CANADA'S CHALLENGE & OPPORTUNITY

Transformations for major reductions in GHG emissions

Full Technical Report and Modelling Results

PROJET TROTTIER POUR L'AVENIR ÉNERGÉTIQUE

TROTTIER ENERGY FUTURES PROJECT

Trottier Energy Futures Project Partners

April 2016

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The Canadian Academy of Engineering | L'Académie canadienne du génie
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Foreword

The Intergovernmental Panel on Climate Change (IPCC) 2014 Synthesis Report states that "substantial [greenhouse gas] emissions reductions over the next few decades can reduce climate risks in the 21st century and beyond, increase prospects for effective adaptation, reduce the costs and challenges of mitigation in the longer term, and contribute to climate-resilient pathways for sustainable development."

The report suggests that there are multiple transformational pathways to attaining the goal of significantly reducing greenhouse gas (GHG) emissions.

The challenge of significantly reducing GHGs in Canada is complex, involving a number of combinations of possible pathways. To explore ways of achieving deep reductions, the Trottier Energy Futures Project is defined by the goal of reducing GHG emissions by 80 per cent from 1990 levels by the year 2050, and with consideration of reducing GHG emissions by 100 per cent or more by the end of the century. The Project employs a systems analysis approach by specifying a target reduction for GHG emissions from combustion sources. It uses two models to optimize pathways to attaining the target at minimum cost, for a variety of scenarios that define alternative futures. The approach defines the least-expensive ways forward and sets the stage for informed conversations that will increase understanding of GHG reduction options open to Canada, and the steps that will lead to early reductions.

The pathways outlined could be more economically attractive when the co-benefits are considered, such as improved public health, traffic management, and infrastructure life-cycle costs. An economic assessment of co-benefits and risks for each scenario was beyond the scope of this research.

Finally, this study is a collaborative effort by three organizations. We may have differing opinions about some of the pathways outlined, but we are in strong agreement that it is important to publish the results of the study in order to stimulate an informed discussion about how to meet internationally defined GHG reduction targets. We need to have those conversations as quickly as possible in order to create the future we desire.

Trottier Family Foundation

The Canadian Academy of Engineering

David Suzuki Foundation

Acknowledgements

The initiative and funding for the Trottier Energy Futures Project (TEFP) came from Lorne Trottier, through the Trottier Family Foundation. Lorne Trottier is an engineer, an entrepreneur, and a philanthropist. He is a Member of the Order of Canada and a Fellow of the Canadian Academy of Engineering. He is a proud Canadian and is committed, with his family, to being a catalyst for Canada to assume a leadership role in addressing the serious climate-change challenge in Canada and around the world.

The project was jointly sponsored by the Canadian Academy of Engineering (CAE) and the David Suzuki Foundation (DSF). Overall direction for the project was provided by a three-person Project Board, including John Leggat (CAE), Peter Robinson (DSF), and Lorne Trottier.

The Project Team included Oskar Sigvaldason, Project Manager and President, SCMS Global; Kathleen Vaillancourt, President, ESMIA Consultants; Michael Hoffman, President, whatIf?; Mara Kerry, Director of Science and Policy, DSF; Ian Bruce, Science and Policy Manager, DSF; and Kevin Goheen, Executive Director, CAE. Other principal contributors included Professor Warren Mabee, Queens University; Professor Emeritus Robert Evans, University of British Columbia; and Alex Boston, President, Boston Consulting. Professor Olivier Bahn, École des Hautes Études Commerciales de Montréal, was Advisor to ESMIA Consultants. Professor Patrick Condon, University of British Columbia, was Advisor to Boston Consulting. Valuable support was provided by Erik Frenette (ESMIA), and by Bas Straatman and Shona Weldon (whatIf?). A four-person Expert Review Panel provided quality assurance for the project. Members of the panel included Professor Andre Plourde, energy economist and Dean of Public Affairs, Carleton University; John Leggat, former Assistant Deputy Minister (Science & Technology), Department of National Defence; Ken Ogilvie, environmental policy consultant to governments, business and environmental organizations; and Professor Miguel Anjos, Canada Research Chair in Discrete Nonlinear Optimization, Polytechnique Montréal and GERAD.

During the course of the project, discussions were held and reviews were conducted with selected representatives from government, industry, non-profit organizations, and universities across Canada, including the National Energy Board, Natural Resources Canada (including the Canadian Forest Service), Environment Canada, Statistics Canada, Canadian Electricity Association, Canadian Association of Petroleum Producers, and Alberta Innovates — Energy and Environment Solutions.

Following preparation of the Draft Report, reviews were carried out by CAE and DSF. For CAE, reviews were done by a committee chaired by Professor Douglas Ruth that included Sara Jane Snook, Eddy Isaacs and Professor Aniruddha Gole. Reviews were conducted by Miles Richardson and Professor Peter Victor, Directors of the Board of DSF, and by Peter Robinson and Gideon Forman of DSF.

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1. Introduction

The initiative and funding for the *Trottier Energy Futures Project* (TEFP) came from Dr. Lorne Trottier, through the Trottier Family Foundation (TFF). Dr. Trottier is a proud Canadian and is committed, with his family, to be a catalyst for Canada to assume a leadership role in addressing the very serious global warming and climate change challenge.

One of the world's greatest challenges over the next century is to achieve effective and timely mitigation of global greenhouse gas (GHG) emissions. Although its relative contribution to global GHG emissions is small, it is essential for Canada to make real and demonstrated progress on reducing its GHG emissions. By demonstrating leadership in addressing this challenge, Canada can move progressively over the next century to become a respected global partner in this endeavour.

This is Canada's challenge and opportunity.

1.1 Project Goal

The stated primary goal of the project is to assess and select strategies for reducing GHG emissions in Canada by 80% by 2050, relative to 1990. However, as has become evident, and as reported in the *Fifth Assessment Report* of the Intergovernmental Panel on Climate Change (IPCC), the ultimate global goal is to achieve 100%, or greater, net reduction in GHG emissions by the end of the century (IPCC, 2014b, p. 20). This has been accepted, in broad terms, as the secondary goal of the project.

1.2 Summary of Project

With the objective of bringing together a wide diversity of interests, inputs and perspectives for the project, it was arranged that the project would be jointly sponsored by the Canadian Academy of Engineering (CAE) and the David Suzuki Foundation (DSF). Overall direction of the project was provided by a three person Project Board, including Dr. John Leggat (CAE), Chair; Dr. Peter Robinson (DSF); and Dr. Lorne Trottier (TFF).

The fundamental approach for the project was to derive minimum cost solutions for achieving progressive reductions in total GHG emissions, from 2011 to 2050, for all of Canada. The approach included rigorous, comprehensive and integrated consideration of all sectors that produce or consume GHG's, in all jurisdictions, and in a multi time period context. Extensive background assessments were carried put on production of GHG emissions and on transformation options, including costs, for reducing such emissions. Two mathematical models (including a formal optimization model) were used, to derive minimum cost solutions. The analyses were carried out for eleven sets of scenarios which represented alternative futures for different combinations of premises and options for GHG mitigation.

The principal aspects of this overall approach included:

- Assembly of a broad based team of specialists covering the full range of disciplines required for the project, including specialists in energy systems, environmental science, economics, electricity supply, fossil fuels, biomass and bio-fuels, transportation, industrial systems, residential/

commercial energy systems, urban systems, agriculture and forestry, carbon capture and retention, and systems analysis.

- Preparation of a series of working paper to assess the potential for reducing GHG releases for all sectors in Canada that produce or absorb GHG's. This included defining GHG reduction relations with associated cost representations for GHG sources and sinks, in each of the provincial and territorial jurisdictions across Canada, and including time varying representation from 2011 to 2050.
- Use of two mathematical models for systematic selection of investments and transformation strategies for achieving targeted net reduction in GHG releases across Canada, at minimum overall cost. The two models include:
  - The *North American TIMES Energy Model* (NATEM), a proprietary optimization model developed and maintained by ESMIA Consultants. NATEM includes a Canadian version of the TIMES/MARKAL family of optimization models, supported and coordinated globally by the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency (IEA).
  - The *Canadian Energy System Simulator* (CanESS), a proprietary model developed and maintained by whatIf? Technologies.
- Both models have been calibrated with Canadian data from National Energy Board, Statistics Canada, Natural Resources Canada and Environment Canada.
- For the models, Canada's energy-environmental system includes separate representations of the various sectors of the Canadian economy, by the thirteen provincial and territorial jurisdictions, and in a multi time period context, from 2011 to 2050.
- Selection of eleven scenarios for analysis with the two models to determine whether and how the 80% reduction target can be met and to provide early perspectives on the most important considerations for achieving major reductions in GHG emissions in Canada.
- A four person Expert Review Panel providing quality assurance and general direction oversight for the project.
- Discussions and reviews with selected representatives from Government, Industry, Not for Profit organizations, and Universities in Canada. The project received valuable input from Canada's National Energy Board, Statistics Canada, Environment Canada, Natural Resources Canada, Forest Service Branch of Natural Resources Canada, Canadian Electricity Association, Canadian Association of Petroleum Producers, Alberta Innovates - Energy and Environmental Solutions, and B.C. Hydro.
- Following preparation of the Draft Report, detailed reviews by Canadian Academy of Engineering, David Suzuki Foundation and Trottier Family Foundation.

1.3 Outline of Report

The report begins with describing the context and setting for the climate change challenge in Canada (Section 2). The approach for seeking minimum cost solutions to this challenge is described in Section 3. With the use of two mathematical models for deriving minimum cost solutions to this challenge for different scenarios, it was necessary to define essential inputs for the two models. This information in presented in Section 4. Results for the eleven sets of scenarios are presented in Section 5. Overview assessments of results from the scenarios, in the context of the Canadian challenge, are included in Section 6. Perspectives on alternative pathways, actions, consequences and opportunities for Canada, for achieving timely progress on the GHG mitigation challenge, are included in Section 7.

More specifically, contents of each of the respective sections of the report are as follows.

The next section (Section 2) includes a description of context and setting for the project. This includes a description of GHG emissions in Canada, and outlines the dominant framework for the project. This included separating GHG emissions into three areas for investigation and assessment.

- Combustion based GHG emissions (72% of total emissions)
- Non combustion GHG emissions (28% of total emissions)
- Net negative emissions

In the project, primary emphasis was given to defining strategies for reducing emissions from combustion of fossil fuels. The two mathematical models were used dominantly for selecting transformation strategies for achieving targeted reductions in combustion-based GHG emissions at overall minimum cost for all of Canada.

However, it was also important to carry out assessment of potential reductions from non-combustion emissions. This has been based on literature reviews and expert opinions, with such reporting also included in Section 2. However, such considerations were not represented in the models, primarily due to lack of well-defined transformation options and associated data.

The importance of developing strategies that result in net extraction of GHG's, dominantly carbon dioxide (CO_2), from the atmosphere (net negative emissions) has also been highlighted in the *Fifth Assessment Report* (IPCC, 2014b, p. 28). Assessments of such strategies have been based dominantly on a literature review, which is also reported in Section 2. However, it is noted that one of the strategies, bioenergy with carbon capture, use and storage (BECCS), has been represented in the optimization model, and is included in the reporting of quantitative results.

There is also a description of the changing economic and socioeconomic setting in Canada, from 2011 to 2050. This includes projections of population growth, Gross Domestic Product (GDP) per capita, total GDP, and industrial gross output.

The general approach for deriving minimum cost solutions for achieving targeted reductions in GHG emissions, from combustion of fossil fuels, is described in Section 3. This includes descriptions of the two mathematical models, as well as special considerations for ensuring appropriate system representation in the models. There is also a brief description of approaches in other selected countries for addressing the GHG mitigation challenge.

In Section 4, there is a description of the various options and associated inputs for defining GHG combustion based emissions and associated costs in Canada. This is presented for the five end use sectors (residential, commercial, transportation, industry, agriculture) and for production and delivery of electricity and fossil fuels. There are also descriptions of biomass/biofuels, and carbon capture, use and storage (CCUS).

In the project, minimum cost solutions for targeted reductions in GHG emissions from combustion of fossil fuels, were derived with the models for eleven separate sets of scenarios. These scenarios represent different combinations of premises. These results, along with associated analyses and interpretations, are presented in Section 5.

The principal observations from the project are presented in Section 6. This includes summary results from the scenarios, as well as consideration of non-combustion emissions and net negative emissions.

Alternative pathways for achieving major reductions in GHG emissions are presented in Section 7. This includes a discussion on the huge challenge of implementing fundamental transformations, including major reductions in combustion of fossil fuels, and correspondingly increased roles for electricity and biomass/biofuels. Perspectives are provided on the highest priority options for immediate implementation, as well as associated actions for addressing remaining challenges. Perspectives are provided on a carbon pricing framework for Canada and for determining carbon prices. There are also suggestions concerning the need for a sustainable institutional capability to support development of approaches and pathways to respond to the urgent GHG mitigation challenge.

2. Context and Setting

2.1 Introduction

This section includes the context and setting for the project. A presentation of the GHG challenge, in both global and Canadian contexts, is presented. There is a description of Canada's energy sector, especially as it relates to production of GHG emissions. This is followed by analyses of GHG production in Canada, including from both combustion and non-combustion sources. Options for reducing GHG emission from these respective sources are then described. Strategies for producing net negative emissions (net extraction of CO_2 from the atmosphere) are important, and such options are also described. Finally, there is a discussion on projected economic and socio-economic setting in Canada, including population projections, GDP, and gross outputs from the industrial sector.

2.2 The Greenhouse Gas Challenge

2.2.1 Global Perspective

It is well recognized and respected that a dominant global concern is the impact of global warming and climate change resulting from increasing GHG emissions, and selecting and implementing strategies and actions that minimize or neutralize its projected impacts.

The IPCC, which was created in 1988, is the recognized global organization that is providing perspectives on this challenge (IPCC, 2016). The initial task for the IPCC, as outlined in UN General Assembly Resolution 43/53 of 6 December 1988, "…was to prepare a comprehensive review and recommendations with respect to the state of knowledge of the science of climate change; the social and economic impact of climate change; and possible response strategies and elements for inclusion in a possible future international convention on climate". Today, IPCC's role is as defined in the Principles Governing IPCC Work, "...to assess on a comprehensive, objective, open and transparent basis the scientific, technical and socio-economic information relevant to understanding the scientific basis of risk of human-induced climate change, its potential impacts, and options for adaptation and mitigation. IPCC reports should be neutral with respect to policy, although they may need to deal objectively with scientific, technical and socio-economic factors relevant to the application of particular policies."

Over the past 27 years, the IPCC has played a major role in carrying out and coordinating global initiatives leading to production of the most comprehensive scientific information about climate change. This information has been documented in their Assessment Reports. The scientific evidence brought up by the first IPCC Assessment Report of 1990 underlined the basis for establishing the United Nations Framework Convention on Climate Change (UNFCCC), the key international treaty to reduce global warming and cope with consequences of climate change (UNFCCC, 2016).

Since 1990, the IPCC has produced four additional Assessment Reports, including the *Fifth Assessment Report* in 2014. It has also responded to the need for information on scientific and technical matters from the UNFCCC, through Methodology Reports and Special Reports, and from governments and international organizations. Methodology Reports serve as methodology and guidelines to help Parties to the UNFCCC prepare their national GHG inventories.

The participation of the scientific community in the work of the IPCC has grown greatly, in terms of the number of authors and contributors involved in writing and reviewing the reports, geographical distribution of authors, and the topics covered by the reports.

The IPCC finalized the *Fifth Assessment Report* in 2014 (IPCC, 2014a). This Report includes four separate documents as follows:

- *Climate Change 2013 - The Physical Science Basis*
- *Climate Change 2014 - Impacts, Adaptation & Vulnerability*
- *Climate Change 2014 - Mitigation of Climate Change*
- *Climate Change 2014 - Synthesis Report*

In the Synthesis Report, there are important summary perspectives provided in their *Summary for Policymakers*, under the following broad headings (IPCC, 2014b):

- Observed changes and causes
- Future climate changes, risks and impacts
- Future pathways for adaptation, mitigation and sustainable development
- Adaptation and mitigation

The following stated perspectives from the first category (Observed changes and causes) are important in the context of the project (Figure 1 and Figure 2):

- SPM 1: Human influence on the climate system is clear, and recent anthropogenic emissions of GHG are the highest in history. Recent climate changes have had widespread impacts on human and natural systems.
- SPM 1.1: Warming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, and sea level has risen.
- SPM 1.2 Anthropogenic GHG emissions have increased since the pre-industrial era, driven largely by economic and population growth, and are now higher than ever. This has led to atmospheric concentrations of carbon dioxide, methane and nitrous oxide that are unprecedented in at least the last 800,000 years. Their effects, together with those of other anthropogenic drivers, have been detected throughout the climate system and are extremely likely to have been the dominant cause of the observed warming since the mid-20th century.
- SPM 1.3: In recent decades, changes in climate have caused impacts on natural and human systems on all continents and across the oceans. Impacts are due to observed climate change, irrespective of its cause, indicating the sensitivity of natural and human systems to changing climate.
- SPM 1.4: Changes in many extreme weather and climate events have been observed since about 1950. Some of these changes have been linked to human influences, including a decrease in cold temperature extremes, an increase in warm temperature extremes, an increase in extreme high sea levels, and an increase in the number of heavy precipitation events in a number of regions.

The following perspectives from the same Summary for Policymakers are particularly relevant with respect to mitigation measures:

- SPM 2: Continued emission of GHG will cause further warming and long-lasting changes in all components of the climate system, increasing the likelihood of severe, pervasive and irreversible impacts for people and ecosystems. Limiting climate change would require substantial and sustained reductions in GHG emissions which, together with adaptation, can limit climate change risks.
- SPM 2.4: Many aspects of climate change and associated impacts will continue for centuries, even if anthropogenic emissions of GHG are stopped. The risks of abrupt or irreversible changes increase as the magnitude of the warming increases.
- SPM 3.2: Without additional mitigation efforts beyond those in place today, and even with adaptation, warming by the end of the 21st century will lead to high to very high risk of severe, widespread and irreversible impacts globally (high confidence). Mitigation involves some level of co-benefits and of risks due to adverse side effects, but these risks do not involve the same possibility of severe, widespread and irreversible impacts as risks from climate change, increasing the benefits from near-term mitigation efforts.
- SPM 3.4: There are multiple mitigation pathways that are likely to limit warming to below 2°C relative to pre-industrial levels. These pathways would require substantial emissions reductions over the next few decades and near zero emissions of CO2 and other long-lived GHG by the end of the century. Implementing such reductions poses substantial technological, economic, social and institutional challenges, which increase with delays in additional mitigation and if key technologies are not available. Limiting warming to lower or higher levels involves similar challenges but on different timescales.
- SPM 4.1: Adaptation and mitigation responses are underpinned by common enabling factors. These include effective institutions and governance, innovation and investments in environmentally sound technologies and infrastructure, sustainable livelihoods and behavioural and lifestyle choices.
- SPM 4.3: Mitigation options are available in every major sector. Mitigation can be more cost-effective if using an integrated approach that combines measures to reduce energy use and the GHG intensity of end-use sectors, decarbonize energy supply, reduce net emissions and enhance carbon sinks in land-based sectors.

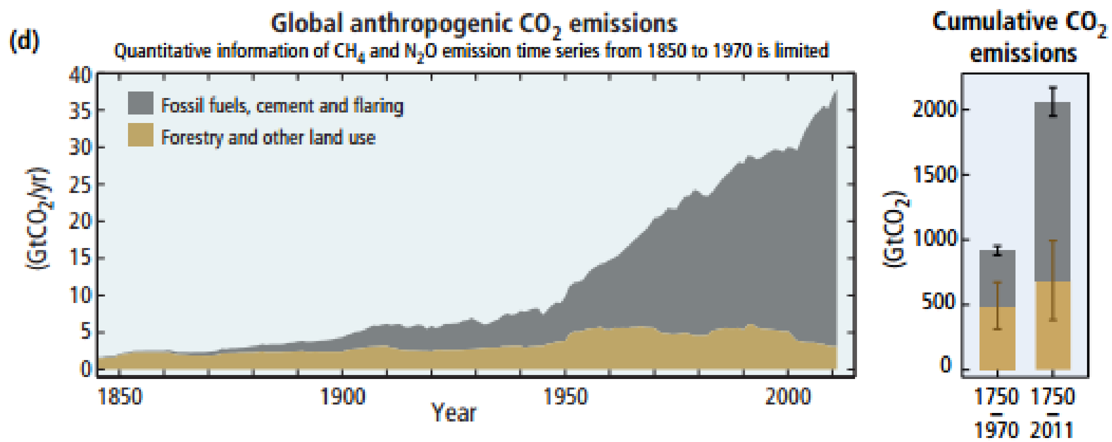
There are additional perspectives provided in other portions of the *Fifth Assessment Report* (IPCC, 2014c), which provide more detailed dimensions of the overall challenge:

- Cumulative fossil CO_2 emissions from 1750 to 2011 are estimated to be 1,340 billion tonnes (Gt) of CO_2, while cumulative CO_2 emissions from land use changes are 680 Gt CO_2 (roughly 2/3 and 1/3), for a total of just over 2,000 Gt CO_2 (Figure 1).
- It is estimated that, in order to limit temperature rise to no more than 2°C, cumulative CO_2 emissions from all anthropogenic sources since 1870 should remain below about 2,900 Gt CO_2. As cumulative CO_2 to 2011 is about 2,000 Gt CO_2, remaining global CO_2 emissions would need to be limited to an additional 900 Gt CO_2. Emission scenarios leading to GHG concentrations in 2100 of about 450 ppm CO_2-eq (equivalent to 2°C temperature rise) are characterized by 40% to 70% global anthropogenic GHG emissions reductions by 2050 compared to 2010, and net emissions levels at or below zero by 2100.

- Annual anthropogenic GHG emissions have increased from 27 to 49 Gt CO_2-eq per year (80% increase) between 1970 and 2010. GHG emissions during the 2000 to 2010 decade were the highest in human history, with GHG emissions increasing on average by 1 Gt CO_2-eq per year, compared to 0.4 Gt CO_2-eq per year between 1970 and 2000. This has occurred primarily as a consequence of rapid economic growth, with associated rapidly expanding energy demands, in emerging economies. The consequence of this is that CO_2 concentrations in the atmosphere are now increasing at 3 ppm per year, having reached 400 ppm per year in 2014.
- Without additional efforts to reduce GHG emissions beyond those in place today, global emissions growth is expected to persist, driven by growth in global population and economic activities. Global mean surface temperature increases in 2100 in baseline scenarios – those without additional mitigation – range from 3.7 to 4.8°C above the average for 1850-1900 for a median climate response, and from 2.5°C to 7.8°C when including climate uncertainty (5th to 95th percentile range).
- Multiple lines of evidence indicate a strong, consistent, almost linear relationship between cumulative CO_2 emissions (from 1750) and projected global temperature change in the year 2100. Any given level of warming is associated with a range of cumulative CO_2 emissions. Future climate will depend on committed warming caused by past anthropogenic emissions, as well as future anthropogenic emissions and natural climate variability.
- Warming will continue beyond 2100 as long as there are continuing GHG emissions. Surface temperatures will remain approximately constant at elevated levels for many centuries after a complete cessation of net anthropogenic emissions. A large fraction of anthropogenic climate change resulting from CO_2 emissions is irreversible on a multi-century to millennial time scale, except in the case of large net removal of CO_2 from the atmosphere over a sustained period.
- Well-designed systemic and cross-sectoral mitigation strategies are more cost-effective in cutting emissions than a focus on individual technologies and sectors, with efforts in one sector affecting the need for mitigation in others. Mitigation measures intersect with other societal goals creating the possibility of co-benefits or adverse side effects. These intersections, if well-managed, can strengthen the basis for undertaking climate action.
- Mitigation options are available in every major sector. Mitigation can be more cost-effective if using an integrated approach that combines measures to reduce energy use and the GHG intensity of end-use sectors, decarbonize energy supply, reduce net emissions and enhance carbon sinks in land-based sectors. A broad range of sector mitigation options is available that can reduce GHG emission intensity, improve energy intensity through enhancements of technology, behaviour, production and resource efficiency, and enable structural changes or changes in activity.

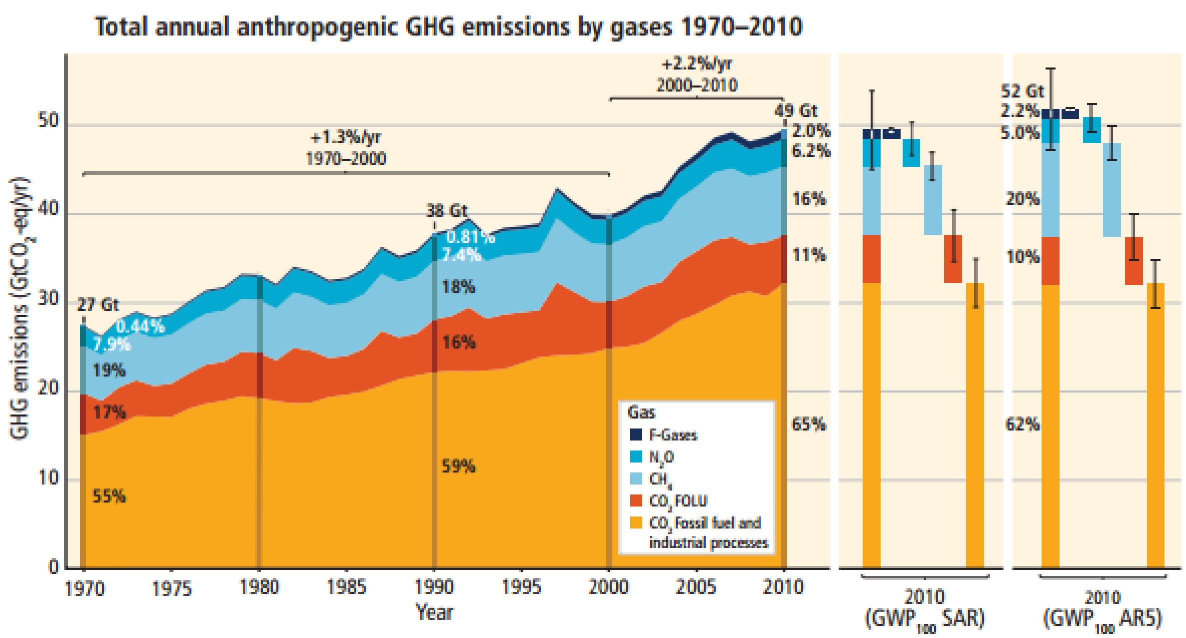
Based on the forgoing information, there should be no doubt that the climate change challenge is both enormous and urgent. There is an immediate need for early transformations that results in major reductions in GHG emissions. There is further accentuated by the absolute need, before the end of this century, to effectively eliminate net emission to the atmosphere, and for complete reversal of rising GHG concentrations, with resulting progressive reversal of climate change impacts.

Figure 1. Global anthropogenic CO_2 emissions



Source: IPCC, 2014b, p. 3.

Figure 2. Total annual anthropogenic GHG emissions, 1970 – 2010



Source: IPCC, 2014b, p.5.

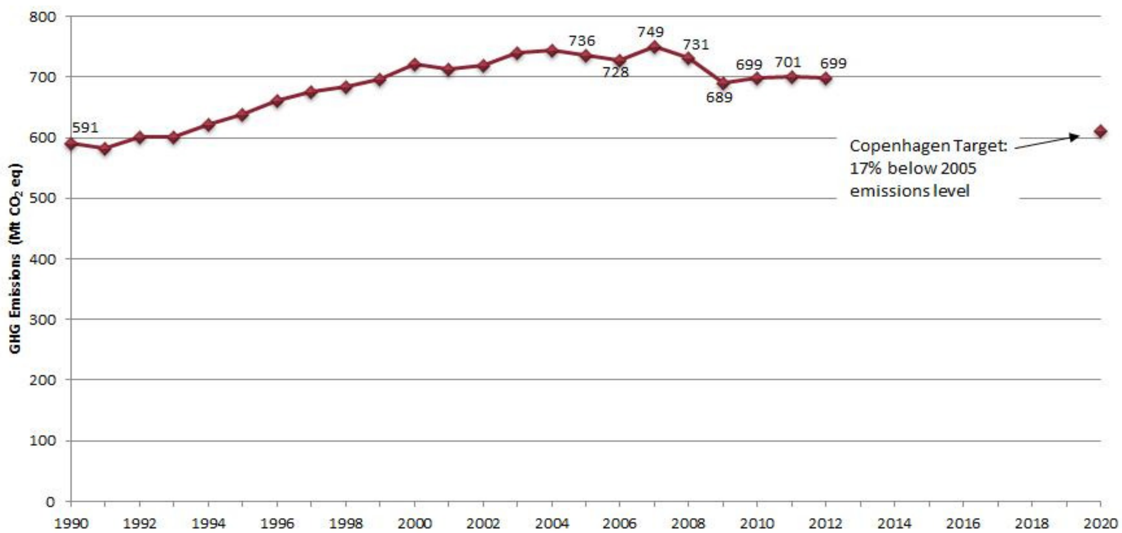
2.2.2 Canada's Status with Reducing GHG Emissions

Canada has participated in UNFCCC reporting since 1990, including producing annual National Inventory Reports. Overall results from 1990 to 2012 are presented on Figure 3 (Environment Canada, 2014). Trends, in terms of per capita production of GHG's, are shown Figure 4 for the same 1990 to 2012 period.

Commentary with respect to Canada's status with reducing GHG emissions may be summarized as follows:

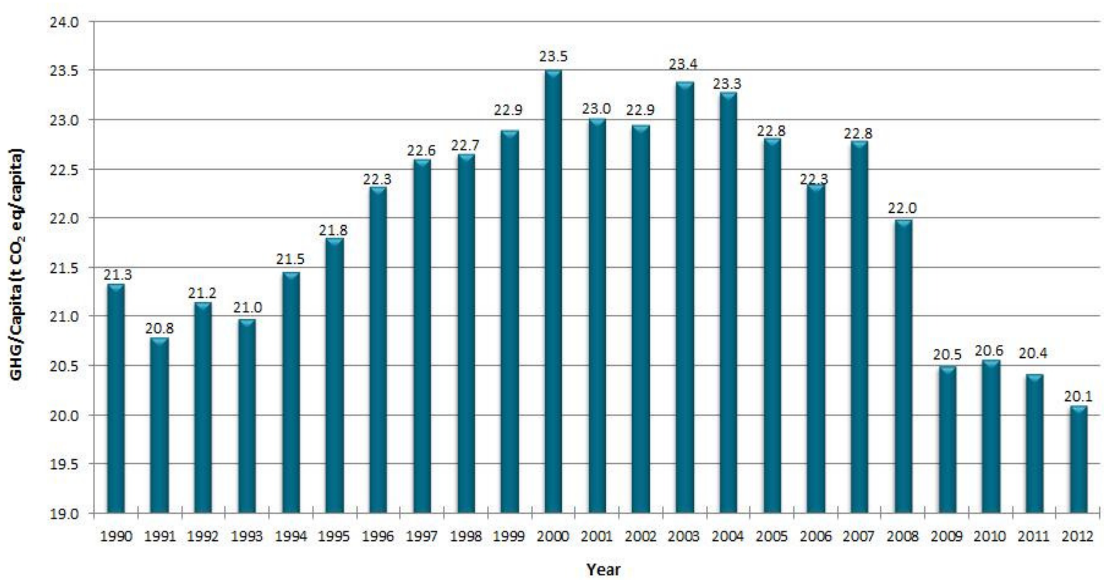
- Canada's emissions increased from 591 million tonnes (Mt) of CO_2-eq in 1990, to 699 Mt in 2012. If Canada were to take no further action to reduce GHG emissions, and as projected for the Reference Scenario (see Section 5.3), GHG emission would continue to increase, reaching 1,109 Mt in 2050.
- As a signatory to the *Copenhagen Accord* at the U.N. 15th Conference of the Parries (COP 15) in December, 2009, Canada committed to reducing its GHG emissions to 17% below 2005 emissions levels, by 2020, to a target of 611 Mt (Government of Canada, 2015a). Recently, the Government of Canada has announced a further target of reducing GHG emissions to 30% below 2005 levels, by 2030 (Government of Canada, 2015b).
- The principal actions, taken to date, in response to the *Copenhagen Accord* have included reducing emissions from the coal fired generating facilities, and from the transport sector. This has included banning construction of traditional coal–fired generating plants, and imposing Corporate Average Fuel Economy (CAFE) standards for fuel use efficiencies for vehicles.
- With introduction of the recent GHG reduction target for 2030, the additional planned measures include:
    - Reducing potent methane releases, especially from the oil and gas sector, following development of corresponding regulations in the United States.
    - Additional regulations for reducing GHG releases from natural gas generating facilities, which is an extension of earlier regulations for traditional coal fired generating facilities.
    - Reducing GHG releases from production of chemicals and nitrogen fertilizer.
- Though GHG emissions have risen by 18% since 1990, Canada's economy has grown more rapidly, with GDP rising by 67%. As a result, emission intensity for the entire economy (GHG per GDP) has improved considerably, dropping by 29% (Figure 4). Early in the period, emissions rose nearly in step with economic growth. However, after 1995, the paths began to diverge, a shift that can be attributed to increases in efficiency, modernization of industrial processes, and structural changes in the economy.
- In a recent Report from the Conference Board of Canada (2016), if was noted that, at 20.1 Mt per capita per year, Canada still remains as one of the highest per capita emitters in the world. Canada ranks 15th out of 17 OECD countries, significantly higher than the average of 12.5 Mt per capita, and nearly three times greater than Switzerland, the top performer.

Figure 3. Canadian GHG emissions trend, 1990–2012, and Copenhagen target



Source: Environment Canada, 2014.

Figure 4. Canadian per capita GHG emissions, 1990–2012



Source: Environment Canada, 2014.

2.2.3 Perspectives on Goals of the Project

The primary goal was to define pathways and options for how Canada could reduce its GHG emissions by 80% by 2050, relative to 1990. This corresponds to 118 Mt (20% of the recorded 589 Mt in 1990). The secondary goal was to assess strategies for reducing net GHG emissions by more than 100%, by the end of the century.

In Section 2.8.1, it is shown that Canada's population is projected to increase to 48 million by 2050. To meet the stated 2050 goal, the corresponding per capita emissions would need to reduce to less than 2.5 tonnes per capita. This corresponds to an 88% reduction below the recorded 20.1 tonnes per capita in 2012, as shown in Figure 4.

As should be evident, such massive reductions in emissions will require major transformations in the overall economy. The largest transformations will need to occur in the energy sector, which is where, as shown by the World Resources Institute, 60% of global GHG emissions occur (Herzog, 2009). The remaining 40% include land use changes (18.2%), agriculture (13.5%), industrial process emissions (3.4%), and waste (3.6%). When considering only the industrialized world, land use changes do not normally represent a major source of GHG emissions. In such cases, a more representative proportion of GHG emissions from the energy sector, is 75% of total GHG emissions.

It is certainly evident, when considering reductions of 88% of per capita emissions by 2050 and more than 100% by 2100, every sector of the economy will be impacted. As noted, the dominant focus will be on transformations for reducing emissions in the energy sector, from combustion of fossil fuels. However, there will also need to be changes in the agricultural sector, reducing non-combustion process emissions in the industrial sector, and reducing emissions from waste.

In addition to making major reductions in emissions from various sources, there will also be a need to select approaches that result in net extraction of GHG's (net negative emissions), dominantly CO_2, from the atmosphere. An approach will clearly be essential for reaching 100%, or greater, reductions before the end of the century. However, as there are major challenges with reducing some classes of emissions, such as from the agricultural sector, it will be necessary to also give early consideration to net negative emissions.

2.3 Canada's Energy System

The largest share of GHG emissions come from the energy sector.

A Sankey diagram for a representative year (2007) shows energy flows from primary source to end use, for Canada, as prepared by Lawrence Livermore Laboratories, is shown on Figure 5. This was part of a global initiative undertaken by this organization for assessing energy flows for 136 countries around the world, and aggregated to show total global energy flows (Smith et al, 2011).

Some key perspectives from review of this diagram, and in the context of productions of GHG's, especially CO_2, are as follows:

- Primary energy supply (including imports) for Canada in 2007 was 21,400 petajoules (PJ)[1]. Of this amount, 9,660 PJ of fossil fuels and 90 PJ of net electricity export represented total export of 9,750 PJ. Of the remaining 11,650 PJ, 970 PJ was for non-energy uses (production of petrochemicals), leaving 10,680 PJ for domestic energy-based uses. 3,930 PJ of this amount was

1 A joule is the amount of energy required for one ampere of electrical current to flow through one ohm of resistance for one second (watt-second). A petajoule (PJ) is one quadrillion (10^15) joules. One Terrawatt hour (Twhr.) equals 3.6 PJ.

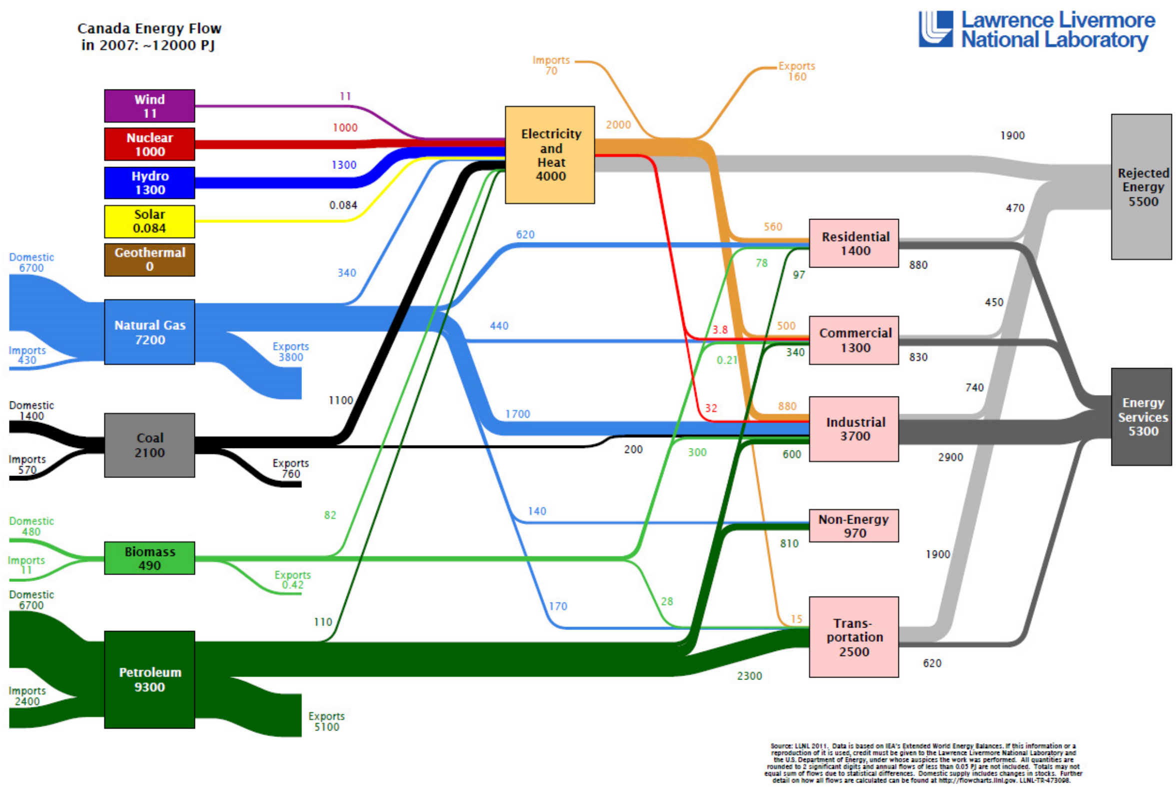
for electricity production and 6,750 PJ for direct use in the residential, commercial, industrial, and transportation sectors.

- 51% of primary energy (5,500 PJ) is not beneficially used for meeting energy based end uses, and is simply rejected, virtually entirely as waste heat. This is dominantly due to thermodynamic losses associated with conventional steam turbines, combustion turbines and internal combustion engines. With conventional coal fired generating facilities, for example, conversion efficiencies are generally of the order of 32% to 38 %. Conversion efficiency values for nuclear generating facilities are even lower, typically about 30%. For gas fired combustion turbines, conversion efficiencies are about 40%. With addition of heat recovery steam generators, overall efficiency can increase to 55 to 60%. With further addition of cogeneration, overall efficiency can increase to 75 to 80%.
  For the transportation sector, losses are even higher, with more than 75% (1,900 PJ out of 2,500 PJ) of primary energy being rejected in the form of waste heat.
- For meeting the 8,900 PJ of energy based end uses, the supply includes 1,900 PJ from electricity (21%), 6,590 PJ from direct use of fossil fuels and its derivatives (74%) and 410 PJ from biomass/biofuels (4.6%).
- It is of interest to note that the mix of primary energy supply for electricity and heat production includes 3,930 PJ, which is 37% of total primary energy supply for energy based needs in Canada. Of this amount, 1,550 PJ (39%) is from burning fossil fuels, 1,000 PJ (25%) is from nuclear, 1300 PJ (33%) is from hydro and 82 PJ (2%) is from biomass. For 2007, electricity production included fossil fuels (25%), nuclear (15%), hydro (60%) and biomass (1%). These numbers demonstrate the higher overall conversion efficiency from hydro production (typically of the order of 90%), relative to thermal and nuclear facilities with much lower conversion efficiencies, as noted above.
- The importance of fossil fuels for export is clearly evident in Figure 5. The 9,750 PJ pf energy export is only slightly less than all energy used in Canada for its domestic needs, including energy for production (extraction, upgrading, refining, etc.) of fossil fuels for export.
- In the context of strategies for reducing CO_2 emissions from Canada's energy system, the most obvious opportunities from examination of the Sankey diagram are as follows:

  - With combustion of fossil fuels providing 74% of energy based end uses, with corresponding production of CO_2, the most obvious strategy is to decrease the role of fossil fuels, and to correspondingly increase the respective roles of electricity and biomass/biofuels, for meeting such end uses, with corresponding reduced production of CO_2 emissions.
  - A significant portion of fossil fuels is used directly for electricity generation, with associated CO_2 emissions. Such emissions can be reduced with increasing electricity production from non-emitting sources, especially renewables (hydro, wind, solar, etc.) and nuclear.
  - With more than 50% of primary energy being rejected in the form of waste heat, an obviously important strategy is to examine various forms of heat recovery and re-use in the various sectors, especially when the primary energy source is from burning fossil fuels. This includes combined cycle and cogeneration facilities for combined power and heat production, heat recovery and re-use options for industrial facilities, and developing district and distributed energy systems in urban and municipal regions.
  - There are very significant conversion losses in use of energy, with the most serious being in the transportation sector. This brings obvious attention to the importance of including

options which are more efficient in conversion of primary energy, especially when the primary energy is from fossil fuels. The most obvious conversion gain is with motive power, with electric motors having conversion efficiencies in excess of 90%, as compared to ICE engines with conversion efficiencies of approximately 25%.

Figure 5. Energy flows for Canada, 2007



Source: Smith et al, 2011.

2.4 GHG Production in Canada

Actual recorded production of GHG emissions for 1990 and 2010, as reported in Canada's annual National Inventory Reports, are shown on Figure 6 and Figure 7, respectively (Environment Canada, 2014). Projected results for 2050, as derived for Scenario 1 (see Section 5.3), based on the premise of no additional measures for GHG mitigation, other than those that were in place in 2011, are shown on Figure 8.

In these figures, it is shown that GHG emissions are in two parts: GHG emissions from combustion of fossil fuels, and from non-combustion sources. These ratios are 72% and 28% respectively, for both 1990 and 2010. For 2050, the ratio alters to 68% and 32%, primarily as a consequence of projected overall increase in production and export of fossil fuels.

GHG emissions for the five classes of end uses (residential, commercial, transportation, industrial and agriculture) represent almost 50% of total GHG emissions (47% in 1990, 44% in 2010 and 43% in 2050). These emissions are for direct use for meeting energy based end uses, such as burning natural gas for space heating, or combusting gasoline in vehicles. These emissions are referred to as "consumption" emissions.

With respect to emissions from fossil fuel "production", it is important to appreciate that such emissions include emissions for the entire supply chain for production, processing and delivery of fossil fuels and its derivatives. This includes extraction, collection, processing, upgrading, refining, transport by pipeline, and delivery to point of final use (such as gasoline to local service stations, or refined natural gas to homes and commercial establishments). The production emissions can be separated into three categories:

- Production, processing and delivery directly for end uses
- Production and delivery to electricity generation facilities
- Production and transport to export terminals for international sale

From detailed assessment of production and consumption emissions for directly meeting end uses (first item above), it is observed that emissions are dominantly for energy use, often referred to as consumption. For example, when analyzing results for 2050 (Figure 8), total emissions for the five categories of end uses was 541 Mt. The corresponding emissions for production, processing and delivery for directly meeting these end uses (first item above) was 71 Mt (portion of total 213 Mt for fossil fuel production in Figure 8). In this specific case, emissions for meeting end uses was 13% for supply chain production and 87% for end use consumption. While there are some nominal variations in emissions generation in both end uses and the supply chain, it should be appreciated that GHG emissions are dominantly associated with energy consumption. This very key observation was the basis for giving prime attention in the project for defining transformation strategies for changes to end uses, where the dominant changes will need to happen in order to meet the defined 80% GHG reduction target.

The basic approach in the project was to focus dominantly on selecting transformation strategies for reducing GHG emissions from combustion sources. Options for defining transformation strategies are reasonably well known and are suitable for analytical analysis. The approach for combustion emissions is described in Section 2.5.

For non-combustion emissions (industrial process, fugitive, agriculture and waste), strategies are not as well defined, and are fundamentally different for each of the four sources of such emissions. In addition, the quality of information, in several cases, needed for carrying out rigorous analytical assessments, is either not available or not credible. Accordingly, the approach adopted for assessment of strategies for non-combustion emissions was based on literature reviews and reliance on expert opinions. This included consideration of transformation strategies for reducing non-combustion emissions, as well as for defining reasonable limits on reduction potential. Results of these assessments are presented in Section 2.6.

Finally, as already noted, the goal for the project for 2100, can only be realized with real progress on ways for producing net negative emissions. Descriptions of such options are described in Section 2.7.

Figure 6. GHG emissions (589 Mt) in Canada, 1990

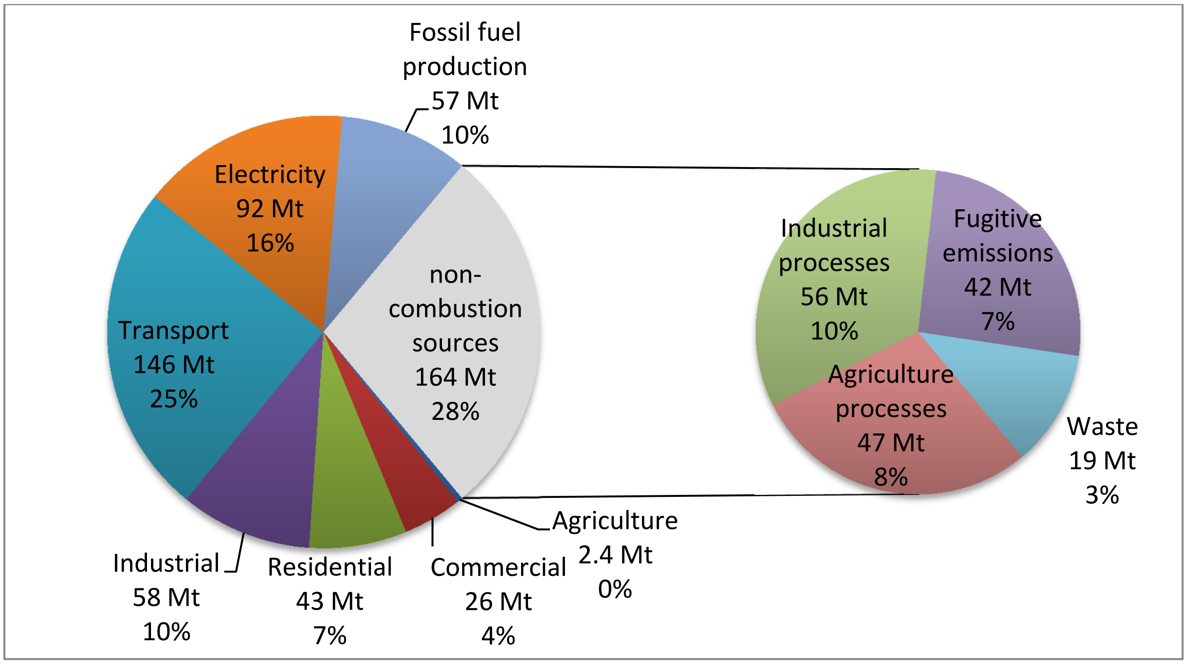


Figure 7. GHG emissions (692 Mt) in Canada, 2010

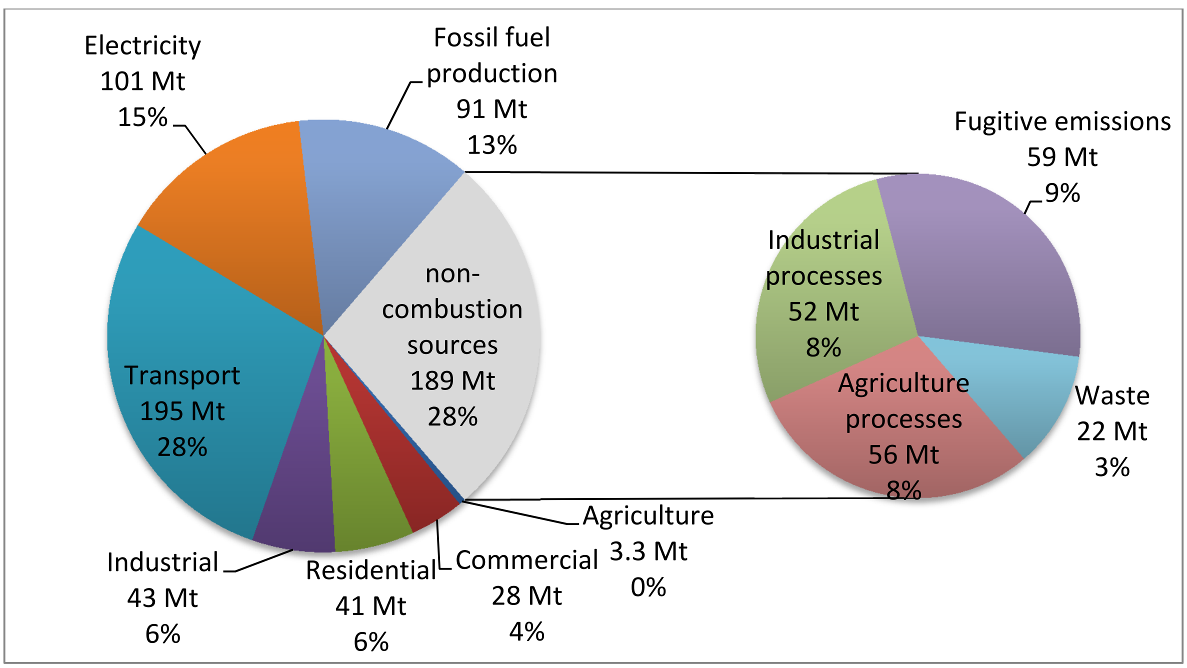
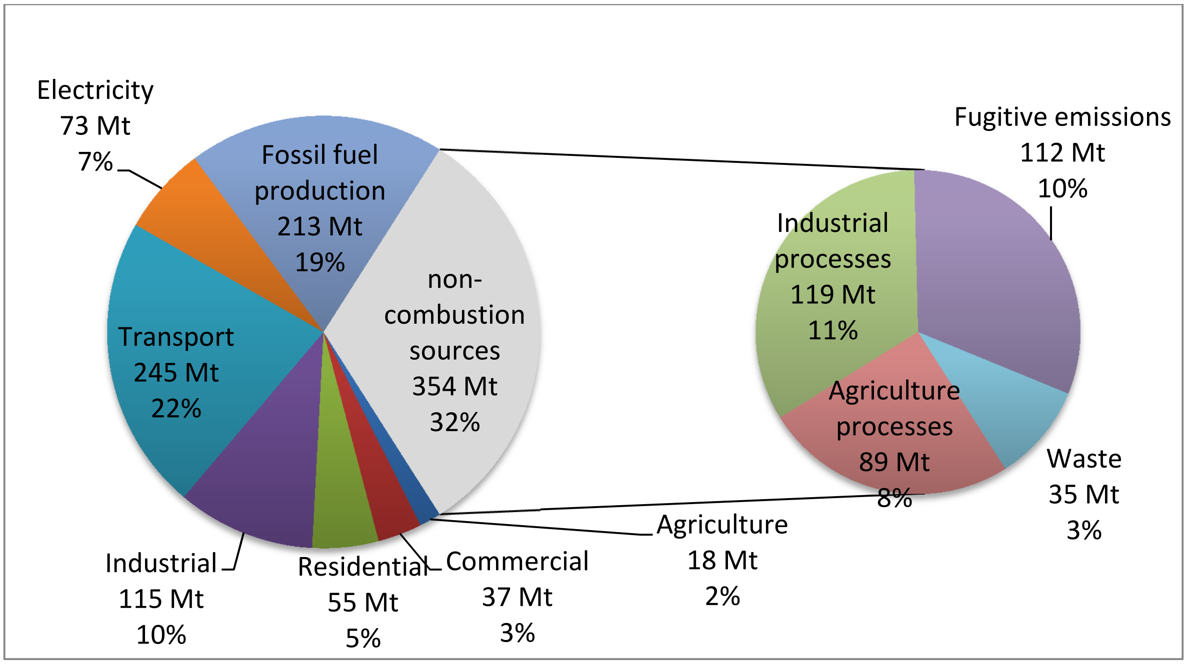


Figure 8. Projected GHG emissions (1109 Mt) in Canada, 2050 - No GHG mitigation



2.5 Options for Reducing Combustion Emissions

The largest source of GHG emissions is from combustion of fossil fuels. These are for meeting five classes of end uses (residential, commercial, transportation, industrial and agriculture), and for production and delivery of electricity and fossil fuels.

The dominant strategies for reducing GHG emission from combustion of fossil fuels include:

- Energy conservation and energy efficiency;
- Transforming thermal energy demands from burning fossil fuels, to the use of electricity or biomass/biofuels;
- Transforming motive power demands from burning fossil fuels to the use of electric motors or biofuels to replace fossil fuel derivatives;
- Decarbonizing electricity supply.

A key reference point for reductions in combustion based emissions was the actual 427 Mt value for combustion emissions in 1990. All results are presented in relation to this reference point value.

The general approach was based on using two mathematical models for systematic selection of transformation strategies and investments for satisfying both increasing demands for energy related services, and for increasingly stringent mitigation targets, at overall minimum cost. The two models, the NATEM Canada optimization model and the CanESS simulation model are described in Sections 3.3.2 and 3.3.3, respectively. A description of the complementing development and use of the models is described in Section 3.3.1.

While most of the analyses in the project have been based on deriving minimum cost solutions for reducing combustion based emissions, it is important to note that these results have been combined with results of non-combustion emission and net negative emissions as a basis for defining overall results in a comprehensive context. Such combined results are presented in Sections 5.3.6, 5.10.6 and 5.11.6. Key corresponding observations are presented in Section 6.3. Suggestions concerning required changes and possible strategies for overall emissions reductions, are included in Sections 7.1, 7.3 and 7.5.

2.6 Options for Reducing Non-Combustion Emissions

As outlined in Section 2.4, 28% of GHG emissions have come from non-combustion emissions. There are four separate source of non- combustion emissions. They include:

- Industrial non-combustion emissions
- Fugitive releases
- Agriculture non-combustion emissions
- Waste

Each of these sources of GHG emissions will be described in sequence.

2.6.1 Process Emissions in Industry

Industrial process emissions (8% of total emissions) include emissions dominantly from chemical processes, with GHG gases being emitted as process by-products. Such emissions include conversion of carbonaceous material (such as CO_2 release from conversion of limestone to lime for cement production), oxidation of carbonaceous materials, electrolysis, and various other processes. The dominant sources of such emissions in Canada are from different industrial sectors, including cement and lime, iron & steel, aluminum, chemical, petrochemical and semi-conductors. GHG emissions include CO_2, as well as nitrous oxide, methane and the various fluorinated gasses (hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride). Detailed descriptions of processes and magnitudes of such emissions are presented in Canada's annual National Inventory Reports, produced as part of annual reporting for UNFCCC (Environment Canada, 2014).

From literature reviews of global developments for GHG mitigation, including the most recent IPCC *Fifth Assessment Report*, there has been virtually no progress on reducing GHG emissions from industrial process emissions (IPCC, 2014d). The principal transformation opportunities being considered include process changes that result in less emissions; carbon capture and storage, such as for cement and steel production; and improved capture, storage and reuse, especially for fluorinated gasses. However, there are very few actual facilities that have been developed anywhere in the world for reducing industrial process emissions.

Needless to say, this remains as an especially challenging sector for GHG mitigation. On the basis of existing knowledge and global experience, it was considered that the most appropriate judgement for the project was to consider that the potential for reducing industrial process emissions was negligible. However, since this source of emissions is expected to increase, generally in proportion to overall industrial expansion, this source of emissions cannot be ignored. As will be shown in results from selected scenarios (as presented in Sections 5.10.6 and 5.11.6), this source of emissions has the potential of becoming a dominant challenge in later years, especially if good progress is achieved in reducing combustion emissions.

2.6.2 Fugitive Emissions

Fugitive emissions in Canada (Table 1), as reported, represent 9% of total emissions (2010).

As reported in the *National Inventory Report*, "The Oil and Natural Gas category of fugitive emissions includes emissions from oil and gas production, processing, oil sands mining, bitumen extraction, in-situ bitumen production, heavy oil/bitumen upgrading, petroleum refining, natural gas transmission and natural gas distribution" (Environment Canada, 2014).

Table 1. Fugitive emissions in Canada

Year	1990	2000	2005	2010
Fugitive Emissions from Fuels	42,400	63,000	63,300	58,600
Solid Fuels—Coal Mining	2,000	1,000	1,000	1,000
Oil and Natural Gas	40,200	62,100	62,300	57,600
- Oil[1]	4,180	5,440	5,650	5,700
- Natural Gas[1]	11,400	17,700	19,200	19,300
- Venting and Flaring[2]	24,600	38,900	37,500	32,600
- Venting	20,200	33,500	32,000	28,300
- Flaring	4,400	5,400	5,500	4,300

1. All other fugitives except venting and flaring.
2. Both oil and gas activities.
Source: NIR, 2010.

The following commentary is provided with respect to fugitive emissions, in both global and Canadian contexts.

- It is common practice for gasses to be flared or vented simply as a way to dispose of unwanted natural gas released during crude oil extraction or in the gas refining process. There are also substantial losses in distribution systems and at points of final delivery resulting in substantial waste of natural gas that could otherwise be used. The World Bank estimates that the annual volume of natural gas being flared and vented worldwide each year is about 110 billion cubic meters (about 3% of all gas marketed in the world), enough to provide natural gas for annual consumption of Central and South America, or that of Germany and Italy (USGAO, 2004).
- While large fugitive releases occur in overseas countries, it is clearly evident that fugitive releases in North America are, almost certainly, larger than values reported in official documents. In a recent report (Golden, 2014), results of more than 200 earlier studies confirms that the emissions of methane in the United States are considerably higher than official estimates. Stanford's Adam Brandt and colleagues have found that methane leakage from the natural gas infrastructure in the United States is much higher than official estimates. The first thorough comparison of evidence for natural gas system leaks confirms that organizations, including the Environmental Protection Agency (EPA), have underestimated United States methane emissions generally, as well as those from the natural gas industry. A number of studies show that accurate measures of fugitive emissions using advanced technologies are often three to four times higher than officially reported.

- There is a special consideration with respect to venting versus flaring. Natural gas, typically, is about 75% methane before processing, and 95%, after processing. Accordingly, in venting, methane is released directly into the atmosphere, which has a global warming potential 34 times greater that CO_2 on a 100 year time horizon. On the other hand, if natural gas is flared, the methane is converted to CO_2, which has much lower global warming potential. This consideration also extends to normal leaks which again, are dominated by methane being released directly to the atmosphere.
- With respect to actions in Canada to address the challenge of fugitive emissions, the following commentary is provided:

  - Uncertainty remains around the scope of the problem (i.e. an accuracy of measurement challenge), and how to address it (e.g. voluntary, regulation, incentives). In spite of this, Governments and Industry have worked together to develop regulations, best practices codes, and voluntary guidelines. For example, the Canadian Association of Petroleum Producers (CAPP, 2007) has implemented *Best Management Practice guidelines for the oil and gas industry*. The Government of Alberta Energy Resources Conservation Board (ERCB, 2013) has issued *Directive 060 on Upstream Petroleum Industry Flaring, Incineration and Venting* which has some very important directives. For example "The ERCB does not consider venting an acceptable alternative to flaring. If gas volumes are sufficient to sustain stable combustion, the gas must be burned (or conserved)".
  - In spite of this, there are criticisms with the basis for decision making for reducing GHG emissions from fugitive emissions. The fundamental premise is based on an economic return and not on consideration of environmental impact. The particular challenge for companies in this regard is making the decision to allocate financial resources to fugitive emissions reductions when the rate of return on the investment may be lower than for other possible allocations (e.g. drilling a new well). Moreover, the time lag between the investment and the return is typically greater for reducing fugitive emissions than for other production related activities. This suggests opting for short-term profits over the environment.

With respect to addressing the fugitive emissions challenge in the project, the following commentary is presented:

- Based on the commentary as provided above, it is very likely that fugitive emissions are larger than reported in Canada's *National Inventory Report*.
- It is clear that there are substantial opportunities for reducing fugitive emissions in Canada. In a longer term context, the opportunities include:

  - Improving data collection on venting, flaring, equipment and pipeline leaks, and incineration of natural gas. In addition to greatly improving knowledge about the inventory of fugitive releases, this also provides improved knowledge about the potential for capture of natural gas for productive use and for temporary storage. It is considered that there is significant potential for associated economic benefits.
  - Implementing fundamental changes with respect to effecting major reductions in venting, and equipment and pipeline leaks. Wherever possible, the first option should be capture and either storage or combustion for meeting energy based needs. If it is not possible to

store or combust the gas, then the gas should be flared rather than being vented directly to the atmosphere. As less than 10% of fugitive release in Canada, as reported, are flared, there are, very clearly, substantial opportunities for achieving major reductions in GHG emission with flaring, in preference to venting.

- Establishing a comprehensive fugitive emissions management plan for Canada. Such a plan will require addressing the need for a more complete and accurate inventory of fugitive emissions, establishing management and control processes for reducing such emissions, implementing appropriate policy changes to ensure that there are clear GHG reduction targets from fugitive releases, and that such targets be achieved in a manner that respects principles of overall cost efficiency.

A qualitative assessment of the magnitude for potential reductions in fugitive releases was carried out in this project, for the purpose of assessing potential for overall reduction in GHG emissions. On the one hand, as noted above, fugitive emissions are virtually certain to be substantially higher than reported in official documents, possibly by factors as high as 3 to 4. On the other hand, the ability to reduce such emissions is recognized as being not overly complex, with corresponding costs that should not be excessive. This applies especially to areas of significant point source emissions, such as at well heads, and in gas processing facilities and refineries. On the other hand, there are challenges in gas transmission and distribution systems, especially because of highly dispersed locations for actual and potential gas leaks.

With these various considerations, it was judged that fugitive emissions could be reduced by 50% relative to results, as reported. In actual fact, this is likely to be in the range of 60 to 80% reduction, relative to actual fugitive emissions.

2.6.3 Agriculture Emissions

The agriculture sector produces 8% (2010) of non-combustion GHG emissions (Environment Canada, 2014). The principal components include:

- Enteric fermentation – 2.7%
- Manure management – 1.0%
- Agricultural soils - 4.3%

Enteric fermentation is production of methane arising from gastro-intestinal releases from normal digestive processes in animals, especially from ruminant animals, including especially cattle. Manure management includes releases from animal wastes. With respect to agricultural soils, this is dominated by direct emissions of nitrous oxide from application of nitrogen based fertilizers and crop residue decomposition.

There is some potential for reducing non combustion emissions from the agricultural sector. However, these are limited by improved feeding methods and use of feed additives for reducing enteric fermentation, by better application of nitrogen based fertilizers, and improved agriculture tillage. Opportunities for substantial reductions in agricultural non-combustion emissions are especially challenging. There will be continuing demands for beef and dairy products, and for land-based food production. There may also be further challenges with expanded production of energy crops for biofuel production.

Based on reviews of the literature, and from comparative assessment of potential reductions in other countries, it was judged that the potential for reducing non-combustion emissions in the agriculture sector could not likely exceed 15% of actual GHG emissions relative to no action being taken on GHG mitigation.

2.6.4 Waste

The waste sector (3%) includes emissions from treatment and disposal of wastes (Environment Canada, 2014). Sources include solid waste disposal on land (landfill sites), wastewater treatment, and waste incineration. The dominant emissions are methane emissions from municipal landfill sites.

A significant challenge for GHG mitigation for landfill sites is to develop an overall program for efficient collection of produced gasses in respective landfill sites, followed by efficiently converting such gasses for meeting energy based needs, or for flaring. This is contingent on landfill design and the manner in which such landfills are operated and maintained. With respect to options after capture, the most common option is to simply flare the captured gas, rather than venting it directly to the atmosphere. Other options include processing and treatment of captured gas for sale or use as an energy source to create electricity, steam, heat, or alternate fuels, such as pipeline quality gas or for vehicles.

With respect to assessing potential for reducing GHG emission from waste sources, it was considered that 50% reduction represented an ambitious target for GHG mitigation by 2050 for all of Canada, especially when considering the diversity of sites across Canada, along with combinations of overall efficiency for landfill gas collection, and for combustion of such gasses, either for energy end uses, or for flaring.

2.7 Net Negative Emissions

As mentioned, a very important goal is to achieve 100% reduction in net GHG emissions before the end of the 21st century, and with a subsequent need for implementing strategies for net extraction of GHG's from the atmosphere leading to declining GHG concentrations, especially CO_2.

While there is scope for making major reductions in GHG emissions from both combustion and non-combustion sources, it is also recognized that achieving 100% reduction, from either of these sources, is impossible. So, the challenge is not only to implement strategies that result in enough net GHG extraction (net negative emissions) to counter remaining GHG emissions from combustion and non-combustion sources, but to also eventually have such net extractions progressively exceeding remaining emissions from such sources.

There are several alternative strategies for achieving net negative emissions. They can be broadly grouped as follows:

- Enhanced carbon retention
- Indirect extraction and storage
- Direct extraction and storage

2.7.1 Enhanced Carbon Retention

An underlying premise when considering carbon retention is that trees and plants, while alive and growing, absorb CO_2 from the atmosphere, and subsequently, release the same amount of CO_2 back to the atmosphere during the process of decay. From this, it follows that if there is no change in the volume of trees and plants, there is no net change of net CO_2 release to the atmosphere from such sources.

It follows, when considering any strategy for carbon retention, that this can only be achieved with altering the balance between CO_2 absorption during the cycle of being alive and growing, and decay.

The dominant options for enhanced carbon retention include:

- Reforestation and afforestation, by increasing carbon retention with net increase in forest biomass.
- Improved forest management, also by increasing carbon retention with net increase in forest biomass
- Development of harvested wood products, such as lumber production, for long term use in buildings, which also result in carbon retention in wood products
- Changed agricultural practices, for increasing carbon retention in soils

It is important to appreciate that such strategies can only continue to improve the net carbon balance, as long as there is progressive increase, year over year, in net carbon retention.

2.7.2 Indirect Extraction and Storage

This class of options relates to taking advantage of CO_2 absorption during the living and growing cycle, and then, in effect, capturing the absorbed CO_2 and storing it, so that it is not released back to the atmosphere.

The most promising option in this class, as noted by IPCC, is bioenergy with CCUS (IPCC, 2014c). In effect, this option is based on the premise of burning biomass for electricity and/or heat production, and then capturing the CO_2 for storage, ideally combined with commercial opportunities, such as enhanced oil recovery. There are many variants on this option, including using biomass for cogeneration, integrated gasification combined cycle, and combined integrated gasification combined cycle with cogeneration. There are also opportunities for combining this with conventional fossil fuel generation.

A parallel initiative, albeit at an earlier stage of development, is to use algae for production of biomass, which can again be used for electricity and heat production, and with the CO_2 again captured and stored. An interesting option with algae production is that the captured CO_2 may have additional value for accelerated production of algae in a high concentration CO_2 environment. However, this potential option is still at a very early stage of research and development (Algenol, 2016).

Another option is to use unused parts of food crops and specialty fast-growing crops (such as switchgrass) as biomass for production of biochar (International Biochar Initiative, 2016).

Production of biochar is by pyrolysis, in which the plant material is burned in an oxygen free environment. Biochar is a stable form of charcoal which can be spread over existing croplands, potentially keeping CO_2 locked in the soil for thousands of years, while also helping to enrich the soil. A side benefit of this process is production of synthetic fuels (syngas). It is estimated that biochar production has the potential to absorb a significant percentage of anthropogenic emissions each year. However, costs for producing biochar are high, which has been a deterrent against its development and use.

2.7.3 Direct Extraction and Storage

The concept of direct extraction is to capture CO_2 directly from the atmosphere, referred to as Direct Air Capture (DAC).

There are some interesting options currently in development:

- There is a special initiative by Carbon Engineering in Calgary (Carbon Engineering, 2016). The process is based on using liquid sodium hydroxide to produce a concentrated stream of CO_2, which is then stored underground, or used for commercial purposes, including production of low carbon synthetic fuels.
- Climeworks in Switzerland has a patented CO_2 capture technology, which is based on cyclic adsorption / desorption process on a novel filter material (sorbent) (Climeworks, 2016). During adsorption, atmospheric CO_2 is chemically bound to the sorbent's surface. Once the sorbent is saturated, the CO_2 is driven off the sorbent by heating, thereby delivering high-purity gaseous CO_2. The CO_2-free sorbent can be re-used for adsorption/desorption cycles.
- Another concept, developed by a technology startup, TerraLeaf, makes use of chlorophillin, a salt derived from chlorophyll by combining with an electrically-conducting polymer to extract CO_2 directly from the air, to form carbon-based chemicals (IPAI Global L3C, 2012).

2.7.4 Challenges and Opportunities

There is a clear need to make substantive and early progress on strategies for net negative emissions. Such strategies need to be both cost competitive and have the necessary scale for contributing in a major way towards eventually reaching and exceeding 100% GHG mitigation.

Some examples of challenges and opportunities include:

- The most promising option for achieving early and substantive progress is with carbon retention in forest biomass and harvest wood products. This is a major initiative in the United States and has represented a very substantial credit for their annual GHG Inventory reporting to the UNFCCC. While conditions in Canada are less favorable (less forested land and slower growth rates), this still represents an opportunity that deserves more detailed attention than was possible in the project.
- The second opportunity is related to using biomass for electricity generation, combined with CCUS, as recommended by IPCC (IPCC, 2014c).
- There are potential opportunities for producing carbon products which may or may not have commercial value, for the express purpose of disposing of excess carbon as an inert material, either as pure carbon or as a compound. An example is production of biochar which has value

for soil enrichment and remains essentially inert. A second concept is production of carbon nanofibers which is a strong material that can be used in reinforced concrete.
There have also been attempts at converting CO_2 into rock. These include injecting CO_2 into basalt formations to produce calcite. Another concept is to inject CO_2 into peridotite formations to produce carbonate rocks. There may be other options, which have not yet been discovered

- There is a need to reduce the very substantial parasitic losses (in the 10% to 50% range) for carbon capture with both fossil-based and bioenergy electricity generation. Such large losses lead to requirements for additional generation to compensate for such losses.
- While most CO_2 capture technologies are associated with high volume sources of CO_2, such as the flue gas from thermal generating facilities, there may be opportunities for capture, collection and processing systems from dispersed sources, such as tailpipe emissions.
- While most of the focus to date for storage of captured CO_2 has been geologic storage, there are significant challenges with such storage. Such concerns include progressive leaks from storage sites, as well as long term management, governance and security arrangements for geologic storage.
- There may be opportunities for deep ocean storage, as CO_2 becomes a liquid and is denser than water, at very high pressures.

2.8 Economic and Socioeconomic Setting

For the Project, a fundamental requirement was to develop projections for evolution of Canada's economic and socioeconomic setting from 2011 to 2050 and beyond. The principal determinants included:

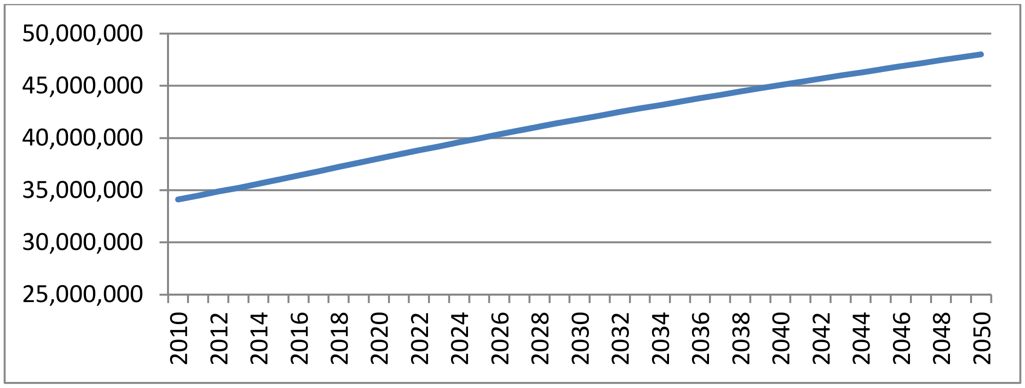
- Projections of population growth
- Projections of GDP per capita growth
- Projections of national GDP
- Projections of industrial gross output

These projections then formed the basis for projecting end use requirements in the different sectors, including, residential, commercial, transportation, industrial and agricultural needs.

2.8.1 Population Growth

Population projections (Figure 9) were based on application of CanESS's population model which had been calibrated with *Canadian socio-economic information management* (CANSIM) system data from 1978 to 2010. The model, using age, gender and region level information, captured continuing population evolution year by year, by applying birth rates, mortality, interprovincial migration, and international migration. It is calibrated to track on CANSIM data from 1978 to 2010 and to track on the National Energy Board's population by province as published by the National Energy Board (NEB 2013) outlook from 2011 to 2035, by adjusting immigration, emigration and interprovincial migration. Post 2035, international immigration and emigration implied in National Energy Board Data for the period out to 2035 is projected to continue growing in a similar way to 2050. Average population growth rate in historic time (1978-2010) is 1.11%; for the National Energy Board projection period (2010-2035), it is 0.98%; and for the further projection (2035-2050), it is 0.63%.

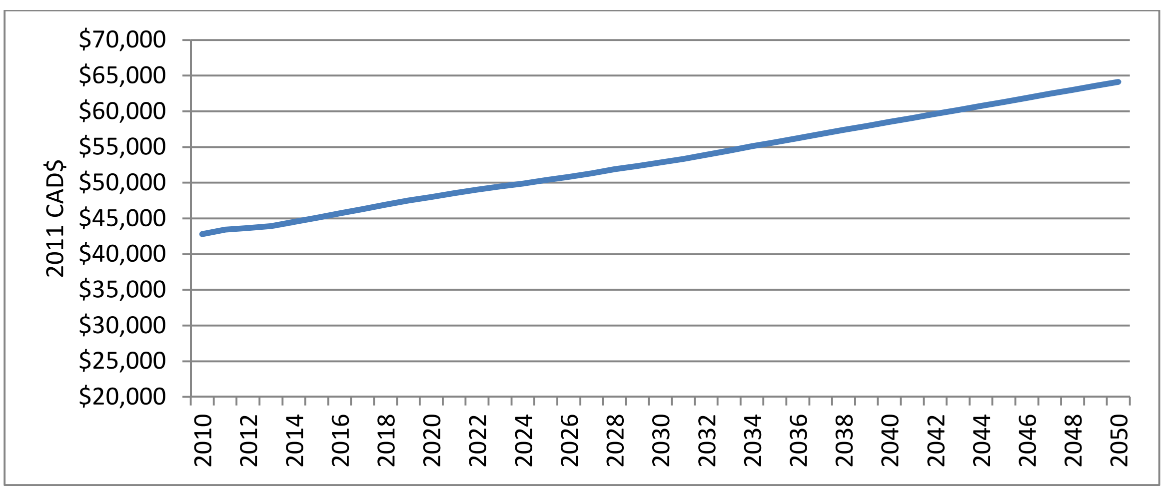
Figure 9. Population projections



2.8.2 Growth in GDP per Capita

Provincial GDP values were obtained from CANSIM for 1978 to 2010, and from National Energy Board projections for the 2011-2035 time period. These were then used to calculate GDP per capita values. Growth rate of GDP per capita was projected for the 2036-2050 period using trends from the 2011 to 2035 period, and with small progressive saturation applied to GDP per capita beyond 2035. Inflation is factored out of the calculation by equating to equivalent 2011 dollars (Figure 10). GDP per capita growth rate is slowly declining over the full time series. The average GDP per capita growth rate in historic time (1978-2010) is 1.9%; in the National Energy Board projection period (2010-2035), it is 1.86%; and for the projected period beyond 2035, (2036-2060), it is 1.31 %.

Figure 10. Projections of GDP per capita

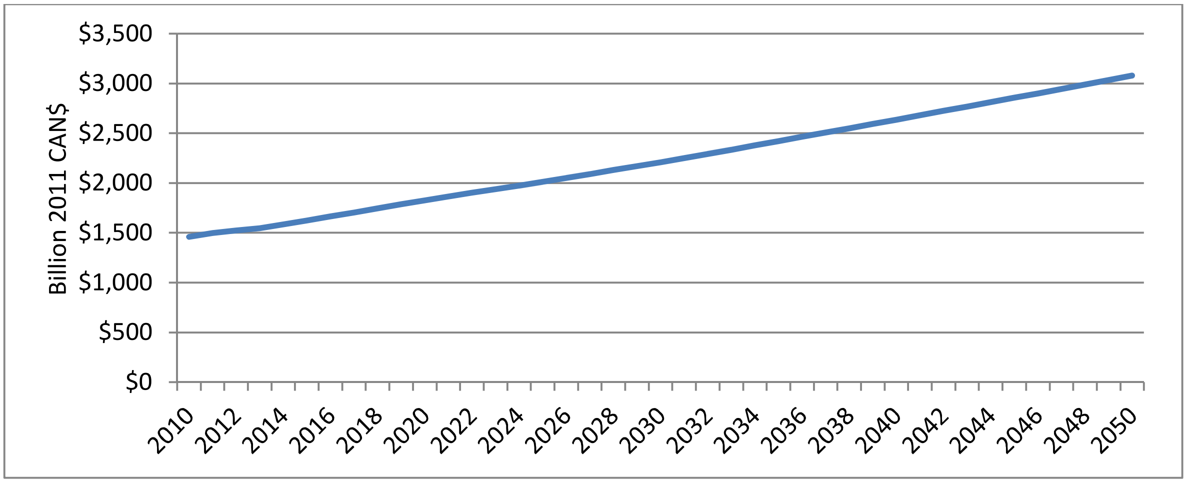


2.8.3 Total GDP

Total GDP in any year is the product of population and GDP per capita. Projected GDP is shown in Figure 11. Again, this is in equivalent 2011 dollars.

As may be observed, total GDP is projected to more than double between 2010 and 2050.

Figure 11. Projected GDP for Canada



2.8.4 Industrial Gross Output

Representation of the industrial sector is in three parts:

- Projection of gross output for the various industrial sub-sectors in dollar values.
- Determination of equivalent energy demands based on energy demand per dollar unit of industry gross output.
- Representation in NATEM model

For the purpose of this project, the industry sector has been assumed to include all industry sub-sectors, except fossil fuel producing industries.

Gross Output and Energy Projections

Information of gross output was obtained from Statistics Canada. Statistics Canada reports gross output in annual (i.e. current) dollars. The CanESS model was used to convert all numbers using GDP deflators by industry into equivalent 2002 dollars (deduced from StatsCan data), with projections based on 2002 dollars. As all work with the NATEM model was based on equivalent 2011 dollars, the CanESS projections were then converted into equivalent 2011 dollars.

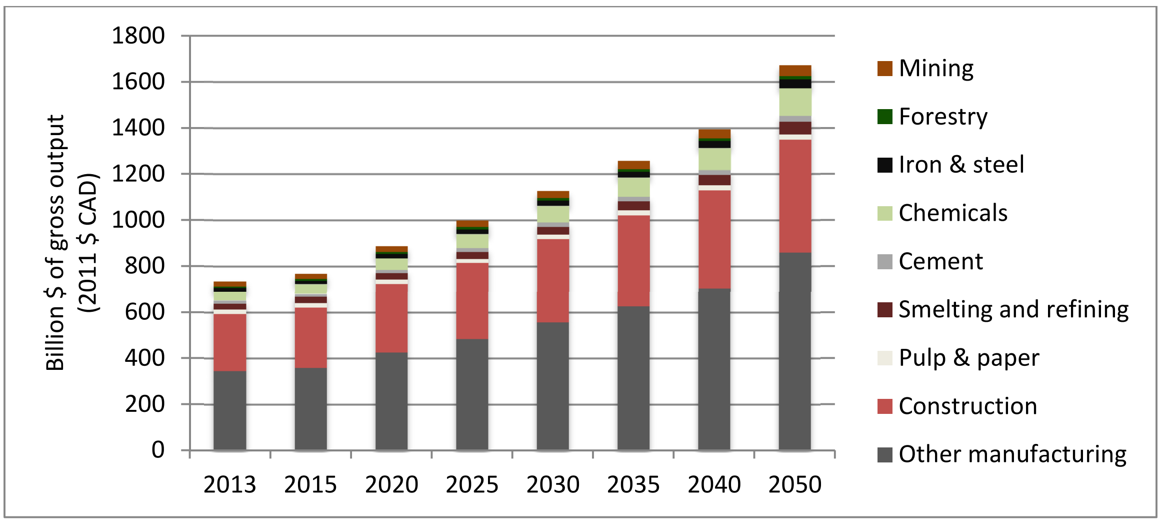
The industrial sectors covered with this approach include a subset of total gross output reported in CANSIM 381-0031. It does not include oil, gas & coal production; it also does not include refined petroleum products such as diesel, gasoline, fuel oil etc. It does include petrochemical products as a sub component of chemicals.

Provincial gross output values for non-fuel producing industrial sectors (totalled over industry) from CANSIM for 1978-2010 and from the National Energy Board for 2011-2035 (NEB, 2013) were used to calculate gross output To GDP ratios. These were then projected to the end of simulation time 2036-2050, with saturating projections. Also, the share of industrial gross output for the respective jurisdictions were calculated using the same information from the same sources, and projected, again with a saturating trend. Finally the national gross output by province and industry was calculated by applying the ratio to the GDP and applying the share to the total gross output by province.

Results from these analyses for all of Canada for the non-fuel producing industries for all of Canada are shown on Figure 12.

It was interesting to note that national gross output to GDP ratios have been declining, especially during the recent recession. Although there is some recovery, this does not reach the ratios of the early 2000's. This reflects the general transition to a service based economy, with some recovery of the industrial sector over time. The provinces with the highest gross output to GDP ratio are Quebec and Ontario and are both still growing. Alberta is quite flat; however the gross output described here does not include fossil fuel industries.

Figure 12. Gross output projections for non-fossil sectors



Commentary with respect to gross output and trends with the various non fossil fuel industrial sectors are as follows:

- Construction and Other Manufacturing are the largest industries, and dominate the national picture in terms of gross output; however, these sectors are not dominant to the same degree in terms of energy use (see below).
    - Food manufacturing
    - Beverage and tobacco product manufacturing
    - Textile and textile product mills
    - Clothing manufacturing
    - Leather and allied product manufacturing
    - Wood product manufacturing
    - Printing and related support activities
    - Fabricated metal product manufacturing
    - Machinery manufacturing
    - Computer and electronic product manufacturing
    - Electrical equipment appliance and component manufacturing

- Transportation equipment manufacturing
- Furniture and related product manufacturing

This sector has no projected growth in early years, but increases in later years.

- Construction is the second largest in terms of gross output. This includes:
  - Residential building construction
  - Non-residential building construction
  - Engineering construction
  - Repair construction
  - Other activities of the construction industry

  This sector has projected growth of 2% to 3%

- With respect to the other industrial sectors, projections are generally as follows:
  - Smelting & Refining (dominated by aluminum production) shows volatility around 0% up to 2020, followed by strong growth, and remaining at about 3% in the 2030's.
  - Iron and Steel shows strong growth with spikes of growth rates above 5% out to 2020 before settling in at about 2%. This industry supports increased oil and gas activity and pipeline building. This is an energy intensive sector, so strong growth has a significant impact on energy consumption, even though it is a small percent of the overall gross output.
  - Chemicals (including petro-chemicals such as plastics and rubber, but not refined petroleum products) is one of the stronger growing industries with rates above 4% periodically until about 2030, and continuing at approximately 3%.
  - Pulp and paper shows high volatility and general reduction which continues for a period, eventually returning to 0%, and returning to modest growth towards 2050.
  - Forestry, other than pulp and paper, shows growth and volatility in the early years and continues at relatively low rates of 1% to 2%.

Energy Demands from Industrial Sector

The second stage in the process was to establish relationships between industrial gross output and energy use. For this, it was necessary to define energy intensity relationships. Information for 2010 is reported in Table 2. This is derived from Statistics Canada CANSIM table 381-0031, relating to its *Report on Energy Supply and demand* (RESD).

It is important to appreciate that there are very substantial differences in energy intensity between the various industrial sectors. For example, the highest energy intensity is in the pulp and paper sector, resulting in 233 MJ per dollar of gross output. This sector represents less than 3% of gross output, but uses more that 33% of the energy in the non-fossil fuels industrial sector. The opposite extreme is the construction industry, at 1.64 MJ per dollar of gross output, with this sector representing 35% of gross output, but using less than 4% of non-fossil fuels energy.

Table 2. Energy intensity for industry sectors

Industries	Energy Intensity MJ/$ ($2010)	Share of Energy Used (%)	Share of GO (%)
Mining	116.00	5.20%	2.57%
Forestry	16.80	0.43%	0.97%
Iron & Steel	93.70	10.00%	2.19%
Chemicals	21.10	10.65%	5.62%
Cement	26.40	2.61%	1.80%
Smelting & Refining	220.00	11.34%	3.82%
Pulp & Paper	233.00	33.77%	2.90%
Construction	1.64	3.49%	34.78%
Other Manufacturing	16.40	22.52%	45.34%

Representation for NATEM Model

The basic information for defining the amount of energy for each industrial sector in each jurisdiction was developed with historical information from Statistics Canada, as contained in the CanESS model. Projections to 2035 were developed primarily from the National Energy Board information, which were further extended to 2050. This served as basic input for defining energy demands for each of the various industrial sectors in the respective jurisdictions, for each of the future years to 2050.

For the NATEM model, the additional actions required for representing the respective industrial sectors for minimizing GHG mitigations costs included the following:

- The total energy demand, for each industrial sector in each jurisdiction, was disaggregated into its respective components, which included electricity, the respective fossil fuel derivatives, and biomass/biofuels, where applicable. This defined energy end use composition for existing facilities, as well as for future facilities.
- Where applicable, there was disaggregated representation of processes within specific industrial sectors, with associated representation of composition of energy uses for such processes. This applied especially to selected energy intensive sectors, such as iron and steel production.
- For each process in each industrial sector in each jurisdiction, the dominant options for GHG mitigation included:

    - Improved energy efficiency
    - Alternative technologies resulting in reduced GHG emissions
    - Fuel switching, including dominantly replacing combustion of fossil fuels with electricity or biomass/biofuels

- For each of these options, GHG cost reduction relationships were incorporated into the NATEM model.

Despite the overall rigour for defining projections for gross output from the respective industrial sectors, in the different jurisdictions over time, it is important to appreciate that there are opportunities for further refinement, which should be addressed in future investigations. As examples, there include:

- There is a need to assess opportunities for industrial process changes, especially in the context of a future carbon pricing environment.
- There would be value in analyses based on further disaggregated representations of process definition, for certain industrial sectors.
- There would be value in reflecting greater appreciation of Canada's potentially enhanced longer term economic advantage for energy intensive manufacturing in Canada, in a decarbonized energy world (see Section 7.6.2).

3. General Approach

3.1 Introduction

As explained in Section 2.4, there are two broad classes of GHG emissions: combustion emissions from burning fossil fuels (72%), and non-combustion emissions (28%). As noted in Section 1.3, primary attention has been given in the TEFP project to deriving minimum cost solutions for reducing emissions from combustion of fossil fuels.

The overall approach for the project has consisted of three broad sets of Activities.

- Application of two mathematical models to provide a rigorous analytical basis for deriving minimum cost solutions for all of Canada, from 2011 to 2050, for meeting both growing demands for energy related services and progressive reductions in combustion emissions.
- Carrying out comprehensive reviews of costs for different options of infrastructure development to meet growing demands, and for essential transformations for reducing emissions.
- Analysis for eleven sets of scenarios, based on different combinations of defining premises, which result in alternative futures which are both internally consistent and minimum cost. The results of such scenarios provide in-depth understanding (including costs and impacts) of the consequences of different premises, and appreciation of the importance of alternative strategies for meeting both growing energy based demands and increasingly stringent emissions reduction targets.

Results of these three broad sets of activities are described in Sections 3, 4 and 5, respectively.

The prime focus for Section 3 is the description of the analytical basis for the project. The first part includes discussion on application of systems methodology, and includes descriptions of the two models that were used in the project. This is followed by descriptions of special analytical considerations and system representations, which were important for the project, and which required additional development, testing and calibration of the two models. In the final portion of this Section 3, there is a brief review of approaches and results that have been adopted in other jurisdictions for addressing the climate change challenge.

3.2 Basic Considerations

As noted above, the fundamental goal is to derive minimum cost solutions which satisfy both growing demands for energy related services and progressive reductions in combustion emissions for all of Canada from 2011 to 2050.

There are several challenges and complexities:

- This reduction needs to be accomplished in the context of a growing population in Canada (increasing to 48 million by 2050) and with increasing economic prosperity (national GDP to more than double by 2050).
- There are enormous variations in composition of primary energy supply between the various jurisdictions across Canada.

- Investment costs in energy infrastructure are high and economic lives for such investments are long. As a consequence, energy systems evolve slowly.
- The energy sector represents the largest source of export earnings for Canada, typically being in excess of $100 billion per year.
- Energy systems across Canada are highly interconnected, especially for supply and delivery of fossil fuels, and increasingly for electricity.
- There are major variations in production and emissions of GHG among jurisdictions, with the largest emissions coming from Alberta and Ontario. The highest per capita emissions are in Alberta and Saskatchewan.
- All jurisdictions in Canada, including the federal government, have plans and strategies in place for reducing GHG emissions (Government of Canada, 2014). However, there is no coordinated national approach as to how to achieve this at minimum overall cost.
- For reducing GHG emissions, special attention needs to be given to transformation strategies for end uses based on combustion of fossil fuels, which is where 85% of fossil fuel based emissions (other than for electricity production) occur. There is also a need to implement transformations for the entire associated supply chain for production of fossil fuels (other 15%). There is also a parallel need to decarbonize electricity supply.

For this challenge, it was considered essential to have an approach that addressed the situation for all of Canada in a comprehensive, integrated manner, and with separate representation for each of the various sectors and for the respective jurisdictions, and with variations over time. More specifically, the approach included the following:

- Specific representation for each of the 13 provincial and territorial jurisdictions across Canada.
- Representation of end use demands and supply for each sector in each jurisdiction, and over time, that produced and/or consumed GHG's, dominantly CO_2.
- Representation of comprehensive range of transformation options for meeting such requirements, along with GHG mitigation relationships, costs and limits.
- Representation of inter-jurisdictional and international flows of energy commodities, along with GHG production relationships and additional potential, with associate parameters.
- Representation of investment and unit operating costs for infrastructure options for meeting growing and changing demands in each and every sector, in each and every jurisdiction, and for all future time periods.
- Parameters for deriving minimum cost, including real discount rate.

As may be appreciated, this is a very complex problem with many different combinations of possible solutions, which vary among sectors, among jurisdictions, and over time. For analyses of such complex problems, the selected approach was based on using a combination of optimization and simulation models for deriving minimum cost solutions. The models included the Canadian portion of the *North America TIMES Energy Model* (NATEM-Canada) which is more fully described in Section 3.3.2, and the *Canadian Energy System Simulator Model* (CanESS), which is more fully described in Section 3.3.3.

The overall approach also included several other aspects:

- Both models had been calibrated with data from Statistics Canada, National Energy Board, Natural Resources Canada and Environment Canada. However, neither model had been previously applied to such a comprehensive representation of Canada's energy system, including an expanded range of transformation options for the various sectors in the various jurisdictions. Also, these two models had never been used together.

- As a consequence, a substantial amount of the early work on the project was dedicated to communications between the two models, and for testing, calibration and comparative investigations. These included:

    - developing a data bridge between the two models for providing effective transmission for large volumes of data being communicated between the two models (see Section 3.3.4),
    - carrying out comprehensive testing and calibration work on the respective models to ensure accuracy in model results,
    - comparing results from the two models for selected combinations of premises. This was to ensure that the two models were producing sensibly consistent results for different combinations of prescribed premises.

- In order to ensure that the most appropriate representation of the various supply sources, end uses, energy conversions and GHG management options, were being incorporated into the two models, 14 Working Papers were prepared to provide required information on specific sectors and subjects. This included premises, assumptions, formulations and key parameters, used as input for the models. Information from the Working Papers, and from other sources, for the respective sectors is presented in Section 4.
- There were special features that were required for one or both models for the benefit of deriving the most credible results. Some of these were addressed early in the project, while others were added later, after reviewing results from the initial analyses. For each of these additional features, there was a need to develop supporting mathematical formulations and system representations, incorporating the additional features into the respective model(s) and follow up testing and calibration. These additional features are described in Section 3.4.
- It was clearly recognized that the future in Canada is not known and that the range of transformation options for achieving GHG mitigation in Canada is not fully known or defined. It was also recognized that there will be future strategic or technologic options for GHG mitigation, which are either known, but not well defined, or may not be known at all at this time.

  With this degree of overall uncertainty, the approach was to derive minimum cost solutions for various combinations of premises (scenarios). These premises were selected so as to represent significant variations for defining alternative futures for Canada, but always based on the fundamental premise of responding to meeting prescribed GHG mitigation targets.

  In the selection of scenarios, it is important to note that Scenario 1 was selected as a Reference Scenario. For this Scenario, there were no GHG reduction constraints. This served as a basis for demonstrating the magnitude and distribution of GHG emissions in the complete absence of additional action on GHG mitigation. This provided a valuable basis for comparative assessment with derived results with targeted GHG mitigation.

  There was another important consideration for all scenarios. This was based on the premise that there were no substantive institutional, economic, socioeconomic, environmental or scheduling constraints for implementing projects or other strategic initiatives, as derived in the minimum cost solutions. The purpose of this was to develop a clear understanding of the composition of minimum cost solutions, and the merits of being able to move quickly in implementing early transformations, and/or making timely decisions on important infrastructure developments. While it is recognized that portions of such solutions may be unrealistic or impractical, it nevertheless provided a basis for clearly understanding the merits for moving quickly, including appreciation of costs consequences with delays in implementing minimum cost solutions. The process for selecting scenarios is described in Sections 5.1 and 5.2, with results of the eleven respective scenarios described in Section 5.3 to 5.12, inclusive.

- With respect to interpretation of results, there were several considerations, as outlined in Section 6.2. First, interpretations were based on quality of information used in the analyses and system representations. Assessments were based on distinguishing clearly among results which formed the basis for recommended early action, and results which were important, but for which additional investigations and analyses were required. There were assessments of problems for which solutions are required, but for which understanding and appreciation of the best options are not yet fully understood. This overall process is based on principles of progressive learning, as explained in Section 6.2.

3.3 Systems Analysis

Systems analysis is a problem solving process which is intended to provide better understanding of the behaviour of complex systems, and to serve as a basis for improved decision making, based on the merits of having access to better information.

The essence of the approach is to separate the overall system into a series of component elements, or sub-systems. The behaviour of the overall system is then defined in terms of the combined behaviour of each of the sub-systems, as well as the behaviour of linkages between sub-systems.

In the context of this project, a sub-system can be considered to be a specific sector in a specific jurisdiction in a specific time period, which needs to respond to associated demands. There are defined relationships which represent interactions with the same sector in other time periods, with other sectors in the same jurisdiction in the same time period, and with other sectors in other jurisdictions in the same time period. There can also be a prescribed goal(s) which defines desired results for the entire system, as well as for some or all of the sub-systems.

For this project, the prescribed goal for each scenario was to derive the minimum cost solution for all of Canada for a sequence of time periods, to satisfy both growing demands and increasingly stringent targets for combustion emissions.

For future extension of the project, such goals can be modified or changed, in response to different requirements and interests.

3.3.1 Application of Models

The general approach for the project has been described in Section 3.1. It was noted that two mathematical models were selected, which are described more fully in Sections 3.3.2 and 3.3.3, respectively.

In this section, it is important to highlight specific aspects associated with combined use of the two complementary models which have contributed to enhancing the overall credibility of results from the TEFP project. These include:

- It is important, first of all, to appreciate complementing attributes of optimization and simulation models for deriving solutions for large complex systems. The optimization model is designed to systematically search though all possible combinations of decision variables for satisfying the objective function (for the project, normally represented as minimum present worth system cost). This process continues until a stage is reached where any further change in every decision variable cannot provide any further improvement to the objective function. This solution then defines both the value of the objective function, as well as overall composition of decisions that are associated with the optimal solution. Such models are sometimes referred to as decision models.
  For representing the overall system and defining various options in the optimization model, there is a level of aggregation which is required for ensuring that the size of the model is practical and that solution times are reasonable. For example, by representing Canada as 13 interconnected jurisdictions and with 2011 to 2050 as nine time periods, there were more than 1 million decision variables in the NATEM model, and run times for each scenario was more than one hour. With further disaggregation, run times became excessive.
  The simulation model, on the other hand, provides more detailed results for any combined set of system definition and decisions. For example, the CanESS model can produce both system responses on a year by year basis, as well as, in most cases, more detailed evaluation of results for the various technologic and strategic options.
  There is added value from applying the simulation model for more detailed assessment of results for the optimum combination of decision variable derived with the optimization model. Such processes serves to provide more detailed insight into derived results and may lead to further refinements to input variables for the optimization model. Associated re-runs with the optimization model can then lead to additional refinement in the value of the objective function, as well as modified composition and values for the decision variables.
- There were several cases in the project where special investigations required detailed representation and testing, which could only be carried out with the CanESS model. For example, for reflecting results of optimum system dispatch for electricity supply in different jurisdictions, normal representation in the optimization model is with prescribed availability factors for the different classes of generating facilities. To improve the credibility of availability factors to be used in the optimization model, the CanESS model was applied and tested for different combinations of electricity system supply to derive appropriate availability factors (see also Section 3.4.3).
- The CanESS model was also used for refining representation for both wind and solar generation. With wind generation, there was a special need to assess capacity factors (capacity factor is ratio of actual electricity production relative to installed capacity at full continuous production) for such facilities for the respective jurisdictions across Canada. Detailed analyses were carried out on historical production from existing facilities by using daily information of average wind velocities and associated electricity generation for independent review of historical capacity factors. This information was then used to project capacity factors for future wind generating facilities in the respective jurisdictions, with consideration of recorded wind regimes and potential for improved capacity factors with improved design and siting of wind generating facilities.

Similar assessments were carried out to assess projected capacity factors for large scale solar generation for grid supply for the respective jurisdictions across Canada. However, in this case, the analyses were primarily limited to assessment of solar regimes in the respective jurisdictions, as there is limited existing solar generation for grid supply.
It is important to note that assessments for both wind and solar generation included detailed representation that reflected variations in electricity production in both seasonal and diurnal contexts.

- There were other special investigations with the CanESS model. These included defining modified inputs for urban regeneration (Section 3.4.6) and for assessing limitations and opportunities for production of biomass and biofuels (Section 3.4.8).
- The CanESS model was also used for projecting population growth, GDP per capita, total GDP, and industrial gross output. It was also used for analyzing breakdown of agricultural outputs.
- One of the very valuable features of the NATEM-Canada model, as with optimization models that are based on application of linear programming, is that the model automatically computes marginal costs for every binding constraint in the final overall solution. This includes marginal costs for imposed GHG mitigation constraints. This can be interpreted as reflecting the implicit carbon price that would be required to achieve targeted GHG reductions. Such marginal costs are included in the presentations of results for the various scenarios, and serve as a valuable basis for discussion on carbon pricing, as presented in Section 7.4. However, such costs can also serve as a useful basis for developing strategies and policies other than carbon pricing, including regulations and incentives, and for modified codes and standards for buildings, equipment and accessories.

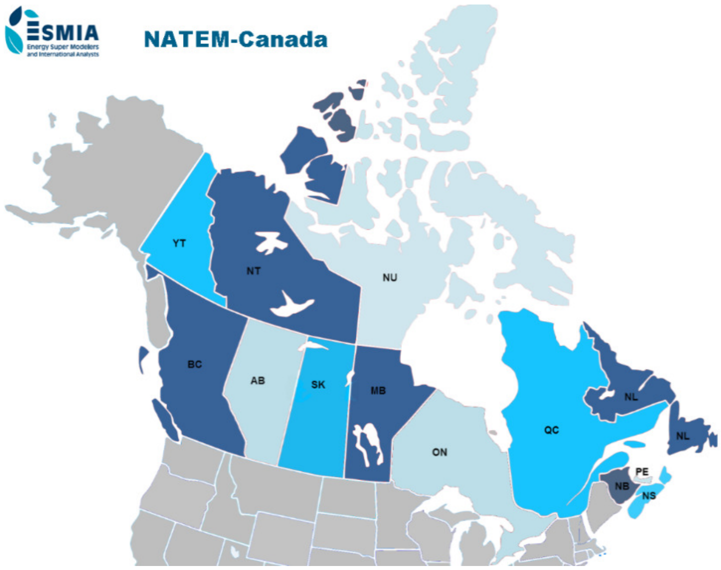
So, in summary, it can be appreciated that the two models were used both together and independently for this project. For detailed scenario results, the NATEM-Canada model was, very clearly, the work horse for the bulk of the analyses which are presented in Section 5. However, the CanESS model also provided valuable support for defining appropriate system definitions, for confirming parameters to be used, for furthering understanding of results, and for extensive background testing and verification to ensure that results from the project were both accurate and credible.

3.3.2 NATEM Canada Optimization Model

The *North American TIMES Energy Model* (NATEM) (ESMIA, 2016) has been developed using the most advanced energy optimization modeling framework: The Integrated MARKAL-EFOM System (TIMES). The MARKAL/TIMES model generators are supported by the Energy Technology Systems Analysis Program (ETSAP, 2016) of the International Energy Agency (IEA) and are currently used by more than 80 institutions in nearly 70 countries.

The 23-region NATEM model platform optimizes the reference energy systems of Canada, United States and Mexico. In particular, Canada is represented as 13 separate but inter-linked jurisdictions (Figure 13). The model allows policy analyses and strategic decision-making at multiple levels of geographical disaggregation. For the TEFP study, the model was used in a stand-alone mode for Canada, called NATEM-Canada, with fixed links with the United States and the rest of the World.

Figure 13. Provinces and territories of Canada



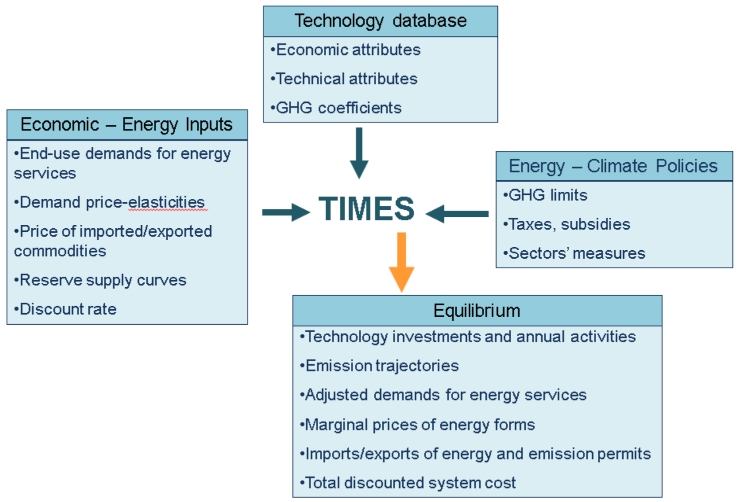
Code	Province/Territory
AB	Alberta
BC	British Colombia
MB	Manitoba
NB	New Brunswick
NL	Newfoundland
NS	Nova Scotia
NT	Northwest territories
NU	Nunavut
ON	Ontario
PE	Prince Edward Island
QC	Quebec
SK	Saskatchewan
YT	Yukon

The TIMES model generator

The TIMES model generator combines all the advanced features of the MARKAL models (Fishbone and Abilock, 1981) and to a lesser extent the ones of the EFOM (Energy Flow Optimization Model) model (Van der Voort, 1982), as well as various new features developed over time (Loulou et al, 2005a). A TIMES model represents the entire energy system of a country or region. Such a system typically includes extraction, transformation, distribution, end-uses, and trade of various energy forms and materials. Each stage is described by means of specific technologies characterized by economic and technological parameters. The model also tracks GHG and criteria air contaminant emissions from fuel combustion and processes. In baseline scenarios, end-use demands are exogenously specified in terms of socio-economic needs (e.g., transportation, expressed in vehicle-kilometres) over a future horizon. A TIMES model is cast as a dynamic linear programming model. Under the assumption that energy markets are under perfect competition, a single optimization, which searches for the maximal net total surplus, simulates market equilibrium. Maximizing the net total surplus (i.e. the sum of producers' and consumers' surpluses) is operationally done by minimizing the net total cost of the energy system that includes investment costs, operation and maintenance costs, plus the costs of imported fuels, minus the incomes of exported fuels, minus the residual value of technologies at the end of the model horizon, plus welfare losses due to endogenous demand reductions. The main model outputs are future investments and activities of technologies at each period of time. Important additional outputs of the model are the implicit price (shadow price) of each energy material and emission commodity, as well as the reduced cost of each technology (reduction required to make a technology competitive).

In addition, TIMES models in general acknowledge that demands are elastic to their own prices contrary to traditional bottom-up models. This feature makes possible the endogenous variation of demands in policy scenarios compared to the baseline, thus capturing the vast majority of structural changes in demands and their impacts on the energy system. In climate policy scenarios, emission reduction is brought about by technology and fuel substitutions which lead to efficiency improvements and process changes, by carbon capture, use and sequestration, and by endogenous demand reductions. Figure 14 gives a schematic view of the main inputs and outputs associated with TIMES models.

Figure 14. Schematic view of information flows in TIMES models



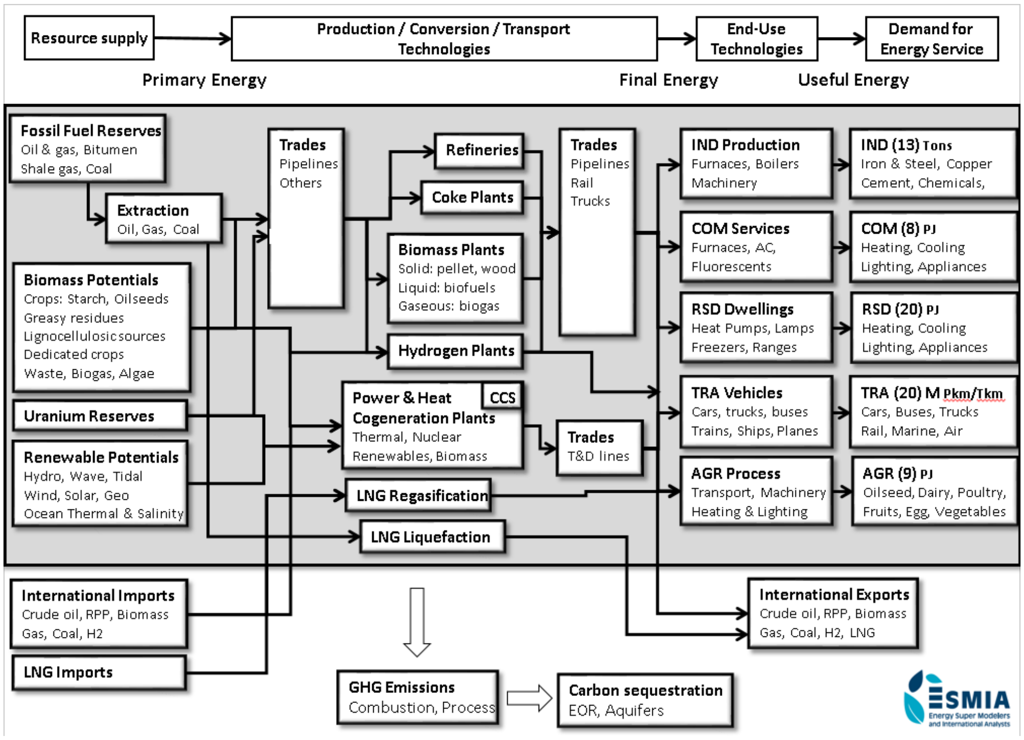
The NATEM-Canada database

The model is driven by 70 end-use demands for energy services in each of the 13 jurisdictions and the database includes more than 4,500 specific technologies and 450 energy, material and emission commodities in each region, logically interrelated in a reference energy system. Figure 15 gives a simplified representation of the reference energy system common to all jurisdictions.

For the TEFP study, the model was solved for the 2011-2050 time frame through 9 time periods of various lengths. Short time periods (1 to 2 years) are defined at the beginning of the horizon, while longer time periods (5 years) are considered after 2020, as uncertainties related to data are increasing. For each period, 16 time slices are defined uniformly across Canada, with four seasons a year (spring, summer, fall and winter) and four intraday periods (day, night, morning peak, evening peak). All costs are in Canadian dollars ($2011).

As a result of the calibration process for the reference scenarios, NATEM-Canada yields for 2011 energy balances and GHG emissions consistent with numerous official statistics and public databases (Statistics Canada, the National Energy Board, Environment Canada, Energy Information Administration (EIA) of the US Department of Energy, etc.).

Figure 15. Simplified representation of the reference energy system of each jurisdiction

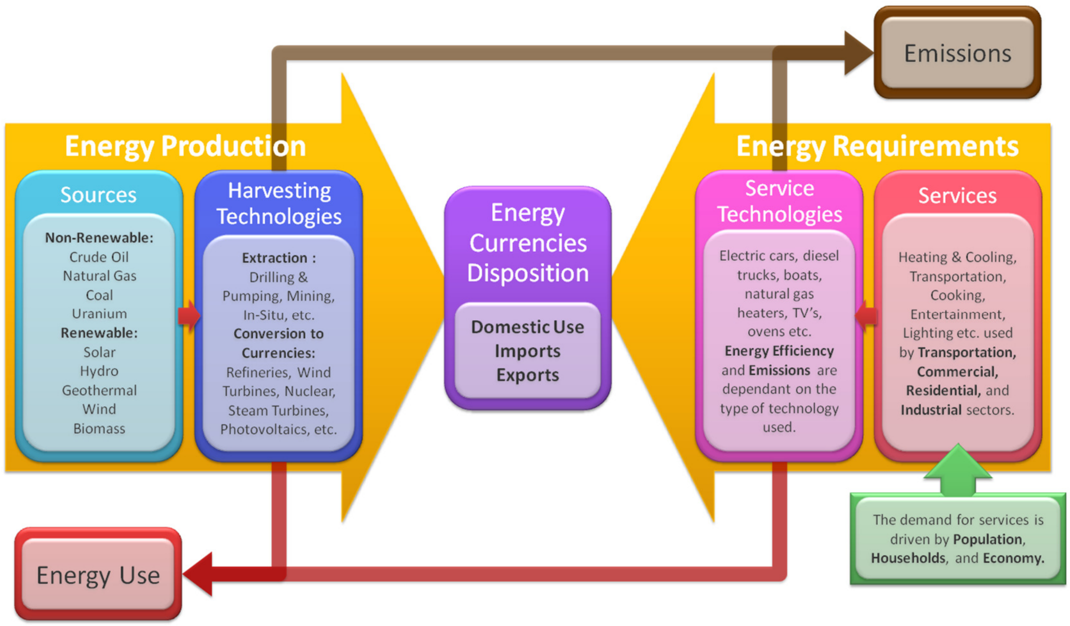


3.3.3 CanESS Simulation Model

The *Canadian Energy Systems Simulator* (CanESS), developed by whatIf? Technologies Inc., is an integrated, multi-fuel, multi-sector, provincially-disaggregated energy systems model for Canada. CanESS enables bottom-up accounting for energy supply and demand, including energy feedstocks (e.g. coal, oil, gas), energy consuming service technology stocks (e.g. vehicles, appliances, dwellings) and all intermediate energy flows. Energy is used when and where technologies are employed, and at the time and location where emissions occur (Figure 16).

Figure 17 below illustrates how the model accounts for changes in technologies and the resulting changes in energy flows. The primary drivers for changes in energy use are demographic and macro-economic dynamics. Together, these two model components determine the final demand in the residential, commercial, transport, industrial and agricultural sectors. These sectors set the demand for energy currencies (electricity, refined petroleum products, natural gas, biofuels, hydrogen, steam) to which energy producers respond. The production of these energy commodities subsequently sets the demand for primary energy sources (crude oil, natural gas, coal, uranium, and biomass) and other renewables (solar, hydro, geothermal, and wind). A balanced supply and demand of energy currencies and energy feedstock is achieved through trade.

Figure 16. Schematic representation of an energy system



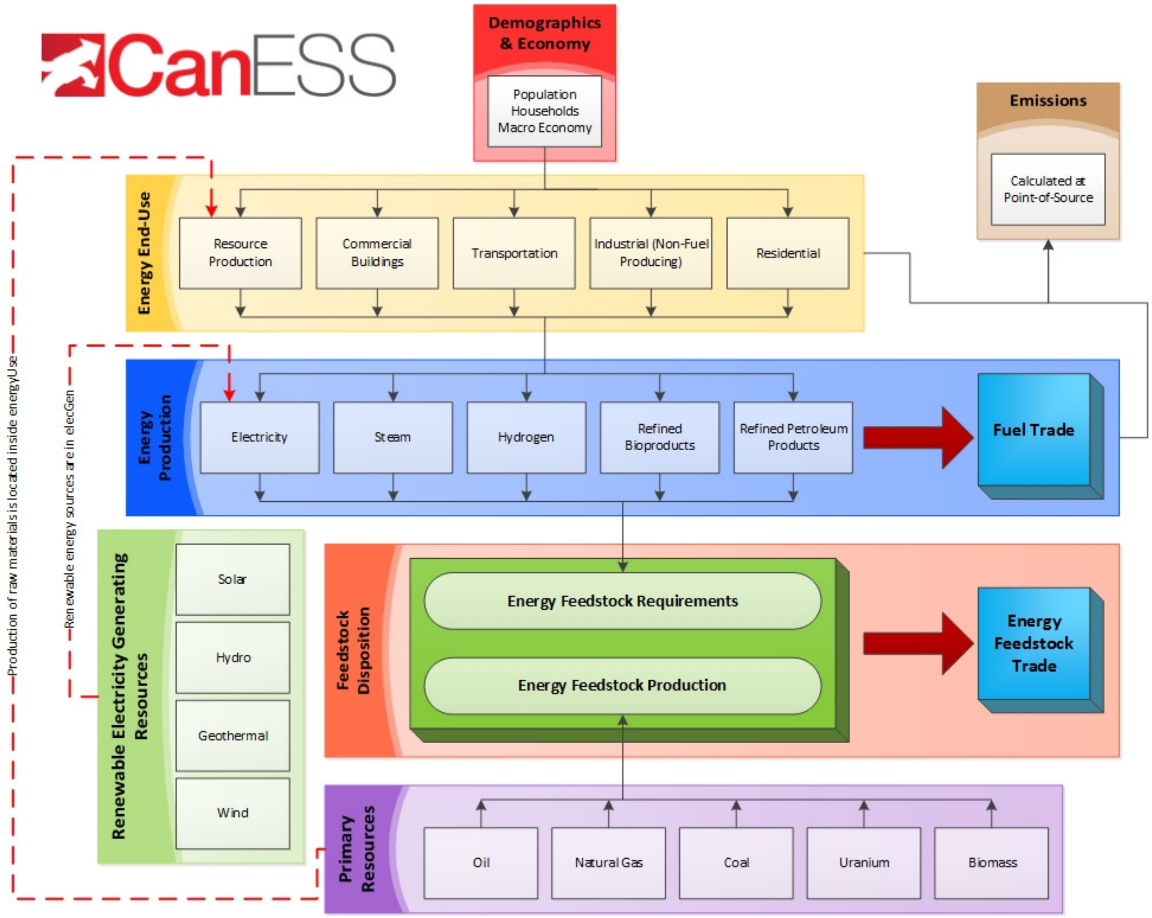
CanESS is calibrated with observed historical data from 1978 to the present in one year steps, and it enables projection of scenarios forward to 2050 and beyond, again in one year steps. The calibration process combines observed data from many different sources to derive historical values for the stock, flow, and parameter variables in CanESS. Major data sources used to populate the model variables are CANSIM and the Energy Efficiency Trends Analysis Database from the Office of Energy Efficiency of Natural Resources Canada. All data are integrated, and model parameters are adjusted to ensure tracking on the Report on Energy Supply and Demand (RESD) from CANSIM in terms of energy use, and on the National Inventory Report from Environment Canada in terms of GHG emissions.

Calibration is an indispensable step in the creation of a simulation model because it not only validates the model, it also provides a technology stock as well as a historical trend for the model variables from which simulation inputs may be derived. A reference scenario is created by extending the observed historical trends (most often with certain saturation limits) into simulation time with an overlay of known developments in the foreseeable future such as committed production capacity to be built, regulations and standards, and communicated policies.

The reference scenario provides a benchmark to assess alternative energy futures that may result from changes in assumed rates of population or GDP growth, changes in harvesting, conversion or service technologies, or changes in policy instruments that affect behaviour. CanESS is a powerful accounting tool to assess energy future scenarios that will inform policy and investment decisions by government as well as industries from a wide range of sectors.

More information on the CanESS model can be obtained at www.caness.ca.

Figure 17. Computational structure of the CanESS model



3.3.4 Data Bridge

One of the goals of using two models has been to establish credibility checks on derived results. This requires transferring results back and forth through the "data bridge" between the two models and comparing results to ensure that the two models are producing sensibly consistent results. When there are discrepancies, there is a process of analyses to determine the basis of such discrepancies, and to make adjustments to either or both models to ensure that system representations are both sensibly consistent and credible.

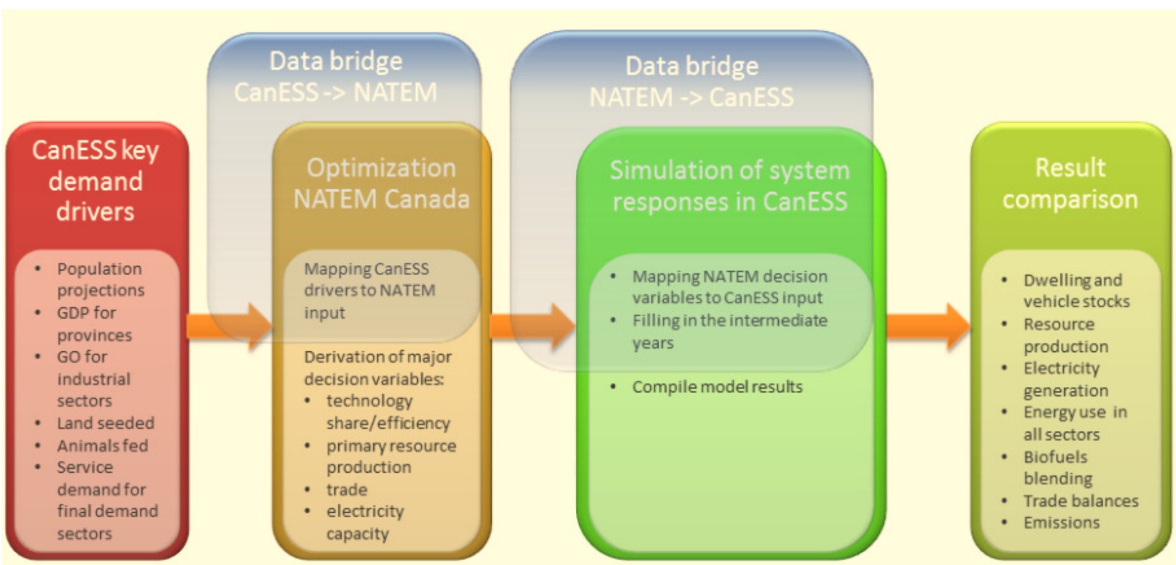
To invoke the two models in the project, the following modelling process was used:

- Basic data concerning key demand drivers were supplied by CanESS. This included population projections, GDP, time based gross output for various industrial sectors, and service demands (such as passenger kilometers in the transportation sector, number and type of dwellings for the residential sector, etc.) for all sectors. These data are the same for all scenarios, and only had to be passed on once.

- Optimization with scenario specific constraint sets was carried out with the NATEM Canada model, with derivation of major decision variables (for example, additional generating capacity for each class of facilities in each jurisdiction in each time period), along with associated system responses.
- For each scenario a more detailed simulation of system responses was carried out with CanESS on year by year basis, with scenario specific input of major decision variables produced by NATEM Canada.
- Results from the two models were compared to ensure that results were consistent and credible. This has required additional runs with both models to ensure that the models are producing sensibly accurate and consistent results.

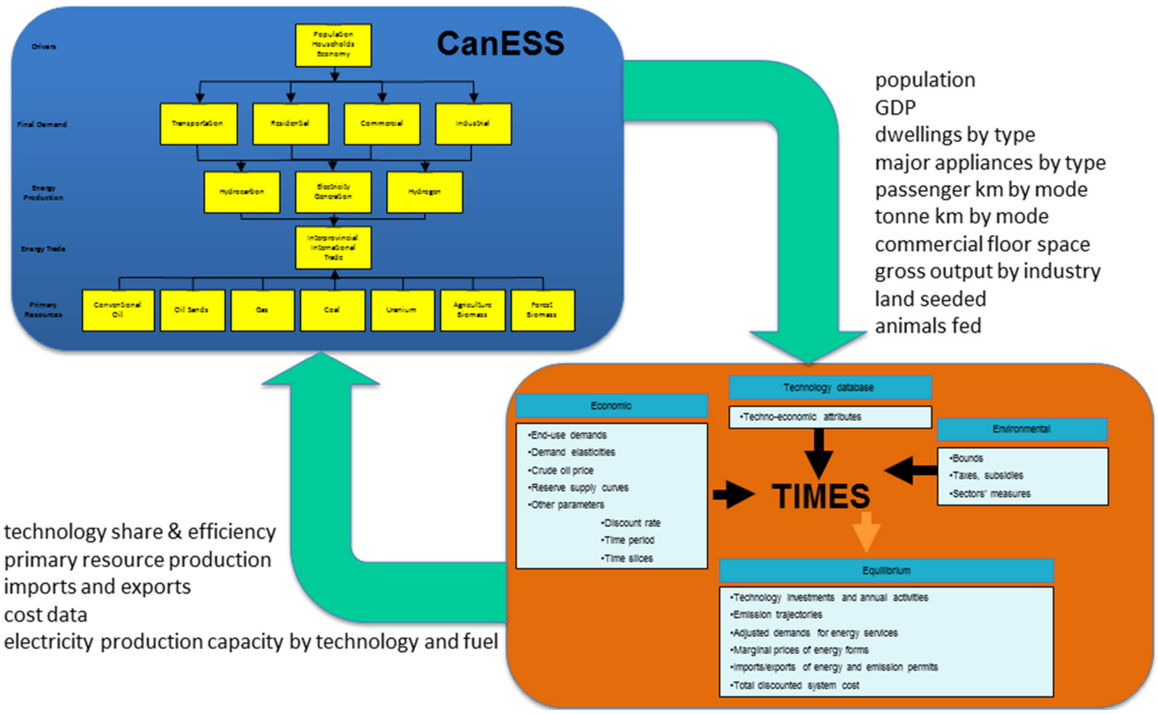
First both models are set to the same final demand for energy services through part one of the data bridge. After deriving scenario specific optimum results on how to provide those services in step 2, the results are passed back to CanESS via part two of the data bridge. The CanESS model was then run with its detailed energy system representation for a credibility check and model result comparison (Figure 18).

Figure 18. Position of the 'data bridge' in the modelling process



Passing data through the data bridge is not a simple matter of one-to-one mapping. In many cases, the CanESS model has more detailed representation of end use demands in the various sectors. Such demands are then aggregated to comply with system representation in the NATEM Canada model. Figure 19 provides an overview of the types of data that is shared between the two models. As the NATEM Canada model makes use of 9 time periods of various lengths and the CanESS model has one year time steps, the decision variables also needed to be interpolated to fill in the intermediate years.

Figure 19. The data that is shared between the two models



Considerable effort was required to port the scenario specific data between the models. Table 3 provides an overview of the variables covered by the data bridge.

Table 3. Overview of variables covered by the data bridge

Data bridge CanESS to NATEM			
sector	**subsector**	**input type**	**# input variables**
population			1
economy		GDP	1
residential		dwellings, floorspace, space conditioning, appliances	4
commercial		floorspace	1
transportation	personal	passenger km	1
	freight	tonne km, load factors	6
industry		Gross output	1
agriculture		activity	2
primary resources	commodities	production	8
secondary resources	electricity	capacity	1
	refining	production	5
	LNG	production	1

Data bridge NATEM to CanESS			
sector	**subsector**	**input type**	**# input variables**
residential	heating	technology shares, efficiencies	3
	lighting	technology shares, efficiencies	2
	appliances	technology shares	1
	water heating	technology shares, efficiencies	2
commercial		output energy intensities, fuel shares, efficiencies, street lighting	9
industrial		output energy intensities, fuel shares, efficiencies	3
transportation	LDV	vehicle shares, fuel use intensities	3
	HDV	vehicle shares, fuel shares, fuel use intensities	10
	subway	fuel use intensities	1
	rail	fuel use intensities	2
	air	fuel use intensities	2
	pipeline	fuel use intensities	1
primary resource production	crude oil	fuel use intensities	1
	coal	fuel use intensities	2
	natural gas	fuel use intensities	2
	uranium	fuel use intensities	1
secondary resource production	electricity	capacity, capacity factors, heat rates	7
	biofuels	capacity, fuel use intensities, blend rates	7
	LNG	production levels, technology shares, fuel use intensities	3
	refining	feedstock, fuel use intensities	9
	hydrogen	technology shares	2
trade	commodities	import/export	12
fossil fuel production levels	commodities	production	16

The activity levels passed from CanESS to the NATEM Canada model have to be transferred once and then are the same for all scenarios. The optimized model parameters generated by the NATEM Canada model are scenario specific and thus each scenario result validation requires passing all input variables from NATEM Canada to CanESS across the data bridge. Once variables are mapped, interpolated and imported into the CanESS model, scenario results are generated and compared with the NATEM Canada results for the same scenario to ensure that results were consistent and credible.

3.4 Special Considerations

For the project, there were several considerations that needed to be given special attention with respect to representation or treatment in one or both models. The more significant considerations are described in this section.

3.4.1 Conservation, Efficiency, Conversion and Demand Management

The first category of options to reduce GHG emissions from fuel combustion are demand side management strategies which result in reduced demand for energy services.

One example included assessing the potential for implementing urban strategies leading to (see Section 5.6):

- Reductions in demand for space heating, space cooling, water heating and other appliances in the residential and commercial sectors.
- Reductions in demands for passenger transportation due to major modal switch to public transport.

The NATEM-Canada model has a special feature which allows for reflecting the impact of demand in relation to cost of energy related services (demand elasticity). This results in demand reductions in reaction to price signals on carbon mitigation.

In addition to the reductions in demand for energy services, it was important to also assess the potential for efficiency improvements and overall conservation since some of these may be available at no or very low cost. Important efforts were dedicated to the representation of such GHG emission reduction options in both models.

Regarding energy efficiency improvement opportunities:

- In each of the end-use demand sector (agriculture, commercial, industrial, residential and transportation), a number of existing technologies are modeled to calibrate each end-use demand at the base year. In order to replace existing technologies at the end of their lifetime, a repository was created in each sector with a large number of new technologies that are in competition to satisfy each end-use demand after the base year. These repositories include identical and improved versions of existing technologies, as well as totally new technologies not existing in the base year. For instance, the new technology repository for residential demand for lighting comprises standard fluorescents, fluorescents with improved efficiency and new electron stimulated luminescence devices.
- The model optimizes the technology mix based on the investment and operation costs of these improved or new technologies, their efficiency as well as the fuel prices. Some technological options are very interesting because their investment costs are offset by the reduction in fuel costs. Rising GHG reduction targets, resulting in higher implicit GHG mitigations costs result in greater efficiency improvements. At the aggregated sector level, the energy efficiency improvements minimally reflect the efficiency gain projected through the implementation of the new building code in the Reference scenario and beyond these gains when an ambitious GHG target is set.

- In the transportation sector, the existing energy efficiency policy (CAFE standards) already in place in the different provinces and territories is forced through as a constraint for specific years and vehicle classes.

Regarding energy conservation opportunities:

- The model has the option of investing in conservation options for residential and commercial buildings in order to reduce energy use for space heating and space cooling: programmable thermostats, wall insulation, roof insulation, duct sealing. Investing in such conservation technologies allows for end-use demands to be satisfied with less energy input. For example, better wall insulation will lead to less heat being needed to sustain the desired temperature. Cost per PJ can be interpreted as being the cost for satisfying one PJ of end-use demand via the corresponding conservation technology.

3.4.2 Dependable Capacity

For electricity supply planning, it is necessary to ensure that, for each respective electricity supply system, two types of demands are being met at all times:

- Total system demand for electrical energy
- Guaranteed generating capacity to meet system demand at all times, including especially during peak demand periods

Special attention was given to ensuring that there was guaranteed generating capacity available at all times, especially during peak demand periods. This special attention was required as there are several classes of generating facilities that provide little or no guaranteed capacity. For example, intermittent renewable generating sources, such as wind, solar and in-stream generation, provide virtually no guaranteed capacity. Run of river hydro projects provide some guaranteed capacity, which is dependent on maximum generation during minimum flow periods, which is usually substantially less than installed capacity. There are also considerations that reflect availability of other facilities (nuclear, thermal, hydro) that normally provide guaranteed capacity when in service, but may be out of service for periods of time because of scheduled maintenance or unplanned outage.

For the project, special formulations were developed and tested to ensure that the sum of guaranteed capacity contributions (referred to as dependable capacity) for each class of generating facilities was equal to or greater than system peak demand. This applied to each of the respective electricity supply systems in the different jurisdictions, for all different time periods in each year, and for all future time periods.

In defining total dependable capacity, treatment of the different classes of generating facilities was as follows.

- For existing generating facilities that will continue to be in operation, dependable capacity was normally based on recorded historical performance, and consistent with treatment of corresponding new generating facilities, as described below.

- For those classes of generating facilities that normally provide guaranteed capacity when in service, dependable capacity was defined as the product of installed capacity and availability. For example, for nuclear and thermal generating facilities which have availability factors of 85%, dependable capacity contribution would be 85% of installed capacity. For future conventional large scale hydro, availability factors are higher, typically 95 to 97%.
- For nuclear generating facilities taken out of service for refurbishment (typically for three year periods), dependable capacity contributions was zero for such periods.
- For intermittent renewables, such as wind, solar and in stream generation, dependable capacity was defined as 5% of the product of installed capacity and capacity factor. Capacity factor is the ratio of average projected electricity generation and the amount of generation that would be produced if the facility operated continuously at full capacity. Representative capacity factors for wind generation were in the 25 to 35% range, while solar was in the 11 to 14% range. The selected 5% value, which accounts for statistical expectation due to diversity of generating locations, was selected after early review of available literature, and from results of discussion with the Canadian Electricity Association.
- For run of river hydro generation, dependable capacity was based on maximum possible continuous generation at such sites during minimum in stream flow periods.
- For large scale dispatchable pumped storage generation, dependable capacity was based on having availability factors comparable to conventional hydro.
  It is noted that the pumped storage option was considered to have two different, but complementary operating modes.

    - For the first operating mode, pumped storage used pumping energy from nuclear or base load thermal generating facilities, with low variable cost generation during off peak hours, and them generating during peak load periods, by displacing high variable cost generation (typically peaking thermal).
    - For the second generating mode, pumped storage would use pumping energy from intermittent renewable sources during periods of excess supply, especially during off peak period (such as high wind energy production during night time periods). The pumped storage facility would then be used for generation during peak demand periods, especially during periods of low production from intermittent renewable generating facilities.

  There is an important consideration with design of pumped storage facilities for providing complementary operation with intermittent generating sources. This relates to having reservoirs (both upstream and downstream) with adequate storage capacity to provide generation for extended periods when there is little or no generation from intermittent sources. While such facilities can be developed as separate facilities for pure pumped storage operation, there are also inherent attractions in combining pumped storage facilities with existing or future hydro developments, especially projects with large reservoirs, or where modifications can be made to provide required regulation capacity for pumped storage operation.
  For the project, there was an implicit premise made that there was adequate potential in Canada for providing pumped storage generation consistent with satisfying the minimum cost objective in the NATEM Canada model.
- One of the promising options for providing dependable capacity at relatively low cost is to add generating capacity at hydro plants (incremental hydro). This includes both existing and future hydro facilities. This option becomes especially attractive as the full potential of the hydro system for producing electrical energy is being reached. The added capacity at the respective hydro sites

then provides dependable capacity to complement energy production from intermittent renewable generating sources.
Again, with this option, dependable capacity contribution would be comparable to conventional hydro facilities.

- It should be noted that a normal requirement for any electrical supply system is to have adequate generating capacity for ensuring reliability of supply. This usually results in having reserve capacity which exceeds peak demand by some defined amount. Reserve requirements are generally higher for systems that have nuclear and thermal units with lower availability factors and lower for systems with higher availability factors (such as hydro dominated systems). The approach for the project was to define dependable capacity for any class of generating facilities as being equal to the product of installed capacity and availability factor (and as further modified for intermittent renewable generating facilities, as described above). This process led logically to solutions where the sum of dependable capacities was equal to peak system demand, and that total installed capacity would be larger than peak demand by amounts that reflected the inverse of the availability factors of the respective classes of generating facilities. This process was considered to provide reasonable approximation for defining reserve capacity.

For the project, this representation was added to the NATEM model. This included a program of development and testing to ensure that this representation was being reflected accurately in the model solutions.

3.4.3 Optimal System Dispatch

One of the important contributions in the project was the development of algorithms, and associated model development and calibration, for representing principles of optimum system dispatch for electricity supply. This was required for ensuring that the amount of generation for each of the various classes of generating facilities in each system was being represented appropriately in term of its respective operating mode, and that associated evaluations of energy production were reasonably accurate.

The special considerations for this development included the following:

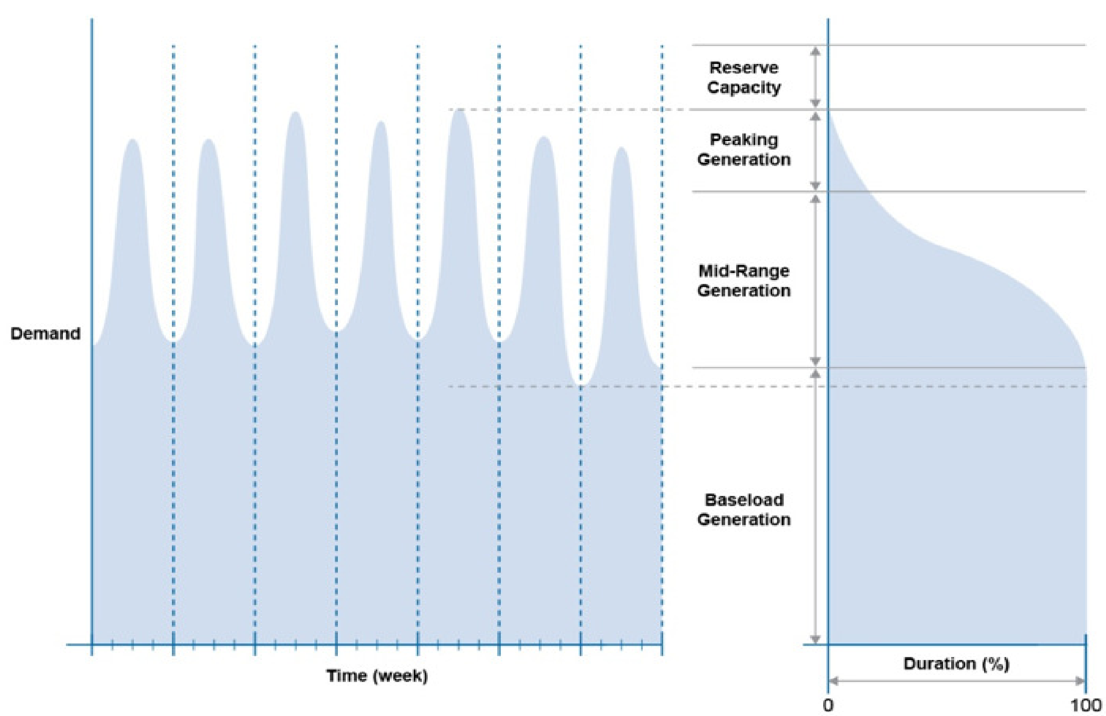
- It was necessary to reflect variability in generation supply for each class of generating facilities, in response to time-based variations in electricity demand. This is shown on Figure 20, which shows conversion of time based demands over a period of time (in this case, one week period), into an equivalent load duration diagram.
- For determining the minimum cost of generation supply in any time period, the various generation supply sources are sequenced in the load duration diagram to comply with the goal of minimizing overall variable operating costs for the given time period. The process for achieving this was generally as follows:

    - For generating facilities, such as nuclear and thermal, that do not have energy supply limitations, such facilities are normally positioned in ascending order from the bottom of the load duration diagram, based on progressively increasing variable operating cost (normally referred to as merit order stacking).
    - For generating facilities that may have energy supply limitations in any time period (such as hydro, where available energy is based on available hydrologic flow in the given time

period), such facilities are stacked in the load duration diagram as a contiguous block so that all available energy and the full installed capacity is utilized.

- For run of river hydro facilities, such facilities are stacked at the bottom of the load duration diagram (lowest variable operating cost) with capacity being the lesser of installed capacity or continuous generating capacity available as determined by available stream flow.
- For intermittent renewable generating sources, these are normally stacked at, or close to the bottom of the load duration curve, when in actual generation mode (again, lowest variable operating cost). Since energy production from such facilities is very variable, it was necessary of have several different load duration diagrams, with each representing different combinations of generation from intermittent renewables and with the other generating options then stacked optimally in relation to each specific combination of intermittent renewables generation. Expected generation for each class of generating facilities and for the system as a whole in each time period, was then evaluated by combining results for each of these evaluations with its associate probabilities.
- For pumped storage generation, load stacking included deriving the optimal combination of pumping energy during low demand periods with varying combinations of generation with intermittent renewables, and then providing the optimum amount of generation during peak demand periods. Special attention was given to ensuring that, for the selected time period, the volume of water used for pumped storage generation was exactly equal to the volume of water pumped. Special consideration was also given to ensuring that any decision for either pumping or generation was also based on reducing net variable cost of electricity supply, including considerations of energy lost in the cycle of generation and pumping (turn-around efficiency being typically 80%).

Figure 20. Time based demand and load duration diagram



With respect to how this was developed and applied in the project, the process was as follows:

- The algorithm for representing optimal system dispatch, and associated testing and calibration was carried out with the CanESS model.
- Following this development, computed results were then compared with actual recorded results for the various jurisdictions across Canada. This led to incorporating various refinements to reflect actual operating experience. In some cases, this led to adjustments in availability factors, or to decision to alter the merit order for some classes of generating facilities. For example, the decision to alter merit order was sometimes based on moving older thermal generating facilities from cycling operation into base load operation to reflect operational challenges with operating such facilities in cycling mode.
- The result of these analyses, including availability factors for each class of generating facilities in each time period, were then transferred to the NATEM model via the Data Bridge.
- The derivation of expected operating costs with the NATEM model, for each jurisdiction in each time period, was generally in accordance with the following guidelines:

    - Energy production, and associated costs, for each class of thermal and nuclear generating facilities was based on the product of the respective installed capacities and availability factors, as provided from the CanESS model.
    - Energy production from hydro generation (conventional hydro and run of hydro) was based on average available energy as defined in existing records
    - Energy production from intermittent renewables was based on projected energy production from such sources, and with special consideration of variations over typical daily cycles and for different season of the year.
    - Energy consumption for pumped storage pumping and energy generation in generation mode, as defined above
    - Ensuring that net energy production for each season was exactly equal to system demand, including accounting for losses in the transmission and distribution network
    - Further testing with the CanESS model of computed results as credibility checks, especially for solutions showing major investments in electricity supply, or unusual combinations of system supply.

3.4.4 High Voltage Interconnections

One of the contributions to the project was the additional consideration of high voltage interconnections between neighboring jurisdictions. This was based on recognition that minimum cost supply for Canada would almost certainly include substantial investment in such facilities. This included consideration of major expansion of electricity supply across Canada as a consequence of reducing reliance on combustion of fossil fuels for meeting energy based demands, and associated transition to greatly increased use of electricity. There was also recognition that the differential cost of electricity supply between various jurisdictions would almost certainly increase, as some supply systems, especially those with electricity supply from thermal generating sources, will require major investments for meeting both growing electricity demand and replacing existing generation capacity.

There were several considerations involved with establishing appropriate representation of high voltage interconnections:

- The distance for high voltage interconnection between neighboring jurisdictions was based on selecting the distance between the closest major substations in the respective grids.
- The cost for interconnection capacity was based on selecting a voltage level and then defining the interconnection potential in terms of number (decision variable in NATEM model) of interconnection circuits. The relation between investment cost and transmission capacity is shown for different voltage levels in Table 4 (see also Section 4.5.1.4).
  The assumed voltage level for interconnection between neighboring provincial jurisdictions across Canada was 500 kV, except for interconnection between New Brunswick and Prince Edward Island, which was assumed to be 230 kV. It was also assumed that the voltage level for interconnection between Alberta and Northwest Territories would be 500kV, primarily for development of the hydro potential of the Mackenzie River. No consideration was given to the potential for interconnection between Yukon and Northwest Territories, between Yukon and British Columbia, and between Nunavut and Northwest Territories. These are options that may be attractive for later consideration, and should be defined in further investigations.

Table 4. Investment costs and capacity for new transmission lines

Voltage	Investment cost	Capacity	Efficiency
kV	M$/km	MW	%
765	2.90	4000	99.0%
500	1.93	2000	99.0%
345	1.61	900	96.2%
230	0.77	350	93.5%

- With interconnections, there is the potential for both sale of dependable capacity and for economy energy exchange.
  With respect to the opportunity for one jurisdiction providing dependable capacity to a neighboring jurisdiction, the evaluation process included in the NATEM model was as follows:
    - The jurisdiction providing dependable capacity export was required to have sufficient dependable capacity to meet both its own need for dependable capacity, as well as the export amount of dependable capacity.
    - The receiving jurisdiction could reduce its supply of dependable capacity by the amount being imported.
    - The capacity of the interconnection would be equal to or greater than the dependable capacity transfer amount
- It should be noted that this process has the implicit premise that peak demands occur in neighboring jurisdictions, more or less, simultaneously. This may be a conservative premise, especially for neighboring jurisdictions that have peak demands occurring at different times of the year. This applies especially to interconnections between certain Canadian utility organizations with peak demands in winter and utilities in the United States with peak demands in summer.

For situations with significant diversity of peak demand, the process could be modified by reducing the requirement of the selling jurisdiction to provide dependable capacity to a level which ensures that the receiving jurisdiction is provided with guaranteed dependable capacity at all times. This is a desirable feature to be added to the NATEM model for future applications.

With respect to economy energy exchange, this reflects the process of sharing benefits of optimal dispatch in the interconnected system. This is achieved by progressive sequencing of generating facilities for supply with lowest variable operating costs. Reductions in overall operating costs for the interconnected system are then shared equitably between participating utility organizations.

- In the project, preliminary testing and calibration was carried out with the CanESS model to simulate addition of interconnections with combinations of nuclear, thermal, hydro and intermittent renewables generation, along with pumped storage pumping and generation (extension of work as described in Section 3.4.3, above). While results from this process confirmed that the NATEM model was producing credible results that included consideration of interconnections, it has also been recognized that this is a complex area and that more development is desirable for obtaining more precise results.

3.4.5 Differential Grid Development Costs

One of the challenges, especially in recent years, has been to ensure that development of high voltage transmission grids occur in parallel with changing composition of generation supply. This applies especially with introduction of additional supply from intermittent renewable generating sources, which lead, in turn, to added generation for dependable capacity. The consequence of this is that total generating capacity for system supply, in some cases, grows more rapidly than demand, especially for systems with large amounts of generation from intermittent renewable sources.

Investment costs for high voltage transmission grids are generally proportional to total generating capacity. Since some of the options being analyzed with the NATEM-Canada model could include large amounts of intermittent renewables, while other options would not include large amounts, it was important to represent differential costs for the high voltage transmission grid for such developments options in the overall cost minimization process.

Based on review of results from the literature, and from discussions with experts from the Canadian Electricity Association, the selected approach was to include investment costs for the high voltage transmission grid as being equal to 16% of investment cost of generation supply. By including this representation in the NATEM-Canada model, it was then possible to reflect differential costs for the high voltage transmissions grid as a direct function of total generating capacity.

3.4.6 Changes in Urban Regions

An important consideration for the project was to assess potential reductions in combustion based emissions from modified approaches for planning and developing urban regions in Canada, including modifications to existing urban regions. The need for this special investigation arose from recognition that 80% of Canadians live in urban regions, and that such regions produce more than half of Canada’s total GHG emissions. There was also recognition that there is substantial scope for making urban regions more functional, more efficient and more livable. There are several elements which are associated with such improvements. These include, as examples, urban densification; fully integrated urban communities; reductions in personal travel by personal transport within urban regions; greatly increased use of public transportation; development of fully integrated local energy systems, including distributed energy, district energy, waste to energy, rooftop solar systems, and battery and thermal energy storage; increased physical activity and improved public health; enhanced environmental space; and reduced production of waste materials.

Such improvements have the benefit of also contributing materially to reducing combustion emissions, and associated costs for GHG mitigation.

The basic approach for the project was to engage globally recognized experts to carry out a review of best global practice for planning and development of urban regions (which included several examples in Canada), and to apply this expertise for defining potential transformations for Canadian urban regions over the next century. Based on the premise that there would be early commitments to implementing such best practice improvements for urban regions in Canada, assessments were made on projected changes in two dominant areas of GHG emissions in urban regions; residential and transportation. Projected reductions and changes in energy based demands were defined specifically for 2030 and 2050, with reductions for other years based on interpolation.

For assessing opportunities for further reducing GHG emissions in the residential sector, opportunities were defined on the basis of reduced floor area and improved thermal performance from a higher percentage of shared walls in more attached dwellings and apartments, and a small, but important share of micro detached residential buildings. These improvements represented further reductions in thermal requirements for the residential sector, relative to projected efficiency improvements, as defined in Section 4.3.2

For the transportation sector, the primary change was due to fundamental change in urban form, with growth more concentrated in city and town centers, and along urban corridors. Major employment would be concentrated in multi-modal, mixed-use hubs situated along major transit corridors. This change in urban form supported cost effective, high quality public transit services. Complete, compact, connected neighborhoods and urban regions supported shifts towards walking, cycling and transit modes, and reduced distances travelled, number of trips, and car ownership. Convenient cost effective car share vehicles became more common, further reducing car ownership. Intercity rail, operating at high speed, connected large metropolitan areas within a few hundred kilometers. This service increased rail share at the expense of short haul air travel and personal automobile.

The information on projected reductions and changes in energy based demands in each of these two areas for each of the jurisdictions across Canada were defined and forwarded for detailed quantification with the CanESS model. This information was then converted to modified end use demands and forwarded via the data bridge as input for the NATEM model. As normal, the NATEM model was run to evaluate minimum present worth costs with these reduced and changed energy demands in urban regions. This information provided assessment of overall cost reductions for GHG mitigation and associated impact on the various sectors, both within and outside urban regions.

It should be noted that there are additional opportunities for reducing GHG emissions, with associated cost reductions, for urban regions, that were not represented in this project, but should be included in future investigations. These include opportunities for reduced waste and more effective use of waste, including for energy production with corresponding reduced release of methane from land fill sites, as well as benefits from more effective use of waste heat from various sources (see Section 3.4.7 below). There are also opportunities with reductions in both short haul freight and urban commercial traffic. There are various co-benefits, such as reduced health care costs from healthier life styles.

3.4.7 Local and Centralized Energy Systems

In recent years, it has been increasingly recognized that there are substantial opportunities for reducing GHG emissions with greater integration of energy and related services at the district level (referred to generically, as district energy systems). District may be considered as reflecting individual municipalities, urban communities, commercial centers, and even, individual households. The motivation for such developments occurs as a consequence of having demands for electricity supply, heating and cooling in densely populated areas, and using locally available supply sources for meeting such demands. District energy systems may include combination of the following types of strategies, services and technologies:

- Small scale local generation, including roof top solar, combustion turbines, etc.
- Small scale cogeneration for combined electricity and heat production
- Municipal or biomass (wood waste) for electricity and/or heat production
- Enhanced waste conservation programs
- Integrated energy management systems for commercial complexes
- Public transit electrification
- Vehicle sharing programs
- Electric vehicle charging stations
- Geothermal heat pumps
- Passive solar thermal systems
- Thermal storage systems
- Heat recovery systems
- Lake water cooling
- Electricity storage, including battery storage, reversible fuel cells, flywheels and supercapacitors

These and other initiatives at the local level for energy supply and management have several benefits, such as:

- Potential for using locally available alternative and renewable energy sources, including waste to energy, and with corresponding potential reductions in centralized generation supply
- Reducing energy use with energy conservation, energy efficiency, and demand side management
- Local exploitation of heat produced from combined heat and power applications, leading to higher efficiencies for end uses
- Shorter planning and construction periods
- Reducing costs with integrating such developments with new infrastructure, including commercial complexes and electrifying public transportation

For the project, these opportunities were recognized as being important for achieving reductions in use of fossil fuels for energy related services and related GHG mitigation.

Consideration was also given to projected balance between large scale electricity generation for supply to the high voltage grid and local electricity production and use. The perspectives, which were based partially on results from the initial scenarios, are summarized as follows:

- The initial optimization runs were based on the premise that all electricity production would be supplied to the transmission grid and that electricity would then be delivered to end users from the respective distribution utilities or directly to major energy users, such as industrial customers. In essence, this is the traditional centralized electricity supply and delivery system
- Based on early model results, there were important observations:
    - The minimum cost solutions resulted in early and rapid decarbonizing of electricity supply, with the supply systems for all of Canada being essentially fully decarbonized by 2030 (within 15 years). The significance of this is that, after 2030, any decentralized source of electricity supply will be competing, at the margin, with centralized generation that is already emissions free.
    - The minimum cost solutions also resulted in major programs of rapid electrification of all end uses and large increases in electricity supply for satisfying emissions reductions. This included almost three-fold increase in electricity supply within 35 years (see Section 5.4.5 and 5.10.5). Within this context, opportunities for meeting such large increases of electricity supply infrastructure from within local supply systems in Canada is minor, and would in general be limited to waste sources (waste to energy), rooftop solar, and district energy systems, some of which may not be emissions free.
- Associated with its extensive hydro systems, Canada has several of the largest reservoirs in the World (see also Section 5.8.3). This is a very valuable resource which is available for complementing energy production from intermittent renewable generating sources, including electricity production from local sources. It also helps to support system operating benefits, especially from hydro facilities, including spinning reserve, synchronous operation, load following, and emergency reserve, all of which have value as operational support for local distribution systems.

From these observations, it was evident that minimum cost solutions for electricity supply and delivery in Canada, especially for satisfying major reductions in GHG emissions, will continue to be dominated by traditional centralized systems with large scale electricity supply, high voltage transmission grids, and local distribution arrangements for delivery of electricity.

However, as has also been evident in this project, local arrangements for production, delivery, use and management of energy will certainly need to change. The potential benefits include better delivery of energy efficiency and conservation opportunities, improved utilization of energy services from fossil fuels, realizing benefits with improved urban planning and development (Section 3.4.6), and integrated management for supply and use of district energy services.

3.4.8 Biomass and Biofuels: Limitations and Opportunities

One of the important initiatives in the project was to develop greater in-depth understanding of the potential for increased production and use of biomass and biofuels to replace fossil fuels in meeting energy-based end uses. In early results from the scenarios, the use of biomass was projected to greatly increase, particularly for first- and second-generation biofuels. This resulted in a series of queries including availability of biomass feedstock, availability of land for increased production of energy crops, potential for significant changes in agricultural practices, and potential for specialty energy crops.

Detailed assessments were carried out with the CanESS model, and results describing availability of feedstock for biomass production were then transferred to the NATEM model for deriving minimum cost solutions with defined limitations on availability of such feedstocks. The processes and some general observations from these investigations are described in this section.

As is the case for all energy commodities, the CanESS model includes calculations of the balance between demand and supply of biofuels. Demand for ethanol and biodiesel can originate in all sectors. However, with federal and provincial regulations on the blending of biofuels with refined petroleum products for transportation purposes, the demand for biofuels is most notably in the transportation sector.

The production of biofuels is modelled by means of a stock roll-over model that captures the production capacity of ethanol and biodiesel, through various processes and different feedstocks (Table 5). Through the projected period to 2050, existing plants are retired and new capacity is added, consistent with the defining premises for each Scenario. As capacities of various technologies are deployed, the CanESS model keeps track of biofuel produced, energy use, energy sources, and feedstock required.

The resulting biofuel production in each jurisdiction is, in general, not the same as the demand for biofuel in the jurisdiction, with the differential being met by interprovincial and international trade.

Biomass feedstock is from several sources. With respect to the agricultural sector, it can be either from commercial crops (hay, wheat, corn, canola, soybean, flaxseed, willow, poplar, switchgrass, miscanthus), or from residues (crop residues or animal residues (tallow)). With respect to the forestry sector, it includes residues from milling, disturbance wood (bugwood), non-merchantable wood, and roadside wood residues. There is also potential for biomass feedstock from municipal solid waste.

Evaluations were carried out to assess potential limits on the availability of biomass feedstock. These limits emerged as an important check on the production of biofuels, especially for the transportation sector, and for direct use (as biomass), for electricity generation. For these evaluations, projections of the availability of non-merchantable wood and mill residues were based simply on historical trends. Projections of biomass residues in municipal solid waste were based on a per capita generation of waste and population growth.

Table 5. Overview of various technologies to produce biofuels

Biofuel	Process pathways examined	Feedstock examined	Fuel replaced
Ethanol	fermentation corn fermentation wheat	cereal crops grain corn fodder corn wheat	oil (gasoline) LPG (rare) natural gas (rare)
	cellulosic hydrolysis (chemical or enzymatic) cellulosic fermentation cellulosic combined fermentation/hydrolysis cellulosic gasification to ethanol	cellulosic residues forest agricultural municipal	oil (gasoline) LPG (rare) natural gas (rare)
	any of the above with cogeneration of heat and power	cellulosic residues forest agricultural municipal	natural gas coal
Biodiesel	transesterification (FAME) from any oil seed from tallow from yellow grease	oilseeds canola soybean flaxseed tallow yellow grease	oil (diesel) LPG (rare) natural gas (rare)
	cellulosic gasification to Fisher-Tropsch (FT) fuels	cellulosic residues forest agricultural municipal	oil (diesel) LPG (rare) natural gas (rare)
	any of the above with cogeneration of heat and power	cellulosic residues forest agricultural municipal	natural gas coal nuclear
Bioelectricity	cogeneration of heat and power	cellulosic residues forest agricultural municipal	natural gas coal nuclear

More detailed assessments were derived for biomass production from the agriculture sector. This included assessment of available agricultural land (crop land, pasture land and other agricultural land), evaluation of utilization rates of this land base, and calculation of food requirements for a growing population, as well as an estimate of food for animals in the meat and dairy industry. The assessment included projections of commercial crops and residue yields, and estimates of the portion of residues that may be available as biomass feedstock. The project carried out research in order to define appropriate limits for commercial crop production which could be converted for biomass/ biofuel production.

Early assessments were made, on the basis of the best readily available information, to establish limits for biomass production and associated options for production of bioenergy and biofuels, including both first and second generation biofuels. Estimates were developed of the maximum available land that was available for agricultural production, based on Canadian land classification categories (i.e. classes 1 to 7). This work allowed the project team to determine land available for high intensity crops, and for other types of crop production, such as hay production, and characterized areas of marginal lands that might be used for willow and poplar production. Yield estimates for each of the crops across different land classification categories were assembled on the basis of best available information. The CanESS model was then used, with this data, to evaluate maximum biomass productions limits for the different types of crops. The results for these analyses are presented in Sections 4.7.1.1 and 4.7.1.2. In particular, the information includes defined upper limits on availability for different classes of biomass feedstock for each of the jurisdictions across Canada.

It needs to be appreciated that the work carried out in this project for deriving biomass/biofuel feedstock production limits should be viewed as being preliminary in nature. The judgements that were made were based on reasonably authoritative knowledge on land availability and land classification categories for the various jurisdictions, and on potential crop yields. However, there are major uncertainties with respect to the amount of agricultural land that can be reasonably converted to production of energy crops, availability of currently unused land to be brought into commercial production, availability of residues from both the agricultural and forestry sectors as biomass feedstock, and availability of municipal waste as biomass feedstock. There are also concerns with when second generation biofuels, especially renewable biodiesel options, will become technically and commercially viable.

In spite of these and other uncertainties, and as will be demonstrated from result of selected scenarios (see Sections 5.7.2 and 5.10.4), this is a very important area for more detailed investigation and development. There is clearly a very substantial potential role in Canada for increasing production of biomass for bioenergy and biofuels, which in turn can help achieve substantial reductions in emissions from combustion of fossil fuels.

3.5 Comparative Assessments

Over the past three decades, there have been initiatives in virtually every country around the world on strategies for GHG mitigation. Such strategies have not only been at the national level, but increasingly at sub-national (province, territory, state), as well as at individual urban and municipal levels. In this Section, brief perspectives are presented to show how selected jurisdictions around the world are taking action on strategy and policy development for GHG mitigation.

The need for a global response to this challenge has been well defined by IPCC. The World is united in recognizing the seriousness of the challenge, and in assembling a globally coordinated response. This was confirmed by 195 countries signing the COP 21 Agreement in Paris on December 12, 2015 (UNFCCC, 2015). The main aim of the Agreement was to keep global temperature rise well below 2^{o}C and to drive efforts to limit temperature increase even further to 1.5^{o}C above pre-industrial levels. To achieve this, the Member Countries are being asked to work together to ensure that emissions peak as soon as possible, and that “carbon neutrality (net zero emissions) is achieved in the second half of the century”.

The basic purpose of presenting results from comparative assessments in other jurisdiction is to review their commitments for GHG mitigation, to review challenges with respect to achieving progress, and to provide perspectives on GHG mitigation strategies and policies that may be of potential value for Canada.

3.5.1 GHG Emissions Reductions in Europe

In a submission prepared jointly by World Resources Institute and Oko-Institut e.V. (Cludius et al, 2012) in 2012 on the policy landscape concerning GHG emissions reductions in the European Union, some key commentary was as follows:

- In 2009, the European Union pledged a unilateral GHG reduction target of 20% below 1990 levels by 2020. This target forms one pillar of a so-called 20-20-20 package that also included 20% share of renewable energy sources in gross final energy consumption, and 20 % improvement in energy efficiency. In addition to its 2020 targets, the European Union set a long-term GHG reduction goal of 80 to 95% below 1990 level by 2050. The GHG emissions reductions targets for 2020 were translated into a comprehensive energy and climate package, which was passed by the European Parliament in December, 2008. The 2050 target is not binding and has not been substantiated by actual strategies or policies; however, several studies have been launched to determine how this long term target can be met.
- For achieving defined GHG mitigation targets, there are two dominant categories of European Union-wide policies; financial incentives and mandatory requirements.

  With respect to financial incentives, the cornerstone has been the European Union Emissions Trading System (EU ETS) which was put into operation in 2005. This is based on establishing CO_{2}-eq allowances (EUA's) on various installations. At the end of each year, such installations are requires to submit one EUA for each tonne of CO_{2}-eq emitted. If they exceed their allowances, they can purchase EUA's to meet their allowances, while other emitters that have not used their allowances can sell their allowances. This process, which is a cap and trade system, is designed to reduce GHG emissions at lowest collective cost. The EU ETS covered only 40% of GHG emissions (50% of CO_2 emissions) in 2012, primarily from the electricity supply and heavy industrial sectors. From 2013 onwards, the system was expanded to include nitrous oxide and perfluorocarbons which would increase the ETS to including 50% of GHG emissions.

  With respect to mandatory requirements, this includes sectors not covered by the ETS, including buildings, transport and agriculture. This includes mandated 10% reduction from 2005 emissions levels in these sectors.
- There have been continuing criticisms of the EU ETS. The most serious criticism is that the caps have consistently been too generous, resulting in an over-supply of allowances. As a consequence, the values of such allowances has dropped to low levels (below 7 euros per tonne), with the result that there have not been the essential incentives for investments in low carbon infrastructure.
- In 2012, the European Union was on target to deliver on its goals for 20% reduction in GHG emissions, and 20% share of renewable energy. However, projections in 2012 indicated that the European Union was on track to only achieve about half of its envisaged energy efficiency goals. In order to overcome this projected shortfall, the European Commission adopted the *Energy Efficiency Plan* and a *Proposal for a Directive on Energy Efficiency 2020*, which was passed by the European Parliament in September, 2012. This legislation was intended to ensure that the energy efficiency objective was achieved and to obligate member states to establish energy savings schemes.

With respect to options for achieving the 2050 reduction target of 80 to 95% reduction relative to 1990, the European Commission prepared an *Energy Roadmap 2050* which was based on results of extensive modelling of alternative scenarios. These scenarios included a Reference Scenario, which was based on policies adopted up to 2010, a Current Policy initiatives (CPI) scenario (including additional policies to 2013), and a series of decarbonisation scenarios. From these results, it was shown that the longer term goal cannot be reached with existing policies, and that additional measures are required to achieve longer term reductions. This exercise served to illustrate options (mainly technical) required to reach the longer term goal, but without providing concrete advice regarding specific policies and measures. However, it was emphasized that it was crucial for the European Union to greatly strengthen its main climate policy tool, the EU ETS, which required much higher prices for providing essential signals for long term investment in low carbon technologies.

3.5.2 GHG Emissions Reductions in the United Kingdom

The more prominent developments in the United Kingdom begin with the announcement by the Chancellor of the Exchequer in July 2005 for a review to be undertaken on the economics of moving to a low-carbon global economy, focusing on medium to long-term perspectives, drawing implications for timescales for action, and the choice of policies and institutions. This Review was led by Lord Nicholas Stern and culminated in the *Stern Review on the Economic of Climate Change*, submitted to the British Government in October, 2006 (Stern, 2006). Although this was not the first report on climate change, it is significant as being one of the most comprehensive and widely known and discussed Report of its kind.

The main conclusion of the Stern Review is that benefits of strong, early action on climate change far outweigh the costs of not acting. Without action, the overall costs of climate change will be equivalent to at least 5% of gross domestic product now and forever. The Review provides a strong basis for prescribing environmental taxes to minimize the economic and social disruptions of climate change.

Results of the Stern Review served as a catalyst for passage of the *Climate Change Act* by the United Kingdom Parliament in 2008 (HM Government, 2008). This Act commits the United Kingdom to 80% emissions reduction by 2050, relative to 1990, and to a system of 5-year carbon budgets to progress towards that target. An independent body, the Committee on Climate Change, advises the Government on the setting of carbon targets, and reports to Parliament annually on progress.

In a Working Paper prepared by World Resources Institute in 2012 on the policy landscape concerning GHG emissions reductions in the United Kingdom, some key commentary was as follows (Gault, 2012):

- By 2012, commitments, as per the most recent *Carbon Plan*, included being 34% below 1990 levels by 2020, and 50% by 2025. Based on the assessment by the World Resources Institute, the United Kingdom was on target to deliver on its *Third Carbon Budget (2018-22)*; however, there will be a need to accelerate additional measures and faster implementation to deliver on the Fourth Carbon Budget (2023-2027). This would require, especially reforms for the electricity market for low carbon generation and new energy efficiency policies.
- Based on reviews of policy approaches for each of the emitting sectors, the dominant strategies include reliance on regulations, incentives and penalties. For the power sector, for example, the

target is to increase renewables in final generation from 3% in 2010 to 15% in 2020. The main policy mechanism is the renewable obligation certificate regime, under which electricity suppliers are required to purchase prescribed portions of their electricity from renewable generators. There are also initiatives for increasing nuclear power and for carbon capture and storage facilities. There are corresponding sector-specific initiatives in the other sectors, including industry, buildings, transport, waste and agriculture.

- With respect to use of market mechanisms, the dominant policy is the European Union cap and trade system; however, as noted, this has not been effective as carbon prices have been much lower than required for encouraging investment in low carbon technologies. For electricity supply, this has been supplemented with introduction of carbon floor prices for investment in low carbon electricity generation based on modified feed in tariff programs. This is for providing greater certainty on investment returns for such facilities. Some initiatives have also been made with introducing climate change levies in the energy tax, especially for combustion of fossil fuels.
- With respect to using models for deriving minimum cost strategies for reducing GHG emissions, the Committee on Climate Change produced a report *Building a Low Carbon Economy* in 2008. They reported on results from applying the United Kingdom version of the TIMES/MARKAL model to the cost of achieving 80% reduction in CO_2 emissions by 2050, relative to 1990, from the energy sector alone. The model did not address emissions other than CO_2. In their report, they showed that the dominant strategies were associated with decarbonizing electricity supply (dominantly thermal generation) with CCUS and/ or nuclear, and increasing use of electricity for transport and heating. The cost would be 1 to 1.5% of GDP. If both CCUS and nuclear would not be available, the cost impact would increase to 3% of GDP.

3.5.3 GHG Emissions Reductions in the United States

- The position of the United States with respect to climate change assumes special importance. The United States are the largest producer of cumulative GHG emissions for the period from 1990 to 2011 (16%) and currently, the second largest producer (2011) of GHG emissions (13%) (Ge et al, 2014).
- Despite their prominent position as a major producer of GHG emissions, there is no federal climate action policy in place (European Parliament, 2015). There have been legislative initiatives to implement a coordinated federal climate action policy; however, these have not been successful. As a result, the overall program to reduce GHG emissions has been based on implementing a large number of different policies in the individual States, sectors and Department of the Government. For example, in their *Climate Action Report 2014* to the UNFCCC, approximately 100 separate near-term policies and measures being undertaken by the Government of the United States are noted (USDOS, 2014).
- The short term plan for reducing GHG emissions is defined in the United States *Climate Action Report 2014*. The prime focus is on reducing GHG emissions by 17% by 2020 relative to 2005 (USDOS, 2014), reflecting the United States commitment as embodied in the *Copenhagen Accord*. Based on programs and measures in place as of September 2012, total gross GHG emissions were projected to be 4.6% lower than 2005 levels by 2020 (Baseline Scenario). However, there have been subsequent initiatives, including *President Obama's Climate Action Plan* (White House, 2015). Amongst many new initiatives, this Plan includes a major focus on carbon pollution standards for power plants, cut energy waste, deploy more renewable energy, reduce methane and hydrofluorocarbon emissions, and further improve standards for fuel use in vehicles. Based on these additional measures, the *Climate Action Report* indicates that the

goal of reducing emissions by 17% below 2005 levels is achievable. The major efforts will include new rules for carbon pollution from the power sector, enhance action on energy efficiency and clean energy technologies, and reduce methane and hydrofluorocarbon emissions (USDOS, 2014).

- Beyond 2020, the United States are also assuming major initiatives. Based on an agreement with China in November, 2014, the United States committed to reduce its carbon emissions by 26% to 28% below 2005 levels by 2025. This rate of reduction of emissions is twice as fast as for the period from 2005 to 2020 (Landler, 2014). In separate communications, the United States have also indicated 42% emission reductions by 2030, in line with reducing emissions by 83% by 2050 (European Parliament, 2015).

3.5.4 Canadian Energy Strategy - Council of the Federation Vision on Energy and Climate Change

In 2012, Canada's provinces and territories, co-led by Alberta, Newfoundland and Manitoba, committed to a process to develop a pan-Canadian energy strategy and vision (Government of Newfoundland and Labrador, 2015). As this provincial process evolved, new governments in Ontario, Quebec, and Alberta forged commitments and regional pacts to prioritize clean energy and policy action on climate change. These commitments, specifically Ontario and Quebec's joint agreement on climate change, were significant enough to revise the Canadian Energy Strategy vision and principles at the Premiers' Council of the Federation summit in Charlottetown in the summer of 2014 to emphasize, for the first time, that reducing GHG emissions would be a key pillar to Canada's strategy.

The *Premiers' Energy Strategy* was released at the July 2015 Council of the Federation meeting in St. John's. At the meeting, the Premiers stated that the cost of inaction on climate change was greater than the cost of action and that Canada's opportunity to lead on this challenge could secure new jobs and economic opportunities. The premiers committed to work toward "concrete solutions including technological investments such as the continued development of wind energy, carbon capture and storage, and innovations that reduce reliance on diesel fuel in remote communities, as well as policy levers such as carbon pricing, hard caps on emissions from electricity generation, and renewable energy targets so that GHG emissions may be better taken into account in decision-making processes".

Canada participated, along with 194 other countries in the COP 21 meetings in Paris in December, 2015. In this meeting, Canada had very broad representation (more than 300 delegates), including the Prime Minister; most of Canada's Premiers; Ministers from Federal, Provincial and Territorial governments; First Nations; cities and municipalities:, Business community:, Universities; and youth. At this meeting, Canada committed to reducing its GHG emissions by 30% by 2030, relative to 2005.

Following this meeting, there was a First Ministers meeting on March 3 in Vancouver (Bailey and McCarthy, 2016). At this meeting, the Prime Minster and Premiers agreed that additional action was required to meet and exceed Canada's international commitment to reduce GHG's by 30% from 2005 levels by 2030. There was also a desire by the Federal Government to establish a minimum carbon price that would apply across the country. This was not accepted. It was agreed, however, that there should be some form of carbon pricing. There was no consensus on what approach to use or whether there should be a minimum floor price for carbon.

Although the federal government has yet to set a firm target for 2050 for deep emission reductions, Canada has endorsed a G7 commitment to achieve a zero-emission energy system before the end of the century.

3.5.5 Actions by Sub-National Governments

Momentum is building among sub-national governments globally, including among Canadian provinces and American states. Ontario, Quebec, and British Columbia have joined California, Oregon, Washington, Vermont and 14 other sub-national governments, to limit the global temperature increase to below 2°C, the same objective as the UNFCCC. In practical terms this means reducing GHG emissions between 80 to 95% below 1990 levels by 2050 to reach a two tonne per capita target. The agreement also commits signatories to tangible policy actions including policies to promote zero emission vehicles and transportation infrastructure, and solutions to promote the large-scale switch to renewable energy and the integration of renewable energy sources. To support subnational governments on this low-carbon pathway, subnational policy development and cooperation is focusing over the medium (up to 2030) on key policy drivers, many of which are outlined or under development through California's 50-50-50 plan (SB350), a strategy to advance low-carbon transportation, energy and buildings.

3.5.6 Carbon Neutral Cities Alliance and C40

The Carbon Neutral Cities Alliance, a global network of 17 large cities including the City of Vancouver and eight cities from the United States, has committed to derive 100% of the energy used within their city boundaries from zero emission energy sources by 2050 (USDN, 2016). For the City of Vancouver, this goal is equivalent to an 80% reduction below 2007 levels. Both Toronto and Vancouver are also part of the C40 initiative, a network of 40 megacities committed to advancing policies to cut GHG emissions and put in place solutions to shield communities from the impacts of climate change.

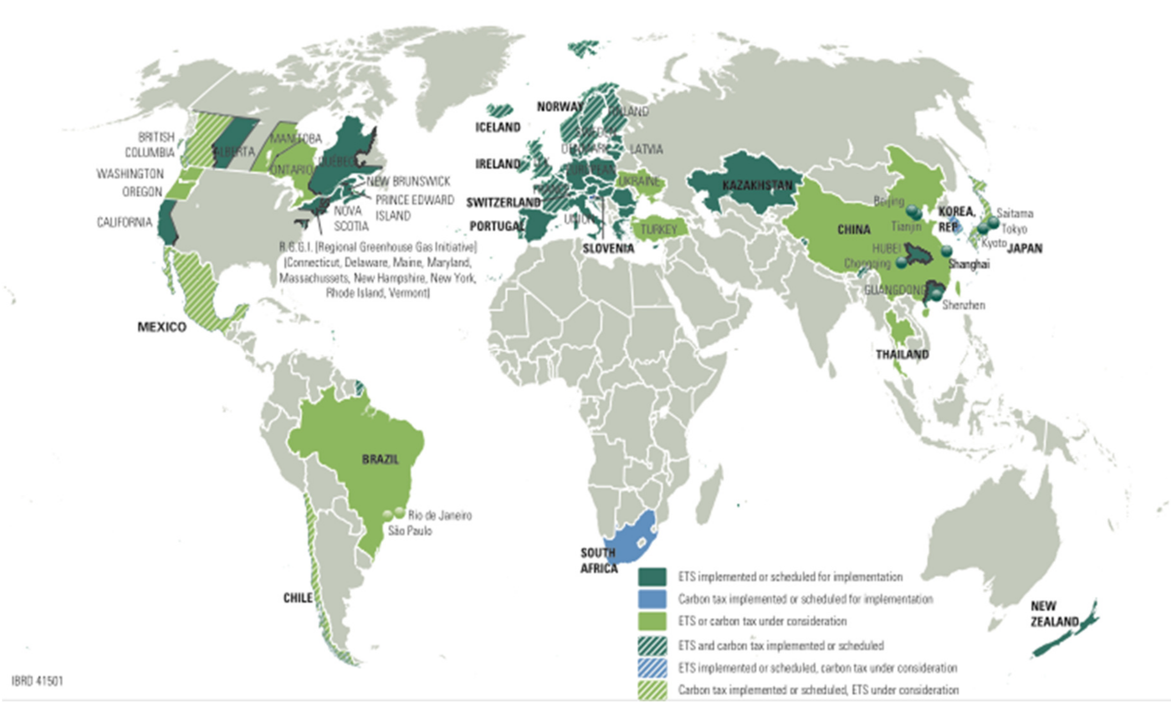
3.5.7 Momentum builds for carbon pricing

Leading global organizations, including the World Bank, World Economic Forum, IPCC and Organization for Economic Cooperation and Development (OECD), agree that a price on carbon emissions though a carbon tax or regulatory cap-and-trade system is a critical foundation of an effective plan to address climate change (World Bank, 2014).

In September 2014, the World Bank reported that 40 national and over 20 sub-national jurisdictions have already enacted or scheduled a carbon pricing system either through a carbon tax and an emissions trading system (Figure 21). Together, these jurisdictions account for more than 22% of global emissions.

Momentum is also building within the global business sector. In 2014, more than 1,000 companies showcased their support for carbon pricing (IIGCC, 2014). This was followed by a call for carbon pricing by over 370 investors through the 2014 Global Investor Statement on Climate Change. Collectively, these investors account for assets totaling US$24 trillion.

Figure 21. Countries with carbon pricing systems



Source: World Bank, 2015.

3.5.8 Carbon pricing in Canada

British Columbia, Quebec and Alberta were early adopters of carbon pricing systems in North America. Ontario and Manitoba announced, in 2014 and 2015, respectively, that they will also implement carbon pricing systems. Although each province has chosen a different approach and level of effectiveness, they all demonstrate the policy's abilities and benefits.

The Ontario government's decision to put a price on carbon emissions in the form of a cap-and-trade system is a significant development, as it is Canada's largest provincial economy. Regulations have yet to be finalized. Combined with British Columbia's provincial carbon tax, Quebec's cap-and-trade system and Alberta's rules for large industrial emitters, Ontario's passage of the legislation means that more than 80% of Canada's population and upwards of 70% of national GDP (i.e. approximately 86% of Canadians and 75-86% of national GDP) will be subject to a form of carbon pricing. This is further enhanced by Manitoba's more recent additional commitment to implementing a cap-and-trade system.

Carbon pricing has proven to be an effective strategy for balancing economic performance with GHG reductions in Canada. When the British Columbia government introduced the carbon tax in 2008, it laid out a path to fight climate change while continuing to stimulate the economy. From the tax's introduction to the end of 2012, British Columbia's consumption of fossil fuels covered by the carbon tax decreased by 19% per capita compared to the rest of the country, according to research by Sustainable Prosperity. Meanwhile, British Columbia's economy outperformed the Canadian average.

3.5.9 Summary Comments

From the background provided on actions being taken in selected jurisdictions around the world in addressing the climate change challenge and for achieving effective progress, there are some important summary observations:

- There is growing global acceptance of GHG reduction targets being approximately 80% by 2050 relative to 1990 or 2005, and with the further need for the even more stringent 100% reduction targets before 2100.
- It is apparent that real progress for effective delivery on increasingly stringent GHG mitigation targets requires a strong and sustained national commitment, including provision of supporting legislation and regular reporting on plans and progress. There are corresponding requirements for additional legislation (or amendments to existing legislation), additional regulations and incentives, and additional policies.
- There is growing appreciation that ultimate success will be dependent of having all jurisdictions engaged and cooperating. This includes not only national governments, but also, sub-national governments (provinces, territories, states) as well as urban regions and individual municipalities. The business community also needs to be fully engaged.
- A cornerstone policy for achieving major reductions in GHG emissions is an effective carbon pricing system that reflects the merit of having effective market mechanisms for achieving emission reductions at minimum cost. However, it is critically important that such system be well designed to ensure that emissions reduction goals are realized.
- There is increasing use of mathematical models for deriving minimum cost solutions for GHG mitigation at both national and sub-national levels.

4. Sector by sector Opportunities for GHG Reductions

The NATEM-Canada optimization model was used to derive minimum cost solutions for reducing GHG emissions from combustion of fossil fuels in Canada in a multi-time period context from 2011 to 2050. The CanESS simulation model was used for more in-depth analyses of some important combinations of premises. This unique combined approach is described in detail in Section 3 with an illustration of input and output flows between the two complementary models (e.g. Data Bridge) and a description of the dispatching module of CanESS. This approach also involved a regular comparison of the solutions derived from both models to ensure that they were producing sensibly consistent results for different combinations of prescribed premises.

This Section 4 presents in more detail the components of each sector and highlights the available mitigation options in each case. First, the five energy end-use demand sectors are covered: transportation, residential, commercial, agriculture and industry. Second, energy supply sectors are presented: electricity, fossil fuels, biomass and biofuels. Lastly, CCUS options are discussed. Although this section refers mainly to the NATEM-Canada model database, a large amount of information also applies to the CanESS model.

Indeed, a tremendous effort was dedicated to data gathering and model calibration over a seven-month period. In addition to the numerous data sources listed in References, both models benefited from a very thorough vetting process to ensure that the data was being obtained from credible and objective sources. In particular, special attention was given to the evolution of technical and economic attributes over time as the cost and performance of emerging technologies are normally expected to improve much more than those of mature technologies over time. In cases of high uncertainty (e.g. cost of second generation biofuel production) or contradictory data sources, the most conservative estimations were used.

Regarding calibration, the process involved regular cross checking of the different data sources used in each of the two models, multiple model iterations and comparisons of preliminary results between the two models as well as a validation process with key stakeholders in various organizations such as the Canadian Electricity Association, the National Energy Board, Alberta Innovates, etc. Moreover, a special constraint has been included in relevant model runs to ensure that the dependable capacity criteria as defined in Section 3.4 was always satisfied.

Consequently, an important portion of the data used for generating the scenarios were developed or validated within the context of the study and implemented in both models. Finally, the NATEM-Canada model database has been improved in several places using more detailed information coming from the CanESS model.

The information introduced below was used to generate the scenarios described in Section 5. The most important assumptions and limitations are also described for each sector to allow a better interpretation of the results.

4.1 Structure of the NATEM-Canada model

The NATEM-Canada model covers in detail the energy system of the 13 Canadian provinces and territories, including:

- *Final energy consumption*. The model is driven by a set of 70 end-use demands for energy services in five sectors: agriculture, commercial, industrial, residential and transportation. In each sector of the database, a repository includes a large number of new technologies that are in competition to satisfy each end-use demand including existing technologies, improved versions of existing technologies and new technologies.
- *Conversion to secondary energy.* This covers all energy conversion technologies such as power plants (thermal with and without carbon capture options, nuclear, renewables, etc.), fossil fuels transformation plants (refineries, coke plants) and biofuels/biomass plants. There are separate modules for a potential future hydrogen economy and liquefied natural gas (LNG) industry.
- *Primary energy supply*. The database compiles all Canadian primary energy sources, such as both conventional and unconventional fossil fuels reserves (oil, gas, coal), renewables potentials (hydro, geothermal, wind, solar, tidal and wave), uranium reserves and biomass (various solid, liquid and gaseous sources).
- *Energy trade*. All primary and secondary forms of energy can be traded within and outside Canada. The domestic trade module deals with energy exchanges between the Canadian provinces and territories. The international trade module covers all energy exchanges between Canada and other countries, including the United States.
- *GHG emissions*. The model tracks CO_2, CH_4 and N_2O emissions from fuel combustion, fugitive emissions (from processes, flaring and venting) from the energy sector and process emissions from the agriculture sector. All emission coefficients are coming from the *National Inventory Report* (Environment Canada, 2013a).
- *Carbon capture, use and sequestration*. Capture options are available in the electricity sector for the new coal plants. Future work will allow the addition of carbon capture options with biomass power plants. In addition to the regular emission reduction options available in the model (technology and fuel substitutions, endogenous demand reductions), a module is also covering sequestration potentials for various options: enhanced oil recovery, enhanced coal bed methane, afforestation, oil & gas fields (onshore and offshore), deep saline aquifers.

The TEFP study covers the 2011-2050 time frame through nine time periods (Table 6): shorter time periods are defined at the beginning of the horizon while longer time periods are used at the end of the projection period. For each period, 16 time slices are defined uniformly across Canada, with four seasons per year (spring, summer, fall and winter) and four intraday periods (day, night, morning peak, evening peak) (Table 7).

Table 6. Time period definition

Period	1	2	3	4	5	6	7	8	9
Milestones	2011	2013	2015	2020	2025	2030	2035	2040	2050

Table 7. Time slice definition and fraction of year for time slices

Season	Definition	N. of days	Period of day	Definition	N. of hours	Time slice	% of year
Spring	March 21st – June 20th	92	Morning Peak	6h - 7h59	2	RP1	2.1%
			Day	8h - 16h59	9	RD	9.5%
			Evening Peak	17h-19h59	3	RP2	3.2%
			Night	20h - 5h59	10	RN	10.5%
Summer	June 21st – September 20th	92	Morning Peak	6h - 7h59	2	SP1	2.1%
			Day	8h - 16h59	9	SD	9.5%
			Evening Peak	17h-19h59	3	SP2	3.2%
			Night	20h - 5h59	10	SN	10.5%
Fall	September 21st - December 20th	91	Morning Peak	6h - 7h59	2	FP1	2.1%
			Day	8h - 16h59	9	FD	9.4%
			Evening Peak	17h-19h59	3	FP2	3.1%
			Night	20h - 5h59	10	FN	10.4%
Winter	December 21st - March 20th	90	Morning Peak	6h - 7h59	2	WP1	2.1%
			Day	8h - 16h59	9	WD	9.3%
			Evening Peak	17h-19h59	3	WP2	3.1%
			Night	20h - 5h59	10	WN	10.3%
Total		365					100.0%

For the 2011 base year, all energy flows are calibrated using energy balances available at Statistics Canada (2011; 2012) in each province and territory while emissions are calibrated to the *National Inventory Report* (Environment Canada, 2013a). Furthermore, the *Comprehensive Energy Use Database* of the Office of Energy Efficiency (OEE, 2011) is used to further disaggregate fuel consumption by end-use demand for energy services in each sector.

4.2 Transportation Sector

4.2.1 Sector Description

The transportation sector includes "… the use of fuel by the transportation industry for transportation purposes. Excluded are any fuels used for activities not directly involved in transportation (i.e. train stations, warehouses, airports, etc.). These amounts are included in commercial and other institutional. Fuels, which have been purchased for use by the agriculture, commercial and public institutions sectors for transportation purposes, are included in the sectors to which the fuel was sold." (Statistics Canada, 2011). Additionally, energy consumption for pipeline transportation has been extracted from the total transportation sector to be included in the supply sector.

The transportation sector is made up of 20 end-use demand categories representing Canada's freight and passenger transport services (Table 8). Demand is specified in either million passenger kilometers (MPkm), million tonne kilometers (MTkm) or petajoules (PJ).

Table 8. End-use demand for energy services in the transportation sector

Description	Unit
Road passenger small cars, long distance	MPkm
Road passenger small cars, short distance	MPkm
Road passenger large cars, long distance	MPkm
Road passenger large cars, short distance	MPkm
Road passenger light trucks	MPkm
Road passenger urban buses	MPkm
Road passenger subways	MPkm
Road passenfer intercity buses	MPkm
Road passenger school buses	MPkm
Road passenger motorcycles	MPkm
Road passenger off-road vehicles[1]	PJ
Road freight light trucks	MTkm
Road freight medium trucks	MTkm
Road freight heavy trucks	MTkm
Passenger train	MPkm
Freight train	MTkm
Domestic air travel	MPkm
International air travel	MPkm
Air freight	MTkm
Marine transport	PJ

1. Includes vehicles not registered for on-road travel such as ATVs, snowmobiles, golf carts and some military vehicles (OEE, 2011).

Technologies and fuels

Vehicles. The different technologies that are in competition to satisfy each transport end-use demand for energy services are shown in Table 9, which includes two key technological parameters: efficiency range (litres per 100km – l/100km) and investment cost range ($ per unit) for each vehicle type. In addition to the existing technologies which are present in the 2011 base year, there is a repository with several new technologies available after 2011 to satisfy the increase in demand and/or to replace vehicles which have reached the end of useful life. This repository includes identical or improved versions of existing technologies (e.g. standard efficiency and improved efficiency gasoline cars), and new technology models not included in the 2011 base year (e.g. advanced plug-in hybrid or all electric cars). There is one representative technology for each possible combination (existing and future) of technology category and fuel type (e.g. plug-in hybrid gasoline small cars).

It is important to note that there are many other technological parameters, which vary by vehicle type, included in the model but not shown here. These parameters allow for a highly detailed representation of the transportation sector, including information such as: existing stocks, average trip length, average number of passengers per vehicle, average load of freight vehicles, useful life of a vehicle, starting year of availability on the market, and yearly operating and maintenance costs.

Technology data are taken from different sources depending on the parameter. Vehicle cost and efficiency data was taken from representative car models (usually the top selling model of its class for existing technologies and most promising model for new technologies), which is directly available on the website of vehicle manufacturers. For example, small gasoline cars are represented by Honda Civic LX data and small diesel cars are represented by Jetta TDI data. Data for cost growth rates and efficiency (miles per gallon) increases were taken from the Energy Outlook Database of the Energy Information Administration (EIA, 2014). In general, advanced technologies show greater cost decrease and efficiency improvements compared with existing and mature technologies. Fixed operating and maintenance annual costs are taken and adapted from the Canadian Automobile Association's (CAA, 2013) estimations, which distinguish between small car, large car and light truck vehicle models. Useful life of vehicles and average distance travelled were taken from the CanESS model (whatIf? Technologies, 2014). Finally, existing stocks and vehicle load factors for passenger and freight were taken directly or calculated from data found in Office of Energy Efficiency (OEE, 2011). Technology data were also compared and validated using the Technology Briefs of the ETSAP (2014) and the Energy Technology Perspective of the IEA (2012a).

Table 9. Technologies available in the transportation sector

End-use demand	Technology & Fuel	Year	Internal combustion Engine		Electric motor (plug-in hybrid and all electric)[2]	
			l/100 km	$/unit	l/100 km	$/unit
Road, Passenger, Small Cars	Small cars (gasoline, diesel, NGL, natural gas, gasoline hybrid, diesel hybrid, ethanol, cellulosic ethanol, biodiesel, FT diesel, plug-in gasoline hybrid, plug-in diesel hybrid, all electric)	2012	4.6 - 11.2	18 900 - 24 560	1.4 - 4.4	23 280 - 43 340
		2050	3.1 - 6.9	21 200 - 27 360	0.8 - 1.5	20 430 - 103 430
Road, Passenger, Large Cars,	Large cars (gasoline, diesel, NGL, natural gas, gasoline hybrid, diesel hybrid, ethanol, cellulosic ethanol, biodiesel, FT diesel, plug-in gasoline hybrid, plug-in diesel hybrid, all electric)	2012	5.1 - 9.8	25 600 - 33 270	1.3 - 4.8	25 720 - 90 110
		2050	3.5 - 7.6	27 470 - 35 750	1.0 - 3.1	23 730 - 169 650
Road, Passenger, Light Trucks	Light trucks; passenger (gasoline, diesel, gasoline hybrid, diesel hybrid, ethanol, cellulosic ethanol, biodiesel, FT diesel, plug-in gasoline hybrid, plug-in diesel hybrid, all electric)	2012	9.8 - 13.1	24 440 - 25 920	2.0 - 9.8	27 380 - 171 040
		2050	7.1 - 9.0	27 160 - 28 220	0.9 - 6.9	28 110 - 114 420
Road, Passenger, Urban Buses	Urban buses (gasoline, diesel, NGL, natural gas, gasoline hybrid, diesel hybrid, ethanol, cellulosic ethanol, biodiesel, FT diesel, plug-in gasoline hybrid, plug-in diesel hybrid, all electric)	2012	31.4 - 67.2	321 000 - 347 000	16.8 - 39.2	498 000 - 724 000
		2050	23.5 - 47.0	354 000 - 368 000	12.4 - 26.1	440 000 - 486 000
Road, Passenger, Subways	Subways (electric)	2012	N/A	N/A	39.2	497 690
		2050	N/A	N/A	21.4	486 290
Road, Passenger, Intercity Buses	Intercity buses (gasoline, diesel, NGL, natural gas, gasoline hybrid, diesel hybrid, ethanol, cellulosic ethanol, biodiesel, FT diesel)	2012	47.0 - 78.4	321 000 - 353 000	29.4 - 33.6	519 000 - 551 000
		2050	39.2 - 47.0	354 000 - 434 000	23.5	N/A
Road, Passenger, School Buses	School buses (gasoline, diesel, NGL, natural gas, gasoline hybrid, diesel hybrid, ethanol, cellulosic ethanol, biodiesel, FT diesel, plug-in gasoline hybrid, plug-in diesel hybrid, all electric)	2012	47.0 - 78.4	270 390 - 289 000	8.7 - 33.6	227 000 - 604 460
		2050	39.2 - 58.8	283 670 - 304 120	5.0 - 23.5	137 920 - 367 640
Road, Passenger, Motorcycles	Motorcycles (gasoline, diesel, gasoline hybrid, ethanol, cellulosic ethanol, FT diesel, plug-in gasoline hybrid, all electric)	2012	5.6 - 6.2	3 520 - 8 210	0.4 - 5.5	6 600 - 28 830
		2050	4.1 - 4.4	3 920 - 6 000	0.2 - 3.9	6 450 - 12 120

End-use demand	Technology & Fuel	Year	Internal combustion Engine		Electric motor (plug-in hybrid and all electric)[2]	
			l/100 km	$/unit	l/100 km	$/unit
Road, Passenger, Off road vehicles[1]	Generic off-road transportation technology	2012	-	-	N/A	N/A
		2050	-	-	N/A	N/A
Road, Freight, Light Trucks	Light trucks; freight (gasoline, diesel, NGL, natural gas, gasoline hybrid, diesel hybrid, ethanol, cellulosic ethanol, biodiesel, FT diesel, plug-in gasoline hybrid, plug-in diesel hybrid, all electric)	2012	9.8 - 18.1	27 000 - 39 530	1.9 - 11.8	50 050 - 193 100
		2050	6.7 - 11.2	31 320 - 40 970	1.1 - 8.4	48 680 - 123 950
Road, Freight, Medium Trucks	Medium trucks (gasoline, diesel, NGL, natural gas, gasoline hybrid, diesel hybrid, ethanol, cellulosic ethanol, biodiesel, FT diesel, plug-in gasoline hybrid, plug-in diesel hybrid, all electric)	2012	16.8 - 29.4	57 240 - 70 000	5.9 - 19.6	88 470 - 165 600
		2050	11.2 - 18.1	57 240 - 72 000	2.4 - 13.8	86 040 - 146 960
Road, Freight, Heavy Trucks	Heavy trucks (diesel, NGL, natural gas, diesel hybrid, biodiesel, FT diesel, plug-in diesel hybrid, all electric, hydrogen)	2012	21.4 – 47.0	232 200 - 1 016 120	N/A	N/A
		2050	18.1 - 39.2	232 200 - 827 640	N/A	N/A
Rail, Freight	Freight trains (Diesel, biodiesel, FT diesel, electric)	2012	1809.3	761 000	1176.1	860 000
		2050	1809.3	794 000	1176.1	897 000
Rail, Passenger	Passenger trains (Diesel, biodiesel, FT diesel, electric)	2012	1809.3	740 000	1176.1	851 000
		2050	1809.3	772 000	1176.1	888 000
Air, Passenger, Domestic	Passenger planes (aviation gasoline, aviation turbo fuel, biojet)	2012	940.9	18 200 000	N/A	N/A
		2050	392.0	74 700 000	N/A	N/A
Air, Passenger, International	Passenger planes (aviation gasoline, aviation turbo fuel, biojet)	2012	940.9	18 200 000	N/A	N/A
		2050	392.0	74 700 000	N/A	N/A
Air, Freight, Generic	Freight planes (aviation gasoline, aviation turbo fuel, biojet)	2012	1383.6	18 000 000	N/A	N/A
		2050	635.7	88 200 000	N/A	N/A
Marine, generic[1]	Generic marine transportation technology	2012	-	-	N/A	N/A
		2050	-	-	N/A	N/A

1. Generic technology represented to capture fuel consumption only (and not via techno-economic attributes). N/A = Not applicable (no technology existing for the category).
2. Efficiency values of the plug-in hybrid vehicles using an internal combustion engine along with an electric battery.

Fuel options and infrastructure. There are several fuels available for consumption by technologies in each end-use demand category. The list includes the main conventional fuels used in the 2011 base-year (gasoline, diesel, natural gas and natural gas liquids (NGL), ethanol and biodiesel) and alternative fuels such as electricity for plug-in hybrid and all electric vehicles, second generation biofuels (cellulosic ethanol and FT biodiesel) and hydrogen. The distribution network of each fuel is represented through generic technologies accounting for the actual infrastructure and possible investments in new infrastructure.

Transport electrification also requires charging infrastructure in order to recharge plug-in hybrid and all electric vehicles. Different types of charging stations are modelled for both residential, commercial and public usages:

- Residential stations represent a mix of typical level 1 charging stations (110/120 volts) allowing a full recharge in about 12 hours and level 2 charging stations (220/240 volts) allowing a full recharge in about 3 to 5 hours. All plug-in hybrid and electric vehicles sold in North America have both level options (CAA, 2014). Investment costs vary between $340 per kW and $1112 per kW.
- Commercial and public stations represent a mix of typical level 2 and level 3 fast charging stations (480 volts) available in large urban areas and allowing a 80% recharge in less than 30 minutes (CAA, 2014). Availability factors of each type of station are set up in a way to reflect greater charging activities at night in residential areas and during the day in commercial and public areas. Investment costs vary between $589 per kW and $1729 per kW.

Electrification of transport modes that do not rely on battery and charging stations but are directly connected to the grid (railcars and subways) are modelled in a more generic way than other fuels: generic technologies account for the actual infrastructure (which is very limited) and possible investments in new infrastructure at a cost of about $5.75 million per km and using the average number of kilometers between major cities (e.g. Montreal-Quebec, Calgary-Edmonton, etc.).

The hydrogen supply chain is modelled in detail including centralized and decentralized production from natural gas and water electrolysis, transportation and distribution in liquid or gaseous forms, and consumption in the heavy trucking transportation sector (fuel cells). Hydrogen is currently not used in Canada and this new option is expensive since the entire supply chain needs to be built before hydrogen becomes available in the transportation sector as an option to reduce GHG emissions. Investment costs for hydrogen production vary between $2.17 per GJ and $11.25 per GJ depending on the technologies while the operation and management costs vary between $0.42 per GJ and $3.50 per GJ. Investment costs for transportation by railcars or trucks and distribution vary between $0.44 per GJ and $14.50 per GJ while operation and management costs vary between $0.77 per GJ and $19.34 per GJ (Dodds and McDowall, 2012; USDOE, 2014).

Policy implications

All scenarios including the reference scenario implicitly take into account the most recent perspectives related to energy projects under development or already committed for the near future, and energy and environmental policies already in place in the different provinces and territories. In the transportation sector, this includes the renewable fuel regulation and the CAFE standards.

Renewable fuel requirements. Following federal legislation (Government of Canada, 2010), a constraint requires that gasoline contains a minimum of 5% renewable fuels and diesel a minimum of 2% renewable fuels. This requirement applies to the fuels sold in Canada globally allowing some jurisdictions to compensate for others that have less potential for biofuel production and consumption. Consequently, at the technology level, all conventional gasoline vehicles can use a mix of 5% ethanol, while all conventional diesel vehicles can use a mix of 2% biodiesel. Constraints are added to account for the provincial regulations:

- Gasoline: 5% of renewable contents in Ontario, Alberta and British Colombia; 8.5% in Manitoba; 7.5% in Saskatchewan.
- Diesel: 2% of renewable contents in Alberta, Manitoba and Saskatchewan; 4% in British Colombia.

CAFE Standards. The CAFE standards are implemented as a constraint in all scenarios. The CAFE standards were introduced in the United States in 1975 as an attempt to lessen the dependency on foreign oil (a reaction to the 1973-74 oil embargo). They consist of yearly targets for vehicle efficiency for different vehicle classes. Canada has decided to adopt the same standards for its vehicles until 2025, the last year of the current rules presented by the Obama administration. We keep these standards constant between 2025 and 2050

Table 10 shows the CAFE standards efficiency targets for years 2012 to 2025 in litres per 100 km (l/100 km). Note that efficiency for CAFE standards are calculated in a slightly different manner than how car manufacturers advertise efficiency (the equivalent manufacturer's window efficiency).

Table 10. CAFE standards for years 2012-2025

Year	Passenger Cars l/100 km		Light Trucks l/100 km	
	Small	**Large**	**Small**	**Large**
2012	6.5	8.4	7.8	10.7
2013	6.4	8.3	7.6	10.5
2014	6.2	8.1	7.4	10.2
2015	6.0	7.8	7.1	10.0
2016	5.7	7.6	6.9	9.6
2017	5.3	7.1	6.5	9.4
2018	5.2	6.9	6.4	9.4
2019	5.0	6.7	6.2	9.4
2020	4.8	6.5	6.0	9.4
2021	4.6	6.2	5.6	9.4
2022	4.4	5.9	5.3	9.0
2023	4.2	5.6	5.1	8.7
2024	4.1	5.3	4.9	8.3
2025	3.9	5.1	4.7	7.8

Source: Converted from NHTSA, 2011.

4.2.2 Mitigation Measures

The main mitigation options for the transport sector include increased vehicle efficiency, electrification and substitution of traditional fuels by biofuels.

Energy efficiency improvements. In all end-use demand categories, the model can invest in more efficient versions of technologies in order to reduce fuel consumption and emissions.

Road passenger. Electric motors are approximately three to four times more efficient than internal combustion engines (USDOE, 2014), and, when coupled with a decarbonized electricity supply system, electric vehicles are non-emitting. They represent the most feasible mitigation option for reducing emissions from road passenger vehicles (except for long distance intercity buses for which there is no electrification option in the model database). Higher biofuel blend rates than the minimum requirements is also an option available: up to 10% for ethanol and up to 5% for biodiesel. There are no limits for second generation biofuels (FT diesel and cellulosic ethanol) as they are direct substitutes for petroleum based fuels.

Road freight. Electric vehicles remain a viable option for light and medium freight trucks, however, heavy freight truck electrification is not feasible due to the longer travel distances and greater weight being transported. There are two main feasible mitigation options for heavy freight: biofuels and hydrogen.

- Biofuels are a cost effective option but have limited GHG emission reduction potential. First generation biodiesel is limited to a maximum of 30% of the fuel mix by 2050 and thus a majority of the emissions are still emitted. This is based on the fact that the cloud point of biodiesel is lower than traditional petroleum-based diesel and it was observed through several projects that a fuel mix containing more than 10% biodiesel would be problematic for internal combustion engines operating in colder weather (Lagace, 2014). This 30% theoretical maximum for 2050 is very optimistic considering that the maximum concentration is currently limited to 10% for a portion of the year in Canada (during cold weather up to -29°C), but could be increased up to 20%-40% during milder periods. Second generation biofuels, on the other hand, can be used as a direct substitute for traditional gasoline and diesel, and, therefore, are not constrained by fuel mix requirements (FT diesel can constitute 100% of a trucks fuel consumption). However, the limited feedstock available in Canada for FT diesel production (along with other biomass-to-energy uses) means that complete substitution of traditional diesel use for heavy freight is not possible.
- Hydrogen engine-based heavy trucks are a significantly costlier mitigation option; however, they are not limited by fuel mix constraints or limited feedstock supply as is the case with biofuels.

Rail. Rail transport mitigation options include biofuels and electrification. Biofuels can be used to substitute fossil fuel consumption, however the potential of this option is constrained by limited feedstock supply. Electrification represents a more costly option as current railway systems would need to be changed to include an electricity transmission system.

Air. Air transport mitigation options include investments in more efficient planes and the use of biojet fuel to substitute traditional jet fuel starting from 2020. As is the case with biofuels in general, biojet fuel production must compete with other biofuel applications, including heavy-duty transport.

Marine. Marine transport also has the option of using biofuels to substitute for heavy fuel oil consumption.

4.3 Residential, Commercial and Agriculture Sectors

4.3.1 Sector Description

These sectors cover:

- Commercial: "Public administration includes all establishments of federal, provincial and municipal governments primarily engaged in activities associated with public administration. NAICS code 91. The commercial and institutional activities include final consumers other than those listed above. This includes service industries related to mining, transportation, as well as storage and warehousing, communications and utility (excluding electricity and natural gas), wholesale and retail trade, finance and insurance, real estate and business service, education, health and social services and other service industries." (Statistics Canada, 2011).
- Residential: "Residential includes all personal residences including single family residences, apartments, apartment hotels, condominiums and farm homes." (Statistics Canada, 2011).
- Agriculture: "Agriculture includes all establishments primarily engaged in agricultural, hunting and trapping activities. NAICS codes 111, 112, 1142, 1151 and 1152. Excluded are any operations primarily engaged in food processing, farm machinery manufacture and repair." (Statistics Canada, 2011).

These sectors are made up of 37 end-use demand categories representing Canada's residential, commercial and agriculture services (Table 11). In the residential sector, three of the end-uses (space heating, space cooling, and water heating) are differentiated by dwelling types (single detached houses, single attached houses, apartments and mobile homes). Demand is specified in either PJ of output or in Mt.

Table 11. End-use demands in the residential, commercial and agriculture sectors

Description	Unit
Commercial	
Space heating	PJ
Water heating	PJ
Space Cooling	PJ
Lighting	PJ
Street lighting	PJ
Auxiliary Equipment	PJ
Auxiliary Motors	PJ
Other Services	PJ
Residential	
Space heating - Single - detached house	PJ

Description	Unit
Space heating - Single – attached house	PJ
Space heating - Multi – apartment	PJ
Space heating - Mobile Homes	PJ
Space cooling - Single - detached house	PJ
Space cooling - Single – attached house	PJ
Space cooling - Multi – apartment	PJ
Space cooling - Mobile Homes	PJ
Water heating - Single - detached house	PJ
Water heating - Single – attached house	PJ
Water heating - Multi – apartment	PJ
Water heating - Mobile Homes	PJ
Lighting	PJ
Refrigeration	PJ
Freezing	PJ
Dish washing	PJ
Cloth washing	PJ
Cloth drying	PJ
Cooking	PJ
Other electric	PJ
Agriculture	
Grains and Oilseeds	Mt
Dairy	Mt
Beef	Mt
Hog	Mt
Poultry	Mt
Eggs	Mt
Fruit	Mt
Vegetables	Mt
Other	Mt

Technologies and fuels

Heating & cooling systems, appliances. The different technologies that are in competition to satisfy each commercial and residential end-use demand are listed in Table 12 which include two key technological parameters: efficiency range (%) and investment cost range ($ per GW for all space heating, space cooling and water heating demands; $ per thousand units for the others). In addition to the existing technologies present in the 2011 base year, there is a repository with several new technologies available after 2011 to satisfy the increase in demand and/or to replace those which have reached the end of useful life. This repository includes identical or improved versions of existing end-use devices, and new technologies not existing in the 2011 base year. For instance, the new technology repository for residential lighting comprises standard fluorescents, fluorescents with improved efficiency and new electron stimulated luminescence devices. For new devices, greater distinctions are made regarding efficiency, and consequently, more versions of the same devices are introduced in the database such as standard, improved, energy star, and maximum potential efficiency.

It is important to note that there are many other technological parameters included in the model which are not shown and which allow for a highly detailed representation of the residential and commercial sectors, such as: operating and maintenance annual costs, availability factor, useful life, starting year of availability on the market, etc. Technology data are taken from different sources depending on the parameter. The OEE (2011) *Comprehensive Energy Use Database* provides data on the commercial floor space, existing stocks of heating and cooling systems with respective efficiency and total number of residential appliances. Estimates on stock numbers per fuel and efficiency category were refined through several model iterations. Other model databases such as TIAM (TIMES Integrated Assessment Model) and PET (the Pan-European TIMES model) and expert assumptions are used to complete the information required to effectively characterize the residential & commercial sectors at the 2011 base year: start year of availability on the market, availability factors, dual fuel shares and dual demand shares (for those technologies that can satisfy two demands, namely heat pumps for space heating and cooling). Useful life of technologies are taken from the CanESS model (whatIf? Technologies, 2014).

Regarding the new technologies, all cost attributes and energy efficiency improvements were specified using numerous data sources: research reports, retailer websites, customer guide, and personal communications with entrepreneurs in construction and renovation. Data for energy efficiency improvements were derived from the Energy Outlook Database of the Energy Information Administration (EIA, 2014). Finally, a lot of information comes from the Technology briefs of the ETSAP (2014) and to a lesser extent from the Energy Technology Perspective of the IEA (2012a).

Table 12. Technologies available in the commercial and residential sectors

End-use demand	Technology & Fuel	Efficiency (%)		Investment cost ($ / kw or k units)	
		Min	Max	Min	Max
Space heating	Oil furnace	67%	84%	$356	$397
	Oil combined boiler	80%	84%	$1,875	$1,969
	Wood stove	55%	65%	$417	$724
	Wood combined boiler	79%	83%	$1,786	$2,067
	NGL fire place	52%	58%	$2,000	$3,308
	Natural gas furnace	81%	89%	$356	$416
	Natural gas heat pump	82%	87%	$721	$1,173
	Natural gas combined boiler	79%	83%	$1,786	$2,067
	Electric baseboard	100%	100%	$45	$45
	Electric furnace	100%	100%	$344	$398
	Electric heat pump	100%	100%	$721	$835
	Geothermal heatpump	100%	100%	$8,388	$11,507
	Solar collector with backup	82%	100%	$2,567	$2,994
	Heat exchanger	90%	90%	$721	$721
Water heating	Oil system	79%	79%	$337	$337
	Wood system	52%	52%	$337	$337
	Natural gas furnace	82%	82%	$337	$337
	Heat exhanger	90%	90%	$338	$338
	NGL storage tank	52%	52%	$160	$160
	Natural gas storage tank	82%	88%	$105	$250
	Electric storage tank	92%	98%	$105	$250
	Solar collector with backup	100%	100%	$1,103	$1,796
Space Cooling	Air conditioner (central, wall unit).	100%	100%	$793	$918
Lighting	Incandescent, halogen, fluorescent, compact fluorescent, light emitting diode, solar lamp.	100%	100%	$0.0004	$0.0550
Street lighting	Generic street lighting technology.	100%	100%	$0.05	$0.07

End-use demand	Technology & Fuel	Efficiency (%)		Investment cost ($ / kw or k units)	
		Min	Max	Min	Max
Auxiliary Equipment	Generic auxiliary equipment technology (natural gas, heat, light fuel oil, heavy fuel oil, natural gas liquid, electricity).	50%	100%	$0.05	$0.07
Auxiliary Motors	Generic auxiliary motors technology (electricity).	100%	100%	$0.01	$0.69
Other Services	Generic other services technology.	100%	100%	n/a	n/a
Space heating	Oil furnace	79%	88%	$356	$397
	Wood stove	55%	75%	$417	$724
	Pellet wood stove	80%	90%	$5,571	$8,357
	NGL fire place	55%	64%	$2,000	$3,308
	Natural gas furnace	81%	95%	$356	$416
	Natural gas heat pump	92%	95%	$1,064	$1,173
	Electric baseboard	100%	100%	$45	$45
	Electric furnace	100%	100%	$344	$398
	Electric heat pump	100%	100%	$721	$835
	Geothermal heat pump	100%	100%	$8,388	$11,507
	Solar collector with backup	80%	100%	$2,567	$2,994
	Heat exhanger	90%	90%	$721	$721
Space cooling	Central air conditioning, window unit, wall unit.	98%	100%	469$	833$
Water heating	Oil system	79%	79%	$337	$337
	Wood system	52%	52%	$337	$337
	NGL storage tank	52%	52%	$167	$167
	Natural gas storage tank	82%	88%	$105	$250
	Electric storage tank	100%	100%	$105	$250
	Natural gas tankless system	84%	90%	$32	$75
	Electricity tankless system	100%	100%	$35	$83
	Solar collector with backup	100%	100%	$1,103	$1,796
Lighting	Incandescent light bulbs, Halogen light bulbs, Fluorescent light bulbs, compact fluorescent lamp, light emitting diode, solar lamp.	100%	100%	$0.0004	$0.0550
Refrigeration	510 litres without freezer, 510 litres with freezer, Energy Star 510 litres.	100%	100%	$0.55	$0.85
Freezing	Standard freezer, Energy Star freezer.	100%	100%	$0.50	$0.70

End-use demand	Technology & Fuel	Efficiency (%)		Investment cost ($ / kw or k units)	
		Min	Max	Min	Max
Dish washing	Standard dishwasher, Energy Star dish washer.	100%	100%	$0.36	$0.42
Cloth washing	Standard washing machines, combined washers and dryers.	100%	100%	$0.65	$1.30
Cloth drying	Electric dryer, natural gas dryer.	100%	100%	$0.60	$0.98
Cooking	Electric range, natural gas range, propane range.	55%	100%	$0.93	$1.19
Other electric	Other electric equipments	100%	100%	$0.20	$0.28

Conservation methods. The model has the option of investing in conservation methods for residential and commercial buildings in order to improve efficiency. Investing in conservation technologies (Table 13) allows for end-use demands to be satisfied with less energy input. For example, better wall insulation will lead to less heat being needed to sustain the desired temperature. Cost per PJ can be interpreted as being the cost for satisfying one PJ of end-use demand via the corresponding conservation technology.

Table 13. Conservation technologies in the residential and commercial sectors

Type	Investment cost per PJ	
	Residential	**Commercial**
Programmable thermostats	$2,245	$2,245
Duct sealing low	$1,860	$2,325
Duct sealing base	$1,937	$2,422
Duct sealing high	$2,325	$2,906
Roof insulation low	$2,872	$6,902
Roof insulation base	$3,590	$8,628
Roof insulation high	$4,267	$9,155
Wall insulation low	$4,308	$10,353
Wall insulation base	$4,445	$11,444
Wall insulation high	$5,334	$13,732

Technologies in agriculture. The agricultural sector is characterized by a set of generic technologies with calibrated energy inputs and outputs following Statistics Canada data on agriculture fuel consumption per end-use demand category (I.e.: energy inputs required for output of beef production). Fuel consumption in each end-use demand category is disaggregated into energy services (transport, machinery, heating & lighting, complementary and non-farm) and there is one generic technology representative for each possible combination fuel/energy service in each end-use demand category.

For the new technology repository, the generic technologies calibrated to 2011 Statistics Canada data are modified to allow for an increasingly flexible fuel mix as energy input through time. For example, the technology which provides heating and lighting for beef production can use an increasing amount of electricity for its fuel mix, and this fuel mix flexibility increases over time, from 2011 to 2050.

Fuel options and infrastructures. There are several fuels available for consumption by technologies in each end-use demand category. The list includes the main conventional fuels used in the 2011 base-year (fuel oil, biomass, natural gas, NGL, electricity, etc.) and alternative fuels such as solar and geothermal for heating systems. The distribution network of each fuel is represented through generic technologies accounting for the actual infrastructure and possible investments in new infrastructure. There are more fuel options for some end-use demands than others: space and water heating for instance can be satisfied through almost any types of fuel. However, space cooling, lighting and most of the appliances consume mainly electricity; only a small amount of natural gas is consumed for cooking and clothes drying.

4.3.2 Mitigation Measures

In the commercial and residential sectors, mitigation measures are:

Energy efficiency. Within homes and buildings, energy efficiency improvements and energy savings can be achieved by replacing existing end-use devices by more efficient ones, including (Pembina Institute, 2011; NREL, 2013a):

- Energy-efficient systems for heating, cooling and refrigeration: While energy conservation measures can generate important demand reductions for heating cooling and refrigeration, replacement of standard heating, cooling and refrigeration systems can generate important energy savings.
- Efficient lighting devices: Major energy savings can be achieved using more efficient lighting devices in the residential sector, but even more in the commercial sector especially where demand for lighting building and streets is higher. For instance, replacing incandescent bulbs by compact fluorescent or LED devices can generate energy savings through consumption reductions between 69 and 75%.
- Energy Star appliances: Total potential energy savings associated with the replacement of standard appliances by Energy Star appliances can reach 10 to 50%. Efficiency standards, rebates and labelling measures need to be combined with awareness programs regarding potential energy and cost savings.
- Efficient auxiliary motors and equipment: Auxiliary motors include devices such as pumps, ventilators, compressors and conveyors that are mostly used for heating, cooling and refrigeration (and consequently covered in that corresponding section). Auxiliary equipment includes power supplied equipment (computers, printers, photocopiers, etc.) and other energy sources supplied equipment such as natural gas appliances. Replacing standard equipment with Energy Star products can generate important energy savings.

Energy conservation. In addition to fuel switches and increasing energy efficiency, the model can also invest in conservation methods, such as programmable thermostats and improved wall insulation, in order to decrease energy requirements for residential and commercial buildings. Since residential houses and commercial buildings consume a significant amount of fuel for space heating, space cooling and water heating, retrofit options for existing homes and buildings and standards and codes for new buildings are relevant options to achieve GHG emission reductions. Improvements of up to 25% can be reached in existing houses/buildings and up to 35% can be observed in new houses/buildings compared with existing typical houses (Pembina Institute, 2011).

Fuel switching. In addition to the potential energy savings associated with more energy efficient technologies, important GHG emission reductions can be achieved by replacing conventional fuels with cleaner fuels. Space and water heating are the end-use demands with the highest potential since the other demands consume mainly electricity. Fuel switching can occur in two ways: without replacement of heating devices (e.g. replacement of heating oil by a biofuel blend in a particular heating device) or with replacement of heating devices (e.g. replacement of an oil furnace by an electric heat pump system). Regarding fuel switching through replacement of end-use devices, new opportunities keep emerging with the penetration of advanced technologies on the market: wood pellet stoves, ground source heat pumps, geo-exchangers, solar thermal systems, passive solar water heating systems, hydrogen units, etc. The potential for GHG emission reductions will vary across provinces as fuel prices and availability are the main incentives for defining the optimal energy mix.

Distributed renewable electricity. Finally, generation of distributed electricity from renewable sources is gaining popularity where appropriate financial incentives are provided for both technology developers and consumers. This is the case for solar PV and wind turbines, for instance. Common applications include roof-top solar panels. The potential is high but nonetheless limited by the physical space required (e.g. size of rooftops or land).

In the agriculture sector, mitigation measures are:

Fuel switching. Since the agricultural sector is modelled through a set of generic technologies satisfying agricultural end-use demand, the only option for GHG emission mitigation is through the increased flexibility of fuel inputs for these technologies over time, more specifically, the substitution of fossil fuel use by electricity. These fuel switches simulate, for example, using electric motors for tractors and using electricity-based technologies for heating and lighting.

4.4 Industrial Sector

4.4.1 Sector Description

This sector covers the manufacturing industries and other mining industries (excluding oil & gas extraction), forestry and construction:

- "Total manufacturing - The summation of manufacturing industries.
    - Pulp and paper - Includes establishments primarily engaged in manufacturing pulp, paper and paper products. Up to and including 2003; NAICS codes 322111, 322112, 322122 and parts of 321216, 322121 and 322130. After 2003; NAICS code 322.
    - Iron and steel - Establishments primarily engaged in operating blast furnaces, casting mills, rolling mills or coke ovens operated in association with blast furnaces including steel foundries. Up to and including 2003; NAICS codes 331110, 331221 and 331514. After 2003; NAICS codes 3311, 3312 and 33151.
    - Smelting and refining, non-ferrous - Establishments primarily engaged in the production of aluminum and the refining of non-ferrous metals. Up to and including 2003; NAICS codes 331313 and 331410. After 2003; NAICS codes 3313, 3314 and 33152.
    - Cement - Establishments primarily engaged in manufacturing cement. NAICS code 327310. This classification does not include ready-mix concrete operations, which is included in Other Manufacturing.
    - Chemicals - Establishments primarily engaged in manufacturing industrial organic and inorganic chemicals and chemical fertilizers. Up to and including 2003: NAICS codes 325110, 325120, 325130, 325181, 325189, 325313 and parts of 325190, 325210, 325410 and 325610.After 2003: NAICS code 325.
    - Other manufacturing - All other manufacturing industries (NAICS codes 31, 32 and 33) not listed above. In some instances, this classification is used when no breakdown of the component manufacturing industries is provided." (Statistics Canada, 2011).

- "Other industries:
    - Forestry - Establishments primarily engaged in forestry and logging services. NAICS codes 113 and 1153.
    - Construction - Establishments primarily engaged in the construction of buildings, highways, dams, etc., and those providing services to the construction industry. Special trade contractors primarily engaged in construction work is such specialties as plumbing, carpentry, painting, etc. are included here. NAICS code 23. Sales of asphalt (in Non-energy refined petroleum products table) for paving purposes, regardless of the purchaser, are included here." (Statistics Canada, 2011).
- Other mining industries: "Comprises establishments primarily engaged in extracting naturally occurring minerals. This includes metal mines, non-metal mines, coal mines, crude petroleum and natural gas extraction industries, stone quarries gravel pits, exploration for minerals, development of mineral properties and contract drilling operations. NAICS code 21." (Statistics Canada, 2011).

Energy consumption for petroleum refining and oil and gas extraction is extracted from total manufacturing and included in the supply sector.

The industrial sector is made up of 13 end-use demand categories representing Canada's industrial services (Table 14). Demand is specified in either Mt or PJ.

Table 14. End-use demand for energy services in the industrial sector

Description	Unit
Pulp and Paper - high quality	Mt
Pulp and Paper - low quality	Mt
Iron and Steel	Mt
Non Ferrous Metals: Aluminium	Mt
Non Ferrous Metals: Copper	Mt
Non Ferrous Metals: Others	Mt
Cement	Mt
Chemicals: Ammonia	Mt
Chemicals: Chlorine	Mt
Chemicals: Others	Mt
Other Manufacturing Industries	PJ
Other Industries	PJ
Other Mining Industries	PJ

Technologies and fuels

Industries are divided into different categories: energy intensive industries (iron & steel, non-ferrous metals, pulp & paper, cement and chemicals), other manufacturing industries, other industries (forestry and construction) and other mining activities (excluding oil& gas extraction). For the energy intensive industries, a process-oriented structure capturing energy and material flows along the supply chain was adopted whereas for non-energy intensive industries fuel uses are modelled through more generic processes where inputs are exogenous mixes of the following five energy services: steam (boilers), process heat, machine drive, electrochemical and others processes.

The different technologies that are modelled in each energy intensive industry are shown in Table 15, which gives indications on investment cost range ($ per Mt). In addition to the existing technologies which are present in the 2011 base year, there is a repository with new technologies available after 2011 to satisfy the increase in demand and/or to replace those which have reached the end of useful life. This repository includes improved versions of existing technologies and new technologies with more fuel options such as biofuels to replace fossil fuels. In the non-energy intensive industries, there is one representative technology for each possible combination fuel/energy service in each industry.

Table 15. Technologies available in the energy intensive industrial sectors

End-use demand	Technology and Fuel	Investment cost ($/Mt)	
		Min	Max
Pulp and Paper - high quality	High quality paper production, mechanical pulp production, Chemical pulp production, recycling pulp production.	$324	$7,868
Pulp and Paper - low quality	Low quality paper production, mechanical pulp production, Chemical pulp production, recycling pulp production, process kilns.	$324	$7,868
Iron and Steel	Finishing processes, argon oxygen furnace, ferrochrome smelting furnace, blast oxygen furnace, electric arc furnace, cast iron cupola, iron blast furnace, cyclone converter furnace, pellet production, sinter production.	$54	$1,080
Non Ferrous Metals: Aluminium	Finishing processes, Hall Heroult process standard, Hall Heroult process with point feeders, Hall Heroult process with optimal Electrolysis, Hall Heroult process with reduced electrolyte temperature, inert anodes, recycling production standard, recycling production with scrap pre-heat, recycling production with enhanced furnace.	$540	$5,643
Non Ferrous Metals: Copper	Finishing processes, regular production, recycling production.	$540	$5,702
Non Ferrous Metals: Others	Generic other non-ferrous metals production technology.	$3,166	$3,166
Cement	Finishing processes, dry process production, wet process production.	$11	$3,482
Chemicals: Ammonia	Standard production, advanced production, advanced production with CO_2 capture.	$297	$428
Chemicals: Chlorine	Standard membrane production, advanced membrane production, standard mercury production, standard diaphragm production.	$810	$1,418
Chemicals: Others	Generic other chemicals production technology.	$763	$840

The structure of the industrial sector was defined based on the Pan-European model database (Loulou et al, 2005b) with adaptations to the Canadian context. The global energy consumption data come from the main energy balance of Statistics Canada (2011). Due to the high level of confidentiality of data in this sector, energy consumption data were disaggregated and allocated to the different industrial processes using the historical data of the CanESS model (whatIf? Technologies, 2014). Some technology data come from the Technology briefs of the ETSAP (2014).

4.4.2 Mitigation Measures

The options for industry related GHG emission mitigation are limited in the model due to the manner in which this sector is represented. There are three ways in which emissions in this sector can be reduced: electrification, efficiency improvements, and substitution of fossil fuels for biofuels and biomass.

Electrification. First, GHG emissions can be reduced through electrification of industrial processes. However, the extent to which this transformation can be implemented is limited when compared to other end-use sectors. In the industrial sector, as is the case with the agricultural sector, fuel switching (including electrification) are determined by constraints on the ratio of each fuel type consumed in the sector. The flexibility of the constraint on fuel mixes increases with time, which allows for more electricity to be consumed in proportion to other fuels. The electrification potential is based on the base year's maximum amount of electrification of industrial processes across jurisdictions. For instance, the highest amount of electrification in a jurisdiction was often used as the upper limit of electrification potential for all other jurisdictions. The argument behind this assumption is a technical one: if a particular industry can be electrified up to a certain percentage in a jurisdiction, it means it is technically feasible to reach that level. This assumption is conservative since more advanced technologies are expected to become available in the longer term. However, this was a more reasonable assumption to make in the actual context with a lack of data.

Energy efficiency. Second, industry-related GHG emissions can be reduced by replacing current technologies with more efficient versions of the same technology. The model can invest in these improved versions of existing technologies in order to reduce energy consumption in the industrial sector. Efficiency improvements have an increased importance when the electrification potential is unknown as they reduce the remaining fossil fuel consumption related to processes which are not electrified.

Biofuels and biomass. Finally, the model can replace its fossil fuel consumption by consuming biofuels and biomass. Biofuels can be used to replace any processes relying on gasoline or diesel, and biomass can be used to replace fossil fuels used for heat generation. This option also represents an additional way of overcoming the limited electrification potential by allowing for the substitution of remaining fossil fuel consumption, after the potential for electrification of industrial processes is reached, by biofuels and biomass.

4.5 Electricity Supply and Delivery

4.5.1 Sector Description

The electricity sector covers production of electricity and heat by utilities and industries. The total installed capacity, electricity generation and fuel consumption by jurisdiction is calibrated using the main balance of Statistics Canada (2011) for primary electricity (hydro, nuclear, wind, tidal and solar), thermal electricity and additional sources (Statistics Canada, 2013a; 2013b; 2013c).

Technologies and fuels

Existing power plants. The model database depicts individually all existing electricity plant units of more than 50 MW in Canada, in addition to units already planned for construction or refurbishment in future years (Table 16). A total of 670 existing technologies are modelled. The list of units and installed capacity comes from various sources including CBC (2014), Canadian Wind Energy Association (2014) and the websites of the main utilities in each jurisdiction. Efficiency and annual availability factors are the theoretical values coming from the power generation industry.

New power plants. A repository of several new types of electricity generating technologies has been created to analyze the replacement of existing capacity at the end of lifetime or the addition of new capacity to meet the additional demand for electricity. The repository includes all the different types of thermal, nuclear, biomass and renewable power plants that can potentially be built in Canada in the near future (e.g. more efficient version of the existing plants), or that are assumed to become available in later years (e.g. wave power generation). Table 17 shows the different technologies included in the model which produce electricity along with characteristics for each type of fuel source. Technical and economic attributes over time come from NREL (2012a), EIA (2013b). In addition, NREL (2013b) and IEA (2014) are used for the cost evolution of solar power.

Table 16. Categories of power plant generation units existing in 2011

Source	Unit type	Efficiency[1]	Availability factor[2]	Life
		%	%	Years
Coal	Un-scrubbed coal steam, Coal steam with scrubber, Pulverized coal, Integrated Gas Combined Cycle	30%-38%	85%	50
Distillate	Distributed electricity generation	25%	85%	50
Residual fuel	Oil combustion turbine, Oil steam	27%-45%	85%	50
Natural gas	Gas steam, Gas combustion turbine, Gas combined cycle	25%-38% 45%-60%	88%	50
Nuclear	Conventional nuclear unit	32%	84.5%	30
Biomass	Biomass/wood plant	28%	85%	40
Municipal solid waste	Municipal solid waste plant	26%	90%	50
Biogas	Biogas plant	22%-26%	90%	50
Hydro	Conventional hydro	90%	26% (AB) 58% (BC) 78% (MB) 55% (SK) 46% (NB) 68% (NL) 33% (NS) 48% (ON) 56% (QC) 56% (NT) 56% (NU) 65% (YT)	100
Wind	Wind farm	100%	25%-33% (all) 37% (YT) 40% (PE) 68% (NL)	40
Solar	Solar photovoltaic plant	100%	11.8% (ON)	40
Tidal	Tidal plant	100%	33%	40

1. Efficiency values refer to electricity generation only and do not account for heat production with cogeneration. Efficiencies of wind, solar and tidal power (100%) is based on the output and do not reflect the real conversion efficiency of the turbine.
2. Availability factors represent the maximal fraction of the year a technology is technically available for electricity generation (100% = 365 days * 24 hours = 8760 hours). These factors account for plant closures for maintenance reasons and resource limitation (wind and solar). More information is provided in Section 3.4.2 and 3.4.3. Hydro, wind and solar plant units are characterized by different values of the availability factor for different time slices.

Table 17. New power plant technologies

Technology	Life	Investment cost 2012[1]	Investment cost 2020	Investment cost 2050	Fixed O&M cost 2012	Fixed O&M cost 2050	Variable O&M cost	EFF	AF[2]
	Years	$/kW	$/kW	$/kW	$/kW	$/kW	$/MWh	%	%
Hydro: run of river	100	$5,486	$5,486	$5,486	$24.2	$24.2		90%	37%
Hydro: conventional dam large	100	$4,988-7,481	$4,988-7,481	$4,988-7,481	$17.1	$17.1	$0.6	90%	65%
Wind: onshore Turbine	30	$2,762	$2,762	$2,762	$68.4			100%	37%
Wind: offshore fix foundation	30	$4,278	$4,103	$3,848	$114.0			100%	38%
Wind: offshore floating structure	30		$5,300	$4,988		$148.2		100%	38%
Solar: photovoltaic fix 1MW	25	$4,472	$2,847	$1,529	$57.0	$49.0		100%	13%
Solar: photovoltaic fix 10MW	25	$3,731	$2,460	$1,349	$57.0	$49.0		100%	13%
Solar: photovoltaic fix 100MW	25		$2,335	$1,290		$49.0		100%	13%
Solar: photovoltaic rotating 1axis 1MW	25	$4,860	$3,050	$1,624	$57.0	$49.0		100%	14%
Solar: photovoltaic rotating 1axis 10MW	25	$4,028	$2,615	$1,421	$57.0	$49.0		100%	14%
Solar: photovoltaic rotating 1axis 100MW	25		$2,506	$1,370		$49.0		100%	14%
Geothermal: hydrothermal dual flash steam	50	$6,243	$6,243	$6,243	$132.0	$132.0	$17.7	90%	75%
Geothermal: hydrothermal binary cycle	50	$4,362	$4,362	$4,362	$100.0	$100.0	$15.9	90%	75%
Geothermal: enhanced geothermal systems	50		$11,081	$9,599	$132.0	$132.0	$17.7	90%	75%
Nuclear: reactor fission	40	$8,693	$8,693	$8,693	$144.8	$144.8	$2.0	32%	85%
Wave: wave energy conversion	20		$7,934	$4,560		$237.1		100%	40%
Tidal: current sea generation turbine	25	$7,374	$4,970	$3,682	$225.7	$127.7		100%	30%
Biomass: combustion stoker boiler	30	$5,143	$5,143	$5,143	$105.6	$105.6	$1.1	35%	75%
Biomass combustion: fluidized bed boiler	30	$5,143	$5,143	$5,143	$105.6	$105.6	$1.1	35%	75%
Biomass gasification: integrated combined cycle	30	$8,180	$8,180	$8,180	$356.1	$356.1	$1.1	40%	75%
Biogas: landfill gas internal combustion engine	20	$2,104	$2,104	$2,104	$22.7	$22.7	$5.3	25%	75%
Solid waste plant	30	$8,312	$8,312	$8,312	$392.8	$392.8	$1.1	26%	75%
Wood pellet: combustion fluidized bed boiler	30	$5,143	$5,143	$5,143	$106.0	$106.0	$1.1	45%	75%

Technology	Life	Investment cost 2012[1]	Investment cost 2020	Investment cost 2050	Fixed O&M cost 2012	Fixed O&M cost 2050	Variable O&M cost	EFF	AF[2]
	Years	$/kW	$/kW	$/kW	$/kW	$/kW	$/MWh	%	%
Heavy fuel oil: steam turbine conventional	35	$1,727	$1,727	$1,727	$15.1	$15.1	$0.9	30%	60%
Heavy fuel oil: integrated gasification	35	$1,806	$1,806	$1,806	$28.0	$28.0	$1.0	30%	60%
Light fuel oil: distributed diesel engine	35	$757	$757	$757	$14.4	$14.4	$1.1	30%	60%
Natural gas: gas turbine combustion	35	$765	$765	$765	$6.0	$6.0	$1.1	40%	85%
Natural gas: combined cycle gas turbine	35	$1,402	$1,402	$1,402	$7.2	$7.2	$0.7	59%	85%
Coal: pulverized coal[3]	35	$3,295	$3,295	$3,295	$26.2	$26.2	$1.1	38%	86%
Coal: integrated gasification combined cycle[3]	40	$4,571	$4,571	$4,571	$47.4	$47.4	$1.5	40%	86%

1. Investment cost of hydro power varies across provinces: the cost being lower in BC, MB, NL, QC, medium in NB, NS, NT, PE SK and higher in AB, NU, ON, YT. Conventional hydro dam and nuclear technologies include an additional 25% accounting for the interest during construction time.
Cost of wind and solar power include an additional 25% to account for the cost of connecting each generating resource into the grid and the cost of upgrading the grid as additional investments are required in the transmission network. See more details in Section 3.4.5. The additional investment in the grid required corresponds to about 16% of the technology's investment cost, this number is taken from projections about future investments in infrastructure for electricity generation, transmissions and distribution in Canada (IEA, 2012b). There are no differential costs for distribution on the premise that this cost does not vary between scenarios.
2. Hydro, wind and solar plant unit are characterized by different values of the availability factor for different time slices. Thermal power plant have a minimum availability factor of 10% to avoid the model building new plants without any activity and to account for dependable capacity.
3. Although conventional coal-fired power plants are part of the database, they are not allowed to play any role in any scenario of the TEFP project without CCUS.

Pumped storage. There is currently only one existing pumped storage facility in Canada: Sir Adam Beck Pump Generating Station, which has an installed capacity of 174 MW. This is included in the model. There are also plans to build an additional 400 MW pumped storage facility in Ontario (Northland Power, 2014) and between 80 to 150 MW in Alberta (Hydroworld, 2014). These planned facilities were not included in the baseline as construction has not been officially confirmed. Additionally, the construction of new pumped storage facilities is possible in most provinces. Currently no limit on pumped storage potential has been set, therefore the creation of new pumped storage facilities is only bounded by cost parameters. Table 18 shows the technology parameters for a new pumped storage facility. As a way to store electricity between seasons, the pumped storage technology option allows the integration of a more significant proportion of intermittent renewables in the system.

Table 18. Pumped storage technology parameters

Name	Efficiency[1]	Life[1]	Investment Cost[2]	Fixed O&M Cost	Variable O&M cost	Availability Factor
Pumped Hydro	80%	100 years	$2,500 / KW	$18 / KW	$0.0023 / kWh	90%

1. Turn around efficiency (including losses from both pumping and generation) was chosen from the range of efficiencies present in the literature (65% to 85%). Operational life was also chosen from a range found in the literature of 50 to 100 years. Sources: Northland Power, 2014; Hydroworld, 2014; Mondaq, 2014; Deane et al, 2010.
2. Cost data taken and adapted from Mamora project costs (Financial Post, 2013).

Decentralized electricity. The model captures the existing amount of grid-connected solar PV generated in each jurisdiction at the base year. This generation capacity differs from centralized generating capacity in terms of the physical distance to the load served, i.e., decentralized electricity generating technologies are located closer to the load they serve. Options for decentralized electricity generating technology are currently limited to solar PV systems in the model. Note that the installed capacity of grid connected distributed solar PV systems has been allocated arbitrarily to the residential (80%) and the commercial (20%) sectors (Table 19). The availability factor is set to 14%.

Cost evolution for new capacity additions of grid-connected solar PV generation is shown in Table 20.

Table 19. Grid connected solar PV systems in 2012

MW	Total	Residential	Commercial
AB	2.181	1.745	0.436
BC	2.058	1.646	0.412
MB	0.265	0.212	0.053
NB	0.146	0.117	0.029
NL	0.000	0.000	0.000
NS	0.100	0.080	0.020
NT	0.210	0.168	0.042
NU	0.028	0.022	0.006
ON	257.400	205.921	51.480
PE	0.186	0.149	0.037
QC	0.212	0.170	0.042
SK	0.124	0.099	0.025
YT	0.049	0.039	0.010
Total	262.960	131.480	131.480

Source : Luukkonen et al, 2013.

Table 20. Solar PV cost assumptions

$/kW	Residential	Commercial
2011	$6791	$5955
2012	$6190	$5234
2013	$5589	$4514
2014	$5029	$4077
2015	$4469	$3629
2016	$3909	$3181
2017	$3360	$2733
2018	$2800	$2296
2019	$2240	$1848
2020	$1680	$1400
2025	$1540	$1283
2030	$1400	$1167
2035	$1260	$1050
2040	$1120	$933
2050	$1053	$877

Source: NREL, 2013b; IEA, 2014.

Resources

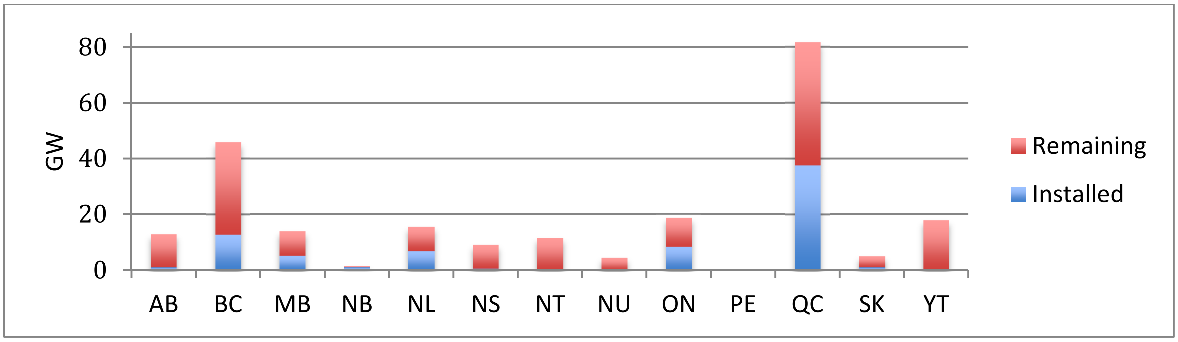
Cumulative renewable potentials. Total cumulative potential is specified for each limited energy source in order to impose a constraint on total investments over the whole horizon (Table 21). Consequently wind and solar are not limited resources and in excess of expected requirements to satisfy any minimum cost solution. This refers to the technical potential, i.e., the total quantity of available energy that could be produced using specific technologies, without taking into account technical constraints or socio-economic factors. This potential can be exploited to its upper limit in a flexible manner by the model with the different available technologies, predominantly conventional large scale hydro. Currently, the model database does not include the potential for additional hydro capacity at existing sites to meet future additional dependable capacity requirements - see Section 3.4.2.

Hydro potential estimations cover sites and rivers with low to high hydroelectric potentials (EEM, 2006). The total remaining potential is estimated to be 163.17 GW, more than double of the existing capacity in 2011 (Figure 22). The lowest cost opportunities are located in Quebec, Manitoba, British-Colombia, Newfoundland & Labrador and the Northwest Territories. There is substantial potential in several other jurisdictions, but at considerably greater cost (Ontario, Alberta, Nova Scotia), or distance (Yukon).

Table 21. Cumulative potential for renewable electricity by jurisdiction

GW	Hydro	Geothermal	Tidal	Wave
AB	12.68	1.50	-	-
BC	45.75	6.00	4.00	37.00
MB	13.81	-	-	-
NB	1.54	-	0.60	14.65
NL	15.34	-	0.50	58.60
NS	8.90	-	2.10	43.95
NT	11.55	-	-	-
NU	4.31	-	30.60	-
ON	18.62	-	-	-
PE	0.00	-	-	14.65
QC	81.56	-	4.30	14.65
SK	4.81	-	-	-
YT	17.74	1.50	-	-
Total	236.61	6.00	42.20	183.50

Figure 22. Technical potential for hydroelectricity and existing capacity in 2011



Source: EEM, 2006.

There is some geothermal potential in Western Canada due to the proximity to the Pacific Ring of Fire. Conventional geothermal potential in British Columbia could reach between 3.00 GW and 6.00 GW according to different sources (IPPBC, 2010; Western GeoPower Corp., 2010). The development of the 100 MW South Meager site is the only existing project (IPPBC, 2010). There is a small geothermal potential in Yukon of between 0.50 and 1.50 GW (Yukon Energy, 2009). Alberta also has some potential (Bell and Weis, 2009) that is arbitrarily estimated at 1.50 GW due to the lack of data.

Canada has a tidal potential of about 42.20 GW based on preliminary estimates of existing tidal flows (Tarbotton and Larson, 2006). The wave potential amounts to about 37.0 GW along the Pacific coast and about 146.50 GW along the Atlantic coast (CHC, 2006). Only a proportion of these potentials can be converted into electricity. These are mean power; there is a high variation of the tidal and waves resources on a daily and seasonal basis. For instance, wave power potential in winter can be six to seven times larger than in summer on the Pacific coast.

Variability of solar, wind and hydro resources. In the case of solar and wind, the potential for electricity generation is not limited by the availability of the primary resources. The contribution of solar and wind for electricity production will depend on geographical, technical, economical and implementation issues. However, due to some constraints on dependable capacity, these limits are never reached and there are no limits imposed on the availability of these two renewable sources.

The annual availability of solar energy varies across jurisdictions, while the maximum availability in each time slice is similar for all regions (Table 22). The maximum values were derived from the interactive maps of solar potential in Canada (NRCan, 2007) showing that Saskatchewan, Alberta and Manitoba have the best solar resource in Canada, with an average electricity generation potential of 1361 kWh per kW for Regina (SK), 1292 kWh per kW for Calgary (AB) and 1277 kWh per kW for Winnipeg (MB). There is no significant potential for concentrated solar power in Canada as it requires high direct solar irradiance.

The availability of wind energy differ both annually and by time slice (Table 23). Values were adapted from hourly data coming from the CanESS model (whatIf? Technologies, 2014), aggregated into time slices as defined in the NATEM-Canada model. Finally, availability varies across season for hydro dam and run-of-river technologies (Table 24). These seasonal availability factors are used as inputs into the model to account for the estimated distribution of hydro energy over an annual cycle.

Table 22. Availability factors by time slice for solar

	AB	BC	MB	SK	ON	QC	NB	NL	NS	PE	NT	NU	YT
Annual existing					11.8%								
Annual new fix axis	14.4%	12.3%	14.9%	15.1%	13.4%	13.1%	13.1%	10.9%	12.4%	12.7%	11.9%	11.7%	11.3%
Annual new rotating - 1 axis	15.1%	12.9%	15.7%	15.9%	14.1%	13.8%	13.7%	11.4%	13.0%	13.3%	12.5%	12.3%	11.9%
Spring – Day	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Spring – Night	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Spring – Morning peak	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Spring – Evening peak	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Summer – Day	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Summer – Night	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Summer – Morning peak	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Summer – Evening peak	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Fall – Day	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Fall – Night	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Fall – Morning peak	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Fall – Evening peak	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Winter – Day	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Winter – Night	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Winter – Morning peak	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Winter – Evening peak	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%

Source: Annual solar availability (NRCan, 2007).

Table 23. Availability factors by time slice for wind

	AB	BC	MB	SK	ON	QC	NB	NL	NS	PE	NT	NU	YT
Annual existing	33.0%	28.2%	33.0%	33.0%	25.0%	25.0%	25.0%	40.0%	25.0%	40.0%	0.0%	0.0%	37.0%
Annual new	33.8%	34.1%	35.8%	38.1%	29.3%	36.3%	39.5%	41.2%	38.3%	38.0%	41.2%	41.2%	41.2%
Spring – Day	42%	38%	41%	45%	36%	43%	48%	44%	38%	46%	44%	44%	44%
Spring – Night	24%	24%	31%	37%	23%	32%	30%	33%	36%	31%	33%	33%	33%
Spring – Morning peak	49%	41%	46%	45%	42%	45%	58%	44%	37%	47%	44%	44%	44%
Spring – Evening peak	40%	34%	39%	41%	31%	36%	44%	37%	37%	34%	37%	37%	37%
Summer – Day	34%	31%	35%	34%	26%	38%	37%	37%	31%	41%	37%	37%	37%
Summer – Night	15%	20%	22%	25%	13%	20%	18%	26%	28%	24%	26%	26%	26%
Summer – Morning peak	42%	38%	41%	37%	35%	40%	48%	39%	31%	39%	39%	39%	39%
Summer – Evening peak	32%	32%	30%	32%	24%	25%	33%	32%	28%	31%	32%	32%	32%
Fall – Day	36%	35%	41%	39%	30%	40%	40%	46%	38%	40%	46%	46%	46%
Fall – Night	21%	27%	35%	33%	19%	31%	26%	37%	37%	26%	37%	37%	37%
Fall – Morning peak	42%	35%	41%	43%	32%	37%	43%	43%	39%	39%	43%	43%	43%
Fall – Evening peak	31%	31%	35%	33%	23%	30%	27%	37%	36%	28%	37%	37%	37%
Winter – Day	28%	41%	34%	36%	34%	35%	42%	48%	48%	43%	48%	48%	48%
Winter – Night	34%	30%	38%	41%	39%	41%	46%	48%	43%	43%	48%	48%	48%
Winter – Morning peak	35%	49%	35%	53%	31%	40%	38%	52%	49%	41%	52%	52%	52%
Winter – Evening peak	34%	40%	29%	34%	30%	44%	53%	58%	57%	55%	58%	58%	58%

Source: Seasonal and daily wind availability adapted from the CanESS model (whatIf? Technologies, 2014).

Table 24. Availability factors by time slice for hydro dam and run of river

Hydro dam	Annual	Spring	Summer	Fall	Winter
AB	26%	31%	27%	23%	22%
BC	58%	55%	54%	59%	63%
MB	78%	81%	79%	75%	74%
SK	55%	66%	58%	50%	47%
ON	48%	57%	50%	43%	40%
QC	56%	59%	57%	54%	54%
NB	46%	69%	62%	30%	21%
NL	68%	71%	69%	66%	65%
NS	33%	39%	34%	29%	28%
PE					
NT	56%	67%	59%	50%	48%
NU	56%	67%	59%	50%	48%
YT	65%	67%	59%	50%	48%
Run of River	**Annual**	**Spring**	**Summer**	**Fall**	**Winter**
BC	37%	44%	56%	33%	21%

Uranium reserves. There is a supply curve for each type of uranium reserves (WNA, 2014). It is found mainly in the north of Saskatchewan, but also in Newfoundland & Labrador, Quebec, and Nunavut (Table 25). In 2011, the province of Saskatchewan is the only producer and 83% of the production is exported to the United States, the European Union and Japan. Extraction costs were derived initially from Cameco's expenses in the 2014 Annual Report (Cameco, 2014) and adjusted for the different types of reserves and provinces.

Table 25. Uranium reserves by type and jurisdiction

Jurisdiction	Type of reserve	Cumulative reserve		Extraction cost
		Tonnes	PJ[1]	($/GJ)
SK	Proven & Probable Reserves	242,971	162,807	$0.060
SK	Measured & Indicated Resources	126,055	84,465	$0.069
SK	Inferred Resources	86,870	58,209	$0.078
NU	Proven & Probable Reserves	-		
NU	Measured & Indicated Resources	-		
NU	Inferred Resources	49,153	32,936	$0.313
NL	Proven & Probable Reserves	-		
NL	Measured & Indicated Resources	30,000	20,102	$0.277
NL	Inferred Resources	13,670	9,160	$0.313
QC	Proven & Probable Reserves	-		
QC	Measured & Indicated Resources	4,740	3,176	$0.277
QC	Inferred Resources	6,320	4,235	$0.313

1. Using a conversion factor of 670.07 KJ/g; this is not the electricity generation potential which is lower (nuclear power reactor efficiency is around 25-32%).

Transmission & Distribution

Each jurisdiction has a transmission and distribution efficiency parameter representing the efficiency of its own grid infrastructure in order to represent electricity losses associated with intra-regional distribution. Table 26 shows the transmission efficiency parameters for each jurisdiction. Although a single efficiency accounts for both transmission and distribution systems in the model, it is worth mentioning that losses are predominantly at the distribution level. Indeed, losses are low (under 2%) in high voltage grids even for long distance transmission.

Table 26. Intra-region electricity transmission efficiency

Jurisdiction	2011	2020	2030	2050
NB	94.71%	95.18%	95.66%	95.66%
NL	86.33%	86.76%	87.19%	87.19%
NS	97.77%	97.77%	97.77%	97.77%
PE	99.41%	99.41%	99.41%	99.41%
ON	93.36%	93.82%	94.29%	94.29%
QC	88.35%	88.79%	89.24%	89.24%
AB	83.28%	83.70%	84.11%	84.11%
BC	82.10%	82.51%	82.92%	82.92%
MB	99.13%	99.13%	99.13%	99.13%
SK	97.95%	98.44%	98.93%	98.93%
NT	95.58%	96.05%	96.53%	96.53%
NU	95.58%	96.05%	96.53%	96.53%
YT	99.87%	99.87%	99.87%	99.87%

Source: Efficiencies computed from Statistics Canada, 2011.

Trade

International trade. Most provinces are able to trade electricity with the United States. The different trade parameters are shown in Table 27: installed capacity in 2011 for importing (exporting) electricity from (to) the United States and the activity levels for those same link options. The utilization factor is simply the ratio of actual import (export) levels over total imports (export) capacity for each jurisdiction in 2011. After reaching the installed capacity limits, the model may decide to invest in new interconnections. The last two columns show the costs associated with building and maintaining new transmission lines. The life is set at 50 years for all new transmission lines.

The installed capacity in Table 27 is the sum of interconnection in each province; details on individual transmission lines are provided in Table 28. Investment costs used in the model are derived using the 500 kV transmission lines (Table 29). This gives the model some flexibility in choosing trade amounts. However, international trade movements are modelled exogenously, i.e., using fixed prices and lower/upper limits on quantities, as NATEM-Canada has fixed links with the rest of the world. Upper bounds on trade projections between Canada and the United States are shown in Table 30. Electricity is exported and imported at an average of 10.1 ¢ per kWh.

Table 27. International trade parameters

	Installed capacity in 2011		Activity levels in 2011		Utilization factors in 2011		Investment Cost	Annual fixed O&M costs[1]
	Export	Import	Exports	Imports	Exports	Imports	All	All
	GW	GW	GWh	GWh	%	%	$/kW	$/kW
AB	0.15	0.12	128	991	10%	94%	$482.70	$7.24
BC	3.15	2.00	9,955	10,564	36%	60%	$217.22	$3.26
MB	2.18	0.70	9,345	137	49%	02%	$724.05	$10.86
SK	0.15	0.09	110	321	8%	41%	$482.70	$7.24
ON	2.12	1.95	11,014	1,775	59%	10%	$289.62	$4.34
QC	4.26	3.27	19,881	443	53%	2%	$337.89	$5.07
NB	1.12	0.66	1,875	1,085	19%	19%	$289.62	$4.34
NL	-	-	-	-	-	-	$1,689.45	$25.34
NS[2]	0.10	0.10	5	146	1%	17%	$386.16	$5.79
PE	-	-	-	-	-	-	-	-

1. Does not include any additional cost that may arise for QC to synchronize with neighboring jurisdictions.
2. Imports and exports through NB.
Source: Levels of imports/exports for 2011 are from Statistics Canada, 2011.

Table 28. International trade parameters-detailed

		Installed capacity in 2011	
		Export GW	Import GW
NB	United States New-England	1.00	0.55
NB	United States Maine	0.12	0.11
NB	Total	1.12	0.66
ON	United States New-York	2.28	1.77
ON	United States Minnesota	0.14	0.09
ON	United States Michigan	1.98	1.86
ON	Total	2.12	1.95
QC	United States New-York	2.00	1.10
QC	United States New-England	2.26	2.17
QC	Total	4.26	3.27

Table 29. Investment costs for new transmission lines

Voltage	Investment cost	Loadability	Efficiency
kV	M$/km	MW	%
765	$2.90	4000	99.0%
500	$1.93	2000	99.0%
345	$1.61	900	96.2%
230	$0.77	350	93.5%

Source: IEA, 2012b; Vaillancourt, 2014c.

Table 30. Trade projections with the United States used as upper limits

GWh		2011	2012	2015	2020	2035	2050
AB	Imports	991	996	1321	1321	2916	5102
AB	Exports	128	129	176	123	70	70
BC	Imports	10563	8813	6199	6741	7945	9136
BC	Exports	9954	10004	7520	8872	8358	7940
MB	Imports	137	138	138	138	133	133
MB	Exports	9344	8293	8630	9092	7185	5748
NB	Imports	1085	563	127	259	0	0
NB	Exports	1875	1884	2843	2819	2271	2271
NS	Imports	146	145	145	145	0	0
NS	Exports	5	5	5	0	0	0
ON	Imports	1775	1192	4700	5518	5844	6136
ON	Exports	11013	14643	13426	11287	8506	6380
QC	Imports	443	88	705	705	705	705
QC	Exports	19879	20378	20249	21816	21877	21877
SK	Imports	321	323	323	327	792	1584
SK	Exports	110	106	609	532	196	78

Source: Projections are adapted from NEB 2013 with some assumptions after 2035.

Domestic trade. The domestic trade module deals with energy exchanges between the Canadian jurisdictions. Trade movements are modelled endogenously, i.e., the model computes the energy prices and determines the optimal quantities up to the current infrastructure capacities. In the model, interprovincial trade is represented by a technology for every trade possibility. Table 31 shows the different parameters for the seventeen interprovincial trade possibilities. In addition, the following premises hold:

In all scenarios including reference, three interconnections are allowed to contribute to the importing province's dependable capacity: the Churchill Falls interconnection where Newfoundland & Labrador supplies Quebec, the contract between Newfoundland & Labrador and Nova Scotia (20% of the Muskrat Fall production for 35 years) and the one between New Brunswick and Prince Edward Island (5% of the nuclear energy generated at Point Lepreau).

Investments in new interconnection capacities are allowed between all jurisdictions that are already connected together. New infrastructure is added only when existing installed capacity is used at 98%.

The model can decide if new interconnections are built from the Northwest Territories to Alberta and from Nunavut to Manitoba.

Table 31. Interprovincial trade parameters

Exporting region to destination	Installed capacity in 2011	Activity levels in 2011	Utilization factor in 2011	Distance	Investment cost	Fixed O&M cost
	GW	GWh	%	km	$/kW	$/kW
AB to BC	1.00	41	13%	775	$374.09	$5.61
AB to SK	0.08	48	16%	525	$253.42	$3.80
BC to AB	1.20	5,500	11%	775	$374.09	$5.61
MB to ON	0.343	659	32%	1,750	$844.73	$12.67
MB to SK	0.15	859	70%	570	$275.14	$4.13
NB to NS	0.30	378	11%	260	$125.50	$1.88
NB to PE[1]	0.22	1,006	60%	165	$79.65	$1.19
NB to QC	0.79	216	2%	500	$241.35	$3.62
NL to QC[1]	5.15	29,820	67%	1,400	$675.78	$10.14
NS to NB	0.35	4	1%	260	$125.50	$1.88
PE to NB	0.22	0	0%	165	$79.65	$1.19
ON to MB	0.28	1,091	0%	1,750	$844.73	$12.67
ON to QC	1.98	5,744	25%	600	$289.62	$4.34
QC to NB	1.03	3,651	16%	500	$241.35	$3.62
QC to NL	0.00	20	98%	1,400	$675.78	$10.14
QC to ON	2.38	2,294	11%	600	$289.62	$4.34
SK to AB	0.15	900	49%	525	$253.42	$3.80
SK to MB	0.05	581	41%	570	$275.14	$4.13
NL to NS[1, 2]				520	$502.01	$7.53
NT to AB[3]				437	$421.88	$6.33
NU to MB[3]				600	$579.24	$8.69

1. Connections that contribute to dependable capacity in the importing region in all scenarios.
2. Project scheduled to deliver first power in 2017: 20% of the Muskrat Fall production for 35 years.
3. Does not correspond to scheduled projects but these transmission lines are options available in the model.
Source: Existing capacities and activity levels are from Statistics Canada, 2011. Distance are computed from main cities and costs from the information available in Table 29.

Sector specific parameters

Reserve factors and peak contribution. The model also imposes a constraint on the dependable capacity each province must have in excess of expected peak demand (see more information in Section 4.3.2). This is an arbitrary buffer for more dependable capacity than expected peak demand in order to represent the need for reserve capacity in case of unexpected demand increases at peak hours. However, the reserve factor has been set to zero for the TEFP project. Each class of electricity generation plant can have a different contribution to the peak demand: 100% for thermal, geothermal, nuclear, conventional hydro and biomass power plants, 15% for run of river hydro and 5% for wind, solar, wave and tidal.

Policy implications

Decommissioning. The retirement profile of each class of generating facilities has been established using the specific starting and retiring years of each plant unit. For units without a specific retiring year, a default lifetime has been fixed for all jurisdiction. In addition, the following two premises have been accounted for:

- Nuclear refurbishment will occur as planned
- Coal-fired electricity generation will be phased-out after the useful life of each plant (and no new coal plant can be built without carbon capture options)

Nuclear refurbishment. There are currently 20 reactors in Canada contributing 14,235 MW to total capacity. Refurbishment is scheduled for 10 of these reactors, all located in Ontario; the dates at which these reactors will be closed for refurbishment are listed in Table 32. For the TEFP project we assume that all scheduled refurbishments will take place. The Point Lepreau plant located in New-Brunswick has been in operation since 1982 but was closed between 2008 and 2013 for refurbishment. Quebec closed its only nuclear plant, Gentilly-2, at the end of 2013.

Table 32. Nuclear reactors and refurbishment dates

Jur.	Reactor unit	Installed Capacity (MW)	Start	End	Life	Refurb-ishment Period	Start	End	Life
NB	Point Lepreau	660	2013	2038	25				
ON	Bruce 1 (BA1)	750	2012	2042	30				
ON	Bruce 2 (BA2)	750	2012	2042	30				
ON	Bruce 3 (BA3)	750	2004	2018	15	2019-2022	2022	2052	31
ON	Bruce 4 (BA4)	750	2003	2016	14	2016-2020	2019	2050	32
ON	Bruce 5 (BB5)	820	1985	2022	38	2022-2025	2025	2055	31
ON	Bruce 6 (BB6)	820	1984	2024	41	2024-2027	2027	2058	32
ON	Bruce 7 (BB7)	820	1986	2026	41	2026-2029	2029	2059	31
ON	Bruce 8 (BB8)	820	1987	2028	42	2028-2031	2031	2061	31
ON	Darlington 1 (D1)	880	1992	2019	28	2019-2022	2022	2052	31
ON	Darlington 2 (D2)	880	1990	2016	27	2016-2019	2019	2049	31
ON	Darlington 3 (D3)	880	1993	2020	28	2021-2024	2024	2054	31
ON	Darlington 4 (D4)	880	1993	2022	30	2022-2025	2025	2055	31
ON	Pickering 1 (PA1)	500	1971	2020	49				
ON	Pickering 4 (PA 4)	500	1973	2020	47				
ON	Pickering 5 (PB 5)	525	1983	2020	37				
ON	Pickering 6 (PB 6)	525	1984	2020	36				
ON	Pickering 7 (PB 7)	525	1985	2020	35				
ON	Pickering 8 (PB 8)	525	1986	2020	34				
QC	Gentilly 2	675	1983	2013	30				

Source: Ministry of Energy, 2013; OPG, 2013; Bruce Power, 2013.

Coal-fired phase-out. Coal-fired electricity accounts for approximately 11% of Canada's total GHG emissions and 77% of GHG emissions from electricity and heat generation. Additionally, coal-fired plants contribute only 15% of Canadian electricity supply. These facts have led the Canadian government to implement new regulations concerning coal-fired electricity generation that came into effect on July 1st, 2015. On this date a new performance standard is introduced for all new plants. Units that were commissioned before 1975 will operate until the end of the 50-year useful life or until 2019 if the useful life extends beyond 2019. Units commissioned on or after 1975 but before 1986 will either close at the end of the 50 year useful life or in 2029, whichever comes earlier.

The Canadian government estimates that these regulations will result in a net cumulative reduction of GHG emissions of about 214 Mt (Environment Canada, 2013b). Table 33 shows the coal-fired electricity plants included in the model and the expected closure dates as outlined by the new regulations. The plants with end years shaded gray have the useful life shortened by the new regulations (i.e., they are closing before the end of useful life).

Table 33. Existing coal plants and expected termination years

Jurisdiction	Unit name	Start	Life	End
AB	Battle River	1969	50	2019
AB	Genesee 1	1994	50	2044
AB	Genesee 3	2005	50	2055
AB	H. R. Milner	1972	47	2019
AB	Keephills 1	1983	46	2029
AB	Keephills 3	2011	50	2061
AB	Sheerness	1986	50	2036
AB	Sundance 1	1970	49	2019
AB	Sundance 2	1976	49	2026
AB	Sundance 3	1977	50	2027
AB	Sundance 4	1973	50	2019
AB	Sundance 5	1978	46	2028
AB	Sundance 6	1980	50	2030
MB	Brandon	1970	49	2019
SK	Boundary dam 1	1959	50	2009
SK	Boundary dam 2	1973	46	2019
SK	Boundary dam 3	1970	49	2019
SK	Boundary dam 4	1978	41	2019
SK	Poplar river	1980	49	2029
SK	Shand	1993	50	2043
NS	Lingan	1983	46	2029
NS	Point Aconi	1993	50	2043
NS	Point Tupper	1973	46	2019
NS	Trenton	1969	50	2019
ON	Atikokan	1985	27	2012

Jurisdiction	Unit name	Start	Life	End
ON	Lambton	1970	42	2012
ON	Nanticoke	1973	41	2014
ON	Thunder bay	1981	33	2014

Source: Environment Canada, 2013b; utilities' websites.

4.5.2 Mitigation Measures

Decarbonization. We have seen that the electrification of end-use demands in the transportation, residential, commercial, agricultural and industrial sectors is one of the key mitigation measures for reducing GHG emissions in Canada. However, in order for this strategy to be effective, it must be coupled with a decarbonization of electricity supply: a substitution of fossil fuels for electricity to satisfy end-use demands is more potent if the electricity supplied has the lowest emissions possible for its generation.

In order to decarbonize electricity supply, electricity generation will need to switch from fossil fuel based generation (natural gas, coal and oil) to non-emitting generation sources such as hydro, wind, solar, geothermal, and nuclear. Additionally, CCUS technologies allow for continued use of fossil fuel based generation with limited emissions as approximately 90% of emissions are captured. CCUS technologies are covered in Section 4.8.

Intermittent (wind and solar) coupled with pumped storage. The main issue with including more intermittent renewable generation, such as wind or solar based generation, is the lack of dependable capacity they provide. Their intermittent nature leads to planning issues for satisfying electricity demand because they are not viable as a source of dependable capacity (see Sections 3.4.2, 3.4.3 and 3.4.4).

One interesting possibility for circumventing this issue of intermittency is to couple wind and solar generation with electricity storage technologies. Pumped storage is most viable for the foreseeable future. The idea behind coupling wind and solar generation with pumped storage is to store excess energy when the wind is blowing and the sun is shining by pumping water into an elevated water reservoir from a reservoir situated below. When wind speed falls and sunshine is limited, the water in the higher reservoir is let through to the lower reservoir, activating the turbines and producing energy to compensate for the lack of generation from wind and solar.

Interjurisdictional dependable capacity. Another option for increasing the overall efficiency of the Canadian electricity supply system is to allow for interjurisdictional dependable capacity. This allows for jurisdictions which are endowed with more feasible clean generation options to supply other jurisdictions during peak demand periods. For example, Manitoba and Quebec have more feasible hydroelectric generating potential available to them than Ontario, and could provide Ontario with a cheaper option for non-emitting generation than if it were left to its own devices. The option of using interjurisdictional dependable capacity is enabled starting in Scenario 3 and available throughout all subsequent scenarios (scenarios 3 to 9). For more information see Sections 3.4.2, 3.4.3 and 3.4.4.

4.6 Oil, Natural Gas, Coal, LNG Supply and Trade

4.6.1 Sector Description

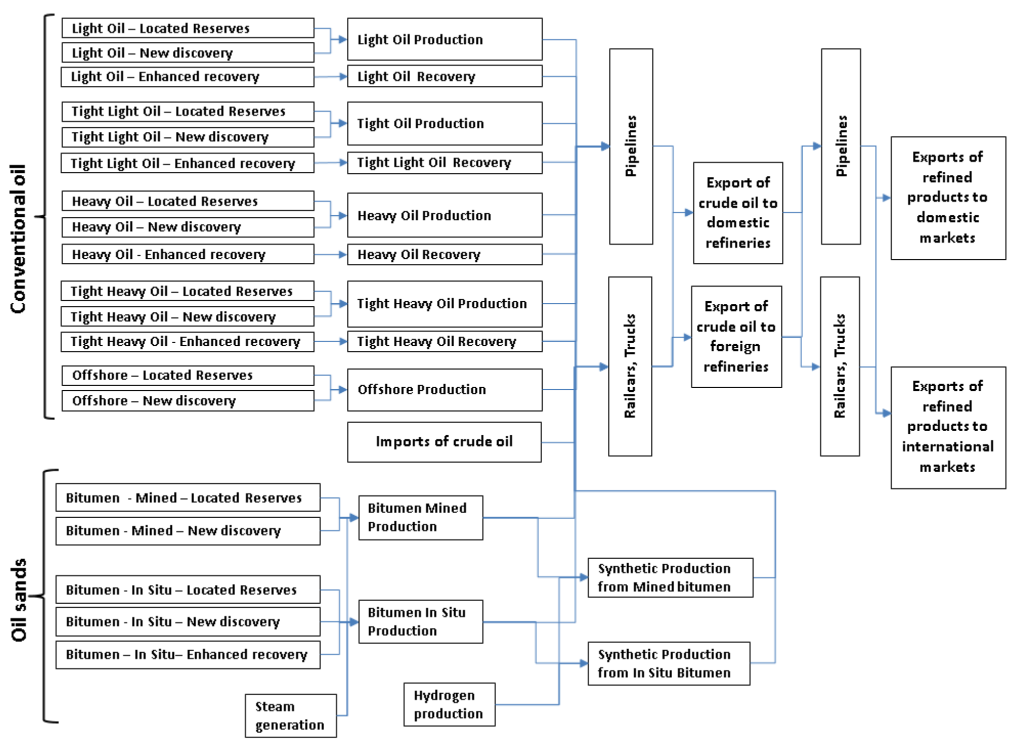
This section covers the whole supply chain of fossil fuels including 1) reserves of oil, gas and coal, 2) primary extraction processes, 3) transportation of raw resources through pipelines and other means (trucks and trains), 4) secondary transformation processes such as refineries and cokeoven gas plants, and 5) delivery of refined products to end-use sectors.

The fossil fuels considered include:

- Conventional oil: light oil (onshore and offshore), heavy oil, condensate, pentanes
- Unconventional oil: oil sands - mined, oil sands - in situ and synthetic
- Conventional gas: natural gas and natural gas liquids (NGLs)
- Unconventional gas: shale gas, tight gas and coalbed methane
- Coal: anthracite, bituminous, sub-bituminous and lignite

The supply sector also tracks the energy consumed by primary extraction processes, secondary transformation processes and transportation by pipelines and other means. GHG emission reduction options exist at each stage of the supply chain to replace fossil fuels combustion with electricity or biofuels. The oil sector has been already described in Vaillancourt et al (2015); Figure 23 gives a simplified representation of the oil sector in the model.

Figure 23. Schematic representation of the oil supply sector



Source: in Vaillancourt et al, 2015.

Technologies and fuels

Oil exploration and extraction. Primary extraction technologies are modelled for each type of oil, reserve and step of the reserve supply curve. Different technologies account for the extraction of conventional light oil, conventional heavy oil, tight light oil, tight heavy oil, offshore light oil and bitumen. For each of these oil types, a distinction is also made between production from located reserves/new discoveries and from enhanced recovery, as the latter needs more energy.

Moreover, there are different technologies for bitumen extraction from either mined or in situ methods. While most of the bitumen has been extracted using mining techniques (e.g. the truck and shovel approach), the use of in situ processes is expected to grow considerably in the future as only a minor portion of the bitumen reserves are close to the surface. Finally, there are two different methods for in situ extraction: one method is cyclic steam stimulation (CSS), and a more recent method is steam assisted gravity drainage (SAGD). Both technologies use injection of steam into oil-sands deposits to reduce their viscosity and allow the bitumen to be moved to the well, but the SAGD method allows for a better oil recovery factor and a better steam-to-oil ratio. Most of the mined bitumen (95%) is currently upgraded into synthetic oil, while the in situ bitumen is mixed with condensates to produce a diluted bitumen appropriate for transport by pipeline (see Section 4.6.1). All these technologies are characterized by different costs and energy requirements.

Exploration and development costs for oil extraction technologies are shown in Table 34. The costs vary with the oil types as exploration is associated with different levels and requires different technologies for development, but are assumed to be constant in time. The variation in costs in the Western Canadian Sedimentary Basin (WCSB) is related to the location of wells: costs are normally lower in Alberta than in the rest of the region. Table 35 contains the annual well maintenance and operation costs by type of oil and extraction methods (CERI 2013a; 2013b). Costs decrease at a yearly rate of 0.075% until 2035 (CERI 2011) and stay constant thereafter. Transportation costs are presented in Section 4.6.1.

Oil upgrading and refining. Most of the bitumen extracted through mining operations is currently upgraded on the extraction site into synthetic oil of quality comparable to conventional light oil. Synthetic oil can be treated in any refinery along with conventional oil (light and heavy). Although in reality synthetic crude is not a perfect substitute for conventional crude in refining processes, this simplification was made in the modeling formulation of refineries. Differently, most of the raw bitumen recovered from in-situ techniques is mixed with condensates to produce diluted bitumen appropriate for transport by pipeline. Diluted bitumen can be treated only in refineries equipped with upgrading capacities.

Downstream activities includes six stand-alone upgraders located in Alberta and Saskatchewan with a total capacity of 1.2 million barrel per day (CAPP, 2013a). Upgrading processes are modelled independently from the extraction processes due to different energy requirements.

In addition, there are 18 refineries with a total capacity of 2.06 million barrel per day which produce a full range of refined products (CAPP, 2013a): liquefied petroleum gas (LPG), still gas, motor gasoline, kerosene, stove oil, diesel fuel oil, light fuel oil (nos. 2 and 3), heavy fuel oil (nos. 4, 5 and 6), petroleum coke, aviation gasoline, aviation turbo fuel, non-energy products. Crude oil input and refined product output data for refineries are provided in the main energy balance for refineries:

"Establishments primarily engaged in manufacturing of a group of refined petroleum products including fuels, blended oils and greases. NAICS code 324110 and part of 324190." (Statistics Canada, 2011). Expert assumptions are used to disaggregate the crude oil type and quality in each refinery (Table 36).

Table 34. Exploration and development costs for conventional and unconventional oil

$ / barrel	WCSB-Min	WCSB-Max	Offshore East	Northern Territories
Conventional light				
Light crude oil located reserves	$12.57	$29.11		$47.25
Light crude oil enhanced recovery	$18.76	$35.30		$53.45
Light crude oil new discovery	$24.96	$41.49		$59.64
Light tight oil located reserves	18.76	$35.30		
Conventional heavy				
Heavy crude oil located reserves	$15.54	$22.42		
Heavy crude oil enhanced recovery	$21.74	$28.61		
Heavy crude oil new discovery	$27.93	$34.80		
Heavy tight oil located reserves	$21.74	$28.61		
Offshore				
Offshore oil located reserves			$29.42	$47.25
Offshore oil new discovery			$41.80	$59.64
Unconventional – Oil sands				
Mined bitumen located reserves	$23.04			
Mined bitumen new discovery	$29.23			
In situ bitumen located reserves	$25.27			
In situ bitumen enhanced recovery	$31.46			
In situ bitumen new discovery	$37.65			

Source: CERI 2013a; 2013b; expert assumptions.

Table 35. Well maintenance and operation costs for conventional and unconventional oil

$ / barrel	2011	2012	2013	2015	2050
Light crude oil	$7.93	$7.87	$7.80	$7.68	$6.63
Light enhanced recovery	$14.12	$14.00	$13.93	$13.69	$11.77
Light tight oil	$14.12	$14.00	$13.93	$13.69	$11.77
Heavy crude oil	$7.93	$7.87	$7.80	$7.68	$6.63
Heavy enhanced recovery	$14.12	$14.00	$13.93	$13.69	$11.77
Heavy tight oil	$14.12	$14.00	$13.93	$13.69	$11.77
Offshore oil	$20.90	$20.73	$20.61	$20.27	$17.43
Mined bitumen	$17.90	$17.77	$17.59	$17.34	$14.93
In situ bitumen	$9.35	$9.23	$9.17	$9.04	$7.80
Mined bitumen with upgrading	$24.59	$24.40	$24.21	$23.84	$20.50
In situ bitumen with upgrading	$15.98	$15.85	$15.73	$15.48	$13.31

Source: CERI 2011; 2013a; 2013b

Table 36. Existing refining capacity at base year 2011

Location	Refinery	Type	barrel / day
NB, St-John	Irving Oil	Cracking	298,742
NS, Dartmouth	Imperial Oil	Cracking	84,994
NL, Come-by-Chance	North Atlantic Refining	Cracking	114,937
QC, Montreal	Suncor	Cracking	136,987
QC, St-Romuald	Ultramar	Cracking	264,969
ON, Nanticoke	Imperial Oil	Cracking	118,987
ON, Sarnia	Imperial Oil	Coking	118,987
ON, Corunna	Shell	Cracking	76,994
ON, Sarnia	Suncor	Hydrocracking	84,994
ON, Sarnia	Nova Chemicals	Topping	79,874
AB, Lloydminster	Husky	Topping Asphalt	29,057
AB, Edmonton	Imperial Oil	Cracking	186,893
AB, Edmonton	Suncor	Coking	139,987
AB, Scotford	Shell	Hydrocracking/coking	95,094
BC, Burnaby	Chevron	Cracking	56,604
BC, Prince George	Husky Oil	Cracking	12,000
SK, Moose Jaw	Moose-Jaw Asphalt	Topping asphalt	14,937
SK, Regina	Co-op Newgrade	Hydrocracking/coking	144,654
Total			2,059,692

Source: CAPP, 2013a.

Only a small number of refineries in Ontario and Alberta are currently configured to upgrade bitumen directly. All technologies are characterized by different costs and energy requirements. Natural gas is used for steam generation (bitumen recovery) and hydrogen production (bitumen upgrading). Corresponding GHG emissions from fuel combustion and fugitive emissions are modelled at each step of the supply chain including flaring and venting of emissions.

The model can invest in new refineries and upgraders. The investment costs vary between 20.0 and 24.2 k$ per barrel per day for refining capacity expansion; between $17.7 and $26.0 thousand per barrel per day for refining capacity addition; between $19.2 and $90.9 thousand per barrel per day for upgrading capacity addition at a refinery; approximately $114.0 thousand per barrel per day for refining capacity addition with upgraders and CCUS (Vaillancourt, 2014b). Total operation costs fluctuate between US$5.72 and US$9.73 per barrel (1999-2009) for the American refiners (Vaillancourt, 2014b). The investment cost for stand-alone upgraders is approximately $52.3 thousand per barrel per day (Angevine, 2012).

Natural gas exploration and extraction. Exploration and development costs for natural gas extraction technologies are shown in Table 37. The costs vary by gas type as exploration is associated with different levels and require different technologies for development, but are assumed to be constant in time. Table 38 contains the annual well maintenance and operation costs for different Canadian region by type of natural gas and extraction methods. Maintenance costs for natural gas wells are assumed to remain constant through time.

Table 37. Exploration and development costs for natural gas

$ / GJ	Average
Conventional natural gas	
Natural gas located reserves	$0.90
Natural gas enhanced recovery	$0.95
Natural gas new discovery	$0.95
Shale gas	
Shale gas located reserves	$0.90
Shale gas new discovery	$0.95
Tight gas	
Tight gas located reserves	$0.93
Tight gas new discovery	$0.98
Coal bed methane	
Coalbed methane located reserves	$1.17
Coalbed methane new discovery	$1.22
Offshore (East)	
Offshore gas located reserves	$1.1
Offshore gas new discovery	$1.16

Source: CERI 2013c; Expert assumptions.

Table 38. Well maintenance costs for natural gas

$ / GJ	WCSB		Other provinces	
	Min	Max	Min	Max
Natural gas	$2.00	$4.55	$2.32	$4.69
Shale gas	$2.00	$3.80	$3.80	$3.80
Tight gas	$2.00	$2.60	$2.60	$2.60
Coal bed methane	$7.60	$7.60	$7.60	$7.60

Source: CERI 2013c; Expert assumptions.

Coal exploration and extraction. Exploration and development costs for coal extraction technologies are shown in Table 39. The costs vary by coal type as exploration is associated with different levels and requires different technologies for development, but are assumed to be constant in time. Table 40 contains the annual mine maintenance and operation costs. Maintenance costs for coal mines are also assumed to remain constant through time.

Table 39. Exploration and developments costs for coal

$ / GJ	Average
Anthracite	
Anthracite recoverable reserves	$2.44
Anthracite measured reserves	$4.44
Bituminous coal	
Bituminous coal recoverable reserves	$4.06
Bituminous coal measured reserves	$4.22
Subbituminous coal	
Subbituminous coal recoverable reserves	$0.52
Subbituminous coal measured reserves	$2.52
Lignite	
Lignite located reserves	$0.66
Lignite new discovery	$2.66

Source: Vaillancourt, 2014a.

Table 40. Coal mine maintenance cost

$ / GJ	Canada
Anthracite	$0.28
Bituminous coal	$0.25
Subbituminous coal	$0.23
Lignite	$0.24

Source: Vaillancourt, 2014a.

Coal transformation. There are coke oven gas plants located in Ontario, producing coke and coke oven gas used in the manufacturing industries. The coal consumption and the output of these plants are provided in the main energy balance of Statistics Canada (2011).

Fuel use. All energy requirements for oil extraction, transformation and transportation are modelled. Initial data come from Statistics Canada (2011) for producer own consumption, refined petroleum product manufacturing, mining oil and gas extraction and pipeline transportation and then calibrated using additional information from the CanESS model (whatIf? Technologies, 2014) in order to account for fuel use at each step of the supply chain. In particular, natural gas is used to generate steam required for bitumen extraction and producing the hydrogen used for bitumen upgrading at wells and refineries. This natural gas is both purchased gas (two-third) and the co-products generated during the in situ extraction and upgrading operations. Corresponding GHG emissions from fuel combustion and fugitive emissions (CO_2, CH_4) are modelled at each step of the supply chain as well as flaring and venting emissions from oil, gas and coal production.

Resources

Table 41 shows the Canadian cumulative reserves of conventional and unconventional oil, gas and coal.

Table 41. Fossil fuel reserves by type and jurisdiction

	BC	AB	SK	MB	Other provinces
Oil (PJ)					
Light crude oil	2,650	28,846	16,826	2,639	98,344
Light tight oil		12,574	3,457	3,054	
Light crude oil enhanced recovery	191	2,391	680	233	1,807
Heavy crude oil		9,353	23,808		
Heavy tight oil		3,520	8,680		
Heavy crude oil enhanced recovery		1,056	1,311		
Mined bitumen		395,076			
In situ bitumen		1,751,060			
Natural gas (PJ)					
Natural gas	59,399	43,943	3,516		249,253
Shale gas	85,218	157,710			4,242
Tight gas	296,912	192,800	75,385		13,303
Coalbed methane		38,252			386
Coal (PJ)					
Anthracite	296,912	192,800	75,385		
Bituminous coal		38,252			82,219
Subbituminous coal					
Lignite					

Source: Statistics Canada, 2008; NEB, 2013; CAPP, 2013b.

From cumulative reserve, extraction and development costs, three-step supply curves are calculated for the different types of fossil fuels (oil: conventional light, tight, heavy and non-conventional bitumen; natural gas: conventional, tight, shale, coalbed methane; coal: lignite, anthracite, bituminous and subbituminous), reserves (located reserves or producing pools, enhanced recovery or reserves growth, and new discovery), and extraction techniques for oil sands (mined or in situ). Each step is characterized by the cost of the resource and the amount of energy (annual) available at this cost. Most of the Canadian oil reserves are located in the WCSB located in four provinces (Alberta, Saskatchewan, British Columbia, Manitoba), with the oil sands in particular being located in Alberta.

Trade

This section provides an overview of the different transportation methods (pipelines as well as trucks/trains) and trade parameters for fossil fuels. First, the pipelines system will be shown as it is implemented in the model (other means of transportation are modelled in a more generic manner with associated costs). Second, LNG technologies used to import or export natural gas overseas will be presented. Finally, domestic and international trade parameters will be described.

Oil pipelines. The model database includes existing transportation capacity and planned projects for capacity expansion or new infrastructure. Uncertain projects such as TransCanada Keystone XL are given as investment options in the model. Due to the location of the main production centres in the WCSB and of the major markets in the United States Midwest and Gulf Coast regions, the pipeline network in North America has a strong North-South linkage. There are four main pipelines exiting the WCSB with a total capacity of 3.67 million barrel per day. The existing pipelines and planned projects are listed in Table 42 for exports from the WCSB to international destinations; they are presented on maps in CAPP (2013a). In addition, rail transportation capacity has evolved quickly from 46 thousand barrel per day in 2012 to 300 thousand barrel per day in 2014 (CAPP, 2014). The growth in rail capacity is expected to slow down and reach a maximum of 945 thousand barrel per day in 2050.

Table 42. Existing and proposed pipelines for international exports

Pipeline	Target In-Service	Capacity (k barrel/day)	Capacity (PJ)
Enbridge Mainline	1950	2500	5,651
Kinder Morgan Trans Mountain	1953	300	678
Spectra Express	1997	280	633
TransCanada Keystone	2010	591	1,336
Total Existing Capacity		3,671	8,298
Enbridge Alberta Clipper Expansion	2015	120	271
Enbridge Alberta Clipper Expansion	2016	230	520
TransCanada Keystone XL	2020	830	1,876
Trans Mountain Expansion	2017	590	1,334
Enbridge Northern Gateway	2017	525	1,187
Total Proposed Capacity		2,295	5,188
Total Capacity		5,966	13,486

Source: CAPP, 2013b.

For domestic trade, two major new projects are proposed and considered as committed in the model (Table 43) (CAPP, 2013a). These projects would allow synthetic oil from the WCSB to be exported to Eastern refineries (not equipped to process bitumen) and consequently reduce imports for Quebec and Atlantic provinces from foreign countries. The existing pipeline capacity between Canadian jurisdictions is assumed to be used at 85% of maximum capacity. New investment in pipeline capacity is required if exports increase by more than 15% above current levels.

The model allows for increase in export levels in three phases: 1) until 100% of the existing capacity is reached (least cost option) and 2) until 100% of the committed new capacity (e.g. expansion plan) is reached by 2020 and 3) by investing in new transportation infrastructure such as pipeline and rail tracks (most expensive option).

Table 43. New pipelines for domestic exports

Pipeline	Target In-Service	Capacity (k barrel/day)	Capacity (PJ)
Enbridge Line 9 reverse	2015	300	678
TransCanada Energy East	2018	1,100	2,486

Source: CAPP, 2013b.

Cost assumptions are presented in Table 44. The total investment cost for new pipeline projects vary between \$16.6 per barrel to \$34.2 per barrel. For the TransCanada Energy East project in particular, the cost was estimated at \$11.3 billion (Deloitte, 2013) or approximately \$28.1 per barrel. The investment cost for new rail is assumed to be 75% of the new pipeline cost. For modelling purpose, the total investment costs of building new transportation capacity was allocated to the different provinces on a distance basis from Alberta in order to adequately account for the transportation costs for each province and to capture the effect on the endogenous oil commodity prices (Vaillancourt et al, 2015). Similarly, although the maintenance and operation costs are constant on a per barrel basis (approximately \$0.7 per barrel using assumptions in Karangwa (2008); Statistics Canada 2015a; 2015b), they vary with the distance between provinces. The maintenance and operation costs of the rail transportation mode are assumed to be higher than those of the pipeline mode, although this difference is reduced over time.

Table 44. Cost assumptions by transportation mode

\$/barrel	Pipeline		Rail	
	Min	Max	Min	Max
Investment costs for new projects by province	\$1.5	\$3.8	\$1.1	\$2.8
Annual operation costs for existing and new transportation mode 2011-2019	\$0.7	\$4.1	\$1.0	\$6.1
Annual operation costs for existing and new transportation mode 2020-2050	\$0.7	\$4.1	\$0.8	\$4.9

Finally, all domestic trading activities involving refined products are modelled through generic technologies and all existing and projected values are derived from the historical data of the CanESS model (whatIf? Technologies, 2014).

Natural gas pipelines. Natural gas pipelines are not modelled in as much detail as oil pipelines. They are represented by a generic technology which allows the natural gas to travel to its destination. The majority of natural gas is extracted in the Western provinces of Alberta and British Columbia. The gas then has three different potential destinations. First, it can be delivered domestically by pipeline to the other provinces. Second, it can be transported via pipeline south to the United States. Lastly, it can be transported to an LNG terminal in British Columbia for liquefaction and shipment overseas.

Liquefied natural gas (LNG). LNG terminals represent an additional natural gas transportation option. Two different LNG terminals are modelled (Table 45). The Canaport regasification terminal in St-John, New Brunswick, allows for the import of natural gas from overseas. The Kitimat terminal in British-Columbia allows for natural gas exports from Canada. Other LNG projects are highly uncertain following the discovery of low cost methods of extracting new unconventional gas sources. Different types of generic terminals are included in the database to allow flexibility in the model for potential growth of this industry.

Table 45. Modelled LNG terminals

Name	Location	year of operation	capacity, bcf/day
Canaport	New Brunswick	2011	1.2
Kitimat	British Columbia	2017	0.6 to 1.3

Source: Canaport, 2015; Northwest Institute, 2015

Exports prices. The model captures six types of oil commodities (light oil, heavy oil, bitumen, synthetic oil, condensates and pentanes) that can be transported by pipelines and/or other means (trucks, trains and tankers) from primary production wells to different destinations: domestic refineries, American refineries and export terminals (e.g. Kitimat) to reach international destinations. International trade movements are modelled using fixed prices and limits on quantities by origin and destination, while domestic trade movements within Canada are determined endogenously (i.e. prices and quantities are determined by the model based on the available infrastructure capacities and cost of investing in new capacities).

Table 46 shows the price for exported oil, gas and coal (and imports) on international markets. These prices were first based on oil price forecast given by the National Energy Board (NEB, 2013) taking into account a constant difference of $7 per barrel for Brent over WTI until 2035 and different assumptions regarding destinations: United States, Rest of the World-West and Rest of the World-East. Due to the excess of oil supply in North America and the lack of pipeline to reach demand markets, the domestic oil prices are lower than on international markets. This table also shows the different export prices for natural gas, LNG and coal depending on the destination and varying in time. The same price was used for the four different coal types: lignite, anthracite, bituminous and subbituminous.

Table 46. Exported fossil fuel prices by destination, 2012-2050

$/GJ[1]	2012	2013	2020	2025	2030	2050
Oil – Min	$15.85	$15.66	$16.85	$17.27	$17.69	$21.23
Oil – Max	$16.98	$16.79	$17.98	$18.40	$18.82	$22.59
Gas - Pipeline to United States	$2.63	$3.44	$4.18	$5.00	$5.76	$6.50
LNG to Rest of the World from British Colombia	$5.63	$5.73	$6.53	$7.13	$7.63	$9.50
Coal	$1.88	$1.88	$2.53	$2.72	$2.91	$3.55

1. Oil prices are converted from $/barrel using a coefficient of 6.193 PJ/barrel; gas and coal prices are converted from MMBTU using a coefficient of 1 MMBTU = 1.055 GJ.

4.6.2 Mitigation Measures

Emissions from fossil fuel extraction can be grouped into two main categories. In the first category, fossil fuels are consumed, and combustion related emissions released, by the primary extraction processes, secondary transformation processes and transportation by pipeline (fuel for equipment). Since all energy requirements are accounted for at each stage, there are modelled options for substituting fossil fuels (mainly natural gas) by electricity when possible. This is the focus of this section.

In the second category are fugitive emissions that consist of gases or vapors which are released into the atmosphere during the extraction process. These releases stem from inefficiencies in the extraction system. Mitigation options for fugitive emissions are not modelled, thus, the only way of reducing emissions related to fugitive emissions in the model is to reduce the activity level of fossil fuel extraction.

Reduced domestic fossil fuel consumption. The most straightforward way of reducing fossil fuel extraction related emissions is to reduce production volume. This can be achieved, first, by reducing domestic demand. As we have seen in previous sections, the electrification of end-use technologies represents the main mitigation option for end-use sectors and it gains in viability when considering the resulting decrease in domestic fossil fuel demand it entails. Therefore, electrification of end-uses is also a viable solution to reducing emissions from fossil fuel extraction by reducing extraction volume.

Reduced exports of fossil fuels. Considering the significant amount of fossil fuel production destined for trade, reduction of fossil fuel exports must also be considered as an important mitigation option for fossil fuel extraction related emissions. This approach is characterized by balancing the tradeoff between the loss in export revenue compared to the cost of GHG emission reduction.

Electrification of steam generation for in-situ extraction. An important option is to electrify the technologies which are involved in fossil fuel extraction. Steam generation for in-situ extraction is responsible for a significant amount of natural gas consumption in the fossil fuel supply sector. By replacing natural gas fired steam generators by electric steam generators, emissions related to in-situ extraction can be considerably reduced. This natural gas consists of both purchased gas (two-thirds) and the co-products generated during the in situ extraction and upgrading operations. It was assumed in the model that the purchased portion could be replaced with cleaner fuels such as electricity.

Other electrification options for extraction. Other electrification options exist for the extraction process by replacing purchased natural gas for bitumen separation (about 40%). Due to the lack of information, more conservative assumptions were made for the electrification potential in conventional and tight oil extraction (10% more electricity) and for conventional and unconventional gas extraction (10%).

Electrification of hydrogen production for upgrading. Natural gas is also consumed for producing the hydrogen used for bitumen upgrading at wells or at the refineries. The whole supply chain is modelled in detail including centralized and decentralized production from natural gas and water electrolysis. Consequently, emission reduction options exists for the upgrading process by replacing natural gas with electricity for hydrogen production.

Electrification options in refining and pipelining. Other significant electrification options exist through the whole supply chain by replacing purchased natural gas and refined products. Due to the lack of information, conservative assumptions were made for the electrification potential for refineries (10-20% more electricity), oil pipelines (25%) and gas pipelines (20%).

4.7 Biomass Feedstocks & Biofuels, Supply and Trade

4.7.1 Sector Description

Normally, biomass feedstocks and biofuel production do not represent an energy sector per se, but rather are available as means of reducing GHG emissions in the different energy sectors. Indeed, the supply chain for production of biomass/biofuels is not treated as a separate category in the National Inventory Report (NIR) but covered through the agriculture sector and the forestry segment of the industrial sector amongst others.

Nevertheless, it is important that the entire supply chain for production of biomass/biofuels be subject to the same rigor for reducing combustion of fossil fuels with replacement of electricity supply and biomass/biofuels. In this Section, the focus will be on both production of biomass/biofuels and the role of biomass/biofuels in reducing GHG emissions by replacing combustion of fossil fuels.

The other main biomass related mitigation technology, biomass based electricity generation with CCUS technologies, is covered in Section 4.8. Note that other biomass-based technologies are included in the model but are not explicitly covered in this section as they are not considered to be significant means of mitigation (examples include wood-based water heaters, wood stoves, etc.).

Technologies

Ethanol production. Table 47 shows existing ethanol production plants at base year 2011 with technology parameters for feedstock input and useful life. An arbitrary $5-10 per kW was used as the annual operation and maintenance costs due to the lack of data. Canadian ethanol production is based on the transformation of corn, forestry residues, and wheat, and total installed capacity is around 41 PJ of production per year, which equates to about 1.8 billion litres of ethanol per year.

Table 47. Existing ethanol production plants

Jurisdiction	Plant	Main Feedstock[1]	Production PJ/yr[2]	Life
QC	Fermentation, Varennes	Corn	2.7	60
	Ethanol by gasification, Westbury	Forestry residues	0.1	10
	Ethanol by gasification, Sherbrooke	Forestry residues	0.01	10
ON	Fermentation, Tiverton	Corn	0.6	60
	Fermentation, Chatham	Corn	4.4	60
	Fermentation, Sarnia	Corn	9	60
	Fermentation, Johnstown	Corn	4.5	60
	Fermentation, Havelock	Corn	2.7	60
	Fermentation, Aylmer	Corn	3.6	60
	Hydrolysis, Ottawa	Agriculture residues	0.07	60
AB	Fermentation, Red Deer	Wheat	0.9	60
	Fermentation, Hairy Hill	Wheat	0.9	60
	Waste to ethanol, Edmonton	Wheat	0.9	10

Jurisdiction	Plant	Main Feedstock[1]	Production PJ/yr[2]	Life
MB	Fermentation, Minnedosa	Wheat	2.9	60
SK	Fermentation, Lloydminster	Wheat	2.9	60
	Fermentation, Lanigan	Wheat	0.3	60
	Fermentation, Weyburn	Wheat	0.5	60
	Fermentation, Belle Plaine	Wheat	3.4	60
	Fermentation, Unity	Wheat	0.56	60

1. The table indicates the main feedstock used although a mix of feedstocks is used in several plants. Fuels such as electricity, petroleum products and natural gas are also used during the biofuel production process to transform the feedstock into biofuel.
2. Production capacity was converted from litres to PJ using a conversion factor of 22.385 MJ per liter.

Source: CRFA, 2013.

Biodiesel production. Table 48 shows existing biodiesel production plants by jurisdiction at base year 2011. Different mixes of greasy residues and vegetable oil are used to produce biodiesel depending on the technology. An arbitrary $5-10 per kW was used as the annual operation and maintenance costs due to the lack of data.

Table 48. Existing biodiesel production plants

Jur	Plant	Main Feedstock[1]	Production PJ/yr[2]	Life
QC	Transesterification, Ste-Catherine	Greasy residues, Soy	1.9	60
QC	Transesterification, St-Jean	Greasy residues, Soy	0.2	60
ON	Transesterification, Mississauga	Greasy residues, Soy	0.2	60
ON	Transesterification, Hamilton	Greasy residues, Soy	2.3	60
ON	Transesterification, Welland	Greasy residues, Soy	5.8	60
ON	Transesterification, Sombra	Greasy residues, Soy	1.7	60
ON	Transesterification, Springfield	Greasy residues, Soy	0.17	60
AB	Transesterification, Airdire	Greasy residues, Canola	0.03	10
AB	Transesterification, Lloydminster	Greasy residues, Canola	9.1	60
AB	Transesterification, Lethbridge.	Greasy residues, Canola	2.3	60
BC	Transesterification, Delta	Greasy residues, Canola	0.3	60
BC	Transesterification, Delta	Greasy residues, Canola	0.4	60
SK	Transesterification, Foam Lake	Greasy residues, Canola	0.7	60

1. The table indicates the main feedstock used although a mix of feedstocks is used in several plants. Fuels such as electricity, petroleum products and natural gas are also used during the biofuel production process to transform the feedstock into biofuel.
2. Production capacity was converted from litres to PJ using a conversion factor of 34.395 MJ per liter.

Source: CRFA, 2013.

Total installed production capacity in Canada sums to about 25 PJ per year in 2011, which is equivalent to around 0.73 billion litres of biodiesel per year. In addition to the biodiesel production plants, there are three technologies available for vegetable oil production. Either, canola, soy or other oilseeds can be used to produce vegetable oil by crushing them. Vegetable oil can then be used by the previously shown biodiesel production technologies.

New technologies. In order to allow the model to invest in additional biofuel production for emission mitigation, generic technologies are available in all provinces including those which currently do not have any installed biofuel production capacity (Table 49). An arbitrary investment cost of $3000 per kW of capacity is used so the model can invest in the new technologies starting in 2015. This high cost was obtained from calibration, i.e. this is the cost that was required to avoid further penetration of biofuels in the reference scenario (an initial premise of the TEFP study).

Table 49. New first generation biofuel production plants

Jur	Description	Main Feedstock[1]	Start	Life	Investment cost $/kW[2]	Operating and maintenance cost $/kW[2]
NB, NS	Ethanol by fermentation	Corn	2015	35	$3,000	$5
NB, NL, NS, PE	Biodiesel by transesterification	Greasy residues, Fish oil	2015	35	$3,000	$5
QC, ON	Ethanol by fermentation	Corn	2015	35	$3,000	$5
QC, ON	Biodiesel by transesterification	Greasy residues, Soy	2015	35	$3,000	$5
AB, BC, MB, SK	Ethanol by fermentation	Wheat	2015	35	$3,000	$5
AB, BC, MB, SK	Biodiesel by transesterification	Greasy residues, Canola	2015	35	$3,000	$5

1. The table indicates the main feedstock used although there are mix of feedstock used in several plants. Fuels such as electricity, petroleum products and natural gas are also used during the biofuel production process to transform the feedstock into biofuel.
2. Ethanol is converted from litres using a conversion factor of 22.385 MJ per liter and biodiesel using a conversion factor of 34.395 MJ per liter. And 1 GW= 31.536 PJ/y.

Second-generation biofuels production. Table 50 shows the technologies included in the model which are responsible for second-generation biofuel production. It is interesting to note that the inputs do not include any traditional food crops; second-generation biofuels do not compete with land-use for food production as first generation biofuels do. Second-generation biofuel technologies were assumed to be available at the earliest from 2015 for cellulosic ethanol, 2017 for FT diesel and bio-oil and 2020 for biojet. More work would be required to better capture all second generation biofuel options with more accurate data. Two promising technology platforms are considered: converting cellulosic biomass and lignin into biofuel and other products and, gasifying or liquefying biomass for power production or for catalytic conversion to valuable products (chemicals or materials, power, etc.).

Table 50. Second generation biofuel production technologies

Description	Feedstock input	Start	Life	Investment cost 2012 $/kW[1]	Investment cost 2050 $/kW[1]	Operating and maintenance cost $/kW[1]
FT diesel	Agricultural residues, industrial waste, forestry residues and dedicated crops	2017	50	$4,878	$3,252	$369
Cellulosic ethanol by enzymatic hydrolysis	Agricultural residues, industrial waste, forestry residues and dedicated crops	2015	50	$4,878	$3,252	$369
Biojet production	Agricultural residues, industrial waste, forestry residues and dedicated crops	2020	50	$4,878	$3,252	$400

1. Ethanol is converted from litres using a conversion factor of 22.385 MJ per liter and biodiesel using a conversion factor of 34.395 MJ per liter. And 1 GW= 31.536 PJ/y.

Source: Assumptions made based on the work of Stephen et al., 2013 and Chemicals-technology, 2015. The cost for biojet production is highly uncertain and set at the same level as other second generation biofuels.

Pellet production. Table 51 shows the available pellet production through conventional densification technologies by province. Pellets (or pellet fuels) are made from compressed biomass (agriculture residues, forestry residues and dedicated crops) and are used for space heating by wood stoves or for electricity generation. The capacity by province in 2011 is shown. Additionally, any capacity increases since the calibration year of 2011 are also included in the model and shown in the following column. Around 5% of pellet production is assumed to be exported to the United States, 63% to rest of the World and the remaining 32% is consumed domestically. New technologies such as the torrefaction process are included but do not play a significant role in the mitigation scenarios.

Table 51. Pellet production technologies

Jurisdiction	Production capacity in 2011, PJ	Additional production capacity since 2011, PJ
ON	1.998	16.038
QC	9.396	4.500
NB	4.230	2.160
NL	1.138	-
NS	3.510	-
AB	2.160	-
BC	35.100	9.000
MB	0.036	-
SK	0.108	-

Source: Canadian Biomass, 2012.

Resources

This section lists the maximum annual potential for each category of biomass feedstock which were used as inputs for the biofuel production technologies (Table 52). The average cost of producing each feedstock is shown along with the maximum annual availability.

Table 52. Biomass feedstock resources

Region	Feedstock	Cost, $/GJ	Annual potential up to 2050, PJ
AB, BC, MB, SK	Corn, Wheat, Other starch or sugar crops	$26.96	48.36
	Soybeans, Canola, Other oilseed crops	$30.36	357.91
	Greasy residues	$2.36	12.04
	Agricultural residues, industrial waste, forestry residues and dedicated crops	$7.46	605.41
ON,QC	Corn, Wheat, Other starch or sugar crops	$26.96	86.08
	Soybeans, Canola, Other oilseed crops	$30.36	15.00
	Greasy residues	$2.36	75.50
	Agricultural residues, industrial waste, forestry residues and dedicated crops	$7.46	591.69
NB,NL,NS,PE	Corn, Wheat, Other starch or sugar crops	$26.96	3.07
	Fish oil	$9.52	275.4
	Greasy residues	$2.36	1.0
	Agricultural residues, industrial waste, forestry residues and dedicated crops	$7.46	82.16

Source: Maximum crop availability is coming from the CanESS model (whatIf? Technologies, 2014). Average costs are coming from Labriet (2014) and EcoRessources Consultants & Agronovita (2008).

Trade

Biofuels. Interjurisdictional trade of biofuels is included in the model, however, limits on the distance of trade have been implemented. That is, jurisdictions can trade within regional areas (within Western, Central and Eastern Canada), but jurisdictions which are far apart cannot (for instance Alberta to New Brunswick). International imports and exports of biomass and biofuels are assumed to cancel each other out; no international trade is modelled. Transportation cost are derived from EcoRessources Consultants & Agronovita (2008).

Biomass feedstocks. Feedstock trade is not included in the model, both for international and interjurisdictional exchanges.

Policy implications

As mentioned in Section 4.2 on the transportation sector; following federal legislation implemented in 2010 and 2011, a constraint requires that gasoline contains a minimum of 5% ethanol and that diesel contains a minimum of 2% biodiesel. This guarantees a minimal level of biofuel production for the reference case scenario.

4.7.2 Limitations

Biomass and biofuels have a few limitations concerning its potential as a mitigation measure.

Fuel mix restriction in transportation sector. As discussed in Section 4.2 on the transportation sector, first-generation biofuels cannot completely substitute traditional fossil fuels for transportation due to performance issues in cold weather. This is resolved by the introduction of second-generation biofuels which do not suffer from this issue and can entirely substitute traditional fuels used for transport. However, second-generation biofuels are deemed a disruptive technology as they are not yet commercially proven.

Limited feedstock reserves. Biomass feedstock resources are limited, and these limits combined with the absence of international and interjurisditional trade can hamper the potential of biomass and biofuels as a mitigation measure. For example, biomass-based electricity generation with CCUS technology is limited to jurisdictions with corresponding feedstock inputs - dedicated crops, agricultural residues and forestry residues; however, these are also used as inputs for second-generation biofuels. The limits of this constraint become apparent if a jurisdiction could benefit from biomass-based electricity generation with CCUS technology and either does not have sufficient reserves of corresponding feedstocks within its own jurisdictional borders, or its feedstocks are already being fully used to produce second-generation biofuels. There is a need for a more precise evaluation of all biomass potential for energy production. Future studies could allow interjurisditional trade of biomass, increasing the potential for this mitigation options in jurisdictions with limited feedstock resources.

4.8 Carbon Capture, Use and Storage (CCUS)

4.8.1 Sector Description

This section also differs from previous sections in the sense that CCUS is not an energy sector, but rather an emerging technology with GHG emission reduction potential.

While there are three concepts for capturing CO_2 from thermal generating facilities (post combustion capture, pre-combustion capture and oxyfuel combustion), only post-combustion options for which reliable information is available are currently represented in the model database. More precisely, CCUS options are available for coal fired and biomass fired generation, including both retrofits for existing facilities and new facilities.

This option allows for a considerable reduction in emissions related to the combustion of fossil fuels. First, CO_2 is separated and captured from exhaust gases. Second, the captured $CO_2$is put into long-term storage, mainly in underground reservoirs.

Technologies

Three main options for electricity generating technologies for CCUS are included in the model: retrofit of existing coal plants to include a CCUS module, build new coal-fired plant with CCUS and build new biomass-fired plant with CCUS (Table 53). For new commercial scale CCUS projects, 2020 was decided as the first available year for the CCUS technologies. Efficiency of power plant with CCUS is about 25% less than conventional plants.

Electricity generation from biomass with CCUS technology differs from the other options in that it can generate carbon credits. Carbon dioxide is first sequestered by the solid biomass during its growing phase. Subsequently, 90% of this sequestered carbon is captured by the CCUS technology when carbon dioxide is released during biomass combustion. Therefore, a majority of the sequestered carbon contained in the biomass is never released into the atmosphere and can be counted as negative emissions or carbon credits.

Table 53. Power plant with CCUS technologies

Technology	Start	Life	Efficiency	Capture rate (%)	Investment cost ($/kW)	Annual operating and maintenance costs ($/kW)
Refection of existing coal-fired plants	2020	40	28%	90%	$1,655	$67.36
New coal-fired plants	2020	35	30%	90%	$5,895	$43.11
New biomass-fired plants	2020	35	26%	90%	$5,895	$43.11

Source: IEAGHG, 2011; Evans, 2014.

Carbon sinks

Table 54 shows CO_2 sink potential across provinces. Deep saline aquifers, which refer to sedimentary rock types saturated with saline water (non-potable), represent the highest carbon sink potential in Canada. Enhanced oil recovery represents the carbon sink option with the second highest potential which consists of pumping carbon dioxide into oil reservoirs in order to extract extra oil. The carbon dioxide used to pump the extra oil is then stored in the ground.

Enhanced coal bed methane recovery represents the option with the third largest potential. It is very similar to enhanced oil recovery in that carbon dioxide is used to extract coal bed methane and is then stored underground. The last two options for carbon dioxide sequestration consist of storing CO_2 in depleted gas and oil fields. Considering that enhanced oil recovery is the most economically feasible option for Canada, Alberta and Saskatchewan are the jurisdictions with the most attractive options for carbon dioxide sequestration.

Table 54. CO_2 sink potential by jurisdiction

kt of CO_2	AB	BC	MB	ON	SK
Deep saline aquifers	37195000	1855000	310000	15000	4900000
Enhanced coal bed methane recovery, over 1000 m meter deep	420000	0	0	0	0
Enhanced coal bed methane recovery, less than 1000 m meter deep	420000	0	0	0	0
Enhanced oil recovery	1009000	1000	74000	0	692000
Depleted offshore gas fields	0	0	0	0	0
Depleted onshore gas fields	80720	80	5920	0	55360
Depleted offshore oil fields	0	0	0	0	0
Depleted onshore oil fields	80720	80	5920	0	55360

Source: NETL, 2010; Experts assumptions for disaggregation between oil & gas wells.

Trade

CO_2 transportation is not currently modelled, therefore CCUS technology is jurisdictionally limited in the sense that CCUS plants must be built in jurisdictions endowed with adequate carbon sink potential. Future model enhancements could allow transportation of CO_2 across jurisdictions and consequently increase the potential for carbon capture in jurisdictions with limited sequestration options.

4.8.2 Limitations

Electricity generation from biomass with CCUS. Electricity generation from biomass represents a very interesting mitigation option when coupled with CCUS technology as it allows for the generation of carbon credits. However, limited biomass feedstocks represent a significant limitation to the potential of this technology, especially when considering that second generation biofuels compete for the same feedstocks. Additionally, biomass transport is not implemented in the model. Therefore, biomass based electricity generation with CCUS is jurisdictionally limited to areas with adequate biomass feedstocks.

Carbon sink potential. Since transport of CO_2 is not implemented in the model, CCUS technology potential is jurisdictionally limited by CO_2 sink potential. Therefore, only provinces shown in Table 54 can benefit from electricity generation equipped with CCUS technology and its economic viability also varies within these five provinces; Alberta and Saskatchewan being the jurisdictions with the highest economic viability due to the potential for enhanced oil recovery.

10% of emissions remain. A significant current limitation of CCUS technologies is that they do not completely eliminate CO_2 emissions. The 10% of emissions which are released limit the feasibility of CCUS technology, especially when considering that a completely decarbonized electricity supply is feasible for Canada due, in majority, to its endowment of hydro potential. Consequently, the potential for reducing this percentage to lower levels is an important area for future investigation. For more stringent reduction scenarios, the marginal cost of GHG emission reduction may reach levels were CCUS technology is not as economically viable as technologies such as nuclear generation which has a much higher investment cost yet does not emit any GHGs.

In summary, the potential role of CCUS in ambitious GHG emission reduction strategies is very conservative and would benefit from further model additions and refinements. A detailed representation of biomass and CO_2 trading options between jurisdictions would significantly increase the potential for biomass based electricity generation with CCUS and allow achieving net negative emissions on a longer term horizon. Finally, other opportunities have not been represented such as CCUS with natural gas combined cycle cogeneration, industrial processes and other non-combustion sources.

5. Scenarios

5.1 Introduction

As is well recognized, the use of scenarios is very valuable for producing insight and understanding for complex problems, including associated responses over time for specific combinations of premises. Any single scenario can be considered as a plausible description of a potential future, which is derived from an internally consistent combination of defined premises. By prescribing different combinations of premises, and analyzing the results of associated scenarios, it is then possible to understand how different premises, or combinations of premises, influence results, and how different futures occur as a consequence.

For the scenarios, prime focus has been on options for reducing GHG emissions from combustion of fossil fuels. As reported, this represents 72% of total GHG emissions, with the other emissions (28%) coming from non-combustion sources.

For the project, there were eleven sets of scenarios. For all scenarios, the approach was to derive minimum cost solutions with the NATEM-Canada optimization model, and with selected results being confirmed with the CanESS simulation model (see Section 3.2). Input data for the two models was based on information in the various Working Papers for the project, and as summarized in Section 4.

For this project, there were several key premises that served to define the basis for the various scenarios. These are summarized as follows (Table 55):

- For all scenarios, demand was defined by progressively increasing end uses from 2011 to 2050, with such growing demands based on economic and socioeconomic development in Canada, as described in Section 2.8. Demands were defined for each of the various classes of end uses over time, for each sector and in every jurisdiction.
- There were two Reference Scenarios which were based on the premise that there was no requirement for reducing GHG emissions. All other scenarios had reduction targets for GHG emissions. By comparing results of such scenarios against results of the respective Reference Scenario, it was then possible to assess impacts of GHG mitigation on the overall solution, including the respective sectors, different jurisdictions, and associated costs.
- It should be noted that for all scenarios, other than the Reference Scenarios, there were profiles for defining progressive reductions in combustion emissions over time, from 2011 to 2050. These were defined by targeted reductions in 2050, which varied from 30% to 60% (70% in selected cases) below the actual recorded value of 427 Mt in 1990.
- For most of the scenarios, an important foundational premise was that minimum cost solutions were derived, to the maximum extent possible, based on absence of developmental constraints. It was assumed that there were no socioeconomic or environmental constraints. It was also assumed that infrastructure developments as derived in minimum cost solutions, would be available for on-line service at the optimum time. Also, there were no equity constraints.
- The value of this approach was to demonstrate, as a starting point, minimum cost solutions in the absence of constraints. Constraints could be subsequently introduced into the optimization

model, which would result in increases in minimum cost solutions, and thereby, provide a basis for demonstrating cost impacts associated with imposition of such constraints.

- An important starting premise was to accept production projections of fossil fuels, as defined by the National Energy Board, with nominal modifications (reductions) after discussions with the Canadian Association of Petroleum Producers and Alberta Innovates. This projection was used for eight of the eleven scenarios.
- It was considered that this premise could represent unduly high projections for production and export of fossil fuels, especially in the context of progressively reducing use of fossil fuels world-wide, in response to global progress on reducing GHG emissions. Accordingly, a second series of scenarios was based on lower production and export projections of fossil fuels in Canada.
- For three of the eleven scenarios, it was assumed that there would not be any additional electricity interconnections between neighboring jurisdictions. There are existing interconnections for economy energy exchange between neighboring jurisdictions. There are also, at this time, dedicated agreements for capacity transfer from the Point Lepreau nuclear generating facility in New Brunswick to Prince Edward Island, from the planned Muskrat Falls hydro development in Newfoundland & Labrador to Nova Scotia, and from the Churchill Falls Hydro project in Newfoundland & Labrador to Quebec.
  It was recognized that the merit of including high voltage interconnections between neighboring jurisdictions would almost certainly result in significant reductions in overall minimum cost. Accordingly, this option was included in the remaining eight scenarios.
- For four of the scenarios, only options, which were commercially proven, were included. These included the various proven fossil fuel and electricity supply options, first generation biofuels, energy efficiency & energy conservation, etc.
- For other scenarios, additional technologies were included, which are known, but are not fully developed commercially. These were referred to as disruptive technologies. These included second generation biofuels (ethanol from lignocellulose and biodiesel), coal fired generation with CCUS, biomass based electricity generation with CCUS, and biojet fuel.
- A special study was carried out to assess the potential for reducing GHG emissions from improved urban form. Quantitative assessments were carried out for potential reductions in residential demand and personal transport. These results are reported for one of the scenarios (Scenario 4).
- A special assessment was carried to assess results for the possible case that there will not be any additional development of nuclear power in Canada. These results are reported in one of the scenarios (Scenario 7).
- One of the special considerations was to assess potential impact from including 30 GW of additional large scale hydro in British Columbia. At the present time, such developments are not permitted due to existing legislation in the Province. This option was included in two of the scenarios.
- There was one scenario which was not based on application of the optimization model (Scenario 6). This included consideration of increased export and trade of electricity with neighboring jurisdictions in the United States, especially from Canadian jurisdictions with availability of low cost hydro for increased production of dependable capacity. For this Scenario, the assessment was based on literature reviews of likely changes in the respective electricity supply systems, and associated assessment of opportunities for increased export and trade between such jurisdictions.

Table 55. Premises for Eleven Scenarios

Eleven Scenarios (S1-S8 and S1a-S8a)											
Premises Included in Scenarios	High Fossil Fuel Production/Export								Low Fossil Fuel Production/Export		
	S1	S2	S3	S4	S5	S6	S7	S8	S1a	S3a	S8a
No Targeted Reductions in GHG Emissions	X								X		
Targeted Reductions in GHG Emissions		X	X	X	X	X	X	X		X	X
No New High-voltage Interconnections		X									
New High-voltage Interconnections			X	X	X	X	X	X		X	X
Changes in Urban Form				X							
Second Generation Biofuels					X			X			X
Carbon Capture and Storage (CCUS)					X			X			X
Increased Electricity Export to United States						X					
New Nuclear Power Generation	X	X	X	X	X	X		X	X	X	X
No New Nuclear Power Generation, other than Retrofits to Existing Plants							X				
Biojet Fuel								X			X
Bioenergy with CCUS (BECCS)								X			X
New Large-scale Hydro in B.C.								X			X

For each of the scenarios, there is extensive reporting of results, along with associated interpretations. The principal results for each scenario are summarized at the end of each Sub-section.

A special assessment was carried out to review immediate actions for achieving major reductions in GHG emissions by 2030 (short term results). Results for maximum reductions in GHG emissions for the most ambitious scenario (Scenario 8a) are compared with Canada's internationally committed GHG reductions, from the recent COP 21 meeting in Paris, in December, 2015.

In Section 6, results from all scenarios are reviewed in a collective sense. This process leads to greater understanding and insights into the most important strategies for achieving targeted GHG mitigation at minimum cost. The results also provide a basis for demonstrating the most cost effective options for achieving early and cost effective progress on GHG mitigation, and for assessing priorities for early action. In addition, the results provide insights into promising areas where more information and understanding is required, and to establish priorities for further investigation and research.

5.2 Description of Scenarios

In Section 3.2, there is a description of the general approach for this project. The dominant premises, and overview descriptions of the respective scenarios, are described in Section 5.1.

In this, each of the eleven scenarios is described in more detail, including purpose, premises and process.

5.2.1 Scenario 1: Reference Scenario

Purpose: The purpose of this scenario is to derive the minimum cost solution to 2050, for Canada, in the absence of any imposed GHG reduction limits and for high fossil fuel production projections.

Premises:

- Every jurisdiction implements energy efficiency, energy conservation and demand side management measures, consistent with fully capturing cost reduction benefits with such measures.
- Transformation strategies are limited to those which are proven and commercially viable. Projected improvements in efficiency and cost over time are included.
- Every jurisdiction will continue to be responsible for electricity self-sufficiency. This includes meeting all additional energy demand and dependable capacity requirements from within its respective jurisdiction, including existing agreements.
- Exchange of electrical energy between jurisdictions based on principles of economic efficiency exchange, through normal optimum joint system dispatch arrangements.

Process:

- Basic data concerning key economic drivers were supplied by CanESS, based on economic and socioeconomic projections, as reported in Section 2.8. This included population projections, GDP, time based gross output for various industrial sectors, and service demands (such as passenger kilometers in the transportation sector, number and type of dwellings for the residential sector, etc.) for all sectors.
- Optimization was carried out with NATEM Canada model, with derivation of major decision variables (for example, additional generating capacity for each class of facilities in each jurisdiction in each time period), along with associated system responses.
- More detailed simulation of system responses carried out with CanESS on year by year basis, with input of major decision variables produced by NATEM Canada
- Results from two models compared to ensure that results were consistent and credible. This has required additional runs with both models to ensure that the models produced sensibly accurate and consistent results.
- More detailed review of results, especially with NATEM Canada model, to provide insight on sensitivities, robustness of derived solutions, optimal solutions, etc.
- Detailed documentation of premises, results, and principal observations, conclusions and recommendations

5.2.2 Scenario 2: Scenario 1, with Reduced Combustion Emissions

Purpose: The purpose of this scenario was to demonstrate minimum cost solutions to 2050, for Canada, for a series of defined GHG reduction targets.

Premises: The premises were essentially the same as for Scenario 1, but with a series of model runs with the NATEM Canada model, with GHG reduction targets for combustion emissions, in 2050, varying from 30% to 60% reduction (in 10% increments) below the 427 Mt of total fossil fuel combustion emissions in 1990. These same emissions reduction profiles were also used in the CanESS model.

Process: Again, the process was essentially the same as for Scenario 1. The CanESS model was run with results for selected scenarios, for testing and verification. In the analysis and reporting of results, special consideration was given to comparing results to the Reference Scenario (Scenario 1), including insight on the most cost efficient transformation strategies for achieving major GHG reductions.

5.2.3 Scenario 3: Scenario 1 with National Electricity Self Sufficiency

Purpose: The purpose of this scenario was to demonstrate cumulative minimum cost solutions to 2050, for Canada, for progressively increasing GHG reduction targets.

The basic difference between Scenario 3, and Scenario 2, is that the requirement for electricity supply self-sufficiency from within each jurisdiction is eliminated, and is replaced with the option of purchasing energy and dependable capacity from other jurisdictions, when such supply is less costly.

Premises: The premises will be essentially the same as for Scenario 2, again with model runs with the NATEM Canada model, with GHG reduction targets varying from 30 to 60%, in 10% increments. The difference was that the model would search for optimal solutions based on purchase of energy and/or dependable capacity from other jurisdictions, including adding investments in high voltage interconnections.

Process: Again, the process was essentially the same as for Scenario 2. The CanESS model was run with results for selected scenarios, for testing and verification. In the analysis and reporting of results, special consideration has been given to comparing results with Scenario 2.

5.2.4 Scenario 4: Scenario 3 with National Electricity Self Sufficiency and Improved Urban Form

Purpose: The purpose of this scenario is to demonstrate the potential impact from a very progressive approach with best-in-class development and transformation of Urban Regions in Canada. This has included more specific attention to opportunities with changed urban form and urban typology, including urban densification, integrated multi-modal transportation systems, and reduced energy demands from improved residential developments (see also Section 3.4.6).

Premises: The premises were essentially the same as for Scenario 3, except that the runs were for only for two cases – 30% and 60% GHG reduction, respectively.

Process: The process was essentially the same as for Scenario 1. The CanESS model was run first with changed input definitions for energy and other end use demands, based on inputs provided by Boston Consulting for 2030 and 2050, respectively. In the analysis and reporting of results, special consideration was given to comparing results with results from Scenario 3

5.2.5 Scenario 5: Scenario 3 and Disruptive Solutions

Purpose: The purpose of this scenario was to demonstrate cumulative minimum cost solutions to 2050, for Canada, for progressively increasing GHG reduction targets, including addition of disruptive technologies. Disruptive technologies included primarily bio-diesel from biomass, ethanol from lignocellulose, and CCUS. These technologies were assumed to be technically and commercially viable after about 2020.

The basic difference between Scenario 5, and Scenario 3, was that additional options for reducing GHG emissions were added, with results being obtained for larger targeted reductions in GHG emissions.

Premises: The premises were essentially the same as for Scenario 3, again with model runs with the NATEM Canada model, with GHG reduction targets varying from 30% to 60% reduction, in 10% increments.

Process: The process was essentially the same as for Scenario 3. The CanESS model was run with results for selected scenarios, for testing and verification. In the analysis and reporting of results, special consideration was given to comparing with results for Scenario 3.

5.2.6 Scenario 6: Scenario 3 and Electricity Export

Purpose: The purpose of this scenario was to demonstrate potential economic opportunities with additional export of emissions free dependable capacity and increased trade of electrical energy from Quebec to the United States North-East region, and from Manitoba to the United States Mid-West region.

Premises: The premises were similar to Scenario 3. However, as there was not detailed information readily available for the regions of the United States, the analysis was based primarily on literature reviews on likely changes to the electricity supply systems in both Canada and the United States, and assessment of opportunities for enhanced trade, including especially increased export of dependable capacity. Information was obtained from the U.S. Department of Energy, *Annual Energy Outlook 2013* (EIA, 2013a); U.S. Department Energy, NREL *Renewable Electricity Futures Report* (NREL, 2012b); and *Report on Pathways to Deep Decarbonization* in the United States.

Process: In the analysis and reporting of results, special consideration was given to assessing economic potential for export of dependable capacity, in addition to enhanced trade in electricity.

5.2.7 Scenario 7: Scenario 3 and no Additional Nuclear Generation

Purpose: The purpose of this scenario was to demonstrate cost impacts with imposing constraints on additional nuclear generation. This included demonstrating trade-offs between including and not including additional nuclear generation in the future electricity supply mix.

Premises: The premise was a modification to Scenario 3. The major changes with respect to electricity supply included: no additional nuclear generation; existing nuclear in Ontario and New Brunswick would continue with planned refurbishments

Process: The process was essentially the same as for Scenario 3. Again, the CanESS model was run with results for selected scenarios, for testing and verification. In the analysis and reporting of results, special consideration was given to comparing with results for Scenario 3.

5.2.8 Scenario 8: Scenario 5 and Additional Transformation Strategies

Purpose: The purpose of this scenario was to demonstrate maximum potential for reductions in GHG emissions by 2050. In addition to including proven and disruptive solutions, there were additional transformation strategies included to achieve maximum reductions.

Premises:

- The premises were the same as for Scenario 5, but with the following additional considerations.
- Addition of 30GW of large scale hydro development in British Columbia.
- Carbon capture and storage from conventional thermal generation, using biomass as feed stock.
- Addition of bio-jet fuels for airline and marine transport.
- Addition of improved urban form (Scenario 4).

Process: The process was similar to Scenario 5. The CanESS model was run with results for selected scenarios, for testing and verification. In the analysis and reporting of results, special consideration was given to comparing with results from Scenario 5, and providing perspectives on the most promising options and associated need for additional investigations. Assessments were also made from combining results of this scenario with the best available perspectives for reducing non-combustion emissions and consideration of net negative emissions.

5.2.9 Scenarios 1a, 3a and 8a: Reduced Production of Oil and Natural Gas

Purpose: Scenarios 1a, 3a and 8a are three separate scenarios, all of which are associated with reduced fossil fuel production and export (sometimes referred to collectively as the Ninth Scenario). These are for direct comparison with results from Scenarios 1, 3 and 8, respectively.

The purpose of these scenarios was to demonstrate cost and GHG impacts associated with lower potential projections for fossil fuels production, use and export for Canada. The fundamental premise was that with reduced projected use of fossil fuels in Canada, that use of fossil fuels in the rest of the world should reduce correspondingly, and by extension, export of fossil fuels from Canada would also reduce correspondingly.

Premises: The premise was based on assessing impacts from potentially reduced production, use and export of fossil fuels in Canada. A lower bound for use of fossil fuels in Canada was based on the 60% GHG reduction results from Scenario 2, which was the largest reduction derived in that Scenario. A lower bound for export was also based on the premise that exports would reduce by the same ratio as use in Canada would reduce. The formulation for the optimization model was then defined so that the model would select the most optimistic combination of production, use and export within a defined range, between the lower bound as noted above and an upper bound as defined by modified National Energy Board projections.

Process:

- To derive modified production projections for fossil fuels, based on the 60% GHG reduction results from Scenario 2
- Carry out model runs with the NATEM Canada model to produce a modified Reference Scenario (Scenario 1a), modified Scenario 3 results (Scenario 3a) and a modified Scenario 8 results (Scenario 8a)
- The CanESS model was used to derive modified drivers for NATEM Canada. After receiving results from NATEM Canada, the CanESS model was used for selected scenarios, to provide normal testing and credibility checks.

5.3 Results from Scenario 1 (No GHG Reduction)

Scenario 1 is a Reference Scenario. This scenario is intended to provide a basis for demonstrating progressive increases in overall GHG emissions, in the absence of any concerted attention for reducing such emissions. It is also assumed that there are no substantive changes in existing jurisdictional responsibilities for energy, including no reliance on dependable capacity for electricity supply from other jurisdictions, other than those which are already in place.

Based on this, there are no imposed targets for reducing combustion emissions. The model derives minimum cost solutions for meeting growing energy based demands. This includes investment and operating costs for additional infrastructure, as well as cost savings from improvements in energy conservation, energy efficiency and demand side management.

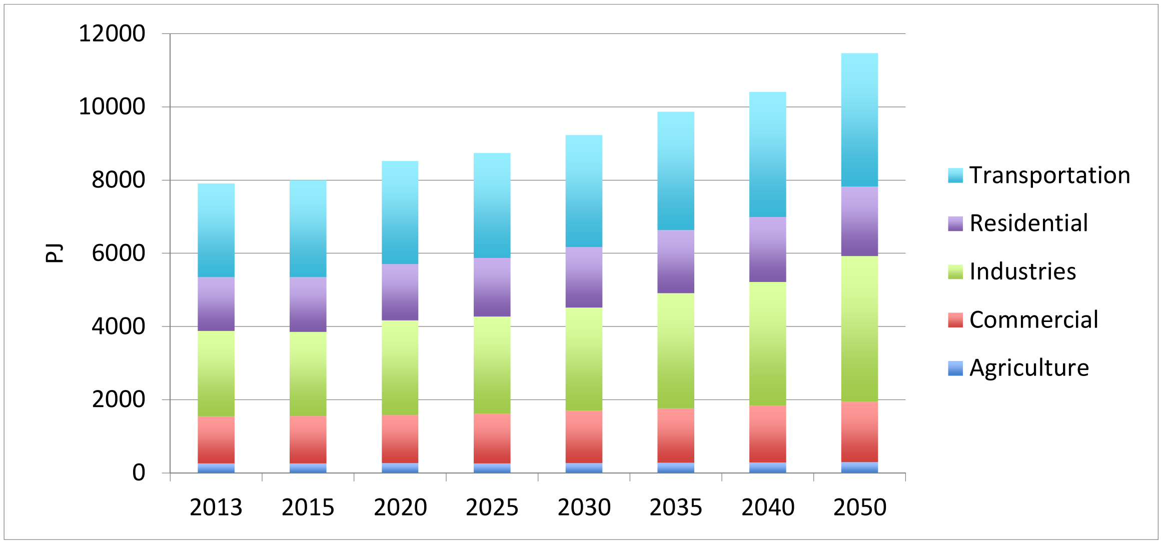
5.3.1 Final Energy Consumption

Final Canadian energy consumption by end-use demand sector is shown in Figure 24. Total final energy consumption increases from 7,914 PJ in 2013 to 11,470 PJ in 2050, a 45% increase. From 2013 to 2050, transport final energy consumption increases from 2,569 PJ to 3,645 PJ (42% increase), residential final energy consumption increases from 1,467 PJ to 1,901 PJ (30% increase), industrial final energy consumption increases from 2,336 PJ to 3,976 PJ (70% increase), commercial final energy consumption increases from 1,285 PJ to 1,657 PJ (29% increase), and finally, agriculture final energy consumption increases from 258 PJ to 292 PJ (13% increase).

Key observations from detailed review of results are as follows:

- There is continuing growth in energy demand in all end use sectors.
- There are some nominal shifts in energy use between the five end use sectors. Energy demand in the industrial sector grows more quickly than in the other sectors.
- The impact of energy conservation, energy efficieny, and demand side management are most evident in the transportation, residential and commercial sectors. For the residential and commercial sector, the impact of improved efficiencies of appliances and other end use technologies results in reducing rate of growth for energy demand. For the transportation sector, there is the combined impact from implementing CAFE standards and progressive shift towards more electric and hybrid vehicles, especially in jurisdictions with low cost electricity.

Figure 24. Final energy consumption by sector

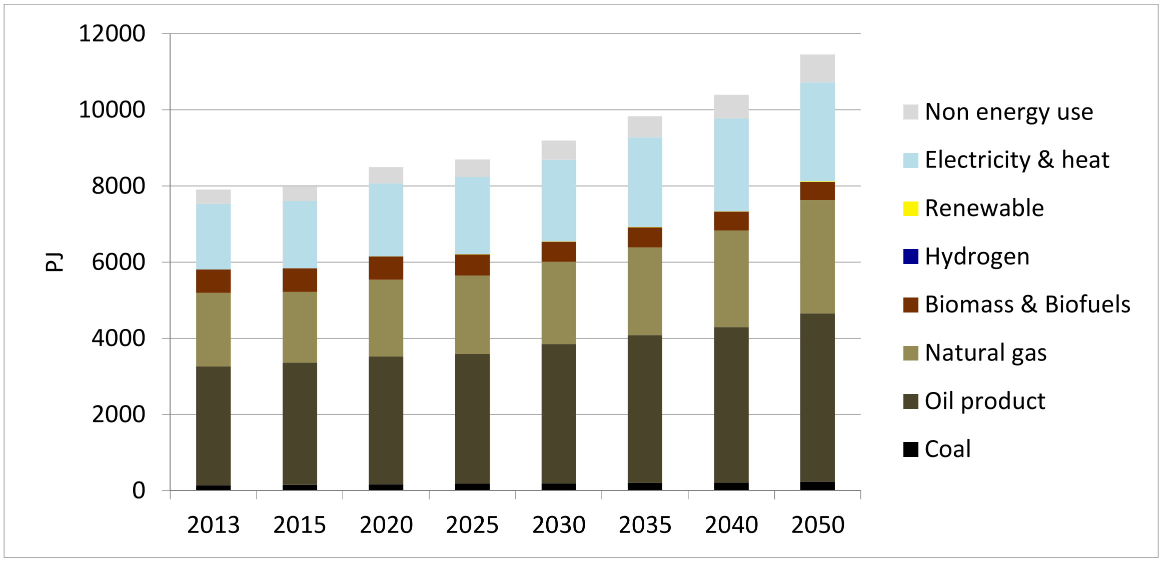


Final energy consumption is shown in Figure 25 (same as Figure 24), but with energy end use being represented by fuel type. From 2013 to 2050, consumption of oil products increases from 3,114 PJ to 4,421 PJ (42% increase), consumption of natural gas increases from 1,929 PJ to 2,977 PJ (54% increase), consumption from electricity and heat increases from 1,729 PJ to 2,600 PJ (50% increase), and final consumption of solid biomass and biofuels (ethanol and biodiesel) decreases from 613 PJ in 2011 to 478 PJ in 2050 (22% decrease). The share of total final energy consumption attributed to oil, natural gas, electricity and heat, and biomass and biofuels, are, respectively, 39%, 24%, 22% and 8% in 2013, and 39%, 26%, 23% and 4% in 2050.

Key observations from detailed review of results are as follows:

- There is continuing growth in all traditional energy sources, except biomass/biofuels, for meeting energy end use requirements.
- There is some nominal shift towards increasing reliance on electricity and heat, and natural gas, primarily because of competitive cost. There are significant variances between jurisdictions, depending on relative cost of energy commodities in respective jurisdictions.
- The role of renewables (solar thermal and decentralized geothermal heat) and hydrogen is virtually negligble.
- The increased use of coal (coking coal) is primarily to satisfy growing demand in the iron and steel sector.

Figure 25. Final energy consumption by fuel



5.3.2 Primary Energy Production

Primary energy production by source is shown in Figure 26. Total primary energy production increases from 24,634 PJ in 2013 to 33,693 PJ in 2050, a 37% increase. From 2013 to 2050, primary oil production increases from 8,219 PJ to 13,095 PJ (59% increase). Natural gas production increases from 6,365 PJ to 10,170 PJ (60% increase). Coal production increases from 1,731 PJ to 1,936 PJ (12% increase). Uranium production decreases from 6,186 PJ to 5,701 PJ (9% decrease). Hydro production increases from 1,397 PJ to 1,936 PJ (39% increase). Biomass reduces from 646 PJ to 559 PJ (13% decrease). The share of each source of primary energy production from 2013 to 2050 is shown in Table 56.

Key observations from detailed review of results are as follows;

- Dominant growth is with production of oil, natural gas and hydro. Oil continues to be the dominant source of primary energy production for the entire period.
- There is continuing expansion of export of energy commodities, dominantly oil and natural gas.
- The role for renewables, other than hydro, is minor, with little projected growth.
- The portion above the export line (approximately 3,000 to 4,000 PJ) includes energy losses in primary production.

Figure 26. Primary energy production by source

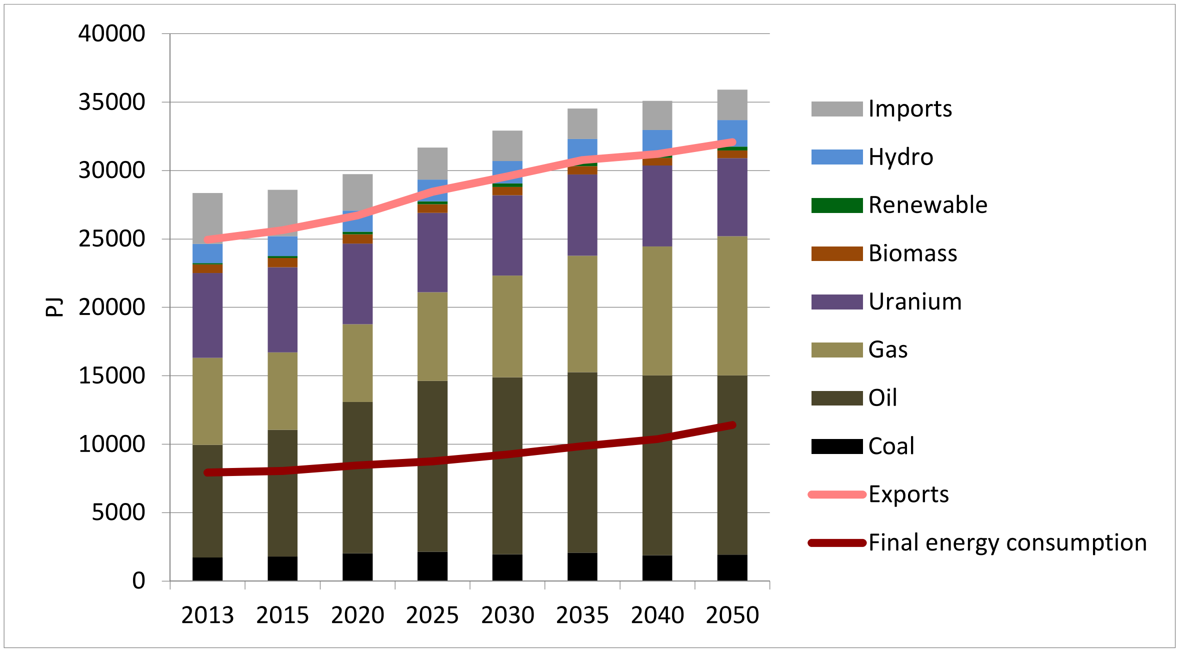


Table 56. Share of primary energy production by source

	2013	2015	2020	2025	2030	2035	2040	2050
Coal	7%	7%	8%	7%	6%	6%	6%	6%
Oil	33%	37%	41%	43%	42%	41%	40%	39%
Gas	26%	22%	21%	22%	24%	26%	29%	30%
Uranium	25%	25%	22%	20%	19%	18%	18%	17%
Biomass	3%	3%	2%	2%	2%	2%	2%	2%
Renewables	0%	1%	1%	1%	1%	1%	1%	1%
Hydro	6%	6%	6%	5%	5%	5%	5%	6%

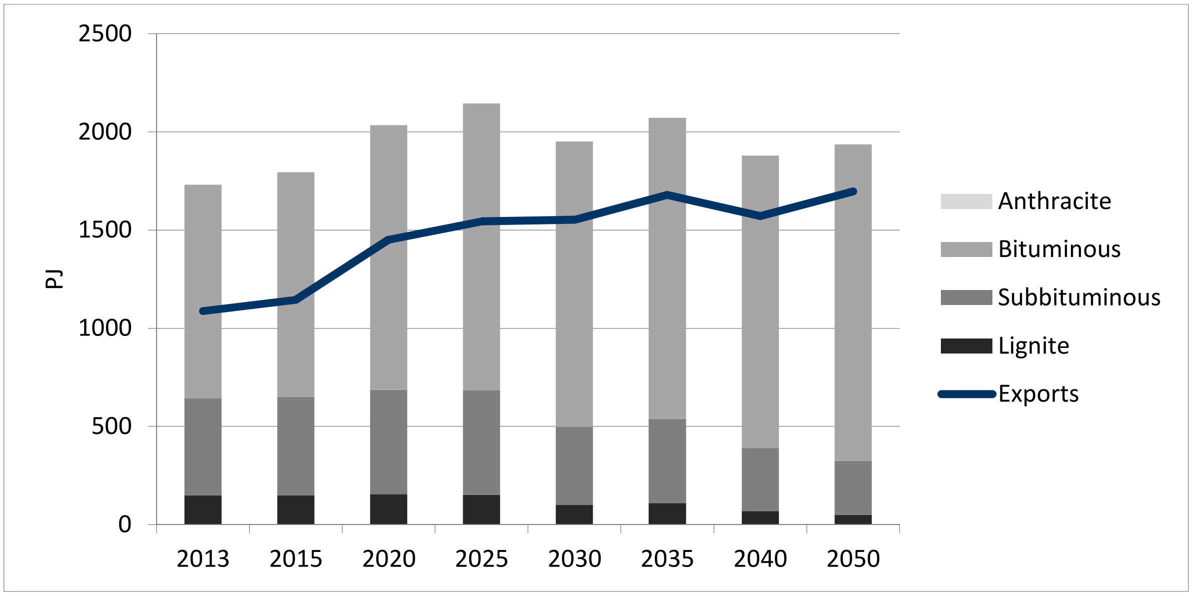
Primary Production of Coal

Total coal production increases from 1,731 PJ to 1,936 PJ, a 12% increase (Figure 27).

Key observations from detailed review of results are as follows

- Export of coal increases from 1,088 PJ (63%of total production) in 2013 to 1,698 PJ (88%) in 2050. This is driven primarily by reducing use of coal for thermal generation in Canada, as a consequence of progressive phase out of conventional coal fired plants, and corrseponding increase in export of thermal coal.
- Production of coking coal has continuing growth, dominantly for the export market, as well as projected increase for iron and steel production in Canada.

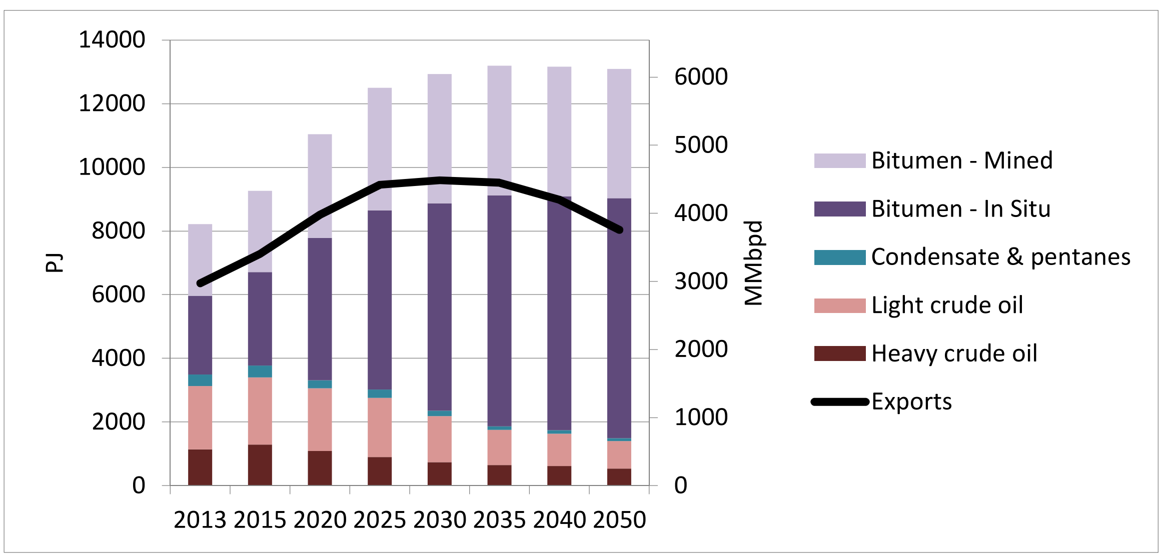
Figure 27. Primary coal production by source



Primary production of oil

In Figure 28, oil production is shown to increase from 8,219 PJ in 2013 to 13,095 PJ in 2050 (59% increase). Bitumen production increases from 4,724 PJ in 2013 to 11,602 PJ in 2050. Conventional oil production decreases from 3,131 PJ in 2013 to 1,402 in 2050. Exports increase from 6,346 PJ (77% of total production) in 2013, to 8,036 PJ (61%) in 2050.

Figure 28. Primary oil production by source



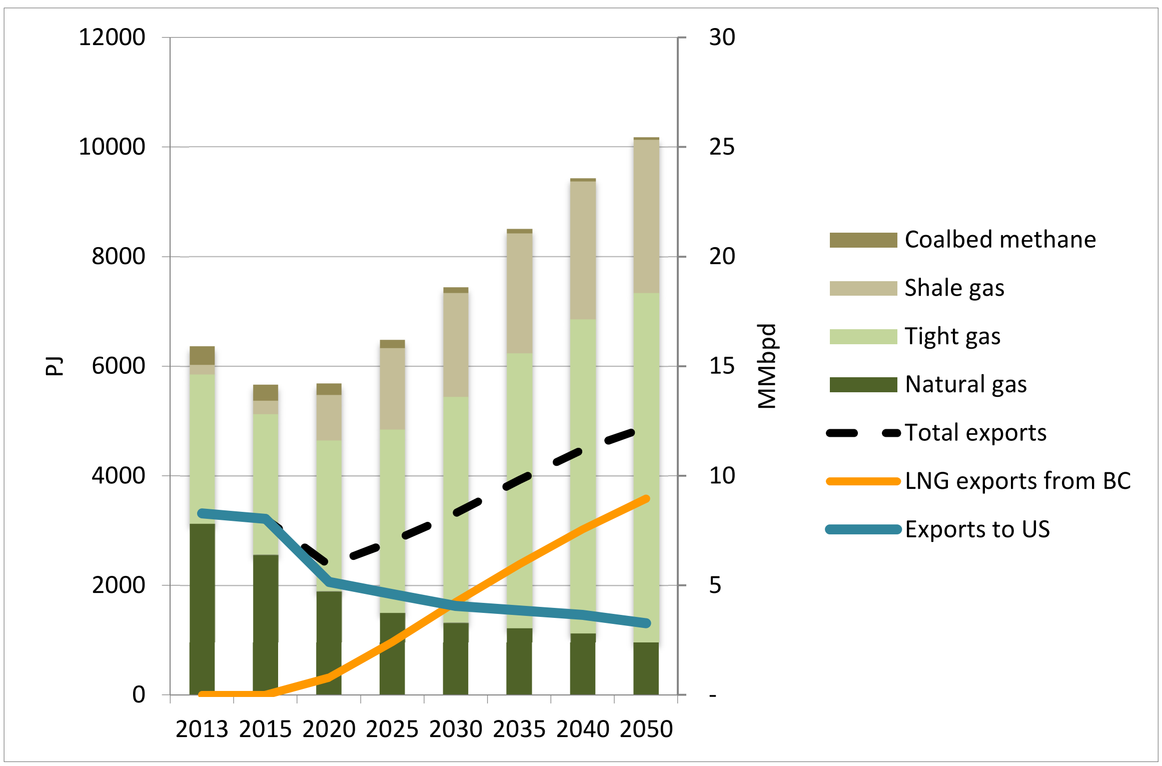
Key observations from detailed review of results are as follows:

- Dominant growth of oil production is from in-situ extraction of heavy bitumen in the oil sands. Most of this increased production is projected for export to the United States Gulf Coast, where the major facilities in North America exist for upgrading and refining heavy bitumen.

Primary Production of Natural Gas

Total natural gas production is shown in Figure 29. Natural gas production increases from 6,365 PJ in 2013 to 10,170 PJ in 2050 (60% increase). Conventional natural gas is progressively replaced by unconventional sources, with conventional production decreasing from 3,129 PJ in 2013 to 967 PJ in 2050 (69% decrease). Unconventional gas (tight gas, shale gas and coal bed methane) production increases from 3,235 PJ in 2013 to 9,202 PJ in 2050 (184% increase). Total exports represent 51% of production in 2013 and 48% in 2050.

Figure 29. Primary gas production by source



Key observations from detailed review of background documentation and results are as follows:

- Current projections include rapid increase in production of natural gas, especially after 2020. This is due primarily by the rapid recent increase in availability of unconventional natural gas in Canada at globally competive cost, and driven especially by the shale gas revolution in North America.
- The short term decline from 2013 to 2020 is due to four factors. Firstly, there is rapid decline of export to the American market for consumption in the United States. This arises as a direct consequence of the recent major increase in shale gas production in the United States, with

corresponding reduced dependence on import from Canada. Secondly, production from conventional sources in Canada is declining. Thirdly, projected production from non-conventional sources in Canada is not projected to increase rapidly until after 2020. And fourthly, export of LNG is projected to develop slowly, occurring only after securing of contracts for export of LNG to overseas markets and completion of major capital intensive supporting infrastructure.

- The growth in production after 2020 is premised on successful rapid increase in LNG export, dominantly from the Canada's West Coast to the Far East.
- Both tight gas and shale gas are classified as non-conventional gas, which generally require extraction by a combination of horizontal drilling and hydraulic fracturing (fracking).

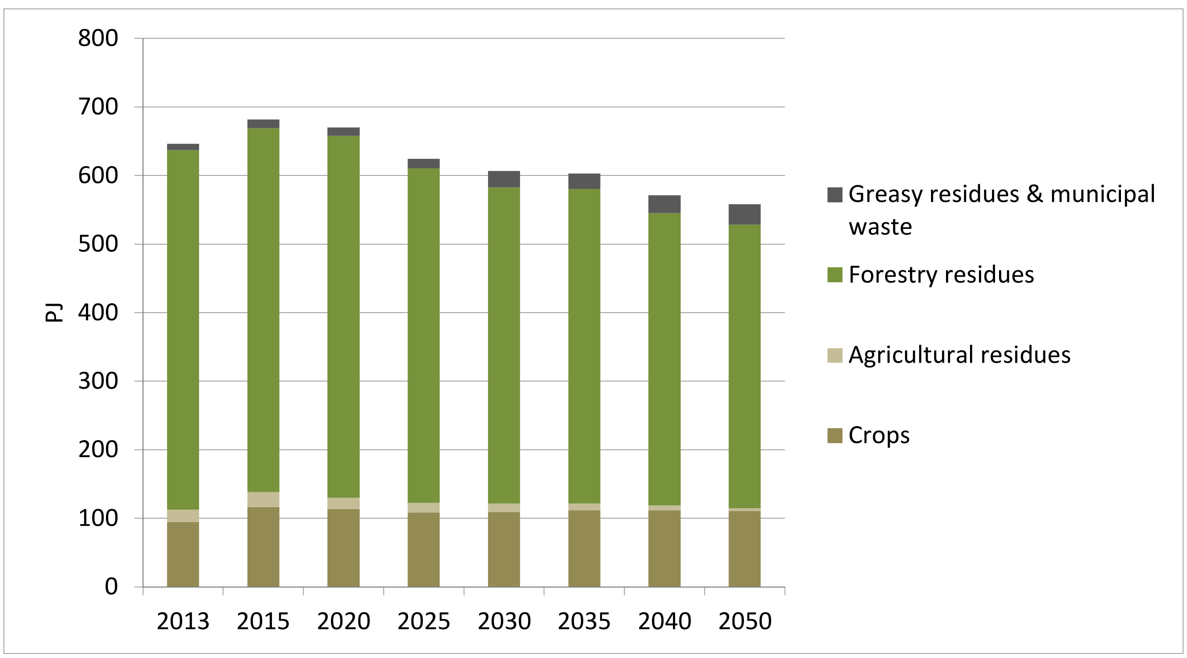
Primary production of biomass / bio-fuels

Primary production of biomass is shown in Figure 30. This is shown to decrease from 646 PJ in 2013 to 559 PJ in 2050 (13% decrease). The majority of this production is forestry residues, used primarily in the pulp and paper industry. Some of the residue is also used for heat and steam production. Biomass from crops is used for biofuel (ethanol) production.

Key observations from detailed review of background documentation and results are as follows:

- The demand for bio-fuels includes the need to satisfy existing legislation, with ethanol being generally 5% in gasoline and bio-diesel being generally 2% in diesel fuel (see Section 4.7.1)

Figure 30. Primary biomass production by source



5.3.3 End-Use Demand Sectors

The models separate Canadian energy consumption into five energy demand sectors: residential, commercial, industrial, transport and agriculture. Each sector has its own set of end-use demands (70 in total) for energy services across sectors, as shown on Table 57. In this Section, each energy consuming sector is defined and corresponding useful energy demand and final energy demand projections are presented.

Table 57. End-use demands by sector

Sectors	Number of segments	Units	End-use demand segments
Residential	20	PJ	Space heating (Detached houses; Attached houses; Apartments; Mobile homes); Space cooling (Detached houses; Attached houses; Apartments; Mobile homes); Water heating (Detached houses; Attached houses; Apartments; Mobile homes); Lighting; Refrigeration; Freezing; Dish washing; Cloth washing; Cloth drying; Cooking; Other
Commercial	8	PJ	Space heating; Water heating; Space cooling; Lighting; Street lighting; Auxiliary equipment; Auxiliary motors; Other
Industrial	13	Dollars and PJ	Iron and steel; Pulp and paper (Low quality, High quality); Cement; Non-ferrous metals (Aluminum, Copper, Others); Chemicals (Ammonia, Chlorine, Other); Other manufacturing industries; Other mining industries; Other industries
Transport	20	Million passenger-km (MPkm) and PJ Million tonne-km (MTkm) and PJ	- Road / Passenger: Small cars (Short distance, Long distance); Large cars (Short distance, Long distance); Light trucks; Urban buses; Subways; Intercity buses; School buses; Motorcycles; Off road - Road / Freight: Light trucks; Medium trucks; Heavy trucks - Rail: Freight; Passenger - Air: Freight; Passenger domestic; Passenger international - Marine
Agriculture	9	Dollars and PJ	Grains and Oilseeds, Dairy, Beef, Hog, Poultry, Eggs, Fruit, Vegetables, Other

Residential sector

According to Statistics Canada "Residential includes all personal residences including single family residences, apartments, apartment hotels, condominiums and farm homes." (see also Section 4.3.1).

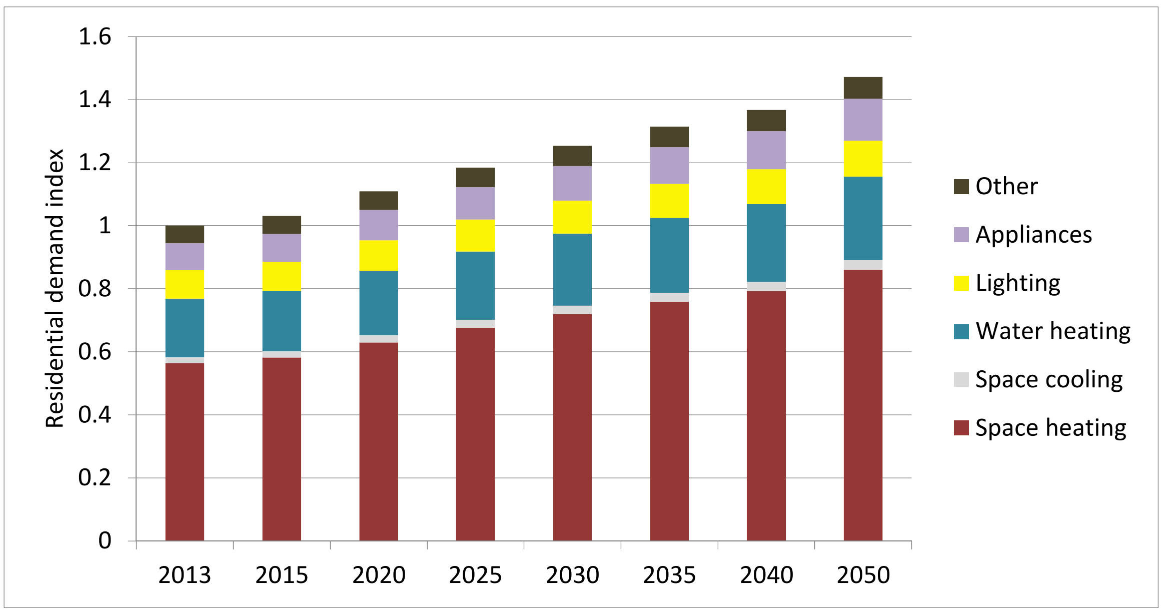
In this Section, there will be presentations on final energy demand by both service and energy source for the residential sector (Figure 31 and Figure 32, respectively).

In Figure 31, the residential sector's useful energy demand is shown. Total useful energy demand increases by 47% from 2013 to 2050. The proportion of each type of useful energy demand stays relatively constant over time. In 2013, the shares of total useful energy demand for appliances, lighting, water heating, space cooling and space heating were, respectively, 9%, 9%, 19%, 2% and 56% in 2013 and, 10%, 10%, 19%, 2% and 54% in 2050. These demand projections are determined by using the CanESS demand drivers and are exogenous; they are prescribed in the model.

Key observations from detailed review of background documentation and results are as follows:

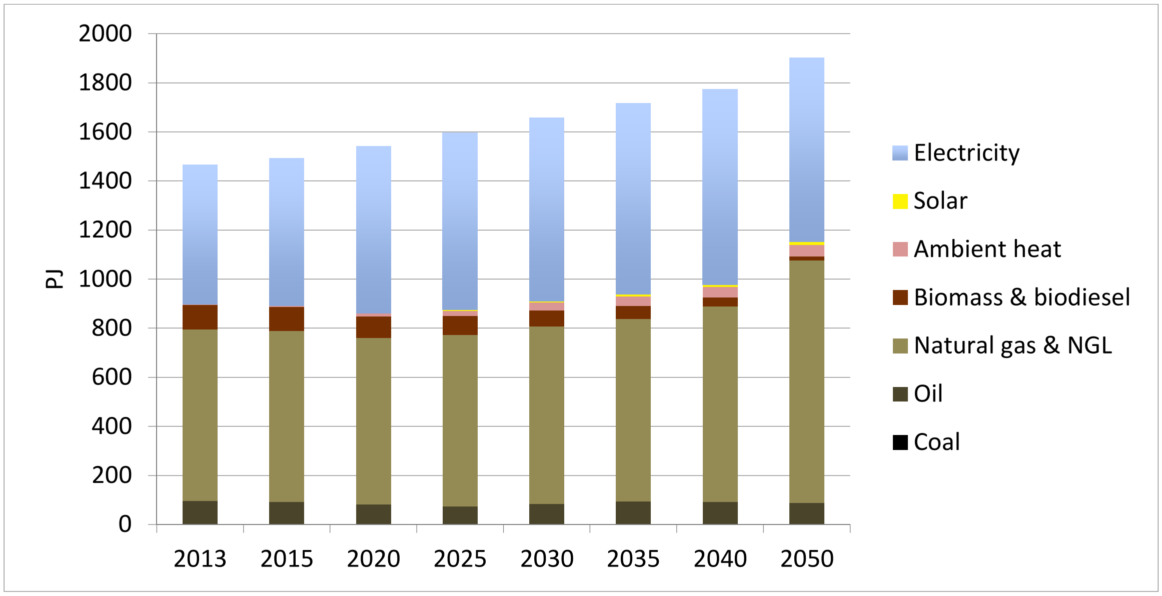
- Electricity supply and natural gas are projected to continue dominating energy supply for the residential sector, with natural gas and natural gas liquids (NGL), dominantly propane, being the dominant energy source for space heating and hot water supply. Electricity remains as the dominant energy source for lighting, appliances and other residential end uses. Electricity is also a source for residential heating and hot water supply, especially in jurisdictions with low cost electricity.
- The role of solar thermal is almost negligible. Ambient energy, associated with heat pumps, is also very minor.

Figure 31. Residential useful end use energy demand by service



Note: an index for residential and commercial end-use demand was created, with total demand by end-use category (i.e.: lighting) of each sector summing to 1 for the reference year of 2013. The purpose of the index is to avoid discrepancies between energy inputs and outputs of end-use technologies which arise from the manner in which technological efficiency improvements are modeled in the residential and commercial sectors.

Figure 32. Residential useful end-use by energy source



Space heating in the residential sector accounts for 62% of energy use in 2013, and increases nominally to 66% by 2050. As this is the dominant source of end use demand in the residential sector, it was arranged that this specific end use would be analyzed in further detail.

In Figure 33, energy use for residential space heating by fuel type is shown, with corresponding proportions shown in Figure 34.

Key observations from detailed review of background documentation and results are as follows:

- Space heating demand is met, in majority, by natural gas furnaces, electric baseboards, electrically driven heat pumps and oil furnaces. These represent, respectively, 49%, 27%, 5% and 8% for 2013 demand, and, 50%, 33%, 8% and 6%, respectively, for 2050 demand.
- The share of each type of energy used for space heating remains relatively constant over time. Electricity, natural gas & NGL, and oil represent 28%, 53% and 9%, respectively, of total space heating energy usage in 2013. In 2050, these proportions are 35%, 53% and 7%.
- Other space heating technologies include wood and coal furnaces and stoves.

Figure 33. Energy source for residential space heating

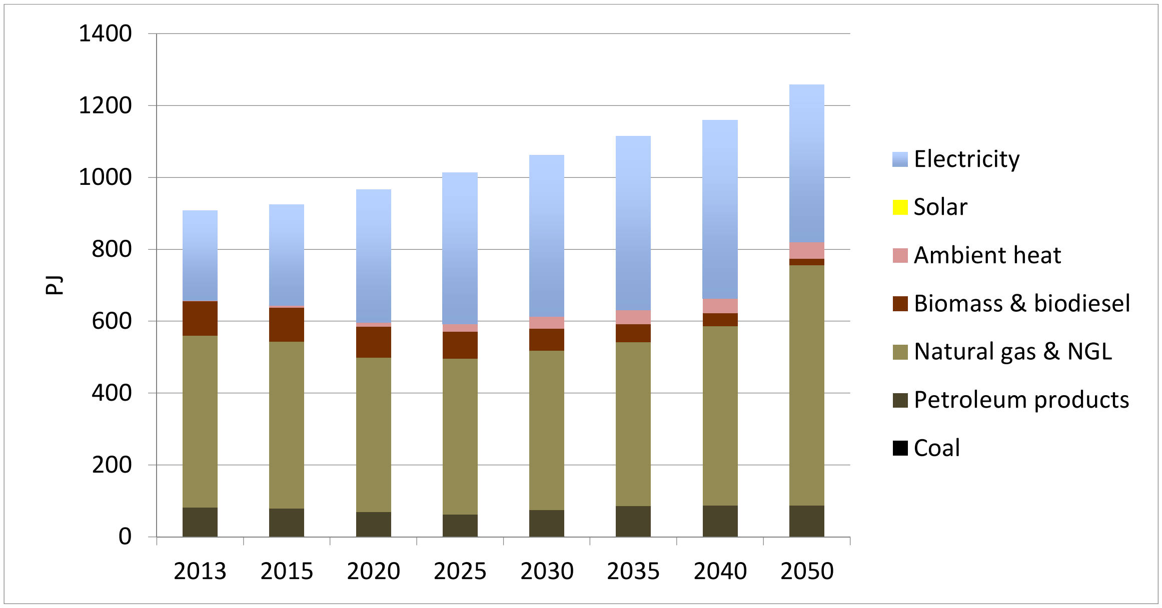
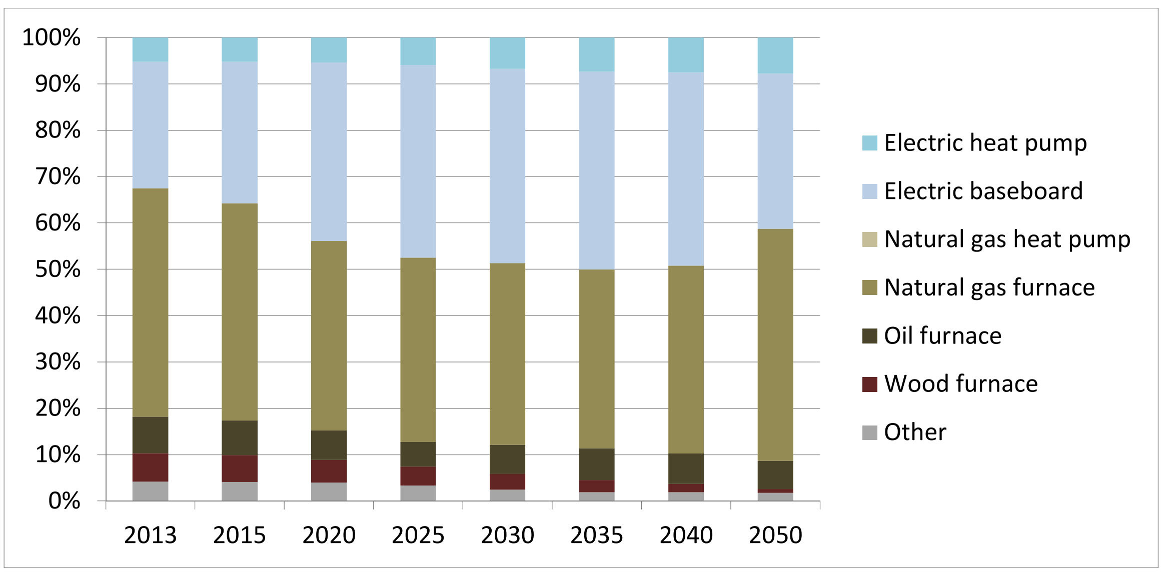


Figure 34. Market share for residential space heating



Commercial sector

According to Statistics Canada (2011): "The commercial sector includes service industries related to mining, transportation, as well as storage and warehousing, communications and utility (excluding electricity and natural gas), wholesale and retail trade, finance and insurance, real estate and business service, education, health and social services and other service industries." (see also Section 4.3.1).

As shown on Figure 35, the commercial sector's useful energy demand increases by 55% by 2050. The proportion of each type of useful energy demand stays nearly constant over time. The shares of total useful energy demand for auxiliary motors and equipment, water heating, space cooling, space heating, and lighting were, respectively, 18%, 5%, 3%, 25% and 33% in both 2013 and 2050. These demand projections are derived with the CanESS model and are exogenous.

Total final energy consumption for the commercial sector by energy source is shown in Figure 36. Energy consumption increases from 1,285 PJ in 2013 to 1,657 PJ in 2050 (29% increase). Natural gas consumption decreases slightly, from 527 PJ in 2013 to 440 PJ in 2050. Electricity consumption increases from 529 PJ in 2013 to 822 PJ in 2050. There is also an increase in ambient heat consumption, from heat pumps, from 5 PJ in 2013 to 61 PJ in 2050.

Key observations from detailed review of background documentation and results are as follows:

- As with residential demand, space heating again represents a major source of energy demand. Lighting demand and energy requirements for auxiliary motors and other equipment are also large.
- The general shift from natural gas & NGL, and petroleum products, is generally as a consequence of greater escalation of real costs for such products.
- There is an increase in use of heat pumps, as reflected in greater use of ambient heat
- Solar thermal is very minor, as it is not cost competitive.

Figure 35. Commercial useful energy demand

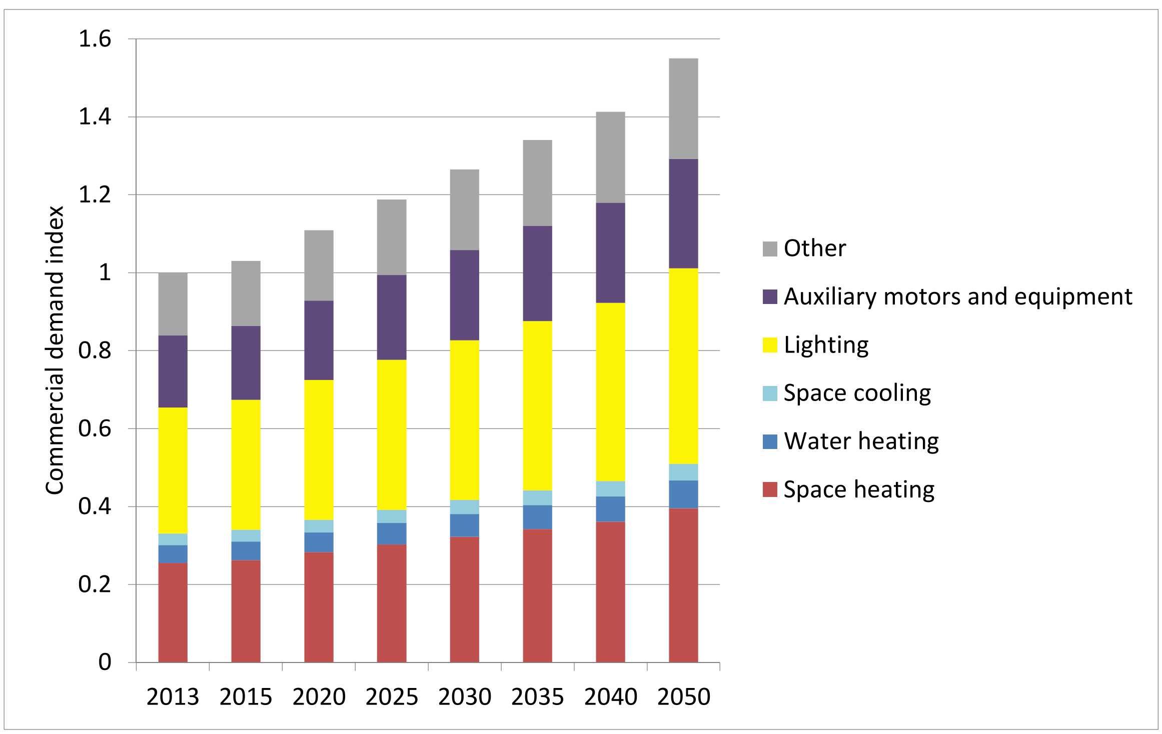
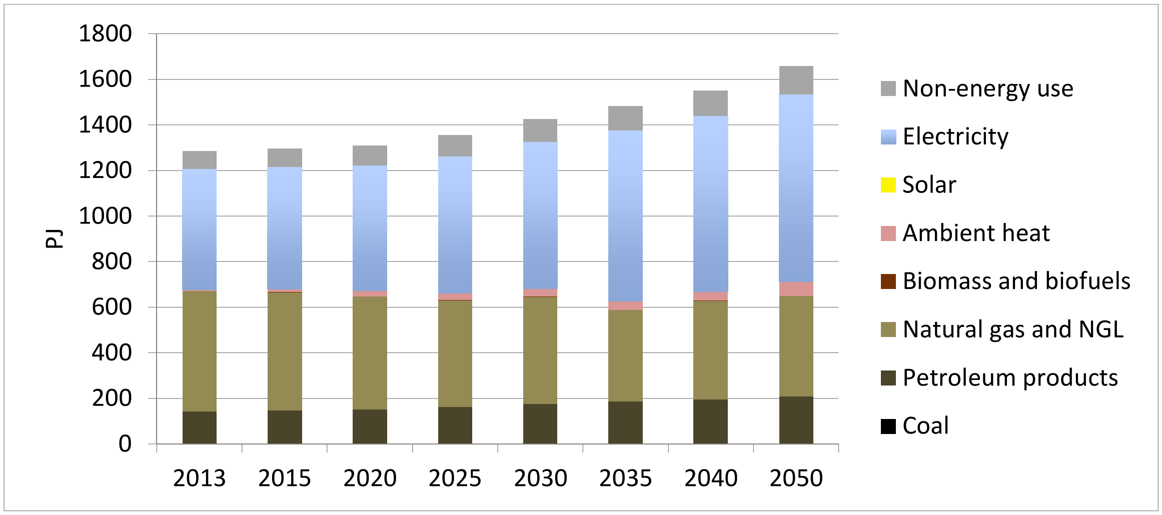


Figure 36. Commercial final energy consumption



Industry sector

According to Statistics Canada (2011), "this sector covers the manufacturing industries as well as other mining industries (excluding oil & gas mining), forestry and construction. Manufacturing industries include: pulp and paper, iron and steel, smelting and refining, cement, chemicals, and other manufacturing. Other industries include forestry and construction. Other mining industries include metal mines, non-metal mines, coal mines, crude petroleum and natural gas extraction industries, stone quarries gravel pits, exploration for minerals, development of mineral properties and contract drilling operations." (see also Section 4.4.1).

Energy consumption for petroleum refining is subtracted from total manufacturing and is included in the fossil fuels supply sector. Energy consumption for mining oil and gas extraction is also accounted in the fossil fuels supply sector.

Gross output for the industrial sector is shown on Figure 37, with corresponding energy usage on Figure 38. Gross output increases from $734 billion in 2013 to $1,672 billion in 2050. The construction sector increases from $247 billion to $491 billion.

Key observations from detailed review of background documentation and results are as follows:

- Final energy consumption for the industrial sector increases from 2,336 PJ in 2013 to 3,976 PJ in 2050 (70% increase). The most rapid increase is with natural gas, with the proportion increasing from 29% to 39%. The proportion of electricity use in total industry final energy demand decreases slightly, from 25% in 2013 to 22% in 2050. There are small changes in the proportional use of petroleum product and biomass & biofuels.
- The increased use of coal is driven dominantly by increased need for coking coal in the iron and steel sector.

Figure 37. Gross output for industrial sectors

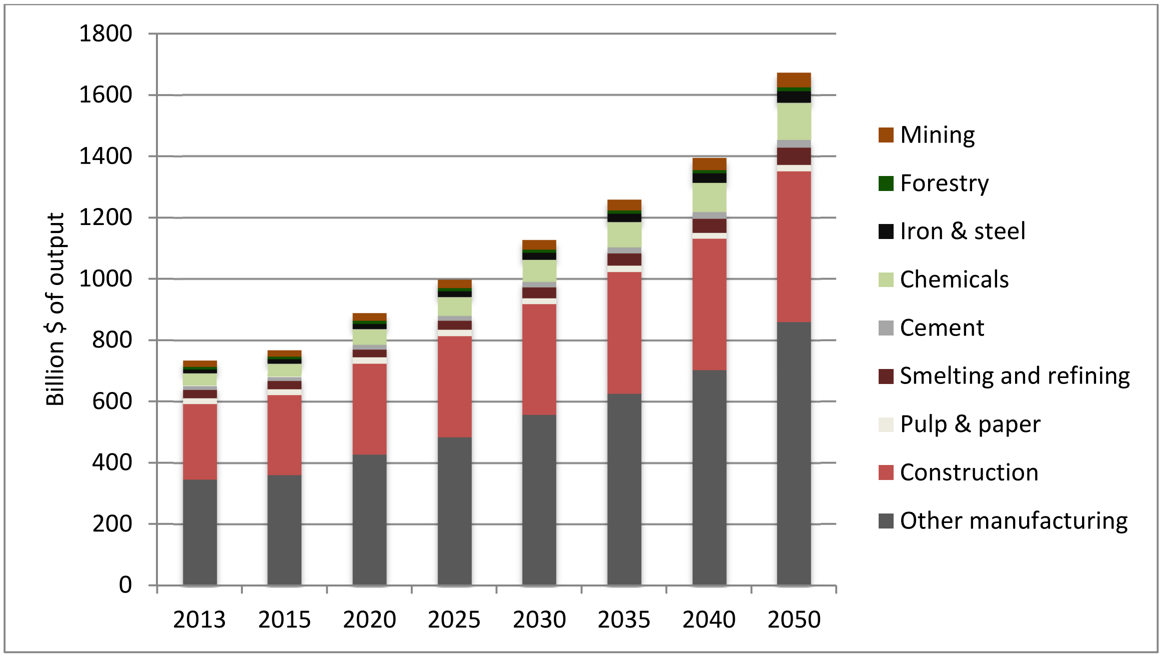
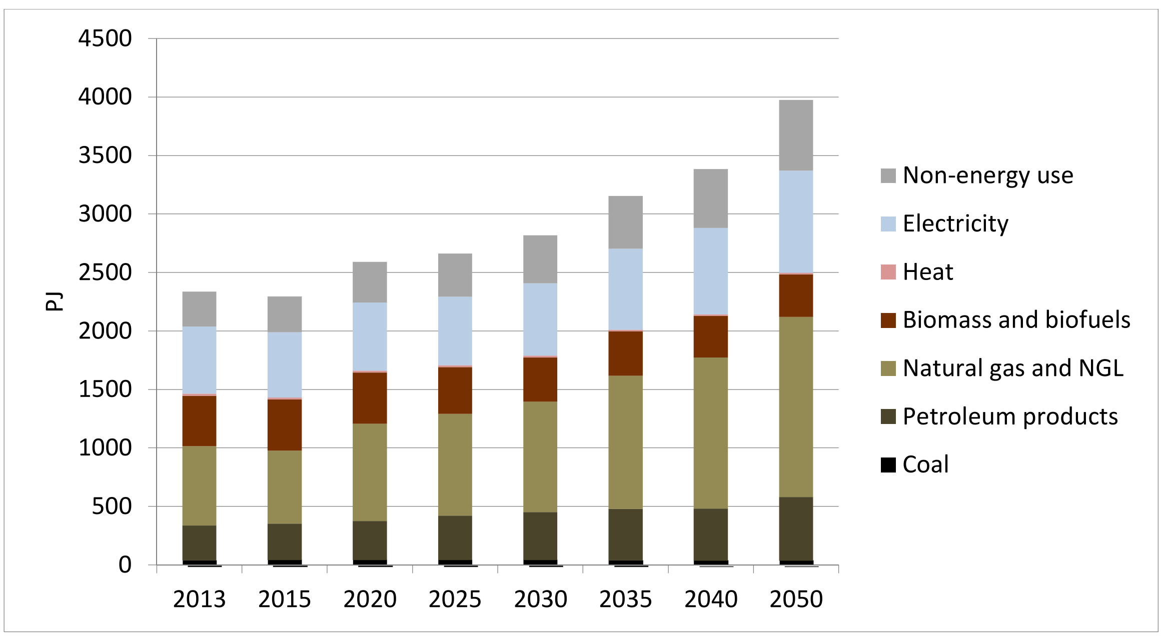


Figure 38. Industrial final energy consumption



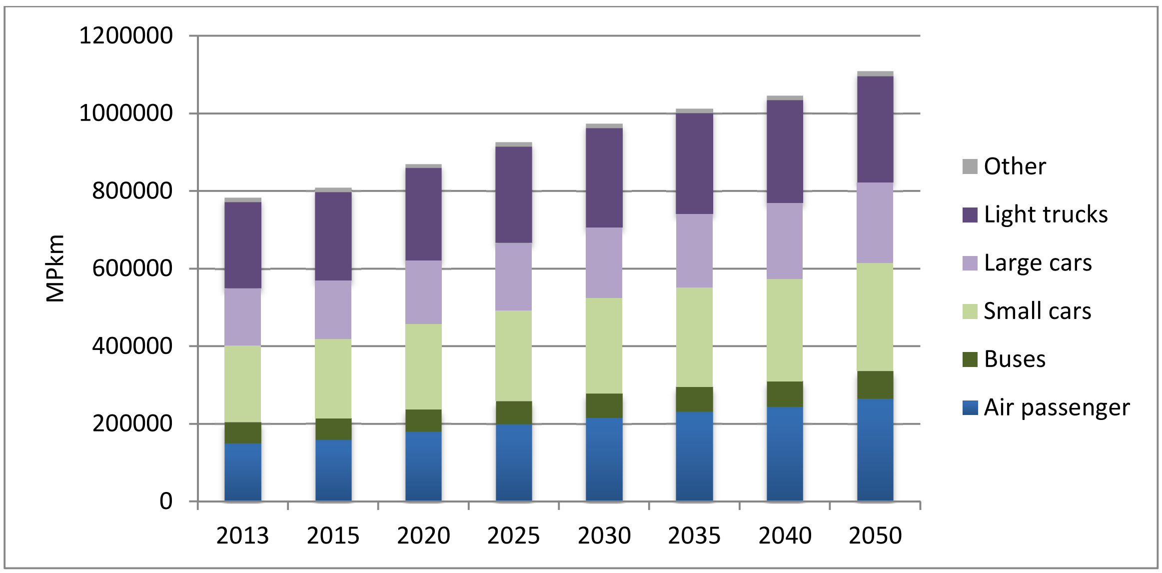
Transportation Sector

The transportation sector (Statistics Canada, 2011) includes "only the use of fuel by the transportation industry for transportation purposes. Excluded are any fuels used for activities not directly involved in transportation (i.e. train stations, warehouses, airports, etc.). These amounts are included in commercial and other institutional. Fuels, which have been purchased for use by the agriculture, commercial and public institutions sectors for transportation purposes, are included in the sectors to which the fuel was sold." Further details are included in Section 4.2.1.

It is noted that energy consumption for pipeline transport has been subtracted from total transport and is included in the fossil fuels supply sector.

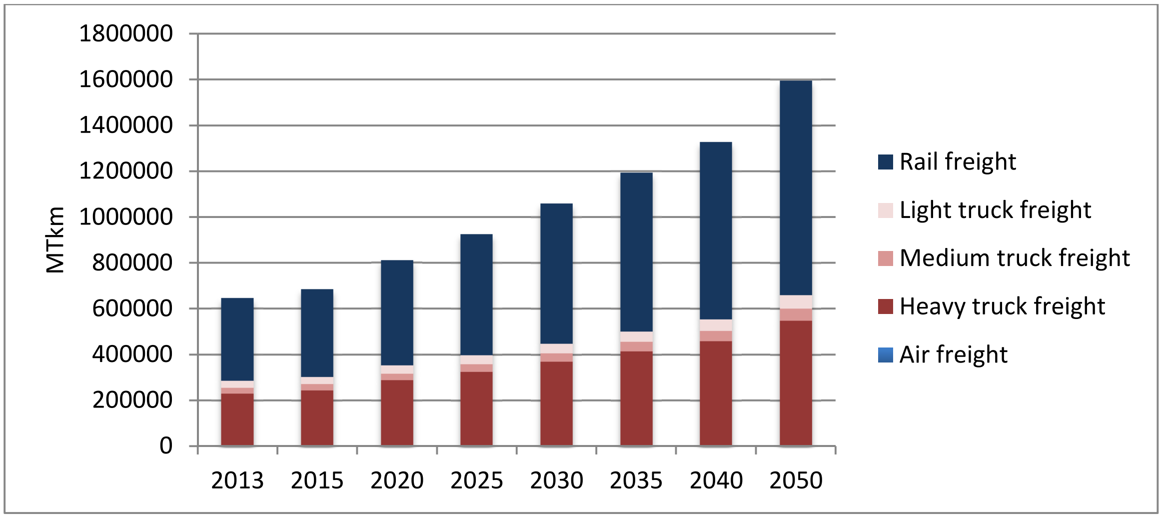
Projected changes in the transportation sector in MPkm is shown in Figure 39. Demand for passenger vehicles is projected to increase from 782,390 MPkm in 2013 to 1,107,800 MPkm in 2050 (42% increase). Road passenger demand accounts for 79% of total passenger vehicles demand in 2013 and 74% in 2050. The most rapid projected increase is with air passenger transport, increasing from 19% in 2013 to 24% in 2050. Bus passenger demand decreases slightly, from 7% in 2013 to 6% in 2050. The Other category includes passenger trains, off-road vehicles, motorcycles and subways.

Figure 39. Transport, passenger vehicles



Projected demand for freight transport is shown in Figure 40. Freight transport is projected to increase from 646,000 MTkm in 2013 to 1,597,000 MTkm in 2050 (147% increase). Freight is dominated by rail and heavy truck, with only nominal variations in overall share; rail freight increasing from 56% in 2013 to 59% in 2050 of total freight and road freight declining from 44% in 2013 to 41% in 2050. Air freight represents only 0.3% of total freight transport demand from 2013 to 2050.

Figure 40. Transport demand, freight vehicles

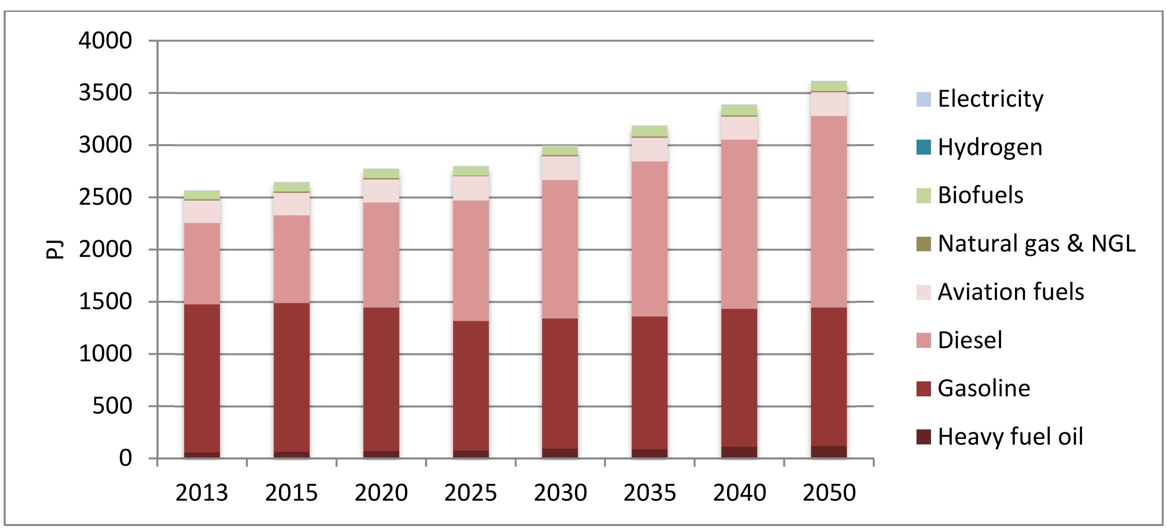


Total final useful energy consumption in the transport sector is projected to increase from 2,569 PJ in 2013 to 3,645 PJ in 2050 (42% increase), as shown in Figure 41. The share of fossil fuel energy stays constant at around 97% of total final energy consumption in 2013 and 2050. Gasoline usage is progressively replaced by diesel; respective shares are 55% and 30% in 2013, and 36% and 50% in 2050.

Key observations from detailed review of background documentation and results are as follows:

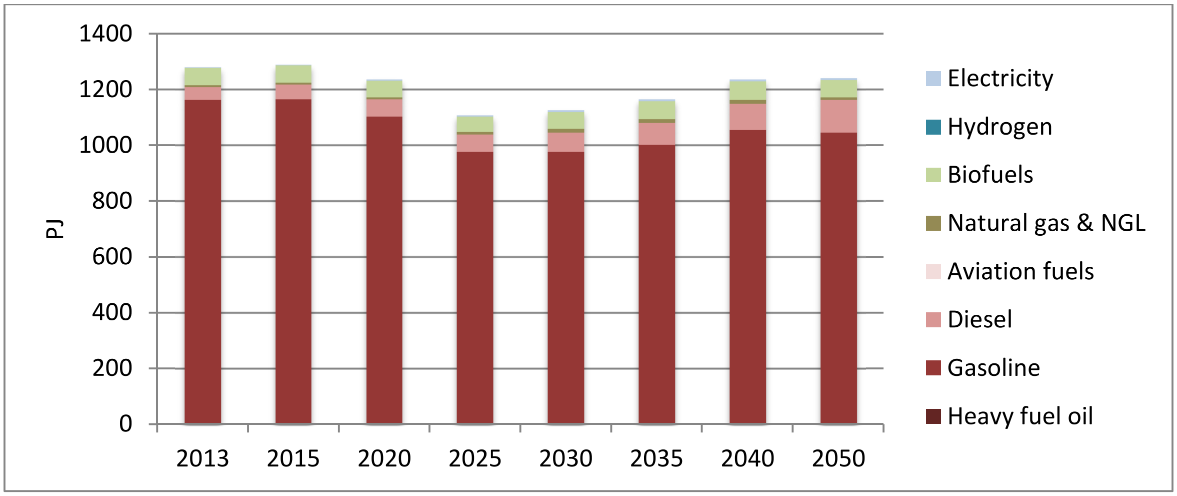
- The progressive substitution from gasoline to diesel is due primarily to two causes. Gasoline consumption for cars and light duty vehicles decreases due to rapidly increasing vehicle efficiencies (CAFE). Increased demand for diesel occurs because of major increase in freight transport (Figure 42 and Figure 43).

Figure 41. Transport final useful energy consumption



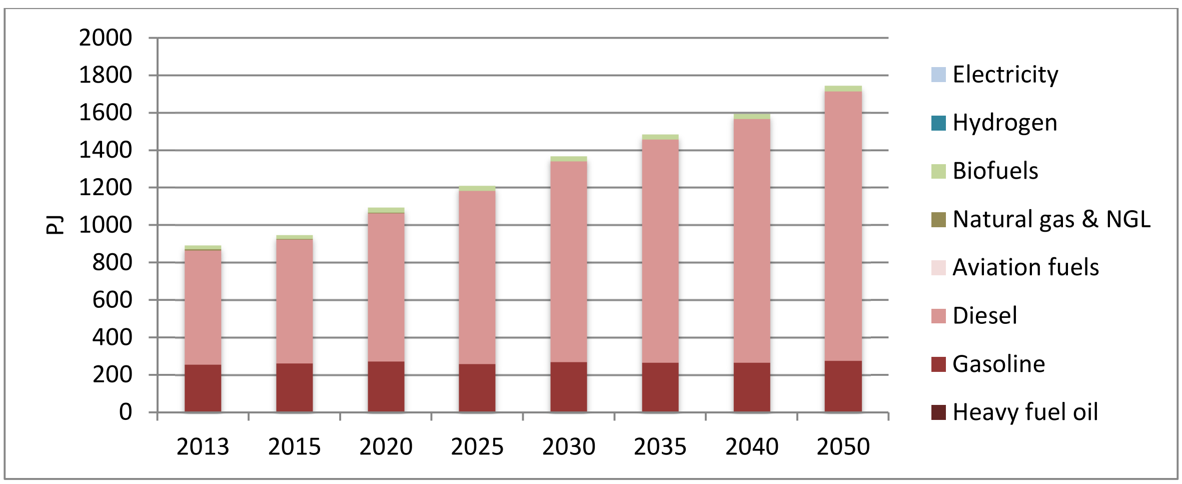
Note: Natural gas and NGL, hydrogen and electricity consumption are too small to appear on figure.

Figure 42. Road passenger final energy consumption



Note: Natural gas and NGL, hydrogen and electricity consumption are too small to appear on figure.

Figure 43. Road freight final energy consumption



Note: Natural gas and NGL, hydrogen and electricity consumption are too small to appear on figure.

Road vehicle efficiency (freight and passenger) is constrained to reach national efficiency standards, which follow the United States CAFE standards for passenger and freight vehicles. Passenger vehicles must meet or surpass these constraints until 2025 (last year of current CAFE standards) and freight vehicles are constrained until 2018. The effects of this are clearly observed with major reductions in vehicle energy consumption due to efficiency improvements imposed on new vehicle models until 2025.

The progressive evolution of efficiency improvements in passenger vehicles is shown in Figure 44. In 2025, small car, large car and light truck efficiencies are, respectively, 19%, 28% and 46% higher than 2013 levels. In 2050, they are 47%, 81% and 22% more efficient than 2013 levels.

Progressive evolution of efficiency improvements for freight vehicles is shown on Figure 45. In 2025, light and medium freight vehicles are, respectively, 10% and 4% more efficient than 2013 levels, heavy freight efficiency decreases by 3%. In 2050, light, medium and heavy freight trucks are 40%, 23% and 2% more efficient than 2013 levels, respectively.

Key observations from detailed review of background documentation and results are as follows:

- Efficiency improvements for both passenger vehicles and freight transport continue beyond the designated CAFE period except, for light passenger trucks. The additional capital costs for new vehicles are more than offset by reduced operating costs for the economic life of such vehicles.
- The lesser efficiency gains for freight vehicles is partially caused by reducing load factor for freight transport. This is a historical trend that has been observed with the CanESS model.

Figure 44. Road passenger vehicle efficiencies

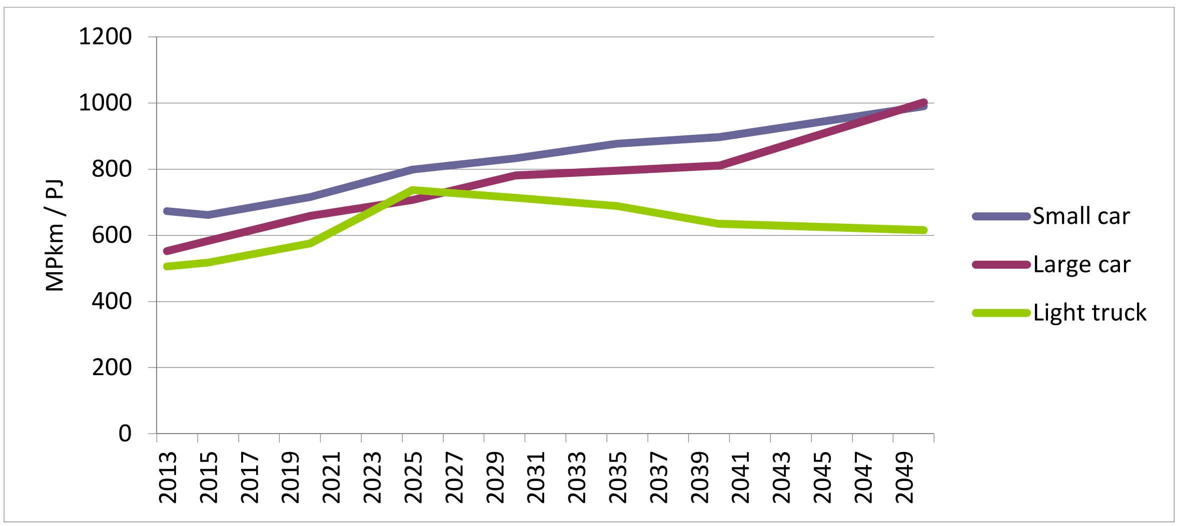
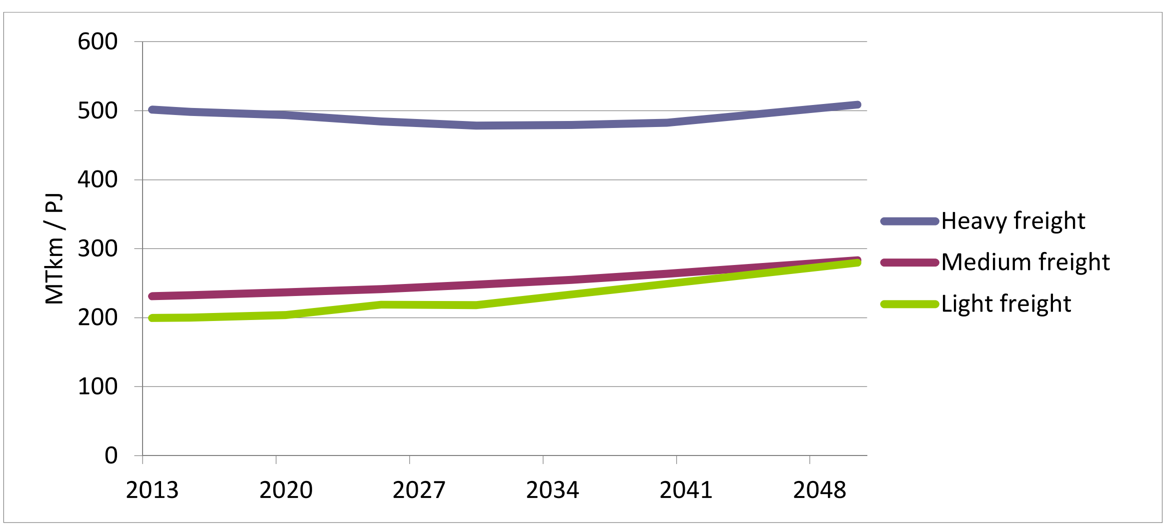


Figure 45. Freight vehicle efficiencies



Agriculture sector

According to Statistics Canada (2011), agriculture includes: “all establishments primarily engaged in agricultural, hunting and trapping activities. Excluded are any operations primarily engaged in food processing, farm machinery manufacture and repair” (see also Section 4.3.1).

Agriculture production, as shown on Figure 46, increases from 55 Mt in 2013 to 73 Mt in 2050. The proportion of each product being produced remains relatively constant from 2013 to 2050. Grains and oilseeds production is approximately 65% of total production by weight.

Associated useful energy use is shown on Figure 47. Final energy consumption is projected to increase from 258 PJ in 2013 to 292 PJ in 2050.

Key observations from detailed review of background documentation and results are as follows:

- The dominant driver for production growth in Canada is to meet growing domestic demand with an expanding population
- The energy supply mix is a progressive shift from petroleum products to natural gas and NGL.
- Electricity provides roughly 10 % of total energy needs, with a slight decrease over the time period.
- Biomass and biofuels remain very minor.

Figure 46. Agriculture Production

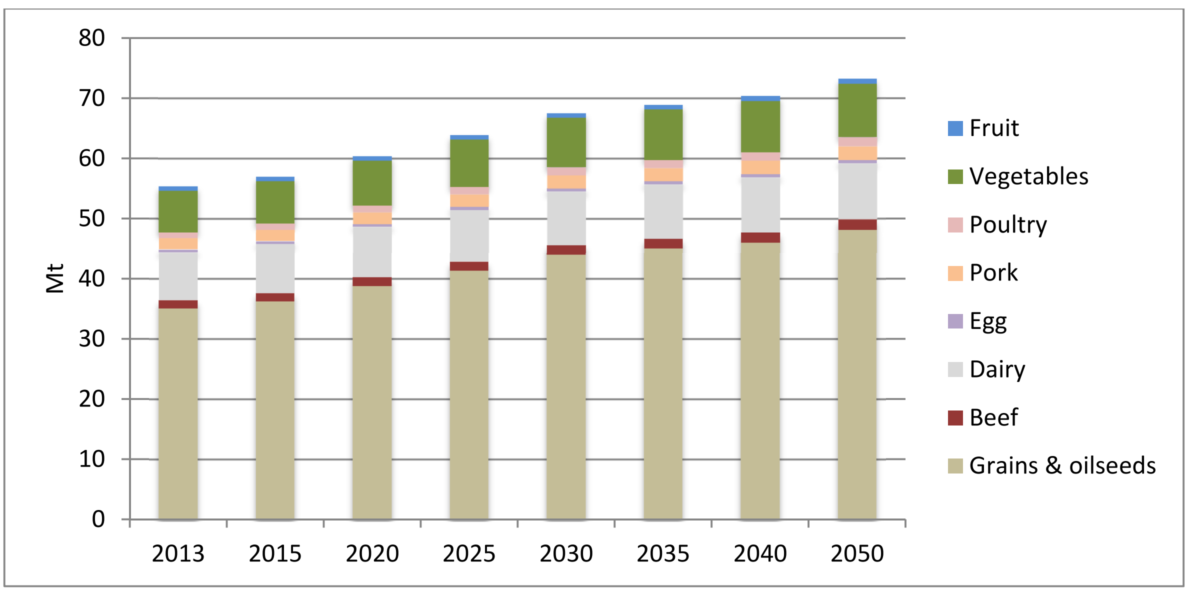
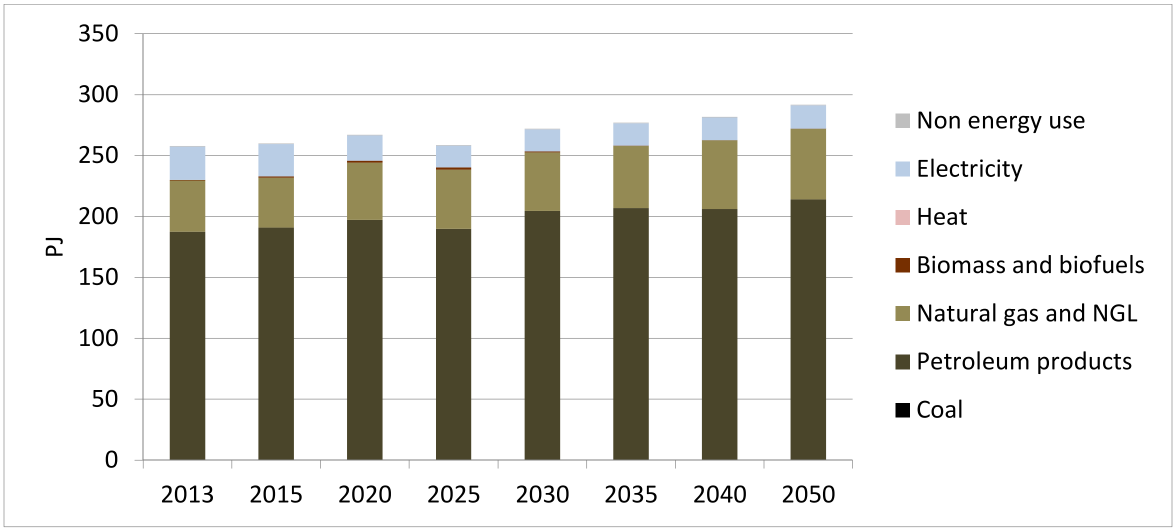


Figure 47. Agriculture final energy consumption



5.3.4 Electricity

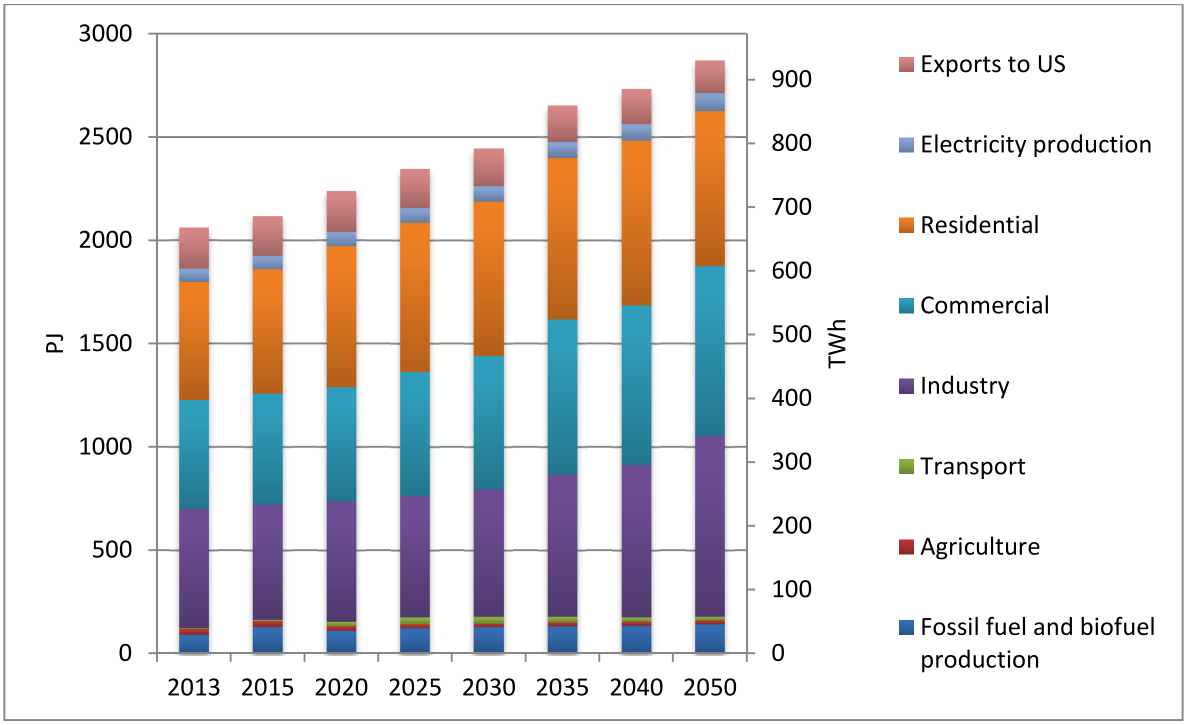
The following section includes results for electricity consumption, generation and production for Canada and its jurisdictions for the years 2013 to 2050.

National electricity consumption by end use is shown on Figure 48. Total electricity consumption increases from 2,060 PJ in 2013 to 2,869 PJ in 2050, an increase of 39%. The residential, commercial and industry sectors are the dominant sectors, accounting for 1,666 PJ (81%) in 2013 and 2,523 (85%) in 2050.

Key observations from detailed review of background documentation and results are as follows:

- There are no substantive changes in the relative role of electricity in the respective sectors
- The role of electricity in the transport and agricultural sectors remains small
- Electricity export continues to be significant, driven primarily by availability of relatively low cost electricity from selected jurisdictions, especially Quebec, Manitoba and British Columbia.

Figure 48. Electricity consumption by end use



Electricity Generation

Electricity-generating capacity by type is shown on Figure 49. Total capacity increases from 138 GW in 2013 to 176 GW in 2050 (28% increase). Hydro capacity increases from 76 GW in 2013 to 102 GW in 2050, and represents 55% and 58% of total installed capacity in 2013 and 2050, respectively. Conventional coal-based thermal generation capacity is progressively phased out, reducing from 12 GW in 2013 to 1 GW in 2050 - due to progressive phase out of existing coal-fired plants (see Section 4.5.1). Oil based generation capacity is also progressively phased out, from 7 GW in 2013 to 3.7 GW in 2050. There is a major increase in natural gas based thermal generating capacity, from 19 GW in 2013 to 43 GW in 2050. Natural gas capacity represents 14% of total capacity in 2013 and 25% in 2050. Nuclear generating capacity decreases from 14 GW in 2013 to 7 GW in 2050, representing 10% of total capacity in 2013 and 4% in 2050. The decrease in nuclear capacity is due primarily to planned closing of Ontario's Pickering power plant in 2020 (see also Section 4.5.1 re; planned nuclear refurbishment program). Wind capacity increases from 9 GW in 2013 to 16 GW in 2050.

In Figure 50, changes in installed capacity, and associated composition, from 2013 to 2050, are shown for each of the 13 jurisdictions across Canada. Electrical energy production is shown on Figure 51.

Key observations from detailed review of background documentation and results are as follows:

- Growth in electricity supply is dominated by additional investment in hydro and natural gas based thermal generation. This is to meet both growing demand and for replacing progressive phasing out of both coal and oil fired generation.
- There is no additional investment in nuclear generating capacity.

- Investment in additional intermittent renewables generation is dominated by wind generation. Solar and other intermitent renewables tend to be less cost competitive.
- Biomass and biofuels for electricity generation remains negligible.
- Investment in additional hydro is confined almost totally to Quebec, Newfoundland & Labrador, Manitoba and Saskatchewan. There is virtually no additional investment in hydro in British Columbia, due to existing legislation preventing additional investment in conventional large scale hydro and with run of river hydro not being cost competitive. Additional investment in natural gas based thermal generation occurs dominantly in Alberta, British Columbia and Ontario. Additional wind generation is dominantly in Alberta and Ontario.

Figure 49. Electricity generating capacity by primary energy source

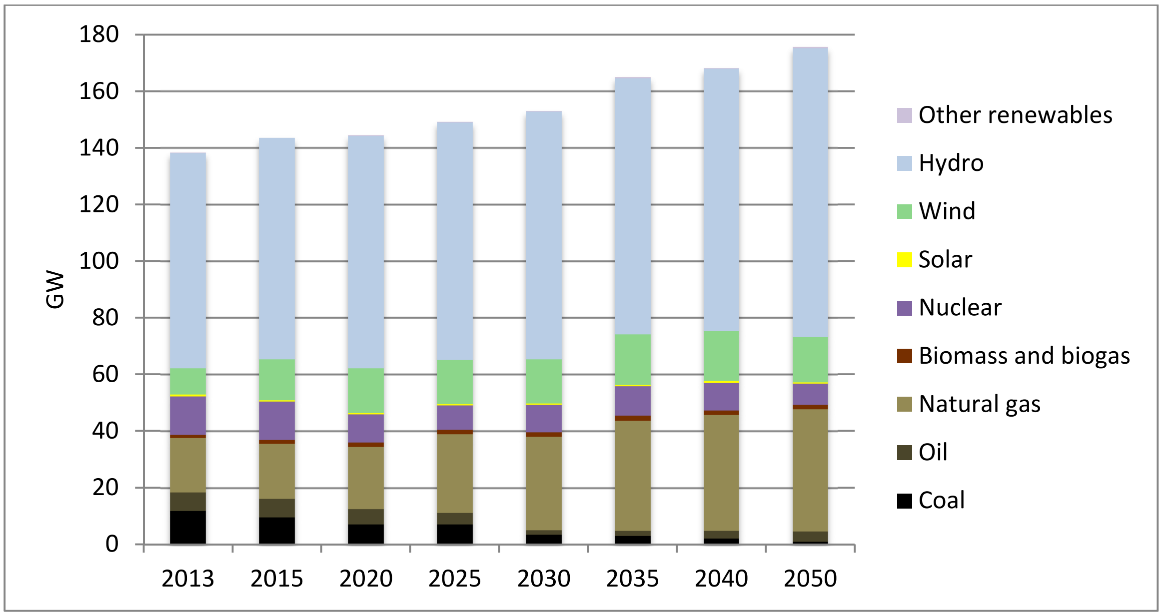


Figure 50. Electricity generating capacity by province, 2013 & 2050

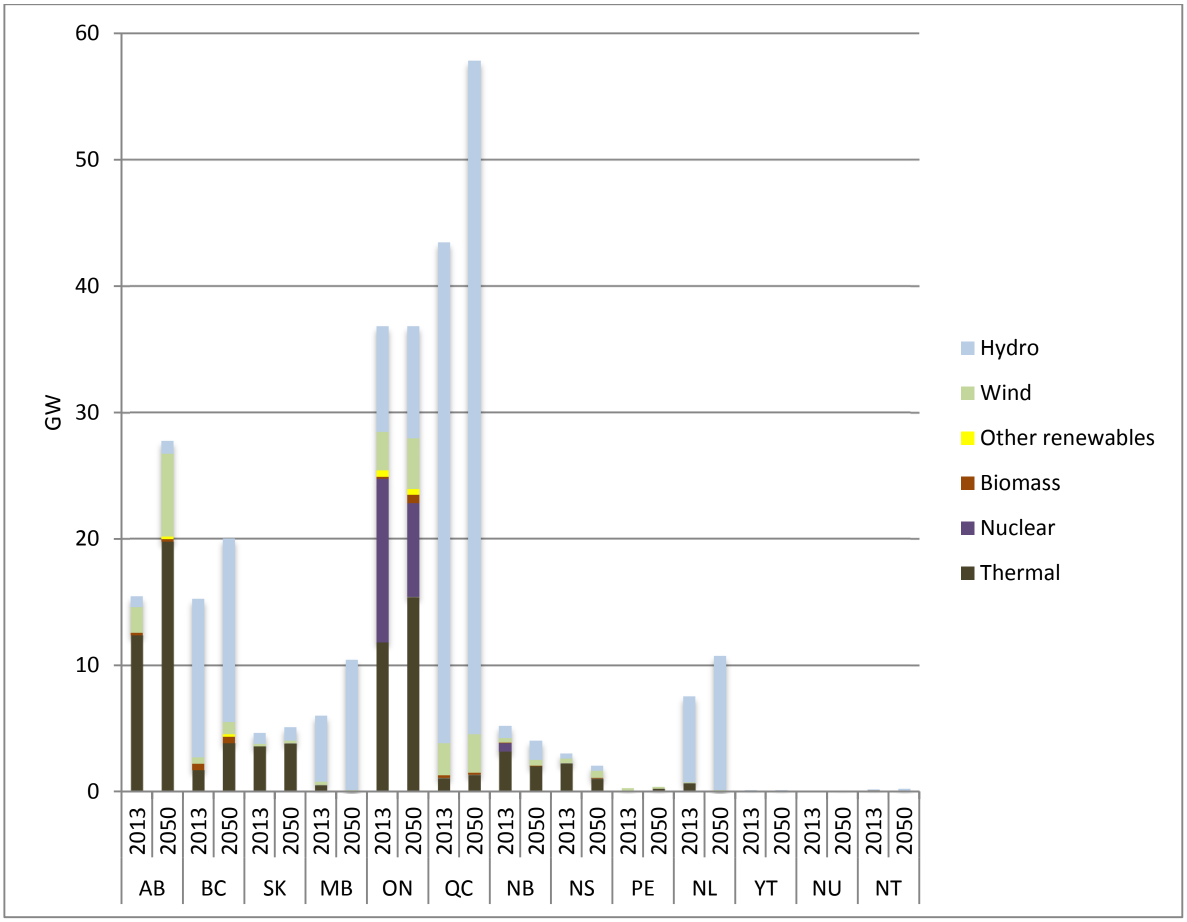
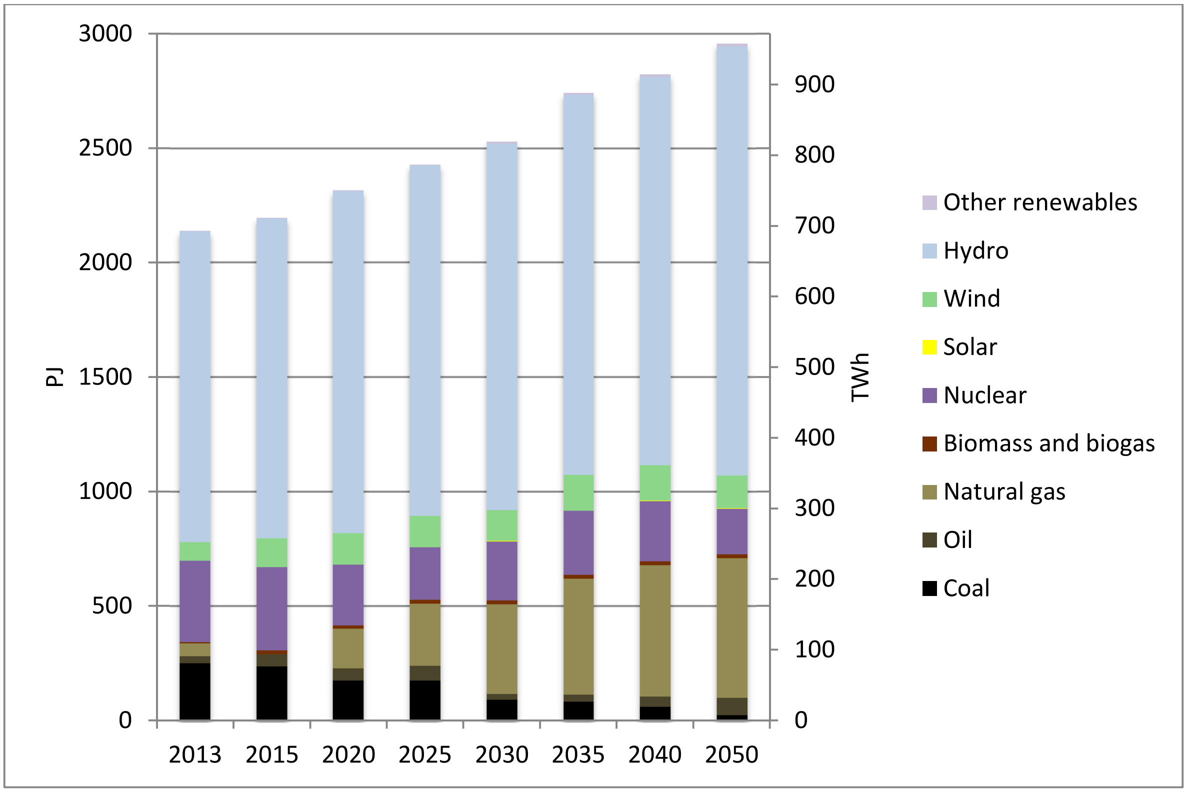


Figure 51. Electrical energy production by primary source



Hydro Potential

Because of the dominance of hydro generation for overall electricity supply in Canada, additional assessments were carried out on projections for hydro developments for the various jurisdictions across Canada. Projected hydro capacity for each jurisdiction, for selected years, is shown on Table 58. Corresponding percentages of installed hydro capacity relative to ultimate potential (EEM, 2006) in each jurisdiction, also for selected years, is shown on Table 59.

Key observations from detailed review of background documentation and results are as follows:

- Relative to Canada's economically competitive hydro potential of 239 GW (see Section 4.5.1), the increase will be from 75.8 GW (32%) in 2013 to 102 GW (43%) in 2050.
- The dominant increase occurs in those jurisdictions which are already hydro dominant (Quebec, Manitoba, and Newfoundlan & Labrador). There is limited increase in other jurisdctions, because of high cost (Alberta, Ontario, Nova Scotia), or because of low demand and remoteness (Yukon, Nunavut).

Table 58. Hydro capacity by province

GW	2013	2020	2030	2040	2050
Alberta	0.89	0.99	0.99	0.99	0.99
British Columbia	12.52	13.52	13.52	14.52	14.52
Manitoba	5.26	5.39	8.12	8.12	10.26
New Brunswick	0.96	0.96	1.54	1.54	1.54
Newfoundland	6.78	9.86	10.14	10.14	10.62
Nova Scotia	0.39	0.39	0.39	0.39	0.39
Northwest Territories	0.08	0.08	0.13	0.13	0.19
Nunavut	0.01	0.01	0.01	0.01	0.01
Ontario	8.41	8.92	8.92	8.92	8.92
PEI	0.00	0.00	0.00	0.00	0.00
Quebec	39.59	41.14	42.53	46.88	53.30
Saskatchewan	0.86	0.86	0.86	0.86	1.06
Yukon	0.06	0.06	0.06	0.09	0.14
Total	75.80	82.16	87.21	92.59	101.94

Table 59. Percentage of potential hydro capacity, by province

	2013	2020	2030	2040	2050
Alberta	6%	7%	7%	7%	7%
British Columbia	27%	30%	30%	32%	32%
Manitoba	38%	39%	59%	59%	74%
New Brunswick	62%	62%	100%	100%	100%
Newfoundland	44%	64%	66%	66%	69%
Nova Scotia	4%	4%	4%	4%	4%
Northwest Territories	1%	1%	1%	1%	2%
Nunavut	0%	0%	0%	0%	0%
Ontario	43%	45%	45%	45%	45%
PEI	0%	0%	0%	0%	0%
Quebec	49%	50%	52%	57%	65%
Saskatchewan	18%	18%	18%	18%	22%
Yukon	0%	0%	0%	1%	1%
Total	32%	34%	37%	39%	43%

5.3.5 International Trade

International trade of energy commodities are shown on Figure 52.

Energy export is shown to increase from 17,043 PJ in 2013 to 20,676 PJ in 2050. Oil exports increase from 6,346 PJ to 8,286 PJ in 2050. Natural gas exports increase from 3,472 PJ to 4,971 PJ in 2050.

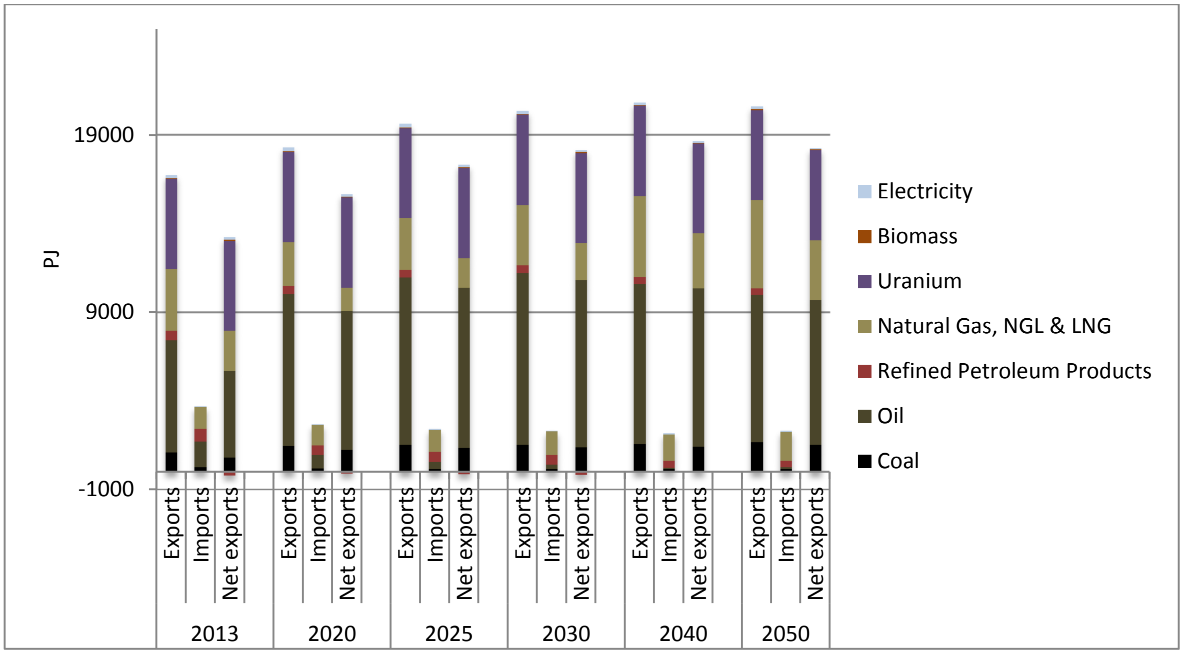
Energy imports decrease from 3,713 PJ in 2013 to 2,343 PJ in 2050. Oil imports decline from 1,466 PJ in 2013 to 101 PJ in 2050 (93% decrease).

On a net basis, net exports increase from 13,330 PJ in 2013 to 18,333 PJ in 2050 (38% increase). Net export of oil and refined petroleum product increases from 4,880 PJ in 2013 to 8,185 PJ in 2050. Refined petroleum products represent a relatively small percentage (around 4%) of crude oil trade. Trade of refined petroleum products changes from 187 PJ net import in 2013, to 3 PJ net export in 2050. Natural gas, NGL and LNG exports increase from 2,251 PJ in 2013 to 3,349 PJ in 2050. By 2050, LNG represents 72% of natural gas export. With no import of uranium, exports of uranium remain constant at 5090 PJ through to 2050. Finally, net export of coal increases from 824 PJ in 2013 to 1,525 PJ in 2050.

Key observations from detailed review of background documentation and results are as follows:

- International trade in energy commodities is dominated by export of oil, natural gas and uranium. There is also net export of electricity and coal. There is no assumed trade in biomass and biofuels.
- With respect to natural gas export, there are significant changes from 2013 to 2020, and from 2020 to 2050. There is no LNG export in 2013, but then increases rapidly, from 313 PJ in 2020, to 3,582 PJ in 2050. Natural gas export to the Unites States decreases from 3,312 PJ in 2013 to 1,312 PJ in 2050.
- Export of coal is small, and is shown to increase, primarily in response to reducing domestic consumption, especially thermal coal (associated with phasing out conventional coal fired generation).
- Refined petroleum products represent a small portion of international trade, representing only 2 to 4% of oil export, with variations on a year to year basis.
- Oil imports, dominantly into Eastern Canada are projected to decline, primarily as a consequnce of increasing supply from domestic sources, including pipeline extension to Eastern Canada.

Figure 52. International Energy Trade, by energy type



5.3.6 GHG Emissions

GHG emissions for all GHG emission sources (including both combustion and non-combustion sources) are shown on Figure 53). A chart showing a more detail projected breakdown of GHG emissions from various GHG sources is shown on Figure 54.

GHG emissions from all sources are shown to increase from 708 Mt CO_{2}-eq in 2013 to 1,109 Mt CO_{2}-eq in 2050.

Key observations from detailed review of background documentation and results are as follows:

- GHG production is dominantly from the transportation, industrial (both combusiotn and industrial process emissions) and fossil fuels supply (combustion and and fugitive emissions).
- The most rapid increase in production of GHG's is directly associated with an expanding oil and natural gas sector, dominantly for increasing export. This also has a corresponding projected increase in production of fugitive releases, which is assumed to be proportional to oil and natural gas production
- The observed decrease in emissions from the electricity sector is mainly due to planned phase out of conventional coal generating facilities, elimination of light fuel oil and heavy fuel oil electricity generation, and a significant increase in hydro energy generation. Thermal generation in 2050 is primarily natural gas based generation, dominantly for peaking and mid-range operation in selected jurisdictions.
- The declining proportion of GHG emissions from the residential and commercial sectors is due to a combination of improving thermal efficiencies of new buildings and a progressive shift towards electrification of end uses, including especially for space heating.

Changes in GHG emissions intensity for electricity generation are shown in Figure 55. CO_2-eq emissions are shown to decline from 0.13 kg per kWh in 2013, to 0.09 kg per kWh in 2050.

Figure 53. GHG emissions by sector

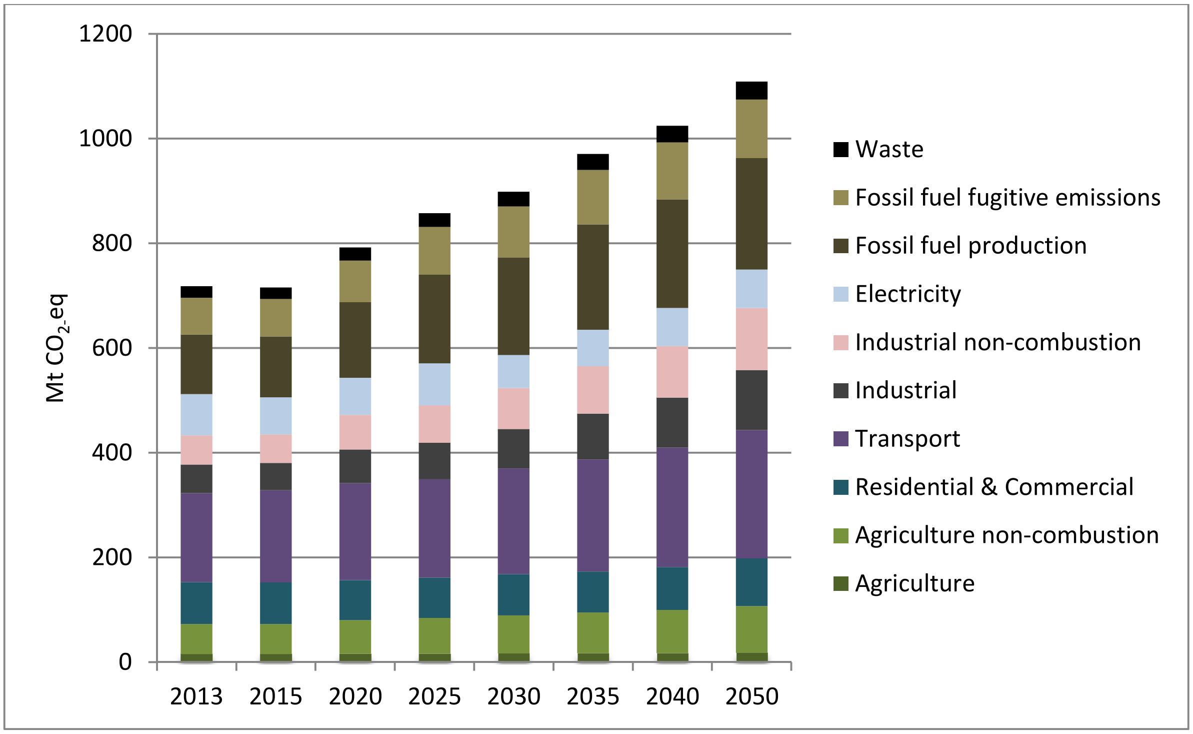


Figure 54. Projected GHG Emission Sources (1109 Mt) in 2050

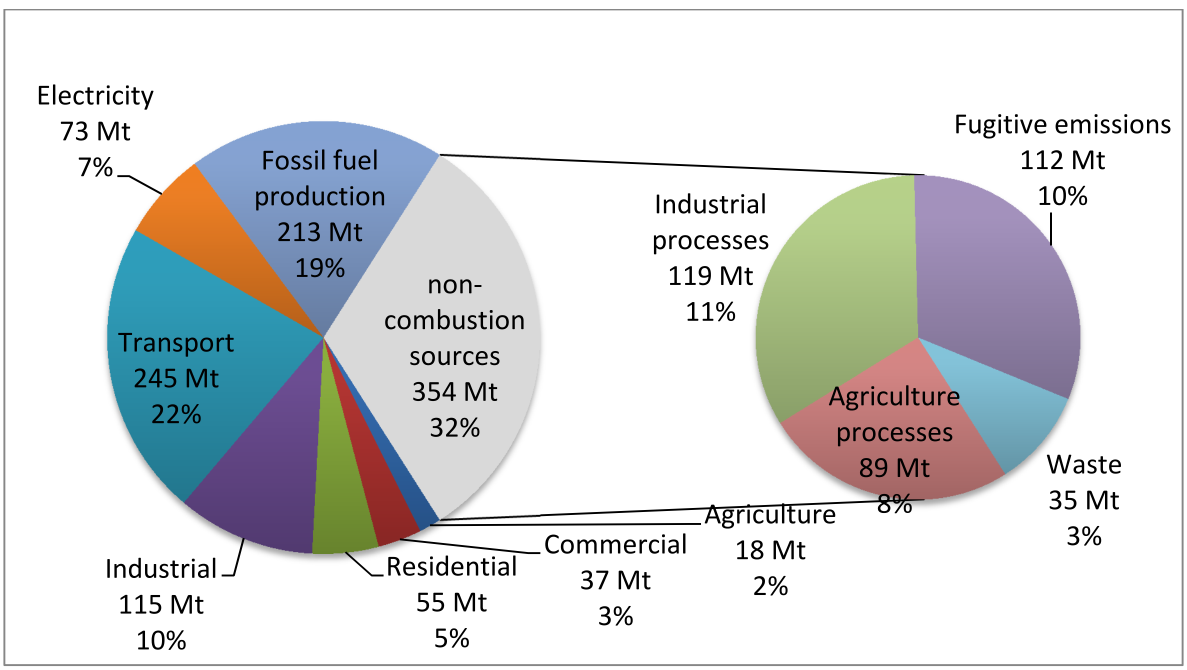
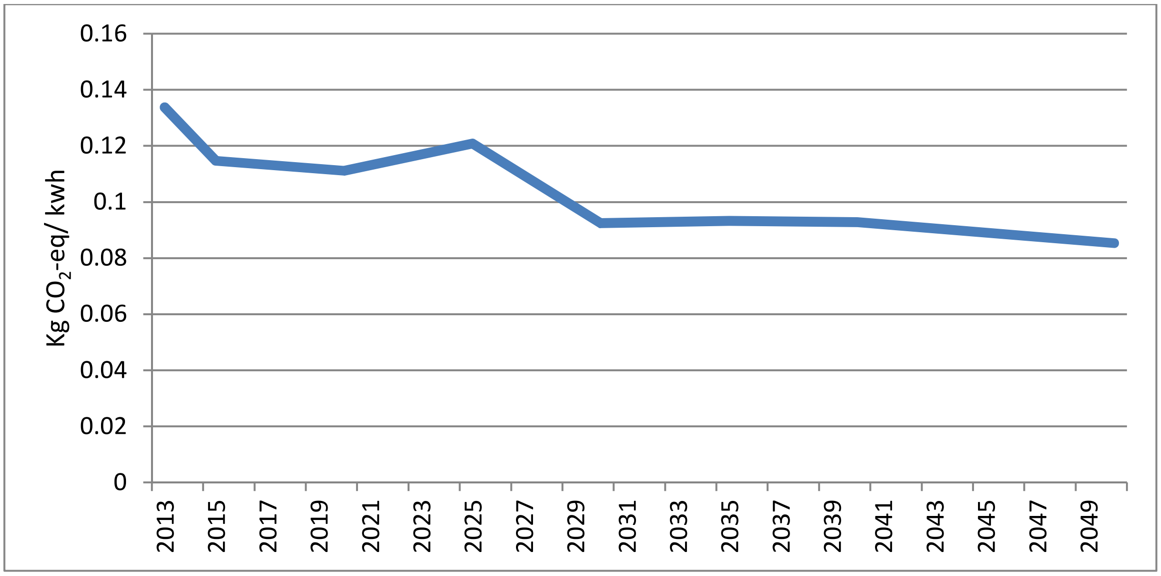


Figure 55. Electricity generation GHG intensity



5.3.7 Principal Observations

Projected results for Scenario 1 (Reference Scenario for high fossil fuel production) have been presented. This is based on the premise that the future to 2050 will be based on meeting growing demands in the various sectors of the Canadian economy at minimum cost, and that there are no GHG reduction constraints influencing these decisions.

In the following sub-sections, there will be presentations of results for the remaining scenarios. Each of these will include minimum cost solutions with imposition of GHG constraints for different combinations of prescribed premises, as described in Section 5.2 (except Scenario 1a which is a corresponding Reference Scenario for low fossil fuels production and export). By comparing such results with results from this Scenario 1, it will be possible to have in depth appreciation of the impact of such premises on GHG reductions, including cost and associated impacts.

In the earlier sub-sections of Section 5.3, results were presented for the period from 2013 to 2050. This included an overview of final energy consumption and primary energy production. More in-depth assessments were carried out on consumption in the principal sectors; residential, commercial, industry, transportation and agriculture. This was followed with more in depth assessment of electricity consumption and generation. There is also assessment of international trade in energy commodities, and an overview of growing GHG emissions.

A summary of the principal observations are presented. This is in the context of providing a high level reference for assessing impacts of results from the remaining scenarios.

- Growth in energy demand by sector: Not surprisingly, there will be continuing growth of energy demand in all energy consuming sectors, with some nominal shifts, but no major changes.
- Growth in energy demand by fuel type: Energy demand will continue to be dominated by oil, natural gas and electricity. The role of bio-fuels will remain modest, being influenced dominantly

by regulatory requirements. The role of coal will be small. Direct use of intermittent renewables, such as solar thermal, is negligible.

- Efficiency improvements: The impact of efficiency improvements for reducing energy demand is substantial, especially in the residential, commercial and transportation sectors. Reductions in the residential and commercial sectors arise from improved efficiencies of electrical equipment and accessory equipment, and in buildings. Efficiency improvements in the transportation sector are influenced dominantly for cars and light duty vehicles, as a result of CAFÉ standards and continuing efficiency improvements for such vehicles.
- Growth in primary energy production: Growth in primary energy production is dominated by oil and natural gas, as well as hydro for electricity production. Growth in bio-fuels remains nominal. Growth in intermittent renewables, dominantly wind for electricity production, is also nominal. Oil supply is increasingly from oil sands bitumen deposits in Western Canada, including both mining and in-situ extraction. Natural gas production is increasingly from tight and shale gas deposits, both of which require extraction by fracking.
- Growth in energy export: Energy export is dominated by oil, natural gas and uranium, all of which are projected to increase. There is also export of coal and electricity. The export market for oil is projected to shift from being only to the United States, to including other international markets. The market for natural gas will decline over the next decade, because of reduced demand from the United States; however, it is projected to increase subsequently, with LNG export to an international market, primarily from Western Canada, after the necessary infrastructure is developed. Oil Imports into Eastern Canada are projected to decline, especially after the necessary infrastructure is in place to bring oil from Western Canada into the Maritime Provinces.
- Energy consumption in residential and commercial sectors: Energy for the residential and commercial sectors will increasingly be dominated by natural gas and electricity; natural gas for space heating and hot water and steam production, and electricity for appliances.
- Energy consumption in transportation: At the present time, energy consumption for passenger transport and freight transport is approximately equal. However, projected energy use for passenger transport is projected to actually decline (due to efficiency improvements), while energy demand for freight transport is projected to increase very substantially. The overall effect of this is that there is a major shift from use of gasoline to use of diesel fuel in this sector. The role of electricity in the transportation sector is projected to remain small; less than 1%.
- Energy consumption in industry: Energy demand in the industrial sector will continue to be dominated by natural gas and electricity. There is a minor shift from use of electricity to use of natural gas.
- Energy consumption in agriculture: Energy consumption is dominantly petroleum products and natural gas. There is a progressive shift from use of petroleum products to natural gas and natural gas liquids. Electricity remains relatively small (less than 10%) with little change. Use of biofuels remains minor.
- Growth in electricity demand: Demand for electricity is dominantly for the residential, commercial and industrial sectors. Use of electricity in the transportation and agricultural sectors remains small. The role of electricity increases nominally, from 22% to 23% of energy based end uses.
- Electricity supply: Increase in electricity supply is dominated by hydro and natural gas thermal generation. There is no additional nuclear generation. Electricity from coal and oil fired generation is progressively phased out. Electricity from intermittent renewables is nominal, dominantly wind generation. There is no generation from geothermal or biomass/biofuels.

There are major differences in composition of electricity supply between jurisdictions. The hydro dominant jurisdictions (Quebec, Manitoba, Newfoundland & Labrador) will continue to be hydro dominant. Jurisdictions with limited additional or expensive hydro potential (Alberta; Ontario) will shift increasingly to natural gas based generation, with some wind generation. Because of the moratorium on additional conventional large scale hydro generation in British Columbia, its additional generation will be dominated by natural gas fired generation. Saskatchewan will develop some of its remaining undeveloped hydro potential.

- Growth in emissions: There will be progressive overall increase in emissions, reaching 1,109 Mt in 2050, as compared to 589 Mt in 1990 and 692 Mt in 2010. Overall emission will be dominantly for fossil fuels production, industry and transportation. On a relative basis, the portion for fossil fuel extraction and refining will increase from 16% (25% when also including fugitive emissions) to 19% (28% when including fugitive emissions). Emissions from electricity supply will actually decline, primarily as a consequence of phasing out coal fired generation.

5.4 Scenario 2: With Reductions in Combustion Emissions

The purpose of this scenario was to derive minimum cost solutions to 2050, for all of Canada, for progressive reductions in combustion emissions from 2011 to 2050. The premises were essentially the same as for Scenario 1, but with imposition also of combustion reduction requirements by 2050, which were below the 427 Mt of recorded combustion emission in 1990. Results were derived with the NATEM-Canada model for four separate reduction targets in 2050, from 30 to 60%, in 10% increments.

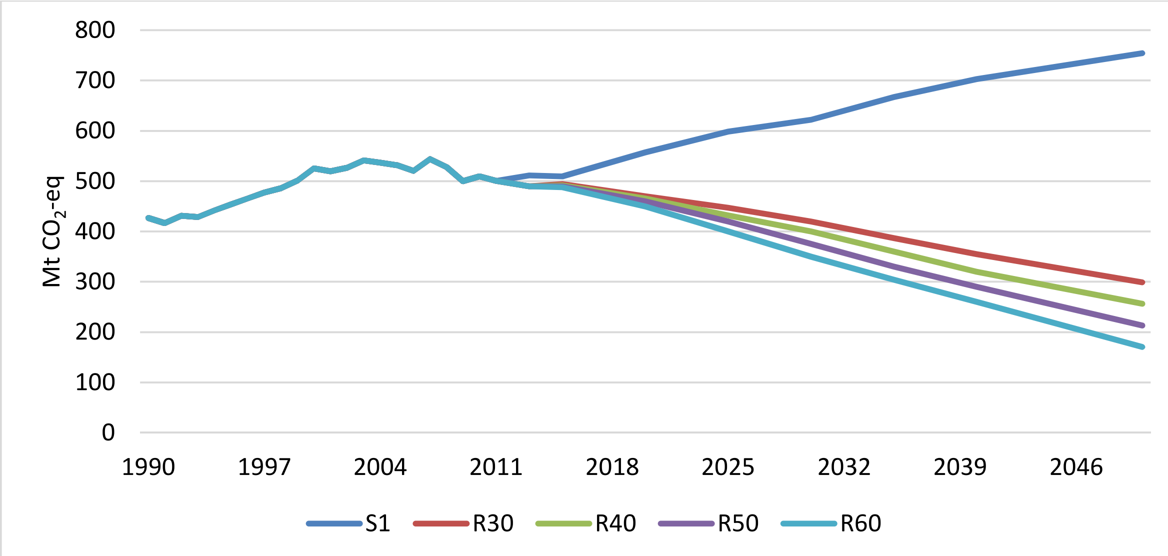
It is important to note that the 60% reduction target was selected, after several trials, as the maximum realizable target for the combination of possible transformation options prescribed for this Scenario. Any substantive increase in the target beyond 60% did not produce credible results, because of unacceptably high marginal costs.

In analysis and reporting of results, special consideration was given to comparing results to the Reference Scenario (Scenario 1), including insight on the lowest cost combinations of transformation strategies for achieving prescribed GHG reduction targets.

There is a significant premise that needs to be appreciated at this stage. In defining the GHG reduction target for 2050, it was clear, from preliminary analyses, that realistic results would only be derived by also prescribing intermediate GHG reduction targets. On this basis, it was decided that the reduction scenarios and the reference case begin at 501 Mt of CO_2-eq emissions for 2011 and progressively diverge. It was decided that the intermediate reduction targets, for the following years should be essentially linear between 2015 and 2050, as shown in Figure 56.

It should be appreciated that this is an area that merits further assessment. For example, there may be other GHG reduction profiles which may be more appropriate, including smaller changes in earlier years and larger changes in later years.

Figure 56. Total emission reduction profiles from 1990 levels



5.4.1 GHG Emissions

Results from the NATEM Canada model runs for target GHG reduction levels from 30% to 60% are shown on Figure 57. Progressive phasing of GHG emission reductions for the 60% reduction Scenario, is shown on Figure 58.

Key observations from detailed review of background documentation and results are as follows:

- The most significant change is with achieving the 30% reduction target. Relative to results from the Reference Scenario with projected GHG emissions from combustion of 754 Mt in 2050, the 30% reduction target includes overcoming the increase of 74 Mt from 1990 to 2013, the additional projected increase of 253 Mt from 2013 to 2050, and the 30% reduction below 1990 (128 Mt) for a total reduction of 455 Mt relative to Scenario 1. In comparison, the reduction from 30% to 60% is an additional 128 Mt, with total reduction being 583 Mt, relative to Scenario 1, for 60% reduction.
  In comparison to the Reference Scenario, the 30% reduction relative to 1990 corresponds to 60% reduction relative to projected emissions in 2050. Similarly, the 60% reduction relative to 1990 corresponds to 76% reduction relative to projected emissions in 2050.
- The dominant changes occur, not surpringly, in the sectors that are the largest emitters. These include the transportation, industrial, and fossil fuels supply sectors. There are also siginificant reductions in emissions from electricity supply, and from the commercial and residential sectors.
- The largest early contributer to reducing GHG emissions is de-carbonizing electricity sypply.
- With respect to the various sectors, reductions in combustion related emissions in 2050 for the 60% reduction Scenario, relative to the Scenario 1, are summarized as follows;

    - Electricity emissions decrease from 73 Mt to 0.34Mt (almost entirely decarbonized)
    - Transport emissions decrease from 245 Mt to 49 Mt (80% decrease)
    - Fossil fuels supply sector emissions decrease from 213 Mt to 66 Mt (69% decrease)
    - Industrial emissions decrease from 115 Mt to 35 Mt (70% decrease)

- Residential emissions decrease from 55 Mt to 6 Mt (89% decrease)
- Commercial emissions decrease from 36 Mt to 9 Mt (75% decrease)
- Agriculture emissions decrease from 18 Mt to 6 Mt (67% decrease)

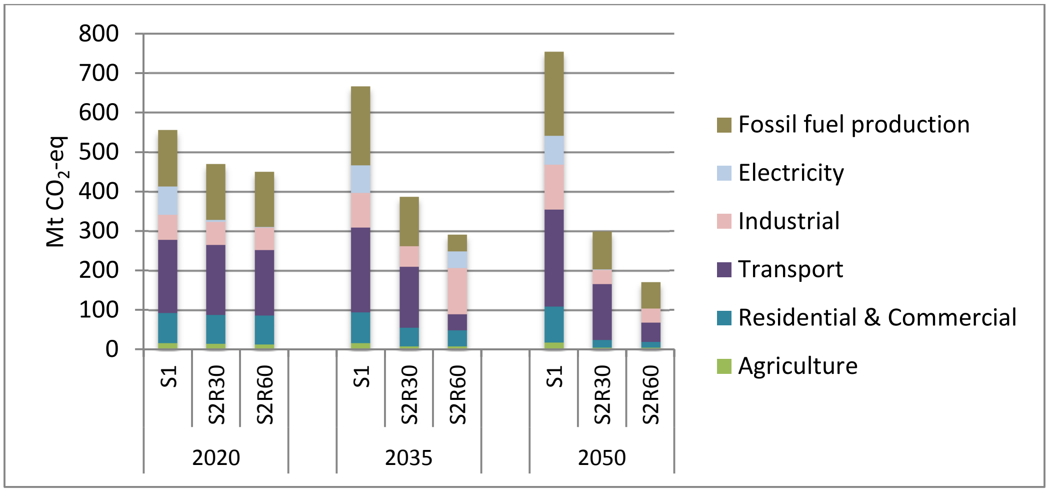
- The dominant transformations in the various sectors are summarized as follows;

  - For transportation, combination of efficiency for ICE engines, electrification of passenger vehicles, electrification of light and medium freight vehicles, and introduction of hydrogen for heavy freight vehicles
  - For fossil fuels supply, dominantly electrification of the supply chain, including extraction, collection, upgrading, refining, transport and distribution
  - For industry and agriculture, increased electrification
  - For commercial and residential, more conservation and increased electrification, especially for space heating, and hot water and steam production
  - For electricity supply, switching from thermal based generation to renewables (hydro and wind) and nuclear

- It is noted that the general trends observed for the 60% reduction scenario are repeated for the 30% reduction scenario, with the only significant difference being the relative magnitude of the respective reductions. From this, it follows that general observations for the 60% GHG reduction target apply also for other GHG reduction targets. These includes the importance of early de-carbonization of electricity supply, the importance of ensuring GHG reduction in all energy consuming sectors, the major increased role of electricity for electrification of end uses, and the importance of conservation and efficiency improvements.
- Some provincial highlights for the 60% reduction scenario in 2050 include;

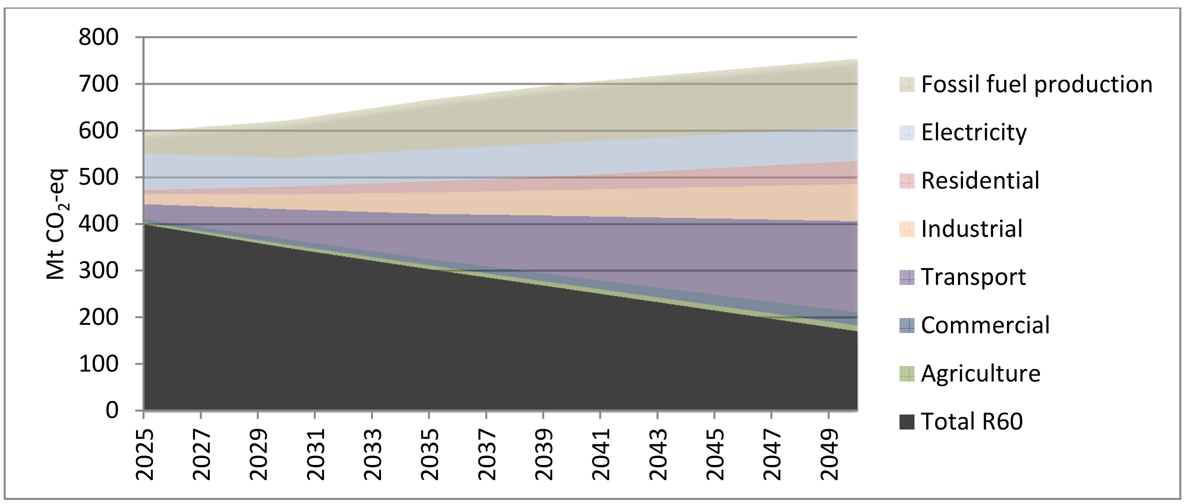
  - Total national combustion related emissions: 171 Mt.
  - Fossil fuels supply sector in Alberta (combustion): 34 Mt (20% of emissions).
  - Fossil fuels supply sector in British Columbia: 16 Mt (9% of emissions).
  - Industrial sector in Ontario: 17 Mt (10% of emissions).
  - These three provinces specific sector emissions account for nearly 40% of total national combustion related emissions in 2050.

Figure 57. Combustion related GHG emissions by activity sector



Note: S1 denotes Scenario 1; S2R30 denotes Scenario 2 for 30% reduction in 2050, relative to 1990.

Figure 58. Progressive phasing of combustion emission reductions between S1 and S2R60



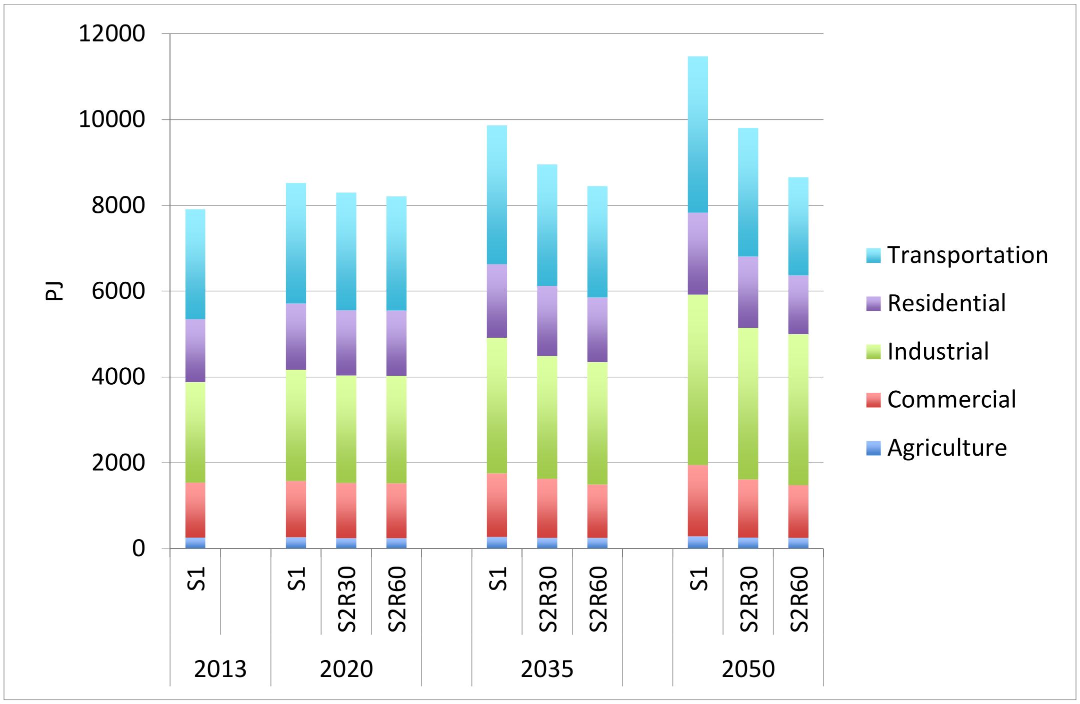
5.4.2 Final Energy Consumption

Domestic consumption of energy is shown in Figure 59, for the respective scenarios with GHG reduction targets varying from 30% to 60%.

Key observations from detailed review of background documentation and results are as follows:

- With respect to comparison with Scenario 1, the overall reduction in energy consumption is from 11,470 PJ to 8,654 PJ, a reduction of 2,816 PJ (25%). The largest reductions are; 1356 PJ in the transportation sector, from 3,645 PJ to 2,289 PJ (37%); 531 PJ in the residential sector, from 1,901 PJ to 1,370 PJ (28%); and 429 PJ in the commercial sector, from 1,657 PJ to 1,228 PJ (26%). Consumption in the industrial sector declines from 3,976 PJ to 3,513 PJ. Consumption in the agricultural sector declines from 292 PJ to 253 PJ.

Figure 59. Final energy consumption by end-use sector



The model results also include efficiency gains from the various sectors, which have an overall impact on energy consumption (Figure 60). Average yearly efficiency gains for Scenario 1 were;

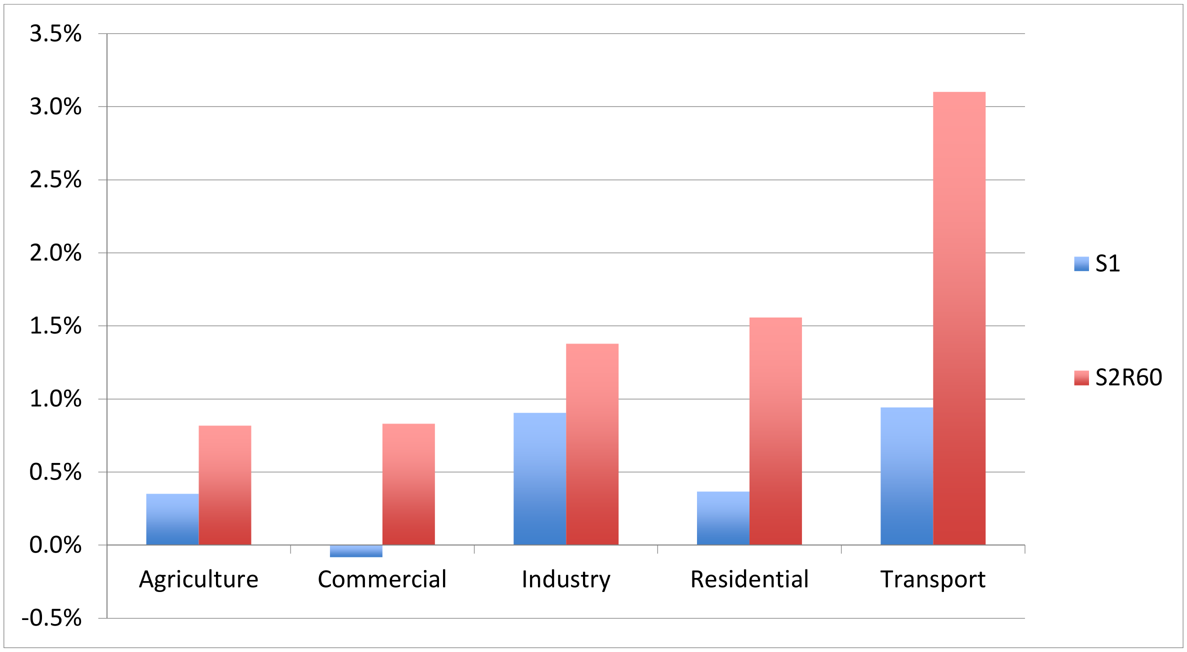
- Agriculture: 0.4%
- Commercial: -0.1%
- Industry: 0.9%
- Residential: 0.4%
- Transport: 0.9%

For 60% reduction for Scenario 2, the corresponding efficiency gains were;

- Agriculture: 0.8%
- Commercial: 0.8%
- Industry: 1.4%
- Residential: 1.6%
- Transport: 3.1%

Major additional efficiency improvements are observed to occur for the 60% GHG reduction target. It is also to be noted that maximum efficiency gains are realized for all sectors for the 30% GHG reduction target, except transportation. Transportation efficiency continues to increase with increasing GHG reduction targets.

Figure 60. Average yearly efficiency gains by sector

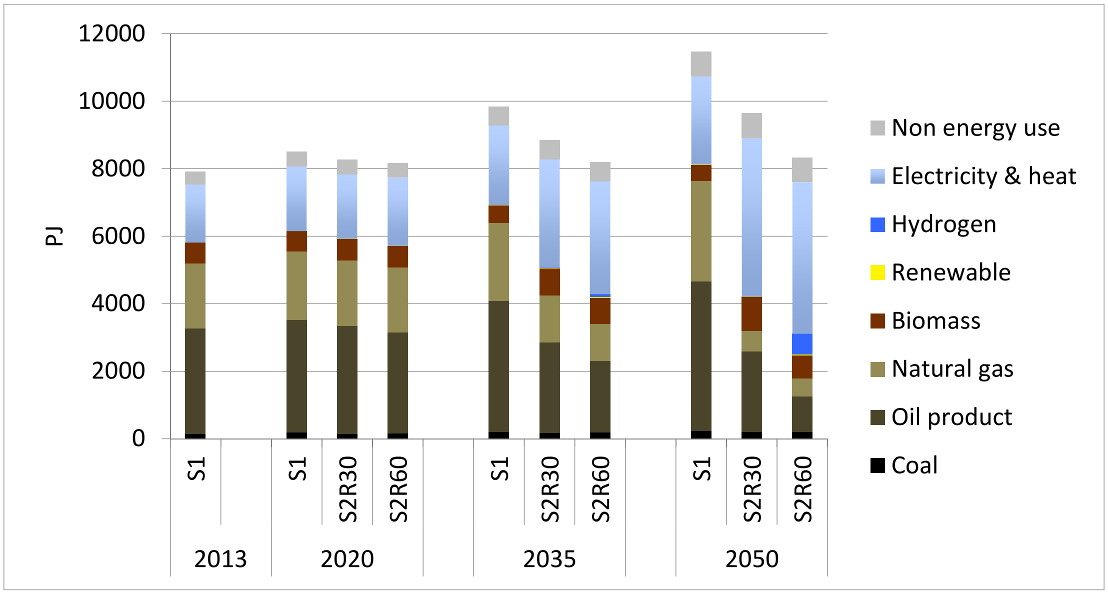


Final energy consumption by fuel type is shown in Figure 61.

Key observations from detailed review of background documentation and results are as follows:

- As observed in Figure 59, and again in Figure 60, there is an overall reduction in final energy consumption.
- The dominant changes are reduced use of fossil fuels, primarily oil and natural gas, and increased use of electricity and bio-fuels. These trends are progressive, from the 30% GHG reduction target, to the 60% GHG reduction target.
- Electrification increases with increasing GHG reduction targets. For the 60% GHG reduction target, electricity meets 53% of energy end use in 2050, as compared to 23% for Scenario 1.
- The other significant supply change is with biofuels. For the 60% GHG reduction scenario in 2050, biofuels meet 8% of total energy consumption, which is a 45%% increase, relative to Scenario 1. It should be recognized that this could be in conflict with food production, as both first generation ethanol and biodiesel production are from conventional food production sources.
- There are corresponding reductions in use of fossil fuels, with oil use declining by 76% and natural gas by 82%, for the same 60% GHG reduction target in 2050.

Figure 61. Final energy consumption by fuel type



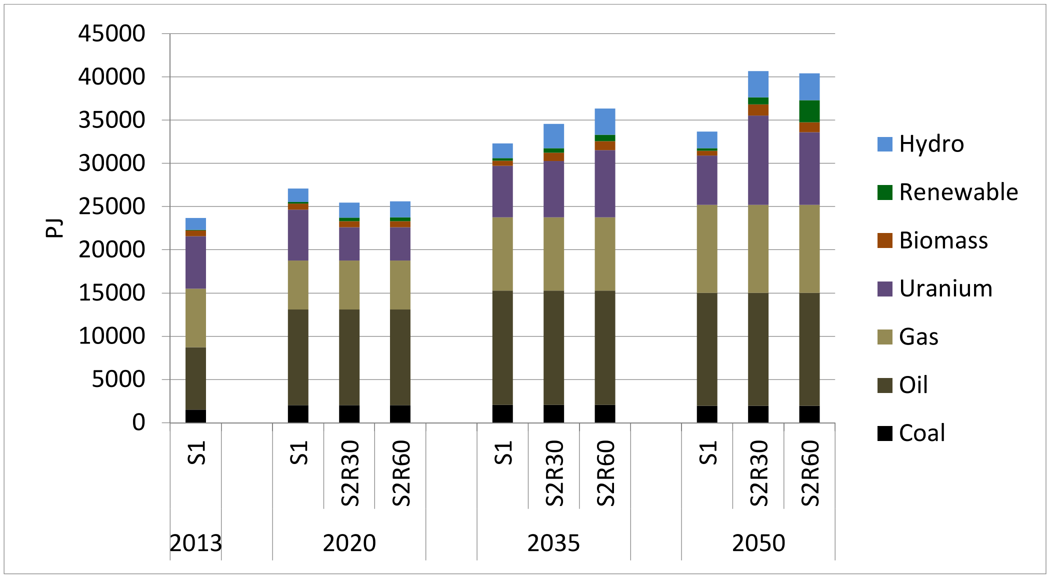
5.4.3 Primary Energy Production

Primary energy production is shown on Figure 62 for selected years and for the four selected GHG reduction targets.

Key observations from detailed review of background documentation and results are as follows:

- Production projections for fossil fuels supply were determined on the basis of information from Canada's National Energy Board to 2035, and as projected beyond 2035 on the basis of recent market observations and global trends. As will be observed, these are precribed and unchanging for each of the selected years
- Relative to the Reference Scenario, there are increases in all supply sources, primarily for increased electricity production, and especially towards the end of the planning period. For the 60% reduction target in 2050, nuclear generation increases from 796 PJ to 2582 PJ (224% increase); hydro increases from 1,936 PJ to 3,091 PJ (60% increase); other renewables (dominantly wind) increase from 316 PJ fo 1,750 PJ (more than five-fold increase); and biomass/biofuels increase from 559 PJ to 1,132 PJ (103% increase).

Figure 62. Primary energy production - S1 & S2



5.4.4 End-Use Demand Sectors

Analyses will be carried out for each of the five end use sectors; residential; commercial; industrial; transportation; and agriculture. These will be assessed, in sequence.

Residential Sector

Energy consumption for the residential sector is shown on Figure 63. As space heating is the dominant energy use, special attention has been given to analyzing this in more detail. Figure 64 includes results for Scenario 1, while Figure 65 includes comparable results for Scenario 2 for the 60% GHG reduction target. In Figure 66, reductions are shown for the influence of energy conservation and energy efficiency.

Key observations from detailed review of background documentation and results are as follows:

- There are two dominant changes from the Reference Scenario
    - Overall reduction in energy use, driven by conservation and energy efficiency gains, and increasing use of heat pumps
    - Major reduction in use of natural gas for space heating, hot water and steam production, and cooking. For the 60% GHG reduction target in 2050, natural gas use declines by 89%, while electricity increases by 55%.
- There is progressive elimination of refined petroleum products and biofuels for meeting residential energy requirements.
- Natural gas used for direct heating is replaced partially by natural gas heat pumps, which in turn are repaced by electric heating and electric heat pumps.
- Solar thermal has a minor role for Scenario 2, and dominantly towards the end of the planning period

- There are only minor differences in results for the prescribed range of GHG reduction targets analyzed
- Additional energy efficiency and conservation become significant, especially towards the end of the planning period. For Scenario 2 with 60% GHG reduction target for 2050, there is projected 28% reduction; 8% from energy efficiency improvements (energy star appliances, LED and CFL light bulbs, etc.) and 20% from conservation (thermal efficient buildings, programmable thermostats)

Figure 63. Residential final energy consumption

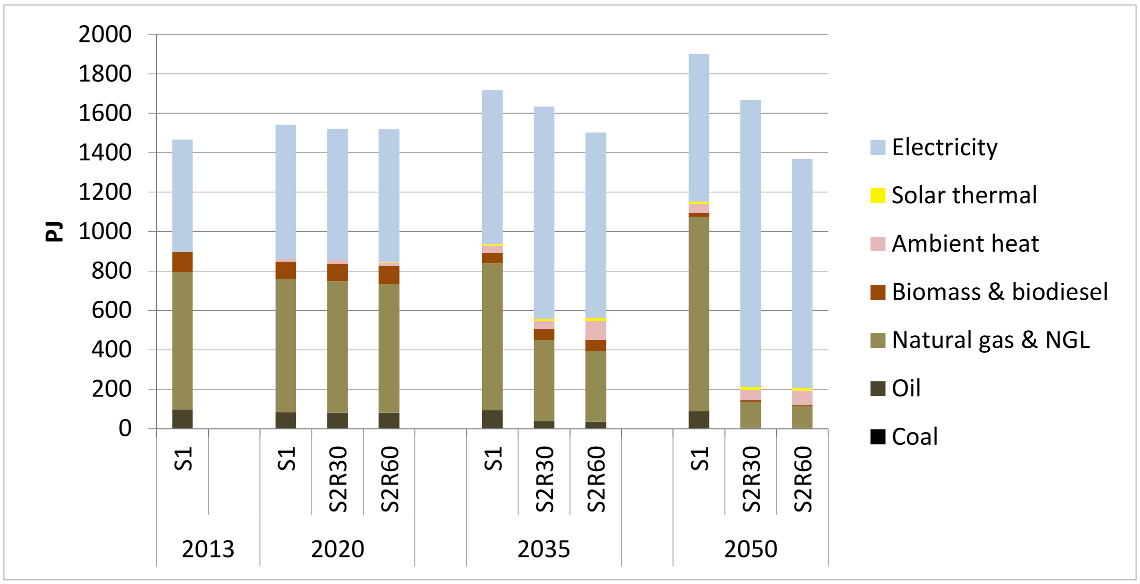


Figure 64. Space heating technology market shares - S1

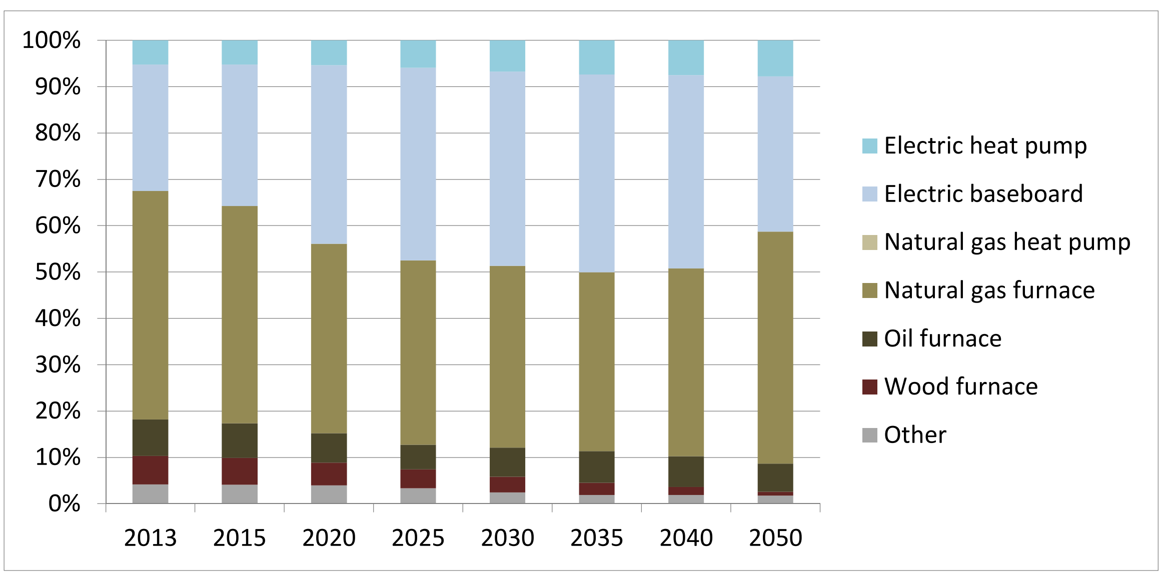


Figure 65. Space heating technology market shares - S2R60

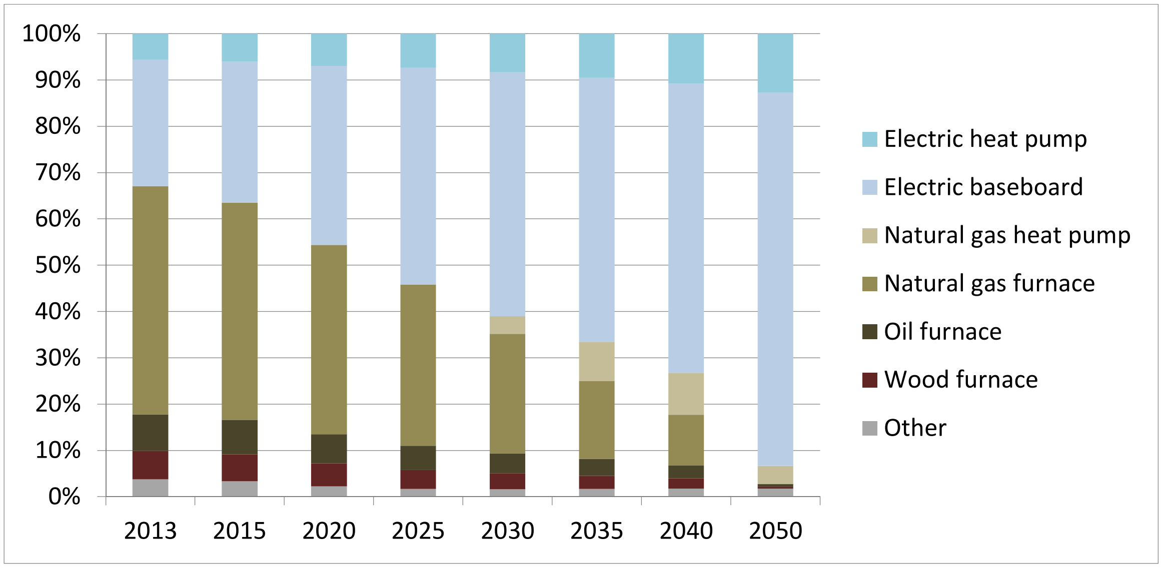
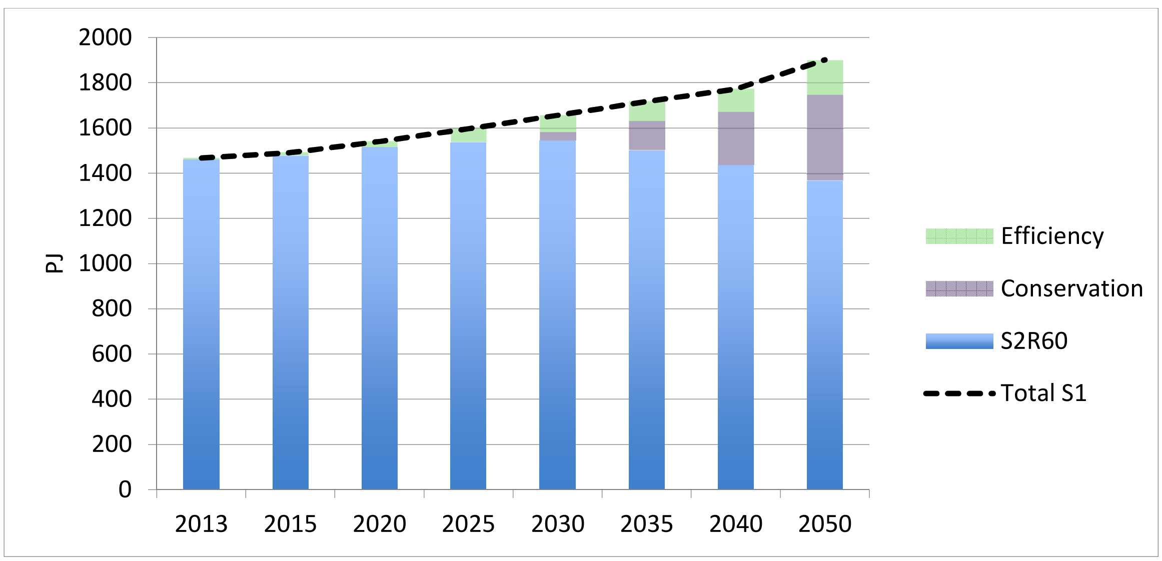


Figure 66. Energy consumption reduction in residential sector - S2R60 compared to S1



Commercial sector

Results for Scenario 2, with comparison to results from Scenario 1 are shown on Figure 67. On Figure 68, the impact of energy efficiency and energy conservation are shown.

Key observations from detailed review of background documentation and results are as follows:

- As with the residential sector, there are reductions in energy demand, relative to Scenario 1. This is due primarily to energy efficiency improvements and energy conservation, especially in later years. There is also progressive elimination of natural gas, which declines from 440 PJ to 19 PJ in 2050, for the 60% GHG target reduction scenario

- There is progressive shift from natural gas to electricity for space heating, and hot water and steam production
- Biomass and biofuels have an increasing role, especially in later years
- Petroleum products are progressively phased out
- Solar thermal systems are not cost competitive.
- The observed trends are sensibly consistent for the full range of GHG reduction targets analyzed for Scenario 2

Figure 67. Commercial final energy consumption

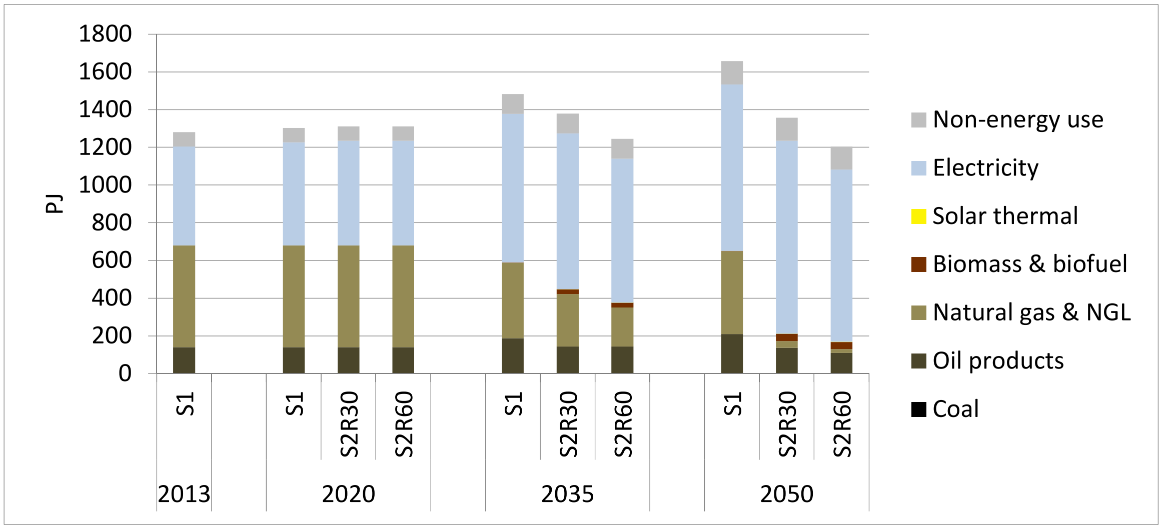
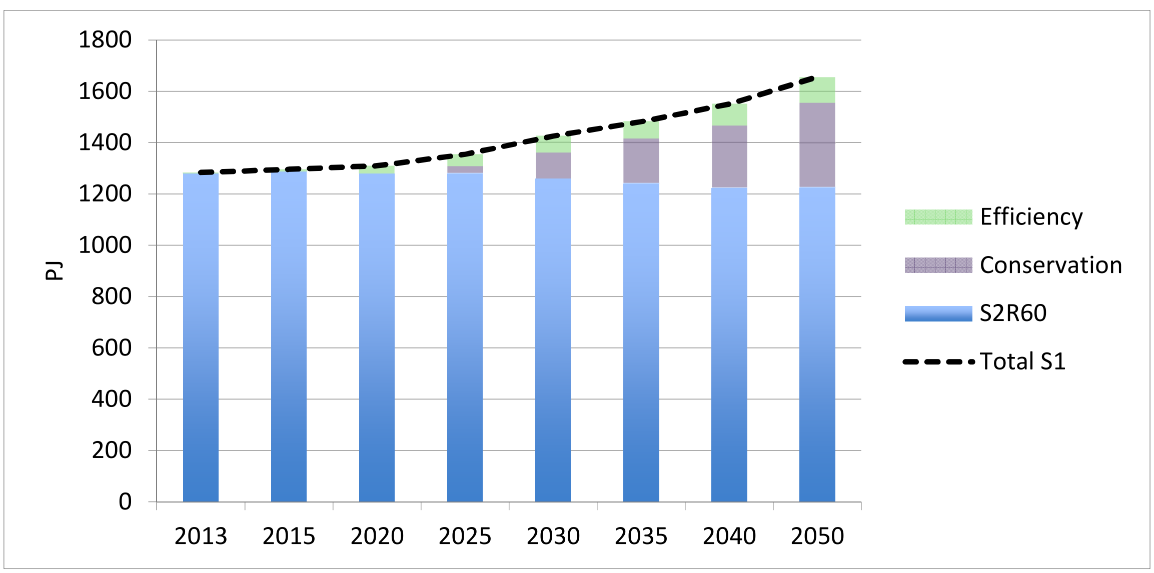


Figure 68. Energy consumption reduction in commercial sector, S2R60 compared to S1



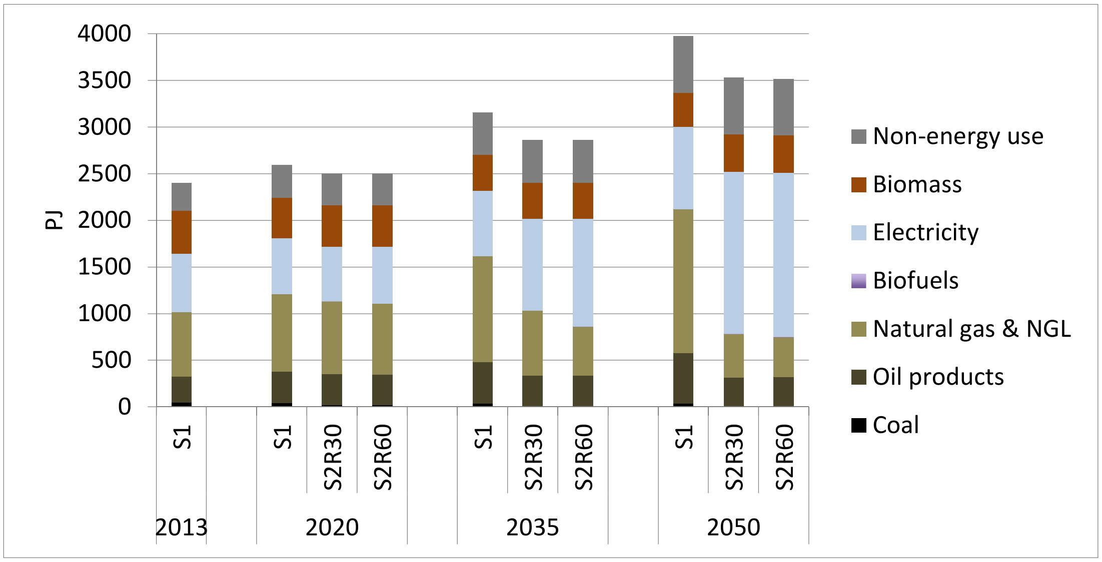
Industrial sector

Results for the industrial sector are shown on Figure 69, including comparison with results from Scenario 1.

Key observations from detailed review of background documentation and results are as follows:

- There are only minor reductions in overall demand, relative to the Reference Scenario.
- The dominant change is with increased electrification (more than double for 60% GHG reduction target in 2050), with corresponding reductions in natural gas and natural gas liquids (62% reduction), and petroleum products (29% reduction).

Figure 69. Industrial final energy consumption



Note: Biofuels amount is too small to appear on figure.

Transportation sector

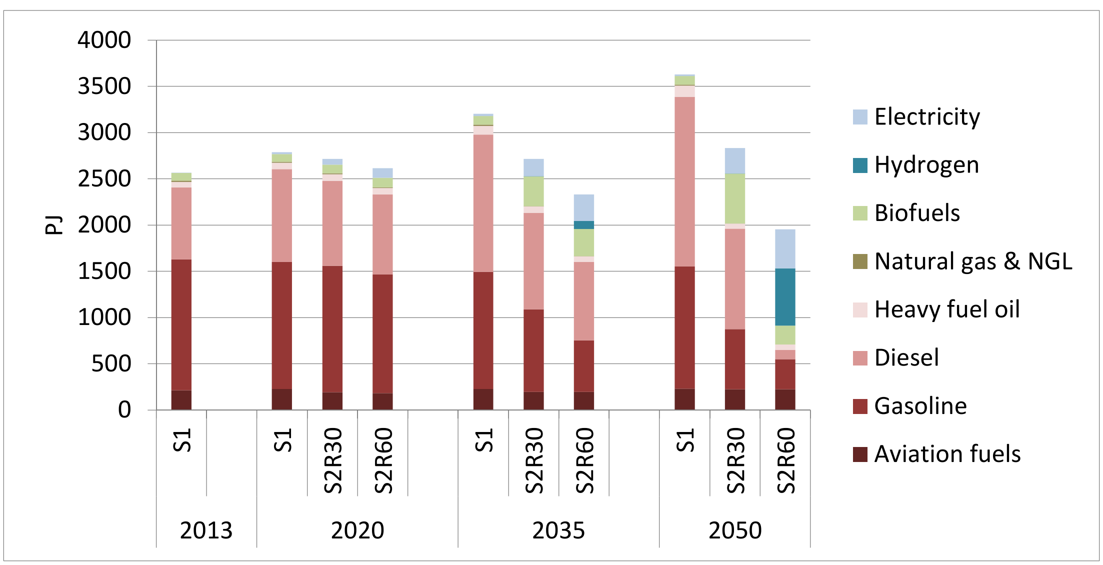
Results for the transport sector are shown on Figure 70. These results are then shown separately for passenger transport (Figure 71) and freight transport (Figure 72).

Key observations from detailed review of background documentation and results are as follows:

- The first observation is that, despite the rapid increase in both passenger and freight tranport, overall energy needs do not increase substantailly, and even decrease, in selected cases. The principal reason is that there is extensive electrification of passenger transport, which results in major reduction of energy input, dominantly due to greatly increased conversion efficiency of electric vehicles realtive to ICE vehicles (see Section 3.4.1). For example, for the 60% GHG reduction target in 2050, energy demand for passenger transport reduces from 1,069 PJ tp 215 PJ, relative to Scenario 1.
- For freight transport, there is an overall increase in energy requirement, which is tempered by increasing efficiency of ICE engines. However, the large reduction with electric vehicles for passenger transport is not considered to be a viable option for heavy freight transport vehicles, because of limitations with large scale battery storage.

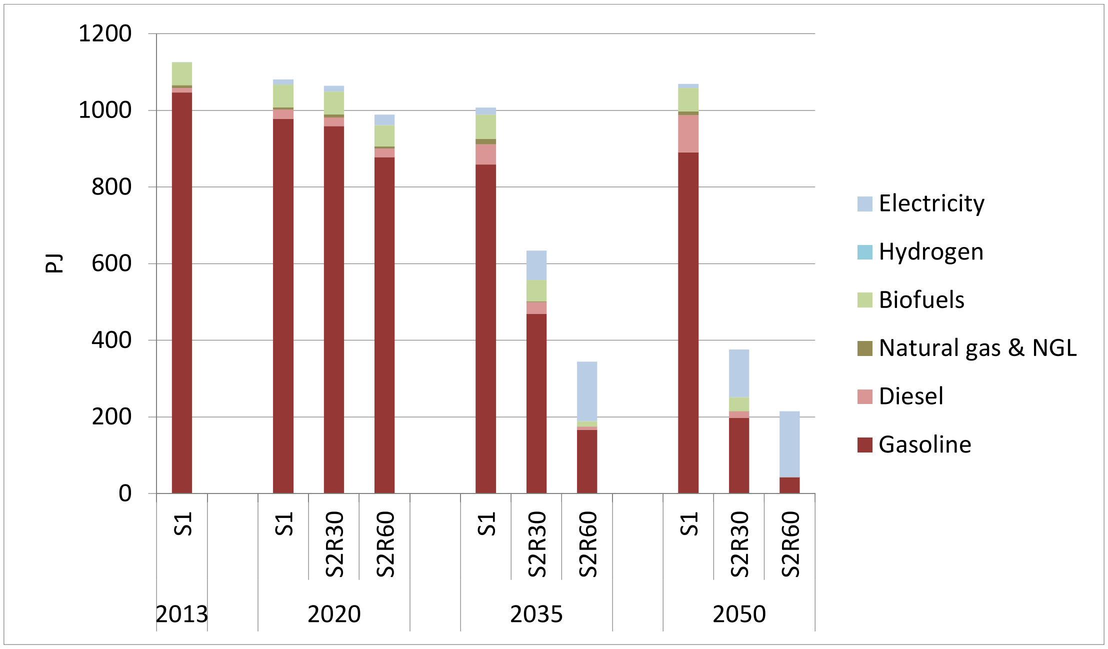
- There are major changes in the mix of fuels for the transport sector. For example, in comparing results for the 60% GHG reduction target in 2050 for Scenario 2, with results for Scenario 1, the changes are as follows;
    - Electricity consumption increases from 19 PJ to 420 PJ
    - Biofuels consumption increases from 94 PJ to 205 PJ (dominantly, for freight transport)
    - Diesel decreases from 1,836 PJ to 103 PJ (dominantly, freight transport)
    - Gasoline decreases from 1,324 PJ to 324 PJ
    - Hydrogen increases from 0 to 621 PJ (heavy freight only)
- Since heavy freight cannot be electrified, diesel is progressively replaced by hydrogen. For the 60% GHG reduction target, the mix for heavy freight portion of freight transport changes from 100% diesel in 2011, to 4% diesel, 1% biodiesel and 95% hydrogen in 2050.
- Hydrogen transport only appears for the 60% GHG reduction target and dominantly towards the end of the planning period
- For passenger transport, there are differences between smaller and larger passenger vehicles. For smaller vehicles, there is a general shift from gasoline to battery powered vehicles. For the 60% GHG reduction target in 2050, for example, Scenario 2 has virtually 100% battery powered vehicles, as compared to nearly 100% gasoline and diesel for Scenario 1. For larger passenger transport, there is a more dominant trend to plug-in hybrid vehicles in Scenario 2, while Scenario 1 is dominated by gasoline and some ethanol based vehicles.
- For freight transport, there are distinctions between heavy freight, medium freight and light freight. For heavy freight, diesel which dominates for Scenario 1, is replaced by hydrogen (which comes in near the end of the planning period). For medium freight, diesel is the dominant fuel for Scenario 1. For Scenario 2, this is progressively replaced by electric battery vehicles. For light freight, the trend is from dominantly gasoline (Scenario 1) to a mixture of gasoline and gasoline electric hybrid vehicles.

Figure 70. Transportation sector final energy consumption



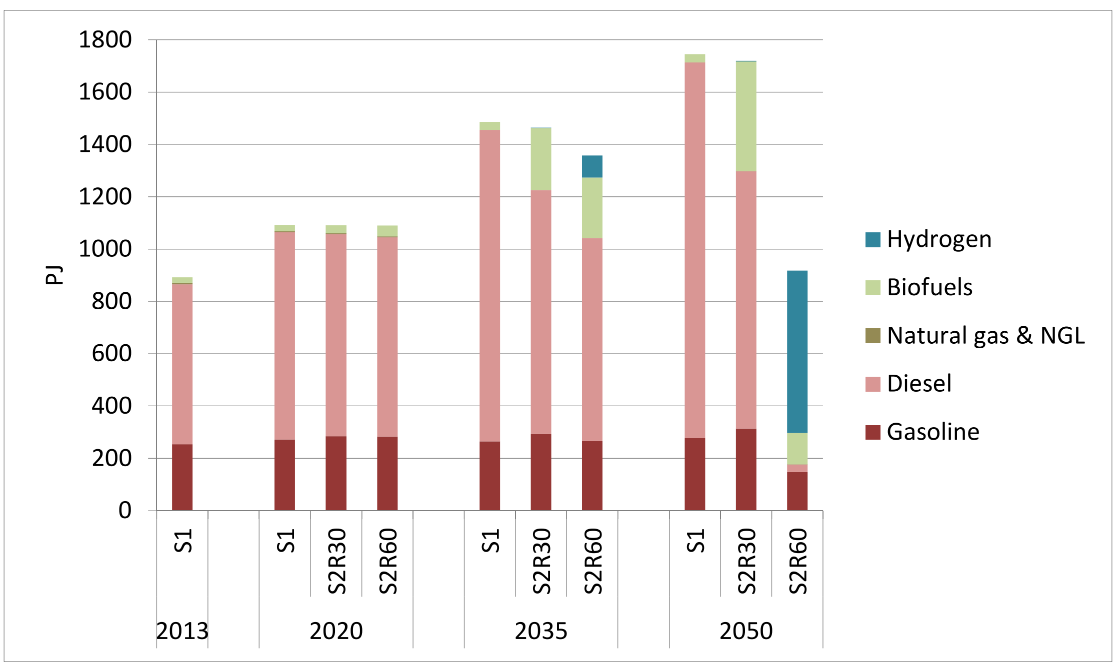
Note: Natural gas and NGL amounts are too small to appear on figure.

Figure 71. Road passenger fuel consumption



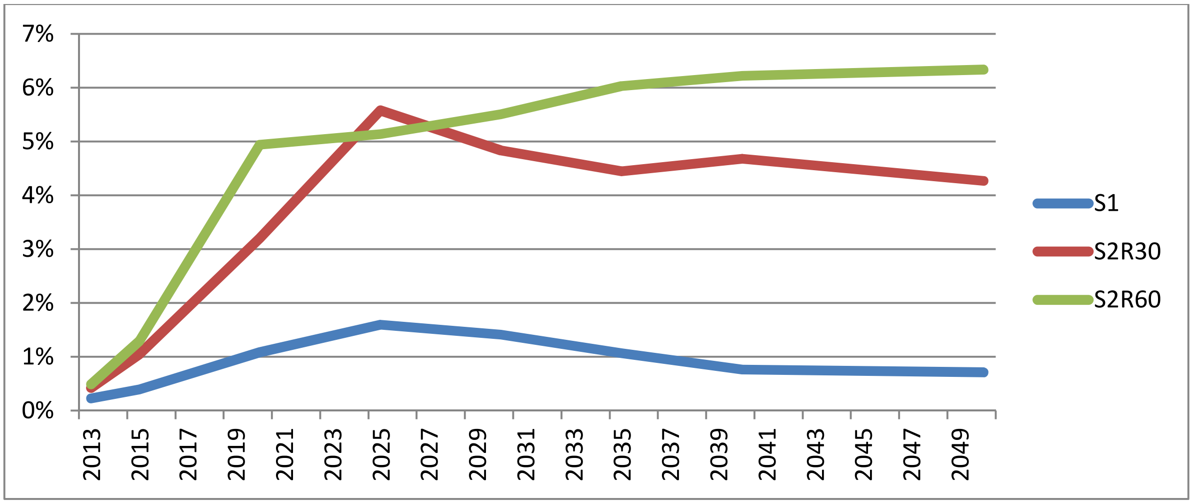
Note: Natural gas and NGL amounts are too small to appear on figure.

Figure 72. Road freight fuel consumption



In Figure 73, the projected proportion of electricity used by the transportation sector is shown. The principal observation is that, even with the major changes being projected, electricity demand remains as a relatively small proportion of total electricity demand. Even for the 60% GHG reduction target, the maximum demand is only slightly higher than 6% of total electricity demand, and increases at a relatively modest rate.

Figure 73. Share of electricity consumed in transport sector over total electricity consumption

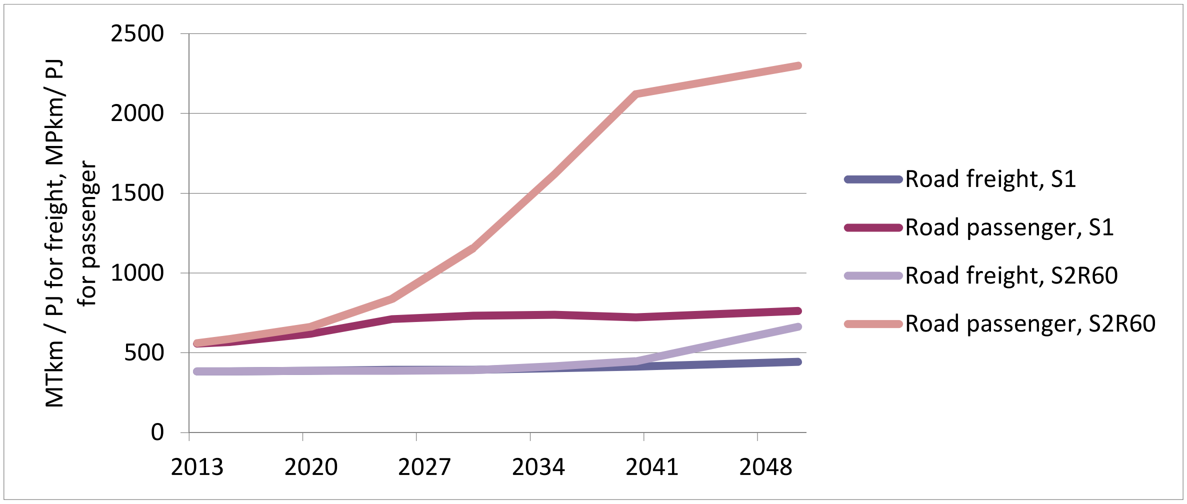


Projected efficiency improvements for both passenger and freight transport are shown on Figure 74.

Key observations from detailed review of background documentation and results are as follows:

- For the 60% GHG reduction target in 2050, passenger transport efficiency increases from 588 MPkm per PJ in 2011 to 2,299 MPkm per PJ in 2050. This is due to combination of electrification of most passenger vehicles (electric powered vehicles are about 3-4 times more efficient than internal combustion vehicles) and increased efficiencies for internal combustion engines.
- There is also nominal increase in vehicle efficieny for freight transport.
- While CAFE standards are included in the model as limiting constraints on vehicle efficiency until 2025, the results indicate that these minimum efficiencies are, in general, being exceeded after 2025. This means that cost and national GHG emission incentives are the main drivers of efficiency growth, and not CAFE standards.

Figure 74. Road passenger and freight efficiency evolution, 60% GHG reduction target



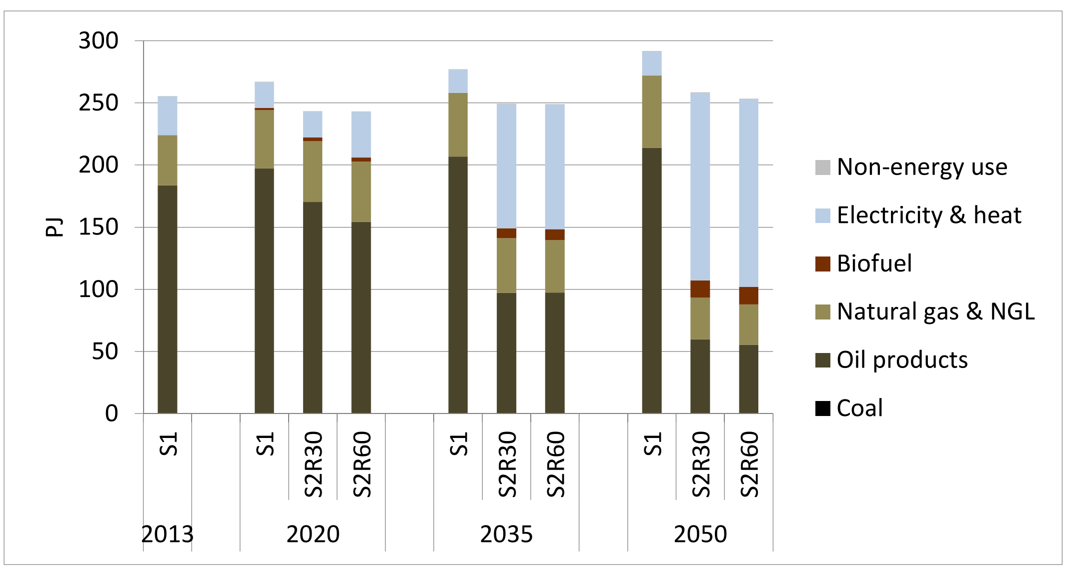
Agriculture sector

Results for the agricultural sector are shown on Figure 75.

Key observations from detailed review of background documentation and results are as follows.

- There is a nominal reduction in energy use in Scenario 2 relative to Scenario 1. This is primarily due to greater use of electric motors, which are more efficient than ICE engines.
- The dominant change is with increased use of electicity (seven fold increase for the 60% reduction target in 2050, relative to Scenario 1), and reduced use of natural gas (45% reduction) and reduced use of petroleum products (74% reduction).
- Use of biofuels also increases from 0 PJ in S1 in 2050 to 14PJ in S2R60.

Figure 75. Agriculture final energy consumption



5.4.5 Electricity

The changing role of electricity for meeting Canada's energy demands is shown on Figure 76. The ratio of electricity relative to total energy demands is shown on Figure 77.

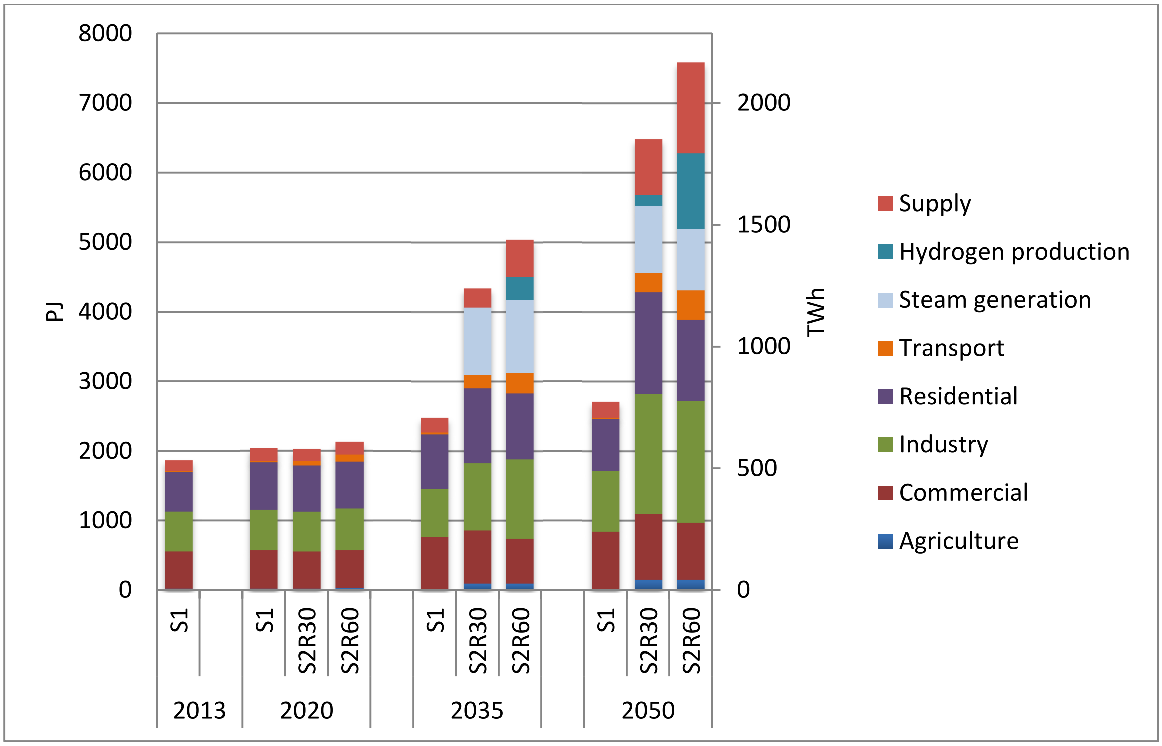
Key observations from detailed review of background documentation and results are as follows:

- In the absence of GHG constraints (Scenario 1), the role of electricity changes only nominally, increasing only from 22 to 23% from 2013 to 2050. As GHG constraints are introduced, the role of electricity increases, especially after 2020. Its role increases as the GHG reduction constraint increases. For the 60% GHG reduction target 2050, electricity satisfies 7,600 PJ of energy demand, as compared to 2,710 PJ for Scenario 1 (280% increase). The corresponding portion of energy based end uses, correspondingly, increases from 22% to 53%.
- While all sectors are being increasingly electrified with increasing GHG constraints, the dominant change is with electrification of fossil fuel supply. Electricity supply for the energy supply increases from 230 PJ for Scenario 1 in 2050 to 3,280 PJ for the 60% GHG reduction target in 2050. This includes 21 PJ for biofuel production and 144 PJ for electricity supply. The remaining 3,115 PJ is for fossil fuels and includes the following;

    - 27% for steam generation used in bitumen extraction
    - 35% for hydrogen production (electrolysis)
    - 20% for tight and shale gas production
    - 9% for liquefying natural gas (LNG production)

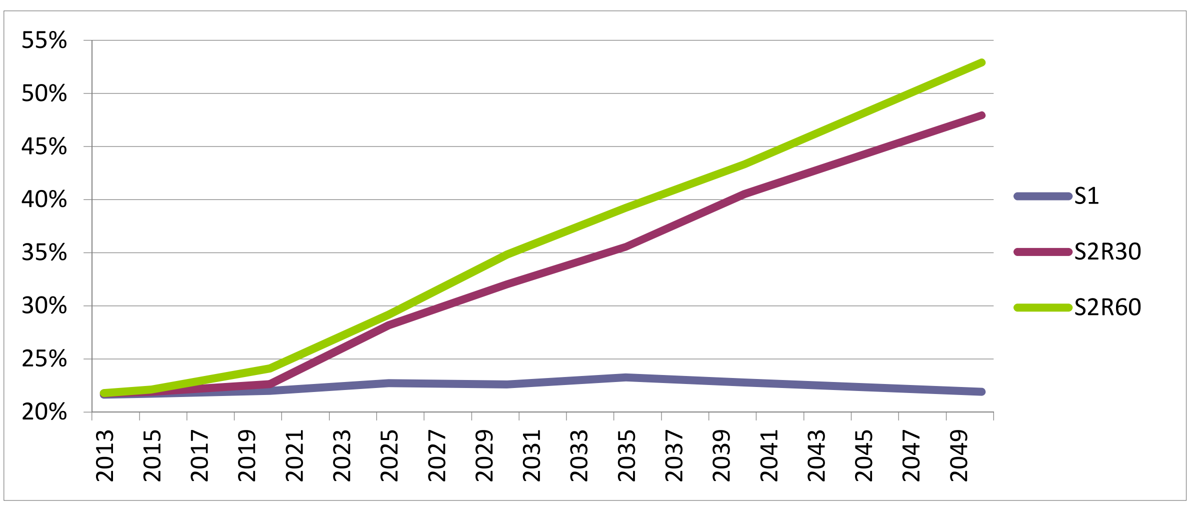
- The second significant change is with the transport sector. Electricity increases from 19 PJ for Scenario 1 in 2050, to 426 PJ for the 60% GHG reduction target in 2050.
- It should be noted that electricity export to the United States is prescribed for each year.

Figure 76. Electricity consumption



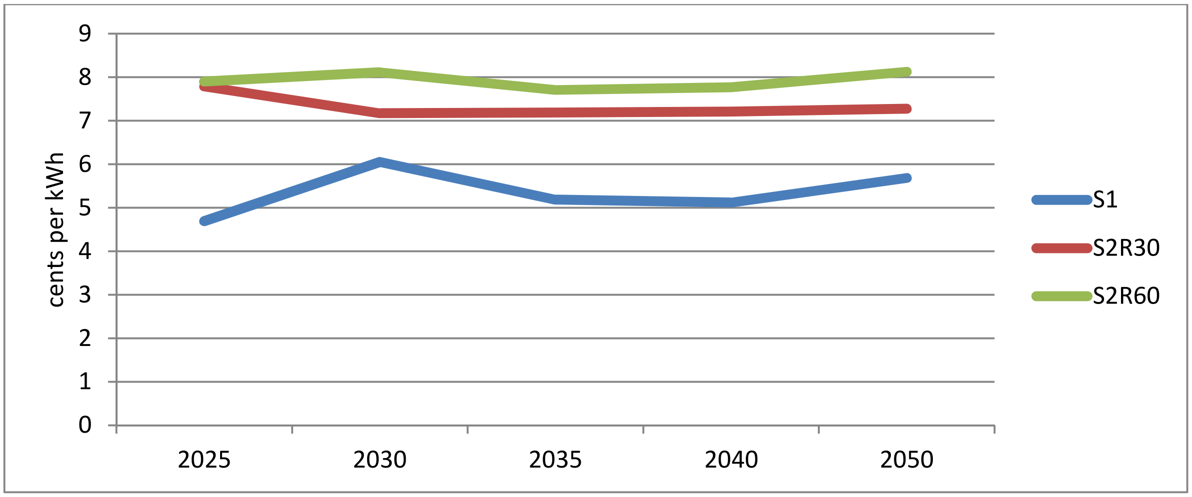
Note: Supply includes electricity for production of fossil fuels, electricity and biomass/ biofuels.

Figure 77. Ratio of electricity consumption over total final energy consumption



The average cost of incremental electricity is shown on Figure 78. This includes the combination of investment and operating costs for generation and transmission only. It does not include costs for distribution and for other utility related costs. It is noteworthy that, even though costs increase with increasing GHG constraints, these increases are not large, being only of the order of 1¢/kWh, and remaining relatively unchanging for the planning horizon.

Figure 78. Marginal cost of electricity, national average



Electricity produced from the different energy sources for both Scenarios 1 and 2, from 2013 to 2050, are shown on Figure 79. GHG emissions intensity is shown for Scenario 1, and for 30% and 60% GHG reduction targets for Scenario 2, on Figure 80. Total installed generating capacities for Canada, for each of the sources of electricity generation, from 2013 to 2050, for both Scenarios 1 and 2, are shown on Figure 81. Generating capacities in each of the jurisdictions for 2013 are shown on Figure 82. Projected capacities in 2050 for both Scenario 1, and Scenario 2 for 60% reduction in GHG emissions, for the respective jurisdictions, are shown on Figure 83. The corresponding percentages of installed hydro capacity for the respective jurisdictions, for the 60% GHG reduction target in 2050, are shown on Table 60.

Key observations from detailed review of background documentation and results are as follows;

- The rapid increase in electrification of end uses to meet GHG reduction targets is accompanied simultaneously by rapid decarbonizing of electricity supply. Electricity supply is close to being fully decarbonized before 2030, for both the 30% and 60% GHG reduction scenarios. Remaining thermal generation is used primarily for meeting peak system demands.
- This is a very key observation, as it demonstrates clearly the value of early decarbonizing of the electricity supply system for achieving cost effective reductions for combustion emissions.
- The dominant changes in electricity supply, relative to Scenario 1, include major increases in nuclear, wind generation and hydro generation, and almost complete elimination of all thermal based generation. There is a relatively small amount of geothermal generation (British Columbia) and no solar or biomass generation. Changes for the 60% reduction scenario in 2050, relative to Scenario 1, are as follows:

    - Nuclear increases from 7 GW to 100 GW
    - Wind increases from 16 GW to 204 GW
    - Hydro increases from 102 GW to 166 GW
    - Natural gas decreases from 43 GW to 21 GW
    - Pumped storage increases from 0.03 to 88 GW (for providing dependable capacity for wind generation and to complement nuclear generation)

- With respect to mix of generation supply, the dominant changes occur in those jurisdictions which are currently dependent on thermal generation, where there is limited potential for conventional hydro generation, and/or where there are major demands for electrification of end uses. This includes British Columbia, Alberta, Saskatchewan and Ontario. More specifically, the dominant changes in these jurisdictions for the 60% GHG reduction scenario in 2050, compared to Scenario 1, include;
    - Alberta: Introduction of nuclear generation of 74 GW; 28 GW of large scale pumped storage, to complement nuclear and geothermal, and to provide dependable capacity for wind generation; Decrease in thermal generation, from 20 GW to 8 GW
    - British Columbia: Introduction of nuclear generation of 6 GW; 6 GW of geothermal; No additional conventional hydro; 27 GW of pumped storage
    - Saskatchewan: Dominant increase in wind (23 GW), and small amount of large scale pumped storage generation
    - Ontario: Increase in nuclear to 21 GW; Increase in hydro from 9 to 19 GW; Decrease in thermal from 15 to 8 GW, primarily for peaking supply
- For the other jurisdictions, trends are similar to Scenario 1, except that there is more capacity for satisfying increasing electrification of end uses. For example, Manitoba, Quebec and Newfoundland & Labrador, remain as hydro dominated jurisdictions, with greater installed hydro generation capacities.
- It can be seen that, for the 60% GHG reduction scenario in 2050, installed hydro increases 121%. The major increases are in Quebec, Newfoundland & Labrador, Manitoba and Saskatchewan, with smaller increases in New Brunswick and Nova Scotia. Perhaps surprisingly, there is relatively little increase of hydro in British Columbia, as run of river hydro, with its low dependable capacity ratio, is not cost competitve. Also, even though Alberta has substantial undeveloped hydro potential, it is expensive and not cost competitive with combination of nuclear, geothermal, wind and large scale pumped storage.
- It should be apparent that the amount of electricity infrastructure required to meet defined mitigation targets is truly enormous, and almost certainly, is not realizable within the given time frame. However, it also needs to be appreciated that, if there are delays, the overall minimum cost solution will only increase for the same prescribed mitigation profile from 2011 ro 2050. This serves to demonstrate the full enormity of the challenge for achieving rapid progress on GHG mitigation as defined by the goal of this project. This is amplified further in Section7.3.

Figure 79. Electricity produced by energy source

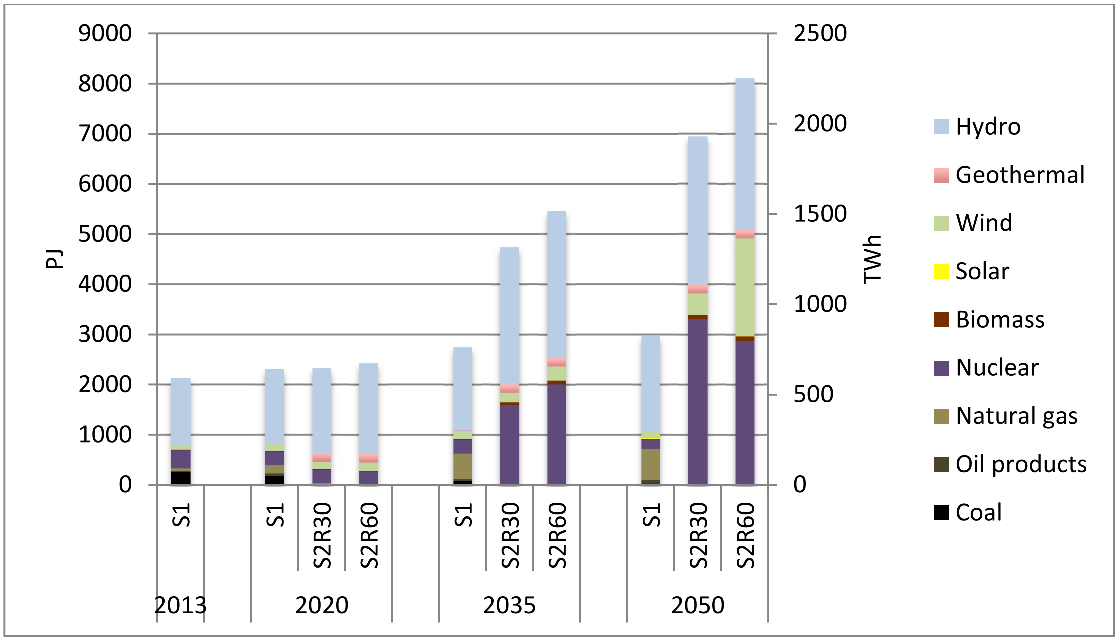


Figure 80.GHG emission intensity of electricity generation

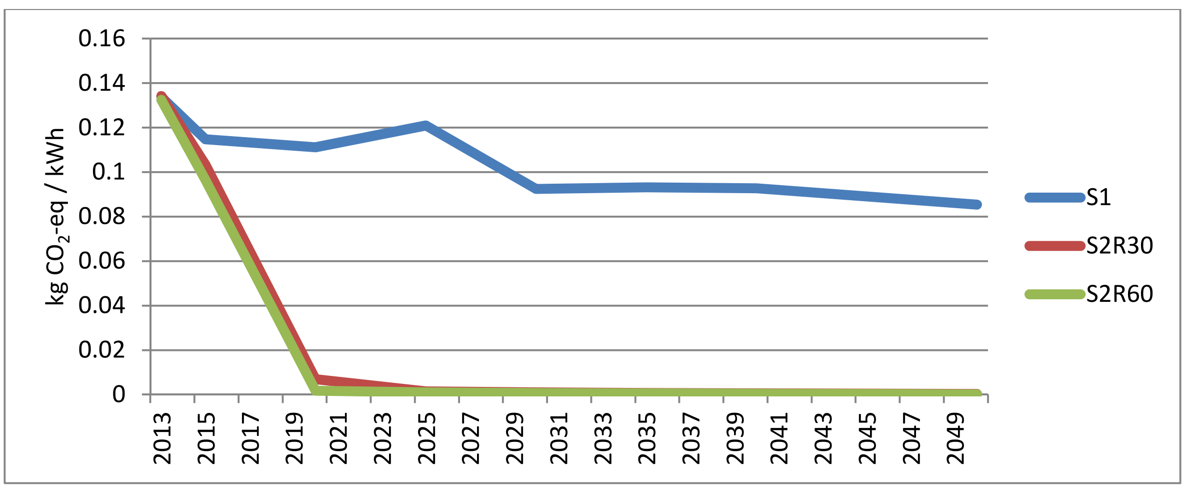


Figure 81. Electricity generating capacity for Canada

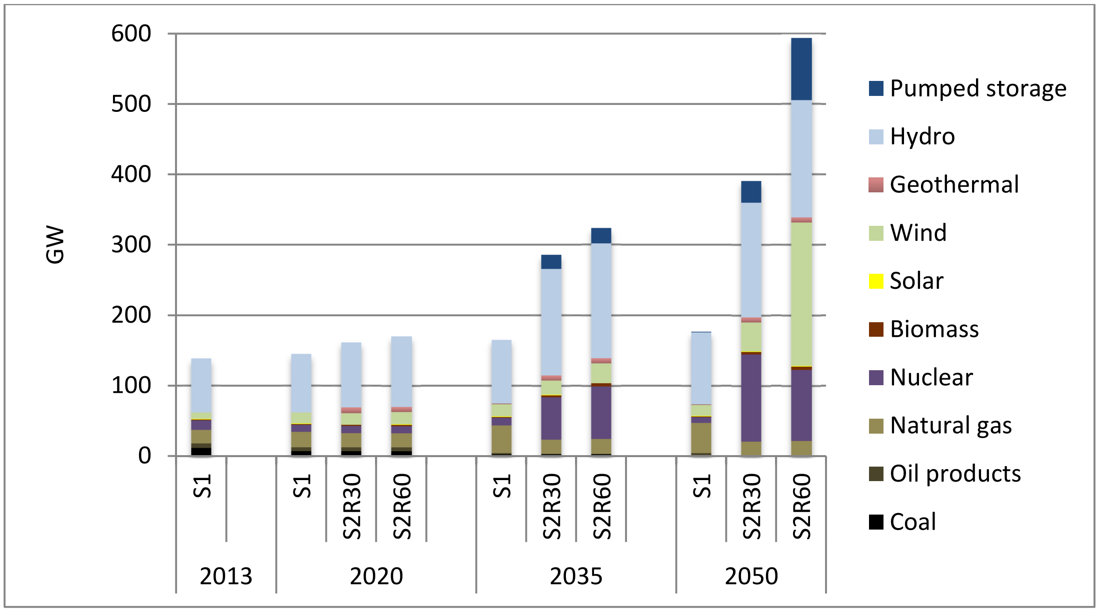


Figure 82. Electricity generating capacity by jurisdiction in 2013

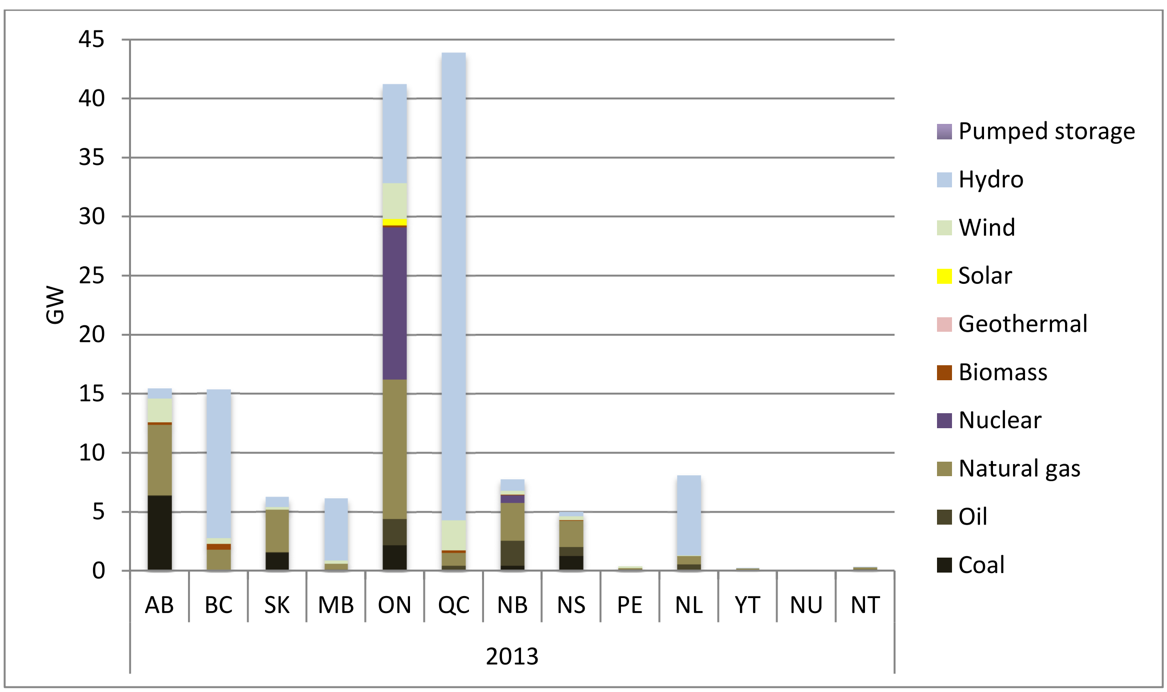


Figure 83. Electricity generating capacity by jurisdiction - S2R60 compared to S1

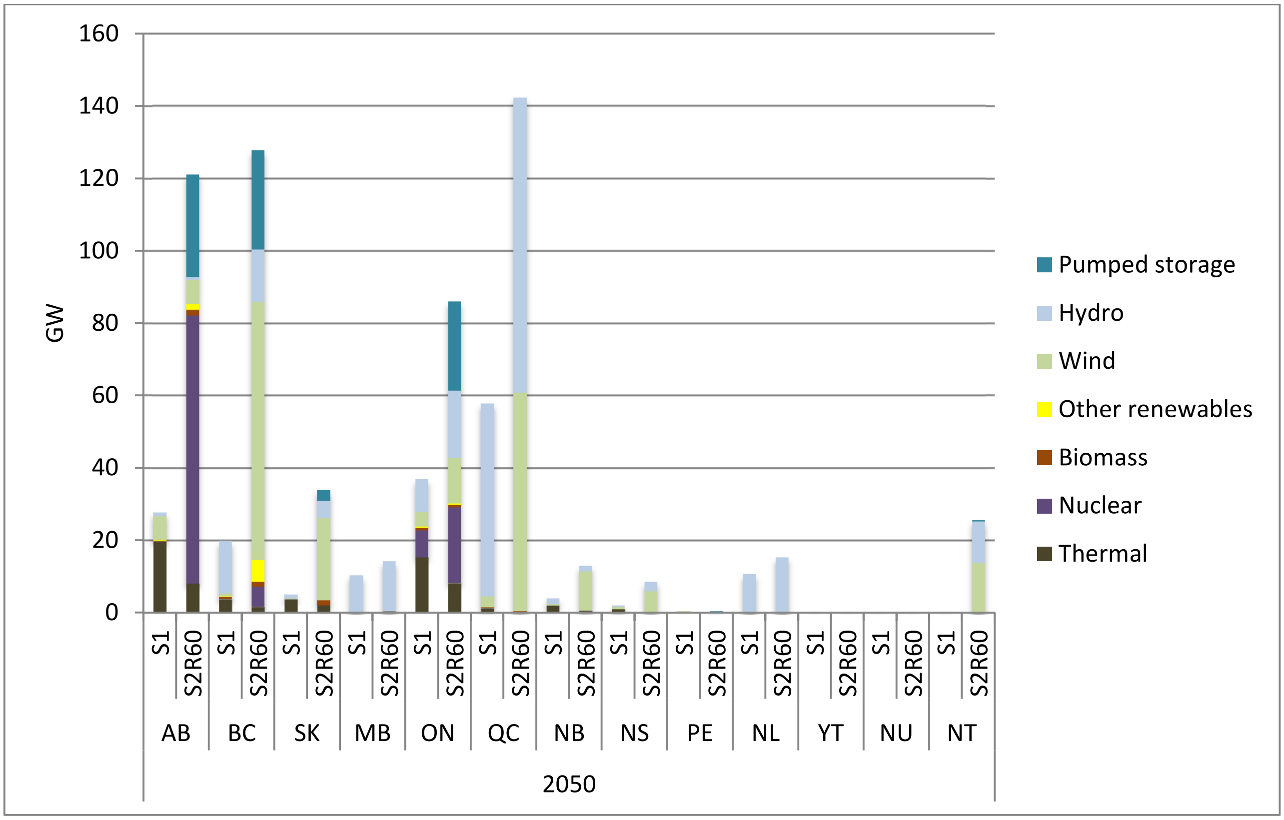


Table 60. Hydro capacity (% of technical potential) for S2R60

	2013	2020	2030	2040	2050
Alberta	6%	7%	7%	7%	7%
British Columbia	27%	30%	30%	32%	32%
Manitoba	38%	51%	78%	100%	100%
New Brunswick	62%	62%	100%	100%	100%
Newfoundland	44%	67%	69%	100%	100%
Nova Scotia	4%	4%	15%	19%	30%
Northwest Territories	1%	23%	100%	100%	100%
Nunavut	0%	0%	0%	0%	0%
Ontario	43%	60%	95%	95%	95%
PEI	0%	0%	0%	0%	0%
Quebec	49%	59%	87%	100%	100%
Saskatchewan	18%	70%	96%	96%	100%
Yukon	0%	0%	0%	1%	1%
Total	32%	42%	61%	69%	69%

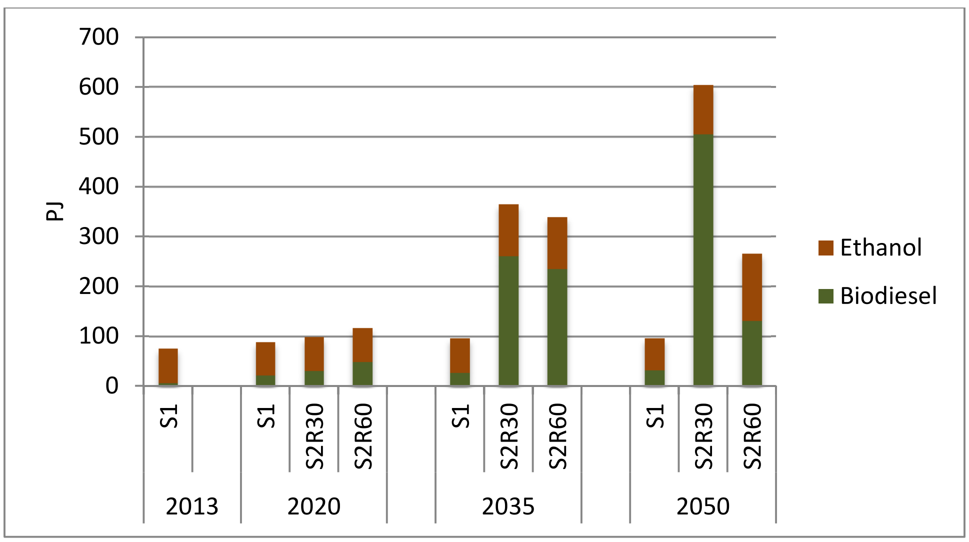
5.4.6 Biofuels

Changes in biofuel production between Scenarios 1 and 2 are shown on Figure 84.

Key observations from detailed review of background documentation and results are as follows:

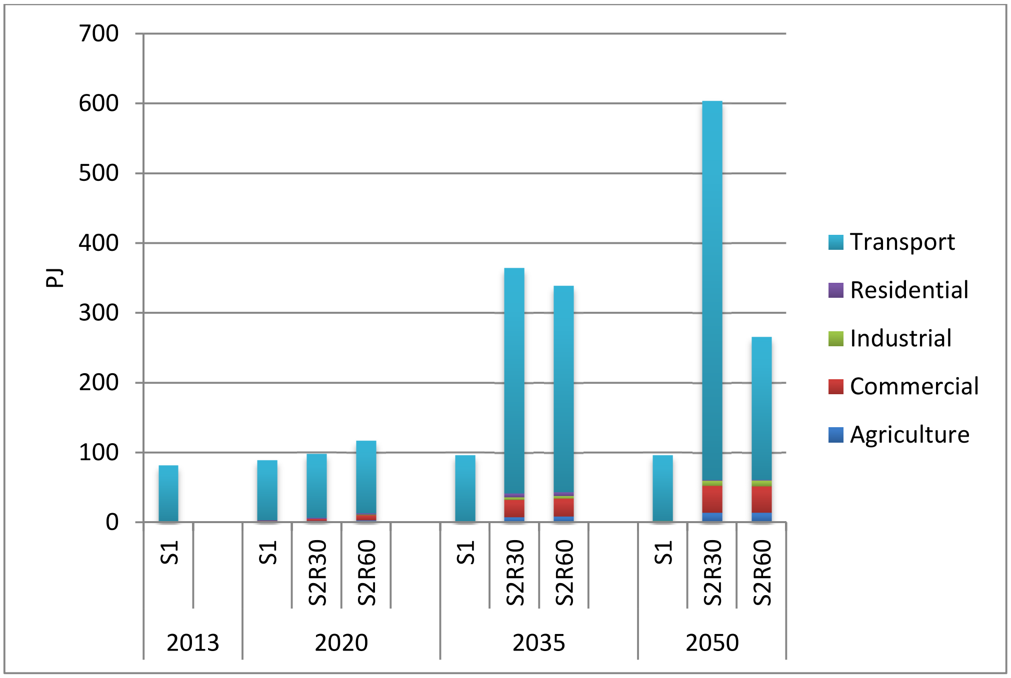
- There are major increases in production of both ethanol and biodiesel in Scenario 2, dominantly for the transport sector. For example, ethanol production increases from 69 PJ for Scenario 1 to 135 PJ for the 60% GHG reduction scenario in 2050. Biodiesel production correspondingly increases from 18 PJ to 131 PJ.
- It is important to note the decrease in biodiesel production from S2R30 to S2R60. The cause of this decrease is inversely related to the substitution of traditional diesel heavy freight vehicles by hydrogen based vehicles. Biodiesel can be used (up to a certain ratio of diesel input) in diesel based heavy freight vehicles, however in S2R60, the need for further emission reductions in the transport sector leads to a switch to hydrogen based technologies.

Figure 84. Biodiesel and ethanol production



Changes in use of biofuels for the five end use sectors are shown in Figure 85. As already noted, changes between Scenarios 1 and 2 are almost entirely in the transport sector. Total biofuel for the transport sector increases from 94 PJ for Scenario 1 to 205 PJ for 60% GHG reduction for Scenario 2 in 2050.

Figure 85. Biofuel use (ethanol and biodiesel) by sector



5.4.7 International Trade

With reducing use of energy in Canada, especially fossil fuels, there are corresponding opportunities for increasing export of such energy commodities. The impact of this is shown on Figure 86. Projected real values for various energy commodities in 2011 dollars are shown on Table 61.

Key observations from detailed review of background documentation and results are as follows:

- For Scenario 1, energy export is projected to increase from \$133 billion to \$237 billion, representing an increaese of 78%. This large increase arises as a result of both increased export and projected increased real value of energy commodites.
- Export of energy commodities is dominated by oil and natural gas (including LNG). There is some export of coal, electricity and refined petroleum products, although these are relatively minor.
- With growing GHG emissions reductions, use of fossil fuels for domestic consumption decreases progressively, with correpsonding increased availablity of fossil fuels for export, especially after 2020. For the 60% GHG reduction constraint in 2050, exports increase from \$237 billion (Scenario 1) to \$320 billion (Scenario 2), an increase of \$83 billion.

Figure 86. Energy export

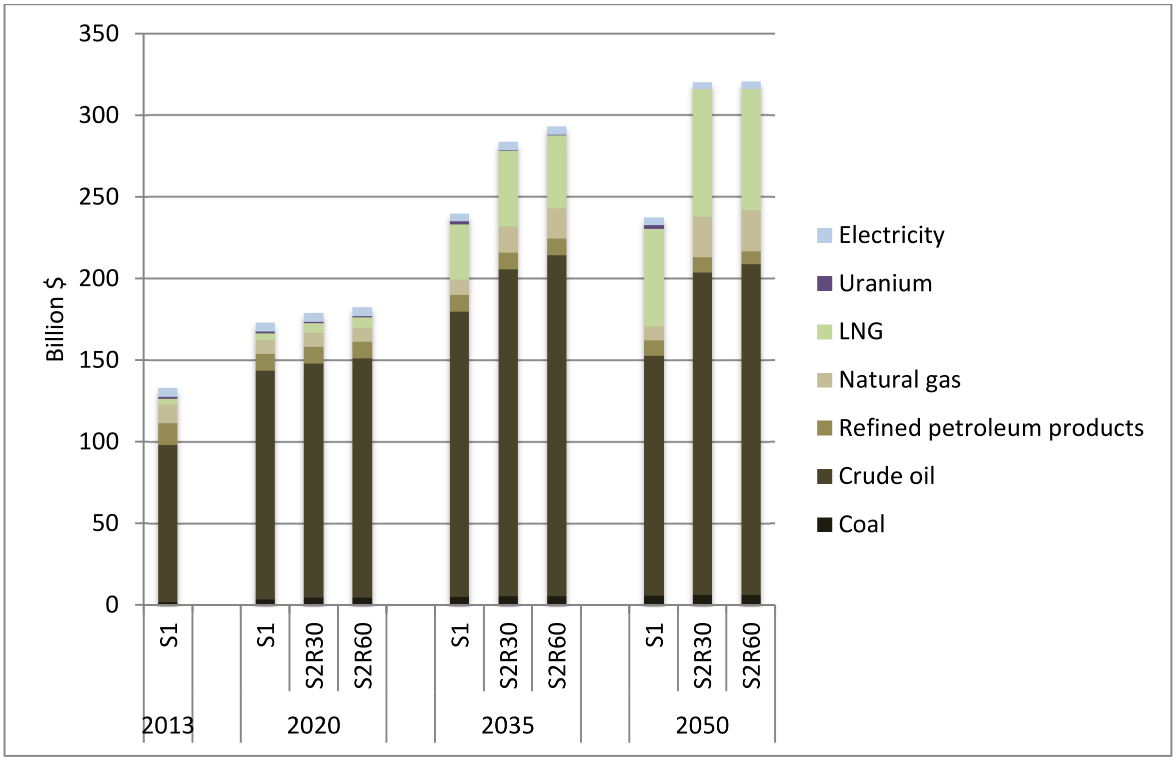


Table 61. Energy export prices

$ per GJ (2011 dollars)	2013	2015	2020	2030	2040	2050
Coal	$1.88	$2.04	$2.20	$2.53	$2.81	$3.09
$ per tonne	$50.86	$55.20	$59.53	$68.30	$75.75	$83.33
Electricity	$27.98	$27.98	$27.98	$27.98	$27.98	$27.98
$ per MWh	$100.72	$100.72	$100.72	$100.72	$100.72	$100.72
Natural gas and NGL	$3.44	$3.81	$4.18	$5.76	$11.38	$14.19
LNG		$9.00	$10.00	$14.00	$18.00	$20.00
Refined petroleum products	$24.21	$22.72	$21.23	$24.22	$24.22	$24.22
Gasoline, $ per liter	$1.01	$0.90	$0.87	$0.97	$1.11	$1.15
Crude oil	$16.11	$16.70	$17.30	$18.14	$20.81	$21.77
$ per barrel	$99.77	$103.44	$107.11	$112.35	$128.86	$134.82
Uranium	$0.24	$0.28	$0.31	$0.39	$0.46	$0.50
$ per kg	$106.88	$123.75	$140.63	$174.38	$208.13	$225.00

Conversion assumptions: Coal: 27 GJ per tonne; Electricity: 3.57 GJ per Mwh ; Gasoline: 0.034 GJ per liter; Crude oil: 6.193 GJ per barrel ; Uranium: 450 GJ per kg

5.4.8 Cost

A preliminary assessment was carried out to assess costs for achieving the prescribed GHG reduction targets.

The principal reporting measure was marginal cost, as derived by the optimization model. This is a direct measure of the lowest incremental cost for achieving a further unit of GHG reduction at the optimal solution. At the derived minimum cost solution, the unit cost of every available option for reducing GHG emissions will be either equal to or greater than this derived marginal cost.

This value has special significance when considering carbon pricing. Based on the assumption of perfect market responses, and with the goal of achieving GHG reduction results as reported in this project, the sequence of carbon prices, over time, would need to be equal to the derived marginal costs.

The sequence of derived marginal costs for 30% and 60% GHG reductions for Scenario 2 are shown on Figure 87.

Key observations with consideration of the afore-noted comments, the principal results are summarized as follows:

- As expected, for any Scenario, marginal costs increase over time. This arises as the lowest cost options for GHG mitigation are selected first, with future options being progressively more expensive.
- Also, as expected, marginal costs are higher with increasingly stringent GHG emissions targets.
- It need to be appreciated that marginal costs, as reported here, reflect marginal costs (equivalent carbon prices) in hundreds of dollars per tonne for CO_2 mitiagtion, and not tens of dollars per tonne, which has been the basis for carbon pricing frameworks in several jurisdictions (see also Section 3.5).
- When considering limits on GHG mitgation, marginal cost provided an important basis for such assessment. In general, when marginal costs began to significantly exceed \$500 to \$1,000 per tonne, it was considered that such very high cost solutions might not be credible. This then served as the basis for recognizing the importance of options not included in the analyses, or seeking further refinements for those options which were resulting in major cost increases.
- It is important to appreciate potential impacts of different drivers that result in further increaeses or decreases in marginal costs, and associated overall costs for GHG mitigation. Examples of drivers for reducing costs include:

    - Including options for GHG mitigation that are not represented. For this Scenario 2, these could include, as examples, electricity system internconnectionn, second generation biofuels, CCUS, industrial process changes, etc.
    - Cost reductions for GHG mitigation options, especially those that are resulting in high marginal costs
    - Impact of breakthrough technologies
    - Reductions in demand
    - Reducing fossil fuel production

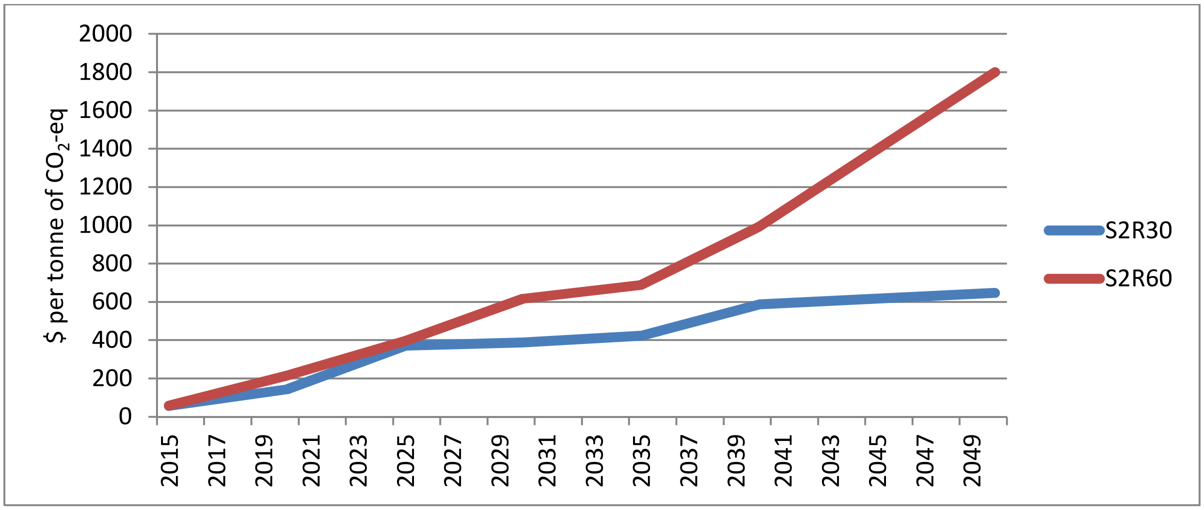
  Examples of drivers for increasing costs include:

    - Removing or delaying certain classes of infrastructure options, especially if they are part of the minimum cost solution
    - Rejection of certain technologies
    - Imposition of socio-economic or environmental constraints

  - Imposition of equity constraints – such as inter-jurisdictional cost sharing or inter-sectoral arrangements
  - Policy and regulatory structures with non-optimal implicit GHG mitigation costs

- With respect to assessment of marginal costs for this Scenario 2, it is recognized that these costs are high. With adddition of other development option and technologies, there is definite potential for reducing overall costs, and associated marginal costs. This will be reported futher for Scenarios 3 to 8, as well as for Scenarios 3a and 8a.

Figure 87. Marginal cost of emission reductions



5.4.9 Principal Observations

Projected results for Scenario 2 have been presented. This is based on the premise that the future to 2050 will be based on meeting growing energy demands in the various sectors of the Canadian economy at minimum cost. However, GHG reduction constraints have been prescribed for Scenario 2, which has led to increases in overall cost, relative to Scenario 1, which had no GHG reduction constraints. This has also resulted in major transformations in several sectors.

In this Section, the principal observations from analysis of results from Scenario 2 will be summarized. Repeated reference will be made to corresponding Observations from Scenario 1.

Growth in energy demand by sector: As with Scenario 1, there is growing energy demand in all energy consuming sectors. However, demand increases more slowly in all energy consuming sectors (27% reduction relative to Scenario 1), with the dominant reductions being in the residential, commercial and transportation sectors.

Changing energy demand by fuel type: There are major changes in demand by fuel type. The dominant change is away from use of fossil fuels. The role of electricity increases in all sectors, but most dominantly in the residential, commercial and transportation sectors. Electrification increases from satisfying 22% of energy based end uses (Scenario 1), to as high as 53% in the most extreme example (Scenario 2). Thermal based generation is progressively replaced by nuclear, hydro and wind. Large scale pumped storage becomes a significant option in some jurisdictions as a source of dependable capacity to complement wind generation. Biofuels also assume a greatly increased role, especially for freight transport.

Efficiency improvements: There are further improvements in energy efficiency in all sectors, based strictly on being economically preferred options in the overall solution process.

Primary energy production: There is an overall increase in primary energy production. Production of fossil fuels remains unchanged, as it is a prescribed production projection. However, with fossil fuels being used less for meeting domestic requirements, there are increasing investments in other primary energy sources. These include nuclear, hydro, intermittent renewables (dominantly wind) and large scale pumped storage for increasing electricity supply, as well as large scale production of biofuels.

Energy Export: Export of energy commodities increase in Scenario 2, primarily as a consequence of reduced domestic use. This is dominated by increased export of oil and natural gas, including LNG. The value of this additional export, up to $83 billion in 2050, is a significant credit against overall cost for reducing GHG emissions.

Energy consumption in residential and commercial sectors: There are significant shifts in use of energy in the residential and commercial sectors. There is an overall reduction in energy use, primarily from increased energy efficiency and energy conservation. There is also progressive elimination of use of natural gas, and greatly increased use of electricity. There are substantial shifts towards increased use of electrically driven heat pumps for space heating.

Energy consumption in transportation sector: There are major changes projected for the transportation sector. Conversion from ICE to electric cars and light duty vehicles results in actual reduction in energy use for personal transport, due dominantly to greater conversion efficiency of electric motors (ratio of 3 to 4 relative to ICE). For heavy duty vehicles used for freight transport, there is substantial conversion to use of biofuels to replace gasoline and diesel fuel. There is also a shift to use of hydrogen in the most extreme case, and only towards the end of the planning period. It is noteworthy that the greatly increased use of electricity in the transportation sector results in only nominal increase in electricity supply (not including electricity consumed for hydrogen production for heavy freight vehicles), again as a result of greatly enhanced conversion efficiency of electric motors.

Energy consumption in industry: Again, there is a general shift with reducing use of fossil fuels, primarily natural gas and petroleum products, to greater use of electricity.

Energy consumption in agriculture: There is a general shift with reducing use of fossil fuels, natural gas and petroleum products, to greater use of electricity. There is also a reduction in overall use of primary energy, primarily due to greater use of electric motors to replace ICE powered equipment.

Growth in electricity demand: As noted above, there is greatly increased demand for electricity. This includes meeting growing demands in the various end use sectors associated with reducing use of fossil fuels. It also includes progressive electrification of the supply sectors, including especially the entire supply chain for fossil fuels extraction, collection, upgrading, refining, transport and distribution. All jurisdictions have increased demand for electricity for progressive electrification of end uses relative to Scenario 1. However, the largest increases occur in those jurisdictions which also require electrification of energy supply, especially fossil fuels supply. For example, electricity demand in 2050 for Scenario 1 (2,710 PJ or 753 Twhrs) increases to 7,589 PJ (2,108 Twhrs) (2.8 fold increase). The corresponding increase in Alberta is from 439 PJ (122 Twhrs) to 2,455 PJ (682 Twhrs), more than five-fold increase.

Growth in electricity supply: With major growth in electricity demand, there is a corresponding increase in electrical generating capacity, combined with virtual full decarbonizing of electricity supply. This is dominated by increased nuclear, conventional hydro, intermittent renewables (dominantly, wind) and large scale pumped storage. There are also major differences in supply mix between jurisdictions. Jurisdictions which are hydro dominated (except British Columbia) will continue to be hydro dominated, while other jurisdictions will rely dominantly on nuclear, wind, and large scale pumped storage developments for additional generation supply.

Cost Impacts: An analysis of cost impacts for implementing GHG reductions has also been included. It has been shown that marginal costs are substantial. Such costs increase over time, as well as being higher with increasingly stringent GHG mitigation targets. There is scope for reducing costs in the longer term, based on consideration of technologies and strategic options that are not included in the analysis, including potential options that are not yet fully developed and commercially viable.

On the other hand, it needs to be also appreciated that overall costs and associated marginal costs will increase, whenever constraints are imposed that mitigate against implementing minimum cost solutions.

5.5 Scenario 3: Scenario 2 Plus Interconnections

The purpose of Scenario 2 was to demonstrate cumulative minimum cost solutions to 2050, for Canada, for progressively increasing GHG reduction targets. The premises were essentially the same as for Scenario 1, but with a series of model runs with the NATEM Canada model, with GHG reduction targets varying from 30 to 60% reduction (relative to 427 Mt (1990)).

For Scenarios 1 and 2, it was assumed that responsibility for electricity supply would remain essentially unchanged, with the respective provinces and territories ensuring that supply of firm energy and dependable capacity would be available from within its own jurisdiction, except for the three existing inter-jurisdictional arrangements. It was assumed that there would not be any additional inter-jurisdictional agreements for supply of dependable capacity.

It is well recognized that there are substantial differences in cost of electricity between jurisdictions. Jurisdictions with lowest cost electricity are the hydro dominated jurisdictions; Quebec, Manitoba, British Columbia and Newfoundland & Labrador. Other jurisdictions have had rising costs, due to combinations of several factors; phasing out conventional coal fired generation, investment in intermittent renewals (wind, solar and run of river hydro), and refurbishment and/or phasing out existing nuclear generation.

In meeting the GHG challenge between now and 2050, differences in cost of electricity supply between jurisdictions will become even greater. For hydro dominated jurisdictions, such as Quebec and Manitoba, existing hydro generation will remain in operation for the foreseeable future and will be supplemented with additional hydro from within its jurisdiction to meet both continuing load growth and increasing electrification of end uses. On the other hand, jurisdictions such as Alberta, Saskatchewan and Ontario, have the challenge of not only satisfying major increases in electricity demand from electrification of end uses and energy supply systems, but also having to replace major portions of their existing supply systems. For example, Alberta's electrical utility supply system, which is currently 92% coal fired generation, will need to be almost fully replaced and/or retrofitted with CCUS.

The prime purpose of Scenario 3 is to demonstrate benefits of system composition changes, with associated overall cost reduction potential for sale and purchase of dependable capacity between neighboring jurisdictions. This includes considerations for investing in both increased generation supply capacity in selected low cost jurisdictions and associated high voltage interconnections, to replace high cost generation supply in neighboring jurisdictions.

As with Scenario 2, minimum cost solutions were obtained for Scenario 3 for the same reduction levels as Scenario 2 (30%, 40%, 50% and 60% reduction of GHG emissions compared to 1990 levels). The same GHG reduction profiles from 2013 to 2050 were retained for Scenario 3.

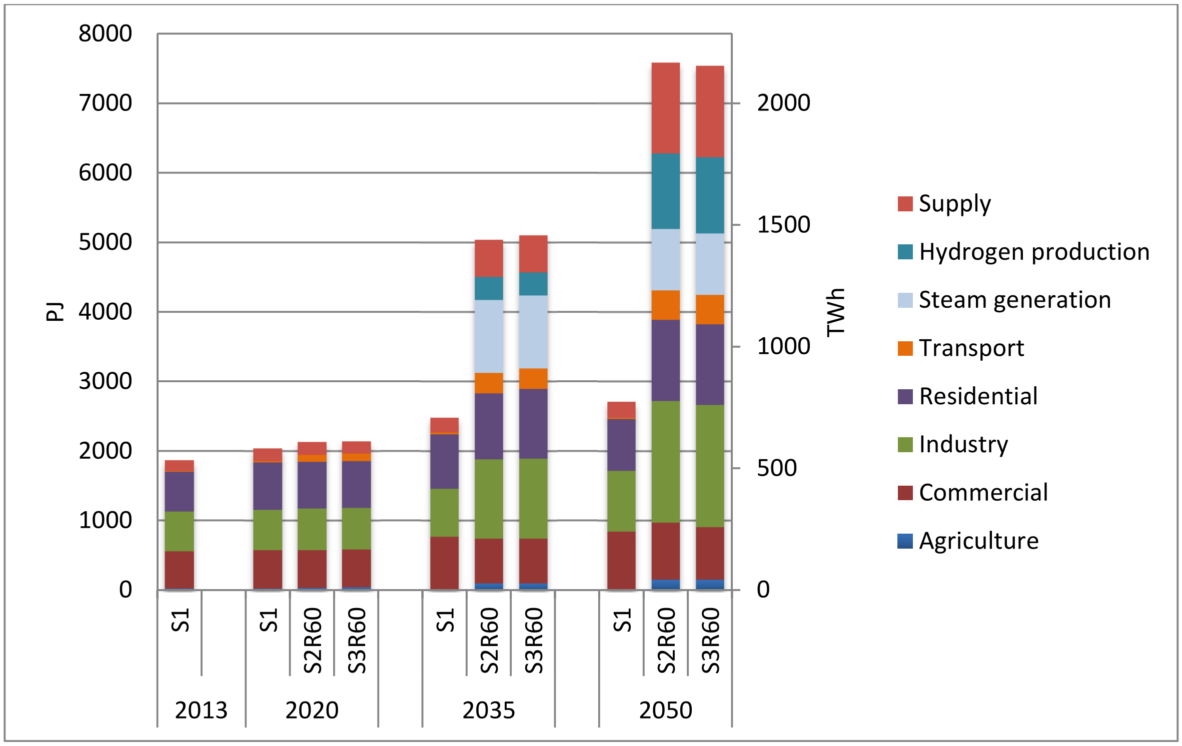
5.5.1 Electricity Demand

Results showing total electricity demand for Scenarios 2 and 3, along with comparison with results of Scenario 1 are shown on Figure 88.

Key observations from detailed review of background documentation and results are as follows:

- There is very little change in overall energy demand between Scenarios 2 and 3. This general observation applies for all results for Scenarios 2 and 3.

Figure 88. Electricity consumption - S1, S2R60 & S3R60



5.5.2 Electricity Supply

As already noted, results for Scenario 3 are based on the premise that there are opportunities for reducing overall costs for electricity supply, relative to Scenario 2, with interconnections and transfers of dependable capacity. In this Section, changes in generation supply are described. In Section 5.5.3, corresponding changes in transmission capacity are described.

Results showing changes in dependable capacity for the 60% GHG reductions in 2050, for the various jurisdictions are shown on Figure 89.

Key observations from detailed review of background documentation and results are as follows:

- As noted previously, each jurisdiction meets its maximum electricity demand in each year with dependable capacity contributions from its own generating facilities combined with net import of dependable capacity from neighboring jurisdictions.
- From comparing results of Scenarios 2 and 3, the principal changes are as follows;
    - Alberta replaces a portion of its dependable capacity with net import of hydro from the Northwest Territories. It should be noted that this import is equal to the full reported development potential of the hydro resources of the Mackenzie River (11.2 Gw). On more detailed inspection, it has been observed that this potential is fully developed by as early as 2035 for all scenarios.

      This import of dependable capacity to Alberta also causes dependable capacity contributions from generating sources in Alberta to reduce correspondingly.

These results also show pumped storage in the Northwest Territories, replacing pumped storage in Alberta. Such development would be combined with conventional hydro on the Mackenzie River in the Northwest Territories.

- Other significant changes are with transfer of dependable capacity from Quebec to Ontario, and to a lesser extent, to New Brunswick. The transfer to New Brunswick, in turn, allows for further transfers to both Prince Edward Island and Nova Scotia.
- There are also transfers, albeit smaller, from Newfoundland & Labrador to Quebec and from Manitoba to Saskatchewan.
- It is noted that there is essentially no transfer between Alberta and British Columbia. This arises as a direct consequence of the premise that British Columbia will not be investing in any additional conventional large scale hydro generation after completing Site C on the Peace River. The consequence of this is that all additional base load generation supply in both provinces will be nuclear, with limited economic opportunities for purchase or sale of dependable capacity.

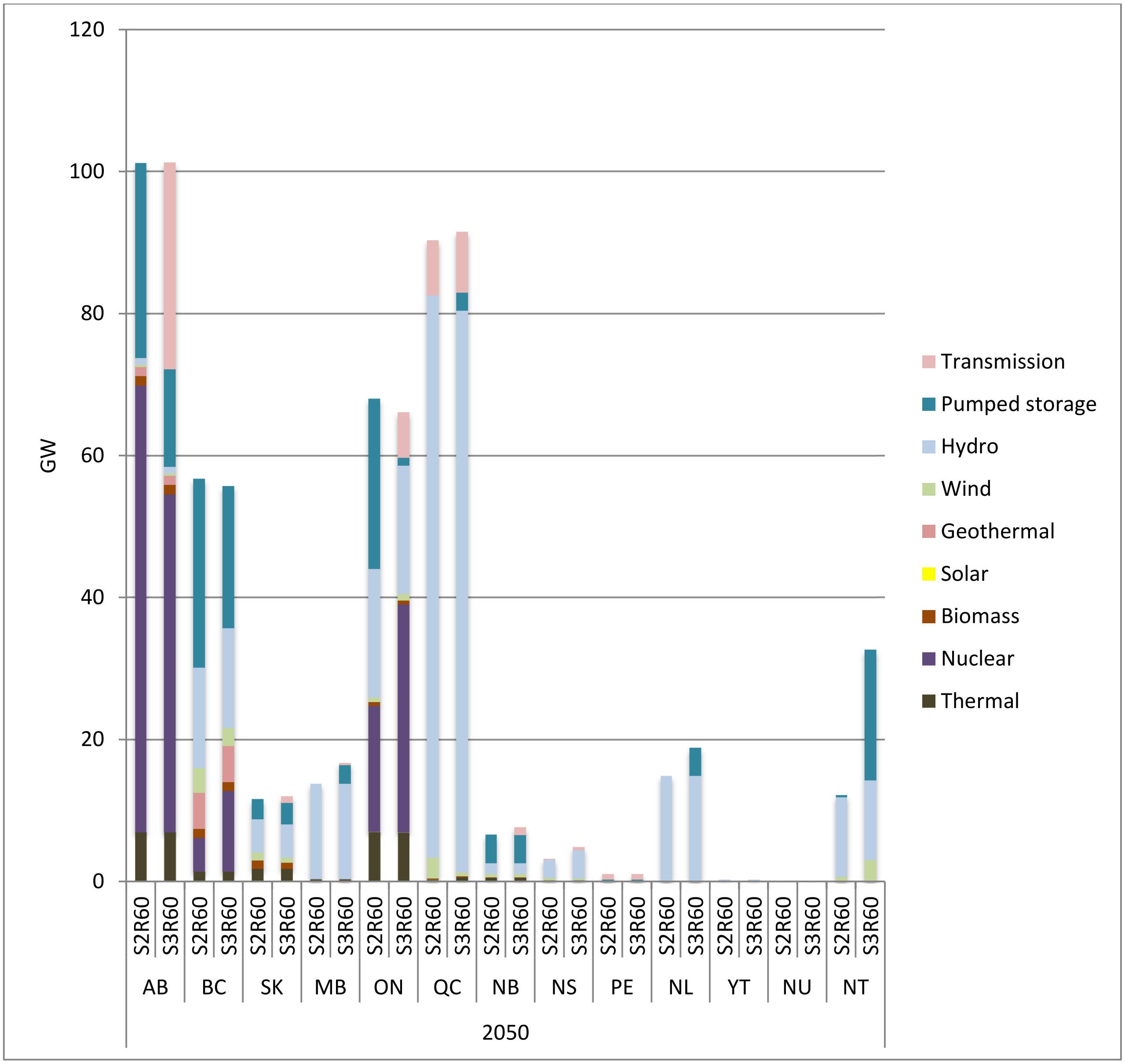
  It is also noted that results from the optimization model show that all remaining hydro generation potential, in most jurisdictions, will be fully developed well before 2050. The remaining options, other than thermal generation, for providing dependable capacity are nuclear and large scale pumped storage.

  However, at this stage, there are two considerations which have not been captured with the optimization model. Firstly, additional dependable capacity can be obtained, at relatively low cost, with additional generating caspacity at either existing or planned conventional hydro generating facilities. This would tend to replace large scale pumped storage, as well as eliminating associated pumping costs. Secondly, it is expected that there is substantially more hydro potential in Canada than is noted in existing published reports, especially for providing dependable capacity to complement energy generation from intermittent renewable generating sources.

  The likely effect of this is that results, as reported here, showing pumped storage in Quebec, Manitoba, Newfoundland & Labrador, and Saskatchewn would be replaced with incremental hydro at existing and future hydro sites in these or neighboring jurisdictions. It is also likely that the optimal installed capacity at hydro sites in the Northwest Territories (dominantly for additional dependable capacity) would be substantially larger than the 11.2 Gw. noted in published reports. This would, in turn, have a direct impact on the optimal electricity generating supply mix for Alberta.
- It will be observed that, before the hydro potential in hydro dominated jurisdictions is fully developed, it is beneficial to accelerate such developments for capturing overall cost reduction benefits. There are significant benefits associated with early dependable capacity transfer from Quebec to Ontario, before Quebec's hydro potential is fully developed. This has the benefit of deferring investment in Ontario's nuclear development program and remaining hydro potential, which tend to be expensive. This same principle would also apply to early development of Manitoba's hydro potential for supply to Saskachewan, and for Northwest Territories hydro potential for supply to Alberta.

  In Scenario 8, the potential for including additional conventional hydro in British Coumbia is assessed. With this option, there is also additional opportunity for sale of dependable capacity from British Columbia to Alberta.

Figure 89. Dependable capacity by province, 2050 - S2R60 & S3R60



The analysis was extended further to assess overall impact on both dependable capacity and total installed capacity for Canada. These results are shown on Figure 90 and Figure 91, respectively. The impact on the respective jurisdictions is shown on Figure 92.

Key observations from detailed review of background documentation and results, are as follows:

- Total generating capacity for all of Canada is approximately 20 Gw less for Scenario 3 than for Scenario 2. The reduction is dominated by reduced wind generation. There is nominal increase in hydro and nuclear generation in jurisdictions that are in preferred positions for investing in dependable capacity for sale to neighboring jurisdictions.

- Investment in hydro tends to occur early for both dependable capacity and firm energy. For example, for both the 30% and 60% GHG reduction scenarios, the full hydro potential of the Mackenzie River (11.2 Gw) in the Northwest Territories is fully developed by 2035. Again, as with Scenario 2, hydro comes in early and tends to be developed to its maximum potential in most jursidictions well befor 2050.
- Hydro import from the Northwest Territories to Alberta leads to a reduction in both dependable capacity and installed capacity in Alberta. There are reductions in both nuclear and large scale pumped storage in the Province.
- There are also further impacts on mix of generation supply in Briticsh Columbia and Saskatchewan, as a direct consequence of introducing hydro and wind generation in the Northwest Territories. The general effect is to reduce wind generation in British Columbia and Saskatchewan and take advantage of the greater complementarity of hydro and nuclear generation.
- The second major change is with supply mix between Ontario and Quebec. In the early years, Quebec accelerates development of its hydro resources to increase export of dependable capacity to Ontario. However, all of Quebec's remaining economic hydro potential is fully developed by 2040. The next stage in the process is for Ontario to develop nuclear geeration, with export of dependable capacity to Quebec in later years. With this overalll development, there is less wind generation than in Scenario 2.

It should be noted that one of the shortcomings in the NATEM model is that it does not yet include representation of incremental hydro (incremental hydro is the addition of hydro capacity at existing or future hydro sites). The value of incremental hydro is that dependable capacity is added at relatively low cost, to complement energy generation from intermittent renewables, also at relatively low cost. If this had been included in this analysis, it would almost certainly have resulted in more hydro capacity in Quebec, less nuclear capacity in Ontario, less pumped storage, more trade between Quebec and Ontario, and further reductions in overall supply cost.

Figure 90. Dependable capacity - S1, S2 & S3

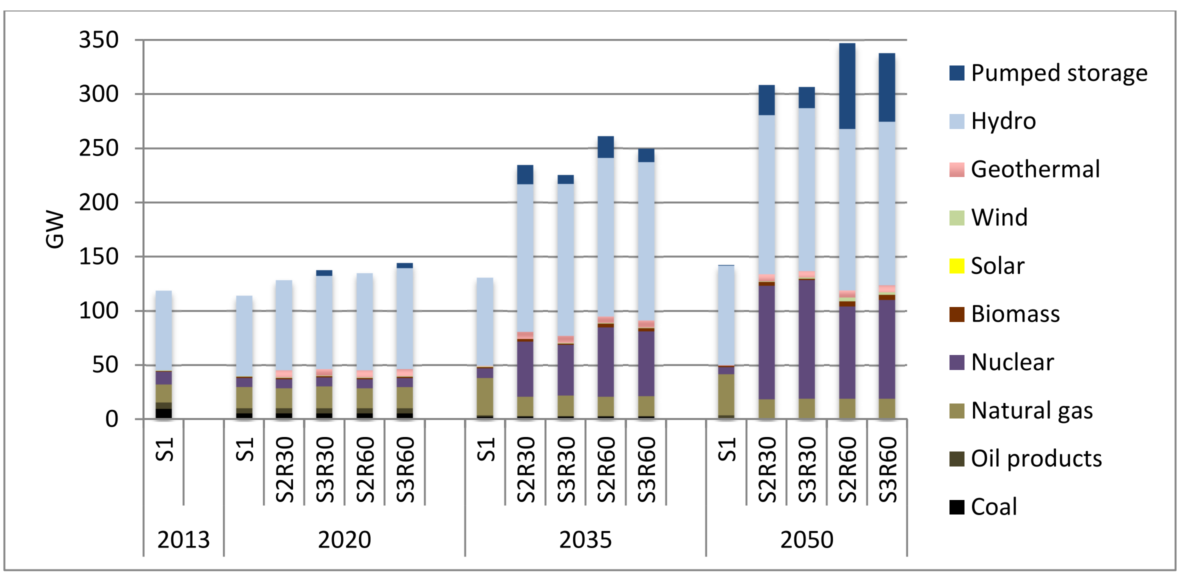


Figure 91. Electricity generating capacity - S1, S2 & S3

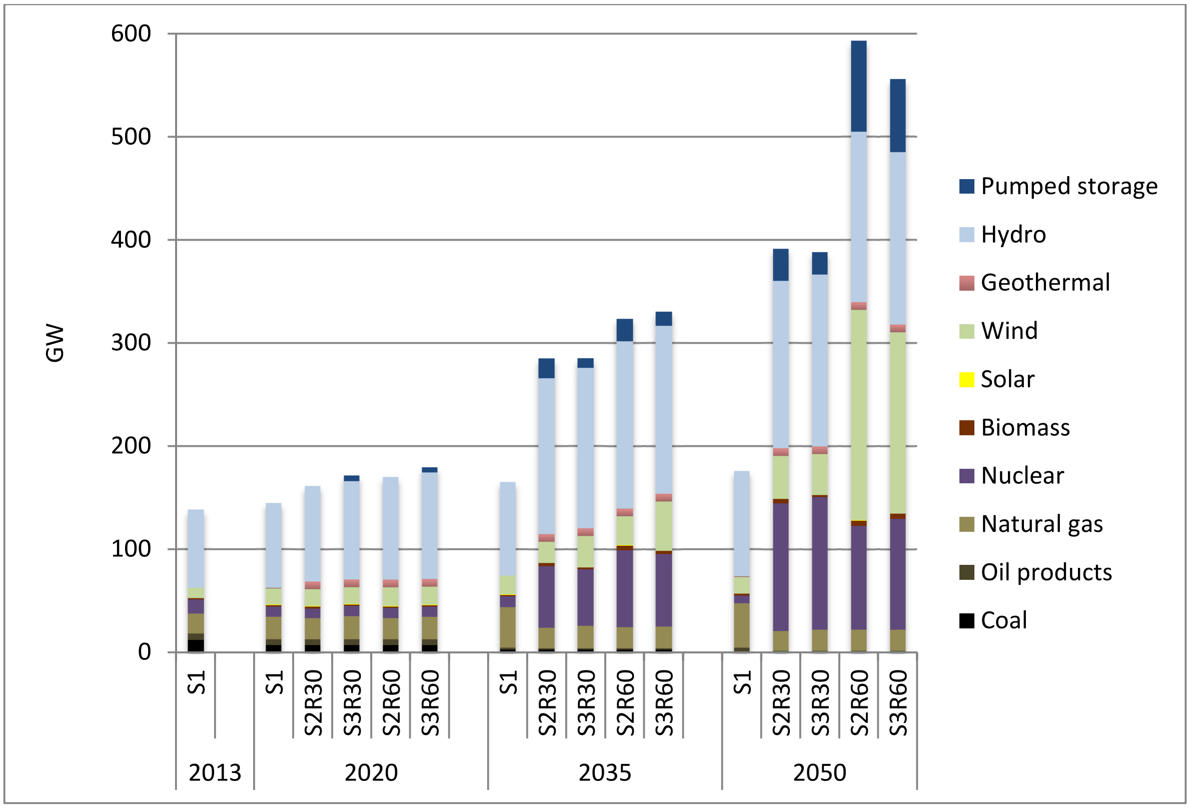
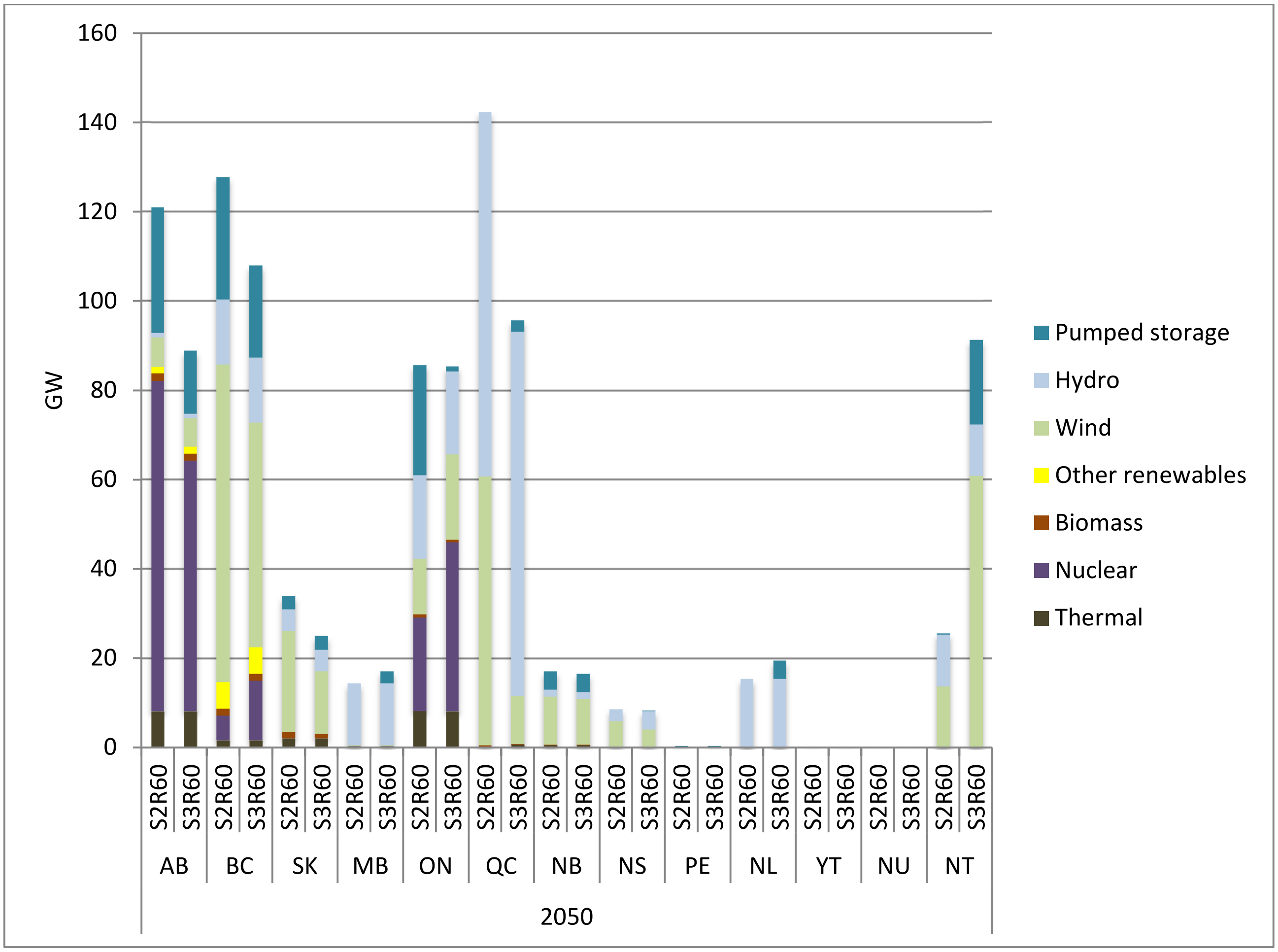


Figure 92. Electricity generating capacity by province, 2050



5.5.3 Inter-connection Transmission Capacity

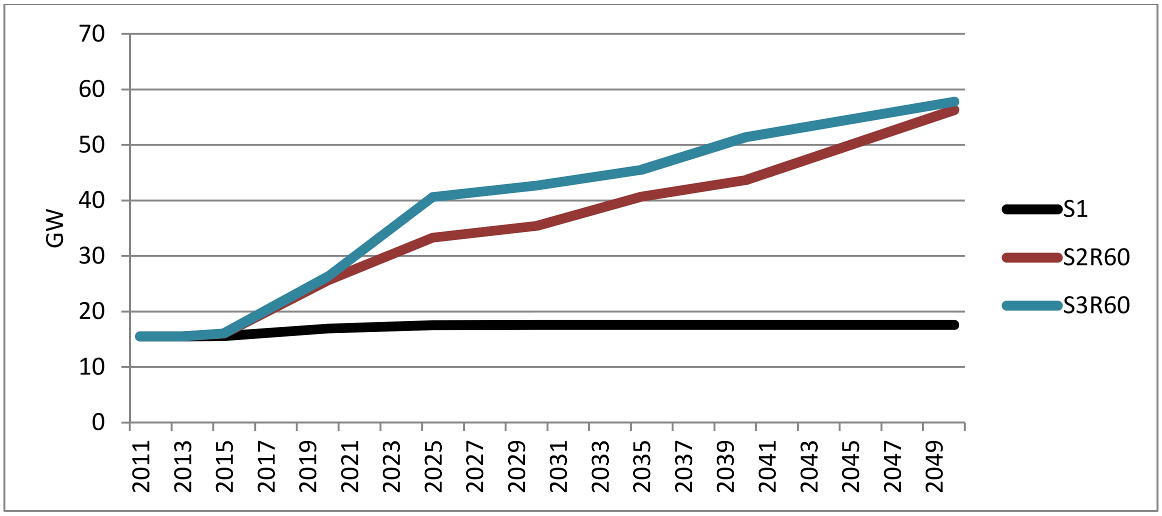
It is necessary to invest in additional high voltage interconnection capacity to benefit from increased trade of both electrical energy and dependable capacity between neighboring jurisdictions. The amount of interconnection transmission capacity is shown on Figure 93 for Scenarios 1, 2 and 3.

Key observations from detailed review of background documentation and results, are as follows:

- For Scenario 1, there is essentially no increase in transmission capacity between jurisdictions.
- For Scenario 2, there is some investment in interrconnection capacity, primarily to benefit from increased trade in electrical energy arising from significant differentials in variable opertaing costs between neighboring jurisdictions. This is also associated with the very large overall increase in investment in electricity supply for Scenario 2, relative to Scenario 1.
- For Scenario 3, there is additional investment in interconnectin capacity, primarly to benefit from additional trade in dependable capacity between neighboring jurisdictions.
- It is noteworhy that there is little computed difference in interconnection capactity in 2050 between Scenarios 2 and 3. Again, this arises as a direct consequence of not having represented incremental hydro in the analyses. It is almost certain that this additional representation will

result in more investment of incremental hydro, more trade of dependable capacity, and more investment in inter-jurisdictional transmission capacity.

Figure 93. Total inter-jurisdictional electricity transmission capacity

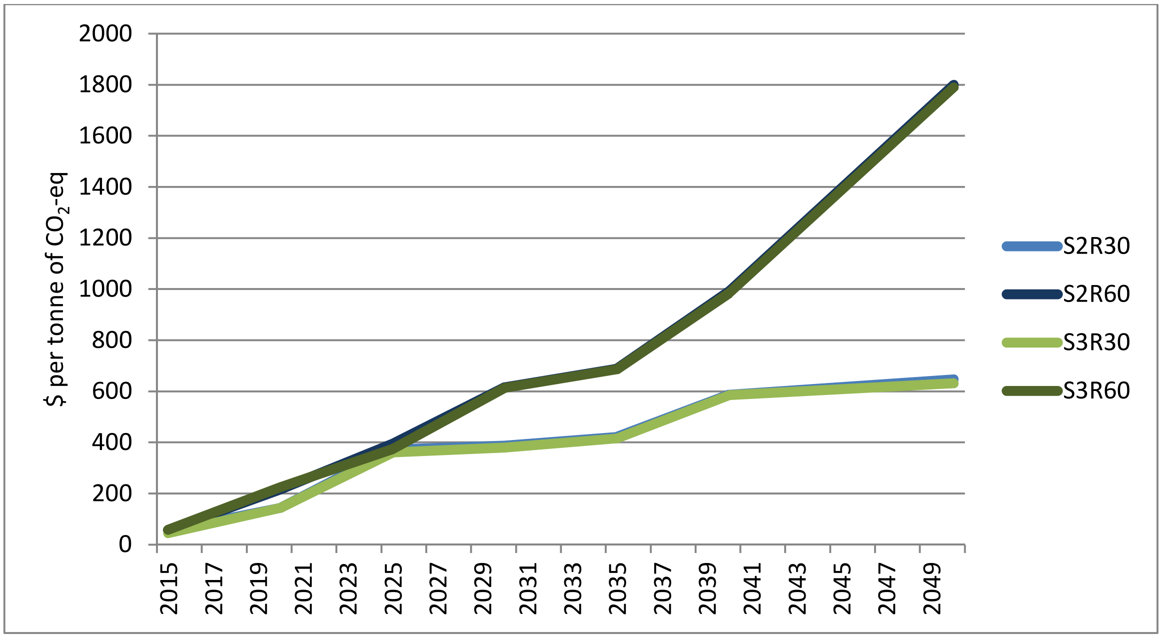


5.5.4 Cost

With this Scenario, there will be an overall reduction in cost for supply and delivery of electricity in Canada. Based on detailed review of cost results for Scenarios 2 and 3 for the period from 2020 to 2050, the computed average cost reduction across Canada is 6%. It is important to appreciate, however, that this is based on only additional investment and operating costs as derived by the NATEM model. Nevertheless, it can be appreciated that cost reductions are substantial, especially for specific jurisdictions (Ontario, Alberta, Saskatchewan, New Brunswick, Nova Scotia and Prince Edward Island) that can benefit directly from import of both low cost electrical energy and dependable capacity. Also, as noted above, there could be further overall cost reductions with adding incremental hydro, especially in hydro dominated jurisdictions (Quebec, Newfoundland & Labrador, Manitoba, British Columbia, and Northwest Territories).

In Figure 94, it is shown that there is virtually no change in marginal costs for GHG mitigation between Scenarios 2 and 3. This reflects that the marginal cost for GHG mitigation is dominated by factors other the marginal cost of electricity supply.

Figure 94. Marginal cost for GHG mitigation



5.5.5 Principal Observations

The principal observations from Scenario 3 may be summarized as follows:

- There are substantial cost reductions associated with inter-jurisdictional transfers of both electrical energy and dependable capacity from lower cost electricity supply jurisdictions to higher cost neighboring jurisdictions. The lowest cost jurisdictions include the hydro dominated Provinces and Territories; Quebec, Newfoundland & Labrador, Manitoba, and Northwest Territories. The principal opportunities are for transfers from Quebec to Ontario, and from Northwest Territories to Alberta. There are also opportunities with transfers from Manitoba to Saskatchewan, and from Quebec to New Brunswick and by extension, also to Nova Scotia and Prince Edward Island.
- It is apparent that existing legislation against development of conventional large scale hydro in British Columbia is a constraint against both low cost electricity generation and GHG mitigation in Western Canada. If the legislation were changed, minimum cost results, in all likelihood, would be different. The principal changes would probably include increased development of conventional hydro in British Columbia, incremental hydro at both existing and future hydro generating sites in British Columbia, increased interconnection with Alberta, export of both electrical energy and dependable capacity from British Columbia to Alberta, less nuclear generation in both British Columbia and Alberta, reduced large scale dispatchable pumped storage generation, and reduced overall cost.
- It is important to extend the capability of both models used in this project, to incorporate treatment of incremental hydro for further investigations. This has the potential for taking advantage, especially in hydro dominant jurisdictions, of the complementarity between incremental hydro for dependable capacity and intermittent renewables for electrical energy.

5.6 Scenario 4; Changes in Urban Development

The prime purpose of Scenario 4 is to demonstrate additional potential reductions in GHG emissions, associated with modified approaches for planning and developing urban regions in Canada, including modifications to existing urban regions. This is based on processes which result in urban regions becoming more functional, more efficient and more livable. There are several elements which are associated with such improvements. These include urban densification; fully integrated urban communities; reductions in personal travel by personal transport within urban regions; greatly increased use of public transportation; development of fully integrated local energy systems, including distributed energy, district energy, waste to energy, rooftop solar systems, and battery and thermal energy storage; increased physical activity and improved public health; enhanced environmental space; and reductions in production of waste materials.

On the premise that that there will be major progress with implementing better planning and associated development of urban regions in Canada, assessments were carried out to establish projected reductions in two dominant areas of GHG emissions in urban regions; residential and transportation. Projected reductions were defined specifically for 2030 and 2050 respectively, with reductions for other years based on linear interpolation.

The information on projected reductions in each sub-area was defined and forwarded for detailed quantification with the CanESS model. This information was then converted to modified end use demands and forwarded via the data bridge as input for the NATEM model. As normal, the NATEM model was run to evaluate minimum present worth costs with these reduced demands in urban regions.

As with prior runs, minimum cost solutions were derived for progressive reductions in combustion emissions. The premises were essentially the same as for Scenario 3, but with a series of model runs with the NATEM Canada model, with GHG reduction targets of 30 and 60% in 2050, respectively, relative to 427 Mt in 1990.

5.6.1 Reductions in Demand

Reductions in residential and transport demands are shown in Figure 95 and Figure 96, respectively, for the 60% GHG reduction target, with comparison to results from Scenario 3.

Key observations from detailed review of background documentation and results are as follows:

- Overall reduction for residential demand, on average, is 14%. As may be appreciated, this includes all of Canada, including both urban and rural regions. When assessing the impact more specifically for urban regions alone, the average reduction would be larger than this 14% amount.
- Reductions occur for all residential end uses, with variations from a maximum of 17% for space heaing to a minimum of 8% for appliances and water heating.
- With respect to changes in transport demand relative to Scenario 3, there are both increases and decreases;
    - For passenger cars and light duty vehicles, there is a reduction from 785,000 MPKM to 416,500 MPKM (47% reduction)

- Subway travel increases from 7,300 MPKM to 57,500 MPKM (almost eight-fold increase)
- Inter-city and urban bus travel increases from 29,000 MPKM to 91,400 MPKM (more than three-fold increase)
- Inter-city rail transport increases from 1,650 MPKM to 22,940 MPKM (14-fold increase), including major shift from short haul inter-city air travel to inter-city rail travel
- Domestic air travel reduces from 102,000 MPKM to 46,500 MPKM (54% decrease)

Figure 95. Changes in residential energy demand

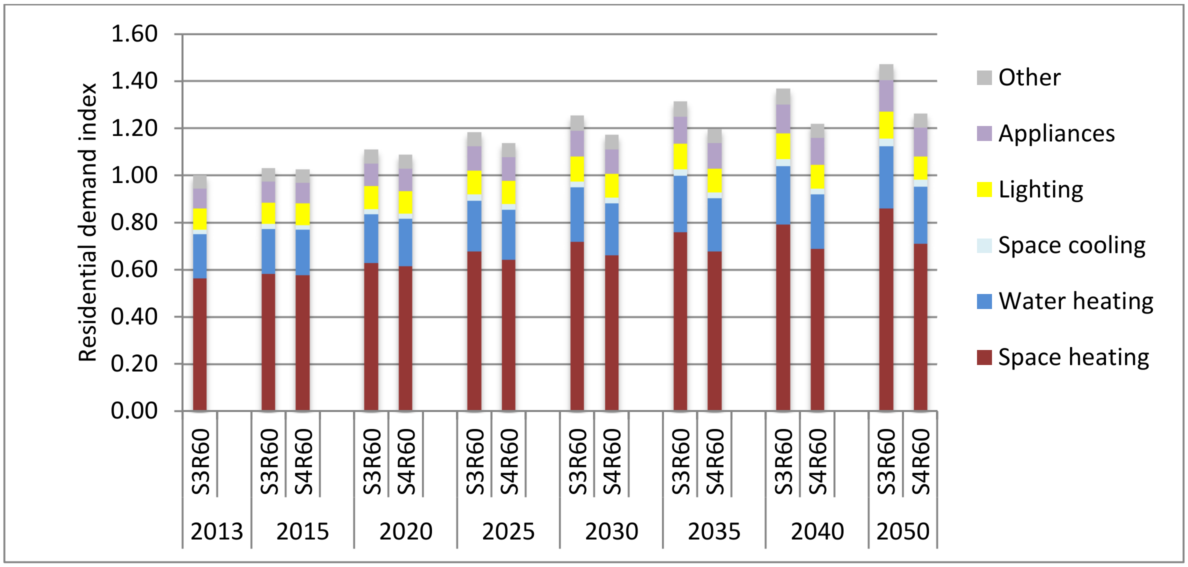
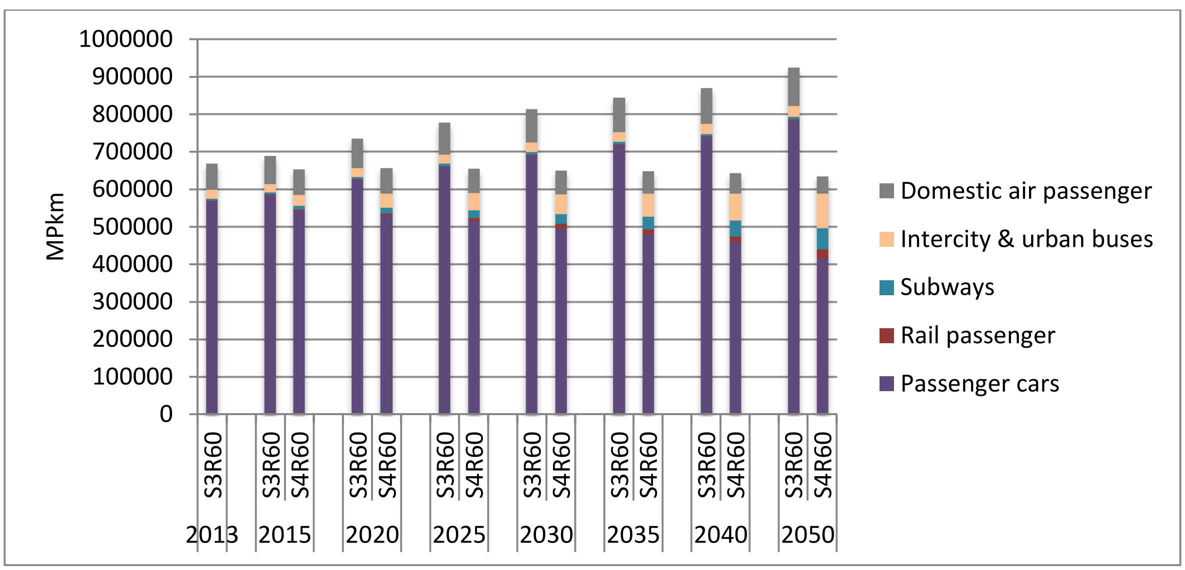


Figure 96. Changes in transport demand



5.6.2 Final Energy Consumption

As a consequence of these changes in residential and transport demand, there are corresponding changes in energy consumption. These changes are shown on Figure 97 and Figure 98 for residential energy and transport energy, respectively.

Key observations from detailed review of background documentation and results are as follows:

- With respect to energy consumption in the residential sector, there is further reduction of about 100 PJ, which is dominantly associated with reduced electricity.
- With respect to energy consumption in the transport sector, there is a slight increase in energy consumption due to hydrogen being replaced by biodiesel when compared to Scenario 3 (hydrogen vehicles are more efficient, therefore a larger amount of biodiesel is needed to substitute it). The increase in electiricty use arises from increased public transport. It should be noted that, overall, these trends are favorable for reducing GHG emissions, as electricty is essentially decarbonized and burning biofuels does not increase net GHG emissions.

Figure 97. Change in residential energy consumption

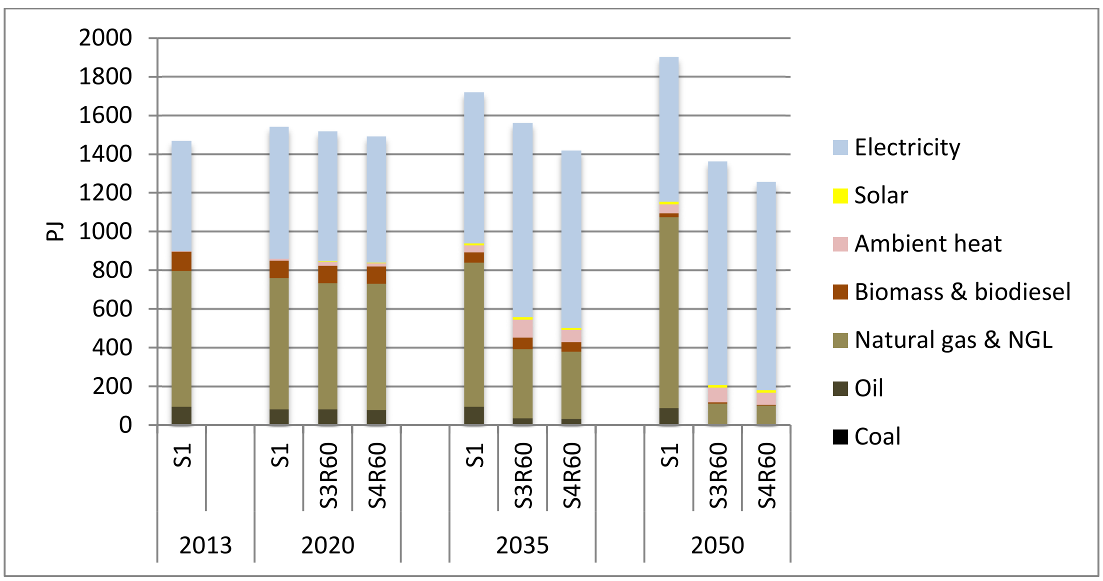
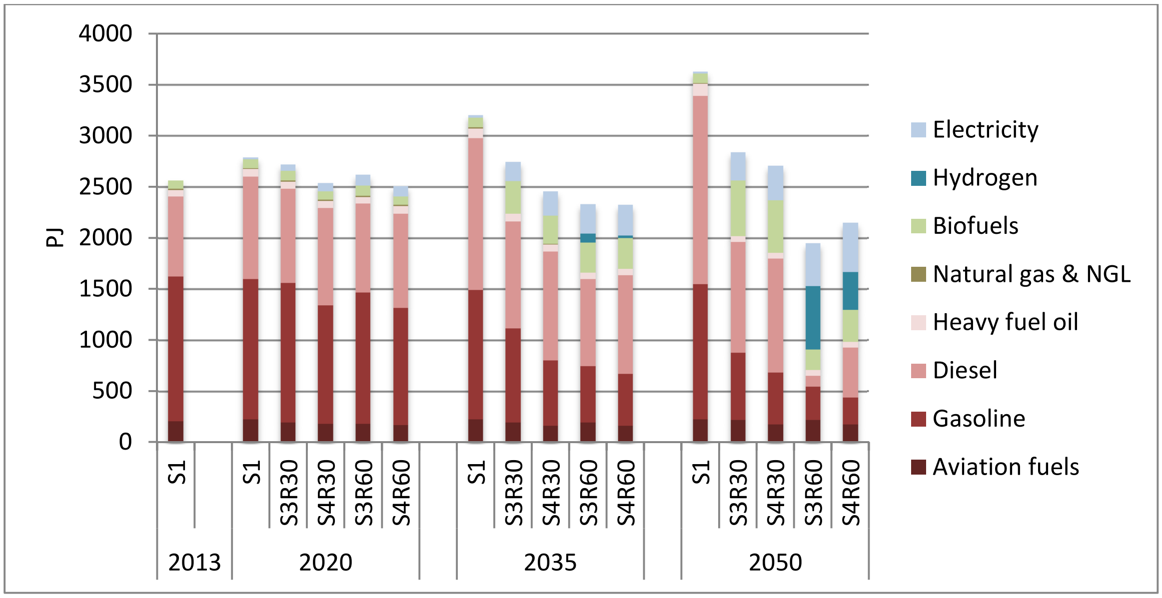


Figure 98. Changes in transport energy consumption



5.6.3 GHG Emissions

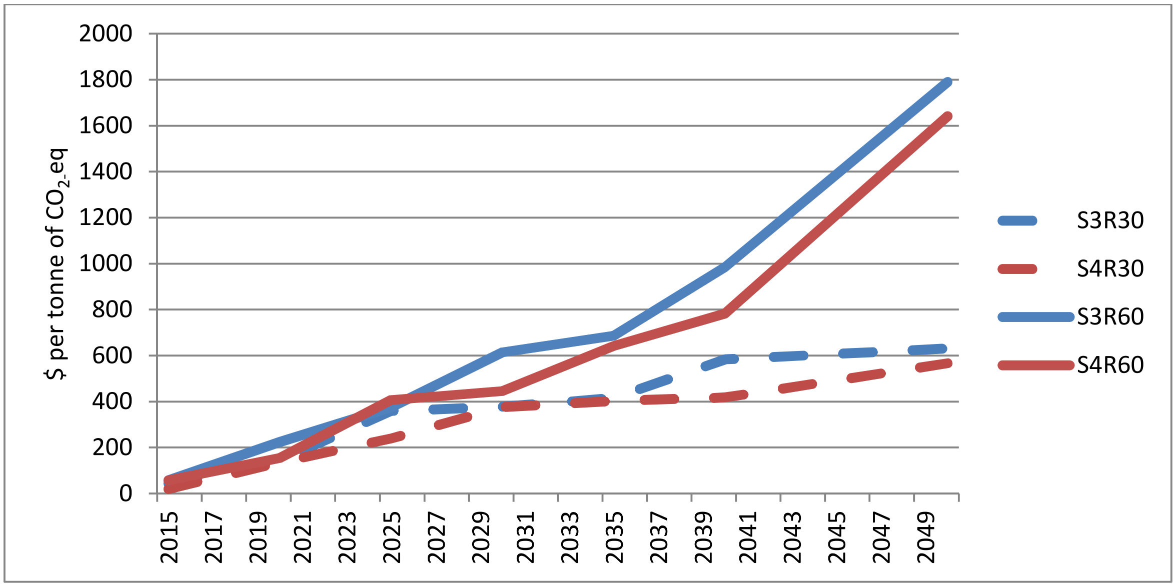
Based on detailed analysis of results, there are nominal reductions in GHG emissions that can be attributed to changes in development of urban regions. However, as computed, these are not as large as might have been expected. It is important, however, to provide some additional context:

- The results of Scenario 3 already include an electricity supply system that is virtually fully decarbonized. Consequently, when considering changes in electricity consumption for Scenario 4 (either increase or decrease), there is virtually no additional impact on GHG emissions.
- However, changes in fuel mix in the transport sector for urban regions have beneficial impacts outside urban regions. For example, there is a reduction in use of hydrogen for heavy duty transport, which is expensive. As may be observed from analysis of cost data, there is an overall reduction in total cost, as shown by reduced marginal cost for GHG mitigation for the entire period from 2015 to 2050.

5.6.4 Cost

The impact of reduced energy-based demands from improved urban development and urban regeneration is shown on Figure 99. The important observation is that cost impact on GHG mitigation is very significant. For both the 30% and 60% GHG reductions targets, the differential in marginal cost for GHG mitigation is generally about $100 per tonne. As noted above, the cost reduction may not necessarily be reflected directly in GHG mitigation in urban regions; instead, with reduced GHG emissions in urban regions, there are impacts which are directly associated with reducing or eliminating the most expensive reduction options in other sectors, such as use of hydrogen for heavy duty transport.

Figure 99. Marginal cost for GHG mitigation



5.6.5 Principal Observations

The principal observations from Scenario 4 may be summarized as follows;

- Analyses were carried to assess the impact of achieving major progress in implementing fundamental change in development of urban regions in Canada, including modifications for existing urban regions. This program is based on following through on fundamental changes in planning and developing urban regions which result in such regions being more functional, more efficient and more livable. The analyses were based on assessed progress to 2030 and 2050, respectively, with prime consideration of reduced energy use in the residential and transport sectors. The analyses included assessment of overall impact on energy use, GHG mitigation, and reductions in system wide cost for GHG mitigation.
- Results of the analyses showed substantial reductions and changes in both composition and magnitude of energy use to satisfy energy-based needs in urban regions. There was a nominal reduction in energy use in the residential sector, and, somewhat surprisingly, a slight increase in the transport sector. However, when analyzing these results in more detail, the overall impact was to change the composition of overall system-wide energy supply, resulting in reductions in the most expensive supply options in other sectors, including energy supply for heavy freight transport.
- The overall impact on cost is substantial. In general, reductions in marginal cost for meeting both the 30% and 60% GHG reduction targets are about $100 per tonne.
- While the focus in this project was to assess impacts from reductions in energy use and GHG emissions in the residential and transport sectors, there are additional opportunities in urban regions which were not represented. These include potential benefits from greater integration of energy systems and services in urban communities, associated with various combinations of distributed energy, district energy, roof-top solar systems, waste-to-energy systems, energy storage (battery and thermal storage), combined with smart grid management. These are

important additional opportunities for reducing energy use and reducing GHG emissions in urban regions.

5.7 Addition of Disruptive Technologies

The purpose of Scenario 3 was to derive minimum cost solutions for progressively increasing GHG reduction targets. For that Scenario, the options for GHG mitigation were limited to technologies, systems and processes which were established as being technically and commercially viable.

For Scenario 5, the prime purpose was to derive minimum cost solutions with consideration of additional technologies, systems and processes which are promising, but are not yet fully developed. These additional disruptive technologies included;

- New coal-fired generation with CCUS, combined with enhanced oil recovery in selected jurisdictions
- Retrofitting existing coal-fired generation with CCUS and enhanced oil recovery
- Second generation ethanol production from lignocellulose
- Second generation biodiesel from biomass, based on FT process

With addition of these technologies, systems and processes, the following principal assumptions were made:

- These options were assumed to become commercially viable as follows: CCUS in 2020; second generation biodiesel in 2017; second generation ethanol in 2015.
- With respect to the option of retrofitting existing coal fired generating facilities, this was limited to existing coal-fired plants in Alberta and Saskatchewan, and were combined with enhanced oil recovery.
- For coal fired generation with CCUS, 90% of the CO_2 is removed, leaving 10% still being emitted directly to the atmosphere.
- All additional coal-fired generation in Canada would be combined with CCUS.
- With production of second generation biodiesel, the constraint which applied in Scenario 3 concerning an upper limit of 30% of first generation biodiesel with fossil based diesel would remain. However, it was also assumed that second generation biodiesel will be directly competitive with fossil based diesel, thereby also allowing first generation biodiesel to be blended with both fossil diesel and biodiesel up to the same 30% limit.

5.7.1 Coal-fired Generation with CCUS

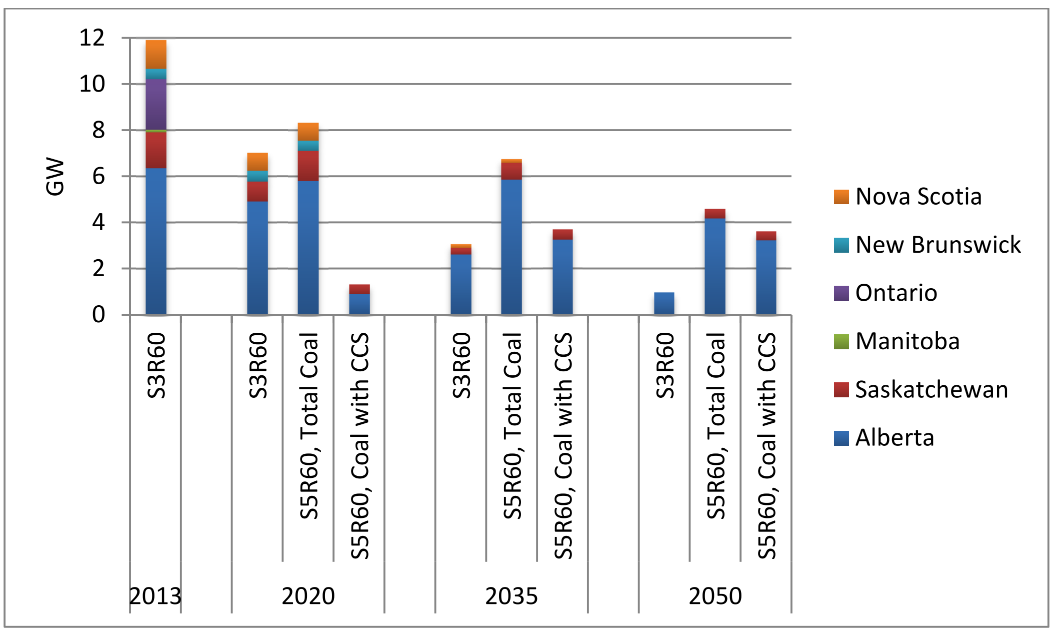
Results from analyses with retrofitting existing coal fired generation facilities with CCUS are shown on Figure 100, including comparison of results with Scenario 3.

Key observations from detailed review of background documentation and results are as follows:

- Results for S3R60 (60% reduction target for Scenario 3) show the progressive reduction in coal fired generation for the period to 2050, as existing coal fired generation facilities are phased out at the end of their respective 50 year economic lives. By 2050, the 12,000 Mw. of existing coal fired generation is reduced to less than 1,000 Mw, virtually all of which is in Alberta.

- With the option of retrofitting existing coal fired generation facilities, approximately 4,500 Mw. of coal fired generation is still in operation in 2050, all of which is in Alberta and Saskatchewan. Of this total, 3,700 Mw is retrofitted with CCUS, with the remaining 800 Mw still not having reached the end of its 50 year economic life.
- Based on evaluation of minimum system wide costs, the results showed a cost advantage with retrofitting existing coal fired generating facilities in comparison to investing in new nuclear facilities, even after accounting for the 10% GHG emissions with retrofitted coal fired plants with CCUS.
- It is interesting to note that minimum cost solutions do not include any additional coal-fired generation with CCUS, as nuclear becomes more cost competitive, especially when also considering the 10% GHG emissions with CCUS.
- These analyses did not include consideration of new natural gas fired (including combined cycle and/or cogeneration) facilities with CCUS. This represents an important additional area of investigation, especially for those Provinces with ready access to low cost fossil fuels, especially natural gas. Based on results from this project, a possible outcome could still include replacing some or all of nuclear base load generation with fossil based generation, combined with CCUS.

Figure 100. Coal fired generation with CCUS



5.7.2 Biofuel Consumption

Results for addition of second generation biofuels are shown on Figure 101, Figure 102 and Figure 103. In Figure 101, changes in biofuel consumption for the 60% GHG reduction target, are shown for the five end use sectors, with comparison to results of Scenarios 1 and 3. As most of the change occurs in the transportation sector (for heavy duty transport), changes in the fuel supply mix are shown on Figure 102, again in comparison to results for Scenarios 1 and 3. Changes in overall composition of biofuels are shown on Figure 103.

Key observations from detailed review of background documentation and results, are as follows:

- Use of biofuels is dominantly for the transportation sector, including heavy duty transport, rail transport, and off road equipment. The increase from Scenario 1 to Scenario 3 is associated with first generation ethanol and biodiesel for reducing GHG emissions. There is a further major increase with addition of second generation biofuels in Scenario 5, with more than a four–fold increase (205 to 912 PJ) use of biofuels in 2050. It is also noted that there are increases, albeit modest, in use of biofuels for the commercial and agricultural sectors.
- There is an increase in energy consumption for the transportation sector, especially for the 60% reduction target. The role of biofuels increases very substantially, and includes greater use of fossil diesel combined with first generation biodiesel. There are corresponding reductions in use of hydrogen and gasoline and very modest reductions in use of electricity, primarily associated with reduced production of hydrogen.
- It is noteworthy that results for lower GHG reduction targets show extensive use of FT biodiesel for passenger and freight train transport; however, for higher GHG reduction targets, there is a shift from using biodiesel for train transport to heavy freight transport, and increased electrification of train transport.
- The dominant change in composition of biofuels is with increase of biodiesel, both first and second generation biodiesel. Use of biodiesel increases from 131 PJ for Scenario 3, to 745 PJ for Scenario 5. This is associated with heavy freight, rail and off road transport, all of which currently relies on fossil diesel. On the other hand, the role of ethanol actually declines slightly, as gasoline use for passenger transport and light duty vehicles is replaced with electrified transport.
- It is noteworthy that, with the introduction of second generation FT biodiesel, that use of first generation biodiesel increases (more than triple in 2050 for 60% GHG reduction target). This arises from the premise that FT biodiesel is directly competitive with fossil diesel, thereby allowing first generation biodiesel to be blended up to 30% with both fossil diesel and FT biodiesel.

Figure 101. Biofuel produced for end use sectors

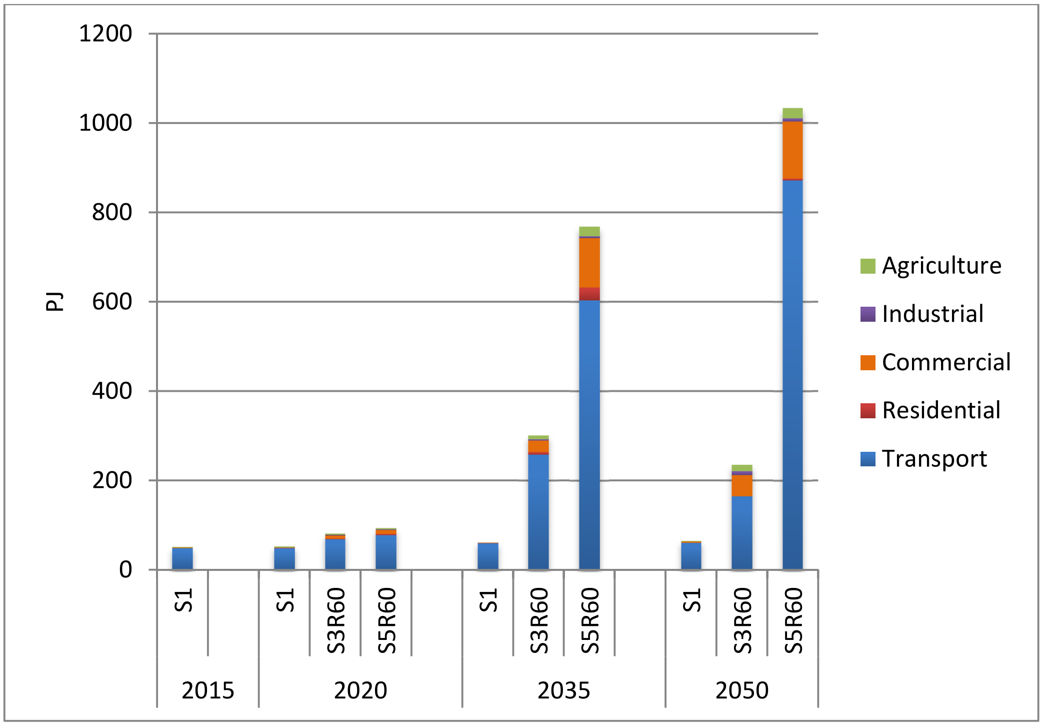


Figure 102. Energy use in transportation sector

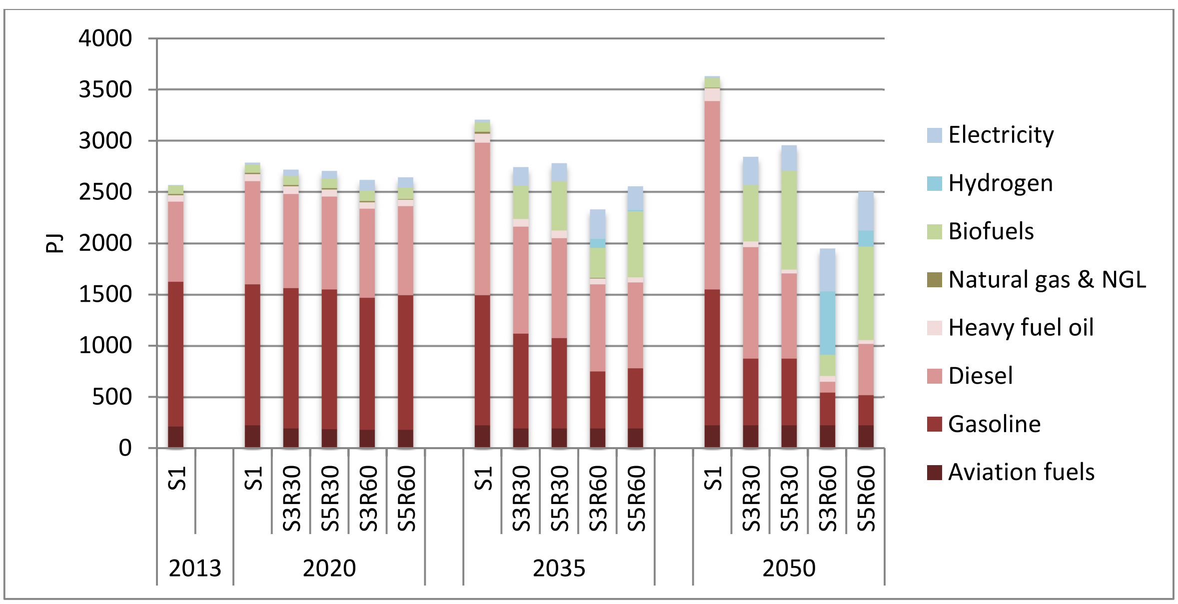
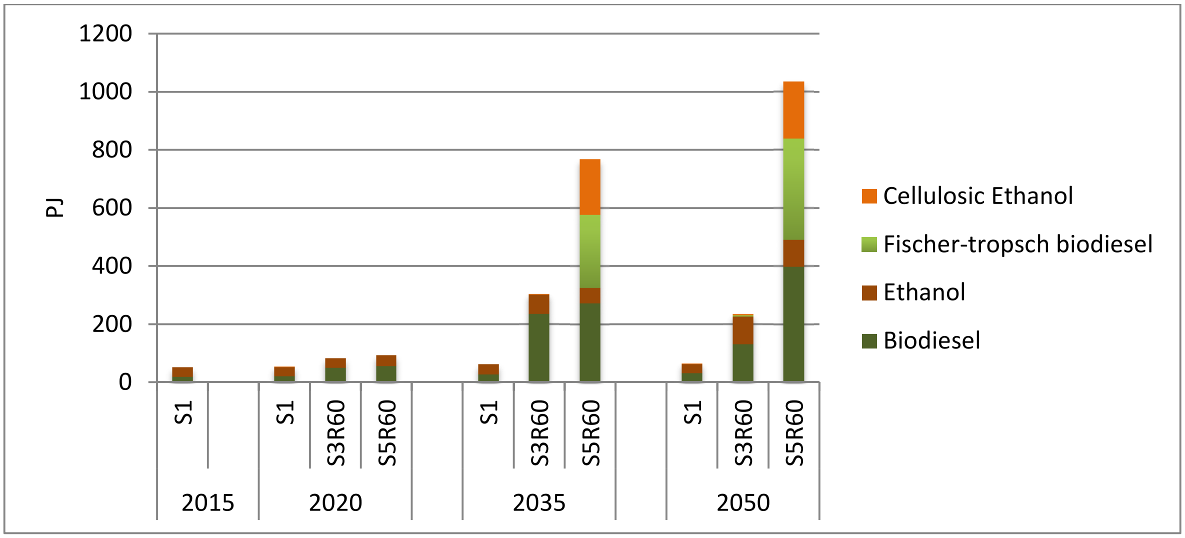


Figure 103. Composition of biofuels produced for end-use sectors



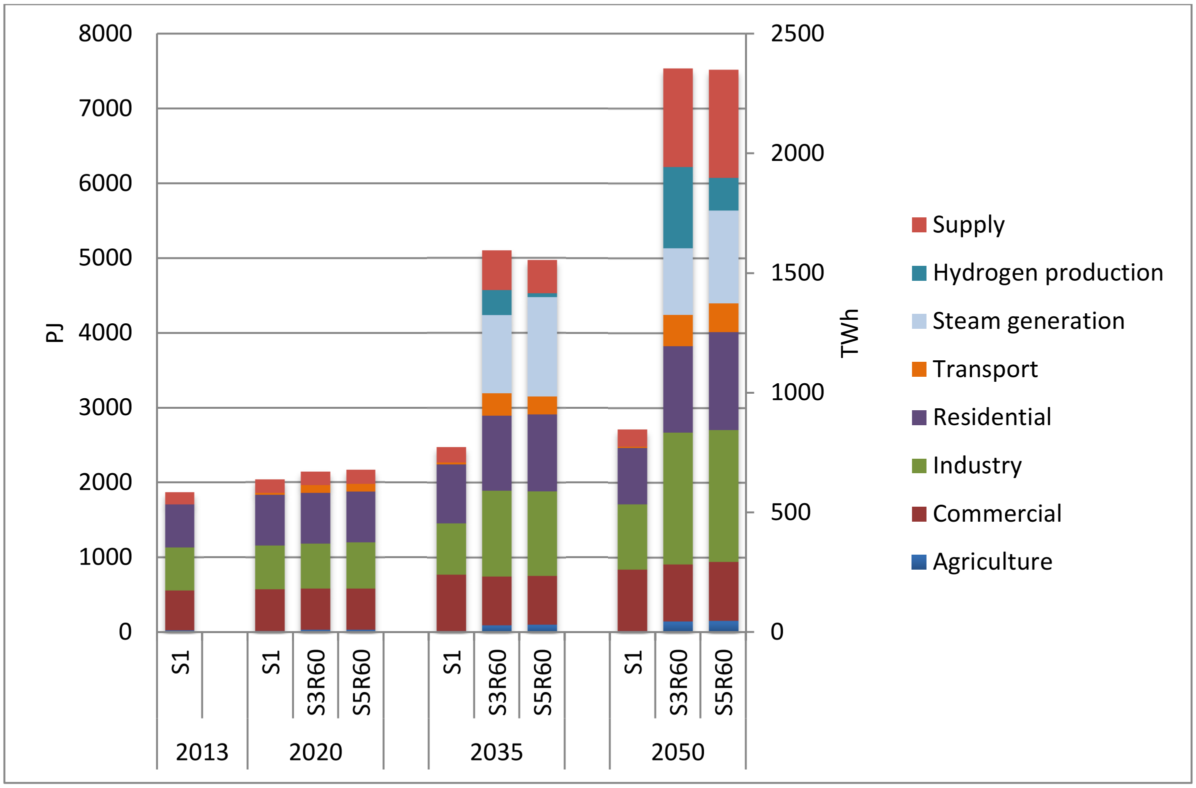
5.7.3 Electricity Demand

Changes in electricity demand for Scenario 5, relative to Scenarios 1 and 3, are shown on Figure 104.

Key observations from detailed review of background documentation and results are as follows:

- Consumption of electricity actually decreases slightly in Scenario 5, relative to Scenario 3. There is an increase in electicity use for production of biofuels and a decrease for hydrogen production. There are also increases in electricity demand in the residential and commercial sector, as some of the higher cost energy efficiency improvements are not realized to the same extent as for Scenario 3, because of lower overall marginal costs (see below).
- Electricity for hydrogen production declines, as there is less use of hydrogen for heavy freight transport in Scenario 5. It is especiallly noteworthy that use of hydrogen arises, as a direct consequence of defined feedstock supply constraints for production of biofuels, and not from cost competitiveness considerations. The area of biofuel feedstock limitations is an especially important area for additional investigation, especially as use of hydrogen tends to be very expensive.

Figure 104. Comparison of electricity consumption



5.7.4 Electricity Supply

Changes in electricity supply are shown on Figure 105, Figure 106 and Figure 107 for Scenario 5, with comparisons to results for Scenarios 1 and 3. Total generating capacity is shown on Figure 105, with corresponding dependable capacity results on Figure 106. More detailed results for the respective jurisdictions are shown on Figure 107.

Key observations from detailed review of background documentation and results, are as follows:

- As there is a decrease in electricity demand for Scenario 5 relative to Scenario 3, there is a decrease in generating capacity, dominantly wind generation. Again, as noted from analysis of results from Scenario 3, there is no significant change in hydro capacity, as much of the remaining economic hydro potential in Canada will have been fully developed well before 2050.
- With respect to changes in various jurisdictions, these are relatively minor. There is additional retrofitted coal fired generation in Alberta, additional wind generation in British Columbia, and nominal additional pumped storage generation in several jurisdictions.
- The most basic changes that are required with respect to assessing options that were not included in these analyses include:
    - Additional natural gas fired generation with CCUS – could also include combined cycle and cogeneration;
    - Incremental hydro at both existing and future hydro generating facilities;
    - Thermal generation with biomass, combined with CCUS.

- With these three options, it is expected that there would be significant changes in the composition of electricity supply and corresponding reductions in overall cost for electricity supply. One likely change would be associated with thermal generation with CCUS replacing base load nuclear, especially in Alberta and Saskatchewan. The second likely change would be replacing pumped storage with incremental hydro for dependable capacity contribution and some associated reductions in both nuclear and wind generation.

Figure 105. Electricity generating capacity

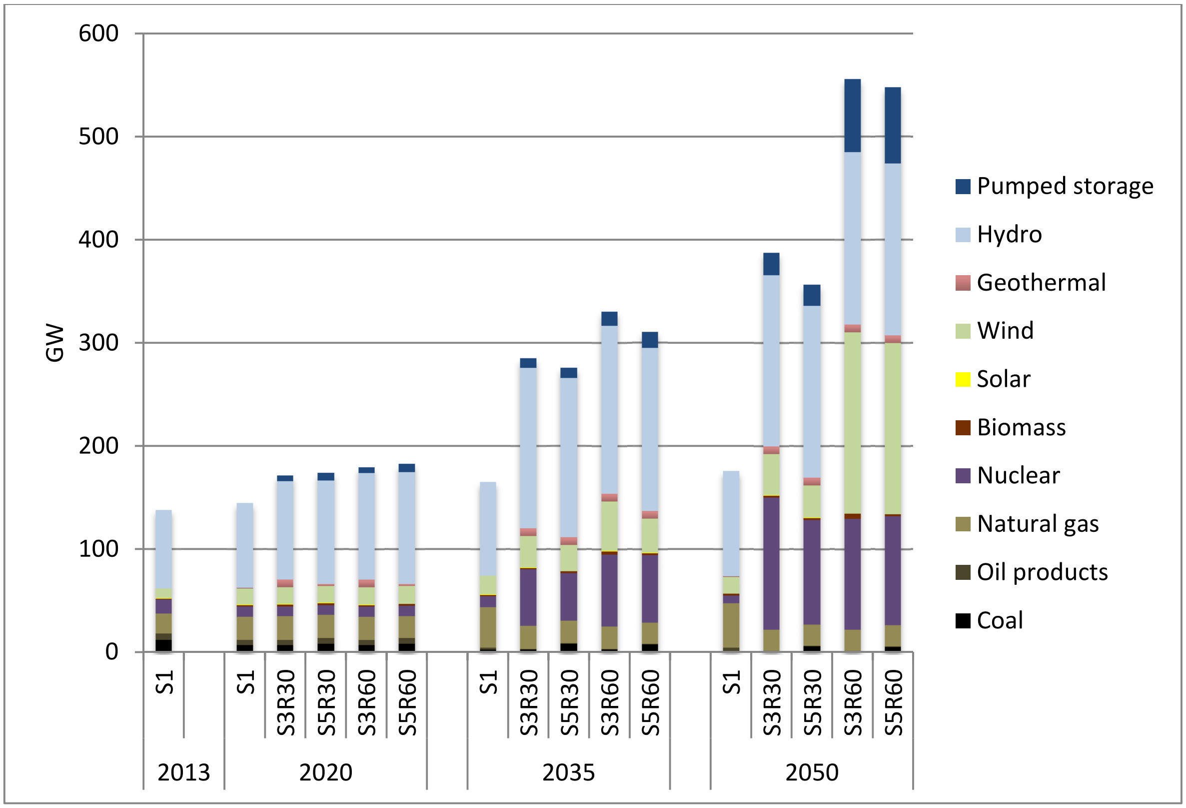


Figure 106. Dependable electricity capacity

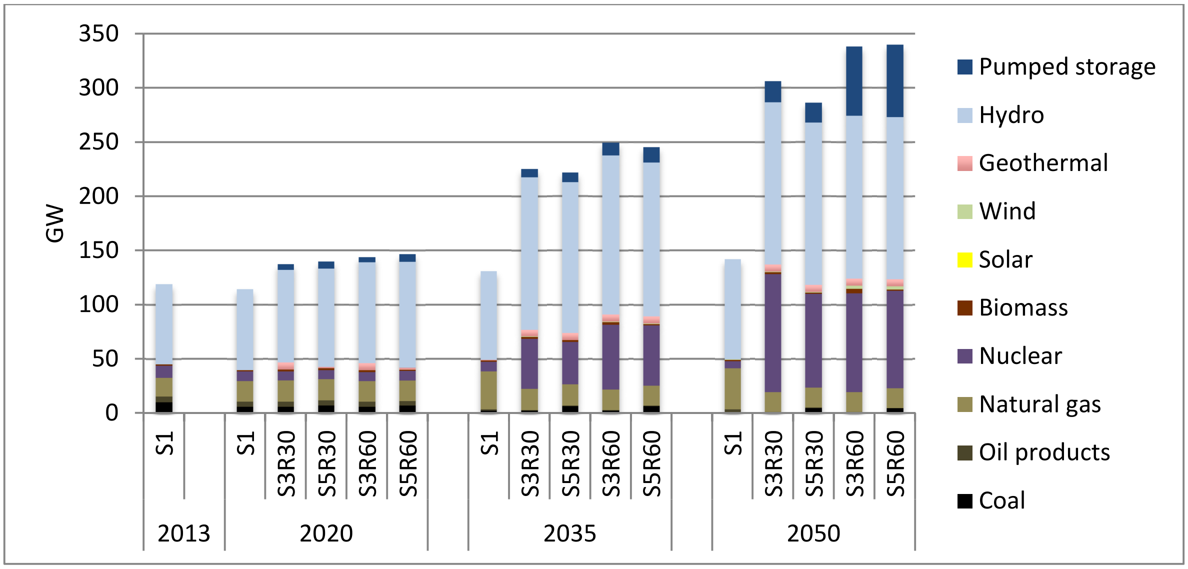
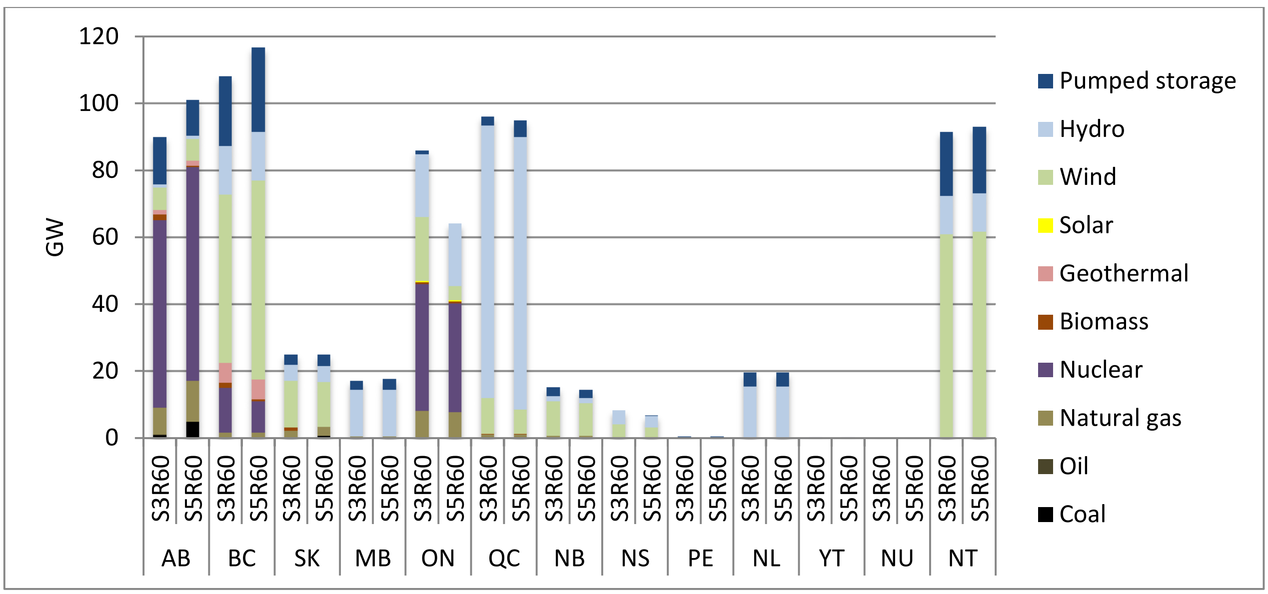


Figure 107. Electricity generating capacity by jurisdiction



5.7.5 Cost

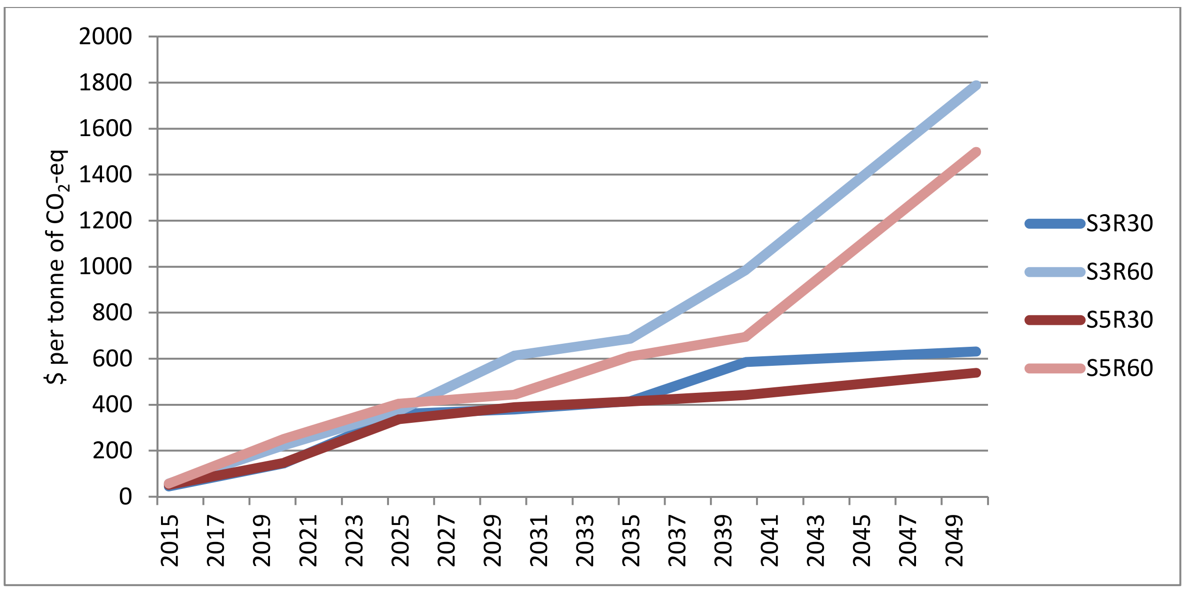
Reductions in marginal cost for for Scenario 5, relative to Scenario 3, are shown on Figure 108 (see also Section 5.4.8).

Key observations from detailed review of background documentation and results, are as follows:

- For both the 30% and 60% GHG reduction targets, there are reductions in overall cost, including marginal costs for both sets of GHG reduction targets. For the early years (to 2025) these reductions are very nominal, as the principal changes from introducing disruptive technologies occur dominantly after 2025.

- Reductions in marginal costs, after 2030, are roughly $100 per tonne for the 30% GHG reduction target, and $300 per tonne for the 60% GHG reduction target. These numbers reflect significant reductions in both total and marginal cost.
- There are significant opportunities for further reductions in both average and marginal cost with these technologies. For electricity supply, the principal opportunities are with inclusion of additional thermal generation with CCUS, and combined with combined cycle and cogeneration, wherever possible. The economics of such developments are enhanced when also combined with commercial use of CO_2, including enhanced oil recovery or accelerated algae production. There are also opportunities with including incremental hydro at both existing and future hydro generating sites. With respect to biofuels, the dominant opportunity is with removing possible feedstock supply contraints for production of FT biodiesel, which could eliminate the need for hydrogen production, which tends to be expensive.

Figure 108. Marginal cost for GHG emissions reduction



5.7.6 Principal Observations

The principal observations from Scenario 5 may be summarized as follows;

- For Scenario 5, additional opportunities for reducing GHG emissions and associated costs were assessed with the addition of three disruptive technologies. These included:
    - Combining coal fired generation (both existing and future) with CCUS and enhanced oil recovery
    - Second generation biodiesel from biomass, based on FT process technology
    - Second generation ethanol from lignocellulose
- With respect to retrofitting CCUS to existing coal-fired generating facilities, this is economically attractive and has the benefit of replacing alternative nuclear generation supply for base-load

generation. However, new coal-fired generation with CCUS appears to be less competitive than nuclear for base load generation.

- With respect to adding second generation biofuels, the most attractive option is second generation biodiesel, which results in a major shift in energy supply for the transportation sector, especially for heavy duty transport; heavy freight transport, rail, and off road transport. The introduction of second generation biodiesel also results in a major increase in use of first generation biodiesel.
- Overall, gasoline usage is projected to decline as a consequence of electrification of personal and light duty transport, with the potential role for ethanol declining correspondingly.
- There are significant reductions in average and marginal cost with introducing these disruptive technologies, especially CCUS and second generation biodiesel.
- There are significant additional opportunities for GHG mitigation, and associated cost reductions with these disruptive technologies, including combining with exiting commercially proven technologies. The most important opportunities include additional natural gas and biofuel based thermal generation with CCUS, incremental hydro, and removal of possible biomass feedstock supply constraints for biodiesel production.

5.8 Added Sale of Dependable Capacity to the United States

The purpose of Scenario 6 is to demonstrate potential additional economic opportunities with export of clean dependable capacity to the United States, as well as increased trade of electrical energy between Canada and the United States. This includes greater integration between the United States North East region and Quebec, and between the United States Mid-West region and Manitoba.

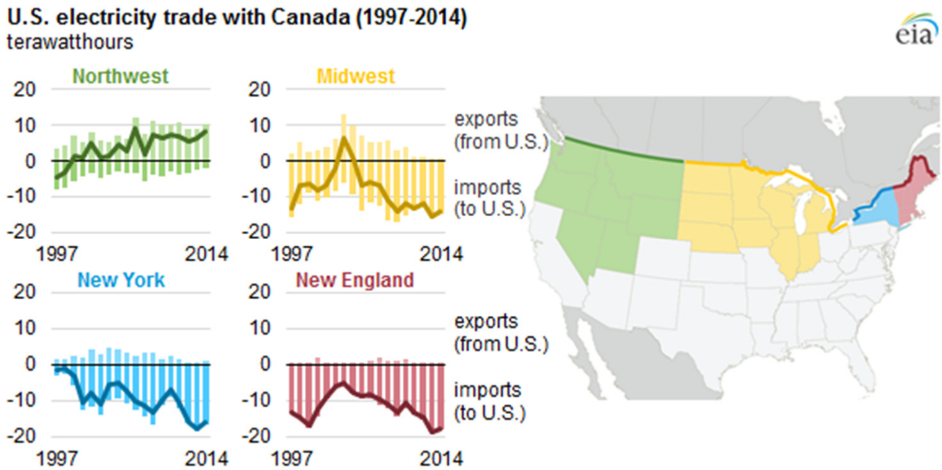
For this Scenario, the treatment is based primarily on interpretations from literature reviews. No attempt was made to carry out a quantitative assessment, as there were not adequate resources available in the project, to provide such representation for the two American regions. This would have required substantial additional testing and verification with the two models, for credible quantitative evaluation of this potential. However, as already stated, it is suggested that such additional development and assessment should be carried out. This would allow demonstration of the potential magnitude of this potential.

5.8.1 Background and Context

There is a long history of electricity trade between Canada and the United States, which has been progressively increasing over the past two decades (Figure 109) (EIA, 2015). Overall, Canada is a net exporter to the United States. The export is dominated by hydroelectric generation in Quebec and Manitoba. Quebec exports electricity into the New England and New York regions, while Manitoba exports into the Midwest region. There is also trade between British Columbia and other members of the Western Electricity Coordinating Council (WECC), albeit that there is net import into British Columbia.

In 2014, there were 58.4 TWh of electricity exported to the United States. This represented 1.6% of electricity sales in the United States and 10% of Canadian electricity generation. The dominant exporters were Hydro Quebec (16.4 TWh) and the Manitoba Hydro Electric Board (8.6 TWh).

Figure 109. United States electricity trade with Canada



Source: EIA, 2015

The mutual benefits of sale and trade of electricity for Quebec and Manitoba and its neighboring regions in the United States, respectively, have included;

- Economic opportunities for sale of lower cost electricity supply from Quebec and Manitoba into American States with higher cost electricity supply
- Opportunities for economy energy exchange, by optimal integrated system dispatch
- Minimizing overall cost of system supply, by increasing role of hydro production for peaking and cycling duty in larger systems contexts, complemented with increased use of lowest cost baseload generation (typically, nuclear and base load thermal)
- Emergency reserve sharing
- Use of hydro for load following, spinning reserve, system synchronization and system stability.

These benefits have resulted in overall cost savings between neighboring utility organizations. There have also been direct benefits for Canadian utilities, by maintaining lower electricity rates for its customers.

5.8.2 Future Changes

There are several projected changes, which are expected to result in modifications to existing arrangements. These are summarized as follows:

- Reference Case projections, as prepared by the United States Department of Energy's Energy Information Administration in 2013, indicated total demand for electrical energy in the United States increasing by 27% from 2011 to 2040; from 4,130 to 5,230 billion kWh (EIA, 2013a). The dominant changes include coal fired generation declining from 42% of total generation in 2011 to 35% in 2040; natural gas increasing from 24% to 30%; renewables increasing from 13% to 17%; and nuclear declining from 19% to 17%.

- From these and related projections, there are some important observations:

    - Firstly, these projections are based on the best available estimates in the United States concerning projections for electricity supply over this period, with limited consideration being given to increased electrification of end uses for GHG mitigation.
    - Over this period, the change in use of fossil fuels for electricity supply changes from 66% to 65%, with a progressive shift from use of coal to use of natural gas. Additional thermal generation is dominantly with natural gas fired generation
    - The growth of supply from renewable generating sources is dominated by intermittent renewables, mostly wind and solar. There is virtually no additional investment in hydro generation.
    - There is little additional investment in nuclear generation.

- In this same Report (EIA, 2013a), one of the major changes occurs in the composition of renewables generation. Results are shown on Figure 110, Figure 111 and Figure 112. Capacity additions to 2040, from solar and wind generation, are 46 and 42 GW, respectively. There are also 5 and 7 GW's, respectively, of additional geothermal and biomass generation. Despite no additional investment in hydropower, electricity production from hydro remains as the largest source of electricity production from renewables, because of its relatively high capacity factor production.
  In the context of this Scenario 7, the main significance is that with large projected growth of intermittent renewables, especially wind and solar, there has to be complementation of dependable capacity, preferably from non-fossil fuel generating sources. This takes on special significance for the North-East and Mid-West regions where there is very limited hydro potential, and no planned expansion of nuclear generation. Availability of hydro, for dependable capacity supply, from neighboring Quebec and Manitoba, has obvious attraction, in addition to being a source of non-emitting electricity.
- In a *Renewables Electricity Futures Study* carried out for the United States Department of Energy Office of Energy Efficiency and Renewable Energy, prospects for large-scale deployment of specific renewable generation and storage technologies were explored, along with some of the issues and challenges associated with their integration into the electricity system (Figure 113 and Figure 114) (NREL, 2012b). These analyses were carried out for generation mixes with renewables increasing from the current 17% level, to 90%. Some key results from this Study are as follows:

    - It was confirmed that renewable energy resources, using commercially available technologies, could adequately supply 80% of total electricity generation in the United States in 2050, while balancing supply and demand at the hourly level. This could include close to 50% of capacity being from intermittent generating sources.
    - All regions of the United States could contribute substantial renewable electricity supply by 2050, consistent with their local renewables resource base.
    - Additional challenges for planning and operations would occur with higher (above 80%) renewables electricity capacity, including management during low demand periods and curtailment of excess electricity generation.

  Again, the significance of this in the context of Scenario 7, is that there is a complementing need for dependable capacity, preferably from non-emitting sources. There is again a potential opportunity for such capacity being available from hydro generation in Canada, especially for the United States North-East and Mid-West regions

- The *Deep Decarbonization Pathways Project* (DDPP) is a collaborative global initiative to explore how individual countries can reduce GHG emissions to levels consistent to limiting the anthropogenic increase in global mean temperatures to less than 2°C. This initiative is led by the Sustainable Development Solutions Network (SDSN) and the Institute for Sustainable Development and International Relations (IDDRI). The DDPP initiative includes research teams from 15 countries, including both the United States and Canada. These 15 countries, collectively, produce more than 70% of global GHG emissions.

  The study was carried out jointly by Energy & Environmental Economics, Lawrence Berkeley National Laboratory, and Pacific Northwest National Laboratory (Williams et al, 2014).

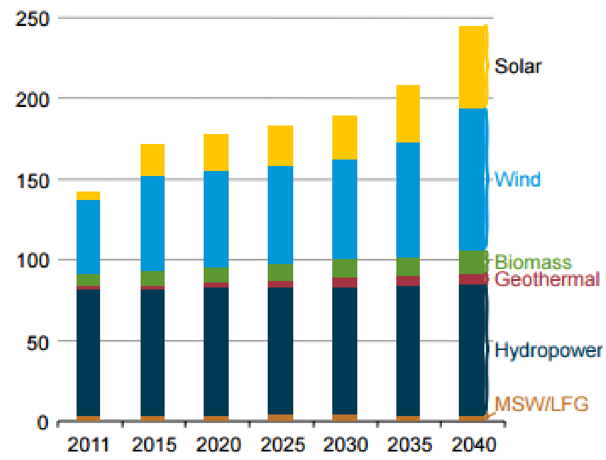
  The prime goal of the project was to assess the technical and economic feasibility for reducing GHG emissions in the United States by 80% below 1990 levels by 2050, as part of the broader goal by the international community to reduce net GHG emissions to zero by the end of the 21st century.

  One of the important observations, from this study, is that in order to achieve such reductions in GHG emissions, it would be necessary to implement major changes in energy supply and end use technology and infrastructure. The dominant strategy would be to fully decarbonize electricity supply, and switch a large share of end uses from direct combustion of fossil fuels, to electricity, or fuels produced by electricity (such as hydrogen from electrolysis). With these changes, use of electricity would increase from 20% to more than 50% of total energy production. This would result in deployment of 2,500 GW of wind and solar generation (30 times present capacity) for their high renewables Scenario. By 2050, petroleum consumption would reduce by amounts in the 76 to 91% range.

  It is especially noteworthy that these general trends align with results from the TEFP project, as reported herein. This includes especially the very large conversion of end uses away from combustion of fossil fuels to use of electricity, and rapid decarbonizing of electricity supply.

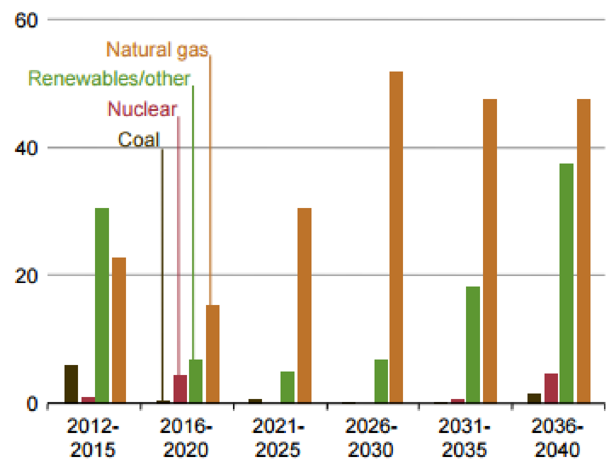
  In the context of this Scenario 7, this potential development in the United States, especially in the North-East and Mid-West regions, represents an even further opportunity for supply of non-emitting dependable capacity from Canada to complement massive projected increases in electricity generation from intermittent renewable generating sources in the United States. The dominant options for dependable capacity in these regions include nuclear, fossil–fired generation with CCUS, and hydro import from Canada.

Figure 110. Renewable electricity generating capacity by energy source, 2011 - 2040 (GW)



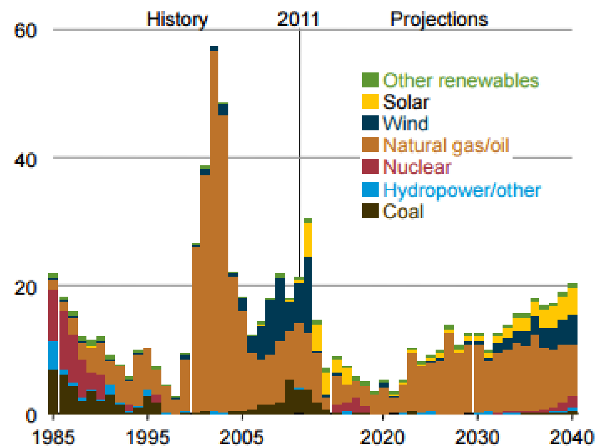
Source: EIA, 2013a, p. 74.

Figure 111. Electricity generation capacity additions by fuel type, 2012 - 2040 (GW)



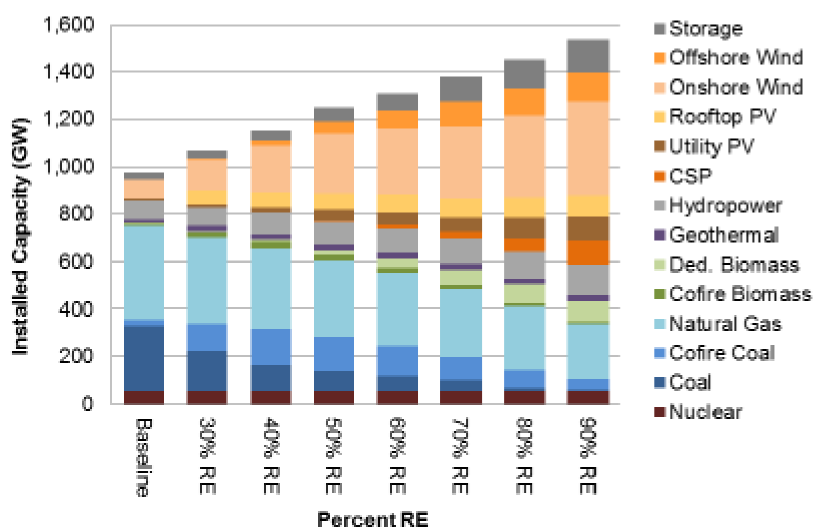
Source: EIA, 2013a, p. 72.

Figure 112. Additions to electricity generating capacity, 1985-2040 (GW)



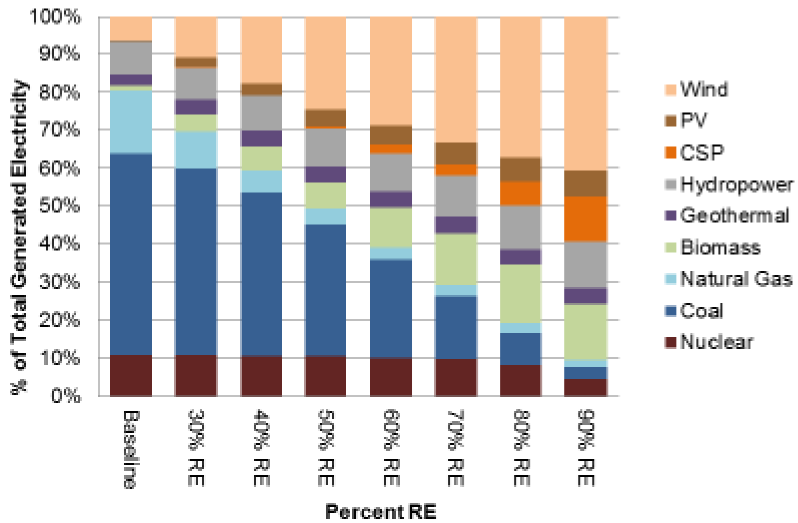
Source: EIA, 2013a, p. 72.

Figure 113. Capacity mix in 2050 for exploratory scenario



Source: NREL, 2012b, p.2-5.

Figure 114. Generation mix in 2050 for exploratory scenario



Source: NREL, 2012b, p.2-5.

5.8.3 Opportunities for Enhanced Export and Trade of Electricity

There are likely to be major changes in the role and composition of electricity supply in the United States. This includes both major increases in the role of electricity for meeting energy based end uses, as well as rapid decarbonisation of electricity supply. Much of the projected increase in electricity generation in the United States is likely to be from intermittent renewable generating sources, dominantly wind and solar. The dominant complementing sources of dependable capacity include nuclear, fossil fired thermal with CCUS, and hydro. Within this context, and especially for the North-East and Mid-West regions of the United States, the potential for supply of emissions-free dependable capacity from Quebec and Manitoba becomes a greatly enhanced option for consideration in an integrated development context. These opportunities are in addition to traditional opportunities as noted in Section 5.8.1. Further commentary related to such integration considerations is as follows:

- One of the challenges, with having a high proportion of electricity supply from intermittent renewable generating sources, is the requirement for significant storage over extended periods of time to compensate for possible variations (weeks or months) in electricity production from such sources. Quebec has reservoir storage which is more than one full year of electricity supply for the province of Quebec. Similarly, Lake Winnipeg Regulation is one of the largest energy storage systems in the world. Such storage systems provide excellent complementation for electricity production within their respective jurisdictions, as well as representing opportunities for complementing electricity production from intermittent renewable generating source in neighboring jurisdictions.
- The opportunities for achieving complementing benefits may be further enhanced by the fact that peak demands occur at different times of the year. This is especially true in the North East of the United States (summer peak) and in Quebec (winter peak). The difference in the respective peaks is large for both supply systems, which is of mutual benefit for reducing cost of electricity

supply in both countries. With major projected increased electrification of end uses, this opportunity will increase further.

- Finally, there are additional opportunities arising from significant differences in cost of electricity supply. Quebec and Manitoba have traditionally been amongst the lowest cost jurisdictions for electricity supply in North America. This provides attractive opportunities for further integrated development within a larger system supply context. With major projected growth of electricity supply in both the United States and Canada, this opportunity should be further enhanced.

5.8.4 Possible Next Steps

From the foregoing, it is evident that there are likely to be significant shifts towards major electrification of end uses, as well as decarbonizing supply systems for production of electricity, fossil fuels and biofuels, in both the United States and Canada. This will clearly result in major expansion and changes in infrastructure for electricity supply and delivery, with large associated investments. It is also appreciated that both the United States and Canada are committed to making major changes and associated investments, in responding to the imperatives of climate change, which include major transformations of electricity supply systems.

From the foregoing, it is clearly evident that there are substantial economic opportunities for maximizing the potential from optimum integrated development from the North East of the United States with Quebec and the Mid-West of the United States with Manitoba systems, to 2050 and beyond.

In order to develop greater appreciation of this potential, it is suggested that an approach, using two models, as used in this project, be used to demonstrate such opportunities and associated strategies for achieving maximum net benefits from integrated development and expansion of the electricity supply systems.

5.9 Scenario 7: No Additional Nuclear Generation

The prime purpose of Scenario 7 is to demonstrate cost impacts associated with not including any additional nuclear generation for electricity production. There is also a requirement to provide perspectives on impacts with not including additional hydro generation. Comparisons, with results from Scenario 3, are presented.

As with Scenario 3, minimum cost solutions were obtained for Scenario 7 for the same 30% and 60% GHG reduction targets. The same GHG reduction profiles from 2013 to 2050 were retained for Scenario 7.

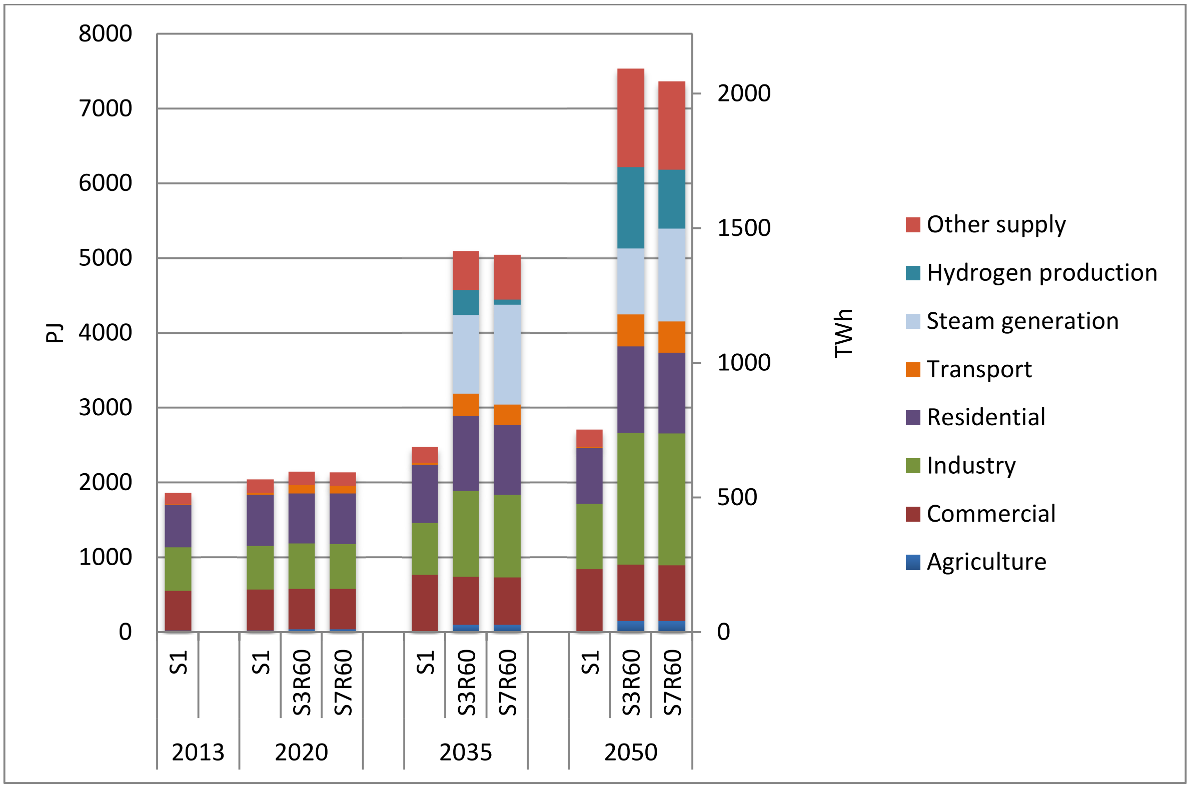
5.9.1 Changes in Electricity Demand

Changes in electricity consumption are shown on Figure 115 for this Scenario, with comparison to results for Scenarios 1 and 3.

Key observations from detailed review of background documentation and results are as follows:

- When any generation supply option which appears in a minimum cost solution is removed as an option (such as nuclear generation in Scenario 3), the resulting minimum cost without that option will increase. This may also result in reducing demand for electricity, as marginal costs for electricity production will increase. Such results can be observed in Figure 115, where the overall demand for electricity declines.
- The actual decline in electricity consumption is relatively modest, with reduction in 2050 being only 178 PJ (or 50 Twhrs), equivalent to 2.4%.

Figure 115. Electricity consumption



5.9.2 Changes in Electricity Supply

Changes in electricity supply are shown on Figure 116 to Figure 120, again with comparisons with results for Scenarios 1 and 3. Total generating capacity is shown on Figure 116, with corresponding dependable capacity shown on Figure 117. Results for the respective jurisdictions are shown on Figure 118 and Figure 119, for total generating capacity and dependable capacity, respectively. The ratio of electrical energy to total energy is shown on Figure 120.

Key observations from detailed review of background documentation and results, are as follows:

- With removal of nuclear generation as an additional electricity supply option, the dominant lowest cost option is a combination of additional wind generation for electrical energy and pumped storage for dependable capacity. There is a small increase in hydro generation;

however, this is limited, as much of the full economic potential will already have been fully developed in the hydro dominated jurisdictions in Scenario 3. There is a small amount of solar energy for grid supply, dominantly in Alberta. The dominant changes occur in Alberta, British Columbia, Saskatchewan and Ontario, which are the four jurisdictions which had significant nuclear in the minimum cost solution in Scenario 3.

- With the removal of nuclear, total installed capacity increases from 560 Gw to 800 Gw, an increase of 43%.
- As may be observed in Fugure 5.9.6, the proportion of electricty for end uses decreases from 54% to 50%, due to increased marginal cost of electricity supply.
- There are significant changes in the amount of electricity consumend in various jurisdictions. For example, in 2050, electricity consumption in Ontario reduces from 527 billon Kwhrs (Scenario 3) to 438 billion Kwhrs (Scenario 7), reduction of 17%. Again, this is due entirely to increased marginal cost of electricity supply.
- If additional conventional hydro were also to be excluded as an electricity supply option, there would be even further changes in composition of electricity supply, and increased costs. The dominant consideration is with provision of dependable capacity. The principal options for dependable capacity include conventional hydro, nuclear, thermal, geothermal and large scale dispatchable storage (such as pumped strage). When both nuclear and conventional hydro are removed, the only remaining options are geothermal (which is both of limited potential and expensive in Canada), thermal and large scale dispatchable storage.
- There are important options which have not been included in these analyses, which should be included in further investigations. The most important additional options include;

    - Gas-fired thermal with CCUS, and including combined cycle and cogeneration
    - Incremental hydro at existing and future hydro generation facilites for dependable capacity
    - Biofuels for thermal generation combined with CCUS

Figure 116. Electricity generating capacity

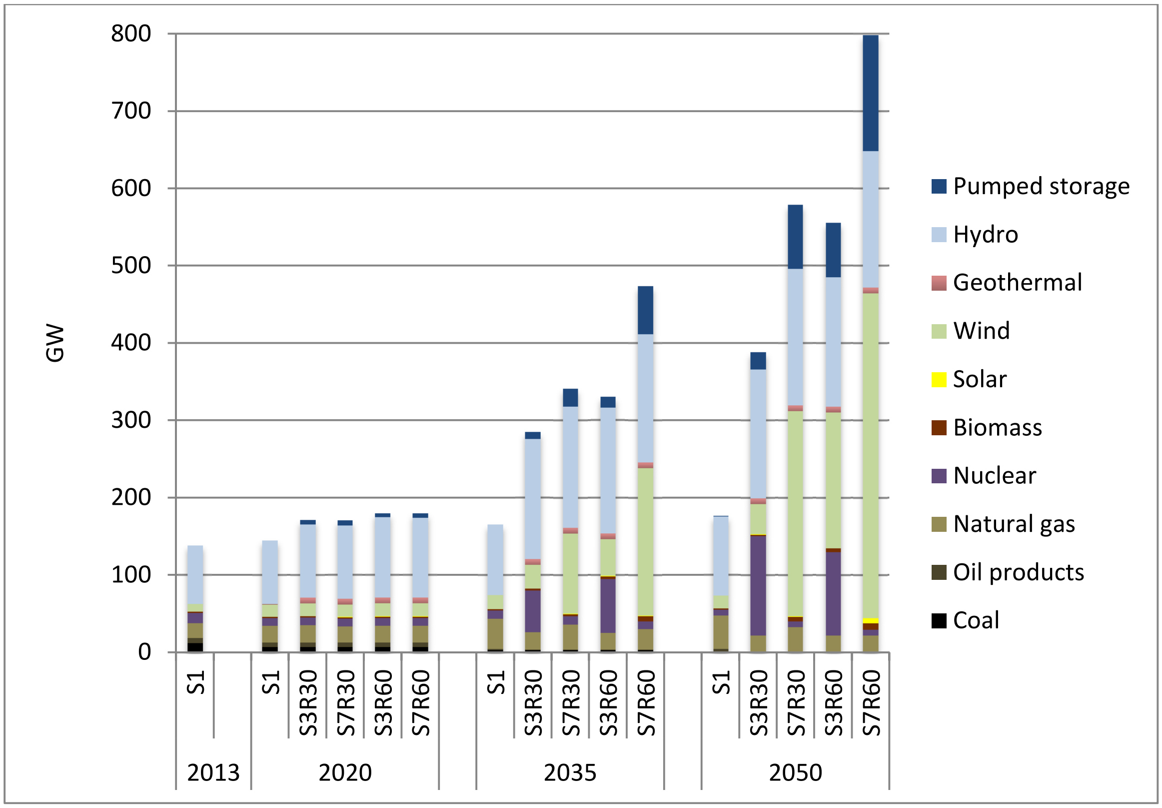


Figure 117. Electricity dependable capacity

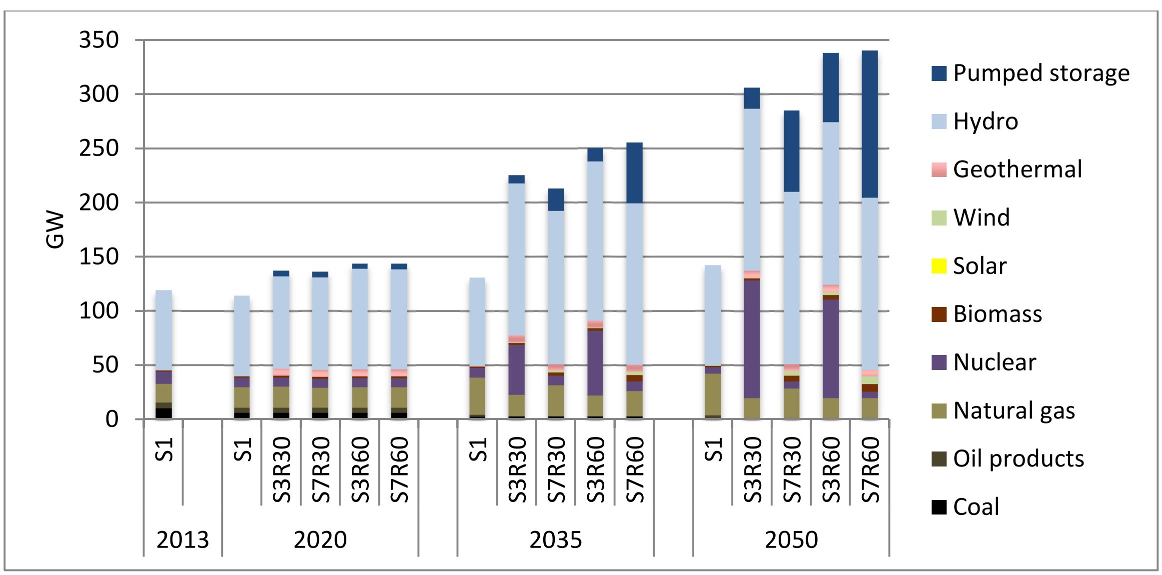


Figure 118. Electricity generating capacity by jurisdiction

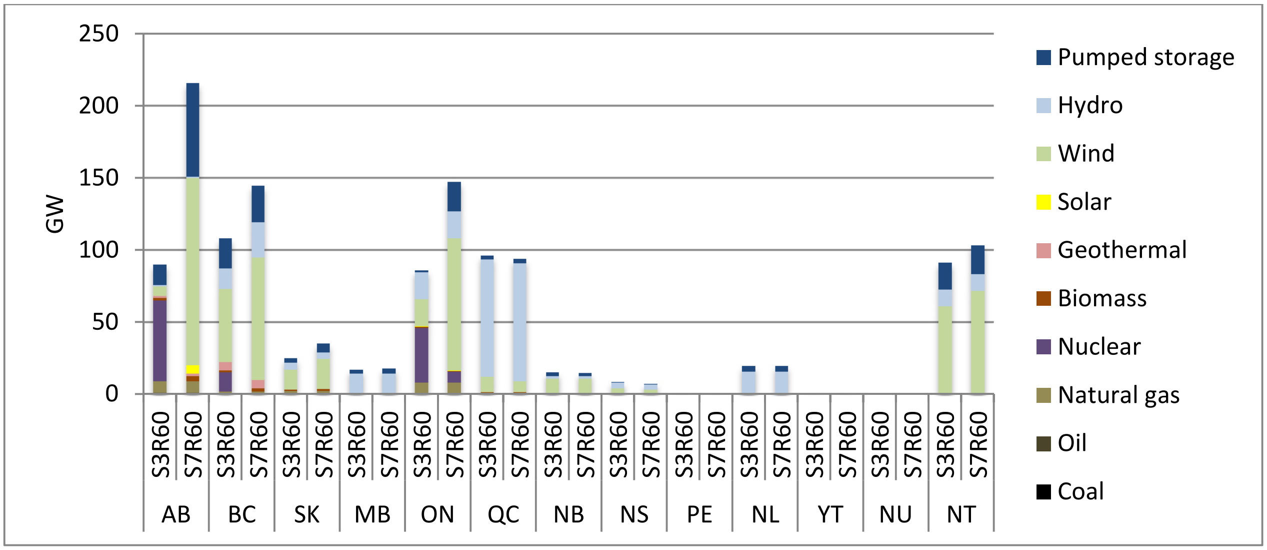


Figure 119. Electricity dependable capacity by jurisdiction

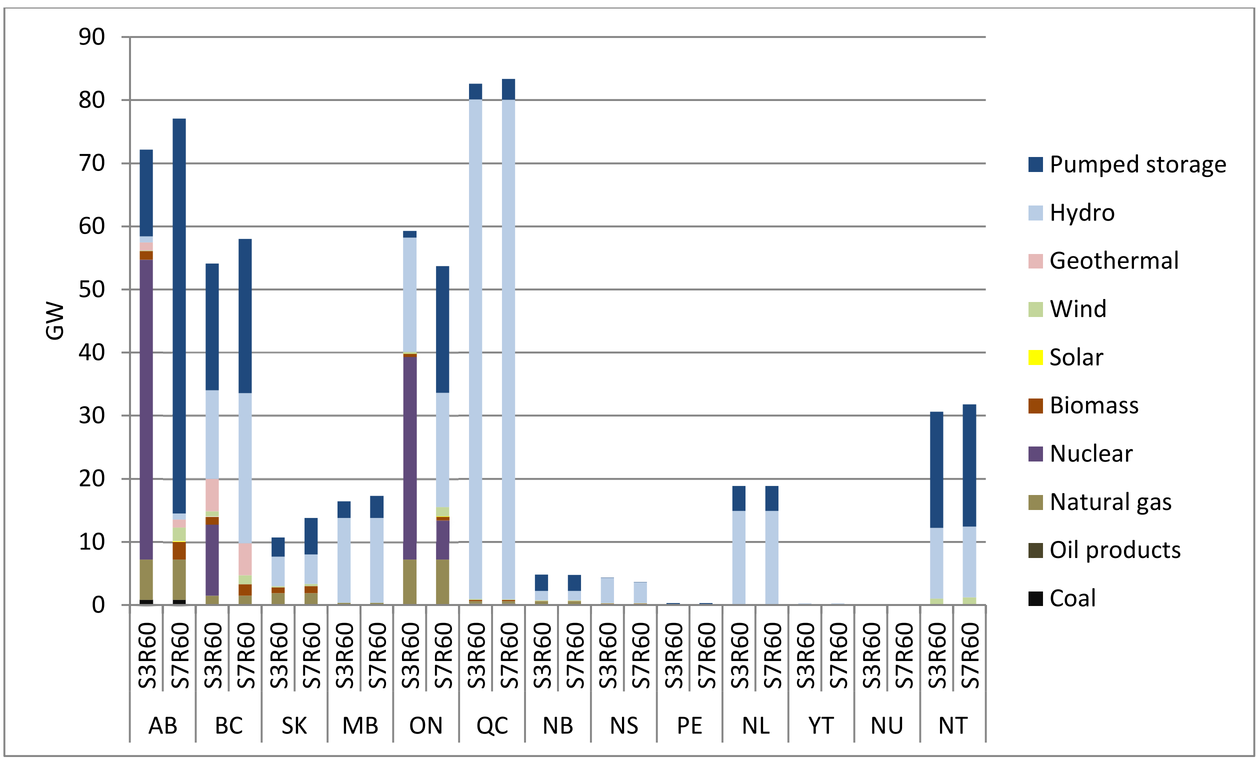
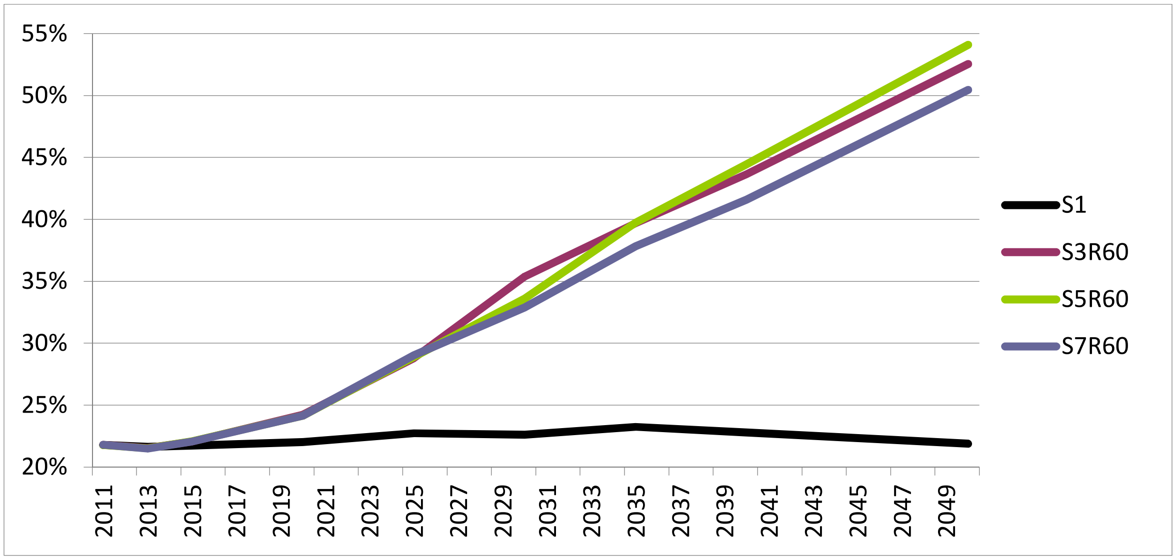


Figure 120. Ratio of electricity consumption - Total energy consumption



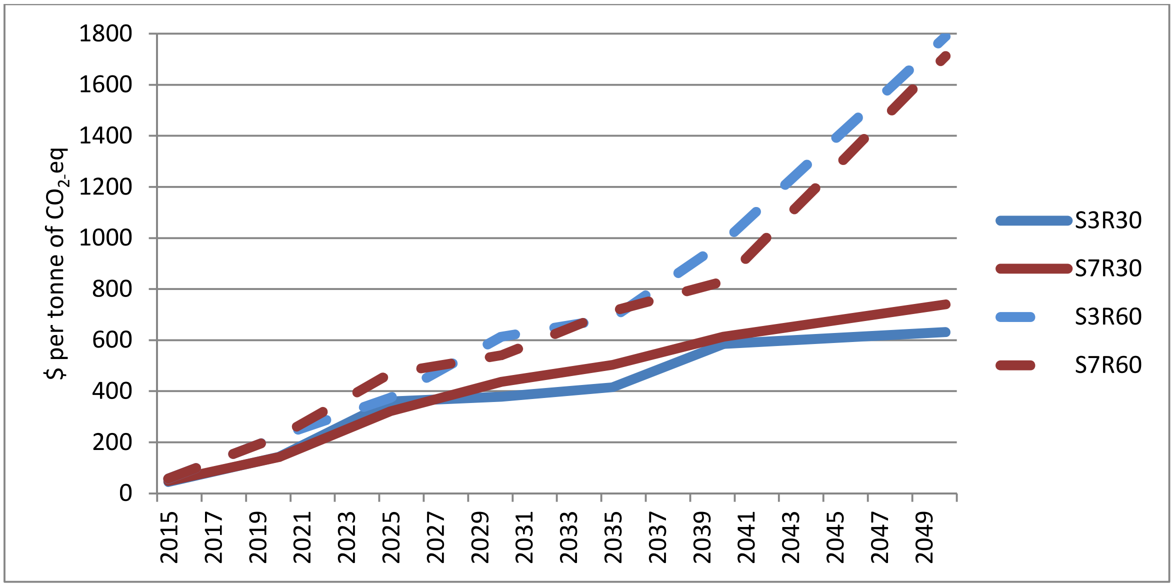
5.9.3 Cost

Marginal costs for GHG reduction are shown on Figure 121, with comparison to results from Scenario 3.

Key observations from detailed review of background documentation and results are as follows:

- Differences in marginal costs for GHG mitigation for Scenario 3 (which includes nuclear in the supply mix) and for Scenario 7 (which excludes nuclear), for both 30% and 60% GHG reductions, are relatively minor.
- Separate reviews were carried out to compare present worth costs for the respective Scenarios. Although overall costs for Scenario 7 are higher than for Scenario 3, cost differences are less than 1% of total present worth cost for both 30% and 60% GHG reductions. This is somewhat surprising, especially given the very substatnial change in the overll supply mix for the two sets for results. This suggests that excluding nuclear in the electricity supply mix may be achieved with relatively small cost impact, as there are other combinations of supply options which may be closely competing.
- It is important to appreciate, however, that this is a very preliminary observation. The dominant replacement for nuclear is combinations of wind and pumped storage, with nominal increases in hydro and thermal generation. However, the viability of such options need to be addressed in the respective jurisdictions, especially with major additions of pumped storage generation, for which very little credible site-specific infromation is currently available. It is also important to assess sensitivities in relation to changing demands, cost information, and other potential impacts in the different jurisdictions.

Figure 121. Marginal costs for GHG mitigation



5.9.4 Principal Observations

The principal observations from Scenario 7 may be summarized as follows:

- There are significant impacts associated with removing the option of additional nuclear generation for electricity supply. The principal impacts include:
    - Major changes in composition of electricity supply, especially in those jurisdictions that had nuclear generation in their respective minimum cost electricity supply mix – dominant shift to increased wind generation and increased large scale dispatchable storage (pumped storage).
    - More than 40% increase in generating capacity.
- Based on preliminary results, it is possible that cost impacts from excluding additional nuclear generation, in the short term, may not be large. However, this is a very preliminary observation, and much more work is required before any definitive statement can be made.
- It also needs to be appreciated that availability of hydro generation in Canada has an eventual resource limit, with a longer term requirement for dependable capacity and electricity generation to come from other sources. The dominant remaining non-emitting supply source at such time may be limited to nuclear generation.
- Although there were no runs carried out for excluding additional conventional large scale hydro generation, it is evident that results for such cases would certainly result in greatly increased costs. This consideration arises from recognition that minimum cost solutions lead to early development of remaining economic hydro potential, especially in hydro dominated jurisdictions.
- There are several important options which have not been included in these analyses, and which are important to include in follow-up investigations. The most important options include coal- and natural gas-fired thermal generation with CCUS, incremental hydro at existing and future hydro sites, and biomass based generation with CCUS. The impacts of these additions are likely

to result in further changes to the minimum cost electricity supply mix, and may impact on results for scenarios with and without nuclear generation.

5.10 Scenario 8: Comprehensive Range of Options

The prime purpose of Scenario 8 is to demonstrate impacts associated with combining options from Scenarios 3, 4 and 5, and adding additional options that were not included in these prior Scenarios. Scenario 8 includes the following features from earlier scenarios:

- Exchange of electrical energy and dependable capacity between jurisdictions (Scenario 3)
- End use remand reductions from urban regeneration (Scenario 4)
- Disruptive technologies (thermal generation with CCUS, and second generation biodiesel and ethanol) (Scenario 5)

Additional features in Scenario 8 include:

- Additional conventional large scale hydro (up to 30 GW) in British Columbia from 2030, based on reversal of existing legislation
- Biomass for thermal-based electricity generation, combined with CCUS
- Biojet fuel for air transport

As with prior scenarios, minimum cost solutions were obtained for Scenario 8 for the same 30% and 60% GHG reduction targets. However, as there were additional options included in Scenario 8, the NATEM Canada model was also applied to analyze a 70% reduction Scenario.

The same GHG reduction profiles, from 2013 to 2050, were retained for Scenario 8.

For this Scenario, there was also an initiative to combine analyses of reductions in GHG emissions from combustion sources, with emissions reductions from non-combustion sources. This was further extended to include early assessments for net GHG reductions, based on both use of biomass for electricity generation with CCUS, and net carbon retention with harvest wood products (HWP).

5.10.1 Bioenergy with CCUS

One of the very important areas of investigation, recommended by IPCC, is to implement strategies that lead to net negative emissions. This will be required to offset continuing GHG emissions from sources which are difficult, if not impossible, to curtail. In the long term, there is a need to not only offset such emissions, but to also eventually reach a state where overall net global emissions are nullified, and then for continuing progress towards net negative GHG emissions, so that CO_2 concentrations in the atmosphere can be progressively returned to historical levels.

In Scenario 8, one of the important areas of investigation was to assess the economic potential for electricity generation with biomass combined with CCUS. The principal assumptions for these analyses included:

- The analyses were limited to only jurisdictions that had both substantial availability of biomass feedstock and known carbon sinks. This included the four Western Provinces and Ontario.

Captured CO_2 could be combined with enhanced oil recovery in the four Western provinces or could be stored in saline aquifers in either British Columbia or Ontario.

- There was no inter-jurisdictional transfer of biomass for electricity generation or for disposition of captured CO_2. The NATEM model had not been developed to include such options.

Results of analyses for electricity production with biomass combined with CCUS for the 60% GHG reduction target are shown on Figure 122. Net negative GHG emissions are shown on Figure 123, including results for both the 30% and 60% GHG reduction targets.

Key observations from detailed review of background documentation and results, are as follows:

- Electricity generation with biomass is of the order of 1.5 to 2.5 GW. Despite its higher cost for electricity generation, there is an offsetting benefit from the implicit value of the CO_2 that is captured and stored. This results in this option being included in the minimum cost supply solution for electricity supply. This is of increasing value with higher GHG reduction targets, due to the correspondingly higher implicit costs for GHG mitigation.
- Corresponding net negative GHG emissions, after 2020, are of the order of 20 Mt.
- The reduction in electricity generation with biomass in 2050, and the corresponding reduction in net negative GHG emissions, for the 60% GHG reduction target, arise as a direct consequence of biomass feedstock supply constraint in 2050, and not from cost competitveness. In 2050, the value of biofuels produced from biomass for heavy transport in the transportation sector is higher than for electicity production, with the result that less biomass is available for electricity generation.

Figure 122. Electricity generation with biomass, combined with CCUS - S8R60

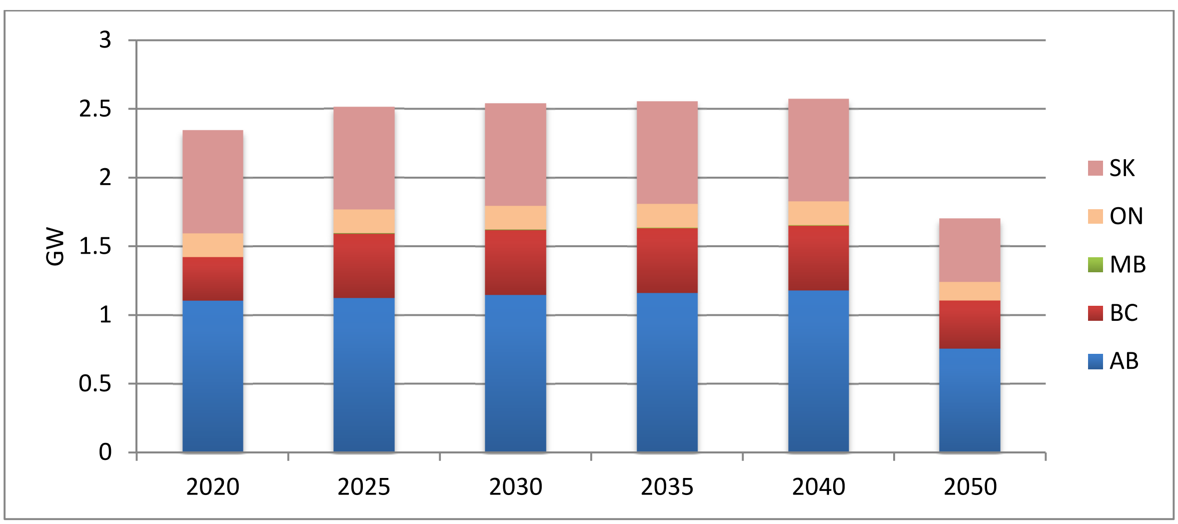
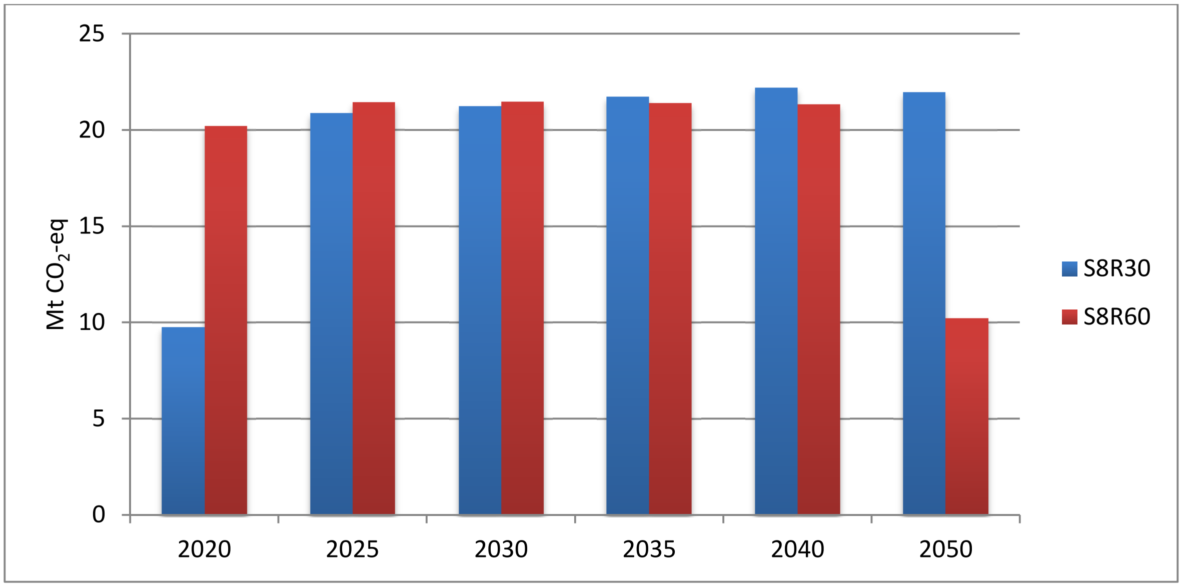


Figure 123. GHG credits from electricity generation with biomass, combined with CCUS



- Although the magnitude of electricity production, as reported here, is relatively modest, it should be appreciated, nevertheless, that the potential for this option, or variants of this option, could be very substantial. They include:
    - increased electricity production with interjurisdictional transfers of both biomass and captured CO_2
    - potentially increased availability of biomass for electricity production
    - use of CO_2 for acccelerated algae production for producing biomass
    - biomass gasification for combined cycle and/or cogeneration, combined with CCUS
- With this area recognized as being economically competitive as well as being one of the favored options for achieving net negative emissions, it is especially important to expand model development to represent this option and its possible variants in a more comprehenisve manner.

5.10.2 Biomass Feedstock Supply Constraints

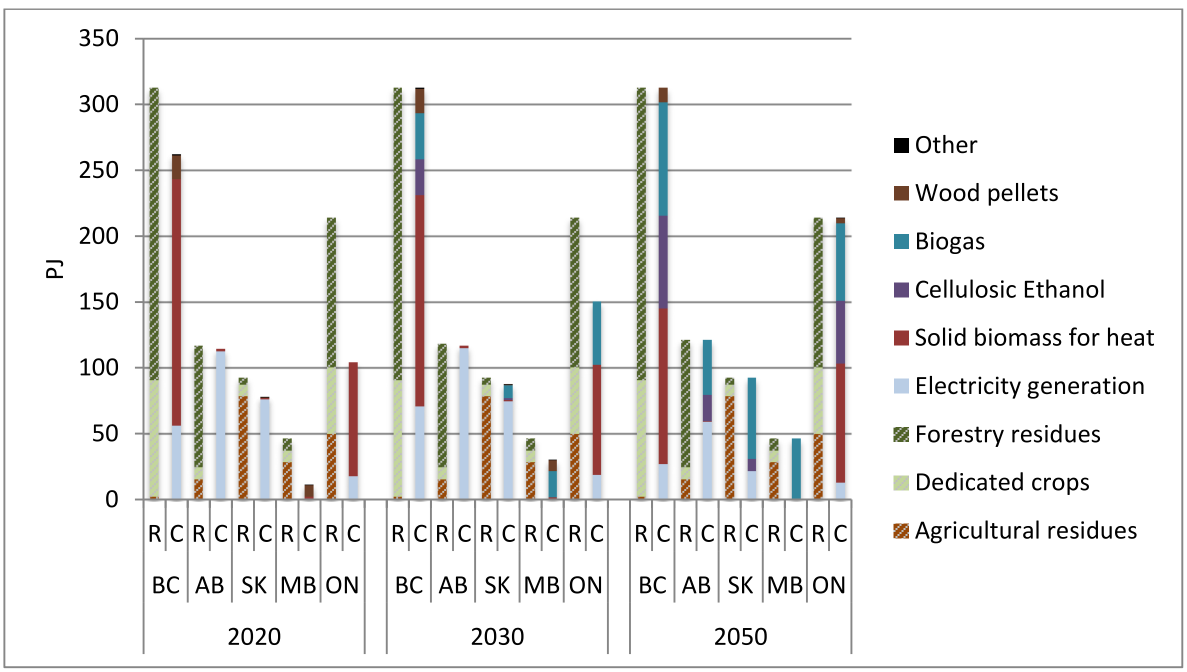
As noted above, one of the key concerns is feedstock resource limitations for biomass production. As discussed in Section 4, resource limits were defined on the basis of existing and potential feedstock resource availability potential, and with balanced consideration for agricultural production for other purposes (including food production) and the forest products industry. These considerations included progressive changes in all three areas to ensure overall maximization of economic potential, including expanded use of marginal lands for biomass production. It should be appreciated that this analysis is limited to production of biomass, and not for all biofuels, as the prime focus was on potential use of biomass for electricity generation, with consideration of other competing uses.

Results from analyses of biomass feedstock availability and consumption are shown on Figure 124 for the four Western Provinces and Ontario for the 60% GHG reduction target.

Key observations from detailed review of background documentation and results, are as follows:

- In an overall context, availability of biomass feedstock tends to become a constraint relatively quickly. The full resource potential is fully utilized in all five jurisdictions by 2050. In addition, it is also fully utilized, as early as 2030, in Alberta and British Columbia.
- The three sources of biomass feedstock are forest residues, agricultural residues and dedicated crops for biomass production. The dominant source is forest residues, especially in British Columbia, Alberta and Ontario. Agricultural residues are dominantly in Saskatchewan and Manitoba. Dedicated crops for biomass production are dominantly in British Columbia and Ontario.
- As desribed for Scenario 5, and as shown on Figure 125, the dominant use of biofuels is for the transportation sector. With the introduction of the option to include biomass also for electricity production, there is an interplay between use of biofuels for heavy transport and biomass for electricity production, along with reaching biomass feedstock resource limits. The principal change in 2050 occurs in Ontario, as it reaches its resource availability limit between 2030 and 2050, resulting in less biomass being available for electricity production.
- While these analyses have focussed on Western Canada and Ontario, the issues and opportunities, very clearly, apply also to the other jurisdictions across Canada. Further work in this area needs to be fully comprehensive, and including resource availability, and production and consumption of biomass. There is also a need to include more comprehenisve consideration of interjurisdictional transfers of biomass feedstock.

Figure 124. Biomass feedstock resource availability and consumption - S8R60



Note: “R” is Reserves; “C” is Consumption.

5.10.3 Biojet Fuel

Although use of biojet fuel was introduced as a supply option for airline transport, none of the results included use of biojet fuels in the respective minimum cost solutions. This arose primarily as a consequence of feedstock resource limits, with use of biofuels for heavy duty transport and electricity production with CCUS, having a cost advantage over use of biojet fuel for airline transport. There was also an additional consideration, as introduction of biojet fuel occurred after major energy efficiency improvements had already been included in airline transport.

5.10.4 Biofuel Consumption

The use of biofuels is shown on Figure 125, Figure 126 and Figure 127 for Scenario 8, with comparisons to Scenarios 1, 3 and 5. Use of biofuels by end use is shown on Figure 125. Breakdown by type of biofuel is shown on Figure 126, with further separation for the transportation sector shown on Figure 127.

Key observations from detailed review of background documentation and results, are as follows:

- As noted from analyses of prior scenarios, use of biofuels is dominantly for use in the transportation sector, especially for heavy freight and rail transport, and for off road transport.
- Biofuel consumption for transport increases in Scenario 8 in 2050, relative to Scenario 5. This arises as there is a general cascade of impacts from addition of large hydro in British Columbia with its corresponding reductions in GHG emissions, which in turn leads to increased availability of both fossil diesel and second generation biodiesel, combined with first generation biodiesel, for the transportation sector. In turn, this results in reduced use of hydrogen for transport, which is expensive.
- As with results from Scenario 5, second generation biodiesel, based on FT process, becomes a dominant option for production of biofuels.

Figure 125. Biofuel production for end use sector

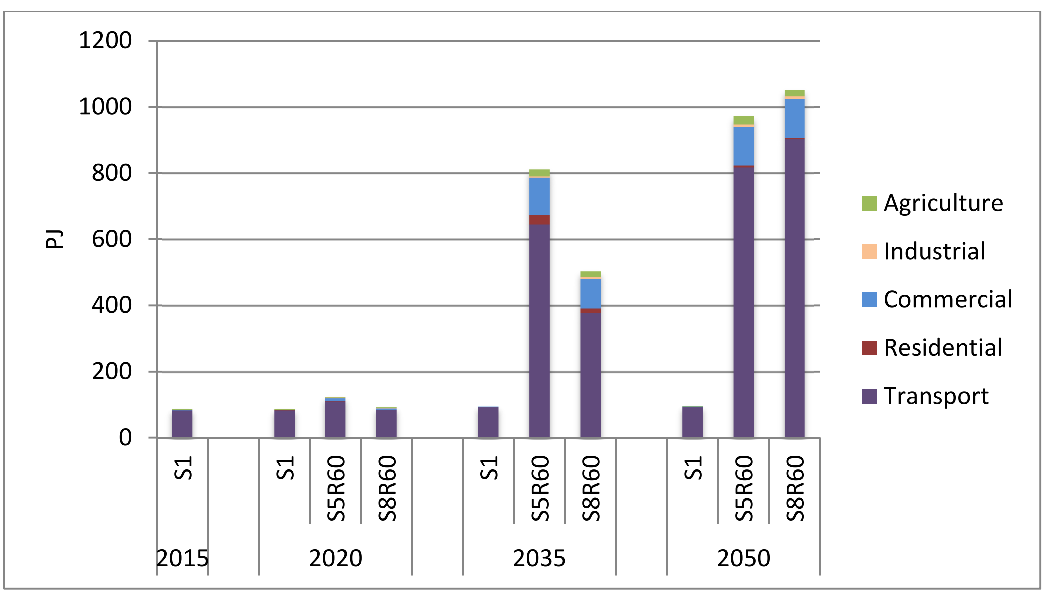


Figure 126. Biofuel production by fuel type

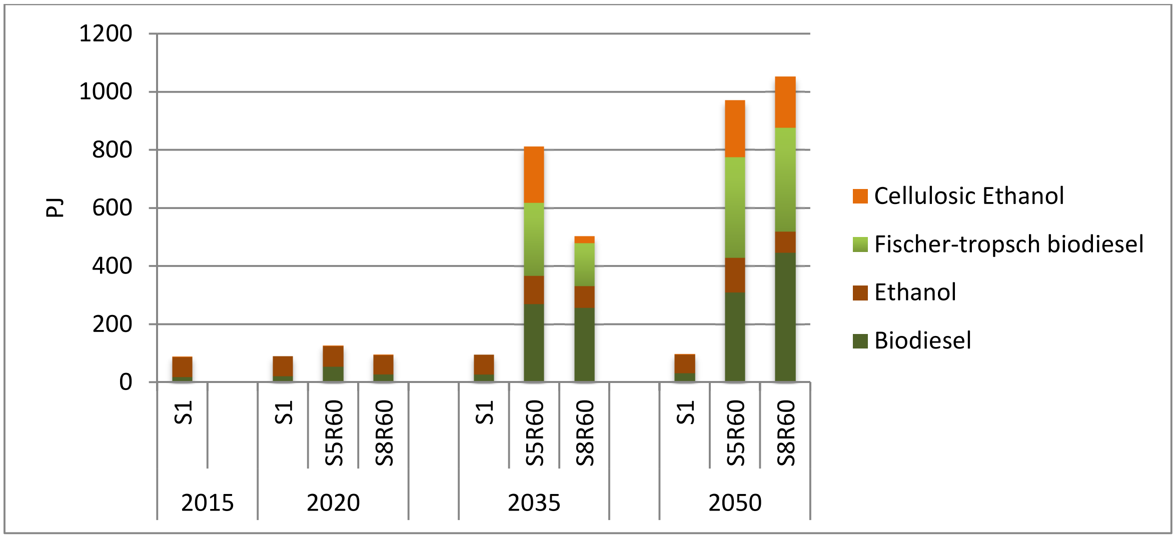
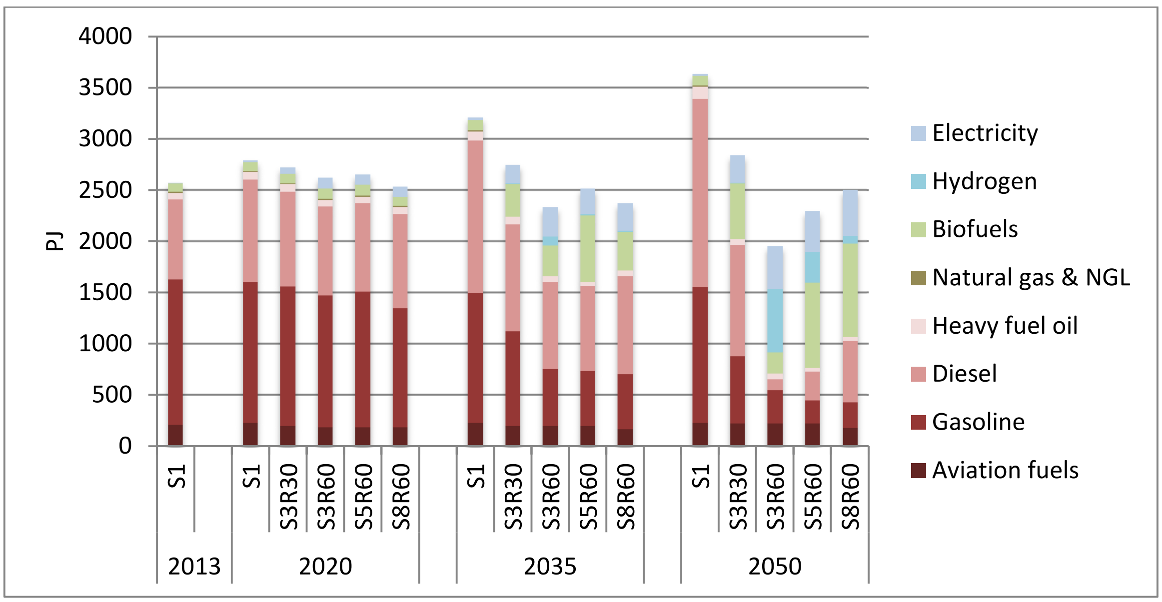


Figure 127. Fuel Consumption by fuel type in transportation sector



5.10.5 Electricity Production

Results showing changes in electricity supply for Scenario 8, relative to results for Scenario 3, are shown on Figure 128, figure 129 and Figure 130. Changes in total generating capacity and dependable capacity are shown on Figure 128 and Figure 129, respectively. Changes in total generating capacity for the respective jurisdictions are shown on Figure 130.

Key observations from detailed review of background documentation and results, are as follows:

- There are very significant changes in composition of electricity supply between Scenarios 3 and 8. These incude:

- With up to 30 GW of large scale conventional hydro in British Columbia being added to the potential supply mix, beginning in 2030, this entire additional potential is added to electricity system supply by 2040, in the minimum cost solution.
- There is additional coal generating capacity as a consequence of retrofitting existing coal fired generating units with CCUS (Scenario 5). There is also addition of electricity generation with biomass, combined with CCUS, which also becomes part of the overall supply mix, especially in Alberta and Saskatchewan.
- There is some natural gas generation, primarily for peak energy generation and for dependable capacity contribution.
- There are major reductions in wind and pumped storage generation.
- There is an overall reduction of 116 GW in total generating capacity (around 20%).

- As the overall cost of electricity declines with these additional options, the role of electricity actually increases, as shown by the increase in dependable capacity. This even includes effects of urban regeneration which has reduced demand for electricity (Scenario 4).
- The most significant change is with the mix of electricity supply between British Columbia, Alberta and Northwest Territories. Wind and pumped storage generation in British Columbia is replaced almost entirely with large scale conventional hydro generation. Nuclear generation in British Columbia decreases. When large hydro is built in British Columbia in the 2030 to 2040 period, there is also investment in high voltage inteconnection between British Columbia and Alberta to allow for export of electricity and dependable capacity from British Columbia to Alberta. However, with increasing electricity demand later for LNG liquifaction in British Columbia, export to Alberta declines, with Alberta then investing in nuclear generation for base load supply and gas fired combustion turbines for peak-load generation. There is also associated reduction in import of wind generation from Northwest Territories.
- This complex interplay of investment results has served to demonstrate that the overall minimum cost solution can be very sensitive to composition of options in the supply mix and timing of end use requirements. As noted with results from Scenario 5, the combination of wind and pumped storage tends to be somewhat competive with nuclear. The consequence of this is that relatively minor changes in relative costs, may result in major changes in compostion of supply mix, especially for combinations of nuclear, wind, pumped storage, peaking thermal and interconnections.
- It is observed that, for jurisdictions with large scale hydro potential at competitive cost, this option comes into the minimum cost supply mix very quickly. For the earlier scenarios, large scale hydro was the dominant additional electricity supply option for jurisdictions with remaining economically competitive conventional large scale hydro potential, including Quebec, Manitoba, Newfoundland & Labrador, and Northwest Territories. For this Scenario 8, the same result occurs for British Columbia, where hydro is added quickly for additional supply. This is a result which tends to remain relatively unchanged (robust) for different combinations of supply options for electricity supply, and for nominal variations in costs.
- It is interesting to note that, in general, additional hydro in Alberta does not become part of the minimum cost solution, even though there is extensive undeveloped hydro potential in Alberta. This is because most of the undeveloped hydro potential (except Slave River project) in Alberta is relatively expensive, and appears as being not cost competitive with other electricity supply options. This requires more detailed assessment.

Figure 128. Electricity generating capacity

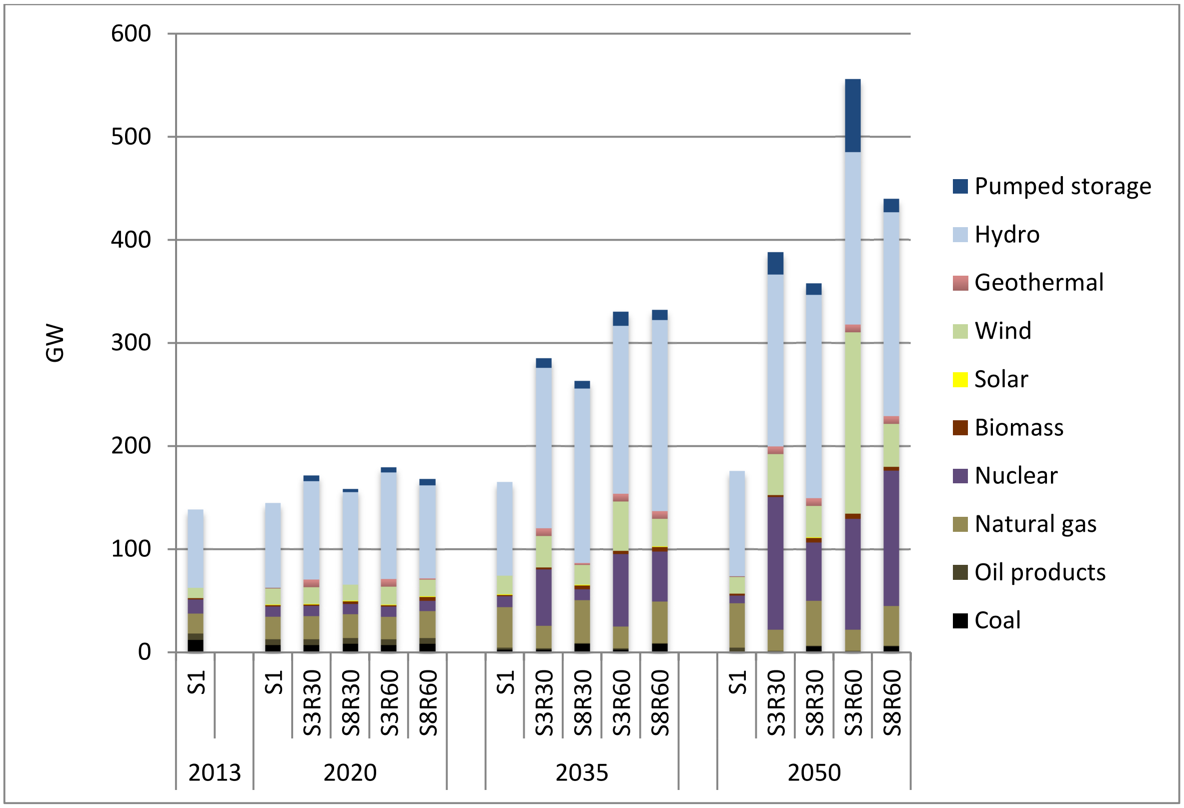


Figure 129. Electricity dependable capacity

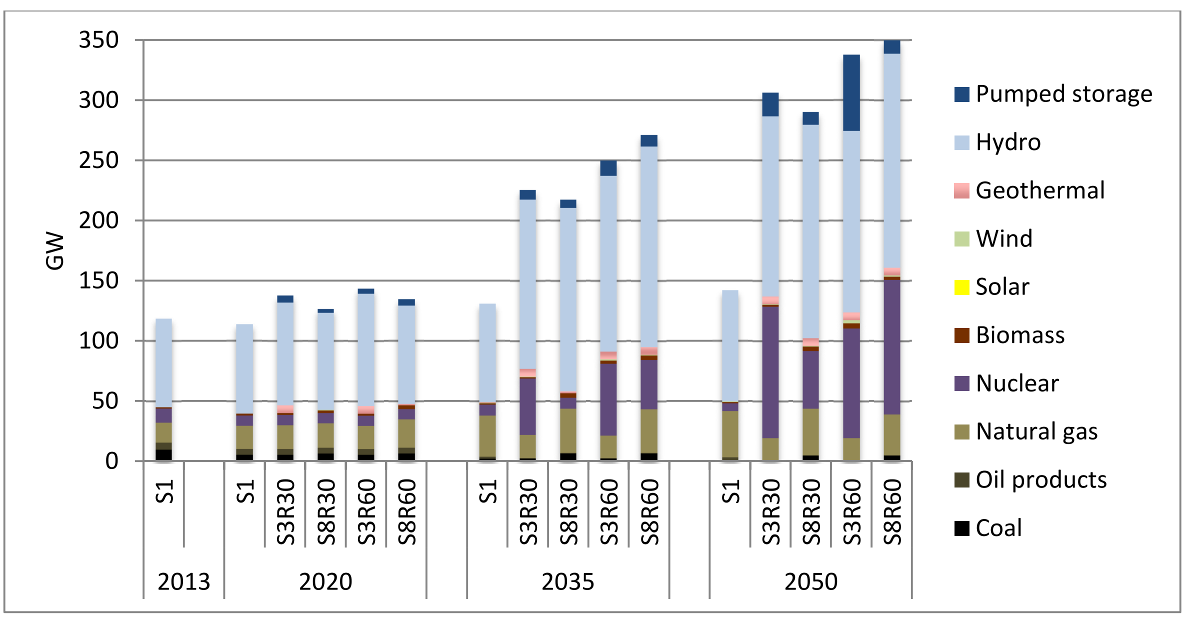
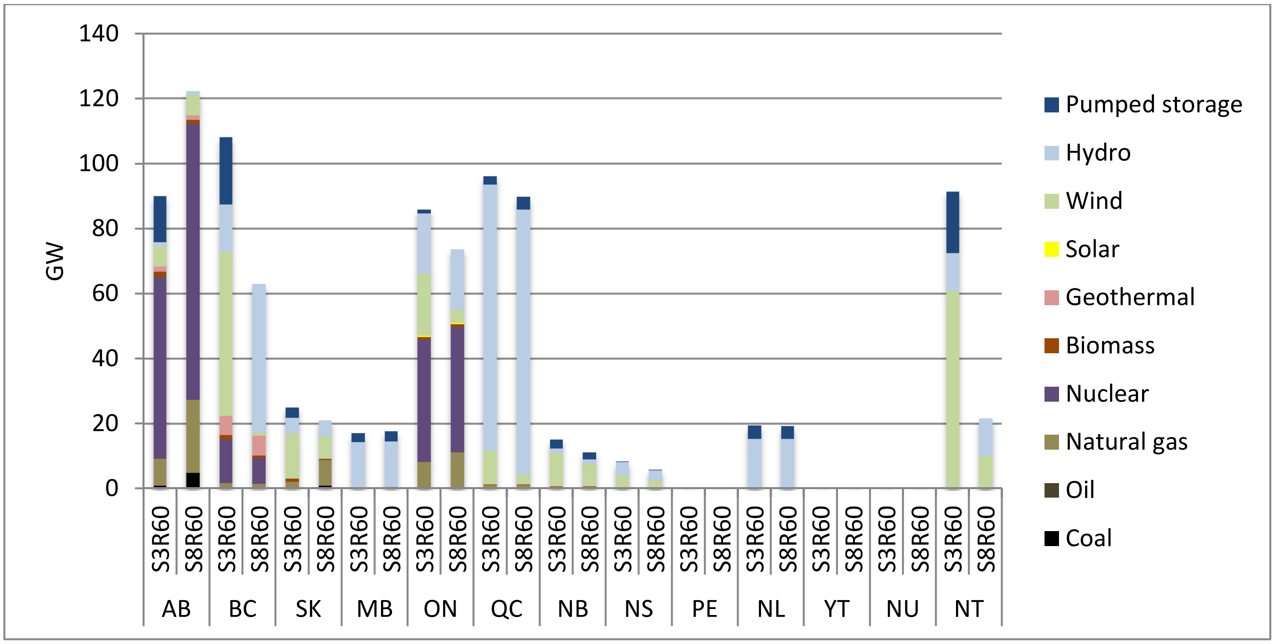


Figure 130. Electricity generating capacity by jurisdiction, 2050



5.10.6 GHG Emissions

GHG reduction results from Scenario 8 have been combined with GHG reduction results from non-combustion emissions. These results are presented on Figures 131 to 135. Results for combinations of combustion emissions (for 60% GHG reduction target) and non-combustion emissions (no reductions) are shown in aggregated form on Figure 131. The corresponding breakdown of the various categories of emissions from both combustion and non-combustion sources are shown on Figure 132. Analyses were then carried out to assess potential for reducing non-combustion emissions based on premises, as presented in Section 2.6. There was also further introduction of additional potential gain (net negative GHG emissions) with a long term strategy with harvested wood products (HWP), based on excellent work being undertaken by Canada's Forest Services Branch. This is described in Section 2.7. These combinations of results are shown on Figure 133. The results are also shown in pie chart form, including breakdown of GHG emissions without and with reductions for non-combustion emissions, on Figure 134 and Figure 135, respectively.

Key observations from detailed review of background documentation and results, are as follows:

- For this Scenario 8, analyses were carried out to also include 70% GHG reduction target for combustion emissions, which would have resulted in 128 Mt of combustion emissions in 2050 - as compared to 754 Mt for Scenario 1. Although feasible solutions were obtained, marginal costs were extremely high, with such results considered to be unrealistic. A decision was made to report, instead, on results of the 60% GHG reduction target, corresponding to 171 Mt of combustion emissions in 2050. Even with the 60% GHG reduction target, marginal costs, as computed, are still in excess of $1,000 per Mt (see Section 5.10.7).
- For non-combustion emissions, and in the absence of any corresponding GHG mitigation measues, such emissions would increase progressively from 162 Mt in 1990 to 354 Mt in 2050 (Scenario 1). Total GHG emissions in 2050 would then be 525 Mt, including results for the 60%

GHG reduction target for combustion emissions. With GHG mitigation for non-combustion emissions based on premises as presented in Section 2, computed GHG emissions in 2050 would reduce from 354 Mt to 268 Mt. In that case, total GHG emisions would be 438 Mt.

- Based on results of discussions with Forest Services Branch at NR Can on their program for long term reduction of GHG emissions with carbon retention in harvested wood products (HWP), it is considered that there is potential for annual reductions of 40 Mt of GHG emissions by 2050. With this addition, projected emissions in 2050 would be reduced to 398 Mt. Relative to the goal of 118 Mt in 2050, this still represents a shortfall of 280 Mt.

Figure 131. Emissions from combustion and non-combustion sources - S8R60

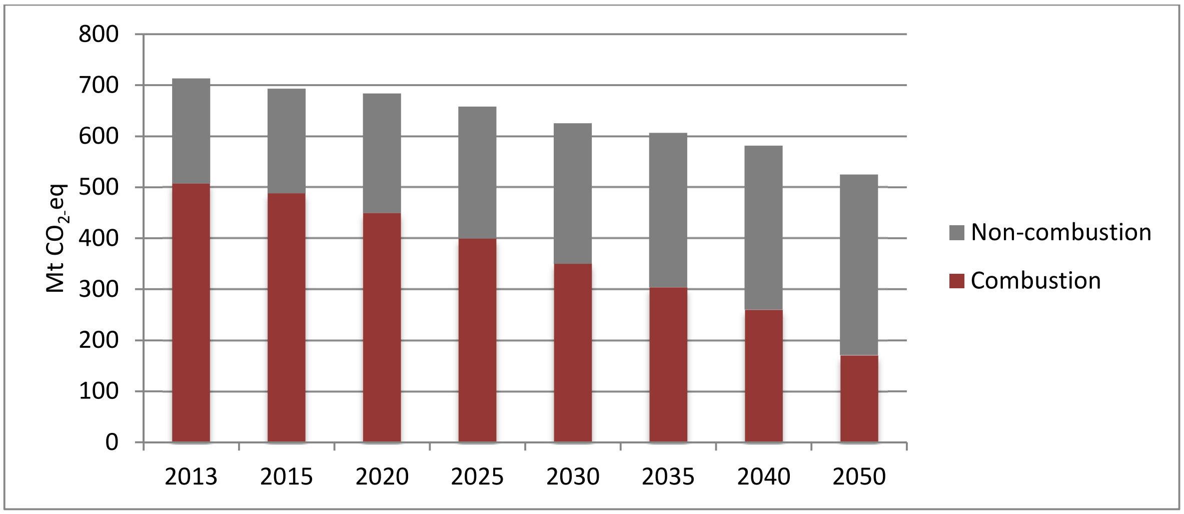


Figure 132. Breakdown of emissions - S8R60

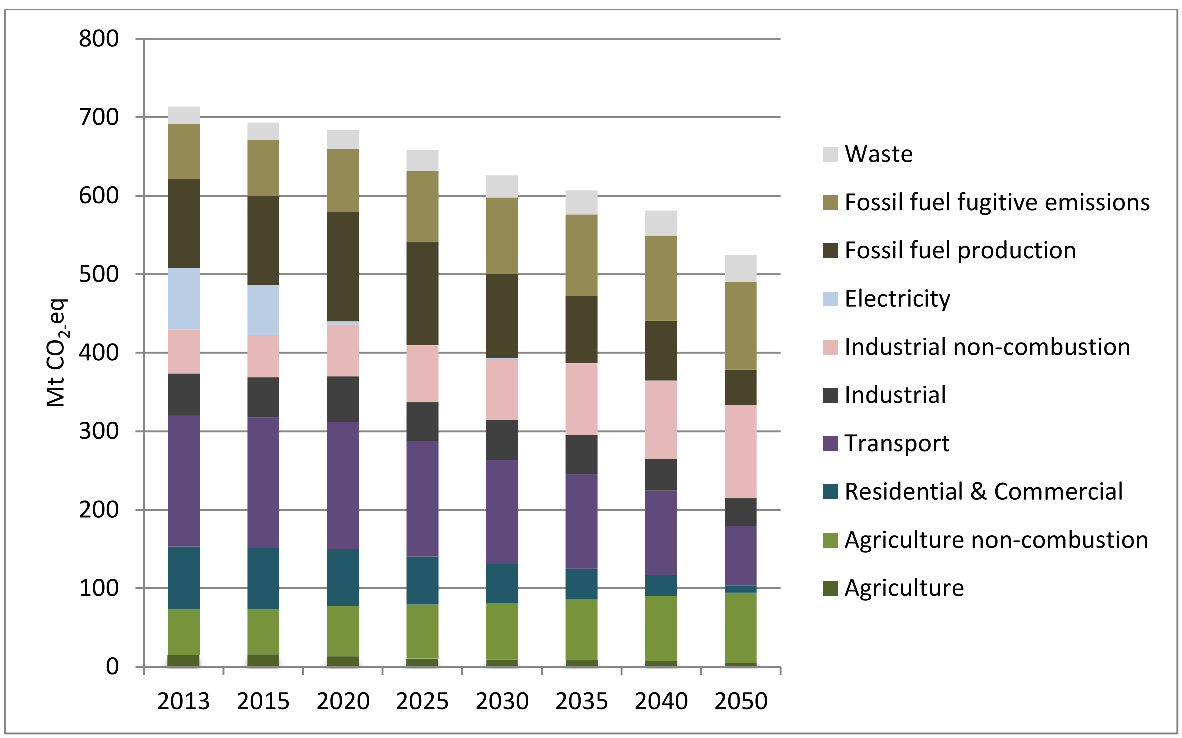


Figure 133. GHG emissions with non combustion reductions and HWP gain, 2015 - S8R60

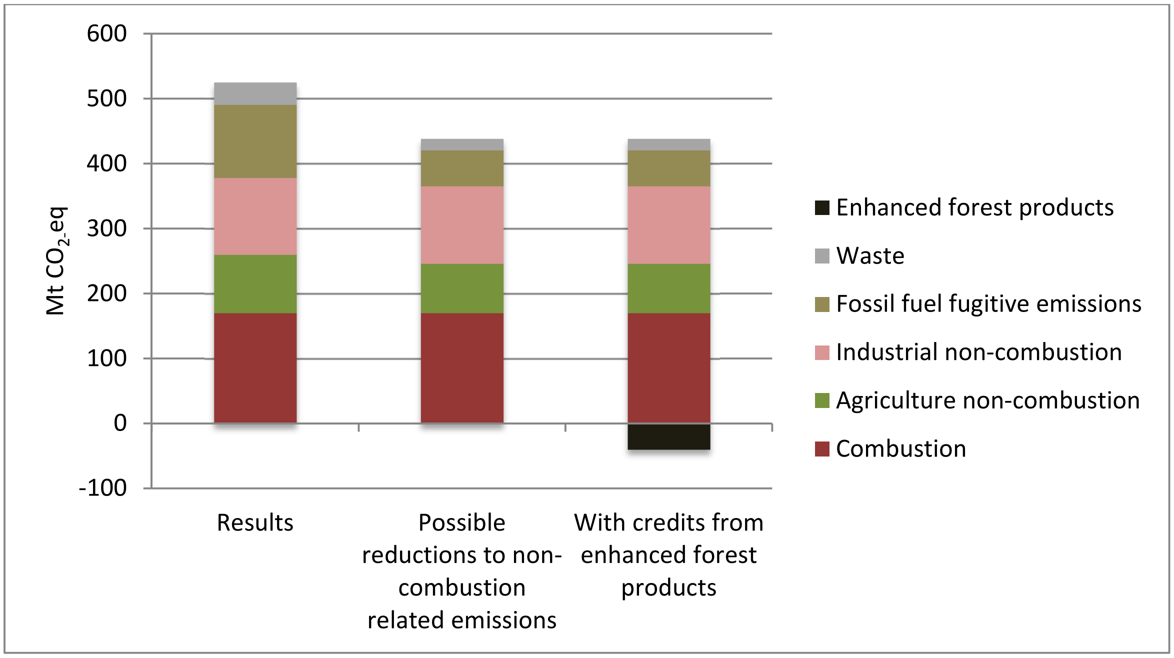


Figure 134. Emissions in 2050 (525 Mt)- No reduction in non combustion emissions - S8R60

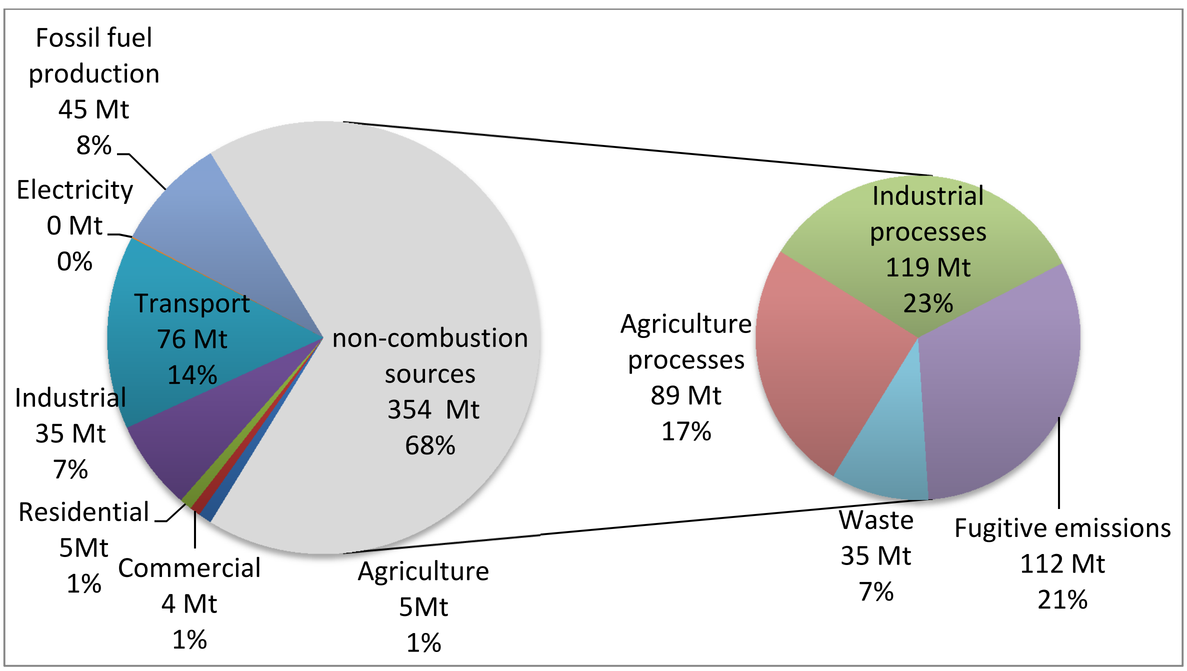
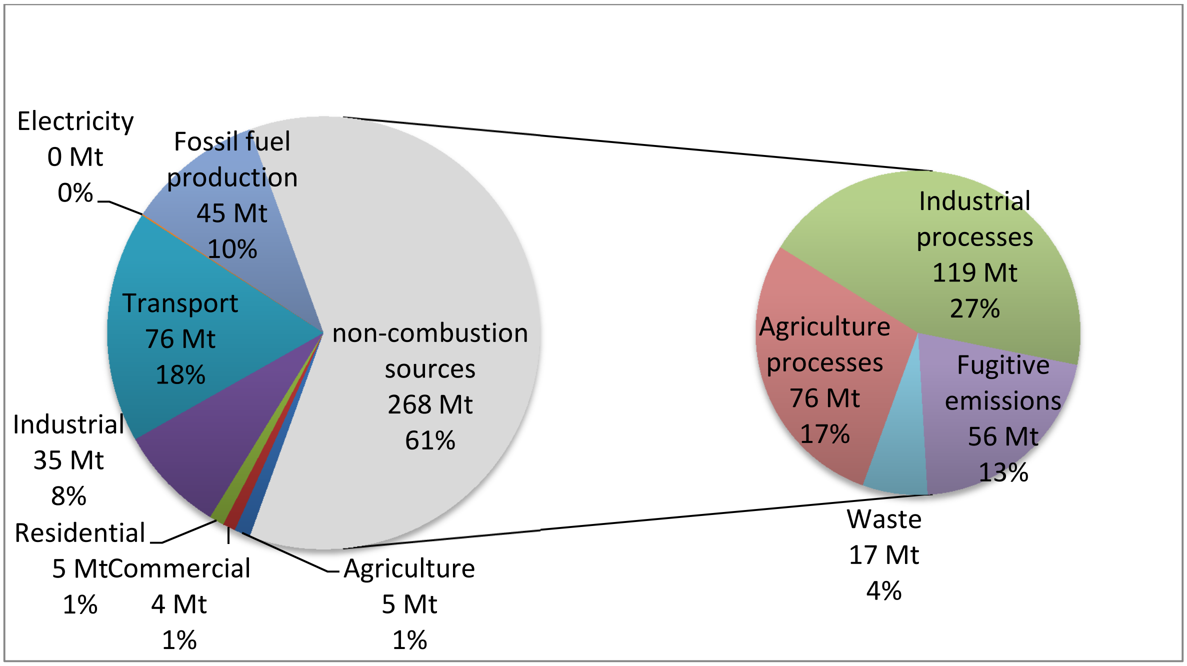


Figure 135. Emissions in 2050 (438 Mt) – With reduction in non combustion emissions - S8R60



While results of these analyses represent a significant shortfall relative to the goal of reaching 118 Mt in net GHG emissions by 2050, there are several key observations to be noted.

- These results should not, in any way, be interpreted as suggesting that the 80% GHG reduction target in 2050 is not attainable. This target is critically important for Canada. Furthermore, as emphasized by IPCC, this should be considered as an intermediate target, with a subsequent, equally important target, being achievement of net zero GHG emissions by about 2100.
- The analyses carried out in this project have been based on reconnaissance-level information. This has provided a preliminary basis for deriving minimum cost solutions for assessing the more promising transformation strategies for achieving major reductions in GHG emissions. However, there is a clear need for more in-depth evaluation of results, with improved information and more detailed analyses.
- This project has provided a unique opportunity for assessing opportunities for reaching the 80% GHG reduction goal. While some of these opportunities have been analyzed in some detail, it is also acknowledged that many opportunities have only been assessed in a very preliminary manner, while others have only been identified.
- With respect to further reductions in combustion-based GHG emissions, the principal opportunities are associated with further GHG mitigation opportunities in the transportation, industrial and fossil fuels supply sectors. In all cases, there is a need to examine opportunities for process changes; efficiency, conversion and conservation opportunities; and technology innovations.
- With respect to non-combustion emissions, this is a very important area that merits much greater in-depth assessment than was possible in this project. There are four areas which are very different, with each area requiring independent assessment. Solutions will vary, from needs for process change, conservation and technologic innovation.

- There is a very important requirement for defining strategies that contribute to net negative emissions. In this project, two such opportunities were addressed in a very preliminary manner; use of biomass for electricity generation, combined with CCUS, and a long term strategy for implementing a program for harvested wood products (HWP). However, this is an area that is promising for very substantial expansion. Amongst others, this include improved forest management, reforestation, afforestation, accelerated algae production combined with CCUS and biofuel production, and direct extraction of CO_2 from the atmosphere. These areas of investigation need to be accorded high priority.

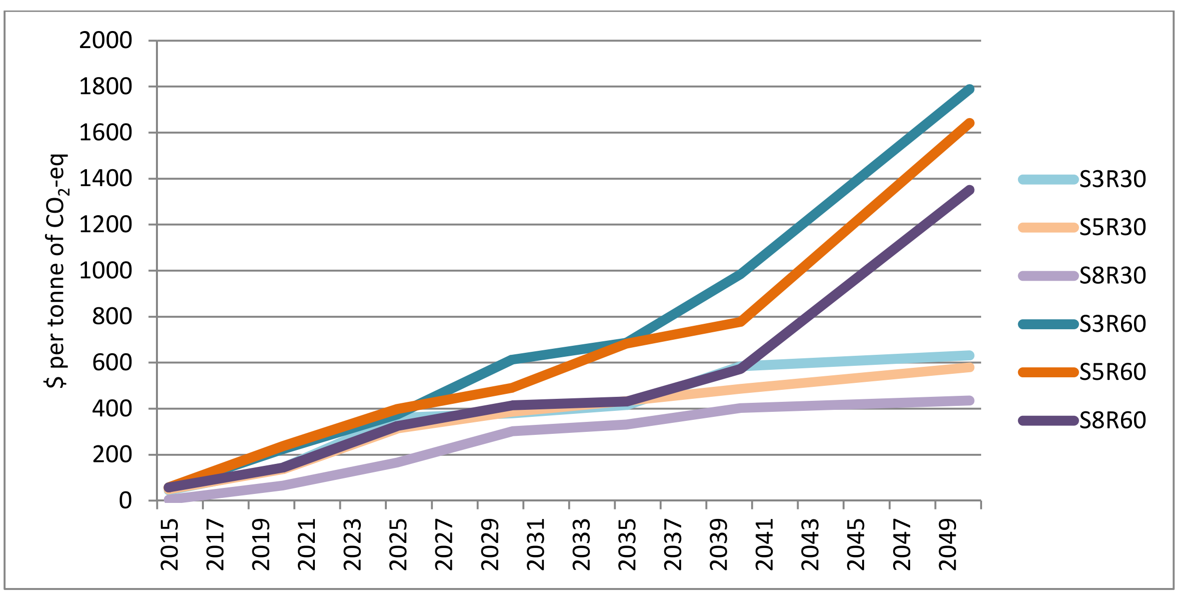
5.10.7 Cost

Marginal costs for GHG mitigation for Scenarios 3, 5 and 8 for the 30% and 60% GHG reduction targets are shown on Figure 136.

Key observations from detailed review of background documentation and results, are as follows:

- As would be normally expected, marginal costs for GHG mitigation decline as more options for reducing GHG emissions are added to the overall mix of possibilities. There are substantial reductions in marginal cost, from Scenario 3 to Scenario 5, with further reductions from Scenario 5 to Scenario 8.
- For the 60% GHG reduction target, marginal costs in 2050 are very high (almost certainly, unaccetably high), even for Scenario 8. This places special emphasis on the importance of assessing those options that enter the solution process in the 2040 to 2050 period, and exploring options and constraints that should be assessed, for contributing to more acceptable costs for GHG mitigation for the long term.

Figure 136. Marginal costs for GHG mitigation



5.10.8 Principal Observations

The principal observations from Scenario 8 may be summarized as follows:

- Scenario 8 includes consideration of options from prior scenarios, as well as three addional options: up to 30 GW of additional conventional large scale hydro generation in British Columbia; use of biomass for electricity generation, combined with CCUS; and biojet fuel.
- The option of using biomass for electricity generation, combined with CCUS and enhanced oil recovery, proved to be cost competitve for electricity supply, along with having a direct impact on producing net negative GHG emissions. Its use was ultimately limited by biomass feedstock supply constraints and cost competition with use of biofuels for heavy duty transport. However, this option certainly merits more in-depth assessment, including consideration of various technologies, as noted, and review of biomass feedstock supply limitations.
- Use of biojet fuels for air tranport did not enter minimum cost solutions for any of the variants in Scenario 8. The principal reason was as a result of biomass feedstock limitations and greater cost competitiveness with using biofuels for heavy duty transport and biomass for electricity generation, combined with CCUS.
- With the addition of several supply options for electricity supply, there were substantial changes in the overall electricty supply mix, especially in Western Canada. The entire 30 GW of conventional large scale hydro generation in British Columbia was fully absorbed into the supply mix in 10 years. It replaced nuclear, wind and pumped storage generation in British Columbia and increased export of electrical energy and dependable capacity to Alberta. The compostion of electricity supply in Alberta and Northwest Territories also changed very substantially.
- There are two important observations from analyses of these results. Firstly, with the rapid increase in electricity supply to meet major shifts towards electrification of end uses, hydro becomes the dominant early supply option in those jurisdictions which are hydro dominated and have significant remaining economically attractive undeveloped hyro potential. From analyses of results for prior scenarios, remaining hydro potential was added quickly in Quebec, Manitoba, Newfoundland & Labrador, and Northwest Territories. In Scenario 8, this same observation was again evident with rapid addition of the entire 30 GW of conventional large scale hydro in British Columbia.
- The second observation is that some mixes of electricity generation tend to be closely cost competitive, with the result that small changes in relative costs, may result in significant changes in composition of overall supply mix. This applies especially for mixes that include nuclear, wind, pumped storge, peaking thermal and interconnections.
- A review was carried out to assess results of GHG reductions with combining combustion based emissions, non combustion emissions, and stratgeies for producing net negative GHG emissions. Based on results from this project for these three areas, computed net GHG emissions in 2050 is 398 Mt. This is in comparison to 1,109 Mt GHG emissions that would be generated in 2050 with no consideration for reducing GHG emissions, and the project goal of 118 Mt.
- It was noted that the project goal of reducing GHG emissions to 118 Mt by 2050 remains as a fundamentally very important Goal; reported results from this project should not, in any way, suggest that this goal is not attainable. There are numerous additional opportunities for contributing to reducing net GHG emissions. There is a clear need to extend the various initiatives from TEFP, and to capitalize on the valued perspectives, for defining the most promising initiatives for progressively achieving the TEFP Goal.

- Costs for achieving GHG mitigation for Scenario 8, as expected, are significantly lower than for Scenarios 3 and 5. However, marginal costs for the 60% GHG reduction scenario are still high, especially after 2040. There is a need for more in-depth assessment to explore options for reducing such costs to more acceptable levels for the long term.

5.11 Scenarios 1a, 3a and 8a; Reduced Fossil Fuels

For Scenarios 1 to 8, production of fossil fuels to 2050 was defined, based on projections to 2035 from Canada's National Energy Board and as extrapolated to 2050 (see Section 5.1). For Scenarios 1a, 3a and 8a, premises concerning future production and use of fossil fuels in Canada were changed. The dominant change was based on the premise that there would be an overall and progressive reduction in use of fossil fuels around the world, in response to the global climate change challenge. As Canada progressively reduced its dependence on fossil fuels, the rest of World would be doing the same, and correspondingly, the export market for fossil fuels from Canada would decline in direct proportion.

Results for the three reduced fossil fuel scenarios were for direct comparison with results of Scenarios 1, 3 and 8 (see also Section 5.2 and Table 55).

For Scenarios 1a, 3a and 8a, there was another significant difference in approach. In Scenarios 1 to 8, production projections were prescribed. The impact of this was that, as use of fossil fuels in Canada declined, there would be a corresponding increase in export in such commodities. The value of this increased export was netted out in the calculation of overall minimum cost. For Scenarios 1a, 3a and 8a, the NATEM model was modified to provide complete flexibility in selecting production, use, and export of the respective fossil fuel commodities, as part of the process for evaluating overall system-wide net minimum cost. This was done to also provide valued insight into the economic merits of expanding production of fossil fuels for increased export to the global market.

In providing this enhanced capability in the NATEM Canada model, it was also important to define appropriate limits on exports of energy commodities. The upper limit was as defined in the modified National Energy Board production projection for the high fossil fuel production scenarios. The lower limit was selected on the basis of reducing exports in proportion to reduced use of fossil fuels in Canada, as defined from results of Scenario 3 for the 60% GHG reduction target. This was the most extreme reduction target for Scenario 3. This selection was considered to represent an appropriately large range for potential export of fossil fuels.

There was an additional initiative for Scenarios 1a, 3a and 8a. Because of high marginal costs for GHG mitigation, in general, an assessment was carried out to assess potential reductions in demand arising from such high marginal costs. There is a feature in the NATEM Canada model which includes direct representation of demand elasticity, which reflects the relationship between reductions in demand for energy related services (and associated GHG emissions) as a direct function of increasing costs for such services. Demand elasticity values are available from internationals sources, including IEA ETSAP.

As with prior scenarios, minimum cost solutions were obtained for the same 30% and 60% reduction targets for combustion emissions, relative to 1990. However, as there were additional options included in Scenario 8a, the NATEM Canada model was also used to derive minimum cost solutions for 70% reduction in combustion emissions.

The same reduction profiles for combustion emissions, from 2013 to 2050, were retained for Scenarios 3a and 8a (Figure 56).

As with analysis of results of Scenario 8, there was an initiative to combine analyses of reduced GHG emissions from combustion sources with reduced emissions from non-combustion sources. This was further extended to include early assessments for net GHG reductions, based on carbon retention with harvest wood products (HWP).

5.11.1 Export and Import of Fossil Fuels

Results showing changes in export of fossil fuels for Scenarios 1a, 3a and 8a, are shown on Figure 137 and Figure 138. Results for Scenario 1a and 3a, with comparison to results for Scenario 1 and 3, are shown on Figure 137. Results for Scenario 8a, with comparison to results of Scenario 8 for both 30% and 60% GHG reduction targets, are shown on Figure 138.

Key observations from detailed review of background documentation and results, are as follows:

- There is a significant reduction in export of fossil fuels for Scenario 3a relative to Scenario 3. For this Scenario, exports of all fossil fuels tend to be at their lower bound by 2050, as defined above. This reflects that, for this case, export values for fossil fuels are lower than the incremental cost for producing such fuels, with the result that the optimizing process leads to minimizing production of fossil fuels. It is important, however, to note that this process occurs slowly, as exports in the earlier years (2020 and 2030), are not at their lower bound.
- However, it is important to note that export of fossil fuels, especially natural gas, does not reach lower limits to the same extent. The most significant difference is that there is more export of natural gas, especially from the West Coast, which is enhanced by lower cost of electricity production in British Columbia, from addition of 30 GW of conventional large scale hydro, some of which is available for liquefying natural gas for export.
- It is interesting to note, that, even for Scenario 1a, some fossil fuel exports (especially, coal) are lower than for Scenario 1 (no GHG reduction constraints). This reflects that future value of such exports may be lower than future system-wide incremental production costs for such commodities.

Figure 137. Energy exports- S1a & 3a

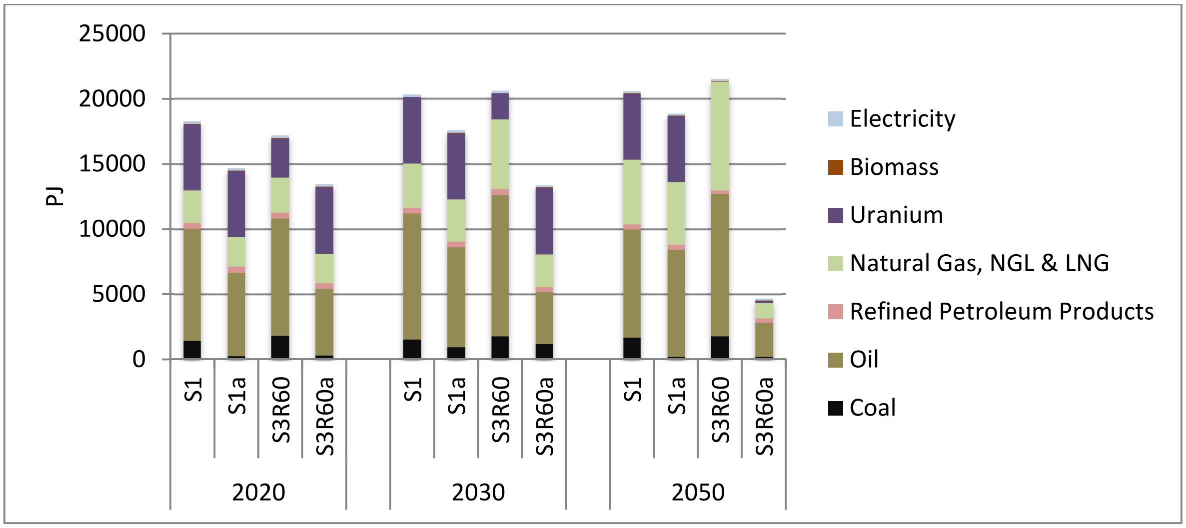
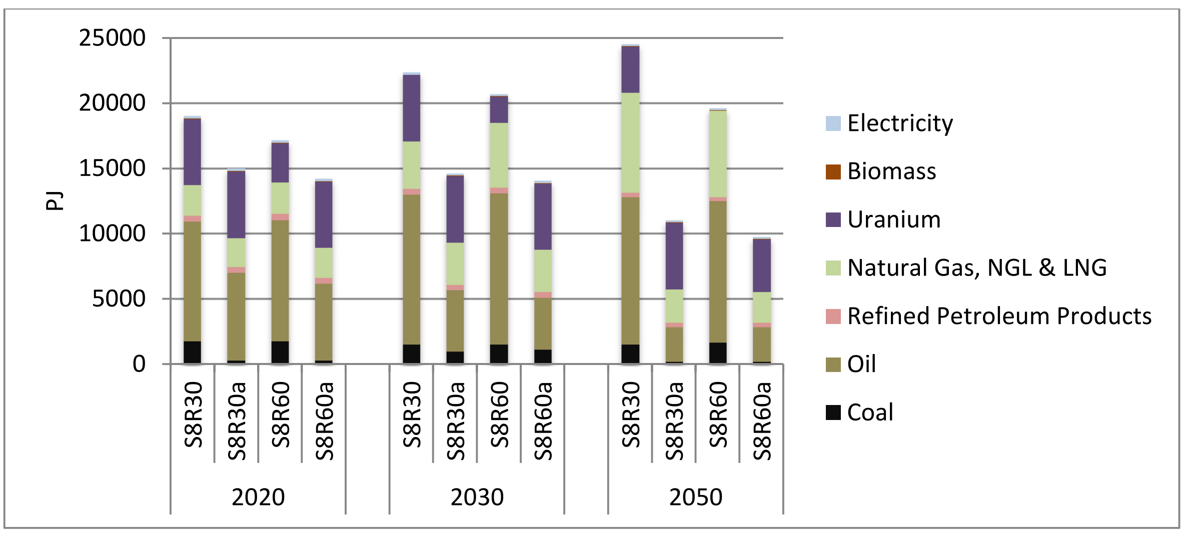


Figure 138. Energy exports - S8a



Results for energy imports are shown on Figure 139 and Figure 140. Results for Scenarios 1a and 3a, with comparison to results for Scenario 1 and 3, are shown on Figure 139. Results for Scenario 8a, with comparison to results for Scenario 8, for the 30% and 60% GHG reduction targets, are shown on Figure 140.

Key observations from detailed review of background documentation and results, are as follows:

- The most significant observation is that imports of fossil fuels are lower in all scenarios, in comparison to results of the respective complementing scenarios. However, trade in fossil fuels continues to be important. This includes oil imports into Eastern Canada, which is dominated by demands in Newfoundland & Labrador.
- Computed imports for Scenario 8a are generally lower that for Scenario 3, and tend to also decline with increasing GHG mitgation targets.

Figure 139. Energy imports - S1a & S3a

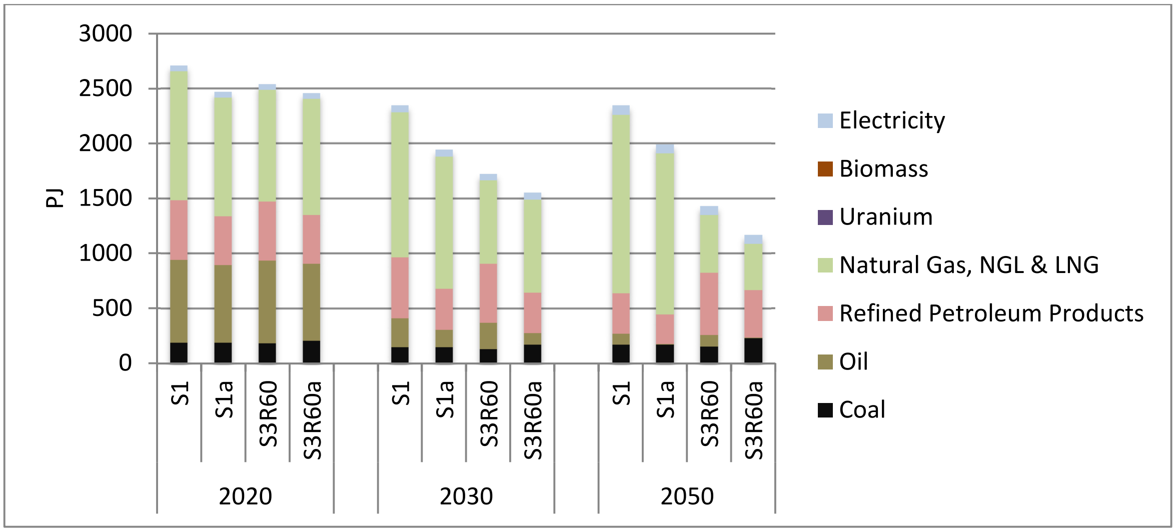
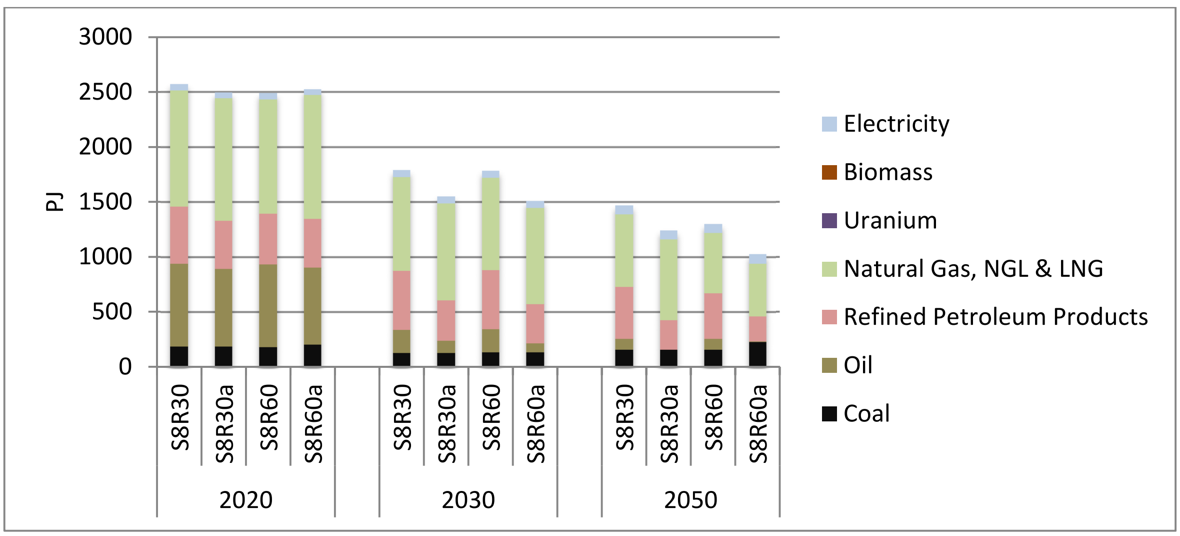


Figure 140. Energy imports - S8a



5.11.2 Final Energy Consumption

Breakdowns of energy consumption for Scenarios 1, 3, 3a, 8 and 8a, are shown on Figure 141. The separation of final energy consumption for meeting end uses is shown on Figure 142.

Key observations from detailed review of background documentation and results, are as follows:

- There are major shifts in final energy consumption with imposition of GHG reduction targets. For Scenario 1, where there are no GHG reduction requirements, energy consumption increases progressively, but with the balance between fossil fuels, electricity and biomass & biofuels, remaining essentially unchanged at 71%, 24% and 4%, respectively. For Scenario 8a, the mix for final energy consumption is very different, with the mix being 28%, 55% and 16%, respectively. With even higher GHG reduction targets, this shift would continue even futher. Even with these ratios, this means that there will be a four-fold increase in use of biomass & biofuels and up to three-fold increase in electricity for final energy consumption by 2050.

- An important observation, is that there is little change in overall composition of energy type for meeting end uses for the 60% GHG reduction target in any specific year. However, as noted above, there are major progressive shifts over time.
- With Scenario 8a, and with reduced demand for fossil fuels, especially for export, there is corresponding elimination of need for hydrogen, which was required in prior scenarios (including Scenario 8) for the transportation sector.

Figure 141. Final energy consumption by energy type

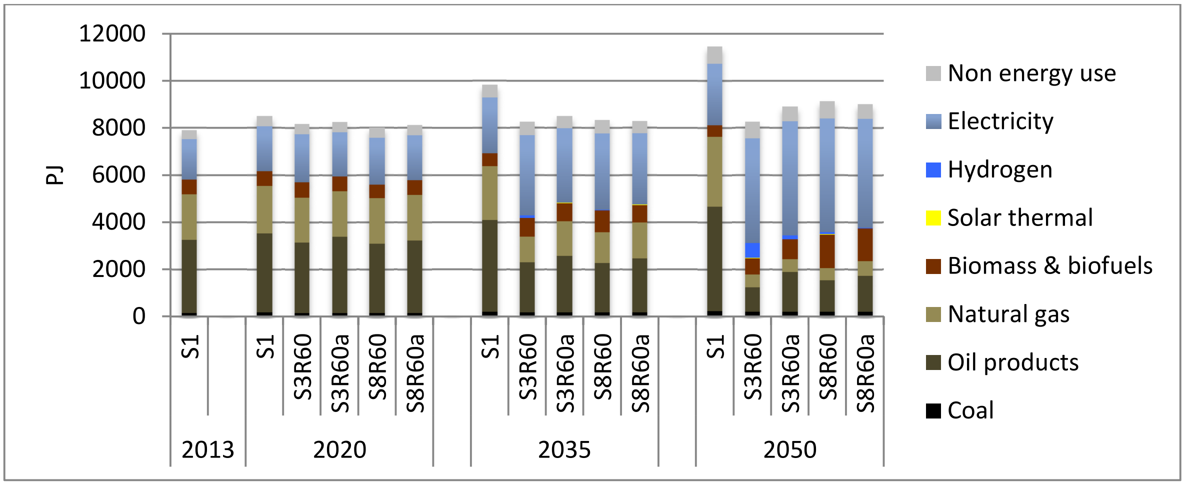
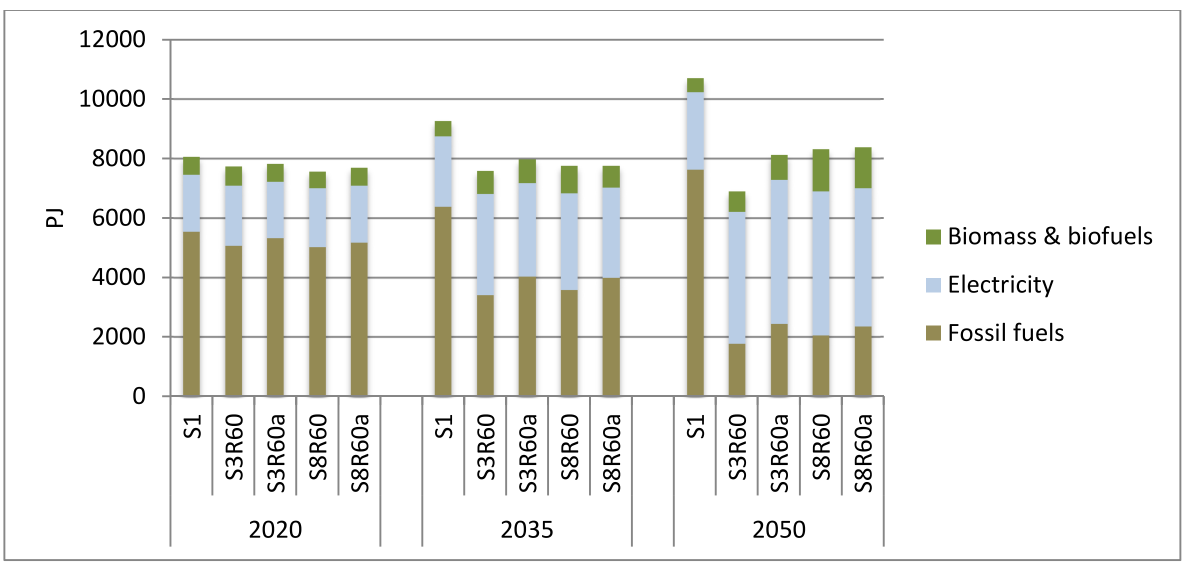


Figure 142. Final energy consumption



5.11.3 Primary Energy Production

Results of analyses of primary energy production are shown on Figure 143 to 150. Total primary energy production for Scenarios 1a and 3a, with comparison to results of Scenarios 1 and 3 are shown on Figure 143. Total primary energy production for Scenario 8a, with comparisons to Scenario 8 for the 30% and 60% GHG reduction targets, are shown on Figure 144. Corresponding energy production results for the petroleum, natural gas and coal sectors are shown on Figure 145 and Figure 146 for petroleum, on Figure 147 and Figure 148 for natural gas, and on Figure 149 and Figure 150 for coal.

Key observations from detailed review of background documentation and results, are as follows:

- There are major reductions in overall production of fossil fuels, as well as for each of the three classes of fossil fuels. This is demonstrated by comparing results of Scenarios 1, 3 and 8, with Scenarios 1a, 3a and 8a. This reduction is dominated by reductions in export of fossil fuels, as noted above. There are only minor changes for meeting domestic demands. With the greater flexibility in choosing between increasing export, with its associated development costs, and not increasing export, the minimum cost decision process leads, in general, to not increasing export.
- There are, however, significant exceptions. For Scenario 8a, there is a significant increase in production, and associated export, of fossil fuels, relative to results for Scenario 3a. The increased export is for both natural gas and coal, occurs coincidentally with development of additional 30 GW of conventional large scale hydro in British Columbia. On closer examination, this increased export is from the West Coast, and includes greater use of lower cost and GHG emissions free hydro energy for liquefaction.

Figure 143. Primary energy production - S1a & S3a

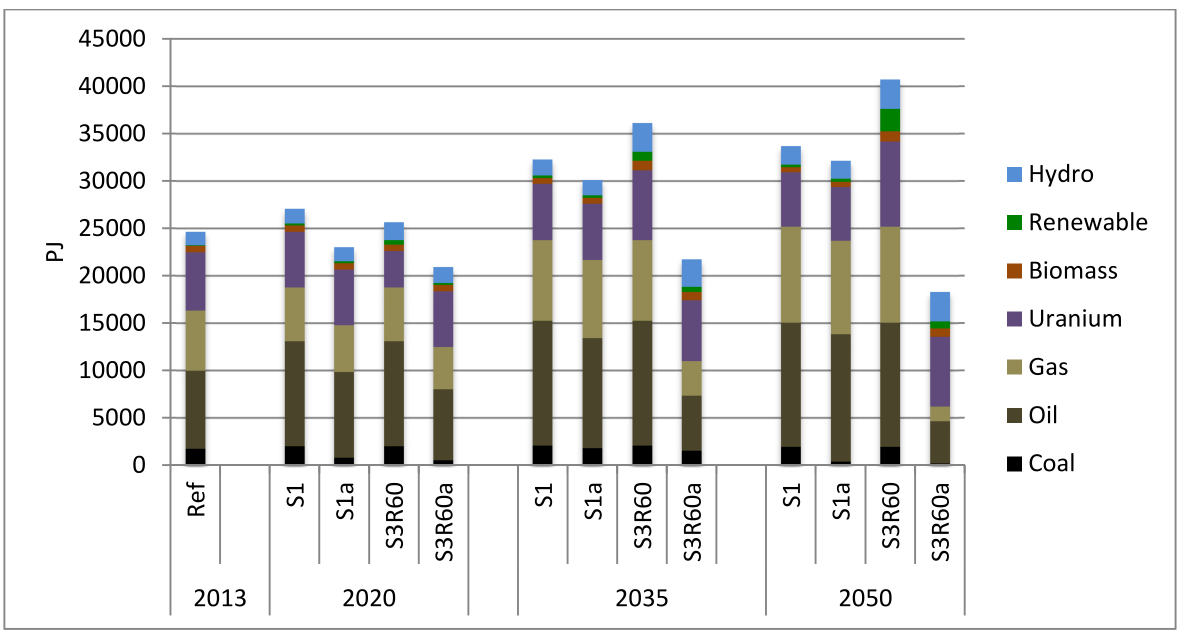


Figure 144. Primary energy production - S8a

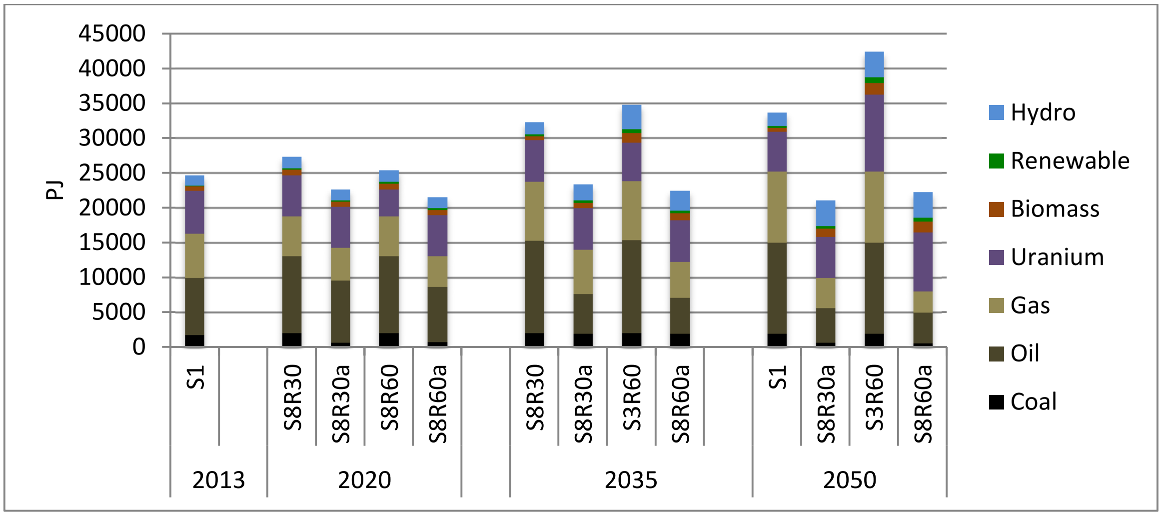


Figure 145. Primary production of petroleum - S1a & S3a

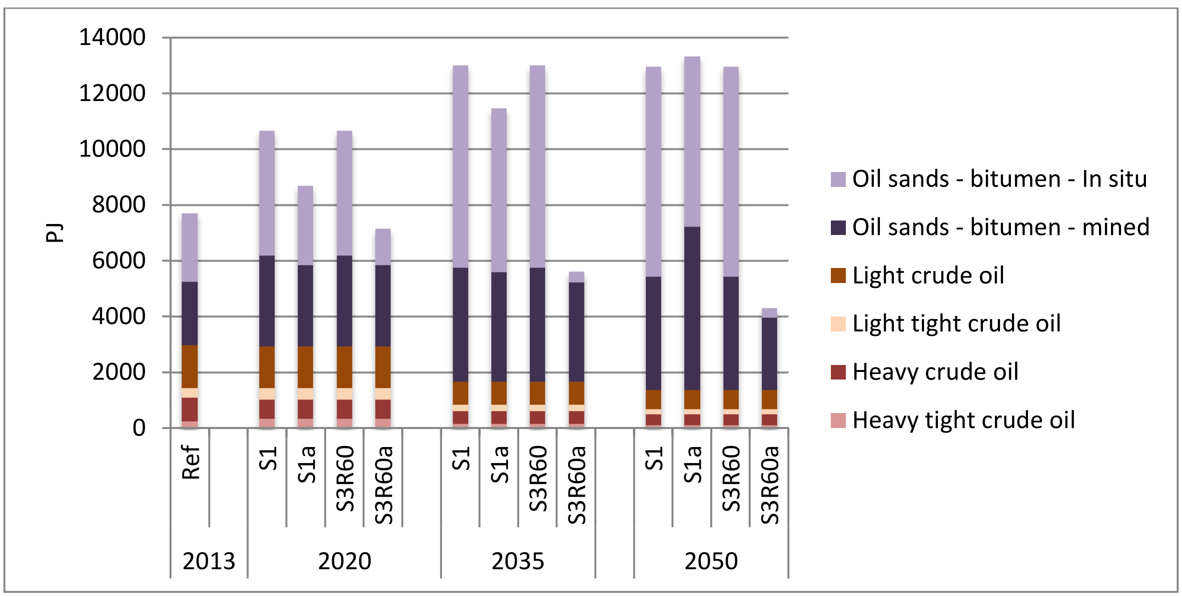


Figure 146. Primary production of petroleum - S8a

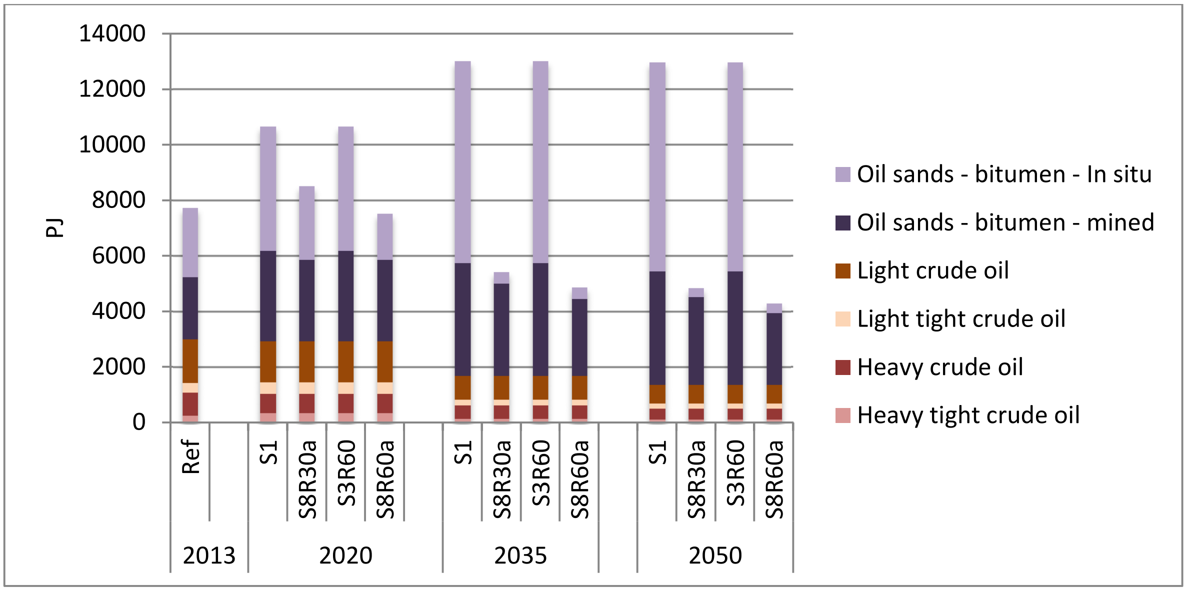


Figure 147. Primary production of natural gas - S1a & S3a

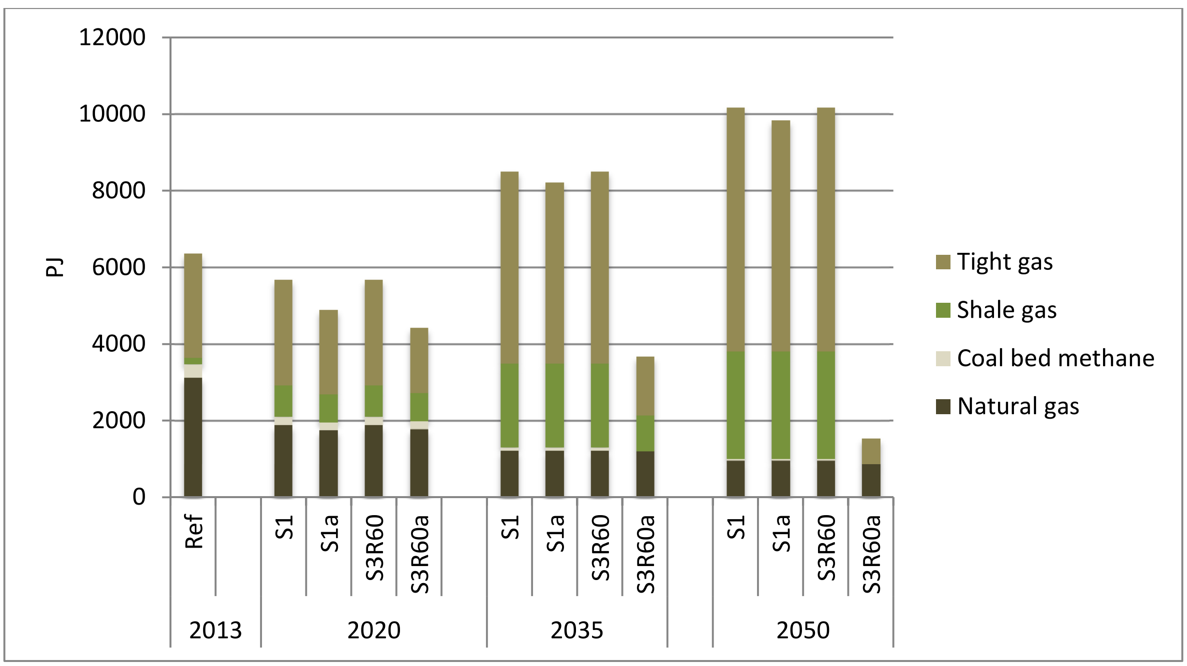


Figure 148. Primary production of natural gas - S8a

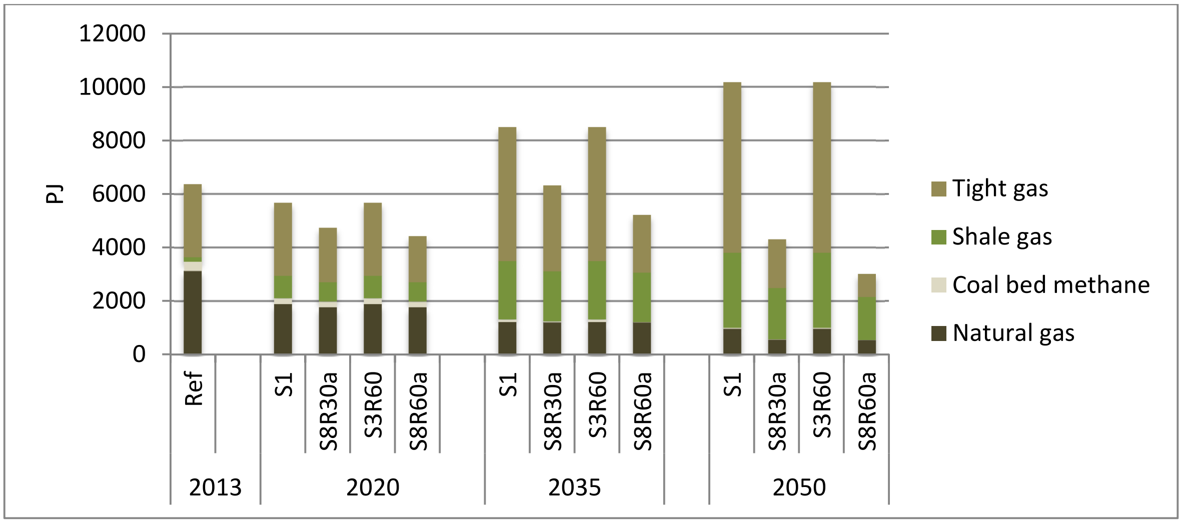


Figure 149. Primary production of coal - S1a & S3a

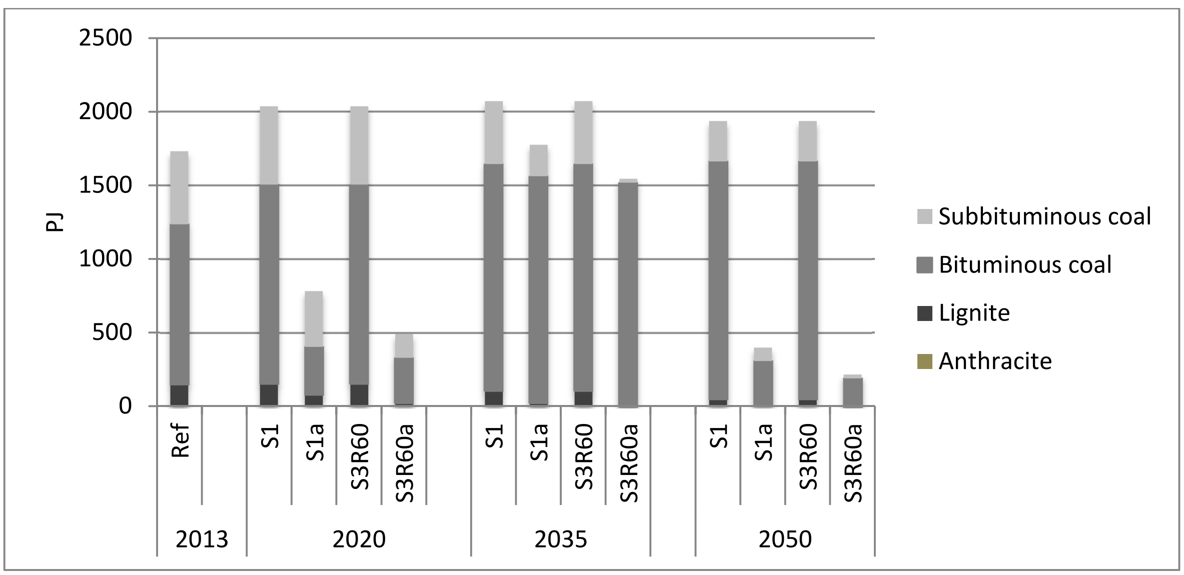
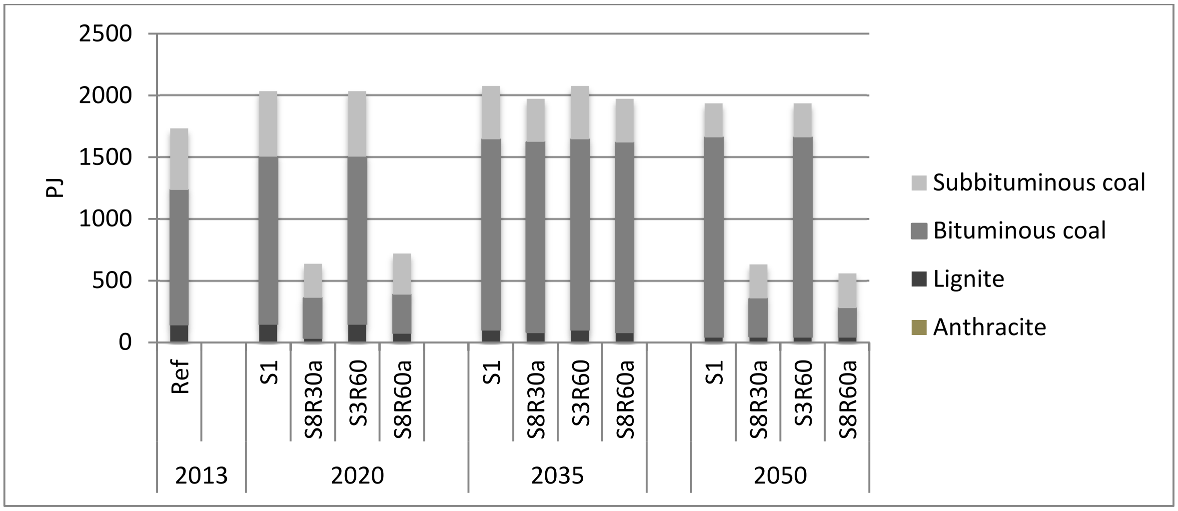


Figure 150. Primary production of coal - S8a



5.11.4 Electricity

Results showing changes in electricity generation between Scenarios 1, 3 and 8, and Scenarios 3a and 8a, are shown on Figure 151, Figure 152 and Figure 153. Total generating capacity and corresponding dependable capacity values are shown on Figure 151 and Figure 152, respectively. Total generating capacity in 2050 for each of the respective jurisdictions is shown on Figure 153.

Key observations from detailed review of background documentation and results, are as follows:

- The dominant changes between Scenarios 3a and 3, and between Scenario 8a and 8, are associated with substantial reductions in both electricity generating capacity and dependable capacity. This reduction is dominantly for reduced electricity requirements for fossil fuels supply (such as use of electricity to replace natural gas for steam production, including in-situ production in the oil sands). In comparing results of Scenario 3a with Scenario 3, there is a reduction from 555 GW to 336 GW. In comparing results of Scenario 8a with Scenario 8, there is a reduction from 440 GW to 339 GW. The reduction in dependable capacity is from 351 GW to 274 GW; 23% reduction.
- These changes occur dominantly in British Columbia, Alberta and Saskatchewan. In British Columbia, the nuclear and geothermal capacity requirement in Scenario 8 is eliminated, with system supply being virtually completely hydro dominated in Scenario 8a. In Alberta, the dominant change is reduced need for nuclear generation, from 85 GW to 21 GW. In Saskatchewan, the need for generating capacity is reduced by 50%, with less nuclear and virtually no wind generation.
- In the results, the dominant changes in overall composition of electricity supply is less nuclear generation and less pumped storage generation. However, as noted in analyses of prior scenarios, there is a strong possibility that the computed pumped storage generation values would be largely replaced with incremental hydro and that some of the nuclear generation may also be replaced with combinations of wind, incremental hydro, peaking thermal and interconnections. There is a clear need to add additional capabilies to the NATEM Canada model, in order to obtain improved overall results.

Figure 151. Electricity generating capacity

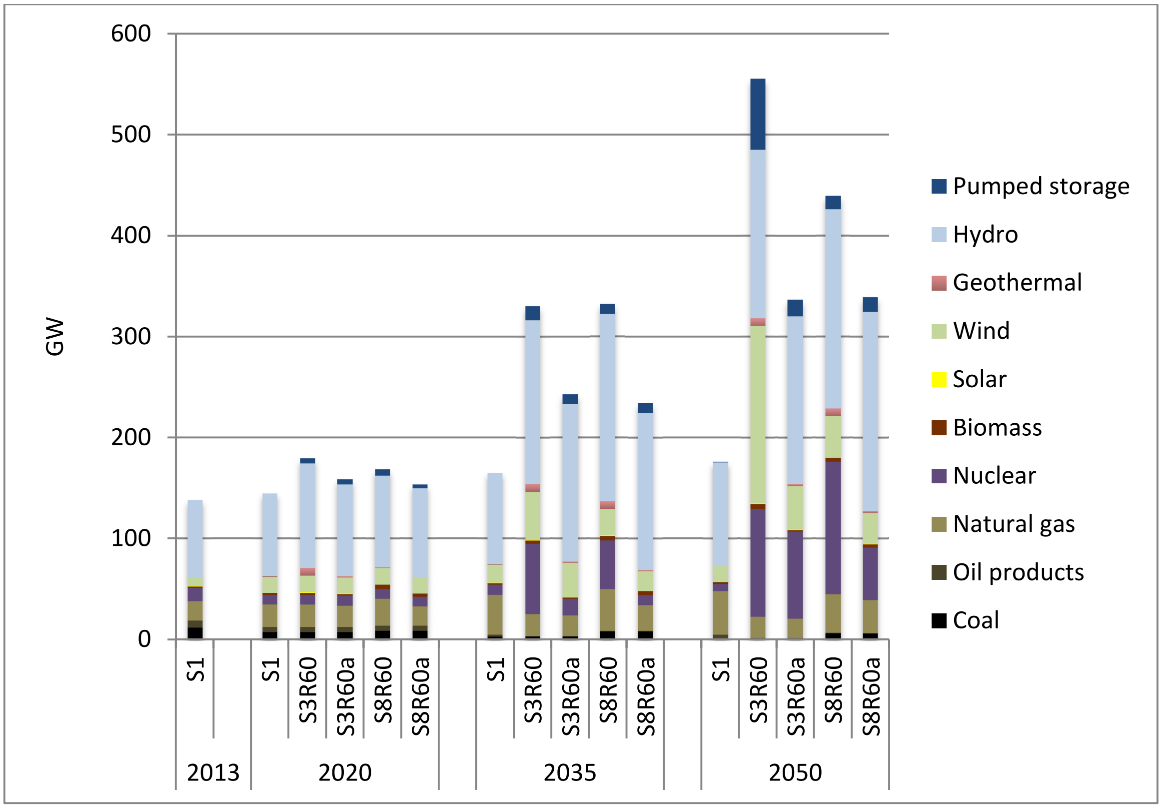


Figure 152. Electricity dependable capacity

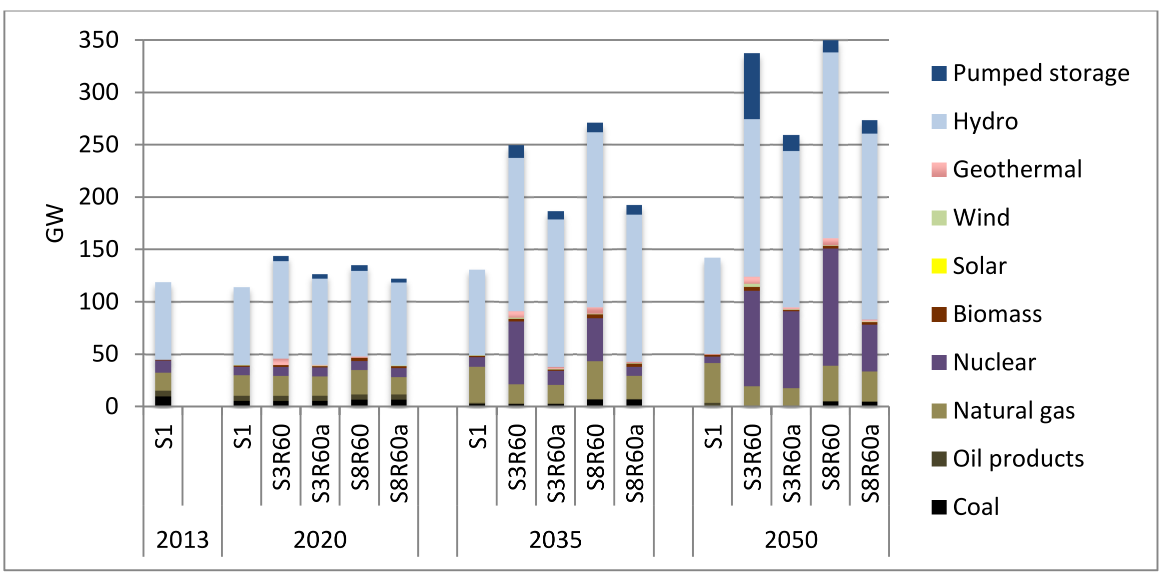
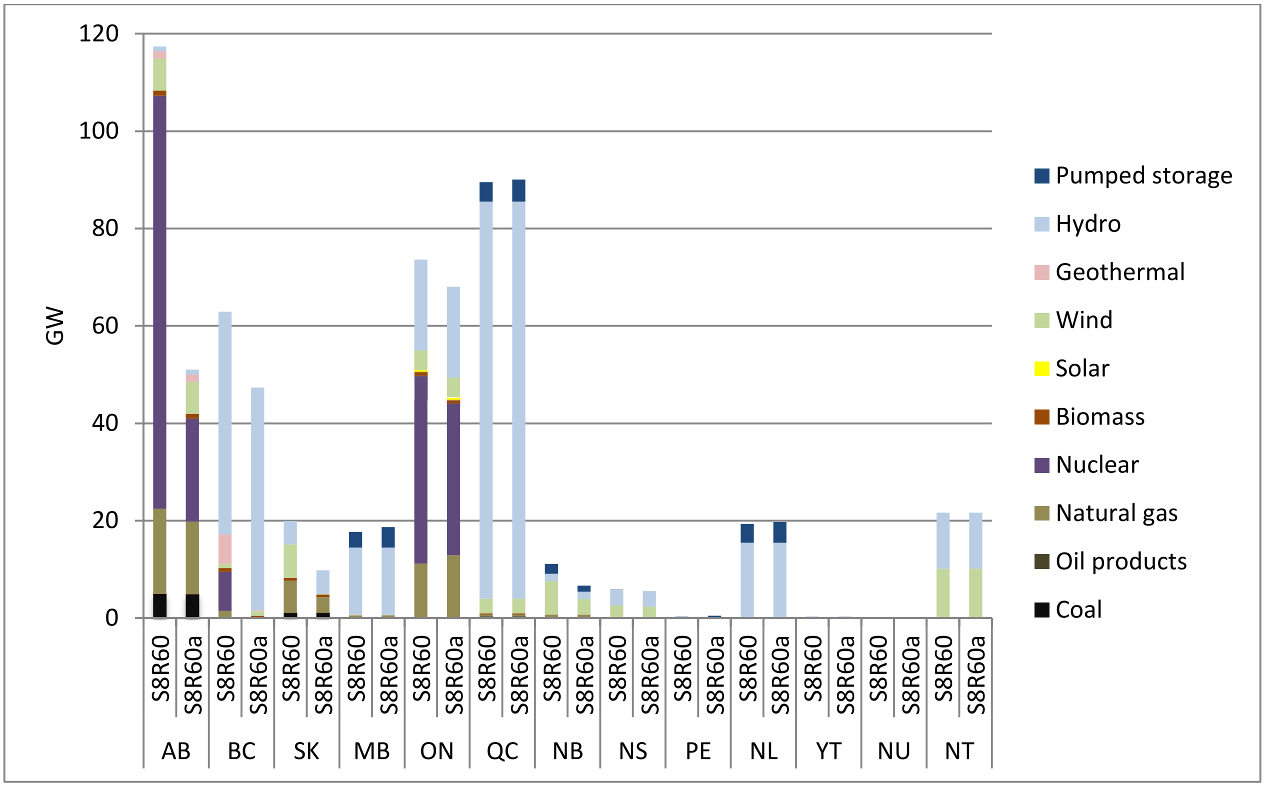


Figure 153. Electricity generating capacity by jurisdiction, 2050



Additional analyses were carried out to obtain improved understanding of the interplay between British Columbia and Alberta following development of 30 GW of additional hydro generation in British Columbia, and the need for very significant additional electricity production for liquefaction of natural gas for export from the West Coast. Results of these additional analyses are shown on Figure 154 and Figure 155. Results of electricity transfers from British Columbia to Alberta for Scenarios 3, 3a, 8, and 8a for the 60% GHG reduction target are shown on Figure 154. Electricity requirements for LNG liquefaction are shown on Figure 155.

Key observations from detailed review of background documentation and results, are as follows:

- From examination of results for Scenario 8, there are very substantial transfers of electricity from British Columbia to Alberta in the early years. However, as electricity demand for LNG liquefaction increases in later years, it is more cost effective to shift electricity production in British Columbia towards this use, and reduce exports to Alberta, correspondingly.
- From examination of results for Scenario 8a, it is especially significant that there is still need for LNG liquefaction for this Scenario, albeit at a lower level. This indicates that, even for this Scenario, it is cost effective to continue production and export of natural gas.
- Results for Scenarios 3 and 3a are very different. These scenarios do not include any additional conventional large scale hydro generation in British Columbia. For Scenario 3a, there is essentially no electricity export to Alberta. For Scenario 3, there is a small amount of export, but only in the early years. With respect to LNG liquefaction, results for Scenario 3 show very substantial electricity demand for serving this need. On the other hand, for Scenario 3a, there is no electricity for LNG liquefaction. This suggests that the opportunity for export of natural gas

from the West Coast may be directly dependent on availability of additional large scale conventional hydro generation in British Columbia, with its lower overall cost for electricity supply.

Figure 154. Electricity transfers from British Columbia to Alberta

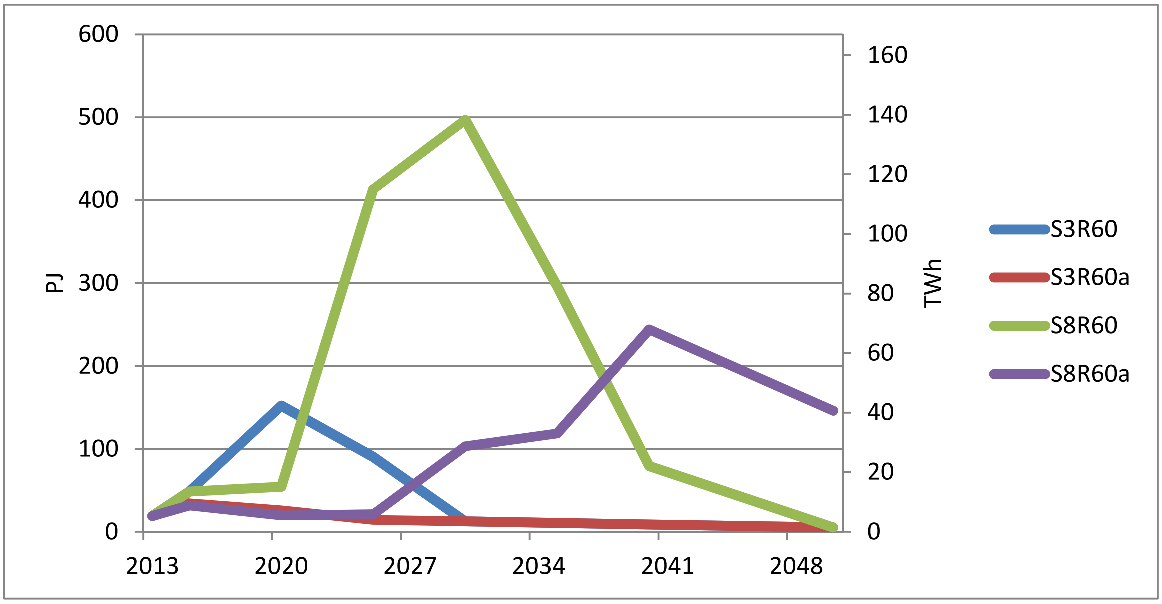
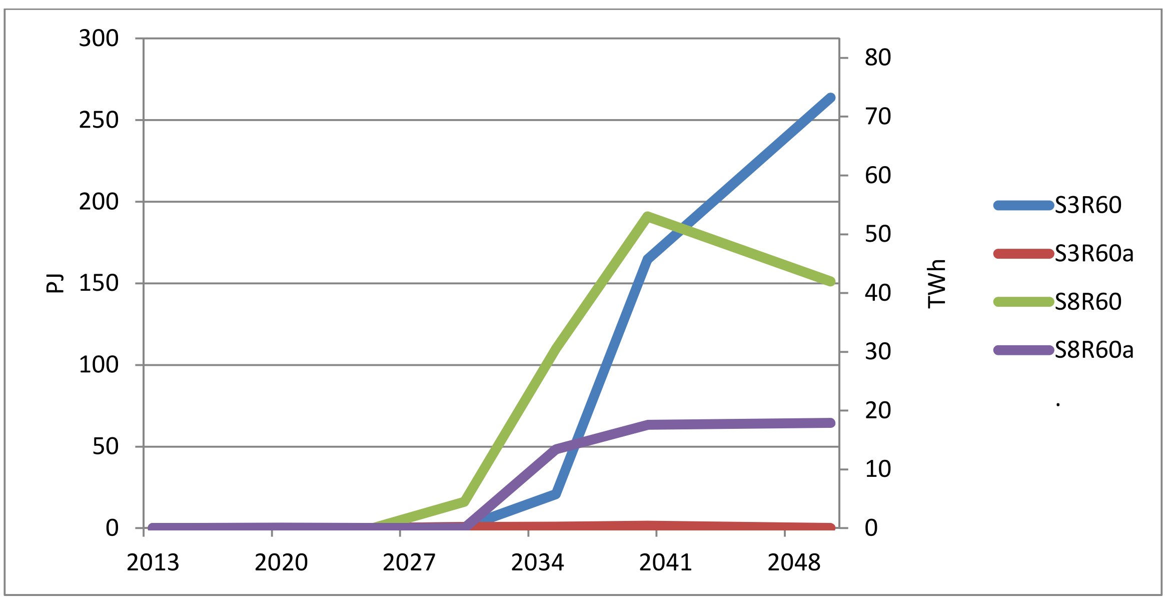


Figure 155. Electricty demand for LNG liquefaction



5.11.5 Combustion Based GHG Emissions

Results for combustion based emissions for the 60% GHG reduction target for Scenarios 1, 8 and 8a are shown on Figure 156. As the transportation sector is the sector with the largest GHG emissions, this was analyzed in more detail, with results shown on Figure 157. Additional analyses were carried out for the 70% GHG reduction target. Results of these analyse for total combustion emissions, and for the transportation sector, specifically, are shown on Figure 158 and Figure 159, respectively.

Key observations from detailed review of background documentation and results, are as follows:

- It may be observed that there is reduction of GHG emissions for fossil fuels production, with the result that the transportation sector becomes even more dominant with respect to production of GHG emissions. The increased emissions in the transportation sector are dominated by increased use of diesel fuel and gasoline and reduced use of electricty.
- With further increase to 70% reduction in GHG emissions, the dominant reductions are in the transportation sector and for production of fossil fuels. The further reduction in the transportation sector includes reduced use of diesel fuel and gasoline and increased use of electricity. The use of hydrogen again enters the minmum cost solution, primarily as biomass feedstock supply is a constraint limiting availability of biofuels for heavy duty transport in the transportation sector.

Figure 156. Combustion Emissions - S1, S8 & S8a

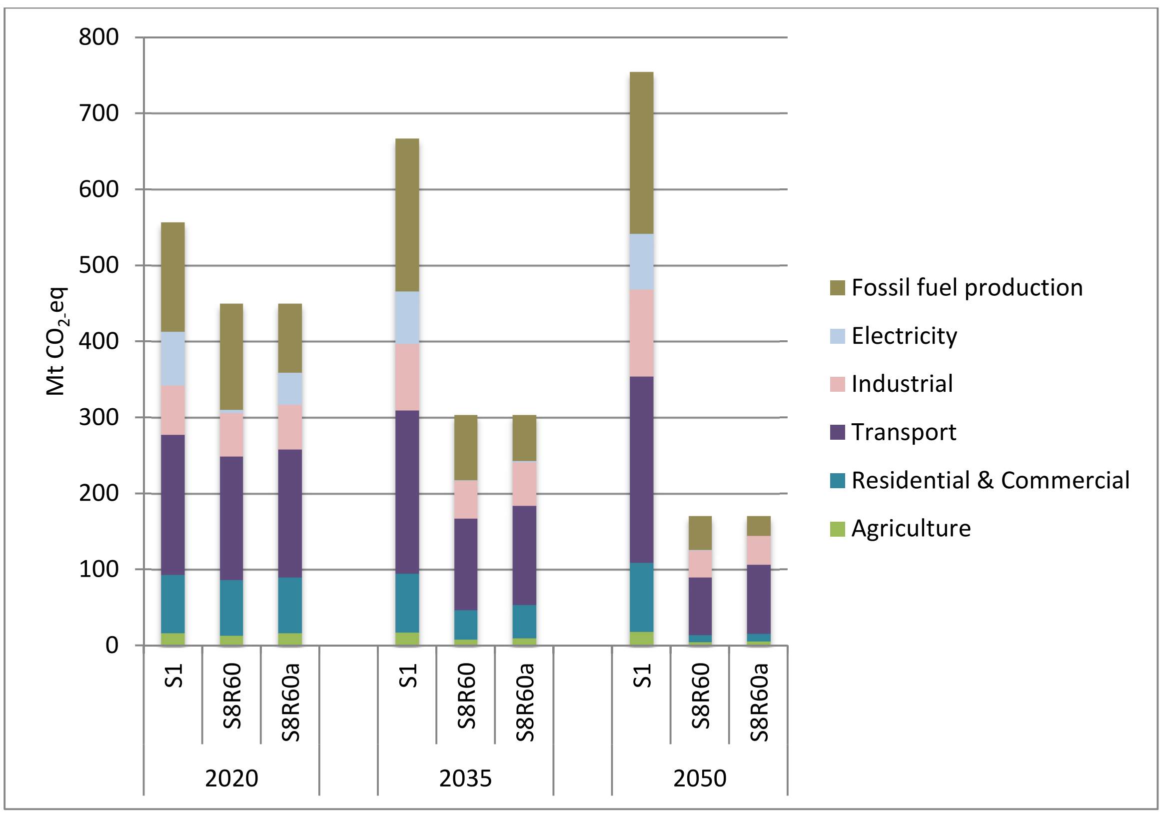


Figure 157. Energy consumption in transportation sector

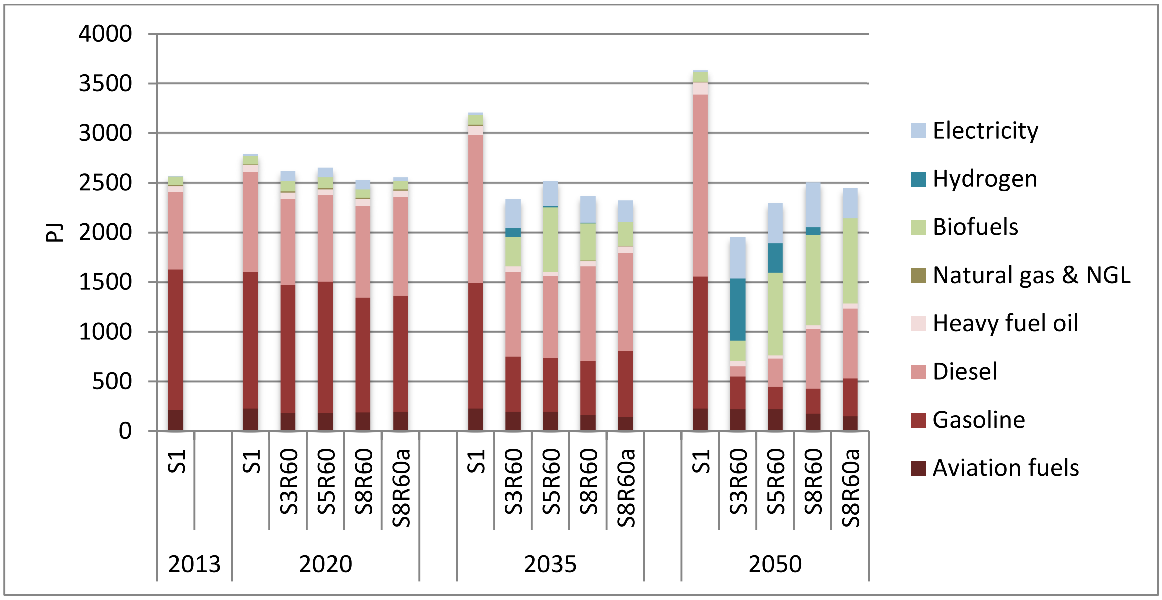


Figure 158. Combustion emissions - 70% reduction in GHG emissions

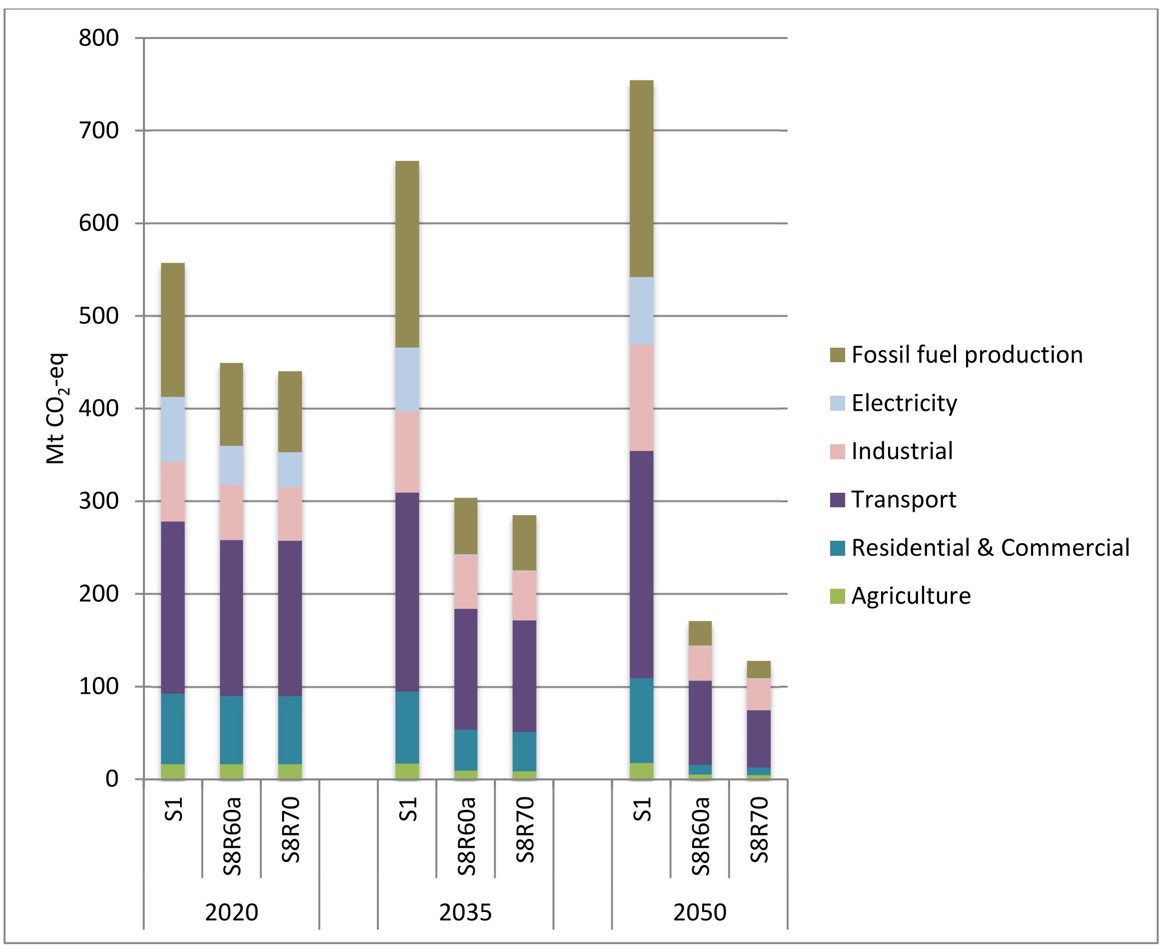
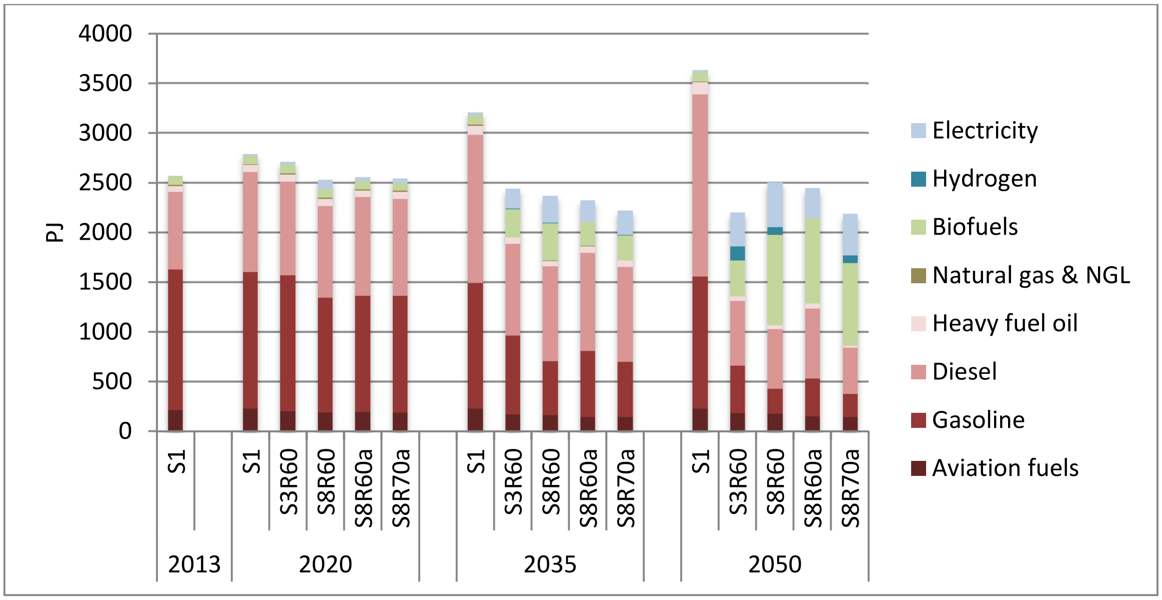


Figure 159. Energy consumption in tranportation sector - 70% reduction in GHG emissions



5.11.6 Total GHG Emissions

Analyses were carried out to assess total GHG emissions for Scenario 8a, with prime emphasis on comparison with Scenario 8. This included both combustion and non-combustion emissions, along with credits with negative GHG emissions for harvest wood products.

There is an important difference in non combustion emissions with Scenario 8a, arising from reduced fugitive releases. For this project, it has been assumed that projected fugitive emissions are proportional to oil and natural gas production. With reduced production of oil and natural gas for Scenario 8a, fugitive emissions reduce correspondingly, as shown on Figure 160. These reduced emission are included with other non-combustion emissions (without reductions) and combustion based emisions, for the 60% GHG reduction target, and presented in aggregate form, on Figure 161. A corresponding breakdown of all emission sources (both combustion and non-combustion) is shown on Figure 162. The results for 2050 are then shown with selected reduction ratios for non-combustion emissions, as well as with the HWP credit on Figure 163. The breakdown of combustion emissions, without reductions, and with reductions, of non combustion emissions, respectively, are shown on Figure 164 and Figure 165.

Key observations from detailed review of background documentation and results, are as follows:

- Fugitive emissions reduce from 112 Mt for Scenario 8 to 18 Mt for Scenario 8a. This has a significant impact of total GHG emissions, as noted below.
- From comparison of results for total GHG emissions between Scenarios 8a and 8, the following commentary is provided
    - For Scenario 8a in 2050, combustion emissions for the 60% GHG reduction target are 171 Mt Non combustion emissions (no reduction) are 268 Mt, for a total of 439 Mt. For Scenario 8, the corresponding GHG combustion, non-combustion and total emissions are

171, 354 and 525 Mt, respectively.The difference is stricty due to the change in fugitive emissions.

- When including reduced production of non combustion emissions with suggested ratios as presented in Section 2.6, total emissions for Scenario 8a reduce to 396 Mt. When also including GHG credit of 40 Mt for HWP, projected emissions reduce to 356 Mt. The correponding values for Scenario 8 are 438 Mt without the HWP credit, and 398 Mt with the HWP credit.
- It is important to note that the 70% GHG reduction results for combustion based emissions for Scenario 8a are more directly comparable with 60% GHG reduction results for Scenario 8. The 70% reduction results correspond to 128 Mt of combustion based emissions, as compared to 171 Mt for the 60% reduction results. Based on this observation, the more relevant comparison is a reduction in total net GHG emssions from 398 Mt for Scenario 8 to 313 Mt for Scenario 8a.
- As noted for Scenario 8, this is a significant, albeit smaller, shortfall relative to the goal of reaching the 80% GHG reduction target (118 Mt) by 2050. However, as presented in concluding commentary for Scenario 8 (Section 5.10.6), these results should not, in any way, be interpreted as suggesting that the 80% GHG reduction target is not attainable. There are various suggestions concerning required priorities and actions for achieving this very important goal. Such commentary certainly applies also in the context of assessing results for Scenario 8a.

Figure 160. Fugitive emissions - S1, S8 & S8a

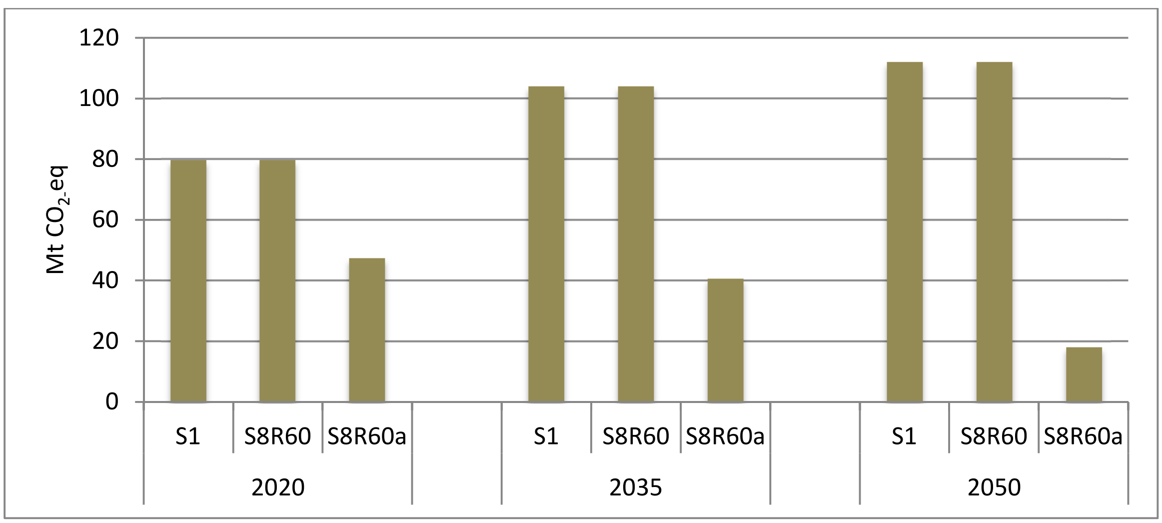


Figure 161. Total emissions (60% reduction) and non combustion emissions (no reduction)

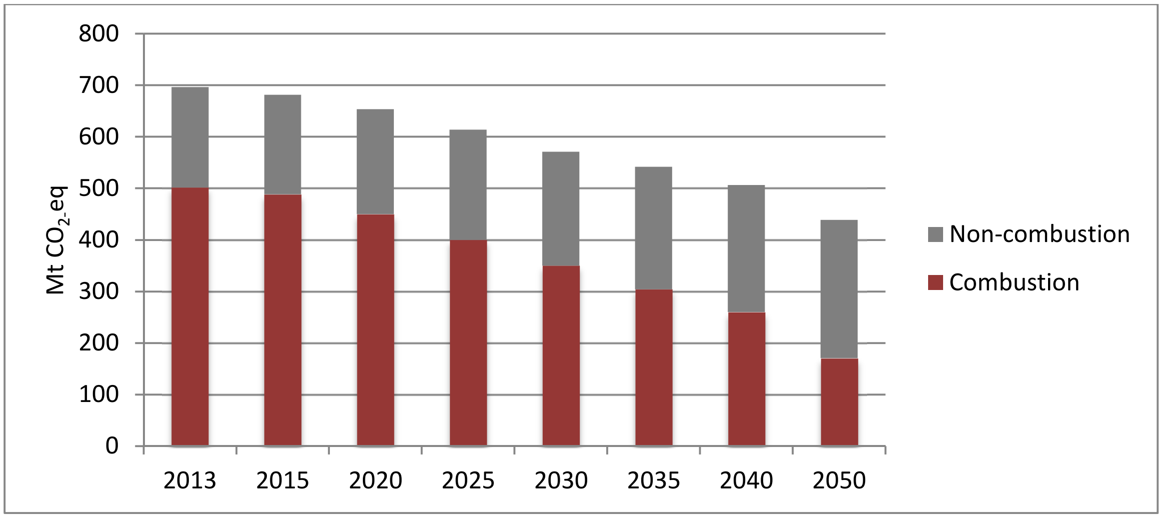


Figure 162. Total emissions (60% reduction) by sector

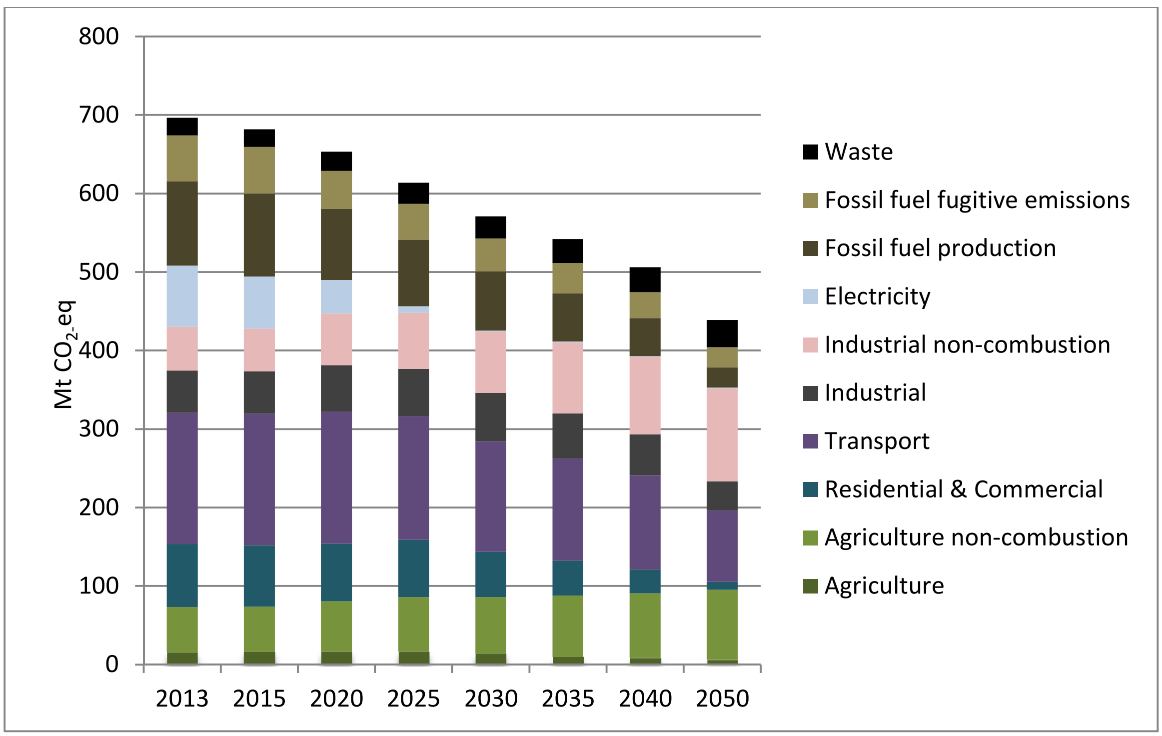


Figure 163. Total emissions for S8a - 60% reduction for combustion emissions, reductions for non combustion emissions, and HWP credit

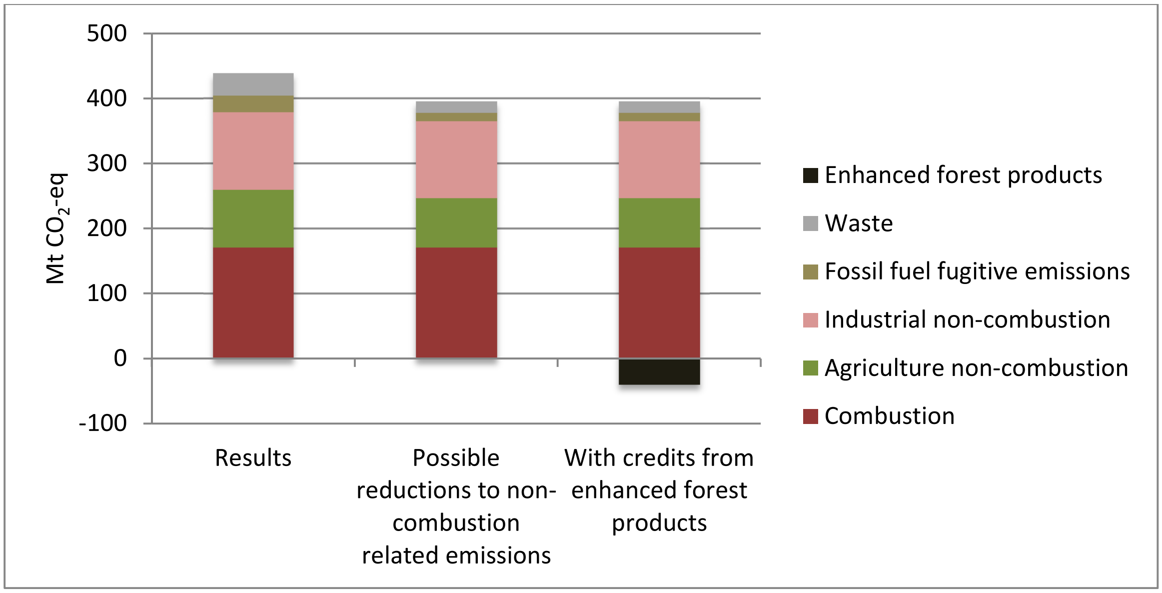


Figure 164. Breakdown of emissions in 2050 (439 Mt) - 60% reduction for combustion emissions and no reductions for non combustion emissions

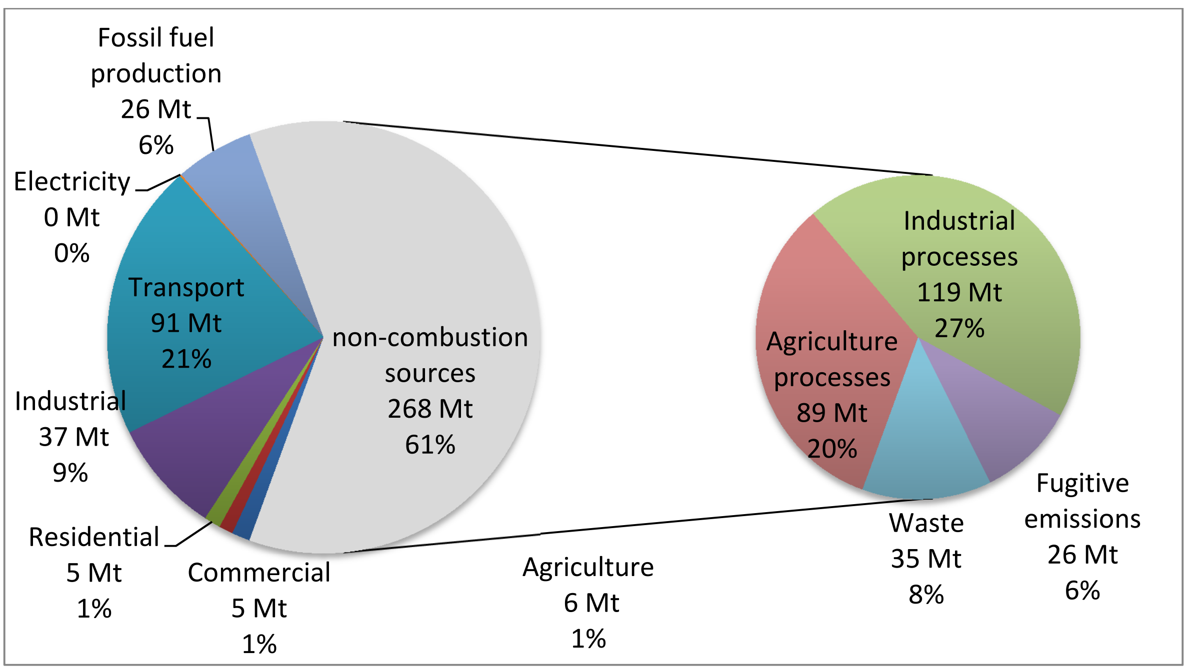
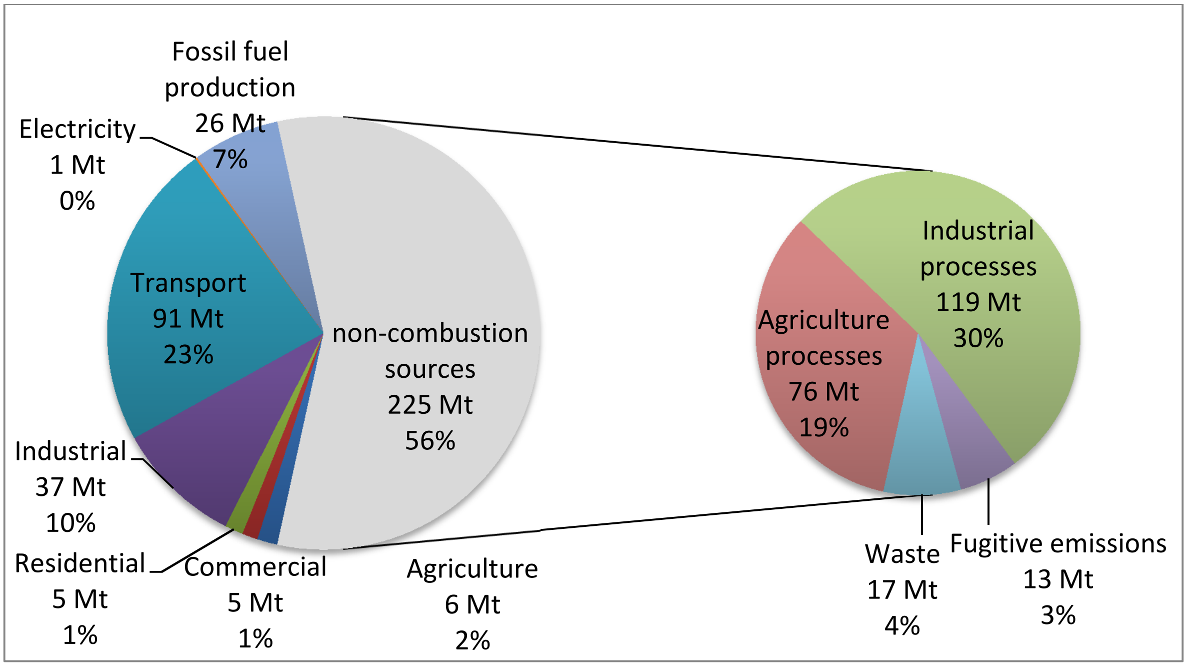


Figure 165. Breakdown of emissions in 2050 (396 Mt) - 60% reduction for combustion emissions and reductions for non combustion emissions



5.11.7 Cost

Results showing marginal costs for reducing GHG combustion emissions for Scenario 8a, with comparsions to Scenario 8, for the 30% and 60% reduction targets for combustion emissions, are shown on Figure 166. There was also an analysis of marginal cost with increasing the target from 60% to 70%. These results are shown on Figure 167. It was also agreed that it would be of interest to observe possible changes in overall results, including reductions in marginal cost with representaion of demand elasticity for energy based end uses. Results showing reductions in marginal costs for Scenario 3a and 8a are shown on Figure 168.

Key observations from detailed review of background documentation and results, are as follows:

- Based on observations of marginal costs for Scenarios 8 and 8a, it is clearly evident that marginal costs for Scenario 8a are significantly lower than for Scenario 8. Marginal costs for Scenario 8a remain below $200 per tonne up to 2030, with continuing increases beyond 2030, but with such costs being typically lower by about $200 per tonne. This general observation is also evident with results for the 30% reduction target.
- When assessing results for the 70% reduction target, marginal costs, as expected, are higher than for the 60% reduction target. This difference is relatively modest up to 2040. However, there is a significant difference in marginal cost after 2040, which is caused primarily by hydrogen based transport entering the overall solution mix for heavy duty transport for 70% reduction, but not for 60% reduction.
- With demand elasticity included in the solution process, overall demand for energy related services decline, with corresponding reductions in combustion based emissions. This also results

in reductions in the profile of marginal costs for meeting prescribed reductions in combustion emissions.

This repesentation is a very valuable feature, as it provides a more accurate evaluation of marginal costs and associated total costs for GHG mitiagtion. However, the credibility of the process is dependent on ensuring that demand elasticity valuses represent overall responses to use of energy as a function of cost. This is an important feature which merits greater attention in future assessments, for providing more accurate results.

Figure 166. Marginal cost for mitigation - S8 & S8a

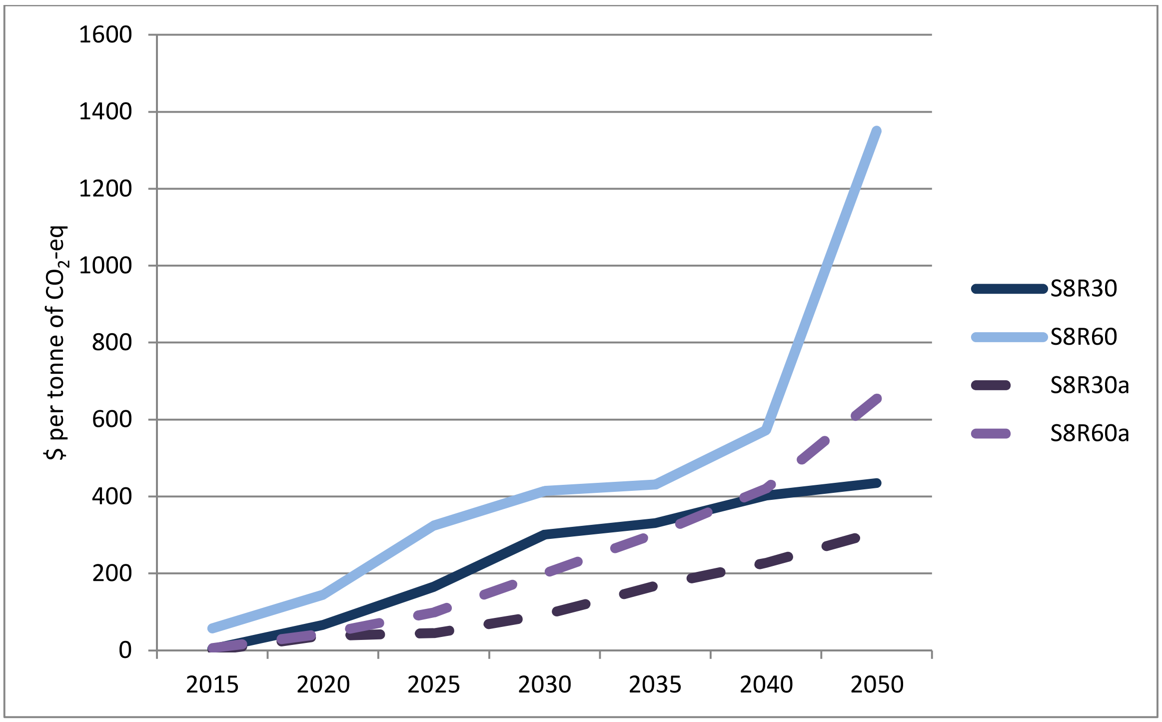


Figure 167. Marginal costs for mitigation - S8a for 60% & 70% reductions

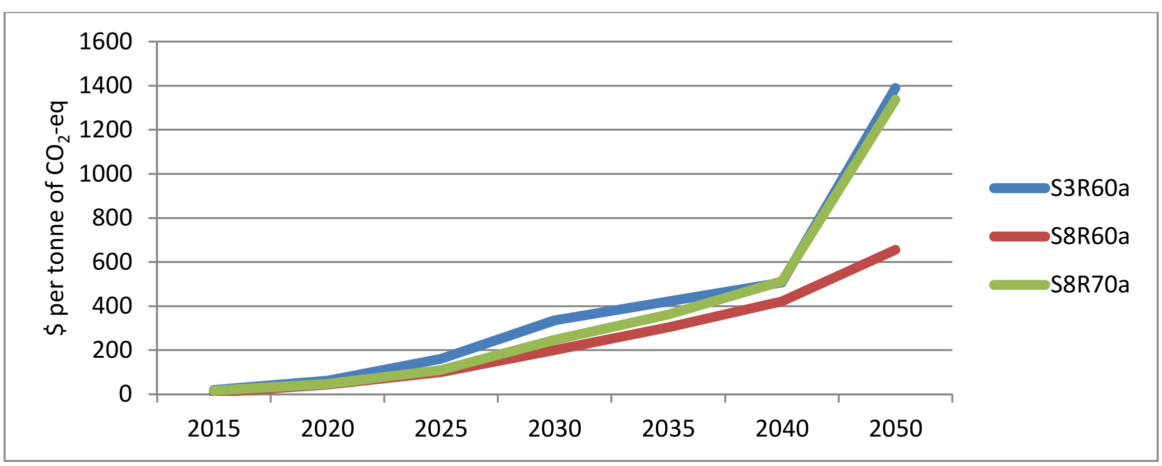
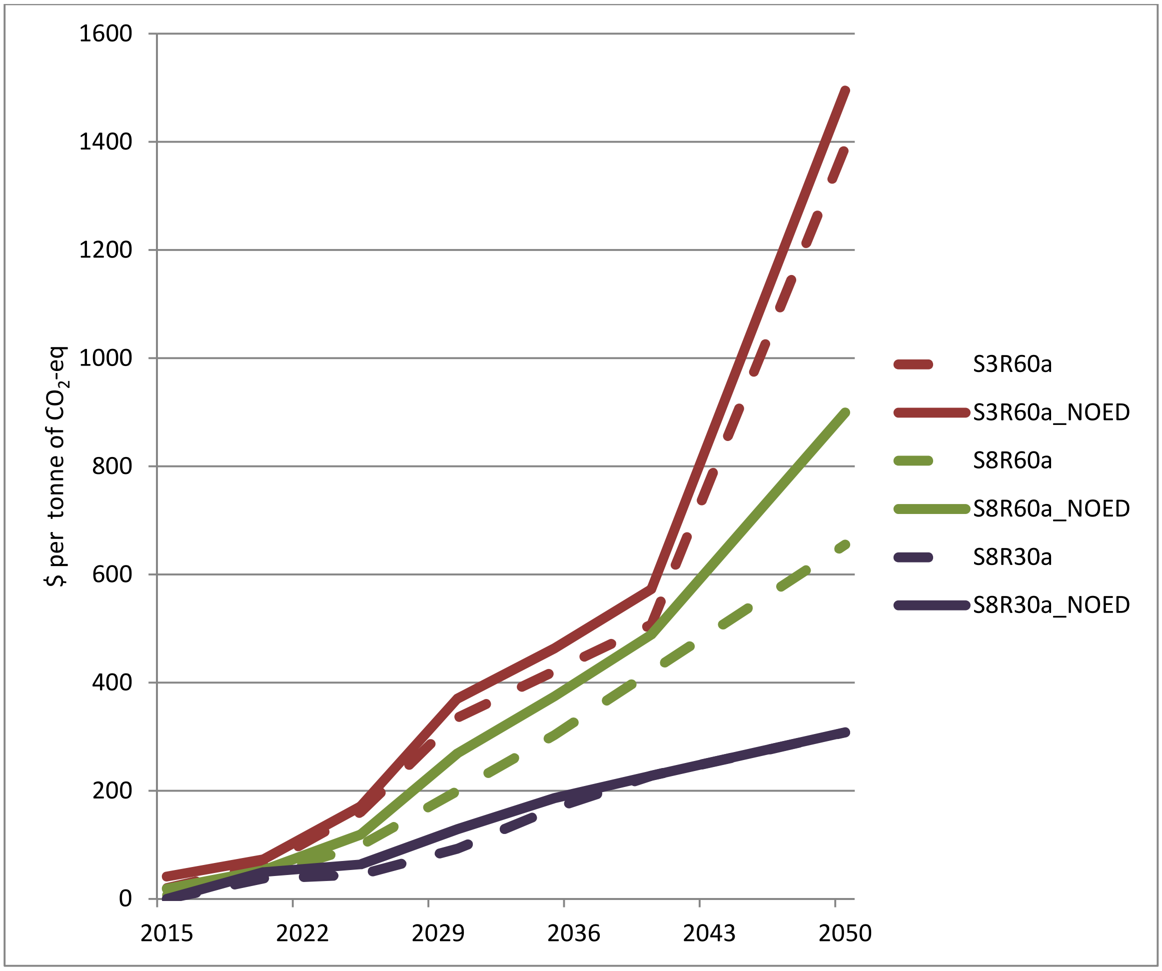


Figure 168. Marginal costs for mitigation with demand elasticity



Note: NOED denotes effects of demand elasticity.

5.11.8 Principal Observations

The principal observations from Scenarios 1a, 3a and 8a, for direct comparison with Scenarios 1, 3, and 8, may be summarized as follows:

- Scenarios 1a, 3a and 8a are based on the premise that there will be greatly reduced production and use of fossil fuels in Canada, and that exports will also decline correspondingly in response to simialr trends around the World. The overall approach was also modified to allow overall cost minimization to be in response to selecting optimal production, use and export of fossil fuels to satisfy the minimum net present worth cost function in the NATEM Canada optimization model, but within prescibed upper and lower bounds.
- While the model had the ability to select optimal values for production, use and export of fossil fuels, there was a general trend to reduce exports to the prescribed lower bound. This reflected a general observation that the values of such commodties on the global market were less than the marginal costs for producing such commodities in Canada for export.

- There was however an interesting exception to this general trend. For Scenario 8a, which included development of up to additional 30 GW of conventional large scale hydro in British Columbia, the results included LNG liquefaction on the West Coast. The overall result was continuing export of both natural gas and coal from Western Canada, albeit at much reduced levels relative to results of Scenario 8.
- It is important to note, however, that these analyses do not include potential benefits for reducing GHG production with technologies other than using electricity to replace natural gas for thermal energy production. For example, when there are high implicit costs for producing GHG's, there may be more cost effective ways for in-situ extraction of oil in the oil sands, than replacing natural gas boilers with electric boilers for high pressure steam production. It is important that such areas be subject to more comprehensive investigation than was possible in this project.
- It was noteworthy that with Scenarios 1a, 3a and 8a, use of fosil fuels in Canada remained sensibly the same as for Scenarios 1, 3 and 8, respectively. As a consequece, the dominant driver for changes in production of fossil fuels in Canada was based on changes in export of such commodities.
- With reduced overall production of fossil fuels, driven dominantly by reduced export, there were major associated reductions in electricity generation and dependable capacity (dependable capacity, for example, decreased by 22%) for Scenario 8a. There were also major changes in composition of electricity supply, especially in British Columbia, Alberta and Saskatchewan. In British Columbia, the nuclear and geothermal capacity additions in Scenario 8 were eliminated, with system supply being virtually completely hydro dominated in Scenario 8a. In Alberta, the dominant change was reduced need for nuclear generation, from 85 GW to 21 GW. In Saskatchewan, the need for generating capacity was reduced by 50%, with less nuclear and essentially no wind generation.

  As noted with analysis of results of other scenarios, however, there is a need to improve representation of options for electricity supply in the NATEM Canada model. This includes especially representation of the incremental hydro option. With addition of this option, it is expected that there will be further changes in overall compostion of electricity supply, with some further reductions in overall cost.
- Analysis of total emissions for Scenario 8a was computed, and compared with results for Scenario 8. Computed emissions for Scenario 8 for the 60% GHG reduction target and for reduction ratios for non combusion emissions as presented in Section 2.6, and including the 40 Mt credit for HWP, resulted in net emissions of 396 Mt. Corresponding net emissions for Scenario 8a were 313 Mt.
- As noted for Scenario 8, this is a significant shortfall relative to the goal of reaching the 80% GHG reduction target (118 Mt) by 2050. For Scenario 8a, even though the shortfall is less, the concluding commentary for Scenario 8 (Section 5.10.6) also applies to Scenario 8a. There are various suggestions concerning required priorities and actions for achieving this very important goal.
- Based on observations of marginal costs for GHG mitigation for Scenarios 8 and 8a, it is clearly evident that marginal costs for Scenario 8a are significantly lower than for Scenerio 8. The marginal cost remains below $200 per tonne up to 2030, with continuing increase beyond 2030, but with such marginal costs being typically lower by about $200 per tonne.
- With demand elasticity included in the solution process, marginal costs decline, as expected. The prinicpal benefit, with including representation of demand elasticity, is that there is an opportunity for deriving more accurate results which reflect effects of reduced demand in

response to increased costs. For any prescribed reduction in GHG emissions, computed marginal costs and associate overall costs for GHG mitigation will be correspondingly lower.

5.12 Short Term Opportunities for Mitigation

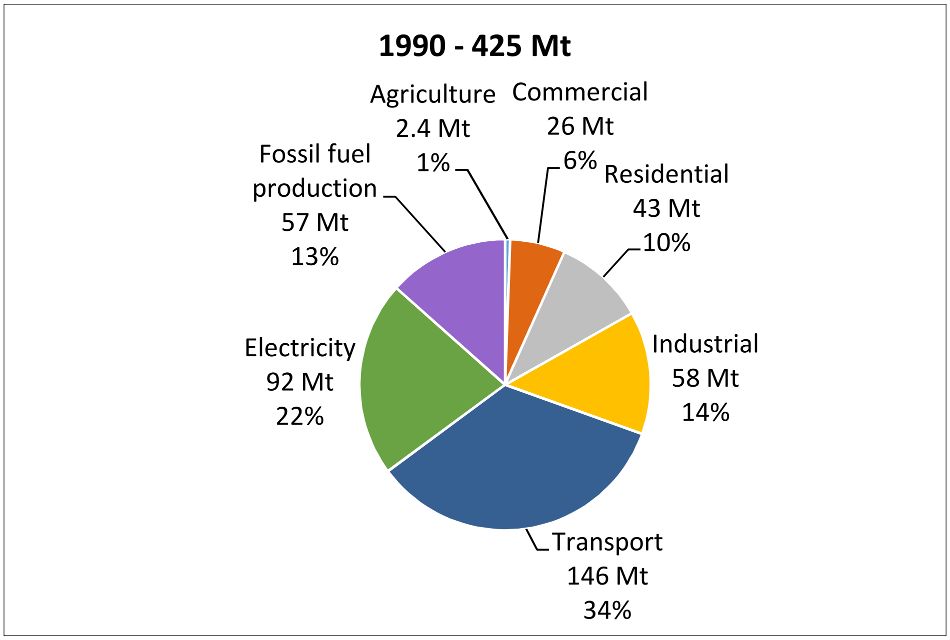
An assessment was carried out to assess short-term opportunities for achieving GHG mitigation targets by 2030. This was based on including all premises for Scenario 8a, as well as maximum reductions in non-combustion emissions.

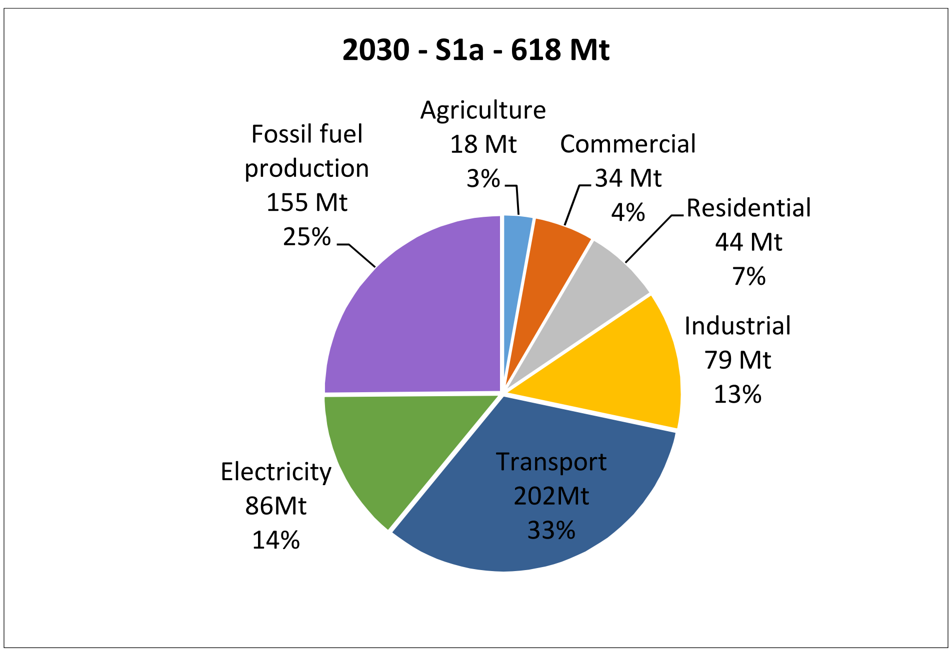
Results of this analysis are shown on Figure 169. In the absence of any concerted action on GHG mitigation, combustion emissions would increase from 427 Mt in 1990 and 503 Mt in 2010, to 618 Mt in 2030. However, by immediately accepting all the premises for reducing combustion emissions as prescribed for Scenario 8a, combustion emissions could reduce to 335 Mt by 2030, corresponding to 46% reduction relative to the Reference Scenario.

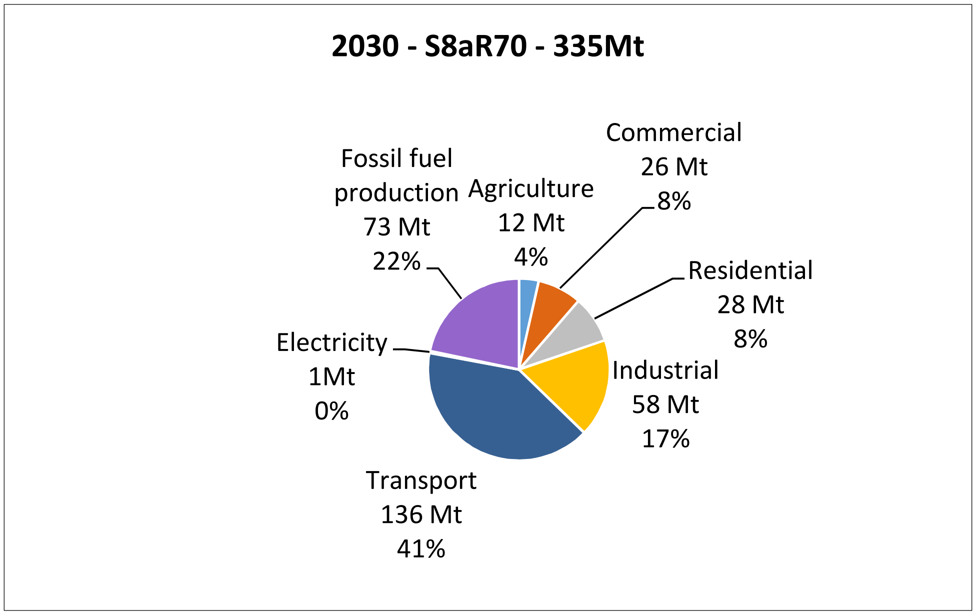
To achieve this, the principal changes from 2011 to 2030 would include:

- Progressive reductions in use of fossil fuels and increased use of both electricity and biomass/ biofuels in all five end use sectors, including, as examples:
  - Increased use of electricity and biofuels in the transportation sector, from 3% in 2011 to 18% by 2030.
  - Increased use of electricity in the residential sector from 38% in 2011 to 58% in 2030, with increased use of electric boilers, electric water heaters, baseboard heaters and electrically driven heat pumps
  - 45% increase in electricity production between 2011 and 2030, compared to 18% increase for the Reference Scenario.
- Rapid decarbonizing of electricity supply, including:
  - 76% increase in hydro generation, with hydro's portion of total electricity generation increasing from 62% in 2011 to 75% in 2030
  - 3.5–fold increase in intermittent renewables (dominated by wind), with the portion of total generation increasing from 3% in 2011 to 6% in 2030
  - 48% reduction in conventional thermal generation, with the portion of total generation declining from 20% in 2011 to 7% in 2030
  - Introduction of biomass-based generation, combined with CCUS by 2030, resulting in net negative emissions, with associated net combustion emissions for electricity production declining from 87 Mt in 2011 to 1 Mt in 2030
- Additional cost effective energy efficiency improvement in all sectors.

Figure 169. Combustion emissions in 1990 and projections for low fossil fuel emissions







An area of obvious interest is to assess how these results compare with Canada's most recent commitment at the COP 21 meeting in Paris in December, 2015. At that time, Canada committed to reducing its GHG emissions by 2030 to 30% below the 731 Mt in 2005, which corresponds to 512 Mt.

By combining the 335 Mt from Scenario 8a with 235 Mt of projected non-combustion emissions in 2030, total GHG emissions in 2030 could be 570 Mt, in the absence of any reduction in non-combustion emissions. This is 58 Mt higher than the commitment made at COP 21.

From the foregoing, it can be readily appreciated that there is a major challenge for Canada to be able to deliver on its COP 21 commitment by 2030. There should be opportunities for achieving some reductions in non-combustion emissions, especially fugitive releases. There are also opportunities for reducing combustion emissions, as summarized in Section 6.3. On the other hand, the premises assumed for Scenario 8a are extremely ambitious, especially in the context of the short time frame between now and 2030.

6. Observations

6.1 Introduction

It has been shown that GHG emissions in Canada are from combustion of fossil fuels (72%) and from various non-combustion sources (28%). It was shown that the non-combustion sources include industrial (8%), fugitive emissions (9%), agriculture (8%) and waste (3%) (2010). Each of these sources has been described in Section 2.6, including perspectives on potential for reducing GHG emissions from such sources.

For the immediate future, major progress on GHG mitigation can only be achieved with major reductions in release of GHG's to the atmosphere, from both combustion and non-combustion sources. However, as clearly outlined in the IPCC *Fifth Assessment Report*, it will be necessary to supplement this with strategies that result in net extraction of GHG's (dominantly, CO_2) from the atmosphere (net negative emissions).

In this project, primary attention has been given to assessing strategies that result in reduced emissions from combustion of fossil fuels. The two models (NATEM Canada and CanESS) have been used to derive minimum cost solutions for various combinations of premises, as summarized in Section 5.1, and as described more specifically for each of eleven scenarios in Section 5.2. Results, including summary observations from the eleven scenarios, are presented in Sections 5.3 to 5.11. Perspectives on achieving 30% reduction below 2005 levels by 2030, as committed by Canada at COP 21, are included in Section 5.12.

In this Section, overall results of the project will be summarized. Primary attention will be given to strategies for reducing emissions from combustion of fossil fuels, which was the prime focus for the scenarios. However, there will also be observations which are based on integrating such results with considerations for GHG mitigation from non-combustion sources, as well as the longer term need for strategies that result in net extraction of GHG's from the atmosphere.

6.2 Key Considerations

Before presenting summarized results, it is important to provide context on several aspects of the project that have influenced the process for interpreting results. These are summarized as follows:

- It needs to be respected that this is the first time in Canada that such a comprehensive integrated multi-jurisdictional approach, in a multi time period context, has been taken for deriving minimum cost solutions for meeting prescribed GHG mitigation targets for all of Canada. It is also the first time that two models have been used in such an integrated manner for such a project.
- With this consideration, there was extensive testing and calibration carried out in earlier stages of the project to ensure that the two models were producing accurate and sensibly consistent results for the same combinations of premises. This was effectively completed before carrying out the comprehensive program of model runs with the NATEM model for the various scenarios.
- As described in Section 3.4, special attention was given to developing and calibrating both models with representations that were recognized as being of special importance for this project. These included, as examples, rigorous treatment of dependable capacity, system dispatch, high

voltage interconnections, biofuels limitations, etc. For each of these representations, it was essential to carry out calibration for each of the two models, to ensure that the models were producing accurate results.

- Very substantial effort has been dedicated to collection and assembly of the best possible input data for the two models. Separate working papers were prepared for each sector, to define a comprehensive range of transformation options, with associated GHG mitigation and cost relationships. As described in Section 4.1, such cost information was assembled from established and credible information sources. Special attention was given to time varying costs, such as for solar generation, with significant reduced costs projected in future. In several cases, costs were reviewed with industry leaders.
- The overall approach for assembly of cost information was based on being as accurate as possible, for known technologies, such as costs for conventional generating facilities for electricity supply. However, when considering technologies which are known, but not commercially proven, the general guideline was to work with available and credible information to the maximum extent possible, and to avoid accepting unduly optimistic projections.
- At the outset of the project, there were many transformation options considered for each sector, which were based on the best available information and perspectives on expected results from the model runs. Following analyses of such results from progressive model runs, it was apparent that some of the solutions were different, or that some options were either more or less prominent, than expected. This is consistent with progressive learning that is an important feature in application of models for such complex problems. The result of this is that it is now known that there are additional transformation options that need to be added to the two models for further assessment, in order to obtain more precise results. This will result in further refinements for deriving the best combination of GHG mitigation strategies for achieving prescribed GHG reduction targets at minimum cost.
- It is important to note that there was a basic premise that energy based end uses would continue to be provided, but that there would be transformations in delivery of such end uses – such as electricity or biofuels to replace natural gas for heating, or electric cars to replace internal combustion engines (ICE) for personal transportation. Any reductions in such end uses would be based strictly on responses to cost considerations. There were no assumptions related to undefined external influences causing fundamental changes in life style.
- Limited attention was given to potential process changes in industry and for production of fossil fuels. The only process change included in the models was for potential replacement of steam methane reforming using natural gas as feedstock, to electrolysis, for production of hydrogen in refineries.
- This is potentially a significant limitation, especially for production of oil from the oil sands. In the model, the only option provided for in-situ extraction is replacement of natural gas for steam production with electric boilers, at significantly increased cost. There are other options, such as use of solvents with reduced high temperature steam production that may be more favorable, especially for high GHG mitigation scenarios. Such options need to be incorporated into the two models for further model runs.
- Such limitations may also be important for selected industrial processes which may reduce, or even fundamentally change, for high GHG mitigation projections, including from both fossil fuel combustion and non-combustion sources. This is an important area for further study, as noted in Section 7.5.7.

- In the interpretation of results, it is important to distinguish between near term solutions (to 2030) and longer term solutions (after 2030). For the short term, the options are generally well defined in terms of both definition and cost, and the number of options is more limited.
- For the longer term, the problem is more complex. In addition to currently known options, there are other options which may be known, but are not well defined in terms of either definition or cost. There are still other options that are only understood in broad context, and for which there is little or no credible definition or information available. Finally, there may be other options which are completely unknown, and may arise as a consequence of some strategic or technologic breakthrough.
- This leads logically to the need for progressive decision making to achieve GHG mitigation in the most cost effective manner. For the short term, decisions need to be taken that ensure that there is immediate action on GHG mitigation. Such decisions should include known and proven investment and transformation options that are consistently part of minimum cost solutions, and required for immediate implementation.
- The other element of this progressive decision process is that results from the models, and associated interpretation, should provide the essential basis for defining priorities for further investigation. This may include the most promising strategic, policy and technologic options. This process should lead to systematic upgrading of the knowledge base, so that future decisions on investments and transformation options can continue to be made in the most cost effective manner.
- When interpreting results from the various scenarios, special consideration was given to high marginal cost values produced with the NATEM Canada model. As explained in Section 3.3.2, for each imposed GHG reduction target, the NATEM Canada model systematically searches through all possible combination of options for minimizing overall cost, until it arrives at a combination of solutions, where any change will only lead to increased cost. At this minimum cost solution, there is also information on the lowest marginal cost for further GHG mitigation. For the lower GHG mitigation targets, marginal costs were generally in the range of a few hundred dollars per tonne, and progressively increasing over time. However, with higher GHG mitigation targets, marginal cost could increase quite dramatically, to well in excess of $1,000 per tonne, especially towards 2050. It was considered that solutions with such high marginal costs were not acceptable. This provided the general guideline for assessing practical upper limits for GHG mitigation.

6.3 Summary of Results

As noted previously, the prime reference for the project was the 589 Mt of GHG emissions in 1990. This included 427 Mt (72%) of combustion emissions, and 162 Mt (28%) of non-combustion emissions. For Scenario 1 (Reference Scenario), which was based on the premise of having no GHG emission constraints, the projected status for Canada in 2050 would be 1,109 Mt of GHG emissions. This includes 754 Mt (68%) of combustion emissions and 355 Mt (32%) of non-combustion emissions.

- The prime goal of the project is to achieve 80% reduction in GHG emissions in Canada by 2050, relative to 1990. This corresponds to 118 Mt in 2050, which is 80% below the 589 Mt, as reported, for 1990. It is also 89% below the projected value of 1,109 Mt for the Reference Scenario.

A related second goal, as defined by IPCC, and as adopted by the project, is to continue with strategies that also achieve at least 100% net reduction in GHG emissions by the end of the century.

- From analysis of results of the scenarios, the most dominant change required by 2050, for reducing emissions from combustion of fossil fuels, is to progressively reduce the role of fossil fuels for meeting energy based end uses, from 74% to 25%, or less. This change in end uses will require corresponding shifts for electricity supply to increase from 22% to 60%, or more, and for biomass/ biofuels to increase from 4% to 15%, or more.

  It needs to be fully respected that these changes represent major and fundamental transformations for production and delivery of fossil fuels, electricity, and biomass/biofuels, and for all uses of such energy based services.
- With respect to reducing emissions from combustions of fossil fuels, the maximum reduction which was achieved in the analyses was 70% below the combustion based emissions value of 427 Mt in 1990 (128 Mt). This corresponded to 83% below the 754 Mt for the Reference Scenario value for 2050. The dominant limitations were from options in which switching from dependence on fossil fuels was not considered possible or credible, based on the best currently available information. There was continuing need for fossil fuels in 2050, especially diesel and jet fuel for heavy freight, rail and air transport, primarily as a consequence of feedstock supply constraints for production of biofuels, limitations on use of electricity for heavy freight and rail transport, and very high marginal costs for other energy sources. There were also fuel switching limitations for the industrial and fossil fuel supply sectors.

  It is important to appreciate that these results are based on an initial set of premises and that more work is required to assess whether the limitations, as defined, for these initial model runs, can be relaxed, or whether there are other options that could lead to 80%, or even greater, reductions in emissions from combustion of fossil fuels by 2050.
- With respect to reducing GHG emissions from non-combustion sources, ratios of possible reductions were derived from literature review, including extensive reporting by IPCC in their *Fifth Assessment Report* (see Section 2.6). Based on this information and associated assessments of appropriate reduction ratios to be used for this project, the projected change for non-combustion emissions is an increase from 162 Mt in 1990 to 268 Mt in 2050 for Scenario 8. The 268 Mt in 2050 can be compared directly with 355 Mt in the Reference Scenario, in which it is assumed that no action is taken to reduce emissions from such sources.
- With respect to the potential for realizing GHG gains from net negative emissions, there were two possible areas assessed in the project. These included:

  - Electricity generation with biomass, combined with CCUS, and including enhanced oil recovery, where possible.
  - Carbon retention with Harvest Wood Products (HWP)

- The options for electricity generation with biomass, combined with CCUS and enhanced oil recovery, was shown to be part of an overall minimum cost solution for reducing combustion based GHG emissions. The HWP option, assessed as potentially providing a net annual gain of 40Mt by 2050, was included in the overall assessment for evaluating net GHG emissions.
- When combining the most optimistic combinations of evaluated options from the project, the maximum reduction is from 589 Mt in 1990 to 313 Mt in 2050 (47% reduction). This is equivalent to 72% reduction from the Reference Scenario value of 1,109 Mt in 2050. It represents a shortfall of 195 Mt relative to the goal of 118 Mt in 2050.

From analyses of results from the scenarios, from literature reviews, and from comparative analyses from developments in other jurisdictions around the World, there are several options which are available for achieving the stated goal, but which have not been quantitatively assessed in the project. Preliminary perspectives, and assessments on the most promising options, include:

- **Reducing GHG emissions from combustion sources**: The analyses have served to demonstrate that the dominant remaining source of GHG emissions for meeting end uses in 2050 is in the transportation sector (63%). The dominant challenges are associated with potential limitations on availability of feedstock for production of biofuels, high costs for electrifying inter-urban rail transport and use of hydrogen (very expensive) for heavy freight transport.

  The second major source of combustion based GHG emissions is in the industrial sector. In an economic environment in which costs of fossil fuels increase substantially to reflect the full cost of carbon, there may be changes in industrial processes to reflect impacts of such costs. Such impacts have not been assessed in the project, but may be important drivers for reducing combustion emissions in the industrial sector.

  The third major source of combustion emissions is with the entire supply chain for production of fossil fuels. Again, the dominant strategies include increased electrification and increased use of biofuels to replace use of fossil fuels for the supply chain. There are, however, further opportunities for reducing GHG emissions associated with process changes in the supply chain – such as switching from use of high pressure steam to use of solvents for in-situ extraction of oil from the oil sands. Such options were not assessed in this project.

  It is considered, that with more in-depth assessment of these options, there are likely to be additional opportunities for reducing combustion-based GHG emissions.

  Reducing GHG emission from non-combustion sources: As noted in Section 2.6, this is a challenging area for achieving major reduction in GHG emissions. From literature reviews, and from comparative assessments from other jurisdictions around the World, the opportunities for achieving substantial reductions, especially in the agricultural sectors, are not encouraging. However, as non-combustion emissions currently represent 28% of total GHG emissions, as reported, and could increase to 70% or more, if there are major reductions in combustion emission and no progress with reducing non combustion emissions, it is important that this area be given balanced consideration.

  For reducing non-combustion GHG emissions in the industrial sector (8%), it is important that attention be given to combinations of strategies, including conservation, efficiency improvements, process changes, material re-use, and CCUS.

  For reducing non-combustion GHG emissions in the agricultural sector (8%), it is important that attention be given to combinations of strategies that would include improved agricultural practices (increased carbon retention in soils), better fertilizer management, and opportunities for collection and use of methane from enteric fermentation and manure management.

  For reducing non-combustion emissions from fugitive releases (8%, but almost certainly significantly higher), this is a very important area, which requires better information and development of more comprehensive strategies for achieving major reductions in uncontrolled releases from both venting and flaring, especially venting. This is an area which certainly requires a more proactive and cooperative approach by Governments, Industry, Cities and Municipalities for reducing such emissions, and will almost certainly require strengthened regulations for achieving major reductions in such releases. This is an area that certainly merits immediate attention (see Section 7.5.2)

For reducing non-combustion releases from waste (3%), it is important that attention be given to a combination of strategies that combine reduced production of waste (overall conservation ethic) with strategies that capture and integrate waste management with re-use of waste products, and are integrated with overall improved energy management within urban communities.

- **Realizing GHG gains with net negative emissions:** This is an area that has substantial potential for realizing significant contributions to reducing net GHG emissions. While only two areas were examined, in a very preliminary manner, in this project, there are additional potential opportunities with these two strategies, as well as with other strategies that were not quantified in this project. Additional strategies include, as examples:

  - Afforestation and reforestation
  - Improved forest and agriculture management for increased carbon retention
  - Accelerated photosynthesis, including accelerated algae production, with concentrated CO_2, for production of biomass and biofuels
  - Direct extraction of CO_2 from the atmosphere

From these assessments, it is important to appreciate that there are several options that were not included in the project, but which have potential for significant additional contributions to GHG mitigation. This requires a more comprehensive approach that fully integrates the combined potential with reducing GHG emissions from both combustion and non-combustion sources, as well as addressing the substantial potential for net negative emissions, especially from the forestry and agriculture sectors.

6.4 Interpretation of Results

In this Section, the principal results from the scenarios are summarized. This is based on collective analysis of the results from the eleven sets of scenarios (which are summarized at the end of each of the respective Sections 5.3 to 5.11, inclusive), key considerations (Section 6.2), and summary observations (Section 6.3).

- For the Reference Scenario (Scenario 1), as reported above (no reductions in GHG emissions), there is continuing growth of energy demand in all energy consuming sectors, with some nominal shifts, but no major changes. Energy efficiency improvements for reducing energy demand are substantial, driven primarily by CAFÉ standards for the transportation sector and efficiency improvements for electrical and accessory equipment and improved building standards in the residential and commercial sectors. Growth in primary energy production is dominated by oil and natural gas, as well as hydro for electricity production. Oil is increasingly from the oil sands, and natural gas is increasingly from tight and shale gas deposits. Growth in biofuels and intermittent renewables is nominal. There are no major shifts in the relative roles of fossil fuels, electricity and biomass/biofuels for meeting end uses. There is a significant shift in the transportation sector for passenger and freight transport with energy use for passenger transport actually declining as a result of the CAFÉ standards, while growth in freight transport increases rapidly. This results in a major shift from use of gasoline to use of diesel fuel in this sector. Overall, GHG emissions increase to 1,109 Mt by 2050, dominated by transportation, industry and fossil fuel production.

- Results of the various scenarios, other than the Reference Scenario, have been assessed with primary comparison to results of the Reference Scenario. Changes in results are dominated by minimum cost solutions for prescribed time varying GHG reductions of varying amounts, and for different combinations of premises, as described in Sections 5.1 and 5.2. The assessments have also been carried out with respect to considerations, as outlined in Section 6.2 above. Results of these assessment are as follows:

    - With progressive reductions in GHG emissions from combustion of fossil fuels, end uses based on use of fossil fuels progressively reduce, with corresponding increases in use of electricity and biomass/ biofuels. These changes occur in all end use sectors.
    - There are corresponding changes in production and delivery of electricity, fossil fuels and biofuels.
    - Results, in all cases, demonstrate that minimum cost solutions include early and rapid decarbonizing of electricity supply. This includes expansion of hydro, especially in jurisdiction with remaining competitively priced large scale conventional hydro, intermittent renewables (especially wind), nuclear, thermal generation with CCUS, and large scale pumped storage. It is also observed that there are substantial cost reductions with adding high voltage interconnections between jurisdictions for transfer of dependable capacity.
    - Results demonstrate that, as additional options are introduced for the overall solution process, overall costs for achieving GHG reductions progressively decrease.
    - With high GHG reduction targets (60 to 70%), the residential, commercial and agricultural sectors are, by and large, fully decarbonized by 2050. The dominant sectors still producing combustion based emissions include transportation, industrial, and fossil fuel supply and delivery
    - Minimum cost solutions with improved urban form were substantially lower than for the case without improved urban from. There is a need for more assessment in this area, as there are additional options available for reducing GHG emissions in urban regions, which were identified, but not analyzed in the project.
    - In deriving minimum cost solutions for varying production levels for fossil fuels, including for export, it was observed that the increased costs for producing fossil fuels for export tended to be higher that the values of such exports on the global market. This applied especially for scenarios with high mitigation targets. This needs to be further assessed in the context of potential process changes, especially for production of fossil fuels from the oil sands
    - Minimum cost solutions for including nuclear generation as an option for electricity supply, were virtually identical to minimum cost solutions without including nuclear generation. This suggests that there are closely competing cost options when excluding nuclear generation as an option in the electricity supply mix. However, this requires more comprehensive assessment. There also need to be recognition that nuclear should remain as an option for electricity supply, as there are ultimate resource limits on hydro production.
    - There are significant reductions in overall minimum cost with adding large scale conventional hydro in British Columbia. The addition of this option also results in major changes in the overall energy mix in Western Canada, and enhances the economic attractiveness for LNG export from the Province.

- Marginal costs for satisfying GHG reductions are dependent of the selected Scenario. They are generally more than $100 per tonne in the early years, and generally increasing over time. There are also opportunities with reducing the rate of increase in marginal costs over time, with progressive development of additional strategies, policies and technologies.

- The project provided an opportunity for providing insight into some of the more important areas requiring further investigation, including possible research. These include:

  - Review limitations of feedstock availability for production of biomass/ biofuels, as well as opportunities for expanding such supplies
  - Development of second generation biofuels, especially biodiesel
  - Review cost effective options for reducing GHG emissions for heavy freight and rail transport
  - Review opportunities for reducing emissions in the industrial sector and for production and delivery of fossil fuels - to include possible impacts of potential process changes
  - Review options and strategies for major reductions in fugitive emissions
  - Review options for using energy from fossil fuels, with reduced release of GHG's to the atmosphere
  - Carry out long term planning of electricity supply, including combining potential for incremental hydro with large scale conventional hydro, nuclear, thermal generation with CCUS, biomass generation with CCUS, large scale pumped storage, intermittent renewables, high voltage interconnections, and expanded export to the United States.
  - Strongly support need for urban regeneration, and its potential benefits for reducing both overall costs and GHG emissions.
  - Integrating energy and waste management services in urban communities with the goal of reducing costs and enhancing overall efficiency for delivery of such services
  - Explore economics for the production and export of fossil fuels, with consideration of progressive reductions in the use of fossil fuels globally, and the potential for reducing costs for supply and delivery from Canada, in a high carbon price environment.
  - Review overall economics for introducing additional large scale conventional hydro generation in British Columbia.

7. Opportunities for Progress on GHG Mitigation

In Section 6, the principal observations from the project have been summarized. In this concluding Section, options and pathways are presented for how progress on GHG mitigation can be achieved, including delivery on global commitments, both short term and long term. These options and pathways are presented with the intent of providing perspectives on the overall challenge and on the importance for achieving cost effective and timely progress on GHG mitigation. The intent is to serve as a foundation for informed dialogue and to provide better insights into costs of and consequences for effective GHG mitigation.

The information presented in this concluding section is based on the premise that Canada is committed to achieving 80% reductions in GHG emissions by 2050, relative to 1990, and continuing towards 100% net GHG reductions by 2100.

7.1 Approach and Premises

As described in Section 2.4, the overall approach and principal premises for this project are summarized as follows:

- The GHG challenge is separated into three parts:
  - Reducing GHG emissions from combustion of fossil fuels, which represents 72% (unchanging from 1990 to 2010) of total GHG emissions
  - Reducing GHG emissions from non-combustion sources, which represents 28% of total GHG emissions
  - Strategies for achieving net negative GHG emissions
- Most of the analyses in the project sought to derive minimum cost solutions for reducing GHG emissions from combustion of fossil fuels. However, qualitative analyses were also carried out to assess potential for reducing GHG emissions from non-combustion sources, as well as to assess opportunities for achieving net negative emissions. The results of these analyses are reported in Sections 2.5 to 2.7, 5.10 and 5.11. The principal observations are summarized in Section 6.3, and overall interpretation of results is summarized in Section 6.4.
- There were 11 sets of scenarios analyzed with the NATEM Canada model, with selected checks with the CanESS model. Results of analyses for each of these scenarios are reported in Section 5.

7.2 Changes

As noted in Section 6, the fundamental changes that are required to achieve the Goal of the project are:

- Reduce use of fossil fuels, by energy conservation, efficiency improvements and demand side management.
- Reduce use of fossil fuels for meeting end uses, by progressive and rapid transformation towards greater reliance on electricity and biofuels.
- Decarbonize electricity supply and the supply chain for production of fossil fuels and biofuels.
- Ensure that there is a comprehensive approach to also reducing non-combustion GHG emissions.

- Prepare plans and implement early strategies for achieving net negative emissions.

The following commentary is provided with respect to these fundamental changes:

- The first option should always be to reduce energy use, especially use of fossil fuels. This places special emphasis on always having, as the absolute first priority, reduction in use of energy. The second priority is the essential focus on energy efficiency, especially with using fossil fuels. Several of these opportunities are available at low, or even, negative cost. Special attention should also be given to conversion of motive power from fossil fuels to electric motors, wherever possible, with corresponding reductions in primary energy consumption by ratios of about 3 (4, in some cases).
- The dominant change is the transformation of end uses away from burning fossil fuels, and towards increasing reliance on electricity and biomass/biofuels. The change is an increase in end uses for electricity from 22% to 60% (approximately three-fold increase), biomass/biofuels from 4% to 15% (approximately four-fold increase), and decrease of fossil fuel uses from 74% to 25%. As noted in Sections 3.2 and 6, this change is absolutely fundamental as 85% of GHG emissions, from production and use of fossil fuels, occur in meeting energy based end uses.
- It is also important to decarbonize the supply chain for production of electricity, fossil fuels and biomass/biofuels. Canada is the fortunate position of being able to move relatively quickly to decarbonize its electricity supply with combinations of hydro, nuclear, geothermal (limited), thermal with CCUS (including both fossil and biomass – fired generation), and dispatchable storage for dependable capacity and electricity generation. This can be conveniently complemented with relatively low cost intermittent renewables (dominantly, wind) for additional electricity generation.

  It is also important that all reasonable steps be taken to decarbonize the supply chain for production of fossil fuels, again dominantly replacing combustion of fossil fuels with electricity and biomass/biofuels.

  It will also be important that production of biomass/biofuels be also based on maximum use of electricity and biofuels.
- Reducing GHG emissions from non-combustion sources (28% of total GHG emissions) is especially challenging. Each of the four sources of such emissions is very different, and there are no general GHG reduction strategies that apply to all such sources. Nevertheless, it is essential that early investigations be carried out with the goal of defining cost effective transformation opportunities that lead to systematic reductions for each of these four sources of GHG emissions, and maintains overall balance between strategies for reducing emissions from combustion and non-combustion emissions, respectively. Strategies for reducing GHG emissions from non-combustion sources are addressed further in Sections 7.5.2, 7.5.7 and 7.5.8, below.
- With respect to achieving net negative emissions, it needs to be appreciated that this is a very important option, which needs to be started early. Without substantial progress on such options, it will be virtually impossible to achieve 80% reduction by 2050, and absolutely impossible to achieve 100% reduction by 2100. Virtually all strategic options require long lead times and sustained commitment. It is especially important, therefore, that early attention be given to defining a comprehensive integrated long term strategy that ensures that the potential contribution from achieving net negative emissions is realized, and that progressive development of this potential increases over time.

7.3 Managing Massive and Fundamental Change

It needs to be appreciated that the greatest challenge arising from this project is implementing massive and fundamental change for achieving major reductions in release of GHG emissions from combustion of fossil fuels. The following information is presented to provide context for the dramatic scale of this challenge.

- Based on analysis of energy flows for every country in the World, including Canada, the Lawrence Livermore Laboratory showed that, in 2007, electricity provided, on average, 18% of energy based end uses for the entire world. For Canada, the corresponding percentage was 22%, while in the United States, it was 15%.
- Based on analyses of trends in use of electricity for meeting end uses over the past four decades in developed economies, there have been minor variations, with only a modest increase in the relative role of electricity.
- The trends are generally similar with use of biomass/biofuels.
- On a global basis, fossil fuels represent 82% of primary energy supply (2007). On a global basis, the percentage of fossil fuels for primary energy supply has actually been rising over the past two decades, albeit modestly.
- The rate of GHG emissions to the atmosphere and the rate of increase of CO_2 concentrations in the atmosphere, has been increasing continuously since 2000. The annual rate of increase in CO_2 concentration in the atmosphere is now rising at 3 ppm. per annum, as compared to 2 ppm. per annum in 2000.

It is against this backdrop that the enormity of the challenge can be fully appreciated: to increase the role of electricity from its current 22% to 60%, to increase the role of biomass/biofuels from 4% to 15%, and to reduce the role of fossil fuels for end use combustion from 74% to 25%.

While a transformation of this magnitude is daunting, it is also helpful to appreciate that massive transformations of this scale are not unprecedented. Over the past century or so, for example, we have witnessed a transformation from “horse and buggy” to the world of today.

To achieve essential and rapid progress on this formidable challenge, the principal elements for success will certainly include all of the following:

- There needs to be clarity in conveying fundamental understanding and appreciation that the dominant challenge is with implementing transformations away from combustion of fossil fuels for meeting energy based end uses. The dominant transformations are increased electrification and increased use of biomass/biofuels.
- It is essential to also convey clearly that today, every Canadian, as a user of energy related services dependant on combustion of fossil fuels, is contributing directly to the climate change challenge. Correspondingly, there is need to also convey greater appreciation of the options that are available for still receiving those same services, but with reduced GHG impact. This is required so that all Canadians have greater appreciation of the respective actions that can be taken individually and collectively on GHG mitigation.
- There also needs to be clarity that there are different transformation options that are available for each sector in reducing or eliminating dependence on combustion of fossil fuels, each with its relative effectiveness and associated costs. The ultimate solution will require implementing

numerous combinations of transformation options for each sector in each jurisdiction, and including, in some cases, significant variations between jurisdictions.

- It needs to be clearly understood that achieving the 80% GHG reduction Goal by 2050 will involve significant cost, including introduction of carbon pricing. Managing the implications of these costs will require special attention, including progressively increasing costs over time.
- It also needs to be respected that the overall problem is complex, and that that the overall solution will require greater cooperation among all levels of Government, between Government and Industry, as well as full engagement of Non Profit organizations, stakeholder groups, Universities & Colleges, and citizens.
- The process for ensuring that there is progress on this challenge will require an approach that is based on appreciation that a minimum cost solution for achieving targeted GHG reductions requires analyses that respect the full complexity of the challenge, including the many alternative transformation options in each sector in each jurisdiction, and over time, and the associated need to ensure efficient deployment of capital.
- While the dominant immediate challenge is to decide and implement the most cost effective transformation options that lead to progressive and rapid reduction in reliance on combustion of fossil fuels for meeting energy based end uses, this is not the only challenge. As outlined in Section 7.2 above, there needs to be a balanced approach that ensures that there are corresponding transformations for achieving reduced GHG emissions for the supply chain for electricity, fossil fuels and biofuels, for reducing non combustion emissions, for strategies for achieving net negative GHG emissions, and for implementing various efficiency, conservation, conversion and demand side management measures.
- The overall solution for achieving the 80% reduction Goal by 2050 is not yet fully defined. The ultimate solution will require selection and implementation of strategic options that have been identified, but not analyzed in this project, as well as other options which are not known at this time. However, it is clear that reducing reliance on combustion of fossil fuels to meet both energy-based end uses and the supply chain for production of electricity, fossil fuels and biofuels is absolutely essential. It is very important to move forward immediately in implementing the lowest cost transformation options for achieving such transformations while, at the same time, carrying out additional investigations that provide improved bases and understanding of additional cost effective options for later implementation.
- In parallel with implementing major transformations in Canada, there is also the need to work with other countries around the world, including especially industrialized countries, to ensure rapid and cost effective progress in effecting essential international transformations for reducing global GHG emissions.
- Finally, there is an absolute requirement for strong leadership at all levels, to ensure that there is a cultural shift away from resisting change, to embracing the absolute imperative for promoting and driving change in response to a very major global challenge that, frankly, requires strong, committed, sustained, and unwavering leadership.

7.4 Carbon Pricing

As explained in Section 3.3, one of the valuable outcomes from using an optimization model, such as the NATEM Canada model, is that it derives marginal costs for achieving prescribed GHG mitigation targets over time. In the context of the problem as defined, these values can also be interpreted as corresponding to the optimal CO_2 unit price values for achieving prescribed GHG emission reductions. In the context of results from the various scenarios, this leads to the following proposed actions concerning principles for a carbon pricing framework for Canada:

- A carbon pricing system will be important for providing cost efficient market based incentives to support essential transformations away from burning fossil fuels for energy related services, towards options that deliver those same services with reduced GHG emissions.
- Optimal carbon values and progression of values over time will be dependent on underlying premises concerning most likely evolution of the Canadian economy, and GHG reduction targets and associated projections. However, as is clear from results of the various scenarios, an effective carbon pricing system for producing major reductions in GHG emissions will certainly need to be well in excess of $100 per tonne, with full recognition that this will increase progressively over time. This recognition is amplified as a direct consequence of the high rate required for decarbonizing the economy over a relatively short time period.
  While results from the project, in some cases, include high marginal costs in the long term, it is important to appreciate that such longer term costs will, almost certainly, reduce. There will be options for the long term which are either not known at the present time, or are not adequately understood. There are many promising new technologies in early development. It is impossible to predict which options will be most cost effective at this stage. Progressive increases in the price of carbon should provide incentives to bring these innovations and breakthroughs to market, which may well drive down costs significantly. Such advances may be developed in Canada, or may be developed in other countries and then adopted in Canada.
- On the other hand, it is also important to appreciate that there are many drivers which can increase both total costs and marginal costs. These included considerations, such as excluding selected classes of infrastructure that would otherwise be included in minimum cost solutions, scheduling delays, imposition of equity constraints, non-optimal policy structures and regulatory arrangements, etc. (see also Section 5.4.8)
- However, for the immediate future (to 2030), marginal costs as computed can be considered as providing reliable insight into appropriate carbon pricing values for immediate assessment.
- For developing a carbon pricing framework for Canada, there are several key considerations:

    - The dominant goal of the framework should be on being a price driver for reducing CO_2 emissions from combustion of fossil fuels, and providing incentives towards developing and using cleaner technologies and/ or more energy efficient practices. Since 85% of CO_2 is generated by end users (residential, commercial, transportation, industrial, agriculture) in burning fossil fuels, it is clearly evident that the primary focus will need to be on the end user. This same pricing structure will then need to be extended through the entire supply chain for production of electricity, fossil fuels and biofuels, to ensure that costs for reducing CO_2 emissions are applied consistently and comprehensively across the entire economy. It is important that this framework be completely transparent
    - It is desirable that carbon pricing systems be consistent across jurisdictions. Variabilities in costs will lead to more expensive overall solutions for achieving national GHG reductions. This consideration places special emphasis on working towards harmonized carbon pricing frameworks in a multi-jurisdictional context. This becomes even more important for contiguous regions because of greater inter-dependence between neighboring jurisdictions.
    - It is important to ensure that the pricing structure, as implemented, is consistent with optimal carbon pricing values. In particular, pricing structures which are either higher or

lower that the optimal price values will lead to increased overall costs for achieving the prescribed GHG reduction target. The normal temptation to start with values lower than the optimal values will result in either failing to meet the prescribed GHG reduction target, or require imposition of additional more expensive regulatory measures.

- It is important to have a rigorous analytical basis for deriving optimal GHG price values for achieving GHG reduction targets. While the analyses for this project have been based on deriving optimal marginal values which apply for all of Canada for each time period, the capability of the NATEM Canada model can be extended to adapt to simultaneous consideration of different pricing frameworks for the respective jurisdictions, and including projected parallel developments elsewhere, especially in the United States.
- Finally, it is important to appreciate overall complexity in developing and implementing a successful and comprehensive carbon pricing framework for Canada. There are major differences in energy systems between Canada's different jurisdictions, as well as differences in approaches to achieving progress on the climate change challenge. From this, the overall framework will need to find effective balance between jurisdictional approaches and priorities, and the national need to deliver its share of global GHG emissions reductions. Clearly, this will require a cooperative approach among all levels of Government, as well as between Governments and the Business Community.
- This overall approach will require careful consideration of strategic and policy options, based on results from rigorous analyses of carbon pricing impacts and GHG projected reductions, with comprehensive integrated multi-jurisdictional consideration in a long term context.

  It is important to respect that, as of today, five Provinces, collectively representing more than 85% of national GDP, have implemented carbon pricing. This is an encouraging start.
- There is real urgency in developing progressively a comprehensive and well considered carbon pricing framework for Canada. There is a need to also ensure that this framework is developed progressively with the goal of achieving alignment nationally and with the United States in the short term. There is also a need and opportunity for Canada to assume a stronger global leadership role in working with Governments, Industry and stakeholder organizations around the world to make major progress on this formidable global challenge.

- It is recognized that carbon pricing frameworks, while obviously very important, are designed to deliver solutions that respond to market-based incentives. With this recognition, it is important that there be other mechanisms that also contribute to achieving deep GHG emission reductions. These include, as examples, regulatory impositions, financial and other incentives, modified or new codes and standards, and support for important research and development priorities.

7.5 Strategic Priorities

Results from the scenarios, as well as the work carried out on non-combustion emissions and net negative emissions, have served as a basis for developing perspectives on the most important challenges and priorities for early attention and action. This is within the context of the five sets of changes that are required to achieve the 80% reduction Goal by 2050, as listed in Section 7.2.

In presenting strategic priorities, it is important to note, once again, that short to medium term results for GHG mitigation, are more credible than long term results. For the short to medium term, the options are clearly understood, are well defined, and are more limited. Solutions from the various scenarios, such as increased energy efficiency and early large scale electrification, were shown to be robust solutions, and should be implemented quickly.

On the other hand, for the longer term future, there may be transformation options, which were not adequately represented in the two models, or are still not defined. It needs to be respected that, as additional transformation options and technologies are better defined, the same analytically rigorous approach needs to be repeated for assessing objectively the merits of such options in future investigations, for defining longer term GHG mitigation solutions.

In this Section, the general approach is to address the short to medium term, as well as the long term future. For the long term, special consideration is given to defining the more important challenges that should be addressed in the short term, so as to have better information for longer term future optimization studies.

7.5.1 Immediate Initiatives

The most important immediate initiative and challenge is to implement transformation strategies that achieve major reductions in combustion of fossil fuels, and correspondingly, increase the role of electricity and biofuels to deliver these same energy related Services (see also Section 6.4). This applies dominantly to effecting major and fundamental change to meeting end uses (85%), but also applies to transforming the entire supply chain for production of electricity, fossil fuels and biofuels.

The strategic option, that has the largest potential impact and is best established in terms of knowledge and expertise in Canada, is increased electrification of end uses, rapid expansion of electricity supply infrastructure, and decarbonizing electricity supply. For all scenarios, these strategies were consistently part of the minimum cost solution. It was also observed, from results of the various scenarios, that these options were implemented immediately and quickly.

The other immediate initiatives include implementing energy efficiency improvements and conservation methods. As also noted in Section 6, many of these options also occur early in the minimum cost solution, especially as many of these options are relatively low cost options (including several at negative cost).

While these are the dominant priorities for immediate implementation, it also needs to be appreciated that other options, as listed in Section 7.2, are also important. However, for several of these options, the immediate Plan of Action is less clear, with more review and assessment clearly required. As examples, these include development of second generation biofuels, CCUS, strategies for heavy duty transport, and process changes in industry and fossil fuels supply. Implementing carbon pricing with progressively increasing carbon prices, will almost certainly lead to technologic developments and possible breakthroughs. There is an obvious need to carry out more investigations, as well as research and development, on these and other high priority initiatives, in order to systematically provide improved definition of the most promising longer term strategic options for achieving the GHG emissions reduction Goals.

7.5.2 Fugitive Emissions

Fugitive emissions, as reported, are 9% of total emissions. However, as documented in the IPCC *Fifth Assessment Report*, and as reported in various investigations in North America and elsewhere, GHG emissions from fugitive sources are, almost certainly, under-reported, possibly by factors as high as 4, or even higher.

The most serious problem is with venting and leaks of natural gas, which is 75 to 95% methane. Methane has a global warming potential 34 times greater than CO_2. To reduce global warming impact from venting and leaks, the clear preference is to capture and flare the natural gas, by converting methane to CO_2.

Fugitive emissions occur at wellheads (for both oil and gas production), in collection systems, at gas processing facilities, in refineries, in transmission and distribution systems, and at locations of final delivery and use. There are also fugitive emissions in coal mining, albeit that these are relatively minor.

Taking action on reducing GHG emissions from fugitive sources is both urgent and overdue. The essential elements of an action plan include:

- There is need for a coordinated and comprehensive program of information collection to establish the overall magnitude, and distribution of the fugitive emissions challenge in Canada. This includes developing in depth understanding of the magnitude of fugitive emissions from drilling operations, from oil and natural gas collection systems, in gas processing facilities, in refineries, in transmission and distribution systems, and at locations of final delivery and use.
- There is need to define options, including technologies and associated costs, for reducing GHG emissions from such sources, through capture and processing. This includes processes for collection and conversion to salable products, and/or for flaring. It is also necessary to define limits on the magnitude of such opportunities.
- There is a need to include such considerations in an overall minimum cost approach for GHG mitigation, to determine optimum levels for reducing GHG emissions from fugitive sources. It is noted that the NATEM Canada model already has this capability. However, this feature was not used in the project, as there was no reliable information available to represent opportunities for capture and processing of such gasses, and for including such captured gasses in the overall natural gas supply system, with associated economic benefits.
- For Canada to make major progress on reducing GHG fugitive emissions, there is a need for a comprehensive policy framework. This may include carbon pricing, but may also require a more effective and efficient regulatory framework for limiting such emissions.
  Such approaches and frameworks need to be aligned with parallel developments in other leading jurisdictions around the World.

7.5.3 Reducing Fossil Fuel Emissions

As is clearly evident, the primary transformation required in Canada's energy system, is to reduce emissions from burning fossil fuels, fundamentally because this produces CO_2 which is the dominant source of rising GHG concentrations in the atmosphere and the principal cause of climate change. This is truly a global challenge. For the fossil fuel industry, this represents a special challenge, as there is a dominant global need to achieve major reductions in release of CO_2 to the atmosphere from burning fossil fuels.

Against this backdrop, the challenges for the fossil fuel industry in adapting to fundamental and major change may be summarized as follows:

- There will still be a need for combustion of fossil fuels as an energy source over the next century, while the global community progressively implements strategies which reduce dependence on burning of fossil fuels to meet energy based needs. While there is real urgency in effecting such global transformations as quickly as possible, this will continue to be a major global challenge and will take time.
- It will be important for the fossil fuel industry to explore strategies for meeting energy based needs without, at the same time, producing GHG emissions which are being released to the atmosphere. While the dominant current strategy is CCUS, it will be important to assess other strategic options, such as possible process concepts that produce energy from fossil fuels, but with reduced GHG emissions, or developing carbon based products that may have market value and/or may be readily stored as waste products.
- Where fossil fuels continue to be burned for meeting energy based end uses, it will be important to alter the overall approach for meeting such needs. As the cost for burning fossil fuels increases with progressive implementation of carbon pricing systems around the world, there will be increasing financial incentives to ensure that this energy is utilized more fully. This will include various thermal capture and use options, such as combined cycle generation, including cogeneration, thermal recovery and reuse systems, longer term thermal storage systems, and district energy systems. There will also be increasing incentives for co-location planning for industrial, commercial and residential developments to minimize thermal losses from burning fossil fuels.
- It is also important to recognize that fossil fuels will still remain as an important feedstock for the petrochemical industry, as well as being an important resource for certain industrial non combustion processes, such as producing graphite electrodes for smelting operations.

7.5.4 Electricity Supply and Delivery

As already noted in Sections 6, 7.2 and 7.5.2, the dominant immediate strategies included rapid electrification of end use and supply systems, major expansion of electricity supply and delivery (three-fold increase over 35 years) and decarbonizing electricity supply. Such major changes have obvious impacts on the electricity supply industry, including fundamental changes in the way in which electricity supply systems are planned and developed for future needs. These may be summarized as follows:

- As noted in Section 5.11.4, minimum cost solutions for the various scenarios include rapid expansion of renewable electricity supply, especially in those jurisdictions which have major remaining competitively priced conventional large scale hydro potential, and complemented with intermittent renewables electricity production, dominantly wind generation. Also, as noted, for those jurisdictions that do not have competitively priced undeveloped large scale conventional hydro potential, the minimum cost solutions include combinations of nuclear, wind, coal fired thermal with CCUS retrofits, dispatchable large scale pumped storage, gas fired thermal, geothermal, solar, and high voltage interconnections with neighboring jurisdictions.

It is important to note, once again, that the NATEM Canada model did not include representation of incremental hydro (adding hydro capacity at existing or future hydro sites) for dependable capacity supply. If this had been included, it is expected that this option would displace much of the dispatchable large scale pumped storage generation in the various scenario solutions. This is an important feature to be added to the NATEM Canada model for future applications.

- For those jurisdictions which are already hydro dominated and are the lowest cost jurisdictions for electricity supply in North America (Quebec, Manitoba, British Columbia, and Newfoundland & Labrador), the minimum cost solutions demonstrate rapid development of all remaining conventional hydro potential in the respective jurisdictions within 25 years. This applies also to developing the full potential of the hydro resources of the Mackenzie River in the Northwest Territories. While such rapid development of remaining hydro potential in Canada is not realistic, it nevertheless demonstrates that early and rapid development of Canada's remaining hydro potential is an important component of the minimum cost solution for achieving Canada's GHG mitigation targets.

  There is an important consideration with planning development of Canada's remaining hydro potential, while also ensuring that continuing development of electricity supply in hydro dominant jurisdictions continues to be cost competitive and emissions free. As remaining hydro potential, as reported, is only 163,000 MW, it is clear that remaining hydro potential in most jurisdictions will be close to being fully developed within a relatively short time, especially in terms of electricity energy production. As this electrical energy production limit is being reached, the normal evolution in such systems will be towards intermittent renewables, especially wind, for additional electrical energy generation, and complemented with additional generating capacity at existing or future hydro sites for additional dependable capacity.

  Because of rapid projected expansion of electricity supply in such jurisdictions, it will be especially important to ensure that development of all remaining conventional large scale hydro projects is carried out with consideration for installing additional generating capacity at later dates. There will also be a need to assess potential for adding additional generating capacity at existing hydro sites, especially sites which are close to major load centres.

  It should also be appreciated that, for the long term future, such hydro sites may also be attractive for development of large scale dispatchable pumped storage, especially to complement electricity supply from intermittent renewables sources (either in the respective jurisdiction or in neighboring jurisdictions). This will apply especially for sites with relatively large lower and upper reservoirs, and in proximity to major load centres.

  This potential evolution of hydro, including large scale conventional hydro, incremental hydro and pumped storage, in hydro dominant jurisdictions, reflects a progressive shift in the role of hydro in such jurisdictions. This is obviously accelerated by the need to increase the role of electricity supply three-fold over a 35 year period. The shift is from being the dominant source of electricity to assuming a central role in both supply of dependable capacity and flexible backup with storage, for additional electricity supply from intermittent renewables. This role can extend to including neighboring jurisdictions. This evolution was only partially assessed in the current project, but certainly deserves more detailed assessment.

- For the other major jurisdictions, there are several challenges, including:

  - Reducing dependence on conventional coal-fired thermal generation, to ensure compliance with Federal Regulation SOR/2012-167 (maximum of 420 tonnes of CO_2 per GWHR of electricity production). This requires installation of CCUS retrofits at existing

coal–fired generating facilities, possible early closure of existing coal fired generation facilities, and taking existing facilities out of operation after 50 years of service
  - Adding or introducing nuclear generation, for base load generation
  - Introducing new coal-fired generation with CCUS, for base load generation
  - Adding gas-fired generation, with combined cycle and/or cogeneration and/or CCUS
  - Introducing biomass generation, combined with CCUS
  - Adding intermittent renewables for energy supply
  - Adding high voltage interconnections with neighboring jurisdictions which have lower cost electricity supply

  For these jurisdictions, the differential unit cost of electricity supply, relative to hydro dominant jurisdictions, will tend to increase. This differential will become more significant as the role of electricity for meeting end uses, increases three-fold. This should, quite naturally, result in greater cooperation between neighboring jurisdictions, especially where projected differential costs for electricity supply are high, for meeting increasingly electrified end uses.

- With respect to the process for decarbonizing electricity supply, there are several important options, especially in jurisdictions which have limited hydro potential, and ready availability of fossil fuels, especially natural gas and coal. These considerations include, as examples:

  - Development of thermal generation (coal or natural gas) with CCUS
  - Development of CCUS retrofits with existing coal fired generation
  - Development of coal gasification with combined cycle and cogeneration, and including CCUS
  - Gas fired generation for peaking or stand by service, especially in or close to major load centres

  It is important that all such options be carefully assessed in the context of assessing opportunities for delivering low cost electricity for future situations with projected carbon pricing.

  For the longer term, the electricity supply sector will be one of the major opportunities for producing net negative GHG emissions, especially with the bioenergy with CCUS option. As has been demonstrated in this project, this option is part of the overall minimum cost solution for some scenarios. As projected by IPCC in its *Fifth Assessment Report*, this is a very important option for future electricity supply.

  It is especially important that this option be included in future electricity supply planning in Canada, especially in jurisdictions without major undeveloped conventional hydro potential and with substantial potential for increased biomass production.

- A very important consideration is the interplay between investing in large scale electricity supply, including the high voltage grid, and addressing opportunities for reducing demand at the urban community level. As demonstrated in Section 3.4.7, the role of local distribution utilities will need to change to effectively capture benefits from integrating energy and waste management services. The elements of this include, as examples, energy management/conservation systems in commercial developments, distributed energy, district energy for hot water and steam production, waste conservation, waste to energy, solar electricity supply from residential and commercial buildings, geothermal and air source heat pumps, passive solar thermal systems, thermal energy storage, and smart energy management systems. With integration of such services at the community level, the role of the local distribution utilities should change in major ways, as described in Section 3.4.7. This includes not only purchase of electricity from the high voltage grid for distribution to individual households, and to commercial and institutional complexes; it will also include both selling and purchasing electricity and other services within the urban community, managing comprehensive integrated local systems that are much more complex than classical distribution utilities, and buying and selling electricity from and to the grid company.

Due to limitations in time and available funding, these options were not fully explored in the current project. This is an area that certainly merits further investigation.

It is important to emphasize, once again, that such developments will be complementary to the role of large scale electricity supply, including the high voltage grid. The grid is still required to meet large scale electricity demands where economies of scale are dominant, and for ensuring reliability of supply, including for urban communities.

- As demonstrated with results of Scenario 7, there are additional potential economic opportunities with sale of GHG emissions free dependable capacity to the United States, especially from Quebec and Manitoba. This is available at competitive cost, as peak demands in the United States and Canada occur at different times of the year.
- When considering dependable capacity, it will be important to recognize that there will be ultimate limits on the amount for dependable capacity available in Quebec, Manitoba and other hydro dominated jurisdictions, even with additions of both incremental hydro and large scale dispatchable pumped storage generation. There will be increasing competition for dependable capacity in such Provinces, as well as from neighboring provinces, neighboring states in the United States, and increasing potential demands from energy intensive industrial developments.

7.5.5 Biomass, Biofuels and Forest Products

At the present time, production of biofuels is small, but significant. It is driven primarily by requirements of Bill C33; Canada Environmental Protection Act (2010). The Renewable Fuel Regulation, in this Act, mandates that gasoline should have 5% ethanol and diesel fuel should have 2% biodiesel. This is supplemented by additional regulations in selected provinces, with higher biofuel requirements. These requirements are equivalent to annual production capacities of 2.1 billion liters of ethanol and 585 million liters of biodiesel, respectively. In 2013, production capacities were 1,785 million liters of ethanol and 464 million liters of biodiesel production capacity, with the shortfall being imported, primarily from the United States. These requirements are to serve energy based needs in the transportation and industrial sectors.

Liquid biofuels are produced primarily from food crops; corn and wheat to ethanol, and vegetable oil (or waste oils) to biodiesel. Technologies to shift liquid biofuel production from lignocellulosic (biomass) feedstocks are under development. At the present time, biomass-to-energy options in Canada are almost entirely linked to electricity and heat production. At the present time, this includes 39 cogeneration plants, in the pulp & paper and sawmills sectors, with total capacity of 1,349 Mw, and 16 biomass to electricity projects with total capacity of 465 Mw. These facilities also produce thermal energy (hot water, steam, and space heating). There are also eight community wood to heat facilities. Collectively, this represents approximately 2% of primary energy supply in Canada. When also including liquid biofuels, total primary energy supply from biomass and biofuels is 4%.

In this project, it has been demonstrated that a very significant component of the overall solution for achieving major reduction in GHG emissions, is for biomass and biofuels to assume greatly enhanced roles for replacing dependence on fossil fuels to meet end uses, as well as for decarbonizing the entire supply chain for production of fossil fuels, biofuels and electricity. Over the next 35 years, there is a projected four-fold increase in use of biomass/ biofuels.

There are however several issues and challenges which need immediate attention. These are required as a basis for providing greater clarity for developing a comprehensive integrated plan for defining major transformations, dominantly in the forestry and agricultural sectors to 2050, and beyond. There are also certain initiatives that can proceed, without delay. The key issues, challenges, and early recommended actions are summarized as follows:

- The first challenge is to redefine the role of both the agricultural and forestry sectors in terms of greatly increased demands for both traditional products, as well as additional products (dominantly energy products) that are requires to achieve major reductions in GHG emissions. The dominant traditional products include food and first generation energy crops (i.e. oilseeds) in the agricultural sector, and forest products in the forestry sector (dominantly pulp & paper, and processed wood products). In the project, assessments were made concerning the potential for additional energy crops (corn, wheat, oilseeds, as well as biomass crops such as switchgrass) to be generated from the agricultural sector. Similarly, assessments were carried out with respect to additional biomass production from the forestry sector, while respecting ongoing production of pulp & paper and wood products. The analyses also included preliminary consideration for bringing marginal forest and agricultural lands into production, especially for energy crops. There was also special consideration for introducing high productivity energy crops, such as switchgrass or miscanthus.

  Based on these preliminary assessments, the results from the Scenarios demonstrate that there is a significant shortfall in availability of both biomass and biofuels for meeting end uses for achieving major targeted reductions in GHG emissions. High priority should be given to developing in-depth appreciation of possible resource limits for production of energy crops, in addition to traditional outputs from the agriculture and forestry sectors. This will include in depth consideration of appropriate limits for potential conversion of food production crops to energy crops in the agricultural sector.
- The dominant limitation for achieving reductions in combustion based emissions of more than 60 or 70%, relative to 1990, was due to limits on biofuel supply for heavy freight transport. This constraint has a high marginal value, as unit costs for all other options for heavy transport are very high (see Section 7.5.6). The analyses demonstrated that competitively-priced biodiesel is requires to meet heavy transport needs. This could include both first and second generation biodiesel. High and immediate priority should be given to further research and development of second generation biodiesel, including FT biodiesel.
- The agricultural and forestry sectors will, almost certainly, become the dominant source for production of net negative GHG emissions. In the project, two important areas for this overall strategy include use of biomass for electricity generation, combined with CCUS, and strategic management of harvested wood products, which serve as a carbon sink during their active lifetime. Development of HWP as a strategy for carbon storage requires long term and sustained commitment. Given the importance of this strategy for meeting the 2050 Goal, as well as the even more challenging Goal in 2100, this is a strategy which should be strongly supported and initiated immediately.

  Early development of the biomass based electricity generation with CCUS option also needs to be given early attention. However, this option needs to be assessed in the context of a minimum cost solution which includes more detailed consideration of the potential biomass/ biofuel supply constraints, as per item 1 above.

The other major considerations which requires immediate attention is afforestation and reforestation in the forestry sector, and carbon retention strategies in the agriculture sectors. With introduction of carbon pricing, there will be an enhanced economic case for increasing the proportion of managed forest lands in Canada, as well as enhancing management of existing managed forest lands. There will also be a need to enhance carbon retention strategies for farmed agricultural lands.

- With projected expansion of both the forestry and agricultural sectors to meet both traditional needs and enhanced energy products, there is a special need to address principles of sustainable development. This is especially important, not only for Canada, but also for the World, as a very substantial portion of the world's forests and cultivated lands are in Canada; 10% of the World's forests and 5% of the World's cultivated land are in Canada. In the forestry sector, for example, it will be important to maintain the tradition of having forest development plans that comply with laws and regulation, based on sustainable forest management principles, including maintaining ecosystem health and creating economic opportunities for communities.
- In the project, there was extensive work carried out with both the NATEM Canada and CanESS models to represent the forestry and agricultural sectors in a comprehensive, integrated, multi-jurisdictional and long term context. It will be important to continue reflecting the overall minimum cost solutions for meeting national GHG mitigation targets, trade-offs, and constraining conditions, with more detailed representation of the various development and production options, with continuing detailed analyses.

7.5.6 Heavy Freight Transport

Based on results from the various scenarios, the dominant remaining challenge in 2050 for achieving major reductions in combustion based GHG emissions is the high cost for reducing GHG emissions for heavy duty truck freight and rail transport in the transportation sector. This sector has one of the fastest growth rate of emissions.

The interplay of options included:

- Upper limit reached on production of feedstocks for biodiesel for heavy freight transport
- Electrification of rail transport between major urban centres
- Use of hydrogen to displace diesel and biodiesel for heavy duty truck and rail transport

Costs for electrifying rail transport between major urban centres and use of hydrogen proved to be very expensive (well in excess of $1,000 per tonne of CO_2-eq), and accordingly, were considered as not being viable options.

This situation results in a special challenge, which requires more comprehensive consideration of a range of options which were not considered in the project. This is an area that could merit innovative thinking and development of selected concepts. Some preliminary ideas, as examples, include:

- Strategies for overcoming the apparent limitation on availability of biodiesel for heavy freight and rail transport, including potential technological developments, such as accelerated algae production with concentrated CO_2

- Reconsideration of large scale battery storage systems, including large scale interchangeable battery packs for heavy duty truck and rail transport
- Development of mobile and interchangeable CCUS systems
- Reducing costs for production and use of hydrogen
- Replacing diesel engines with higher efficiency combustion turbines, and possibly, including mobile compressed air energy systems that increase energy output three-fold

It will be important that these and other possible options be assessed over the next decade, with the goal of providing credible options for more detailed consideration within the next decade.

7.5.7 GHG Reductions from Industry

GHG emissions from industry occur from two sources; combustion and non-combustion. For 1990, these were 63 and 56 Mt, respectively, from these two sources, for a total of 119 Mt, equivalent to 22% of total emissions. For the Reference Scenario, these increased to 115 and 119 Mt by 2050, respectively, again representing 22% of total emissions (11% each). For Scenario 8, combustion emissions reduced from 115 Mt to 35 Mt in 2050, while there was no reduction in non-combustion emissions. As a consequence, for this scenario in 2050, industrial combustion emissions represented 8% of total emission, while industrial non-combustion emissions represented 28% of total emissions.

From this, it is evident that there is a special need to assess options for reducing GHG emissions from both combustion and non–combustion sources in the industrial sector, with special attention to reducing GHG emissions from non- combustion sources.

It needs to be acknowledged again (see also Section 2.6.1) that this is a particularly challenging area, especially as this option for reducing potential reductions in GHG emissions has received relatively little attention, and there are few examples world–wide which demonstrate successful applications for achieving significant reductions in GHG emissions from such sources.

Nevertheless, because of the scale and overall complexity of the challenge, this needs to be addressed, and should not be set aside for review at some later date. In addressing this challenge, consideration should be given to the following:

- As with combustion emissions, the first option should always be to assess the potential for efficiency improvements and overall conservation. Some of these may be available at very low cost, or even, at negative cost. It will also be important to include cost relationships which reflect unit costs for achieving efficiency improvements.
- As with the overall approach with assessing options for reducing GHG emissions from combustion sources, the primary focus should be on analyses of transformation options at every location in each industrial process where GHG emissions are being generated, and where there is potential for reducing or eliminating such emissions. These transformation options can be costed in terms of unit costs for GHG mitigation. As with the overall approach for minimizing overall cost for reducing GHG emissions from combustion sources, the minimum cost approach can be extended to also include reducing GHG emissions from non-combustion sources. This will, however, require investigations into potential transformation options for reducing GHG

emissions in the various industrial processes, along with analyses of associated unit costs and limiting constraints.

This overall cost minimization approach will include reductions from implementing transformation options in the various industrial process, as well as reductions from implementing respective efficiency improvements and conservation options.

- The approach, as defined above, is based on the premise that the same industrial outputs will continue to be produced, with the only change being process changes within the overall production process that reduce or eliminate GHG emissions. While most industrial outputs will still be required, it is possible that some industrial outputs will reduce, or will be replaced. Such changes may be influenced by impacts of GHG pricing, either explicit or implicit. It will be especially important to develop in depth understanding of projected impacts from GHG pricing on likely changes in the mix of industrial outputs.

It is suggested that special investigations be carried out over the next decade to assess the potential for reducing GHG emissions from the industrial sector. This includes reductions from both combustion and non-combustion sources, with special attention to non-combustion sources. This should include reviews of process changes, as well as efficiency improvements and conservation methods, within the various industrial processes that lead to reductions in GHG emissions. It is also desirable to extend the current cost minimization approach to also include cost minimization for transformation options for non-combustion GHG mitigation. As also noted above, it will be important to assess and understand the likely impact of GHG pricing on the projected mix of industrial outputs.

With this improved knowledge of GHG mitigation options for the industrial sector, it should then be possible, within the next decade, to define a clearer long term strategy for the industrial sector for GHG mitigation, including reductions from both combustion and non-combustion sources.

7.5.8 GHG Reductions from Agriculture

GHG emissions in the agricultural sector include both combustion and non-combustion emissions. For the Reference Scenario (Scenario 1), projected emissions in 2050 are 18 Mt and 88 Mt respectively, representing 2% and 8% of total emissions. For Scenario 8, combustion emissions reduce to 5 Mt, or 0.5% of total emissions. However, non-combustion emission, even after considering 15% reduction (see Section 2.6.3) are still 75 Mt, which is 17% of total emissions in 2050 for the 60% reduction Scenario.

This is an especially challenging area for achieving substantial reductions in GHG emissions. The sources of emissions are dispersed, costs for achieving substantial reductions are high, and administration can be time consuming. Furthermore, there are absolute limits concerning ultimate GHG reduction potential. For example, enteric fermentation is the result of methane release from digestive processes in ruminant livestock. There are opportunities for reducing such emissions with better feeding methods, and feed additives; however, this reduction potential is not large, as there will still be methane releases for basic digestive processes.

As explained in Section 2.6.3, there are opportunities for reducing GHG emissions from non-combustion sources in the agricultural sector. Clearly, there is merit in having improved knowledge of such potential options, including costs for effective administration of such options. This will become more important with projected expansion of the agricultural sector for increased production of energy crops. With such developments, it will be important to give special consideration to improved management of nitrogen based fertilizers, which are the source of nitrous oxide emissions from increased fertilizer application.

Relative to other strategic priorities for reducing GHG emissions, this is a lower priority area. Opportunities for reducing GHG emissions from agriculture non combustion emissions need to be continually monitored; however, it should be respected that the potential for achieving major reductions in GHG emissions from this sector are unlikely to be large.

7.6 Economic Impacts

As noted in Section 7.3, the process of implementing fundamental change in Canada, to achieve major reductions in GHG emissions, will impact every Canadian very directly. There will be a need for strong leadership at all levels of Government, by industry leaders, by stakeholder groups, by Not-for-profit organizations, and by Universities and Colleges, for this massive change to be fully realized.

In this Section, there will be brief discussions on those sectors which will be subject to the greatest expected change. This will include considerations for responding to impacts of such changes, as well as identifying potential economic opportunities in Canada for potential growth and development.

It is also noted that there is a fundamental theme that applies to all sectors. With major changes occurring as a result of major GHG mitigation measures, there are opportunities for new strategic initiatives or technological developments that contribute to enhancing opportunities in all sectors. This includes enhancing direct benefits in those sectors that are positively impacted by GHG mitigation, or minimizing disbenefits for those sectors that are negatively impacted. In all cases, such developments have economic potential in Canada, including within the respective sector, through expansion to other sectors by cross-fertilization, and potentially, for export of such initiatives and technologies, and including related services.

7.6.1 Fossil Fuels Sector

As noted in Section 7.5.2, this is the sector that will be subject to the greatest change. In Canada and around the world, there will be a need to greatly reduce dependence on burning fossil fuels for providing energy related services. Over the next century, as the World moves progressively toward eliminating net GHG emissions to the atmosphere, there will be enormous pressures for the fossil fuel industry to adapt to this very fundamental change.

Against this context, it is important to appreciate that the dominant challenge for the fossil fuel industry, is one of adaptation to changing needs. The World will still require fossil fuels as feedstock for various industrial processes and products. The World will still require fossil fuels for combustion to meet selected energy based needs. And, the World will still be seeking options for delivering energy from fossil fuels by processes that result in greatly reduced GHG emissions.

It is also important to appreciate, that despite the overall urgency in making major progress on reducing GHG emissions, the greatest immediate challenge is with progressively implementing fundamental transformations for converting end uses away from reliance on combustion of fossil fuels to having these came energy related services provided with electricity and biomass/biofuels. Despite best intentions and commitments, such major transformations will not occur quickly. This provides the basis for ensuring that progressive and fundamental change in the fossil fuel industry can occur in an orderly and timely manner.

7.6.2 Low Cost and Clean Electricity Supply

As noted in Sections 6.5.3, Canada is in a uniquely advantageous position with respect to electricity supply. Historically, Canada has produced the lowest cost electricity in the OECD. Also, Canada is one of the few countries in the World which produces more than 80% of its electricity from non-emitting sources.

Based on results from the scenarios, it has been demonstrated that Canada can move quickly to having its electricity produced almost entirely from non-emitting sources, as well as being produced at competitive rates, relative to other jurisdictions around the World. In addition to responding to the very important need to increase the role of electricity almost three-fold to meet Canadian domestic needs, there are additional opportunities which have added potential for enhancing Canada's economy;

- Provide a globally competitive basis for producing energy intensive products, especially in metals and mining, forestry, and energy intensive manufacturing
- Provide export of electrical energy and dependable capacity, especially to selected neighboring regions in the United States.

These opportunities will be amplified for Canada, with progressive implementation of global carbon pricing frameworks, which will lead to the progressively increasing costs for energy intensive products in jurisdictions with carbon intensive electricity production.

7.6.3 Forestry and Agriculture

As noted in 7.5.5, the changes required to achieve major reduction in GHG emissions will require major changes in the forestry and agriculture sectors. The dominant changes will include:

- Expanded production of biomass and energy crops in both the forestry and agricultural sectors for production of biofuels, and biomass for electricity production
- Expanded production, and better management, of harvested wood products
- Expanded production from the agriculture sector, including production of energy crops from marginal lands
- Expanded management of forestry and agricultural resources for enhanced carbon retention, including improved forest management and afforestation.

This will represent greatly increased expansion of both the forestry and agriculture sectors, especially for meeting growing domestic demands.

7.6.4 Urban Regeneration

As noted in Sections 3.4.6 and 5.12, there are very significant opportunities with effecting fundamental changes in planning and developing urban regions.

In this project, a compelling Vision has been articulated, for how Canadian urban regions can be transformed over the next century. Based on assumed early progress in implementing such transformations, it has been demonstrated that there are substantial contributions for GHG mitigation.

It is important to appreciate that the process of transforming urban regions will be driven dominantly by factors other than climate change. These include aspects such as more efficient use of public monies for transportation and public services, healthier life styles and improved public health, affordable housing, and better protection of natural resources.

Nevertheless, it will be important to fully recognize opportunities for achieving reductions in GHG emissions from urban regions, and that this reality serve as a powerful catalyst for advocating fundamental changes in planning and developing better urban regions, including transformations of existing urban regions.

7.7 Institutional Development

As will be clearly evident from this project, the challenge with defining GHG mitigation strategies is highly complex. It is necessary to define transformation options for all GHG sources and sinks, and to derive corresponding unit costs and limits for respective transformation options. These options need to be analyzed in a comprehensive integrated multi-sector and multi-jurisdictional context, and over a long time horizon, in order to derive overall minimum cost solutions for achieving prescribed time varying GHG mitigation targets. The solution mix will be changing over time, in response to changing conditions.

This challenge is made even more complex with other considerations. At any point in time, some of the transformation options (proven technologies) are well defined, while other options are less defined. There are also options that are not known, but which may have possible definition at a later date. There are also options which may be represented, but for which there is inadequate credible information (such as, for example, fugitive emissions).

There is also the challenge of addressing strategic and policy options which serve as the basis for effecting the very fundamental changes required for early and rapid reductions in GHG emissions, including optimum carbon pricing systems and associated time varying values. These may also vary between jurisdictions.

It is also recognized that this challenge will continue for a very long time, almost certainly for the next century, and probably longer.

For addressing these and related challenges on a continuing basis, it is clearly important to establish a sustainable institutional capability. In principle, responsibilities for such an institutional entity could include:

- Maintaining comprehensive state of the art analytical capabilities for deriving optimal solutions for varying combination of premises for overall GHG mitigation;
- Providing a basis for improved understanding of the GHG mitigation challenge, including assessments of results for different combinations of premises, and demonstrating trade-offs between such premises;
- Producing information which would be of direct value in assessing projected effectiveness of certain strategies and policies, including carbon pricing frameworks and associated optimal carbon price values;
- Providing an informed basis for overall communication on the GHG challenge, and on the most effective options for GHG mitigation;
- Being a focus for systematic definition of the most challenging areas for GHG mitigation, and providing a basis for selecting general approaches, strategies, policies and technologies for achieving cost effective progress on such challenges. This may include support for selecting and monitoring progress on priority areas for research, development, demonstration and deployment of selected technologies;
- Being a focus for systematic updating and upgrading of the overall information base for the GHG challenge in Canada, so as to ensure that future analyses and assessments are based on reliable and credible information;
- Providing a consistent framework for evaluation of GHG mitigation potential, including regular updating of transformation options and costs for alternative strategies and technologies;
- Being a catalyst for strategic and policy integration between Governments, Industry, Not for Profit entities and stakeholder organizations, based on fact-based advice;
- Working directly with global organizations who are active with providing updated information on the global GHG challenge (IPCC, IEA-ETSAP, WEC, etc.), as well as with global, regional, national and sub-national organizations that are designing and implementing effective GHG mitigation strategies.

7.8 Concluding Comments

The TEFP project has provided an innovative and rigorous analysis of the potential for deep reductions in Canadian GHG emissions. The project has identified promising and implementable low-GHG options and pathways for Canada, and has shown the least costly ways to achieve GHG reductions for combustion emissions. The deep-reduction pathways are challenging and involve extensive energy conservation and efficiency measures, major restructuring of our energy infrastructure, deployment of promising but not yet commercially available technologies, and fundamental changes in how people think about and use energy. The energy options that must be implemented to achieve deep GHG reductions (reduced use of fossil fuels for end uses, decarbonization of electricity supply, and increasing use of biomass/biofuels) all result in developments between now and 2050 that present formidable challenges. The results from the project cast considerable doubt about the timely availability of technology and associated infrastructure; however, the greatest challenge may not be technical or even economic, as much as political and social/cultural. Deep reductions, therefore, will affect all Canadians and will necessarily involve changes in lifestyle, some of which were studied in Scenario 4, which included assumptions about improved urban from. The project results also speak to a requirement for carbon pricing and supporting regulations. The accomplishment of the societal transformations involved in reducing GHG emissions by 80% or more, will require leadership from all sectors of society, including government, industry and non-profit organizations, and will require all Canadians to develop a widely shared vision of low-carbon lifestyles and energy systems.

However, the GHG emissions challenge may also present unique opportunities for Canada.

Canada is positioned to be one of the very few countries that can produce emissions-free electricity at globally competitive cost. Opportunities will arise for the manufacturing of energy-intensive products for export, especially from Canadian jurisdictions that can produce low-cost, emissions-free electricity. Electricity exports to the United States could increase and could include increased sale of dependable capacity to selected neighbouring American jurisdictions.

With the greatly enhanced potential role for use of biomass and biofuels, both the forestry and agricultural sectors could see opportunities in the provision of energy commodities (biomass and both first- and second- generation biofuels), and in carbon retention, including afforestation reforestation, improved forest management, and production of harvest wood products.

For those sectors involved in production, processing and transport of fossil fuels, opportunities will open for those who find ways to use these products with greatly reduced emissions, using cost-effective techniques for CCUS or for producing low-maintenance, carbon based storage products.

The results of the project provide insights into Canada’s unique position regarding GHG reduction options and pathways, and can be used to inform national dialogue on strategies needed to achieve deep emission reductions. Our future will be determined by the choices we make today about use of energy and reductions of GHG emissions. The open and frank discussion this Report engenders can lead to meaningful progress and build confidence that Canada can work in harmony internally and with other nations to restore the health and resiliency of the planet’s climate system.

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