Planning for net-zero GHG emissions by 2050:
Moving from technical feasibility assessments to actionable analysis

by

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Abstract

Researchers with the Intergovernmental Panel on Climate Change (IPCC) predict that the net flux of anthropogenic greenhouse gas (GHG) emissions must reach zero by 2050 to limit global warming to 1.5°C within this century. This target requires that all GHG emissions resulting from human activity are offset by equal levels of natural or technological carbon uptake, meaning that action towards net-zero GHG emissions may involve measures aiming to minimize GHG sources or maximize GHG sinks. Achieving net-zero greenhouse gas (GHG) emissions may only be possible through the rapid deployment of new technologies at an unprecedented rate, requiring policymakers to develop creative policy instruments to facilitate collaborative action across sector boundaries. This research describes a novel approach to planning for and assessing action towards net-zero GHG emissions based on bottom-up, accounting-based energy modelling techniques.

The first part of this research develops a framework for assessing the contribution potential of energy-efficiency measures towards economy-wide net-zero emission targets. The framework uses a bottom-up energy model spanning the agriculture, cement, chemicals, commercial and institutional, iron and steel, oil extraction, petroleum refining, and residential sectors, together accounting for over 75% of annual energy demand in the case study region of Alberta, Canada. 81 energy-efficiency improvements were identified for these sectors which, by 2050, may mitigate 8% of regional annual GHG emissions relative to a baseline in which shares and efficiencies of existing technologies are held constant. Considering the interaction effects between simultaneously applied measures, measures representing 80% of the identified cumulative mitigation potential may be implemented at negative cost. The assessed energy-efficiency measures represent cost-effective and readily deployable GHG mitigation strategies for most major economic sectors, but together only account for a small fraction of the GHG mitigation required

for complete energy system decarbonization in the assessed region. This framework offers value to policymakers developing actionable policy and milestone targets towards long-term emissions-reduction goals.

This framework was expanded to assess technology-specific measures toward achieving net-zero GHG emissions within a multi-regional multi-sectoral economy, where the effects, costs, and benefits of various GHG mitigation measures could be assessed incrementally. A portfolio of 184 measures was developed. Measures were categorized according to practical type and technological readiness and their maximum technical GHG mitigation potential was evaluated. These measures are applicable in the cement, chemicals, commercial and institutional, iron and steel, oil sands, petroleum refining, pulp and paper, residential, and transportation sectors. The effects of these measures were compared to a static reference scenario and a business-as-usual scenario reflecting current policy. Together, the assessed measures represent an extensive portfolio of commercially available opportunities for energy efficiency improvement, fuel switching, and carbon capture and storage. Under current policy, these measures may mitigate 33% of baseline GHG emissions by 2050 and represent significant economic cost savings. If implemented to their maximum extent, they may reduce baseline GHG emissions by 50% by 2050 at additional economic costs. The results indicate that there is a clear gap between national GHG reduction ambitions and available solutions and highlight the need for more transparent and specific energy systems models for decarbonization assessment.

This research ultimately highlights the gap between currently available GHG reduction measures and complete decarbonization; achieving net-zero GHG emissions will only be possible through a complete transformation of entire energy systems and economies. Existing assessment frameworks that represent net-zero as a system-wide constraint and model hypothetical technologies alongside proven measures often fail to communicate the magnitude of change implied by this target.

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Table of Contents

List of Tables

List of Figures

Abbreviations

Alberta	AB
Alternative fuel use	AFU
Atlantic	ATL
Bioenergy with carbon capture and storage	BECCS
British Columbia	BC
Business as usual scenario	BAU
Canadian dollar	CAD
Carbon capture	CC
Carbon capture and storage	CCS
Carbon capture and utilization	CCU
Carbon dioxide removal	CDR
Cement sector	CEM
Chemical manufacturing sector	CHEM
Commercial and institutional sector	COM
Compact fluorescent light	CFL
Developing GHG mitigation measures	DEV
Direct air capture	DAC
Electric arc furnace	EAF
Electricity generation sector	EGN
Electrification	ELE
Energy-efficiency improvement	EFF
Energy demand reduction	EDR
Energy intensity	EI
Environment and Climate Change Canada	ECCC
Established GHG mitigation measures	EST
Fuel switching	FSW
Greenhouse gas	GHG
Gross domestic product	GDP
Heating, ventilation, and air conditioning	HVAC
High efficiency	HE
Integrated assessment model	IAM
Intergovernmental Panel on Climate Change	IPCC
International Energy Agency	IEA

Iron and steel sector	IRO
Light-emitting diode	LED
Low Emissions Analysis Platform	LEAP
Manitoba	MB
Marginal abatement cost	MAC
Maximum efficiency improvement	MEI
Maximum GHG mitigation scenario	MAX
Mineral mining sector	MIN
Natural carbon sequestration	NCS
Natural gas	NG
Net present value	NPV
Net-zero GHG emissions	NZE
Oil sands sector	OIL
Ontario	ON
Petroleum refining sector	PET
Projected efficiency improvement	PEI
Pulp and paper	PUL
Quebec	QC
Reference scenario	REF
Residential sector	RES
Saskatchewan	SK
Service demand reduction	SDR
Technology readiness level	TRL
US dollar	USD
Variable speed drive	VSD
Waste heat recovery	WHR

1 Introduction

1.1 Net-zero GHG emissions

The Intergovernmental Panel on Climate Change (IPCC) states that humanity must reduce net anthropogenic GHG emissions levels to zero by 2050 to avoid the worst consequences of climate change [1]. Failure to meet this target may lead to complete ecological collapse due to the undeterminable effects of induced climactic feedback loops: global temperature rise contributes to permafrost thawing, larger and more numerous forest fires, and accelerated seagrass loss, which all lead to increased levels of GHG emissions. Instability in these complex biophysical systems poses risks to human health, food security, water supply, and economic growth, thus making climate change a critical priority for policymakers, researchers, and consumers around the world.

The target of achieving net-zero GHG emissions (NZE) by 2050 represents an unprecedented global challenge: as of June 2022, 140 countries accounting for 90% of global GHG emissions have committed to this target in some form [2], yet fossil fuel combustion levels continue to break all-time highs [3]. There is no "silver bullet" to complete energy-system decarbonization [1, 4, 5]; global supply chains, buildings, transport infrastructure, and manufacturing processes are all heavily dependent on fossil fuels, and achieving NZE may require the extensive deployment of technological solutions as well as policy measures to effectively reshape modern economic paradigms. NZE implies radical transformations across all economic sectors but has historically been framed as a target achievable through interventions that are minimally disruptive to existing markets, such as blanket carbon taxation or cap and trade emissions trading schemes. Several economists argue that these measures and growth-minded public investment are fundamentally incompatible with decarbonization [6]. The magnitude of systemic change implied by NZE is becoming increasingly clear, but region-specific accounts of available technological GHG mitigation potential are nonetheless required to fully understand the minimum levels of change required to achieve this target.

The IPCC suggests that both incremental and transformational adaptations are needed to avoid the worst consequences of climate change, and that incremental changes are especially relevant in the short to medium term [1]. Research has shown that improving energy efficiency can lead to significant global GHG emissions reductions but that additional measures will be necessary [7]. Additional GHG mitigation may be achieved through fuel-switching or electrification measures, but the applicability of these measures in aviation and heavy industry sectors is uncertain [8]. Carbon dioxide may be captured and stored in these "hard-to-abate" sectors. However, the technological and economic feasibility of these projects is still being investigated [9]. Negative emissions measures involving biophysical carbon sequestration may be used to offset residual GHG emissions within a region [10], but there are environmental limits and risks associated with these nature-based solutions as well [11].

Achieving NZE may only be possible through a portfolio of different mitigation measures involving end-use technology changes, alternative energy production systems, and consumer behaviour changes, yet optimal combinations of these types of measures regarding their effects on the economy, land-use, and water and food availability are largely unknown. Pathways towards net-zero GHG emissions have been proposed, but GHG mitigation measures are often included without regard for practical constraints or commercial availability. To successfully deploy these strategies, governments and corporations must establish comprehensive emissions reduction policies and sector-specific decarbonization milestone targets. Numerical energy models can help policymakers develop these plans by providing whole-system emissions and economic costs accounting for and allowing GHG mitigation pathways strategies to be assessed practically and economically.

Given the urgent need for robust and transparent energy modelling tools, this thesis presents a framework for assessing incremental decarbonization strategies for a multi-regional and multi-sectoral advanced economy. Other economy-wide analyses do not represent end-use technologies from the bottom-up, nor do they differentiate between measures based on technological readiness and commercial availability. Instead, NZE is assessed through a transformational lens; that is, the fundamental research questions are concerned with how an NZE energy system or economy might look or operate. Conversely, this thesis aims to provide an assessment framework that lends itself to policy recommendations based on incremental action; that is, GHG mitigation measures are conceptualized as building blocks that may be implemented through a variety of policy tools. Previous studies representing end-use technologies in detail seldom do so for all major economic sectors.

1.2 GHG sources and mitigation measures

Energy production and use accounts for around three quarters of global GHGs, making NZE a challenge for energy producers, consumers, and energy economies alike [12]. Energy system decarbonization is thus a priority for any jurisdiction aiming for NZE. Canada's GHG inventory is dominated by emissions from the Oil and gas and Transport sectors, as shown in Figure 1. The basic functions and main GHG sources for each sector are shown in Table 1.

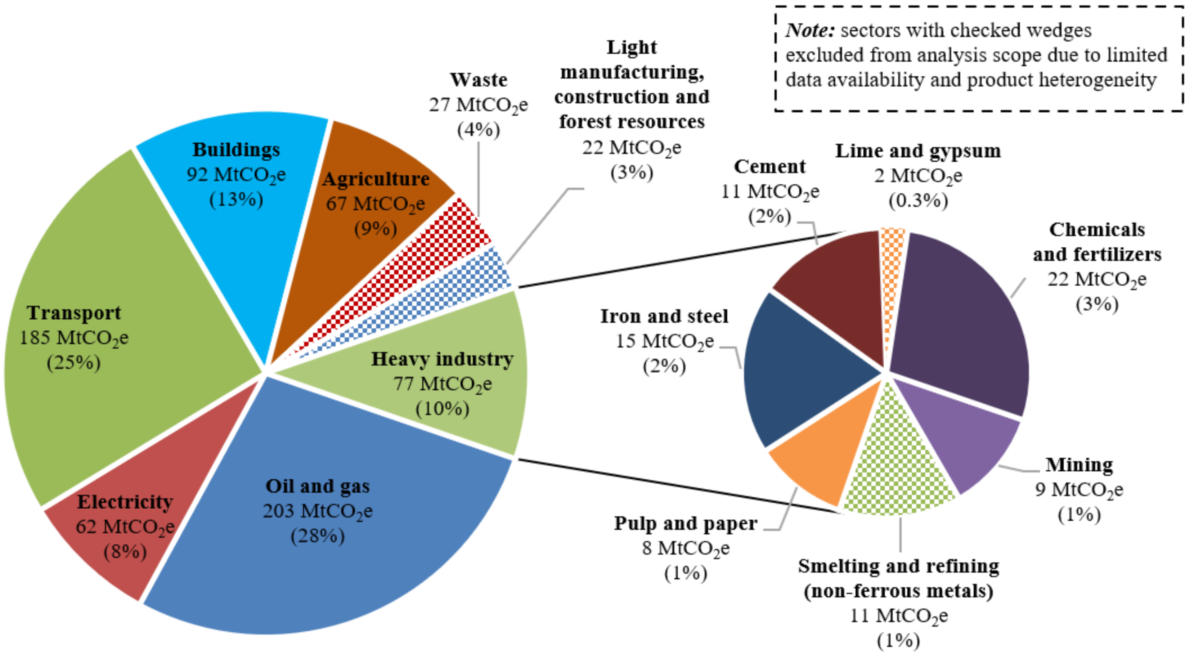

Figure 1: Canadian GHG levels by major economic sector, 2019 [13]

Table 1: Summary of Canada's emissions-intensive economic sectors

Sector	2019 GHG level ($MtCO_2e$)	Function	Main GHG sources
Oil and gas	203 (27.2%)	Extract, refine, and distribute oil and gas products	Pumps (conventional oil) and steam generation (oil sands) [14]
Transport	185 (25.2%)	Transport passengers and freight via road, rail, aviation, and marine vehicles	Road passenger and freight vehicles [15]
Buildings	92 (12.5%)	Meet space conditioning, water use, and other needs of residential and commercial building occupants	Space heating [16, 17]

Sector	2019 GHG level ($MtCO_2e$)	Function	Main GHG sources
Agriculture	67 (9.1%)	Produce goods from animal and plant sources	Non-energy processes (e.g., animal production and fertilizer application) [18]
Electricity	62 (8.4%)	Generate electricity from fossil fuel and renewable energy sources	Coal and natural gas combustion [19]
Iron and steel	15 (2.0%)	Convert iron ore pellets, powder, and scraps to usable iron and steel products	Blast and electric arc furnaces [20]
Chemicals and fertilizers	13 (1.7%)	Produce chemicals and fertilizers from various feedstocks	Steam methane reforming and steam cracking [21]
Cement	11 (1.5%)	Produce cement from limestone	Clinker kiln firing [22]
Mining	11 (1.5%)	Extract raw minerals from surface and underground mines	Pelletizing firing, mine ventilation, and product drying [23]
Pulp and paper	8 (1.1%)	Produce pulp and paper from biomass feedstocks	Pulp reforming [24]

To minimize the risks associated with climate change, researchers have proposed various types of strategies towards mitigating future GHG levels. GHG mitigation measures can be grouped into four main categories, each containing two sub-categories and belonging to one of two general groups. Measures are differentiated based on the physical mechanism by which they reduce the net flux of GHG emissions.

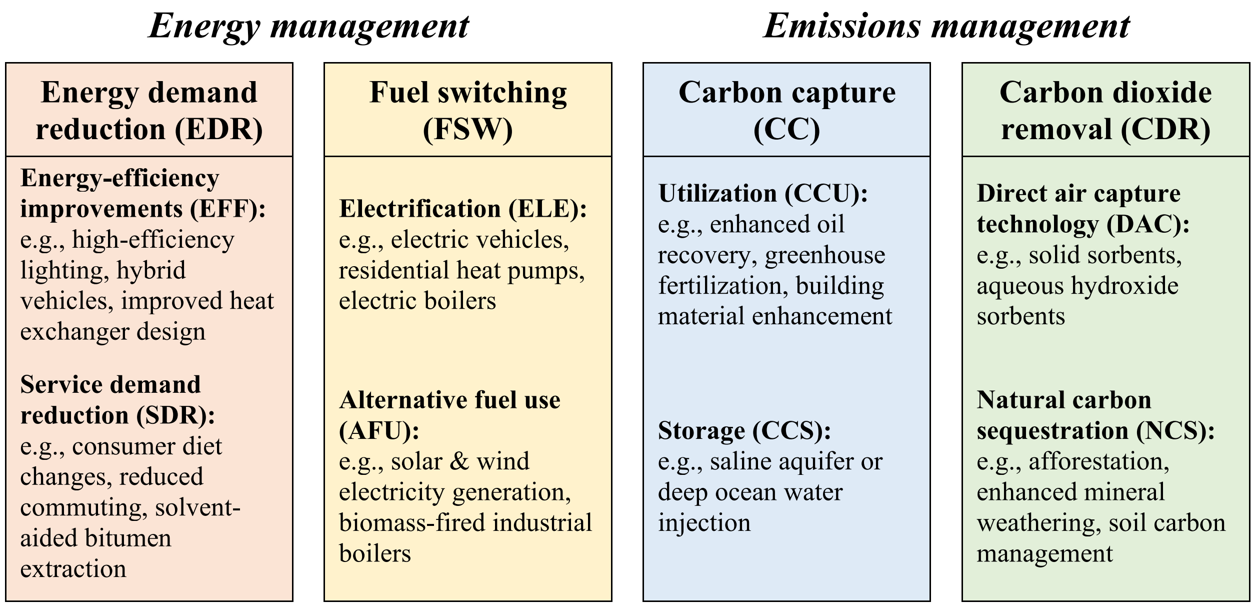

Figure 2: Categorization of GHG mitigation measures. Examples are non-exhaustive and are included for illustrative purposes only.

Anthropogenic GHG levels may be controlled through energy or emissions management strategies. Energy management strategies involve changes to how energy is produced or consumed through either energy demand reduction (EDR) and fuel-switching (FSW) measures. Emissions management strategies involve changes affecting produced GHG emissions, independent of the energy or non-energy process by which they are emitted. GHG emissions can be captured at their source through a variety of different carbon capture (CC) processes or retroactively removed from the atmosphere through carbon dioxide removal (CDR) strategies.

Figure 3 provides a visual overview of all general measure types. A generic process where a base technology, t, uses a quantity of fuel, f, to provide a level of service, s, contributes a specific GHG emissions level, g, to a net GHG flux, x. The net flux of GHG emissions associated with this process can be reduced through a variety of different approaches, which are described in the sections that follow. Other researchers have defined GHG mitigation measures based on macroeconomic indicators affected in the Kaya identity [25, 26], whereas the categories shown here reflect the specific type of action being taken at the end-use technology level. Specific definitions of all measure categories are provided in Section 3.2.1.1.

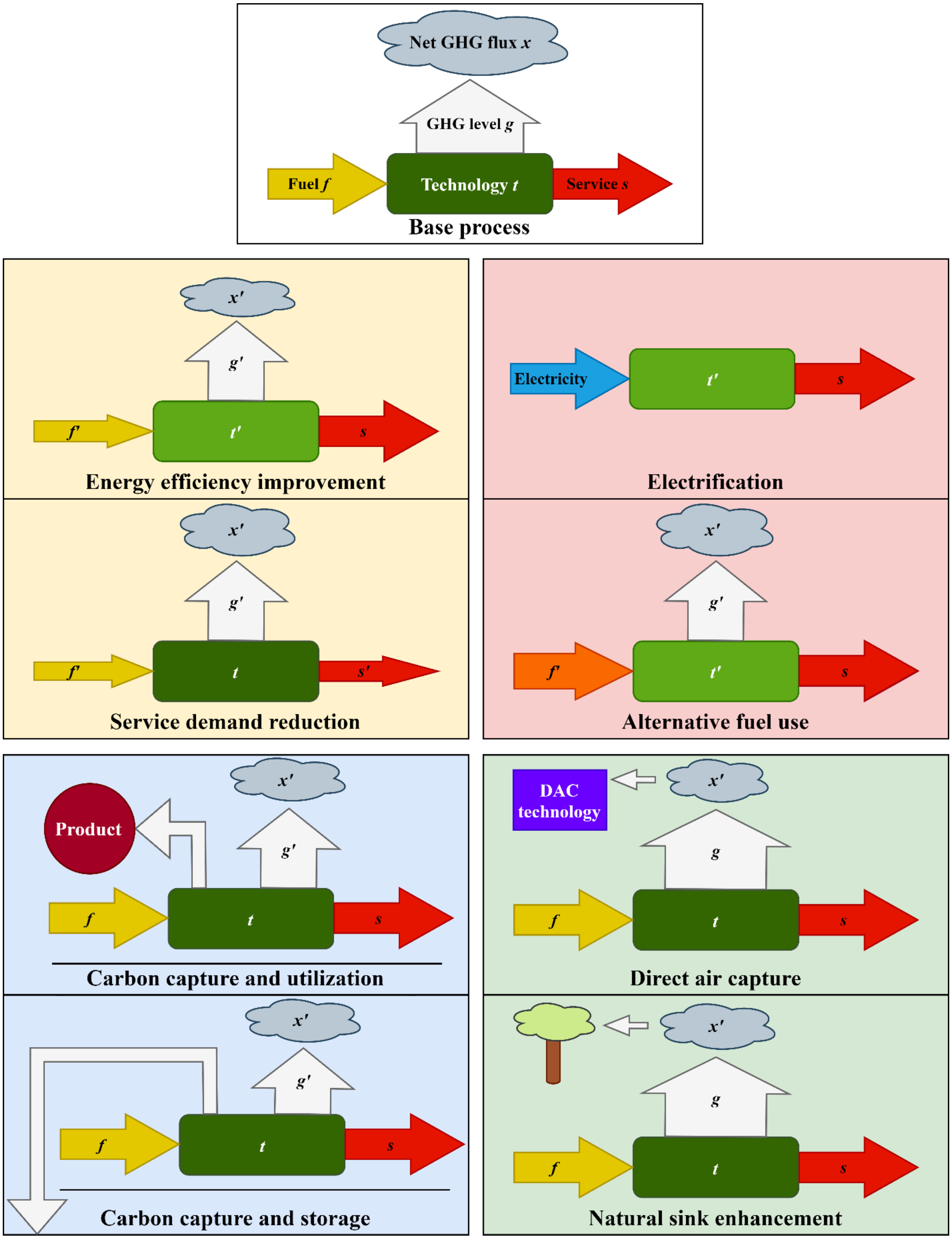

Figure 3: Visual summary of GHG mitigation measures categories showing effects on base technology (*t*), input fuel (*f*), output service (*s*), GHG emissions (*g*), and net GHG flux (*x*). Variables affected by each measure are denoted by the prime symbol (′).

1.2.1 Energy demand reduction

System-wide energy demand can be reduced by improving the efficiency of or by reducing the level of service (*s*, Figure 3) required from a process or technology. Energy-efficiency improvements (EFFs) are often cost-effective and do not require significant changes or adaptations from the end-user, whereas service demand reductions (SDRs) are achievable through changes in end-user behaviour or needs. SDR measures do not require the adoption of new technologies and are thus difficult to assess from an engineering perspective; predicting behavioral changes like global diet shifts or increased levels of bicycle commuting are beyond the scope of this work. Both EFF and SDR strategies lead to reduced energy demand and thus reduced GHG levels as well.

1.2.2 Fuel-switching

GHG emissions associated with an end-use technology or process can be reduced or altogether eliminated if the energetic requirements are met by an alternative source with a lower emissions intensity. End-use electrification is a promising GHG mitigation strategy since electric end-use technologies do not emit GHGs, are often inherently more efficient than traditional fossil fuel-consuming technologies, and may complement decentralized renewable energy production (e.g., space heating electrification coupled with rooftop solar PV generation). GHG levels can also be reduced by using alternative fuels instead of traditional fossil fuels (*f*, Figure 3). Hydrogen, biofuels, and synthetic hydrocarbons can all be used as energy carriers and may be advantageous over electricity because of the high capital costs associated with end-use electrification and the low gravimetric energy density of current electric battery technologies.

1.2.3 Carbon capture and utilization / storage

Figure 3 depicts simple post-combustion carbon capture systems, but CO_2 may also be captured from a GHG-emitting process before combustion or through an oxy-fuel combustion system, both of which imply changes to the input energy source and combustion technology. In all of three methods of carbon capture, GHG emissions are reduced when a portion is captured and stored or used, leading to reduced GHG levels (*g*, Figure 3). Carbon capture and utilization (CCU) is often more cost-effective than carbon capture and storage (CCS) since energy consumers can realize some economic benefit from the sale or use of captured CO_2. However, CO_2 use may not achieve the same environmental benefit as storage since carbon used in the production of synthetic fuels or enhanced oil recovery still contributes to GHG emissions.

1.2.4 Carbon dioxide removal

Anthropogenic GHG emissions may also be offset through carbon dioxide removal (CDR) strategies. These measures affect the net flux (*x*, Figure 3) of GHGs and do not affect the input fuel, technology, service, or direct GHG emissions associated with an energy-consuming technology or process. CO_2 can be removed from the atmosphere through the development of direct air capture (DAC) technologies, which use media such as solid or aqueous sorbents to remove CO_2 from processed ambient air. Alternatively, CO_2 emissions can also be offset by enhancing natural carbon sinks like forests, wetlands, and farmlands. These natural carbon sinks can sequester additional carbon through careful management or expansion. The focus of this research is on energy-system decarbonization measures, so CDR measures are not included in the assessments.

1.3 Knowledge gaps

Existing decarbonization assessments have primarily focused on single sectors instead of the entire energy system. Achieving net-zero GHG emissions in a single sector may not be effective in complete regional decarbonization if measures are not implemented simultaneously across sectors (e.g., increased natural gas electricity generation due to electrification of end-use industrial equipment) [27]. Resource and technology costs may be inconsistent across separate sectoral analyses as well, which may lead policymakers to misconstrue findings or prioritize action inappropriately. In an economy-wide model, using consistent data across all sectors ensures that measures can be compared on the same cost basis. Tools facilitating whole-system planning are thus essential to meeting ambitious national emissions reduction targets.

To the best of the author's knowledge, no research examining the mitigation potential of energy-efficiency improvements across an entire economy through bottom-up energy system modelling has been published. GHG mitigation assessments found in the reviewed literature focus on the mitigation potentials of energy-efficiency measures within single sectors, rely on top-down modelling approaches, or estimate GHG mitigation potential across multiple sectors without categorizing levels by measure type. Gambhir et al. reviewed criticisms of existing integrated assessment models and highlight that the models often lack methodological transparency, understate input assumption uncertainty, oversimplify the effects of innovative technologies, represent consumer behaviour inaccurately, and use inconsistent operational definitions of "feasibility" [28].

There is also a lack of credible pathways toward NZE in the literature. Researchers have not always distinguished between currently available and unproven solutions and have often modelled them alongside each other without explicitly communicating the differences in uncertainty, availability, and practicality between them. This thesis work describes an assembled portfolio of previously assessed measures for which specific costs, energy effects, and emissions effects have been quantified, excluding measures dependent on hypothetical technologies. By filtering measures in this way, this framework highlights the gaps between ambition and currently available solutions and identify areas where more research and innovation are required before specific, effective policy can be developed.

The framework presented in this research addresses the identified research gaps by facilitating economy-wide, bottom-up analysis of energy supply and demand sectors. The model used in this analysis integrates several energy demand and supply models allowing for both single-sector and economy-wide analysis and accurate representation of interaction effects between co-penetrating technologies. This framework is adaptable to other climatic and economic regions and offers utility to policymakers since it may facilitate region-specific economic analyses of commercially available technologies and processes. Ultimately, this research offers a novel, transparent approach for the assessment of NZE targets where the GHG mitigation potential of individual decarbonization strategies can be quantified and consumer behaviour can be represented based on factors including cost and technology readiness.

1.4 Objectives

Based on the research gaps identified through the literature review, the primary objectives of this work are to

1. Establish a framework for assessing the GHG mitigation potential of energy-efficiency measures within energy- and emissions-intensive sectors
2. Perform a case-study analysis of the GHG mitigation potential of energy-efficiency measures in Alberta, Canada

3. Develop a transparent multi-regional, multi-sector, technology-explicit assessment framework to quantify the GHG mitigation potential of energy-related decarbonization measures and technologies
4. Assemble a portfolio of established and developing decarbonization strategies involving energy-efficiency improvements, fuel-switching, and carbon capture and utilization/storage across all major economic sectors applicable between 2021 and 2050
5. Using Canada as a case study, assess the maximum GHG mitigation potential of the combination of identified measures relative to a constant energy and emissions intensity "reference" case and a "business-as-usual" case
6. Evaluate Canada's current position relative to its long-range GHG reduction targets

1.5 Limitations

There are several limitations that should be kept in mind when reading this work. Scenarios representing changes to sectoral activity were not considered. Achieving NZE will require widespread changes across all energy-intensive sectors, but the evaluated scenarios only involved new technological adoption or replacement, *ceteris paribus*. Assessing how sectoral activity will change under different policy scenarios is crucial to fully understand the economic consequences of system-wide decarbonization but is outside the scope of the present work. This limitation was addressed by examining changes in sectoral activity drivers including population, gross domestic product (GDP), and energy prices in the sensitivity analysis.

This research involves an extensive but incomplete portfolio of GHG mitigation measures previously assessed for all major energy-intensive economic sectors across Canada. There are additional GHG mitigation measures currently available in the industrial, residential, and commercial sectors that were not included in this assessment; technologies like heat pump water heaters in buildings [29], carbon capture in ammonia plants [30], and methane capture technologies [31] may all contribute to significant levels of GHG mitigation. This framework was developed with this limitation in mind and is designed to accommodate future portfolio expansion based on the commercialization of novel technologies.

All costs reported in this research are calculated by considering an entire-energy-system boundary and do not accurately reflect the costs faced by specific sectors or consumers within the energy system; reported costs instead reflect those faced by the entire economy This limitation primarily affects the marginal abatement costs reported in Section 2.3.3 of this research and is explained further in Section 2.3.5. Additionally, reported system-wide costs include GHG emissions externality costs, which are less straightforward to quantify than capital or energy resource costs. Carbon pricing is a real cost that influences consumer decisions, but in considerations of economic costs affecting an entire energy system, carbon pricing is more abstract. The federal government's carbon tax schedule [32] was used as a uniform externality cost applied to all sectors, meaning that the cost should be interpreted as long-term expenses related to damages to human and environmental health due to pollution and climate change. Two alternative carbon price schedules were considered in the sensitivity analysis (Section 3.3.6) to explore how this assumption affects key results. Additional analysis-specific limitations are discussed in Sections 2.3.5 and 3.3.4.

1.6 Organization of thesis

This thesis is organized as a combination of papers. This thesis is organized accordingly: Chapter 2 describes the development of a framework used to assess the GHG mitigation potential of energy-efficiency measures applied to the province of Alberta, Canada, which accounts for upstream and downstream effects and the practical and thermodynamic limitations of simultaneously applied measures. This chapter also compares the marginal GHG abatement costs and cumulative GHG mitigation potentials of measures assessed across all sectors and ultimately highlights the limits of efficiency improvements towards system-wide decarbonization.

Chapter 3 describes the development of an economy-wide net-zero analysis framework in which GHG mitigation measures involving energy-efficiency improvements, energy service demand reduction, fuel-switching, electrification, and carbon capture are assessed. This framework is applied to all major energy-intensive economic sectors in seven Canadian regions: British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, and Atlantic provinces. Ultimately, the results of this analysis highlight the gaps between current policy and the maximum technical potential of all assessed measures, and between the maximum potential and the GHG mitigation required for complete system-wide decarbonization.

Chapter 4 provides a qualitative overview of the measures. Chapters 2 and 3 include chapter-specific introductions and conclusions, and a general conclusion and future research recommendations are in Chapter 5.

2 Development of an energy efficiency assessment framework[1]

2.1 Introduction

This chapter describes the development of a framework used to assess the GHG mitigation potential and economic costs of energy-efficiency improvements across all major sectors within a single geographic region. Section 2.1.1 summarizes reviewed literature involving system-wide energy demand and efficiency models and assessments of the GHG mitigation potential of energy-efficiency improvements towards achieving net-zero emissions (NZE) near mid-century.

Generally speaking, energy-efficiency improvements represent the most easily implementable and least costly GHG mitigation measures since they typically integrate with existing systems with minimal disruption [33]. Chappin et al. quantify abatement barriers using the *Y-factor*, which shows how the implementation of GHG mitigation measures may be hindered by financial costs, bureaucratic process, physical disruptiveness, and social behaviour [34]. Of the 12 examples of GHG abatement measures that the authors analyzed using this metric, energy-efficiency improvements were generally associated with lower levels of implementation barriers than fuel-switching or carbon sequestration measures.

Fuel-switching and carbon capture technologies may exist today, but will likely require large, sustained capital investment which may not be available in all regions [7]. Aside from natural carbon sink enhancements like afforestation and forest carbon management, proposed carbon sequestration measures often rely on pilot-stage technologies [35] that are seldom the most cost-effective [36, 37], widely-deployable [38, 39], or publicly supported [40, 41] GHG abatement measures available today. Furthermore, some researchers argue that carbon dioxide removal (CDR) strategies should not be extensively relied on in NZE pathway development as they may limit future climate action if they are unsuccessful [42-44].

[1] A version of this chapter has been prepared for journal submission

Energy-efficiency is thus a common focus of many national net-zero policy plans and an essential first step towards achieving deep decarbonization in industry, agriculture, and building sectors, but the total degree to which these measures may contribute to achieving NZE is largely unknown.

2.1.1 Background

The following is a summary of the literature that was reviewed on system-wide energy demand and efficiency models and assessments of the GHG mitigation potential of energy-efficiency improvements towards achieving NZE near mid-century.

The target of NZE was assessed as a pathway-independent end state using bottom-up energy system modelling approaches: Fujimori et al. considered scenarios where atmospheric CO_2 reaches 450 ppm and 550 ppm by 2030 and 2050 using a general equilibrium model and estimated GDP loss and recovery rate for energy demand reduction scenarios for building, transport, and industrial sectors [45]. This approach offers value as a high-level feasibility assessment tool, but generally lacks the technological specificity necessary for the development of actionable policy.

Fleiter et al. presented a bottom-up energy model of the industrial technologies and processes, FORECAST, and used it to assess the mitigation potential and costs of measures related to energy-efficiency, fuel-switching, material efficiency, and carbon capture and storage for Germany's industrial sector [46]. The authors found that through these measures, up to 83% of GHG emissions from Germany's industrial sector may be mitigated by 2050 relative to their current policies scenario. The FORECAST model represents energy-efficiency improvements with high levels of technological detail, but the authors did not quantify the respective contributions of different measure types in their work.

Van Sluisveld et al. used the IMAGE model to assess four different GHG mitigation scenarios for heavy industry (including chemical, iron and steel, pulp and paper, and cement and clinker subsectors) in six different regions worldwide [47]. The authors examined pathways involving technological replacement, process efficiency improvement, demand management, and circular economy development and showed that global decarbonization of heavy industry may be difficult to achieve prior to 2050 but that negative emissions measures in other sectors may be able to fully offset industrial emissions by 2040. The authors ultimately suggested that decarbonization strategies need to be tailored for specific industries and regions as they are highly dependent on specific processes and local conditions. They did not provide GHG mitigation assessments for specific regions and instead focussed on the target of achieving NZE globally.

Napp et al. used the bottom-up TIAM-Grantham energy model to examine the mitigation potential of currently available energy-efficiency improvement opportunities and advanced energy demand-reducing and low-emissions technologies across demand sectors including efficient industrial boilers, hyperloops replacing rail transport, carbon capture and storage in industry, and electricity generation from tidal power and nuclear fusion [9]. The authors found that advanced and developing technologies can significantly reduce the level of GHG emissions offsets required from negative-emissions technologies required to limit global warming to 2°C. Furthermore, the authors noted that achieving complete decarbonization with existing technologies will be "extremely difficult" and that both technological innovation and widespread behavioural shifts will be necessary to reduce energy demand to a level necessary to meet NZE. The authors did not provide an estimate of the respective contribution that energy-efficiency measures may offer in complete energy system decarbonization but highlight that advanced technologies can reduce reliance on bioenergy with carbon capture and storage (BECCS) in NZE pathways by 18% compared to pathways where only currently available technologies are considered.

2.1.2 Case study region

The province of Alberta, Canada was selected for a case-study application of this framework since it is one of the most GHG emissions-intensive regions in North America, is home to the GHG emission-intensive oil sands sector, and represents the critical path in Canada's push to achieve NZE by 2050. Alberta produced 3.1 million bbl/day of raw bitumen and 0.5 million bbl/day of crude oil in 2019 [48] and exported 3.2 million bbl/day of crude oil, accounting for $57 billion CAD [49]. GHG emissions from conventional and oil sands production were 92 $MtCO_2e$ in 2019, accounting for over 33% of the province's annual emissions [13]. Considering GHG emissions from in situ extraction, surface mining, bitumen upgrading operations, and cogenerated electricity, oil produced from Alberta's oil sands had an average emissions intensity of 0.066 tCO_2e/bbl in 2019 [50].

The Government of Canada recently announced its plan to increase the federal carbon pricing to \$170/t CO_2e by 2030 [32], but other policy and regulatory mechanisms aimed at achieving NZE are still under development [51]. Applying the framework in this region may thus provide value to local policymakers and demonstrate the use of assessing the GHG mitigation potential of energy-efficiency measures in other emissions-intensive regions around the world. Additionally, this framework may be used to determine the degree to which Alberta's exported oil emissions intensity can be reduced in the near term, which may help develop a long-term economic strategy in the global oil market.

2.1.3 Energy-efficiency modelling with LEAP

The Low Emissions Analysis Platform (LEAP) developed by the Stockholm Environment Institute facilitates bottom-up energy modelling organized in demand, transformation, and resource modules [52]. LEAP has been used to assess demand reduction scenarios for Alberta's major economic sectors individually, which the present work updates and harmonizes.

Katta et al. assessed 30 energy demand-reducing scenarios for Alberta's most emissions-intensive sector: the oil sands [14]. The authors estimated that 7.6 $MtCO_2e$ could be mitigated annually through measures including the adoption of advanced control systems, the improvement of heat exchanger networks, and the implementation of energy monitoring and management programs. Bonyad et al. assessed GHG mitigation potentials of various energy-efficiency improvements and fuel-switching measures in the province's agriculture sector, and estimated that energy-efficiency improvements offer a total cumulative mitigation potential of 3-7% by 2050 relative to the baseline emissions projection [18]. The assessed measures include the adoption of high efficiency lighting, heating, and farm machines.

Talaei et al. investigated the GHG mitigation potential associated with energy-efficiency improvements in Canadian iron and steel production facilities and estimated that 6% of annual emissions from the sector may be mitigated by 2050 through the adoption of energy-efficient low-carbon technologies and processes [20]. In another study, Talaei et al. estimated that 29.7 $MtCO_2e$ in cumulative emissions reduction is possible by 2050 through energy-efficiency improvements in Alberta's ammonia and ethylene production sectors [21]. In another study, the authors estimated that between 2017 and 2050, a cumulative 9.74 $MtCO_2e$ may be mitigated through the adoption of process-level efficiency improvements in the Alberta's petroleum refining sector [53], and that 59 $MtCO_2e$ could be mitigated through the application of similar measures in Canada's cement industry [22].

Subramanyam et al. assessed the GHG mitigation potential associated with efficiency improvements in both Alberta's residential and commercial and institutional sectors [16, 17], and estimated that between 2015 and 2050, 55 $MtCO_2e$ in cumulative mitigation could be achieved be achieved through energy-efficiency improvements in lighting, space heating, space cooling, water heating, and auxiliary equipment in commercial and institutional buildings. The authors did not provide an explicit estimate of the total mitigation potential for the residential sector, but through mitigation estimates provided for simultaneously applicable individual scenarios, suggest that 101.5 $MtCO_2e$ could be mitigated between 2015 to 2050 through the adoption of similar technologies described in their commercial sector analysis.

2.2 Methods

2.2.1 Framework

This section is organized by the analysis steps shown in Figure 4.

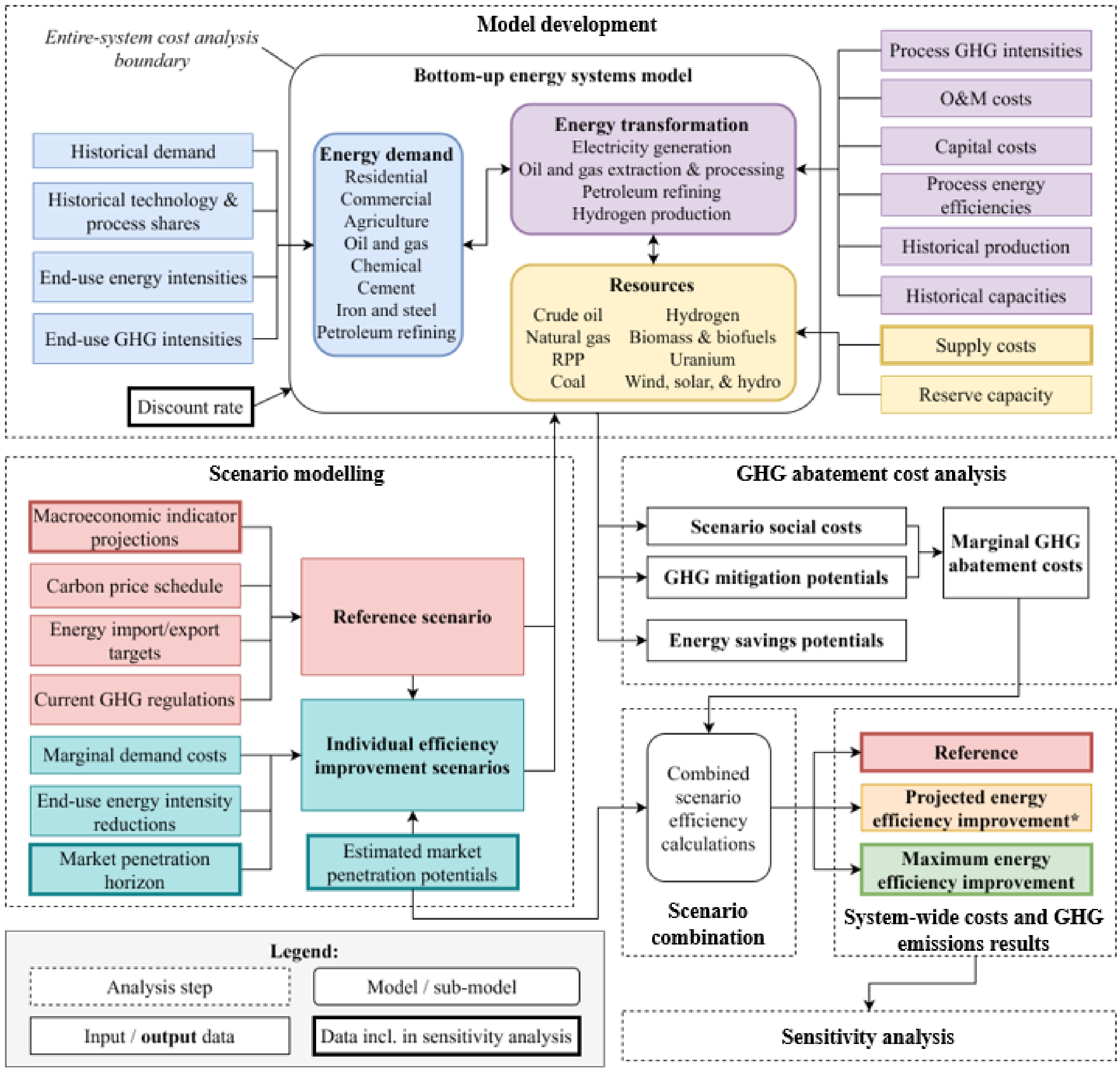

Figure 4: Schematic overview of developed framework. Model development is described in section 2.2.2, scenario modelling is in section 2.2.3, cost analysis is in section 2.2.4, and combined scenario development is in section 2.2.5. Results and sensitivity analysis are in section 2.3. *Projected energy efficiency improvement scenario includes all measures with negative marginal GHG abatement cost.

This analysis relies on the LEAP-Canada model developed in the Stockholm Environment Institute's Low Emissions Analysis Platform (LEAP) software [54]. LEAP organizes energy systems into energy demand, energy transformation, and energy resource modules. The LEAP-Canada model incorporates disaggregated energy demand with detailed energy transformation models that allows for upstream emissions and economic costs to be accounted for in all assessed GHG mitigation scenarios. The energy demand sectors, transformation processes, and resource pools included in the model are shown in Figure 4. Details regarding the development of each subsector model are included in Section 2.2.2.

Section 2.2.3 provides details on the assessed energy efficiency-improving measures. Each energy-efficiency measure was described with three data items: market penetration potential, energy intensity effect, and marginal demand cost. Section 2.2.4 describes the processes used to calculate marginal abatement costs for every individual measure. These values can be used to compare the economic performance of different GHG reduction measures within a specific sector and allow for scenarios to be organized according to cost-effectiveness.

Section 2.2.5 summarizes the methods used to develop the projected and maximum efficiency-improvement system-wide scenarios. In the projected efficiency-improvement scenario, all measures with negative marginal abatement cost were adopted to their maximum potential by the end year. In the maximum efficiency improvement scenario, all measures were adopted to their maximum potential regardless of cost. For both combined scenarios, all included measures may be simultaneously applied and interaction effects are accounted for within the market penetration model. Annual energy demand, social costs, and GHG emissions were then calculated using the LEAP-Canada model for the two combined scenarios.

2.2.2 Bottom-up energy system model development

Provincial energy use was modelled by disaggregating end-use demand in the major economic sectors. For all models, annual energy use and activity data from 1990-2017 were used to forecast activity, energy demand, and GHG emissions for 2018-2050. This assumption was made in order to develop consistency between sectors and to allow for the isolated effects of specific technologies to be assessed incrementally. End-use demand models for the residential and commercial and institutional sectors were redeveloped by incorporating data from earlier work [16, 17] and integrated with the group's models for the chemicals [21], iron and steel [20], cement [22], petroleum refining [53], agriculture [18], oil sands [14], and electricity generation [19] sectors. Together, these sectors accounted for 63% of Alberta's annual emissions in 2019 [13]. Demand in the transportation and pulp and paper sectors was omitted from this work since these subsectors have not been modelled yet and is part of future work.

Sectoral activity was projected in terms of households (residential), floor area (commercial and institutional), tonnes of product (agriculture, cement, chemical, and iron and steel), and barrels of oil (oil sands and petroleum refining). Future activity projections were made using correlations with appropriate macroeconomic indicators. Details describing the models used to represent the targeted sectors are included in the sections below.

2.2.2.1 Residential sector

In the residential sector, activity is quantified in terms of households and all energy intensities are defined on a per household basis. The total number of households is projected to 2050 by dividing the forecasted population [55] by a constant occupancy of 2.7 people per household from recent census data [56]:

Table 2: Residential sector activity projections (thousand households)

Building type category	1990	2000	2010	2020	2030	2040	2050
Single detached	568.0	701.3	910.1	1064.5	1231.7	1383.8	1531.8
Single attached	102.7	125.8	162.3	188.7	217.1	242.5	266.8
Apartments	198.0	229.7	285.5	318.7	351.0	374.8	393.6
Mobile homes	38.7	46.8	60.0	69.2	79.0	87.5	95.6

The residential sector model incorporates specific system-share data to account for the effects of control systems and building envelopes on heating ventilation and air conditioning (HVAC) energy use. Energy used in this sector was disaggregated into four categories: HVAC, water-heating, lighting, and appliances. The energy demand tree for this sector is shown in the Appendix A. Energy intensities for all end-use technologies were calculated according to the processes described in Appendix B.

2.2.2.2 Commercial and institutional sector

We disaggregated energy use in the commercial and institutional sector into four main categories: HVAC, water heating, lighting, and auxiliary equipment. Energy intensities for all end-use technologies were calculated on per-unit-area bases, and 10 different building types were considered along with street lighting. The energy demand tree used to model this sector is shown in Appendix A. Activity projections for this sector were made based on observed floorspace-per-capita trends and are summarized in the table below (historical activity data is from Natural Resources Canada [57]).

Table 3: Commercial and institutional sector activity projections (million m^2 floor area)

Building type category	1990	2000	2010	2020	2030	2040	2050
Wholesale trade	5.6	6.0	6.8	6.9	7.4	7.8	8.1
Information and Cultural Industries	1.5	1.8	2.2	2.3	2.5	2.6	2.7
Retail trade	11.2	13.1	16.6	17.0	18.5	19.5	20.2
Transportation and Warehousing	5.0	5.1	5.3	5.2	5.6	5.9	6.2
Offices	30.5	35.9	43.9	46.5	50.4	53.1	55.2
Educational services	9.7	10.9	13.4	15.3	16.6	17.5	18.1
Health Care and Social Assistance	5.5	6.0	7.4	8.2	8.9	9.4	9.7
Arts and Entertainment and Recreation	1.7	2.0	2.5	2.7	3.0	3.1	3.2
Accommodation and Food Services	3.8	4.4	5.6	6.3	6.9	7.3	7.5
Other services	1.4	1.7	1.9	2.0	2.2	2.3	2.4

Energy intensities for all end-use technologies were calculated using data from Natural Resources Canada [57] according to the processes described in Appendix B.

2.2.2.3 Industrial and agriculture sectors

Disaggregated energy demand models of the agriculture [18], chemicals [21], iron and steel [20], petroleum refining [53], cement production [22], and oil sands [14, 58] sectors were integrated with the redeveloped residential and commercial and institutional sector models. Updated demand trees for these models are shown in Appendix A.

2.2.2.3.1 Updated activity projections

Activity in the agriculture sector was projected through linear extrapolation of per-capita production trends from 1990-2017. Historical activity for all considered products is available through data published by Statistics Canada and The Government of Alberta [59-61]. Production projections for crops, fruit and vegetables, and livestock are summarized below:

Table 4: Agriculture sector activity projections (thousand tonnes of product)

Product category	1990	2000	2010	2020	2030	2040	2050
Grain and oilseed	15856.6	15350.1	18368.1	22828.5	26133.9	29052.0	31823.7

Product category	1990	2000	2010	2020	2030	2040	2050
Fruit and veg.	30.1	27.6	21.5	26.7	30.6	34.0	37.2
Greenhouse and nursery	18.4	20.4	18.8	35.0	40.1	44.5	48.8
Cattle	2711.1	2334.9	2471.1	1837.8	1546.8	1255.7	964.6
Hog	320.5	265.6	338.1	344.5	394.3	438.4	480.2
Poultry and eggs	62.4	94.1	108.4	139.1	159.2	177.0	193.9
Dairy	554.4	620.0	650.0	802.0	918.1	1020.7	1118.0
Other farm products	5.0	3.8	5.2	5.4	6.2	6.9	7.5

Activity in the petroleum refining sector was projected based on historical refinery capacity, utilization, and local government plans for future development.

Table 5: Petroleum refining sector activity projections (million barrels of feedstock)

Product category	1990	2000	2010	2020	2030	2040	2050
Conventional feedstocks	102.8	89.5	41.5	79.4	85.3	85.3	85.3
Oil sands feedstocks	61.9	75.2	123.2	167.2	179.5	179.5	179.5

Activity projections for bitumen upgrading levels in Alberta's oil sands are provided by the Canada Energy Regulator [55]. Activity levels for surface mining and in-situ bitumen extraction were projected using an integrated oil-price based econometric model developed by Radpour et al. [62]. The model relies on annual new capital investment data from the Canadian Association of Petroleum Producers and Western Canada Select oil price projections from the Alberta Energy Regulator [48, 63].

Table 6: Oil sands sector activity projections (million barrels of product)

Process category	1990	2000	2010	2020	2030	2040	2050
Bitumen upgrading	76.1	117.1	256.4	389.3	454.6	477.0	464.3
Surface mining of bitumen	76.1	138.7	312.6	494.6	561.3	615.5	647.6
In situ bitumen extraction	49.4	104.9	274.5	561.2	622.0	744.3	835.9

Talaei et al. provide iron and steel production forecasts based on historical activity and anticipated market trends [20]. Their regional production forecasts for Alberta were used in this analysis.

Table 7: Iron and steel sector activity projections (thousand tonnes of product)

Process category	1990	2000	2010	2020	2030	2040	2050

Integrated plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electric arc furnace	300.0	410.0	330.0	330.0	360.0	400.0	440.0

Activity in the chemical manufacturing sector was projected by considering regional production capacity data (capacity and plant commissioning timeline data from Mascarenhas, Taylor, and NOVA Chemicals [64-66]) and historical production per dollar GDP. Historical production data for both ammonia and ethylene are available from Statistics Canada [67-69]:

Table 8: Chemical sector activity projections (thousand tonnes of product)

Product category	1990	2000	2010	2020	2030	2040	2050
Ammonia	2554.3	3039.5	3334.5	3490.7	3553.5	3482.1	3201.4
Ethylene	1331.6	3202.4	3883.2	4139.7	4155.4	3990.8	3555.9

Provincial cement production levels projected by Talaei et al. [22] based on North American forecasts were used in this analysis. Provincial production shares were assumed to remain constant and an annual growth rate of 0.71% was used:

Table 9: Cement sector activity projections (thousand tonnes of product)

Process category	1990	2000	2010	2020	2030	2040	2050
Dry processing	1742.9	1910.5	2095.7	2309.3	2479.0	2661.3	2836.7

2.2.2.3.2 Energy intensity calibration

Baseline energy intensity (EI) values for technologies and processes in the agriculture, cement, chemicals, iron and steel, and petroleum refining sectors were calibrated using current provincial fuel-specific demand data from Natural Resources Canada [70] since the original values developed by Bonyad et al. and Talaei et al. [18, 20-22, 53] relied on older data. EI values for the cement and iron and steel sectors originally developed using national energy-use data were updated to incorporate regional data. Using the baseline energy intensities from the original models, demand results were generated and compared with historical demands for each fuel type, t, to produce calibration factors, α, for each year, y, between 1990 – 2017:

$$\alpha_{t,y} = \frac{E_{t,y,actual}}{E_{t,y,model}} \quad \text{(Eq. 2.1)}$$

Energy intensities for each fuel type were calibrated by multiplying the base energy intensity by the calculated calibration factor:

$$EI_{t,y,cal} = EI_{t,y,base}\alpha_{t,y} \quad \text{(Eq. 2.2)}$$

These values quantify fuel-specific EI deviation between the originally developed models and historical results. The calibration factors for 2000 – 2017 for agriculture, chemical, iron and steel, cement, and petroleum refining sectors can be found in Appendix C.

The original natural gas (NG) EI values for the iron and steel and cement sectors are respectively 64% and 85% lower on average than those calculated using provincial data, which may be understood by considering the widespread use of the fuel in the province due to high availability and low costs. The NG EI included in the original agriculture sector model overrepresents NG consumption by 33%, and EIs for transport fuels underrepresent diesel and gasoline consumption by 17% and 47%, respectively. The EI for liquified petroleum gas (LPG) in the agriculture model is accurate for the base year but underrepresents recent and historical LPG use by 42%. The original electricity EI developed for Alberta's chemical sector overrepresents electricity usage in all years, while the NG EI does not show a clear pattern of over or underrepresentation.

Since calibration factors are equally applied to all end-use technologies of the same fuel-type, the energy demand shares of technologies of a common fuel type are assumed constant. Deviations between EI values from the original sectoral models and historical data may be due to changes occurring within a single demand area, but in the integrated model, applied corrections affect all areas equally. Accurate allocation of these deviations would require historical data of much finer resolution than what is currently available in the public domain.

2.2.2.4 Energy transformation module

The LEAP model accounts for upstream social costs and GHG emissions in the energy transformation modules. In this analysis, GHG emissions and costs associated with electricity generation, bitumen upgrading, petroleum refining, and natural gas extraction processes are considered, allowing for analysis of both the environmental and economic effects of the assessed measures on upstream and downstream activity.

The electricity generation model for the analyzed region is detailed in previous work by Davis et al. [19]. Electricity generation is represented by an optimized merit order dispatch system, reflective of market dynamics in the case study region. The model includes processes to represent all types of existing generating capacity in the region as well as alternative future capacity pathways including wind, solar, nuclear, biomass, and hydroelectricity. In every scenario, capacity additions are optimized to minimize system cost while meeting regulatory requirements including renewable targets and coal power phase-outs.

Natural gas extraction, bitumen upgrading, and petroleum refining process data developed by Davis et al. [71] are also included in the regional model. The GHG emissions intensity of the modelled natural gas extraction process was updated based to reflect historical fugitive emissions data from the Government of Canada [13] and the Government of Alberta's current methane emissions reduction plan [72].

2.2.2.5 Model validation

Energy demand and GHG emissions results from the model were validated by comparing historical and projected levels for all three combined scenarios alongside historical emissions data from Canada's National Inventory Report (NIR) [13], historical demand and emissions data from Natural Resources Canada (NRCan) [70], and demand projections from the Canada Energy Regulator (CER) [73]. Validation figures for all sectors are shown in Appendix D. For most sectors, energy-intensities calibrated to historical demand data produce emissions levels that closely agree with historical emissions data. Since calibrated energy demand in the cement sector closely agrees with historical data from NRCan, deviation between modelled emissions and historical emissions from NRCan may be attributed to high levels of non-energy emissions over 2002-2016. A constant non-energy process emissions factor of 0.32 tCO_2e per tonne of produced cement was applied to the model to address this discrepancy[2].

[2] Data developed by Garrett Clark for an upcoming analysis of decarbonization in the cement sector

Figure 5 shows historical provincial emissions data from Environment and Climate Change Canada (ECCC) [74] alongside total provincial emissions projections made using the developed model. The projections show close agreement with those made by ECCC. The largest deviation between modelled emissions and historical data is 11% in 2011 and may be partially attributed to emissions from natural gas extraction and processing. Data necessary to accurately characterize upstream natural gas emissions is limited, so a constant fugitive emissions intensity was assumed over 1990-2017. The fugitive emissions intensity associated with natural gas extraction has likely improved over time, thus explaining the underestimation of emissions in this study from this sector in 2011. Nonetheless, the consistent agreement between modelled and historical provincial emissions provides confidence in the validity of the developed model.

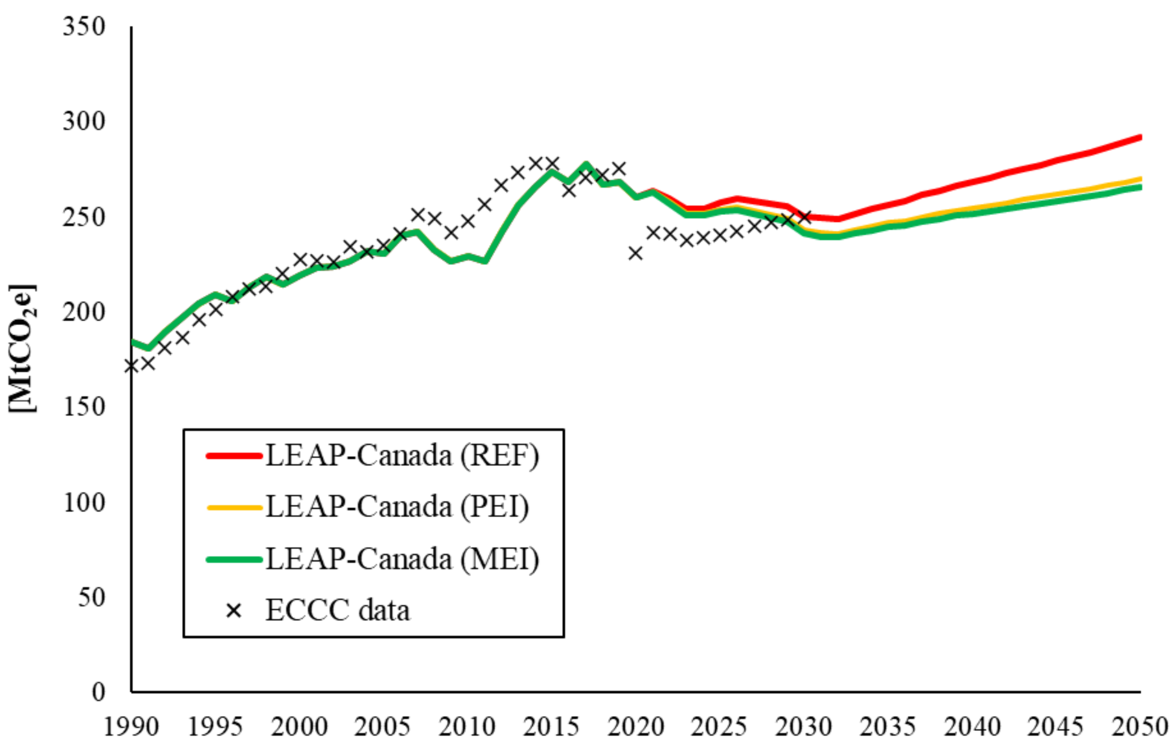

Figure 5: Modelled and reported annual GHG emissions in Alberta (1990-2050)

2.2.3 Scenario modelling

Market shares of high-efficiency end-use technologies and processes are represented by linear interpolations between base and final year shares. In the reference scenario, technology shares and associated energy intensities are assumed to be constant between the base and final years. To account for uncertainty in the penetration rate of the technologies and processes represented by the analyzed scenarios, the results for two separate cases are presented: one in which final year market shares of alternative technologies are achieved in 2030 and remain constant until 2050, and one in which market shares of alternative technologies increase at a constant rate until reaching their maximum in 2050. All individual scenarios were adapted from the LEAP models developed for each specific sector. When possible, base year market share assumptions were updated to reflect current estimates and scenarios of similar demand areas were combined to simplify the model.

The energy efficiency scenarios considered in this work were drawn from a variety of sector-specific analyses. All assessed measures are commercially available but reflect varying levels of technological maturity. Talaei et al. [22] include measures from the European Cement Research Academy [75] and Hollingshead et al. [76] in their analysis of the cement sector. Measures assessed for the chemical sector [21] were adapted from Griffin et al. [77] and Ma [78] to reflect Alberta's chemical manufacturing industry. The penetration of advanced thermal control systems was added to earlier developed list of energy-efficiency measures applicable to the commercial and institutional sector [16]. Measures assessed for the iron and steel sector [20] were based on work by Worrell et al. [79]. Bohm et al. [80] present numerous energy-efficiency measures for surface mining, in situ extraction and bitumen upgrading operations which were assessed for Alberta's oil sands sector. Talaei et al. assessed measures for the petroleum refining sector based on energy intensity reduction estimates made using a process model developed with Aspen HYSYS [53]. Subramanyam et al. present energy efficiency opportunities for the residential sector affecting space heating, space cooling, water heating, lighting, and appliance demand [17].

Market penetration potentials were estimated based on available data or feedback from industry representatives. Data describing energy intensity effects were gathered from published studies and process modelling results. Marginal demand costs rely on estimates of capital costs, operations and maintenance (O&M) costs, and technological lifetimes, which were assumed based on data available in the literature. Cost data were harmonized to a consistent base year and redefined for appropriate activity indicators.

Descriptions of all assessed individual measures are included in the table below (i.e. Table 10).

Table 10: Assessed energy efficiency improvement scenarios (combined and individual)

No.	Scenario name	Description
	Combined scenarios	
	Reference (REF)	Base year energy intensities and technology shares for all processes are constant
	Projected efficiency improvement (PEI)	Measures with negative marginal GHG abatement cost are assumed to be adopted to their maximum potential by the end year
	Maximum efficiency improvement (MEI)	All measures are assumed to be adopted by the end year
	Agriculture sector	
1	*HE livestock lighting (AGR_HE Livestock Lighting)*	Existing incandescent bulbs used for all livestock lighting can be replaced with high-efficiency T8 fluorescent bulbs.
2	*HE livestock ventilation (AGR_HE Livestock Ventilation)*	Existing 8.4 cfm/W fans are replaced with ones that are 50% more efficient.
3	*Tankless dairy water heaters (AGR_Tankless Dairy Water Heaters)*	Storage tank water heaters used for dairy production are replaced with tankless systems, and concrete tank water heaters used for feedlots and cow-calf farms are replaced with high-efficiency electric systems.
4	*HE tractors (AGR_HE Tractors)*	Tractors with Tier III engines are replaced with more-efficient Tier IV engine tractors.
5	*HE diesel trucks (AGR_HE Diesel Trucks)*	Standard diesel trucks used for various farm operations are replaced with high-efficiency trucks.
6	*HE irrigation systems (AGR_HE Irrigation)*	Energy consumed by both natural gas and electricity-powered irrigation systems is reduced through the adoption of new pumps and motors and improved maintenance schedules.
	Cement sector	
7	*Kiln fan VSDs (CEM_Kiln Fan VSD)*	Existing kiln fans are replaced with VSD fans to reduce energy consumption and maintenance costs.
8	*Reciprocating grate cooler (CEM_Blended Cement)*	Replacing planetary or rotary coolers with reciprocating grate coolers reduce fuel consumption because of their higher recuperation efficiency.
9	*EM and process control (CEM_Recip. Cooler)*	Expert systems, model-predictive control, or fuzzy logic control systems to optimize combustion and clinker cooler processes are used to significantly reduce energy consumed in both.
10	*Improved CM refractories (CEM_EM and Process Control)*	New kiln refractories last longer than conventional materials and offer energy savings due to improved insulation.
11	*Indirect firing clinker making (CEM_Improved CM Refractories)*	Decoupling primary air supply from the coal mill reduces primary air demand and energy consumption. This strategy is already used in most modern plants.

No.	Scenario name	Description
		Combined scenarios
12	*Kiln combustion system improvements (CEM_CM Ind Firing)*	Optimizing the composition of the fuel-air mixture entering the kiln improves flame shape, reduces excess combustion air, and reduces energy consumption.
13	*Clinker cooler WHR (CEM_Kiln Comb. Sys. Imp.)*	Waste heat is recovered from the clinker cooler as product is cooled from 1200°C to 100°C.
14	*Suspension preheaters (CEM_Clinker Cooler WHR)*	Exhaust fan energy consumption is reduced when cyclones are upgraded with suspension preheater systems.
		Chemicals sector
15	*Ethylene process integration (CHE_ETH Proc Int)*	Energy use is improved through the adoption of power generation processes alongside the refrigeration cycle for ethylene separation.
16	*Ethylene high-pressure combustion (CHE_ETH HP Comb)*	Combustion in high-pressure oxygen-rich environments improves the energy efficiency of the cracking process.
17	*Adiabatic prereformer (CHE_Adiabatic Prereformer)*	The use of waste-heat recovery systems and highly active catalysts reduces energy consumption in the ammonia pre-reforming process.
18	*Flue gas heat recovery (CHE_Heat Recovery)*	Heat recovered from reformer flue gas is used to preheat combustion air, produce steam, or preheat boiler feedwater.
19	*Low energy CO_2 removal tech (CHE_LE CO2 Removal Tech)*	CO_2 is physically absorbed from reformed flue gas by an organic solvent instead of MEA. Since MEA requires more energy during the regeneration process, the use of alternative solvents will result in lower utility consumption.
20	*Autothermic methanolizing methanation (CHE_Auto methanol. Methan.)*	Electricity demand is reduced when heat from the ammonia synthesis reaction is used in the conversion of CO and CO2 to methanol and methane.
21	*Low temperature conversion technology (CHE_LT Conversion tech)*	Installing low temperature shift guard reactors and converters leads to lower CO spillage, lower hydrogen consumption, and thus higher ammonia yield.
22	*Unpowered ammonia recovery (CHE_Unpowered Ammonia Recovery)*	Ammonia is recovered from vented purge gas without the use of additional power, thus improving process yield and reducing the energy required to recover diluted aqueous ammonia.
23	*Automatic temperature control (CHE_Automatic temp control)*	Optimizing the synthesis reactor temperature will decrease the amount of waste heat lost in flue gas, improve reactor performance, and decrease the energy intensity of the synthesis process.
24	*Large scale axial and radial ammonia synthesis convertors (CHE_LS Axial and Radial Amm. Synth)*	Axial-radial flow converters have lower pressure drops and higher conversion efficiencies than conventional axial flow converters, translating to reduced energy demand.

No.	Scenario name	Description
		Combined scenarios
25	*Combined heat and power (CHE_CHP)*	The overall efficiency of combined heat and power generations systems can be as much as three times higher than conventional standalone systems.
26	*Evaporative condensers (CHE_Evaporative Condenser)*	Evaporative condensers reduce pump and fan demand compared to conventional technologies.
27	*Molecular sieve dryers (CHE_Synth Gas Molecular)*	Molecular sieve dryers separate make-up gas steam from water and CO_2 using less energy than conventional technologies.
28	*Methanolization-hydrocarbylation purification (CHE_Methan. HC. Purify.)*	Energy demand associated with methane purification is reduced by using a system of heat exchangers, etherification systems, and hydrocarbon reaction towers.
		Commercial sector
29	*HE space heating (COM_SH)*	HE fuel-burning furnaces and boilers are assumed to account for close to half of current space heating technologies in the commercial Sector. Replacement of standard heating systems with new HE technologies is ongoing, but additional emissions may be mitigated if uptake accelerates.
30	*HE water heating (COM_WH)*	Tankless and condensing boilers are considered as HE alternatives for commercial water heating. Condensing systems are associated with higher energy intensity reductions. Equal base year shares of these two technologies are assumed.
31	*HE auxiliary motors (COM_MOT)*	Standard motors may be replaced with variable speed drive (VSD) motors or HE motors in various applications across the sector. Energy savings may be maximized if VSD motors replace both standard and HE motors.
32	*HE auxiliary equipment (COM_AUX)*	Standard electrical equipment including computers, printers, and digital displays may be replaced with HE versions of the same devices.
33	*HE lighting (COM_LIGH)*	Interior building lights are replaced with CFL or high-intensity discharge ballasts. This scenario also includes the adoption of HE streetlamps.
34	*HE space cooling (COM_SC)*	Rooftop A/C units and HE chillers offer higher energy efficiency than standard A/C units and central chillers. In practice, these two alternative technologies may not be applicable for all building types, so a single energy intensity reduction was assumed for both alternatives.
35	*HE building envelope (COM_HVAC BE)*	Space heating and cooling energy demand is reduced through the improvement of building envelopes. The effect and penetration potential of this measure are estimated from historical data [81].
36	*HE HVAC control (COM_HVAC CTRL)*	HVAC energy use is reduced through the adoption of thermal control systems based on novel network-based learning algorithms [82, 83].

No.	Scenario name	Description
		Combined scenarios
		Iron and steel sector
37	*EAF bottom-stirring gas injection (IRO_EAF_BS Gas Injection)*	The injection of inert gases instead of oxygen at the bottom of the EAF reduces energy consumed by the furnace.
38	*EAF UHP transformers (IRO_EAF_UHP Transformers)*	Ultra-high power (UHP) transformers are associated with lower energy loss than conventional transformers.
39	*EAF eccentric bottom tapping (IRO_EAF_Elect. Bot. Tap)*	Tapping the EAF from the bottom instead of the side increases electrode life, reduces tap-to-tap time, and increases ladle life.
40	*EAF flue gas control (IRO_EAF_Flue Gas Control)*	Flue gas composition and flow rate can be monitored with optical sensors, allowing for the optimization of combustion conditions and reduced energy demand.
41	*EAF foamy slag practice (IRO_EAF_Foamy Slag Practice)*	Radiative heat loss is reduced through the addition of granular coal and oxygen into the EAF, which creates a foam layer over the melt surface.
42	*EAF neural network process control (IRO_EAF_ Neur Network Proc. Control)*	Advanced control systems monitor and optimize various process variables to reduce total energy demand.
43	*Hot rolling oxygen control and VSDs (IRO_HR_O2 Control and VSDs)*	Using VSD oxygen fans in the reheating furnace improves combustion conditions and reduces electricity consumed by the fan.
44	*HE hot rolling drives (IRO_HR_HE RM Drives)*	Replacing existing roller drives with high-efficiency drives reduces electricity demand.
45	*Hot charging (IRO_HR_Hot Charging)*	Slabs are charged in the reheating hot-rolling furnace, which reduces energy consumption and improves slab quality.
46	*Hot rolling furnace insulation improvements (IRO_HR_Furn Ins Improv.)*	Heat lost through reheating furnace walls is reduced by replacing conventional insulative materials with low thermal mass ceramics.
47	*Hot strip mill process control (IRO_HR_HS Mill Proc. Control)*	Optimizing combustion conditions in hot strip mills reduces process downtime and energy consumptions.
48	*Hot rolling recuperative burners (IRO_HR_Recup. Burners)*	Pre-heating combustion air with heat from the exhaust gas improves overall combustion efficiency.
49	*Hot rolling cooling WHR (IRO_HR_Cooling WHR)*	Heat transferred from the rolled steel to sprayed cooling water is recovered with absorption heat pumps and used on-site as low-pressure steam.
		Oil sands sector
50	*Surface mining: energy management (OIL_SM_EM)*	Day-to-day energy consumption is reduced through the implementation of energy management and monitoring programs.

No.	Scenario name	Description
	Combined scenarios	
51	*Surface mining: use efficiency (OIL_SM_UE)*	Wasted energy is reduced through minimized idling time, avoided unplanned outages, and more reliable operation.
52	*Surface mining: improved heat exchangers (OIL_SM_HEX)*	Energy loss in various processes including waste heat recovery is reduced by replacing existing heat exchangers with systems with higher effectiveness.
53	*Surface mining: improved utilities (OIL_SM_UT)*	Existing boilers and power-recovery turbines are replaced with high-efficiency models.
54	*Surface mining: process optimization (OIL_SM_PROC)*	Process parameters such as flue gas temperatures, operating pressures, and flow rates are optimized to reduce energy loss across all demand categories.
55	*Surface mining: improved control systems (OIL_SM_CTRL)*	Advanced control systems with online analyzers are used to optimize energy-intensive processes, and thus reduce total energy consumption.
56	*In situ extraction: reduced heat loss (OIL_IN_HL)*	Heat lost from steam to the earth and water reduced through improved well development processes and the use of waste heat recovery systems.
57	*In situ extraction: improved heat exchangers (OIL_IN_HEX)*	See scenario 52.
58	*In situ extraction: improved utilities (OIL_IN_UT)*	See scenario 53.
59	*In situ extraction: process optimization (OIL_IN_PROC)*	See scenario 54.
60	*Bitumen upgrading: improved heat exchangers (OIL_UP_HEX)*	See scenario 52.
61	*Bitumen upgrading: energy management (OIL_UP_EM)*	See scenario 50.
62	*Bitumen upgrading: process optimization (OIL_UP_PROC)*	See scenario 54.
63	*Bitumen upgrading: improved control systems (OIL_UP_CTRL)*	See scenario 55.
	Petroleum refining sector	
64	*Crude distillation unit heat integration (PET_CDU Heat Integration)*	Pinch analysis is used to design optimal heat recovery systems for feed stream preheating, which reduces furnace fuel consumption.

No.	Scenario name	Description
		Combined scenarios
65	*Crude distillation unit air preheating (PET_CDU Air Preheater)*	Heat exchangers can be used to preheat combustion air from 30°C to 425°C with recovered waste heat from exhaust.
66	*Vacuum distillation unit air preheating (PET_VDU Heat Integration)*	See scenario 65.
67	*Delayed coking unit air preheating (PET_DCU WHR)*	See scenario 65.
68	*Fluid catalytic cracking heat integration (PET_FCC WHR)*	See scenario 64.
69	*Alkylation unit HP distillation (PET_Alk Unit HP Distillation)*	Conventional reboiling units can be replaced by compressors with additional heat exchangers.
70	*Isomerization heat pump distillation (PET_Iso HP Distillation)*	See scenario 69.
71	*Hydrocracking air preheating (PET_Hydrocracking WHR)*	See scenario 65.
72	*Hydro-treating unit heat air preheating (PET_Hydro Treating Design)*	See scenario 65.
73	*Catalytic reforming unit heat integration (PET_CRU Air Preheating)*	See scenario 65.
74	*HE process pumps (PET_HE Pumps)*	Conventional pump drives are replaced with VSDs to reduce energy lost by all process pumps.
		Residential sector
75	*HE space heating (RES_SH)*	HE NG furnaces have an annual fuel utilization efficiency above 90% and already account for close to half of the total market share of residential space heating technologies. In the PEI scenario, shares of all space heating technologies are forecasted based on historical trends, meaning HE NG furnaces will reach 90% market share by 2050 even without accelerated uptake.
76	*HE water heating (RES_Water Heating)*	Market penetration of condensing and tankless water heaters will reduce sectoral energy use. In the MEI scenario, shares of condensing water heaters decrease to reflect increased adoption of more energy efficient tankless condensing water heaters.
77	*HE appliances (RES_Appliances)*	Modelled appliances include fridges, freezers, clothes washers and dryers, dishwashers, stoves, ovens, and other electronics. Per-

No.	Scenario name	Description
		Combined scenarios
		device capital costs and energy intensity improvements were taken to be the same for all appliance types.
78	*HE lighting (RES_LIGH)*	Energy used for lighting may be reduced through the continued replacement of incandescent bulbs with halogen, CFL, or LED bulbs. In the MEI scenario, existing shares of halogens and CFLs decrease to allow for maximum penetration of LEDs.
79	*HE space cooling (RES_ SC)*	Air conditioners sold in Canada after 2016 must have a seasonal energy efficiency ratio (SEER) above 14 [84], but energy used for space cooling may be further reduced through the accelerated replacement of less efficient units or by the adoption of new units with SEERs above 14.
80	*HE building envelope (RES_HVAC BE)*	Both space heating and space cooling energy use are reduced through improved building envelope design, which may be achieved by building homes with high-efficiency insulation or by retrofitting existing homes with new windows, walls, and doors. The effects and penetration potential of HE building envelopes are estimated based on historical data [85].
81	*HE HVAC control (RES_HVAC CTRL)*	The use of programmable or smart thermostats reduces energy used for both space cooling and space heating. These devices are assumed to comprise 50% market share in the base year [86].

Details describing key assumptions for all scenarios are shown in the tables below (i.e. Tables 11-18), including applicability, energy-use effects, and capital and operations and maintenance (O&M) costs (2017 CAD):

Table 11: Residential sector energy-efficiency measures

Name	Demand area	Technology	Max Δ shares	Δ EI	Capital cost	Lifetime (years)	Annual O&M
RES_SH	Space heating	HE NG furnace	53%	-30 %	$2,100.00 /hh	18	$0.00 /hh
RES_Water Heating	Water heating	Tankless boilers	90%	-25 %	$750.00 /hh	18	$0.00 /hh
RES_Appliances	Appliances	HE appliances (all)	50%	-20 %	$1,000.00 /device	18	$0.00 /device
RES_LIGH	Lighting	LED	65%	-80 %	$100.00 /hh	10	$0.00 /hh
RES_ SC	Space cooling	HE central cooling	55%	-10 %	$4,100.00 /hh	18	$0.00 /hh
RES_HVAC BE	Space heating and cooling	Heat-recovery ventilator	78%	-14 %	$336.00 /hh	20	$0.00 /hh
RES_HVAC BE	Space heating and cooling	HE building envelope	78%	-40 %	$15,000.00 /hh	35	$0.00 /hh
RES_HVAC CTRL	Space heating and cooling	HE control	50%	-6 %	$100.00 /hh	10	$0.00 /hh

Table 12: Commercial and institutional sector energy-efficiency measures

Name	Demand area	Technology	Max Δ shares	Δ EI	Capital cost	Lifetime (years)	Annual O&M
COM_SH	Space heating	HE NG furnace / boiler	55%	-13 %	$16.80 /m^2	25	$0.00 /m^2
COM_WH	Water heating	HE boilers	90%	-30 %	$3.36 /m^2	20	$0.00 /m^2
COM_MOT	Aux. motors	VSD motors	95%	-40 %	$19.49 /m^2	15	$0.00 /m^2
COM_AUX	Aux. equipment	HE equipment	90%	-30 %	$13.44 /m^2	15	$0.00 /m^2
COM_LIGH	Lighting	High-intensity discharge ballasts	90%	-35 %	$4.03 /m^2	3	$0.00 /m^2
COM_LIGH	Lighting	HE street lighting	90%	-50 %	$5.38 /m^2	5	$0.00 /m^2
COM_SC	Space cooling	HE rooftop AC	90%	-50 %	$33.60 /m^2	25	$0.00 /m^2
COM_HVAC BE	Space heating and cooling	HE building envelope	95%	-13 %	$74.93 /m^2	35	$0.00 /m^2
COM_HVAC CTRL	Space heating and cooling	HE control	90%	-15 %	$5.92 /m^2	10	$0.01 /m^2

Table 13: Oil sands sector energy-efficiency measures

Name	Demand area	Technology	Max Δ shares	Δ EI (NG)	Δ EI (elec.)	Capital cost	Lifetime (years)	Annual O&M
OIL_SM_EM	Surface mining	Energy monitoring and management	90%	-2.14%	-2.14%	$0.02 /bbl	35	$0.00 /bbl
OIL_SM_UE	Surface mining	Use efficiency	90%	-0.63%	-0.05%	$0.01 /bbl	35	$0.00 /bbl

Name	Demand area	Technology	Max Δ shares	Δ EI (NG)	Δ EI (elec.)	Capital cost	Lifetime (years)	Annual O&M
OIL_SM_HEX	Surface mining	Improved heat exchanger networks & WHR	90%	-1.91%	0.00%	$0.03 /bbl	35	$0.00 /bbl
OIL_SM_UT	Surface mining	Utilities	90%	-1.25%	-0.11%	$0.03 /bbl	35	$0.00 /bbl
OIL_SM_PROC	Surface mining	Process and technology changes	90%	-0.63%	-0.06%	$0.01 /bbl	35	$0.00 /bbl
OIL_SM_CTRL	Surface mining	Control system	90%	-5.91%	-2.35%	$0.02 /bbl	35	$0.00 /bbl
OIL_IN_HL	In situ extraction	Reduce heat loss to earth and water	90%	-0.12%	-0.10%	$0.24 /bbl	35	$0.00 /bbl
OIL_IN_HEX	In situ extraction	Improved heat exchanger networks & WHR	90%	-3.95%	-0.00%	$0.55 /bbl	35	$0.00 /bbl
OIL_IN_UT	In situ extraction	Utilities	90%	-3.95%	-3.95%	$0.02 /bbl	35	$0.00 /bbl
OIL_IN_PROC	In situ extraction	Process and technology changes	90%	-0.12%	0.00%	$0.02 /bbl	35	$0.00 /bbl
OIL_UP_HEX	Upgrading	Improved heat exchanger networks & WHR	90%	-1.83%	0.00%	$0.17 /bbl	35	$0.00 /bbl
OIL_UP_EM	Upgrading	Energy monitoring and management	90%	-0.58%	-0.58%	$0.01 /bbl	35	$0.00 /bbl
OIL_UP_PROC	Upgrading	Process and technology changes	90%	-0.82%	-0.82%	$0.01 /bbl	35	$0.00 /bbl
OIL_UP_CTRL	Upgrading	Control system	90%	-1.02%	-1.02%	$0.01 /bbl	35	$0.00 /bbl

Table 14: Chemicals sector energy-efficiency measures

Name	Demand area	Technology	Max Δ shares	Δ EI (NG)	Δ EI (elec.)	Capital Cost	Lifetime (years)	Annual O&M
CHE_ETH Proc Int	Ethylene	Energy integration	90%	-30%	0%	$1.12 /t	20	$0.00 /t
CHE_ETH HP Comb	Ethylene	High pressure combustion	40%	-7%	0%	$13.44 /t	20	$0.00 /t
CHE_Adiabatic Prereformer	Reforming	Adiabatic process	90%	-6%	0%	$16.80 /t	20	$0.00 /t
CHE_Heat Recovery	Reforming	Flue gas WHR	90%	-1%	0%	$1.12 /t	20	$0.00 /t
CHE_LE CO2 Removal Tech	Gas purification & shift conversion	Low-energy CO_2 removal	24%	-79%	0%	$14.56 /t	20	$30.24 /t
CHE_Auto methanol. methan.	Gas purification & shift conversion	Autothermic non-constant pressure methanolizing-methanation process	38%	-63%	0%	$11.20 /t	20	$0.00 /t
CHE_LT Conversion tech	Gas purification & shift conversion	Low-temperature conversion	18%	-25%	0%	$14.56 /t	20	$0.00 /t
CHE_Unpowered Ammonia Recovery	Synthesis loop	Unpowered ammonia recovery technology	41%	-20%	0%	$1.12 /t	20	$0.00 /t

Name	Demand area	Technology	Max Δ shares	Δ EI (NG)	Δ EI (elec.)	Capital Cost	Lifetime (years)	Annual O&M
CHE_Automatic temp control	Synthesis loop	Automatic control and optimization of ammonia synthesis reactor temp	43%	-26%	0%	$0.00 /t	20	$0.00 /t
CHE_LS Axial and Radial Amm. Synth	Synthesis loop	Large-scale axial and radial ammonia synthesis tower	44%	-95%	0%	$4.48 /t	20	$0.00 /t
CHE_CHP	Reforming	Cogeneration	90%	-14%	0%	$11.20 /t	20	$0.00 /t
CHE_Evaporative Condenser	Gas purification & shift conversion	Evaporative condenser cooling	27%	0%	-45%	$2.24 /t	20	$0.00 /t
CHE_Synth Gas Molecular	Synthesis loop	Molecular sieve dryer and direct synthesis converter feed	29%	-35%	0%	$4.48 /t	20	$0.00 /t
CHE_Methan. HC. purif.	Gas purification & shift conversion	Methanolization-hydrocarbylation purification technology	31%	-55%	-90%	$12.32 /t	20	$0.00 /t

Table 15: Petroleum refining sector energy-efficiency measures

Name	Demand area	Technology	Max Δ shares	Δ EI (oil sands)	Δ EI (conventional)	Capital cost	Lifetime (years)	Annual O&M
PET_CDU Heat Integration	Crude distillation unit	Heat integration	80%	-4.40%	-7.50%	$0.05 /barrel	10	$0.00 /t
PET_CDU Air Preheater	Crude distillation unit	Combustion air preheating	80%	-9.00%	-18.60%	$0.08 /barrel	10	$0.00 /t
PET_VDU Heat Integration	Vacuum distillation unit	Air preheating and process optimization	80%	-3.30%	-14.00%	$0.10 /barrel	10	$0.00 /t
PET_DCU WHR	Delayed coking unit	Air preheating	80%	-4.70%	-4.20%	$0.08 /barrel	10	$0.00 /t
PET_FCC WHR	Fluid catalytic cracking	Air preheating	80%	-3.10%	-3.80%	$0.03 /barrel	10	$0.00 /t
PET_Alk Unit HP Distillation	Alkylation unit	Heat pump-assisted distillation	80%	-0.70%	-4.90%	$5.73 /barrel	10	$0.00 /t
PET_Iso HP Distillation	Isomerization unit	Heat pump-assisted distillation	80%	-3.20%	-9.10%	$14.44 /barrel	10	$0.00 /t
PET_Hydrocracking WHR	Hydrocracking unit	Air preheating	80%	-4.70%	-16.70%	$0.47 /barrel	10	$0.00 /t
PET_Hydro Treating Design	Hydrotreating unit	Air preheating and process optimization	80%	-6.50%	-7.20%	$1.88 /barrel	10	$0.00 /t
PET_CRU Air Preheating	Catalytic reforming unit	Heat integration	80%	-10.50%	-7.30%	$0.73 /barrel	10	$0.00 /t

Name	Demand area	Technology	Max Δ shares	Δ EI (oil sands)	Δ EI (conventional)	Capital cost	Lifetime (years)	Annual O&M
PET_HE Pumps	Pumps	High efficiency pumps	80%	-30.00%	-30.00%	$0.18 /barrel	10	$0.00 /t

Table 16: Iron and steel sector energy-efficiency measures

Name	Demand area	Technology	Max Δ shares	Δ EI	Capital cost	Lifetime (years)	Annual O&M
IRO_EAF_BS Gas Injection	Electric arc furnace	Bottom stirring gas injection	11%	-3.70%	$1.03 /t	0.5	-$3.43 /t
IRO_EAF_UHP Transformers	Electric arc furnace	Efficient UHP transformers	40%	-3.20%	$4.71 /t	15	$0.00 /t
IRO_EAF_Elect. Bot. Tap	Electric arc furnace	Eccentric bottom tapping	52%	-2.60%	$5.48 /t	10	$0.00 /t
IRO_EAF_Flue Gas Control	Electric arc furnace	Flue gas monitoring and control	50%	-2.60%	$3.43 /t	10	$0.00 /t
IRO_EAF_Foamy Slag Practice	Electric arc furnace	Foamy slag practice	30%	-3.70%	$17.14 /t	10	-$3.08 /t
IRO_EAF_ Neur Network Proc. Control	Electric arc furnace	Improved process control neural network	90%	-5.80%	$1.63 /t	10	-$1.71 /t
IRO_HR_O2 Control and VSDs	Hot rolling	Controlling oxygen level and VSDs	50%	-16.70%	$0.75 /t	10	$0.00 /t
IRO_HR_HE RM Drives	Hot rolling	Energy efficient drives in rolling mill	50%	-0.80%	$0.29 /t	20	$0.00 /t
IRO_HR_Hot Charging	Hot rolling	Hot charging	36%	-29.90%	$22.43 /t	10	-$1.97 /t
IRO_HR_Furn Ins Improv.	Hot rolling	Improved insulation of reheating furnace	30%	-8.00%	$14.96 /t	10	$0.00 /t
IRO_HR_HS Mill Proc. Control	Hot rolling	Process control in hot strip mill	69%	-14.90%	$1.05 /t	10	$0.00 /t
IRO_HR_Recup. Burners	Hot rolling	Recuperative burners	20%	-35.10%	$3.74 /t	10	$0.00 /t
IRO_HR_Cooling WHR	Hot rolling	Waste heat recovery for cooling water	69%	-1.70%	$1.20 /t	15	$0.00 /t

Table 17: Cement sector energy-efficiency measures

Name	Demand area	Technology	Max Δ shares	Δ EI (NG)	Δ EI (elec.)	Capital cost	Lifetime (years)	Annual O&M
CEM_Kiln Fan VSD	Kiln	Variable speed drive fan	50%	-1.4%	-16.4%	$0.26 /t	10	$0.00 /t
CEM_Blended Cement	Crusher	Mixing in additives	50%	-11.6%	0.0%	$11.76 /t	15	-$0.09 /t
CEM_Recip. Cooler	Clinker cooler	Conversion to reciprocating grate coolers	60%	-5.1%	0.0%	$11.20 /t	20	$0.00 /t
CEM_EM and Process Control	Clinker making	Energy management and process control systems	90%	-3.3%	-8.5%	$1.01 /t	10	-$1.99 /t
CEM_Improved CM Refractories	Clinker making	Use of improved refractories	30%	-8.1%	0.0%	$0.67 /t	20	$0.00 /t
CEM_CM Ind Firing	Clinker making	Indirect firing	50%	-2.8%	0.0%	$8.96 /t	20	-$5.99 /t
CEM_Kiln Comb. Sys. Imp.	Kiln	Improved combustion conditions	20%	-4.7%	0.0%	$1.12 /t	20	$0.00 /t
CEM_Clinker Cooler WHR	Clinker cooler	Improve heat recovery	50%	-1.9%	0.0%	$0.22 /t	20	$0.00 /t
CEM_Susp. Preheater	Kiln	Replacing vertical shifts with suspension preheater	80%	-55.8%	0.0%	$39.20 /t	40	$0.00 /t

Table 18: Agriculture sector energy-efficiency measures

Name	Demand area	Technology	Max Δ shares	Δ EI	Capital cost	Lifetime (years)	Annual O&M
AGR_HE Livestock Lighting	Lighting (poultry)	Use of T8 fluorescent bulbs	80%	-70 %	$1.60 /t	6	$0.00 /t
AGR_HE Livestock Ventilation	Ventilation (poultry)	Improved fan efficiency	90%	-50 %	$1.06 /t	10	$0.00 /t
AGR_HE Livestock Lighting	Lighting (dairy & cattle)	Use of T8 fluorescent bulbs	80%	-77 %	$2.07 /t	6	$0.00 /t
AGR_HE Livestock Ventilation	Ventilation (dairy, cattle & hog)	Improved fan efficiency	90%	-50 %	$1.10 /t	10	$0.00 /t
AGR_HE Water Heaters	Water Heating (dairy & cattle)	Use of tankless heaters (dairy)	80%	-60 %	$3.69 /t	12	$0.00 /t
AGR_HE Water Heaters	Water heating (dairy & cattle)	High-efficiency electric heaters (cattle)	90%	-40 %	$0.00 /t	12	$0.00 /t
AGR_HE Livestock Lighting	Lighting (hog)	Use of T8 fluorescent bulbs	80%	-77 %	$0.04 /t	6	$0.00 /t
AGR_HE Tractors	Tractors	Efficient tractors	90%	-20 %	$0.47 /t	15	$0.00 /t

Name	Demand area	Technology	Max Δ shares	Δ EI	Capital cost	Lifetime (years)	Annual O&M
AGR_HE Diesel Trucks	Trucks	High-efficiency diesel trucks	90%	-20 %	$0.57 /t	12	$0.00 /t
AGR_HE Irrigation	Irrigation (crops)	Efficient pumps and motors (elec.)	90%	-36 %	$0.09 /t	10	$0.00 /t
AGR_HE Irrigation	Irrigation (crops)	Efficient pumps and motors (NG)	90%	-29 %	$0.31 /t	10	$0.00 /t

2.2.4 Cost analysis

Marginal GHG abatement costs were calculated for each measure by dividing the NPV of all social costs by cumulative GHG mitigation.

$$MAC = \frac{NPV_{scen} - NPV_{ref}}{GHG_{scen} - GHG_{ref}} \qquad \text{(Eq. 2.3)}$$

Here, the marginal abatement cost (MAC) of a specific measure is defined as the difference between the net present values (NPV) of all social costs associated with mitigation scenario (NPV_{scen}) and the reference scenario (NPV_{ref}) divided by the difference between cumulative GHG emissions of the mitigation scenario (GHG_{scen}) and reference scenario (GHG_{scen}). Scenarios with negative MAC are considered cost-effective.

Costs were defined in Canadian dollars (CAD) and discounted to 2020 assuming a discount rate, r, of 5%. This discount rate was selected to maintain consistency with previous decarbonization analyses [22, 87, 88]. A boundary around the entire energy system was considered to reflect the objectives of this study. For each year, i, of n total years, costs associated with annualized capital (C_{ann}), operations and maintenance ($O\&M$), fuel (F), and emissions externalities (E) are considered.

$$NPV = \sum_{i=0}^{n} \frac{C_{ann,i} + O\&M_i + F_i + E_i}{(1+r)^i} \qquad \text{(Eq. 2.4)}$$

Capital costs from previous analyses were all adjusted to the selected base year and redefined on appropriate activity bases when necessary. Costs for residential HVAC technologies were updated using recent data [89]. Capital costs ($C_{ann,i}$) for all measures were defined in annualized terms using the expression shown below:

$$C_{ann,i} = CC * \frac{i}{1-(1+r)^{-l}} \qquad \text{(Eq. 2.5)}$$

where CC is the marginal overnight capital cost defined relative to the standard respective technology, r is discount rate, and l is lifetime. Assumed capital cost and lifetime data for all technologies are shown in Table 11 - Table 18.

Fuel costs are accounted in the model's energy resources module. Primary energy resource costs for electricity generation, bitumen upgrading, petroleum refining, and natural gas extraction processes are shown in Table 19.

Table 19: Selected resource supply costs for all modelled fuels ($/GJ)

Year	1990	2000	2010	2020	2030	2040	2050
Crude oil [90]	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Natural gas [91]	7.9	7.9	3.6	1.7	2.9	3.5	3.8
Bitumen [92]	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Coal [19]	1.1	1.1	1.1	1.1	n/a	n/a	n/a

To reflect Canada's carbon pricing plan within the selected cost boundary, carbon costs are accounted as inflation-adjusted externality costs. These costs represent the damages sustained by human health and infrastructure due to GHG emissions and are based on the Government of Canada's current carbon price plan [32]. Nominal costs are adjusted by assuming a 1.6% annual inflation rate based on the ten-year average common consumer price index for Canada from 2010 to 2020 [93].

Table 20: Canadian current policy carbon pricing schedule ($/t$CO_2$e)

Year	2020	2025	2030	2035	2040	2045	2050
Nominal price	30	95	170	170	170	170	170
Inflation-adjusted price	30	87	143	143	143	143	143

2.2.5 Combined scenario development

After calculating the marginal GHG abatement costs of all individual measures, measures were added to projected efficiency improvement (PEI) and maximum efficiency improvement (MEI) groups based on cost. All measures with net negative social costs were included in the PEI scenario since consumers are expected to invest in cost-saving measures. This simple assumption does not reflect sector-specific decision-making criteria but was made to maintain a high-level consistency across all sectors. Accurate assessment of specific costs faced by consumers in each sector is beyond the scope of this study.

No energy-efficiency measures are included in the reference scenario, and market shares and energy intensities of all technologies are assumed to remain constant. To isolate the effect of energy-efficiency measures alone, the reference scenario includes projected changes to transformation processes including increased wind power capacity and reduced coal power capacity in response to Canada's carbon tax plan and Alberta's coal phase-out schedule [94].

Applying multiple energy-efficiency improving measures simultaneously may create interaction effects both upstream and at the point of emissions. Modelling energy-efficiency improvements as absolute energy intensity reductions oversimplifies the thermodynamics of energy-consuming processes. As the amount of energy wasted by a process is reduced by a measure, the potential for further reductions diminishes. To reflect this, measures were defined in terms of relative energy intensity reductions. A single energy efficiency measure, i, will reduce the base energy intensity, EI_0, of a process by fraction, r_i, resulting in final energy intensity EI_i:

$$EI_i = EI_0 * (1 - r_i) \qquad \text{(Eq. 2.6)}$$

If multiple energy-efficiency measures are applied to the same processes, the final energy intensity can be written as a product of the base energy intensity and the EI fractions associated with each relative reduction:

$$EI_{final} = \frac{E_{total}}{N_{total}} = EI_0 \prod_{i=1}^{n} (1 - r_i) \qquad \text{(Eq. 2.7)}$$

Alternatively, the effects of combined measures can be modelled as a series of diminishing reductions applied to a constant energy intensity:

$$EI_{final} = EI_0 - \sum_{i=1}^{n} r_{i,combo} EI_0 \qquad \text{(Eq. 2.8)}$$

The relative EI reduction of a measure when combined with other measures can be determined by equating the two above expressions:

$$EI_0 \prod_{i=1}^{n}(1 - r_i) = EI_0 - \sum_{j=1}^{n} r_{j,combo} EI_0 \qquad \text{(Eq. 2.9)}$$

$$\prod_{i=1}^{n}(1 - r_i) = 1 - r_{1,combo} - r_{2,combo} \dots - r_{n,combo} \qquad \text{(Eq. 2.10)}$$

Solving for $r_{n,combo}$ gives the recursive function shown below:

$$r_{n,combo} = 1 - \sum_{j=1}^{n} r_{j-1,combo} - \prod_{k=1}^{n}(1 - r_k) \qquad \text{(Eq. 2.11)}$$

where $r_{0,combo} = 0$. In the model, measures assumed to be applied in order of decreasing cost-effectiveness (i.e. EI reduction r_1 is associated with the most cost-effective measure and r_n with the least).

2.3 Results & discussion

The results of this analysis framework applied to the province of Alberta, Canada, assuming penetration over 2021-2050, are shown and discussed in the following sections. The calculated marginal abatement costs for all measures and sector-specific curves are shown in Appendix E. The results for the 2021-2030 penetration case are shown in Appendix F. Sections 2.3.1 and 2.3.2 provide whole-system perspectives on the role that energy efficiency could play in future energy demand and emissions reduction pathways, respectively. Section 2.3.3 presents cumulative GHG mitigation potentials and marginal GHG abatement costs of all individual measures, providing insights regarding the most economical and effective GHG mitigation measures available in each sector. Considering both system-wide and sector-specific results, general policy recommendations towards provincial decarbonization are given in Section 2.3.4. Limitations of this framework are discussed in Section 2.3.5 and a sensitivity analysis is in Section 2.3.6.

2.3.1 Annual energy demand reduction potential

The combined effects of all assessed measures on Alberta's total energy demand are summarized by Figure 6. Together, energy-efficiency improvements may reduce Alberta's projected energy demand in 2050 by 9% if only cost-effective measures are realized and by 10% if all assessed measures are implemented regardless of cost. Reducing natural gas demand constitutes most of the total identified energy-savings potential; reducing demand for electricity and other fuels is less significant. Since fuel-switching measures were not considered, the values shown here are likely underestimations of 2050 electricity demand and overestimations of 2050 natural gas and other fuel demand. Nonetheless, there remains significant unrealized energy-savings potential through efficiency improvements in the analyzed region.

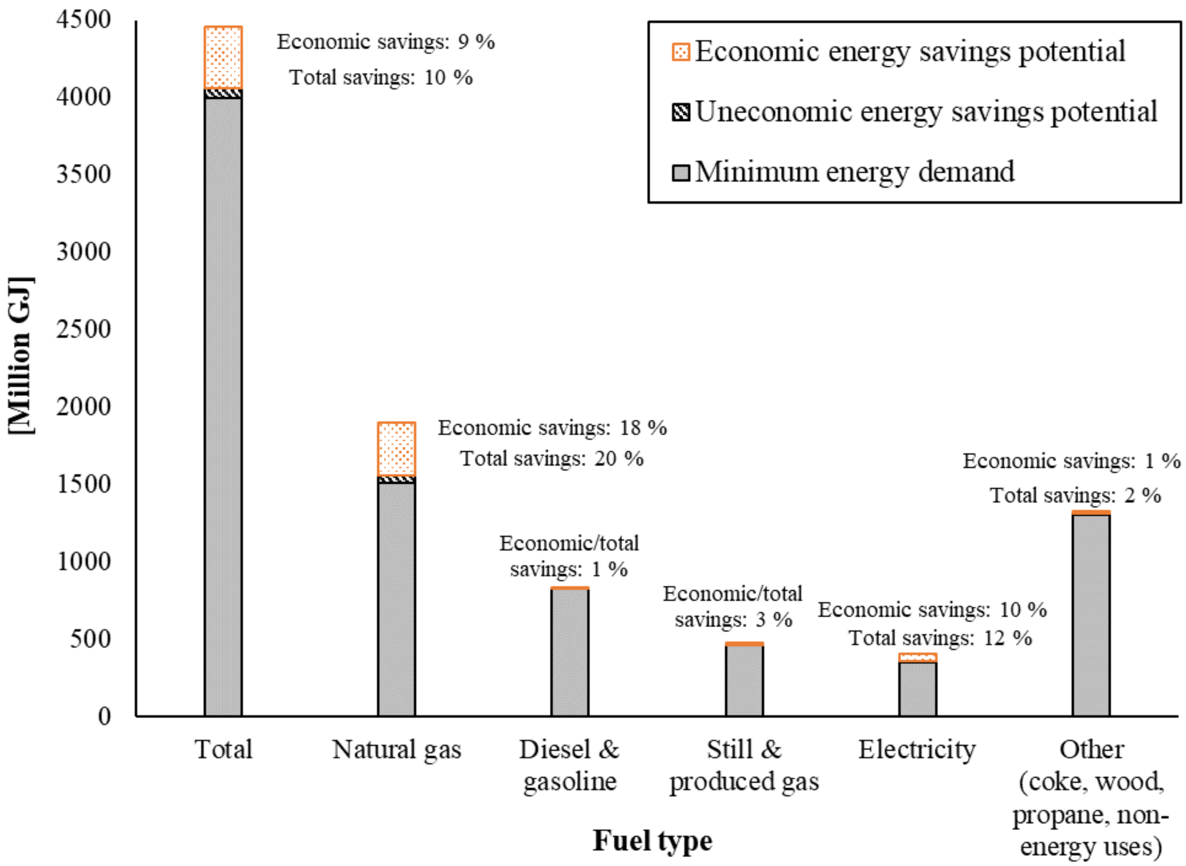

Figure 6: Energy savings potential of efficiency improvement measures in Alberta, by fuel type. Economic energy savings potential refers to projected demand reduction if measures with negative marginal GHG abatement are implemented, and uneconomic energy savings potential refers to the difference between the maximum demand reduction and economic savings potential, giving total savings potential when added together.

2.3.2 Annual emissions reduction potential

Figure 7 shows that without the adoption of any energy-efficiency improvements, annual emissions in Alberta are projected to rise by 12% from 2020 to 2050. If cost-effective energy-efficiency improvements are realized, annual GHG emissions' growth reduces to 5% by 2050. Together, the application of all assessed energy efficiency scenarios would limit GHG emissions growth to 3% between 2021 and 2050. Measures included in the projected efficiency improvement scenario could mitigate 7% (19 $MtCO_2e$) of reference scenario emissions by 2050. At most, all assessed energy-efficiency measures could mitigate 8% (24 $MtCO_2e$) of reference scenario emissions by 2050.

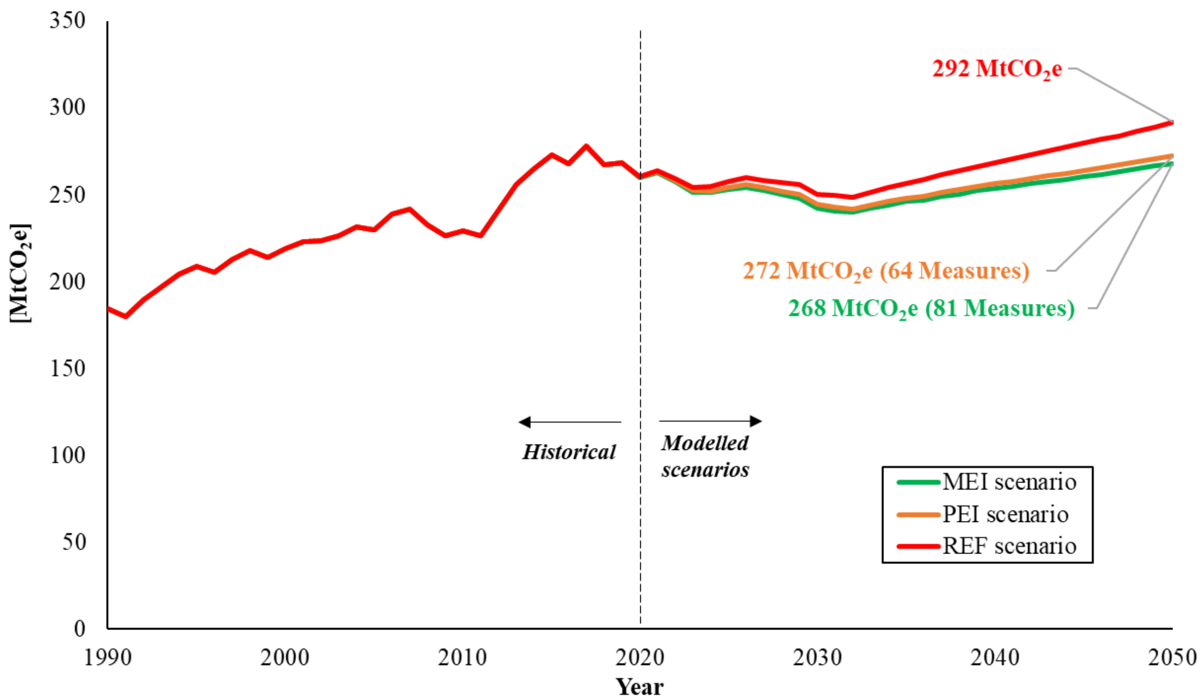

Figure 7: GHG projections for combined energy efficiency scenarios (2021-2050 penetration).The reference scenario (REF) includes no changes to end-use technology shares or energy or emissions intensities. The projected efficiency improvement scenario (PEI) includes measure with negative marginal abatement costs. The maximum efficiency improvement scenario includes all identified measures.

As expected, energy-efficiency improvements offer significant benefits in terms of emissions and economic costs: the cumulative NPV of the PEI scenario relative to the reference is 16 billion CAD, while the MEI represents a relative value of 5 billion CAD. Maximum annual mitigation potentials for all sectors are illustrated in Figure 8. Since the MEI scenario represents the simultaneous application of several energy-efficiency measures, mitigation potentials are allocated to respective points of emissions. Energy transformation (TRA) is shown as its own sector.

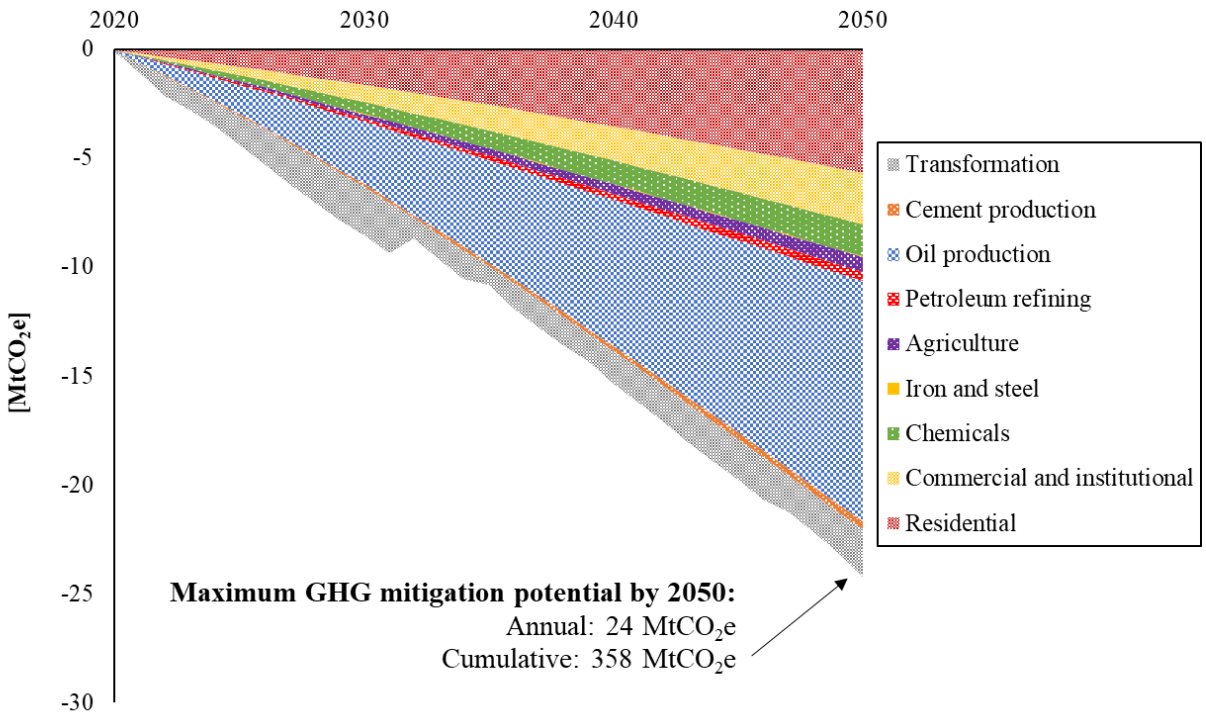

Figure 8: Maximum GHG mitigation through energy-efficiency measures (2021-2050 penetration)

Figure 8 shows that GHG mitigation from all demand-side sectors aligns with the assumed linear penetration of energy-efficiency measures between 2021-2050. GHG mitigation in the energy transformation sector deviates from this trend between 2030 and 2033 because of differences in electricity capacity addition. All efficiency-improving measures reduce total energy demand, but since the developed model features a detailed energy transformation module, resultant emissions are affected by electricity generation processes as well. Alberta's electricity grid is undergoing rapid decarbonization and previous work has shown that renewable energy is expected to constitute the majority of capacity additions in the next 15 years [50], meaning that in the developed model, reduced capacity additions due to demand reduction temporarily lead to higher levels of natural gas combustion in the electricity generation sector.

Figure 9 shows direct annual GHG emissions mitigation potential by sector organized into economic and uneconomic totals alongside 2050 annual emissions projections for all three combined scenarios. Alberta's oil sands are associated with the largest absolute sectoral emissions mitigation potential, which is entirely economic.

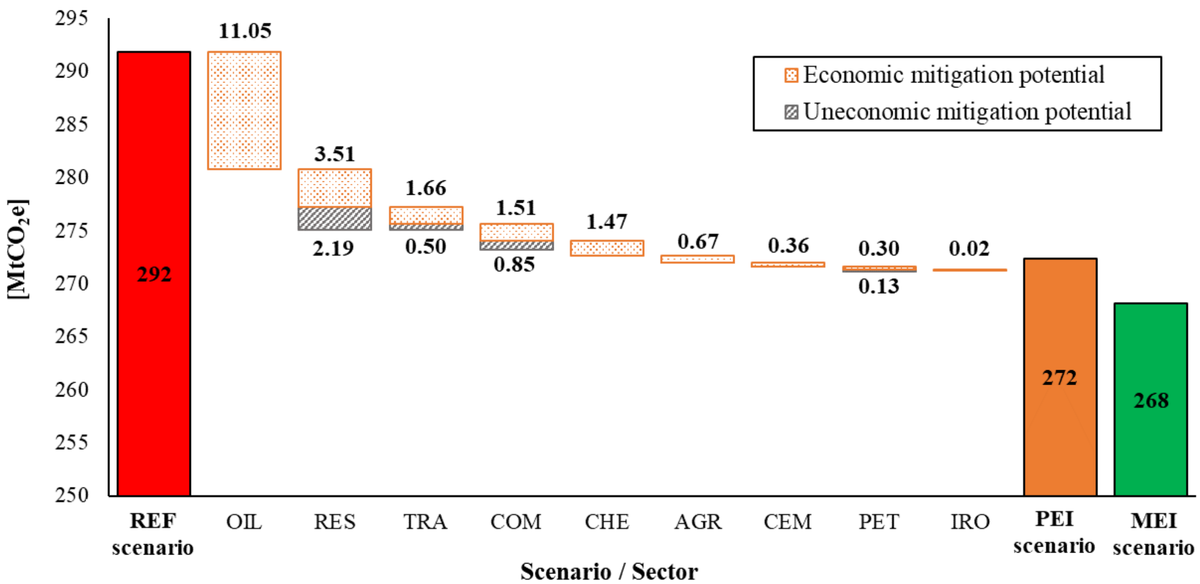

Figure 9: GHG mitigation potential of energy-efficiency measures, 2050 (2021-2050 penetration). Direct GHG mitigation values are allocated to points of emission in the oil sands (OIL), residential (RES), commercial (COM), chemicals (CHE), agriculture (AGR), cement (CEM), petroleum refining (PET), and iron and steel (IRO) sectors. Indirect GHG emissions reductions are allocated to energy transformation sector (TRA). Resultant annual regional GHG emissions are shown for the reference (REF), projected efficiency improvement (PEI), and maximum efficiency improvement (MEI) scenarios. Vertical axis is truncated for visibility.

The residential and commercial and institutional sectors show significant levels of mitigation potential beyond the economic measures. These additional measures may prove to be cost-effective to energy consumers in each respective category and may thus show market penetration without requiring additional financial incentive. The low levels of total GHG mitigation potential shown for the iron and steel and cement sectors may be attributed to limited activity in the province, whereas the GHG mitigation potential identified for the petroleum refining sector is low compared to the sector's total GHG emissions footprint.

If all of the assessed measures achieve market saturation before 2050, at least 97% of 2019 annual GHG emissions (268 $MtCO_2e$) will need to be mitigated through other measures or offset by carbon negative strategies to achieve NZE by 2050. Most of the GHG mitigation potential held by energy-efficiency improvements are achievable at negative cost, but together, energy efficiency represents only 8% of the annual GHG mitigation level necessary to achieve NZE by 2050. These findings reiterate suggestions from the International Energy Agency that energy-efficiency improvements are crucial first steps towards decarbonization, but not sufficient to achieve carbon neutrality on their own [7].

2.3.3 Marginal GHG abatement costs of individual measures

Cumulatively, 358 $MtCO_2e$ may be mitigated through energy-efficiency improvements across major economic sectors in Alberta between 2021 and 2050, and 80% of this potential may be realized at negative cost. If penetration occurs over 2021-2030, a cumulative GHG mitigation potential of 596 $MtCO_2e$ is possible, with the 82% of this total achievable at negative cost. Cumulative GHG mitigation potentials, marginal abatement costs, and annual GHG mitigation potentials for all assessed measures are shown in Appendix E. Calculated marginal GHG abatement costs do not significantly change between the different penetration timeframes. For both cases, the MACs for commercial and residential space cooling efficiency improvements are the highest among all assessed measures; this may be understood by considering that scenarios are associated with electrical EI reductions only and that the associated demand areas for each scenario represent a relatively insignificant share of each respective sectors' total energy demand. Alberta's rapid electricity grid decarbonization is forecasted to continue until 2036, meaning that the associated GHG mitigation potential of scenarios affecting electrical EI diminish as the province's grid becomes more reliant on non-emitting sources. Thus, these scenarios are associated with low mitigation potentials and high MACs. These outlying scenarios demonstrate that the definition of cost-effectiveness is a limitation of this analysis and are discussed further in Section 2.3.5.

Scenarios for all sectors, ordered by MAC, are shown below.

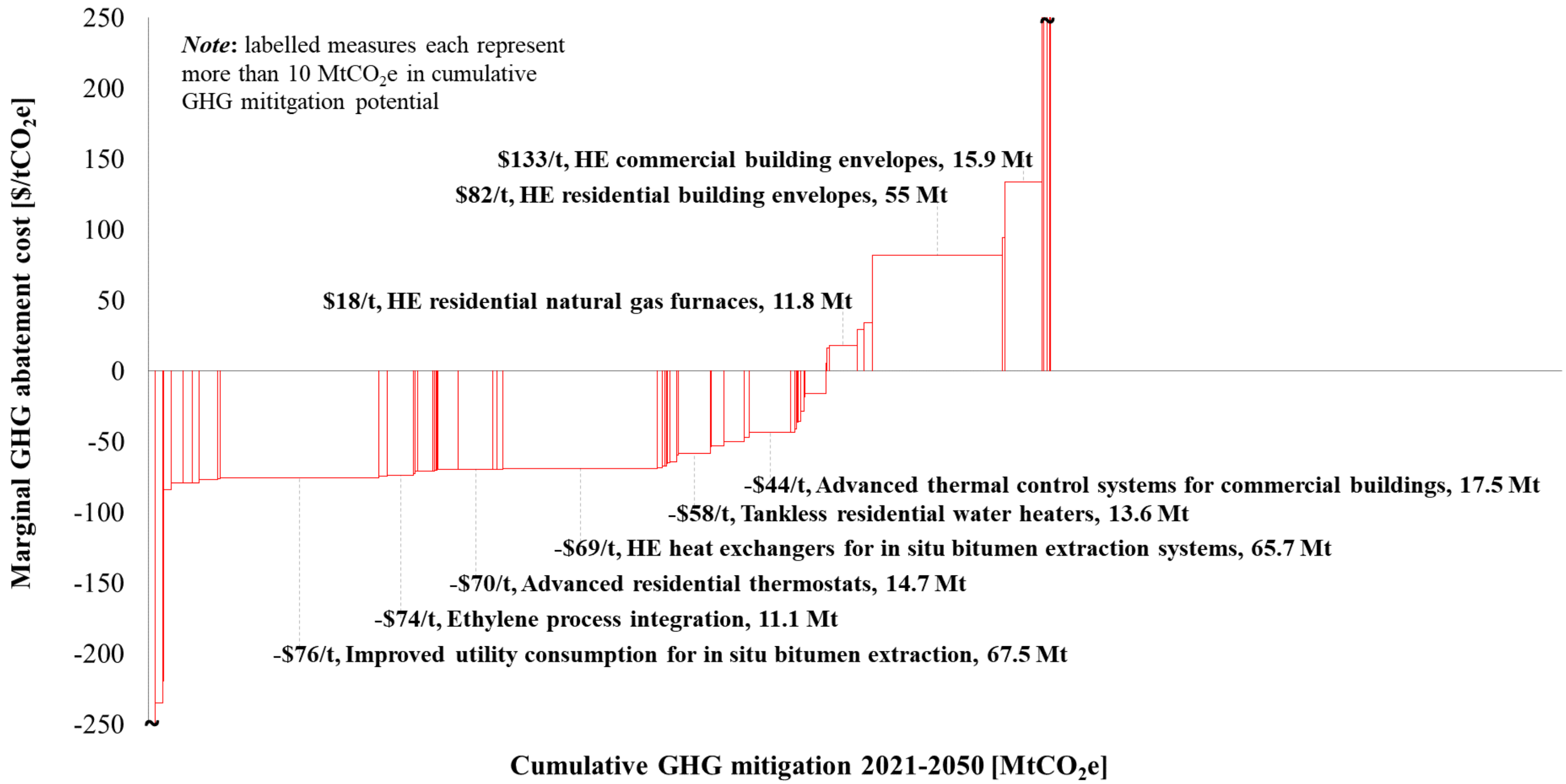

Figure 10: Marginal GHG abatement costs of energy-efficiency measures (2021-2050 penetration). Vertical axis is truncated for readability.

Figure 10 shows that pricing carbon at \$170/tCO_2e by 2030 is sufficient to make most energy-efficiency measures achievable at negative cost, and that 273 MtCO_2e in cumulative GHG mitigation may be achieved through the implementation of the nine labelled measures in the residential, commercial and institutional, chemicals, and oil sands sectors. Figure 11 summarizes the cumulative mitigation potentials and social costs of all energy-efficiency measures applied in each sector. Measures affecting the buildings sectors are the only ones with positive average MAC. Emissions mitigation in all other sectors may be achieved at negative costs ranging from -\$73/tCO_2e to -\$49/tCO_2e.

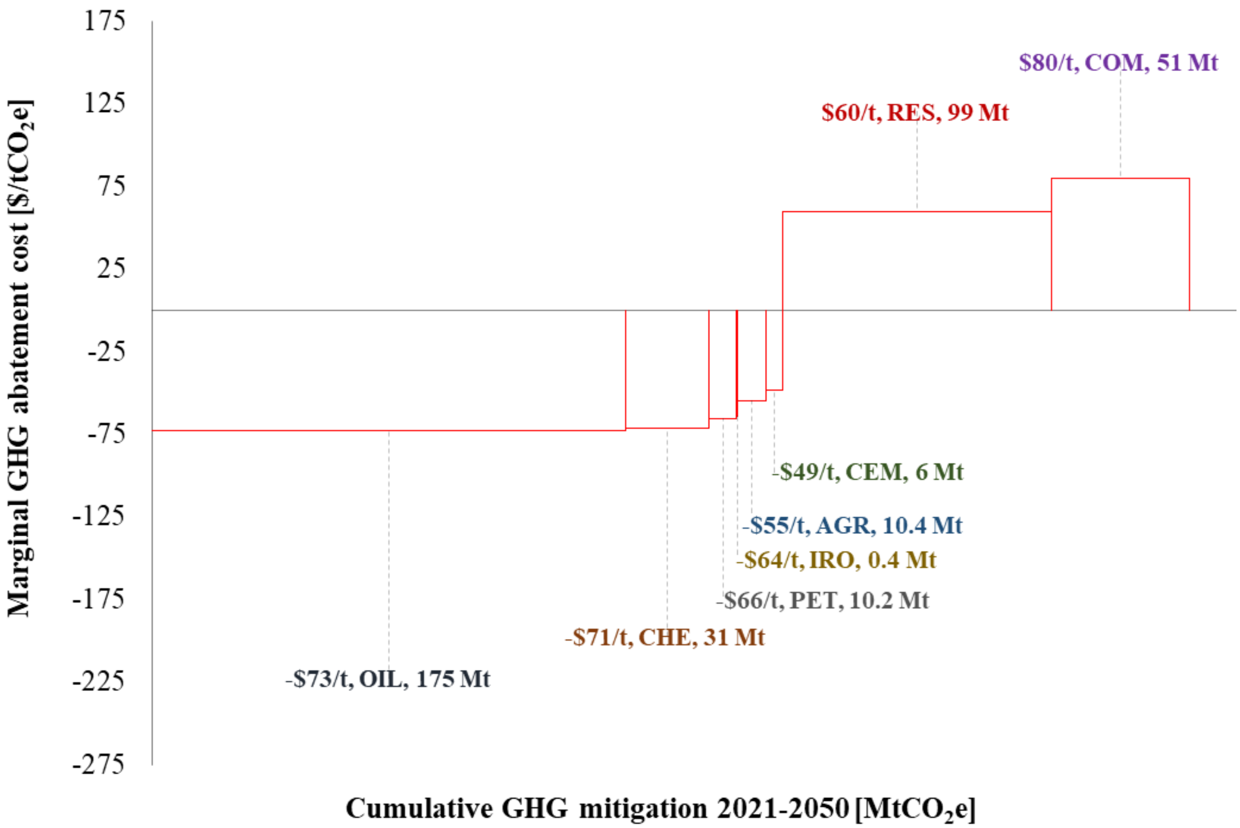

Figure 11: Average sectoral abatement costs of energy-efficiency measures (2021-2050 penetration). Calculated costs reflect the maximum penetration of measures in the oil sands (OIL), chemicals (CHE), petroleum refining (PET), iron and steel (IRO), agriculture (AGR), cement (CEM), residential (RES), and commercial (COM) sectors.

Energy-efficiency improvements in the oil sands sector represent significant economic and environmental benefits, while efficiency improvements in the petroleum refining, iron and steel, agriculture, and cement sectors together represent a low level of cumulative GHG mitigation potential. Measures assessed for the buildings sectors show significant GHG mitigation potential but have the highest average MAC among all sectors: other types of GHG mitigation measures in these sectors may be more cost-effective than energy-efficiency improvements. The residential and commercial sectors have similar GHG footprints in Alberta, but the assessed measures represent a larger GHG mitigation potential in the residential sector due to the different effects of building envelope retrofits in these two sectors.

2.3.4 Policy implications

Decarbonization policies in Alberta should focus on improving energy efficiency in the short term (5-10 years) as identified in this study could result in significant GHG mitigation potential through these measures across most sectors. Notably, emissions from Alberta’s oil and gas sector and chemicals sector may be significantly reduced through the implementation of negative-cost measures including judicious energy management and technological retrofits. GHG levels in the residential and commercial sectors may also be significantly mitigated by energy-efficiency improvements, but additional policy may need to be implemented for consumers to adopt these measures. Consumer-facing costs may deviate from the values calculated in this analysis when rebates, retail markups, and carbon cost-exposure levels are considered, but it is expected that energy-efficiency will remain a cost-effective focus for both consumers and governments looking to reduce GHG emissions levels. Future decarbonization assessments should address the uncertainty of consumer behaviour with more detailed decision-making models.

The results in this study show that the relative GHG mitigation potential of energy-efficiency improvements in Alberta’s agriculture sector is relatively insignificant since GHG emissions from this sector are dominated by non-energy sources. Decarbonization of this sector will require a combination of product demand changes (e.g. reduced beef production) and natural or technological carbon-negative measures or offsets (e.g. tree planting or development of DAC facilities). GHG reduction opportunities in Alberta’s iron and steel and cement production facilities are limited due to low activity in the province. The decarbonization of other sectors should receive higher priority in the short term.

In most cases, energy-efficiency improvements are cost-effective and readily available GHG mitigation strategies, but implementing these measures together represents at most only a small fraction of the GHG reduction level necessary to achieve NZE in Alberta by 2050. Energy-efficiency improvements may represent a higher relative level of GHG mitigation potential in regions where emissions are less heavily dominated by fuel-intensive industrial processes like those in Alberta's oil and gas sector. Decarbonization in Alberta's oil and gas sector represents a critical path towards achieving NZE nationally and will likely require a combination of fuel-switching and carbon-capture measures that may come at a higher cost than energy efficiency [36, 88]. In Alberta and similarly fossil-fuel intensive jurisdictions, Governments cannot rely on energy-efficiency measures alone in the pursuit of complete energy system decarbonization.

Considering the findings of this analysis and the challenges summarized above, the following considerations towards meeting national NZE ambitions.

1. **Short-term focus (5-10 years):**
    a. Highlight the economic benefits of cost-effective energy-efficiency improvements to residential and commercial energy consumers through the development of a provincial energy efficiency body or by expanding the mandate of existing government organizations to include efficiency awareness campaigns for non-industrial energy consumers.
        - The US Department of Energy's Property Assessed Clean Energy (PACE) program allows homeowners to finance GHG emissions-reducing projects through property-based assessments, which aims to reduce the level of hesitancy that property owners may feel towards investing in capital-intensive retrofits for homes that they may be selling within a few years [95].
        - The City of Edmonton's Home Energy Retrofit Accelerator program incentivizes residential GHG emissions-reducing measures by providing homeowners with certified Energy Advisors to recommend energy-saving measures and offering rebates for qualified expenses. Less than 0.3% of homeowners have participated in the program, indicating abundant opportunity for expanded program reach [96].

    b. The uptake of energy-efficiency improvements in the oil sands may be accelerated through the implementation of energy management standards such as ISO 50001

[97]. Compliance with such standards may be mandated or incentivized through financial compensation or recognition programs [98].

2. **Medium-term focus (10-20 years):**
    a. Liaise with the federal government on setting provincial emissions-reduction milestones. Alberta's environmental footprint and economic landscape mean that the province will be more heavily affected by Canada's push to achieve NZE than any other region, so any federal decarbonization mechanisms must address region-specific implications in a just way.
3. **Long-term focus (20-30 years):**
    a. Continue supporting research to assess optimal paths forward towards complete energy system transition. Achieving NZE in Alberta will require drastic changes to region's economy and the associated social and environmental impacts to all communities within Alberta must be considered.

2.3.5 Limitations

The broad perspective adopted for this analysis offers value to policy makers and professionals interested in the analysis of entire energy systems but may limit the utility of this research for other audiences. From an energy-consumer perspective, efficiency improvements are generally low-risk investments, but some measures shown here may not be worthwhile since energy-efficiency improvements have not been compared against other measure types or considered the implementation of sector-specific standards. Measures affecting the transport sector were excluded from this work since estimating the mitigation potential of high efficiency combustion engine vehicles is of little value if shares of electric vehicles rapidly increase in the coming years and is part of future work. Similarly, although high-efficiency natural gas furnaces and air-conditioning units offer significant cost and energy savings to both residents and entire energy systems, heat pumps may be more cost-effective if consumer-facing rebates are considered. Measures assessed for ammonia production facilities may not be applicable in facilities where hydrogen is produced by electrolysis instead of steam methane reforming. This study does not try to predict radical sector-wide fuel-switches in the analysis, but instead has addressed this uncertainty by generating results for short- and long-term horizons and including variations in penetration potential in the sensitivity analysis to show how the mitigation potential of energy-efficiency measures might change under different future markets.

The focus of this research is on the degree to which energy-efficiency measures may reduce a region's annual emissions towards achieving NZE, meaning that sector-specific technology uptake factors have not been included in the scope of this analysis. Costs were defined within an entire energy system boundary and assumed penetration decisions are based on those costs alone. A measure's true cost-effectiveness may depend on government subsidies, retail costs of energy, rebates from carbon pricing mechanisms, and other factors not included in the generalized cost analysis. Drawing cost boundaries around sectors specifically may allow for more practical quantification of cost-effectiveness but would not facilitate economic assessment of system-wide emissions targets like NZE. In previous single-sector GHG mitigation analyses, authors have considered varying levels of carbon pricing exposure to reflect uncertainty in sector-specific carbon costs [36, 88]. The uncertainty in penetration due to the simplified carbon price representation was addressed by examining the sensitivity of the results to the assumed penetration potentials of all measures in Section 2.3.6.

Furthermore, all efficiency measures were assumed to be fully implemented over the same base and end years, which may not accurately reflect the varied levels of technological readiness between measures across all sectors. For example, based on historical data, the shares of HE residential furnaces may reach market saturation faster than the shares of industrial plants using novel processes will. Uncertainty has been addressed in penetration rate by including results for two penetration cases and showed that annual mitigation potential by 2050 is largely unaffected by penetration rate. Since the focus of this research is on annual emissions mitigation potential in 2050, the assumption of binary technology adoption decisions is appropriate for this research.

The findings in this research should not be taken as the total level of GHG mitigation potential possible through the adoption of all energy demand-reducing technologies since only process efficiency improvements were considered and fuel-switching measures were excluded. For example, end-use electrification offers environmental benefits to energy systems since electrical demand may be met with non-emitting electricity generation and electrified systems can be inherently more efficient than fuel-powered systems due to reduced thermal loss. Induced energy-efficiency improvements associated with electrified heating systems, transport, or other fuel-switching measures may significantly reduce total energy demand in a region but have not been considered in this research.

2.3.6 Sensitivity analysis

The sensitivity of the model was examined by recording the responses in cumulative mitigation, cumulative social cost, and annual mitigation for the MEI scenario compared to the reference scenario by changing input variables to reflect the lower and upper bounds, as shown below.

Table 21: Sensitivity analysis input variable deviations

	Deviation from base value	
Input variable	Low bound	High bound
Fuel costs	-50%	+100%
GDP	-10%	+10%
Penetration potential	-10%	+10%
Population	-15%	+15%
Projected oil production	-15%	+15%
Discount rate (absolute change)	-4%	+15%

Bounds shown for fuel costs, GDP, population, and forecasted oil production represent relative deviation from the base case in 2050 and were modelled as linear interpolation functions between zero and the low or high bound. Low and high bounds for discount rate represent absolute, non-temporal deviations.

Deviations in fuel costs were applied to all resource supply costs and reflect uncertainty in future energy prices projected by the Canada Energy Regulator [55]. Deviations in GDP are also based on the difference between low and high GDP projections provided by the Canada Energy Regulator. Low and high bounds for penetration potential reflect uncertainty in current shares of HE technologies and processes. Since estimates of existing shares were based off either reported data or consultation with industry, bounds were selected to represent a conservative level of uncertainty for all sectors. Low and high bounds for population were selected to reflect the maximum difference between low and high population projections provided by the Government of Alberta [99]. Bounds for forecasted oil production were selected to reflect estimates from the Canada Energy Regulator [55]. Bounds for discount rate were selected based on historical extremes of the national bank interest rate as reported by Statistics Canada [100].

The responses in key results to all input variable deviations are presented in the figures below. Figure 12 shows the response of cumulative mitigation potential, Figure 13 shows the response of cumulative social costs, and Figure 14 shows the response of annual GHG mitigation potential to changes in key input variables.

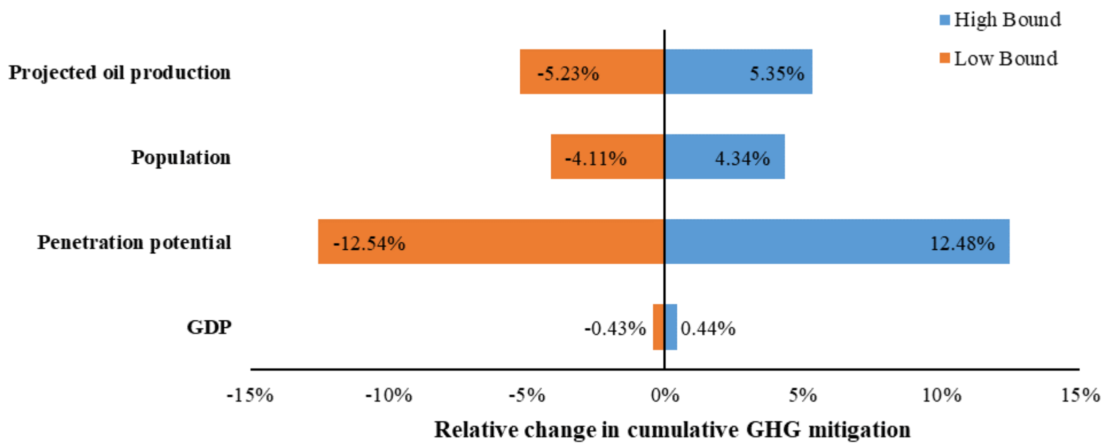

Figure 12: Sensitivity of cumulative GHG mitigation to key input parameters

Cumulative mitigation for the MEI scenario is observed to be most sensitive to projected oil production and penetration potential since the province's emissions are heavily dominated by crude oil production and penetration potential directly affects the maximum GHG mitigation level achieved by all measures.

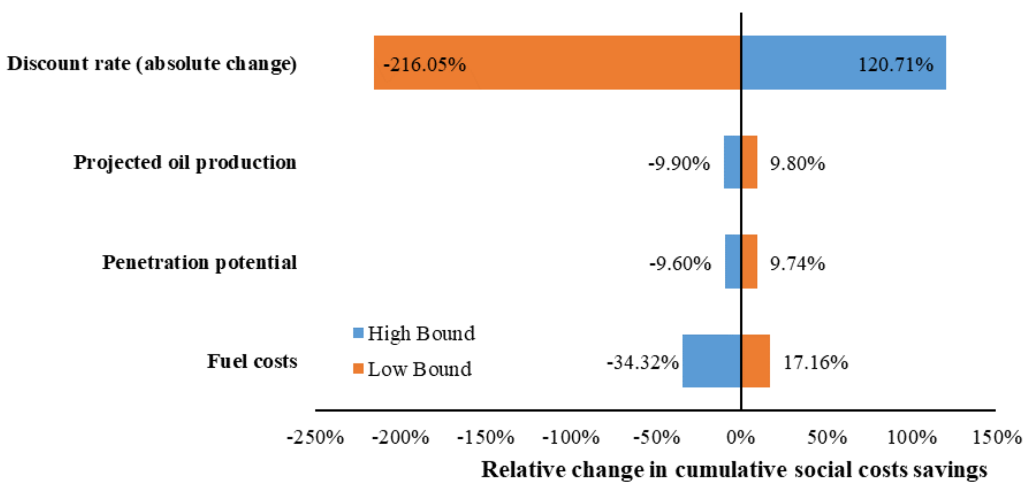

Figure 13: Sensitivity of cumulative social costs to key input parameters

Cumulative social costs are sensitive to discount rate since all values are expressed in discounted terms, capital costs for all demand-side technologies are expressed as annualized costs, and annual fuel supply and externality costs are projected to grow significantly. Estimated cumulative social costs are observed to change significantly depending on fuel costs as well.

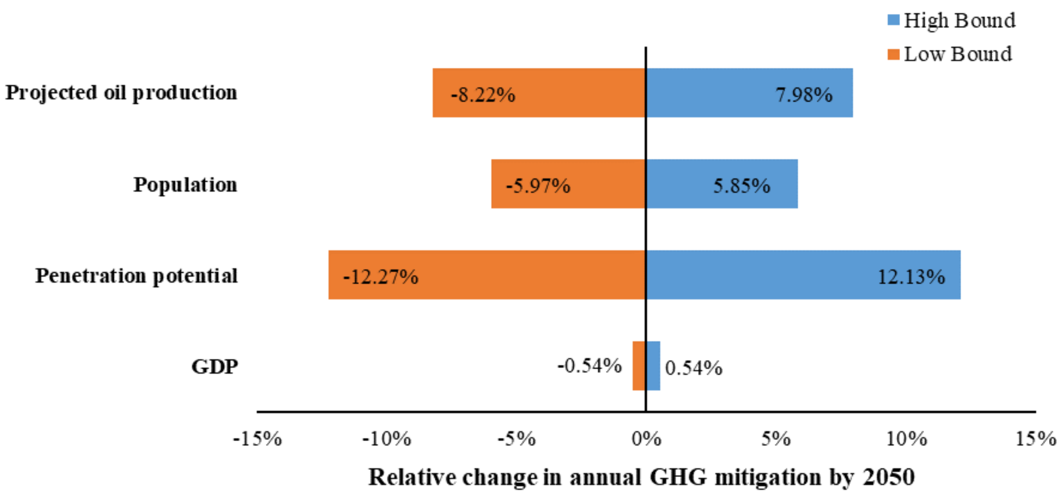

Figure 14: Sensitivity of 2050 annual GHG mitigation to key input parameters

Like cumulative GHG mitigation, annual GHG mitigation is observed to be most sensitive to projected oil production and estimated penetration potential since oil production constitutes the majority of emissions in the province and penetration potential directly affects the degree to which mitigation measures are applied.

The figures shown above demonstrate that social and marginal abatement cost results are generally associated with higher uncertainty than projected GHG mitigation results. Considering uncertainties in projected oil production, population, measure penetration potential, and GDP, it was estimated that the maximum level of annual GHG mitigation achievable with energy efficiency improvement measures in Alberta by 2050 is between 6% and 10% relative to reference scenario GHG emissions. This analysis relies on several projections with high levels of uncertainty, but since sensitivity bounds were selected to represent extreme cases, the results shown here provide confidence in the validity of the model and analysis framework.

2.4 Conclusion

This research developed an analysis framework for quantifying the emissions mitigation potential of specific energy efficiency-improving technologies and processes across all major sectors of an economy. This framework may be applied at regional and national scales and offers utility to policy makers, energy system planners and operators, and industrial professionals through the facilitation of financial cost and emissions mitigation assessment of energy-efficiency measures. This work addresses the lack of bottom-up economy-wide energy efficiency models identified in the literature. Specifically, this research introduces a novel method of accounting for the limitations of simultaneously applied energy-efficiency measures, allowing for accurate quantification of the GHG mitigation potential of combined energy-efficiency measures. Assessing the GHG mitigation potential of energy efficiency-based measures using this framework ensures that the potential contribution of energy-efficiency improvements towards achieving net-zero emissions within a region is not overestimated. As more jurisdictions develop plans towards achieving net-zero emissions by mid-century, it is expected that the demand for this type of research will grow.

In this case-study it was shown that ramping up carbon pricing to \$170/tCO_2e by 2030 is sufficient to incentivize almost all identified state-of-the-art energy efficiency improvement opportunities in Alberta's industrial sectors. It is expected that by 2050, measures accounting for 80% of the total annual GHG mitigation potential offered by all assessed measures will be implemented, meaning that opportunities for further GHG mitigation through energy efficiency improvement beyond the projected efficiency improvement scenario are limited. Additional GHG mitigation potential in the buildings sectors may be realized through the development of specific, targeted policy. Currently, it is recommend that consumers focus on implementing only the economic energy efficiency improvement measures, as further decarbonization must be addressed by other measure types which may end up being more cost-effective than the remaining efficiency-based opportunities.

If all identified energy-efficiency measures are adopted regardless of financial cost, it is estimated that relative to the reference scenario in this study, a total of 24 MtCO_2e can be mitigated annually by 2050 at an average marginal GHG abatement cost benefit of \$13/tCO_2e, reiterating suggestions from national environmental bodies that energy efficiency represents a cost-effective initial focus for any net-zero roadmap. Nonetheless, this total accounts for less than 10% of the region's forecasted annual emissions in 2050. The bulk of GHG mitigation required to achieve NZE by 2050 will likely need to come from a combination of fuel switching, carbon capture, direct air capture or natural carbon sink enhancement strategies.

Opportunities for GHG emissions reductions through energy-efficiency improvements in other regions may be abundant but are seldom quantified. The framework presented in this analysis may be applied in regions around the world to estimate the contribution that energy efficiency may offer in reducing anthropogenic GHG emissions towards complete decarbonization. Based on the review, studies detailing bottom-up economy-wide energy models are limited, which indicates a lack of tools available for policymakers to develop actionable, technology-specific emissions reduction strategies.

3 Development of a national net-zero assessment framework[3]

3.1 Introduction

3.1.1 Background

The target of achieving net-zero GHG emissions (NZE) by 2050 is an unprecedented global challenge. As of June 2022, 140 countries accounting for 90% of global GHG emissions have committed to this target in some form [2], yet fossil fuel consumption continues to grow [3]. There is no “silver bullet” to complete energy-system decarbonization [1, 4, 5]. Research has shown that improving energy efficiency can significantly reduce global GHG emissions [7]. GHGs may also be mitigated by fuel-switching and electrification measures, but the applicability of these measures in the aviation and heavy industry sectors is uncertain [8]. Carbon dioxide may be captured and stored in these “hard-to-abate” sectors, but the technological and economic feasibility of these projects is still being investigated [9]. Negative emissions measures involving biophysical carbon sequestration may be used to offset residual GHG emissions within a region, but there are environmental limits and risks associated with these nature-based solutions [10, 11].

Achieving NZE may only be possible through a portfolio of different mitigation measures involving end-use technology changes, alternative energy production, and consumer behaviour changes. Pathways towards net-zero GHG emissions have been proposed, but GHG mitigation measures are often included without regard for practical constraints or commercial availability. To successfully deploy these strategies, governments and corporations must establish comprehensive emissions reduction policies and sector-specific decarbonization milestone targets. Numerical energy models can help policymakers develop these plans by providing whole-system emissions and economic cost accounting and allowing for GHG mitigation pathways strategies to be assessed practically and economically.

[3] A version of chapter 3 has been prepared for journal submission.

3.1.2 Entire-energy-system models

Integrated assessment models (IAMs) are widely used for energy planning and emissions forecasting and have been used to develop decarbonization assessments of diverse geographical regions [28]. They are capable of representing complex the interactions between consumers, industry, and the environment. In 2020, the International Energy Agency (IEA) released its "Net Zero by 2050: A Roadmap for the Global Energy Sector" based on results from five combined models: a global competitive energy market model, a technology-rich energy demand and conversion model, an atmospheric pollutant and human health model, a bioenergy and land-use model, and a global spending and investment model [7]. The study describes a single central NZE pathway, but the authors emphasize that other pathways can be possible and that policy "roadmaps" must be tailored to region-specific environmental and economic contexts. Key milestones from the central NZE pathway include no new sales of commercial or residential fossil fuel boilers by 2025, complete phase-out of unabated coal electricity generation by 2030 in advanced economies, best-in-class appliances, cooling systems, and industrial motors achieving near full-market share by 2035, net-zero emissions electricity available globally by 2040, 50% of global heating demand met by heat pumps by 2045, and 7.6 $GtCO_2e$ of carbon captured annually by 2050. The highlighted pathway shows that NZE can technically be achieved by 2050 but will require "nothing short of a total transformation" (p. 3) of global energy systems and an increase in average annual spending equal to 1% of global GDP relative to the past five years. The modelling approach used by the IEA allows the effects of specific technologies to be examined but does not account for local economic and environmental conditions. Assessment frameworks with finer regional resolution are needed in order to develop specific and effective climate change policy.

Williams et al. used two integrated models, EnergyPATHWAYS and RIO, to represent energy demand and energy supply, respectively, in the USA [101]. With these models, the authors developed 7 carbon-neutral pathways and one carbon-negative pathway and showed that net-zero CO_2 emissions can be achieved for energy and industrial processes at a net cost of 0.2-1.2% of the country's projected GDP in 2050. Renewable electricity generation and end-use electrification are fundamental elements in all their assessed pathways. Carbon capture and storage (CCS) and utilization (CCU) are essential components in every pathway as well; the authors estimate that up to 1063 $MtCO_2e$ may need to be captured annually for use (56%) and geological sequestration (44%). This study highlights the utility of IAMs in whole-system, multi-regional decarbonization analysis. However, since NZE is prescribed as an end-state constraint in the authors' model, uncertainty regarding the availability and costs of developing GHG mitigation measures like CCS and DAC is not reflected in the results. Critics of existing IAMs, like Low and Schäfer [102], argue that including unproven GHG mitigation measures like bioenergy with carbon capture and storage (BECCS) in net-zero analyses may be misleading to policymakers who are not fully familiar with the assumptions used in the model. IAMs do not always account for differences in technology readiness level (TRL) among measures, meaning that the reported results may make decarbonization targets appear more feasible than they currently are.

Vats and Mathur used the MARKAL energy system model to model pathways toward net-zero GHG emissions in India [5]. They found that even under ambitious emissions reduction assumptions such as achieving global best industrial energy efficiency by 2050, banning fossil-fuel passenger vehicle sales by 2030, electrifying all rail transport by 2050, and stopping investment into coal-based power plants by 2030, nearly 60% of the country's 2019 GHG emissions will need to be offset by carbon-negative strategies. The authors ultimately conclude that despite the wide range of GHG reduction measures included in their assessment, currently available decarbonization strategies are insufficient to achieve NZE by 2050 in India. The authors do not provide details on the assessed technologies and instead rely on assumed energy efficiency improvement rates.

Li et al. assessed the feasibility of achieving net-zero carbon emissions in Switzerland by 2050 using the bottom-up Energyscope model [27]. The model represents natural carbon sinks and DAC technologies, allowing for the analysis of closed carbon cycles under the prescribed 2050 NZE constraint. This is approach is unique in handling NZE as a least-cost optimization problem for a complex system of carbon sinks and sources. The primary utility of the authors' work is in assessing the theoretical feasibility of achieving net-zero GHG emissions instead of helping develop technology-specific policies that might be implemented toward this target.

In the reviewed works described above, energy systems researchers have chosen to prioritize assessment scope over technological specificity. Some authors have used more detailed energy models to assess process- and technology-specific GHG mitigation opportunities for specific sectors [78, 79, 103], but, to the best of the author's knowledge, GHG mitigation assessments that span all major economic sectors and represent end-use technologies from the bottom up have not been performed. The practical limits of GHG mitigation strategies cannot be accurately quantified through top-down modelling approaches where simulation algorithms pick sets of alternative technologies to satisfy prescribed end conditions irrespective of technological readiness.. Additionally, policymakers must maintain economy-wide perspectives when developing decarbonization policy; interventions may prove ineffective if GHG reductions in one sector are outweighed by GHG growth in another. Considering the increasing global priority of achieving NZE by 2050, there is a clear need for energy models that feature high levels of technological detail for all major emissions sources across an entire economy.

3.1.3 Knowledge gaps

Despite their prevalence in energy systems research, existing energy system models have been critiqued for lacking methodological transparency, understating input assumption uncertainty, oversimplifying the effects of innovative technologies, representing consumer behaviour inaccurately, and using inconsistent operational definitions of "feasibility" [28]. To address these critiques, this research offers a novel, transparent approach for the assessment of NZE targets in which the GHG mitigation potential of individual decarbonization strategies are quantified and represent consumer behaviour based on factors like cost and technology readiness.

Bottom-up decarbonization assessments have primarily focused on single sectors instead of the entire energy system. Achieving net-zero GHG emissions in a single sector may not be effective in complete regional decarbonization if measures are not implemented simultaneously across sectors (e.g., natural gas combustion may increase at electricity plants because of the electrification of end-use industrial equipment) [27]. Resource and technology costs may be inconsistent across separate sectoral analyses as well, which can lead policymakers to misconstrue findings or prioritize action inappropriately. In an economy-wide model, using consistent data across all sectors ensures that measures can be compared on the same cost basis. Tools facilitating whole-system planning are thus essential for meeting ambitious national emissions reduction targets.

Published NZE pathways do not accurately reflect current realities. Researchers do not always distinguish between currently available and unproven solutions and often model them beside each other without clearly communicating the differences in uncertainty, availability, and practicality among them. In this thesis, a portfolio of previously assessed measures are assembled for which specific costs, energy effects, and emissions effects have been quantified, and exclude measures involving unproven technologies. By filtering measures in this way, the gaps between ambition and currently available solutions are highlighted and areas where more research and innovation are required before specific, effective policy can be developed are identified.

3.1.4 Objectives

The primary objectives of this research are to:

1. Develop a transparent multi-regional, multi-sector, technology-explicit assessment framework to quantify the GHG mitigation potential of energy-related decarbonization measures and technologies;
2. Assemble a portfolio of established and developing decarbonization strategies involving energy-efficiency improvements, fuel switching, and carbon capture and utilization/storage across all major economic sectors;
3. Using Canada as a case study, assess the maximum GHG mitigation potential of the combination of identified measures relative to a constant energy and emissions intensity reference case and a business-as-usual case;
4. Evaluate Canada's current position relative to its long-range GHG reduction targets.

3.1.5 Regional context

Canada announced its commitment to achieving net-zero GHG emissions by 2050 in 2019 [104]. The country has fallen short of all previously established national emissions reduction targets, and its net-zero commitment is the most ambitious to date, as shown by Figure 15. Canada officially enshrined the target in legislation through the Canadian Net-Zero Emissions Accountability Act*,* which establishes a framework through which the target may be planned towards and continuously assessed [105]. Additionally, the federal government recently released a roadmap toward the 2030 emissions reduction target detailing key focus areas, sectoral emissions reduction budgets, and milestone targets relating to methane emissions, zero-emissions vehicles, and renewable electricity generation [106].

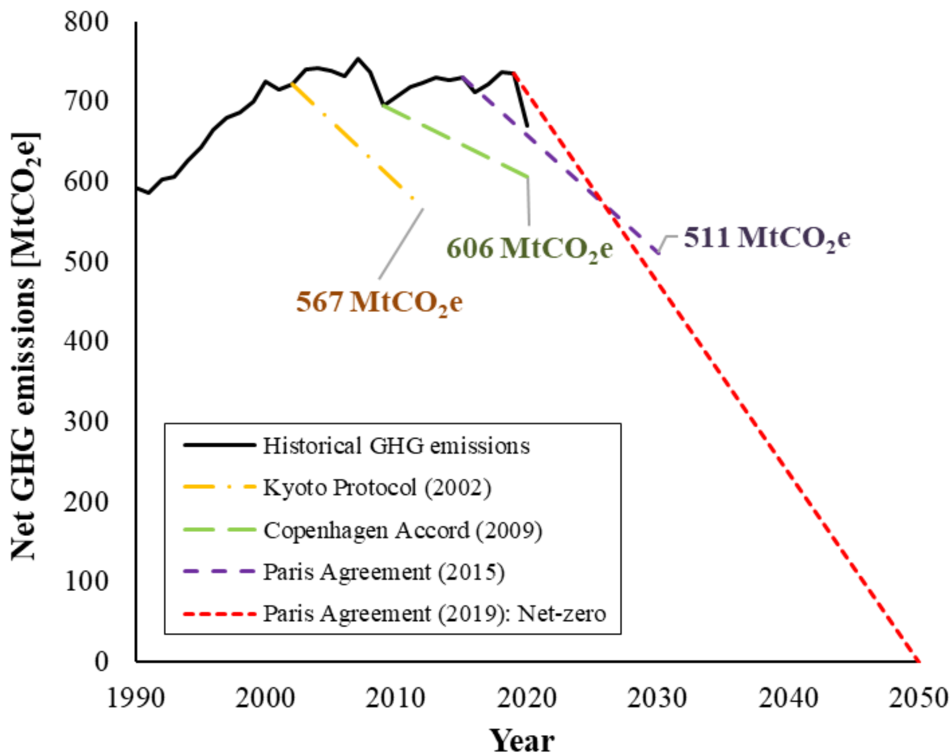

Figure 15: Historical GHG emissions and reduction targets in Canada

Canada's per capita GHG intensity is more than triple the global average [107]. In 2019, the country's net GHG emissions were 738 $MtCO_2e$, of which 38% were from the province of Alberta, 28% were related to oil and gas production, and 20% were related to oil and gas production in the province of Alberta alone [13]. In 2020, Canadian oil and natural gas producers contributed $105 billion to the country's GDP (6.4%) [108]. Besides oil and gas, large shares of national GHG emissions come from the transportation sector (25%), residential and commercial buildings (12%), and agriculture (9%). Although renewable electricity generation and electric vehicles have become emblematic of national GHG mitigation efforts, any credible path towards nationwide decarbonization must address GHG emissions from the oil and gas sector and the economic consequences of associated changes in production levels or costs.

3.2 Methods

A framework was developed that can be used to assess potential action towards net-zero GHG emissions in multi-sectoral, multi-regional economies. The framework uses a bottom-up energy systems model that can be adapted to any region using local data describing historical energy use, sectoral activity, energy transformation, and macroeconomic factors. Figure 16 summarizes the steps by which this framework is organized. All subsections contained in this section describe both the general approach used at each step and details regarding their application in a case study for Canada.

Section 3.2.1 provides details on data collection and review, which involves defining GHG mitigation measure categories, identifying potential GHG mitigation measures from sector-specific GHG mitigation assessments and other sources, and applying filtering criteria to develop a comprehensive range of currently available measures. Section 3.2.2 describes data organization and preparation, which involves tabulating data on the costs and effects of the individual measures using consistent bases and boundaries. As described in Section 3.2.3, energy modelling involves adding these scenarios into an integrated energy system model comprised of disaggregated sectoral models. Scenario analysis is described in Section 3.2.4 and involves calculating system-wide energy demand, GHG emissions, and social costs, which provide insights on the costs of different GHG mitigation measure types, the gap between GHG reduction ambition and available solutions, and additional GHG mitigation strategies that will need to be deployed to address this gap. These insights can be used to provide recommendations to policymakers responsible for developing plans towards NZE.

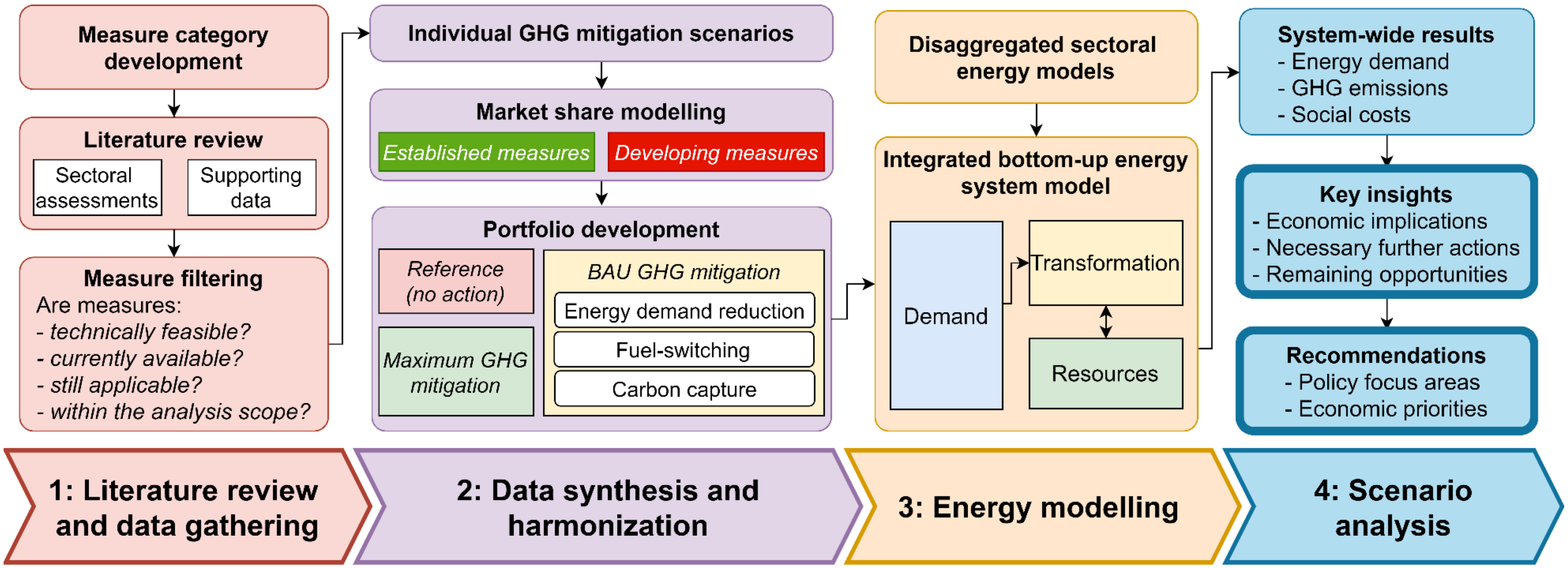

Figure 16: Schematic overview of the analysis framework

3.2.1 Literature review and data gathering

3.2.1.1 Measure category development

Measures are categorized based on the physical mechanisms by which they reduce GHG emissions, as introduced in Chapter 1. Measures in which a process or technology is improved or replaced without changing the end-use service or energy source are classified as energy-efficiency improvements. Energy demand reduction (EDR) may also be achieved if end-user requirements change irrespective of process efficiency changes. These measures are referred as service demand reductions (SDR). Measures involving partial fuel switching are categorized as energy-efficiency improvements if the main fuel type does not change. Fuel-switching (FSW) measures may involve end-use electrification or alternative fuel use, including biomass-fired or solar-powered boilers. Carbon capture (CC) technologies can reduce or eliminate GHG emissions from a fossil fuel combustion process. After CO_2 is captured at the emissions source through pre-combustion, post-combustion, or oxyfuel combustion processes, it can be injected into geological formations or ocean waters for long-term sequestration (CCS) [39] or used in a variety of applications providing economic benefit [109]. Carbon dioxide removal (CDR) strategies involve the capture and sequestration of atmospheric CO_2, which may occur through direct air capture (DAC) technology or the enhancement of natural carbon sequestration mechanisms like forest uptake.

In this case study, only CC measures involving post-combustion or oxy-fuelled combustion capture processes are assessed, as well as use in enhanced oil recovery or storage in geological formations. SDR measures involving human behaviour changes are not assessed in the analysis because of the high complexity of social dynamics [110]. All CDR strategies are excluded from this research since the scalability of these measures is uncertain [42] and they fall outside the scope of energy system analysis.

3.2.1.2 Literature review

The second step in the framework is to review the literature on sectoral or regional GHG mitigation assessments spanning all major energy-intensive economic sectors. Studies should be included in the analysis if they have been peer-reviewed and involve specific individual measures with explicitly defined cost, applicability, and effect data. In cases where more recent or rigorously developed data are available, supplementary sources should be used. Publications should be monitored regularly to ensure that novel measures resulting from technological innovation and commercialization are included.

In this case study, the focus is on previously-published GHG mitigation assessments [111]. Figure 17 summarizes the literature reviewed for this case study and shows the number of measures assessed for each sector and the sources detailing their development. Industrial sectoral assessments have primarily focused on energy-efficiency improvements since these measures are readily available and can be simply defined in terms of applicability, end-use, improvement, and marginal cost [14, 16, 17, 20-22, 25, 53, 112]. Decarbonization assessments of transportation and electricity generation sectors have generally focused on FSW measures [15, 87]. Researchers have assessed a diverse range of GHG mitigation strategies for Canada’s oil sands since the oil and gas sector represents the single largest GHG source nationwide [13]. Supporting data from technology manufacturers [89] and novel case studies [82, 113] were used to update costs and develop scenarios representing new space conditioning technologies in the residential and commercial sectors.

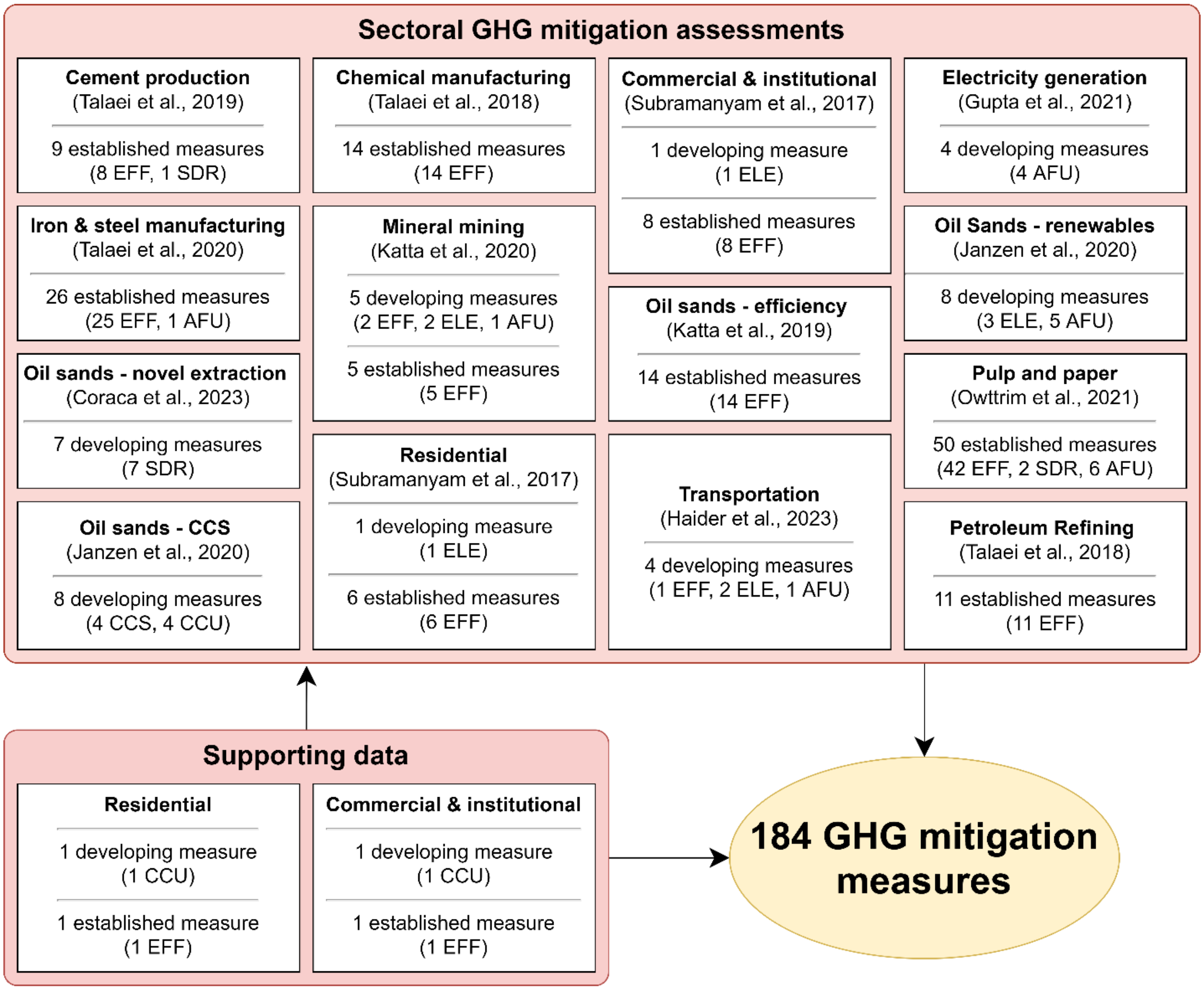

Figure 17: Integration of sector-specific GHG mitigation assessments and supporting data. Assessed measure categories are energy efficiency (EFF), service demand reduction (SDR), electrification (ELE), alternative fuel use (AFU), carbon capture and storage (CCS), carbon capture and utilization (CCU).

3.2.1.3 Measure filtering

Measures are filtered from the assessment if they are not technically feasible, based on speculative technologies, no longer applicable, or are associated with significant effects outside the energy system. These filtering criteria can be adapted to reflect different assessment goals but should eliminate redundancies between measures and ensure that they are currently applicable.

Table 22 provides an overview of all the changes applied to the original sectoral assessments consulted for this case study as well as the changes applied to the sectoral energy models. Citations for the original publications themselves as well as supporting data used to justify these updates are included below.

Table 22: Summary of included measures, original sources, and included updates

Sector	Original publications	Updates and changes
Cement	[22]	- None
Chemicals	[21]	- None
Commercial	[16]	- Model structure updated to improve accuracy and data resolution - Model extended to all regions of Canada - Historical activity and demand updated with the latest available data - Penetration of heat pumps modelled [89] - Penetration of CCU for NG space heating modelled [113] - HE building envelope improvement estimated using national energy consumption data [81]
Electricity generation	[87]	- Redefined optimization constraints for reference and maximum mitigation scenario
Iron and steel	[20]	-None
Mining	[23]	- Scenarios combined for all minerals - Redundant grinding scenarios excluded
Oil sands	[14, 36, 88, 114, 115]	- Market share models represent competition between all technologies - Market share models applied to replaceable and new production capacity
Petroleum refining	[53]	- None
Pulp and paper	[25]	- 50 top-performing GHG mitigation measures included in analysis (representing over 93% of total cumulative GHG mitigation potential)
Residential	[17]	- Model structure updated to improve accuracy and data resolution - Model extended to all regions of Canada - Historical activity and demand updated with the latest available data - Penetration of air source heat pumps modelled [89] - Penetration of CCU for NG space heating modelled [113] - HE building envelope improvement estimated using national energy consumption data [70]
Transportation	[15]	- None

3.2.2 Data synthesis and harmonization

3.2.2.1 Individual GHG mitigation scenarios

The resulting group of measures represents an extensive portfolio of individual GHG mitigation strategies that must be properly synthesized to ensure that the effects of combined measures are accurately accounted for. For a thorough assessment, the individual measures should span across major economic sectors as well as different measure type categories.

Table 23 includes descriptions of all 184 GHG mitigation measures included in this case study assessment, and Figure 18 summarizes the distribution of measure types for all disaggregated sectors. Specific technical details for all assessed measures are in Appendix G.

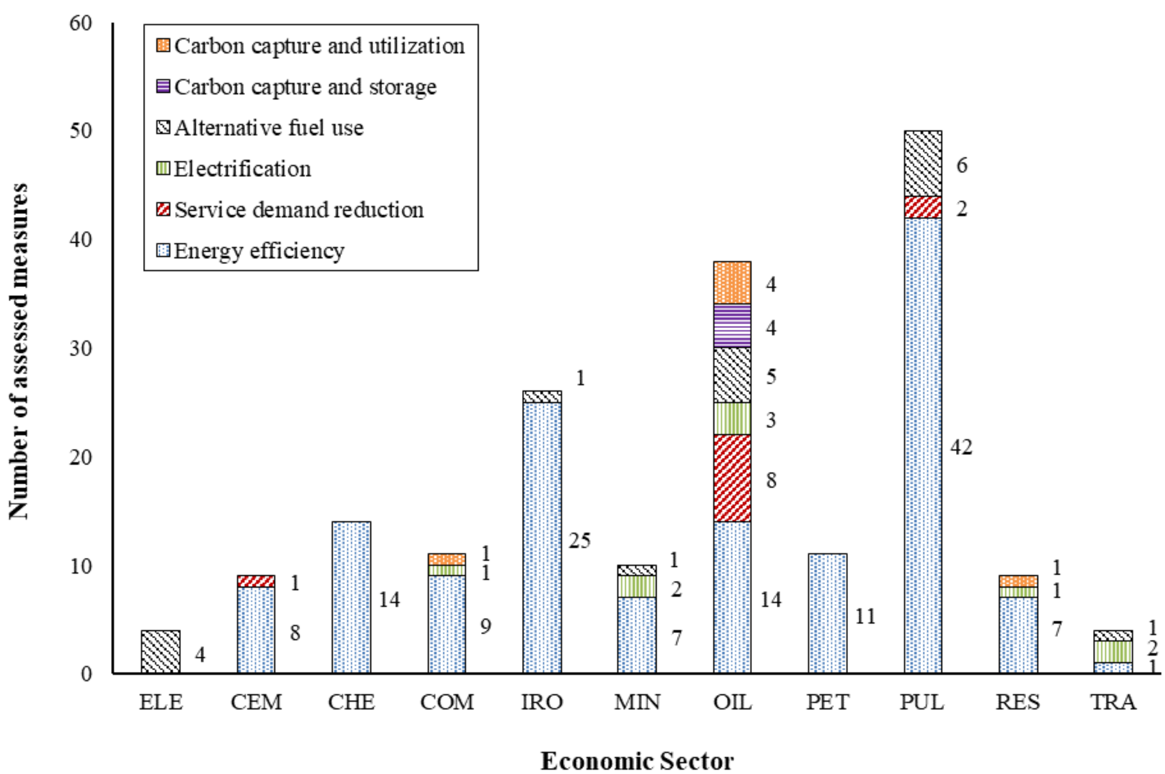

Figure 18: Number of assessed GHG mitigation measures by category for all disaggregated sectors: electricity generation (ELE), cement (CEM), chemicals (CHE), commercial and institutional (COM), iron and steel (IRO), mineral mining (MIN), oil sands (OIL), petroleum refining (PET), pulp and paper (PUL), residential (RES), and transportation (TRA).

Table 23: Assessed GHG mitigation measures for all sectors

Scenario name	Measure type and category	Demand area/branch	Description
		Cement	
CEM_EFF CLM_INF	EFF – EST	Clinker making	Decouple primary air supply from coal mill, reducing primary air demand
CEM_EFF CLM_EMP	EFF – EST	Clinker making	Optimize combustion process parameters using expert systems, model-predictive control, or fuzzy logic systems
CEM_EFF CLC_IHR	EFF – EST	Clinker cooler	Upgrade clinker coolers for more efficient heat recovery
CEM_EFF CLM_REF	EFF – EST	Clinker making	Use new refractories to protect kiln shell against chemical, mechanical, and thermal stresses, leading to extended lifetimes and energy savings
CEM_EFF KIL_COM	EFF – EST	Kiln	Optimize mixture composition to reduce excess combustion air and improve flame shape
CEM_EFF KIL_VSD	EFF – EST	Kiln	Use variable speed drive kiln fans to reduce energy consumption and maintenance costs
CEM_EFF CLC_RGC	EFF – EST	Clinker cooler	Install reciprocating grate coolers with higher heat recuperation efficiency than traditional planetary or rotary coolers
CEM_EFF KIL_SPR	EFF – EST	Kiln	Install suspension preheater to reduce energy consumed by exhaust gas fans in kiln
CEM_SDR ALL_BLN	SDR – EST	General	Add fly ash, slag, or limestone to cement to reduce cement requirements
		Chemicals	
CHE_EFF RFM_CHP	EFF – EST	Reforming	Generate power alongside steam
CHE_EFF ETH_HPC	EFF – EST	Ethylene	Combust in high-pressure, oxygen-rich environments
CHE_EFF GPS_LER	EFF – EST	Gas purification & shift conversion (pumps)	Replace MEA removal process with physical absorption using organic solvent, leading to lower circular loading and lower utility consumption

Scenario name	Measure type and category	Demand area/branch	Description
CHE_EFF SYN_LST	EFF – EST	Synthesis loop	Use axial and radial (not just axial) synthesis towers to decrease pressure drop in synth. Process
CHE_EFF GPS_LTC	EFF – EST	Gas purification & shift conversion	Install low-temperature shift guard reactor and convertor, leading to lower CO spillage and hydrogen consumption and increased ammonia production
CHE_EFF RFM_APR	EFF – EST	Reforming	Use waste heat recovery (WHR) in reformer convection section and highly active catalyst in pre-reforming
CHE_EFF GPS_AME	EFF – EST	Gas purification & shift conversion	Implement alternative process in shift conversion and CO_2 removal sections
CHE_EFF SYN_ACO	EFF – EST	Synthesis loop	Minimize process temperatures using auto-control systems
CHE_EFF GPS_EVC	EFF – EST	Gas purification & shift conversion	Eliminate need for water treating and pumping, leading to reduced fan power demand and lower operating temperatures
CHE_EFF RFM_WHR	EFF – EST	Reforming	Use waste heat to preheat combustion air, produce steam, or preheat boiler feedwater
CHE_EFF GPS_MHP	EFF – EST	Gas purification & shift conversion	Purify methane in shift conversion and CO_2 removal section, leading to reduced methane demand
CHE_EFF ETH_PIN	EFF – EST	Ethylene	Generate power alongside cooling
CHE_EFF SYN_MSD	EFF – EST	Synthesis loop	Install sieve dryer to remove CO_2 and water from makeup gas steam
CHE_EFF SYN_UAR	EFF – EST	Synthesis loop	Increase ammonia production through purge gas recovery systems
Commercial and institutional			
COM_EFF SHC_HEB	EFF – EST	Space heating & cooling	Improve building envelope efficiency by retrofitting windows, doors, walls, ceilings
COM_EFF SHC_HEC	EFF – EST	Space heating & cooling	Implement high-efficiency temperature control strategies (i.e., smart thermostats)
COM_EFF AUX_HEE	EFF – EST	Aux. equipment	Install high-efficiency appliances and office equipment
COM_EFF AUX_HEM	EFF – EST	Aux. motors	Install variable speed drive motors

Scenario name	Measure type and category	Demand area/branch	Description
COM_EFF LIG_HEL	EFF – EST	Lighting	Install high-intensity discharge bulbs
COM_EFF LIG_HES	EFF – EST	Lighting	Install LED street lighting
COM_EFF WHE_TCH	EFF – EST	Water heating	Install tankless condensing water heaters
COM_EFF SHC_HEF	EFF – EST	Space heating & cooling	Replace standard furnaces with high-efficiency furnaces
COM_EFF SHC_HEC	EFF – EST	Space heating & cooling	Replace standard air conditioners with high-efficiency devices
COM_ELE SHC_GHP	ELE – DEV	Space heating & cooling	Install ground source heat pumps for space heating and cooling
COM_CCU SHC_CCU	CCU – DEV	Space heating & cooling	Install carbon capture units on existing NG furnaces
Electricity generation			
ELE_AFU WIN_TRB	AFU-DEV	n/a	Generate electricity from wind farms
ELE_AFU SOL_PVA	AFU-DEV	n/a	Generate electricity from photovoltaic solar farms
ELE_AFU BIO_STE	AFU-DEV	n/a	Generate electricity from biomass-fired steam cycle
ELE_AFU NUC_STE	AFU-DEV	n/a	Generate electricity from nuclear-fired steam cycle
Iron and steel			
IRO_EFF SIN_IPC	EFF – EST	Sintering	Use numerical models and automated control systems to improve process efficiency
IRO_EFF BLF_ICS	EFF – EST	Blast furnace	Optimize process parameters (e.g., rate of reducing agent injection) to improve system performance and efficiency
IRO_EFF BLF_IGR	EFF – EST	Blast furnace	Capture and use heat from recovery gas, which can contain as much as 30% of the heat generated in the blast furnace
IRO_EFF BLF_HPC	EFF – EST	Blast furnace	Maintain optimal stove conditions to reduce fuel consumption and improve stove reliability and lifetime
IRO_EFF BLF_ING	EFF – EST	Blast furnace	Use natural gas instead of coke in blast furnace to reduce CO_2 formation
IRO_EFF BLF_HBR	EFF – EST	Blast furnace	Use blast stove flue gas to preheat fuel and air entering the stove

Scenario name	Measure type and category	Demand area/branch	Description
IRO_EFF BOF_CNC	EFF – EST	Basic oxygen furnace	Reduce energy demand through the elimination of intermediate storage and reheating processes
IRO_EFF BOF_ELP	EFF – EST	Basic oxygen furnace	Reduce energy demand through temperature control technologies, hoods, or recuperative and oxyfuel burners
IRO_EFF CMK_APC	EFF – EST	Coke making	Use programmed heating processes instead of conventional continuous heating
IRO_EFF CMK_CMC	EFF – EST	Coke making	Use heat from coke oven gas to reduce coal moisture content from 8-10% to 6%, reducing carbonization heat and improving coal quality
IRO_EFF CMK_CDQ	EFF – EST	Coke making	Use inert gas instead of sprayed water in quenching process, allowing for heat recovery and use in steam production or coking coal preheating
IRO_EFF EAF_BSG	EFF – EST	Electric arc furnace	Inject stirring gas at the bottom of the furnace to improve heat transfer and yield of liquid metal
IRO_EFF EAF_UHP	EFF – EST	Electric arc furnace	Install new transformers to allow for the use of high-power or UHP furnaces, minimizing energy loss
IRO_EFF EAF_EBT	EFF – EST	Electric arc furnace	Reduce energy consumption by reducing electrode consumption, reducing tap-to-tap time, and increasing ladle life
IRO_EFF EAF_FGC	EFF – EST	Electric arc furnace	Optimize combustion process by monitoring exhaust gas flow rate and composition
IRO_EFF EAF_FSP	EFF – EST	Electric arc furnace	Inject granular coal and oxygen to cover arc and melt surface, minimizing radiative heat loss
IRO_EFF EAF_NNC	EFF – EST	Electric arc furnace	Optimize combustion process using advanced control systems (e.g., monitoring carbon content, temperature)
IRO_EFF HRL_HED	EFF – EST	Hot rolling	Replace standard drives with high-efficiency drives
IRO_EFF HRL_HSC	EFF – EST	Hot rolling	Reduce downtime by optimizing the combustion process
IRO_EFF HRL_VSD	EFF – EST	Hot rolling	Optimize combustion processes by controlling combustion air and oxygen flow

Scenario name	Measure type and category	Demand area/branch	Description
IRO_EFF HRL_WHR	EFF – EST	Hot rolling	Recover heat from cooling water and spray onto rolled steel
IRO_EFF HRL_FIN	EFF – EST	Hot rolling	Replace conventional insulation with low thermal mass insulation materials (reducing heat loss through furnace walls)
IRO_EFF HRL_HCH	EFF – EST	Hot rolling	Synchronize casting and rolling processes to reduce energy consumed by the reheating furnace in plants where caster and reheating furnaces are located near each other
IRO_EFF HRL_RBR	EFF – EST	Hot rolling	Replace old recuperators with new ones, increasing the efficiency of the heat transfer between the exhaust gas and incoming combustion air
IRO_AFU SIN_WFU	AFU – EST	Sintering	Reuse waste as fuel (e.g., oil from cold rolling mills substituting coke breeze); this affects both energy consumption and emissions
IRO_EFF SIN_WHR	EFF – EST	Sintering	Use waste heat from sinter cooler in hot water generation, district heating, combustion air preheating, raw sinter mix preheating, or the recirculation system
Mineral mining			
MIN_EFF TRA_HTO	EFF – EST	Ore transport	Reduce stopping frequency during operation
MIN_EFF IRO_SOE	EFF – EST	Iron ore extraction	Improve shovel operator efficiency
MIN_EFF GRN_HPG	EFF – EST	Iron and gold ore grinding	Install high-pressure grinding rollers and ball mill
MIN_EFF UND_VOD	EFF – EST	Gold and potash mine ventilation	Use sensor-integrated ventilation on demand systems to optimize ventilation runtime
MIN_EFF POT_SGD	EFF – EST	Steam generation and drying	Improve steam boiler efficiency for potash mining
MIN_ELE TRA_AHT	ELE – DEV	Ore transport	Replace diesel haul trucks with electric
MIN_EFF TRA_AHT	EFF – DEV	Ore transport	Replace diesel haul trucks with hybrid
MIN_ELE LOA_LHD	ELE – DEV	Ore loading	Electrify load-haul-dump equipment
MIN_EFF LOA_LHD	EFF – DEV	Ore loading	Use hybrid load-haul-dump equipment

Scenario name	Measure type and category	Demand area/branch	Description
MIN_AFU LOA_LHD	AFU – DEV	Ore loading	Use fuel cell load-haul-dump equipment
		Oil sands	
OIL_EFF INS_HEX	EFF – EST	In situ	Improve energy transfer efficiency in heat exchanger (HEX) and WHR systems
OIL_EFF INS_RHL	EFF – EST	In situ	Develop well efficiently and use WHR in tailings disposal
OIL_EFF INS_PTC	EFF – EST	In situ	Optimize operating parameters for various processes
OIL_EFF INS_IUT	EFF – EST	In situ	Improve boiler efficiencies and power-recovery turbines
OIL_EFF SMI_CNS	EFF – EST	Surface mining	Use advanced control systems, including online analyzers
OIL_EFF SMI_EMM	EFF – EST	Surface mining	Improve energy use through by adopting an energy management program for day-to-day use
OIL_EFF SMI_HEX	EFF – EST	Surface mining	Improve energy transfer efficiency in HEX and WHR systems
OIL_EFF SMI_PTC	EFF – EST	Surface mining	Optimize operating parameters for various processes
OIL_EFF SMI_IUE	EFF – EST	Surface mining	Improve energy use – reduced idling time, unplanned outages, reliable operation
OIL_EFF SMI_IUT	EFF – EST	Surface mining	Improve boiler efficiencies and install power-recovery turbines
OIL_EFF UPG_CNS	EFF – EST	Upgrading	Use advanced control systems, including online analyzers
OIL_EFF UPG_EMM	EFF – EST	Upgrading	Improve energy use through the adoption of the energy management program (day-to-day use)
OIL_EFF UPG_HEX	EFF – EST	Upgrading	Improve energy transfer efficiency in HEX and WHR systems
OIL_EFF UPG_PTC	EFF – EST	Upgrading	Optimize operating parameters for various processes
OIL_SDR SAG_SAS	SDR – DEV	SAGD steam gen	Inject light hydrocarbon & steam mixture for SAGD bitumen extraction
OIL_SDR SAG_VPX	SDR – DEV	SAGD steam gen	Inject propane instead of steam after initial operation
OIL_SDR CSS_LSR	SDR – DEV	SAGD steam gen	Inject pentane late in CSS process to boost oil production
OIL_SDR SAG_NSL	SDR – DEV	SAGD steam gen	Inject solvent vapour (propane or butane) instead of steam

Scenario name	Measure type and category	Demand area/branch	Description
OIL_SDR SAG_ESE	SDR – DEV	SAGD steam gen	Preheat reservoir by electromagnetic antenna and inject light solvent
OIL_SDR SAG_ERB	SDR – DEV	SAGD steam gen	Inject steam alongside light hydrocarbons
OIL_SDR SAG_SEG	SDR – DEV	SAGD steam gen	Combust natural gas in combustion well, producing steam with water provided by injection well
OIL_ELE UPG_WNT	ELE – DEV	Upgrading	Produce hydrogen from single wind turbines (small-scale)
OIL_ELE UPG_WNF	ELE – DEV	Upgrading	Produce hydrogen production from wind farms (large-scale)
OIL_ELE UPG_HYD	ELE – DEV	Upgrading	Produce hydrogen from hydroelectric dams
OIL_AFU UPG_BIG	AFU – DEV	Upgrading	Produce hydrogen via biomass gasification
OIL_AFU UPG_BIP	AFU – DEV	Upgrading	Use bio-oil in SMR reactions for H_2 production
OIL_AFU CSS_SLS	AFU – DEV	CSS – steam generation	Use solar heat for CSS steam generation
OIL_AFU SAG_NUC	AFU – DEV	SAGD – steam generation	Use nuclear power for steam production only
OIL_AFU SMI_GEO	AFU – DEV	Surface mining – heat generation	Use geothermal heat instead of NG to heat water for surface mining extraction processes
OIL_CCS UPG_SMR	CCS – DEV	Upgrading	Produce hydrogen via steam methane reforming with carbon capture and saline aquifer storage
OIL_CCS UPG_UCG	CCS – DEV	Upgrading	Produce hydrogen via underground coal gasification with underground storage
OIL_CCU UPG_SMR	CCU – DEV	Upgrading	Produce hydrogen via steam methane reforming with carbon capture and utilization in enhanced oil recovery operations
OIL_CCU UPG_UCG	CCU – DEV	Upgrading	Produce hydrogen via underground coal gasification with use in enhanced oil recovery
OIL_CCS SAG_OFN	CCS – DEV	SAGD – steam generation	Produce SAGD steam with oxyfuel natural gas boilers and store captured CO_2
OIL_CCS SAG_OFB	CCS – DEV	SAGD – steam generation	Produce SAGD steam with oxyfuel bitumen boilers and store captured CO_2

Scenario name	Measure type and category	Demand area/branch	Description
OIL_CCU SAG_OFN	CCU – DEV	SAGD – steam generation	Produce SAGD steam with oxyfuel natural gas boilers and use the captured CO_2 for enhanced oil recovery
OIL_CCU SAG_OFB	CCU – DEV	SAGD – steam generation	Produce SAGD steam with oxyfuel bitumen boilers and use the captured CO_2 for enhanced oil recovery
Petroleum refining			
PET_EFF CDU_APH	EFF – EST	Crude distillation unit	Use furnace flue gas to preheat combustion air (30°C to 425°C)
PET_EFF CDU_INT	EFF – EST	Crude distillation unit	Use pinch analysis and feed-stream economizers to reduce fuel consumption in furnace
PET_EFF CRU_APH	EFF – EST	Catalytic reforming unit	Use pinch analysis and feed-stream economizers to reduce fuel consumption in furnace
PET_EFF DCU_APH	EFF – EST	Delayed coking unit	Use furnace flue gas used to preheat combustion air (30°C to 425°C)
PET_EFF FCC_APH	EFF – EST	Fluid catalytic cracking	Use pinch analysis and feed-stream economizers to reduce fuel consumption in furnace
PET_EFF CDU_HEP	EFF – EST	Crude distillation unit	Install variable speed drives and high-efficiency motors
PET_EFF VDU_INT	EFF – EST	Vacuum distillation unit	Use furnace flue gas to preheat combustion air (30°C to 425°C)
PET_EFF ALK_HPD	EFF – EST	Alkylation unit	Replace conventional steam reboiler with compressor & heat exchangers in alkylation unit
PET_EFF HTU_APH	EFF – EST	Hydrotreating unit	Use furnace flue gas to preheat combustion air (30°C to 425°C)
PET_EFF HCU_APH	EFF – EST	Hydrocracking unit	Use furnace flue gas to preheat combustion air (30°C to 425°C)
PET_EFF ISO_HPD	EFF – EST	Isomerization unit	Replace conventional steam reboiler with compressors & heat exchangers in isomerization unit
Pulp and paper			
PUL_EFF ALL_APC	EFF – EST	General	Implement advanced control systems
PUL_EFF ALL_ASD	EFF – EST	General	Use adjustable speed drive motors
PUL_EFF ALL_BBP	EFF – EST	Cogeneration	Optimize boiler operation and maintenance

Scenario name	Measure type and category	Demand area/branch	Description
PUL_EFF ALL_BBU	EFF – EST	Cogeneration	Implement high-efficiency boiler burners
PUL_AFU ALL_BGE	AFU – EST	Cogeneration	Offset natural gas consumption with biogas production from effluent
PUL_AFU ALL_BSB	AFU – EST	Cogeneration	Use supplementary biomass boiler to offset natural gas steam production
PUL_EFF ALL_CDR	EFF – EST	Cogeneration	Reduce steam system losses by re-using returned condensate
PUL_EFF ALL_EAC	EFF – EST	Cogeneration	Reduce air leaks, improve excess air and oxygen trim controls, and monitor boiler air balance
PUL_EFF ALL_FSU	EFF – EST	General	Upgrade blower systems and equipment including ducting, fittings, and other equipment
PUL_EFF ALL_FWE	EFF – EST	Cogeneration	Use feedwater economizers on power boilers
PUL_EFF ALL_HRI	EFF – EST	General	Use pinch analysis to identify and implement general heat integration improvements including preheating, counterflow mixing, and heat recovery
PUL_EFF ALL_HWS	EFF – EST	General	Improve hot water system design and equipment to improve efficiency and reduce losses
PUL_EFF ALL_IER	EFF – EST	General	Reduce and remove idling and redundant equipment
PUL_EFF ALL_INS	EFF – EST	General	Improve insulation of steam lines to reduce heat losses
PUL_EFF ALL_PEM	EFF – EST	General	Upgrade or replace motors with high efficiency models
PUL_EFF ALL_PRM	EFF – EST	General	Improve maintenance practices to prevent equipment breakdowns and improve operation efficiency
PUL_EFF ALL_PSU	EFF – EST	General	Upgrade pump equipment to improve efficiency and reduce losses by eliminating throttle valves and implementing advanced controls
PUL_AFU ALL_SRC	AFU – EST	Cogeneration	Offset fossil fuel use by recovering and combusting sludge from effluent system

Scenario name	Measure type and category	Demand area/branch	Description
PUL_EFF ALL_SSO	EFF – EST	Cogeneration	Improve steam system controls and equipment and line layout and use steam accumulators (does not include steam traps or insulation)
PUL_AFU ALL_STS	AFU – EST	Cogeneration	Reduce fuel consumption by generating steam from solar energy
PUL_EFF ALL_STU	EFF – EST	Cogeneration	Improve steam trap maintenance practices and hardware
PUL_EFF BLE_BFR	EFF – EST	Bleaching	Reduce water and chemical use through counterflow mixing of bleach wash filtrates in post-bleach washing stage
PUL_EFF BLE_CPH	EFF – EST	Bleaching	Use counterflow heat exchange to preheat chlorine dioxide and improve heat integration
PUL_EFF BLE_PHR	EFF – EST	Bleaching	Apply heat recovery to bleach plant effluent
PUL_AFU CPP_BGK	AFU – EST	Recausticization	Replace lime kiln fuel with biogas from small-scale gasification
PUL_AFU CPP_BLG	AFU – EST	Recovery cycle	Implement black liquor gasification to improve overall combustion efficiency, reduce supplemental fuel demand, and improve recovery cycle yield
PUL_EFF CPP_CDM	EFF – EST	Digestion	Improve controls, optimize operating parameters, and improve insulation of continuous digesters
PUL_EFF CPP_CSC	EFF – EST	Feedstock prep	Improve chip screening and conditioning practices and adopt more effective screens and conditioners, reducing steam energy and yield loss
PUL_EFF CPP_CSI	EFF – EST	Recovery cycle	Integrate condensate stripping process with evaporation and chemical recovery to reduce energy loss
PUL_EFF CPP_DFC	EFF – EST	Digestion	Implement black liquor dilution controls to optimize brownstock washing
PUL_EFF CPP_DHR	EFF – EST	Digestion	Recover waste heat from digesters
PUL_EFF CPP_HTM	EFF – EST	Recovery cycle	Monitor boiler temperatures and soot deposition to reduce sootblower use and boiler shutdowns

Scenario name	Measure type and category	Demand area/branch	Description
PUL_EFF CPP_LKG	EFF – EST	Recausticization	Improve lime kiln by upgrading equipment, refractory, insulation, and oxygen supply, etc.
PUL_EFF CPP_RFH	EFF – EST	Cogeneration	Recover waste heat from recovery boiler flue gas to improve thermal efficiency
PUL_EFF CPP_SCW	EFF – EST	Digestion	Adopt improved washing techniques like counterflow and steam washing
PUL_EFF MPP_APT	EFF – EST	Refining	Implement existing and emerging pre-treatment options to reduce thermomechanical pulping (TMP) energy use
PUL_EFF MPP_ARS	EFF – EST	Refining	Incorporate a third stage in the refining line to reduce refining energy consumption
PUL_EFF MPP_BTM	EFF – EST	Refining	Improve TMP line control to maintain steady state operation and reduce steam use
PUL_EFF MPP_CTI	EFF – EST	Refining	Optimize chemi-thermomechanical pulp mixture composition, PH, and temperature to reduce energy demand
PUL_EFF MPP_HER	EFF – EST	Refining	Upgrade refining equipment including rotors, motors, and controls
PUL_EFF MPP_THR	EFF – EST	Refining	Modify mechanical mill refining lines to increase heat recovery from refiners
PUL_SDR PNB_AFF	SDR – EST	Pulp supply	Supplement virgin pulp with fibrous fillers advanced fillers to reduce energy demand for pulp production in integrated mills
PUL_EFF PNB_DMS	EFF – EST	Paper machine	Implement advanced dryer controls and optimize setpoint
PUL_EFF PNB_FWP	EFF – EST	Paper machine	Preheat felt water to improve paper machine heat integration
PUL_SDR PNB_RFS	SDR – EST	Pulp supply	Supplement virgin pulp with recovered fibre in paper, newsprint, and board
PUL_EFF PNB_TRB	EFF – EST	Paper machine	Improve dryer cylinder heat transfer by adding turbulent bars
PUL_EFF PUL_MHR	EFF – EST	Pulp machine	Improve pulp machine heat recovery
PUL_EFF RPB_CLR	EFF – EST	Pulp supply	Recover pulp to conserve heat and chemicals

Scenario name	Measure type and category	Demand area/branch	Description
PUL_EFF RPB_FRR	EFF – EST	Feedstock prep	Recover fibre from screens and centrifuges to reduce waste and improve yield
PUL_EFF VFP_WHD	EFF – EST	Feedstock prep	Use waste heat or effluent to heat debarking water supply
Residential			
RES_EFF SHC_HEB	EFF – EST	Space heating & cooling	Improve building insulation through retrofits (doors, windows, walls, and ceilings)
RES_EFF SHC_HEC	EFF – EST	Space heating & cooling	Implement high efficiency temperature control systems (i.e., smart thermostats)
RES_EFF APP_HEA	EFF – EST	Appliances	Install high-efficiency appliances
RES_EFF LIG_HEL	EFF – EST	Lighting	Install LED bulbs
RES_EFF SHC_HEF	EFF – EST	Space heating	Install high-efficiency furnaces
RES_EFF WHE_TKB	EFF – EST	Water heating	Install instantaneous water heaters
RES_EFF SHC_HEC	EFF – EST	Space cooling	Install high-efficiency central air conditioning systems
RES_ELE SHC_AHP	ELE – DEV	Space heating & cooling	Install air source heat pumps for space heating and cooling
RES_CCU SHC_BCC	CCU – DEV	Space heating & cooling	Install post-combustion carbon capture systems on NG furnaces
Transportation			
TRA_AFU ROA_HFC	AFU – DEV	Road transport	Adopt hydrogen fuel cell vehicles
TRA_EFF ROA_HEV	EFF – DEV	Road transport	Adopt hybrid electric vehicles
TRA_ELE ROA_PHV	ELE – DEV	Road transport	Adopt plug-in hybrid electric vehicles
TRA_ELE ROA_BEV	ELE – DEV	Road transport	Adopt battery electric vehicles

3.2.2.2 Market share modelling

The next step in the framework is to estimate future market shares of alternative technologies based on their current status. Some measures included in the assessment may involve well-established technologies, while others may involve developing technologies with uncertain future adoption and support. Scenarios can be categorized as "established" (EST) or "developing" (DEV) based on existing market shares, technological readiness level (TRL), and barriers to implementation. EST measures already show medium and high levels of market share and technological readiness and face low barriers to implementation; it is expected that these are measures that consumers would invest in without hesitation as they are typically cost effective and do not necessitate significant process changes (e.g., improvement of mining haul truck operation). Conversely, DEV measures include FSW and CC measures that are generally more capital intensive and associated with higher levels of system-wide changes (e.g., electrification of mining haul trucks). The following sections describe the methods used to model market shares of EST and DEV measures.

3.2.2.2.1 Established measures

Energy-efficiency improvements and other EST measures are represented using linear interpolations between assumed base year shares and 100%:

$$MS_{i,y} = MS_{i,y_b} + (y - y_b)\frac{1 - MS_{i,y_b}}{2050 - y_b} \qquad \text{(Eq. 3.1)}$$

where $MS_{i,y}$ is the market share of technology i in year y, and y_b is the base year. In Chapter 2, it is shown that 80% of the GHG mitigation potential represented by energy-efficiency measures in Alberta is achievable at negative cost [116], so all energy-efficiency improvements included in this case study are classified as EST measures. Details describing the costs, energy effects, and applicability of these measures are given in the SI.

3.2.2.2.2 Developing measures

Market shares of DEV GHG mitigation measures are modelled using technology-specific market share calculations because of the competitive nature of these new technologies. Penetration levels for these measures can be modelled with the inverse-power function shown in Eq. 3.2 [117]:

$$MS_{i,y} = \frac{LCC_{i,y}^{-v}}{\sum_{i=1}^{n} LCC_{i,y}^{-v}} \quad \text{(Eq. 3.2)}$$

where $MS_{i,y}$ is the market share of technology i in year y, $LCC_{i,y}$ is the annualized life cycle cost of technology i in year y, n is the number of competing technologies, and v is the cost variance parameter. $LCC_{i,y}$ is calculated as the sum of annualized capital costs, annual operations costs OC_i, annual energy costs EC_i, and annual GHG emissions costs GC_i as shown in Eq 3.3:

$$LCC_{i,y} = CC_i * \left(\frac{r}{1-(1+r)^{-t}}\right) + OC_i + EC_i + GC_i \quad \text{(Eq. 3.3)}$$

where CC_i is the overnight capital cost of technology i, r is the discount rate, and t is the lifetime of the technology. Annual market share values represent the fraction of new and replaceable devices comprised by an alternative technology. For a specific end use, the total number of conventional devices converted to type i in year y, $N_{add,i,y}$, is thus:

$$N_{add,i,y} = MS_{i,y}\left(N_{add,all,y} + N_{exist,base,y-1} * \frac{1}{t}\right) \quad \text{(Eq. 3.4)}$$

In Eq. 3.4, $N_{add,all,y}$ is activity level added to the market in year y, $N_{exist,base,y-1}$ is the total activity level of conventional devices in the previous year, and t is the lifetime of the conventional end-use technology. This equation assumes that the vintages of existing stocks are equally distributed.

A cost variance parameter of 8 is appropriate for energy technology modelling in the case study regions [26]. Measures affecting electricity generation are represented through a more detailed optimization process described in previous work [87].

3.2.2.3 Portfolio development

After calculating annual market shares for all measures, individual GHG mitigation scenarios were combined into two separate portfolios to account for net system-wide effects and costs. These two portfolios were compared to a reference (REF) scenario to quantify the relative costs and GHG mitigation potential of the assessed measures. These portfolios are described further in the following sections.

3.2.2.3.1 Reference scenario

The reference scenario (REF) represents a situation in which no GHG mitigation measures are adopted despite current policy. End-use energy intensities, GHG emissions intensities, and shares of end-use devices are assumed to remain constant from the base year onwards. GHG emissions costs are set to reflect the current carbon price schedule and are included in this scenario to allow for appropriate cost comparisons among scenarios. Electricity generation capacity additions are not constrained by renewable targets or fossil fuel phase-outs and are optimized to minimize overall system cost. Sectoral activity for the case study region is projected for all sectors based on appropriate macroeconomic indicators and is described in previous work [24, 112, 116].

3.2.2.3.2 Combined GHG mitigation scenarios

The framework features two scenarios that represent portfolios of combined measures: one representing “business-as-usual” improvement in energy use and GHG emissions under a current policy carbon price schedule (BAU) and one reflecting the technical maximum GHG mitigation potential of all assessed measures (MAX). These scenarios account for the practical penetration limits of multiple alternative technologies applied in the same demand area. The MAX scenario includes alternatives that lead to the maximum level of GHG mitigation by 2050 regardless of economic cost. Energy-efficiency limits can be accounted for using an approach similar to that detailed in an earlier study [116]. Developing sub-scenarios based on measure type for the BAU scenario allows for the respective contributions of each assessed measure type to be quantified incrementally, as discussed further in Section 3.2.4.

Fleiter et al. developed portfolios of GHG mitigation measures for the German pulp and paper sector representing “frozen efficiency,” “business as usual,” “cost-effective diffusion,” and “maximum technical diffusion” [103]. In the application of this framework, all cost-effective measures in the BAU scenario are included to simplify key results and reflect the increasing priority of climate action among Canadians, but similarly use baseline and maximum scenarios to act as upper and lower bounds for the GHG projections, respectively [118]. In the BAU scenario, all EST pathways with marginal abatement costs (MACs) less than \$170/tCO_2e are implemented and DEV pathways are implemented according to annual market share calculations. Marginal abatement cost values for all scenarios are taken from original sectoral publications and are shown in the detailed scenario tables in Appendix G. The BAU scenario also includes current local policies affecting electricity generation processes, such as Alberta's plan to achieve 30% renewable capacity and phase out coal-fired generation by 2030 [94].

In the case study MAX scenario, it is assumed that all EST and a selection of DEV pathways are implemented, regardless of economic cost. Many of the DEV measures are not simultaneously applicable, so those resulting in the largest annual GHG mitigation by 2050 are included. The selection of DEV measures included in the MAX scenario are shown in Table 24 below. In the MAX scenario, a 100% non-emitting electricity generation target for 2050 for all regions is imposed. This scenario represents the most ambitious, technically feasible GHG mitigation pathway. When considering practical factors, however, the scenario is not realistic: it includes 100% penetration of all included measures, which is unlikely to occur without radical policy interventions action such as outright bans on fossil fuel use.

Table 24: Selected technologies for MAX scenario.

Sector	Demand area	Selected technology
Commercial	Space heating and cooling	Ground-source heat pumps
Mining	Haul trucks	Electric haul trucks
	Load-haul-dump (LHD) equipment	Electric LHD equipment
Oil sands	Steam generators (SAGD)	Nuclear steam generation
	Steam generators (CSS)	Solar steam generation
	H_2 production (upgrading)	Oxyfuel natural gas boilers
Residential	Space heating and cooling	Air-source heat pumps
Transportation	All	Battery electric vehicles

3.2.3 Energy modelling

Combined scenario portfolios are represented in a bottom-up energy system model to calculate annual energy demand and production, GHG emissions, and system-wide costs. Prina et al. reviewed suitable models for various regions around the world [119].

This case study relies on previous work done with the Low Emissions Analysis Platform (LEAP). Researchers have used LEAP to develop highly detailed bottom-up energy models for various regions and economic sectors. LEAP was developed by the Stockholm Environment Institute and facilitates the development of bottom-up energy system models and GHG mitigation assessment [52]. The software interfaces with Microsoft Excel and optimization solvers including IBM CPLEX to accommodate a variety of input data and generate useful results for policymakers, energy system planners, and researchers. Several GHG mitigation assessments for various emissions-intensive sectors have been carried out, and these models have been integrated and updated in previous work [71, 116]. These sector-specific studies provide marginal abatement costs for specific GHG mitigation measures involving EDR, FSW, and CC measures but on their own provide limited insights on the feasibility of achieving carbon neutrality across entire energy systems. Further details describing the disaggregated sectoral models and the integrated national model are given in the sections below.

3.2.3.1 Disaggregated sectoral energy models

A multi-regional, multi-sectoral energy system model was developed by integrating several sector- or region-specific energy models. Integrating several sub-models allows for technological specificity to be preserved and system-wide costs and effects to be accurately assessed.

For this case study, energy demand was disaggregated to the end-use technology level for 10 different sectors: the cement (CEM) [22], chemicals (CHEM) [21], commercial (COM) [27], iron and steel (IRO) [20], mineral mining (MIN) [23], oil sands (OIL) [14], pulp and paper (PUL) [25], petroleum refining (PET) [53], residential (RES) [17], and transportation (TRA) [15] sectors. The structure and organization of the energy demand sectors are shown in Table 25.

Table 25: LEAP-Canada energy demand disaggregation

Sector	Sub-sector / demand area	End uses
Cement (CEM) [22]	(n/a)	Raw material crushing and treatment
		Clinker production
		Finishing, grinding, and distribution
Chemicals (CHE) [21]	Ammonia	Reforming
		Methanation
		Water-gas shift
		Ammonia synthesis
		Compressors
		Boilers
	Ethylene	Cracker
		Compressor
		Separation
Commercial and institutional (COM) [16]	Wholesale trade	HVAC
		Water heating
		Lighting
		Auxiliary equipment
	Information and cultural industries	(same as wholesale trade)
	Retail trade	(same as wholesale trade)
	Transportation and warehousing	(same as wholesale trade)
	Offices	(same as wholesale trade)
	Educational services	(same as wholesale trade)
	Healthcare and social assistance	(same as wholesale trade)
	Arts, entertainment, and recreation	(same as wholesale trade)
	Accommodation and food services	(same as wholesale trade)
	Other services	(same as wholesale trade)
Iron and steel (IRO) [20]	Integrated plants	Sintering
		Coke plant
		Blast furnace
		Basic oxygen furnace
		Casting
		Forming and finishing
	Electric arc furnaces	Furnace
		Casting
		Forming and finishing
	Potash mining	Extraction

Sector	Sub-sector / demand area	End uses
Mineral mining (MIN) [23]		Crushing
		Grinding
		Floatation
		Screening
		Compaction
		Miscellaneous
	Gold mining	Ore extraction
		Communition
		Recovery
		Post-recovery processing
		Heating
		General and administrative
		Miscellaneous
	Iron ore mining	Drilling
		Blasting
		Loading
		Hauling
		Crushing
		Screening
		Drying
		Rail transport
		Support
		Tailings
		Process heat
		Dewatering
		Miscellaneous
Oil sands (OIL) [14]	Bitumen upgrading	Hydroconversion
		Coking
	Surface mining	Pumps
		Conveyors
		Power shovels
		Crushing
		Mixing
		Floatation
		Compressors
		Boilers
	In situ bitumen extraction	Pumps

Sector	Sub-sector / demand area	End uses
		Compressors
		Mixers
		Process heat
Petroleum refining (PET) [53]	Separation	VDU
		Desalter
		CDU
	Conversion	Alkylation
		Cracking
		Reforming
	Treatment	Hydrotreatment
	Utilities	Hydrogen production
		Steam generation
Pulp and paper (PUL) [24]	Chemical market pulp	Feedstock preparation
		Pulping
		Bleaching
		Product machines
		Recausticizing
		Auxiliary equipment
		Power generation
		Coating
	Mechanical market pulp	(same as chemical market pulp)
	Print paper	(same as chemical market pulp)
	Newsprint	(same as chemical market pulp)
	Paperboard	(same as chemical market pulp)
Residential (RES) [17]	Single detached	HVAC
		Water heating
		Lighting
		Appliances
	Single attached	(same as single detached)
	Apartments	(same as single detached)
	Mobile homes	(same as single detached)
Transportation (TRA) [15]	Road	Cars
		Passenger trucks
		Buses
		Motorcycles
		Light freight
		Medium freight

Sector	Sub-sector / demand area	End uses
		Heavy freight
	Air	Passenger
		Freight
	Rail	Passenger
		Freight
	Marine	Freight

Detailed demand tree diagrams showing end-use branches for all disaggregated sectors are in Appendix A. For all sectors, end-use energy intensities are calibrated for all fuel types according to the same process described in Section 2.2.2.3.2. Sectors for which disaggregated energy demand data has not yet been published are represented in the model with aggregate energy intensity data for all major fuel types. Details describing the development and organization of all sectoral demand trees can be found in their respective original publications (provided in Table 25).

3.2.3.2 Integrated bottom-up energy system model

Measure portfolios were added to the multi-sector bottom-up energy system model to calculate system-wide effects. Energy demand is projected based on historical energy consumption, historical activity, and macroeconomic indicators, and then used to calculate the output of energy transformation processes and associated resource consumption. GHG emissions and economic costs associated with end-use demand, energy transformation processes, and resource production are then calculated for all analyzed years.

The case study model was organized into demand, transformation, and resource modules as shown in Figure 19. In this application, scenarios were analyzed for 7 Canadian regions: British Columbia (BC), Alberta (AB), Saskatchewan (SK), Manitoba (MB), Ontario (ON), Quebec (QC), and Atlantic (ATL). Demand sectors for New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland and Labrador were consolidated into a single region to streamline key results. The Territories were excluded from the present work because of limited energy and emissions data availability. The Territories account for less than 0.5% of national annual GHG emissions [13]. GHG emissions from the disaggregated sectors accounted for 80% of the total GHG emissions across all regions in 2019. GHG emissions from sectors including light manufacturing, construction, and smelting and refining are included in the model as aggregate data. Figure 20 shows the shares of regional GHG emissions accounted for by the disaggregated sectors included in this work.

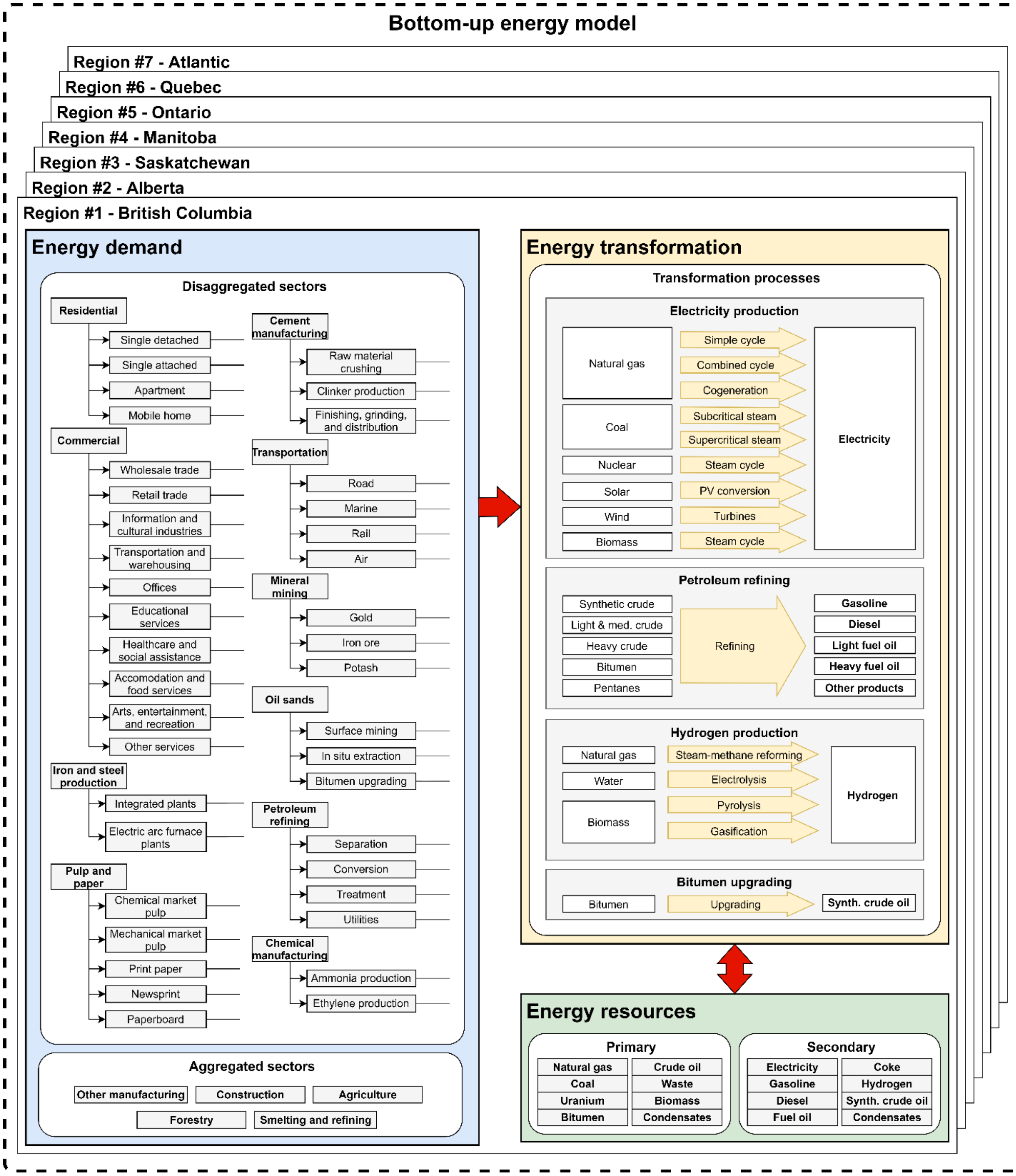

Figure 19: Schematic overview of the disaggregated energy model

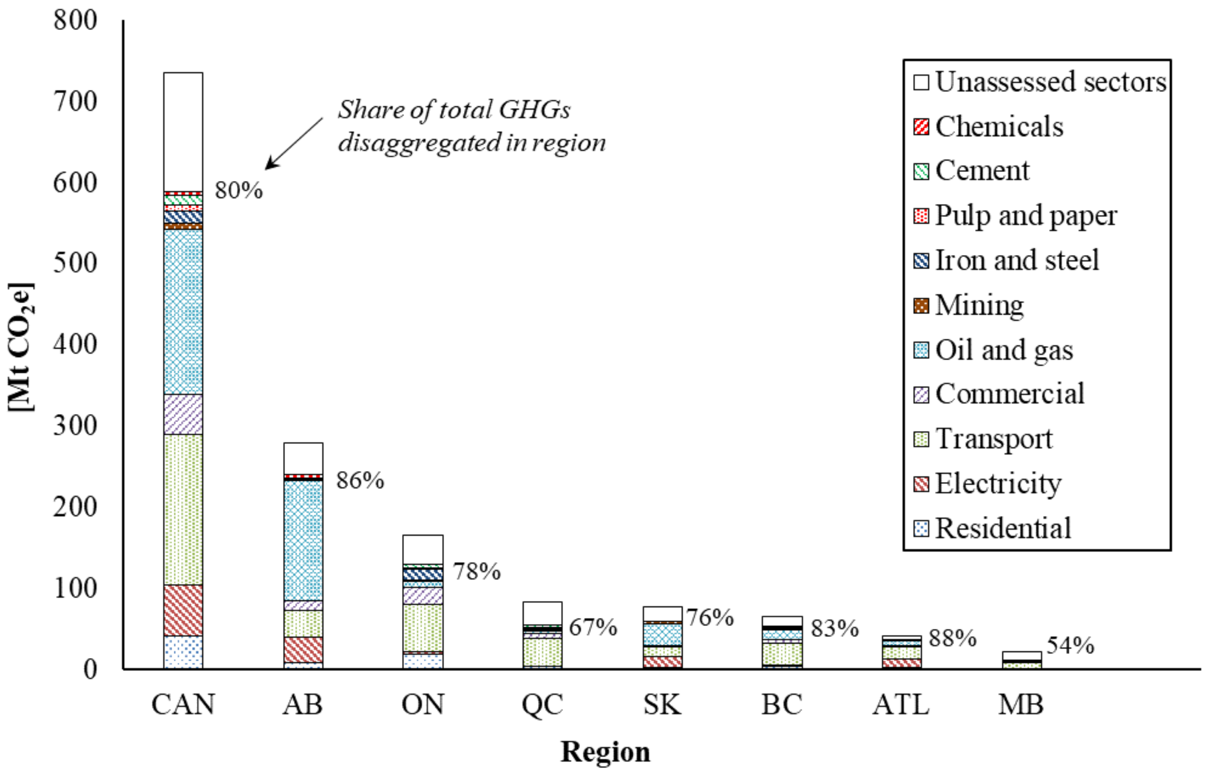

Figure 20: GHG emissions by region and economic sector (2019). "Unassessed measures" includes various manufacturing sectors, waste, and agriculture. No GHG mitigation measures for "unassessed sectors" were included in the analysis. GHGs from "unassessed sectors" were included in the model as aggregate data.

3.2.3.2.1 Energy transformation and resource modules

The energy system model used in the case study features detailed representations of several energy transformation processes that can respond to demand and import/export targets, allowing for upstream costs and effects to be included in system-wide assessments. Sector-specific energy transformation models developed in earlier work [54, 87] are used in this analysis and are shown in Table 26. Each branch corresponds to a single energy transformation category containing various subprocesses. Each subprocess represents the transformation of a primary energy source or feedstock into an end-use energy resource. Shares of processes used to meet a calculated resource demand can be defined explicitly or calculated through least-cost optimization of capacity addition and dispatch.

Table 26: Energy transformation module branches

Transformation branch	Description	Processes
Electricity generation	- Conversion of various energy resources into electricity - Generating capacity dispatched to meet monthly energy demand - Future capacity additions optimized to meet policy constraints and minimize system costs	- Simple cycle natural gas - Combined cycle natural gas - Natural gas cogeneration - Subcritical coal - Supercritical coal - Nuclear reactor - PV solar - Wind turbines - Biomass steam cycle
Hydrogen production	- Conversion of resources including methane, water, and biomass into hydrogen - Dispatched to meet hydrogen demand in fuel-cell electric vehicle scenario	- Steam methane reforming - Water electrolysis - Biomass pyrolysis - Biomass gasification
Natural gas production and processing	- Extraction of natural gas from oil and gas wells - Accounts for fugitive emissions from processing and transport, as well as venting and flaring emissions from associated and solution gas production	- Extraction
Petroleum refining	- Conversion of raw petroleum products into end-use products	- Refining
Bitumen upgrading	- Conversion of raw bitumen to synthetic crude oil for pipeline transport	- Upgrading

Data for natural gas extraction and processing have been updated to include GHG emissions for associated and solution gas venting and flaring using publications from local governments [120, 121]. All upstream costs and GHG emissions are accounted for in these modules. Energy costs are included as resource supply costs to maintain price consistency across all sectors and represent the minimum economic cost to extract and convert primary energy resources into their usable forms. The model version used in this study does not calculate changes in interregional energy resource trade between scenarios. Annual activity for the modelled energy transformation processes are calculated based on regional demand and historical import and export levels. This limitation primarily affects natural gas production and processing, petroleum refining, and bitumen upgrading branches, and is discussed further in Section 3.3.4.

3.2.3.2.2 Validation

The energy systems model is validated by comparing calculated energy demand and GHG emissions with historical data. The bottom-up energy system model used in this case study was validated by comparing GHG emissions for modelled sectors in all regions with historical data from the Government of Canada's National Inventory Report (NIR) [13] and Natural Resources Canada [70]. Figure 21 shows the calculated GHG emissions for all regions alongside officially reported GHG levels from the NIR.

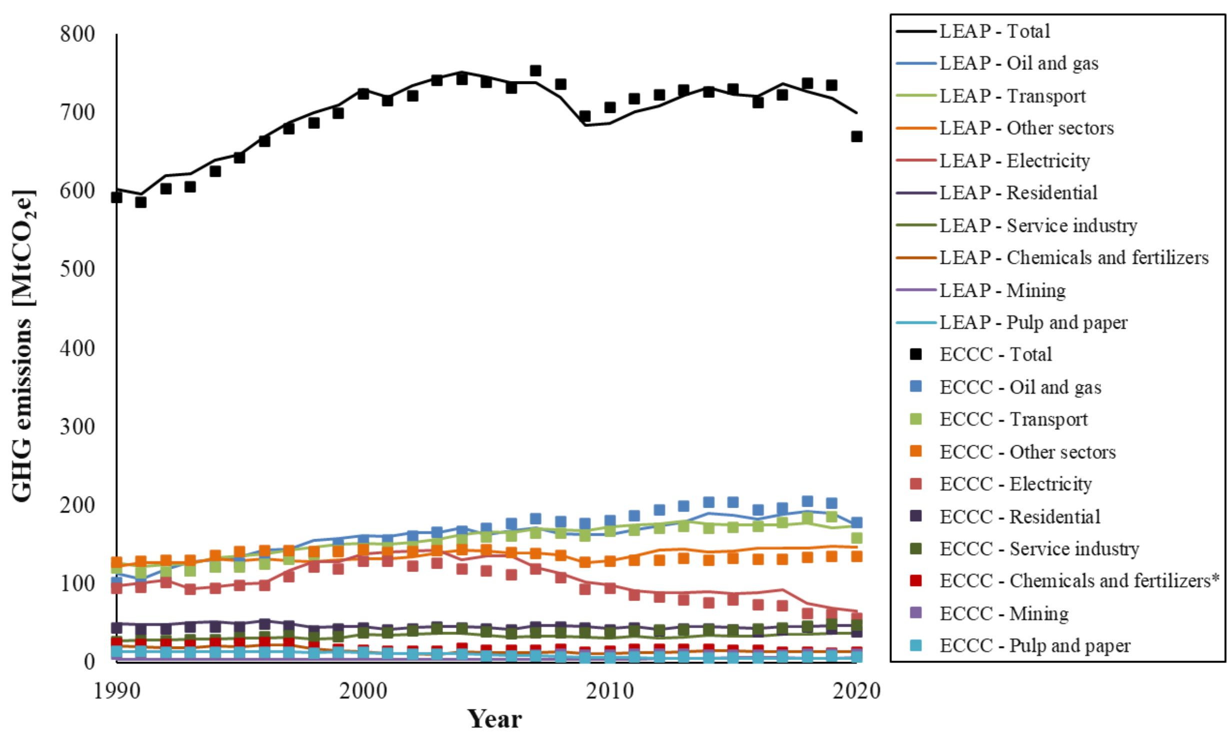

Figure 21: Modelled GHG levels and historical data, 1990-2020. *NRCan data is used for the chemicals and fertilizers sector in Alberta because of GHG allocation discrepancies. "Service industry" is used as a category name instead of "Commercial and institutional" as per NIR convention.

GHG levels calculated with the LEAP model agree closely with the official historical data. The model shows close agreement with historical regional GHG emissions data: total national emissions are within 4% of the reported total for all years and show a mean deviation of 2% from the historical data. The most significant consistent deviations are in the GHG emissions from Saskatchewan and Alberta's oil and gas extraction sectors and historical data and are attributable to the assumption of constant process emissions intensities. Validation figures for all individual regions are in Appendix H.

3.2.3.2.3 Cost data integration

Capital, operating, resource, and emissions costs can be included in the bottom-up model. Using an entire-energy-system cost boundary in this analysis means that the calculated costs represent those facing the entire national economy. Capital and operating costs can be included as annualized marginal demand costs (MDC), which are calculated accordingly:

$$MDC_i = \left(Cap_i * \left(\frac{r}{1-(1+r)^{-t_i}}\right) + OC_i\right) - \left(Cap_b * \left(\frac{r}{1-(1+r)^{-t_b}}\right) + OC_b\right) \quad \text{(Eq. 3.5)}$$

where subscript i denotes capital cost (Cap), lifetime (t), and operating cost (OC) of alternative technology i, and subscript b denotes the same values for the base technology.

In this assessment, energy costs are included as resource supply costs and emissions costs are represented by a uniform externality cost. A single carbon cost pricing schedule reflective of current federal policy in the results shown in Section 3.3 has been considered but include alternative carbon pricing schedules representing carbon tax elimination and carbon tax increase in the sensitivity analysis. All cost results are reported as social costs and are not affected by sector-specific economic factors like emissions reduction incentives or sector-specific regulations.

3.2.4 Scenario analysis

Table 27 provides descriptions of the three assessed scenarios and two sub-scenarios. The general approaches used to generate system-wide results, key insights, and policy recommendations are described in the following sections.

Table 27: Overview of combined scenarios (* denotes sub-scenario)

Scenario	Description
Reference (REF)	End-use technology shares and energy intensities remain constant for all future years
*Energy demand reduction (EDR)	BAU EDR scenarios only
*Energy demand reduction and fuel switching (EDR FSW)	BAU EDR and FSW scenarios
Business as usual (BAU)	All EST measures with MAC < \$170/tCO_2e are fully adopted by 2050, and DEV measures are adopted according to annual market share calculations
Maximum GHG mitigation (MAX)	DEV measures resulting in minimum direct GHGs at each end-use are fully adopted by 2050, and all applicable EST GHG mitigation measures are adopted by 2050

3.2.4.1 System-wide results

The framework was used to calculate energy demand, GHG emissions, and marginal costs up to 2050 for the three developed scenarios: REF, BAU, and MAX. The respective contributions of each measure type category can be assessed by calculating results for the incremental sub-scenarios as well. Differences between energy demand, D, for different scenarios (shown in Figure 22) are calculated accordingly:

$$\Delta D_{BAU,y,j} = D_{BAU,y,j} - D_{REF,y,j} \qquad \text{(Eq. 3.6)}$$

$$\Delta D_{MAX,y,j} = D_{MAX,y,j} - D_{BAU,y,j} \qquad \text{(Eq. 3.7)}$$

In the above equations, $D_{BAU,y,j}$ is the annual demand for fuel j in year y in the BAU scenario, and $D_{REF,y,j}$ is the corresponding value in the REF scenario. The subscript MAX denotes the same values for the MAX scenario.

The respective GHG mitigation potentials of the three included measure categories (EDR, FSW, and CC) under current policy were assessed as well (shown in Figure 24) and are calculated accordingly:

$$\Delta G_{EDR,y} = G_{EDR,y} - G_{REF,y} \quad \text{(Eq. 3.8)}$$

$$\Delta G_{FSW,y} = G_{FSW\ EDR,y} - G_{EDR,y} \quad \text{(Eq. 3.9)}$$

$$\Delta G_{CC,y} = G_{BAU,y} - G_{FSW\ EDR,y} \quad \text{(Eq. 3.10)}$$

In the above equations, ΔG is the category-specific annual GHG mitigation potential for EDR, FSW, and CC measures in year y, and G is the annual system-wide GHG flux. The subscript $FSW\ EDR$ indicates the BAU sub-scenario including FSW and EDR measures only.

The MAX scenario was developed for illustrative purposes and includes measures selected for GHG minimization, so the respective contributions of the different measure types were not calculated. In some cases, the selection of end-use technology may be arbitrary; for example, both nuclear reactors and carbon capture technologies can be used to reduce GHG levels from SAGD boilers, but nuclear reactors are selected to achieve full market share by 2050 since they have a marginally lower GHG intensity. Showing the respective contributions of each measure type in the MAX scenario would understate the GHG mitigation potential of competing technologies that were not selected, so these results were omitted. Additional GHG mitigation potential in the MAX scenario relative to the BAU is calculated as follows:

$$\Delta G_{MAX,y} = G_{MAX,y} - G_{BAU,y} \quad \text{(Eq. 3.11)}$$

GHG mitigation potentials calculated using these equations for the year y = 2050 can be used to assess sectoral and regional progress towards NZE, as shown in Figure 28 and Figure 29.

System-wide marginal costs were calculated for the three main scenarios and two sub-scenarios. Comparing the BAU scenario to the REF scenario shows the costs and benefits of current climate action, while comparing the MAX scenario to BAU indicates the costs and benefits associated with further action. Since most demand costs in the model are included as marginal costs, absolute system-wide costs C are meaningless on their own. Marginal costs for all scenarios and sub-scenarios are calculated accordingly.

$$\Delta C_{EDR,y,k} = C_{EDR,y,k} - C_{REF,y,k} \tag{Eq. 3.12}$$

$$\Delta C_{FSW,y,k} = C_{FSW\ EDR,y,k} - C_{EDR,y,k} \tag{Eq. 3.13}$$

$$\Delta C_{CC,y,k} = C_{BAU,y,k} - C_{FSW\ EDR,y,k} \tag{Eq. 3.14}$$

$$\Delta C_{MAX,y,k} = C_{MAX,y,k} - C_{BAU,y,k} \tag{Eq. 3.15}$$

In the above equations, k indicates a specific cost component relating to demand capital investment and operations, transformation capital investment and operations, energy consumption, or emissions penalties. These components are shown in Figure 30. Reported costs are faced by the entire energy system, meaning GHG emissions costs should be interpreted as damages to public health and infrastructure. Total costs can be used to calculate weighted average marginal abatement costs for each measure type i accordingly (shown in Figure 24):

$$MAC_i = \frac{\sum_{k=1}^{n} \sum_{y=y_b}^{2050} \Delta C_{i,y,k}}{\sum_{y=y_b}^{2050} \Delta G_{i,y}} \tag{Eq. 3.16}$$

In Eq. 3.16, n is the number of cost components considered and y_b is the base year (2021 for this case study).

3.2.4.2 Key insights and recommendations

Scenario-specific results provide insights on the GHG mitigation potential of different measure types and the effects of these measures on system-wide energy demand and costs as well. The results can also show the effectiveness of current policy towards the full realization of all currently available GHG mitigation strategies and the gap between all identified currently available measures and system-wide decarbonization. Ultimately, these insights can be used to provide recommendations to policymakers looking for areas where additional GHG mitigation may be achieved through further action and areas where rapid technological innovation is urgently required.

3.3 Results and discussion

Results are presented and discussed as follows: first, changes to energy demand projections and electricity generation for the modelled portfolios of measures are shown in Section 3.3.1. The net effects of these measures on national and regional GHG emissions levels are described in Section 3.3.2, and system-wide costs are shown in Section 3.3.3. Methodological limitations are discussed in Section 3.3.4. Based on the key findings, recommendations to policymakers are provided in Section 3.3.5. Sensitivity analysis results are in Section 3.3.6.

3.3.1 National energy demand and production

End-use demand reductions for major fuel-type categories are shown in Figure 22 below. In the BAU scenario, annual energy demand decreases by 24% by 2050 relative to the reference scenario, largely driven by reduced demand for natural gas and oil products. The increase in demand for "other" fuels is driven by hydrogen demand for passenger fuel cell vehicles. In the MAX scenario, demand for natural gas and oil products is lower than BAU levels, but demand for electricity and renewables and nuclear is higher, leading to a net reduction of 37% of reference energy demand by 2050. Altogether, the assessed measures represent significant system-wide energy demand reductions; although the MAX scenario includes scenarios representing full electrification of building space heating and road transport, these effects are partially offset by electricity demand reductions through other measures, and more significantly, by drastic reductions in national fossil fuel demand.

Figure 23 shows the differences in how electricity demand is met for the scenario portfolios. Total electricity generation does not differ significantly between the REF and BAU scenarios, but under current policy natural gas generation is largely replaced by wind generation. The reduction in hydro generation in the MAX scenario relative to the BAU is due to cost-driven increased wind capacity across all regions. The increased electricity demand in the MAX scenario relative to the BAU is met by increased wind and solar generation, which are offset by reductions in natural gas, nuclear, and hydro generation. These results show that ambitious demand-side decarbonization strategies are compatible with increased renewable electricity generation. If demand-side decarbonization efforts are not matched by similar changes to the national energy supply, the net

GHG mitigation effects of electricity demand reduction and end-use electrification will increase and decrease, respectively.

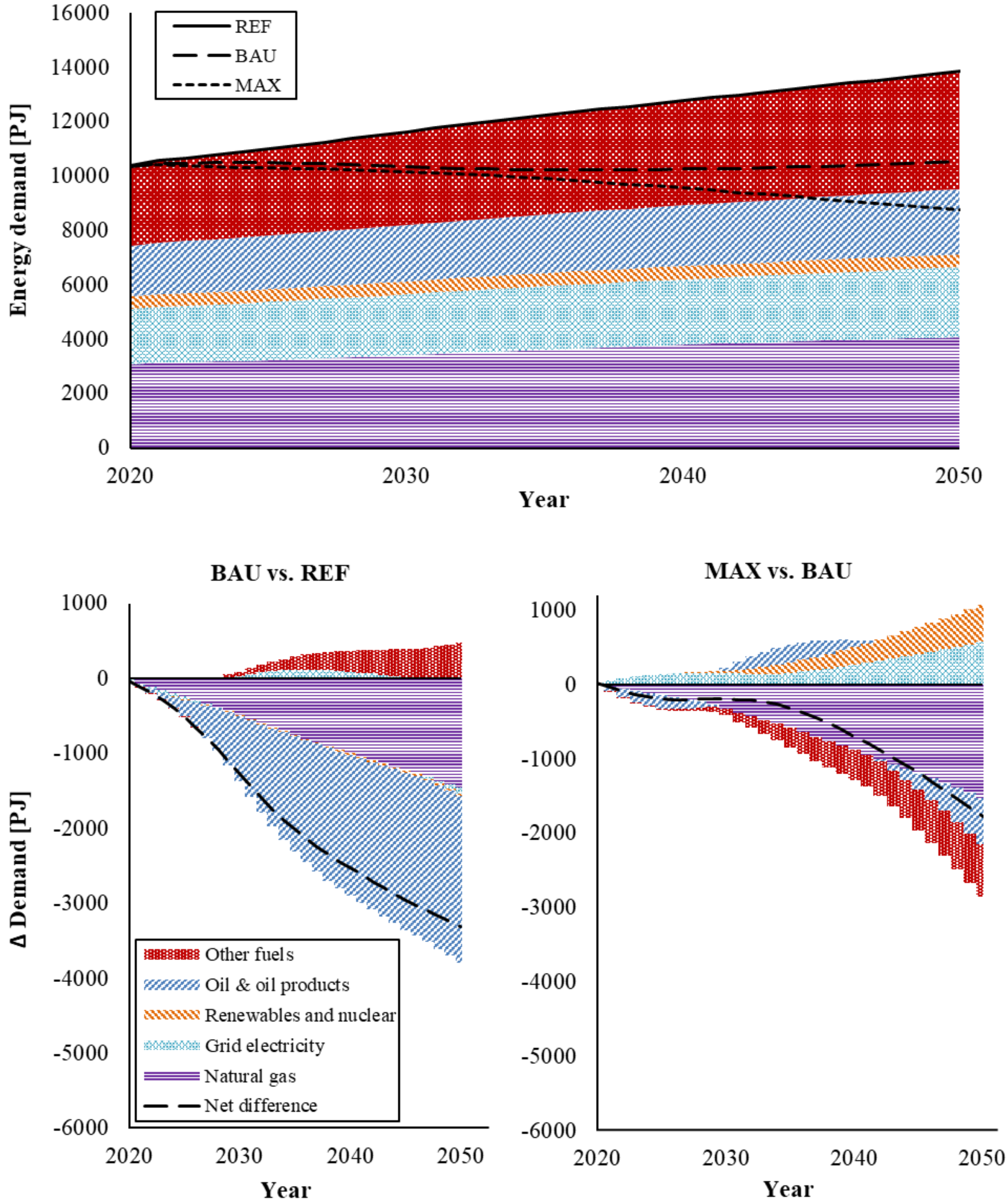

Figure 22: REF scenario energy demand and differences for BAU and MAX scenarios. "Other fuels" includes waste, coal, coke, produced and still gas, and fuels used for non-energy purposes. Onsite demand for wind and solar is not shown.

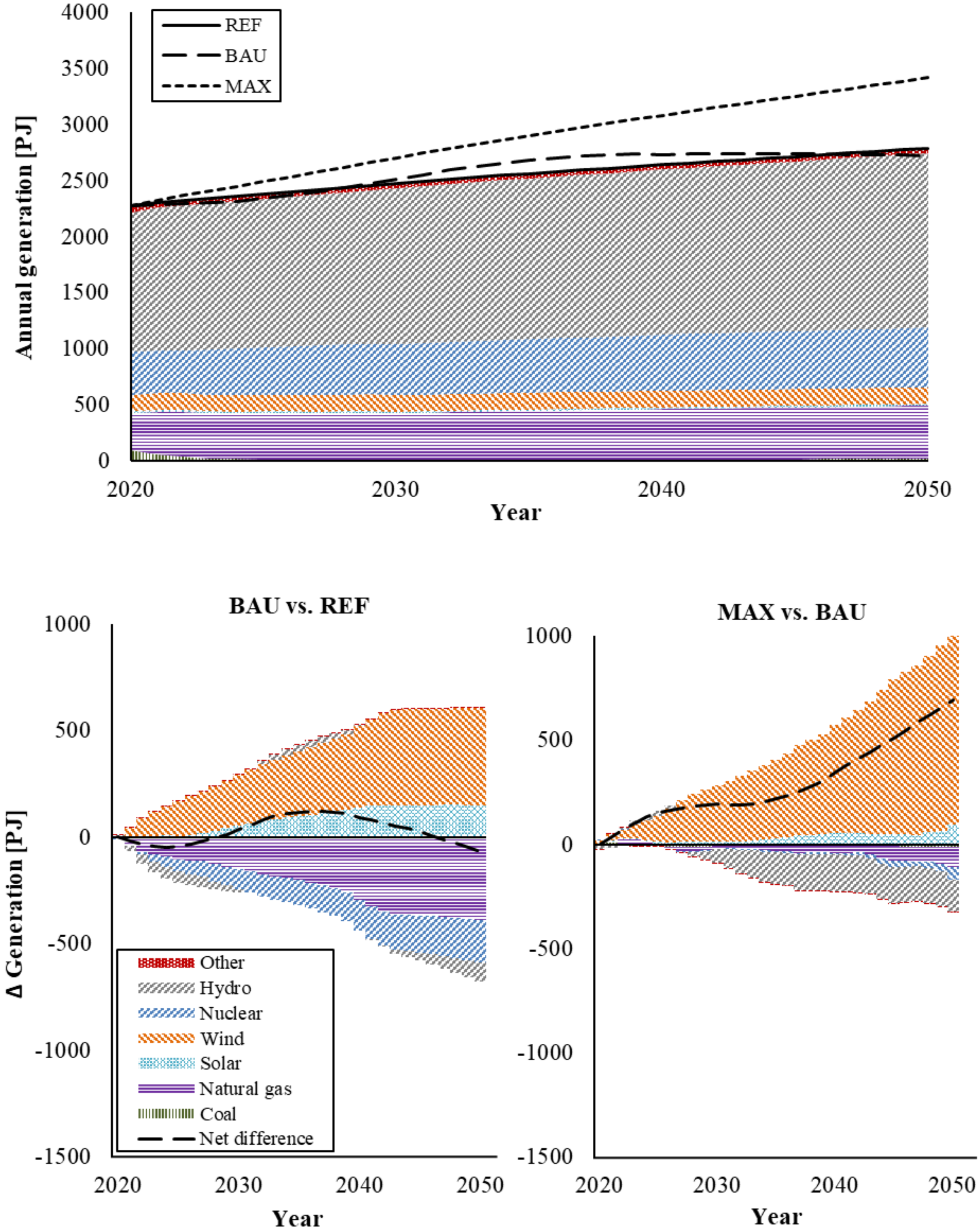

Figure 23: REF scenario electricity generation and differences for BAU and MAX scenarios. "Other" includes electricity generated by oil and biomass combustion.

3.3.2 GHG mitigation potential

3.3.2.1 System-wide potential

Figure 24 shows the projected contribution that each category of assessed GHG mitigation measures may make toward NZE under current policy as well as their weighted average marginal abatement costs. Under current policy, 295 $MtCO_2e$ may be mitigated annually by the portfolio of assessed measures, reducing GHGs levels by 13% between 2020 and 2050. In the REF scenario, GHGs are expected to grow by 29% over this period. The annual GHG mitigation included in the BAU scenario comprises 65% of the technical maximum annual GHG mitigation potential (by 2050) represented by all measures.

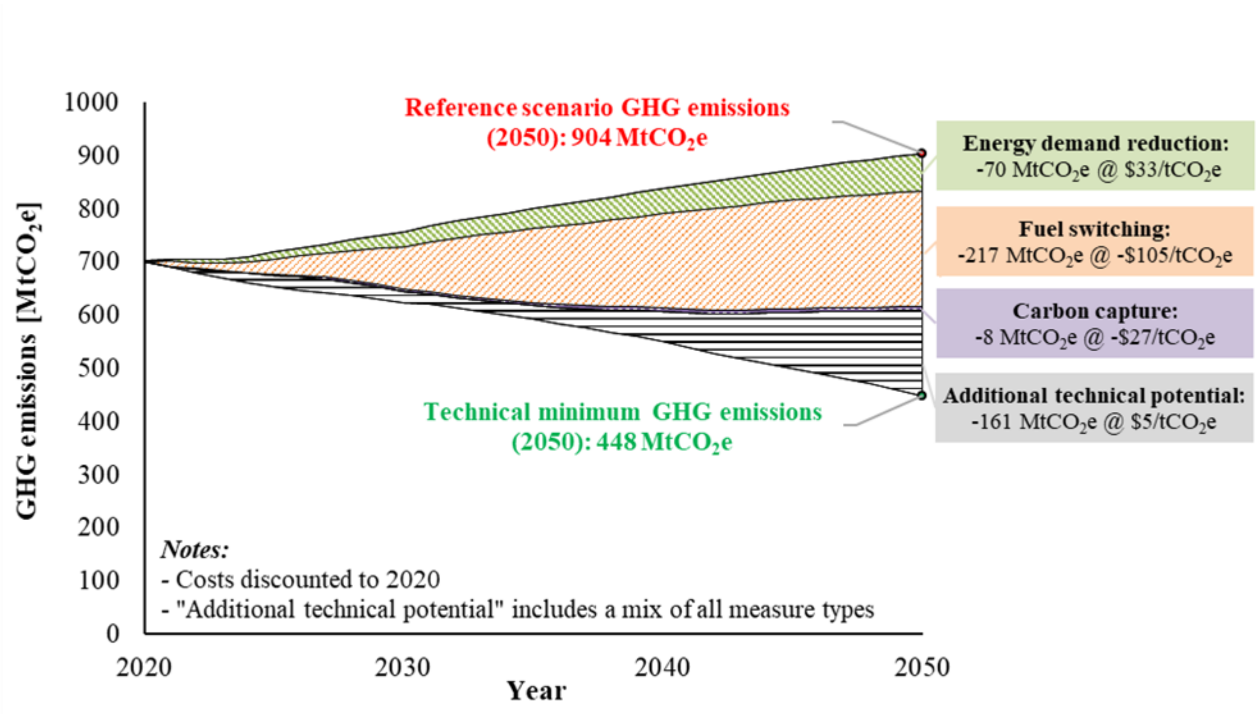

Figure 24: GHG mitigation potential and average marginal abatement costs for all measure types considered in this study

It is expected that achieving NZE will require at least 448 $MtCO_2e$ to be mitigated annually by 2050 through measures not included in this analysis. The assessed measures represent small shares of the total GHG mitigation required for complete decarbonization; altogether, they may mitigate 33% of reference scenario GHG emissions by 2050, with FSW accounting for 24%, EDR 8%, and CC 1%. An additional 17% of annual reference scenario GHG emissions may be mitigated by 2050 through further penetration. The remaining GHG mitigation opportunities are discussed in Chapter 4.

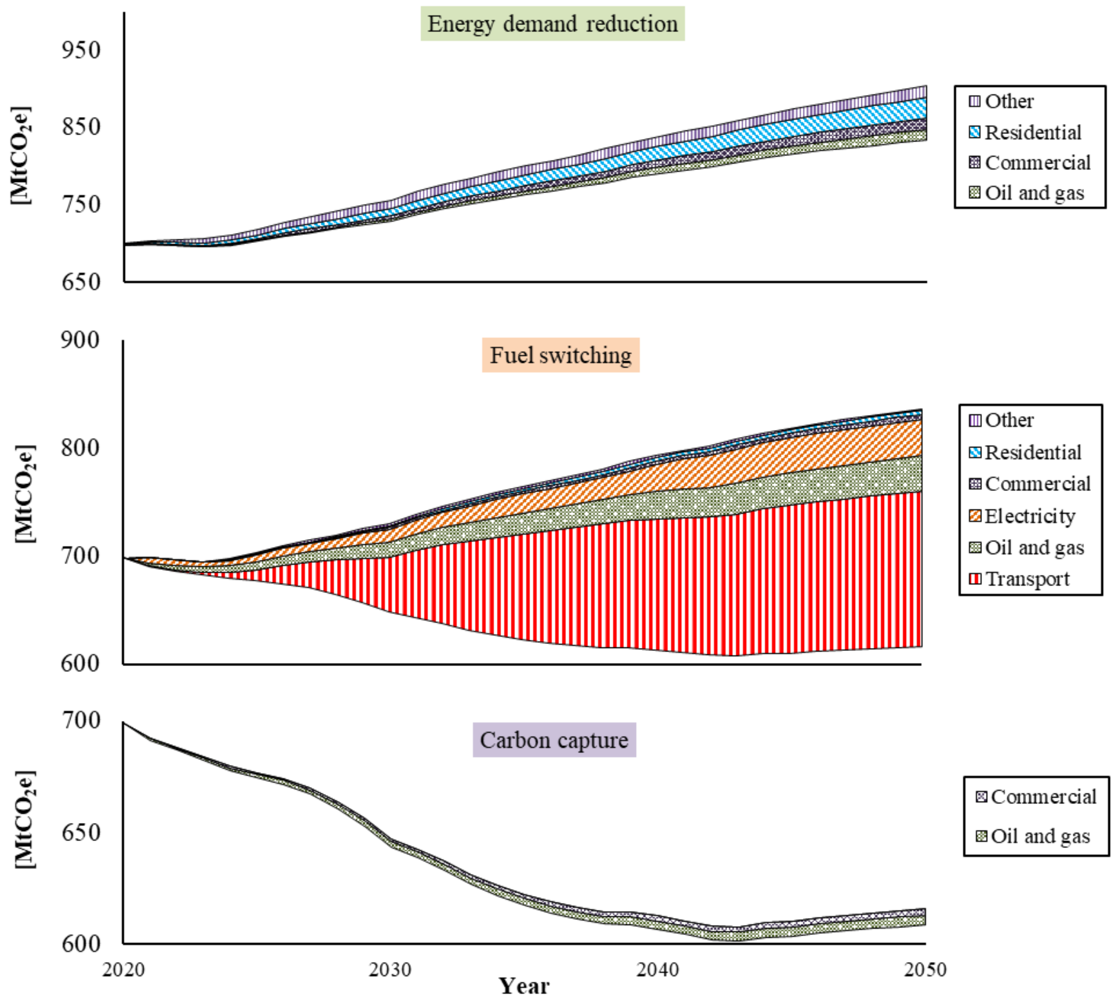

Figure 25: GHG mitigation potential by measure category and sector, BAU scenario

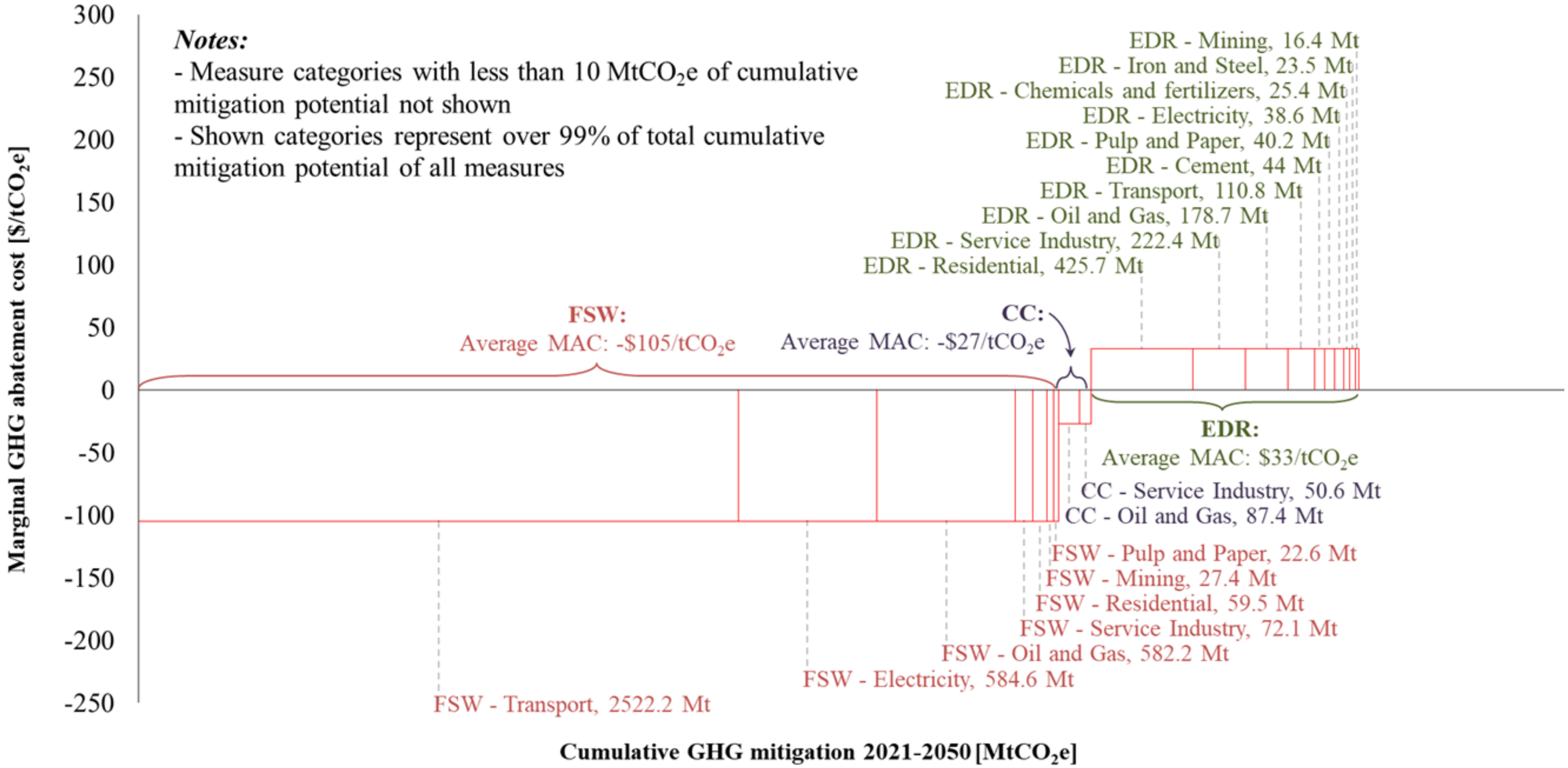

Figure 26: Weighted average marginal GHG abatement costs of measure categories by sector.

Figure 25 shows the annual GHG mitigation achievable under current policy for all three assessed measure types, and Figure 26 shows the weighted average marginal abatement costs of the three assessed measure type categories and the cumulative GHG mitigation potentials from each economic sector. FSW measures represent the largest GHG mitigation potential and are available at the lowest average cost. Most of this potential may be achieved through measures in the transportation, electricity generation, and oil and gas sectors. The cumulative GHG mitigation potential of all assessed FSW measures is dominated by the adoption of battery electric vehicles in the transport sector. Some of the assessed FSW measures represent large capital investment and drastic changes to existing industrial processes (e.g., nuclear steam generation for SAGD bitumen extraction), but the large capital costs of these measures are ultimately outweighed by savings due to energy and emissions reduction and the rapid improvement in the capital costs of renewable energy production capacity.

EDR measures constitute more than 10 $MtCO_2e$ in cumulative GHG mitigation potential in every major economic sector. This group of measures has the largest average MAC because of the diminishing effects of simultaneously applied measures: even though these measures may all have individual MACs below the assumed carbon price, when modelled altogether, the collective GHG mitigation potential is reduced and the average MAC increases. This result is largely a consequence of the high number of EDR measures considered in this analysis and does not dispute that EDR measures are often economical GHG mitigation options when evaluated from the energy consumer's perspective. Rather, EDR measures are not endlessly cost effective and should always be weighed against other options. Determining a cost-optimal portfolio of EDR measures is beyond the scope of this work but should be done at the facility level to account for existing stock, activity scale, and region- and sector-specific energy prices.

CC measures represent the lowest level of GHG mitigation potential since they are among the most nascent GHG mitigation strategies assessed. The CC technologies assessed for the oil sands do not achieve significant levels of penetration in the cost-based market share calculations when competing with renewable energy and advanced extraction alternatives. The building-level CC technologies for natural gas space heaters achieve significant levels of market share (>30%) in most regions under current policy, but do not significantly reduce GHG emissions due to the low capture fraction (13% of exhaust CO_2) of currently available systems [113].

3.3.2.2 Sector-specific potential

Figure 27 shows the maximum relative GHG mitigation potential that the assessed measures represent in each sector. The following paragraphs discuss sectoral GHG mitigation potential relative to the target of NZE. Unassessed measures and limitations are briefly mentioned here and discussed in greater detail in Section 3.3.4 and Chapter 4.

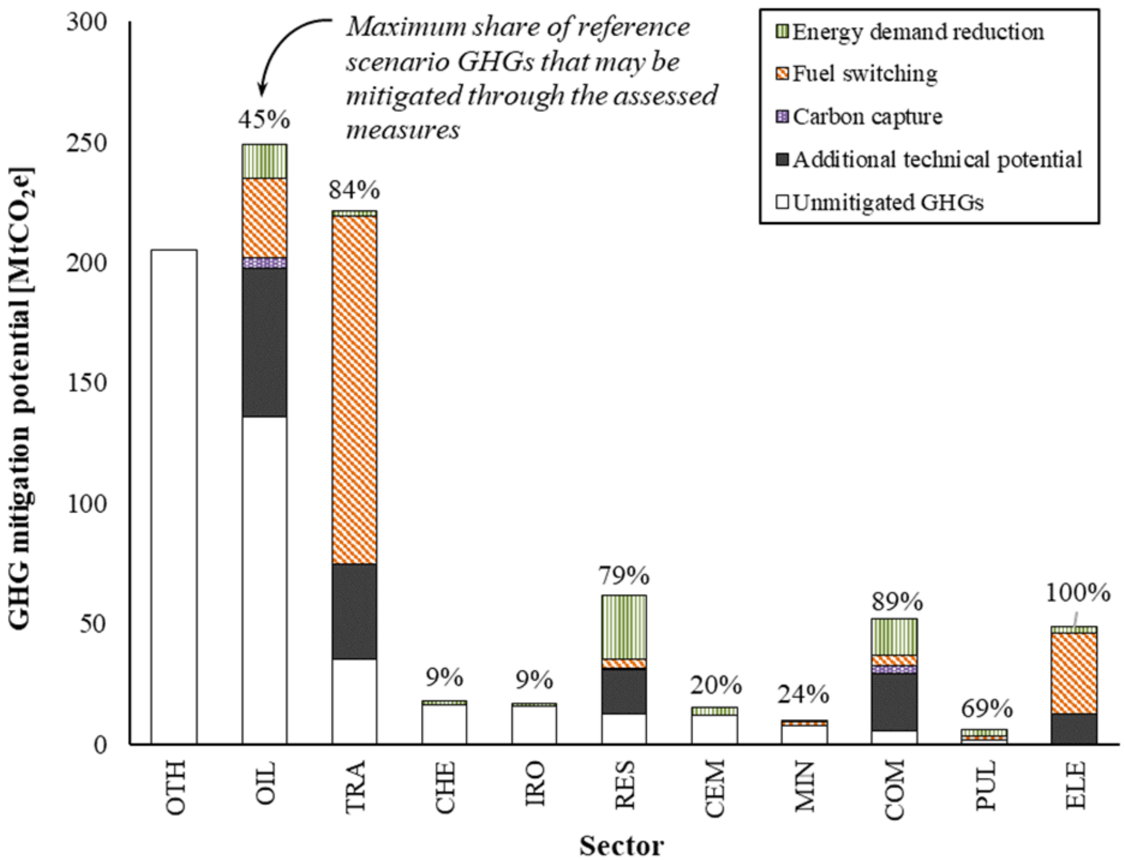

Figure 27: Maximum relative annual GHG mitigation potential of assessed measures by sector, 2050. Other (OTH) GHG emissions sources include agriculture, waste, mineral smelting and refining, light manufacturing and construction, and chemical production outside Alberta.

After considering the maximum level of GHG mitigation possible through the portfolio of assessed measures, the largest single GHG emissions source is the "other sectors" category, which encompasses GHGs from agriculture, waste, mineral smelting and refining, light manufacturing and construction, and chemical production outside of Alberta. These sectors have not been fully disaggregated because of their regional specificity and high levels of non-energy emissions;

however, GHGs from these sources cannot be ignored. Achieving carbon neutrality in non-energy emissions-intensive sectors will not be possible through the types of measures considered in this analysis and may instead rely on the careful management and enhancement of carbon sinks and other carbon-negative measures.

The assessed measures may mitigate up to 45% of GHGs from the oil and gas sector, indicating that further technological innovation will be required for sectoral decarbonization. The modelled CC technologies do not achieve significant levels of penetration because of their high costs and limited applicability; they are only considered for processes related to SAGD steam generation and hydrogen production for bitumen upgrading. CC technologies may be applied elsewhere and are currently the flagship strategy for a coalition of companies in this sector aiming for NZE by 2050, so additional applications of these systems should be explored [122].

The chemical manufacturing sector represents the fourth largest source of unmitigated GHG emissions, but only energy-efficiency improvements for this sector were assessed. Furthermore, the disaggregated model only covers ammonia and ethylene production in Alberta, which represented only 50% of sectoral GHGs in 2019 [70]. The adoption of electrolytic hydrogen production or CC in steam methane reforming Haber-Bosch ammonia plants may greatly reduce process GHGs sector-wide. Decarbonization strategies for other chemical manufacturing processes must be tailored to each specific product.

Up to 84% of GHG emissions from the transportation sector may be mitigated through the portfolio of assessed measures, largely through the adoption of battery and hydrogen fuel cell electric vehicles. The remaining unmitigated GHGs are from aviation and marine transport. Aviation is difficult to decarbonize with current technologies because of the energy density requirements of aviation fuels [7], so the remaining GHG emissions from this sector may need to be partially offset by carbon-negative measures.

Only small shares of GHG emissions from the iron and steel and cement production sectors may be mitigated by the assessed strategies. Previous studies have focused on energy efficiency improvement opportunities in these sectors, so full decarbonization will require additional measures. Nearly one quarter (24%) of baseline GHGs in the mining sector may be mitigated by the assessed measures. The modelled measures were only applied in the gold, iron, and potash mining sectors; GHG emissions from coal, copper, aluminium, cobalt, diamond, and uranium mining operations may be reduced through the application of similar measures as well. Up to 69% of baseline GHG emissions from the pulp and paper sector may be mitigated through the diverse portfolio of measures assessed for this sector. Full decarbonization may require activity changes (i.e., production route shares) or offsets through carbon-negative measures.

GHG emissions in the residential and commercial sectors may be significantly reduced by the assessed measures (by 79% and 89%, respectively). Full decarbonization may be technically feasible if additional FSW measures are considered for water heating, appliances, and auxiliary equipment end-use technologies. The developed model shows that GHG emissions from the electricity generation sector can be fully eliminated by 2050 through the deployment of renewable energy technologies.

Figure 28 shows the annual GHG mitigation potential of all assessed measures by 2050, organized by measure type and sector. 79% of the annual GHG mitigation potential available through measures in the transportation sector is expected to be realized under current policy through FSW measures. All three measure types show GHG mitigation potential in the oil and gas sector but, under current policy, are expected to achieve only 46% of their potential. Measures in the electricity generation sector are expected to reduce annual GHG emissions by 36 $MtCO_2e$ by 2050. Energy demand reduction measures represent 10 $MtCO_2e$ in annual GHG mitigation potential across other industrial sectors, accounting for 53% of the annual abatement potential in these sectors by 2050.

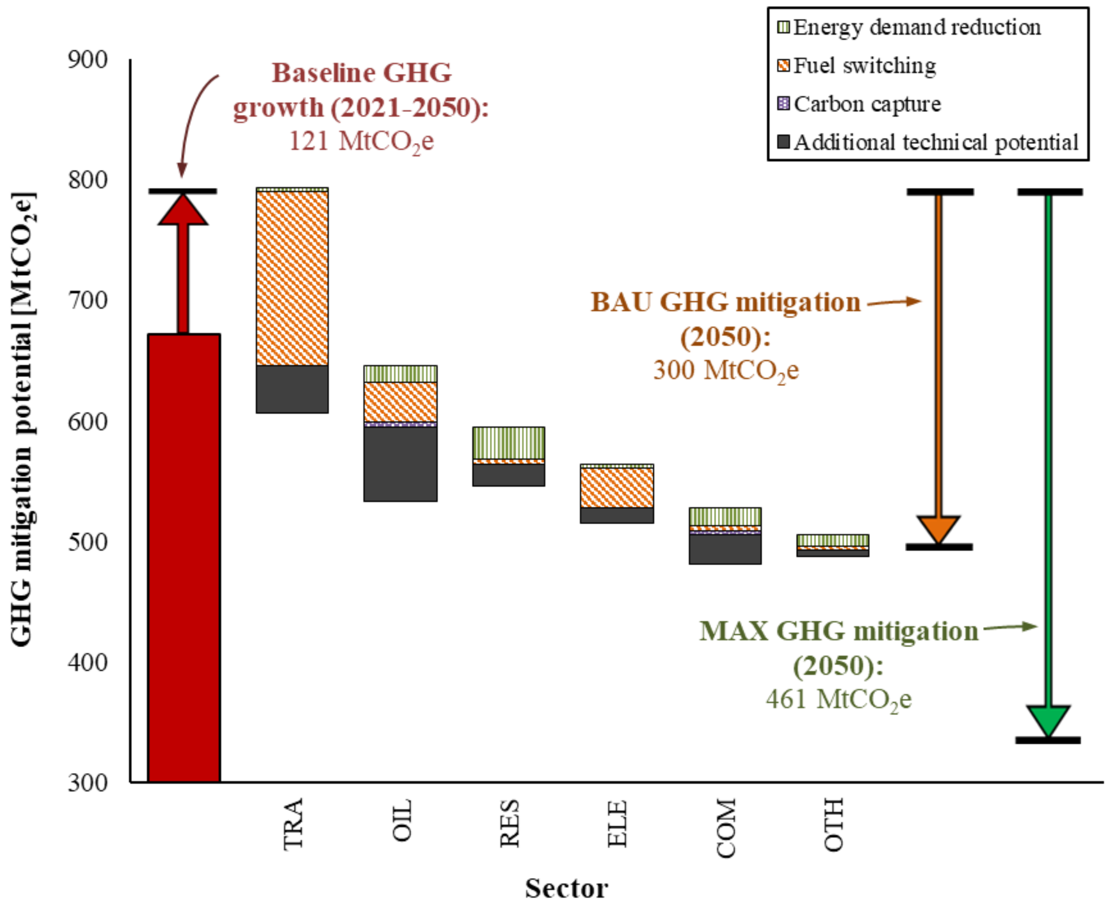

Figure 28: Annual GHG mitigation potential by measure type and sector, 2050. "Other sectors" (OTH) includes chemical manufacturing, cement production, iron and steel, mineral mining, and pulp and paper. Vertical axis truncated for visibility.

3.3.2.3 Region-specific potential

Figure 29 shows that the identified measures represent the largest GHG mitigation potential in Alberta. Despite the large GHG mitigation potential available in the oil sands, Alberta remains the most GHG-intensive region in all three scenarios. GHG emissions from oil and gas in BC and Saskatchewan show significant shares of regional totals in all scenarios since measures for the sector in those regions were not assessed.

In the eastern provinces, GHG emissions from transportation and other sectors dominate regional GHG inventories. GHGs from other sectors are dominated by non-energy emissions from the agriculture sector. Decarbonization of this sector will require radical process changes since 81%

of national agricultural GHGs in 2019 were from non-energy processes like enteric fermentation and fertilizer use [13]. Measures included in the MAX scenario may mitigate over half of reference scenario GHGs by 2050 in these regions since the relative GHG levels from the transportation, residential, and commercial and institutional sectors are high and these regions already have high levels of non-emitting electricity generation capacity. Together, these factors mean that the adoption of BEVs and heat pumps for building space heating will significantly reduce baseline GHGs under current policy. In all regions, achieving carbon neutrality will require more than the measures included in this analysis.

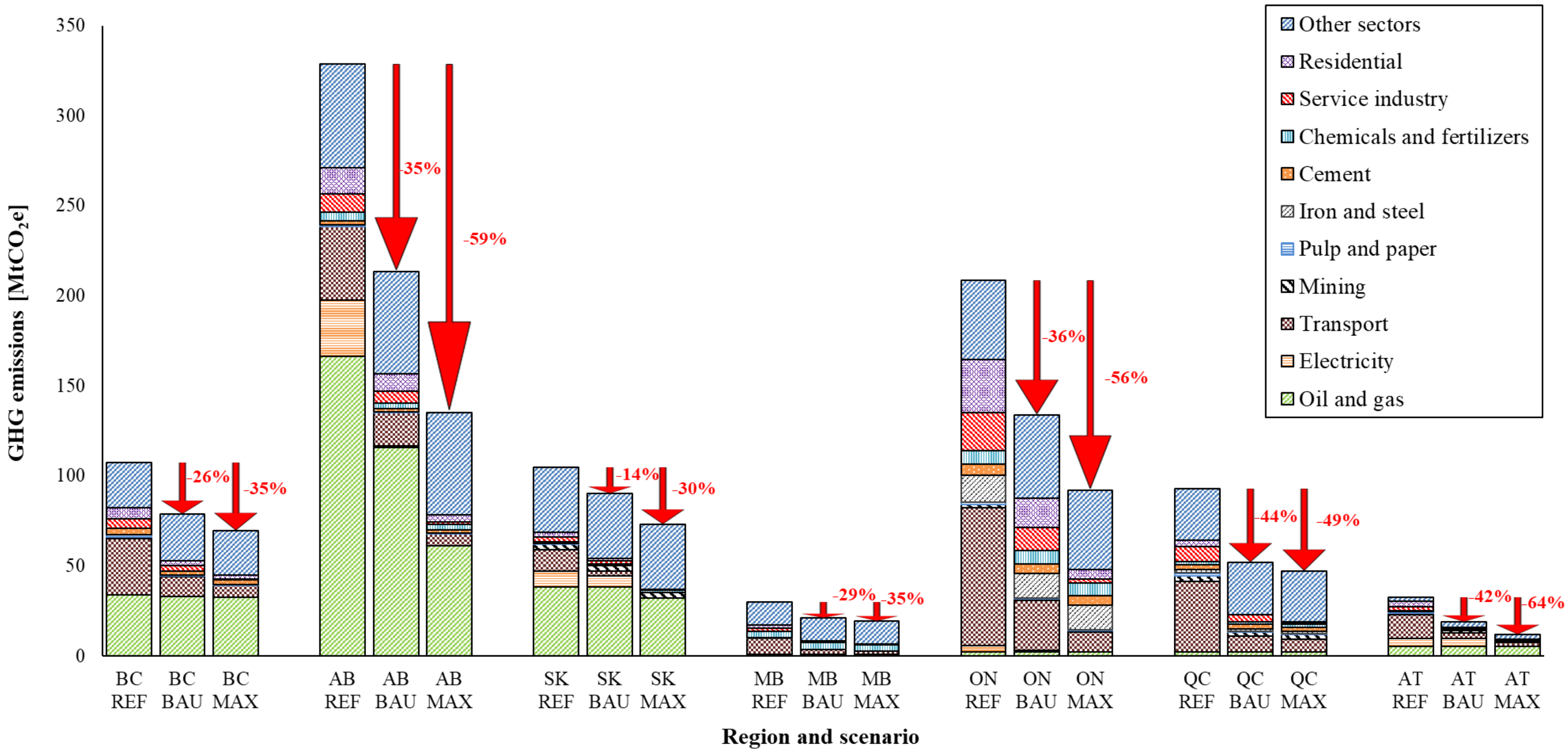

Figure 29::**Annual GHG mitigation potential by region, 2050**

3.3.3 System-wide economic costs and benefits

Figure 30 shows the net present value (NPV) of the BAU and MAX measure portfolios relative to the REF and BAU scenarios, respectively. Costs are categorized into four types corresponding to demand-side capital and operating costs ("Demand CapEx & OpEx"), supply-side capital and operating costs ("Transformation CapEx & OpEx"), energy costs ("Energy"), and GHG externality costs ("Emissions"). Most of the revenue from Canada's federal carbon pricing system is dispersed to consumers to offset energy cost increases, so the true net cost per tonne of CO_2 varies by sector [123]. For this analysis, GHG emissions costs should be interpreted as the costs borne by the whole energy system due to environmental damages to public health and infrastructure.

Supply-side capital and operating costs correspond to renewable electricity generating capacity costs. Under current policy, these technologies represent a relatively low share of total system-wide costs because of the large share (80%) of renewable and non-emitting electricity generation capacity currently comprising Canada's electricity grid [55]. Thus, current electricity decarbonization policies affect only two provinces (AB and SK). Relative to the REF scenario, demand-side capital costs peak around 2030 and diminish thereafter because of reduced penetration rates of novel technologies and unit cost reductions in novel transport sector technologies. Capital expenses between 2020 and 2030 are largely offset by cost savings from reduced energy costs and avoided emissions costs, which offer consistently similar benefits. As the federal carbon pricing achieves its maximum of \$170/tCO_2e in 2030 and demand costs peak, net annual savings grow. Under current policy, the assessed measures represent an NPV of 365 billion CAD. Achieving these measures will require capital investment representing 1% of cumulative GDP over 2020 to 2030 but will ultimately lead to net benefits under current policy primarily because of the cost savings from energy reductions and GHG avoidance.

If the assessed measures are implemented to their maximum extent, additional fuel and emissions savings are outweighed by additional capital and operating costs until 2040, at which point annual cost savings are realized because of growth in GHG emissions cost savings. In this portfolio, the addition of a 100% non-emitting target for the electricity generation sector increases energy supply-side capital and operating costs because of the limited availability of wind and solar resources and the high capital expenses of building new hydro and nuclear capacity. Relative to the BAU portfolio, the MAX portfolio of scenarios represents an incremental NPV of -7 billion

CAD since the additional energy and emissions cost savings are outweighed by high demand-side capital costs.

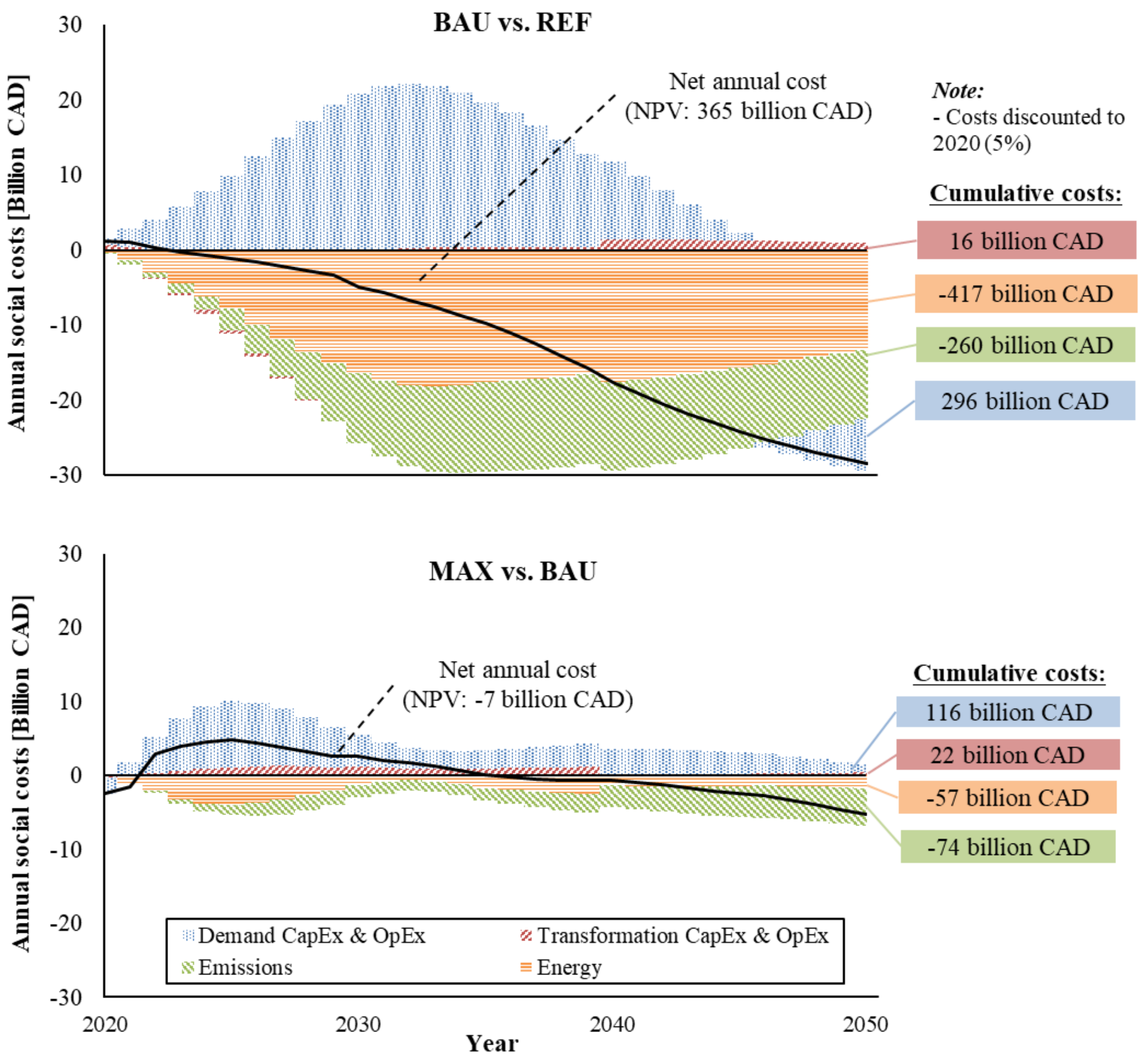

Figure 30: Incremental economic costs and benefits of GHG mitigation portfolios

3.3.4 Limitations

This research is applicable to real-world policy development and other jurisdictional analyses but does have limitations. Simple activity projections in this analysis that do not reflect the complexity of consumer behaviour. The modelling does not represent feedback between energy consumers and markets. Sectoral activity projections are based on single macroeconomic indicators and do not account for consumer demand and behaviour. This limitation affects GHG and social cost projections in every scenario, likely leading to underestimated effects of decarbonization policy and efforts. In the future, defining sectoral activity as an iterative, multi-variable function of GDP, population, global energy prices, and consumer demand variables (e.g., diet and resource consumption) will make the model more robust.

Changes in upstream GHG emissions and costs in natural gas extraction and processing, petroleum refining, and bitumen upgrading branches are underrepresented since interregional energy resource transfers are not calculated. Since oil and gas resources from western Canadian provinces are used to meet demand across the country, this simplification means that any reductions in upstream GHG emissions in BC, AB, and SK due to reduced national fossil fuel demand are not fully accounted for. In the current model, oil and gas activity is dependent on the regional demand calculated for each scenario and projected export, which does not change between scenarios. This assumption is consistent with the approach used to model sectoral demand described above, but ultimately means that the total GHG mitigation potential of measures involving fossil fuel demand reductions have been underestimated. In the future, GHG emissions from oil and gas on-site demand and fugitive emissions from extraction and distribution should be calculated as functions of interregional resource imports, exports, and domestic demand.

The energy resource and transformation modules used in the model only optimize electricity generation processes. If hydrogen and natural gas production processes are also optimized and global trade is considered, additional economic benefits resulting from the export of energy to other jurisdictions might be realized. Accurately representing global energy markets would allow for a more comprehensive assessment of the economic benefits and costs of decarbonization pathways. Achieving net-zero emissions will require radical energy systems transitions to occur globally, so expanding existing energy models to account for global factors should be a priority in future work.

Shares of annual electricity demand and generation are defined for each month to represent seasonal demand and resource availability. Renewable resources and electricity demand follow diurnal patterns that affect availability and capacity needs, meaning that the monthly resolution used in this model does not account for daily energy supply and demand peaks. Without accounting for these effects, results shown by the model overstate the ability of wind and solar to meet electricity demand at all hours of the day. System-wide costs are affected since transformation capital costs are likely underestimated for the BAU and MAX scenarios. Addressing this limitation would increase the computational demand of the current model but would allow for national electricity capacity development and costs to be more accurately analyzed.

It has been assumed that energy-efficiency measures with marginal abatement costs less than \$170/tCO_2e will be adopted by all consumers under current policy. Efficiency improvements are only one type of investment that energy consumers may make to reduce their energy consumption or GHG emissions footprint. In some cases, energy-efficiency improvements can be implemented alongside other measure types (e.g., process efficiency improvements in pulp and paper production alongside biofuel use), but efficiency improvements may also be mutually exclusive with respect to other measure types (e.g., homeowners buying heat pumps instead of high-efficiency furnaces). In these cases, efficiency measures compete against other measure types for market share, but this study does not reflected this competition in all areas of the analysis. Additionally, the economic benefits of energy-efficiency improvements are dependent on what efficiency measures have already been applied. The assumption that consumers will adopt all efficiency measures below \$170/tCO_2e neglects the fact that the effects of these measures change as they as successively implemented. This limitation primarily affects BAU GHG projections for industrial sectors where FSW or CC measures (e.g., chemical and cement manufacturing, petroleum refining, and iron and steel production) have not been considered. If energy-efficiency measures are not implemented to their full capacity in these sectors, overall energy demand may be higher than this study shows but resulting GHG emissions may be lower depending on the technology and processes affected.

Simplified representations of climate policy have been used in this study. This study does not consider all regional emissions regulations or credit-trading frameworks like Alberta's Technology Innovation and Emissions Reduction (TIER) system in the analysis. Similarly, the costs reported in this work reflect national social costs instead of consumer-facing costs, which has affected the market penetration calculations. Investment decisions are based on retail energy costs, available rebates, and industry-specific emissions regulation, whereas in this study market adoption as a function of resource supply costs, capital and operating costs, and the general federal carbon price schedule have been modelled. It is expected that the true adoption of GHG mitigation measures will be higher than the levels predicted in the analysis since effective market interventions will serve to incentivize GHG emissions reduction measures.

3.3.5 Recommendations for policymakers

Achieving NZE will require nothing less than a completely transformed energy system and economy. To date, the Government of Canada's flagship policy towards meeting this target has been a broad federal carbon tax, which was designed to incentivize the adoption of low-carbon solutions across all sectors without increasing costs to consumers [124]. Carbon pricing is conceptually simple and often perceived as the most efficient form of climate action. However, Rosenbloom et al. argue that carbon pricing schemes are fundamentally insufficient to effectively mitigate climate change on their own since they frame the issue of climate change as a market failure rather than a system failure, prioritize efficiency over effectiveness, and generally underrepresent the magnitude of the transformation required for decarbonization [125]. Conversely, the Inflation Reduction Act passed in the USA aims to provide more direct innovation stimulus by incentivizing clean energy use, development, and domestic technology manufacturing through specific tax breaks and a $369 billion budget [126, 127].

It has been shown that unrealized GHG mitigation opportunities exist across all sectors but, under current policy, represent only 16% of the total GHG reduction required to achieve carbon neutrality. GHG emissions from the transportation, residential, commercial, pulp and paper, and electricity generation sectors may be nearly fully eliminated by 2050 through the adoption of currently available technologies like heat pumps, electric vehicles, process improvements, and renewable electricity generation. The extensive portfolio of measures considered for the oil and gas sector represents significant GHG mitigation potential but accounts for no more than 45% of reference GHG levels by 2050. Strategies beyond oil sands operations should be assessed in future work, such as measures to reduce GHG emissions from natural gas flaring, venting, and fugitive leaks in all gas-producing provinces. Additional research and innovation will be required to decarbonize industrial sectors including chemical manufacturing, iron and steel production, cement, and mining sectors since the GHG mitigation potential of energy-efficiency measures in these sectors is limited. It is expected that over 75% of the identified GHG mitigation potential in the transportation and electricity generation sectors will be realized under current policy; roughly half the potential in the oil, residential, and commercial sectors will be incentivized without further action. GHG emissions from sectors not included in the disaggregated energy system model represent the largest unmitigable source by 2050. This source includes non-energy emissions from agriculture, waste, and industrial sectors, and may thus depend on activity changes or the deployment of carbon-negative measures for decarbonization.

Considering the gaps between currently available climate change solutions and future ambitions, the following actions are recommended to policymakers focused on the achieving NZE in Canada by 2050:

1. **Short-term focus (5-10 years) - Communication:** Across all sectors, energy-efficiency improvements have been heralded as cost effective, "low regret," and "safe bet" GHG reduction measures [7, 128, 129]. However, it has been shown that these measures alone are insufficient for decarbonization and are not endlessly cost effective. Consumers may still perceive capital-intensive FSW technologies like electric vehicles and heat pumps as risky investments without clear communication of their long-term benefits. GHG taxation and fuel standards are effective tools for increasing the costs of fossil fuels and incentivizing renewable energy production and use [130]; both are being gradually implemented in Canada under current policy [32, 131]. Yet, many Canadians remain unaware of governmental action toward climate change mitigation [132]. It is recommended that the targeted campaigns to increase consumer awareness of programs like the Canada Greener Homes Initiative [133] and highlight the cost savings potential of fuel switching or other capital-intensive investments for industrial plants.

2. **Medium-term focus (10-20 years) - Innovation:** 8.1% of Canada's GDP in 2020 came from the energy production sector, making the country one of the top energy-producing nations in the world [134]. Global energy resource markets will change radically if energy systems become more reliant on decentralized renewable electricity generation and less dependent on imported fossil fuels, but Canada's natural resources may present opportunities for alternative fuel production such as blue hydrogen production or underground coal gasification in the interim. Policymakers should work to establish trade partnerships with nations where markets for alternative fuels have been identified.

3. **Long-term focus (20-30 years) - Diversification:** Canada must ultimately prepare for a future where global demand for fossil fuels is limited. The IEA's pathway to NZE shows a future where fossil fuel demand, currently accounting for 80% of global energy supply, falls to 20% by 2050 [7]. In 2020, nearly 17% of Canada's export trade value came from petroleum products [135], meaning the global energy transition will have profound impacts on Canada's economy. To avoid significant and rapid job loss, the country must diversify its economic activity in the long term by encouraging new industry growth in new sectors like clean technology manufacturing and new mineral extraction.

3.3.6 Sensitivity analysis

The sensitivities of key results were measured to various inputs to examine how the findings are affected by uncertainties in future economic factors. Lower and upper input variable bounds were conservatively established based on variable-specific factors, as shown in Table 28 below. Responses to these changes are shown in Figure 31 and Figure 32.

Table 28: Sensitivity analysis parameters

Activity (GDP & population)	**Δ by 2050**	**Source**
Low bound	-10%	[55]
High bound	+10%	[55]
Energy prices	**Δ by 2050**	
Low bound	-50%	[55]
High	+50%	[55]
Carbon price	**Δ by 2050**	
Low bound	-100%	n/a
High bound	+100%	n/a
Discount rate	**Rate**	
Low bound	0.01	[100]
High bound	0.1	[100]

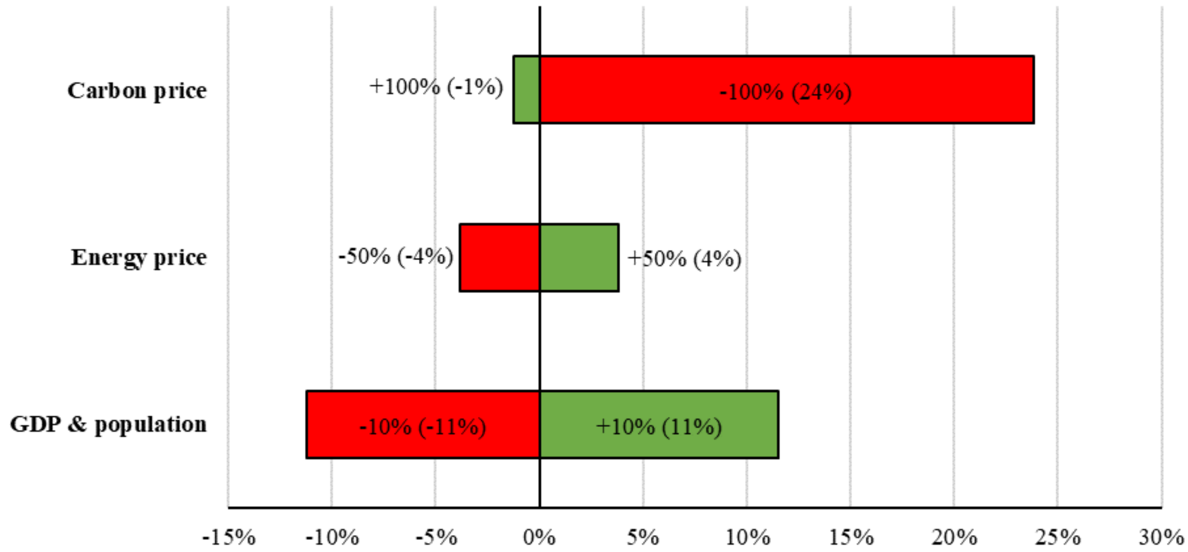

Figure 31: Sensitivity of annual maximum GHG mitigation potential

Annual maximum GHG mitigation potential is observed to be positively correlated with energy price and activity projections and negatively correlated with carbon price schedules. If future GDP and population exceed the forecasts used in the analysis, the GHG mitigation potential of the assessed measures increases as well because of increased total GHG emissions in the respective baseline scenarios. If energy prices are higher than expected, GHG mitigation potential will also increase because of increased overall activity in the oil and gas sectors. Without carbon pricing, the assessed measures represent a larger GHG mitigation potential since the baseline scenario in this case does not achieve the same level of clean electricity generation as the central carbon price baseline. With a higher carbon price, the maximum GHG mitigation potential of the assessed measures decreases less significantly since the optimized baseline includes marginally higher levels of clean electricity production.

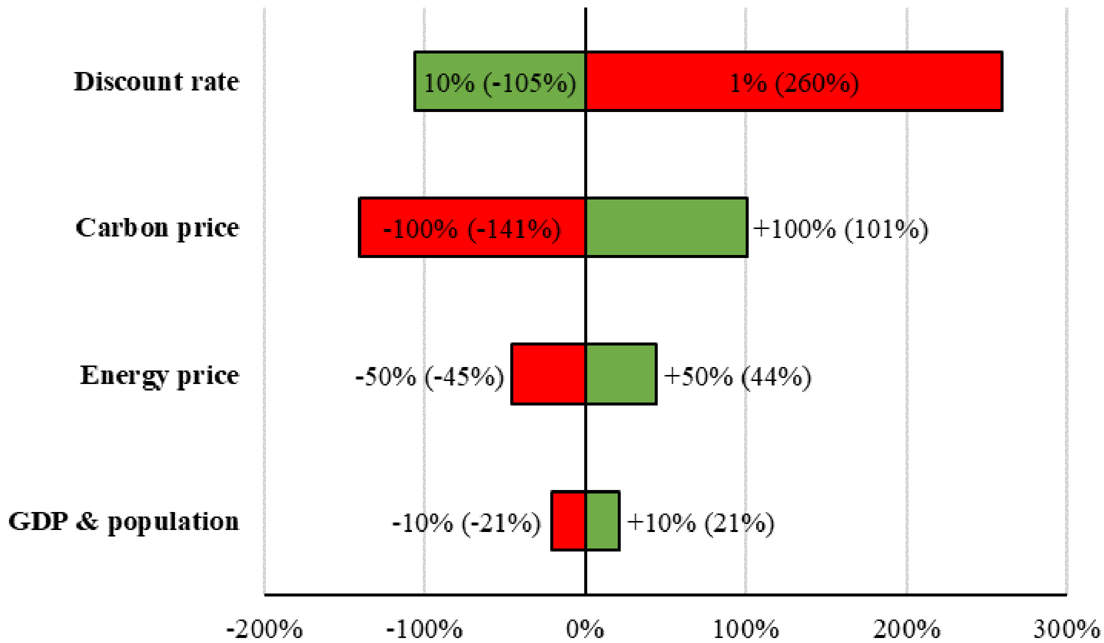

Figure 32: Sensitivity of system-wide NPV

Cumulative discounted costs are much more sensitive to changes in every parameter since components of the calculated system-wide NPV largely offset each other. The NPV of the assessed measures is most affected by the negative change in the discount rate considered in the analysis. Capital costs are unaffected by the discount rate, but the NPV of energy and emissions prices is significantly affected by the 30-year timeframe considered for this work. If future costs are discounted at a lower rate, the cumulative NPV of the assessed portfolio of measures increases, indicating a more significant net cost benefit associated with maximum implementation. Conversely, if a larger discount rate is considered, the long-term cost savings due to reduced energy demand and avoided GHG emissions are less significant. Without a carbon price, the NPV of the portfolio becomes negative, whereas a doubling of the current carbon price results in significant additional net cost savings. If energy prices increase, so too do the cost savings of the assessed measures. Cumulative costs are less significantly affected by activity projections: if the activity is higher than expected, benefits increase by 21%, while a decrease in activity corresponds to a 21% reduction in net benefits.

Together, these results show that that the maximum GHG mitigation potential of the assessed measures will likely fall within 25% of the reported value, but that the reported costs are highly sensitive to future energy and emissions prices and interest rates. Under high energy prices and carbon costs, the assessed measures lead to more significant net savings. When considering a high discount rate, however, long-term savings are diminished and ultimately outweighed by capital costs. These results indicate that the benefits and costs of decarbonization are significantly dependent on global energy markets and carbon pricing systems, both of which are affected by unpredictable factors including public perspectives and global events.

3.4 Conclusions

A net-zero emission (NZE) assessment framework based on a bottom-up, technology-specific, multi-regional energy system model was developed. In the model, NZE is not treated as an end constraint for which the energy system is optimized; this study instead evaluates measures while accounting for the type and commercial availability of each proposed intervention. This approach allows to distinguish between achievable and technical GHG mitigation potential and effectively illustrates the gaps between stated ambitions and currently available solutions. This framework allows for multi-regional assessment and may be applied to other jurisdictions globally.

This study assessed the GHG mitigation potential of 184 strategies for Canada and found that, at most, they may offset anticipated GHG growth and lead to a net reduction of 36% by 2050 relative to the 2020 level. Under current policy, it is predicted that these measures will reduce GHG levels by 13% between 2020 and 2050. These measures come at significant economic costs but lead to net economic benefits when considering the federal government's current carbon pricing plan as a blanket externality cost across all sectors. Under current policy, it is expected that the assessed GHG mitigation measures will save 365 billion CAD relative to a static energy intensity reference by 2050. Implementing all measures will result in an incremental cost of 7 billion CAD relative to the BAU scenario.

Fuel switching measures represent the largest system-wide GHG mitigation potential and have the lowest average marginal abatement cost of the three assessed measure categories. Most of the GHG mitigation potential of these measures is achievable in the transportation and electricity generation sectors. Currently available carbon capture technologies are not cost competitive nor effective enough to represent significant GHG mitigation potential in the oil and gas, residential, or commercial sectors. Energy demand reduction measures were found to have the largest average marginal abatement cost due to the diminishing effects of the large portfolio of measures included in the assessment. This result does not dispute the findings from previous publications or the analysis performed in Chapter 2 which show energy efficiency to be a cost-effective GHG mitigation strategy. Rather, energy efficiency is not an endlessly cost-effective investment; consumers and policymakers should always consider the thermodynamic limits of a process and alternative GHG mitigation measures when evaluating these opportunities.

Since the portfolio of assessed measures includes an extensive list of energy-efficiency improvements, any unabated GHGs will need to be largely mitigated through a combination of unassessed service demand reduction, fuel switching, carbon capture, and carbon dioxide removal strategies. The costs and scalability of many of these measures are highly uncertain, indicating that the achievement of net-zero GHG emissions will be contingent on rapid technological development and radical changes to global energy systems and economies. Specific policy action beyond carbon taxation will be needed to reduce the gap between available GHG mitigation solutions and ambitions.

This study does not assess all possible measures involving end-use fuel switching or carbon capture, but it has been shown that, together, many of the measures available today represent only a fraction of the total GHG mitigation required to achieve net-zero. Framing the target of net-zero GHG emissions as a solvable optimization problem does not demonstrate this gap and understates the social and economic implications of complete decarbonization.

4 Unassessed GHG mitigation opportunities

This study does not consider all possible GHG mitigation measures in the analysis; this study focuses on measures for which specific cost and effect data has been developed through robust research. Distinguishing measures based on research prevalence has allowed us to compile a portfolio of measures that will likely remain necessary and relevant in any future policy or global economy scenarios [129]. Prominent opportunities for additional GHG mitigation involving pre-commercial technologies or novel strategies are discussed qualitatively below. Some of these measures have been assessed in single-sector analyses, but they should be included in future whole-system decarbonization assessments to create a more comprehensive portfolio of GHG mitigation pathways for Canada.

4.1 Carbon dioxide removal

Achieving NZE will require atmospheric CO_2 to be removed through natural or technological processes to offset residual emissions from hard-to-abate sectors like agriculture, aviation, and heavy freight transport [136]. In all the Intergovernmental Panel on Climate Change (IPCC) pathways that limit global warming to 1.5°C, carbon dioxide removal (CDR) is predicted to be on the order of 100-1000 $GtCO_2$ over the 21st century [136]. In these scenarios, CDR is achieved through either BECCS or uptake in the Agriculture, Forestry, and Other Land Use sector. CDR may also occur through DAC and storage methods, enhanced weathering, and ocean management, but these methods are not included in the IPCC pathways because of a lack of available research on their practical and economic feasibility [43, 137].

4.1.1 Direct air capture

DAC technology is a novel GHG mitigation strategy involving the physical separation of CO_2 from atmospheric air. Current technologies are at the pilot scale and rely on solid or aqueous sorbents to capture CO_2 [137]. If DAC becomes deployable at large scales and cost competitive with other GHG mitigation strategies, it may be an attractive investment for large industrial emitters hoping to avoid making radical operations changes to meet environmental targets. However, the scalability and costs of DAC are uncertain: information in literature suggests facilities can be developed which would be capable of capturing 1 $MtCO_2$ annually at a levelized cost of 94-232 USD/tCO_2 [35], but the 18 DAC plants currently in operation globally only capture

0.01 $MtCO_2$ annually altogether [138]. The IEA's net-zero pathway requires DAC to capture 60 $MtCO_2$ annually by 2030, indicating that significant support for DAC technologies is needed over the next 7 years [7].

4.1.2 Natural carbon sink enhancement

GHG emissions from anthropogenic activity are significantly offset by CO_2 uptake and sequestration in the world's forests and oceans [139]. Oceanic carbon fluxes are not currently accounted for under the IPCC reporting protocol, but since the ratification of the Kyoto Protocol, terrestrial carbon sinks have been deductible from national GHG inventories, allowing land management strategies to be recognized as valid climate change mitigation efforts [140]. Griscom et al. estimate that "natural climate solutions," including forest management, afforestation, reforestation, and legume planting, may contribute up to 20% of the global annual GHG mitigation required to achieve NZE by 2050 [10]. Furthermore, the authors estimate that nearly half of the total identified GHG mitigation potential is achievable for less than 100 USD/tCO_2e. Natural carbon sink enhancement strategies represent significant GHG mitigation potential and economic benefits and rely on proven currently available technologies, but the impacts of large-scale tree planting and land-use change on global food security [136], ecological stability [141], and the entire carbon cycle [43] may limit their effectiveness or lead to unintended consequences.

Canada is home to some of the world's largest forest areas, but CO_2 uptake in Canada's forestry sector is outweighed by emissions from the use and disposal of harvested wood products. Although forests affected by natural disturbances are not included in national GHG inventories, increasing rates of forest fires and insect infestations have contributed to significant GHG emissions (160 $MtCO_2e$ in 2019) and ecological damage in recent years [13]. In 2008, Kurz et al. predicted that rising rates of natural disturbances would limit the carbon sink potential of Canada's forests and the degree to which they could be managed for GHG mitigation purposes [44]. Nonetheless, tree planting has remained a flagship GHG mitigation strategy for Canada: in 2019, the federal government committed to planting 2 billion trees by 2030, which is a 40% annual increase in existing commercial tree planting levels [142]. If the maximum GHG mitigation potential of Canada's forests and croplands estimated by Griscom et al. is realized and all 184 measures included in this study's analysis are implemented to their maximum potential, it is estimated that an additional 259 $MtCO_2e$ will need to be mitigated by 2050 through measures involving unassessed CC and FSW technologies, as shown in Figure 33.

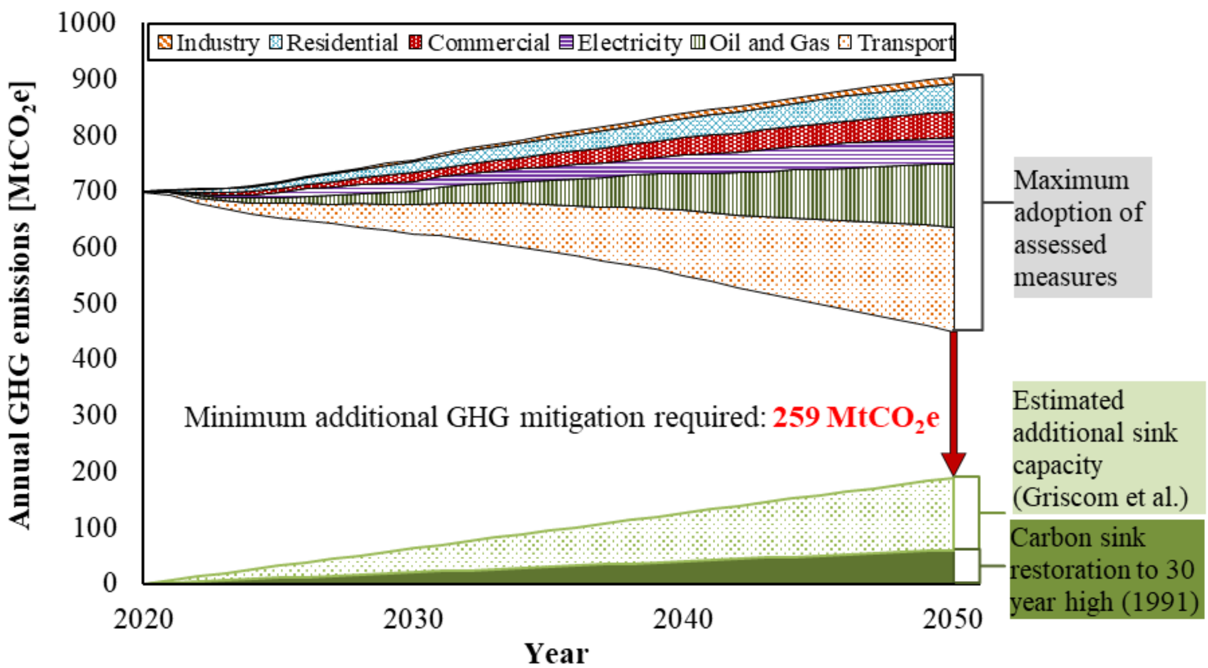

Figure 33: Minimum gap between identified measures and net-zero target

4.2 Use of hydrogen, biofuels, and synthetic fuels

Researchers have proposed various alternative fuels that may be used in place of traditional fossil fuels in NZE pathways, including pure or supplemental hydrogen, fuels derived from biomass or other biological matter, or fuels produced with captured CO_2. These fuels can be used in the transport and industrial sectors, potentially offering decarbonization solutions for otherwise hard-to-abate GHG emissions sources [7]. This study considers 27 FSW measures in the analysis. Hythane may also be used to reduce existing natural gas demand across all sectors as a transitory low-carbon fuel [143]. Additionally, under future carbon markets, producing methanol from captured CO_2 may be a more economically attractive GHG mitigation strategy than BECCS [109]. The commercial viability of both biofuels and synthetic fuels will be dependent on market interventions leading to reduced fossil fuel consumption and the development of CO_2 utilization economies [144, 145].

4.3 Industrial carbon capture and storage

CC is a requisite component of the IPCC's industrial decarbonization pathways, but its price has not dropped the way renewable energy technologies have [58]. Thus, the future commercial viability and deployment of industrial CC systems is uncertain. This study only considers CC measures for buildings and oil sands sectors, which together represent less than one-quarter of national GHG emissions. CC systems may also be implemented in conventional oil production, iron and steel, mineral smelting and refining, cement, and chemicals manufacturing sectors.

CO_2 can be captured from ammonia production plants relatively inexpensively because of its high concentration in steam methane reforming waste gas [77]. Irlam et al. estimate the abatement cost of CCS in the iron and steel and cement sectors to be approximately three (65 USD/tCO_2e) and four (103 USD/tCO_2e) times higher than the cost of CCS for chemical manufacturing (24 USD/tCO_2e) [30]. The economic viability of CC projects may be improved through the establishment of carbon utilization markets, cross-sectoral credit trading frameworks, or tax incentives [146]. Canada's large geophysical carbon storage capacity has spurred the development of CCS pilot programs [147], but the GHG mitigation potential of CC measures is ultimately contingent on capture technology improvement, cost reduction, the development of extensive CO_2 transport infrastructure, and, perhaps most significantly, the global commodification of CO_2 [148]. This study shows that the use of advanced fuels and CC will be necessary to achieve NZE, meaning that specific policies designed to accelerate technological innovation and facilitate international collaboration to improve the economic opportunities of CO_2 utilization are urgently needed.

5 Conclusion

The target of net-zero GHG emissions implies fundamental changes to all global energy systems and economies. Economic and population growth drives energy consumption [149] and fossil fuels have facilitated rapid development over the past 150 years and continue to underpin the modern global economy. System-wide decarbonization is thus a complex challenge affecting energy production and demand sectors alike and has been assessed by many researchers in terms of technical feasibility. However, decarbonization assessments based on integrated assessment models often overrepresent the availability of solutions that may be deployed towards achieving net-zero GHG emissions and neglect the gap between currently available technologies and future aspirations. Effective policies are urgently needed to support the transition necessary to meet this target, and policymakers require tools to accurately assess the net effects and costs of specific measures within an entire national energy system.

In this research, a novel approach was developed to assess action towards achieving net-zero GHG emissions. In other work, researchers have set net-zero GHG emissions as an end-state constraint for energy system models and have worked backwards to assess the total costs and milestones of solved pathways. These approaches are useful for illustrating what a net-zero energy system could theoretically look like, but they provide limited utility in developing specific, practical policy towards the achievement of this goal. The model used in this research was developed by integrating over a dozen bottom-up sectoral energy models with highly detailed energy transformation models and represents over 80% of national GHG emissions sources. 184 GHG mitigation measures were assessed for Canada's most energy-intensive sectors and shared assumptions describing effects on energy-use and associated economic costs. This approach ensures that the GHG mitigation potential of these measures is not overestimated and allows for measures to be prioritized based on GHG mitigation effectiveness and cost.

A framework was developed for specifically assessing the net effects of energy-efficiency measures across all major economic sectors. These measures are often considered to be "low-hanging fruit" GHG mitigation strategies due to their present availability and cost benefits. However, energy-efficiency improvements have thermodynamic limits that must be considered when evaluating their maximum GHG mitigation potential. This research addresses these limits through an accounting-based bottom-up energy systems model.

Energy-efficiency improvements represent opportunities for cost-effective GHG mitigation in most energy-intensive sectors; altogether, up to 8% of Alberta's baseline scenario GHG levels may be mitigated by 2050 through these measures, with most of this potential being available at negative marginal abatement cost under Canada's current federal carbon price schedule (as shown by Figure 34). These measures are readily available, and, considering consumer-facing energy costs and government rebates for residential and commercial investments, may be even more cost-effective than what has been reported in Section 2.3. However, these measures represent only a small fraction of the GHG mitigation required to achieve net-zero GHG emissions by 2050. When compared to fuel-switching and carbon capture measures, investments in energy efficiency may not necessarily be worthwhile or the most cost-effective decarbonization strategies available.

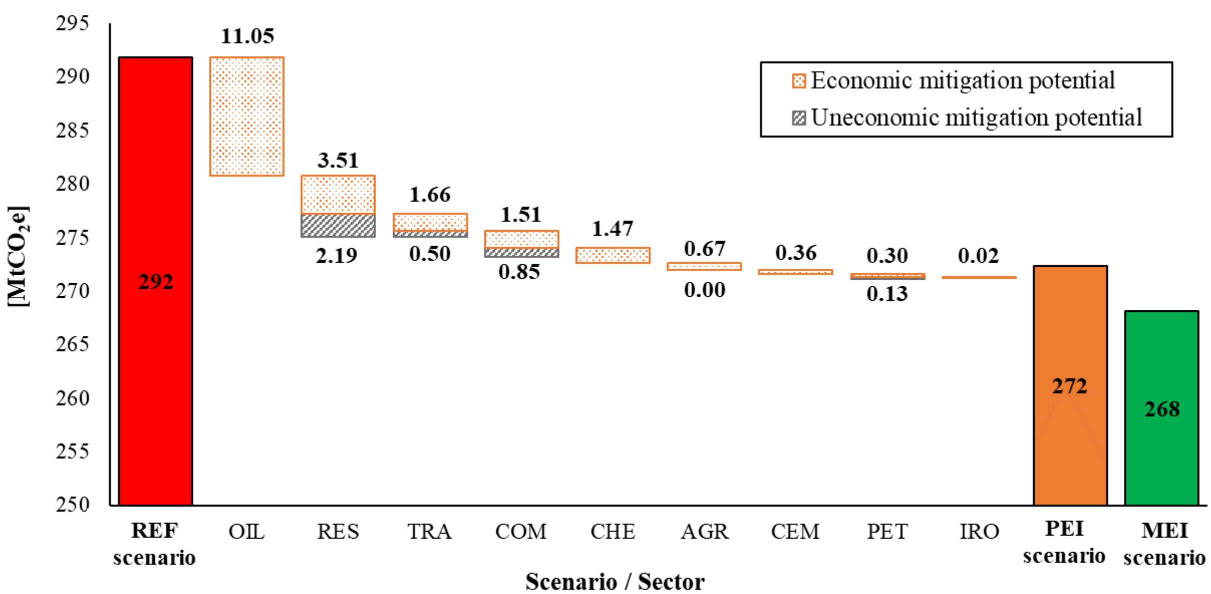

Figure 34: Annual GHG mitigation potential of energy-efficiency improvements in Alberta, 2050. Mitigation potentials shown for the oil sands (OIL), residential (RES), upstream energy transformation (TRA), commercial (COM), chemicals (CHE), agriculture (AGR), cement (CEM), petroleum refining (PET), and iron and steel (IRO) sectors. Resultant emissions shown for reference (REF), projected efficiency improvement (PEI), and maximum efficiency improvement (MEI) scenarios.

GHG levels may also be reduced through energy service demand reduction, fuel switching, and carbon capture measures. In Chapter 3, the research was built upon the work presented in Chapter 2 by adding these measure types to the assessment and applying the framework to seven Canadian regions. This approach allowed to distinguish between established and developing measures and use separate penetration models for the two categories.

The future energy demand, GHG emissions, and system-wide costs were projected for a reference scenario where no measures or energy-use improvements are realized, a "business as usual" scenario where measures are adopted according to technology-specific market share models, and a maximum GHG mitigation scenario where measures resulting in minimum system-wide emissions are fully realized. At the national scale, the portfolio of assessed measures may mitigate up to 50% of baseline GHGs by 2050, but it is expected that only 33% will be mitigated by technologies adopted under current policy. This study does not assess all currently available GHG mitigation measures, but this work nonetheless shows that there are significant gaps between GHG reduction ambitions and present-day solutions (as shown in Figure 35).

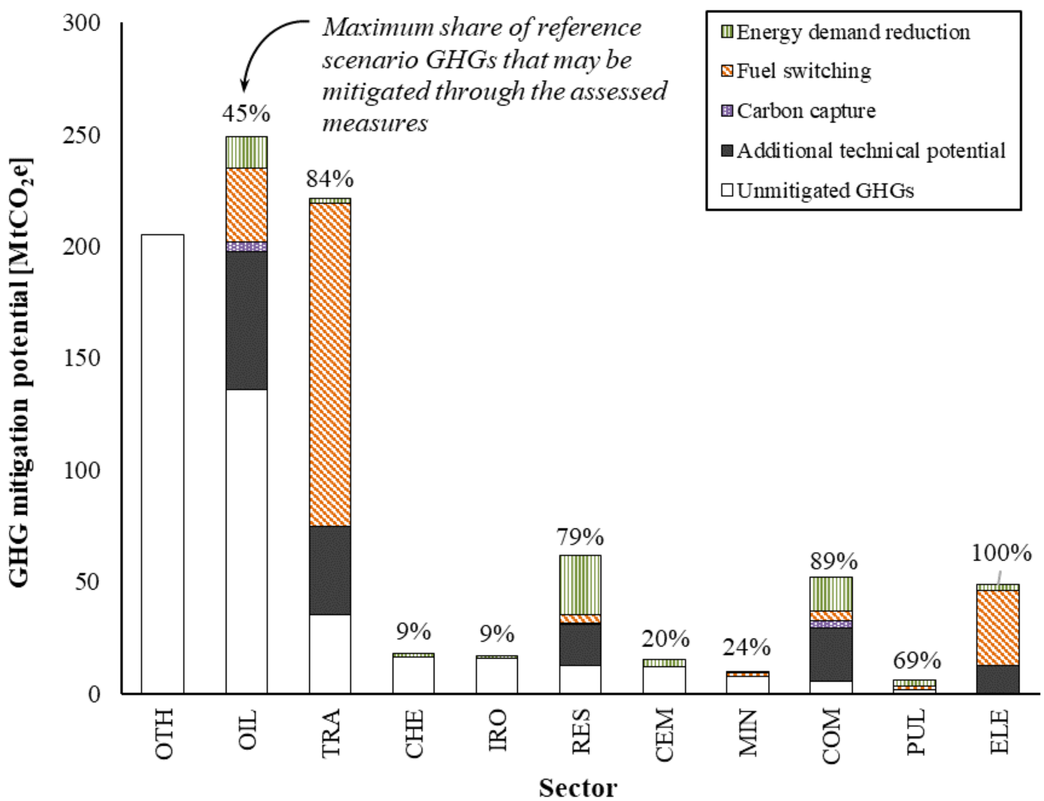

Figure 35: Sectoral gaps between assessed measures and full decarbonization. GHG mitigation potentials shown for other (OTH), oil sands (OIL), transportation (TRA), chemicals (CHE), iron and steel (IRO), residential (RES), cement (CEM), mineral mining (MIN), commercial (COM), pulp and paper (PUL), and electricity generation (ELE) sectors.

In this study, scenarios were developed representing the "business-as-usual" penetration of each measure type and found that fuel-switching measures were associated with the lowest weighted average marginal abatement cost (as shown in Figure 36). The relatively small group of carbon capture measures were found to have a lower weighted average marginal abatement cost than the extensive group of energy demand reduction measures for two main reasons: the carbon capture and utilization scenarios offer significant direct cost benefits to consumers, and the effectiveness of the assessed energy-efficiency measures diminishes as they are successively applied. From an energy consumer's perspective, individual energy-efficiency improvements may be more cost-effective than fuel-switching and carbon capture measures, despite these findings. In Chapter 2, marginal abatement costs were calculated for measures individually and, in most cases, were found to be cost-effective under the current federal carbon tax schedule. The weighted average marginal abatement costs reported in Chapter 3 highlight that the economic performance of an individual measure may change when it is applied alongside other measures, and that these effects must be considered in any decarbonization analysis.

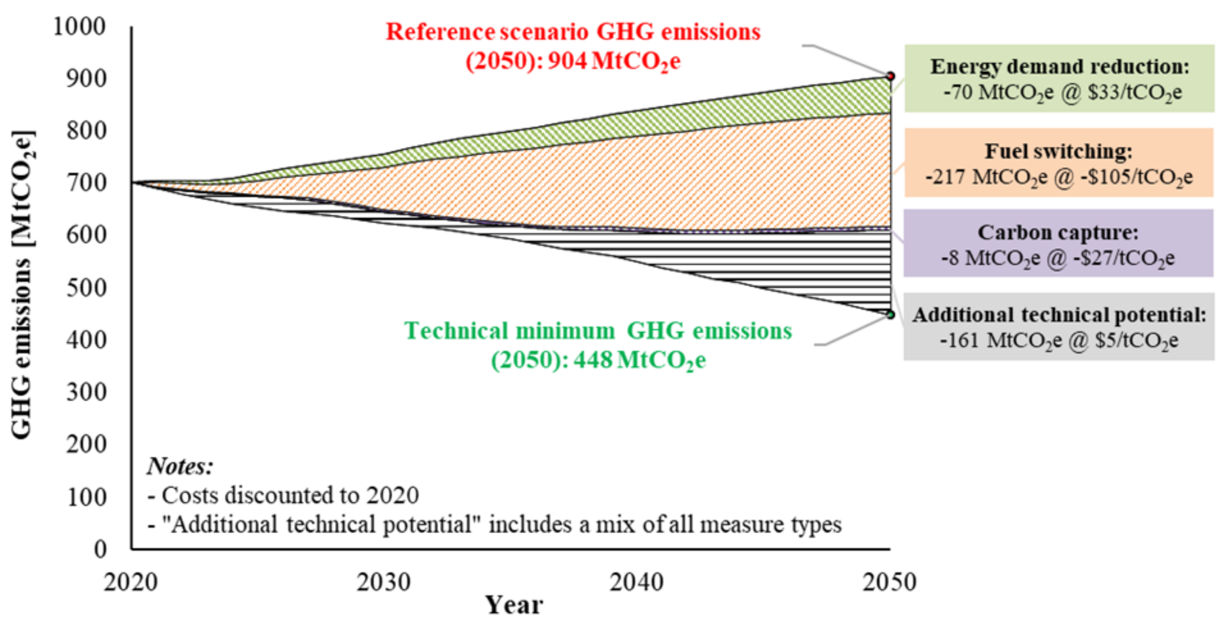

Figure 36: Annual GHG mitigation potential and weighted average MAC of assessed measure types

Achieving NZE will likely rely on the development and commercialization of novel fuel-switching, carbon capture, and direct air capture technologies as well as changes in sectoral activity relative to business-as-usual growth. Natural carbon sinks can also be enhanced to reduce the national annual GHG flux, but Canada's forests have increasingly become a source of GHG emissions in recent years. NZE remains an unprecedented challenge, but this work clarifies what achieving this target will require by establishing an action-oriented framework that can be used to identify focus areas and technology gaps across various sectors within a region.

NZE is a complex challenge requiring more than technological solutions; accurate, credible net-zero pathway development will require interdisciplinary analysis of energy systems, regional and global economies, and socio-economic responses to government interventions and climate change events. This work indicates there is a need for collaborative work between energy systems researchers, economists, and political scientists, and provides a tool by which specific priorities between these groups can be established.

5.1 Recommendations for future research

The framework described in Chapter 3 can be used in future decarbonization assessments as new technologies become commercially available, but there are several areas in which the present work could be improved and expanded on using current data and knowledge.

1. **Improved representation of energy resources:** The model used in this work can calculate upstream energy use, emissions, and costs based on domestic energy demand, inter-regional imports and exports, and international exports, but that functionality was not fully enabled for this work. In the future, resource exports should be calculated for all regions and defined for specific export regions. This approach would allow for the effects of domestic environmental policy to be more accurately captured but would also increase the computational demands of the model.
2. **Modelling of energy storage systems:** Energy storage systems such as utility-scale batteries, hydrogen, and pumped hydro can alleviate some of the challenges posed by intermittent renewable electricity generation and may be attractive investments in Alberta, Saskatchewan, and Atlantic Canada because of the high dependence on fossil fuels, limited hydroelectric resource availability, and historical reluctance to nuclear energy development in these regions. This study does not consider the economic potential of utility-scale energy storage systems in the work. These strategies should be modelled in future work so that

policymakers and electricity system operators have a better understanding of the benefits and challenges of different electricity grid configurations.

3. **Sector-specific application:** The approach developed in this work can be applied in single-sector analyses so that specific policy and costs can be better understood. The broad environmental policy considered in this work represents only a small share of available policy tools that could affect emissions within a sector. In future work, sector-specific policies and costs should included in single sector decarbonization analysis so that plant operators and owners might better understand the true costs of environmental action or inaction. Previous single-sector analyses have not always considered the mutual exclusivity of some measures nor the diminishing effects and co-benefits of simultaneously applied measures. The framework developed for this thesis addresses these limitations.
4. **Feedback and equilibrium modelling:** The model described in this work features a high level of technological specificity but is limited in its ability to represent transformative changes to economic and consumer behaviour. Feedback modelling approaches from integrated assessment models can integrated with this model to represent equilibrium between energy supply and demand sectors, providing a framework for assessing optimized global net-zero scenarios.

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Appendix A: Sectoral demand trees

Industrial sector energy-efficiency measures are assumed to affect all end-use technologies within the same demand area. Energy-efficiency measures for non-industrial sectors are modelled as technology-specific replacement of standard technologies with alternatives. Common symbols used in all demand tree diagrams are shown below.

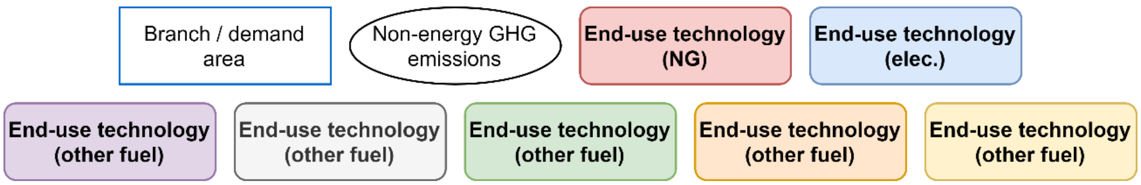

Figure 37: Demand tree legend for all sectors

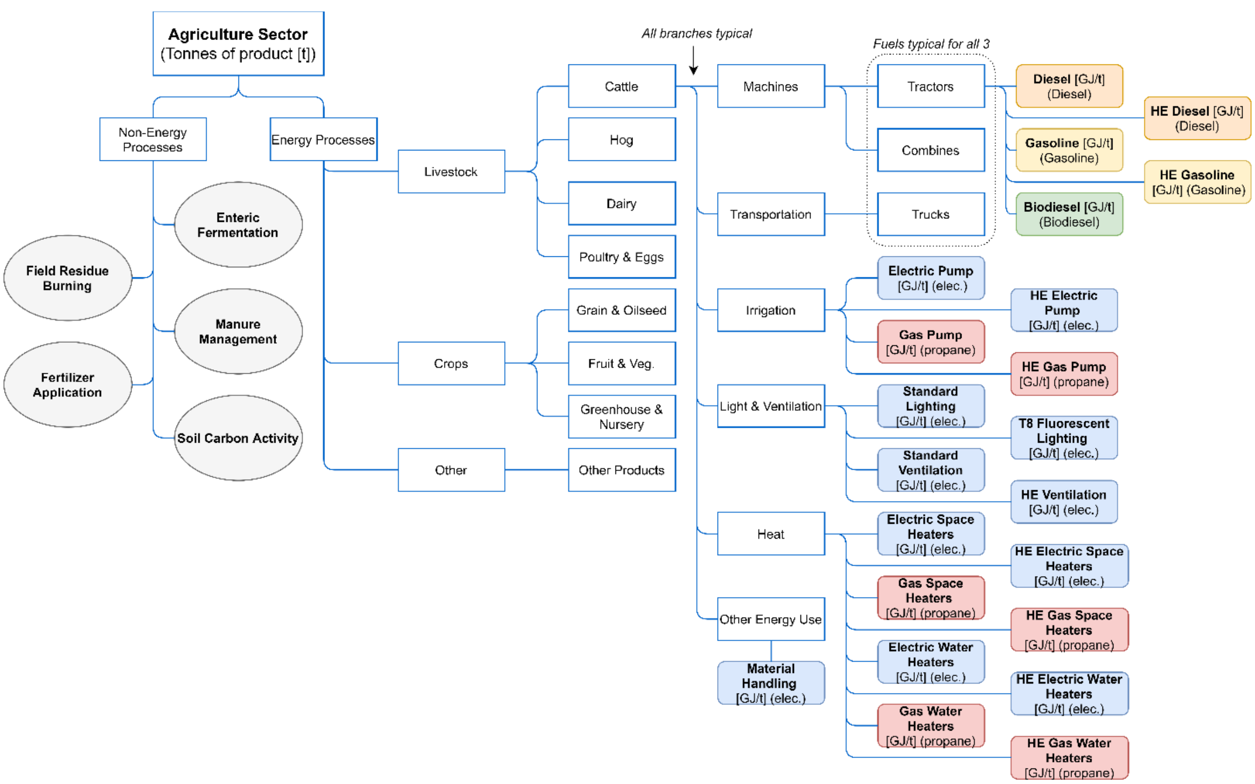

Figure 38: Agriculture sector demand tree

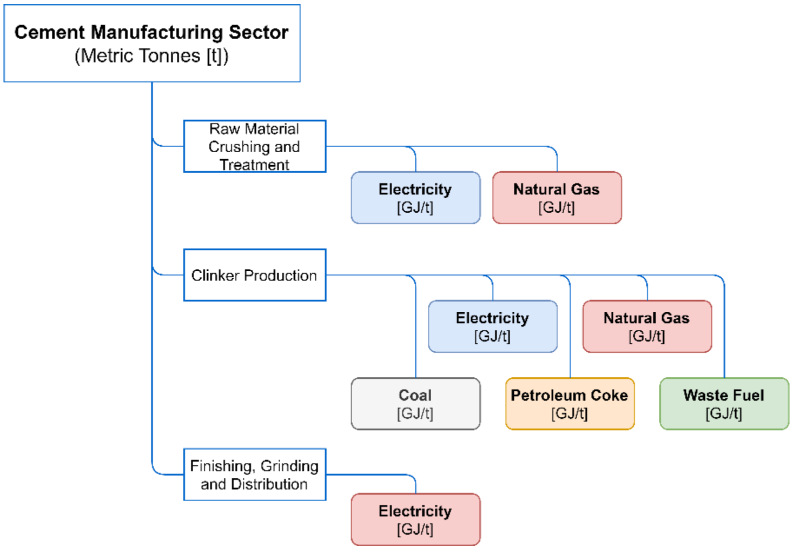

Figure 39: Cement sector demand tree

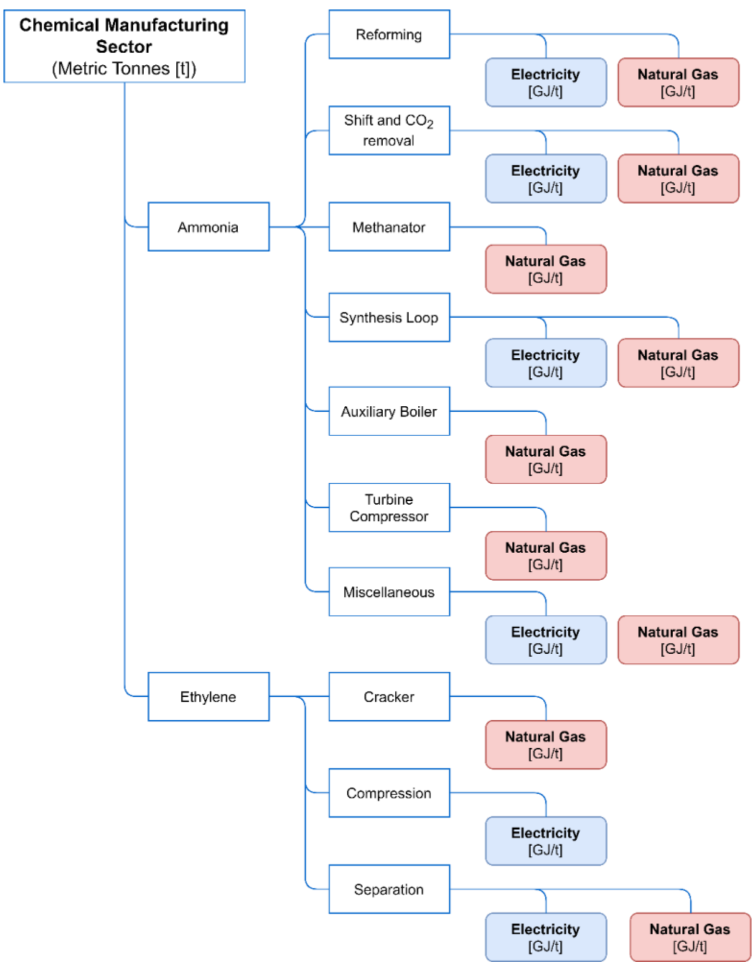

Figure 40: Chemicals sector demand tree

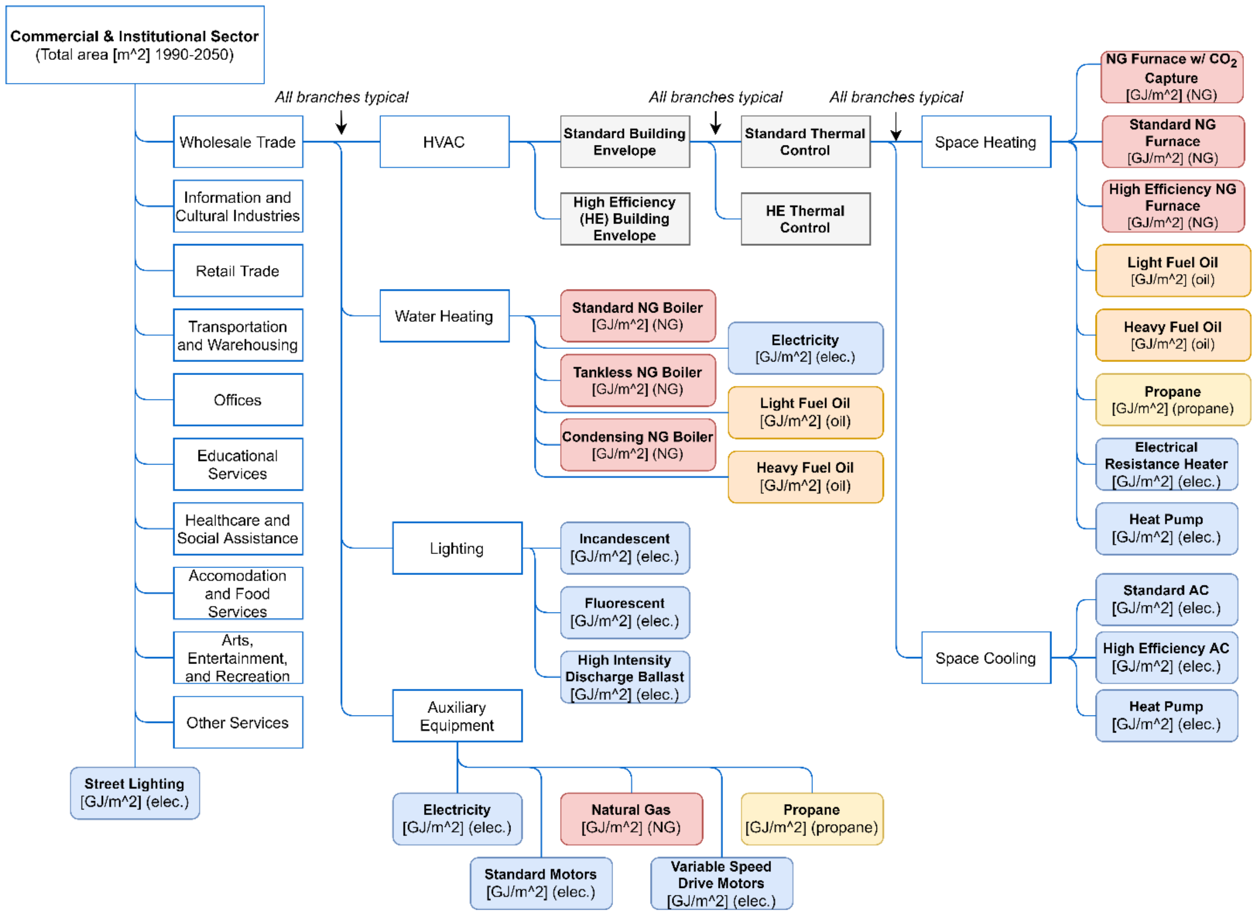

Figure 41: Commercial and institutional sector demand tree

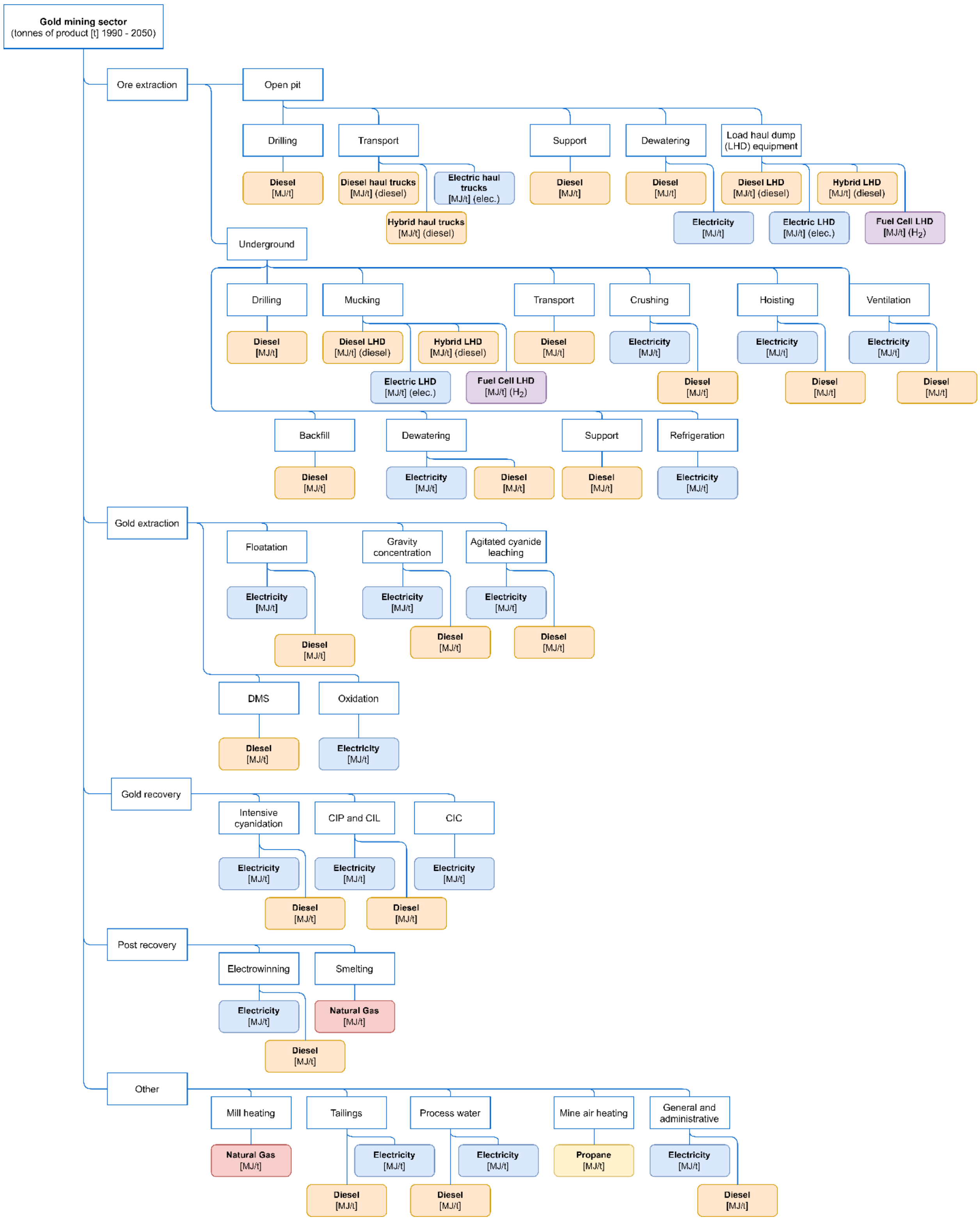

Figure 42: Gold mining sector demand tree

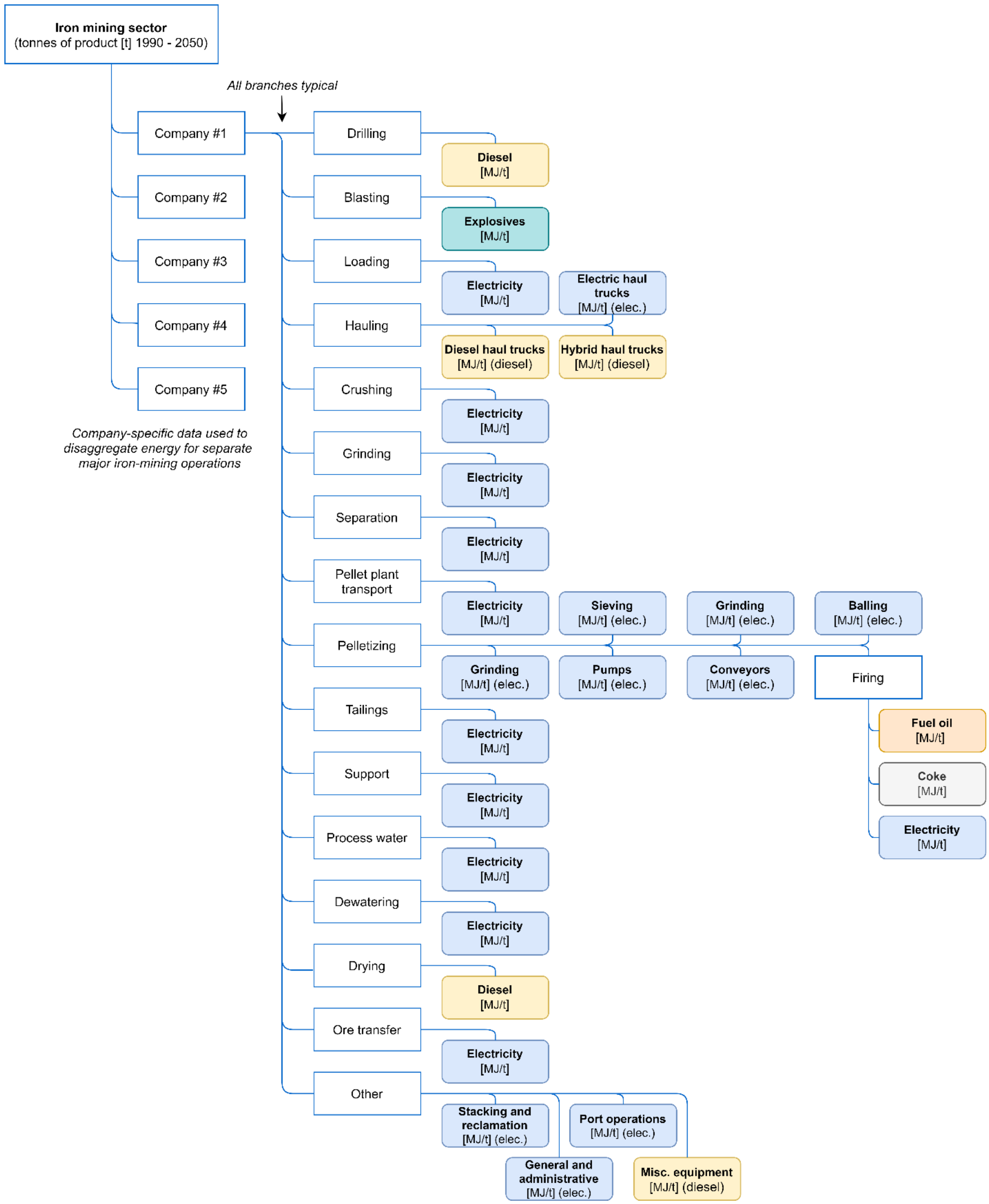

Figure 43: Iron mining sector demand tree

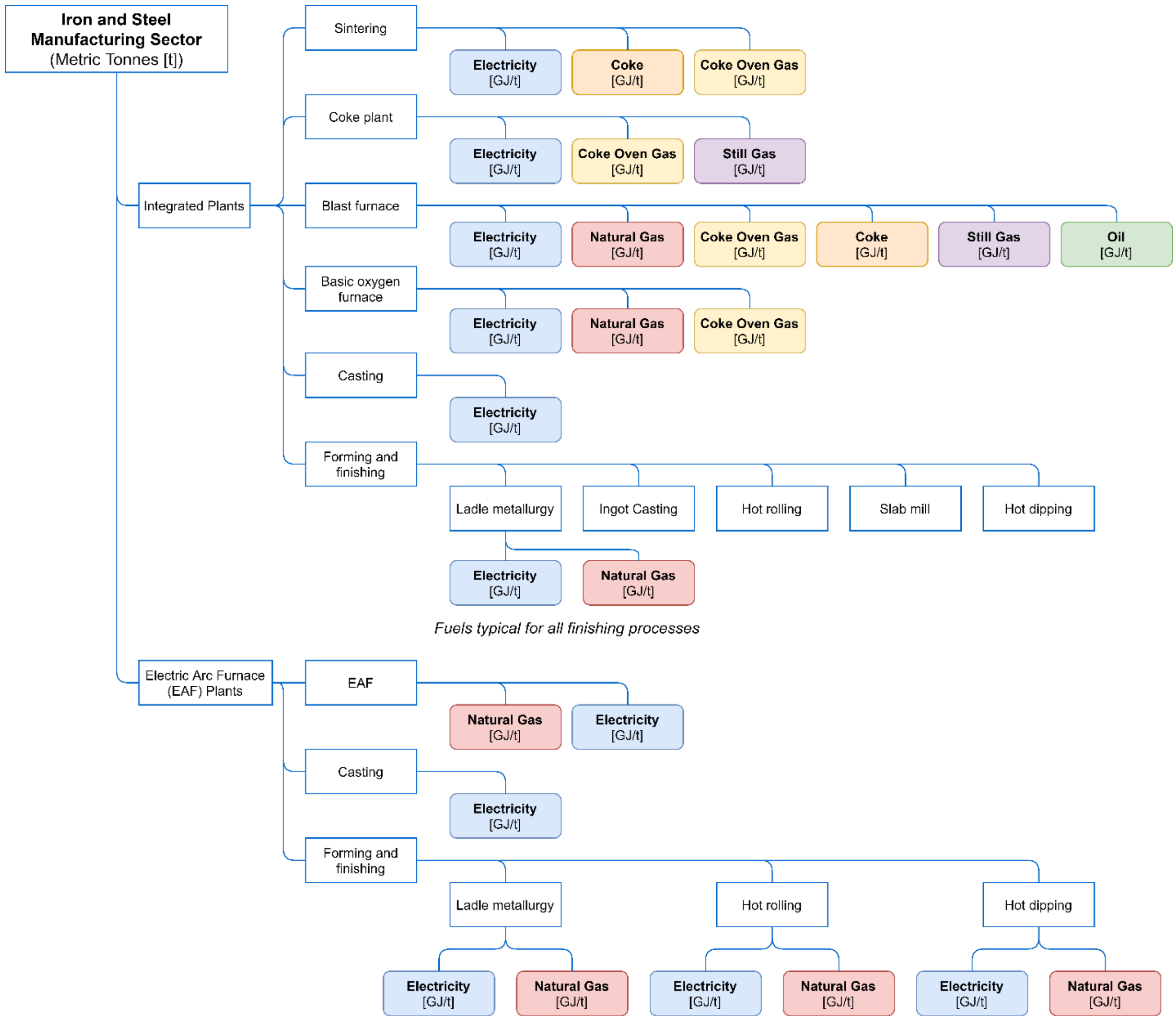

Figure 44: Iron and steel sector demand tree

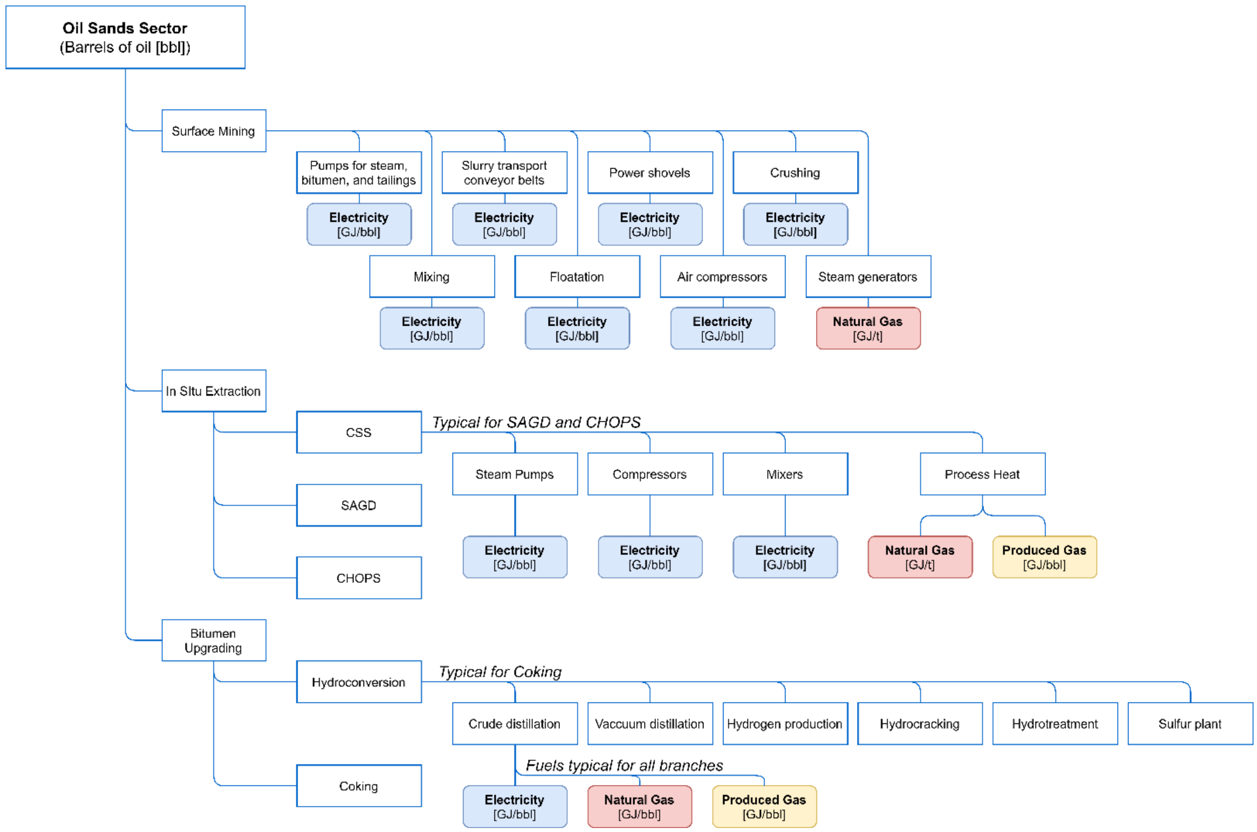

Figure 45: Oil sands sector demand tree

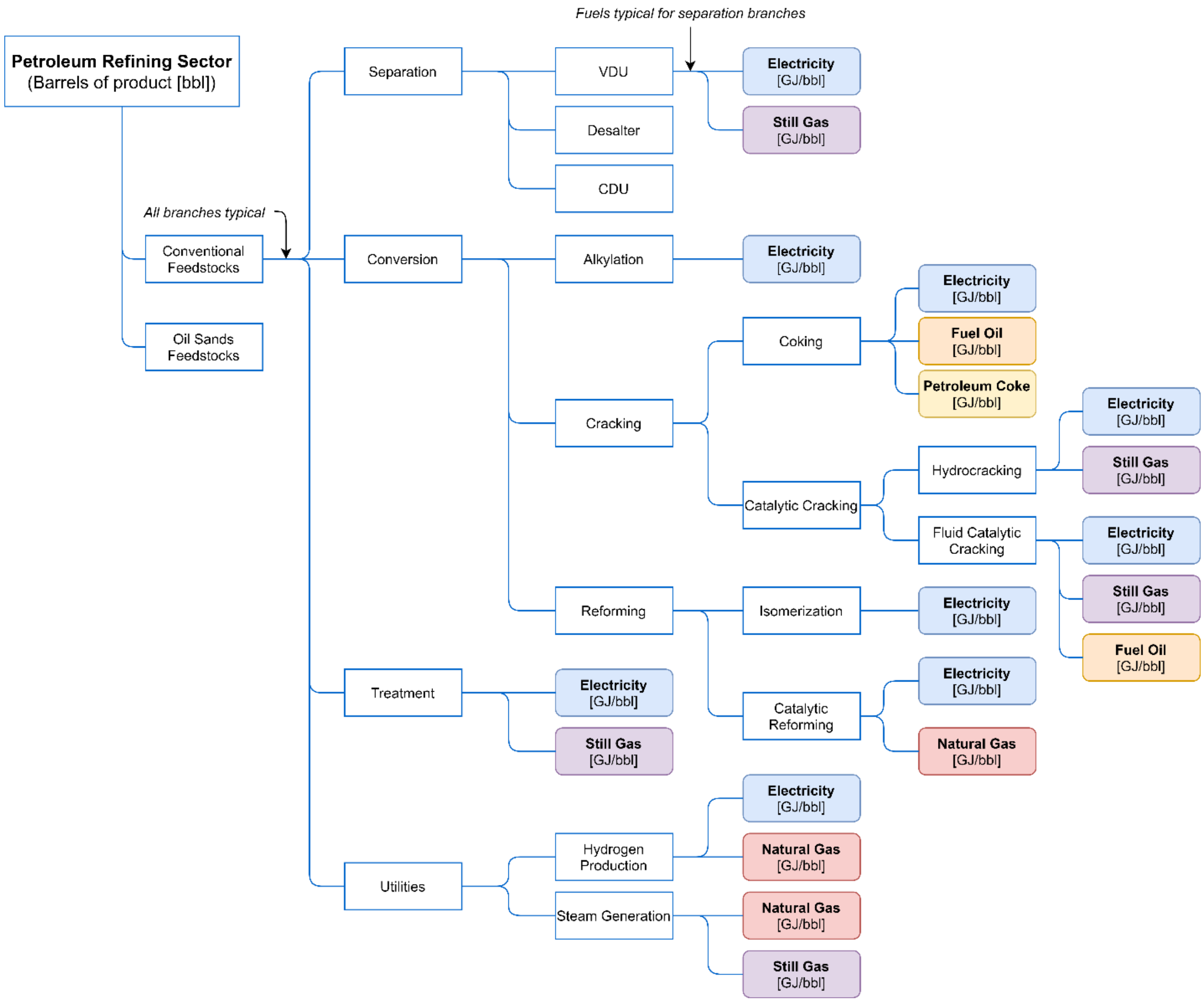

Figure 46: Petroleum refining sector demand tree

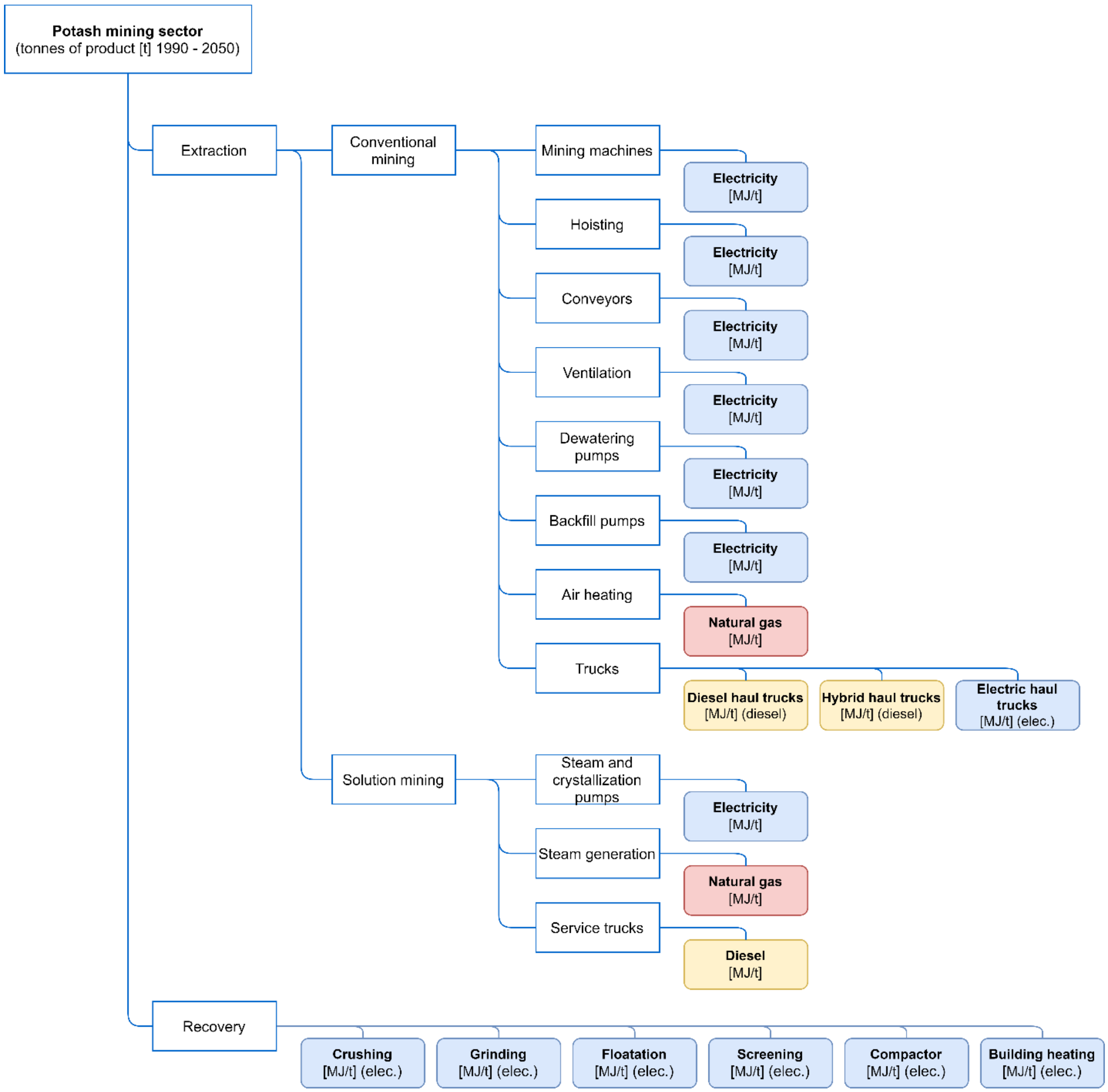

Figure 47: Potash mining sector demand tree

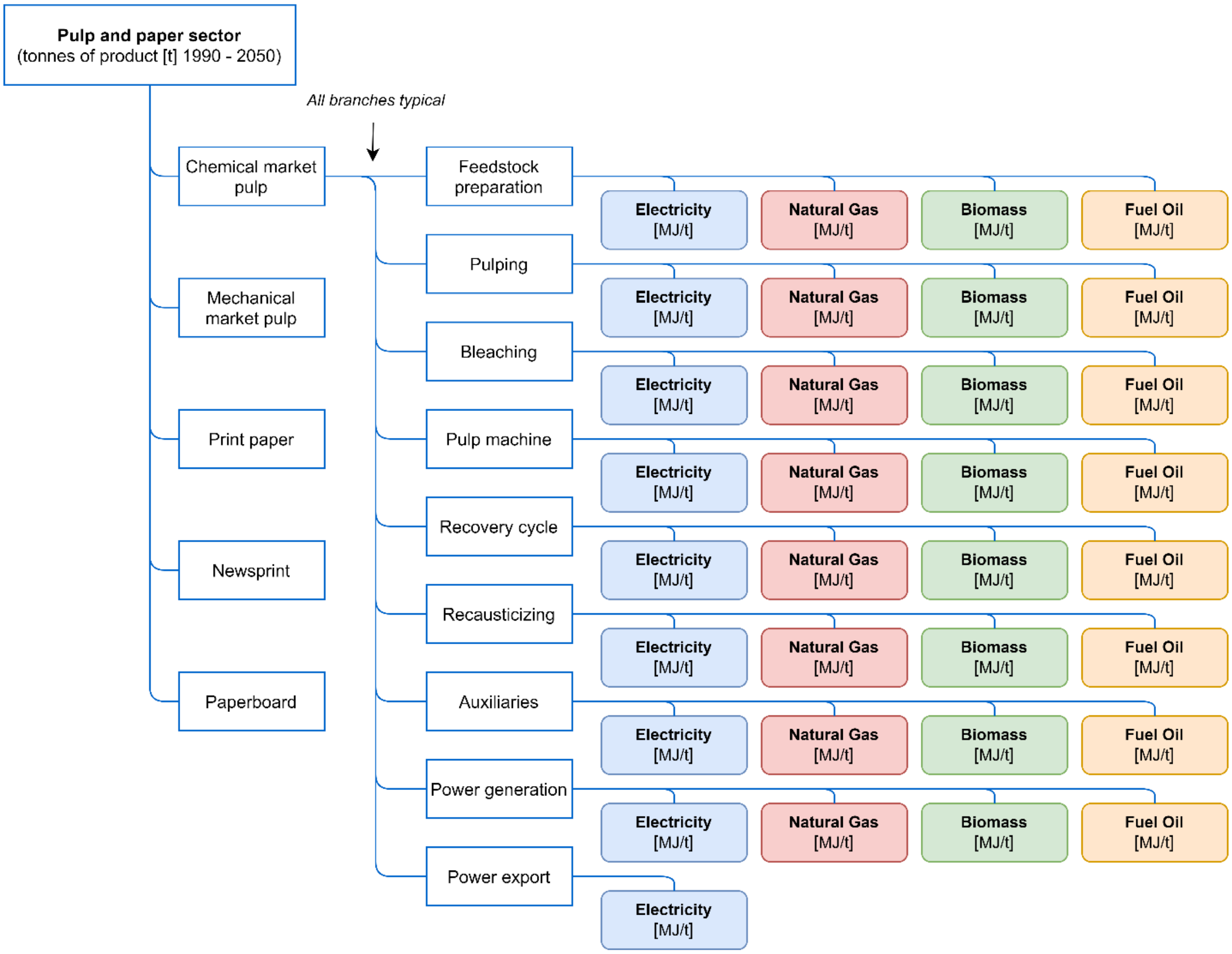

Figure 48: Pulp and paper sector demand tree

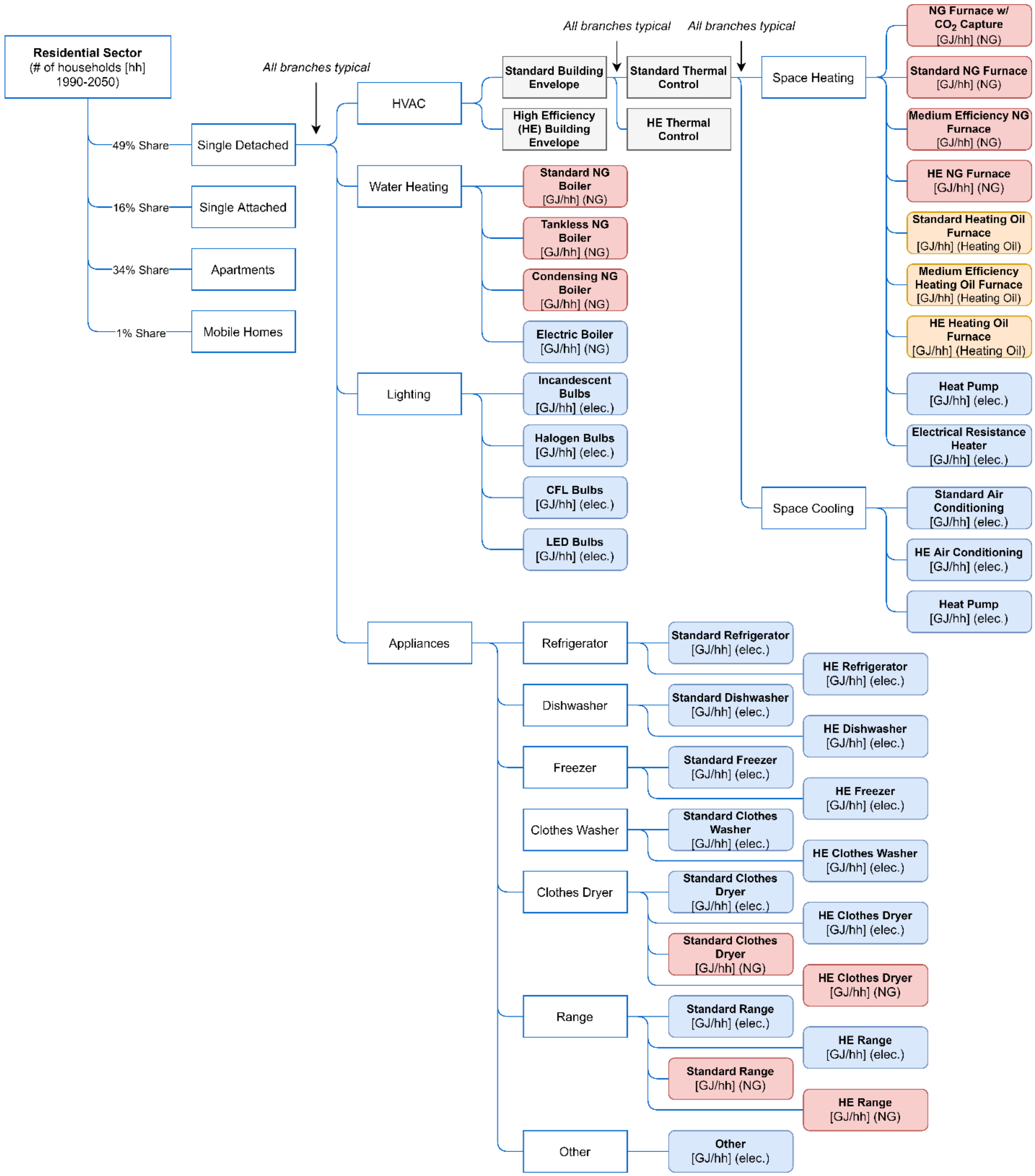

Figure 49: Residential sector demand tree

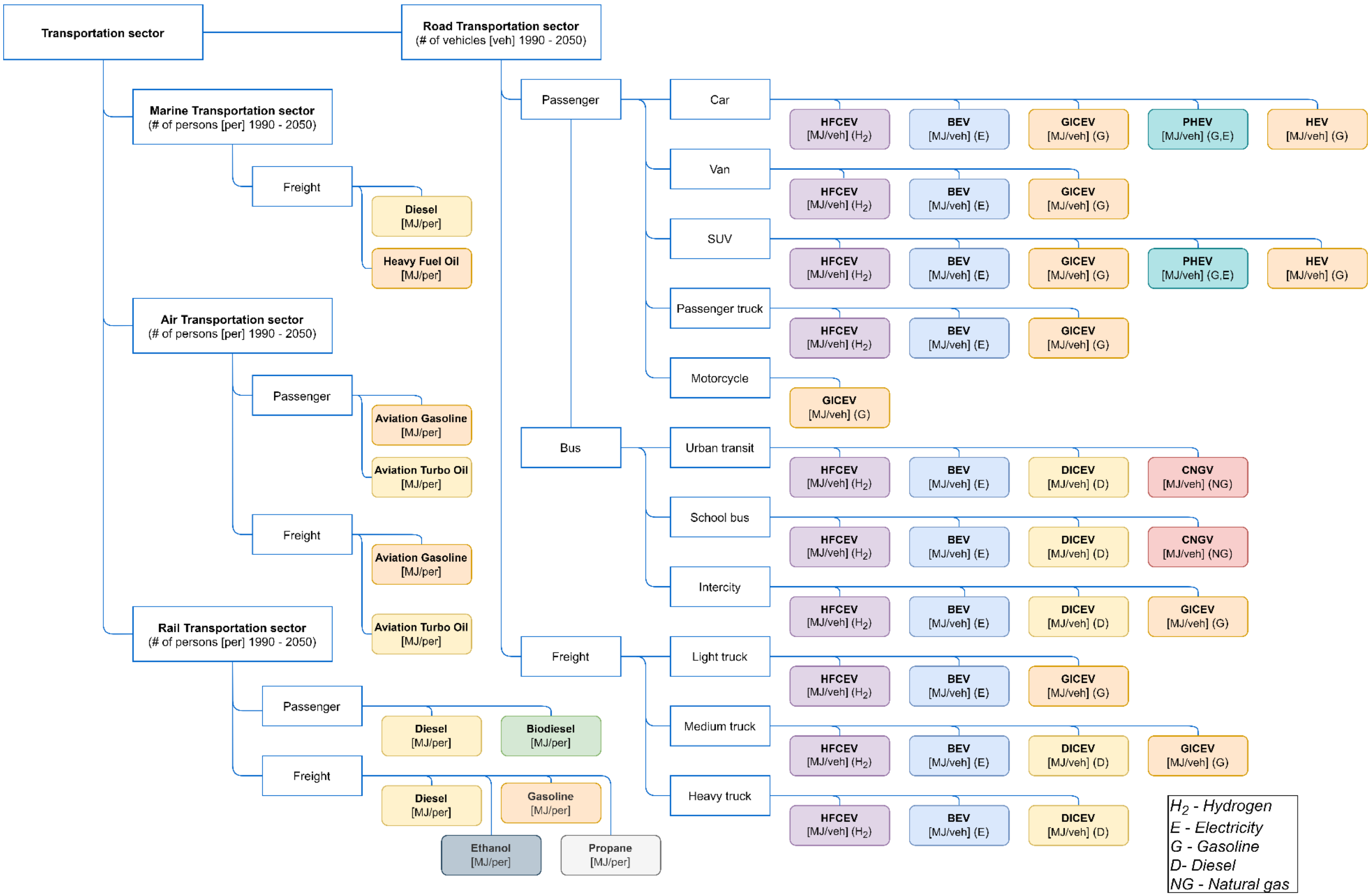

Figure 50: Transportation sector demand tree

Appendix B: Buildings sector energy disaggregation equations

The following sections present key equations used to disaggregate energy use in the residential and commercial sectors to the end-use device level. Key parameters and symbols used throughout the modelling process are shown below:

B.1 Definition of symbols

Variable	Symbol
Activity share	f
Activity level	N
Energy intensity	EI
Energy intensity ratio	λ
Technology efficiency	η
Sectoral energy demand	E
Specific energy demand	e
HVAC efficiency factor	μ

Subscript	Symbol
Average	avg
Technology index	$i \in \{1,2,3,\ldots n\}$
Building category index	$j \in \{A, B, C, \ldots m\}$
High efficiency	HE
Efficient building envelope	BE
Efficient control system	CN
Total	tot
Input	in
Output	out
Standard	std
Space heating	SH
Space cooling	SC
Electricity	$elec$
Natural gas	NG
Heating oil	oil
Heat pump	HP
Lighting	lig
Water heating	WH

B.2 Residential sector

B.2.1 Residential: HVAC

Energy demand in the Canadian residential sector is dominated by space-heating technologies including standard, medium, and high-efficiency heating oil and natural gas furnaces and boilers, electrical resistance heaters, heat pumps, and wood-burning or combined-fuel systems. To calculate the energy intensities of each technology, the average efficiency $\eta_{SH,j,avg}$ for all heating technologies in a single building type j was first calculated.

For buildings with standard building envelopes and control systems, the average efficiency for all heating technologies is defined as the ratio of the total energy delivered to residences as heat ($E_{SH,j,out,std}$) to the total amount of energy consumed for space-heating ($E_{SH,j,in,std}$):

$$\eta_{SH,j,avg} = \frac{E_{SH,j,out,std}}{E_{SH,j,in,std}} \tag{B.1}$$

Here, $E_{SH,j,total,std}$ can be written as the product of the number of buildings with standard building envelopes and control systems $N_{SH,j,std}$ and standard energy intensity $e_{SH,j,in,std}$:

$$E_{SH,j,in,std} = N_{SH,j,std} e_{SH,j,in,std} \tag{B.2}$$

The total amount of energy delivered as heat ($E_{SH,j,out,std}$) can be written as the product of total number of standard buildings ($N_{SH,j,std}$) and the heat required per building ($e_{SH,j,out}$):

$$E_{SH,j,out,std} = N_{SH,j,std}\, e_{SH,j,out} \tag{B.3}$$

The total energy consumed for space heating in standard buildings can be separated by technology accordingly:

$$E_{SH,j,in,std} = N_{SH,j,1} \frac{e_{SH,j,out}}{\eta_{SH,j,1}} + N_{SH,j,2} \frac{e_{SH,j,out}}{\eta_{SH,j,2}} \ldots + N_{SH,j,n} \frac{e_{SH,j,out}}{\eta_{SH,j,n}} \tag{B.4}$$

where $\eta_{SH,i}$ and $N_{SH,j,i}$ are the efficiency of and number of buildings of category j possessing technology i respectively. By writing numbers of households $N_{SH,j,i}$ as products of market share fractions $f_{SH,j,i}$ and total number of standard buildings $N_{SH,j,std}$, Equations (B.2 and (B.28) can be substituted into equation (B.1, which gives:

$$\eta_{SH,j,avg} = \frac{N_{SH,j,std}\, e_{SH,j,out}}{N_{SH,j,std} f_{SH,j,1} \frac{e_{SH,j,out}}{\eta_{SH,j,1}} + N_{SH,j,std} f_{SH,j,2} \frac{e_{SH,j,out}}{\eta_{SH,j,2}} \ldots + N_{SH,j,std} f_{SH,j,n} \frac{e_{SH,j,out}}{\eta_{SH,j,n}}}$$

$$= \frac{1}{\frac{f_{SH,j,1}}{\eta_{SH,j,1}} + \frac{f_{SH,j,2}}{\eta_{SH,j,2}} \ldots + \frac{f_{SH,j,n}}{\eta_{SH,j,n}}} \tag{B.5}$$

We modelled the energy-use improvements associated with high-efficiency building envelopes and thermal control systems by considering four separate categories of HVAC energy demand: standard building envelope with standard control (std), high-efficiency building envelope with standard control (BE), standard building envelope with high-efficiency control (CN), and high-efficiency building envelop with high-efficiency control ($both$). For both building envelops and control systems, high efficiency alternatives were assumed to use fractions of the energy used by the standard technologies, represented by λ_{BE} and λ_{CN} respectively:

$$\lambda_i = \frac{EI_i}{EI_{std}} \tag{B.6}$$

Using these fractions, the total energy used for space heating can be broken down into four categories accordingly:

$$\begin{aligned} E_{SH,j,tot} &= E_{SH,j,in,std} + E_{SH,j,in,BE} + E_{SH,j,in,CN} + E_{SH,j,in,both} \\ &= N_{std,j} e_{SH,j,in,std} + N_{BE,j} e_{SH,j,in,BE} + N_{CN,j} e_{SH,j,in,CN} + N_{BE\&CN,j} e_{SH,j,in,BE\&CN} \\ &= N_{tot} e_{SH,A,in,std} (f_{std} + f_{BE}\lambda_{BE} + f_{CN}\lambda_{CN} + f_{both}\lambda_{BE}\lambda_{CN}) \\ &= N_{tot,j} e_{SH,j,in,std} \begin{bmatrix} (1-f_{BE})(1-f_{CN}) + (1-f_{CN}) f_{BE}\lambda_{BE} \\ +(1-f_{BE}) f_{CN}\lambda_{CN} + f_{BE} f_{CN}\lambda_{BE}\lambda_{CN} \end{bmatrix} \end{aligned} \tag{B.7}$$

The standard energy intensity (i.e., for buildings with standard building envelopes and control systems) can now be written as:

$$e_{SH,j,in,std} = \frac{E_{SH,j,tot}}{N_{tot,j}[(1-f_{BE})(1-f_{CN}) + (1-f_{CN}) f_{BE}\lambda_{BE} + (1-f_{BE}) f_{CN}\lambda_{CN} + f_{BE} f_{CN}\lambda_{BE}\lambda_{CN}]} \tag{B.8}$$

Expressions (B.1), (B.2), and (B.8) and can be used to write the heating requirement per building in terms of efficiencies and shares of different space heating technologies, building envelope types, and control systems:

$$e_{SH,j,out} = \frac{E_{SH,j,out,std}}{N_{SH,j,std}} = \frac{E_{SH,j,in,std}\eta_{SH,j,avg}}{N_{SH,j,std}} = e_{SH,j,in,std}\eta_{SH,j,avg}$$
$$= \frac{E_{SH,j,tot}\ \eta_{SH,j,avg}}{N_{SH,j,tot}[(1-f_{BE})(1-f_{CN})+(1-f_{CN})f_{BE}\lambda_{BE}+(1-f_{BE})f_{CN}\lambda_{CN}+f_{BE}f_{CN}\lambda_{BE}\lambda_{CN}]} \tag{B.9}$$

Energy intensities for different technologies and building types can be calculated using assumed efficiency values and building envelope and/or control system factors as shown below:

$$EI_{SH,j,i} = \frac{e_{SH,j,out}}{\eta_{SH,j,i}}\lambda_{SH,j,i} \tag{B.10}$$

Energy used for space cooling was disaggregated in a similar fashion. Activity shares for households with air-conditioning (AC) provided by Natural Resources Canada were used in conjunction with assumed shares of high-efficiency and standard AC units and an assumed energy intensity improvement factor to calculate a per-household AC energy intensity for all four residence types. Space cooling technology energy intensities are affected by building envelope and control system types, so the relative EI fractions associated with these factors must be considered as well.

The sectoral effects of HE building envelopes and HE control systems can be represented by first defining the product shown in equation (B.7) as a single factor, μ:

$$\mu = (1 - f_{BE})(1 - f_{CN}) + (1 - f_{CN})f_{BE}\lambda_{BE} + (1 - f_{BE})f_{CN}\lambda_{CN} + f_{BE}f_{CN}\lambda_{BE}\lambda_{CN} \tag{B.11}$$

As was done for space-heating technologies, the standard per-household space cooling energy intensity for a single residence type j can be calculated by dividing the total energy consumed for space cooling by the number of houses with space cooling technologies and applying factors accounting for market shares of different end-use technologies, control systems, and building envelopes accordingly:

$$EI_{SC,j,std} = \frac{E_{SC,j,tot}}{N_{SC,j}\mu(f_{SC,1}\lambda_{SC,1} + f_{SC,2}\lambda_{SC,2} + \dots f_{SC,n}\lambda_{SC,n})} \quad \text{(B.12)}$$

The space cooling energy intensity for end-use technology i for building type j can now be expressed as a product of the standard value shown above and the assumed energy intensity ratio, $\lambda_{SC,i}$:

$$EI_{SC,j,i} = \lambda_{SC,i}\, EI_{SC,j,std} \quad \text{(B.13)}$$

B.2.2 Residential: water heating

Energy used for residential water heating was modelled using a process similar to that used for residential HVAC. In this analysis, electric boilers, natural gas boilers, and heating oil boilers are considered to be standard technologies and condensing and tankless boilers are considered as alternatives for both standard natural gas and heating oil boilers. Annual end-use technology shares were assumed based on fuel-type shares and relative shares of high efficiency alternatives.

For each building type, average water heating efficiency was first calculated using assumed technology shares and respective water heating efficiencies:

$$\eta_{WH,j,avg} = \frac{1}{\frac{f_{SH,j,1}}{\eta_{SH,j,1}} + \frac{f_{SH,j,2}}{\eta_{SH,j,2}} \dots + \frac{f_{SH,j,n}}{\eta_{SH,j,n}}} \quad \text{(B.14)}$$

Annual energy output by water heating technologies was calculated on a per-household basis using the calculated average efficiency:

$$e_{WH,j,out} = \frac{E_{WH,j,out}}{N_{WH,j}} = \frac{E_{WH,j,in}\eta_{WH,j,avg}}{N_{WH,j}} \quad \text{(B.15)}$$

The energy intensity of end-use technology i can be simply expressed as a function of the annual energy output defined above and the assumed efficiency of the technology:

$$EI_{WH,j,i} = \frac{e_{WH,j,out}}{\eta_{WH,i}} \tag{B.16}$$

B.2.3 Residential: lighting

Total lighting energy demand data is provided by Natural Resources Canada for all building categories of both the residential and commercial and institutional sectors. In this analysis, incandescent bulbs are considered as a standard technology (1) and CFL, LED, and halogen bulbs as high efficiency alternatives (2,3,4 respectively). Lighting energy consumption was modelled using this data and assumed energy efficiency ratios and market share values (adapted from [140]).

The total amount of energy used for lighting all buildings of type j can be written as a sum of energies consumed by separate technologies accordingly:

$$\begin{aligned} E_{lig,j,tot} = {} & N_{lig,j,1}EI_{lig,j,1} + N_{lig,j,2}EI_{lig,j,2} + N_{lig,j,3}EI_{lig,j,3} \\ & + N_{lig,j,4}EI_{lig,j,4} \end{aligned} \tag{B.17}$$

The above expression can be rewritten in terms of technology shares and relative EI ratios with respect to the standard technology, which can be rearranged to give the standard energy intensity for incandescent lighting:

$$EI_{lig,j,1} = \frac{E_{lig,j,tot}}{N_{j,tot}(f_{lig,1} + f_{lig,2}\lambda_{lig,2} + f_{lig,3}\lambda_{lig,3} + f_{lig,4}\lambda_{lig,4})} \tag{B.18}$$

Energy intensities for high-efficiency alternatives can be calculated by multiplying this value by respective energy intensity ratios:

$$EI_{lig,j,2} = \lambda_{lig,2}EI_{lig,j,1} \tag{B.19}$$

B.2.4 Residential: appliances

High efficiency and standard versions of all major appliances were included as end-use technologies in the model. Energy intensities of standard appliances were calculated on a per-appliance basis using sector-wide demand data, sector-wide appliance stocks data, and assumed high-efficiency shares (adapted from [141]) and energy intensity ratios. For example, the energy intensity of a standard efficiency appliance i can be calculated as:

$$EI_{app,i,std} = \frac{E_{app,i,tot}}{N_{app,i,tot}(f_{app,i,std} + f_{app,i,HE}\lambda_{app,i})} \tag{B.20}$$

The energy intensity of the high-efficiency alternative can be expressed as a product of the standard energy intensity and the assumed energy intensity ratio:

$$EI_{app,i,he} = \lambda_{app,i}\, EI_{app,i,std} \tag{B.21}$$

B.3 Commercial/institutional sector

B.3.1 Commercial/institutional: HVAC

HVAC energy used in the commercial and institutional sector was disaggregated using a process similar to that employed for the residential sector. The commercial and institutional sector encompasses a wide variety of building types, sizes, and vintages, and is thus less straightforward to characterize with publicly available data. As such, a more generalized approach was used here than was for residential HVAC. Instead of using explicit assumed efficiency values for different end-use technologies, relative energy intensity fractions for high efficiency alternative technologies were assumed and end-use technology energy intensities for each building type were calculated separately. End-use technology intensities are assumed to be affected by building envelope and control type, so the HVAC demand modification factor μ used in residential HVAC energy disaggregation was used here as well.

Space-heating fuels used in commercial and institutional HVAC include natural gas, electricity, heating oil, propane, coal, and kerosene. Standard energy intensities per unit area for each fuel type were calculated using total energy demand data from Natural Resources Canada, assumed shares of standard and high-efficiency technologies, and assumed relative energy intensity fractions. For example, the standard energy intensity for natural gas furnaces in building type j was calculated accordingly:

$$EI_{SH,j,NG,std} = \frac{E_{SH,j,NG,tot}}{A_{j,tot}\mu(f_{SH,NG,std}\lambda_{SH,NG,std} + f_{SH,NG,HE}\lambda_{SH,NG,HE})} \tag{B.22}$$

Using this standard value, the energy intensity of a high efficiency natural gas furnace can be expressed accordingly:

$$EI_{SH,j,NG,HE} = \lambda_{NG,HE}\, EI_{SH,j,NG,std} \tag{B.23}$$

Space cooling energy intensities were calculated using fuel-specific space cooling energy demand data, total area data, assumed market shares of standard and high efficiency systems, and assumed energy intensity ratios of high efficiency alternatives. For example, the energy intensity of standard electric AC systems in buildings of type j can be calculated as:

$$EI_{SC,j,elec,std} = \frac{E_{SC,j,elec,tot}}{A_{j,tot}\mu(f_{SC,elec,std}\lambda_{SC,elec,std} + f_{SC,elec,HE}\lambda_{SC,elec,HE} + f_{SC,elec,HE}\lambda_{SC,elec,HE})} \tag{B.24}$$

B.3.2 Commercial/institutional: water heating

Water-heating energy use for the commercial and institutional sector was disaggregated using building and fuel-specific energy demand data from Natural Resources Canada and assumed technology shares. In this analysis, natural gas and heating oil boilers were considered as standard technologies and condensing and tankless boilers were considered as high efficiency alternatives. Assumptions regarding shares of condensing and tankless systems were adapted from an existing sectoral analysis [47].

The energy intensity for a standard efficiency boiler of a certain fuel type for buildings of type j can be calculated by considering fuel-specific water heating energy demand, total area, assumed energy intensity ratios for high efficiency alternatives, and assumed market shares of end-use technologies using said fuel type. For example, the energy intensity for standard natural gas boilers (1) can be calculated by accounting for the market shares of condensing (2) and tankless boilers (3):

$$EI_{WH,j,NG,1} = \frac{E_{WH,j,NG}}{N_{j,tot}f_{WH,j,NG}(f_{WH,j,NG,1} + f_{WH,j,NG,2}\lambda_{WH,NG,2} + f_{WH,j,NG,3}\lambda_{WH,NG,3})} \tag{B.25}$$

B.3.3 Commercial/institutional: auxiliary equipment and motors

Energy used by auxiliary equipment was modelled through the calculation of building and fuel-specific energy intensities based off assumed energy intensity fractions and market shares of high efficiency equipment:

$$EI_{aux,j,i} = \frac{E_{aux,j,i}}{A_{tot,j}(f_{aux,1} + f_{aux,2}\lambda_{aux,2})} \quad \text{(B.26)}$$

The energy intensity for standard electric motors was calculated in the same way:

$$EI_{mot,j,1} = \frac{E_{mot,j}}{A_{tot,j}(f_{mot,1} + f_{mot,2}\lambda_{mot,2})} \quad \text{(B)}$$

The energy intensity of high efficiency auxiliary equipment and motors can be simply expressed as:

$$EI_{aux,j,2} = EI_{aux,j,1}\lambda_{aux,2} \quad \text{(B.27)}$$

$$EI_{mot,j,2} = EI_{mot,j,1}\lambda_{mot,2} \quad \text{(B.28)}$$

B.3.4 Commercial/institutional: lighting

Energy used for lighting was represented using the same process as was the residential sector. For commercial and institutional lighting, high-intensity discharge ballast lighting was considered as a high-efficiency alternative instead of LED lighting.

Appendix C: Sectoral calibration factors

Table 29: Agriculture sector calibration factors

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electricity	1.21	1.25	1.31	1.22	1.13	1.20	1.23	1.13	1.09	1.28	1.12	1.24	1.29	1.37	1.11	1.37	1.03	1.08
Natural gas	1.11	0.88	0.98	0.81	0.68	0.63	0.63	0.79	0.86	0.75	0.54	0.60	0.60	0.59	0.60	0.64	0.66	0.72
Gasoline	1.83	1.67	2.12	2.18	1.62	1.68	1.88	1.61	1.55	1.29	1.63	2.19	2.34	2.16	2.25	2.04	2.21	2.00
Diesel	1.51	1.33	1.10	1.09	0.96	0.97	1.20	1.25	1.22	0.84	0.93	1.15	1.22	1.10	1.44	1.48	1.31	1.44
LPG	2.76	2.56	2.77	1.97	1.92	0.91	1.48	1.34	1.38	1.08	1.24	1.58	2.04	1.68	1.51	1.44	1.18	1.94

Table 30: Cement sector calibration factors

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electricity	1.29	1.19	1.21	0.79	1.03	1.18	1.22	1.15	1.16	1.03	1.13	1.11	1.08	1.15	0.96	0.95	0.80	1.04
Natural gas	7.88	7.29	7.35	4.85	6.31	7.18	7.42	7.02	7.09	6.27	6.90	6.76	6.60	6.41	5.86	5.82	4.91	6.37
Solid waste	0.87	0.47	0.90	1.58	0.91	1.00	1.20	0.98	0.98	1.06	1.48	0.94	0.66	0.57	0.53	0.60	0.60	0.59
Petroleum coke	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	0.60	0.55	0.56	0.37	0.48	0.55	0.56	0.53	0.54	0.48	0.52	0.51	0.50	0.49	0.45	0.44	0.37	0.48

Table 31: Chemical sector calibration factors

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electricity	0.65	0.57	0.55	0.52	0.52	0.52	0.53	0.43	0.41	0.41	0.44	0.50	0.42	0.42	0.49	0.49	0.48	0.49
Natural gas	1.19	0.96	0.90	0.94	0.97	0.98	0.95	0.93	0.94	0.99	1.10	1.25	1.26	1.36	1.10	1.00	0.92	0.91

Table 32: Iron and steel sector calibration factors

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electricity	0.59	0.53	0.67	0.59	0.58	0.55	1.05	1.02	1.33	1.55	1.12	1.08	0.80	0.99	1.08	1.62	0.86	0.91
Natural gas	2.03	1.81	2.30	2.01	1.99	1.90	3.60	3.48	4.55	5.33	3.84	3.75	2.72	3.40	4.01	5.33	2.82	3.14

Table 33: Petroleum refining sector calibration factors

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electricity	1.18	0.87	1.01	1.49	0.12	0.96	1.02	1.07	3.12	2.38	1.05	1.06	1.05	1.03	1.13	1.06	1.05	1.44
Natural gas	1.15	1.14	1.31	1.05	1.20	0.98	1.25	1.20	0.70	0.64	1.03	1.03	1.08	1.06	0.82	0.78	1.00	1.16
Petroleum coke	0.94	0.95	1.15	0.92	1.27	1.01	0.95	0.99	0.67	0.69	1.06	1.11	1.08	1.12	1.33	1.33	1.26	0.95
Heavy fuel oil	0.20	1.07	0.91	0.66	0.05	0.04	0.10	0.24	0.05	0.05	0.64	0.04	0.05	0.05	0.18	0.18	0.18	0.09
Still gas	0.93	0.95	1.15	0.91	1.28	1.01	0.96	1.00	0.67	0.72	1.07	1.15	1.16	1.15	1.37	1.37	1.42	1.23

Appendix D: Sectoral validation figures

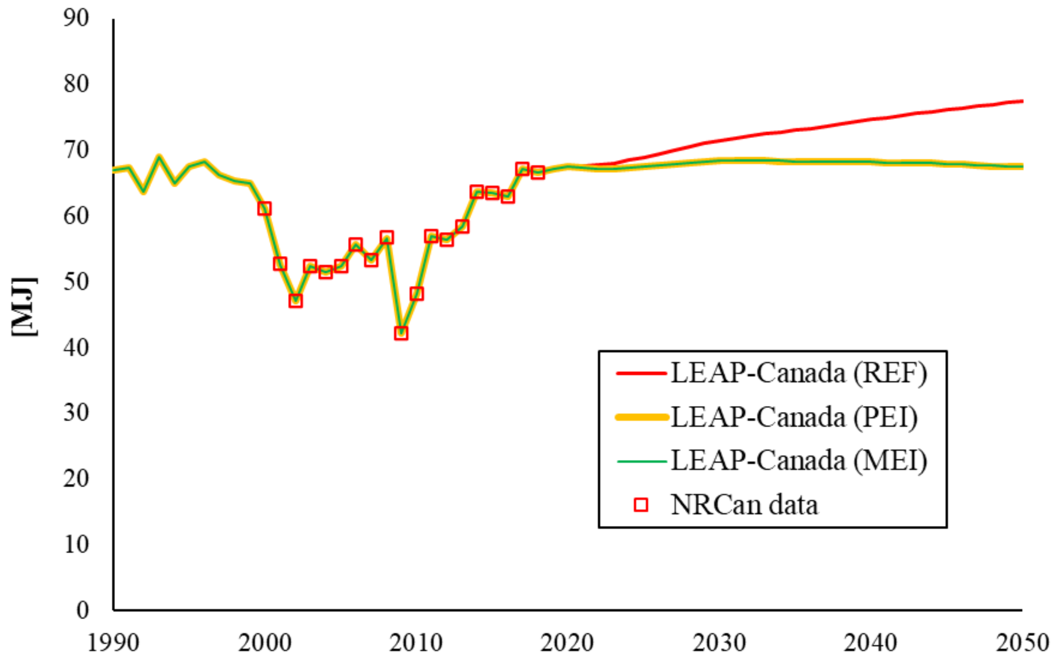

Figure 51: Energy demand validation: Alberta's agriculture sector

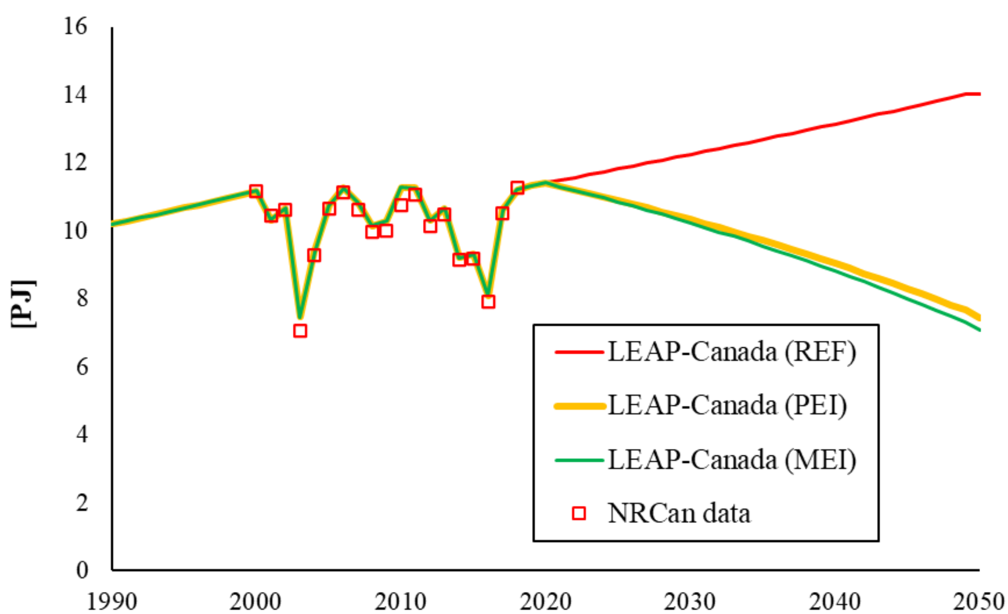

Figure 52: Energy demand validation: Alberta's cement sector

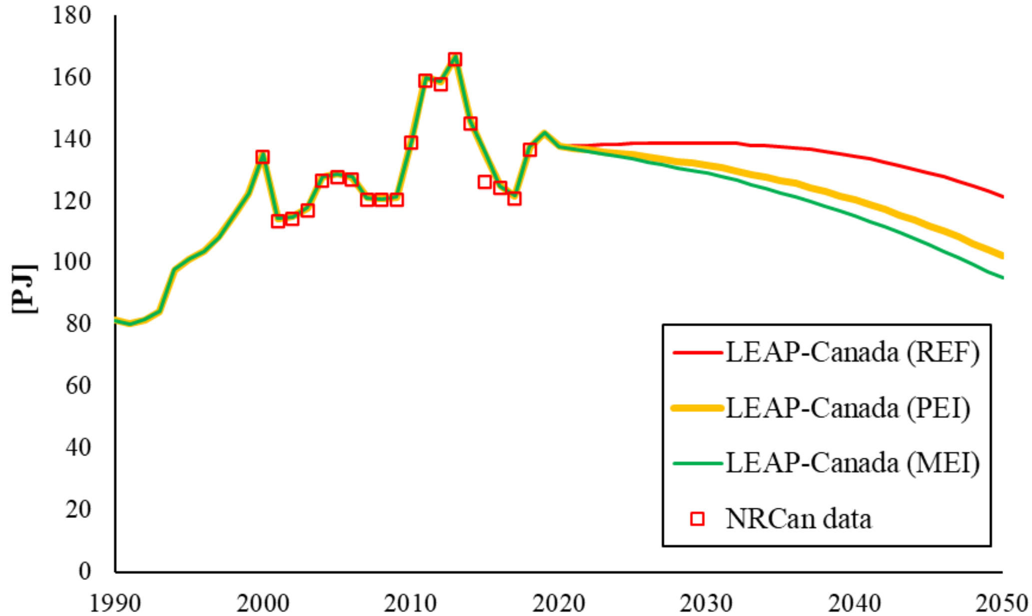

Figure 53: Energy demand validation: Alberta's chemicals sector

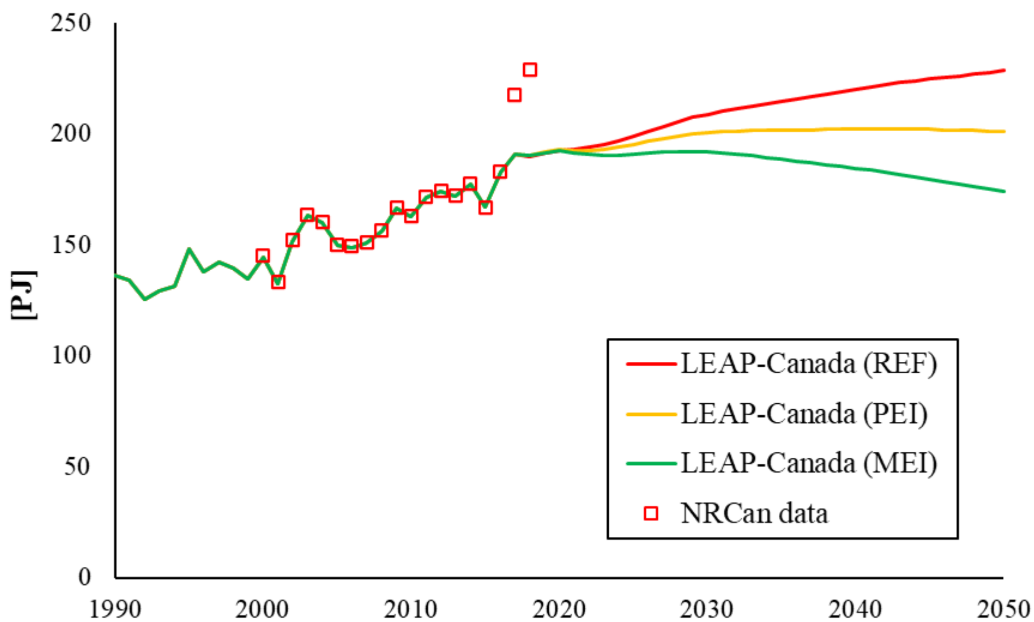

Figure 54: Energy demand validation: Alberta's commercial sector

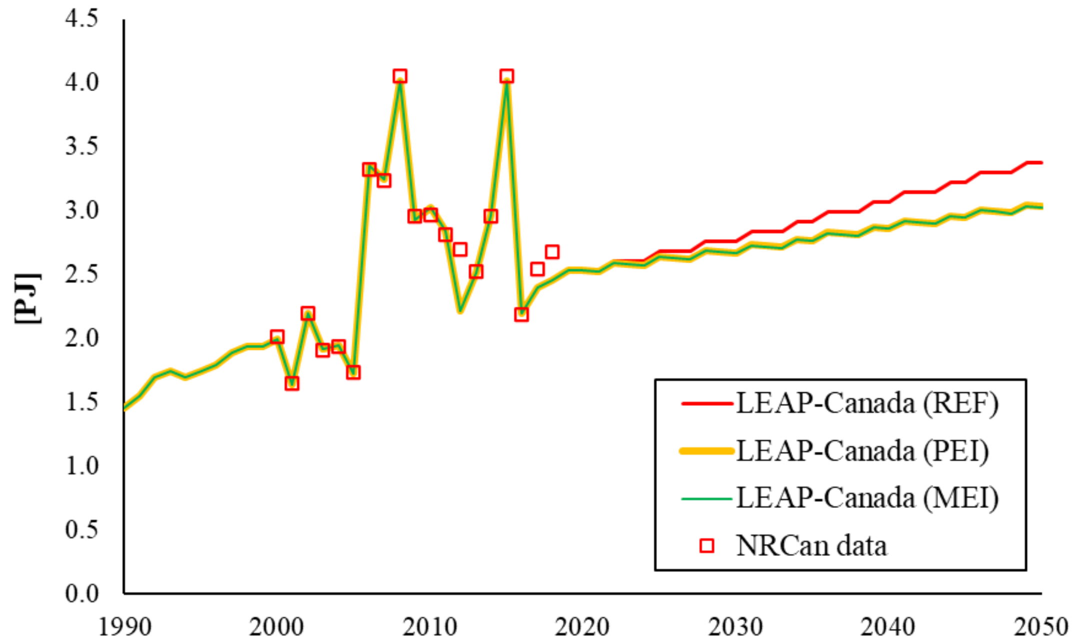

Figure 55: Energy demand validation: Alberta's iron and steel sector

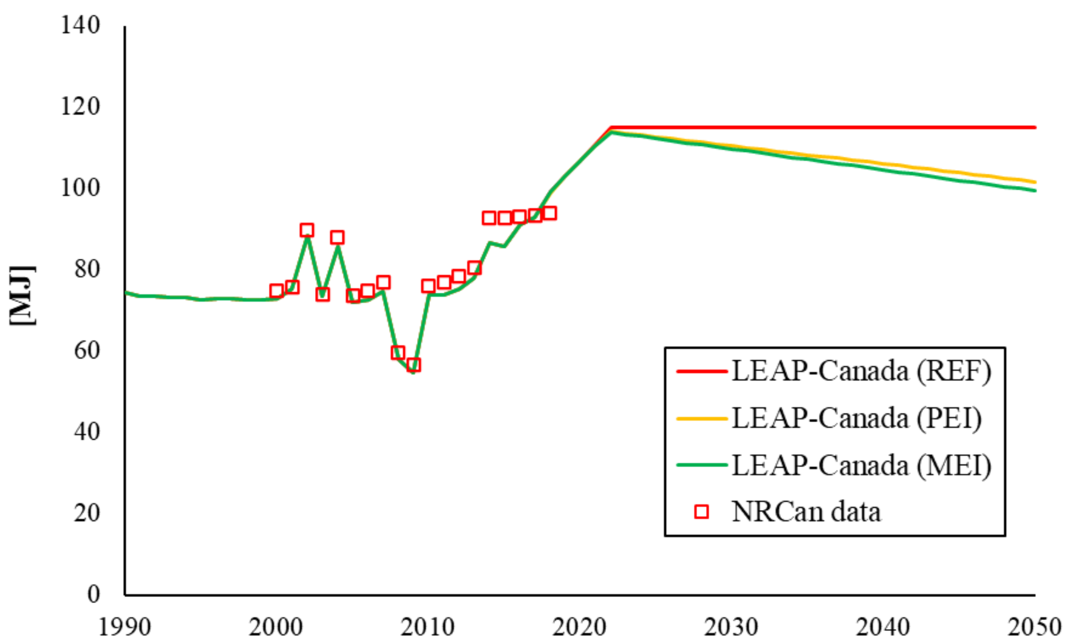

Figure 56: Energy demand validation: Alberta's petroleum refining sector

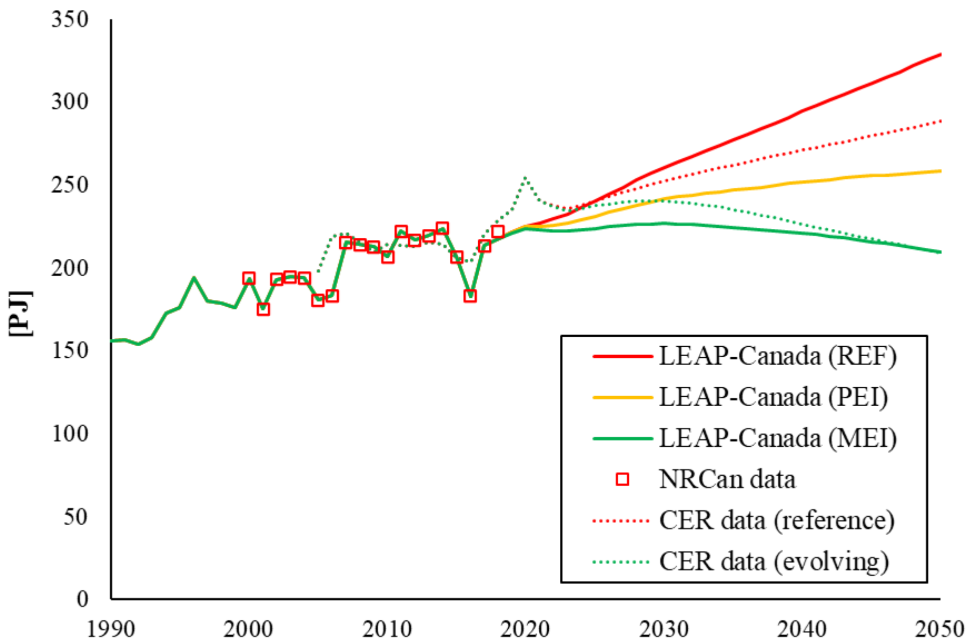

Figure 57: Energy demand validation: Alberta's residential sector

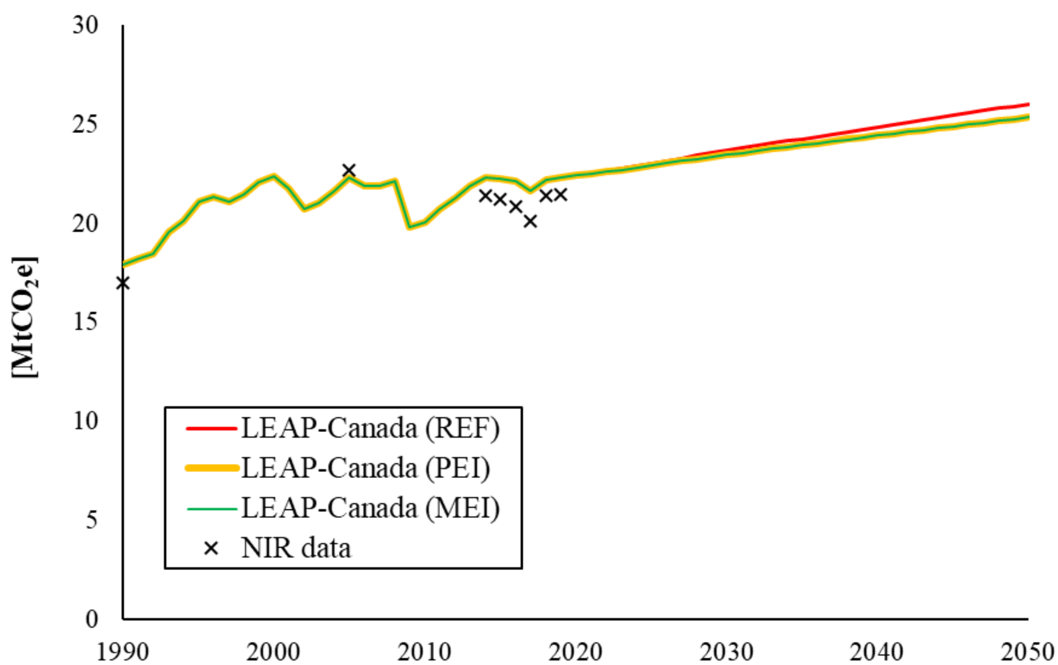

Figure 58: GHG emissions validation: Alberta's agriculture sector

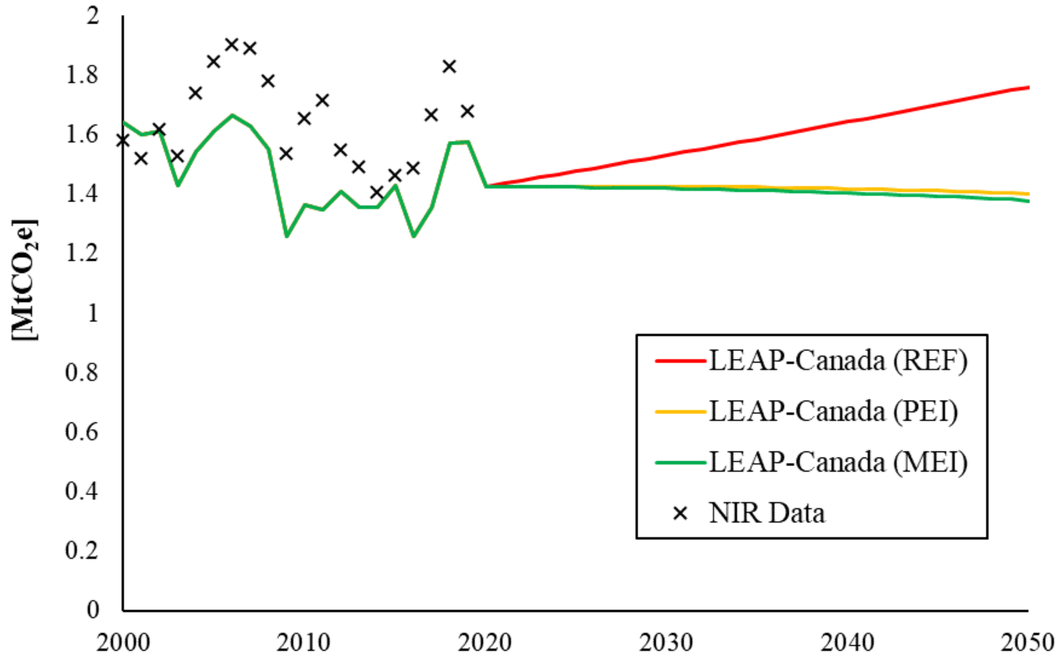

Figure 59: GHG emissions validation: Alberta’s cement sector

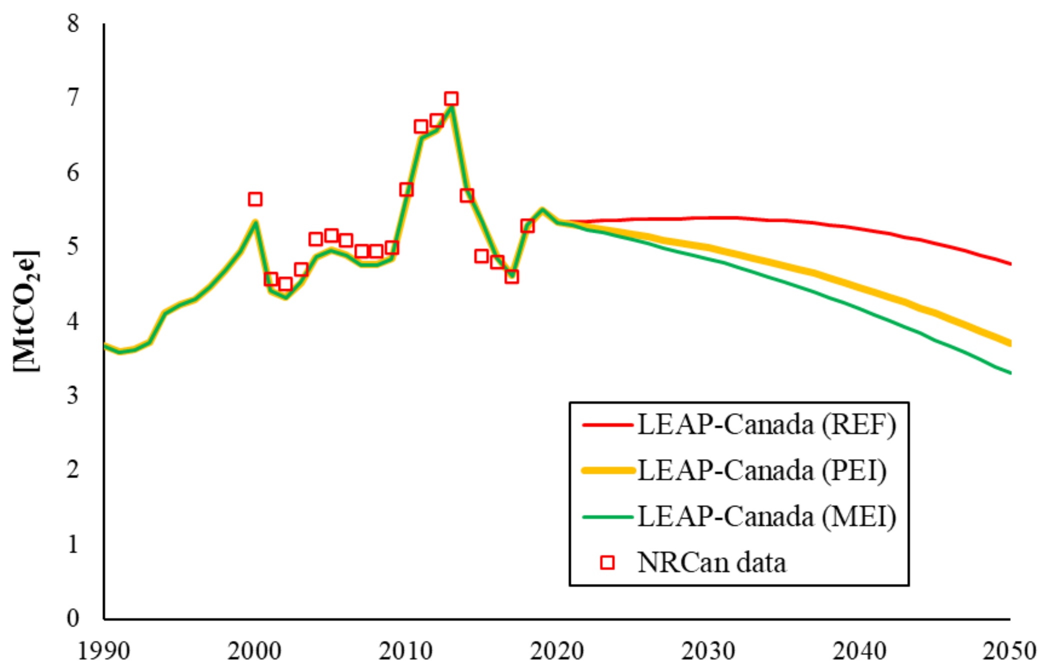

Figure 60: GHG emissions validation: Alberta’s chemicals sector

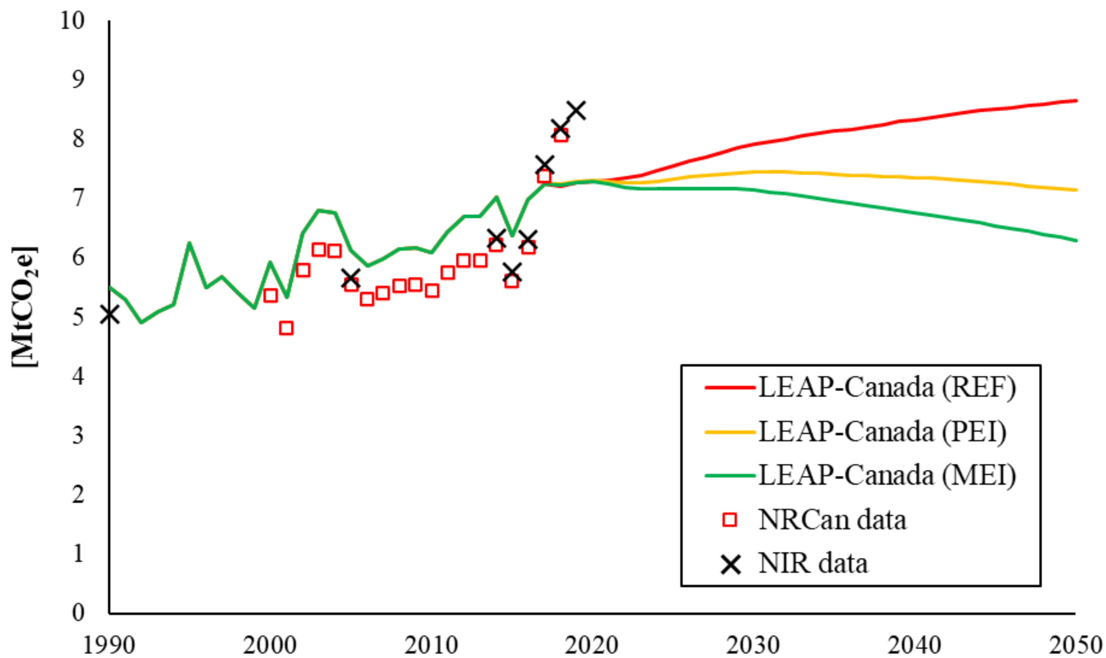

Figure 61: GHG emissions validation: Alberta's commercial sector

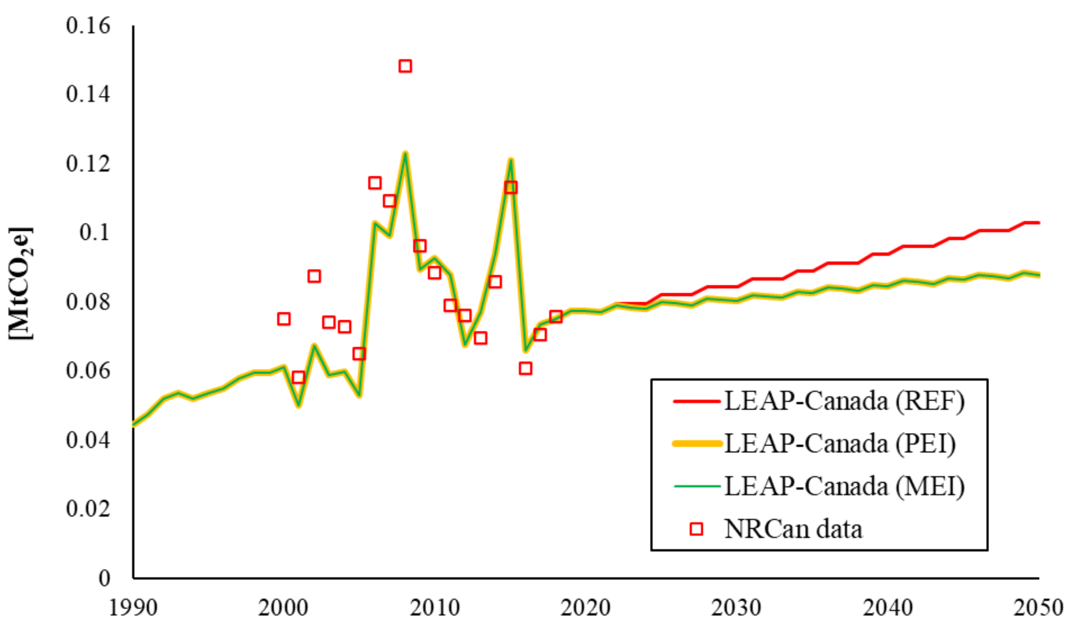

Figure 62: GHG emissions validation: Alberta's iron and steel sector

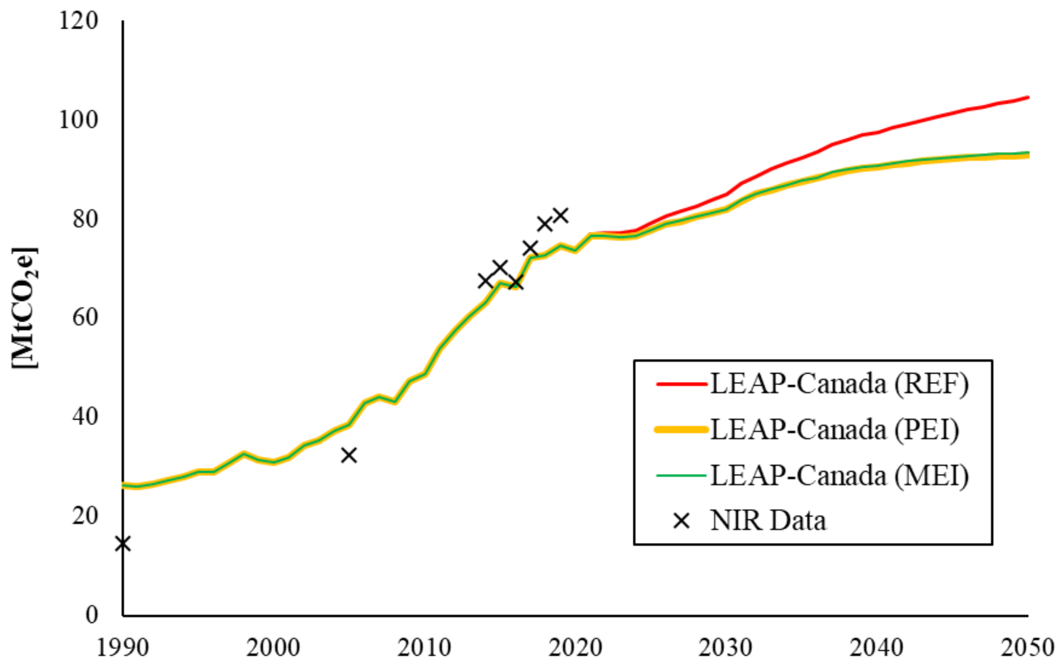

Figure 63: GHG emissions validation: Alberta's oil sands sector

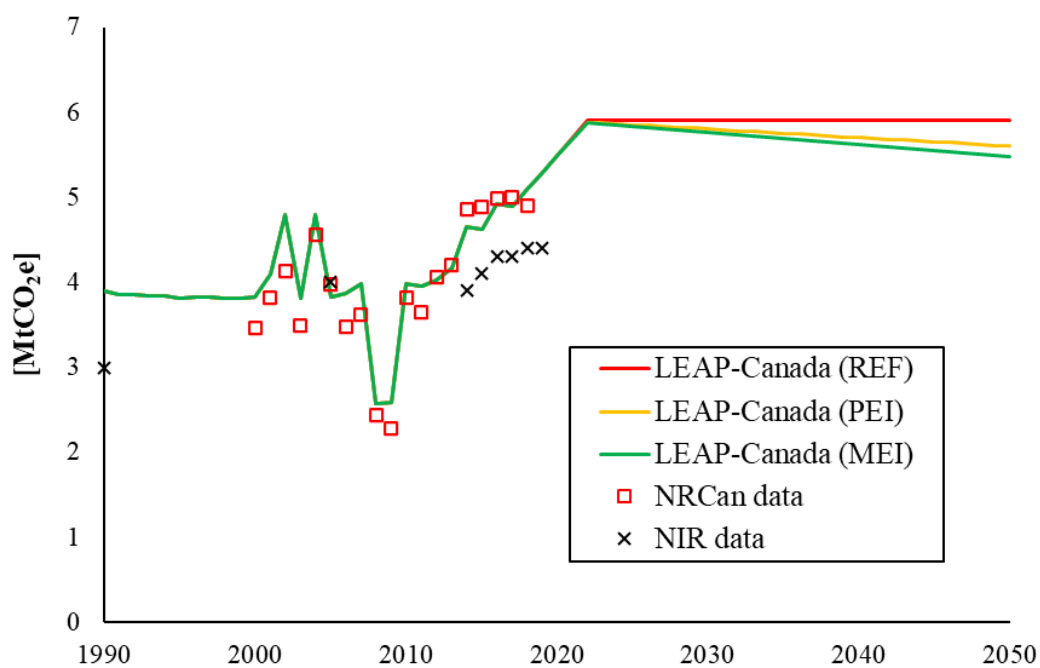

Figure 64: GHG emissions validation: Alberta's petroleum refining sector

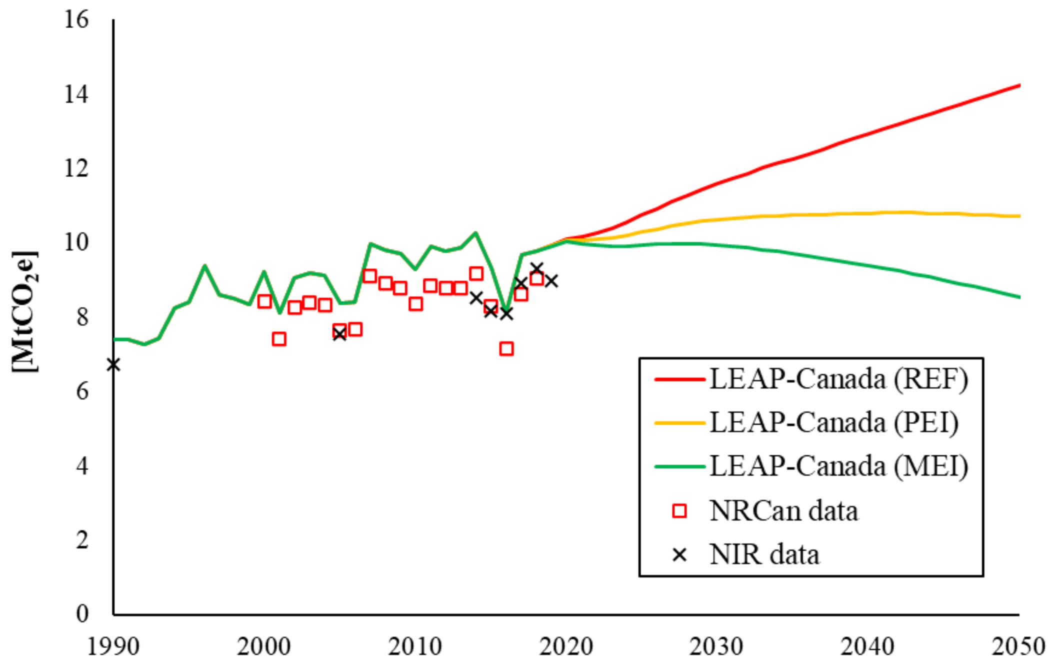

Figure 65: GHG emissions validation: Alberta's residential sector

Appendix E: Marginal GHG abatement costs for energy-efficiency measures in Alberta

Table 34: GHG mitigation and costs of individual efficiency measures (2021-2050 penetration)

Scenario name	Cumulative GHG mitigation ($MtCO_2e$)	MAC ($\$/tCO_2e$)	Annual GHG mitigation by 2050 ($MtCO_2e/yr$)
AGR_HE Livestock Ventilation	0.19	-222.08	0.004
AGR_HE Livestock Lighting	0.15	-219.17	0.004
AGR_HE Livestock Water Heater	0.16	-109.27	0.01
AGR_HE Tractors	8.94	-50.01	0.60
AGR_HE Diesel Trucks	0.94	-35.85	0.06
AGR_HE Irrigation_Elec	0.06	34.47	0.004
CEM_Kiln Fan VSD	0.03	-125.80	0.0016
CEM_Kiln Comb. Sys. Imp.	0.03	-86.89	0.002
CEM_Improved CM Refractories	0.27	-65.27	0.02
CEM_EM and Process Control	0.34	-53.60	0.02
CEM_Susp. Preheater	5.10	-53.03	0.35
CEM_Clinker Cooler WHR	0.02	-36.93	0.001
CEM_Recip. Cooler	0.35	5.22	0.02
CEM_CM Ind Firing	0.16	38.72	0.01
CHE_Evaporative Condenser	0.02	-179.34	0.0004
CHE_Automatic temp control	0.98	-76.37	0.06
CHE_LS Axial and Radial Amm. Synth	3.66	-74.58	0.22
CHE_ETH Proc Int	11.10	-73.69	0.65
CHE_Unpowered Ammonia Recovery	0.70	-72.44	0.04
CHE_Synth Gas Molecular	0.87	-71.05	0.05
CHE_CHP	6.54	-70.96	0.39
CHE_Heat Recovery	0.47	-69.94	0.03
CHE_LE CO2 Removal Tech	0.97	-67.51	0.06
CHE_Methan. HC. purif.	0.91	-67.24	0.05
CHE_ETH HP Comb	1.15	-64.94	0.07
CHE_Adiabatic Prereformer	2.80	-64.56	0.17
CHE_Auto methanol. methan.	0.50	-59.47	0.03
CHE_LT Conversion tech	0.22	-54.53	0.01
COM_HVAC CTRL	17.53	-43.69	1.16
COM_SH	8.83	-16.03	0.54
COM_AUX	3.11	29.45	0.08
COM_Lighting	3.39	33.88	0.09
COM_Water Heating	0.91	94.17	0.06
COM_HVAC BE	15.89	133.42	1.05

Scenario name	Cumulative GHG mitigation ($MtCO_2e$)	MAC ($\$/tCO_2e$)	Annual GHG mitigation by 2050 ($MtCO_2e/yr$)
COM_Motors	1.32	784.64	0.03
COM_SC	0.31	5062.64	0.01
IRO_EAF_ Neur Network Proc. Control	0.01	-225.82	0.0004
IRO_HR_HE RM Drives	0.001	-219.98	0.00002
IRO_EAF_UHP Transformers	0.00	-135.66	0.0001
IRO_EAF_Flue Gas Control	0.00	-110.90	0.0001
IRO_HR_O2 Control and VSDs	0.07	-70.04	0.01
IRO_HR_HS Mill Proc. Control	0.09	-69.21	0.01
IRO_HR_Recup. Burners	0.06	-68.01	0.004
IRO_HR_Cooling WHR	0.01	-54.17	0.001
IRO_HR_Hot Charging	0.09	-46.72	0.01
IRO_EAF_Elect. Bot. Tap	0.00	-22.99	0.0001
IRO_EAF_BS Gas Injection	0.00	-18.98	0.00003
IRO_HR_Furn Ins Improv.	0.02	-9.69	0.001
IRO_EAF_Foamy Slag Practice	0.00	257.52	0.0001
OIL_SM_EM	2.98	-83.90	0.19
OIL_UP_CTRL	5.05	-79.52	0.31
OIL_UP_PROC	4.06	-79.44	0.25
OIL_UP_EM	2.87	-79.28	0.18
OIL_SM_CTRL	7.86	-76.93	0.53
OIL_IN_UT	67.51	-75.62	4.82
OIL_SM_PROC	0.82	-70.79	0.06
OIL_SM_UE	0.82	-70.56	0.06
OIL_UP_HEX	8.68	-69.80	0.55
OIL_SM_UT	1.62	-69.44	0.11
OIL_SM_HEX	2.46	-69.43	0.17
OIL_IN_HEX	65.74	-68.92	4.77
OIL_IN_PROC	2.00	-68.49	0.14
OIL_IN_HL	2.04	-46.96	0.15
PET_HE Pumps	3.19	-235.14	0.08
PET_CDU Air Preheater	1.64	-43.67	0.11
PET_CDU Heat Integration	0.70	-41.19	0.04
PET_VDU Heat Integration	0.38	-36.40	0.02
PET_CRU Air Preheating	0.34	-36.03	0.02
PET_Alk Unit HP Distillation	1.60	-28.82	0.103
PET_Hydrocracking WHR	0.30	-18.52	0.02
PET_Iso HP Distillation	1.12	16.24	0.07
PET_Hydro Treating Design	0.92	256.18	0.06
PET_DCU WHR	0.001	1208.23	0.0001

Scenario name	Cumulative GHG mitigation ($MtCO_2e$)	MAC ($/$tCO_2e$)	Annual GHG mitigation by 2050 ($MtCO_2e$/yr)
PET_FCC WHR	0.001	1821.96	0.0001
RES_Lighting	2.57	-295.45	0.10
RES_HVAC CTRL	14.72	-69.61	1.01
RES_Water Heating	13.62	-58.29	0.96
RES_SH	11.83	17.77	0.77
RES_HVAC BE	54.98	81.86	3.83
RES_Appliances	1.03	2759.74	0.02
RES_ SC	0.07	13600.10	0.004

Table 35: GHG mitigation and costs of individual efficiency measures (2021-2030 penetration)

Scenario name	Cumulative GHG mitigation ($MtCO_2e$)	MAC ($/$tCO_2e$)	Annual GHG mitigation by 2050 ($MtCO_2e$/yr)
AGR_HE Livestock Ventilation	0.52	-163.00	0.004
AGR_HE Livestock Lighting	0.40	-156.79	0.004
AGR_HE Livestock Water Heater	0.32	-107.20	0.01
AGR_HE Tractors	14.51	-55.47	0.60
AGR_HE Diesel Trucks	1.53	-39.18	0.06
AGR_HE Irrigation_Elec	0.10	35.27	0.004
CEM_Kiln Fan VSD	0.06	-118.53	0.0016
CEM_Kiln Comb. Sys. Imp.	0.04	-94.11	0.002
CEM_Improved CM Refractories	0.44	-72.10	0.02
CEM_EM and Process Control	0.55	-58.49	0.02
CEM_Susp. Preheater	8.31	-57.84	0.35
CEM_Clinker Cooler WHR	0.03	-40.45	0.001
CEM_Recip. Cooler	0.56	8.62	0.02
CEM_CM Ind Firing	0.26	46.97	0.01
CHE_Evaporative Condenser	0.05	-133.58	0.0004
CHE_Automatic temp control	1.65	-83.74	0.06
CHE_LS Axial and Radial Amm. Synth	6.16	-81.71	0.22
CHE_ETH Proc Int	18.62	-81.31	0.65
CHE_Unpowered Ammonia Recovery	1.17	-79.92	0.04
CHE_Synth Gas Molecular	1.45	-78.33	0.05
CHE_CHP	10.89	-78.23	0.39
CHE_Heat Recovery	0.78	-77.06	0.03
CHE_LE CO2 Removal Tech	1.61	-74.29	0.06
CHE_Methan. HC. purif.	1.57	-72.49	0.05

Scenario name	Cumulative GHG mitigation ($MtCO_2e$)	MAC ($/$tCO_2e$)	Annual GHG mitigation by 2050 ($MtCO_2e$/yr)
CHE_ETH HP Comb	1.93	-71.30	0.07
CHE_Adiabatic Prereformer	4.67	-70.91	0.17
CHE_Auto methanol. methan.	0.84	-65.09	0.03
CHE_LT Conversion tech	0.37	-59.43	0.01
COM_HVAC CTRL	28.81	-47.00	1.16
COM_SH	13.87	-14.65	0.54
COM_AUX	7.64	16.58	0.08
COM_Lighting	8.38	19.67	0.09
COM_Water Heating	1.48	110.54	0.06
COM_HVAC BE	26.12	153.57	1.05
COM_Motors	3.22	592.81	0.03
COM_SC	0.83	3483.01	0.01
IRO_EAF_ Neur Network Proc. Control	0.04	-161.21	0.0004
IRO_HR_HE RM Drives	0.002	-156.04	0.00002
IRO_EAF_UHP Transformers	0.01	-99.68	0.0001
IRO_EAF_Flue Gas Control	0.01	-82.84	0.0001
IRO_HR_O2 Control and VSDs	0.12	-77.37	0.01
IRO_HR_HS Mill Proc. Control	0.14	-76.43	0.01
IRO_HR_Recup. Burners	0.10	-75.05	0.004
IRO_HR_Cooling WHR	0.02	-59.22	0.001
IRO_HR_Hot Charging	0.15	-50.70	0.01
IRO_EAF_Elect. Bot. Tap	0.01	-23.01	0.0001
IRO_EAF_BS Gas Injection	0.00	-20.26	0.00003
IRO_HR_Furn Ins Improv.	0.03	-8.33	0.001
IRO_EAF_Foamy Slag Practice	0.01	167.83	0.0001
OIL_SM_EM	5.05	-89.85	0.19
OIL_UP_CTRL	8.53	-86.38	0.31
OIL_UP_PROC	6.85	-86.29	0.25
OIL_UP_EM	4.85	-86.12	0.18
OIL_SM_CTRL	12.95	-83.92	0.53
OIL_IN_UT	108.23	-82.92	4.82
OIL_SM_PROC	1.33	-77.89	0.06
OIL_SM_UE	1.33	-77.68	0.06
OIL_UP_HEX	14.28	-76.96	0.55
OIL_SM_HEX	3.98	-76.62	0.17
OIL_SM_UT	2.63	-76.37	0.11
OIL_IN_HEX	104.09	-76.04	4.77
OIL_IN_PROC	3.16	-75.55	0.14
OIL_IN_HL	3.28	-50.56	0.15

Scenario name	Cumulative GHG mitigation ($MtCO_2e$)	MAC ($/$tCO_2e$)	Annual GHG mitigation by 2050 ($MtCO_2e$/yr)
PET_HE Pumps	7.88	-185.11	0.08
PET_CDU Air Preheater	2.70	-48.12	0.11
PET_CDU Heat Integration	1.14	-45.26	0.04
PET_VDU Heat Integration	0.63	-39.77	0.02
PET_CRU Air Preheating	0.56	-38.35	0.02
PET_Alk Unit HP Distillation	2.64	-30.08	0.103
PET_Hydrocracking WHR	0.49	-19.23	0.02
PET_Iso HP Distillation	1.85	21.53	0.07
PET_Hydro Treating Design	1.52	296.23	0.06
PET_DCU WHR	0.002	1389.58	0.0001
PET_FCC WHR	0.001	2094.41	0.0001
RES_Lighting	6.06	-226.65	0.10
RES_HVAC CTRL	23.58	-75.70	1.01
RES_Water Heating	21.81	-63.94	0.96
RES_SH	18.32	23.61	0.77
RES_HVAC BE	89.08	95.12	3.83
RES_Appliances	2.31	2154.24	0.02
RES_ SC	0.20	8329.06	0.004

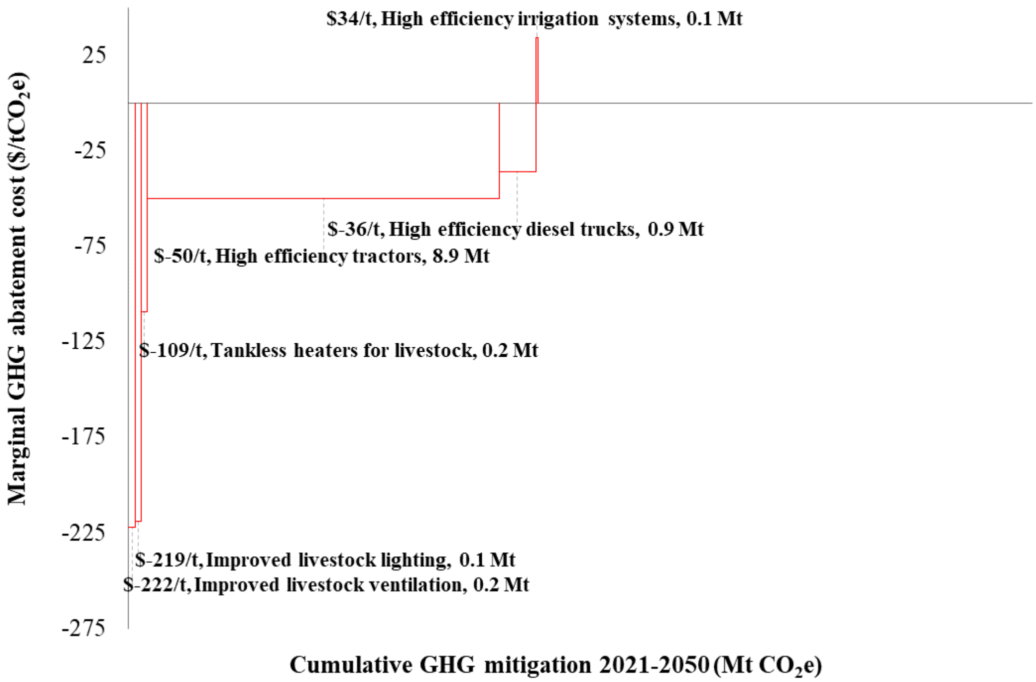

Figure 66: Marginal abatement cost curve for agriculture sector

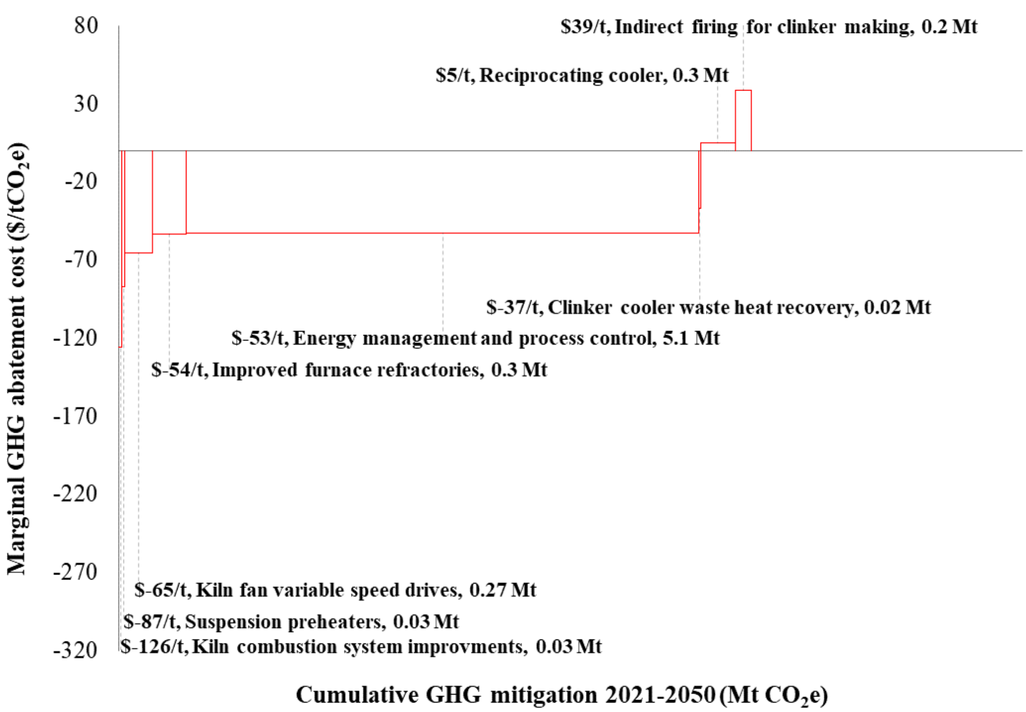

Figure 67: Marginal abatement cost curve for cement sector

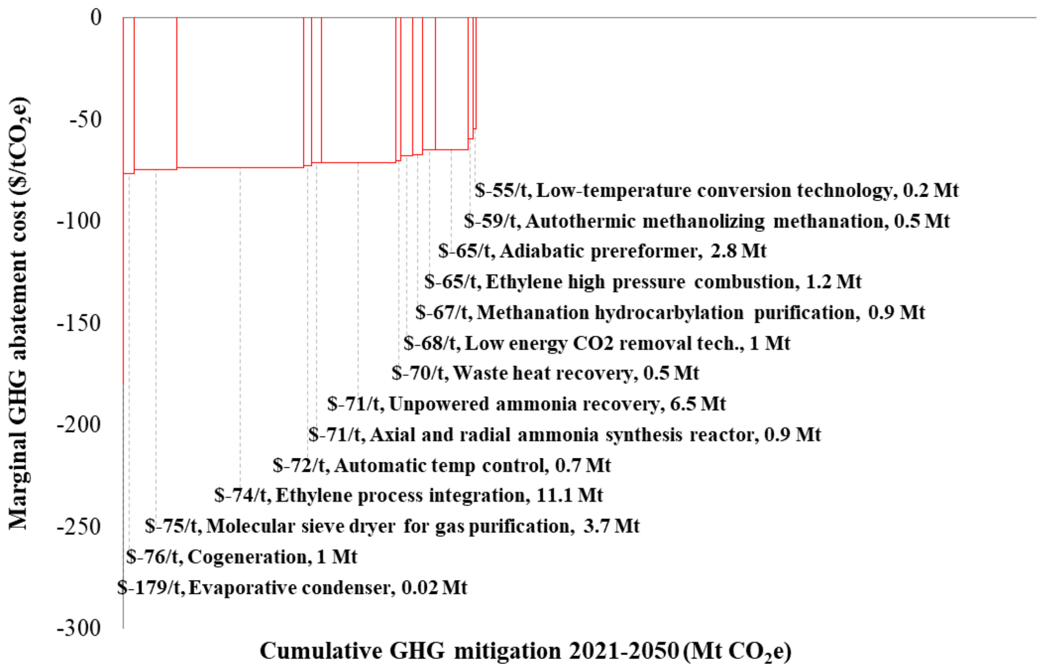

Figure 68: Marginal abatement cost curve for chemical sector

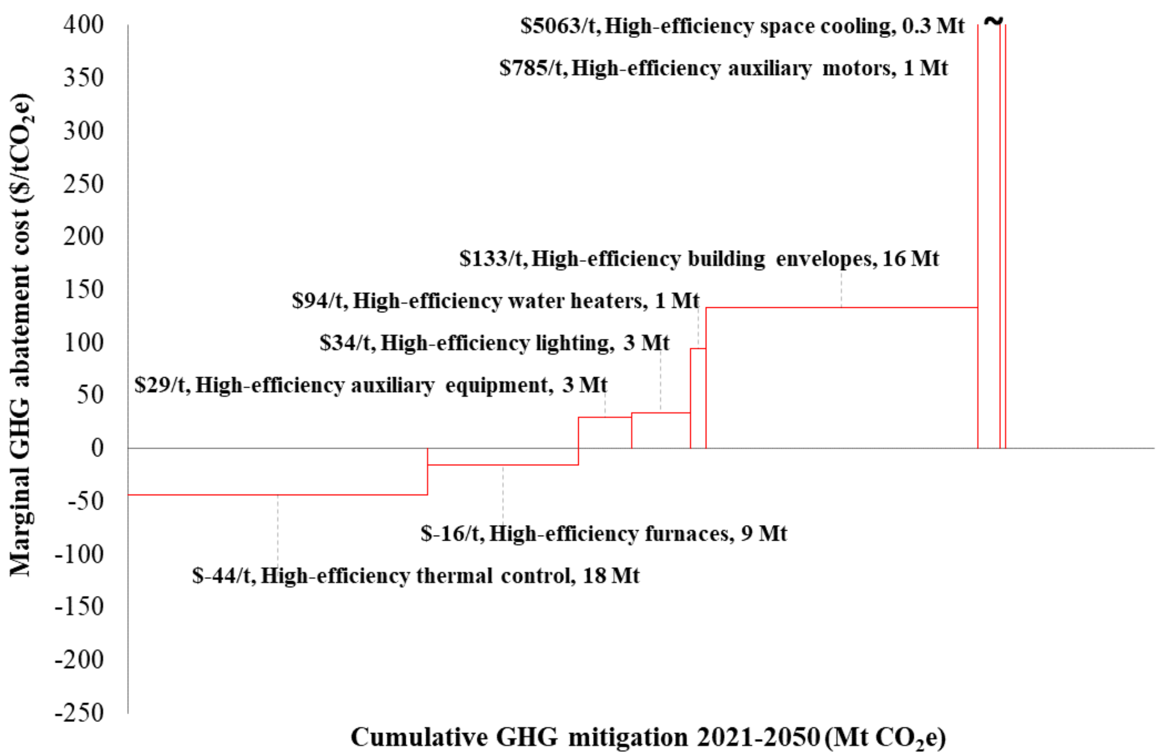

Figure 69: Marginal abatement cost curve for commercial sector

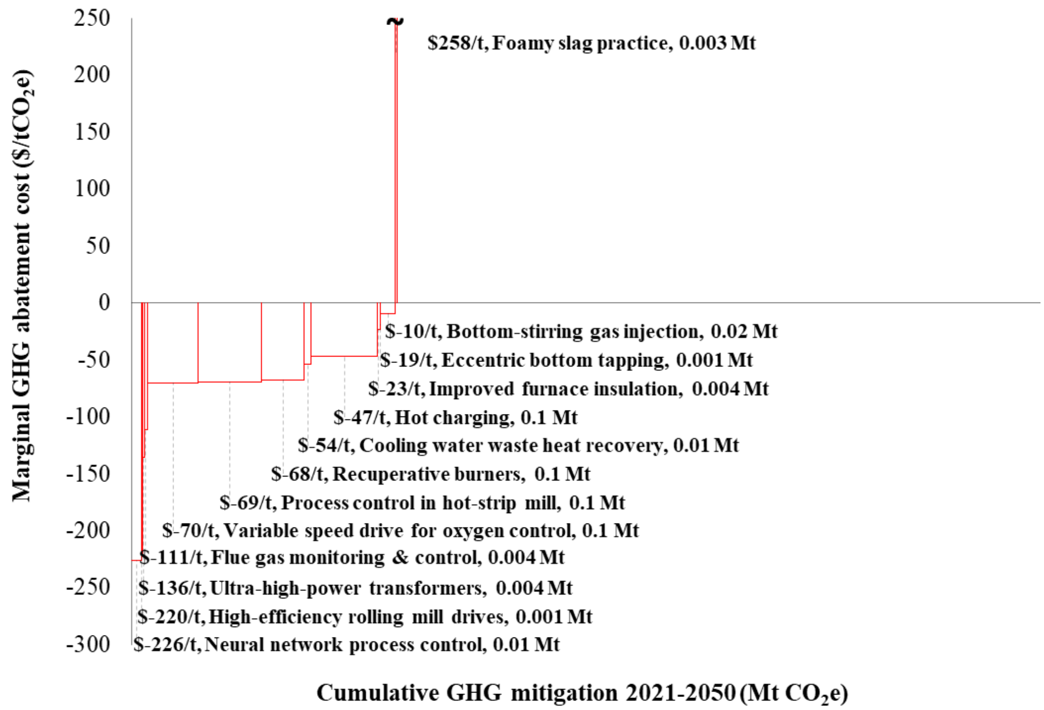

Figure 70: Marginal abatement cost curve for iron and steel sector

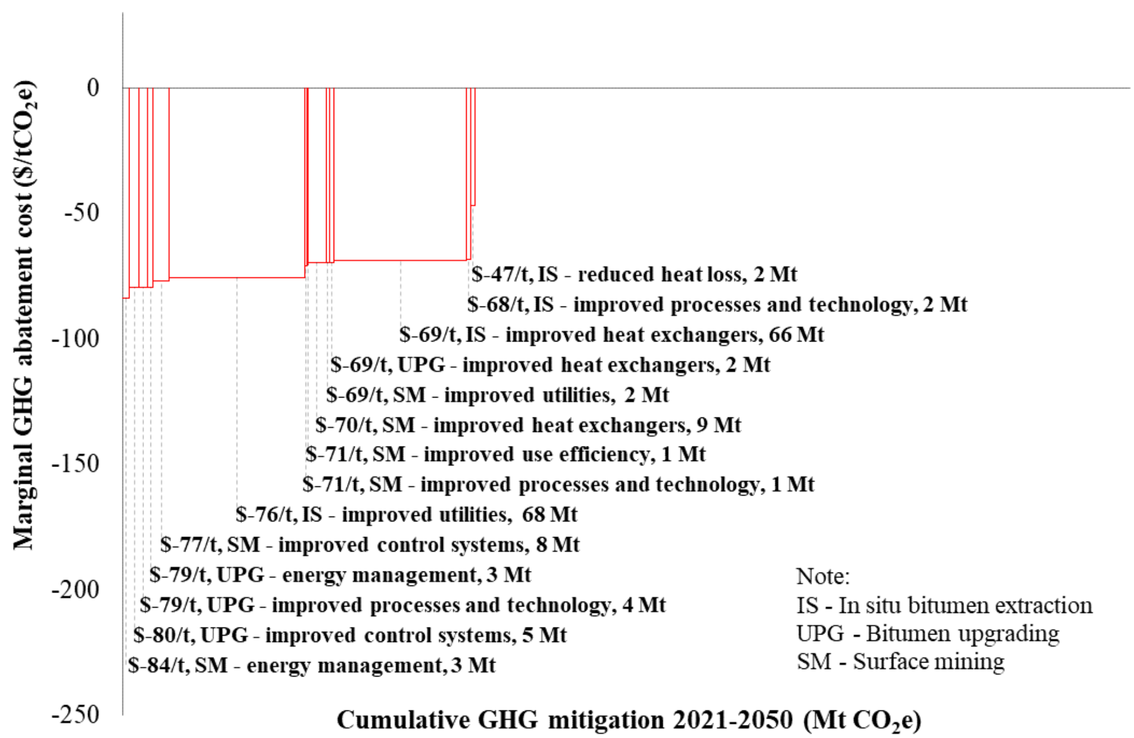

Figure 71: Marginal abatement cost curve for oil sands sector

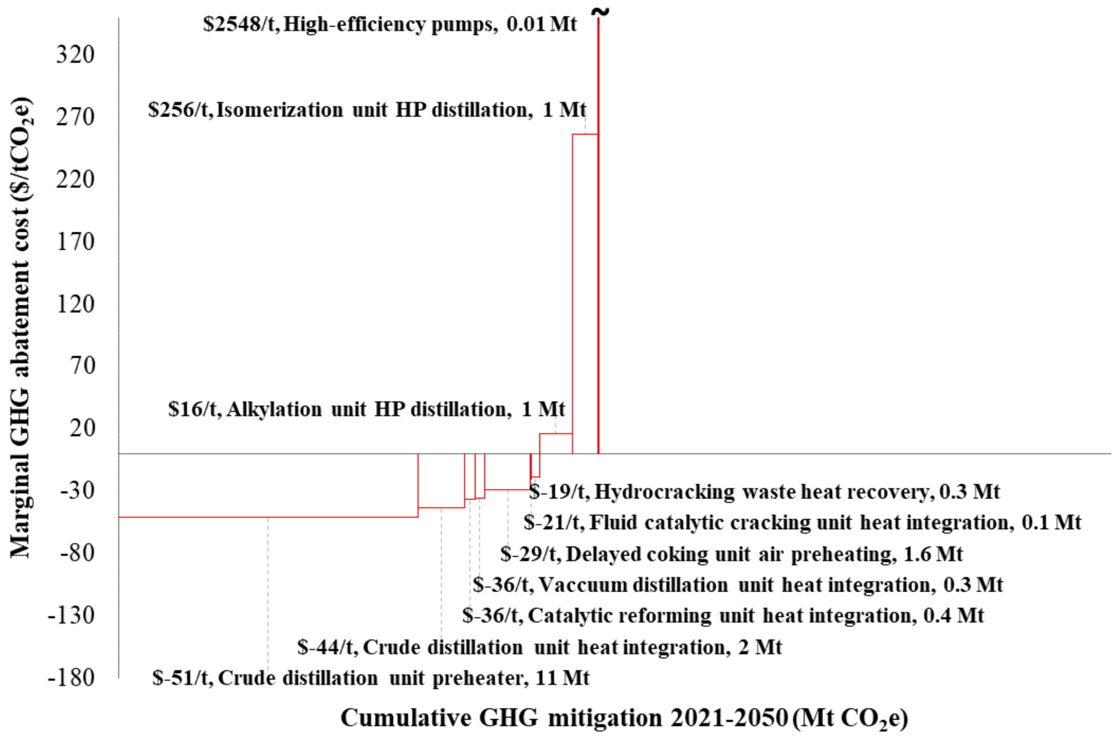

Figure 72: Marginal abatement cost curve for petroleum refining sector

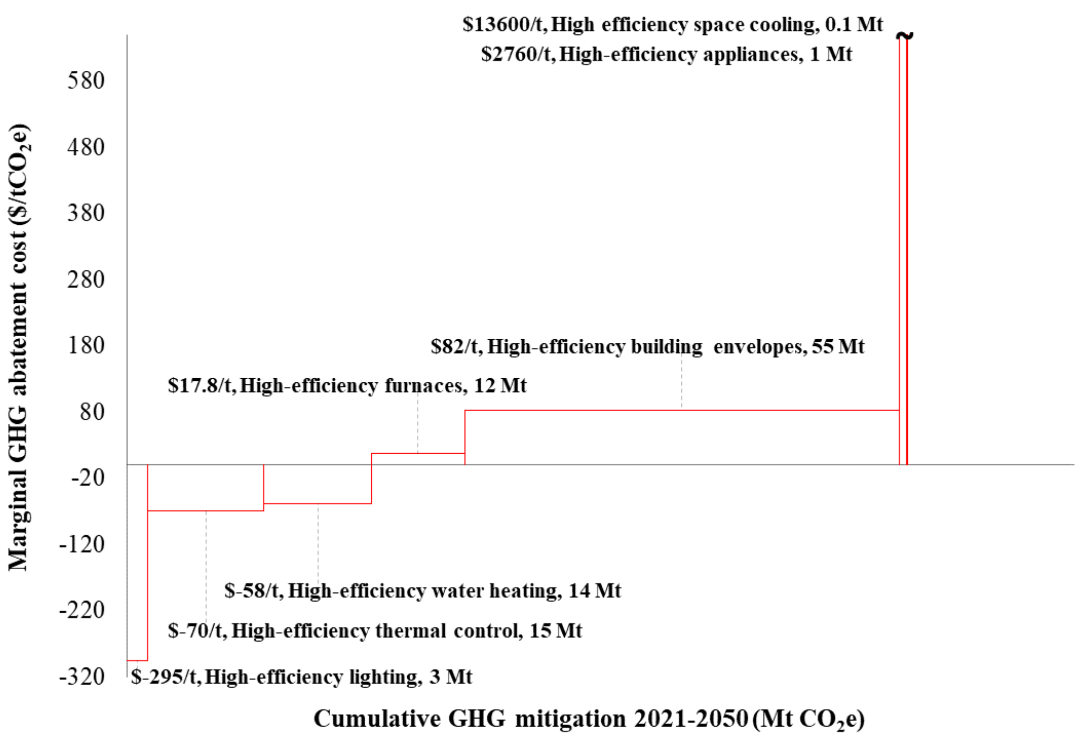

Figure 73: Marginal abatement cost curve for residential sector

Appendix F: Performance of energy-efficiency measures under 2021-2030 penetration

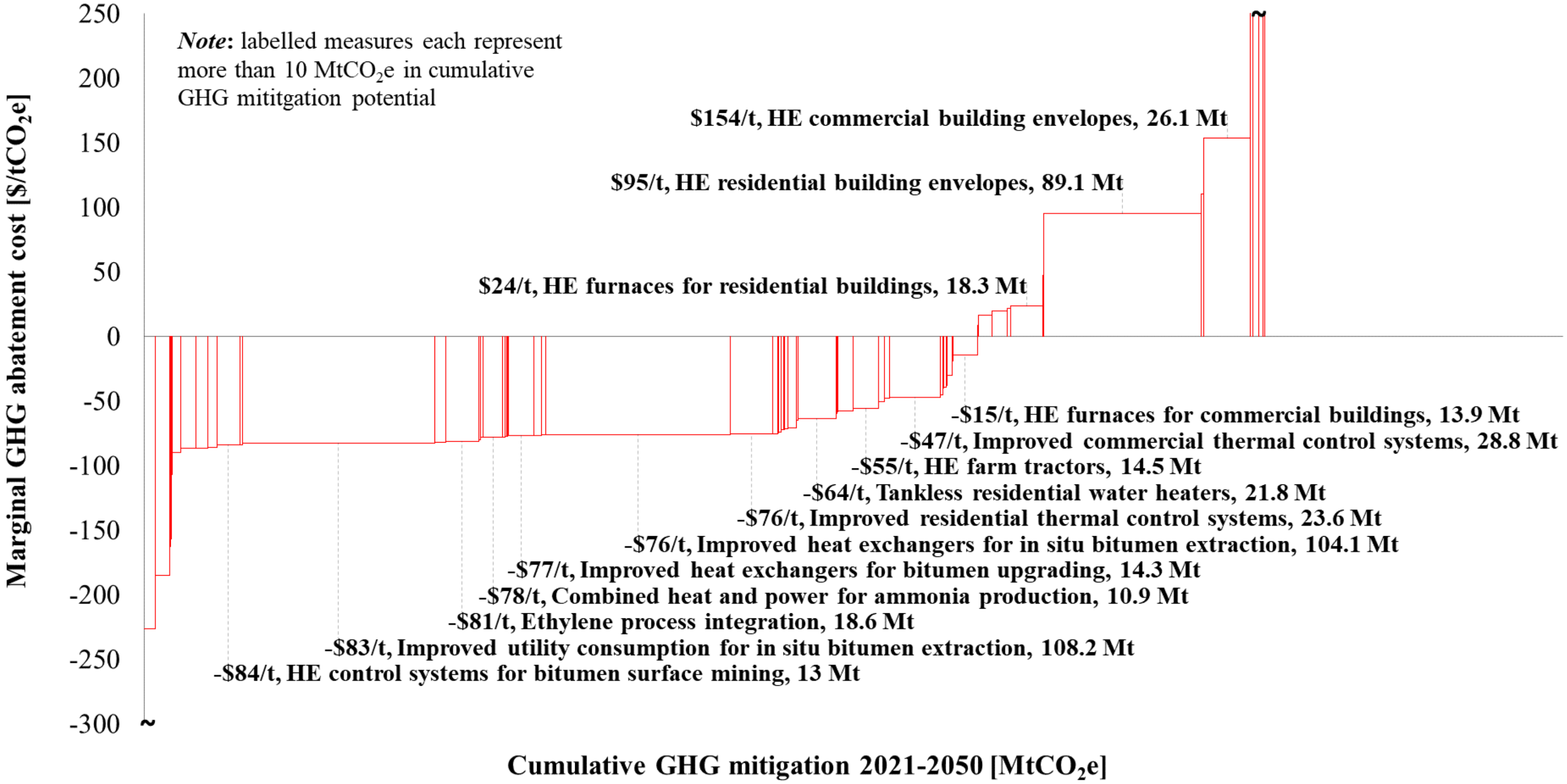

Figure 74: GHG abatement costs of energy-efficiency measures in Alberta (2021-2030 penetration)

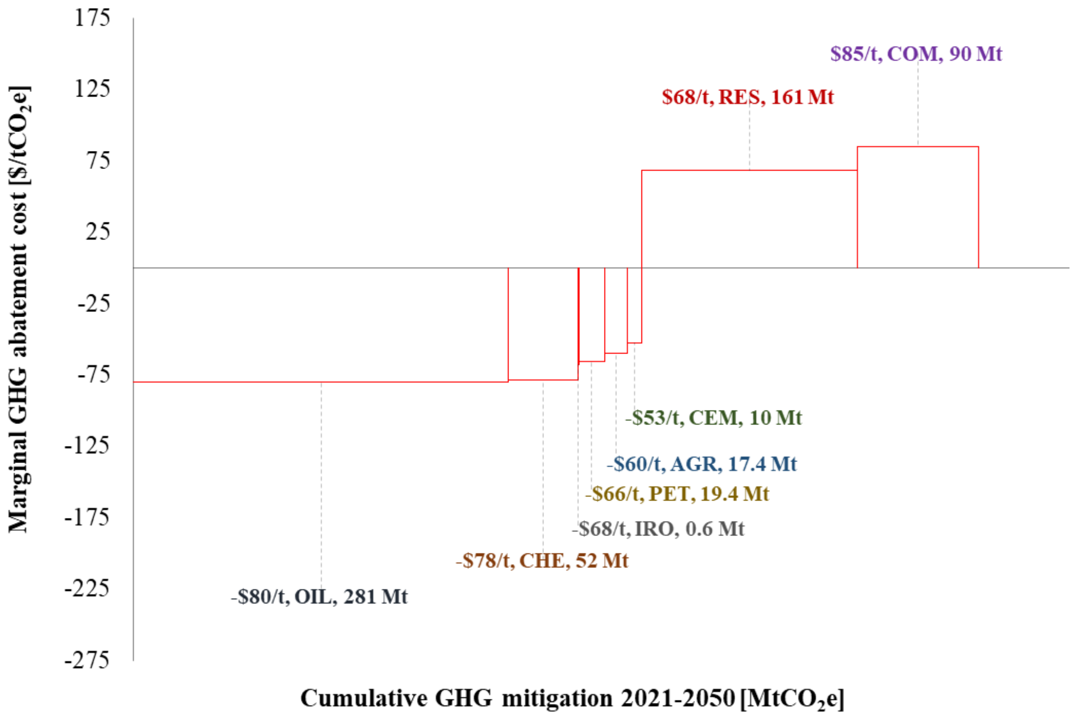

Figure 75: GHG abatement costs of efficiency measures, by sector (2021-2030 penetration)

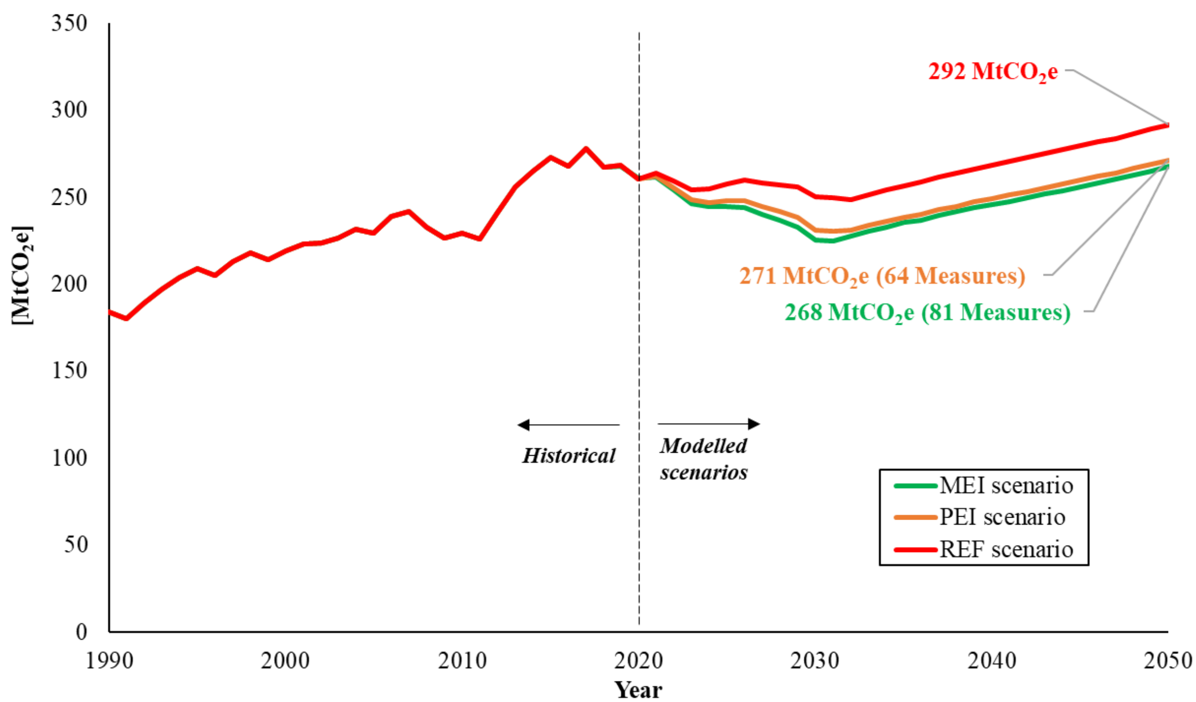

Figure 76: GHG projections of energy efficiency scenarios in Alberta (2021-2030 penetration)

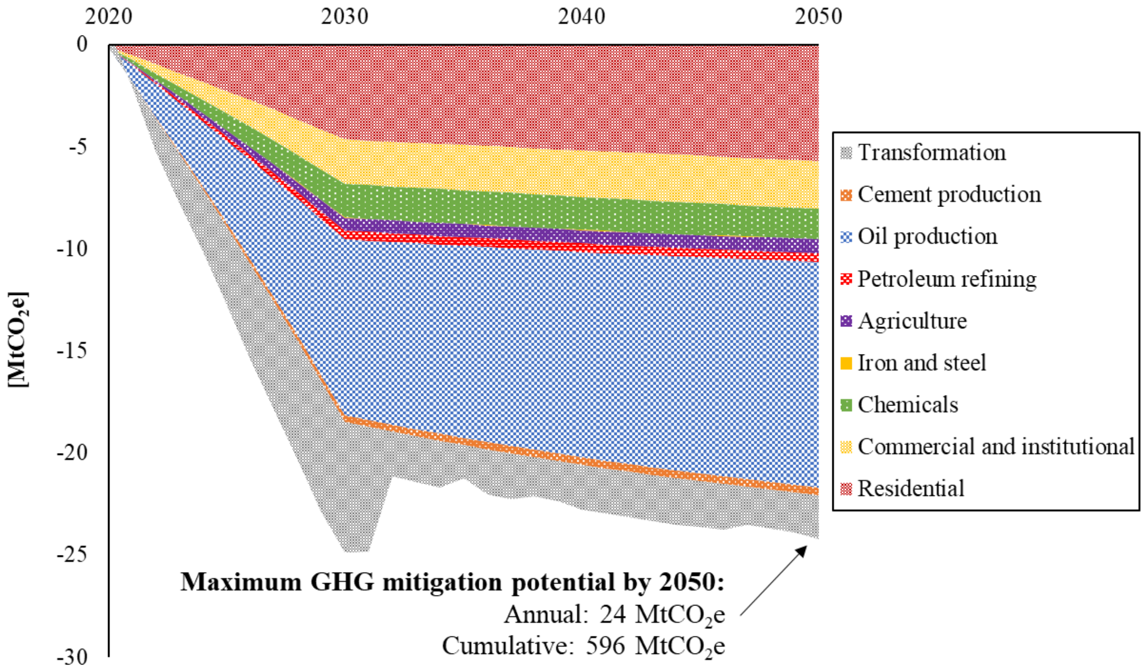

Figure 77: Maximum GHG mitigation potential of efficiency measures (2021-2030 penetration)

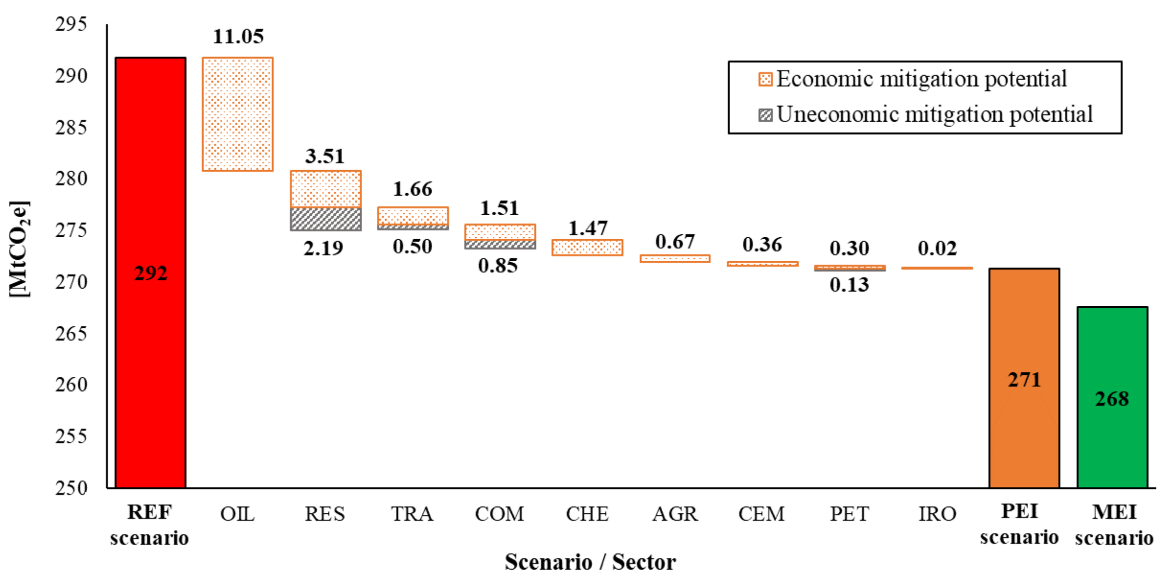

Figure 78: GHG mitigation potential of efficiency improvements, 2050 (2021-2030 penetration). GHG mitigation values are allocated to points of emission. Indirect GHG emissions reductions allocated to energy transformation sector (TRA)

Appendix G: Technical data for nation-wide GHG mitigation measures

Table 36 and Table 37 show all technical data for the assessed established and developing GHG mitigation measures, respectively, including annualized costs, penetration potential, and changes in GHG intensity (GI) and energy intensity (EI). Energy-use reductions for the pulp and paper sector measures are defined for each mill-type specifically; the values shown are for chemical pulp mills.

Table 36: Technical parameters for nation-wide established GHG mitigation measures

Scenario name	Max. penetration	Δ EI (fuel)	Δ EI (electricity)	Incremental annualized costs Capital	Operating	Lifetime (years)
Cement						
CEM_EFF CLM_INF	50%	-3%	0%	$9.41/t	-$6.29/t	20
CEM_EFF CLM_EMP	90%	-3%	-9%	$1.06/t	-$2.09/t	10
CEM_EFF CLC_IHR	50%	-2%	0%	$0.24/t	$0.00/t	20
CEM_EFF CLM_REF	30%	-8%	0%	$0.71/t	$0.00/t	20
CEM_EFF KIL_COM	20%	-5%	0%	$1.18/t	$0.00/t	20
CEM_EFF KIL_VSD	50%	-1%	-16%	$0.27/t	$0.00/t	5
CEM_EFF CLC_RGC	60%	-5%	0%	$11.76/t	$0.00/t	20
CEM_EFF KIL_SPR	80%	-56%	0%	$41.16/t	$0.00/t	40
CEM_SDR ALL_BLN	180%	-46%	0%	$11.00/t	$0.00/t	20
Chemicals						
CHE_EFF RFM_CHP	90%	-14%	0%	$11.76/t	$0.00/t	20
CHE_EFF ETH_HPC	40%	-7%	0%	$14.11/t	$0.00/t	20
CHE_EFF GPS_LER	24%	-79%	0%	$15.29/t	$0.00/t	20
CHE_EFF SYN_LST	44%	-95%	0%	$4.70/t	$0.00/t	20
CHE_EFF GPS_LTC	18%	-25%	0%	$15.29/t	$0.00/t	20
CHE_EFF RFM_APR	90%	-6%	0%	$17.64/t	$0.00/t	20
CHE_EFF GPS_AME	38%	-63%	0%	$11.76/t	$0.00/t	20
CHE_EFF SYN_ACO	43%	-26%	0%	$4.70/t	$0.00/t	20
CHE_EFF GPS_EVC	27%	0%	-45%	$2.35/t	$0.00/t	20
CHE_EFF RFM_WHR	90%	-1%	0%	$1.18/t	$0.00/t	20
CHE_EFF GPS_MHP	31%	-55%	-90%	$12.94/t	$0.00/t	20
CHE_EFF ETH_PIN	90%	-30%	0%	$1.18/t	$0.00/t	20
CHE_EFF SYN_MSD	29%	-35%	0%	$4.70/t	$0.00/t	20
CHE_EFF SYN_UAR	41%	-20%	0%	$1.18/t	$0.00/t	20
Commercial and institutional						
COM_EFF SHC_HEB	95%	-13%	-13%	$78.67/$m^2$	$0.00/ m^2	35
COM_EFF SHC_HEC	90%	-15%	-15%	$5.92/ m^2	$0.01/ m^2	20
COM_EFF AUX_HEE	90%	0%	-30%	$14.11/ m^2	$0.00/ m^2	15
COM_EFF AUX_HEM	95%	0%	-40%	$20.45/ m^2	$0.00/ m^2	15
COM_EFF LIG_HEL	80%	0%	-35%	$4.24/ m^2	$0.00/ m^2	3
COM_EFF LIG_HES	80%	0%	-50%	$5.65/ m^2	$0.00/ m^2	5
COM_EFF WHE_TCH	90%	-15%	0%	$3.53/ m^2	$0.00/ m^2	13
COM_EFF SHC_HEF	55%	-13%	0%	$17.64/ m^2	$0.00/ m^2	25
COM_EFF SHC_HAC	80%	0%	-50%	$35.28/ m^2	$0.00/ m^2	25

Scenario name	Max. penetration	Δ EI (fuel)	Δ EI (electricity)	Incremental annualized costs Capital	Operating	Lifetime (years)
			Iron and steel			
IRO_EFF SIN_IPC	100%	-0.4%	0.0%	$0.05/t	$0.00/t	10
IRO_EFF BLF_ICS	60%	-3.8%	0.0%	$0.58/t	$0.00/t	10
IRO_EFF BLF_IGR	60%	-0.6%	0.0%	$0.49/t	$0.00/t	15
IRO_EFF BLF_HPC	50%	-3.5%	0.0%	$0.49/t	$0.00/t	10
IRO_EFF BLF_ING	70%	-8.5%	0.0%	$8.02/t	-$3.20/t	20
IRO_EFF BLF_HBR	30%	-0.7%	0.0%	$2.25/t	$0.00/t	10
IRO_EFF BOF_CNC	3%	-60.0%	-20.0%	$21.50/t	-$9.63/t	20
IRO_EFF BOF_ELP	90%	-6.1%	0.0%	$0.09/t	$0.00/t	30
IRO_EFF CMK_APC	90%	-1.0%	0.0%	$0.13/t	$0.00/t	10
IRO_EFF CMK_CMC	70%	-1.7%	0.0%	$26.43/t	$0.00/t	10
IRO_EFF CMK_CDQ	70%	-7.1%	0.0%	$37.76/t	$0.27/t	18
IRO_EFF EAF_BSG	11%	0.0%	-3.7%	$1.08/t	-$3.60/t	0.5
IRO_EFF EAF_UHP	40%	0.0%	-3.2%	$4.95/t	$0.00/t	15
IRO_EFF EAF_EBT	52%	0.0%	-2.6%	$5.76/t	$0.00/t	10
IRO_EFF EAF_FGC	50%	0.0%	-2.6%	$3.60/t	$0.00/t	10
IRO_EFF EAF_FSP	30%	0.0%	-3.7%	$17.99/t	-$3.24/t	10
IRO_EFF EAF_NNC	90%	0.0%	-5.8%	$1.71/t	-$1.80/t	10
IRO_EFF HRL_HED	50%	0.0%	-0.8%	$0.31/t	$0.00/t	20
IRO_EFF HRL_HSC	69%	-14.9%	0.0%	$1.10/t	$0.00/t	10
IRO_EFF HRL_VSD	50%	-16.7%	0.0%	$0.79/t	$0.00/t	10
IRO_EFF HRL_WHR	69%	-1.7%	0.0%	$1.26/t	$0.00/t	15
IRO_EFF HRL_FIN	30%	-8.0%	0.0%	$15.71/t	$0.00/t	10
IRO_EFF HRL_HCH	36%	-29.9%	0.0%	$23.55/t	-$2.07/t	10
IRO_EFF HRL_RBR	20%	-35.1%	0.0%	$3.92/t	$0.00/t	10
IRO_AFU SIN_WFU	90%	-1.7%	0.0%	$0.07/t	$0.00/t	10
IRO_EFF SIN_WHR	100%	-5.2%	0.0%	$1.19/t	$0.00/t	10
			Mineral mining			
MIN_EFF TRA_HTO	90%	0.0%	-3.6%	$0.00/t	$0.00/t	4
MIN_EFF IRO_SOE	90%	0.0%	-10.2%	$0.00/t	$0.00/t	4
MIN_EFF GRN_HPG	90%	-13.0%	-27.0%	-$3.28/t	$0.02/t	12
MIN_EFF UND_VOD	90%	0.0%	-30.0%	-$1.05/t	$0.00	4
MIN_EFF POT_SGD	90%	-0.3%	0.0%	$0.00/t	$0.00	0
			Oil sands			
OIL_EFF INS_HEX	90%	-4.0%	0.0%	$0.27/bbl	$0.00/bbl	35
OIL_EFF INS_RHL	90%	-0.1%	-0.1%	$0.02/bbl	$0.00/bbl	35
OIL_EFF INS_PTC	90%	-0.1%	0.0%	$0.02/bbl	$0.00/bbl	35
OIL_EFF INS_IUT	90%	-4.0%	-4.0%	$0.60/bbl	$0.00/bbl	35
OIL_EFF SMI_CNS	90%	-5.9%	-2.4%	$0.02/bbl	$0.00/bbl	35
OIL_EFF SMI_EMM	90%	-2.1%	-2.1%	$0.02/bbl	$0.00/bbl	35
OIL_EFF SMI_HEX	90%	-1.9%	0.0%	$0.03/bbl	$0.00/bbl	35
OIL_EFF SMI_PTC	90%	-0.6%	-0.1%	$0.01/bbl	$0.00/bbl	35
OIL_EFF SMI_IUE	90%	-0.6%	-0.1%	$0.01/bbl	$0.00/bbl	35
OIL_EFF SMI_IUT	90%	-1.3%	-0.1%	$0.03/bbl	$0.00/bbl	35
OIL_EFF UPG_CNS	90%	-1.0%	-1.0%	$0.01/bbl	$0.00/bbl	35
OIL_EFF UPG_EMM	90%	-0.6%	-0.6%	$0.01/bbl	$0.00/bbl	35
OIL_EFF UPG_HEX	90%	-1.8%	0.0%	$0.19/bbl	$0.00/bbl	35

Scenario name	Max. penetration	Δ EI (fuel)	Δ EI (electricity)	Incremental annualized costs Capital	Operating	Lifetime (years)
OIL_EFF UPG_PTC	90%	-0.8%	-0.8%	$0.01/bbl	$0.00/bbl	35
Petroleum refining						
PET_EFF CDU_APH	80%	-4.0%	0.0%	$0.58/bbl	$0.00/bbl	35
PET_EFF CDU_INT	80%	-0.1%	-0.1%	$0.26/bbl	$0.00/bbl	35
PET_EFF CRU_APH	80%	-0.1%	0.0%	$0.02/bbl	$0.00/bbl	35
PET_EFF DCU_APH	80%	-4.0%	-4.0%	$0.02/bbl	$0.00/bbl	35
PET_EFF FCC_APH	80%	-5.9%	-2.4%	$0.02/bbl	$0.00/bbl	35
PET_EFF CDU_HEP	80%	-2.1%	-2.1%	$0.02/bbl	$0.00/bbl	35
PET_EFF VDU_INT	80%	-1.9%	0.0%	$0.03/bbl	$0.00/bbl	35
PET_EFF ALK_HPD	80%	-0.6%	-0.1%	$0.01/bbl	$0.00/bbl	35
PET_EFF HTU_APH	80%	-0.6%	-0.1%	$0.01/bbl	$0.00/bbl	35
PET_EFF HCU_APH	80%	-1.3%	-0.1%	$0.03/bbl	$0.00/bbl	35
PET_EFF ISO_HPD	80%	-1.0%	-1.0%	$0.01/bbl	$0.00/bbl	35
Pulp and paper						
PUL_EFF ALL_APC	50%	-16.3%	-20.7%	$9.95/t	$0.04/t	20
PUL_EFF ALL_ASD	40%	0.0%	-4.2%	$3.38/t	$0.00/t	20
PUL_EFF ALL_BBP	50%	-3.1%	-0.9%	$0.84/t	$0.02/t	20
PUL_EFF ALL_BBU	50%	-2.2%	-0.6%	$0.52/t	$0.00/t	20
PUL_AFU ALL_BGE	50%	0.0%	-38.9%	$41.45/t	$0.24/t	20
PUL_AFU ALL_BSB	33%	0.0%	0.0%	$128.01/t	$0.00/t	20
PUL_EFF ALL_CDR	18%	-3.5%	-1.1%	$1.58/t	$0.00/t	20
PUL_EFF ALL_EAC	33%	-6.1%	-1.8%	$1.15/t	$0.00/t	20
PUL_EFF ALL_FSU	75%	0.0%	-2.3%	$0.19/t	$0.00/t	20
PUL_EFF ALL_FWE	19%	-5.7%	-1.8%	$3.54/t	$0.00/t	20
PUL_EFF ALL_HRI	50%	-16.2%	-5.0%	$10.66/t	$0.11/t	20
PUL_EFF ALL_HWS	33%	-8.0%	-2.5%	$6.77/t	$0.00/t	20
PUL_EFF ALL_IER	75%	0.0%	-3.7%	$0.07/t	-$0.10/t	20
PUL_EFF ALL_INS	50%	-1.3%	-0.4%	$0.21/t	$0.00/t	20
PUL_EFF ALL_PEM	75%	0.0%	-6.0%	$2.46/t	$0.00/t	20
PUL_EFF ALL_PRM	75%	-2.6%	-2.1%	$3.20/t	$0.00/t	20
PUL_EFF ALL_PSU	75%	0.0%	-4.5%	$0.94/t	-$0.01/t	20
PUL_AFU ALL_SRC	28%	0.0%	-45.1%	$1.46/t	$0.00/t	20
PUL_EFF ALL_SSO	75%	-2.9%	-0.9%	$2.47/t	$0.00/t	20
PUL_AFU ALL_STS	33%	0.0%	-8.7%	$13.12/t	$0.00/t	20
PUL_EFF ALL_STU	50%	-21.0%	-5.7%	$1.07/t	$0.06/t	20
PUL_EFF BLE_BFR	50%	-59.8%	-7.6%	$5.14/t	-$0.11/t	20
PUL_EFF BLE_CPH	40%	-60.8%	-7.4%	$1.57/t	-$0.05/t	20
PUL_EFF BLE_PHR	33%	-26.3%	-7.8%	$6.00/t	-$0.23/t	20
PUL_AFU CPP_BGK	75%	-99.8%	0.0%	$61.04/t	$0.00/t	20
PUL_AFU CPP_BLG	50%	0.0%	-513.2%	$836.70/t	-$18.56/t	20
PUL_EFF CPP_CDM	17%	-54.6%	-6.8%	$1.48/t	$0.16/t	20
PUL_EFF CPP_CSC	20%	-33.4%	-3.7%	$1.30/t	-$0.35/t	20
PUL_EFF CPP_CSI	33%	-43.8%	-15.1%	$5.60/t	-$0.13/t	20
PUL_EFF CPP_DFC	50%	-12.6%	-1.6%	$1.72/t	-$0.05/t	20
PUL_EFF CPP_DHR	33%	-12.8%	-4.0%	$12.45/t	-$0.19/t	20
PUL_EFF CPP_HTM	50%	-11.8%	-3.6%	$0.14/t	-$0.02/t	20
PUL_EFF CPP_LKG	75%	-16.1%	0.0%	$8.16/t	-$0.06/t	20

Scenario name	Max. penetration	Δ EI (fuel)	Δ EI (electricity)	Incremental annualized costs Capital	Operating	Lifetime (years)
PUL_EFF CPP_RFH	75%	-1.3%	-18.2%	$58.45/t	$0.00/t	20
PUL_EFF CPP_SCW	33%	-49.8%	-36.5%	$45.52/t	-$27.86/t	20
PUL_EFF MPP_APT	33%	0.0%	0.0%	$25.88/t	-$5.49/t	20
PUL_EFF MPP_ARS	33%	0.0%	0.0%	$0.36/t	$0.00/t	20
PUL_EFF MPP_BTM	33%	0.0%	0.0%	$0.53/t	-$0.01/t	20
PUL_EFF MPP_CTI	20%	0.0%	0.0%	$30.00/t	$0.00/t	20
PUL_EFF MPP_HER	50%	0.0%	0.0%	$8.99/t	$1.91/t	20
PUL_EFF MPP_THR	25%	0.0%	0.0%	$17.46/t	$0.00/t	20
PUL_SDR PNB_AFF	33%	0.0%	0.0%	$0.00/t	$0.54/t	20
PUL_EFF PNB_DMS	50%	0.0%	0.0%	$1.21/t	-$0.08/t	20
PUL_EFF PNB_FWP	50%	0.0%	0.0%	$0.77/t	-$0.31/t	20
PUL_SDR PNB_RFS	33%	0.0%	0.0%	$129.90/t	-$19.78/t	20
PUL_EFF PNB_TRB	32%	0.0%	0.0%	$0.59/t	$0.00/t	20
PUL_EFF PUL_MHR	33%	-2.8%	-0.9%	$1.96/t	$0.00/t	20
PUL_EFF RPB_CLR	33%	0.0%	0.0%	$7.69/t	$0.00/t	20
PUL_EFF RPB_FRR	33%	0.0%	0.0%	$1.21/t	$0.00/t	20
PUL_EFF VFP_WHD	50%	-186.7%	-45.7%	$1.23/t	-$0.05/t	20
Residential						
RES_EFF SHC_HEB	85%	-40%	-40%	$15,000.00/hh	$0.00/hh	35
RES_EFF SHC_HEC	50%	-6%	-6%	$105.00/hh	$0.00/hh	10
RES_EFF APP_HEA	50%	0%	-20%	$1,050.00/device	$0.00/device	18
RES_EFF LIG_HEL	65%	0%	-80%	$105.00/hh	$0.00/hh	10
RES_EFF SHC_HEF	50%	-30%	0%	$2,205.00/hh	$0.00/hh	20
RES_EFF WHE_TKB	90%	-25%	0%	$787.50/hh	$0.00/hh	20
RES_EFF SHC_HAC	50%	0%	-30%	$4,305.00/hh	$0.00/hh	20

Table 37: Technical parameters for nation-wide developing GHG mitigation measures

Scenario name	Δ GI	Δ EI (fuel)	Δ EI (electricity)	Total annualized costs Capital	Operating	Life
Commercial and institutional						
COM_ELE SHC_GHP	Uses electricity equal to 35% of the energy consumed by a standard combustion furnace, and 50% of the energy consumed by a standard A/C unit			$47.41/m^2	$0.00/m^2	25
COM_CCU SHC_CCU	-13%	-10%	n/a	$61.94/m^2	-$1.78/m^2	25
Mineral mining						
MIN_ELE TRA_AHT	n/a	-54%	-60% (vent.)	$14.30/t	$0.33/t	12
MIN_EFF TRA_AHT	n/a	-22%	-20% (vent.)	$9.40/t	$0.63/t	7
MIN_ELE LOA_LHD	n/a	-67%	-40% (vent.)	$0.07/t	$0.00/t	4
MIN_EFF LOA_LHD	n/a	-30%	-30% (vent.)	-$0.18/t	$0.00/t	4
MIN_AFU LOA_LHD	n/a	-50%	-39% (vent.)	$0.74/t	$0.14/t	4
Oil sands						
OIL_SDR SAG_SAS	n/a	-52%	+100 kWh/m^3	$56.80/bbl	$65.80/bbl	35
OIL_SDR SAG_VPX	n/a	-52%	+100 kWh/m^3	$56.80/bbl	$65.80/bbl	35
OIL_SDR CSS_LSR	n/a	-45%	+115 kWh/m^3	$98.20/bbl	$61.80/bbl	35
OIL_SDR SAG_NSL	n/a	-95%	+124 kWh/m^3	$38.90/bbl	$72.30/bbl	35

				Total annualized costs		
Scenario name	**Δ GI**	**Δ EI (fuel)**	**Δ EI (electricity)**	**Capital**	**Operating**	**Life**
OIL_SDR SAG_ESE	n/a	-92%	+591 kWh/m^3	$50.30/bbl	$62.30/bbl	35
OIL_SDR SAG_ERB	n/a	-78%	+100 kWh/m^3	$53.80/bbl	$47.00/bbl	35
OIL_SDR SAG_SEG	n/a	-44%	+100 kWh/m^3	$48.80/bbl	$72.30/bbl	35
OIL_ELE UPG_WNT	n/a	-100%	n/a	$3.44/kg$H_2$	$13.11/kg$H_2$	20
OIL_ELE UPG_WNF	n/a	-100%	n/a	$0.21/kg$H_2$	$9.49/kg$H_2$	20
OIL_ELE UPG_HYD	n/a	-100%	n/a	$0.15/kg$H_2$	$2.43/kg$H_2$	40
OIL_AFU UPG_BIG	n/a	-100%	n/a	$0.51/kg$H_2$	$0.57/kg$H_2$	20
OIL_AFU UPG_BIP	n/a	-100%	n/a	$0.52/kg$H_2$	$2.11/kg$H_2$	20
OIL_AFU CSS_SLS	n/a	-100%	n/a	$16.23/bbl	$6.75/bbl	20
OIL_AFU SAG_NUC	n/a	-100%	n/a	$6.41/bbl	$1.03/bbl	30
OIL_AFU SMI_GEO	n/a	-100%	n/a	$1.71/bbl	$1.05/bbl	30
OIL_CCS UPG_SMR	-65%	+25%	+0.021 GJ/bbl	$1.37/kg$H_2$	$0.32/kg$H_2$	20
OIL_CCS UPG_UCG	-82%	-100% (+0.4 tCoal/kgH_2)	+0.024 GJ/bbl	$2.25/kg$H_2$	$0.38/kg$H_2$	20
OIL_CCU UPG_SMR	-65%	+25%	+0.007 GJ/bbl	$1.26/kg$H_2$	$0.30/kg$H_2$	20
OIL_CCU UPG_UCG	-82%	-100% (+0.4 tCoal/kgH_2)	+0.024 GJ/bbl	$2.01/kg$H_2$	$0.36/ kg$H_2$	20
OIL_CCS SAG_OFN	-90%	+1%	+4.7 kWh/kgH_2	$16.11/kg$H_2$	$8.64/kg$H_2$	20
OIL_CCS SAG_OFB	-80%	-100% (+1.54 GJ bit/kgH_2)	+4.7 kWh/kgH_2	$16.47/kg$H_2$	$8.64/kg$H_2$	20
OIL_CCU SAG_OFN	-90%	+1%	+4.7 kWh/kgH_2	$15.50/kg$H_2$	$6.09/kg$H_2$	20
OIL_CCU SAG_OFB	-80%	-100% (+1.54 GJ bit./kgH_2)	+4.7 kWh/kgH_2	$15.87/kg$H_2$	$6.37/kg$H_2$	20
Residential						
RES_ELE SHC_AHP	Uses electricity equal to 35% of the energy consumed by a standard combustion furnace, and 50% of the energy consumed by a standard A/C unit			$10,000.00/hh	$0.00/hh	20
RES_CCU SHC_BCC	-13%	-10%	n/a	$8,510.87/ hh	-$244.66/hh	20
Transport						
TRA_AFU ROA_HFC	n/a	-100%	+1.23 MJ/veh km (H_2)	vehicle-specific		10
TRA_EFF ROA_HEV	n/a	-45%	n/a	vehicle-specific		10
TRA_ELE ROA_PHV	n/a	-55%	+0.45 MJ/veh km	vehicle-specific		10
TRA_ELE ROA_BEV	n/a	-100%	+0.57 MJ/veh km	vehicle-specific		10

Appendix H: Regional validation figures

The figures below show GHG emissions calculated with the LEAP model for disaggregated sectors in all regions alongside values reported in the National Inventory Report (NIR).

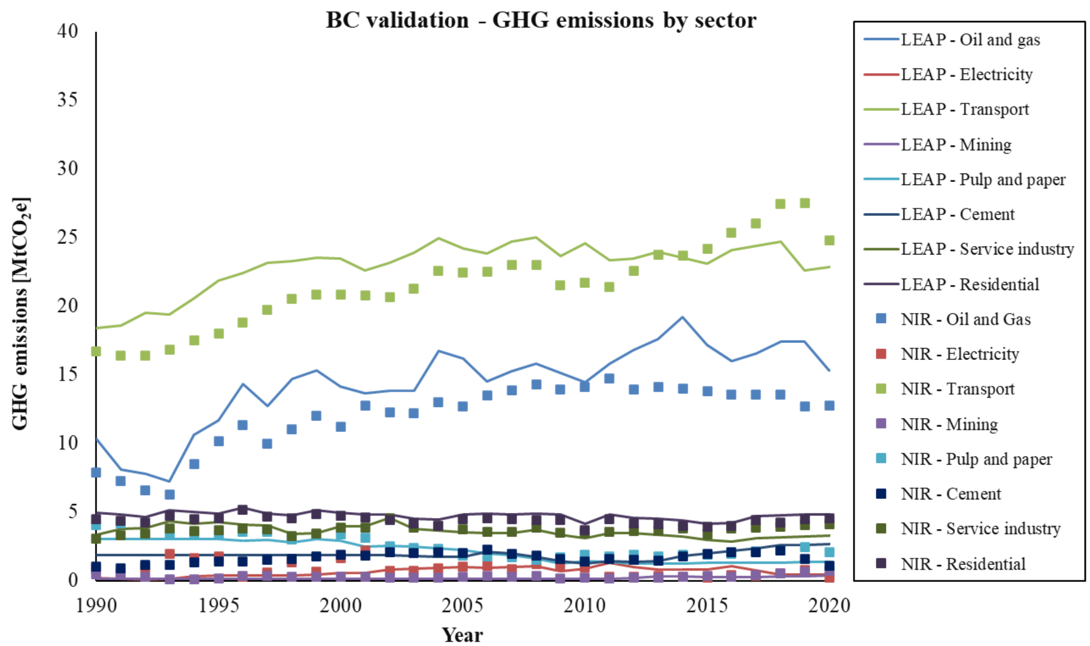

Figure 79: Modelled and reported historical GHG emissions for BC

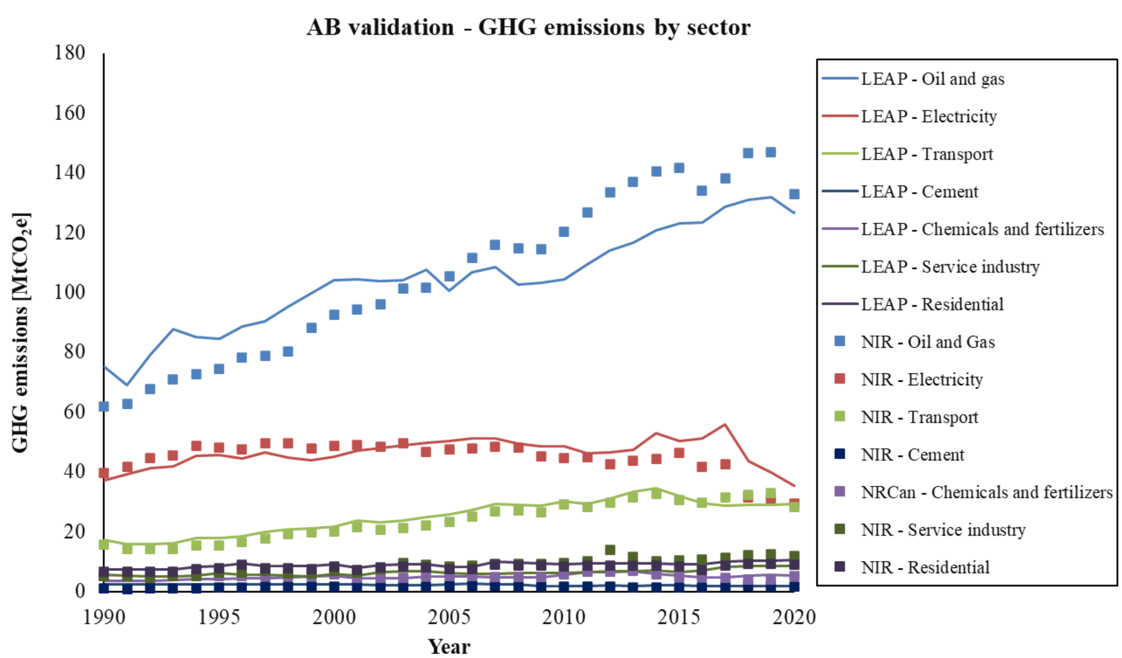

Figure 80: Modelled and reported historical GHG emissions for AB

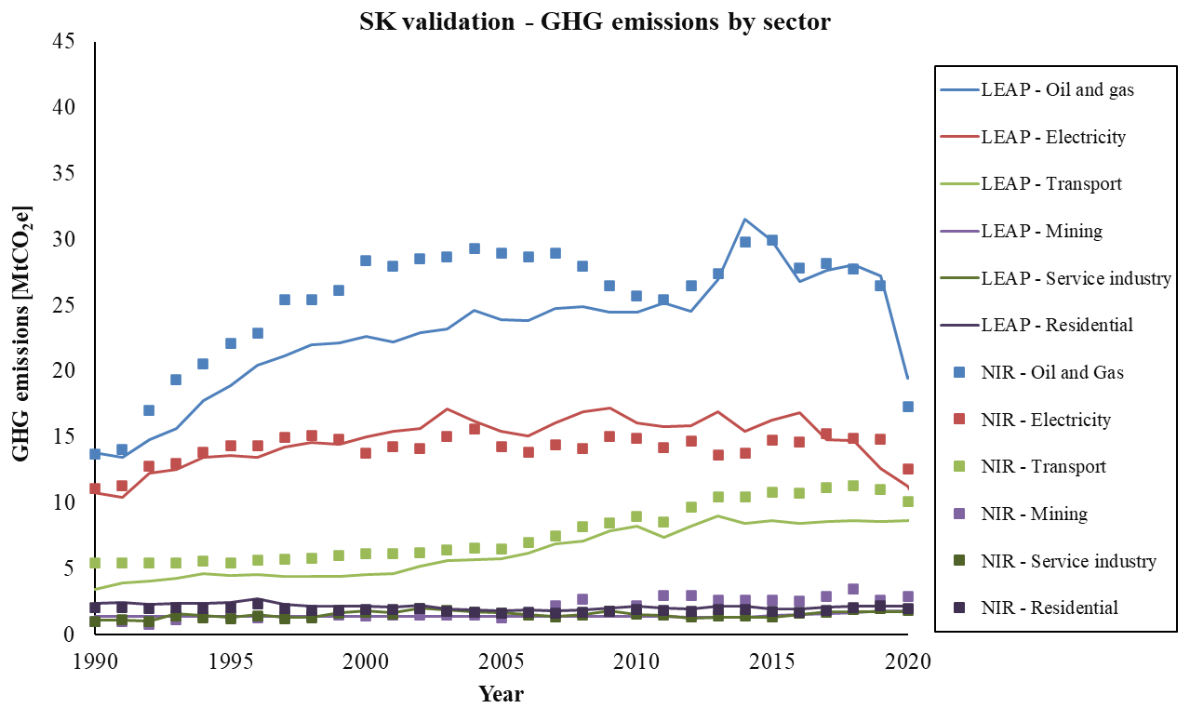

Figure 81: Modelled and reported historical GHG emissions for SK

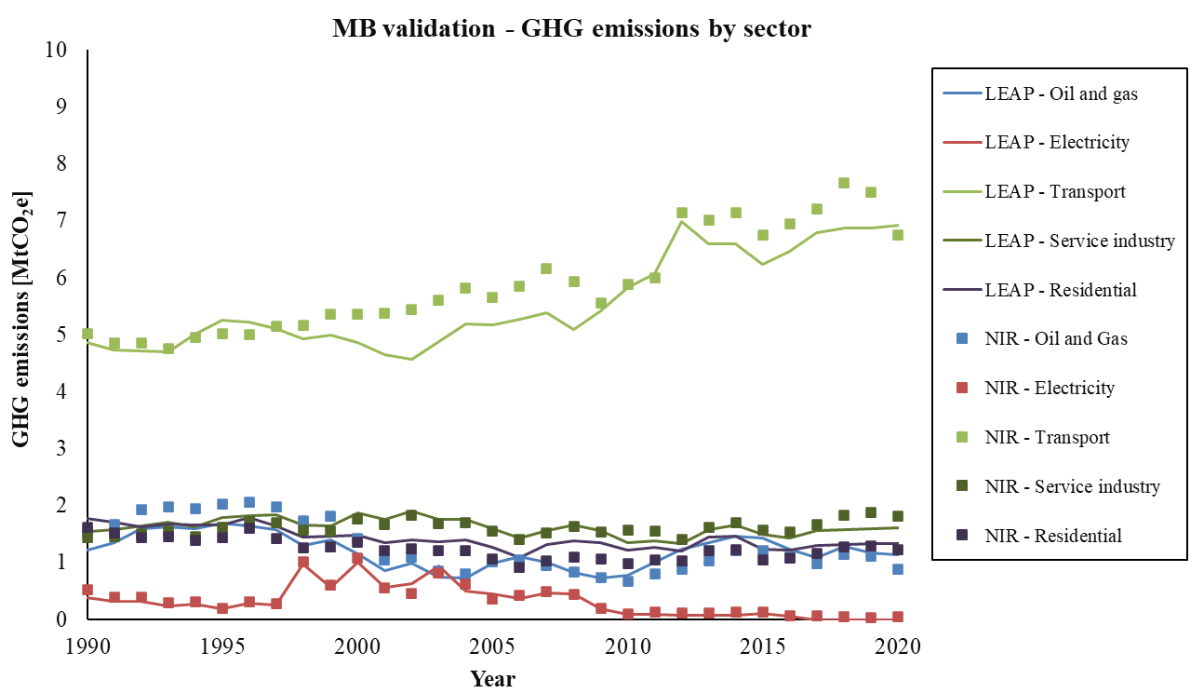

Figure 82: Modelled and reported historical GHG emissions for MB

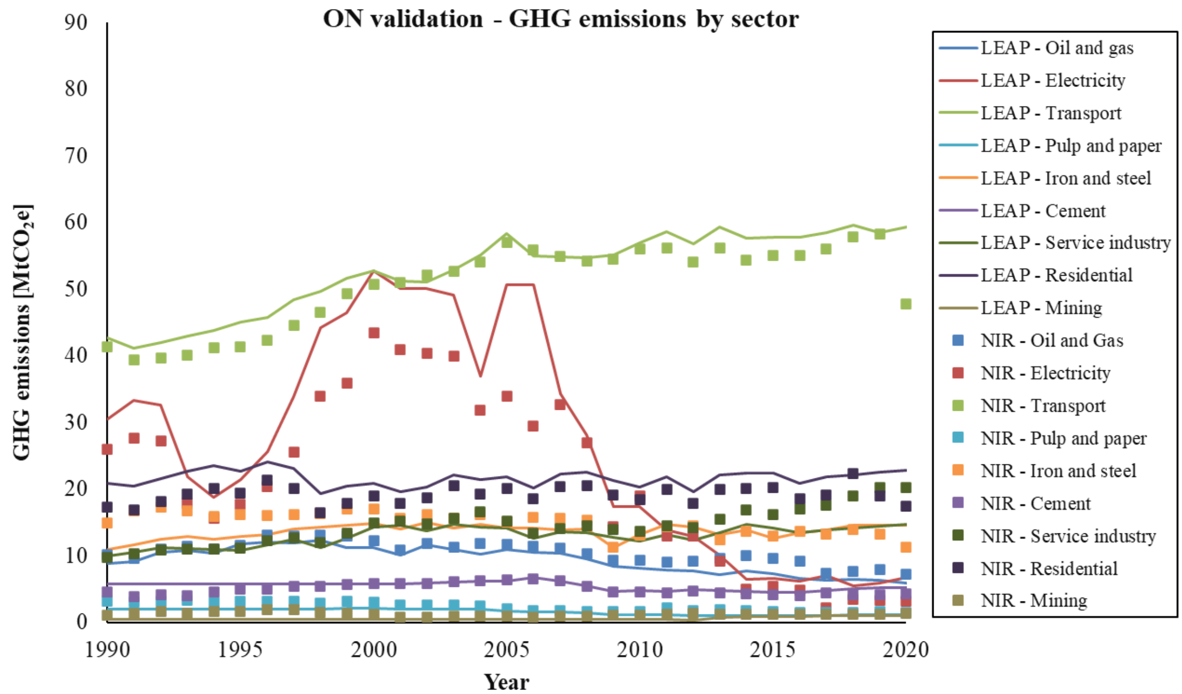

Figure 83: Modelled and reported historical GHG emissions for ON

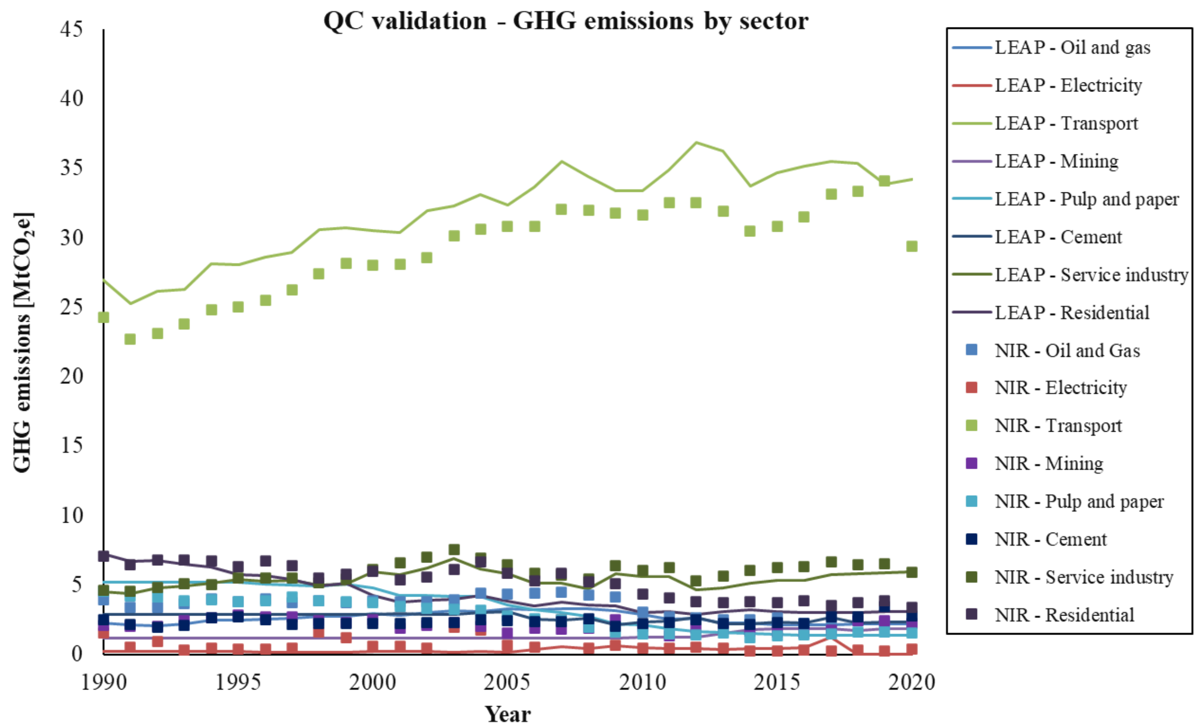

Figure 84: Modelled and reported historical GHG emissions for QC

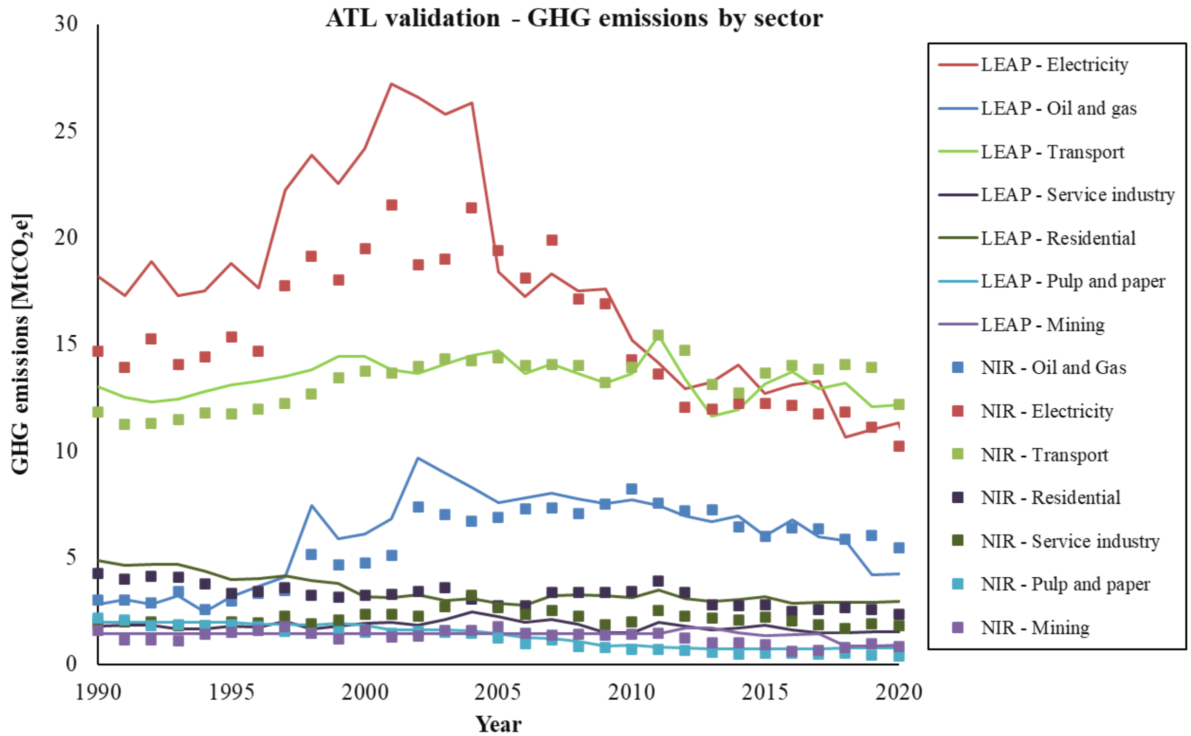

Figure 85: Modelled and reported historical GHG emissions for ATL