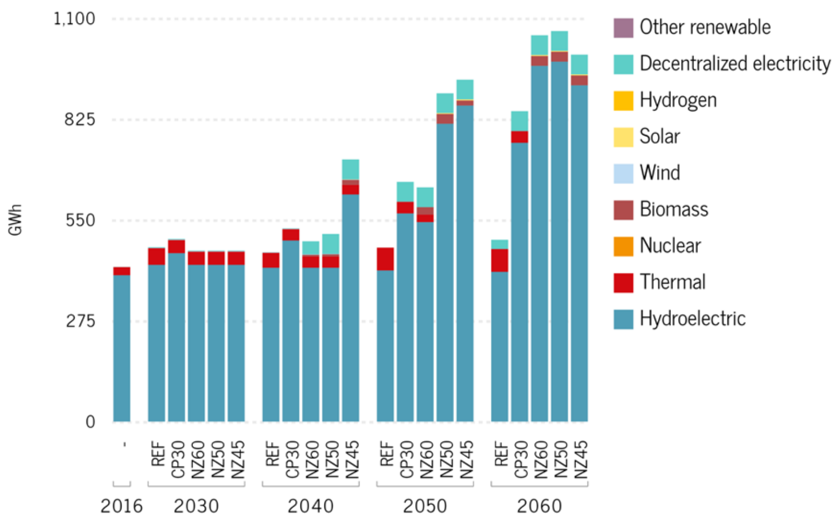
Figure 10.11 – Yukon's energy profile



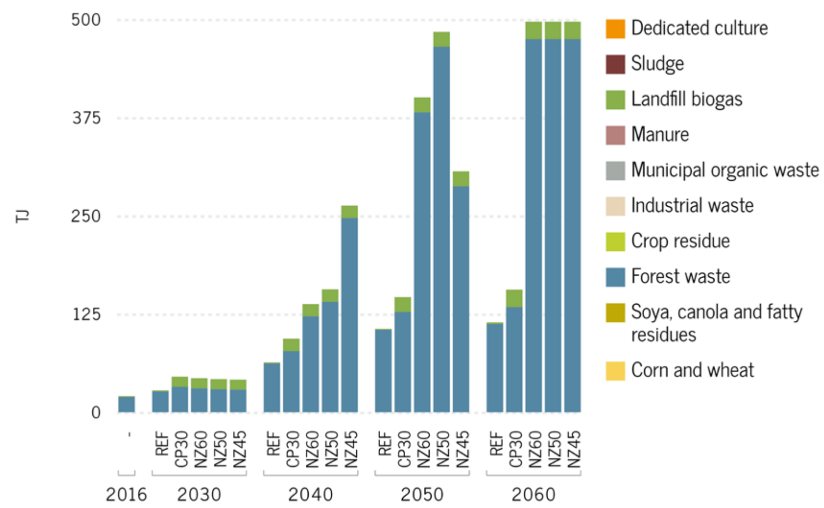
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



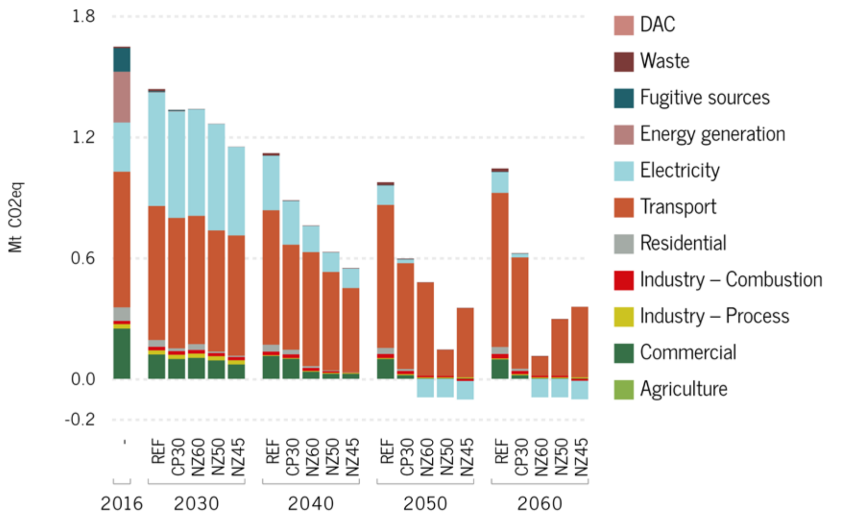
Biomass production by source

Key developments for the Yukon territory:

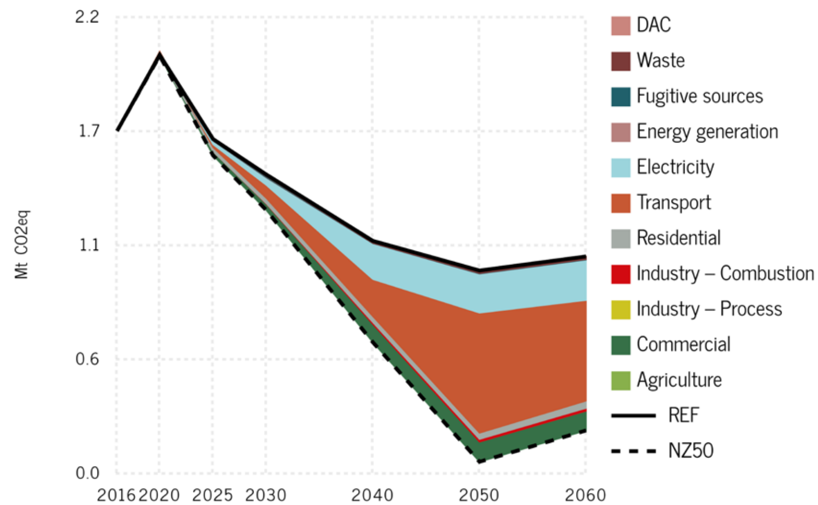
- In the REF scenario, emissions grow by 59% by 2060, largely driven by transport, which produces the overwhelming majority of emissions, with a much smaller contribution from industry and buildings.
- Because of the cost of decarbonizing transport, CP30 sees a 22% increase in emissions in 2030, far from the Canadian average (-9%); as technology prices fall, emissions begin decreasing and reach 85% of 2016 levels in 2060.
- NZ scenarios encounter the same problem, with emissions increasing by 15% in 2030 (NZ50 and NZ45) and some remaining emissions in 2060, with reductions of 63% (NZ45) to 88% (NZ60) with respect to 2016, as reducing GHGs for the Yukon is particularly costly. The net balance in 2060 for these three scenarios is positive but very small, at around 0.1 $MtCO_2e$.
- Transport emissions in net-zero scenarios diverge rapidly away from REF and CP30, especially after 2040. NZ45 is where these reductions are attained the earliest.
- The buildings sector is almost all decarbonized in the first decade, both for commercial and for residential buildings.
- While hydroelectricity constitutes the bulk of power generation, some thermal generation remains even in net-zero scenarios, mainly for communities that are difficult to connect to the grid. Biomass is also used from 2040 to allow for BECCS negative emissions.
- Biomass increases only after 2030 and accelerates in net-zero scenarios past 2040. Part of this biomass is used for space heating, but most goes to BECCS power generation, which helps compensate the remaining emissions in the electricity sector, without however reaching negative emissions.

10.12 Northwest Territories

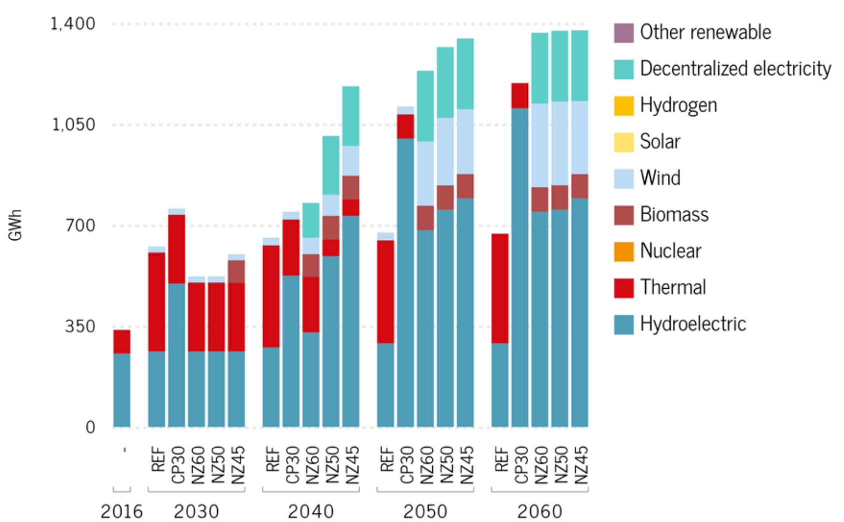
Figure 10.12 – Northwest Territories' energy profile



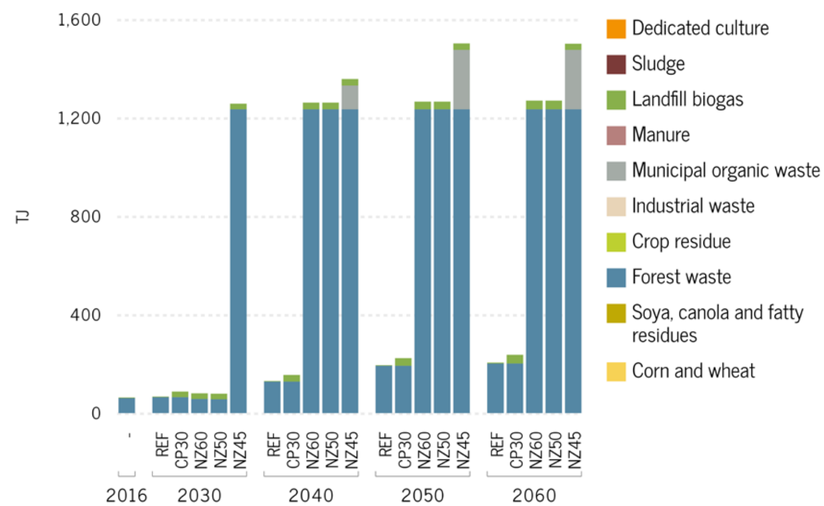
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



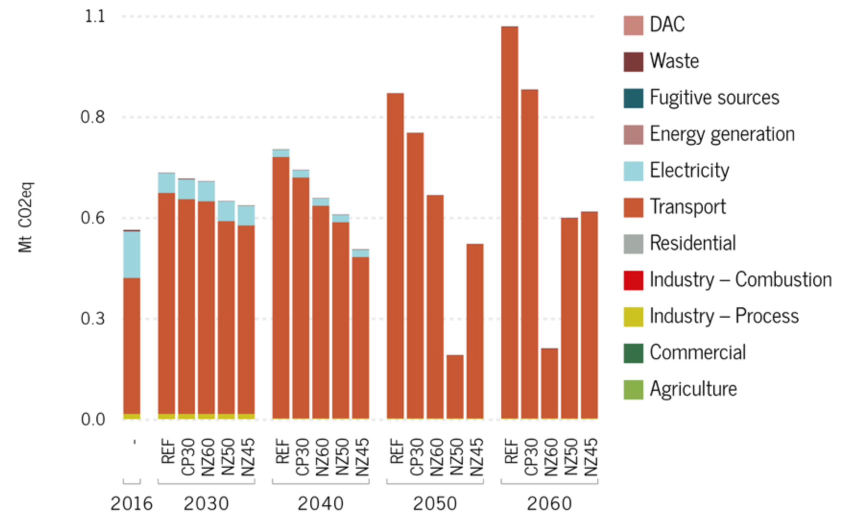
Biomass production by source

Key developments for the Northwest Territories:

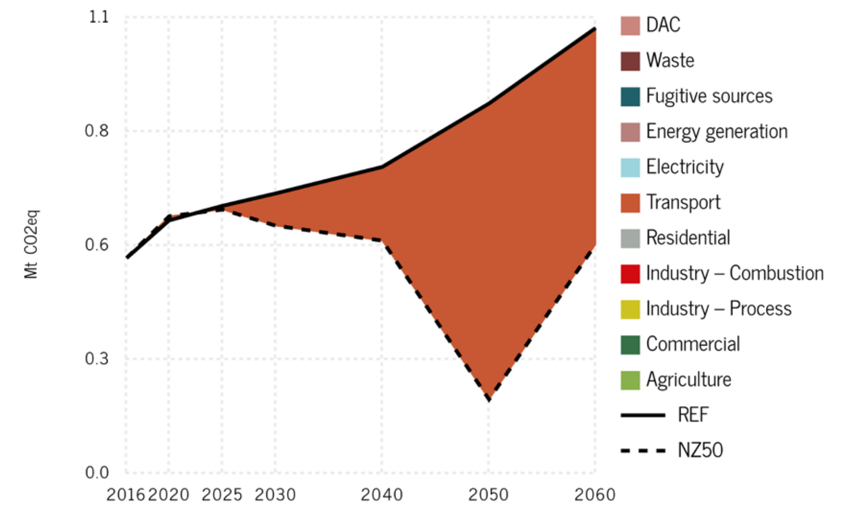
- Of the three territories, the Northwest Territories presents the most diversified emission profile. While the largest source is transport, oil and gas production, buildings, thermal electricity and industry all contribute an important share of the rest.
- The REF scenario projects a decrease in GHG emissions that plateaus in 2050 (-41%), before inching slightly up in 2060, 37% below the 2016 level. This reduction derives mainly from a decrease in oil and gas production and the partial decarbonization of heating spaces away from heating oil and natural gas.
- CP30 accelerates this transformation, with reductions of 19% by 2030, and even 62% by 2060, as space heating fully decarbonizes and electricity partially does too.
- In 2030, there is not much difference between CP30 and NZ scenarios. By 2060, all NZ see some negative emissions with BECCS, almost reaching carbon neutrality with between 0 (NZ60) and 0.25 $MtCO_2e$ (NZ45).
- Oil production is eliminated by 2030 even in REF, but electricity emissions double before 2030 (even in net-zero scenarios). Overall reductions for this period are provided by the contribution of the building sector (in net-zero scenarios)
- After 2030, buildings achieve almost full decarbonization and thermal electricity generation decreases, reducing emissions from power generation. In net-zero scenarios, this is compensated not only by increased hydroelectric production, but also by a small contribution of wind, biomass and decentralized electricity.
- The evolution of biomass production is also an interesting aspect here: only NZ45 sees an increase by 2030, although it is very significant in relative terms as it all derives from forest residues. Other scenarios match this increase by 2040; the only change afterward in net-zero scenarios is through the addition of some municipal organic waste in NZ45. In net-zero scenarios, all of this biomass is used for BECCS electricity production after 2040, except for NZ45, which also produces some hydrogen with BECCS.

10.13 Nunavut

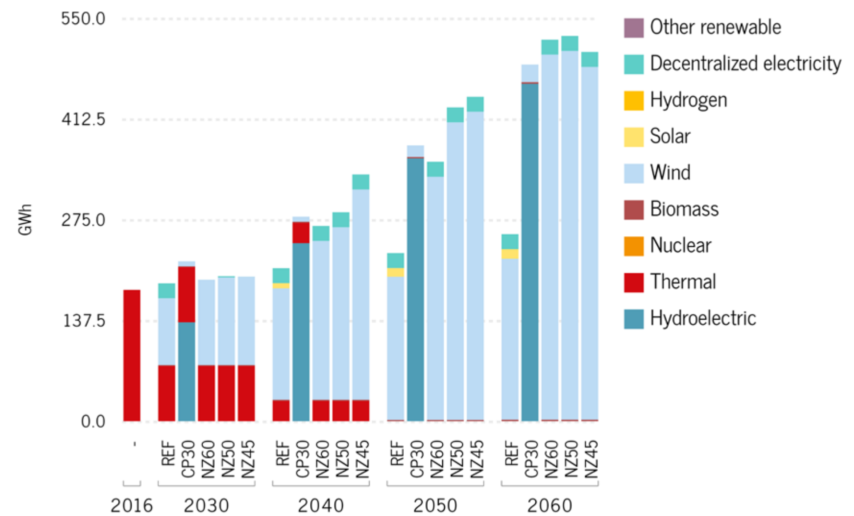
Figure 10.13 – Nunavut's energy profile



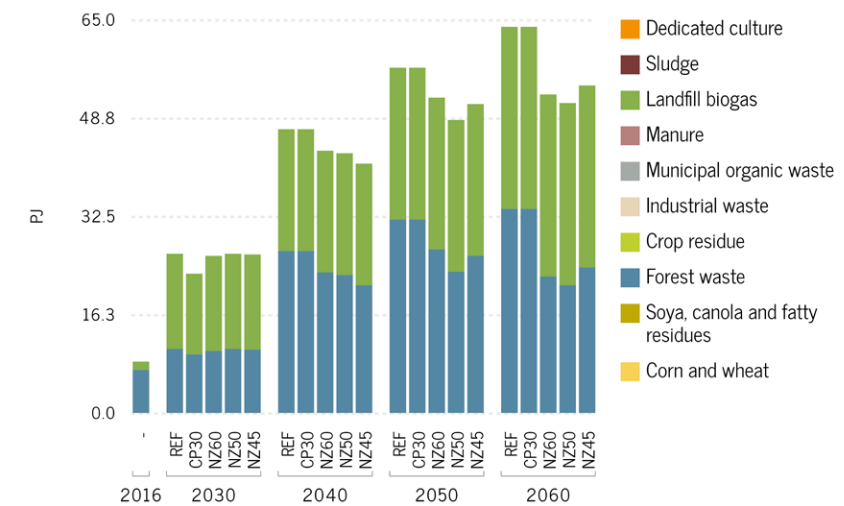
GHG emissions across scenarios



Emission reductions by sector in NZ50



Electricity generation by source



Biomass production by source

Key developments for Nunavut:

- The REF scenario projects the doubling of emissions by 2060, entirely due to growth in transport. In fact, as for the Yukon, an overwhelming majority of emissions are produced from the transport sector, with power generation contributing most of the rest.
- Due to the cost of decarbonizing transport, CP30 shows relatively little difference with REF (+27% emissions in 2030 for CP30 vs. 29% for REF), with a difference that increases as technological costs for green technology decrease (+17 % emissions in 2060).
- Decarbonization is difficult to achieve even in NZ scenarios, which do not lead to a reduction in emissions before 2040 (-11%, only for NZ45). Even in 2060, emissions remain above 2016 (by +6% and +10%, respectively) for NZ50 and NZ45. However, the corresponding absolute numbers are small, with net-positive emissions of 0.5 $MtCO_2e$.
- All generation is provided by thermal at present. In CP30, the grid sees hydroelectric generation rapidly replacing thermal and increasing over time with a little wind. In contrast, in net-zero scenarios, no hydroelectricity is used; instead a large volume of wind is coupled with storage to meet power demand. Some decentralized generation remains for remote communities and a small quantity of thermal capacity is retained as backup.
- Forest residues increase the biomass supply primarily after 2030. However, the notable change for this territory is the significant quantity of landfill biogas capture, which overtakes forest residues as the source of bioenergy and accelerates in net-zero scenarios past 2040. While a little over half of this is used for space heating, most goes to BECCS power generation, which helps compensate the remaining emissions in the electricity sector but without reaching negative emissions.

10.14 Takeaways

When looking at the results presented in Chapters 6 through 9, caution is advised on how to interpret them from a national perspective. Variations in the energy systems in each province, and the very limited integration of these systems across provincial borders, point to different challenges to be met in each province in net-zero pathways. This chapter helps identify not only some of the key differences in these challenges, but also areas where more integration can be useful.

It should be pointed out that while net-zero scenarios lead to carbon emission neutrality, net-zero is not achieved in each province and territory. **From the cost-optimization carried out in the modelling, some provinces end up with net positive emissions, while others are in the opposite situation.** This is largely because of (i) specific challenges for emission reductions based on each province's electricity and industry profiles, (ii) the availability of biomass resources to operate BECCS electricity and hydrogen production at reasonable cost, and (iii) whether DAC operations are used in the province—most provinces do not include DAC in the results. This also means that enforcing a strict net-zero target for each province and territory individually would be more expensive than adopting a national reference.

The first of these points also leads to a different schedule in reducing emissions from specific sectors. For instance, **provinces with smaller industrial emissions and/or low emissions from power generation do not have low-hanging fruits, forcing them to reduce the costliest sectors, such as transport, early on**. The opposite is true in provinces where early and relatively cheap emission reductions can be achieved by reducing oil and gas production or by replacing fossil fuel power generation with renewable sources.

Similarly, **provinces where there is little hydroelectric baseload generation face more important grid infrastructure development issues**. This is where ancillary cost issues associated with high shares of intermittent renewables in the power mix may be most important: a careful combination of storage, increased electricity trade with neighbours, and—in some cases—nuclear power generation may provide help.

The provincial and territorial differences highlighted in this chapter should not obscure the fact that **there is considerable room for nationwide federal government programs to help tackle common challenges**. In particular, the transport sector faces similar difficulties across provinces and increased interprovincial trade could also help mitigate the cost of transforming electricity grids to simultaneously meet rising demand and decarbonize.

11 REACHING CARBON NEUTRALITY—TECHNOLOGICAL PATHS IN OTHER NET-ZERO REPORTS

As more countries announced net-zero ambitions in recent years, modelling and planning reports using net-zero scenarios have become more commonplace around the world. Like this Outlook, these efforts present possibilities for how societies may move towards net-zero emissions, given current technologies and making reasonable assumptions about further innovations.

Since this report has similar aims for Canada, this chapter has two objectives: first, to identify technological paths in reports for other regions of the world, highlighting common ground and key differences in terms of technology and transformations with the results presented in Part 2 of this report; and second, to reflect on the perspectives for Canada if the rest of the world adopts some of these paths and what this means for the country's own efforts and choices to come.

HIGHLIGHTS

- Over the last few years, detailed net-zero reports have been produced for a number of regions and countries. A comparison of four of these reports helps situate Canada's progress and strategy, while providing a better understanding of the country's specific challenges.
- These reports identify a few general consensuses:
  - Massive electrification is required to reach net-zero, calling for investments in grid resiliency and expansion;
  - Negative-emission technologies should only be used to compensate the hardest sectors to decarbonize (i.e., where no carbon-free technologies are foreseeable);
  - Transport is particularly difficult to decarbonize and requires early orientation to support specific infrastructures;
  - Oil and gas production have to decline;
  - Decarbonizing industry is challenging and demands significant research and development efforts;
  - Changes in consumption patterns (not treated in this report) are essential to transform demand.
- With a largely already decarbonized electricity production, a strong oil and gas production and a diverse industrial basis, Canada must transform its economy more quickly than most of the other OECD countries to reach its climate goals.

11.1 Net-zero reports around the world

The announcement of a net-zero target for Canada was made in an international context where such targets are increasingly discussed. Since the signature of the Paris Agreement, a number of countries (Canada, France, Sweden, the United Kingdom, Denmark, New Zealand, Hungary) have introduced net-zero targets, some of which have already been enshrined into law, while others (the European Union, South Korea, Spain, and Fiji) view them as proposals for the time being. All proposals so far use the 2050 horizon, except for Sweden who uses 2045.

While a long list of reports with net-zero scenarios has been completed over the past few years, we choose to focus on a shorter set of four net-zero reports that provides rich information that can be compared with the results of this Outlook, while keeping the discussion within reasonable space. The list below was built because of the level of detail provided in the modelling for each of these reports and to ensure a reasonable geographical coverage. While this coverage is limited to North America and Europe, it should be noted that these regions include Canada's main trading partners, both in terms of energy goods and technologies, and more generally across all sectors. This relates to the second objective of this chapter as outlined above, that is, determining what the rest of the world is likely to do from a technological perspective to reach net-zero emissions, to inform Canada's own thinking about the technological paths it may consider.

The list of reports is as follows:

1. UK – The United Kingdom's Committee on Climate Change's "Net Zero: The UK's contribution to stopping global warming" (UKCCC 2019)
2. US – Princeton University's "Net-Zero America: Potential pathways, infrastructure, and impacts" (Larson et al 2020)
3. EU – McKinsey & Company's "Net-Zero Europe: Decarbonization pathways and socioeconomic implications" (D'Aprile et al 2020)
4. FR – France's Ministère de la transition écologique's "Stratégie nationale bas-carbone : La transition écologique et solidaire vers la neutralité carbone" (Ministère de la transition écologique 2020)

While a summary of general information on emissions to 2050 across the reports is provided in Table 11.1, to compare the various technological paths discussed in each report, a list of key questions on the role of different technologies is used, each identified and addressed in the discussions found in Part 2 of this report. The questions are grouped into the following three topics: sectoral pathways, energy and power production, and overarching technological challenges to reach net-zero.

11.2 Technological pathways by sector

11.2.1 Key changes expected in the industrial sector

All reports discuss the complexities of deep reductions in the industrial sector (outside of energy and power production, which is discussed separately below), as well as the challenges to the variety of solutions available. All see a very large role for electrification for low and medium heat (through boilers and heat pumps), but contrary to some other sectors, many applications cannot be electrified with current technologies and thus remain fueled in large part by natural gas.

Among these applications, cement production and ammonia are cited most often, although the UK also mentions iron and steel blast furnaces. In the other reports, steel furnaces are electrified or the heat is provided by biomass or hydrogen, while iron reduced with hydrogen seems to be a common expectation. For these sectors, CCS is used.

CCS is seen as essential for at least cement and ammonia production and the EU sees a very important role for BECCS in these two sectors. CCS is discussed further for process emissions (see section 11.4.1 below).

11.2.2 Decarbonization of the transport sector

In passenger transport, all reports point to an electrification of all light-duty vehicles by 2050, although the US has some scenarios with lower rates. The EU report mentions that this scenario means that 100% of new sales are electric vehicles sometime in the 2030s. While FR and the UK also discuss the importance of imposing this sales target as early as possible, this point is not mentioned in the US report.

In commercial transport, hydrogen fuel cell or electric play an important role in long-haul, while the UK report extensively discusses the need to reduce demand for kilometres, through both logistic optimization and societal changes. All reports contain a more general discussion of improvements of energy efficiency in almost all sectors, and notably transport.

In other modes, rail electrification is a given in EU, FR and UK. For aviation, biofuels are significant in all reports, with some importance given to alternative fuels (e.g., ammonia) and synthetic carbon-neutral fuels (e.g., hydrogen with carbon capture). However, FR is more explicit on the prioritization of aviation for the use of biofuels given limited supply, an issue scarcely discussed in the other reports.

11.2.3 Variations in net-zero pathways for the buildings sector

The role of electric heat pumps grows significantly in both the residential and the commercial sectors across all reports. In the UK and EU reports, however, district heating with hydrogen boilers plays a substantial role as well. This is in large part because of space constraints (for heat pump installations). UK explicitly discusses the assumption of heat pumps being taken up in non-residential buildings, mainly in less heat dense areas where district heating plays a smaller role.

Water heating is rarely discussed across the reports and leads to different aims: UK sees it as primarily integrated with space heating heat pump systems, while EU insists on solar thermal for heating water.

11.3 Energy production

11.3.1 Evolution of the power sector energy mix

All reports see variable renewable generation, mainly wind and solar, playing a very large role. Battery storage capacity helps meet this requirement in all reports, although to different extents, with the US report's scenarios making varying assumptions on the amount of storage available. Some natural gas remains as the main baseload, chiefly for stability purposes in certain regions, to a small extent across Europe overall but more significantly in the UK and USA.

Despite the decrease in this generation, more infrastructure is built in the US to expand capacity with CCS-equipped plants. UK sees hydrogen to be used to decarbonize this remaining gas power production capacity, especially from electrolysis, which will depend on the price of hydrogen. Nuclear remains, but with a smaller share than today (even in France). Nevertheless, a large number of nuclear powerplants are to be retired in US, compensated by added capacity from SMRs and advanced technologies (the role of SMRs is less explicit in other reports).

All reports see an increase in peak as well as overall demand. To meet this demand, in addition to accommodating variable generation, a large amount of new transmission infrastructure needs to be built. Market reforms and storage help, as do energy efficiency and demand reductions, but they are not enough (although FR insists more than the other countries on the importance of reducing demand). The extent of the need for new infrastructure varies widely across reports: UK mainly focuses on peak, while US argues for a 60% increase in high-voltage transmission and large sums for EV charging infrastructure. Also, the US report is more hopeful for demand management to deal with peak.

11.3.2 Fossil fuels production

Oil and gas production declines by a substantial margin in UK, US and EU—and is in any case negligible in France. Nevertheless, there is substantial variation across scenarios in the US report, with declines of 25% to 85% in oil production, and from 20% to 90% in natural gas production. UK insists on GHG reductions in venting and through gas recovery.

11.3.3 The availability of biomass

FR is by far the most detailed on biomass availability and usage. FR sees a very high competition for biomass resources, which it says will require using biomass in the most efficient places (notably aviation). Similarly, in US, all biomass available is used in all scenarios, while alternative scenarios evaluate the impacts of additional biomass availability. All biomass is used in these scenarios as well, mainly for BECCS.

11.3.4 Hydrogen's contribution

Hydrogen plays a role in all reports, although none see it as a dominant fuel by 2050. As concerns production, UK expects almost all hydrogen to come from methane reforming with CCS, while the others are more optimistic about electrolysis, especially from 2040. US mentions hydrogen produced from BECCS as well as electrolysis and methane reforming. In terms of infrastructure needs, UK discusses the need for infrastructure reform programs to convert existing natural gas distribution networks.

Hydrogen is used to decarbonize the remaining gas power production capacity. To meet this goal, UK sees hydrogen used in pure form to replace natural gas, while US discusses a blend with natural gas. UK also sees hydrogen used as ammonia in shipping; in industrial combustion to displace fossil fuels; in transport for heavy-duty vehicles, buses and trains; in buildings for peak heat; and in power generation as a storable low-carbon fuel for peak generation (with ammonia). US has an overlapping list of uses: in fuel cell trucks, for producing ammonia and other chemicals; for the direct reduction of iron; and in industrial heating. US also sees it as an intermediate fuel: as an input to the synthesis of hydrocarbon fuels and as a supplement to natural gas used in gas turbine power generation. EU has a list similar to UK's and also mentions hydrogen as the most economical alternative in the industry metals segment.

Table 11.1 – Summary of information on emissions across reports

	UK	FR	EU	US	CEO2021
Scenario	**Core + Further ambition measures**	**AMS**	**Macro set of measures**	**E+**	**NZ50**
Total mitigation	95-96% reduction from 1990 by 2050	Net-zero by 2050 (83% reduction + compensation)	Net-zero by 2050 (around 90% reduction + compensation)	Net-zero by 2050	Net-zero by 2050, with 40% reduction by 2030/2005 (around 80% reduction + compensation)
Remaining emissions	From all sectors. Most are compensated through carbon capture. Remaining 4%-5% not eliminated would be covered by speculative options like DAC or increased overtake of lower-carbon diets	From all sectors, but mainly industry, agriculture, and waste	Agriculture: 40% reduction by 2050 Industry: 95% reduction by 2050 with the help of BECCS in processes like ammonia and cement production, and CCS for industrial process emissions	Non-energy emissions reduced by 40% at most compared with BAU	Agriculture, industry, waste, transport, and energy production
Transport	Reduction not specified. 100% battery electric cars and vans by 2050. 91% electric and hydrogen HGVs. 10% sustainable biofuel uptake	97% reduction by 2050	100% decarbonized by 2050	96% electric LDV by 2050	74% reduction by 2050
Industry & energy production	100% CCS in manufacturing sectors with process emissions or internal fuel use	81% reduction for industry 95% reduction for energy production	95% reduction by 2050 Reduce consumer demand for emission-intensive products	Net-zero by 2050	Industry becomes net-negative when including BECCS hydrogen production
Power	All power comes from low-carbon sources (from 50% today)	Included in energy production	100% decarbonized by 2050	Between 70% and 85% carbon-free sources by 2050	Power production becomes net negative because of BECCS electricity production
Buildings	90% low-carbon heat in existing homes 100% low-carbon heat in non-residential buildings	95% reduction by 2050	100% decarbonized by 2050	Nearly fully electric by 2050, with heat pumps and resistance heating dominating the mix	96% reduction by 2050
CO_2 captured and stored	Up to 175 $MtCO_2$ captured and stored total 51 $MtCO_2$ through BECCS 1 $MtCO_2$ through DAC	Compensating emissions come from LULUCF + wood products (82% of compensation for remaining emissions, with the other 18% coming from carbon capture)	Capture is 6% of abatement by 2050 LULUCF plays a major role. BECCS in ammonia and cement production, as well as some steel production	If E+ with no new biomass, DAC increases dramatically to compensate for the inability to do more BECCS H_2	155 $MtCO_2$ captured and stored or used total, including 15 $MtCO_2$ from DAC

11.4 Overarching net-zero technological challenges

11.4.1 Compensation of non-energy emissions remaining in 2050

All reports extensively discuss the challenges specific to remaining emissions outside of energy use, that is, industrial processes, agriculture, waste, and forests. In respect of industrial processes, US and UK discuss the key importance of CCS to reduce process emissions. FR, however, insists on the need for the government to encourage disruptive technologies for process emissions.

Outside of industrial process emissions, each reports pays a very different degree of attention to each sector. In terms of agriculture, UK is much more detailed on measures to consider for nitrogen use efficiency (loosening soil compaction on cropland, use of precision farming and variable rate fertiliser application, more use of organic residues as in anaerobic digestion, better accounting for nutrients in livestock manures, and increased use of legume crops); livestock measures (improving the feed digestibility of cattle and sheep, improving animal health and fertility, and increasing the feed conversion ratio through the use of genetics can reduce methane emissions); manure management (better storage, management and application of animal wastes on land can reduce manure management emissions, better floor design and use of air scrubbers); and improving the thermal efficiency of agricultural buildings through retrofit or new build. EU puts forth some of the same measures but the overall list is less detailed. In turn, FR uses a similar list although it insists more on reducing energy demand. US is much less detailed, merely mentioning increases of annual uptake of carbon stored permanently in forests and agricultural soils.

In relation to forests and land use, UK insists on planting perennial energy crops and short-rotation forestry to increase soil carbon sequestration. It also diminishes the requirement to apply fertilizer, thus avoiding N_2O emissions. US discusses the need for a concerted effort to deploy agricultural and/or forestry land sink enhancement measures, while EU focuses mainly on reforestation and better management of all types of vegetative land. FR mentions a better management of silviculture to maximize substitution and storage of carbon in wood products (mainly increasing wood harvest and orienting it toward more long-term usage and increasing recycling and valorisation of wood products at end of life).

Finally, as concerns waste management, UK and FR discuss biogas, although in rather general terms, whereas US makes no mention of it. Only EU pays significant attention to both biogas consumption and production possibilities.

11.4.2 The role of carbon capture

Carbon capture plays a significant and multifaceted role in all net-zero reports considered here. Even with deep reductions across all sectors, some emissions will remain and must therefore be compensated to reach a carbon neutral economy. As a result, CCS and CCU are used extensively in all four reports. US sees them in particular in cement production, gas- and biomass-fired power generation, natural gas reforming, and biomass derived fuels production. All the other reports also discuss carbon capture in industrial applications, especially for process emissions and for applications where electrification is not available.

Negative emissions technologies like BECCS are used differently and with varying importance across reports. EU says they will be negligible, while the UK plans for 6% of power generation and US sees an important role for BECCS, specifically in hydrogen production.

The use of direct air capture is limited in UK, FR and EU but significant in some scenarios from US, especially if biomass use is constrained. Finally, US is more explicit on storage and transport infrastructure for CO_2, which is discussed in more general terms in the other reports.

11.5 Specific Canadian features highlighted in this Outlook

Building on the overview presented in the previous sections and in Table 11.1, comparisons can be made with the results presented in Part 2 of this Outlook. In the building sector, the four reports overviewed in this Chapter point to a similarly drastic increase in the role of heat pumps, although UK and EU have more district heating, which is virtually absent outside the commercial sector in the results for Canada. In particular, CEO2021 findings show no role for hydrogen in boilers that would be used for district heating. While this is an important technology and distribution option for low-carbon space heating, this difference should not be overstated as possibilities for district heating largely depend on local conditions and existing infrastructure, the latter of which is virtually absent in Canada, increasing the technology's cost. A similar point can be made about the lower rate of heat pumps in the UK since the size of many residential dwellings limits the use of this technology, as discussed in the report.

In the transport sector, most reports insist on sales mandates for EVs. Moreover, all underscore the complexities and technological uncertainties in decarbonizing heavy transport and aviation in particular, as this Outlook does as well. Across all five reports, a similar list of technologies for heavy transport is considered, including catenary lines and hydrogen, which will require decisions for infrastructure. In other words, results for this particular segment of transportation should be treated with care as the variety in the technology mix may be reduced in practice if governments and private sectors make specific choices about which infrastructure to build.

Given the eclectic profiles of industry (outside of energy production) across the five regions covered in these reports, it is difficult to draw firm conclusions when comparing CEO2021 with the other four. Most reports insist on decarbonization of key sectors like cement and steel production, and all pay special attention to the importance of heat needs of various intensities, as does CEO2021. As Chapter 13 points out, the variety of energy and heat needs across industrial sectors leads to a combination of different strategies that can be considered to reduce emissions, not only fuel switching, but also technological innovation, CCS, and production cuts.

The discussion over energy production, which is a major topic of interest in Canada's situation given its importance in respect of both emissions and the economy, varies significantly across reports. Part of this is due to variations in the structure of the sector; France, for instance, has virtually no oil and gas production, while the situation is quite different for Canada and the United States, which leads to a different role for the sector to play in efforts toward net-zero. Although the US report presents a significant interval of production cuts depending on scenarios (cuts as small as 25% and up to 85% for oil, and between 25% and 90% for natural gas), the smaller end of these intervals seems much more limited compared to results in this Outlook's NZ scenarios. Another important difference is the pace: even in US scenarios where production cuts are largest, most of these reductions happen after 2035, while NZ scenarios decarbonize this sector much quicker by dramatically decreasing productions in the next decade. To a large extent, the main reason for this is simply that the Canadian energy sector has fewer low-hanging fruits elsewhere in the economy, while other sectors in the US (power production in particular) offer the opportunity to obtain very large GHG reductions at a cheaper cost. Notably, over 500 coal powerplants are shut down in US by 2030 in the scenarios covered.

Like CEO2021, the four other reports extensively discuss the role of biomass, and the more specific case of BECCS, in helping reach net-zero emissions. Chapter 9 of this Outlook gives special attention to the role of biomass availability as all available biomass is used in the NZ scenarios. This comes closest to similar discussions in US and FR: the former uses variables in scenarios to account for an expansion of biomass should land management techniques help increase the available quantity, and the latter similarly discusses the importance of the careful management of feedstock to maximize its contribution.

The link with BECCS is direct: in US, for instance, almost all additional biomass is used for BECCS (notably for hydrogen production), a result similar to the sensitivity analysis of biomass availability in Chapter 9 of this Outlook. However, EU and CEO2021 provide different results on what BECCS is primarily used for as EU sees a greater role for BECCS in industry (other than hydrogen production), notably in cement.

11.6 Takeaways

As the review of these reports makes clear, the complexity of energy systems and other sources of emissions in various regions of the world can make broad-brush comparisons either difficult or, even worse, misleading. Nonetheless, a synthesis of the comparisons made in this chapter helps highlight a few important points in reflections on how to achieve net-zero in advanced economies.

The first is that regardless of the role that hydrogen may end up playing once uncertainties are reduced and infrastructure choices are made, **low-carbon electricity demand will grow significantly and fast**. While the specifics vary, all regions covered in these reports underscore the key challenges of increasing grid infrastructure capacity to accommodate drastically higher demand (especially peak) despite the efficiency gains of electrification, of managing high shares of variable generation, and of determining the exact role of baseload (nuclear or hydroelectric) and storage in this mix.

A second point is that all reports include a discussion of sectors where many uncertainties remain about the infrastructure development that should be favoured, depending on which, if any, of the many currently emerging or marginal technologies will end up dominating the sector. Results for industry (outside of energy production) and freight and aviation transport in particular show not only that decarbonization is particularly costly with current technologies for these sectors, but also that many options exist that may or may not develop rapidly through technological innovation—to say nothing of developments that are impossible to foresee at this time. In any case, one overarching implication is that **while governments need not choose every specific technology to favour, they must nevertheless make early decisions on which infrastructure to help develop** in a way that enables some flexibility to account for future innovations.

The third point is that all five reports agree on the unavoidable role of CCS and BECCS in reaching net-zero emissions with current technologies, given the remaining emissions from the various sectors, especially agriculture, industrial processes, transport and waste. Most reports explicitly or implicitly follow a line of discussion similar to Chapters 9 and 12 of this Outlook–that is, that given the magnitude of the remaining emissions in net-zero scenarios, carbon capture and negative emissions should be kept only to compensate for unavoidable emissions, which is to say that priority should always be given to mitigation. This point can be extended to the discussion of the role of DAC, which is minor in all reports but US, especially in scenarios where biomass is more constrained.

Finally, informative comparisons like those attempted here need not be limited to the points covered in CEO2021. For instance, an area neglected in this Outlook is the importance of behavioural changes, notably dietary preferences, to which FR and UK give special attention. Perhaps more importantly, while LULUCF is not discussed in CEO2021 and in most of the other four reports, FR pays special attention to the management of forests and land, including through agricultural policies. This is certainly an area to delve into more deeply for other regions as well, including Canada.

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12 USING CARBON CAPTURE IN THE RIGHT PLACE—THE POTENTIAL ROLE OF CCS IN ENERGY PRODUCTION

As countries around the world explore ways to reduce climate risks and set net-zero emission pathways for mid-century, there is a growing realization that carbon capture and storage (CCS) will be essential to decarbonize or compensate sectors such as agriculture, cement, iron and steel, and chemicals, as well as to support low-carbon fossil-fuel-based energy production. Yet despite the emphasis on the latter in discussions of net-zero pathways, CCS emerges primarily as a solution for (i) reducing industrial emissions and for (ii) net-carbon removal from the atmosphere, as is apparent in the projections made in this report. This chapter provides a short analysis of CCS in general before discussing its limits for supporting the use of fossil fuels in a net-zero economy.

HIGHLIGHTS

- Carbon capture and sequestration (CCS) and, to a lesser extent, utilization (CCU) will play a crucial role in reaching net-zero emissions along any pathway.
- However, targeting net-zero instead of simple GHG reductions changes where capture will be used, as any carbon leakage has to be compensated by negative emissions somewhere else; this increases the total cost of capture and favours non-emitting approaches over CCS and, even more, CCU.
- Net-zero coal- and gas-fired power production will likely be too costly to be viable.
- The use of bioenergy with carbon capture (BECCS), which couples photosynthesis carbon capture with CCS-equipped energy, heat and/or power production for net-negative emissions will likely play an important role in ensuring a total net-zero balance on a regional scale.

12.1 Capture, storage and utilization: an overview

A number of recent reports discuss the state of the art and challenges of various technologies and approaches.[1] Given the importance of emissions capture in mitigation scenarios, a long list of technological pathways that have been developed over the past decades and built with capture are becoming a reality, and at scale, as we have seen in the previous chapter. This section discusses various approaches that can be taken to CCS,[2] highlighting three key distinctions used to differentiate capture processes and related activities.

The first distinction is whether the capture of emissions is achieved through a natural process or an industrial one. As part of the global carbon cycle, carbon exchanges continuously occur among oceans, land and the atmosphere. Within this cycle, carbon is absorbed by oceans and taken up by plants for photosynthesis, a portion of which is fixed in living organisms and released back into the atmosphere after decomposition or combustion. Changes in the composition of soil, in the occupation of land and in CO_2 concentrations in oceans, to name only a few factors, all have impacts on the quantity of carbon naturally captured every year. The implication is that any action or policy that results in changes to these factors, notably through land use modifications or forest management, including planting trees, has an impact on net CO_2 quantities present in the atmosphere.

In contrast, industrial capture results from the application of human-made technologies. This is arguably the main type of approach being discussed within carbon capture terminology and a long list of technologies and processes have been developed to make it effective, economically viable and energy efficient. In general, although industrial capture processes are typically more efficient than natural capture, the latter has the advantage of being able to run directly on sunlight, even though it can also be used in more industrial settings when valuable by-products can compensate low CO_2 capture productivity.

Similarly, the storage of the captured gases can be natural or industrial. Natural storage takes place through the accumulation of organic matter in long-lived plants like trees, as well as in anaerobic environments like soils, bogs, lakes, or other bodies of water. Not surprisingly, there are considerable uncertainties about the long-term stability of these reservoirs. Industrial storage takes place through injection into underground salines or empty fossil-fuel geological structures, or through the transformation into stable forms such as carbonates.

The second distinction is whether the capture occurs through preventing emissions at a point source or through removing gases already present in the atmosphere to decrease their concentration. Overwhelmingly, the technological options available or explored are tied to capturing carbon from flue gas streams at point sources, as the result of either power generation, industrial transformation, or fuel and fertilizer production. Power generation from coal, for instance, has seen a few CCS-equipped commercial-scale facilities being put into operation around the world, while CCS applied to power generation from natural gas is more costly but functions along the same principles. Although much less efficient, power or heat generation from biomass holds the promise of the added benefit of the natural capture of CO_2 already realized by feedstock once it enters the power plant, in theory providing negative emissions. This bioenergy with carbon capture and storage (BECCS), used for heat in industry or for electricity or hydrogen production, is at the core of negative emissions technologies in the modelling presented in this Outlook.

[1] See, for example: IPCC 2005; Royal Society and Royal Academy of Engineering 2018; Global CCS Institute 2016; Global CCS Institute 2020; Vega *et al.* 2020; Pilorgé *et al.* 2020.

[2] Although we discuss the distinction between CCS, CCU and CCUS below, for the sake of simplification we use CCS as a general term throughout this chapter, as sequestration will play a central role in reaching net-zero emissions.

Although power generation is often most visible, fuel production and capture from industrial processes are the dominant sectors where capture occurs or is in development. In the case of hydrogen, most of the current production comes from the reforming of natural gas; four industrial facilities around the world are coupled with capture installations. The capture of CO_2 occurs both from the steam methane reforming operation itself and from the burning of fuel to provide heat for the reforming unit. Natural gas processing also results in CO_2, from the use of energy at processing facilities and because unprocessed natural gas often contains CO_2. In fact, the first commercial plant to begin CCUS in 1972 was a natural gas processing plant (Global CCS Institute 2016). Furthermore, CO_2 is captured from the fermentation process in bioethanol production.

Industrially, CO_2 capture also occurs in chemical production (e.g., ammonia and ethylene), fertilizer production, and through the capture of emissions from waste to produce energy. Other processes could also lead to capture. Cement production, for instance, results in CO_2 emissions both through the burning of fuel for its heat needs and through the calcination of limestone. While heat can come from low-emitting sources, the process emissions remain and can be captured. In the iron and steel industry, the transformation of iron ore for use in steelmaking also results in emissions.

Another approach consists in removing CO_2 from the atmosphere through DAC.[3] Although DAC occurs naturally, as mentioned above (for instance, through photosynthesis), it can also be achieved through the formation of metal carbonates or with sorbents. Several processes exist for DAC with sorbents (liquid or solid), either with absorption or adsorption and then treating the sorbent to detach the CO_2.

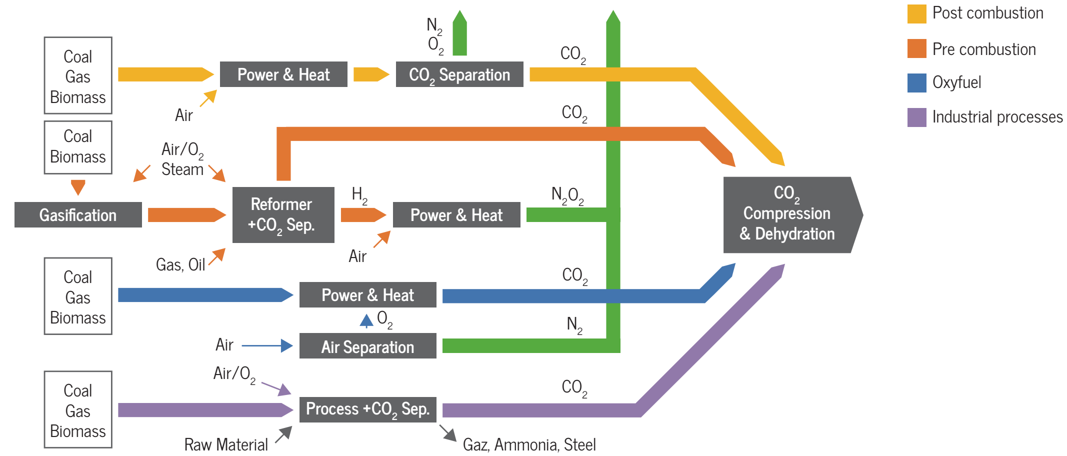
Finally, the third important distinction is whether the CO_2 captured is valued and used or is instead stored, as reflected in CCS (carbon capture and storage) vs. CCU (carbon capture and utilization) terminology. Different combinations of these three distinctions lead to several pathways in the CCUS discussion, although the current preferred option respecting this third distinction is through enhanced oil recovery (see section 12.2 below).

[3] See, for example: Keith, D.W. *et al.* 2018

Figure 12.1 summarizes the capture pathways. At point sources, capture technologies are usually broken down into three categories: post-combustion, pre-combustion and oxyfuel combustion. Post-combustion capture occurs through chemical absorption or using membranes after fuel combustion. Pre-combustion capture first involves the gasification of the fuel, which is transformed into CO and H_2. The CO is then made to react with steam to produce CO_2, allowing its separation and the combustion of H2 to generate energy. The process has the advantage of leading to high concentrations of CO_2 in the flue gas stream, as well as the production of a carbon-free fuel (H_2). The third option is oxy-fuel combustion, which is similar to the post-combustion process but combusts the fuel with pure oxygen, increasing the concentration of CO_2 in the flue gas and preventing NOx and SOx components in the stream. The downside is the significant amount of energy required to generate the pure oxygen. Each of these capture technologies can be coupled with several separation methods, including absorption, adsorption, membrane separation, chemical looping, cryogenic distillation, and hydrate-based separation (Ghiat and Al-Ansari 2021).

As concerns the third distinction (storage vs. use of the CO_2 captured), in theory all pathways provide the option of either storing or using the CO_2 captured, or both. In practice, preferences are often linked to economic factors, with utilization being preferred whenever possible. Storage-only options occur mainly in deep saline formations or in depleted oil and gas reservoirs. There are various utilization possibilities, including direct utilization (e.g., using CO_2 as a refrigerant to improve energy efficiency), chemical conversion (e.g., into fuels or fertilizer), biological conversion (e.g., by microalgae into carbon compounds), and mineral carbonation (e.g., to produce carbonate blocks instead of cement in the construction industry). Finally, enhanced-oil recovery and coal-bed methane recovery, each of which uses CO_2 to facilitate the extraction process, are both a utilization and a storage option as the CO_2 remains sequestered in the formations after its use.

Figure 12.1 – Various CO_2 capture pathways



Source: IPCC 2005

12.2 CCS and CCU today

The development of CCS and CCU has been much slower than promised: while more than 120 CCUS facilities were in construction or in planning in 2011, the total number of worldwide commercial CCUS facilities in operation by 2020 barely reached 26, double what they were 10 years earlier, with the majority of the planned facilities abandoned over the years (Global CCS Institute 2020). This situation can be explained by the technical challenges, the high cost of the technology, long-term storage liabilities and a direct or indirect carbon price that has remained largely below expected values.

In terms of carbon capture, these commercial facilities are mainly dominated by natural gas processing, where the CO_2 separated from the methane is captured and sold. This is followed by other industrial processes associated with chemical production, including fertilizers, ethanol and hydrogen. While CO_2 captured from power plants, such as coal power generation, has attracted considerable interest over the years, it is still minute today.

The net-zero horizon set by a number of countries is creating better conditions for these technologies, facilitating investments and risk-taking as economic models become more credible. This explains why, after a lull in 2017, the number of projects in development has been increasing even though it is still significantly below what it was 10 years ago.

All but 5 of the 26 carbon capture facilities currently in operation finance part of their operation with CCU based on enhanced oil recovery, which is the main utilization pathway at present. This is also the case for the three sites currently in construction. While this strategy clearly limits exposure to low carbon pricing, it greatly reduces the beneficial impact of carbon capture from a life-cycle perspective since carbon nevertheless ends up in the atmosphere.

12.3 Towards Net-Zero

Moving from a framework focused on GHG reductions to net-zero changes the strategic interest of the CCS solutions applied to various economic sectors since it will become necessary to address the total life-cycle emissions, or at least cradle to production emissions rather than only process emissions.

Most of the commercial CCS and CCU operations today contribute to reducing GHG emissions from industrial processes, many of which are difficult or impossible to transform in order to avoid GHG emissions. In this case, three pathways are possible:

1. To find a replacement product with a lower footprint or eliminate the need for the product altogether;
2. To develop a zero-emission production process;
3. To use CCUS to capture point source GHGs.

In the latter case, GHG removal typically focuses on a specific step of the production process and does not capture 100% of the emitted GHG, even at the production site. Therefore, a fully net-zero production needs to be paired with negative-emissions projects in order compensate for any fugitive or remnant emissions.

At present, although numerous negative-emissions enterprises (mainly based on reforestation) exist, no commercial industrial facility delivers a truly integrated net zero process. On the contrary, as most of these facilities repurpose their captured CO_2 for enhanced oil extraction, their net climate benefit remains debatable. Therefore, detailed life-cycle planning and analysis remains to be conducted in order to implement realistic and convincing pathways to net-zero for these industries.

Nevertheless, building on the modelling presented in this Outlook, it is possible to propose that such an integrated approach toward net-zero, which raises the cost of GHG management, will be targeting unavoidable industrial processes rather than serving to support the partial decarbonization of sectors that can be transformed otherwise.

12.4 Energy requirements for fossil-fuel based electricity production

CCUS energy requirements vary widely as a function of the removal process. Precombustion CO_2 capture from natural gas processing is essentially cost-free as the gas separation is a required step to ensure that the natural gas sent through the pipes meets the required energy density and chemical composition. Most of the energy capture cost for these operations is associated with CO_2 transport and injection into a well, which involves compression, pumping and injection. Similarly, the CO_2 generated by the fertilizer production process or by methane reforming is quite pure. In these situations, the cost associated with separating CO_2 from other gases is low and allows for the recovery of up to some 85%-95% in most industrial processes (Leung et al 2014).

Energy costs rapidly increase with the complexity of CO_2 removal and the efforts required to separate these molecules from others. Notably, CO_2 capture from post-combustion thermal plants can significantly reduce the efficiency of the plants measured, for example, by the net electricity produced by GJ of fossil fuels burned. For natural gas, the energy penalty for capturing CO_2 is of the order of 15% and can exceed 30% for coal plants, as shown in Table 12.1, not including the extra energy costs associated with CO_2 storage.

These energy costs increase with the proportion of CO_2 removed. Thus, a natural gas or a coal thermal plant is typically set to remove between 85% and 90% of the CO_2 emitted at combustion even though, technically, it is possible to remove 99% of emission, but with additional effort.

From a life cycle standpoint, it is necessary to expand GHG emission accounting to include upstream emissions associated with the extraction, processing and transport of the fuel to the combustion site. These emissions depend closely on local regulations, the nature of the extraction and the distance to the power plant. They are also likely to decrease over the coming years as tighter regulation is implemented. At present, the IEA estimates that from extraction to combustion, more than 80% of natural gas produces 0.53 $kgCO_2e$/kWh of electricity produced, and coal, 1 $kgCO_2e$/kWh with current technologies (IEA 2020). This means that about 0.17 kg.eq.CO_2 per kWh of electricity produced is emitted upstream from the thermal plant for both coal and natural gas, without CCUS.

When accounting for the reduced efficiency of CCUS-based gas and coal thermal plants, the overall net emissions per kWh of electricity generated from CCUS-equipped facilities therefore remains at 0.35 $kgCO_2e$ for coal and 0.24 $kgCO_2e$ for gas. If these remaining GHGs were to be captured using direct air technologies in a net-zero pathway, the overall primary energy cost for the same kWh would be almost double (196%) for coal power plants and 170% for gas power plants, as compared with current thermal plants. Adding the cost of CO_2 storage explains why these technologies are unlikely to become significant, except for peak or other very specific uses, given the existence of alternative low-cost and low-carbon sources of electricity.

Table 12.1 – Energy cost of producing net-zero electricity from fossil fuels

		Without CCS kg/kWh	With CCS kg/kWh	Removal efficiency %	Energy cost %	Reference
Life cycle GHG production for power generation	Coal	1	0,354			IEA 2020 (and references below)
	Natural gas	0,52	0,24			IEA 2020 (and references below)
		kg CO_2/kWh	kg CO_2/kWh	%	%	
Electricity production	Coal	0,82	0,11	85	36	Finkenrath 2011, Hu 2017
	Natural gas	0,35	0,04	89	17	Smith 2013
Non-combustion emissions	Coal	0,18	0,24			
	Natural gas	0,17	0,20			
		Percentage of additional electricity needed for net-zero. Addition to CCS at production			Additional energy needed with respect to non-CCS production	
Direct air capture	Coal	200	71		96%	
2 kWh/kg CO_2	Natural gas	104	48		70%	

12.5 Takeaways: where is CCS best used?

The move from targeting GHG reductions to aiming for net-zero considerably changes the nature of the challenge of CCUS, as anything but complete avoidance or capture of GHG emissions must be compensated through net-negative emissions efforts somewhere else. Capture for reuse, either through oil-enhanced recovery, vegetable production or synthetic fuel, is no longer sufficient since any of these strategies requires the addition of negative-emission technologies that increase their cost. CCS is therefore largely favoured over CCU.

In fact, the modeling results and the analysis presented in the previous paragraphs suggest that, as discussed previously, on-site CCS will first and foremost be applied to industrial processes for which CO_2 production is largely unavoidable, as well as to biomass-based heat, hydrogen or power production where the net impact on emissions is largely negative. In the results presented in Part 2 of this Outlook, BECCS is also largely preferred to DAC when aiming for negative emissions, as the latter has no valuable output except for the gas captured. In contrast, BECCS results in either electricity or hydrogen production, or in industrial output when applied in industrial heat generation.

Accordingly, from an energy and life-cycle perspective, the constraints of net-zero mean that CCS will be reserved mainly for primary energy production, including biomass-based electricity production, enhanced-oil recovery and net-zero blue hydrogen, where production can be cost-competitive with respect to green hydrogen. It will also be used for biomass-based negative-emissions technologies, although the net advantage of this approach will need to be validated by analyzing real-life, industrial-size sites that are yet to be built. Irrespective of these results, CCS is unlikely to play a significant role in favouring the extensive deployment of baseload coal and gas power plants.

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13

SPECIAL FOCUS ON INDUSTRY—TRANSFORMATION THROUGH TECHNOLOGICAL INNOVATION

One of the main challenges in reaching net-zero stems from the difficulty of eliminating, or even significantly reducing, industrial sector emissions as this sector, outside of fossil fuel production, has already decarbonized a significant portion of its activities. This chapter outlines some of the strategies that could be followed and how they apply to some heavy-emitting industries.

HIGHLIGHTS

- Results from the modelling of specific industrial subsectors and applications show that a mix of strategies, including technological innovation, fuel switching, product switching, and emission capture, is required to reach net-zero targets.
- While some production reductions are necessary to add to these transformations if net-zero targets are to be met, innovation, either through the development of new technologies and processes or through a better integration of heat production and consumption systems, is essential to maintain the highest level of production.
- While carbon capture allows for significant emission reductions, it cannot be scaled down to cover small emitting units and all industrial processes. As a result, although it is important, its role is limited, even beyond cost or storage considerations.
- The design of effective strategies and policies to reach net-zero for the industrial sector (outside of energy production) needs to find common threads among the challenges faced by many subsectors of varying sizes and needs, as well as go beyond energy efficiency objectives.

13.1 Technology-based strategies

Industry[1] is the second largest sector in terms of energy consumption. Absorbing 30% of the total energy supply after transport (37%), it is responsible for only 9% of its energy-related emissions (7% of total emissions), with process emissions representing an additional 7%.

A few reasons explain the relatively good standing of the Canadian industrial sector with respect to GHG emissions. Two in particular stand out: (i) hydroelectricity-rich provinces have deployed considerable efforts over decades to attract energy-intensive industries, such as aluminium smelters and the electrochemical industry; (ii) some sectors, such as the pulp and paper industry, have a long tradition of using their own waste to produce the energy they need, resulting in fewer emissions than the burning of fossil fuels to meet all their needs.

Many strategies can be applied to reduce industrial energy-related emissions:

1. Fuel and/or technology switching for energy consumption in order to use low-carbon sources like electricity or green hydrogen instead of fossil fuels to supply needs;
2. Process switching towards less energy-intensive solutions when they exist, which make it possible to reduce or eliminate industrial process emissions;
3. Equipping production facilities with carbon capture equipment to capture a large percentage of emissions when 1) and 2) are not technically feasible or too costly;
4. Reducing production and demand, including through material substitution, energy efficiency and design;
5. Recovering waste heat through a more effective integration of industrial activity into local energy systems for the provision of other services.

Although many of these strategies overlap with efforts to improve energy efficiency, it is important to remind readers that they are not the same. In some cases, decarbonizing may actually reduce energy efficiency. For example, replacing a gas boiler with a biomass boiler leads to a significant loss of efficiency while considerably reducing GHG emissions.

In the following sections, we discuss results from the modelling of specific subsectors and applications in order to illustrate the implications of the transformations required for industry to reach net-zero targets. This discussion excludes smaller sectors that will nevertheless need to be decarbonized. The sections at the end of this chapter highlight this challenge and potential solutions, including waste heat recovery.

[1] For the sake of simplification, unless otherwise specified, the term "industry" is used as a shorthand for the industrial sector outside of fossil fossil fuels production and electricity generation in the rest of this chapter.

13.2 Cement

In Canada, cement production is responsible for 7.6% of emissions from the industrial sector. Around one-third of emissions from cement production results from the combustion of fuels, while the rest derives from the decomposition of limestone in the production process. As a result, this is a key industrial sector requiring profound transformations in pathways to net-zero emissions.

Given the size of most facilities, a significant share of cement production can be equipped with carbon capture (Figure 13.1). In net-zero scenarios, this share reaches 62% of output as early as 2040 (NZ45 and NZ50), with changes occurring only after 2030 for NZ60. A steel-slag substitute, where the slag is used as a primary cementing material with wood chips as filler in several applications, also replaces part of the production (only after 2030, except in NZ45), reaching 17% of demand. While the carbon pricing added in CP30 helps trigger the adoption of the steel-slag substitute (albeit reaching proportions similar to NZ scenarios only in 2060), CCS remains too expensive without the NZ constraint.

Comparing reductions in NZ50 with emissions in the reference scenario (Figure 13.2), carbon capture allows for over half of the emissions abatement after 2035. Interestingly, this share reaches a high of 58% in 2040, and decreases slowly afterward as REF emissions continue to grow at a higher pace, given that the maximum number of facilities equipped with CCS is reached before 2040. This suggests a limit to the role CCS can play in reducing emissions from cement production, indicating that other strategies (as listed in the introduction above) are needed.

Similarly, the steel-slag substitute reaches its full potential in 2040. Importantly, the evolution of emissions in NZ50 vs. REF also shows how fuel switching has a limited impact in cement production.

Finally, a key result is that around 25% of emission reductions in cement production come from a reduction in industry output in 2040. Moreover, as carbon capture installations are unable to keep pace with the increase in REF emissions, reductions in production constitute an even larger share of emission reductions over time, reaching 30% of abatement compared to REF in 2060. In other words, more than a quarter of emission reductions in NZ50 would be much more costly without decreasing production by a similar share.

Figure 13.1 – Cement production across scenarios

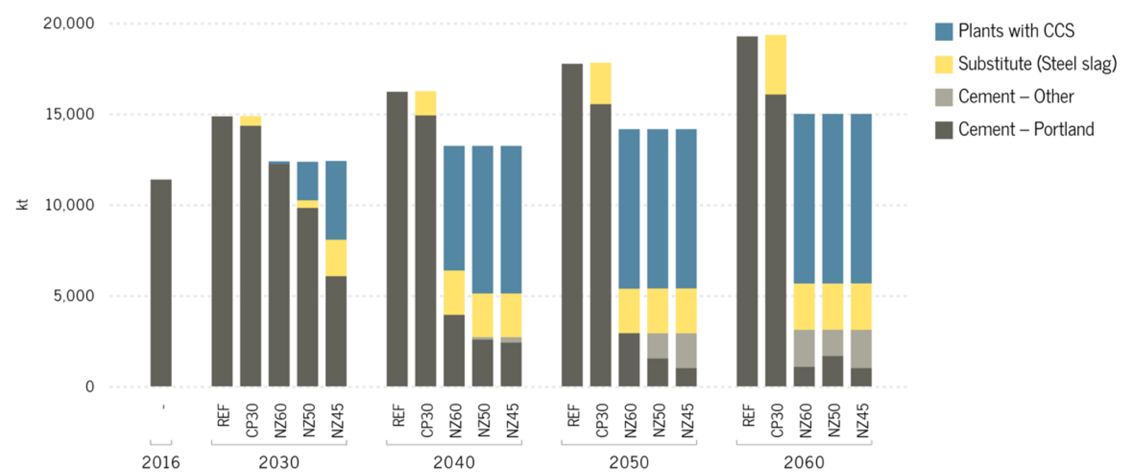
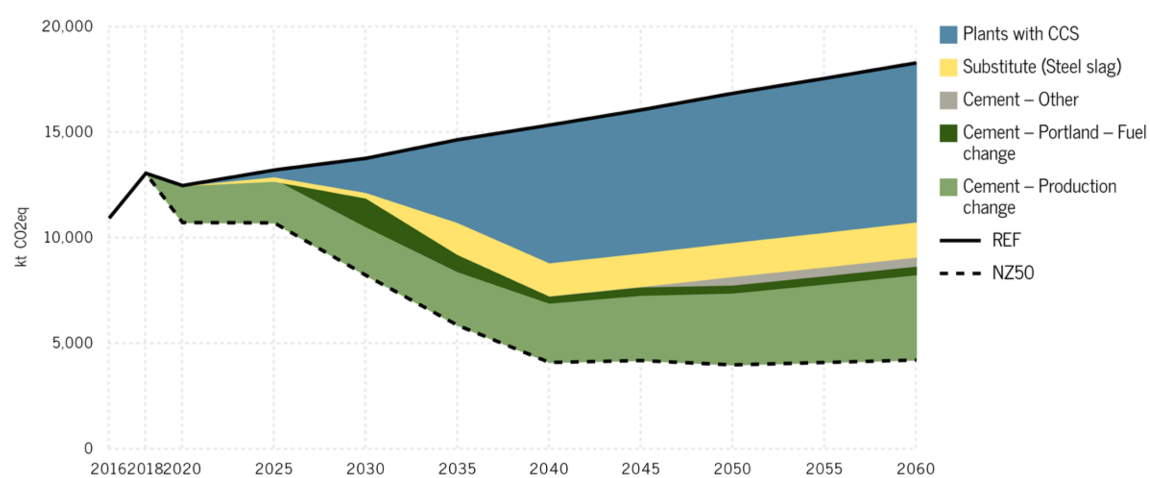


Figure 13.2 – Emission reductions in cement production (NZ50)



13.3 Pulp and paper

Some 10.7% of industrial emissions come from the pulp and paper sector, all resulting from fuel combustion. This sector also makes significant use of its own waste product to power this combustion, improving its emission intensity profile compared to other sectors.

The variety in production output and the size of facilities makes CCS difficult to apply in a larger proportion of the total when compared with cement. This share reaches 30% of output in NZ scenarios, where most of the transformation occurs between 2030 and 2040 (Figure 13.3). Among the various outputs, chemical pulp is where this share is highest (around 50% of production comes from facilities equipped with carbon capture) and also amounts to the largest share of production (36% of output for the sector). Notably, this is also the only sector where CCS equipment is installed in the CP30 scenario (with marginal quantities for paper as well). As for cement, no carbon capture occurs in the reference scenario.

Carbon capture allows for 53% of the emissions avoided in NZ50 compared with REF (Figure 13.4). Most of this abatement happens after 2035. The rest of the reductions comes at first from reducing production, but then fuel switching (to a mix of electricity, black liquor and biomass) takes over, allowing for the rest (outside of CCS) from around 2050.

This suggests that carbon capture can be introduced rapidly (mainly between 2025 and 2040), while fuel switching takes more time, during which reducing production is necessary to follow the net-zero 2050 schedule, before reaching its full potential. It also highlights the fact that fuel switching is key to reducing emissions from this industry, partly as a result of the high proportion of combustion emissions.

Figure 13.3 – Pulp and paper production across scenarios

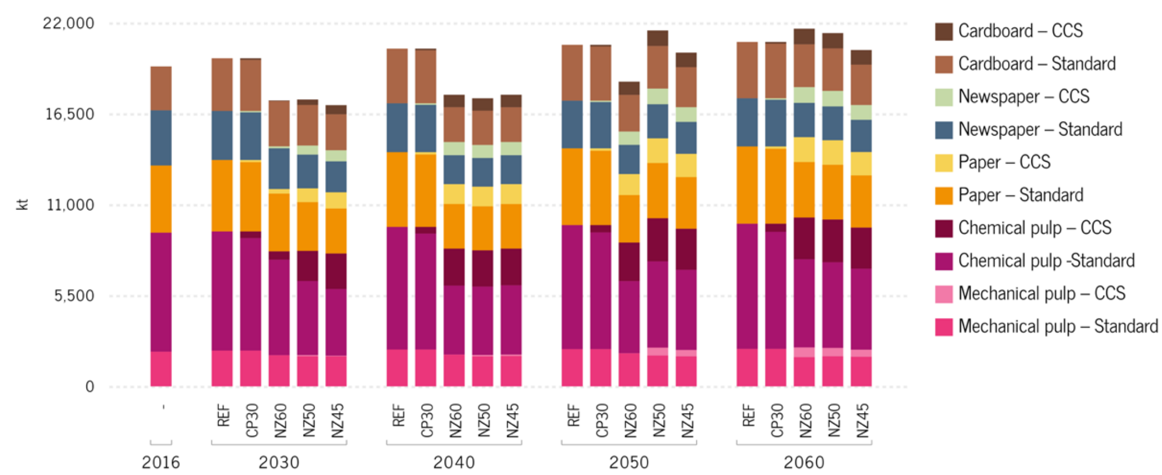
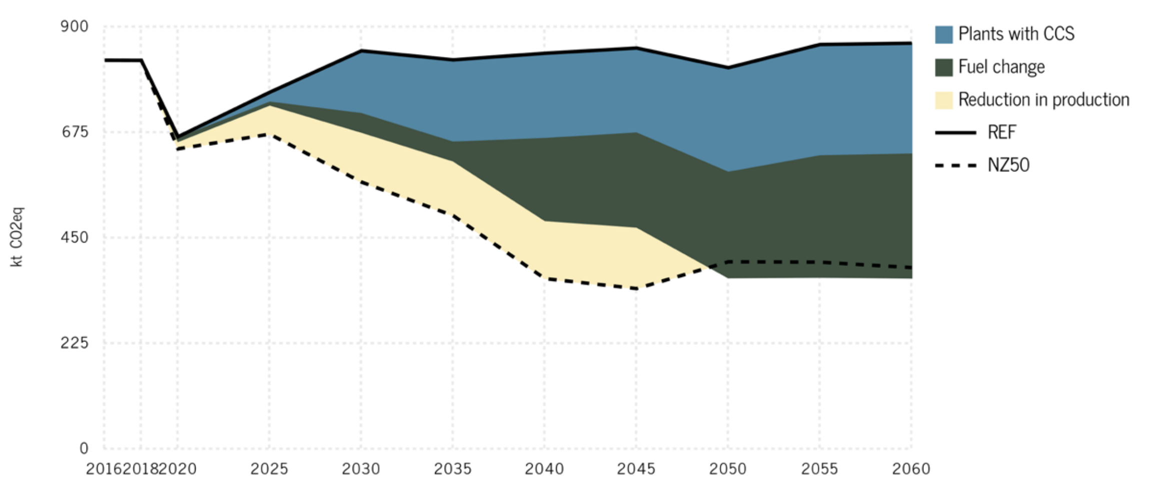


Figure 13.4 – Emission reductions in pulp and paper production (NZ50)



13.4 Chemicals

At most, carbon capture equips 34% of production facilities in the chemicals industry (Figure 13.5). In net-zero scenarios, petrochemicals is the area where this transformation occurs the earliest, with the bulk of facilities (to be equipped over the entire time horizon) upgraded before 2030. Fertilizer is also included in this early CCS conversion, although only 19% of facilities are adapted (compared with about half for petrochemicals). Interestingly, both these early changes show up in CP30 results, in contrast with other sectors discussed above where CP30 is insufficient to trigger CCS conversions without additional constraints, suggesting a lower cost for carbon capture in chemicals on the shorter term.

Net-zero scenarios manage to obtain reductions by reducing production early on, maintaining 20% lower production levels over most of the horizon, compared with REF and CP30. While CCS rapidly increases its role after 2025, it provides at most 33% of the reduction (a share reached in 2035), after which reductions increasingly derive from fuel switching and lower production levels in NZ50 (Figure 13.6). By 2060, only 26% of the reduction in NZ50 compared with REF comes from carbon capture, while fuel switching and lower production levels have grown to 41% and 32% of reductions respectively.

Figure 13.5 – Chemicals production across scenarios

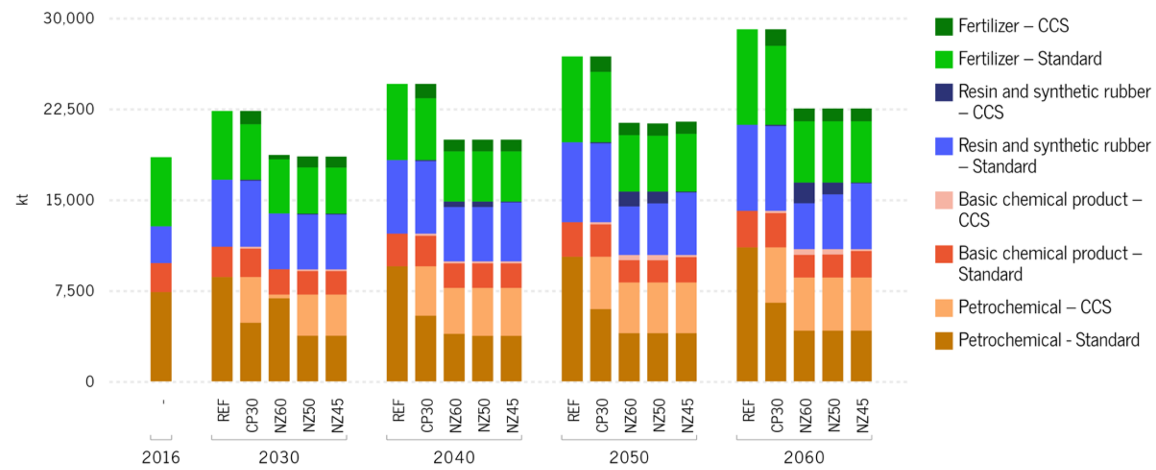
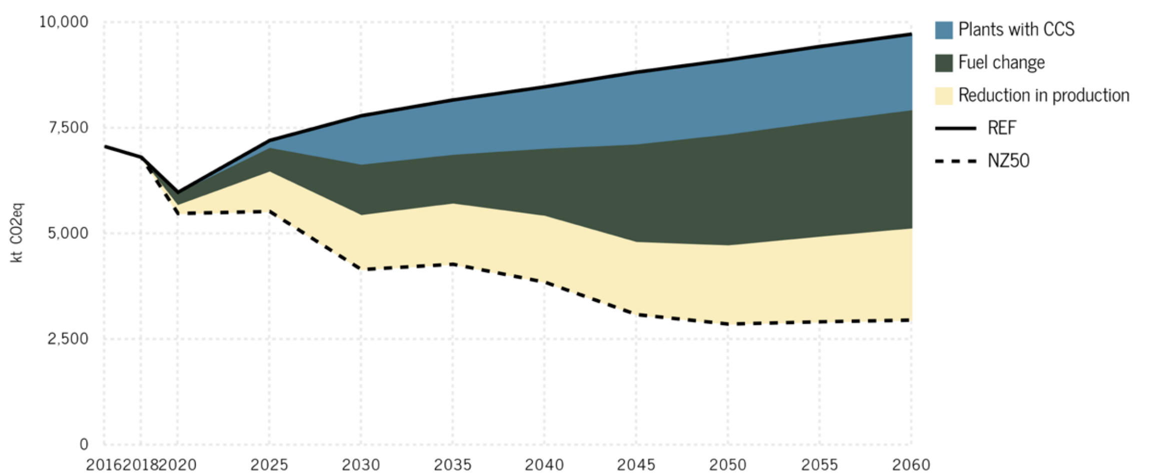


Figure 13.6 – Emission reductions in chemicals production (NZ50)



13.5 Heat demand

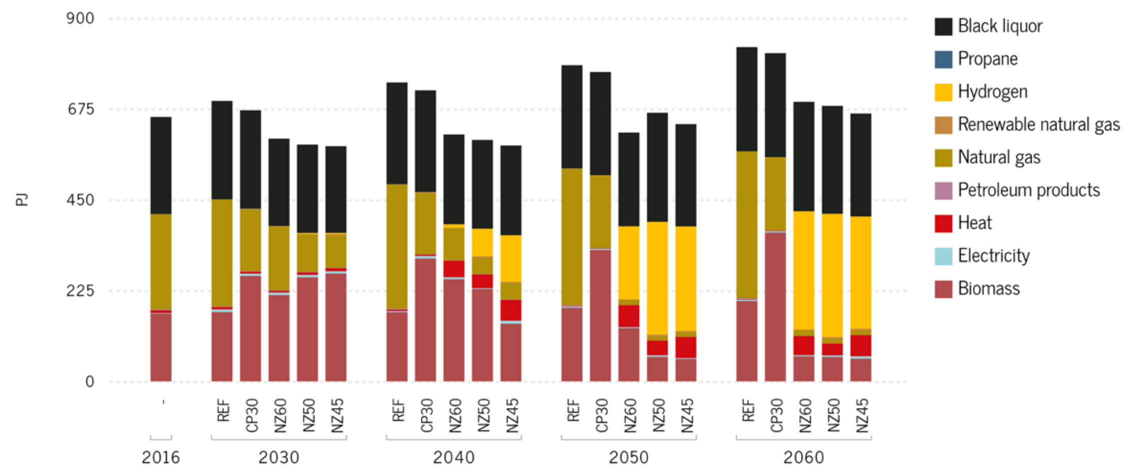
While industrial energy usage is diverse, it can be classified in terms of the required heat. For instance, low-temperature processes include warming up water for washing or pasteurization in the food industry, while medium-temperature applications can be found in distillation for pharmaceuticals for example. In contrast, high temperatures are needed to melt metals like iron and steel. Another important classification of industrial energy usage is intensity, that is, the sheer power of instantaneous amounts of the energy needed to be delivered. Decarbonization solutions have to be adapted to the various characteristics of these needs.

A look at the evolution of energy consumption for industrial boilers (Figure 13.7) provides an overview of how most industrial heat would need to be provided across scenarios. Current needs for boilers are met by natural gas and black liquor in roughly equal shares, as well as by a smaller contribution of biomass and marginal district heating. This mix remains similar over time in REF, although the total demand increases by close to 20% by 2060. In CP30, only one change occurs in comparison with the reference scenario: natural gas rapidly decreases its contribution, shifting demand toward biomass (most of the shift occurs before 2030).

NZ scenarios show two shifts in the short term. First, before 2030, biomass also replaces natural gas, in a comparable volume in NZ60 and CP30, and more significantly in NZ50 and NZ45. Second, total energy demand is reduced, with consumption 13% to 16% lower in NZ scenarios compared with REF in 2030.

After 2030, consumption increases in all scenarios, although more slowly in net-zero scenarios, resulting in the maintaining of this initial decrease compared with REF. In other words, a large part of the difference in total demand between NZ scenarios and REF (or CP30, which presents levels similar to REF) is the result of a rapid change occurring before 2030.

Figure 13.7 – Industrial boilers energy consumption



On the longer term, NZ scenarios depart from REF and CP30 in other important ways as new sources contribute to further emission reductions. While black liquor maintains relatively similar levels over time, natural gas is almost entirely eliminated by 2050 and biomass is reduced significantly (with more rapid reductions in more demanding net-zero schedules). A small part of this reduction is replaced by district heating, which comes to play a small but important role in net-zero scenarios by 2040.

Hydrogen constitutes a much larger source replacing natural gas and biomass from the late 2030s. The tighter the net-zero schedule in the scenario, the quicker hydrogen increases its role, with a marginal share in NZ60 in 2040 but at 20% of the total in NZ45. On the longer term, this share converges at between 42% and 45% of the total by 2060. Although hydrogen, and to a lesser extent district heating, comes to play a dominant role in net-zero scenarios after 2040, both are completely absent in REF and CP30.

The above overview suggests that net-zero scenarios handle heat-related emissions by rapidly controlling total demand and then using fuel switching to progressively replace the most emission-intensive sources like natural gas (first) and biomass (second).

This sequence also allows currently more expensive sources, such as hydrogen, to come into play later and play a significant role by 2050 and 2060.

It should also be noted that the potential contribution of waste heat recovery may be significant despite difficulties in including it in the results. This is also a source that is difficult to model given that the reuse of waste heat strongly depends on a local match between availability and needs. However, it is clear that this possibility should be studied in detail, paying special attention to how barriers to this reuse can be eliminated.

13.6 Takeaways

Industry is one of the sectors in which significant reductions in emissions take place earlier in all scenarios. Nevertheless, given the high costs of achieving substantial emission reductions from the industrial sector, and the competitivity of different options after 2040, efforts to decarbonize must take into account the specific challenges facing each industrial sector to lower costs, accelerate the transformation and minimize risks. However, these factors should not be overstated and lead to missing out on the significant potential benefits of cross-industry solutions that could come from a better integration of needs and supply. Moreover, given the frequent mismatch between energy efficiency improvements and changes resulting in emission abatement, **modifying current energy efficiency subsidy programs is neither a sufficient nor an adequate strategy when targeting net-zero emissions; new programs designed with this goal in mind are required**.

One result that stands out is that **despite the importance of carbon capture in reducing emissions from the sector as a whole, its role is limited overall**. In cement, where CCS provides the highest share of emission reductions among the sectors analyzed above, this contribution is at most barely over half of reductions. While the role of emission capture remains important in decarbonization efforts, this result underscores that other strategies for the industrial sector are also needed in net-zero pathways. Even if technological breakthroughs would allow for a larger share of facilities to be equipped with carbon capture technologies, not all emissions can be captured and there remains considerable uncertainty about the actual share of captured gases despite theoretical potential (see Chapter 12). Even beyond these uncertainties, the cost of carbon capture remains too prohibitive for the REF and CP30 scenarios, with the exception of petrochemicals in CP30.

A second result, discussed in Part 2 of this report, is that **industrial process emissions are harder to avoid when carbon capture is not technologically feasible since strategies like fuel switching are inapplicable**. Moreover, the capture of process emissions is also more difficult than for combustion emissions, which helps explain their important role in remaining emissions once net-zero is reached. Therefore, **unless technological breakthroughs are achieved for industrial processes and all strategies are applied to reduce combustion emissions to their lowest possible levels, significant production reductions are difficult to avoid completely in net-zero scenarios**.

Finally, other sectors not reviewed here may add insight into the building of a profile for the industrial sector that leads to effective mitigation policies. For instance, emissions from the construction sector are often less concentrated than in plants, making carbon capture impossible. **The broad variety of activities in manufacturing outside of metals, iron, chemicals, cement and pulp and paper may complicate one-size-fits-all applications.** Agricultural production in greenhouses, which requires a significantly larger quantity of energy in colder months compared with the rest of the year, also presents distinct challenges. **Designing strategies and policies to address each of these sectors should focus not only on the different options available for reducing emissions, but also on the possibility of integrating sectors and facilities.**

14 ASSESSING THE COSTS OF ENERGY TRANSITION THROUGH ELECTRIFICATION

Since no country has yet completed the shift from fossil fuels to low-carbon sources of energy, the economic implications of energy transitions remain uncertain. While energy transitions are often expected to require substantial investments, diverging assessments suggest that they may either fuel future prosperity or become an economic burden. This chapter proposes an assessment of the net cost of electrifying Canada's primary energy supply by comparing investments in low-carbon electricity production, transmission and storage with savings from reduced consumption of fossil fuels.

Special contribution by:

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- Marcelin JOANIS, Professor, Department of Mathematics and Industrial Engineering, Polytechnique Montréal
- Thomas STRINGER, PhD candidate, Polytechnique Montréal

HIGHLIGHTS

- REF and CP30 scenarios are projecting important increases in fossil fuel expenses in the next decades and declining investments in electrification.
- In contrast, all three NZ scenarios suggest that the increase in electrification investments required by net-zero (especially in the 2030-2050 period) will be more than compensated with net annual savings from avoided fuel expenditure from 2050 onward (as much as $61 billion, when accounting from remaining electricity infrastructure cost).
- Doubling the projected cost of new electricity transmission infrastructure and halving the cost of fossil fuels still results in net savings of up to $23 billion in NZ scenarios.
- The cost of the infrastructure necessary for broad electrification of the economy is important in the next decades; if building those infrastructures will generate economic activity, it is also an investment that will generate substantial savings once completed.

14.1 Introduction

Energy transitions in the industrialized world are largely shaped by the implementation of new technologies, the shutdown of inefficient infrastructure, and the adoption of environmental regulations (Hafner and Tagliapietra, 2020). However, no country has yet completed a shift from fossil fuels to low-carbon sources of energy. The economic implications of these transitions are often uncertain. While diverging assessments suggest that energy transitions may fuel future prosperity or become an economic burden (Mercure *et al.*, 2019), the emergence of new technologies, changes in energy demand, and conflicting policy evidence call for a continuous reassessment of the costs and benefits of energy transitions.

At the same time, several approaches, which vary in complexity and scope, are available to assess the economic impacts of such transitions. The methodology developed in this study is adapted from the assessment of costs incurred in decarbonizing the electricity sector in the U.S. (Heal, 2020). This approach is used to gain understanding of the magnitude of the costs associated with changes in the Canadian primary energy sector rather than quantifying the budget needed to fund a transition in great detail. Accordingly, the results presented in this chapter aim at providing a gross measure of energy transition costs in Canada. More specifically, this chapter provides an order of magnitude for primary-energy costs associated with a deep electrification of Canada's primary energy sector by comparing generation, transmission and storage investment costs incurred by electrification relative to fossil fuel expenditures for the scenarios explored in this Outlook.

Section 14.2 presents the main results derived from the calculation of primary energy transition costs in Canada; Section 14.3 discusses recent findings on projected costs to achieve carbon-neutrality globally; and Section 14.4 surveys the limitations and advantages of the different approaches available for analyzing the macroeconomic aspects of energy transitions. Appendix D presents a complete description of the methodology used in this chapter.

14.2 Costs of electrifying Canada's primary energy supply

Net costs associated with deep electrification of Canada's primary energy sector were calculated for three net-zero scenarios (NZ60, NZ50 and NZ45) and two baseline scenarios (REF, CP30). While baseline scenarios are not projected to generate annual savings in the next decades, all three net-zero scenarios suggest annual net savings may be possible from 2050 onwards (Figure 14.1). Estimates show that annual costs could reach up to $43 billion for baseline scenarios by 2060, while net-zero scenarios are projected to generate annual net savings as high as $78 billion.

This assessment includes the costs of investments in new electricity generation, transmission and storage, and change in fossil fuel expenditures. It does not include expenses associated with new infrastructures, such as charging stations or catenaries, or new equipment, such as heat-pumps and electric vehicles (e.g., Kayser-Bril *et al.* 2021). Although part of the savings will be used to cover these additional expenses, in many cases these transformations may be cost-neutral or cost-saving as markets drive lower costs for electric technologies. Appendix D details the investment costs taken into account in this assessment.

14.2.1 Results and discussion

Annual electrification investment costs (capacity, transmission and storage) and fossil fuel expenditures are calculated for all scenarios. Table 14.1 shows the annualized electrification investment costs and the change in annual fuel expenditures relative to 2016 figures. The investment costs are the amount to be spent annually during a given period to attain the carbon emission objectives of a given scenario. The change in annual fuel expenditures refers to the difference in the amount spent on fossil fuels between the lower bound year of each period and 2016.

Table 14.1 – Annual electrification investment costs and fossil fuel expenditures ($ billion)

		REF	CP30	NZ60	NZ50	NZ45
Electrification investment costs	2016-2030	4.0	8.0	6.1	9.8	13.5
	2030-2050	4.8	7.2	37.6	47.7	46.0
	2050-2060	-4.8	1.1	41.6	14.7	14.4
Change in fossil fuel expenditures	2030-2050	10.3	4.9	-3.1	-13.5	-17.1
	2050-2060	29.2	20.6	-54.3	-75.5	-74.4
	2060+	43.3	34.3	-77.7	-76.8	-73.6

Note: Positive numbers indicate cost increases and negative numbers indicate cost savings.

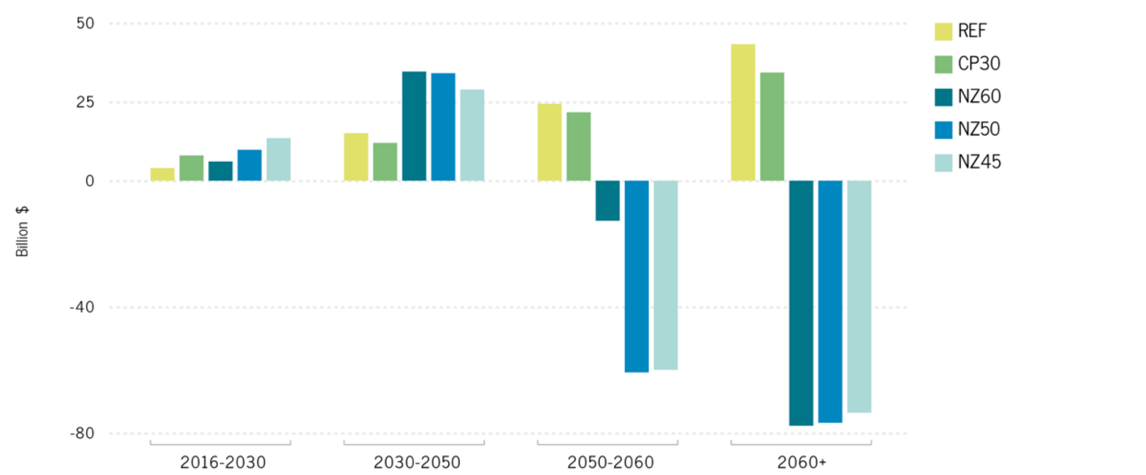
Cost projections for baseline scenarios suggest Canada's fuel expenditures will continue to rise, reaching $4.9–$29.2 billion annually in 2030–2060, while electrification investment costs will decrease over time. Net-zero scenarios suggest larger initial investments in capacity, transmission and storage compared to REF and CP30, reaching $14.4–$47.7 billion annually in 2030–2060. This result is also observed in the Energy PATHWAYS model's findings for the U.S., which indicated that unprecedented investments in new infrastructure would be needed to achieve long-term low-cost outcomes (Larson *et al.*, 2020). Net-zero scenarios suggest savings from avoided fossil fuel expenditures between $3.1 and $77.7 billion annually can be achieved from 2030 onwards.

For each scenario, net annual costs were reached by the sum of costs incurred from investments in new electricity capacity, transmission, and storage and the expenditures incurred from the replacement of fossil fuels with other energy modes (Figure 14.1). We refer to these costs as net costs since they take into account the change in annual fossil fuel expenditures, that is, savings in the net-zero scenarios. REF and CP30 scenarios suggest net annual costs will rise in the next decades due to increasing fuel consumption. The negative value for annual electricity costs in the REF scenario during the 2050–2060 period indicates savings due to a reduction in fossil fuel electricity generation capacity that will not have to be replaced.

Net-zero scenarios suggest that savings from changes in fossil fuels consumption gain importance and significantly outpace investment costs from 2050 onwards. When comparing investments in electricity across net-zero scenarios, investment costs in NZ45 are higher in 2016–2030, while NZ50 costs are higher in 2030–2050, and NZ60 costs are higher in 2050–2060. These scenarios show net annual savings after 2050 due to avoided fossil fuel consumption and heavy investments in electricity capacity, transmission and storage in the first decades. This result may also imply that early spending in electricity infrastructure could result in earlier savings in fossil fuels expenditure, as the bulk of infrastructure spending occurs closer to projected net-zero achievement.

Net annual costs range between 0.2% and 1.9% of GDP for all scenarios (Table 14.2). REF and CP30 suggest increasing cost ratios owing to greater consumption of fossil fuels over the next decades, reaching 1.9% of GDP in 2060. Investments in new electricity infrastructure in net-zero scenarios lead to cost ratios between 0.3 and 1.5% of GDP until 2050, similarly to results from the European Union's and Germany's (Andor *et al.*, 2017; Unnerstall, 2017) net zero pathways (D'Aprile *et al.*, 2020). From 2050 onwards, net-zero scenarios show savings ratios reaching 0.5%–3.4% of GDP.

Figure 14.1 – Net annual costs



Note: Negative values indicate net annual savings

Table 14.2 – Net annual cost (% of GDP)

Period	REF	CP30	NZ60	NZ50	NZ45
2016-2030	0.2	0.3	0.3	0.4	0.6
2030-2050	0.6	0.5	1.5	1.5	1.2
2050-2060	1.1	0.9	-0.5	-2.6	-2.6
2060+	1.9	1.5	-3.4	-3.3	-3.2

Note: Negative values indicate net annual savings.

14.2.2 Sensitivity analysis

Some investment costs assumptions adopted in the methodology are subject to variability and uncertainty. For instance, costs of new wind and solar capacity are expected to decrease over the next decades (IEA. 2020a). Fortunately, this supports our conclusions, as lower capacity costs for renewables imply that initial costs in electricity capacity would be lower in all net-zero scenarios. The same argument can be made for energy storage. Technological advancements will very likely reduce storage infrastructure costs (BloombergNEF, 2020).

However, some changes in the assumptions could alter results non-trivially. One such assumption is the price of combustibles used in our calculations. Because fossil fuels are commodities that are subject to global market volatility, it is difficult to accurately predict the prices of coal, natural gas and oil in the next few decades. Lower fossil fuel prices in the future would change the fuel savings calculated in this study. Transmission costs are also uncertain as projected high voltage power lines for Canada depend on several policy choices (Rodríguez-Sarasty *et al.*, 2021).

To mitigate the price uncertainty of fossil fuels and means of transmission, a sensitivity analysis was carried out, considering fossil fuel prices would be half their baseline price and transmission lines twice as expensive per kilometre. The results from the model with the modified fuel prices and transmission costs suggest that savings from avoided fossil fuels in net-zero scenarios are much smaller (Table 14.3).

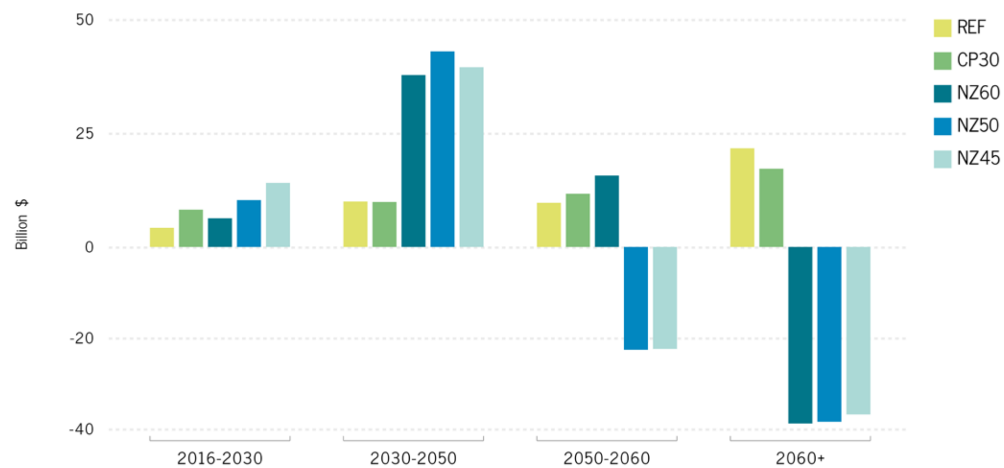
Annual costs show that uncertainty respecting fossil fuel prices or cost overruns in building long-distance power lines would not change the overall outcome of net-zero transitions (Figure 14.2). Lower net annual costs in REF and CP30 are due to lower avoided costs with fossil fuels. Net-zero scenarios still present net annual savings from 2050 onwards, with NZ60 showing net annual savings later than NZ50 and NZ45.

Table 14.3 – Annual electrification investment costs and fossil fuel expenditures ($ billion) – sensitivity analysis

		REF	CP30	NZ60	NZ50	NZ45
Electrification investment costs	2016-2030	4.2	8.2	6.3	10.3	14.1
	2030-2050	4.8	7.5	39.3	48.8	48.1
	2050-2060	-4.9	1.4	42.8	15.1	14.7
Change in fossil fuel expenditures	2030-2050	5.1	2.4	-1.5	-6.7	-8.6
	2050-2060	14.6	10.3	-27.2	-37.8	-37.2
	2060+	21.6	17.1	-38.8	-38.4	-36.8

Note: Positive numbers indicate cost increases and negative numbers indicate cost savings.

Figure 14.2 – Net annual costs ($ billion) – sensitivity analysis



14.3 Investments to reach carbon-neutrality

Many studies have sought to determine whether or how energy transitions can generate economic opportunities (Kuzemko *et al.*, 2020), lead to unsustainable debt levels (Kempa *et al.*, 2021) or hinder economic growth (Court *et al.*, 2018). One macroeconomic analysis suggested that energy transitions could grow global GDP and total employment by 2050 (Garcia-Casals *et al.*, 2019). Another study concluded that energy transitions might be the only way to ensure GDP growth in the future (Nieto *et al.*, 2020). Low-cost electricity could be a feasible way to address global energy demand, with infrastructure costs to produce and distribute renewable energy constituting the largest share of energy expenditures in a net-zero future (Bogdanov *et al.*, 2021). Substantial energy infrastructure costs could also result in investment-to-GDP ratios reaching historical levels akin to wartime spending (Režný and Bureš, 2019).

For instance, achieving the decarbonization of the EU-27 economy by 2050 is estimated to require a total of EUR28 trillion invested over the next three decades (D'Aprile *et al.*, 2020). This would comprise EUR23 trillion (EUR800 billion annually) of funds that would otherwise be invested in incumbent technologies and EUR5.4 trillion (EUR180 billion annually) of additional capital. Reaching net-zero would thus require the equivalent of 1% of the European Union's GDP when considering a range of 600 emissions-reduction initiatives, including emerging technologies that are not yet commercially available (D'Aprile *et al.*, 2020). In the U.S., the Energy PATHWAYS model concluded that a successful net-zero transition could be accomplished with annual spending on energy comparable or lower to what the country currently spends annually on energy as a percentage of the GDP (Larson *et al.*, 2020). The study provided five different technologically and economically plausible energy system pathways and suggested that unprecedented rates of technology and infrastructure deployment will be needed to achieve the lowest-cost outcomes in the country.

Another approach has been proposed to calculate the costs of decarbonizing the electricity sector in the U.S. (Heal, 2020). The costs of transitioning all the electricity production from fossil fuels to solar and wind generation between 2020 and 2050 in the U.S. were estimated at roughly US$6.1 billion annually (Heal, 2020). These estimates suggest that the net costs of the transition to renewable energy in the U.S. are much lower than generally believed due to decreasing capital costs of renewable energy over the last decade (IEA, 2020a). Removing fossil fuels from electricity generation would thus be feasible at a cost that is less than current national expenditure on energy capital equipment. However, these values can only be interpreted as rough estimates of the net cost for decarbonizing the electricity sector in the country.

In Germany, more optimistic assessments have indicated higher economic growth due to early adoption of renewable energy (Blazejczak *et al.*, 2014), although these benefits arguably come at a cost. For example, the country's feed-in tariff system for renewable energy has contributed to the highest increase in electricity rates since 2010 amongst OECD countries (Andor *et al.*, 2017). This increase in the cost of living is despite the 0.8% of GDP invested in renewable energy annually, as Germany started its transition when the costs of renewable energy technology were at their highest. However, the results would be markedly different for a country starting the same transition later. The same decarbonization efforts were projected to cost around only 0.15% of the country's GDP if the transition had occurred between 2017 and 2030 (Unnerstall, 2017), suggesting that technology maturity and rapidly changing costs of power capacity can lead to a substantial cost difference.

Other country-specific studies have also indicated similar results. In Canada, achieving complete decarbonization of electricity production by 2025 could cost \$8.2–\$12.6 billion annually. These estimates vary in function of new transmission lines built across the country, whereas costs could increase by \$16 billion if no new inter-provincial transmission connections are built. This means that the availability of new transmission could reduce decarbonization costs by \$4.2 billion (Dolter and Rivers, 2018). Turkey's energy transition is projected to be costly in the beginning, followed by a reduction of fuel imports and lower electricity production costs by 2050 (Kilickaplan *et al.*, 2017), whereas in Portugal capital costs for a transition may not be higher than expenditures in the oil and gas sector (Fortes *et al.*, 2019).

14.4 Macroeconomic aspects of an energy transition

The wide-ranging impacts of energy transitions in the economy cannot be captured by one single model or approach (Chang *et al.*, 2021). Models of lower complexity are often argued to be more appropriate for decision-making due to their apparent transparency. For instance, in the 1990s, the Dynamic Integrated Climate Economy (DICE) model attempted to understand the interplays of economy and climate change by considering only a few variables (Nordhaus, 1992). Although this model was originally designed for illustrative purposes, it has been used for policy purposes in some countries (Mercure *et al.*, 2016). Models with higher complexity may be more difficult to use, but often present more realistic representations of economic and energy systems. Over and above these considerations, two main approaches for the assessment of macroeconomic aspects in energy transitions can be summarized.

The first approach relies on a descriptive analysis of historical data expressed through a set of indicators and is particularly suitable for an informative and quantifiable overview of the current situation. These "basic" (EPA, 2011) or "analytical" (Hardt and O'Neill, 2017) approaches can be used to obtain broad estimates. Models can be considered analytical if they contain few equations that can be solved numerically by iterative techniques, that is, they can be explained in terms of equations that describe the relationship between different parameters. However, with no attempt to represent the underlying complexity between macroeconomy and energy systems, these models are characterized by relatively simple formulations and data.

While analytical approaches require minimal input data, time and technical expertise, they can also be used for preliminary analyses purposes (EPA, 2011). The Job and Economic Development Impact (JEDI) assessment is an example of a model to estimate the economic impacts of constructing and operating power plants (EPA, 2011). Models based on Input-Output (IO) tables can provide a snapshot view of the economy and are commonly applied to analyze interactions and feedback effects between mutually interdependent industrial sectors (Berg *et al.*, 2015). One analytical model was proposed to determine the effects of transitioning from fossil fuels to renewable energy on GDP per capita (D'Alessandro *et al.*, 2010).

In contrast, the second approach relies on more complex "numerical" models (Hardt and O'Neill, 2017). Numerical models rely on computer-based simulations and often contain a larger number of equations and assumptions. Modelling techniques in numerical approaches, such as Computable General Equilibrium (Vrontisi *et al.*, 2019), Hybrid Models (Ghersi, 2015) and Econometrics (Režný and Bureš, 2018; Garcia-Casals *et al.*, 2019), are useful when analytical rigour is desired and when sufficient data, time and resources are available. In order to conduct a numerical-based macroeconomic analysis of energy transitions, a representation of interactions between the energy systems and the rest of the economy is needed to capture how energy, socioeconomic and environmental aspects interact with each other (EPA, 2011; Lutz *et al.*, 2014). Computational modelling was already used for energy planning as early as the mid-1970s to understand the implications of the first oil embargo (Nakata, 2004).

However, the outcomes of numerical models are tied to implicit theoretical aspects. For instance, conventional equilibrium models imply that all resources are currently allocated in the economy in the most productive way they can be, even though this assumption cannot be verified empirically. Other studies are criticized for their limited treatment of societal actors and socio-political dynamics, while numerical models based on cost-benefit analysis and cost-optimization have several shortcomings (Hardt and O'Neill, 2017). These considerations cast doubt on the realistic representations of numerical approaches and their ability to provide reliable evidence for policy processes (Mercure *et al.*, 2016). It is thus critical to lay out the assumptions and theoretical aspects of numerical approaches in a way that allows for the interpretation of results beyond uncertainties and limitations.

Overall, analytical and numeric approaches have different levels of complexity and vary in scope, yet both rely on approximations and trends. Analytical approaches often use simplified reproductions of macroeconomic dimensions, while challenges in predicting technology adoption and diffusion (IEA, 2020b), change in human behaviour (D'Aprile *et al.*, 2020; Larson *et al.*, 2020), and policy effectiveness and implementation (Mercure *et al.*, 2019) can be observed in numerical approaches. The key consideration for deciding which specific approach should be used thus lies in whether science-policy interfaces can use the results from these approaches to inform specific decision-making processes.

14.5 Conclusions

The assessment of net costs for three net-zero scenarios (NZ60, NZ50 and NZ45) and two baseline scenarios (REF, CP30) suggests that significant investments in the electrification of Canada's primary energy sector from 2016 to 2050 are required in net-zero scenarios. These are larger than the investments needed in baseline scenarios. However, after 2050, net-zero scenarios may lead to significant net savings due to decreases in fossil fuel consumption. As such, infrastructure investments in the early stages of transitions will be compensated by lower fossil fuel expenditures in the following decades. These results are comparable to those obtained in other studies, notably the conclusions of the Energy PATHWAYS model, in which large infrastructure expenditures in the U.S. are necessary to capture important cost savings afterwards (Larson *et al.*, 2020).

Comparisons can also be drawn between previous studies on investment-to-GDP ratios. The results from this model suggest that annualized net costs range between 0.3% and 1.5% of GDP. Similar values were obtained for the cost of energy transitions in the European Union (D'Aprile *et al.*, 2020) and Germany (Andor *et al.*, 2017; Unnerstall, 2017). After carbon neutrality is reached, net-zero scenarios show net savings between 0.5% and 3.4% of GDP. While the figures in this chapter should not be interpreted as the output of a precise budgeting tool, the results indicate that energy transitions in Canada are not outlandish and are in fact economically feasible.

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15 CONCLUSION—THE CHALLENGES OF TRANSFORMING CANADA'S ENERGY SYSTEM TOWARD NET-ZERO

Canada disposes of some of the richest energy resources in the world and is a leading producer of fossil fuels, uranium ore and hydroelectricity. These resources contribute to supporting Canada's rich economy, both directly, as a major export, and indirectly, by providing low-cost energy for its own economy. However, this historic advantage has also allowed Canada to be one of the OECD's lowest energy-productive economies by attracting energy-intensive industries and paying insufficient attention to the efficient use of energy.

This concluding chapter briefly underlines essential points on the current status of these questions in Canada and presents what the modelling teaches us about how Canada can transform its energy production and use if it wants to reach its GHG targets, both for the 2030 and longer-term horizons.

15.1 The potential to reach net-zero by 2050

As the world faces ever increasing disruptions caused by human-induced climate change, the characteristics of Canada's energy production and consumption profile offer both challenges and advantages as it plans an aggressive reduction in its GHG emissions. The challenges include nationwide energy-hungry extraction and industrial sectors, a highly polluting transport sector, a strong economic regional dependence on fossil fuel production, and significant provincial disparity in addressing the energy transition. The advantages consist in the electricity sector being decarbonized at more than 80%, possession of the largest installed hydro reservoirs in the world, considerable potential resources for variable energy production, and substantial uranium and biomass resources.

Building on Canada's GHG emission status, this Outlook explored potential transformations of its energy sector through various optimal techno-economic scenarios centered around Canada's GHG targets for 2030, 2050 and beyond. As the modelling demonstrates, while reaching net-zero by 2050 is technically and economically attainable, it requires deep changes in Canada's energy system. Although some of these changes are already taking place, they are still largely insufficient to ensure the targets will be reached on time.

In lieu of a conclusion, we review a number of issues that are determinant for the transformation of Canada's energy system and that further the understanding of the challenges that the country faces not only to reach its GHG targets, but also to figure out how it can move forward to overcome them.

15.1.1 A missed collateral effect of the pandemic

The effects of the 2020-2021 pandemic on the energy sector and GHG emissions have been drastic. Although the official numbers are not yet available, the pandemic, particularly in the first part of 2020, coupled with an oil-price war, hit Alberta and other fossil-fuel producing provinces very hard. According to ECCC estimates, the slowing down of the economy could have led to a 11% drop in GHG emissions from 2019 to 2020, bringing them to (still) 637 $MtCO_2e$ (ECCC 2021).

While there has been much speculation since March 2020 as to the long-term structural effects of the pandemic, evidence suggests that they will be minor. Canada's GDP has largely bounced back in 2021 and by the end of June it had almost returned to its pre-pandemic level, although employment levels in May 2021 were still 3.9 points below February 2020. Given extensive vaccination, the pandemic should not have any lasting effect on Canada's overall economy—with the exception of a rise in telecommuting. Since both governments and economic actors missed the opportunity to initiate deep transformations in energy production and energy usage, it is likely that energy consumption and GHG emissions will be back to 2019 levels by 2022. This explains in large part why the effect of the pandemic is not specifically treated in the modelling.

15.1.2 The 2030 milestone

The REF scenario of this Canadian Energy Outlook (CEO2021) suggests that measures in place at the federal and provincial levels are insufficient to prevent the growth of GHG emissions; with respect to 2005, these are projected to grow by 3% by 2030. Although including the raising of the carbon price to $170/t by 2030 (CP30) will reverse this trend, this initiative would lead to overall reductions of only 13% with respect to 2005 by 2030. Including the projected reduction of emissions from the implementation of the Clean Fuel Standard brings the reduction only around 3% further (ECCC 2019), leaving total reductions at a level considerably less than the previous 30% reduction target for that year and even further from the recently revised objective of a 40%-45% reduction. As the sections below explain, special attention to the 2030 horizon is essential in analyzing the impact of choices made today – or the absence thereof – for the pathways to net-zero on the longer-term.

What do the various scenarios teach us for 2030?
Extending the modelling period until 2060, the CEO2021 presents cost-optimal transformation trajectories given a certain number of constraints. While REF and CP30 do not impose specific emission reductions, NZ60, NZ50 and NZ45 constrain trajectories compatible with various Canadian GHG targets. In particular, as explained in Chapter 1, NZ60 imposes the official 30% reduction by 2030 with respect to 2005, while NZ50 requires the newly announced goal of a 40% reduction over the same time window.

Comparing CP30's evolution with that of NZ60 and NZ50 (Table 15.1) over the next years enables us to make some specific observations as to foreseeable difficulties and ways to achieve the required transformations, while underlining the challenge that reaching these targets represents in trying to remain on a path to net-zero by 2050.

Table 15.1 – Emission reductions by sector for NZ60 and NZ50 with respect to the model's reference year (2016)

	2016		2030			2050	
	$MtCO_2e$	CP30	NZ60	NZ50	CP30	NZ60	NZ50
Reductions wrt 2005 (730 $MtCO_2e$)		-9%	-28%	-38%	-15%	-79%	-100%
Total emissions ($MtCO_2e$)	705	642	511	438	598	146	0
Main contributing sectors							
Electricity	82	-60%	-70%	-89%	-94%	-155%	-167%
Waste	17	-52%	-63%	-63%	-58%	-64%	-68%
Oil and gas (including fugitive emissions)	161	+7%	-54%	-60.0%	+14%	-88%	-94%
Residential buildings	41	-27%	-33%	-41%	-74%	-93%	-95%
Sectors difficult to decarbonize							
Industry	116	-22%	-26%	-42%	-18%	-106%	-134%
Commercial buildings	31	-3%	-8%	-21%	-9%	-94%	-98%
Agriculture	60	+8%	-5%	-5%	+20%	-27%	-31%
Transport	197	+8%	5%	-6%	+0%	-36%	-74%

The holdout sectors

While technology is available to transform building heating, costs and barriers to investments limit the transformation of this sector over the 2030 horizon and total reductions are below overall targets at -22% and -32% respectively for NZ60 and NZ50, when combining residential and commercial buildings. The building sector is therefore both a low-hanging fruit, because of existing solutions, and a resisting sector due to barriers to entry associated with the technologies needed and the scale of the transformation, which involves hundreds of thousands of buildings.

Transport and agriculture are also difficult to decarbonize over a short horizon. While emissions rise in both CP30 and NZ60, transport decreases its emissions by only 13 $MtCO_2e$ (-6 %) in NZ50, with a similar percentage reached for agriculture.

Energy efficiency and productivity

Many analyses place energy efficiency at the center of decarbonization.[1] While energy efficiency must be sought, historical trends do not support its use as a deep change actor. There are a few reasons for this. First, low-cost energy efficiency is already being implemented in cost-optimized projections, irrespective of GHG targets. Second, energy efficiency requires often careful management that is not sustained over time.[2] Lastly, in the quest for net-zero emissions, it is sometimes necessary to reduce energy efficiency, for example by replacing natural gas with biomass in a furnace.

Energy productivity is a much more reliable approach, especially in the context of electrification. Moving from fossil fuel to electric propulsion, for instance, can increase energy productivity by a factor of three to four. Similarly, replacing electric headboards with heat pumps can multiply energy productivity by two to four. However, this gain is already included in the cost-optimized trajectories presented here and, as such, cannot be counted in addition to the discussed transformations.

Acting on the only possible lever: oil and gas production

In both NZ60 and NZ50, with the exception of waste, electricity production and industry, no sector discussed in this section comes near to reaching its respective fraction of emissions reduction. The CEO2021 modelling for NZ scenarios underlines that to reach 2030's targets, oil and gas production, including fugitive emissions, must compensate for the lack of GHG reductions of other sectors where decarbonization is hardest.

To do so, oil and gas reduce emissions by 54% and 60% for NZ60 and NZ50, respectively, representing a decline of 86 to 97 $MtCO_2e$ with respect to 2016. With projected gains in emission intensity, these targets are associated with a production reduction of nearly 60%. While Chapter 7 discusses alternative pathways that preserve a high production level, all trajectories to reach 2030's targets involve emission reductions for this sector that are above national targets and that compensate for the challenges of decarbonizing the other sectors.

If demand for oil and gas in the rest of the world decreases over the next year, with oil and gas prices falling, Canadian production will naturally falter along with emissions. However, with higher prices, reducing emissions will be more challenging and involve either limiting production or the rapid deployment of effective large-scale technologies to capture and sequester emissions.

The role of industrial transformation

As revealed by this Outlook's modelling, the rapid reduction in emissions needed to reach 2030 targets cannot occur through changes at the individual or distributed level—be they in transport, buildings, or personal buying habits. Sectors that will drive the reduction include a relatively small number of units that interact closely with governments: electricity production, heavy industry and oil and gas. This makes it both easier for authorities to engage in dialogue and harder to resist lobbies. More openness about this challenge, similar to what took place in the 1980s with the ozone-layer, could help build popular pressure to make the appropriate moves.

[1] J. Dion, A. Kanduth, J. Moorhouse, and D. Beugin. 2021. *Canada's Net Zero Future: Finding our way in the global transition*. Canadian Institute for Climate Choices. https://climatechoices.ca/wp-content/uploads/2021/02/Canadas-Net-Zero-Future_FINAL-2.pdf

[2] Saranya Gunasingh, Joe Zhou, and Scott Hackel. 2018. *Persistence of Savings from Retro-Commissioning Measures. A field study of past ComEd Retro-commissioning projects*. Report by Seventhwave. https://slipstreaminc.org/sites/default/files/documents/publications/retrocommissioning-persistence-studyfinal-reportoct-2018.pdf

15.1.3 Thinking in terms of pathways

Irrespective of the modelling tools, the challenge of reaching 2030 targets has changed with the long-term net-zero goal. As long as 2050 involved an ambitious 70% or even 80% GHG reduction, it was possible to see partial decarbonization solutions, such as fuel switching or more aggressive energy efficiency measures, as viable.

With a net-zero focus on a 30-year horizon, such an approach is no longer economically realistic. It makes no sense to deploy technological solutions, such as natural gas in transportation, that will have to be replaced in 15 or 20 years. Such a diversion will reduce investments for net-zero solutions, increasing their cost and further delaying the transformation. This emerges very clearly from the modelling results presented in this document, which show almost no adoption of such technology.

More important than 2030 targets is thus the deployment of measures and the start of deep transformations that will lead to net-zero over a 30-year horizon. It is essential to avoid making moves for the short run that will hinder the longer play.

15.1.4 Current plans need more coherence

As revealed in our modelling (REF scenario), Canada's current approach, when including all publicly available federally and provincially adopted programs and measures, is insufficient to even halt the growth of GHG emissions. Largely driven by the oil and gas sector and transport, emissions are projected to slowly grow for the foreseeable future, in line with the Canada Energy Regulator's projections.

Beyond the measures already adopted, the federal government presented a new plan in December 2020 that includes more than $6 billion in investments, as well as a significant price increase on carbon that will reach $170/tCO_2e$ by 2030. While the expected outcome from the investments is not detailed enough to be modelled, the announced increase in carbon pricing, coupled with the coming Clean Fuel Standard, should deliver a significant GHG reduction over this timeframe. However, according to our model, this reduction is far from the 40-45% GHG emissions reduction promised with respect to 2005. Many emitting sectors, including buildings and transport, need more incentives and more guidance to be able to deeply transform on their own. Regrettably, even though many provincial governments and their federal counterpart have published various strategies for decarbonizing their economy, often announcing billions of dollars of investments, they are generally not coherent, focused or detailed enough to deliver the reductions needed to reach emission targets.[3]

This lack of internal focus within decarbonization strategies is compounded by the absence of overall coherence among the various governmental ministries: as some push for reducing emissions, others continue to support the development of fossil fuels production and use, as well as GHG-intensive industries, sending conflicting messages to citizens and investors.

[3] It is, of course, possible that confidential programs, objectives and measures could deliver the missing reductions. We believe that it is essential for the federal and provincial governments to make this information public so that it can be assessed independently and used by citizens, industry and other governments, to orient their decisions, investments and orientations.

15.2 Learning from modelling Canada's transformation

By modelling various net-zero scenarios, looking at the order in which sectors decarbonize (Table 15.1), and testing various modifications through sensitivity analyses, we are able to draw a number of important conclusions.

15.2.1 Net-zero changes everything

1. **Moving towards a net-zero emission society means that targeting partial reductions of GHG emissions is neither sufficient nor in most cases appropriate.** For example, moving from diesel to natural gas in trucking is not a transformation compatible with net-zero, further debunking the idea of a transition fuel. Similarly, carbon capture and use still leads to net positive GHG emissions that must be captured and sequestered elsewhere in the economy, adding considerable costs to the transition. Given the short horizon for net-zero, all efforts and investments must be aligned with a carbon-neutral society and maintain a sharp focus on intrinsic zero-emission for the maximum number of activities.
2. **Reaching net-zero means giving priority to preventing emissions rather than compensating them with capture.** Given the uncertainties surrounding negative-emission approaches—nature-based and technological—it is at present more cost-beneficial and strategically structuring to limit their use to capturing emissions to compensate those that are almost impossible to prevent, as in agriculture and some industrial processes.
3. **While energy efficiency and productivity are important contributors to the transformation of the energy system, they can in some cases be incompatible with a net-zero objective.** Replacing fossil fuels for electricity will provide significant gains in energy productivity, especially for transport and heating. For example, electric cars consume three to four times less primary energy for the same distance traveled, while heat pumps can provide a service equivalent to three times the energy consumed. However, eliminating GHG emissions can also decrease energy productivity, with the use of hydrogen produced by electrolysis or biomass instead of natural gas in heat production, or by relying on storage to reduce electricity peak demand.
4. **The energy system will continue to evolve after reaching net-zero as relative costs and available technologies change.** This means that non-optimal solutions that deliver on net-zero will most likely be updated in the future; it is therefore not essential that everything be perfect the first time—as long as compatibility with net-zero is taken into consideration.

15.2.2 A need for more effective approaches

5. **Reaching net-zero by 2050 will be much cheaper than projected.** Marginal cost analysis of NZ50 in 2050 (Figure 8.7) and an analysis of the cost of electrifying the primary energy supply (Chapter 14) show that reducing emissions is economically viable and could even deliver considerably savings. A comparison with results from our previous Outlook (Langlois-Bertrand *et al.*, 2018) also shows that decarbonization costs are falling much more rapidly in some sectors than our modelling hypotheses projected, a trend that is likely to persist.
6. **Achieving net-zero requires strong leadership and making immediate difficult choices.** A number of structural barriers, including ill-conceived programs, regulatory and innovation barriers, risk aversion, the slow pace of technological adoption, inadequate workforce training, financial incongruities, and regional economic fabrics, are preventing even cost-beneficial investments that would accelerate the transformation of Canada's energy production and consumption pattern. These barriers cannot be overcome simply with a price on carbon; they must be lowered or eliminated through a strategic, coherent and integrated approach, led at the highest levels of governments, in order to deliver significant results on a horizon of one to four years from now (e.g., see also Meadowcroft 2019 and 2021).

7. **The most cost optimal way to reach 2030 targets is to significantly reduce emissions from the oil and gas sector.** In view of current estimated costs for CCS, our model shows that this must take place through a significant reduction in production. More specifically, the emission reductions through production cuts in this sector are cost optimal. Maintaining current emission levels for this sector would require a much faster decarbonization of the other sectors, including electricity, buildings, industry and transport. However, policies are not in place for some of these sectors, while for others, economically competitive solutions are unlikely to be available on a sufficiently short horizon to enable the transformation needed by 2030.
8. In addition to oil and gas, **the industrial, commercial and electricity sectors must bear the largest efforts early on. Governments should therefore focus a major share of their attention on these sectors.** Due to the nature of Canada's economy, less than 20% of all GHG emissions can be directly assigned to citizens' direct choices, including residential heating (6%) and personal transport - individual vehicles (11%) and airplanes (1%). Indirect emissions associated with consumption can be significant, but for the large fraction of imported goods, these emissions are not assigned directly to Canada. As suggested by the numbers in Table 15.2, to meet their GHG reduction commitments, governments should set targets and develop sector-specific programs for each of the aforementioned sectors.
9. **Transport does not transform as quickly as might be expected.** Transport is one of the sectors where governments are most active with regulations, such as the proposed Clean Fuel Standard (CFS) or those respecting the sales of internal combustion engine vehicles, and massive subsidy programs. While some efforts, such as the CFS, are not compatible with net-zero ambitions (see item 1 in this list), others can only do so much as vehicle fleets typically take 7-10 years to completely renew. Planned for no sooner than 2035, the net effect comes too late for 2030 targets. Decarbonizing transport also requires early and decisive action at multiple levels to ensure results by 2050. While essential, net-zero compatible urban-planning will take decades to have an impact; similarly, heavy public transportation and infrastructures for decarbonizing freight transport can take a decade to plan and build and will require many years afterward to produce results.

15.2.3 Looking beyond modelling

10. **Current international agreements can lead to exports of emissions.** NZ scenarios that follow the Paris Agreement definitions favour a strong decrease in oil and gas production with, in some cases, additional imports of refined fuels for Canada's needs, as production emissions abroad are not added to Canada's GHG balance. Modelling also leaves unaccounted emissions associated with goods produced outside of Canada's borders, while assigning emissions from products that are consumed abroad to Canada. Total carbon pricing for goods, which would assign the environmental costs to the final user, would avoid this issue.
11. **Strong general results do not equate to certainty on all changes, as details will depend on specific developments.** Modelling results closely depend on the conservative hypotheses that we have adopted about the evolution of technologies, the barriers to investments and the overall costs of the transformation. This means that the specific evolution in the understanding of agriculture and nature-based solutions, as well as of technologies under intense development such as hydrogen, small nuclear reactors, large scale energy storage, many industrial processes, and heavy transport, is still uncertain and even unknown. Their future is dependent not only on further research and technological progress but also on political orientations and choices that will lock in some of the infrastructure-heavy solutions (such as catenary or hydrogen-powered trucks) early-on and, by doing so, reduce the number of possible futures to consider (Meadowcroft 2019 and 2021).

15.3 Reconciling discourse and reality: a shared responsibility

These observations, drawn from the modelling results as well as an analysis of the recent evolution of Canada's energy system and GHG emissions, should concern all Canadians. Canada's constitution means that the power of defining climate goals and the responsibility for reaching them are shared by many orders of governments. Over the last two decades, these governments have worked mainly in silos, largely ignoring what the level above or below or the other jurisdictions were doing. This approach, which was accompanied by billions of dollars in subsidies and support of all kinds, has largely failed to deliver the promised transformations.

As this Outlook suggests, continuing with this approach will not enable Canada to reach the GHG targets it has adopted. The depth and speed of transformation needed to do so requires strategy, coordination and efficiency to a degree that is almost unheard of in Canada. Nonetheless, as demonstrated, this is not impossible. From a purely techno-economic point of view, this transformation is affordable and realistic. However, it requires governments, industry and citizens to think and act boldly and in the most open fashion, to accept risk and failure, to embrace change, and to understand that we cannot wait for the perfect solution before we begin to take action.

15.4 References

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APPENDICES

A MAIN MODELLING HYPOTHESES

This Appendix gives an overview of the main hypotheses used by NATEM for this Outlook.

Main macroeconomic hypotheses

Table A 1 – Real GDP

	2020 $2012 Millions	2030 $2012 Millions	2040 $2012 Millions	2050 $2012 Millions
CAN	$ 1,967,403	$ 2,485,475	$ 2,927,379	$ 3,376,625
AB	$ 321,426	$ 423,912	$ 491,053	$ 561,697
BC	$ 258,060	$ 343,769	$ 434,007	$ 514,776
MB	$ 64,395	$ 76,718	$ 86,876	$ 97,397
NB	$ 32,253	$ 37,232	$ 40,103	$ 41,819
NL	$ 30,590	$ 30,017	$ 30,251	$ 27,790
NS	$ 39,705	$ 47,328	$ 53,245	$ 57,392
NT	$ 4,410	$ 5,203	$ 5,660	$ 6,105
NU	$ 3,127	$ 3,525	$ 4,056	$ 4,817
ON	$ 743,502	$ 935,937	$ 1,111,428	$ 1,305,276
PE	$ 6,344	$ 8,037	$ 9,689	$ 11,152
QC	$ 381,214	$ 469,782	$ 541,908	$ 612,390
SK	$ 80,081	$ 101,546	$ 116,497	$ 133,199
YT	$ 2,893	$ 3,226	$ 3,496	$ 3,845

Source: CER (2020). Canada's Energy Future 2020: Energy Supply and Demand Projections to 2050. Macro Indicators.

Table A 2 – Demography

	2020 Persons	2030 Persons	2040 Persons	2050 Persons	2060 Persons
CAN	37,873,700	41,888,100	45,506,800	48,763,100	52,125,000
AB	4,472,800	5,360,500	6,317,800	7,296,617	8,273,243
BC	5,103,500	5,632,900	6,096,400	6,542,190	6,989,516
MB	1,381,900	1,534,800	1,692,500	1,852,417	2,012,066
NB	775,600	796,600	798,100	792,751	788,081
NL	522,300	502,000	470,100	435,122	400,452
NS	967,100	996,100	998,700	992,593	987,315
NT	45,100	47,400	48,600	49,249	49,971
NU	39,300	43,900	48,800	53,718	58,620
ON	14,677,900	16,411,600	17,892,000	19,267,375	20,653,836
PE	157,400	177,600	193,600	208,050	222,630
QC	8,494,500	8,958,900	9,353,100	9,745,387	10,137,053
SK	1,195,100	1,380,400	1,548,700	1,705,701	1,864,042
YT	41,300	45,400	48,300	51,032	53,753

Source: StatCan (2019). Projected population, by projection scenario, age and sex, as of July 1

Main energy prices used for energy commodities imported/exported from/to Canada

Table A 3 – CER's Reference scenario

CANADA		2020	2030	2040	2050
Brent	2019 US$/bbl	$ 37.00	$ 75.00	$ 75.00	$ 75.00
West Texas Intermediate (WTI)	2019 US$/bbl	$ 32.00	$ 71.00	$ 71.00	$ 71.00
Western Canadian Select (WCS)	2019 US$/bbl	$ 18.00	$ 58.50	$ 58.50	$ 58.50
Henry Hub	2019 US$/MMBtu	$ 2.05	$ 3.50	$ 4.00	$ 4.25
Nova Inventory Transfer (NIT)	2019 US$/MMBtu	$ 1.30	$ 2.57	$ 3.10	$ 3.35
Canadian Light Sweet (CLS)	2019 US$/bbl	$ 25.40	$ 68.68	$ 68.67	$ 68.67

Source: CER (2020). Canada's Energy Future 2020: Energy Supply and Demand Projections to 2050. Benchmark Prices.

Table A 4 – CER's Evolving scenario

CANADA		2020	2030	2040	2050
Brent	2019 US$/bbl	$ 37.00	$ 55.00	$ 54.17	$ 50.00
West Texas Intermediate (WTI)	2019 US$/bbl	$ 32.00	$ 51.00	$ 50.17	$ 46.00
Western Canadian Select (WCS)	2019 US$/bbl	$ 18.00	$ 38.50	$ 37.67	$ 33.50
Henry Hub	2019 US$/MMBtu	$ 2.05	$ 3.35	$ 3.75	$ 3.75
Nova Inventory Transfer (NIT)	2019 US$/MMBtu	$ 1.30	$ 2.42	$ 2.85	$ 2.85
Canadian Light Sweet (CLS)	2019 US$/bbl	$ 25.40	$ 48.68	$ 47.84	$ 43.67

Source: CER (2020). Canada's Energy Future 2020: Energy Supply and Demand Projections to 2050. Benchmark Prices.

Oil, gas and coal production profiles

Table A 5 – Crude oil production

CANADA		2020	2030	2040	2050
Total	k bbl/d	4,595	6,224	7,056	7,077
Conventional Light	k bbl/d	612	731	863	837
Conventional Heavy	k bbl/d	631	821	904	934
C5+	k bbl/d	138	173	205	216
Field Condensate	k bbl/d	349	562	762	834
Mined Bitumen	k bbl/d	1,451	1,723	1,711	1,608
In Situ Bitumen	k bbl/d	1,414	2,213	2,611	2,648
(Upgraded Bitumen)	k bbl/d	1,067	1,245	1,307	1,272

Source CER (2020). Canada's Energy Future 2020: Energy Supply and Demand Projections to 2050.

Table A 6 – Natural gas production

CANADA		2020	2030	2040	2050
Total	G ft3 / d	15.72	17.46	21.68	23.21

Source: CER (2020). Canada's Energy Future 2020: Energy Supply and Demand Projections to 2050.

Table A 7 – Coal production

CANADA		2020	2030	2040	2050
Total	kT	45,136	27,379	26,042	25,315

Source: CER (2020). Canada's Energy Future 2020: Energy Supply and Demand Projections to 2050.

Carbon Capture and Storage (CCS) costs

Table A 8 – CCS technology costs

	CCS Additional investment cost $/tonne of material produced	CCS Additional investment cost $/tonne of CO_2
Cement	$ 63.07	$ 55.00
Iron and steel - Pellet/Sinter	$ 27.01	$ 90.00
Iron and steel - Iron making	$ 34.66	$ 78.50
Iron and steel - Foundries	$ 19.90	$ 78.50
Pulp and paper	$ 22.46	$ 57.70
Chemical industry	$ 34.92	$ 65.00

Table A 9 – Investment costs

	2020 $/kW	2030 $/kW	2040 $/kW	2050 $/kW
Combined Cycle + CCS Power plant	$ 4,516	$ 4,243	$ 4,114	$ 3,986
Coal+CCS	$ 7,150	$ 6,812	$ 6,490	$ 6,127
Biomass + CCS	$ 6,621	$ 6,350	$ 5,964	$ 5,545

Table A 10 – Subsidies per unit

	2020 $/kW	2030 $/kW	2040 $/kW	2050 $/kW
Combined Cycle + CCS Power plant	$ 2,258	$ 2,121	$ 2,057	$ 1,993
Coal+CCS	$ 3,575	$ 3,406	$ 3,245	$ 3,064
Biomass + CCS	$ 3,311	$ 3,175	$ 2,982	$ 2,773

Electricity-related costs

Table A 11 – Electricity investment costs

	2020 $/kW	2030 $/kW	2040 $/kW	2050 $/kW
Biomass				
Dedicated Solid Biomass central	$ 4,771	$ 4,667	$ 4,479	$ 4,262
Dedicated Solid Biomass central + CCS (90%)	$ 6,621	$ 6,350	$ 5,964	$ 5,545
Dedicated wood pellet central	$ 4,771	$ 4,667	$ 4,479	$ 4,262
Landfill Gas Internal Combustion Engine				$ 1,353
Coal				
Ultra-supercritical Pulverized Coal	$ 4,658	$ 4,528	$ 4,408	$ 4,259
Integrated.Gasification Combined.Cycle Coal	$ 5,025	$ 4,644	$ 4,446	$ 4,255
Ultra-supercritical Pulverized Coal + CCS (30%)	$ 6,465	$ 6,160	$ 5,869	$ 5,541
Ultra-supercritical Pulverized Coal + CCS (90%)	$ 7,150	$ 6,812	$ 6,490	$ 6,127
Coal + Biomass				
Ultra-supercritical.Pulverized coal Cofire with biomass	$ 5,125	$ 4,907	$ 4,787	$ 4,638
Geothermal				
Hydrothermal Dual Flash Steam Geothermal	$ 5,454	$ 5,188	$ 4,934	$ 4,693
Hydrothermal Binary Cycle Geothermal	$ 7,036	$ 6,692	$ 6,365	$ 6,054
Enhanced Geothermal Systems Near-Hydro Flash	$ 18,718	$ 17,803	$ 16,932	$ 16,105
Enhanced Geothermal Systems Near-Hydro Binary	$ 41,619	$ 39,584	$ 37,649	$ 35,808
Enhanced Geothermal Systems Deep Flash	$ 18,718	$ 17,803	$ 16,932	$ 16,105
Enhanced Geothermal Systems Deep Binary	$ 41,619	$ 39,584	$ 37,649	$ 35,808

Table A 11 – Electricity investment costs (cont'd)

	2020 $/kW	2030 $/kW	2040 $/kW	2050 $/kW
Hydro				
Large conventional dam[1]	$ 7,262	$ 7,078	$ 6,899	$ 6,725
Small conventional dam	$ 9,226	$ 8,993	$ 8,765	$ 8,543
Adaptation of a Large non powered dam	$ 5,007	$ 5,007	$ 5,007	$ 5,007
Adaptation of a Small non powered dam	$ 7,930	$ 7,930	$ 7,930	$ 7,930
Small Run-of-river	$ 6,000	$ 6,000	$ 6,000	$ 6,000
Large Run-of-river	$ 3,845	$ 3,845	$ 3,845	$ 3,845
Natural gas				
Simple cycle Combustion gas turbine	$ 1,149	$ 1,060	$ 1,026	$ 996
Combined Cycle Gas turbine	$ 1,129	$ 1,061	$ 1,028	$ 996
Combiner cycle Gas turbine + CCS (90%)	$ 6,774	$ 6,364	$ 6,171	$ 5,979
Nuclear				
Advanced Reactor	$ 7,724	$ 7,310	$ 6,912	$ 6,471
Small Modular Reactor	n/a	$ 7,722	$ 7,722	$ 7,722
Ocean				
Ocean Thermal Energy Conversion Medium	$ 47,515			
Ocean Thermal Energy Conversion Large	$ 21,264			
Tidal Stream	$ 7,137	$ 4,326		
Wave Energy Conversion	$ 10,814	$ 6,056		
Oil				
Reciprocating Diesel Engine	$ 1,018			
Reciprocating Heavy fuel oil Engine	$ 1,018			

[1] In Quebec, these costs are replaced with a supply curve for the remaining ~40 GW of potential (5280–14,400 $/kW).

Table A 11 – Electricity investment costs (cont'd)

	2020 $/kW	2030 $/kW	2040 $/kW	2050 $/kW
Solar				
Photovoltaic 1 axis – level 1	$ 1,349	$ 1,082	$ 962	$ 858
Photovoltaic 1 axis – level 2	$ 1,484	$ 1,190	$ 1,058	$ 944
Photovoltaic 1 axis – level 3	$ 1,781	$ 1,428	$ 1,270	$ 1,132
Concentrating Solar Tower	$ 8,428	$ 5,970	$ 5,097	$ 4,828
Photovoltaic 1 axis + 200 MW Storage	$ 2,189	$ 1,776	$ 1,401	$ 1,025
Solar - distributed				
Decentralized Residential Rooftop Solar	$ 3,195	$ 1,792	$ 1,452	$ 1,362
Decentralized Commercial Rooftop Solar	$ 2,037	$ 1,591	$ 1,441	$ 1,273
Wind				
Onshore Medium Conventional Wind turbine	$ 1,902	$ 1,559	$ 1,389	$ 1,217
Onshore small Conventional Wind Turbine	$ 2,092	$ 1,596	$ 1,441	$ 1,452
Onshore Large Conventional Wind Turbine	$ 1,578	$ 1,422	$ 1,266	$ 1,095
Offshore Fix foundation Wind turbine	$ 3,762	$ 2,715	$ 1,959	$ 1,414
Offshore Floating Wind turbine	$ 5,231	$ 3,423	$ 2,239	$ 1,465
Wind - distributed				
Decentralized Residential Wind Onshore				$ 6,486
Decentralized Commercial Wind Onshore				$ 1,931

Table A 12 – Electricity fixed operation costs[2]

	2020 $/kW	2030 $/kW	2040 $/kW	2050 $/kW
Biomass				
Dedicated Solid Biomass central	$ 69	$ 69	$ 69	$ 69
Dedicated Solid Biomass central + CCS (90%)	$ 144	$ 144	$ 144	$ 144
Dedicated wood pellet central	$ 69	$ 69	$ 69	$ 69
Landfill Gas Internal Combustion Engine				$ 25
Coal				
Ultra-supercritical Pulverized Coal	$ 42	$ 42	$ 42	$ 42
Integrated.Gasification Combined.Cycle Coal	$ 69	$ 69	$ 69	$ 69
Ultra-supercritical Pulverized Coal + CCS (30%)	$ 88	$ 88	$ 88	$ 88
Ultra-supercritical Pulverized Coal + CCS (90%)	$ 102	$ 102	$ 102	$ 102
Coal + Biomass				
Ultra-supercritical.Pulverized coal Cofire with biomass	$ 42	$ 42	$ 42	$ 42
Geothermal				
Hydrothermal Dual Flash Steam Geothermal	$ 172	$ 172	$ 172	$ 172
Hydrothermal Binary Cycle Geothermal	$ 227	$ 227	$ 227	$ 227
Enhanced Geothermal Systems Near-Hydro Flash	$ 343	$ 343	$ 343	$ 343
Enhanced Geothermal Systems Near-Hydro Binary	$ 882	$ 882	$ 882	$ 882
Enhanced Geothermal Systems Deep Flash	$ 343	$ 343	$ 343	$ 343
Enhanced Geothermal Systems Deep Binary	$ 882	$ 882	$ 882	$ 882

[2] Other attributes include the economic life, construction time, physical and resources constraints, etc.

Table A 12 – Electricity fixed operation costs[2] (cont'd)

	2020 $/kW	2030 $/kW	2040 $/kW	2050 $/kW
Natural gas				
Simple cycle Combustion gas turbine	$ 16	$ 16	$ 16	$ 16
Combined Cycle Gas turbine	$ 13	$ 13	$ 13	$ 13
Combiner cycle Gas turbine + CCS (90%)	$ 43	$ 43	$ 43	$ 43
Nuclear				
Advanced Reactor	$ 129	$ 129	$ 129	$ 129
Small Modular Reactor	n/a	$ 118	$ 118	$ 118
Ocean				
Ocean Thermal Energy Conversion Medium	$ 1,693			
Ocean Thermal Energy Conversion Large	$ 389			
Tidal Stream	$ 143			
Wave Energy Conversion				
Oil				
Reciprocating Diesel Engine	$ 13			
Reciprocating Heavy fuel oil Engine	$ 13			
Solar				
Photovoltaic 1 axis	$ 16	$ 13	$ 12	$ 10
ESOL.Photovoltaïc.1axis.New.	$ 16	$ 13	$ 12	$ 10
ESOL.Photovoltaïc.1axis.New.	$ 16	$ 13	$ 12	$ 10
Concentrating Solar Tower	$ 84	$ 65	$ 65	$ 65
Photovoltaic 1 axis + 200 MW Storage	$ 39	$ 39	$ 39	$ 39
Solar - distributed				
Decentralized Residential Rooftop Solar	$ 26	$ 14	$ 12	$ 11
Decentralized Commercial Rooftop Solar	$ 20	$ 16	$ 14	$ 13

[2] Other attributes include the economic life, construction time, physical and resources constraints, etc.

Table A 12 – Electricity fixed operation costs[2] (cont'd)

	2020 $/kW	2030 $/kW	2040 $/kW	2050 $/kW
Wind				
Onshore Medium Conventional Wind turbine	$ 54	$ 50	$ 46	$ 42
Onshore small Conventional Wind Turbine	$ 44	$ 33	$ 33	$ 33
Onshore Large Conventional Wind Turbine	$ 33	$ 33	$ 33	$ 33
Offshore Fix foundation Wind turbine	$ 140	$ 100	$ 72	$ 52
Offshore Floating Wind turbine	$ 113	$ 85	$ 64	$ 48
Wind - distributed				
Decentralized Residential Wind Onshore				$ 39
Decentralized Commercial Wind Onshore				$ 283

[2] Other attributes include the economic life, construction time, physical and resources constraints, etc.

Table A 13 – Electricity variable costs, technical life expectancy and efficiency

	Variable costs		Tech. life expect. (year)	Efficiency	
	2020 $/kW	2050 $/kW		2040 $/kW	2050 $/kW
Biomass					
Dedicated Solid Biomass central	$ 7.64	$ 7.64	45	0.25	0.25
Dedicated Solid Biomass central + CCS (90%)	$ 38.48	$ 38.48	45	0.23	0.24
Dedicated wood pellet central	$ 7.64	$ 7.64	45	0.25	0.25
Landfill Gas Internal Combustion Engine	$ 7.64	$ 7.64	30	0.26	0.26
Coal					
Ultra-supercritical Pulverized Coal	$ 6.36	$ 6.36	75	0.39	0.39
Integrated.Gasification Combined.Cycle Coal	$ 10.18	$ 10.18	75	0.39	0.46
Ultra-supercritical Pulverized Coal + CCS (30%)	$ 32.07	$ 32.07	75	0.35	0.37
Ultra-supercritical Pulverized Coal + CCS (90%)	$ 45.81	$ 45.81	75	0.29	0.31
Coal + Biomass					
Ultra-supercritical.Pulverized coal Cofire with biomass	$ 6.06	$ 6.06	45	0.35	0.37
Geothermal					
Hydrothermal Dual Flash Steam Geothermal	$ -	$ -	30	0.97	0.97
Hydrothermal Binary Cycle Geothermal	$ -	$ -	30	0.97	0.97
Enhanced Geothermal Systems Near-Hydro Flash	$ -	$ -	30	0.97	0.97
Enhanced Geothermal Systems Near-Hydro Binary	$ -	$ -	30	0.97	0.97
Enhanced Geothermal Systems Deep Flash	$ -	$ -	30	0.97	0.97
Enhanced Geothermal Systems Deep Binary	$ -	$ -	30	0.97	0.97

Table A 13 – Electricity variable costs, technical life expectancy and efficiency (cont'd)

	Variable costs		Tech. life expect. (year)	Efficiency	
	2020 $/kW	2050 $/kW		2040 $/kW	2050 $/kW
Hydro					
Large conventional dam	$ -	$ -	100	0.97	0.97
Small conventional dam	$ -	$ -	100	0.97	0.97
Adaptation of a Large non powered dam	$ -	$ -	100	0.97	0.97
Adaptation of a Small non powered dam	$ -	$ -	100	0.97	0.97
Small Run-of-river	$ -	$ -	100	0.97	0.97
Large Run-of-river	$ -	$ -	100	0.97	0.97
Natural gas					
Simple cycle Combustion gas turbine	$ 9.09	$ 9.09	55	0.35	0.38
Combined Cycle Gas turbine	$ 3.53	$ 3.53	55	0.53	0.54
Combiner cycle Gas turbine + CCS (90%)	$ 9.14	$ 9.14	55	0.45	0.46
Nuclear					
Advanced Reactor	$ 2.95	$ 2.95	60	0.33	0.33
Small Modular Reactor	$ 3.74	$ 3.74	40	0.34	0.34
Ocean					
Ocean Thermal Energy Conversion Medium	$ -	$ -	20	1.00	
Ocean Thermal Energy Conversion Large	$ -	$ -	20	1.00	
Tidal Stream	$ -	$ -	20	1.00	1.00
Wave Energy Conversion	$ -	$ -	20	1.00	
Oil					
Reciprocating Diesel Engine	$ 6.36	$ 6.36	20	0.34	
Reciprocating Heavy fuel oil Engine	$ 6.36	$ 6.36	20	0.34	

Table A 13 – Electricity variable costs, technical life expectancy and efficiency (cont'd)

	Variable costs		Tech. life expect. (year)	Efficiency	
	2020 $/kW	2050 $/kW		2040 $/kW	2050 $/kW
Solar					
Photovoltaic 1 axis	$ -	$ -	30	1.00	1.00
ESOL.Photovoltaïc.1axis.New.	$ -	$ -	30	1.00	1.00
ESOL.Photovoltaïc.1axis.New.	$ -	$ -	30	1.00	1.00
Concentrating Solar Tower	$ 5.22	$ 4.45	30	1.00	1.00
Photovoltaic 1 axis + 200 MW Storage	$ -	$ -	30	1.00	1.00
Solar - distributed					
Decentralized Residential Rooftop Solar	$ -	$ -	30	1.00	1.00
Decentralized Commercial Rooftop Solar	$ -	$ -	30	1.00	1.00
Wind	$ -	$ -			
Onshore Medium Conventional Wind turbine	$ -	$ -	30	1.00	1.00
Onshore small Conventional Wind Turbine	$ -	$ -	25	1.00	1.00
Onshore Large Conventional Wind Turbine	$ -	$ -	25	1.00	1.00
Offshore Fix foundation Wind turbine	$ -	$ -	30	1.00	1.00
Offshore Floating Wind turbine	$ -	$ -	30	1.00	1.00
Wind - distributed					
Decentralized Residential Wind Onshore	$ -	$ -	30	1.00	1.00
Decentralized Commercial Wind Onshore	$ -	$ -	30	1.00	1.00

Electricity storage technology costs

Table A 14 – Electricity storage investment costs

	2020 $/kW	2030 $/kW	2040 $/kW	2050 $/kW
Pumped Hydro	$ 3,977	$ 3,977	$ 4,017	$ 4,056
Compressed Air	$ 2,357	$ 2,357	$ 2,380	$ 2,404
Flywheel	$ 3,660	$ 2,309	$ 1,699	$ 1,438
Hydrogen	$ 6,750	$ 4,259	$ 3,134	$ 2,652
Battery Utility-Scale lithium-ion	$ 1,634	$ 1,031	$ 902	$ 773
Battery Lithium-ion	$ 3,363	$ 1,406	$ 978	$ 856
Battery Vanadium redox-flow	$ 5,387	$ 2,858	$ 2,089	$ 1,869
Battery Lead-acid	$ 5,619	$ 4,425	$ 4,144	$ 4,074
Battery Sodium-sulphur	$ 7,188	$ 4,535	$ 3,337	$ 2,824
Residential Battery + PV	$ 6,384	$ 4,029	$ 3,525	$ 3,022
Commercial Battery	$ 1,969	$ 1,243	$ 1,087	$ 932
Commercial Battery + PV	$ 4,846	$ 3,058	$ 2,676	$ 2,294
Residential Thermal AirCircuit Room Unit	$ 3,880	$ 3,651	$ 3,435	$ 3,232
Residential Thermal AirCircuit Home Unit	$ 12,400	$ 11,668	$ 10,978	$ 10,329

Table A 15 – Electricity storage fixed operation costs

	2020 $/kW	2030 $/kW	2040 $/kW	2050 $/kW
Pumped Hydro	$ 10	$ 3,977	$ 4,017	$ 4,056
Compressed Air	$ 5	$ 2,357	$ 2,380	$ 2,404
Flywheel	$ 9	$ 2,309	$ 1,699	$ 1,438
Hydrogen	$ 60	$ 4,259	$ 3,134	$ 2,652
Battery Utility-Scale lithium-ion	$ 47	$ 1,031	$ 902	$ 773
Battery Lithium-ion	$ 13	$ 1,406	$ 978	$ 856
Battery Vanadium redox-flow	$ 16	$ 2,858	$ 2,089	$ 1,869
Battery Lead-acid	$ 10	$ 4,425	$ 4,144	$ 4,074
Battery Sodium-sulphur	$ 14	$ 4,535	$ 3,337	$ 2,824
Residential Battery + PV	$ 16	$ 4,029	$ 3,525	$ 3,022
Commercial Battery	$ 17	$ 1,243	$ 1,087	$ 932
Commercial Battery + PV	$ 22	$ 3,058	$ 2,676	$ 2,294
Residential Thermal AirCircuit Room Unit	$ -	$ 3,651	$ 3,435	$ 3,232
Residential Thermal AirCircuit Home Unit	$ -	$ 11,668	$ 10,978	$ 10,329

Table A 16 – Electricity storage technical life expectancy and efficiency

	Tech. life expect. (year)	efficiency
Pumped Hydro	15	0.78
Compressed Air	15	0.44
Flywheel	15	0.88
Hydrogen	15	0.4
Battery Utility-Scale lithium-ion	15	0.85
Battery Lithium-ion	15	0.86
Battery Vanadium redox-flow	15	0.73
Battery Lead-acid	15	0.84
Battery Sodium-sulphur	15	0.81
Residential Battery + PV	20	0.9
Commercial Battery	20	0.9
Commercial Battery + PV	20	0.9
Residential Thermal AirCircuit Room Unit	20	0.8
Residential Thermal AirCircuit Home Unit	20	0.8

Table A 17 – Hydrogen and ammonia production

	Investment cost				Efficiency	
	First year		2050		First year	2050
	min ($/kW)	max ($/kW)	min ($/kW)	max ($/kW)	%	%
Hydrogen						
Natural gas - Steam methane reforming	625	1158	469	1158	72	72
Natural gas - Steam methane reforming - Decentralized	1120	1120	859	859	71	74
Natural gas - Steam methane reforming - CCS	1011	1755	691	1200	74	74
Natural gas - Autothermal Reforming - CCS	1059	1571	724	1074	80	80
Natural gas - Autothermal Reforming + Gas heating - CCS	968	1435	697	1032	86	86
Coal - Gasificasion - CCS	2826	17424	1712	16309	67	66
Biomass - Gasificasion	1281	1281	1203	1203	44	46
Biomass - Gasificasion - CCS	2160	4933	1741	3981	66	70
Electrolysis - Polymer electrolyte membrane - Decentralized	2181	2181	1203	1203	60	65
Electrolysis - Alkaline	591	2095	416	558	145	145
Electrolysis - Polymer electrolyte membrane	718	2694	369	615	145	145
Electrolysis - Solid oxide electrolyzer cell	2677	2677	1147	1147	116	105
Ammonia						
Natural gas	1917	1917	1917	1917	45	58
Natural gas - CCS	2786	2786	2468	2468	44	57
Coal - Gasificasion	4608	4608	4608	4608	45	45
Coal - Gasificasion - CCS	5953	5953	5953	5953	43	43
Biomass - Gasificasion	13388	13388	13388	13388	38	38
Electrolysis - Polymer electrolyte membrane	2002	2002	1610	1610	50	57

Table A 18 – Hydrogen transformation

	First year	Investment cost $/GJmax	Efficiency %
Hydrogen liquefaction	2017	56.20	95
Hydrogen to liquid organic hydrogen carrier (LOHC)	2017	1.69	95
LOHC to Hydrogen	2025	4.92	90
Ammonia to Hydrogen	2025	20.60	99

Table A 19 – Hydrogen transmission

	* km average	First year	Investment cost		Efficiency
	km		min ($/GJ)	max ($/GJ)	%
Hydrogen Pipeline	1005	2017	8	39	99
Ammonia Pipeline	1005	2025	157	157	99
LOHC Pipeline	1005	2025	401	401	99

Table A 20 – Hydrogen distribution

	Investment cost			Efficiency
	First year		2050	
	min ($/Gjmax)	max ($/Gjmax)	$/Gjmax	%
Hydrogen distribution by truck as compressed gas	31.32		31.32	99
Hydrogen distribution by truck as liquid	7.51		7.51	99
Ammonia distribution by truck	17.58		17.58	99
LOHC distribution by truck	9.01		9.01	99
Hydrogen distribution by ship as liquid	42.08		42.08	99
Ammonia distribution by ship	1.16		1.16	99
LOHC distribution by ship	0.23		0.23	99
Hydrogen refuelling station (hydrogen for transport sector) as liquid	43.58	125.83	56.66	89
Hydrogen refuelling station (hydrogen for transport sector) as compressed gas	43.58	125.83	56.66	89
Hydrogen refuelling station (hydrogen for transport sector) with the use of ammonia	300.65	300.65	300.65	89
Hydrogen refuelling station (hydrogen for transport sector) with the use of LOHC	411.38	411.38	411.38	89

Table A 21 – Hydrogen storage

	Investment cost		Efficiency
	min ($/Gjmax)	max ($/Gjmax)	%
Hydrogen Storage with Salt Cavern	371	3,750	80
Hydrogen Storage with Storage Tank	949	33,613	80
Hydrogen Storage with Storage Pipe.	5,472	8,664	80
Ammonia Storage with Storage Tank	134		80
LOHC Storage with Storage Tank	25		80

Table A 22 – Synthetic fuels from hydrogen

	Investment cost		Efficiency
	First year ($/GJ)	2050 ($/GJ)	%
Methane from Hydrogen - Methanation - Thermochemical	36.42	22.76	80
Jet fuel from Hydrogen - Fischer-Tropsch	38.70	22.76	80
Methanol from Hydrogen - Fischer-Tropsch	38.70	22.76	80

Table A 23 – Hydrogen consumption

	Investment cost		Efficiency
	min ($/kW)	max ($/kW)	%
Commercial sector - Space heating Hydrogen Furnace	154	873	94
Electricity sector - Hydrogen Fuel Cell, H2 to electricity	892	36,832	60
Residential sector - Space heating Hydrogen Boiler	4,281	4,281	94
Industry sector - Hydrogen Boiler	62	379	99

B ADDITIONAL POLICY DETAIL

This appendix provides additional detail on targets and policies in individual provinces and territories. This serves as a complement to the information summarized in Chapter 5.

British Columbia

British Columbia has its own carbon pricing system, first introduced in 2008 as a revenue-neutral tax on carbon emissions that reached $30/tonne in 2012 (the rate has increased again by $5/tonne per year since 2018 to match federal requirements). The rate applied for the carbon tax depends on the fuel's carbon content, and an additional Motor Fuel Tax applies for gasoline and diesel as well. The legislation originally ensured that the government would cut taxes for individuals or companies each year for an amount equal to the revenues generate by the carbon tax. The tax covers around 70% of the province's emissions, with some exceptions including the agriculture sector, fuel exports, aviation and external marine, emissions linked to industrial processing, and fugitive methane emissions coming from the production and transport of fossil fuels. The revenue-neutral provision was eliminated in 2017.

In 2016, the province also enacted the Greenhouse Gas Industrial Reporting and Control Act (GGIRCA), which puts a price on GHG emissions for industrial facilities or sectors exceeding a threshold. The Act also sets specific performance standards for industrial facilities or sectors, including notably LNG facilities, requiring both to report emissions and to comply with an emission benchmark.

Several other measures were also introduced over the past decade. The Clean Energy Vehicle program (2011) provides cash rebates of up to $8,000 for the purchase of electric and hydrogen fuel cell vehicles and investments in charging and hydrogen fueling infrastructure. The Carbon Neutral Government, in place since 2010, ensures that government and public institutions operations are carbon neutral. A Climate Leadership Plan, released in 2016, expanded the low carbon fuel standard and introduced measures to make buildings ready to be net zero in 2032. The Clean Energy Act (2010) also requires that renewable sources provide 93% of electricity generation.

Most of the climate or energy policies introduced by the province in recent years signal a doubling down of the efforts put in place since the introduction of the carbon tax in 2008. This partly results from the realization that the original 2020 target for GHG emission reductions would be missed by a wide margin. After the change in government following the 2017 election, revised GHG targets were introduced in the Climate Change Accountability Act of 2018 (40% by 2030, 60% by 2040, as well as recommitting to 80% by 2050). Given the results of an assessment of progress in 2020, the province added a 2025 target of 16% reduction by 2025. The Zero-Emission Vehicles Act (2019) also set targets for the share of zero-emission light-duty vehicles sales or leases, which must reach 10% by 2025, 30% by 2030 and 100% by 2040. This comes in addition to the Renewable and Low Carbon Fuel Requirements Regulation, which includes renewable fuels mandates as well as carbon intensity targets for fuels sold.

Most of these initiatives are part of the CleanBC strategy, released after the Climate Change Accountability Act as a set of measures aiming to achieve the province's GHG emissions reduction targets. The strategy also requires that a minimum of 15% of residential and industrial natural gas consumption come from renewable gas. It has given special attention to the buildings sector, aiming to make every new building constructed in the province "net-zero energy ready" by 2032. Additionally, regulations for reducing methane emissions from upstream oil and gas operations by 45% were enacted, with an equivalency agreement reached with the federal government.

The NDP minority government, in place since 2017 and having obtained a majority after the 2020 election, developed its strategy to adjust the province's level of efforts given its very limited success in reducing GHG emissions. The early implementation of carbon pricing in 2008, as well as later efforts, did not result in the province meeting its 2020 GHG target, so the current government has chosen to increase the number and intensity of measures, while revising longer-term target.

Alberta

The election of Jason Kenney as Premier in 2019 changed Alberta's approach to climate and energy policy. Prior to the election, several of the key policies in place were outcomes of the Climate Leadership Plan of 2015. The plan included a phase-out of coal in electricity generation by 2030, a target stating that 30% of electricity produced in the province must come from renewable sources, a legislated annual limit of 100Mt on GHG emission from the oil sand sector, and a reduction target of 45% by 2025 for methane emissions. The plan also led to the creation of Energy Efficiency Alberta, an organization supporting energy efficiency and conservation measures.

These targets were accompanied by measures to achieve them, like the Renewable Electricity Program; a carbon levy applying to diesel, gasoline, natural gas and propane; and a separate carbon pricing system that applied to large industrial emitters – over 100,000 tonnes/year – in the Carbon Competitiveness Incentive program.

After the 2019 election, the new government announced early on that it would modify or remove several provisions following from the Climate Leadership Plan. This began with the Carbon Tax Repeal Act, voiding the Climate Leadership Act and ending the Alberta Climate Leadership Adjustment Rebate. This triggered an announcement from the federal government that the federal carbon pollution pricing system would replace the Alberta carbon tax. The provincial government challenged the federal system in court, following Saskatchewan and Ontario, and lost after the Supreme Court decision in March 2021.

The Carbon Competitiveness Incentive Regulation (CCIR), which replaced the Specified Gas Emitters Regulation (SGER) in 2018, continued to apply. The CCIR requires that facilities' emissions be less than the amount freely permitted in their sector of activity. If they do not meet this benchmark, these emitters face several compliance options: improve their facility's efficiency, purchase credits from better-performing facilities, buy Alberta-based carbon offset credits, or contribute to Alberta's Climate Change and Emissions Management Fund. The Technology Innovation and Emissions Reduction Implementation Act, introduced in late 2019, is aiming to replace this system, in effect creating a hybrid of the CCIR and SGER.

The provincial government also chose not to repeal the 100 Mt cap imposed on emissions from the oil and gas industry, underscoring that it is unlikely that the cap will be reached in the coming several years. As a result, a significant increase in both the province's overall emissions (and Canada's) is possible even while respecting the cap, which would largely offset efforts to reduce emissions through other measures.

In the electricity sector, Alberta remains the province with the highest share of coal in its electricity production. The government has planned a system of transition payments for facilities that were supposed to be in operation passed 2030. The previous government's Renewable Electricity Act had also legislated a 30% share of renewable in the electricity sector by 2030, but the main tool to achieve it – auctions as part of the province's Renewable Electricity Program – has now been cancelled by the Kenney government.

As for cuts in methane emissions, conflicting regulations from both the Alberta and federal governments took effect on January 1st 2020. Talks then led to an equivalency agreement, reached in last 2020.

Saskatchewan

Saskatchewan is the first province in terms of per capita GHG emissions, with the large majority of emissions coming from the electricity and energy production sector. The province released its Prairie Resilience Action Plan in 2017, outlining the province's approach and strategy for reducing GHG emissions. It was followed by the introduction of the Climate Resilience Measurement Framework in 2018, a series of 25 targets for the province and municipalities to meet and manage. Saskatchewan remains the only province not to have signed on to the PCF.

Saskatchewan released a plan to price carbon pollution in 2018. The system uses an output-based performance standards approach for some of its large industrial facilities, and overall resulted in only partially meeting the federal stringency requirements. The federal pricing system applies as an output-based pricing system for electricity generation and natural gas transmission pipelines, which covers facilities from sectors that emit 50,000 tonnes or more of CO_2 equivalent annually; and as a charge on fossil fuels, generally paid by registered distributors (fuel producers and distributors).

Saskatchewan challenged the constitutionality of the federal Greenhouse Gas Pollution Pricing Act in 2019. In a 3-2 decision, the Saskatchewan Court of Appeal disagreed, and the province eventually lost the appeal at the Supreme Court of Canada.

Saskatchewan is one of the four provinces that use coal for electricity generation. After the federal coal phase-out plan was announced, the province reached an agreement in 2019 that allowed it to meet the federal emission requirement on an electricity system-wide basis. This allowed to keep the station running at the Boundary Dam Carbon Capture Project passed 2030, a commercial-scale station that uses carbon capture, utilization and storage (CCUS) technology. The province's public utility, Saskpower, also committed to have at least 50% of its electricity generation come from renewable sources by 2030, double what it was in 2015, while reducing its emissions by 40% by 2030.

The province's Oil and Gas Emissions Management Regulations also took effect in January 2019, regulating flared and vented methane emissions to meet the 40-45% reduction target by 2025. Given the competing federal regulations, Saskatchewan also negotiated an equivalency agreement with its federal counterpart, and settled by the end of 2020 (as British Columbia and Alberta have as well).

Manitoba

In 2017, Manitoba proposed a climate change plan that included a flat carbon price of $25 per tonne of CO_2 equivalent emissions. The system did not meet the federal benchmark, and in 2018 Manitoba abandoned the plan. Therefore, the federal pricing system fully applies in the province. The province launched a court challenge to the constitutionality of the federal carbon pollution pricing system, and in parallel has announced a new plan of $25/tonne to be applied from July 1st 2020, while simultaneously dropping the provincial sales tax by 1 percentage points. The plan was postponed due to the COVID-19 public health emergency, and it is not clear at the moment whether the federal government will accept the plan as meeting its requirements. The court challenge was resolved by the Supreme Court of Canada decision in March 2021.

Since the publication of the Made-in-Manitoba Climate and Green Plan in 2017, long-term GHG emissions reduction targets were replaced by a setting of reduction goals in rolling five-year periods, based on independent expert advice. The current target is 1 Mt cumulative emissions reduction by 2023. The government also announced an increase of its renewable fuels standard in early 2020, raising the minimum ethanol content in gasoline to 10%, and biodiesel content in diesel fuel to 5% (both becoming effective in 2022). Finally, the 2017 plan includes targets to increase energy efficiency in domestic natural gas (11.25%) and electricity (22.5%) consumption over a 15-year period.

Ontario

For the 2003 to 2018 period, Ontario was governed by successive Liberal governments, who enacted several policies aiming to transform the energy landscape of the province and reduce its GHG emissions. Noteworthy among these policies are the phasing out of coal-fired electricity, feed-in tariffs to encourage the deployment of solar and wind energy in the Green Energy and Green Economy Act 2009, and the outlining of 2020 and 2030 GHG emissions reduction targets (-15% and -37% from 1990 levels, respectively). These early actions were followed by the Climate Change Mitigation and Low-Carbon Economy Act 2016, which required the province to development climate action plans and specify how cap and trade proceeds would be spent in order to support projects with GHG emissions reduction potential. Several other action plans were published, including the Long-Term Energy Plan to ensure affordability and reliability to energy consumers over the next 20 years. These efforts culminated in 2018 with the linking of a provincial cap-and-trade system for GHG emission permits with that of California and Quebec, with some allowances for trade-exposed industries.

After its election in the spring of 2018, the new government led by Premier Doug Ford announced several changes to these policies. The government introduced the Cap and Trade Cancellation Act in 2018, resulting in the application of the federal carbon pricing system instead. Although the federal policy was challenged by Ontario in court, the province lost its case. The province received approval from the federal government for a carbon-pricing system for large industrial emitters in 2020, which works as emissions performance standards. Its coverage was however described as concerning by the federal Environment Minister, and will lead to a review in two years. It was not determined, at the time of writing, when the provincial system would take effect. The Green Energy and Green Economy Act was also repealed in 2018.

After the 2018 election, Ontario released its Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan, under which the province commits to a 30% reduction in GHG remissions 2030 from 2005 levels, in line with the federal target at the time. The plan includes emission performance standards for large emitters; the Ontario Carbon Trust, an emissions reduction fund to encourage private investment in clean technology solutions; and the Ontario Reverse Auction, which establishes an auction system that allows bidders to send proposals for emissions reduction projects and compete for contracts based on the lowest-cost GHG emission reductions.

The plan also includes measures for transport, notably increasing the renewable content requirement in gasoline to 15% in 2030 through the Cleaner Transportation Fuels Regulation (which replaced the Greener Gasoline and Greener Diesel Regulations). Details for the renewable diesel portion of the regulation have yet to be published. With regard to the transport sector, the province also cancelled its Electric and Hydrogen Vehicle Incentive Program, which offered rebates for the purchase of low-emission vehicles. The financial incentive to install charging stations for home or business use, as well as the Electric Vehicle Chargers Ontario grant program that developed a network of charging stations across the province, were also cancelled.

Many of these changes were enacted in the midst of debates over rising electricity costs in Ontario. The significant changes in policies to reduce GHG emissions (and to energy policy more generally) underscore the new government's different approach on these issues.

Quebec

In its *Plan d'action 2013-2020 sur les changements climatiques* (2013-2020 Action Plan on Climate Change), Quebec had an objective of reducing GHG emissions by 20% from 1990 levels by 2020. This target was missed, and eyes are now on its later commitment to decrease emissions by 37.5% by 2030. The next strategy, the *Plan pour une économie verte* (Plan for a Green Economy), was released in late 2020, and bets heavily on electrification. Various targets are included in the new strategy, such as no sales of gasoline-powered vehicles from 2035, a 50% reduction in emissions from building space heating by 2030, 10% renewable gas in the natural gas distribution network by 2030, among others. A large part of the efforts are to be achieved through investments from the *Fonds vert* (Green Fund), a fund dedicated to projects with GHG reduction potential.

The fund is financed by proceeds from Quebec's participation in the Western Climate Initiative's cap-and-trade system with California since 2013, which Ontario briefly joined in 2018. The system covers companies in the industrial and electricity sectors which emit more than 25,000 tonnes of CO_2e annually (for instance, aluminum refineries, cement plants, and electricity producers), as well as fossil fuel distributors.

Several other 2030 targets are found in the province's Politique énergétique 2030: the consumption of oil products must decrease by 40%; the use of thermal coal must be eliminated; bioenergy production must increase by 50%; overall renewable energy output must increase by 25%; and energy efficiency must increase by 15%. The policy also created Transition énergétique Québec, which was tasked with developing cohesive action plans every five years to ensure progress toward the objectives of the policy. The first plan was published in 2018, but the agency was abolished in late 2020 and its responsibilities transferred to existing ministries (see below).

Although Quebec missed its target of 100,000 electric and rechargeable hybrid vehicles by 2020, it has a number of policies aiming to electrify transportation. First and foremost is the zero-emission vehicles mandate, by which automakers accumulate credits by selling zero-emission or low-emission vehicles, in order to meet progressively more stringent targets for the share of zero-emission or low-emission vehicles. This share is scheduled to reach 22% in 2025. Automakers that do not meet the annual target can buy credits from others. A similar mandate for heavy-duty vehicles is planned but has yet to be formally announced. A second transport electrification policy offers cash rebates for the purchase of electric vehicles (up to $8,000), which can be combined with the federal program.

Furthermore, Quebec charges several taxes on fuel, on top of the federal excise tax described in Chapter 5 above (and in addition to federal and provincial sales taxes). This includes a fixed tax on gasoline of 19.2¢/litre (20.2¢/litre for diesel), as well as a public transit tax of 3¢/litre in the Greater Montreal region. The provincial tax is reduced for some remote regions or areas close to the Unites States border.

Since its election in the fall of 2018, the new government led by the Coalition Avenir Québec developed a plan to improve the province's approach, which was presented in late 2019 as bill 44. Notably, the bill transforms the management of the *Fonds vert*, after an earlier report documented the mismanagement of the fund and its ineffectiveness in helping the province reduce emissions. Part of the fund's responsibilities now fall to the Ministry of Sustainable Development, Environment, and Fight Against Climate Change. The bill also abolished Transition énergétique Québec, transferring its responsibilities – notably the design of transition plans – back to the Ministry of energy and natural resources, as they were before 2017.

New Brunswick

The federal carbon pricing system applies in New Brunswick. The province initially signaled its intention to challenge its constitutionality, but changed its mind after the federal election in October of 2019. It also intervened in the Supreme Court case on this matter in the spring of 2021.

The province then designed its own plan for small emissions following PEI's proposal, reducing its provincial tax on fuels to make the fuel tax neutral for the consumer. In 2020, the federal government accepted New Brunswick's proposal for large emitters, announced in 2019, but with important reservations about its coverage. The province's proposal for large emitters will replace the federal system as a result, but compliance requirements will be evaluated again in two years.

The Climate Change Act of 2018 set out targets for GHG emissions, and regulation under the Electricity Act mandates that 40% of the electricity sold within the province come from renewable sources. The province has also committed to phasing out coal by 2030, as part of the Climate Change Action Plan (updated in 2017). The update also pledged to make government operations carbon neutral by 2030. It is worth noting that the new minority progressive-conservative government that took power in 2018 did not reject the 2016 plan or its 2017 update, therefore GHG emissions reduction targets still apply.

Nova Scotia

Nova Scotia has put a cap-and-trade system in place since January 2019, which covers around 80% of the province's emissions. Moreover, although the province set an 80% reduction target in GHG emissions by 2050 in its Climate Change Action Plan, the Sustainable Development Goals Act passed in late 2019 changed targets to a 53% reduction by 2030 and net-zero by 2050. This is in addition to the Renewable Electricity Regulations, which requires that utilities supply their customers with 40% renewable electricity.

The province reached an equivalency agreement with the federal government for the phasing out of coal-fired electricity generation, which will be in effect from 2020 to 2024, allowing the province to keep coal-fired plants beyond 2030, pledging in return to achieve more important cuts in emissions throughout its electricity sector. At the time of writing, the current government had just announced that coal would be phased-out by 2030.

Prince Edward Island

The government of Prince Edward Island released its 10-year energy strategy in 2017, and has signed on to the PCF. It also established a Climate Change Secretariat in its 2018-2023 Climate Change Action Plan, which initially reiterated the 30% GHG emissions reduction target (by 2030). However, it revised this target up to 40% following the publication of the IPCC report in 2018 (see Chapter 1`). The province went further in December 2020, passing the Net Zero Carbon Act, which committed it to reduce net emissions to zero by 2040. The legislation also requires the government to publish a yearly report on progress made toward achieving the targets.

With regard to carbon pricing, the province negotiated an equivalency agreement with the federal government for the pricing of fuel emissions, with the additional charge being compensated at the pump by a decrease of the provincial fuel tax. The net effect is currently a 2 cents per liter increase on gasoline and diesel purchased at the pump.

Government measures give special attention to transportation, as the sector accounts for 50% of GHG emissions in the province. The 2018-2023 Climate Change Plan committed to designing and installing a province-wide electric vehicle charging network. This plan was followed by the release of the Sustainable Transportation Strategy in late 2019, which proposes measures like different rate structures for electric vehicles registration.

Newfoundland and Labrador

The province's 2016 Management of Greenhouse Gas Act was updated in 2018 to introduce the federally mandated price on carbon. This came after the province released the Made-in-Newfoundland and Labrador carbon pricing program and had it accepted by the federal. The program launched a carbon tax on combustible fuels which followed the federal requirements, while using a performance standard system for large industrial facilities and large-scale electricity generators. Regarding the latter sector, the Muskrat Falls Hydroelectric Project should become online in 2021.

The Liberals were reelected with a minority in 2019, and released a new climate change action plan for the next five years. The plan reiterated the 30% 2005 by 2030 target.

Territories

Although their contribution to national GHG emissions is small, northern Canadian territories present distinct challenges in terms of meeting reduction targets. In the Yukon, for instance, the federal carbon pricing system applies, but with exemptions for aviation fuel and diesel electricity generation, given their special importance for food security and heating purposes. The territory also published Our Clean Future strategy in late 2019, which proposes several measures and targets. These include notably: reducing GHG emissions by 30% over 2010 levels; reducing diesel use for electricity generation in communities not connected to the main electricity grid by 30% before 2030; and have 40% of heating needs met by renewable sources by 2030. Other action items include the electrification of transport and of the government's vehicle fleet.

The Northwest Territories published in 2018 a Climate Change Strategic Framework 2030, in parallel with their shorter-term Climate Change Action Plan 2019-2023. The plan includes a 30% reduction target for GHG emissions before 2030. The efforts of the Northwest Territories also revolve heavily around energy-related targets: GHG emissions from electricity generation in diesel communities are to be reduced by 25%; those from transportation are targeted to decrease by 10% on a per capita basis from 2016 to 2030; and the share of renewable energy used for community heat must reach 40% by 2030. The Northwest Territories has implemented a carbon tax in 2019.

Finally, Nunavut has no GHG emissions reduction targets. As is the case for the Yukon, Nunavut uses the federal pricing system, with exemptions related to the special circumstances of the territory. These include an exemption for the charge on aviation fuels, as well as for diesel-fired electricity generation for remote communities. Since 2019, the territorial government also offers the Nunavut Carbon Rebate, which subsidizes half of the carbon price for fuels purchased by residents of the territory. The rebate is scheduled for a gradual phaseout of 10% per year from 2022 to 2028.

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C OIL AND GAS ALTERNATIVE SCENARIOS

A sensitivity analysis for the oil and gas sector was conducted in which the reduction in energy production is externally controlled.

A sensitivity analysis for the oil and gas sector was conducted in which the reduction in energy production is externally controlled (see section 7.1.2). The following two alternative scenarios have been compared with NZ50:

- OilExpA: NZ50 targets but both oil production and natural gas production are maintained at a minimum of 25% of the reference scenario levels at all times
- OilExpB: NZ50 targets but both oil production and natural gas production are maintained at a minimum of 50% of the reference scenario levels at all times

Higher production levels for oil and gas, coupled with different sectoral consumption profiles, still allow emissions to be reduced to the same extent but in different ways than in NZ50, as shown in Figure C.1.

The (direct) costs of reducing emissions increase under those alternative scenarios, mainly for two drivers:

a. Reductions transferred from oil and gas production to other industries and to the building and transport sector;

b. Larger use of DAC to compensate for the higher GHG emission left from economic activities: by 2050, DAC would almost triple, from 15 $MtCO_2e$ (NZ50) to 41 $MtCO_2e$ (OilExpB) captured annually.

GHG reductions not achieved in the oil and gas sector would be distributed across other sectors as indicated in Table C.1. Figures C.2 and C.3 present the projection for these two scenarios against NZ50 in two sectors that are discussed in section 7.1.2.

Figure C.1 – Evolution of GHG emissions – alternative scenarios

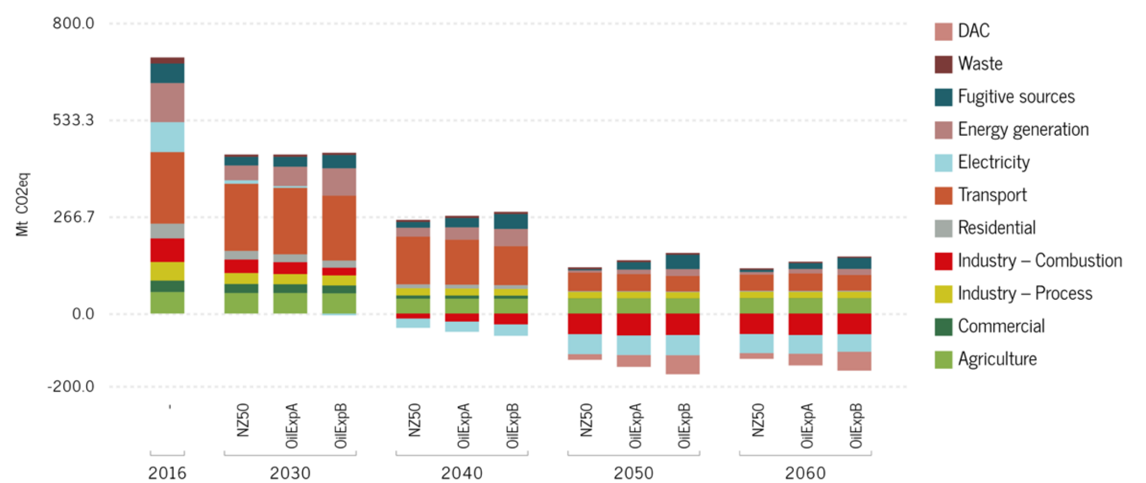


Table C.1 – Oil and gas production and GHG emissions target variation per sector under alternative scenarios

	2005	2016	2030			2050		
			NZ50	OilExpA	OilExpB	NZ50	OilExpA	OilExpB
Scenario constraints								
Final emissions ($MtCO_2e$)	730	705	438	438	438	0	0	0
Reduction wrt 2005			-40,0%	-40,0%	-40,0%	-100%	-100%	-100%
Oil and gas production								
Oil production (PJ)		9 088	4 388	4 887	7 605	507	4 089	8 179
Gas production (PJ)		7 659	3 125	3 462	3 999	749	2 587	5 141
			Total sector	Δ wrt NZ50[1]	Δ wrt NZ50	Total sector	Δ wrt NZ50	Δ wrt NZ50
GHG Emissions ($MtCO_2e$)								
Oil and gas production[2]		161	64	+16	+48	9	+23	+45
Industry[3]		116	67	-7	-19	-39	-8	-7
Electricity		82	9	-5	-14	-55	+1	-1
Buildings[4]		72	49	-3	-7	3	0	0
Transport		197	185	-2	-6	51	-4	-8
Agriculture		60	57	0	-1	41	0	-3
Wastes		17	64	+16	+48	9	+23	+45
Direct air capture		-	-	-	-	-15	-12	-26

[1] Δ wrt NZ50 = Difference in GHG emissions between OilExp scenarios and NZ50; a positive difference means more emissions in OilExp scenario; a negative one, less emissions

[2] regroups energy production and fugitive emissions

[3] regroups Industry processes and combustion

[4] regroups residential and commercial sectors

Figure C.2 – Final energy consumption in the building sector – alternative scenarios

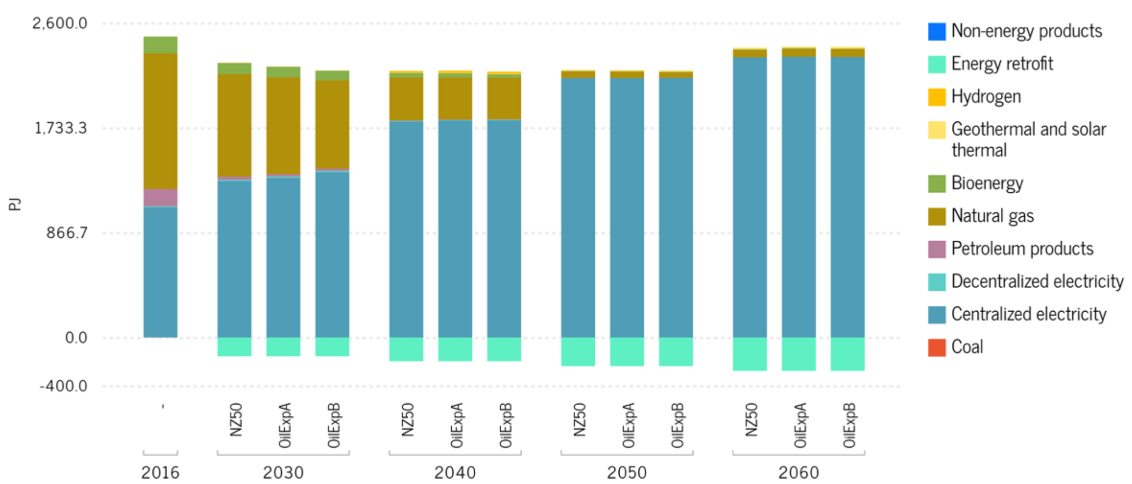
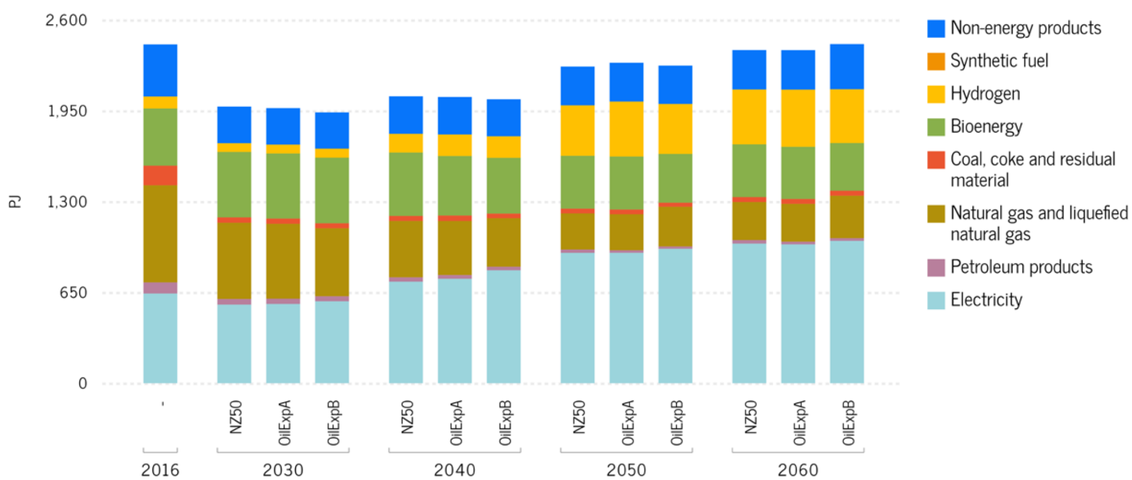


Figure C.3 – Final energy consumption in the industrial sector – alternative scenarios



D METHODOLOGY USED TO ASSESS THE COSTS OF THE ENERGY TRANSITION THROUGH ELECTRIFICATION

This Appendix presents the methodology used to assess the costs of energy transitions through electrification presented in Chapter 14.

This Appendix presents the methodology used to assess the costs of energy transitions through electrification presented in Chapter 14. It was originally developed to address the costs in the electricity sector only. For this report, the calculations were adapted to the Canadian context and modified to fit the data produced for each energy transition scenario.

Two outputs are used to estimate annualized costs for each scenario: electricity production by mode of production; and energy consumption by fuel type for transport, agricultural, industrial and residential sectors in 2016, 2030, 2050 and 2060. Each scenario is divided into four time periods (2016–2030; 2030–2050; 2050–2060; 2060+). The change in production and consumption projections during each period is obtained by subtracting the figures of the lower bound year from the figures of its upper bound year.

We calculate the net annual cost incurred for each of the four time periods. Capacity, transmission and storage costs are annualized and changes in fuel expenditures are based on annual consumption figures. The net annual cost (T_C) for a given year is the sum of the annualized capacity cost (C_C), the annualized transmission cost (C_T) and the annualized storage cost (C_S) plus the change in fossil fuels expenditures in relation to 2016 figures (F_S). T_C is calculated for each time period using the following equation:

$$T_C = (C_C + C_T + C_S) + F_S$$

Equation 1 is used separately for each of the four time periods. In the first period from 2016 to 2030, cost estimates do not take into account changes in annual fuel expenditures. This is because these changes in fuel expenditures are calculated using values from 2016 as base measurements. Consequently, we conservatively assume that the changes in fuel expenditures can only be considered from 2030 onwards. The second and third periods take into account all types of costs and changes in annual fuel expenditures. The last period can be understood as "2060 and beyond", where capacity, transmission and storage costs are considered to be null, since each transition scenario is implied to end at or before 2060. We also assume that fossil fuel consumption does not change after 2060, thus keeping the total annualized fuel expenditures constant from that point on. We assume that a reduction in fossil fuel consumption, if negative, is a source of savings. Thus, if avoided fossil fuel costs are higher than capacity, transmission and storage costs, T_C will be negative, representing net savings.

Capacity costs

Capacity costs refer to the value of the investment needed to construct the new power capacity. They are calculated using the differences between time periods in electricity production for each mode. We consider that that fossil fuel-related assets would have to be replaced. These assets are annualized; thus, their cost is divided by the number of years of the period. It is important to note that in scenarios that feature a reduction in the production capacity of non-renewable sources of electricity, the negative cost values are still taken into account as assets that will not have to be replaced in the future, thus offsetting the additional cost incurred by new renewable electricity sources. The annualized capacity cost (C_C) is calculated by:

$$C_C = \frac{\sum_{m=1}^{n}(\delta_m \times P_m)}{t}$$

Where δ_m is the change in power generation capacity (kW) by power generation mode (m) for a specific energy transition scenario during a time period, P_m is the cost of power generation capacity ($/kW) by power generation mode (m) divided by the mode's capacity factor (Table D.1), n is the number of electricity production methods (hydro, biomass, wind, solar, hydrogen, nuclear, coal, natural gas, oil), and t is the number of years of the period of the projection.

Table D.1 – Cost of power generation capacity divided by capacity factor

Generation mode	P_m ($/kW)	Reference
Hydro	14,011	ESMIA
Biomass	4,916	EIA (2020)
Wind	4,420	ESMIA
Solar	6,274	ESMIA
Nuclear	9,165	EIA (2016)
Coal	4,637	ESMIA
Natural Gas	1,121	ESMIA
Oil	831	Dolter and Rivers (2018)

Storage costs

Increasing shares of variable renewables in the energy mix increase the volatility of electricity wholesale prices and therefore improve the profitability of flexibility and balancing options. At the same time, sinking costs for battery units are already making short-term battery storage an economically attractive option (IEA, 2020a). Adding storage capacity to the electricity network represents an important investment cost. The annualized storage cost (C_S) for a given year is calculated by:

$$C_S = \frac{(S_W + S_S) \times B}{t}$$

Where S_W is the additional storage capacity for new wind capacity (kWh) needed during a period, S_S is the additional storage capacity for new solar capacity (kWh) needed during a period, and B is the cost of energy storage ($/kWh). We assume that two days of electricity storage would be required for the additional solar and wind production capacity added to Canada's grid in each of the scenarios (Heal, 2020). We also consider a cost of storage of USD 100/kWh, which is fairly conservative given average energy storage price predictions from now until 2060. Estimates for 2023 are already in the USD 100/kWh range, with strong downward trends (BloombergNEF, 2020).

Transmission costs

To calculate the transmission investment costs incurred by each transition scenario in our study, we determined how many kilometers of additional power lines would have to be built in Canada according to the total change in electricity production in each scenario. The annualized transmission cost (C_T) for a given year is calculated with:

$$C_T = \frac{L \times E}{t}$$

Where L is the length of high voltage lines to be built (km) during a period and E the cost of high voltage power lines ($/km). We assume that an increase in electricity production required a proportionate increase in power lines. As base measurements, we used Heal's methodology proposal of building 50 000 miles of high voltage power lines for an additional 2.44 billion MWh of annual power generation. We calculate a proportion using these two values with the change in MWh in renewable electricity produced for each time period and each scenario in Canada to find the total length of power lines to build. We use a value for E of $2.4M/kilometer in our calculations (Dolter and Rivers, 2018).

Fossil fuel expenditures

Replacing fossil fuel consumption with electricity reduces the cost of acquiring these combustibles. We calculate the fuel cost differences generated by the change in fossil fuel consumption for each period by using the data provided for the upper bound year of a period minus that of 2016. For the "2060+" period, we use the data from 2060 minus that of 2016. The additional (or lesser) annual costs associated with the consumption of fossil fuels (F_S) for a given year are calculated using:

$$F_S = \sum_{X=1}^{f} (CU_X \times FC_X)$$

Where CU_X is the change in annual fossil fuel consumption between the lower bound of the time period and 2016 (PJ) by type of fossil fuel (X), FC_X are the fossil fuel costs ($/PJ) by type of fossil fuel (X), and f is the number of fossil fuels considered (coal, gas, oil). Since "oil" incorporates many different types of petroleum-based combustibles, we use an average price per liter based on average Canadian wholesale prices in Canada in 2020. We chose to use fixed prices that does not change over time. For each type of fuel saved, we convert the energy figures into physical amounts and used the average price of these fuels in 2021 to find a dollar figure (Table D.2). Negative cost differences correspond to savings.

Table D.2 – Cost of fuel

Fuel type	FC_X ($/PJ)	Reference
Coal	2,527,778	Dolter and Rivers (2018)
Natural Gas	2,509,779	Dolter and Rivers (2018)
Oil	25,000,000	Dolter and Rivers (2018)