Impacts and Opportunities in Alberta's Net Zero Energy System

SUBMITTED TO

Alberta Innovates
Emissions Reduction Alberta
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SUBMITTED BY

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About Us

Navius Research Inc. (“Navius”) is a private consulting firm in Vancouver. Our consultants specialize in analysing government and corporate policies designed to meet environmental goals, with a focus on energy and greenhouse gas emission policy. We have been active in the energy and climate change field since 2004 and are recognized as some of Canada’s leading experts in modeling the environmental and economic impacts of energy and climate policy initiatives. Navius is uniquely qualified to provide insightful and relevant analysis in this field because:

- We have a broad understanding of energy and environmental issues both within and outside of Canada.
- We use unique in-house models of the energy-economy system as principal analysis tools.
- We have a strong network of experts in related fields with whom we work to produce detailed and integrated climate and energy analyses.
- We have gained national and international credibility for producing sound, unbiased analyses for clients from every sector, including all levels of government, industry, labour, the non-profit sector, and academia.

Executive Summary

Achieving net zero emissions is challenging for Alberta for a few reasons - the province is historically a large fossil fuel producer, is home to emissions intensive, expensive-to-abate industry, and has historically relied on an emissions intensive electricity sector. It is within this context, and Canada's ambition to achieve net zero emissions by 2050, that Alberta Innovates and Emissions Reduction Alberta are interested in understanding the future of Alberta's energy system. This analysis evaluates future possible energy systems that achieve net zero emissions in Alberta by 2050 and provides insight into key uncertainties and opportunities for Alberta's energy system in a net zero future.

Analytical approach

Custom versions of Navius' energy-economy model, gTech, and electricity model, IESD, were created to achieve the objectives of this analysis. As a technologically explicit model, gTech accounts for a large range of abatement technologies (over 300 technologies across more than 80 end-uses), while IESD provides additional detail on technologies specific to the electricity sector. Model updates were made to account for dynamics and technologies that are particularly important for Alberta in a net zero future. This includes:

- The ability to simulate different grades of crude oil being used to produce different refined products (bitumen beyond combustion).
- Updated parameterization of solvent-based extraction.
- Addition of carbon capture, storage and utilization technologies including molten carbonate fuel cells, enhanced oil recovery, oxy-combustion natural gas turbines and carbon storage in concrete.
- Updated representation of the Alberta electricity market, simulating marginal cost electricity prices, which differs from other electricity markets across Canada.

Together, this modeling toolkit allows for a comprehensive examination of the impacts of different net zero emission pathways on Alberta's energy future.

Scenario design

These models were used to examine three policy scenarios – current policy ("business as usual"), announced policy and net zero policy. This report focuses on results of the net zero scenario. This scenario includes all currently legislated federal and provincial policies[1] and a cap on emissions at Canada's 2030 emissions target (40-45% reduction from 2005 levels) and net zero emissions in 2050. It assumes that Alberta achieves net zero emissions within its borders, while the rest of Canada also achieves net zero emissions by 2050, and that the U.S. implements stringent climate policy consistent with net zero. It assumes a certain number of emission offsets are available via land-use, land-use change and forestry (LULUCF) in Alberta (12.6 Mt in 2030 and 20.3 Mt in 2050), based on a report by Nature United[2] with additional Alberta-specific information provided by the authors.

Key uncertainties in Alberta's net zero future were examined using sensitivity analysis, including the availability and cost of direct air capture (DAC), cost of carbon capture and storage (CCS), cost of hydrogen production and hydrogen fuel cell vehicles, cost of renewables, batteries and hydrogen storage, and the future global oil price. Detailed assumptions about each sensitivity are provided in the report. Simulating all possible combinations of these sensitivities under net zero policy resulted in examination of over 100 possible net zero pathways for Alberta.

Alberta's net zero energy system

Previous analyses indicate the need for transformation of Canada's energy system to achieve net zero emissions. In general, this transition is away from the combustion of fossil fuels for energy and towards clean electricity and renewable fuels such as renewable natural gas (RNG) and hydrogen. The same is true for Alberta. However, there is uncertainty in the future of some sectors of Alberta's economy, which are uniquely challenging to decarbonize. This includes transitioning the oil and gas sector and a fossil fuel-dominant electricity system.

As such, this report focuses on sectors that are particularly challenging for Alberta's transition to net zero – oil sands, conventional oil, natural gas, and electricity. It also highlights key technologies and opportunities that could become important in helping these sectors transition. Results of this analysis suggest several opportunities could arise for Alberta while addressing the challenge of achieving net zero emissions.

Oil production

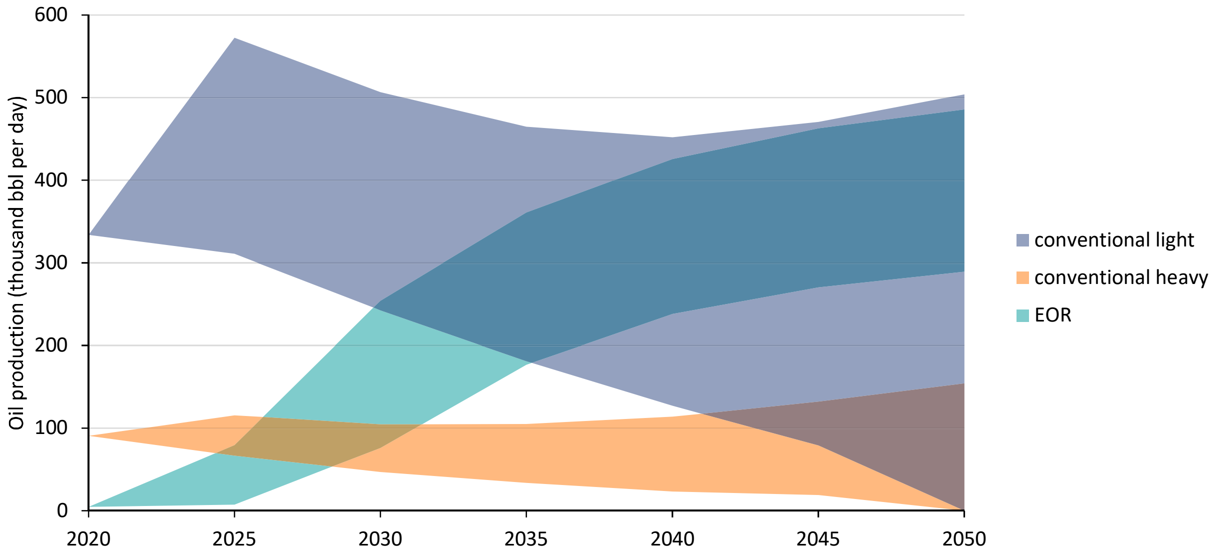
The future of oil production in Alberta is uncertain under net zero policy and is highly dependent on global demand for oil.

There is significant uncertainty in the future of conventional oil production in Alberta under net zero emissions. Total conventional oil production changes from 425

[1] Legislated as of Fall 2022.
[2] https://www.science.org/doi/10.1126/sciadv.abd6034

thousand barrels per day in 2020 to 0-654 thousand barrels per day in 2050 depending on the net zero scenario (Figure A). This range is driven mostly by global demand for oil (i.e., the assumed global oil price), but in the long term (between 2045 and 2050) is also driven by the availability of DAC technology.

Figure A: Oil production in Alberta (range across all net zero scenarios)



Across all net zero scenarios, continued oil production is combined with adoption of methane management technologies, electrification where possible, CCS, and DAC (if available) to mitigate emissions. As such, lower costs of technologies like CCS and DAC are critical to improve the competitiveness of the oil and gas sector in a net zero future.

Enhanced oil recovery offsets some declines in conventional oil production and plays a critical role in deployment of CCS in the near term.

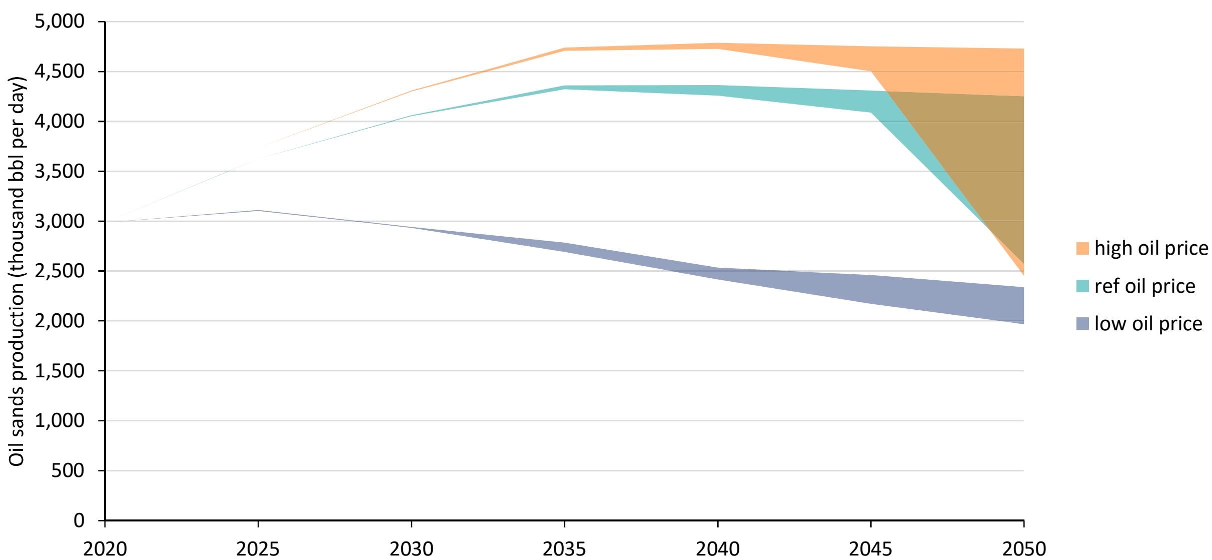
Declines in conventional oil production in a net zero future are partially offset by production using enhanced oil recovery (EOR), which increases significantly in all scenarios, ranging from 76-254 thousand barrels per day in 2030 and 289-483 thousand barrels per day in 2050 (Figure A). EOR creates new revenue for Alberta – it creates a revenue stream for the oil and gas sector by allowing for lower emission oil production, but also creates a new revenue stream for adopters of CCS technology that can sell captured CO_2 for use in EOR. As such, EOR creates an incentive for CCS adoption, increasing adoption in the near term. Of the 10-51 Mt of CCS occurring in Alberta in 2030 in the net zero scenarios simulated, 8-28 Mt of captured CO_2 is used for EOR.

Bitumen's comparative advantage in producing non-combustion commodities means it outcompetes lighter grades of crude oil in a net zero future.

A critical question facing Alberta in a net zero emission future is the role of the oil sands. Similar to conventional oil production, bitumen production from Alberta's oil sands sector is uncertain in a net zero future, particularly in situ oil sands production. Figure presents the range in bitumen production across all net zero scenarios simulated, which is largely driven by global demand for oil. In scenarios where the global oil price is high, production increases from 2,985 thousand barrels per day in 2020 to up to 4,729 thousand barrels per day in 2050. If the global oil price is low, production from the oil sands could decline to 1,968 thousand barrels per day by 2050.

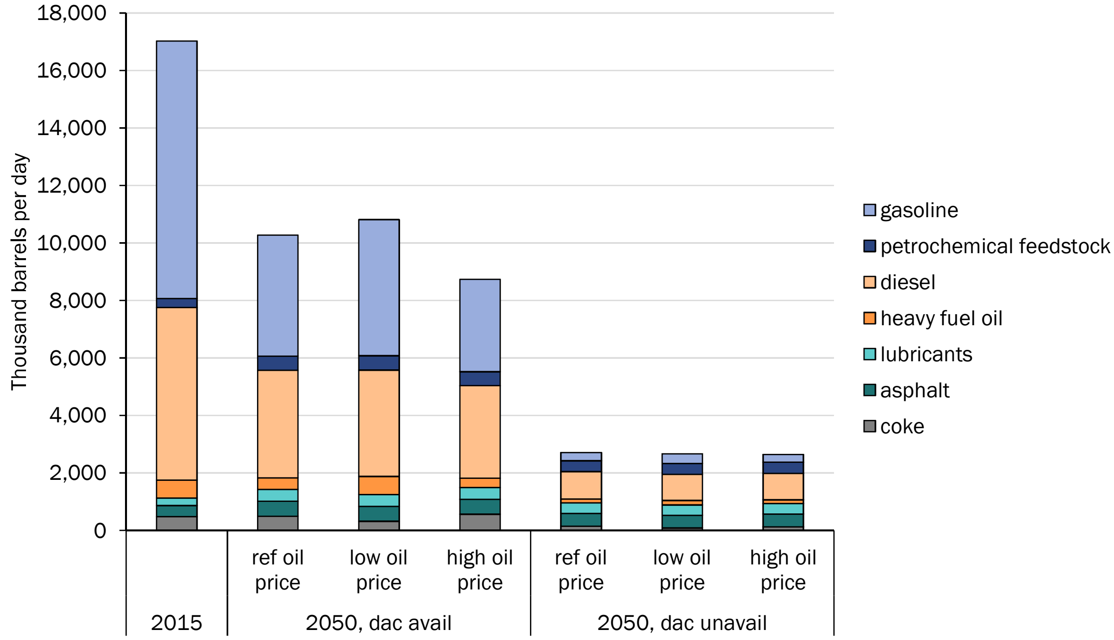
However, production from this sector does not decline as significantly as conventional oil production under net zero policy. Figure B indicates that oil sands production continues out to 2050 in all net zero scenarios simulated. This is a result of the refinery updates made to gTech for this analysis, which account for the comparative advantage of bitumen in producing the heavier ends of the barrel.

Figure B: Oil sands production (range across all net zero scenarios)



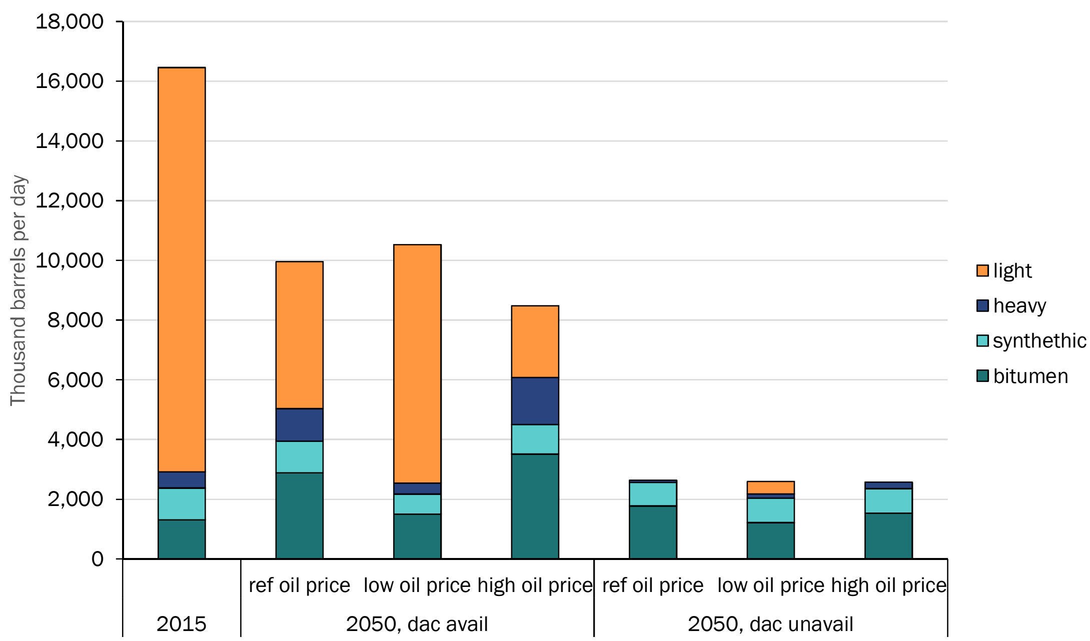
Bitumen currently produces oil at the heavy end of the barrel, which is cracked into the lighter end of the barrel in upgraders and/or refineries to produce liquid fuels. However, in a net zero future in which Alberta achieves deep emissions reductions, there is a reduction in liquid fuels use as demand shifts away from internal combustion engine vehicles to battery electric or fuel cell electric vehicles. As a result, demand for gasoline and diesel declines significantly by 2050, while demand for asphalt and lubricants remains, as illustrated in Figure C.

Figure C: Demand for oil products under net zero policy in Canada and the U.S.



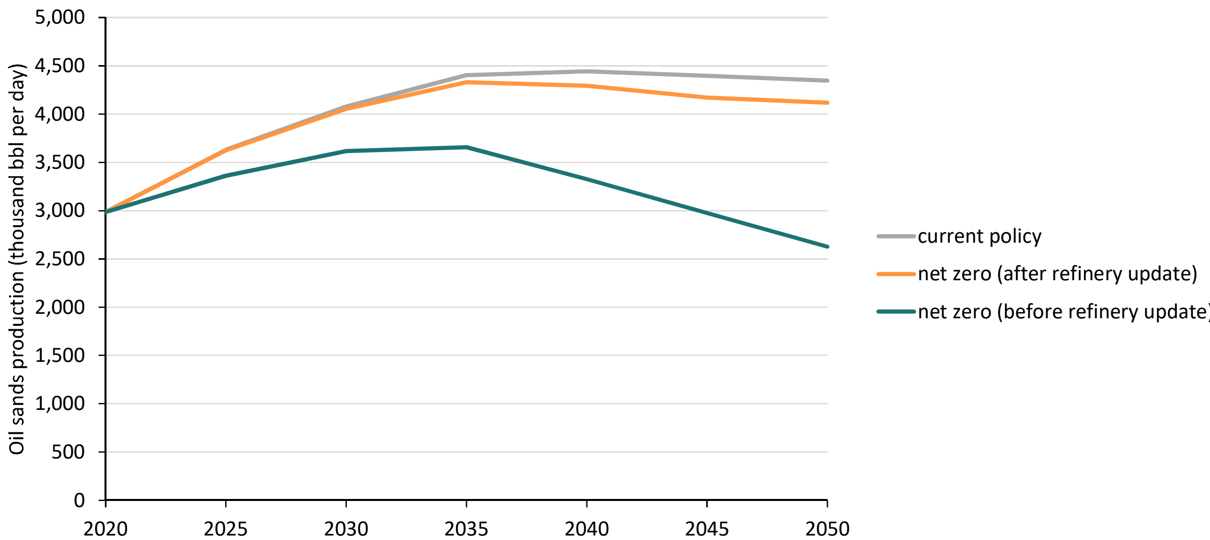
Heavier crudes (like bitumen) have a comparative advantage in producing products in the range for which demand remains in a net zero future. As a result, there is an opportunity to use bitumen to produce asphalt and lubricants instead of liquid fuels, prolonging the life of bitumen in a net zero future. To take advantage of this opportunity, Canadian and U.S. refinery input changes significantly under net zero policy, from mostly light oil in 2020 to more heavy oil and bitumen by 2050 (Figure D).

Figure D: Refinery input under net zero policy in Canada and the U.S.



This has a significant impact on the role of Alberta's oil sands in a net zero future. When accounting for these advantages, results suggests that oil sands may be the "last barrel standing" in 2050 in many net zero scenarios[3]. This is a divergence from previous net zero analyses (conducted prior to adding refinery detail into gTech). Without accounting for the comparative advantage that different grades of crude oil have in producing refined products, oil sands production declines significantly under net zero policy, as indicated in Figure E.

Figure E: Oil sands production under net zero before and after refinery model update[4]



Electricity

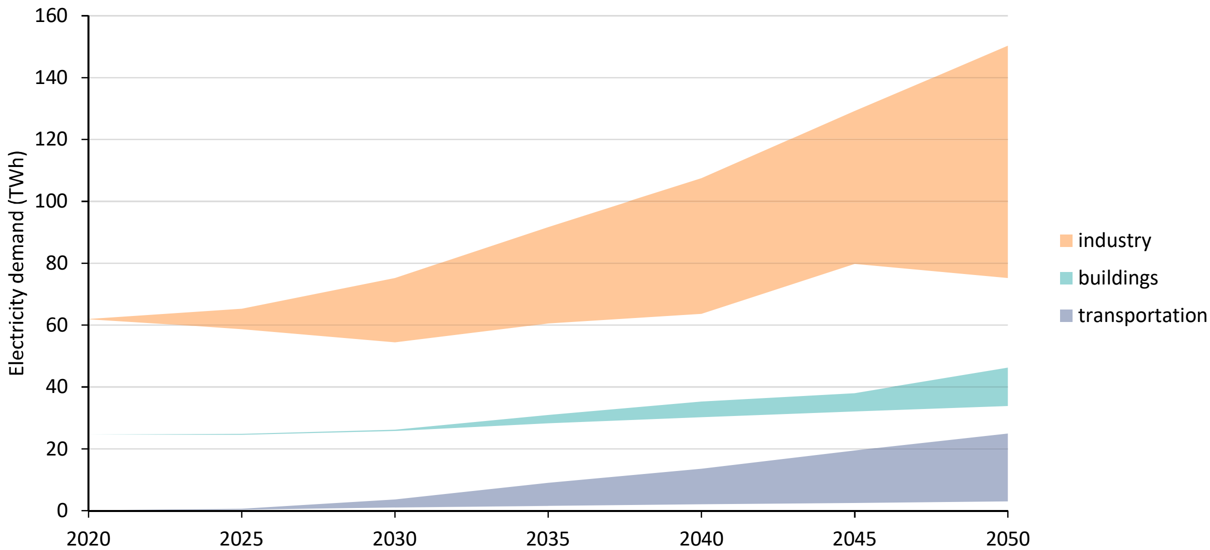
Alberta's electricity sector faces two significant challenges in a net zero future. The first is decarbonizing the province's current electricity grid, which is predominately made up of fossil fuel generation (approximately 90% of generation in 2020). The second is increasing generating capacity to keep up with increasing demand as other sectors of Alberta's economy electrify to comply with net zero.

Figure indicates significant growth in electricity demand across all sectors of Alberta's economy, increasing by 46-139% from 2020 to 2050 in a net zero future. Electricity demand is driven by three key factors. Demand is highest in net zero scenarios in which DAC is not available, as sectors rely more heavily on electrification to reduce emissions when offsets are not available. Electricity demand is also higher in scenarios where Alberta's economy grows more rapidly, which occurs when the global oil price is high. And finally, electricity demand is highest in scenarios in which renewable, battery

[3] The role of oil sands could be even greater if accounting for growth in international demand for asphalt. This, and other limitations of our modeling approach, are discussed further in the report.
[4] This net zero scenario assumes DAC is available, reference global oil price and reference low carbon technology costs.

and hydrogen storage costs come down faster over time, as it is less costly to produce clean electricity. These factors are what drive the low and high end of the range in Figure.

Figure F: Electricity demand by sector in Alberta (range across all net zero scenarios)



Alberta's net zero energy system relies on significant growth in electricity generation, including both renewables with storage and natural gas with CCS.

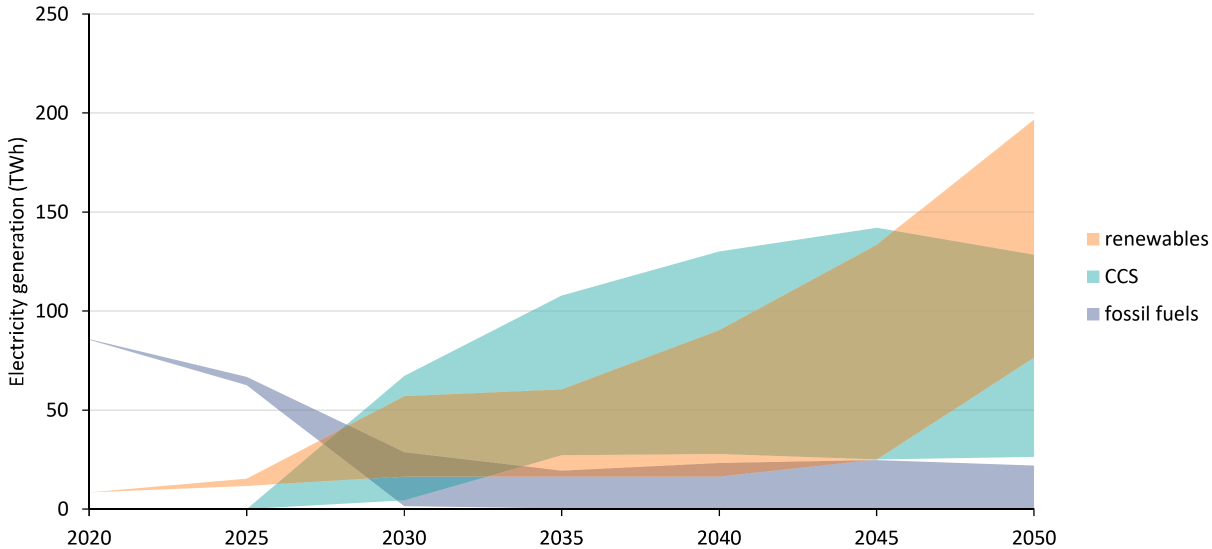
To meet growing electricity demand while decarbonizing, there is significant adoption of renewable electricity generation in the province, as well as installation of CCS on natural gas generation. Figure G presents a range in electricity generation in Alberta across all net zero scenarios simulated. It indicates significant growth in renewable generation, including wind and solar generation, from 8 TWh in 2020 to 77-197 TWh in 2050 under net zero policy. Solar generation increases significantly in all scenarios, from 0.1 TWh in 2020 to 48-143 TWh in 2050, while wind generation increases from 6 TWh in 2020 to 24-63 TWh in 2050.

As intermittent renewables are adopted, storage becomes an important component of Alberta's electricity system to ensure grid reliability and allow for reduced reliance on back-up natural gas capacity. As a result, significant battery and hydrogen storage is adopted to support a highly intermittent grid in some net zero scenarios. Results indicate that storage capacity in Alberta could increase up to 395 GWh by 2050 under net zero policy, with short duration storage adoption ranging from 42-182 GWh and long-duration ranging from 0-273 GWh in 2050.

At the same time, most natural gas electricity generation is fitted with CCS technology. Electricity generation with CCS is available in 2030 and increases to 26-128 TWh by

2050. This includes utility electricity generation, as well as the use of molten carbonate fuel cells (MCFC) and CCS on cogeneration in industry.

Figure G: Electricity generation in Alberta (range across all net zero scenarios)



Results indicate a trade-off between renewable generation with storage and natural gas generation with CCS, depending on the net zero scenario. Across all net zero scenarios, utility generation is dominated by renewables by 2050, facilitated by storage. Renewable generation is highest in scenarios with low renewable, battery and hydrogen storage costs and high CCS costs.

However, in scenarios in which DAC is not available and there is high demand for oil, natural gas with CCS is the primary source of electricity generation in 2050 across the province, driven by cogeneration with CCS and MCFC adoption in industry. This indicates investment in expansion of both CCS and renewables is important to facilitate Alberta's net zero electricity system.

Carbon capture

Several carbon capture, utilization and storage technologies were explored in this analysis, including CCS on process heat, formation CO_2, cogeneration, electricity generation, and hydrogen production. Additionally, we explored the role of MCFC, oxy-combustion gas turbines and DAC.

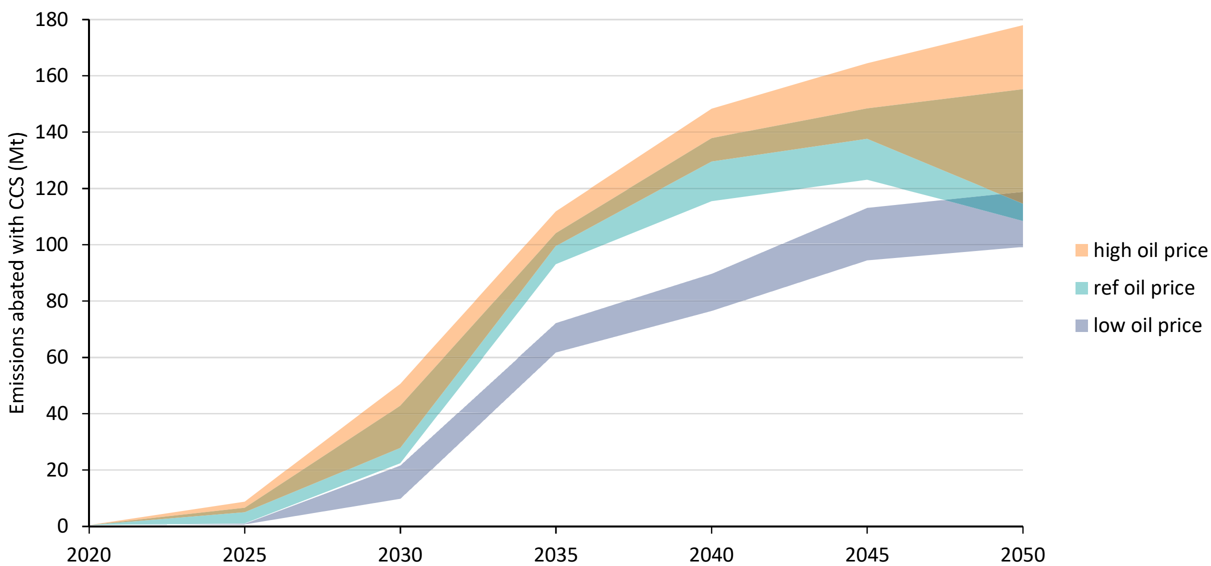
Carbon capture technology is likely to play a transformative role in Alberta's net zero energy system.

CCS adoption across Alberta's economy ranges from 10-51 Mt in 2030, 77-148 Mt in 2040 and 99-178 Mt in 2050 depending on the net zero scenario. Most adoption occurs in Alberta's industrial sector for process heat (including MCFC), where it plays an important role in mitigating emissions.

Although different CCS cost assumptions (low, reference and high) were simulated in this analysis, results suggest that CCS adoption is not driven by the future cost for CCS. Instead, CCS adoption is driven by demand for emissions abatement in industry, particularly the oil and gas sector. Figure H presents CCS adoption in Alberta as a range across net zero policy scenarios, indicating that oil price drives the upper and lower end of the range of CCS adoption.

A high oil price incentivizes CCS adoption in two ways. First, higher oil prices indicate higher demand for oil and lead to greater oil production, and therefore greater investment in CCS technology to reduce emissions in this sector. Second, higher oil prices create a greater incentive for oil production from EOR, which creates a market for captured CO_2 to be used for EOR.

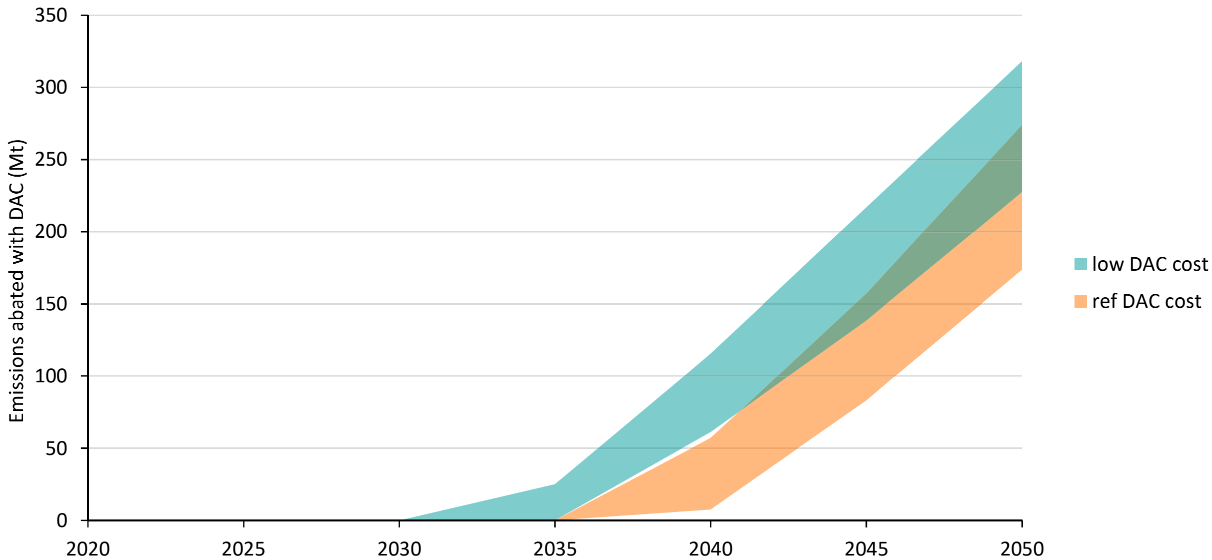
Figure H: CCS adoption in Alberta (range across all net zero scenarios)



In addition to CCS technologies, DAC could play a significant role in Alberta's net zero energy system. Proximity to suitable CO_2 storage makes Alberta an ideal location for a DAC industry and allows the province to offset CO_2 emitted from other regions in Canada. In fact, if DAC is available, Alberta becomes a net emission sink in Canada, helping other provinces to achieve net zero by providing negative emission credits. Alberta's emissions range from -89 to -209 Mt in 2050 in net zero scenarios where DAC is available.

When available, and when net zero policy is implemented, DAC adoption in Alberta ranges from 9-116 Mt in 2040 and 174-318 Mt in 2050 to offset emissions that remain in Alberta and across Canada (Figure I). DAC adoption is driven by the future cost of the technology, with the most adoption occurring in net zero scenarios with low DAC costs, and lower adoption occurring when a reference cost trajectory is assumed.

Figure I: DAC adoption in Alberta (range across all net zero scenarios with DAC available)



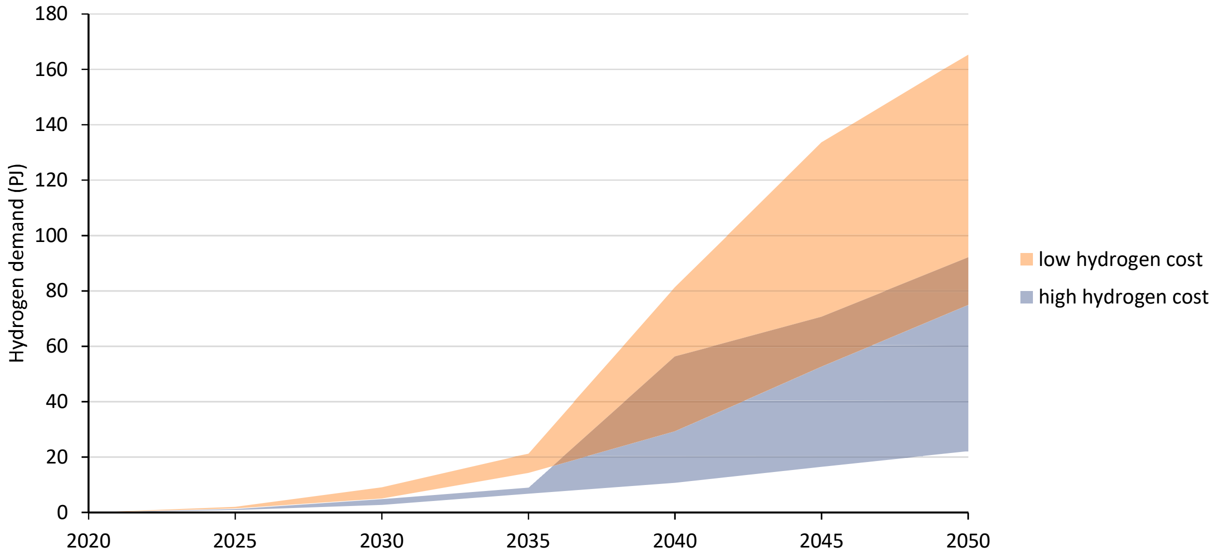
If available, direct air capture technology could make Alberta's net zero transition easier and less costly.

Many scenarios were simulated in this analysis without DAC available, in which case Alberta can still achieve net zero emissions. However, the cost of doing so is higher, as DAC allows for the continued use and production of fossil fuels in the province by providing the ability to offset emissions. As such, DAC not only creates a new revenue stream that directly contributes to the economy, but the availability of DAC allows for greater economic activity in other sectors of the economy, leading to additional GDP benefits. This suggests that the availability of DAC technology is important for minimizing the cost of achieving a net zero energy system in Alberta.

Hydrogen

Hydrogen is a potentially important low carbon fuel if produced with low emissions, such as via steam methane reformation (SMR) with CCS or electrolysis with renewable electricity. Demand for hydrogen increases across all net zero scenarios simulated, from virtually none in 2020 to 22-165 PJ in 2050. Hydrogen adoption is driven by the extent to which hydrogen production costs and hydrogen fuel cell vehicle costs decline over time, as indicated in Figure J which presents hydrogen adoption as a range across all net zero scenarios with low or high hydrogen cost assumptions.

Figure J: Hydrogen fuel adoption in Alberta (range across all net zero scenarios)[5]



Hydrogen adoption occurs mostly in the transportation sector to reduce emissions from hard-to-electrify medium- and heavy-duty transportation (66% of hydrogen consumption in 2050) and the oil and gas sector where it can be blended into natural gas for process heat (15% of hydrogen consumption in 2050).

Economic implications of net zero for Alberta

GDP

Alberta's economy-wide GDP increases in all net zero scenarios simulated, with the average annual GDP growth rate ranging from 0.8-1.9% from 2020 to 2050 depending on the net zero scenario.

Alberta's economy is resilient to a net zero future. Economic growth depends primarily on future global demand for oil and the cost of carbon capture.

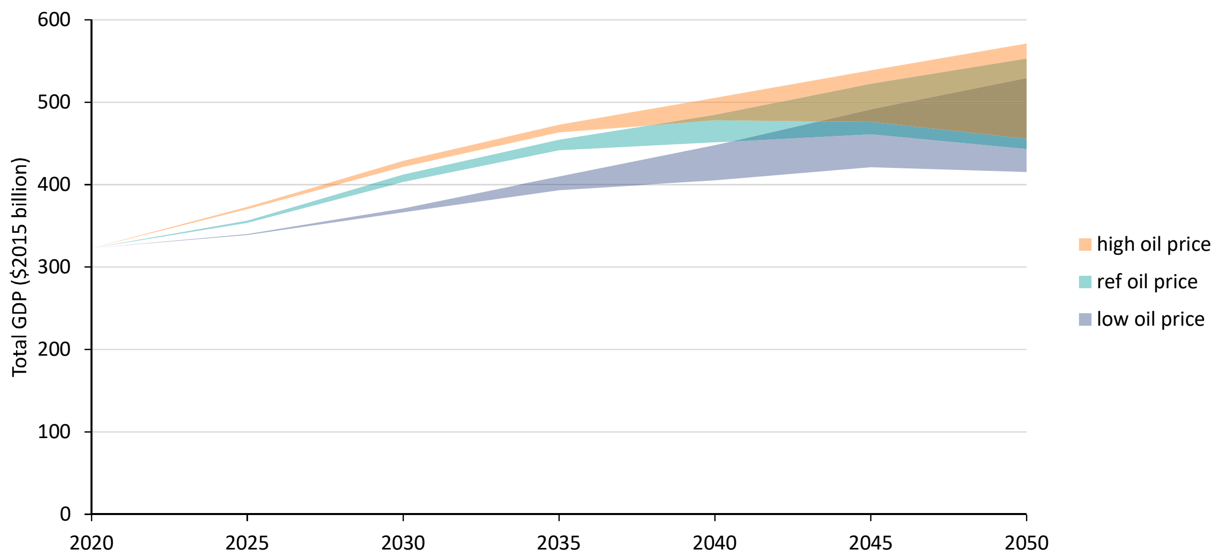
Alberta's GDP grows most in scenarios in which the province continues to produce oil and gas and continues to consume fossil fuels, either capturing emissions with CCS or offsetting emissions with DAC. As such, two key factors that drive the difference in GDP growth across net zero scenarios are the global demand for oil and whether DAC technology is available.

[5] Hydrogen cost refers to both the cost of hydrogen production (SMR with CCS and electrolysis) and the cost of hydrogen fuel cell vehicles, as presented in Section 3.2.6 and 3.2.8.

In scenarios in which DAC is available and global demand for oil is high (i.e., high oil price), Alberta's GDP increases to up to $571 billion in 2050. Alberta's economy grows least in scenarios in which global demand for oil is low, DAC is not available, and low carbon technology costs (including CCS, hydrogen, renewables and storage) are high, leading to a GDP of $415 billion in 2050.

The impact of future global oil demand on Alberta's net zero economy is demonstrated in Figure K, which indicates higher provincial GDP in scenarios in which we assume a high global oil price and lower GDP in scenarios with a low global oil price. If there is little global demand for Alberta's oil and gas, it is not worth investing in emissions abatement in these sectors. Instead, oil and gas production declines in the province, leading to a smaller overall economy in 2050.

Figure K: Alberta's GDP under different oil price forecasts (range across all net zero scenarios)

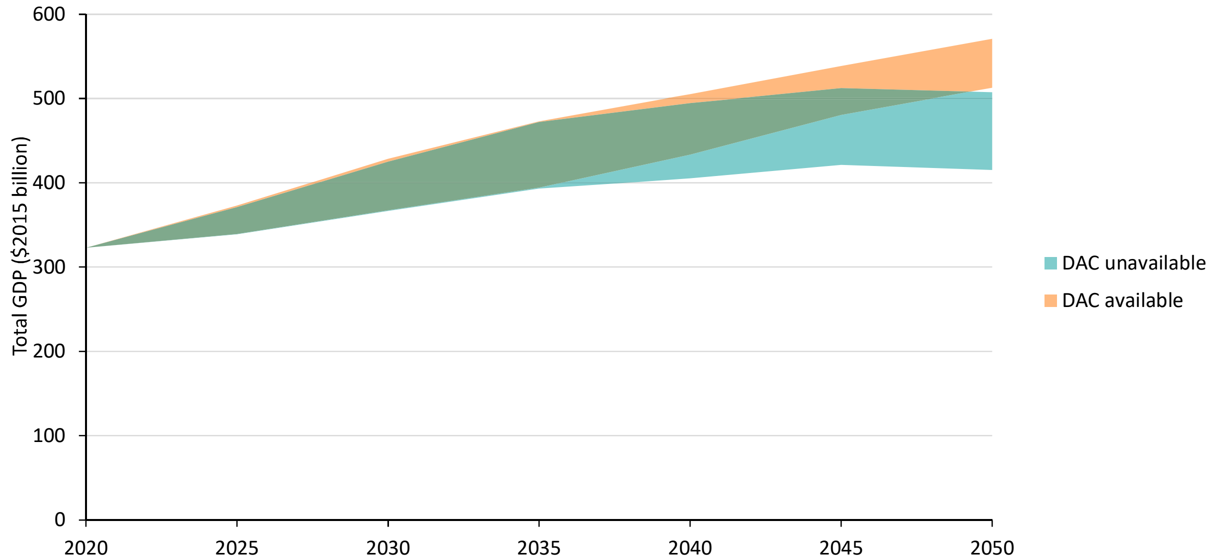


However, Figure also indicates significant overlap between potential economic outcomes independent of the global oil price. The overlap between these ranges is driven by DAC availability, and to a lesser extent, the cost of CCS technology.

Alberta's GDP grows more after 2035 when DAC technology becomes available, relative to scenarios in which this technology is not available (Figure L).

This indicates that even in a low oil price future, Alberta's economy can continue to grow by producing oil and gas with low emissions, given DAC and CCS are available at low cost. It suggests that investing in technologies that can allow for low-emission oil and gas production, including CCS and DAC, is particularly important for facilitating Alberta's net zero future.

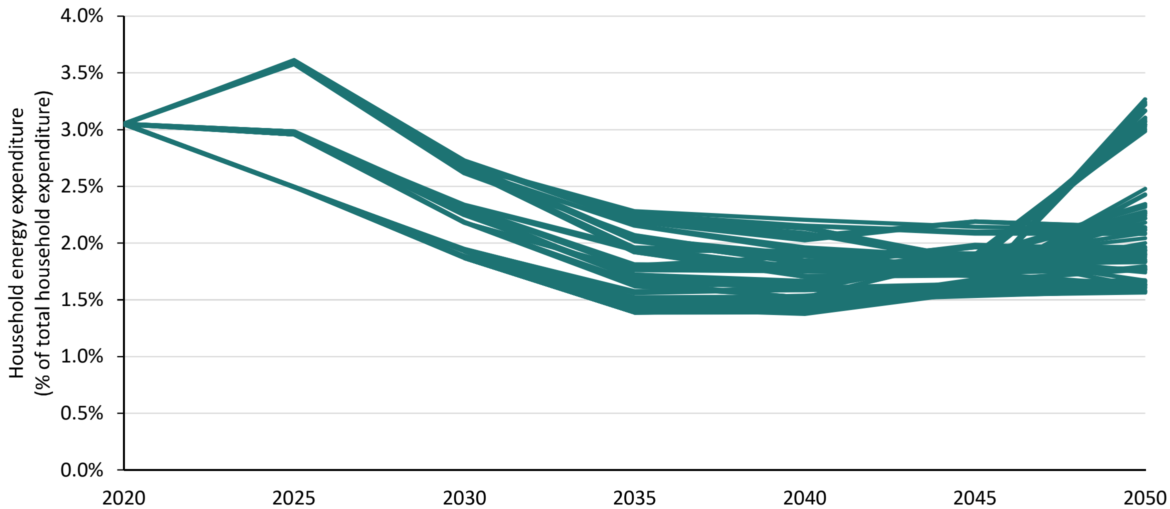
Figure L: Alberta's GDP in scenarios with and without DAC availability (range across all net zero scenarios)



Household energy expenditure

Despite increasing electricity and low carbon fuel prices, household energy expenditure declines as a portion of total household expenditure in most net zero scenarios (Figure M). It declines from 3% of total household expenditure in 2020 to 1.9-2.7% in 2030, and ranges from 1.6-3.3% in 2050 depending on the net zero scenario. This decline in energy expenditure over time in most net zero scenarios is a result of two factors. As personal vehicles and home heating are electrified, and as homes become more energy efficient, energy efficiency gains offset increasing costs of energy. At the same time, as Alberta's economy grows, households become wealthier and total expenditure increases.

Figure M: Household energy expenditure as a portion of total expenditure (all net zero scenarios)



Summary of key insights

Results of this analysis provide four key insights:

1. **The future of oil and gas production in Alberta is uncertain under net zero policy and is highly dependent on global demand for oil.**

   Continued demand for fossil fuels is highly uncertain in a net zero emission future and global demand for oil has a significant impact on the future of oil and gas production in Alberta. Across all net zero scenarios continued oil and gas production is combined with adoption of low carbon technologies, suggesting that lower costs of technologies such as CCS and DAC are critical to improve the competitiveness of Alberta's oil and gas sector in a net zero future.

   a. ***Bitumen's comparative advantage in producing non-combustion commodities means it outcompetes lighter grades of crude oil in a net zero future.***

      Results of this analysis suggest that, due to its comparative advantage in producing non-combustion oil products for which demand remains under net zero policy, bitumen remains the "last barrel standing" in 2050 in many net zero scenarios.

2. **Alberta's net zero energy system relies on significant growth in electricity generation, including both renewables with storage and natural gas with CCS.**

   Electricity generation increases significantly under net zero policy. In all net zero scenarios, utility generation is dominated by renewables by 2050, facilitated by storage. However, in scenarios in which DAC is not available and there is high demand for oil, natural gas with CCS is the primary source of electricity generation in 2050 across the province, driven by cogeneration with CCS and MCFC adoption in industry. This indicates investment in expansion of both CCS and renewables is important to facilitate Alberta's net zero electricity system.

3. **Carbon capture technology is likely to play a transformative role in Alberta's net zero energy system.**

   CCS is adopted in large amounts across all net zero scenarios, driven by demand for abatement in the oil and gas sector. Most CCS adoption occurs for process heat in industry, with MCFC technology playing a potentially significant role in facilitating decarbonization of Alberta's industry.

   a. ***Enhanced oil recovery plays a critical role in deployment of CCS in the near term.***

      EOR creates a market for captured CO_2, providing an additional revenue stream for CCS adopters in the province in the near term (until 2030). After 2030, as increasing amounts of CO_2 are captured, the price for CO_2 declines but EOR remains an opportunity to use and store captured CO_2.

   b. ***If available, direct air capture technology could make Alberta's net zero transition easier and less costly.***

      If DAC technology is available, it can minimize the cost of achieving a net zero energy system in Alberta. Growth of a DAC sector in the province leads to significant direct economic contributions, while at the same time allowing for continued production of fossil fuels, prolonging the life of Alberta's oil and gas sector. DAC also allows for continued consumption of fossil fuels within the province, facilitating greater economic activity in other sectors of the economy by avoiding the need to reduce the most expensive-to-abate emissions.

4. **Alberta's economy is resilient to a net zero future. Economic growth depends primarily on future global demand for oil and the cost of carbon capture.**

   Alberta's GDP grows across all net zero scenarios. It grows most in scenarios in which the province continues to produce oil and gas and continues to consume fossil fuels, either capturing emissions with CCS or offsetting emissions with DAC. Investment to bring down the cost of technologies we know will play an important role in Alberta's net zero future – carbon capture, zero emission vehicles, hydrogen, renewables, storage - will help mitigate emissions in the province and reduce the cost of Alberta's net zero energy transition.

Table of Contents

1. Introduction

Canada has committed to achieving net zero greenhouse gas (GHG) emissions by 2050. Achieving net zero emissions is particularly challenging for Alberta for a few reasons. First, the province is historically a large fossil fuel producer, and the future of fossil fuel demand is uncertain in a net zero emission future. Second, Alberta is home to emissions intensive industry that is expensive to abate. Finally, Alberta has historically had an emissions intensive electricity sector without the large hydroelectric resources that many other provinces rely on for clean electricity.

It is within this context that Alberta Innovates and Emissions Reduction Alberta are interested in understanding the future of Alberta's energy system under net zero emissions. This analysis evaluates future possible energy systems that achieve net zero emissions in Alberta by 2050 and provides insight into key uncertainties and opportunities for Alberta's energy system in a net zero future.

Custom versions of Navius' energy-economy and electricity model were created to achieve the objectives of this analysis, which fill gaps in previous net zero modeling by accounting for dynamics and technologies that are particularly important for Alberta in a net zero future. This includes the ability to simulate different grades of crude oil being used to produce different refined products (bitumen beyond combustion), updated parameterization of solvent-based extraction, and the addition of carbon capture, storage and utilization technologies including molten carbonate fuel cells, enhanced oil recovery, oxy-combustion natural gas turbines and carbon storage in concrete. We also updated our representation of the Alberta electricity market, simulating marginal cost electricity prices, differing from other electricity markets across Canada.

This report addresses the implications of these additions to the model and their impact on Alberta's net zero energy future. It provides an overview of how Alberta's energy system may transition to align with a net zero future, draws attention to key technological opportunities, and explores the economic implications of net zero emissions for Alberta, including under what conditions the province can achieve net zero emissions at lowest cost to the economy and to energy consumers.

This report is structured as follows:

- Section 2 introduces gTech and IESD, the modeling tools used for this analysis, and summarizes the scenarios simulated.
- Section 3 presents the set of modeling assumptions that are critical to this analysis.

- Sections 4 and 5 discuss key results, including Alberta’s net zero energy system and the economic implications of achieving net zero emissions in the province.
- Section 6 provides a summary of the key insights from this analysis.
- Section 7 outlines limitations and opportunities for future research.

2. Analytical Approach

Sections 2.1 and 2.2 provide an overview of our energy-economy model, gTech, and our electricity model, IESD. Section 2.3 outlines the scenarios simulated in this analysis.

2.1. Introduction to gTech

Canada and Alberta's energy-economy is complex. Energy consumption, which is the main driver of anthropogenic greenhouse gas emissions, results from the decisions made by millions of Canadians. For example, households must choose what type of vehicles they will buy and how to heat their homes; industry must decide whether to install technologies that might cost more but consume less energy; municipalities must determine whether to expand transit service; and investors need to decide whether to invest their money in Alberta or somewhere else.

All levels of government in Canada have implemented policies designed to encourage or require firms and consumers to take actions to reduce their emissions. Achieving Canada's net zero by mid-century target will require strengthening existing policies and/or implementing new policies that result in additional emission reduction activities.

Existing policies and those required to achieve Canada's net zero target will have effects throughout the economy and interact with each other. For example, the federal vehicle emission standard and federal/provincial carbon pricing efforts seek to reduce GHG emissions from passenger vehicles, as do a variety of other policies (such as BC's low carbon fuel standard, the federal Clean Fuel Regulations and zero-emission vehicle mandates). The interactive effects among such policies can be complex. The economic effects of all federal and provincial climate initiatives implemented together are even more complex.

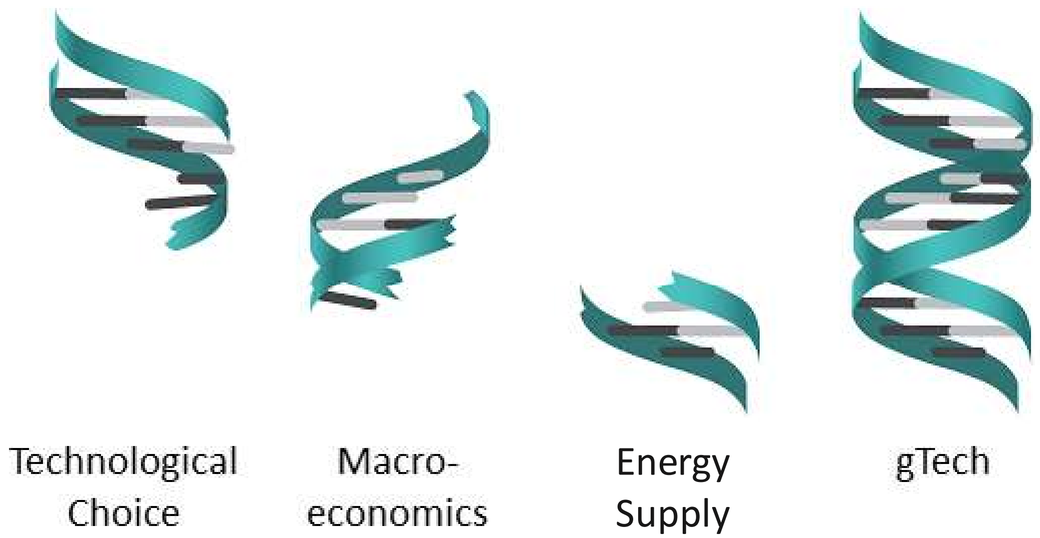
Estimating the sectoral, technological and economic impacts in Alberta of achieving Canada's net zero emissions target therefore requires a modeling framework that captures the complexity of the energy-economic system.

gTech is unique among energy-economy models because it combines features that are typically only found in separate models:

- A realistic representation of how households and firms select technologies and processes that affect their energy consumption and greenhouse gas emissions;

- An exhaustive accounting of the economy at large, including how provinces and territories interact with each other and the rest of the world; and
- A detailed representation of energy supply, including liquid fuel (crude oil and biofuel), gaseous fuel (natural gas and renewable natural gas) and electricity.

Figure 1: The gTech model



gTech builds on three of Navius' previous models (CIMS, GEEM and OILTRANS/IESD), combining their best elements into a comprehensive integrated framework.

gTech simulates technological choice

Technological choice is one of the most critical decisions that influence greenhouse gas emissions in Alberta. For example, if a household chooses to purchase an electric vehicle over a gasoline car, that decision will reduce their emissions. Similarly, if a mining facility chooses to electrify its operations, that decision reduces its emissions.

gTech provides a detailed accounting of the types of energy-related technologies available to households and businesses. In total, gTech includes over 300 technologies across more than 50 end-uses (e.g., light-duty vehicle travel, residential space heating, industrial process heat, management of agricultural manure).

Naturally, technological choice is influenced by many factors. Table 1 summarizes key factors that influence technological choice and the extent to which these factors are included in gTech.

Table 1: Technological choice dynamics captured by gTech

Criteria	Description
Purchasing (capital) costs	Purchasing costs are simply the upfront cost of purchasing a technology. Every technology in gTech has a unique capital cost that is based on research conducted by Navius. Everything else being equal (which is rarely the case), households and firms prefer technologies with a lower purchasing cost.
Energy costs	Energy costs are a function of two factors: (1) the price for energy (e.g., cents per litre of gasoline) and (2) the energy requirements of an individual technology (e.g., a vehicle's fuel economy, measured in litres per 100 km). In gTech, the energy requirements for a given technology are fixed, but the price for energy is determined by the model. The method of "solving" for energy prices is discussed in more detail below.
Time preference of capital	Most technologies have both a purchasing cost as well as an energy cost. Households and businesses must generally incur a technology's purchasing cost before they incur the energy costs. In other words, a household will buy a vehicle before it needs to be fueled. As such, there is a tradeoff between near-term capital costs and long-term energy costs. gTech represents this tradeoff using a "discount rate". Discount rates are analogous to the interest rate used for a loan. The question then becomes: is a household willing to incur greater upfront costs to enable energy or emissions savings in the future? Many energy modelers use a "financial" discount rate (commonly between 5% and 10%). However, given the objective of forecasting how households and firms are likely to respond to climate policy, gTech employs behaviourally realistic discount rates of between 8% and 25% to simulate technological choice. Research consistently shows that households and firms do not make decisions using a financial discount rate, but rather use significantly higher rates.[6] The implication is that using a financial discount rate would overvalue future savings relative to revealed behaviour and provide a poor forecast of household and firm decisions.
Technology specific preferences	In addition to preferences around near-term and long-term costs, households (and even firms) exhibit "preferences" towards certain types of technologies. These preferences are often so strong that they can overwhelm most other factors (including financial ones). For example, buyers of passenger vehicles can be concerned about the driving range and available charging infrastructure of vehicles, some may worry about the risk of buying new technology, and some may see the vehicle as a "status symbol" that they value[7]. gTech quantifies these technology-specific preferences as "non-financial" costs, which are added to the technology choice algorithm.

[6] For example, see: Rivers, N., & Jaccard, M. (2006). Useful models for simulating policies to induce technological change. *Energy policy*, *34*(15), 2038-2047; Axsen, J., Mountain, D.C., Jaccard, M., 2009. Combining stated and revealed choice research to simulate the neighbor effect: The case of hybrid-electric vehicles. Resource and Energy Economics 31, 221-238.

[7] Kormos, C., Axsen, J., Long, Z., Goldberg, S., 2019. Latent demand for zero-emissions vehicles in Canada (Part 2): Insights from a stated choice experiment. Transportation Research Part D: Transport and Environment 67, 685-702.

Criteria	Description
The diverse nature of Canadians	Canadians are not a homogenous group. Individuals are unique and will weigh factors differently when choosing what type of technology to purchase. For example, one household may purchase a Toyota Prius while their neighbour purchases an SUV and another takes transit. gTech uses a "market share" equation in which technologies with the lowest net costs (including all the cost dynamics described above) achieve the greatest market share, but technologies with higher net costs may still capture some market share[8]. As a technology becomes increasingly costly relative to its alternatives, that technology earns less market share.
Changing costs over time	Costs for technologies are not fixed over time. For example, the cost of electric vehicles has come down significantly over the past few years, and costs are expected to continue declining in the future[9]. Similarly, costs for many other energy efficient devices and emissions-reducing technologies have declined and are expected to continue declining. gTech accounts for whether and how costs for technologies are projected to decline over time and/or in response to cumulative production of that technology.
Policy	One of the most important drivers of technological choice is government policy. Current federal, provincial and territorial initiatives in Canada are already altering the technological choices households and firms make through various policies: (1) incentive programs, which pay for a portion of the purchasing cost of a given technology; (2) regulations, which either require a group of technologies to be purchased or prevent another group of technologies from being purchased; (3) carbon pricing, which increases fuel costs in proportion to their carbon content; (4) variations in other tax policy (e.g., whether or not to charge GST on a given technology); and (5) flexible regulations, like the federal clean fuel standard which will create a market for compliance credits. gTech simulates the combined effects of all these policies implemented together.

gTech simulates the macroeconomic impacts of policy

As a full macroeconomic model (specifically, a "general equilibrium model"), gTech provides insight about how policies affect the economy at large. The key macroeconomic dynamics captured by gTech are summarised in Table 2.

[8] Rivers, N., & Jaccard, M. (2006). Useful models for simulating policies to induce technological change. *Energy policy*, *34*(15), 2038-2047.

[9] Nykvist, B., Sprei, F., & Nilsson, M. (2019). Assessing the progress toward lower priced long range battery electric vehicles. *Energy Policy*, 124, 144-155.

Table 2: Macroeconomic dynamics captured by gTech

Dynamic	Description
Comprehensive coverage of economic activity	gTech accounts for all economic activity in Canada as measured by Statistics Canada national accounts[10]. Specifically, it captures all sector activity, all gross domestic product, all trade of goods and services and the transactions that occur between households, firms and government. As such, the model provides a forecast of how government policy affects many different economic indicators, including gross domestic product, investment, household income and jobs.
Full equilibrium dynamics	gTech ensures that all markets in the model return to equilibrium (i.e., that the supply for a good or service is equal to its demand). This means that a decision made in one sector is likely to have ripple effects throughout the entire economy. For example, greater demand for electricity requires greater electricity production. In turn, greater production necessitates greater investment and demand for goods and services from the electricity sector, increasing demand for labor in construction services and ultimately leading to higher wages. The model also accounts for price effects. For example, the electricity sector can pass policy compliance costs on to households, who may alter their demand for electricity and other goods and services (e.g., by switching to technologies that consume other fuels and/or reducing consumption of other goods and services).
Sector detail	gTech provides a detailed accounting of sectors in Canada. In total, gTech simulates how policies affect over 80 sectors of the economy. Each of these sectors produces a unique good or service (e.g., the mining sector produces ore, while the trucking sector produces transport services) and requires specific inputs into production.
Labor and capital markets	Labor and capital markets must also achieve equilibrium in the model. The availability of labor can change with the "real" wage rate (i.e., the wage rate relative to the consumption level). If the real wage increases, the availability of labor increases. The model also accounts for "equilibrium unemployment".
Interactions between regions	Economic activity in Canada is highly influenced by interactions among provinces/territories, with the United States and with countries outside of North America. Each province in the model interacts with other regions via (1) the trade of goods and services, (2) capital movements, (3) government taxation and (4) various types of "transfers" between regions (e.g., the federal government provides transfers to provincial and territorial governments). The version of gTech used for this project accounts for the 10 Canadian provinces, the 3 territories in an aggregated region and the United States. The model simulates each of the interactions described above, and how interactions may change in response to policy.
Households	On one hand, households earn income from the economy at large. On the other hand, households use this income to consume different goods and services. gTech accounts for each of these dynamics, and how either change with policy.

[10] Statistics Canada. Supply and Use Tables. Available from: www150.statcan.gc.ca/n1/en/catalogue/15-602-X

gTech simulates energy supply markets

gTech accounts for all major energy supply markets, such as electricity, refined petroleum products and natural gas. Each market is characterized by resource availability and production costs by province, as well as costs and constraints (e.g., pipeline capacity) of transporting energy between regions.

Low carbon energy sources can be introduced within each fuel stream in response to policy, including renewable electricity and bioenergy. The model accounts for the availability and cost of bioenergy feedstocks, allowing it to provide insight about the economic effects of emission reduction policy, biofuels policy and the approval of pipelines.

Benefits of merging macroeconomics with technological detail

By merging the three features described above (technological detail, macroeconomic dynamics, and energy supply dynamics), gTech can provide extensive insight into the effects of climate and energy policy.

First, gTech can provide insights related to technological change by answering questions such as:

- How do policies affect technological adoption (e.g., how many electric vehicles are likely to be on the road in 2030)?
- How does technological adoption affect greenhouse gas emissions and energy consumption?

Second, gTech can provide insights related to macroeconomics by answering questions such as:

- How do policies affect national and provincial gross domestic product?
- How do policies affect individual sectors of the economy?
- Are households affected by the policy?
- Does the policy affect energy prices or any other price in the model (e.g., food prices)?

Third, gTech answers questions related to its energy supply modules:

- Will a policy generate more supply of renewable fuels?
- Does policy affect the cost of transporting refined petroleum products, and therefore the price of gasoline in Canada?

Finally, gTech expands our insights into areas where there is overlap between its various features:

- What is the effect of investing carbon revenue into low- and zero-carbon technologies? This question can only be answered with a model like gTech.
- What are the macroeconomic impacts of technology-focused policies (e.g., how might a zero-emissions vehicle standard impact GDP)?
- Do biofuels-focused policies affect (1) technological choice and (2) the macroeconomy?

This modeling toolkit allows for a comprehensive examination of the impacts of net zero emission pathways on Alberta's energy future.

2.2. Introduction to IESD

IESD is Navius' electricity model. The model estimates the impact of government policies and economic conditions on electricity demand, supply, and prices by simulating how utilities meet electric load by adding new capacity and by dispatching new and existing units on an hourly basis, including electricity storage.

The electricity supply module of IESD includes a detailed representation of the different units available to generate or store electricity in each region, including their unique costs and generation constraints. The electricity supply simulation determines new generation and storage capacity additions, hourly dispatch of each unit to meet electric load over the course of the year, GHG emissions from the electricity sector and the wholesale price for electricity.

IESD's electricity supply module is a linear programming model that simulates how the electricity sector makes capacity and dispatch decisions based on the hourly load profile, energy prices and the cost of installing and operating different units. The electricity supply module endogenously adds and dispatches electricity units such that the total costs of the electricity system are minimized, system revenues are maximized, and load in each hour is met. Each type of electricity generation resource is characterized by its cost profile, heat rate, and maximum capacity utilization. The value provided by storage technologies and their possible revenue streams are reflected by the extent to which they can minimize system costs relative to other generation technologies. The model can simulate specific policy decisions that may promote or constrain the use of a given technology (i.e., a portfolio standard that requires renewable energy).

Thermal generation can be dispatched at any time when it will minimize total system costs subject to any existing policy constraints. Electricity storage may also be dispatched. However, this dispatch is constrained by the installed storage generation capacity, the amount of energy already stored, and any relevant technological constraints represented in the model. Electricity from intermittent resources must be used when it is available, either consumed, exported, or stored. The hourly wind energy is based on the installed capacity and the hourly capacity utilization in each hour of the representative day being simulated. Solar capacity availability varies for each month of the year but changes each hour according to the movement of the sun through the sky.

IESD provides added resolution on the electricity sector, capturing dynamics unique to the electricity market. IESD is linked to gTech to provide enhanced representation of unique electricity system dynamics such as:

- **Hourly electricity consumption.** Electricity markets are unique from perhaps any other market in that the supply of electricity must be perfectly timed to match demand in every hour of the day and in every day of the year. This poses a challenge because electricity consumption is not consistent throughout the day or year. The implication is that Alberta’s grid must be able to supply enough electricity to balance demand at all times.
- **Hourly generation profiles.** Some generation units can be made available upon demand, but others cannot. For example, generation from wind resources is available when the wind is blowing. Likewise, generation from solar photovoltaics is available when the sun is up. The implication is that these sources of power may or may not be available to meet demand in any given moment.
- **Identifying the potential for emerging technologies.** Because IESD represents short and long-term dynamics important to the electricity system, it can identify the potential for variable renewable electricity (VRE) sources, like wind and solar, and determine opportunities for energy storage technologies to better integrate VREs into grids. Storage technologies will become increasingly relevant as their costs decline and as more wind and solar plants are deployed. IESD also simulates the potential for hydrogen production via electrolysis, either as a dispatchable electricity storage technology or for use in other sectors, such as transport.
- **Load shifting.** An alternative way for meeting peak load is to shift demand to off peak hours. IESD simulates various options for load shifting, such as utility-controlled charging for electric vehicles.

We also align with the National Renewable Energy Laboratory’s ReEDS model[11] to characterize reserve requirements. Reserve requirements are important to ensure

[11] National Renewable Energy Laboratory. (2020). *Regional Energy Deployment System (ReEDS) Model Documentation: Version 2020.* Available from: https://www.nrel.gov/docs/fy21osti/78195.pdf

electricity demand can be met at all times. Table 3 outlines reserve requirements in IESD.

Table 3: Reserve requirements in IESD[12]

Load Requirement (% of load)	Wind Requirement (% of generation)	Solar requirement (% of capacity)
4%	10.5%	4.3%

For the custom version of IESD used in this analysis, we estimate electricity prices as marginal prices rather than average prices to align more closely with how prices are set in Alberta. The approach is aligned with the ReEDS model[13] and Electric Power Research Institute's US-REGEN model[14]. We calculate the marginal price of electricity in each hour based on the marginal cost of the last dispatched generation unit in each representative hour and take an average of the marginals across the year.

2.3. Scenario Design

This section outlines the policies and sensitivities we modeled to examine Alberta's energy system under net zero emissions.

2.3.1. Policy Scenarios

We examined three policy scenarios for this analysis – current policy ("business as usual"), announced policy and net zero policy. This report focuses on results of the net zero scenario, but all three are described below.

Current Policy

This scenario includes all existing federal and provincial policies. The federal carbon pricing backstop remains capped at $50/tCO$_{2e}$ and other existing provincial and federal policies remain in place. Appendix A outlines federal policies and Alberta-specific policies included in the current policy forecast.

12 Ibid.
13 Ibid.
14 Electric Power Research Institute. (2020). *US-Regen Model Documentation*. Available from: https://www.epri.com/research/products/000000003002016601?utm_campaign=ESCA%20Quarterly%20Newsletter&utm_source=hs_email&utm_medium=email&_hsenc=p2ANqtz-8-0mbL6l1JBdJEwo-6C0inoJHta-hkC15MbQM-uy4IUTJcDWoUxXxohddJ64xKt1QURRGv

Announced Policy

This scenario includes Canada's *2030 Emissions Reduction Plan*[15]. For many of these announced policies, there is significant uncertainty regarding coverage, design, stringency, and timelines. Our characterization of many announced policies is illustrative, the purpose being to later show the level of GHG reductions that could be achieved if these policies were implemented. The policies included are listed in Appendix A, including assumptions that have been made to model them. Any subsidies are allocated equally to each technology targeted by the subsidy irrespective of province (unless otherwise specified).

Net Zero Policy

This scenario includes all current policies (but no announced policies) and includes a cap on emissions at Canada's 2030 emissions target (40-45% reduction in emissions from 2005 levels) and net zero emissions in 2050[16]. This scenario assumes that Alberta achieves net zero emissions within its borders, while the rest of Canada also achieves net zero emissions by 2050, and that the U.S. implements stringent climate policy consistent with net zero. It assumes a certain number of emission offsets are available via land-use, land-use change and forestry (LULUCF), based on a report by Nature United[17] with additional Alberta-specific information provided by the authors. This assumption is 78 Mt in 2030 and 103 Mt in 2050 Canada-wide, including 12.6 Mt in 2030 and 20.3 Mt in 2050 in Alberta.

2.3.2. Uncertainty Analysis

Simulating Canada's economy to 2050 is fundamentally uncertain and results are subject to several key assumptions that must be made when forecasting policy impacts. Key uncertainties were examined for each policy scenario using sensitivity analysis. Table 4 outlines the sensitivities examined in this analysis. All possible combinations of the sensitivities listed below were examined.

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[15] Government of Canada. (2022). *2030 Emissions Reduction Plan – Canada's Next Steps for Clean Air and a Strong Economy*. Available from: https://www.canada.ca/en/environment-climate-change/news/2022/03/2030-emissions-reduction-plan--canadas-next-steps-for-clean-air-and-a-strong-economy.html

[16] Under net zero policy, a performance standard applies to all large final emitters (LFEs) and includes 70% free allocations in 2025, 60% in 2030, 41% in 2035, 22% in 2040, 8% in 2045 and 0% in 2050

[17] https://www.science.org/doi/10.1126/sciadv.abd6034

Table 4: Four key uncertainties examined via sensitivity analysis

Sensitivity	Low	Reference	High
Technology uncertainty			
1. Cost of CCS/DAC	Low cost CCS & DAC	Reference cost CCS; DAC unavailable Reference cost CCS & DAC	High cost CCS; DAC unavailable
2. Cost of hydrogen[18]	Low cost	Reference cost	High cost
3. Renewables, batteries and hydrogen storage costs[19]	Low cost	Reference cost	High cost
Commodity price uncertainty			
4. Future oil price	Low price forecast	Reference price forecast	High price forecast

More details on the technology cost uncertainties can be found in Section 3.2 and details on the future oil price sensitivity in Section 3.1.

[18] Including the cost of hydrogen production and fuel cell electric vehicles.
[19] Including the cost of renewables, utility-scale storage (including hydrogen as seasonal electricity storage) and battery electric vehicles.

3. Modeling Assumptions

This section summarizes data sources and assumptions used to characterize Alberta's energy-economy to 2050. Section 3.1 provides assumptions about future economic growth and energy prices, and Section 3.2 provides assumptions for the key abatement technologies relevant to this analysis. More detail on model calibration (including the oil and gas sector) is provided in Appendix B.

3.1. Economic Assumptions

3.1.1. GDP

GDP is calibrated to the 2021 version of Canada's Energy Future [20]. Table 5 provides the GDP forecast for Alberta from this report. GDP by sector is largely determined by this rate of growth and the relative capital and labour productivity of each sector (i.e., the value of goods and services produced for a given amount of capital and labour inputs). In other words, the overall economic growth is "allocated" amongst sectors based on historical data regarding the structure of the economy in Alberta and changes brought on by policy and other factors.

Table 5: Alberta's GDP forecast assumptions ($2012 millions)[21]

Sensitivity	2025	2030	2035	2040	2045	2050
Reference	379,887	423,912	458,356	491,053	526,344	561,697

3.1.2. Energy Prices

Oil and natural gas prices are exogenous[22] inputs to the model (i.e., based on an assumed global price). The Henry Hub natural gas price and the reference WTI oil price are calibrated to the 2021 version of Canada's Energy Future[23]. Table 6 outlines the

[20] Canada Energy Regulator. (2021). *Canada's Energy Future 2021.* Available from: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/index.html
[21] Ibid.
[22] An exogenous input refers to an input that is not solved for by gTech or IES but is instead set from an external source.
[23] Canada Energy Regulator. (2021). *Canada's Energy Future 2021.* Available from: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/index.html

WTI forecast assumptions, including a low and high price sensitivity, while Table 7 outlines the forecast assumptions for the Henry Hub price.

Table 6: WTI oil price forecast assumptions (2020 USD/bbl)

Sensitivity	2025	2030	2035	2040	2045	2050
Low	39.5	37.1	36.2	35.9	35.6	35.1
Reference	68.9	67.8	66.2	65.7	65.1	64.1
High	97.5	93.1	90.9	90.2	89.5	88.0

Table 7: Henry Hub natural gas price forecast assumptions (2020 USD /mmBTU)

Sensitivity	2025	2030	2035	2040	2045	2050
Reference	3.34	3.49	3.65	3.87	4.09	4.26

Note that while we don't include a low and high price forecast for natural gas. Prices will vary endogenously by scenario depending on the oil price and other factors, and higher or lower natural gas prices will be reflected in some scenarios as a result.

The price for other energy commodities is determined by the models based on demand and the cost of production. For example, the price of electricity in Alberta depends on a variety of factors that are accounted for within the model, such as:

- The cost of generating electricity while meeting policy constraints.
- The cost of maintaining the transmission and distribution network.
- Any taxes on or subsidies to the sector.

3.2. Technological Assumptions

As a technologically explicit model, gTech accounts for a large range of abatement technologies. In total, gTech includes over 300 technologies across more than 80 end-uses. IESD provides additional detail on technologies specific to the electricity sector.

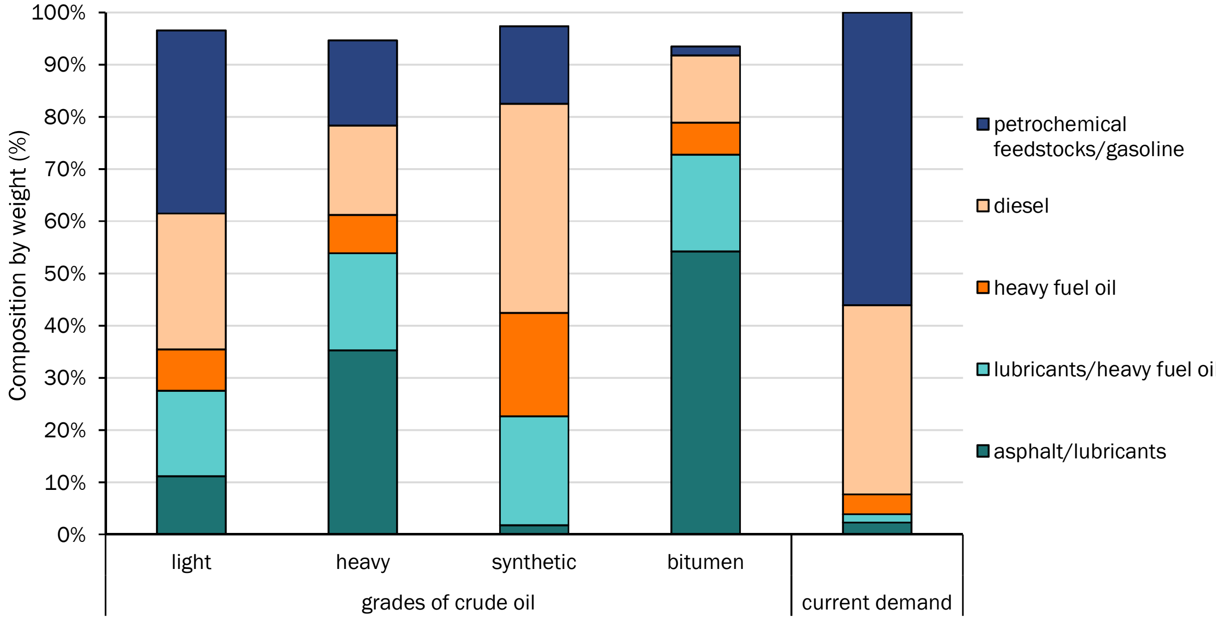
Increased integration of Alberta's energy system is likely a necessity to achieve net zero emissions. By simulating the full energy system, including primary and secondary sources, and the shift away from primary towards secondary energy sources, gTech and IESD are well-suited to represent this increased integration. Examples of integration represented in the models include the production of hydrogen from electrolysis, which integrates the electricity and hydrogen energy systems, and the production of hydrogen from steam methane reformation, which integrates the natural gas and hydrogen energy systems for use in a variety of end-uses including power generation, transportation, refining, etc. This important dynamic is captured by the models but is limited by the technologies included and their parameterization. The models aim to capture the technologies most important for Alberta's energy transition.

3.2.1. Bitumen Beyond Combustion

Alberta's oil sands are unique among other global oil resources in that they are uniquely "heavy" and the resulting distillation fractions are misaligned with current demand for refined petroleum products (Figure 2). While light crude oil produces products directly in line with current demand, only 15% of a barrel of bitumen can produce products in the range of diesel and gasoline (unless cracked), which account for over 90% of current product demand in Canada and the U.S. More than half of a barrel of bitumen can directly produce refined products in the range of asphalt and lubricants, while current demand for these products within Canada and the U.S. accounts for just 4% of refined petroleum products.

As a result of this misalignment between the product demand and what comes out of a barrel of bitumen, the oil industry currently deploys several costly processes to "crack" the heavier ends of the barrel into lighter ends. Refining light oil also requires these processes, but to a lesser extent. These processes are the largest reason why bitumen trades at a discount relative to lighter oil. We currently estimate this discount to be about $20 per barrel.

Figure 2: Composition of a barrel of crude oil by weight



Future demand for refined petroleum products under climate policy

Policies designed to reduce emissions are expected to significantly change the product slate for refined petroleum. Based on our analyses, the demand for gasoline is expected to decline significantly (if not be eliminated entirely) under net zero policy as consumers switch to battery electric vehicles. The demand for diesel is also expected to decline as the freight industry adopts battery electric or fuel cell electric vehicles, or as they substitute traditional fuels with biofuels. Finally, demand for heavy fuel oil is expected to decline as industry increases utilization of lower carbon fuels (e.g., renewable natural gas or natural gas coupled with CCS).

However, some uses for refined petroleum do not emit GHGs once produced, and climate policy does not necessarily discourage their use. These products include asphalt (used in road construction and other building materials like shingles), lubricants (used in industrial machinery as well as engines), and petrochemical feedstocks. Asphalt is disproportionately on the heavier end of the barrel, in which bitumen has a comparative advantage to other crudes as illustrated in Figure 2.

To simulate the future of the upstream and downstream oil industry in Canada and the U.S., we made three changes to gTech, as summarized below.

1. Greater disaggregation of crude oil by grade

Other versions of gTech included two grades of crude oil: bitumen and light oil. Bitumen was upgraded into light oil before it could be refined.

The version of gTech developed for this analysis includes four grades of crude oil: light oil, heavy oil, bitumen, and synthetic crude oil (upgraded bitumen). While upgrading remains an option within the model, synthetic crude oil is no longer analog to light oil. As will be discussed below, refineries can now directly refine bitumen.

Figure 2 above shows each grade of crude oil represented in the version of gTech used for this analysis.

2. Greater disaggregation of refined petroleum products

Other versions of gTech disaggregated most liquid fuels, but did not explicitly disaggregate petrochemical feedstocks, lubricants and asphalt. The model used for this analysis has been updated to explicitly disaggregate these products.

3. New refinery module

To account for how refineries can alter their product slate under climate policy or other economic conditions, a simplified refinery module (Figure 3 provides a schematic) was built into gTech for this analysis to explicitly model how crude oil is:

- **Distilled into various "fractions":** When crude oil arrives in a refinery in gTech, it is distilled into six fractions representing different distillation temperatures.
- **Cracked into more valuable fractions:** gTech has a simplified representation of processes available to "crack" heavier fractions into lighter fractions. These include a delayed coker (for cracking the vacuum residue) and a fluid catalytic cracker and a hydrocracker (for cracking heavy ends that are lighter than vacuum residue).
- **Blended into final products:** Final products include gasoline, petrochemical feedstocks, diesel, heavy fuel oil, lubricants, etc.

The model also accounts for how each unit in the refinery has specific energy requirements. Units require process heat, electricity, and hydrogen. The new model retains the ability for refineries to alter the technologies used to meet the demand for energy end-uses (e.g., deploy carbon capture and storage).

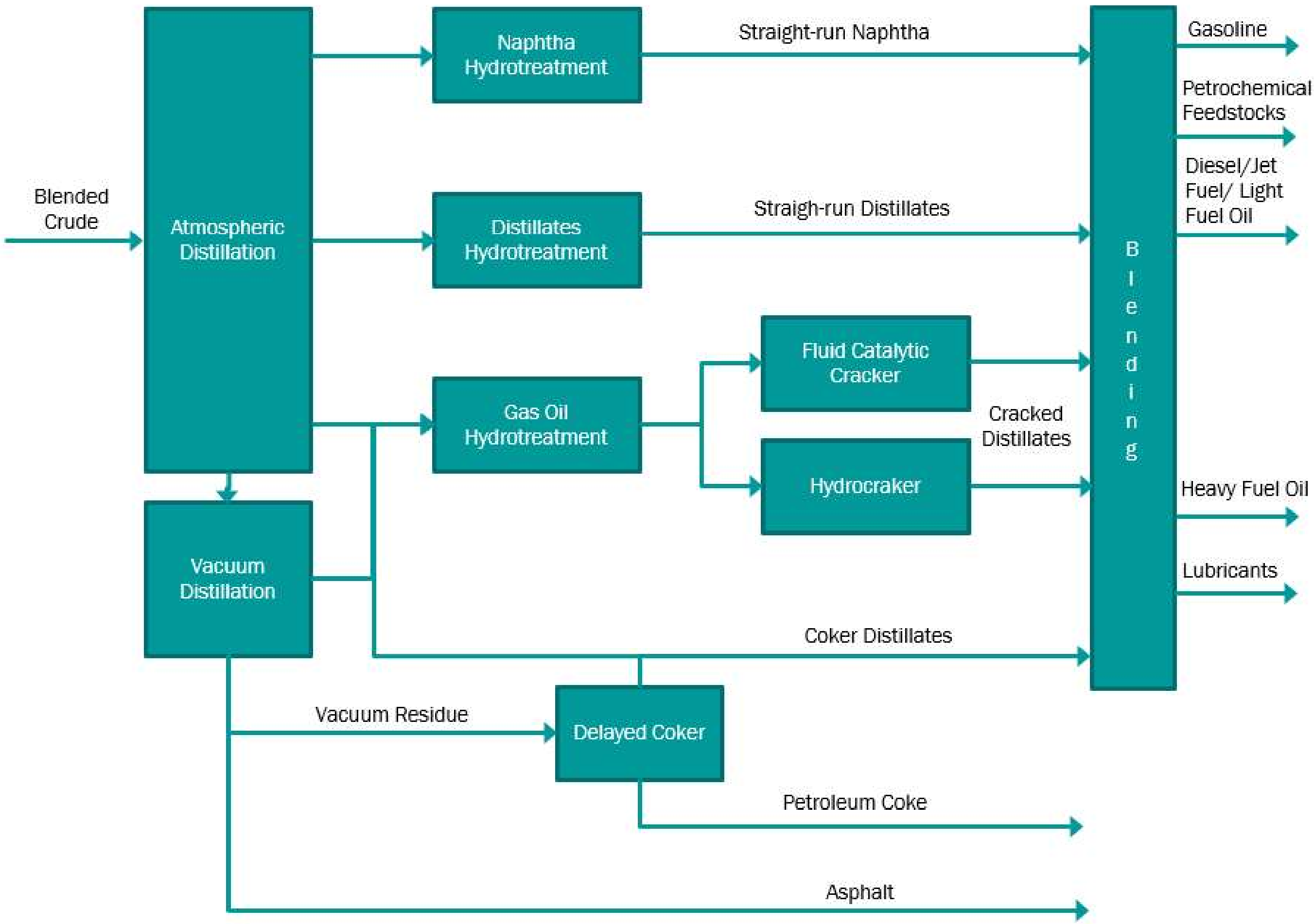
This new refining module allows refineries to respond to climate policy in two important ways:

- **Optimize their crude oil feedstock:** In previous versions of gTech, refineries consumed a single grade of oil which represented the average crude oil refined in Canada and the U.S. To account for the discount between light oil and bitumen, the oil and refining industries would "upgrade" bitumen into light oil. As such, upgraders were the only source of demand for bitumen and refiners could not change their crude oil feedstock in response to changing product demand.

  The new version of gTech explicitly models the distillation of four grades of crude oil into refining fractions and refineries can fully optimize their crude oil feedstock, subject to upstream constraints and their refinery configuration.

- **Change the suite of products produced:** Refineries can produce greater quantities of gasoline through fluid catalytic cracking (FCC), while they can produce greater quantities of light fuel oils (e.g., diesel) by installing a hydrocracker. Refineries can alter the products they produce, subject to the units available to them, thereby using their feedstock to produce a different product slate if demand changes with climate policy.

Figure 3: Structure of the refining module in gTech



Key sources and assumptions

A key assumption that drives the modeling results is the amount of refined petroleum required to produce a given value of asphalt products or lubricants, as this determines the demand for bitumen across Canada and the U.S. Model assumptions are currently aligned with refinery yields as reported by the U.S. Energy Information Administration[24]. Changes to this assumption, however, can have significant impacts on demand for bitumen in the model.

Another key source includes Statistics Canada Supply and Use Tables[25] which we use to calibrate the production of different refined products and types of crude consumed

[24] U.S. Energy Information Administration. (2022). Refinery Capacity Report. Available from: https://www.eia.gov/petroleum/refinerycapacity/
[25] Statistics Canada. Supply and Use Tables. Available from: www150.statcan.gc.ca/n1/en/catalogue/15-602-X

in different refineries in Canada. The Crude Monitor[26] is used to estimate the breakdown of a barrel of crude oil into fractions, and a report by Energetics Incorporated[27] is used to for the energy intensity of refining.

Discussion of the limitations of our approach for modeling bitumen beyond combustion is provided in Section 7.

3.2.2. Solvent-Based Extraction

To parameterize solvent based extraction in the oil sands in situ sector, we use information from the following five sources:

1. BMO Capital Markets (2019). ESG, Yeah You Know Me: Innovation and the Search for 'Friendly Oil'. We use this source for the percentage increase in costs associated with using solvent-based extraction relative to SAGD (steam-assisted gravity drainage).
2. Steam-assisted gravity drainage (SAGD) extraction costs coming directly out of gTech. The BMO Capital Markets report does not provide total costs of oil sands production. We therefore use the cost per barrel value for the oil sands in situ sector in gTech and prorate it based on the information provided by BMO Capital Markets (2019).
3. Information based on conversations with experts. Experts have indicated that the addition of solvents allows each steam plant to produce more barrels of bitumen with the same amount of steam, increasing the production of bitumen by 15-25%. Experts also informed us that there would be an overall reduction in emissions (modelled as an efficiency increase).
4. Amount of solvent required based on conversations with experts from Esso. We were informed that 0.24 bbl diluent is required per barrel of bitumen. If we assume that the diluent is propane, this leads to 0.73 GJ propane required per barrel of bitumen.
5. Heat demand based on conversations with Canadian Natural and S&P Global. We were informed that the steam to oil ratio should be 40% lower for solvent-based extraction than for SAGD.

Table 8 presents the consolidated modelling inputs using information from the five sources listed above. We assume partial solvent-based extraction becomes available in 2026 and full solvent-based extraction becomes available in 2031.

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[26] https://www.crudemonitor.ca/

[27] Energetics Incorporated (2007). Energy and Environmental Profile of the US Petroleum Refining Industry. Available at: https://www1.eere.energy.gov/manufacturing/resources/petroleum_refining/pdfs/profile.pdf

Table 8: Modeling inputs for solvent-based extraction

Metric	SAGD	Partial Solvent Based Extraction	Full Solvent Based Extraction	Source
Heat demand (GJ heat/bbl bitumen)	1.02	-25%	-40%	gTech (SAGD) and conversations with Canadian Natural and S&P Global
CAPEX ($2015/bbl)	22.4	+10%	+20%	gTech (SAGD) and BMO Capital Markets (2019)
FOPEX ($2015/bbl)	2.2	+10%	+30%	
VOPEX ($2015/bbl)	7.2	+10%	+20%	
Solvent required (GJ propane/bbl)	0	0.73	0.73	Conversations with Esso
Efficiency increase		+10%	+20%	Conversations with experts
Output increase relative to SAGD		+15%	+25%	

Please note that we model the injection of solvents but not co-injection of methane. Because of this, results may underestimate the potential for injection technologies in the oil sands.

3.2.3. Carbon Capture and Utilization

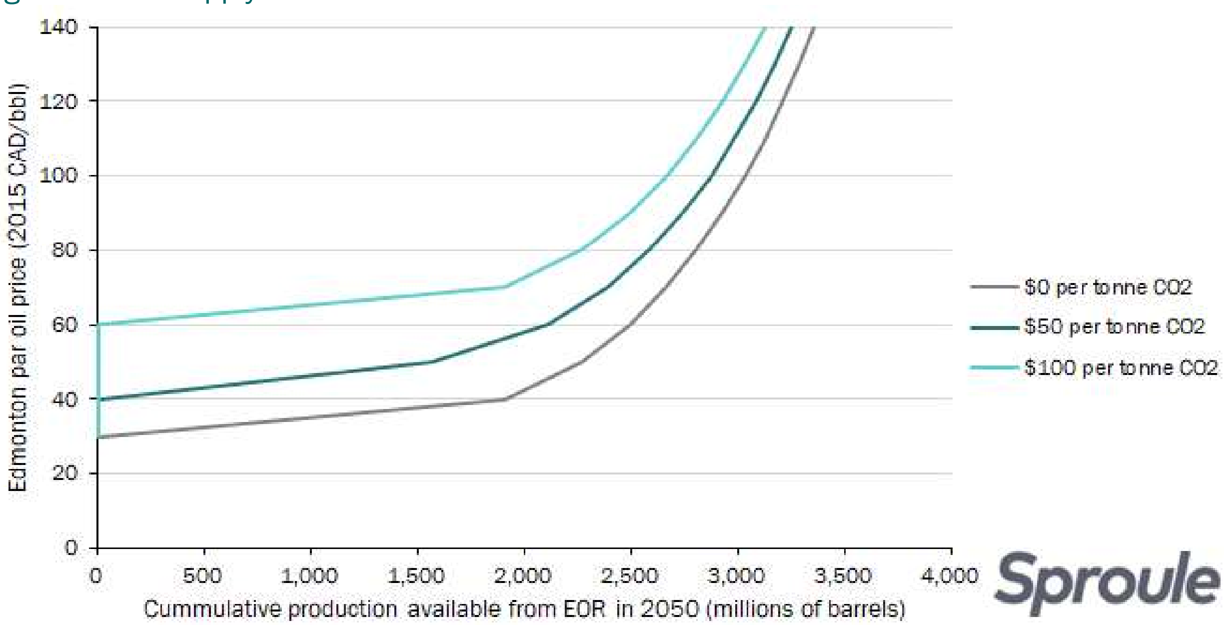
We model two carbon capture and utilization technologies (CCU) for this analysis: enhanced oil recovery (EOR) and concrete.

Enhanced Oil Recovery

EOR is parameterized based on a study by Hares (2020) [28] and conversations with experts at Sproule. In addition to the public report, we received a large raw dataset from the author with many variables including oil price, CO_2 price, and the corresponding amount of CO_2 stored. Based on an assumption that 0.3 tCO_2 is sequestered per barrel of oil produced via EOR, we obtain the incremental oil produced from EOR over a large range of future possible CO_2 prices and oil prices, as outlined in Hares' raw data. The assumptions are best summarized in a supply curve (See Figure 4). We assume that EOR is available in all scenarios starting in 2016. Because the data provided by Hares incorporates constraints like decreasing well quality as more EOR is adopted, the supply curve added to gTech accounts for this implicitly.

Hares' analysis suggests that the cumulative amount of oil available in Alberta to be accessed via EOR is 3.3 billion barrels.

Figure 4: EOR supply curve



Concrete

We parameterize CCU in concrete based on Carbon Upcycling's technology[29]. This technology sequesters CO_2 by adding CO_2 to supplementary cementitious materials (SCM), reducing the amount of clinker required in the cement. Based on conversations

[28] Hares, R. (2020). *Feasibility of CCUS to CO2-EOR in Alberta (Unpublished master's project).* University of Calgary, Calgary, AB. Available from: https://prism.ucalgary.ca/handle/1880/112625
[29] https://carbonupcycling.com/

with Carbon Upcycling, we parameterized this technology using the assumptions summarized in Table 9. CCU in concrete is assumed to be available in all scenarios starting in 2026.

Table 9: CCU in concrete assumptions

Parameter	Unit	Value
Additional cost	$/m^3 of concrete	4.7
CO_2 sequestered	kg/m^3 of concrete	7.5

3.2.4. Carbon Capture and Storage

Carbon capture and storage (CCS) technologies are parameterized in gTech based on studies from the Global CCS Institute[30] and the International Energy Agency[31]. Table 10 presents current costs of CCS (first of a kind) and Table 11 presents future minimum costs (nth of a kind). All costs are presented as levelized incremental costs for carbon capture for each technology using a 15% discount rate, 30-year life, electricity price of $27.13/GJ, coal price of $2.20/GJ, and natural gas price of $2.64/GJ. Additionally, we assume emissions of 0.05 tCO_2e/GJ of natural gas combusted and 0.09 tCO_2e/GJ of coal combusted for the purpose of the tables below. Costs are presented per tCO_2 captured for three different sensitivities.

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[30] Global CCS Institute. (2021). *Technology Readiness and Costs of CCS.* Available from: https://www.globalccsinstitute.com/wp-content/uploads/2022/03/CCE-CCS-Technology-Readiness-and-Costs-22-1.pdf
[31] International Energy Agency. (2021). *Is carbon capture too expensive?* Available from: https://www.iea.org/commentaries/is-carbon-capture-too-expensive

Table 10: Current (first of a kind) levelized cost of CCS (2020 CAD/tCO_2 captured)

CCS application	Reference cost	Low cost	High cost
Co-generation (natural gas with CCS)	221.3	151.1	252.4
Cement heat (coal with CCS)	151.1	103.2	172.4
Cement heat (natural gas with CCS)	221.3	128.1	262.6
Industrial heat (coal with CCS)	141.5	96.6	161.4
Industrial heat (natural gas with CCS)	221.3	128.2	262.6
Low-temperature industrial heat (coal with CCS)	141.5	96.2	161.4
Low-temperature industrial heat (natural gas with CCS)	221.3	128.1	262.6
SMR hydrogen production (with CCS)	100.5	65.6	135.5
Formation CO_2 (with CCS)	48.9	36.4	61.3

Table 11: Future minimum (n^{th} of a kind) levelized cost of CCS (2020 CAD/tCO_2 captured)

CCS application	Reference cost	Low cost	High cost
Co-generation (natural gas with CCS)	127.4	87.0	145.3
Cement heat (coal with CCS)	87.4	59.6	99.6
Cement heat (natural gas with CCS)	107.2	62.1	127.2
Industrial heat (coal with CCS)	75.3	51.4	85.9
Industrial heat (natural gas with CCS)	126.8	73.4	150.5
Low-temperature industrial heat (coal with CCS)	75.3	51.4	85.9
Low-temperature industrial heat (natural gas with CCS)	126.8	73.4	150.5
SMR hydrogen production (with CCS)	96.5	63.0	130.0
Formation CO_2 (with CCS)	27.1	20.2	34.1

Molten carbonate fuel cell

Another technology that utilizes CCS is molten carbonate fuel cells (MCFC). This technology, as characterized in the model, separates CO_2 from natural gas-derived flue gas while simultaneously producing clean electric power. Based on conversations with Canadian Natural (CNRL), we parameterized MCFCs for use in industrial process heat within the model. MCFC could also be used at standalone electricity generation facilities, but this opportunity was not represented in this analysis.

We assume that MCFC can be commercially deployed by 2031. Assumptions describing the cost and performance of this technology when used for carbon capture with industrial heat production are provided in Table 12, based on an MCFC with a 68 MW electrical capacity. Table 13 presents MCFC costs per tonne of CO_2 captured and per tonne of CO_2 avoided (relative to 80% energy efficient natural gas fired steam generation). The abatement costs are calculated using a 15% capital recovery factor and assuming $2.20/GJ for natural gas and $27.13/GJ for electricity. Note that capital costs could decline if the technology is widely adopted, but we did not model this dynamic.

Table 12: Key assumptions for steam generation with MCFC

Parameter	Unit	Value
Incremental capital cost	$ /MWe	4,998,078
Incremental operating cost	$/GJ steam	2.1
Incremental nat. gas consumption	$/GJ steam	0.44
Electricity production	GJ/GJ steam	0.22
Carbon capture rate	%	91%

Table 13: MCFC assumptions expressed in 2020 CAD per tCO_2 captured and avoided

Parameter	$/$tCO_2$ captured	$/$tCO_2$ avoided
Capital cost	85	120
Operating cost	30	42
Fuel cost	13	18
Electricity value	76	107
Net cost (costs less value of electricity)	52	72

Electricity generation with CCS

There are two CCS technologies available in IESD: natural gas generation plants with CCS and oxy-combustion natural gas turbines[32]. Oxy-combustion turbines utilize burning of fossil fuels in high purity oxygen instead of air. This produces a high concentration of CO_2 and moisture, which facilitates the CO_2 capture process.[33] We assume that conventional CCS technologies become available for electricity generation in 2026, and that the oxy-combustion natural gas turbine becomes available in 2031.

To parameterize oxy-combustion turbine power plants we draw on a study from the International Energy Agency.[34] We base the oxy-combustion natural gas turbine on the NET Power technology parameters outlined in the study.[35] The other CCS power generation technologies are parameterized in IESD based on another International Energy Agency study[36] and commentary[37], and a report from the Global CCS Institute[38]. These studies also inform the declining costs for both CCS technologies.

Table 14 presents costs of CCS technologies for power generation in the model. All costs are presented as levelized incremental costs for carbon capture for each technology using a 15% discount rate, 30-year life, electricity price of $27.13/GJ, coal price of $2.20/GJ, and natural gas price of $2.64/GJ[39]. Additionally, we assume emissions of 0.05 tCO_2e/GJ of natural gas combusted for the purpose of the tables below. Costs are presented per tonne CO_2 captured for three different sensitivities. We assume the capital cost of the oxy-combustion turbine declines at the same rate as other CCS electricity generation technologies. We assume a 90% capture rate for CCS technologies, except for the oxy-combustion turbine where we assume a 99% capture rate.

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[32] Please note that we also have retrofits of coal plants with CCS as an option in IESD, but since all coal plants are retired by the model year 2025 and CCS only becomes available in 2026, this is not an option in Alberta.
[33] Kotowicz J., Michalski S., and Brzeczek M. (2019). The Characteristics of a Modern Oxy-Fuel Power Plant. *Energies, 12 (3374)*.
[34] International Energy Agency. (2015). *OXY-COMBUSTION TURBINE POWER PLANTS.* Available from: https://ieaghg.org/docs/General_Docs/Reports/2015-05.pdf
[35] Note that oxy-combustion CCS can be integrated with hydrogen production via the use of waste oxygen produced by electrolysis. This dynamics is not currently represented in the model.
[36] International Energy Agency. (2011). *Cost and Performance of Carbon Dioxide Capture from Power Generation.*
[37] International Energy Agency. (2021). *Is carbon capture too expensive?* Available from: https://www.iea.org/commentaries/is-carbon-capture-too-expensive
[38] Global CCS Institute. (2021). *Technology Readiness and Costs of CCS.* Available from: https://www.globalccsinstitute.com/wp-content/uploads/2022/03/CCE-CCS-Technology-Readiness-and-Costs-22-1.pdf
[39] 2020 CAD.

Table 14: Levelized incremental costs of CCS for power generation (2020 CAD/tCO_2e captured)

Generation technology application	2020			2050		
	Reference	Low	High	Reference	Low	High
Natural gas combined cycle (with CCS)	128.4	115.5	132.3	76.9	53.8	79.3
Oxy-combustion natural gas turbine (with CCS)	174.4	156.9	179.8	104.4	73.1	107.7

3.2.5. Direct Air Capture

Direct air capture technology differs from CCS in that rather than capturing CO_2 at a point source of emissions to prevent it from entering the atmosphere, DAC removes CO_2 directly from the atmosphere, effectively producing negative emissions.

Figure 5 provides the levelized cost of DAC. DAC techno-economic parameters are based on Fasihi (2019)[40], Larsen et al. (2019)[41] and Keith et al. (2018)[42]. The reference case sensitivity is based on an average of the literature reviewed. The high-cost sensitivity represents the highest value reported in the literature. The low-cost sensitivity is a revised version of the lowest value reported in the literature, based on consultation with experts in the field.

Costs were harmonized using a 15% discount rate, 30-year life, $27.13/GJ electricity price, and $2.64/GJ natural gas price[43].

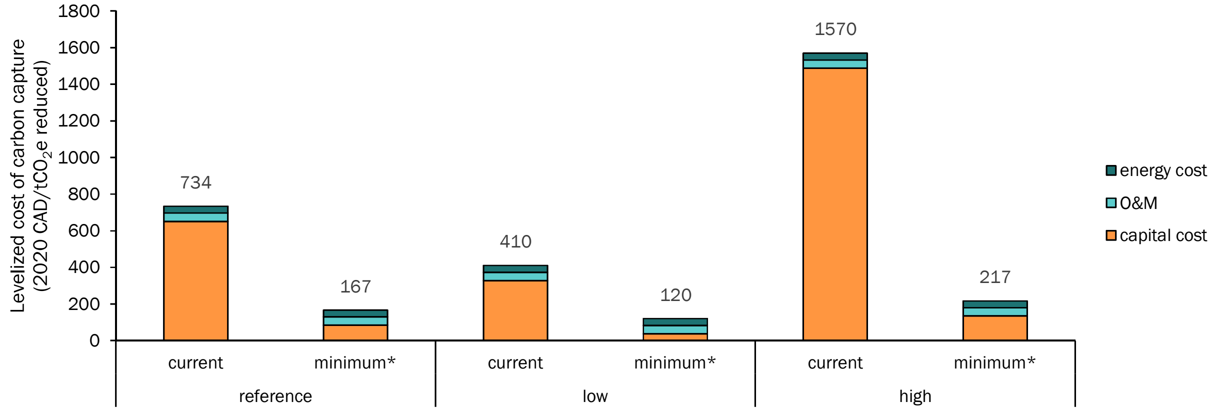
[40] Fasihi et al. (2019). Techno-economic assessment of CO2 direct air capture plants. Journal of Cleaner Production, 224, 957-980.

[41] Larsen et al. (2019). Capturing Leadership, Policies for the US to Advance Direct Air Capture Technology. Rhodium Group.

[42] Keith et al. (2018). A process for Capturing CO2 from the Atmosphere. Joule, 2, 1-22.

[43] 2020 CAD.

Figure 5: Levelized cost of carbon capture from DAC



*Future minimum costs are based on 1557 Mt CO_2 of capture.

3.2.6. Hydrogen

Two production technologies are available for low-carbon hydrogen - electrolysis and steam methane reforming with carbon capture and storage (SMR with CCS). The electrolysis technology parameters are based on IEA's "The Future of Hydrogen" report[44] and NREL's H2A Hydrogen Analysis Production Models[45]. The SMR with CCS technology parameters are based on IEA's "The Future of Hydrogen" report, NREL's H2A Hydrogen Analysis Production Models, and the GCCSI "Global Costs of Carbon Capture and Storage: 2017 Update" report[46].

Figure 6 provides the levelized cost of hydrogen production in gTech under reference, low, and high-cost assumptions. Costs are presented using a plant life of 30 years and a discount rate of 15%. Natural gas price is assumed to be $5.2/MMBtu, electricity price $143/MWh, and electrolysis production electricity rate $91/MWh[47]. Note that these costs are endogenous to the model and will change depending on the scenario.

[44] IEA. (2019). *The Future of Hydrogen*. Available from: https://www.iea.org/reports/the-future-of-hydrogen
[45] NREL. (2019). *H2A: Hydrogen Analysis Production Models*
[46] GCCSI. (2017). *Global Costs of Carbon Capture and Storage: 2017 Update.*
[47] 2020 CAD.

Figure 6: Levelized cost of hydrogen production

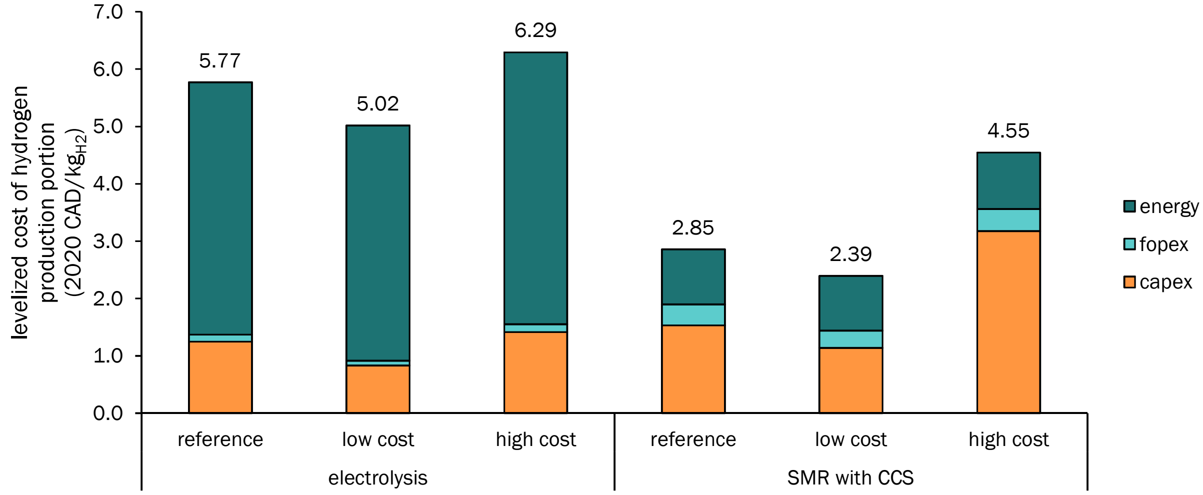


Table 15 outlines additional parameters for the electrolyzer and Table 16 outlines additional parameters for the methane reformer.

Table 15: Additional electrolyser parameters

Parameter	Unit	Value
Electrolyzer capacity (LHV)	MW	2.1
Capacity factor	%	90%
CRF	Ratio	0.15
Output pressure	kWh_e/kWh_{H2}	31
Annual output	MWh/year	16,458
Annual output	Kg/year	493,324

Table 16: Additional methane reformer parameters

Parameter	Unit	Value
Methane reformer capacity (LHV)	MW	600
Capacity factor	%	90%
CO_2 capture rate	%	90%
CRF	Ratio	0.15
Outlet pressure	Bar	24
Annual output	MWh/year	4,730,400
Annual output	Kg/year	141,793,838

3.2.7. Bioenergy

Bioenergy is represented in gTech with liquid and gaseous biofuels (as well as a limited amount of solid wood fuel used in the forest products sectors, power generation and for home heating, consistent with current utilization). We differentiate between "first generation" bioenergy, which is already commercialized, and "second generation" bioenergy produced from woody or grassy biomass via methods that are in the process of commercialization.

First generation liquid biofuels in the model include starch ethanol, biodiesel produced from soy and canola, and hydrogenated renewable diesel produced from canola (a diesel analog that may be produced from vegetable oils and animal fats). The production pathways and costs of these fuels are consistent with current practice and not discussed further in this report. First generation gaseous biofuels include renewable natural gas (RNG) production from decomposing organic material (i.e., food waste and cow manure). The model includes two types of first generation RNG: anaerobic digestion derived RNG and landfill gas derived RNG.

We estimate anaerobic digestion plant costs using information from Hallbar (2017)[48] and IEA ETSAP (2013)[49]. The Hallbar (2017) cost estimates are used for the total cost of the plant, while the IEA ETSAP (2013) medium-sized plant is used to obtain the breakdown of capital, operating and electricity costs. This ratio is applied to the Hallbar (2017) cost estimate to identify the cost breakdown. We use a discount rate of 10% and a technology life span of 20 years to provide levelized costs in Table 17.

Landfill gas derived RNG is estimated based on the EPA Landfill Methane Outreach Program in the EIA LFGcostWeb tool (v3.4)[50]. The tool provides a breakdown of capital, operating and energy costs. We calculate the cost using the weighted average of landfills smaller than 1,149 ft^3/min as Canadian landfills are significantly smaller than U.S. landfills. We use a discount rate of 10% and a technology life span of 20 years to provide levelized costs in Table 17.

Table 17: Levelized costs of first generation RNG ($2020/GJ)

Parameter	Anaerobic digestion derived RNG	Landfill gas derived RNG
Capital cost	12.1	10.0
Operation and management	6.0	2.6
Electricity cost	1.2	1.6
Total	19.3	14.2

Most of the potential bioenergy supply in the model is from second-generation biofuel feedstocks. These second-generation biofuels include cellulosic ethanol, renewable gasoline, renewable diesel and renewable natural gas produced from lignocellulosic feedstocks (i.e., woody or grassy biomass). The second-generation biofuel feedstocks included in gTech are agricultural and forestry harvest residues that can be sustainably extracted without harming soil fertility.

Agricultural residues are the remainders of plants after harvest such as corn stover and wheat straw. Forestry harvest residues are the branches and treetops that are piled and left at the side of forest roads during logging. Residue availability is defined

[48] Hallbar RNG Cost Curve Estimates (Final).xlsx, supporting data for Hallbar Consulting. (2017). Resource Supply Potential for Renewable Natural Gas in B.C., provided to us by the Government of British Columbia in April 2018.
[49] IEA ETSAP. (2013). Biogas and Bio-syngas Production. Available from: https://iea-etsap.org/E-TechDS/PDF/P11_BiogasProd_ML_Dec2013_GSOK.pdf
[50] EPA. (n.d.). Landfill Methane Outreach Program. Available from: https://www.epa.gov/lmop/download-lfgcost-web

for each source each year as a function of agricultural and forestry activity. The quantity can grow or shrink as the activity of the associated sector changes (i.e., more forestry activity produces more harvest residue, more agricultural production in Canada and the US produces more agricultural residue). However, agricultural production is constrained in gTech assuming a fixed land-base, so the model will not allow runaway residue production, nor does it allow runaway production of first-generation biofuel feedstocks (e.g., corn or wheat, canola or soy).

Note that we only include feedstock that is available as a biproduct of harvest activities and do not allow for harvesting for the sole purpose of supplying feedstock for bioenergy production. Additionally, we do not include diversion of construction wood waste as a potential feedstock.

We assume that 328 PJ/year of agricultural ligno-cellulosic residue (18.2 million ODt/year) and 238 PJ/year of forest harvest residue (15.7 million ODt/year) are available in 2015. [51,52,53,54] Conservatively, this represents about 25% of the total agricultural residue that is produced, assuming the rest either needs to be retained for soil fertility or is already used (e.g., as animal bedding). The estimate of forestry residue accounts for technical constraints and sustainability constraints (again related to soil fertility). The model estimates the available ligno-cellulosic feedstock in future years as a function of agriculture and forestry activity.

The cost of these feedstocks is a function of the capital, labour, and other inputs (e.g., fuel, fertilizer for nutrient replacement) required to produce them (Table 18). The costs are given as the baseline inputs per "oven dry tonne" (Odt) but these costs can increase if the cost of the inputs increases. Furthermore, the price of the feedstocks may be well above the cost if demand is larger than the available supply.

The levelized cost of second generation RNG from wood/crop residue in the model is consistent with values found in the literature when holding constant factors such as feedstock and energy prices.[55,56,57,58] While we account for the difference in cost of agricultural and forestry residue feedstock, we do not capture the difference in cost of processing the two. Because of this limitation, we use a production cost that is at the

[51] Agriculture and Agri-Food Canada. (2017*). Biomass Agriculture Inventory Median Values*. Available from: www.open.canada.ca
[52] Statistics Canada, CANSIM 001-0017
[53] Yemshanov et al. (2014). Cost estimates of post harvest forest biomass supply for Canada*, Biomass and Bioenergy, 69, 80-94*
[54] Government of Canada, National Forestry Database, accessed May 28, 2018
[55] Hallbar Consulting (2017). Resource Supply Potential for Renewable Natural Gas in B.C.
[56] Carbo, M., Smit, R., Drift, B.v.d, Jansen, D. (2011) Bio Energy with CCS (BECCS): Large potential for BioSNG at low CO2 avoidance cost. Energy Procedia, 4, 2011, pp 2950-2954.
[57] Müller-Langer, F. (2011) Analyse und Bewertung ausgewählter zukünftiger Biokraftstoffoptionen auf der Basis fester Biomasse. Thesis, 2011, Technische Universität Hamburg-Harburg, Hamburg.
[58] The Energy Research Centre of the Netherlands (ECN) (2014). The Economy of Large-Scale Biomass to Substitute Natural Gas (bioSNG) plants.

high end of literature values. This adjustment aligns with expert feedback we received from the advisory committee for this analysis. For the levelized cost, we use a capital discount rate of 10% and a life span of 30 years to provide levelized costs in Table 19.

Table 18: Baseline biomass feedstock costs, 2020 CAD/ODt

Parameter	Agricultural Residue	Forest Harvest Residue
Capital cost	15.2	15.2
Labour cost	15.7	35.1
Other input cost	30.5	36.6
Total	61.4	86.8

Table 19: Levelized cost of second-generation RNG ($2020/GJ)

Parameter	Ligno-cellulose derived RNG
Capital cost	19.5
Operation and management	1.3
Electricity cost	0.3[59]
Feedstock cost	5.1
Total	26.2

[59] Based on an illustrative electricity price of $23/GJ

Second generation biofuels can also be used to produce renewable gasoline and diesel. The cost of renewable gasoline and diesel production is presented in Table 20.[60,61,62,63] As noted earlier, renewable diesel can also be produced from food crops (canola).

Table 20: Levelized cost of renewable gasoline and diesel from biomass ($2020/L)

Parameter	Renewable gasoline and diesel
Capital cost	1.29
Operation and management	0.26
Natural gas cost	0.04
Electricity cost	0.08
Feedstock cost	0.21
Total	1.89

Note that the feedstock costs provided in the Table 19 and Table 20 are a starting point in 2020, defined by the baseline feedstock production costs in Table 18. gTech solves for the price of feedstock endogenously in future years depending on demand for RNG and biofuels. Because there are limits on the availability of feedstock, the cost can increase significantly in scenarios in which there is a lot of RNG or biofuel demand. Similarly, the electricity cost and natural gas cost associated with RNG and biofuel production will also vary by scenario as electricity price and natural gas price are solved for endogenously in gTech.

Several limitations to note include:

- We do not include third generation biofuels (algal biomass) in our modelling.

[60] Jones S. et al. (2013). Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels
[61] Dutta A. et al. (2015). Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fue
[62] Tan E. et al. (2018). High-Octane Gasoline from Lignocellulosic Biomass via Syngas and Methanol/Dimethyl Ether Intermediates: 2018 State of Technology and Future Research; Analysis Production Case Studies
[63] Swanson R. et al. (2010). Techno-Economic Analysis of Biofuels Production Based on Gasification

- There is a pool of forestry residue that could be used for bioenergy that would have otherwise been burned to reduce fuel loads produced from logging. Using these feedstocks for fuel is clearly a net zero GHG activity. However, with increasing bioenergy production we may tap into other types of feedstocks including larger branches or treetops that would have otherwise taken years to decades to decompose. Taken in isolation, using this material as fuel advances the release of its carbon to the atmosphere and this has an emissions impact that is not captured in gTech.
- Biomass feedstock costs do not account for how transportation costs may vary as a function of how far that material is from the processing plant. This transportation cost may be especially large for forest harvest residues, though there are also some very low transportation/low-cost opportunities. Consequently, our model likely overestimates the cost of forest biomass when this resource is first used and underestimates the cost when there is greater utilization. That being said, when there is significant utilization, the price of the feedstock is driven by scarcity and may be much greater than the cost shown in Table 18 (e.g., more than $150/Odt).

3.2.8. Zero Emission Vehicles

Battery electric vehicles

Figure 7 shows the cost of battery electric vehicles and how it is assumed to decline over time.

Table 21 outlines additional assumptions for low and high cost sensitivities for the technology. Note that charging infrastructure remains a significant cost - an additional $20-50K for medium duty, $200-$300K for heavy-duty. Cost is a function of electrification market share, with lower costs corresponding to greater infrastructure deployment and sharing. All electric vehicles have intangible costs to represent market barriers in addition to financial costs. Intangible costs and capital cost decline as a function of adoption of the technology across Canada and the U.S.

Figure 7: Cost of battery electric vehicles

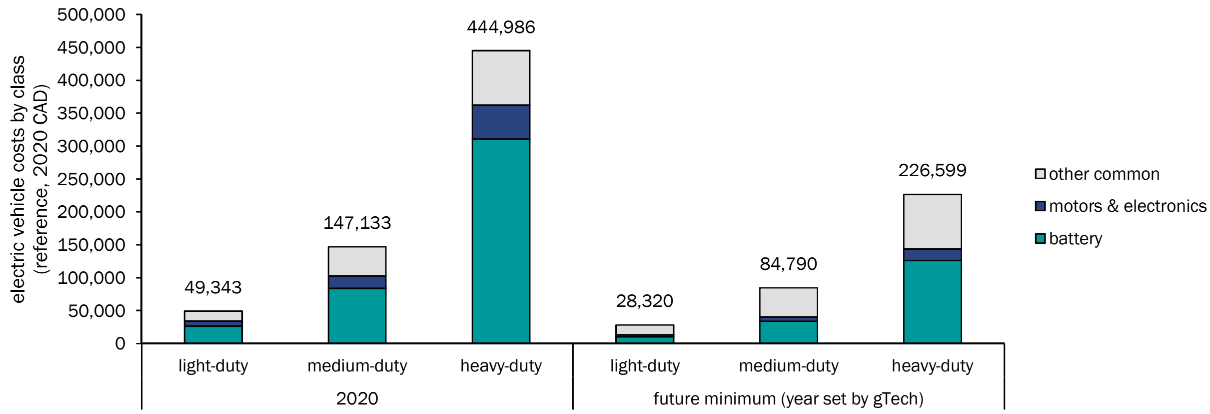


Table 21: Cost of battery electric vehicles[64]

Reference	Low	High	Sources
Total cost of light-duty vehicle in 2020 is $49,343 declining to a minimum of $28,320 with increased adoption. Total cost of medium-duty in 2020 is $147,133 declining to a minimum of $84,790. Total cost of heavy-duty vehicle in 2020 is $444,986 declining to a minimum of $226,599. Doubling of stock reduces battery cost by 25%, other components by 7%.	Total cost of light-duty vehicle in 2020 is $34,588 declining to minimum of $23,521 with increased adoption. Total cost of a medium-duty vehicle in 2020 is $102,420 declining to a minimum of $70,173. Total cost of a heavy-duty vehicle in 2020 is $285,715 declining to a minimum of $174,339. Doubling of stock reduces battery cost by 28%, other components by 9%.	Total cost of a light-duty vehicle in 2020 is $70,162 declining to a minimum cost of $33,392 with increased adoption. Total cost of a medium-duty vehicle in 2020 is $210,643 declining to a minimum of $100,249. Total cost of a heavy-duty vehicle in 2020 is $672,363 declining to a minimum of $281,911. Doubling of stock reduces battery cost by 22%, other components by 4%.	ICCT. (2022, unpublished). A meta study of purchase costs for zero-emission trucks Bloomberg. (2020). Electric Vehicle Outlook. NREL. (2019). Market segmentation analysis of medium and heavy-duty trucks with a fuel cell emphasis. ICCT. (2017). Transitioning to zero-emission heavy-duty freight vehicles. ATRI. (2018). An analysis of operational costs of trucking: 2018 Update Earl et al. (2018). Analysis of long-haul battery electric trucks in EU. ICCT. (2019). Estimating the infrastructure needs and costs for the launch of zero-emission trucks. Fries et al. (2017). An Overview of Costs for Vehicle Components, Fuels, Greenhouse Gas Emissions and Total Cost of Ownership Update 2017.

[64] 2020 CAD

Fuel cell electric vehicles

Figure 8 shows the cost of fuel cell electric vehicles and how it is assumed to decline over time. Table 22 outlines additional assumptions for an alternative low-cost and high-cost sensitivity. Note that all electric vehicles have intangible costs to represent market barriers in addition to financial costs. Intangible costs and capital cost decline as a function of adoption of the technology across Canada and the U.S.

Figure 8: Cost of fuel cell electric vehicles

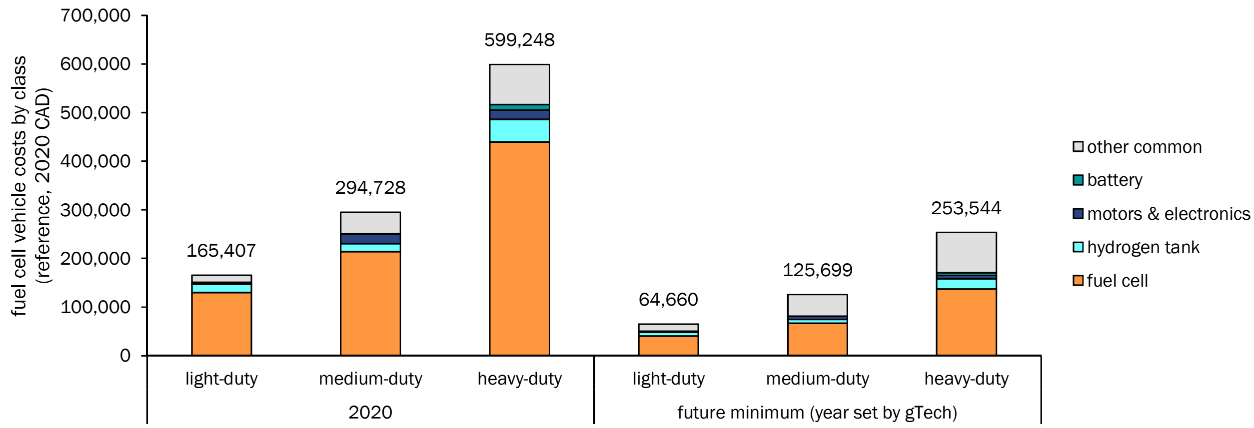


Table 22: Cost of fuel cell electric vehicles[65]

Reference	Low	High	Sources
Total cost of light-duty vehicle in 2020 is $165,407 declining to a minimum of $64,660 with increased adoption. Total cost of a medium-duty vehicle in 2020 is $294,728 declining to a minimum of $125,699. Total cost of a heavy-duty vehicle in 2020 is $599,248 declining to a minimum of $253,544. Doubling of stock reduces fuel cell cost by 13%, tank by 8%.	Total cost of light-duty vehicle in 2020 is$57,014 declining to a minimum of $26,830 with increased adoption. Total cost of a medium-duty vehicle in 2020 is $118,454 declining to a minimum of $65,197. Total cost of a heavy-duty vehicle in 2020 is $233,019 declining to a minimum of $126,772. Doubling of stock reduces fuel cell cost by 17%, tank by 9%.	Total cost of light-duty vehicle in 2020 is $316,460 declining to a minimum of $127,979 with increased adoption. Total cost of a medium-duty vehicle in 2020 is $544,515 declining to a minimum of $228,860. Total cost of a heavy-duty vehicle in 2020 is $1,114,116 declining to a minimum of $467,647. Doubling of stock reduces fuel cell cost by 8%, tank by 2%.	ICCT. (2022, unpublished). A meta study of purchase costs for zero-emission trucks SA Consultants. (2017). Mass Production Cost Estimation of Direct H2 PEM Fuel Cell Systems for Transportation Applications: 2016 Update. SA Consultants. (2016). Final Report: Hydrogen Storage System Cost Analysis. Fueleconomy.gov. (2019). Compare Fuel Cell Vehicles. SA Consultants. (2019). 2019 DOE Hydrogen and Fuel Cells Program Review Presentation.

3.2.9. Intermittent Renewables

We parameterize two intermittent renewable technologies in Alberta in IESD: solar and onshore wind. Table 23 outlines cost assumptions used to parameterize these technologies.

The onshore wind costs described in Table 23 are available for the first 806 MW of capacity. Beyond that, the model adds a cost to additional capacity ranging from $504-761/kW in 2020 and $215-324/kW in 2050 depending on the amount of wind capacity that has been built in Alberta. This is done to reflect wind sites that are more remote, requiring greater infrastructure development.

[65] 2020 CAD

Table 23: Cost of solar and wind[66]

Technology	Reference	Low	High
Solar	Capital cost of solar is $3,257/kW in 2015 declining to $808/kW by 2030 and $608/kW by 2050. Fixed operating cost of $30/kW.	Capital cost of solar is $3,257/kW in 2015 declining to $665/kW by 2030 and $458/kW by 2050. Fixed operating cost of $30/kW.	Capital cost of solar is $3,257/kW in 2015 declining to $1,183/kW by 2030 and $740/kW by 2050. Fixed operating cost of $30/kW.
Onshore wind	Capital cost of onshore wind is $2,250/kW in 2015 declining to $1,048/kW by 2030 and $778/kW by 2050. Fixed operating cost of $51/kW.	Capital cost of onshore wind is $2,250/kW in 2015 declining to $734/kW by 2030 and $515/kW by 2050. Fixed operating cost of $51/kW.	Capital cost of onshore wind is $2,250/kW in 2015 declining to $1,138 /kW by 2030 and $951/kW by 2050. Fixed operating cost of $51/kW.

3.2.10. Electricity Storage

Batteries

We parameterize two storage options in IESD: lithium-ion batteries for short-term duration storage and flow batteries for long-term duration storage. Table 24 outlines cost assumptions used to parameterize these technologies.

The roundtrip efficiency of lithium-ion batteries is 85%, per hour storage loss is assumed to be 0.01%, and energy to power ratio is 1:1. Flow batteries have a roundtrip efficiency of 80%, per hour storage loss is assumed to be 0.02%, and energy to power ratio is 4:1.

66 Natural Renewable Energy Laboratory's Annual Technology Baseline (CAD-USD exchange rate of 1.3). Costs are specified in 2020 CAD.

Table 24: Battery costs[67]

Technology	Reference	Low
Lithium-ion batteries	Storage capital cost is $582.1/kWh in 2015, declining to $198.3/kWh by 2030 and to $93.7/kWh by 2050. Power capital cost of $291/kW in 2015, declining to $99.2/kW by 2030 and to $46.8/kW by 2050.	Storage capital cost is $582.1/kWh in 2015, declining to $146.3/kWh by 2030 and to $65.8/kWh by 2050. Power capital cost of $291/kW in 2015, declining to $61.2/kW by 2030 and to $27.5/kW by 2050.
Flow batteries	Storage capital costs of $437.6/kWh in 2015, decreasing to $150.4/kWh by 2030 and to $65/kWh by 2050. Power capital costs of $1761.9/kW in 2015, decreasing to $605.5 /kW by 2030 and to $261.6/kW by 2050.	Storage capital costs of $437.6/ kWh in 2015, decreasing to $121.9/kWh by 2030 and to $48.8/kWh by 2050. Power capital costs of $1761.9/kW in 2015, decreasing to $490.8 /kW by 2030 and to $196.3/kW by 2050.

Hydrogen storage

We parameterize seasonal electricity storage using hydrogen in IESD. Table 25 outlines the capital cost of seasonal electricity storage. Power capital cost is defined as the cost of producing hydrogen via electrolysis and the cost of reconversion using a fuel cell. Storage capital cost represents the cost of the storage infrastructure, assumed to be man-made underground storage. Roundtrip efficiency is assumed to be 40%, per hour storage loss is assumed to be 0.0003%.

Table 25: Cost of using hydrogen for seasonal electricity storage

Technology	Reference
Seasonal electricity storage using hydrogen	Storage capital cost stays constant at $1.14/kWh. Power capital cost declines from $2,362/kW in 2015 to $1,654/kW by 2030 and $803/kW by 2050.

67 Navius' IESD model and conversations with NRCan. Costs are specified in 2020 CAD.

The following sources were used to parameterize hydrogen as seasonal electricity storage:

- Lord, A. et al. (2014). Geologic storage of hydrogen: Scaling up to meet city transportation demands. *International Journal of Hydrogen energy 39, 15570-45582.*
- Bonadio, L. (2009). Fuels – Hydrogen Storage Liquid. *Encyclopedia of Electrochemical Power Sources, 421-439.*
- Headley. (2020). DOE. Hydrogen Energy Storage. Available from: https://www.sandia.gov/ess-ssl/wp-content/uploads/2020/12/ESHB_Ch11_Hydrogen_Headley.pdf
- Amid A, et al. (2016). Seasonal storage of hydrogen in a depleted natural gas reservoir. *International Journal of Hydrogen Energy, 41, 5549-5558.*
- Korner, A. (2015). *Technology Roadmap Hydrogen and Fuel Cells – Technical Annex.*
- IEA. (2019). *The Future of Hydrogen Annex.* Available from: https://www.iea.org/reports/the-future-of-hydrogen/data-and-assumptions
- Lemieux, A. et al. (2020). Geologic feasibility of underground hydrogen storage in Canada. *International Journal of Hydrogen Energy, 45, 32243-32259.*
- DOE. (2013). Onboard Type IV Compressed Hydrogen Storage Systems – Current Performance and Cost. *DOE Fuel Cell Technologies Office Record.*

3.2.11. Small Modular Nuclear Reactors

The International Atomic Energy Agency defines small modular reactors (SMnRs) as nuclear plants with a power generation capacity below 300 MWe. In contrast to larger nuclear plants, SMnRs are anticipated to be less capital intensive and require less time to construct. They are also more readily deployable in brownfield sites thanks to their smaller footprints, making them well-suited for meeting low carbon heat and power needs of industry.

SMnRs are assumed to be available in all scenarios for this study. The technology archetype is characterized based on an "evolutionary" design. The technology archetype is based on assumptions for on-grid SMnRs in the Economic and Finance Working Group's Roadmap.[68] This archetype builds on current nuclear technology and is at a high technology readiness level. A "revolutionary" archetype is also presented in the Roadmap – reflecting more novel technology that is at a low readiness level – but

[68] Economic and Finance Working Group. (2018). *SMR Roadmap*. Available from: https://smrroadmap.ca/wp-content/uploads/2018/12/Economics-Finance-WG.pdf

is not included in this analysis. To capture the potential for SMnRs to provide heat only (as opposed to power), we modify the SMnR Roadmap's assumptions to account for 1) lower capital and operating costs due to the lack of a steam turbine and 2) a reduction in efficiency losses. Table 26 presents costs of SMnRs in process heat, and Table 27 presents costs of SMnR in cogeneration using a 6% discount rate.

Table 26: Costs of the SMnR process heat archetype

Parameter	Units	Heat
Capital cost incl. decommissioning	$\$/kW_{th}$	2,876
Fixed O&M	$\$/kW_{th}$-yr	32
Variable O&M incl. fuel	$\$/MWh_{th}$	3.7
Capacity factor	%	90
Plant life	Years	40
Levelized cost of heat	$\$/MWh_{th}$	32

Table 27: Costs of the SMnR cogeneration technology archetype

Parameter	Units	Cogeneration
Capital cost incl. decommissioning	$/kW_e$	6,639
Fixed O&M	$/kW_e$-yr	16
Variable O&M incl. fuel	$/MWh_e$	17.8
Capacity factor	%	90
Plant life	Years	40
Levelized cost of electricity	$/MWh_e$	76

SMnRs are assumed to become commercially deployable after 2030 and applicable for use in any industry that demands high-grade process heat. We assume that the following sectors have SMnRs available for process heat and cogeneration: conventional heavy oil, oil sands, upgrading, refining, mining, plastics, chemical and fertilizer manufacturing, resin and synthetic rubber manufacturing, industrial gas manufacturing, metal manufacturing, biofuel manufacturing, and hydrogen manufacturing.

In addition to allowing for SMnRs in process heat, SMnRs may also be an option for electricity generation. Table 28 outlines the cost assumptions in IESD based on the "evolutionary" costs provided by the Economic and Finance Working Group (2018). Note that SMnRs are assumed to become available in all scenarios at this cost starting in 2031. Costs are presented using a 6% discount rate.

Table 28: Costs of SMnRs for electricity generation, evolutionary type

Parameter	Units	Electricity generation
Capital cost incl. decommissioning	$/kW_e$	6,639
Fixed O&M	$/kW_e$-yr	16
Variable O&M incl. fuel	$/MWh_e$	17.8
Capacity factor	%	90
Plant life	Years	40
Levelized cost of electricity	$/MWh_e$	76

4. Alberta's Net Zero Energy System

Previous analyses[69] indicate the need for transformation of Canada's energy system to achieve net zero emissions. In general, this transition is away from the combustion of fossil fuels for energy and towards clean electricity and renewable fuels such as RNG and hydrogen. The same is true for Alberta.

For example, Alberta's transportation sector will see increased adoption of battery electric and hydrogen fuel cell vehicles (from 0.1% of new on-road vehicles in 2020 to up to 88% of new stock in 2050) and greater blending of biofuels (from 2.5% in 2020 to up to 85% of the fuel stream in 2050). At the same time, Alberta's buildings will see blending of RNG and hydrogen into the natural gas stream for heating (from 0% of the fuel stream in 2020 to up to 58% in 2050), as well as adoption of electric heat pumps (from virtually no adoption in 2020 to meeting up to 93% of building heating load in 2050). Although the extent of adoption of these technologies varies by net zero scenario, we know electrification and renewable fuel blending in transportation and buildings will play an important role in Alberta's net zero future, as in most provinces across Canada.

However, there is more uncertainty in the future of other sectors of Alberta's economy that are uniquely challenging to decarbonize. Challenges unique to Alberta's net zero energy transition include transitioning the oil and gas sector and a fossil fuel-dominant electricity system. Results of this analysis suggest several opportunities could arise for Alberta while addressing the challenge of achieving net zero emissions. This includes technologies that provide a new revenue stream under stringent climate policy, such as direct air capture or enhanced oil recovery, or technologies that facilitate compliance with achieving net zero emissions, including carbon capture, utilization and storage, renewables, electricity storage, and hydrogen. This also includes opportunities to supply bitumen products for which demand will remain in a net zero future.

As such, this section focuses on sectors that are particularly challenging for Alberta's transition to net zero – oil sands, conventional oil, natural gas, and electricity. It focuses on how energy consumption in these sectors may change in a net zero future and what technologies may be adopted to mitigate emissions in these sectors. This

[69] Navius Research (2021). Achieving net zero emissions by 2050 in Canada. Available at: https://www.naviusresearch.com/publications/climate-choices-net-zero/

section also highlights key technologies and opportunities that could become important in helping these sectors comply with net zero. It describes the role each technology could play in a net zero future and quantifies the economic contribution each could make to Alberta's net zero economy.

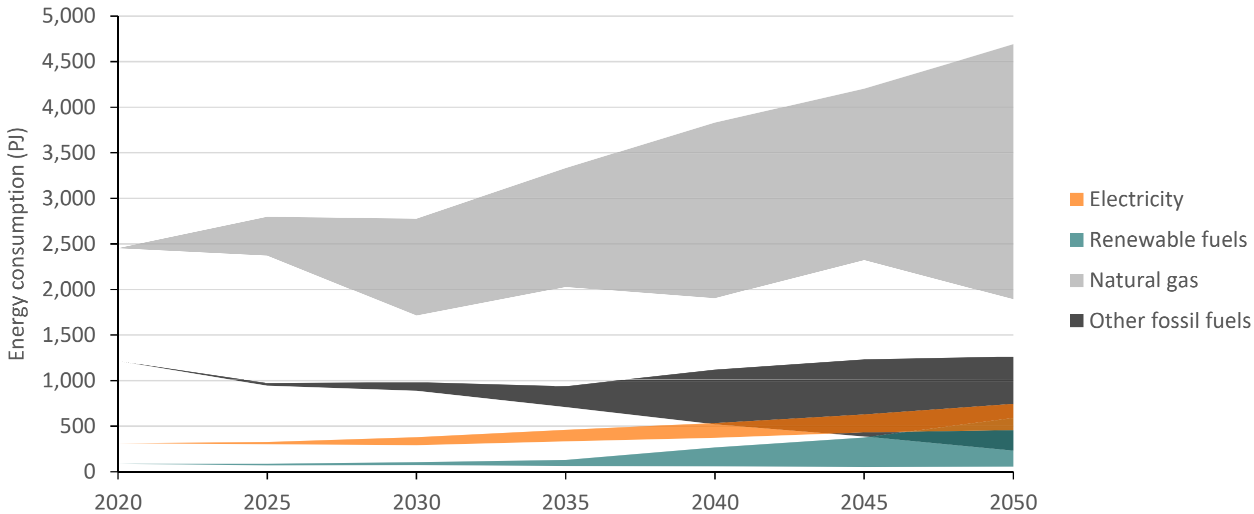
Overview of Alberta's net zero energy system

Figure 9 presents energy consumption in Alberta's economy as a whole, across all net zero scenarios simulated in this analysis. It indicates that total energy consumption changes from 4,067 PJ in 2020 to 3,177-6,712 PJ in 2050 depending on the net zero scenario.

Electricity demand increases in all net zero scenarios, up to 457-745 PJ in 2050 (a 46-139% increase from 2020 levels). Total energy consumption in the province declines by up to 22% from 2020 to 2050, despite increases in population growth, in scenarios in which Alberta relies more heavily on electrification to meet future energy demand. This is because electricity is a more efficient source of energy than fossil or renewable fuels.

Future consumption of natural gas in the province is more uncertain, ranging from 2453 PJ in 2020 to 1893-4690 PJ in 2050. Total energy consumption increases in scenarios in which the province relies on the continued use of natural gas, with CCS to capture or DAC to offset emissions. In this case, Alberta's energy consumption increases by up to 65% from 2020 to 2050. This occurs in net zero scenarios in which the global oil price is high, leading to continued demand for oil and gas production, DAC technology is available, allowing for offsetting of emissions from continued use of natural gas, when CCS costs are low, and when the cost of renewables and electricity storage are high.

Figure 9: Total energy consumption by fuel type in Alberta (range across all net zero scenarios)[70]



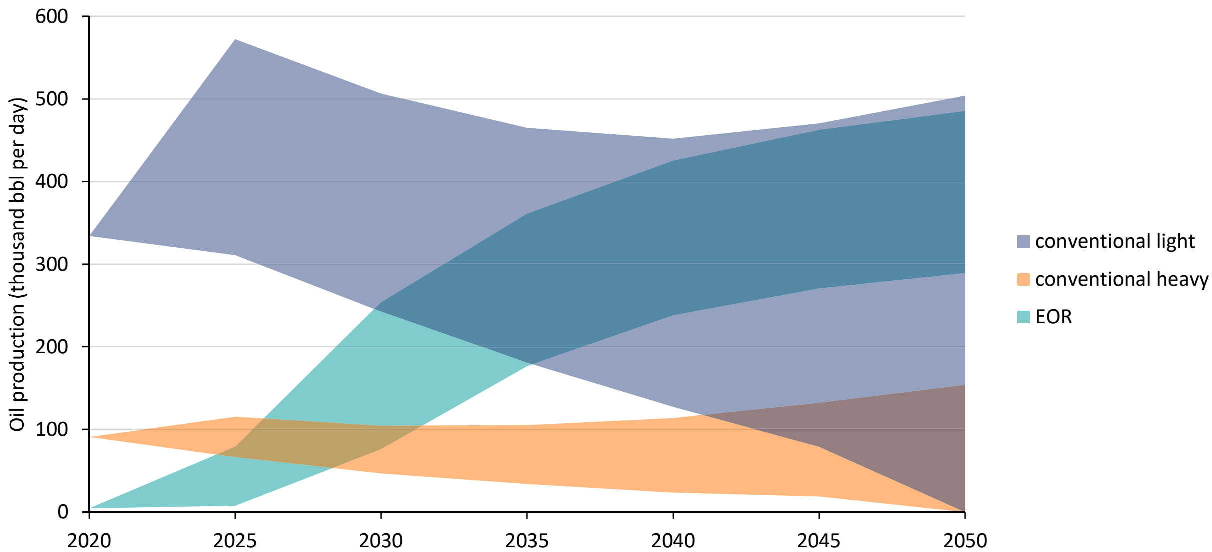
4.1. Oil Production

4.1.1. Conventional Oil

There is significant uncertainty in the future of conventional oil production in Alberta under net zero emissions. Total conventional oil production changes from 425 thousand barrels per day in 2020 to 0-654 thousand barrels per day in 2050 depending on the net zero scenario (Figure 10). This range is driven mostly by global demand for oil (i.e., the assumed global oil price), but in the long term (between 2045 and 2050) is also driven by the availability of DAC technology. Production using enhanced oil recovery increases from 2020 levels in all net zero scenarios, partially offsetting declines in conventional oil production. This is explored in more detail in the next section.

[70] Note that the Increase in "other fossil fuels" over time is driven by the in situ oil sands sector and demand for natural gas liquids for solvents for solvent-based extraction. Consumption of natural gas liquids is greatest in scenarios with the most in situ oil sands production, including high oil price, low CCS and low DAC cost scenarios.

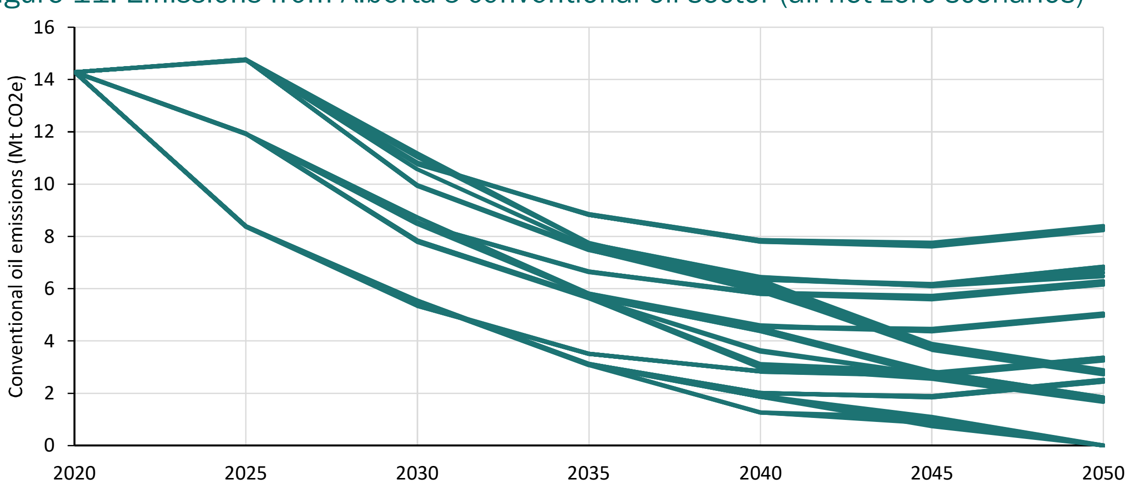
Figure 10: Oil production in Alberta (range across all net zero scenarios)



Emissions from the conventional oil sector decline over time in all net zero scenarios, from 14.3 Mt in 2020 to 0-8.4 Mt in 2050. Figure 11 provides emission trajectories for this sector for all net zero scenarios simulated. The range in emissions is driven by demand for production in this sector, with the three clusters in Figure 11 corresponding to the assumed global oil price (low, reference and high).

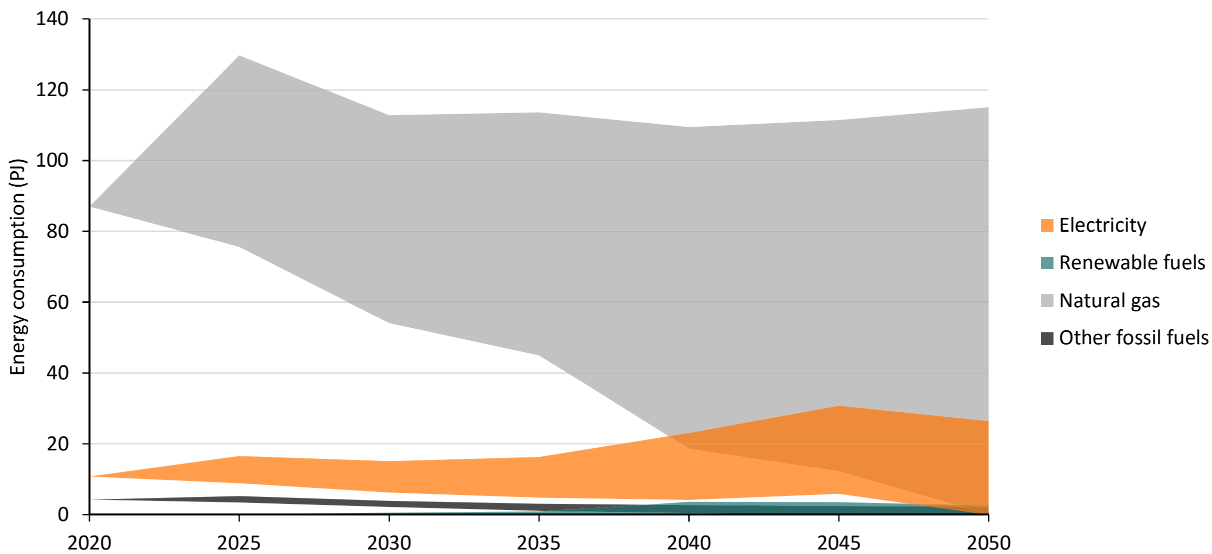
There are a few scenarios in which emissions in this sector decline to zero. These are net zero futures in which Alberta no longer produces conventional oil and instead focuses on the production of non-combustion oil products from bitumen (as discussed in Section 4.1.3). Scenarios in which emissions remain the highest are those with continued conventional oil production, when global demand for oil is high and DAC technology is available at low cost to allow this sector to purchase emission offsets.

Figure 11: Emissions from Alberta's conventional oil sector (all net zero scenarios)



In scenarios with continued conventional oil production, the sector invests in abatement technologies to reduce emissions. Key abatement opportunities available in this sector include methane management, electrification and CCS.[71] Energy consumption as a range across all net zero scenarios is presented in Figure 12, indicating a significant increase in electricity consumption in this sector in some scenarios (up to a 144% increase from 2020 to 2050). This is driven by the electrification of natural gas compressors, with 39-100% of total market share being electric compression by 2050. Methane management is also implemented, with 67-100% of venting and 10-100% of leaking addressed using near zero methane emission technology[72] by 2050.

Figure 12: Energy consumption by fuel type in Alberta's conventional oil sector (range across all net zero scenarios)

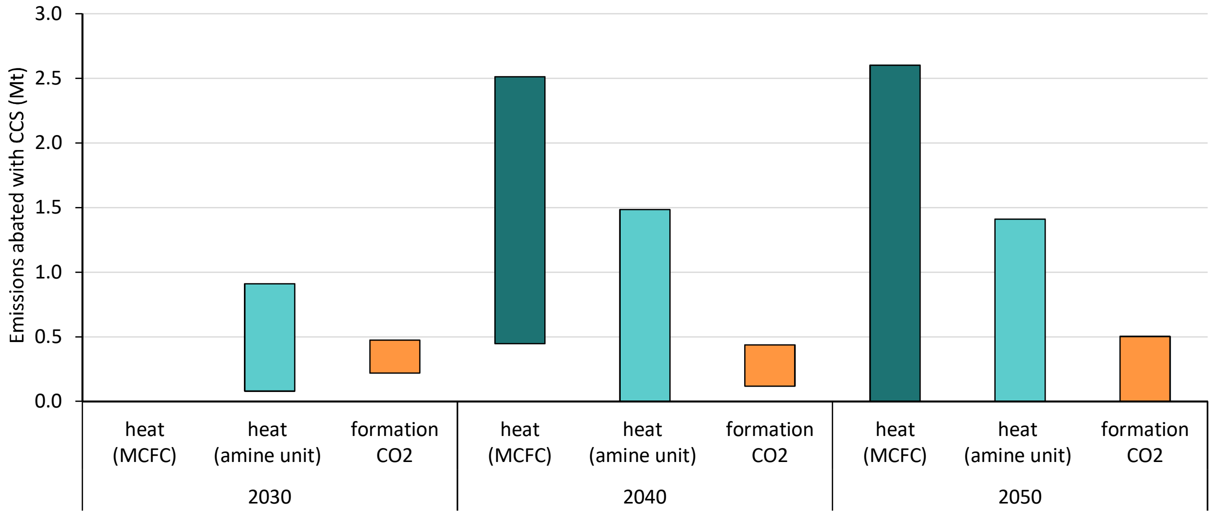


In all net zero scenarios in which conventional oil production continues, this sector continues to consume significant amounts of natural gas (up to 115 PJ in 2050) as shown in Figure 12. Emissions are captured using CCS. CCS is available in this sector to reduce emissions from process heat (amine unit CCS or MCFC technology) and to reduce formation CO_2. CCS adoption in this sector ranges from 0.3-1.4 Mt in 2030, 0.9-3.4 Mt in 2040 and 0-3.7 Mt in 2050. The range in adoption by technology type is presented in Figure 13.

[71] Small modular nuclear reactors for heat production were not a competitive technology in this sector and were adopted in negligible amounts based on the assumptions presented in Section 3.2.11.

[72] Near-zero CH_4 technology includes high frequency of leak monitoring (every month and a half) and repair where necessary (applied to all equipment including transmission pipelines). It also includes elimination of venting from compressors, switching to low-bleed and, where possible, no-bleed devices and chemical injection pumps, capturing and using or flaring methane from storage tanks as well as any gases that need to be released during maintenance or process upsets, and flaring of all stranded gas.

Figure 13: CCS adoption in Alberta's conventional oil sector (range across all net zero scenarios)[73]



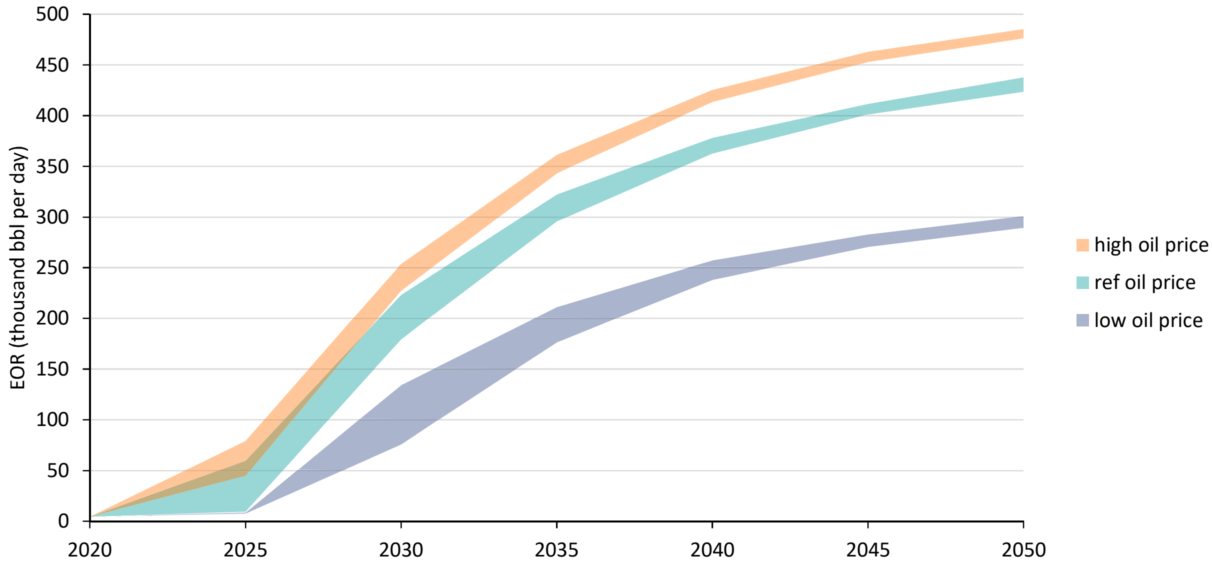
4.1.2. Enhanced Oil Recovery

Declines in conventional oil production in a net zero future are partially offset by production using enhanced oil recovery (EOR). EOR creates a new revenue stream for Alberta – it creates a revenue stream for the oil and gas sector by allowing for lower emission oil production, but also creates new revenue for adopters of CCS technology that can sell captured CO_2 for use in EOR. EOR creates a market for the CO_2 sequestered through CCS, providing an additional incentive and increasing CCS adoption in the province in the short term, while the CO_2 commodity price remains high. In the longer-term (after 2030), the CO_2 price becomes negative in all net zero scenarios, at which point EOR does not provide an additional revenue stream for CCS adoption but remains an opportunity to use and store captured CO_2.

Figure 14 presents EOR adoption in Alberta across all net zero scenarios, which increases significantly over time in all scenarios and ranges from 76-254 thousand barrels per day in 2030 and 289-483 thousand barrels per day in 2050. This corresponds to 8-28 Mt of captured CO_2 being used for EOR in 2030 and 32-53 Mt in 2050. As with CCS adoption, EOR adoption is driven by the global oil price. In net zero scenarios that assume future oil demand is high (simulated as a high global oil price), EOR adoption ranges from 227-254 thousand barrels per day in 2030 and 476-486 thousand barrels per day in 2050. If future demand for oil is low (simulated as a low global oil price), EOR adoption ranges from 76-134 thousand barrels per day in 2030 and 289-301 thousand barrels per day in 2050.

[73] See Section 3.2.4 for cost information on each CCS technology.

Figure 14: Enhanced oil recovery adoption in Alberta (range across all net zero scenarios)



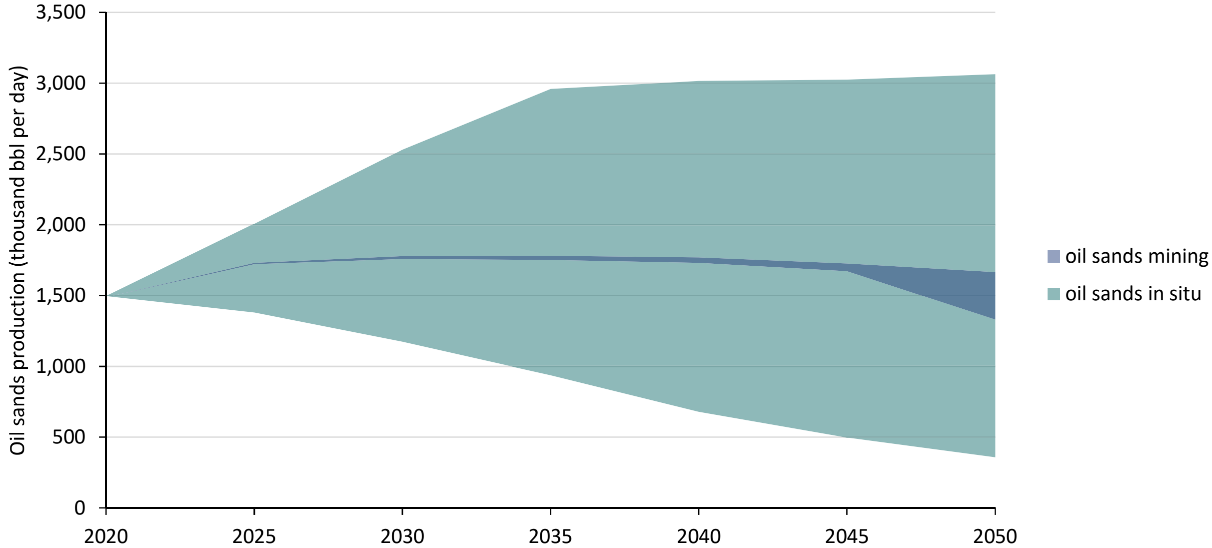
4.1.3. Oil Sands

A critical question facing Alberta in a net zero emission future is the role of bitumen and the oil sands. The oil sands accounted for 80% of Alberta's total oil production in 2020[74] and 45% of GDP in the oil and gas sector.[75] When accounting for the construction and services required by the oil sands, its contribution to Alberta's economy is far greater.

Bitumen production from Alberta's oil sands sector is uncertain in a net zero future, particularly in situ oil sands production. Figure 15 presents the range in bitumen production across all net zero scenarios simulated. This range is largely driven by global demand for oil (simulated as the assumed global oil price), as indicated in Figure 16. In scenarios where the global oil price is high, production increases from 2,985 thousand barrels per day in 2020 to up to 4,729 thousand barrels per day in 2050. If the global oil price is low, production from the oil sands could decline to 1,968 thousand barrels per day by 2050.

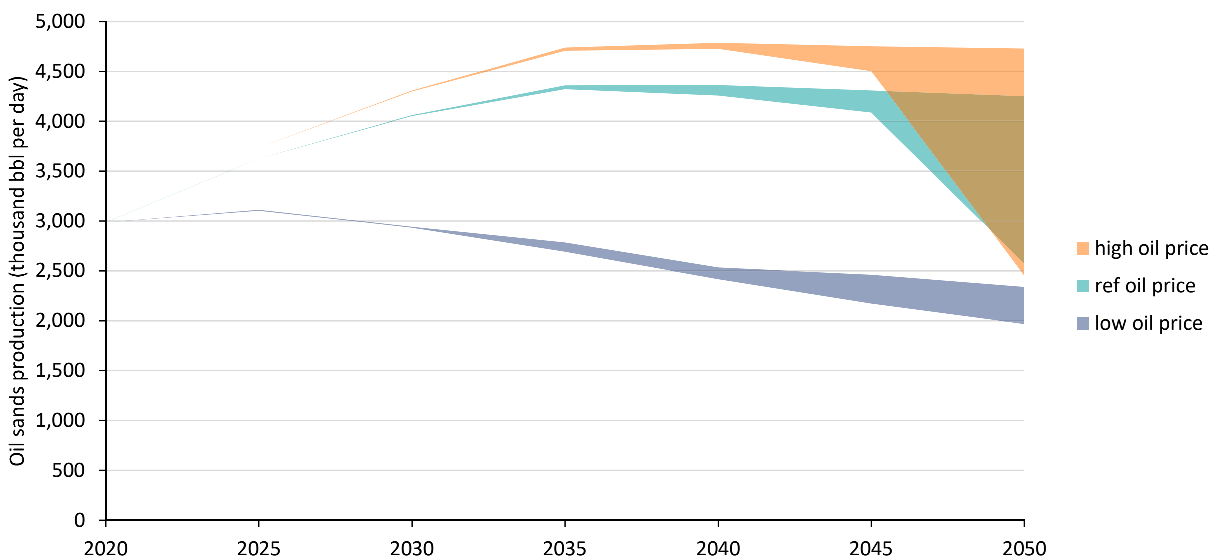
[74] Canada Energy Regulator. (2021). *Canada's Energy Future 2021.* Available from: www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/index.html
[75] gTech, informed by the 2015 Statistics Canada Supply-Use Tables and Canada Energy Regulator (2021).

Figure 15: Oil sands production in Alberta (range across all net zero scenarios)



However, production from this sector does not decline as significantly as conventional oil production under net zero policy. Figure 15 and Figure 16 indicate that oil sands production continues out to 2050 in all net zero scenarios simulated. This is a result of the refinery updates made to gTech for this analysis which account for the comparative advantage of bitumen in producing the heavier ends of the barrel and indicates that bitumen remains “the last barrel standing” in 2050 across many net zero scenarios. In other words, bitumen’s comparative advantage in producing non-combustion commodities means it outcompetes lighter grades of crude oil in a net zero future.

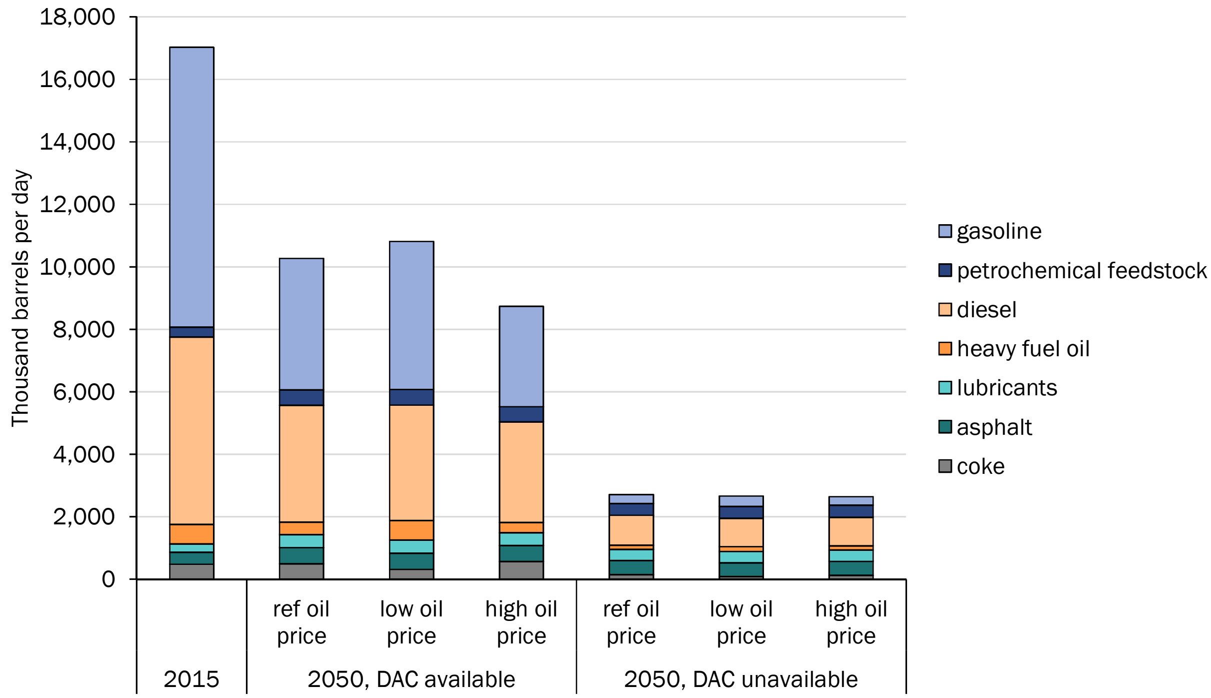
Figure 16: Oil sands production in Alberta (range across all net zero scenarios)



As outlined in Section 3.2.1, bitumen currently produces oil at the heavy end of the barrel, which is cracked into the lighter end of the barrel in upgraders and/or refineries to produce liquid fuels. However, in a net zero future in which Alberta achieves deep emissions reductions, there is a reduction in liquid fuels use as demand shifts away from internal combustion engine vehicles to battery electric or fuel cell electric vehicles. As a result, demand for gasoline and diesel declines significantly by 2050, while demand for asphalt, lubricants and petrochemical feedstocks remains, as illustrated Figure 17.

This change in demand is apparent in all net zero scenarios but is most apparent in scenarios without DAC technology available. When DAC technology is not commercial, fewer offsets are available to allow for continued use of gasoline and diesel across the economy, resulting in a greater decline in gasoline and diesel demand than scenarios with DAC available. In all net zero scenarios, demand for asphalt, lubricants and petrochemicals remains in 2050.

Figure 17: Demand for oil products under net zero policy in Canada and the U.S.[76]



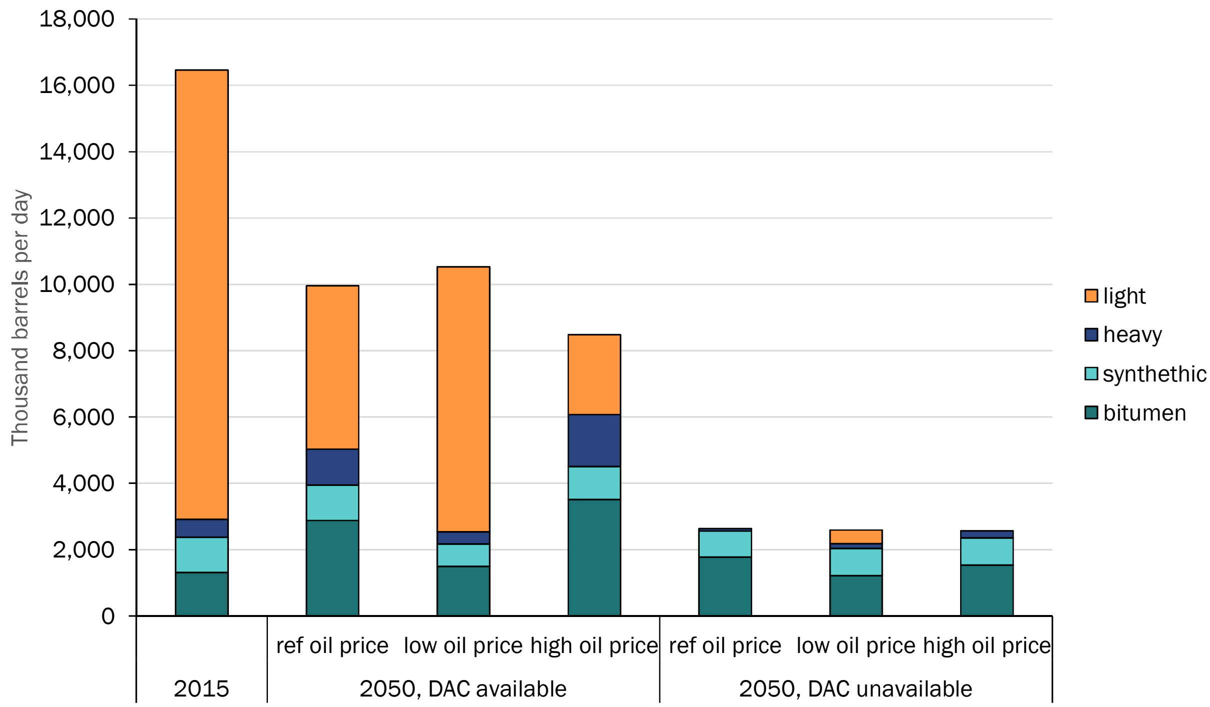
Heavier crudes (like bitumen) have a comparative advantage in producing products in the range for which demand remains in a net zero future. If there is a reduction in demand for the lighter end of the barrel (gasoline and diesel), but demand for asphalt stays the same, the price for light oil declines more rapidly than the price for heavier

[76] The net zero scenarios presented here assume reference CCS, hydrogen, renewable and storage cost trajectories.

crudes. As a result, there is an opportunity to use bitumen to produce asphalt and lubricants instead of liquid fuels, prolonging the life of bitumen in a net zero future.

To take advantage of this opportunity, Canadian and U.S. refinery input changes significantly under net zero policy. Figure 18 presents refinery input by crude type under net zero policy in Canada and the U.S. In a net zero future, refinery input changes from mostly light oil in 2020 to more heavy oil and bitumen by 2050. For the reasons indicated above, a decline in demand for light and heavy oil is especially apparent in scenarios in which DAC technology is not available. However, all net zero scenarios indicate continued demand for bitumen in 2050.

Figure 18: Refinery input under net zero policy in Canada and the U.S.[77]



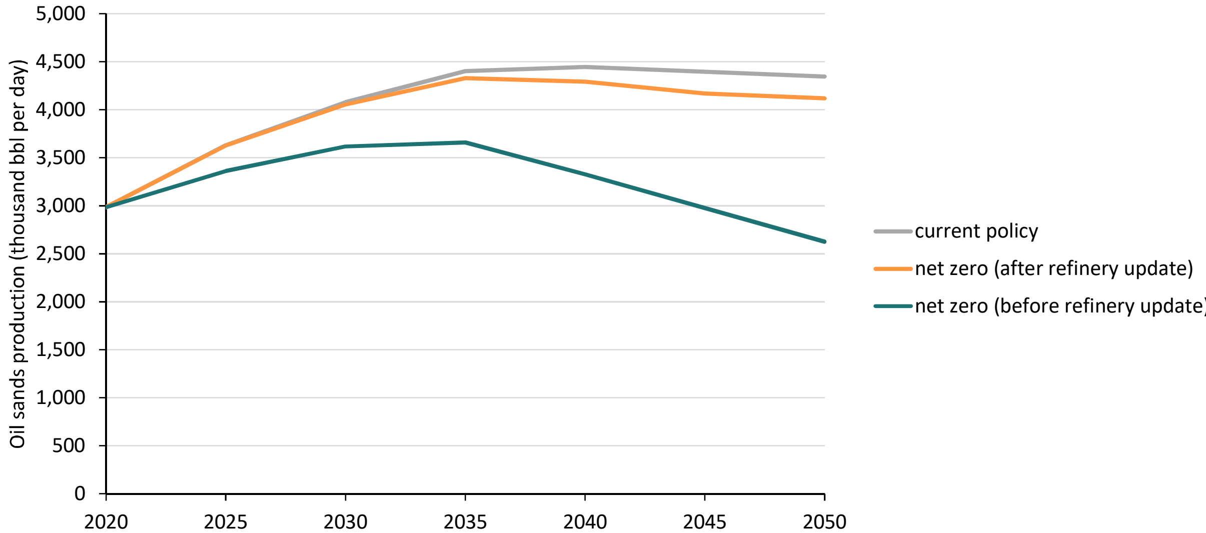
This has a significant impact on the role of Alberta's oil sands in a net zero future. Figure 19 presents oil sands production in Alberta in a net zero scenario prior to introducing refinery detail to account for bitumen beyond combustion, and a net zero scenario after updating gTech with the changes outlined in Section 3.2.1.

Continued oil sands production in 2050 under net zero policy is a divergence from previous net zero analyses conducted prior to adding this refinery detail into gTech. Without accounting for the comparative advantage that different grades of crude oil have in producing refined products, oil sands production declines significantly under

[77] The net zero scenarios presented here assume reference CCS, hydrogen, renewable and storage cost trajectories.

net zero policy, as indicated in Figure 19. When accounting for these advantages, oil sands production under net zero policy remains 1,400 thousand barrels per day higher in 2050 relative to previous net zero analyses. The role of oil sands could be even greater if accounting for growth in international demand for asphalt. This, and other limitations of our modeling approach, are discussed in 7.

Figure 19: Oil sands production under net zero before and after refinery model update[78,79]

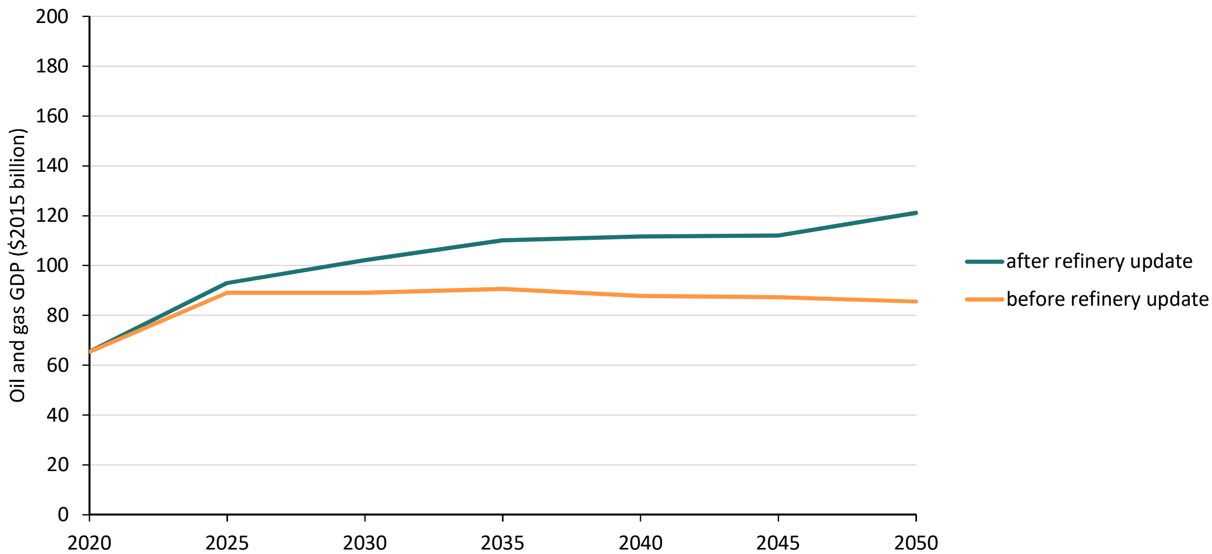


As a result of these changes, we also see significantly higher GDP in the oil and gas sector in a net zero future. Figure 20 presents Alberta's oil and gas sector GDP in a net zero scenario prior to introducing refinery detail to account for bitumen beyond combustion and a net zero scenario after the refinery updates. By 2050, GDP in the oil and gas sector is 42% higher as a result of the new model updates allowing for continued bitumen production.

[78] Please note that this graph provides an estimate of production impacts of allowing for bitumen beyond combustion by comparing the updated model with an older version. However, is not a perfect comparison as the two models are not identical. For example, the new model has extensive updates to refineries beyond allowing for bitumen beyond combustion, which has impacts across all oil and gas sectors.

[79] This net zero scenario assumes DAC is available, reference global oil price and reference low carbon technology costs.

Figure 20: Oil and gas GDP under net zero before and after refinery model update[80,81]

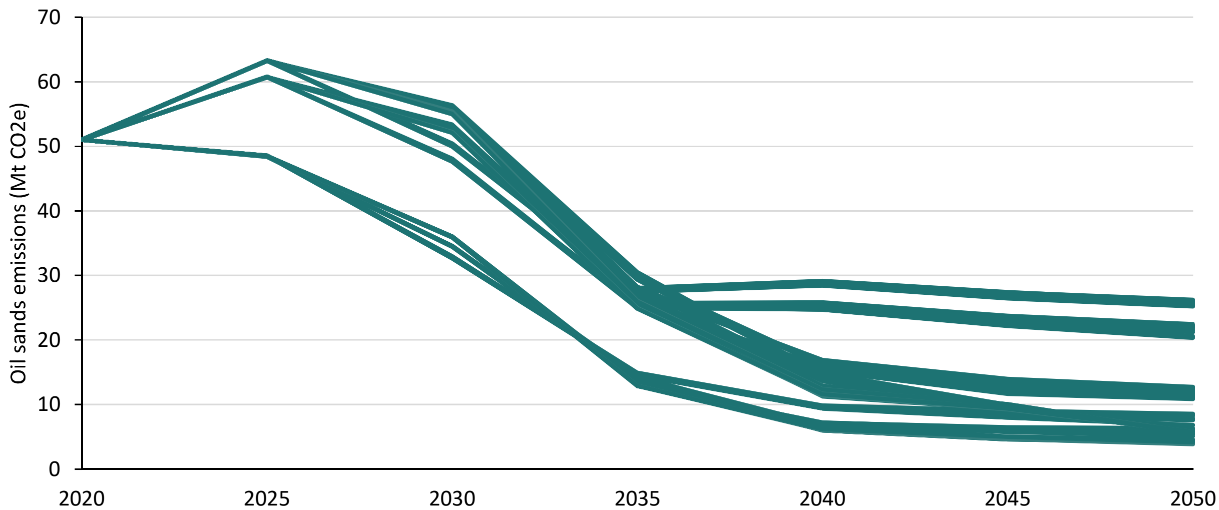


The level of oil sands production remaining impacts emissions from the sector, which decline over time in all net zero scenarios, from 51 Mt in 2020 to 4-26 Mt in 2050. Figure 21 presents the emissions trajectory for this sector across all net zero scenarios simulated. Similar to conventional oil, emissions in this sector are driven by production, which is influenced by two key factors: global oil price and DAC availability. As such, oil sands production and associated emissions remain highest in a net zero future in which DAC is available at low cost and the oil price is high (i.e., global oil demand is high).

80 Please note that this graph provides an estimate of production impacts of allowing for bitumen beyond combustion by comparing the updated model with an older version. However, is not a perfect comparison as the two models are not identical. For example, the new model has extensive updates to refineries beyond allowing for bitumen beyond combustion, which has impacts across all oil and gas sectors.

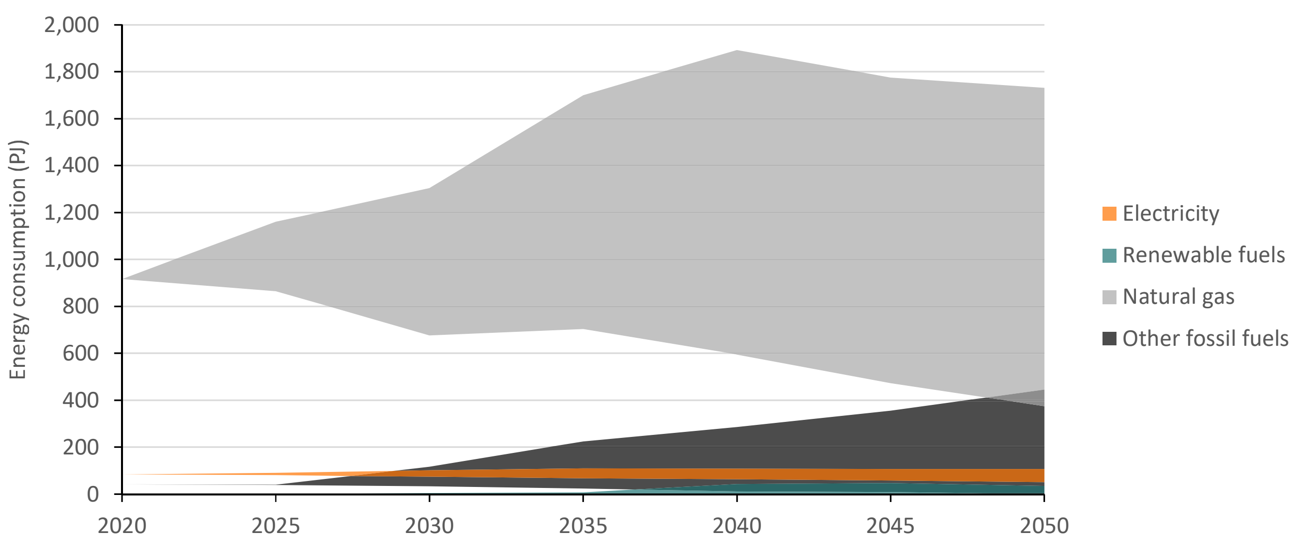
81 This net zero scenario assumes DAC is available, reference global oil price and reference low carbon technology costs.

Figure 21: Emissions from Alberta's oil sands sector (all net zero scenarios)



The primary fuel consumed in the oil sands sector is natural gas, which remains a key source of energy in all net zero scenarios, ranging from 375-1,731 PJ in 2050. The level of consumption in 2050 varies significantly depending on future oil sands production, as indicated in Figure 22. Electricity and renewable fuels play a limited role in this sector, while increases in consumption of other fossil fuels is driven by demand for natural gas liquids which are consumed as solvents for solvent-based extraction.

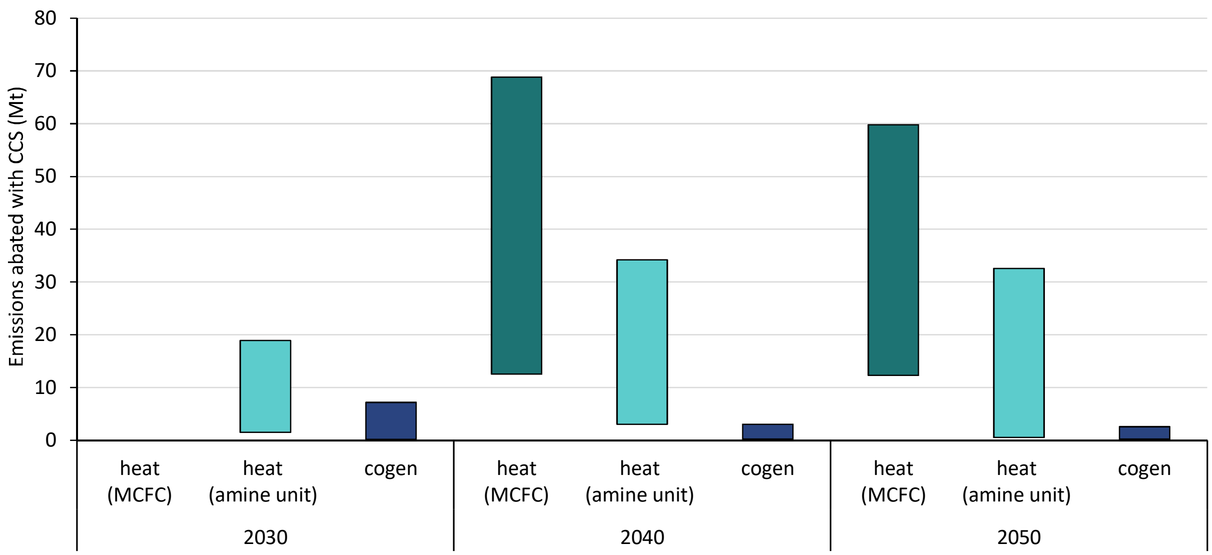
Figure 22: Energy consumption by fuel type in Alberta's oil sands sector (range across all net zero scenarios)



As indicated in Figure 22, there is little opportunity for electrification or renewable fuel consumption to help reduce emissions in this sector. Therefore, emissions abatement is largely driven by CCS adoption, and future CCS cost declines have a significant impact on the cost of decarbonizing this sector in a net zero future. Three CCS options are available for this sector – amine unit for emissions abatement in process heat, molten carbonate fuel cells (MCFC) for emissions abatement in process heat, and CCS on cogeneration[82]. Figure 23 presents a range in CCS adoption in Alberta's oil sands sector across all net zero scenarios simulated.

Total CCS adoption in this sector ranges from 2-20 Mt in 2030, peaks at 24-85 Mt in 2040, and ranges from 15-79 Mt in 2050. A significant portion of this adoption is MCFC technology, which accounts for 38-98% of total CCS adoption in this sector, depending on the scenario. Demand for CCS is driven by production - it is greatest in net zero scenarios with continued oil sands production and lowest in scenarios where oil sands production declines.

Figure 23: CCS adoption in Alberta's oil sands sector (range across all net zero scenarios)



Another abatement opportunity adopted in this sector is the use of small modular nuclear reactors (SMnR) to produce heat. Adoption of this technology in the oil sands sector ranges from 1.3-12.9 PJ in 2035 and 1.3—15.2 PJ in 2050, with highest adoption occurring in scenarios in which CCS costs are high.

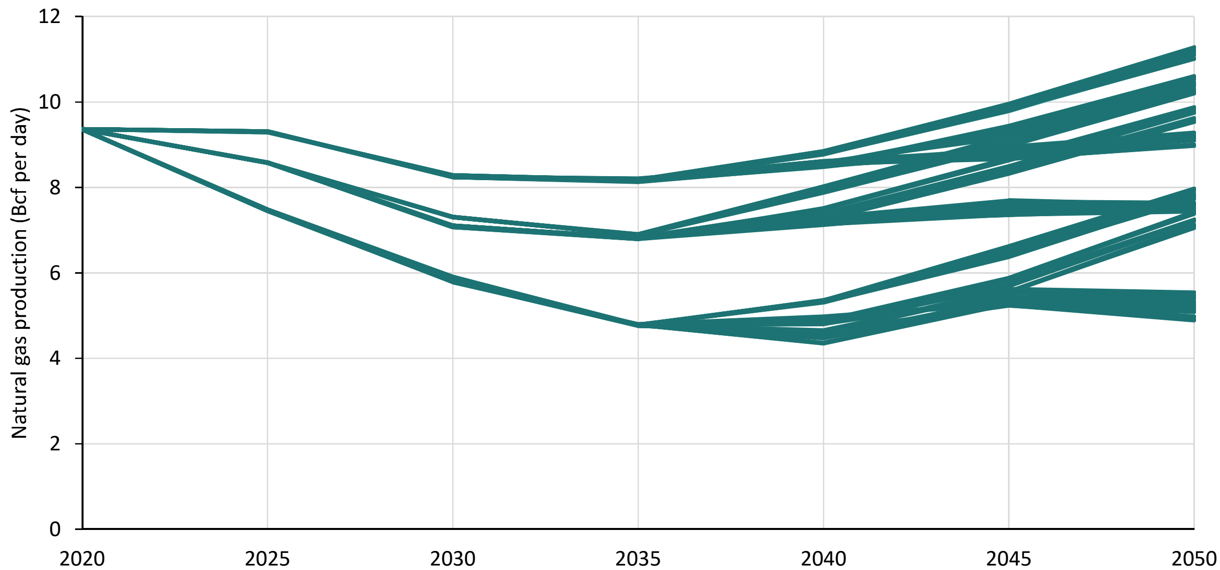
4.2. Natural Gas Production

Similar to oil sands and conventional oil production, future natural gas production in Alberta is uncertain under net zero emissions. As indicated in Figure 24, natural gas

82 See section 3.2.4for cost assumptions for each CCS technology.

production in the province declines from 9 Bcf per day in 2020 to 6-8 Bcf per day in 2030 and 5-11 Bcf per day in 2050, depending on the net zero scenario. This range is driven primary by the global oil price until 2045 (corresponding to the three clusters in Figure 24), after which DAC availability also plays a significant role in the future of natural gas production.

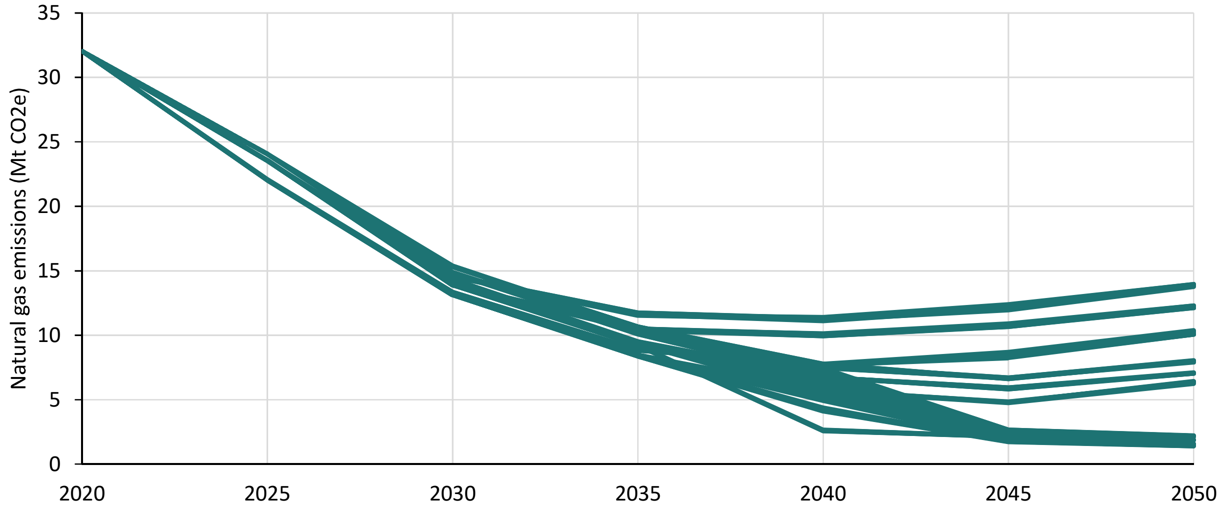
Figure 24: Natural gas production in Alberta (all net zero scenarios)[83]



Emissions in the natural gas sector decline in all net zero scenarios, from 32 Mt in 2020 to 1.4-14 Mt in 2050, as shown in Figure 25. Emissions from this sector are partially driven by production, with higher emissions occurring in scenarios with higher demand for gas production and lower in scenarios with lower demand. However, there is continued demand for natural gas production out to 2050 across all net zero scenarios, and emissions reductions in this sector are primarily driven by the adoption of abatement technologies. Scenarios with the lowest emissions in Figure 25 reflect those in which abatement technology costs are low, particularly CCS costs.

[83] This includes production of solution natural gas.

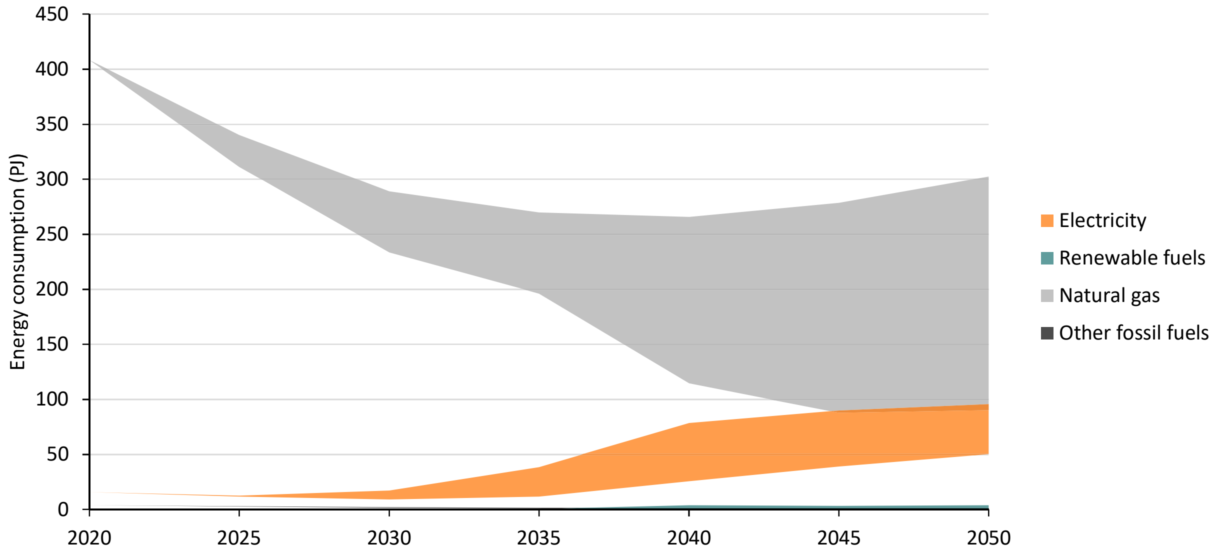
Figure 25: Emissions from Alberta's natural gas sector (all net zero scenarios)



Key abatement opportunities available in this sector include electrification, methane management and CCS.[84] By 2050, 68-96% of venting and 10-97% of leaking are addressed using near zero methane emission[85] technology. Electricity consumption also increases significantly in this sector in all net zero scenarios, as shown in Figure 26. Electricity consumption increases by 2-5 times from 16 PJ in 2020 to 50-96 PJ in 2050, driven by the adoption of electric compressors, which make up 45-100% of all compression technology in this sector by 2050.

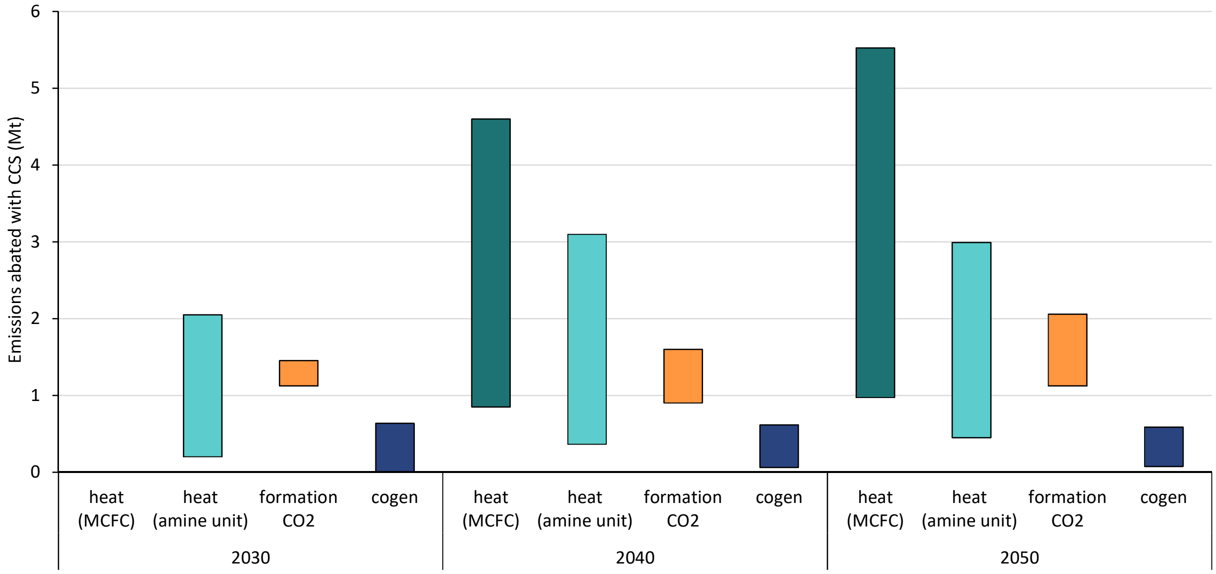
[84] Small modular nuclear reactors for heat production were not a competitive technology in this sector and were adopted in negligible amounts based on the assumptions presented in Section 3.2.11.
[85] Near-zero CH_4 technology includes high frequency of leak monitoring (every month and a half) and repair where necessary (applied to all equipment including transmission pipelines). It also includes elimination of venting from compressors, switching to low-bleed and, where possible, no-bleed devices and chemical injection pumps, capturing and using or flaring methane from storage tanks as well as any gases that need to be released during maintenance or process upsets, and flaring of all stranded gas.

Figure 26: Energy consumption by fuel type in Alberta's natural gas sector (range across all net zero scenarios)



Another key abatement option for this sector is CCS. Four CCS technologies are available – CCS for process heat (amine unit or MCFC), CCS for formation CO_2 and CCS for cogeneration. Figure 27 presents a range in CCS adoption across all net zero scenarios. Total CCS adoption in this sector ranges from 1.8-4.1 Mt in 2030, 4.3-7.4 Mt in 2040 and 5.1-8.4 Mt in 2050. Most of this is for abatement of emissions from process heat. MCFC is a potentially important technology in this sector, making up 15-70% (1-5.5 Mt) of CCS adoption in 2050.

Figure 27: CCS adoption in Alberta's natural gas sector (range across all net zero scenarios)[86]



4.3. Electricity

Alberta's electricity sector faces two significant challenges in a net zero future. The first is decarbonizing the province's current electricity grid, which is predominately made up of fossil fuel generation (approximately 90% of generation in 2020). The second is increasing generating capacity to keep up with increasing demand as other sectors of Alberta's economy electrify to comply with net zero.

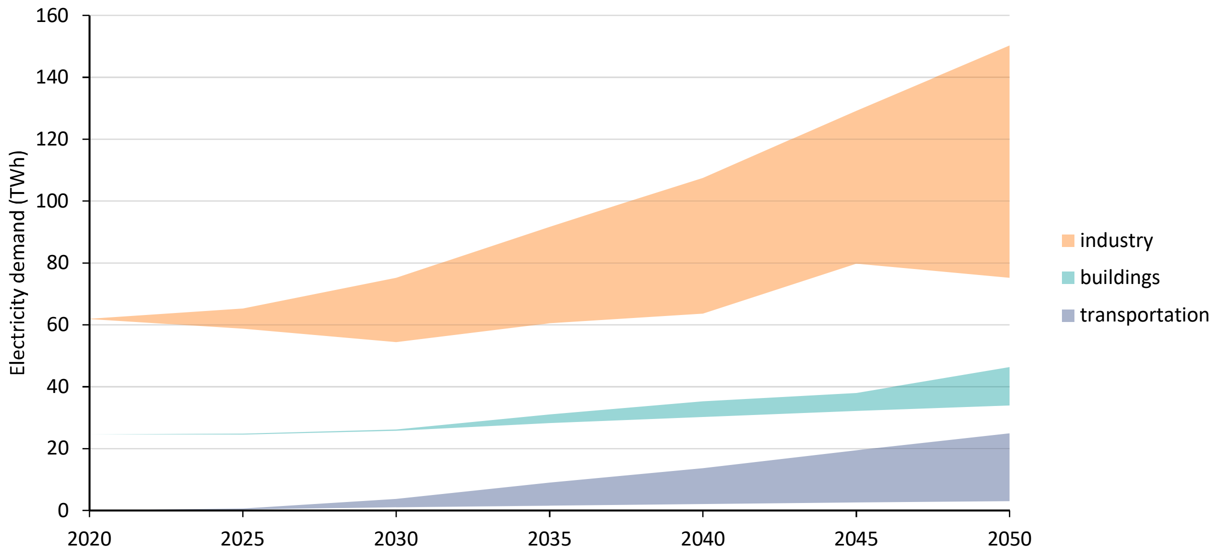
Figure 28 indicates significant growth in electricity demand across all sectors of Alberta's economy, increasing by 46-139% from 2020 to 2050 in a net zero future. Increased demand occurs in the transportation sector (from virtually no electricity demand in 2020 to 3-25 TWh in 2050) as more electric vehicles are adopted, in the buildings sector (38-88% increase from 2020 to 2050) as electric heat pumps and baseboards are adopted, and in industry (21-143% increase from 2020 to 2050) as industrial processes are electrified where possible.

Electricity demand is driven by three key factors. Demand is highest in net zero scenarios in which DAC is not available, as sectors rely more heavily on electrification to reduce emissions when offsets are not available. Electricity demand is also higher in scenarios where Alberta's economy grows more rapidly, which occurs when the global oil price is high. And finally, electricity demand is highest in scenarios in which renewable and storge costs come down faster over time, as it is less costly to produce

[86] See Section 3.2.4 for CCS cost assumptions.

clean electricity. These factors are what drive the low and high end of the range in Figure 28.

Figure 28: Electricity demand by sector in Alberta (range across all net zero scenarios)

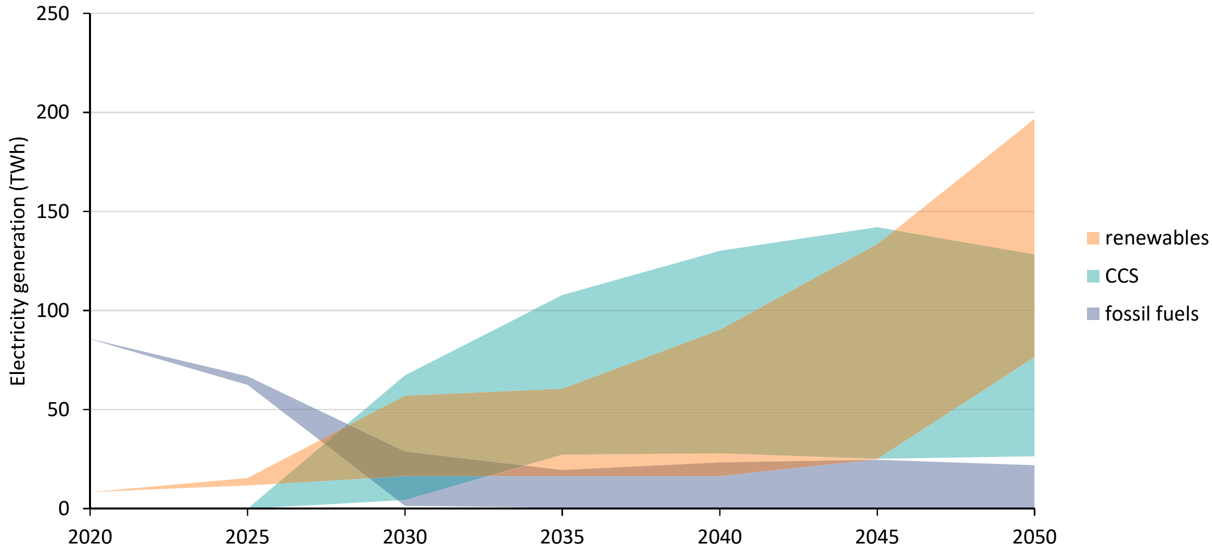


To meet growing electricity demand while decarbonizing, there is significant adoption of renewable electricity generation in the province, as well as installation of CCS on natural gas generation. Figure 29 presents a range in electricity generation in Alberta across all net zero scenarios simulated.[87] It indicates significant growth in renewable generation, including wind and solar generation, from 8 TWh in 2020 to 77-197 TWh in 2050 under net zero policy. As such, renewables account for 40-80% of the electricity grid in 2050, relative to 9% in 2020. Adoption of renewables is primarily solar generation, discussed in more detail below, and requires significant storage capacity to balance intermittency, also discussed below.

As renewable generation increases, fossil fuel generation (without CCS) declines by over 74% between 2020 and 2050, to 0-22 TWh in 2050 depending on the net zero scenario. Many scenarios see no continued fossil fuel generation in 2050. Scenarios with fossil fuel generation remaining in 2050 are those in which DAC is available at low cost to offset emissions.

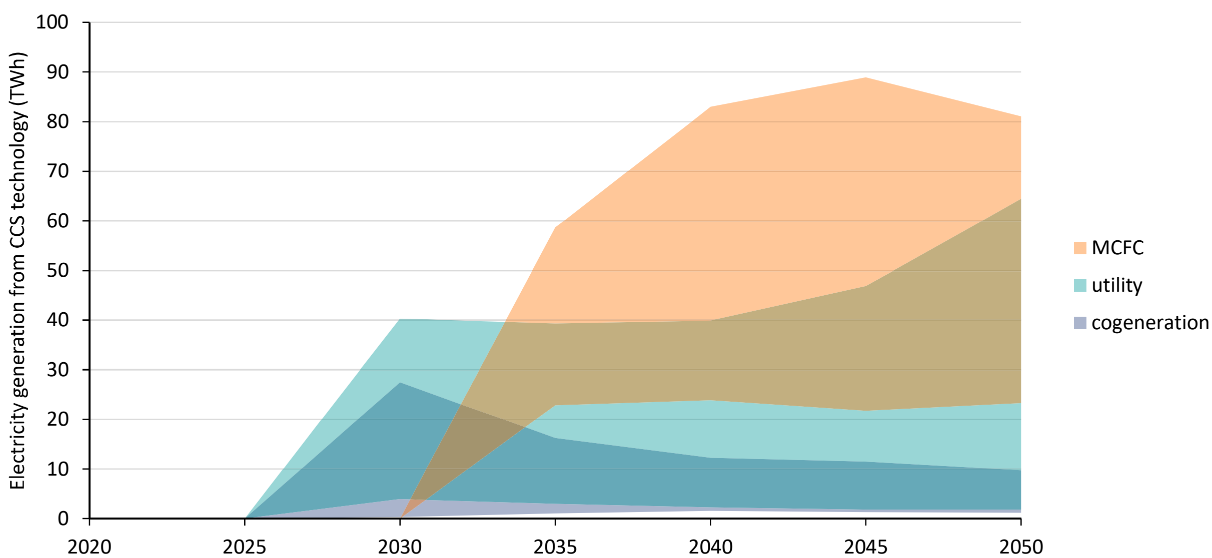
[87] Based on the small modular nuclear reactor (SMnR) assumptions outlined in Section 3.2.11, SMnRs were not adopted for electricity generation in any net zero scenarios simulated. This technology was adopted to a limited extent for heat production in industry, including in the oil sands sector, as mentioned in Section 4.1.3.

Figure 29: Electricity generation in Alberta (range across all net zero scenarios)



In most cases, however, natural gas electricity generation is fitted with CCS technology. Electricity generation with CCS is available in 2030 and increases to 26-128 TWh by 2050. This includes utility electricity generation, as well as the use of MCFC and cogeneration with CCS in industry, illustrated in Figure 30. MCFC makes up a significant portion of Alberta's electricity generation by 2050 in some net zero scenarios, accounting for 47-88% of all electricity generation using CCS.

Figure 30: Electricity generation from natural gas with CCS in Alberta (range across all net zero scenarios)[88]

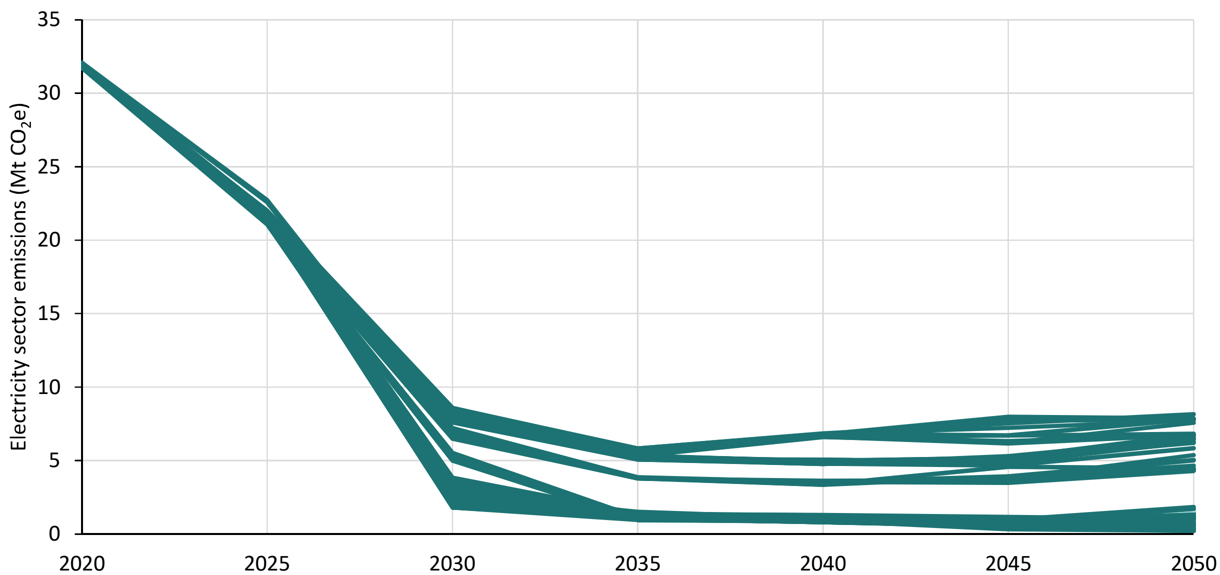


[88] See Section 3.2.4 for CCS cost assumptions.

Results indicate a trade-off between renewable generation with storage and natural gas generation with CCS, depending on the net zero scenario. In all net zero scenarios, utility generation is dominated by renewables by 2050, facilitated by storage. Renewable generation is highest in scenarios with low renewable, battery and hydrogen storage costs and high CCS costs. However, in scenarios in which DAC is not available and there is high demand for oil, natural gas with CCS is the primary source of electricity generation in 2050 across the province, driven by cogeneration with CCS and MCFC adoption in industry. See the next section for more detail on renewables and storage, and Section 4.4 for more discussion of CCS.

This indicates investment in expansion of both CCS and renewables is important to facilitate Alberta's net zero electricity system. As renewable generating capacity and CCS adoption increases, emissions in Alberta's electricity sector decline significantly in all net zero scenarios simulated, from around 30 Mt in 2020 to 0.2-8 Mt in 2050 (Figure 31).

Figure 31: Electricity sector emissions in Alberta (all net zero scenarios)



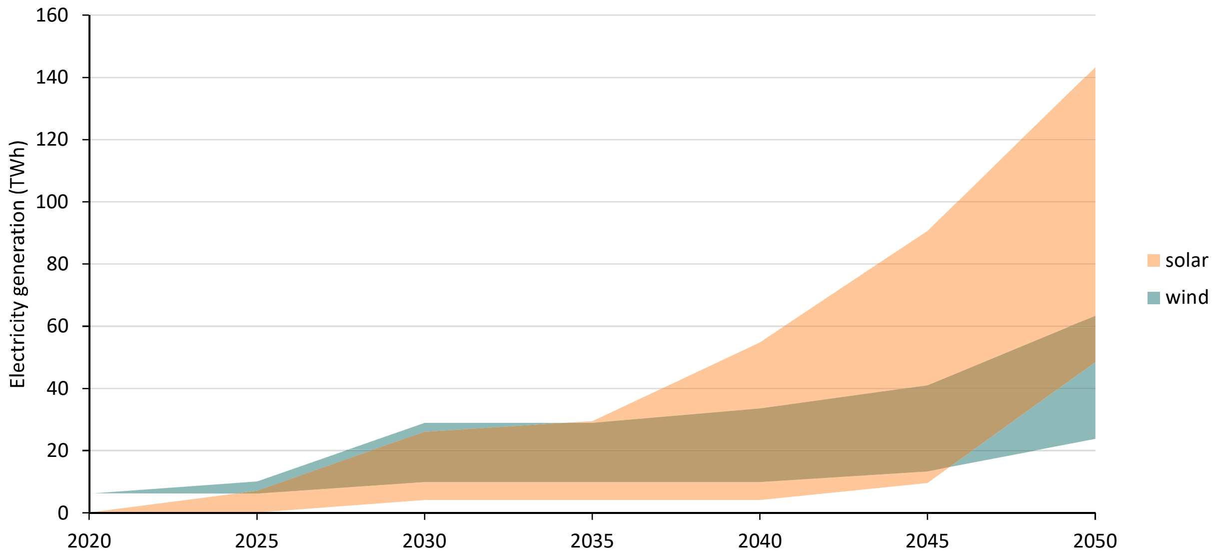
4.3.1. Renewables and Storage

Increased renewable generation capacity is critical to facilitate compliance with net zero emissions in Alberta. Figure 32 presents renewable electricity generation in the province across all net zero scenarios.

Total solar generation increases significantly in all scenarios, from 0.1 TWh in 2020 to 4-26 TWh in 2030 and 48-143 TWh in 2050, while wind generation increases from 6

TWh in 2020 to 10-29 TWh in 2030 and 24-63 TWh in 2050. The upper end of this range occurs in net zero scenarios with greater levels of electrification across Alberta's economy. These are scenarios in which renewable and storage costs are low and scenarios in which DAC is not available to offset continued use of fossil fuels.

Figure 32: Renewable electricity generation in Alberta (range across all net zero scenarios)[89]



As intermittent renewables are adopted, storage becomes an important component of Alberta's electricity system to ensure grid reliability and allow for reduced reliance on back-up natural gas capacity. As a result, significant battery and hydrogen storage is adopted to support a highly intermittent grid in some net zero scenarios. Figure 33 indicates adoption of short-duration (represented using an archetype of a lithium-ion battery) and long-duration (represented using two archetypes: a flow battery and hydrogen storage).[90]

Results indicate that storage capacity in Alberta could increase up to 395 GWh by 2050 under net zero policy, with short duration storage adoption ranging from 42-182 GWh and long-duration ranging from 0-273 GWh in 2050. The most important driver of renewable and short-duration storage adoption is the future cost of renewables and batteries. If the cost of renewables and batteries follow a low cost trajectory, these technologies are more competitive and higher adoption occurs to facilitate electrification of Alberta's economy. For long-duration storage adoption, hydrogen costs are also an important factor, as a significant portion of the long-duration storage adopted is seasonal electricity storage using hydrogen.

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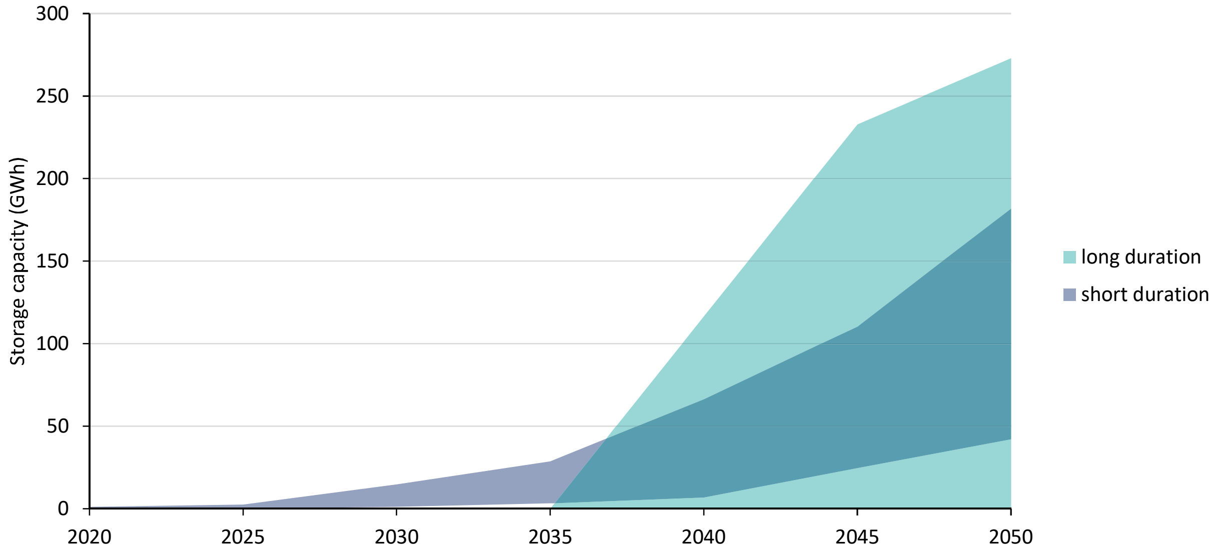
89 See Section 3.2.9 for solar and wind cost assumptions.
90 See Section 3.2.10 for storage technology cost assumptions.

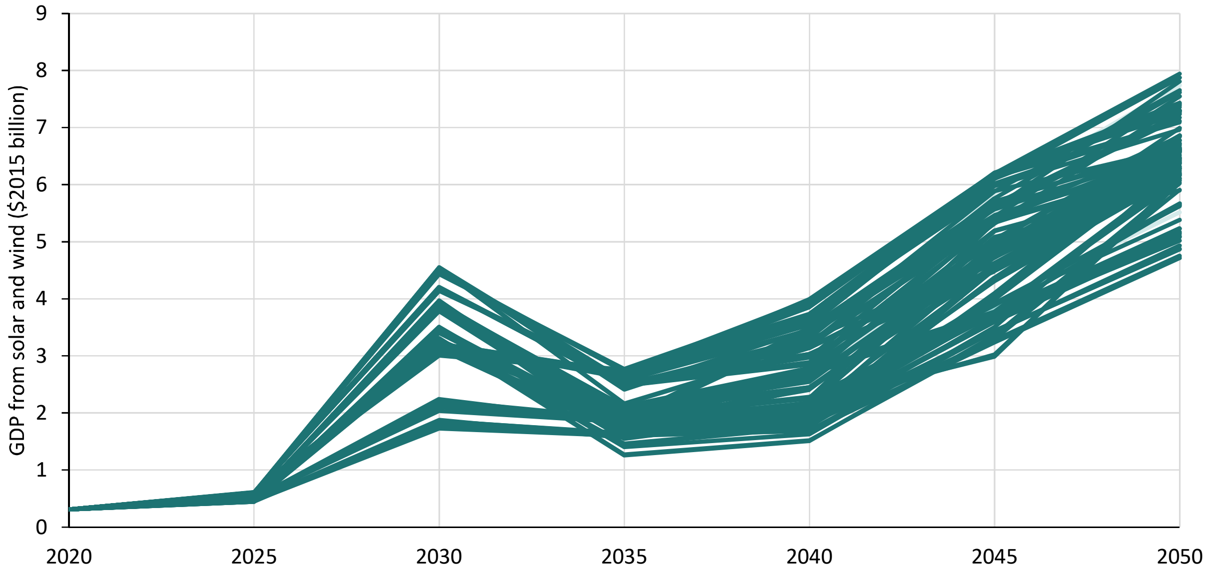
Figure 33: Electricity storage capacity in Alberta (range across all net zero scenarios)[91]



As renewables are integrated into Alberta's electricity grid, they provide a significant economic contribution to the province. This is illustrated in Figure 34, which presents the GDP contribution of wind and solar generation in Alberta across all net zero scenarios. The GDP contribution ranges from $2-5 billion in 2030 and $5-8 billion in 2050.[92] This excludes the value added from electricity storage technologies including batteries and seasonal hydrogen storage, which provides further economic contributions to Alberta's economy.

[91] See Section 3.2.10 for storage technology cost assumptions.
[92] Note that this GDP value is an estimate. Two separate models were used for this analysis – gTech which models Alberta's economy and IESD which model's Alberta's electricity system. Since the two models are not fully integrated, the GDP contribution of renewables does not reflect the detailed electricity modeling done in IESD.

Figure 34: GDP contribution from renewable electricity generation in Alberta (all net zero scenarios)[93]



4.4. Carbon Capture

Results indicate carbon capture could play a transformative role in Alberta's net zero energy system. This section discusses the potential contribution of several carbon capture, utilization and storage technologies modeled in this analysis, as well as direct air capture technology.

4.4.1. Carbon Capture, Utilization and Storage

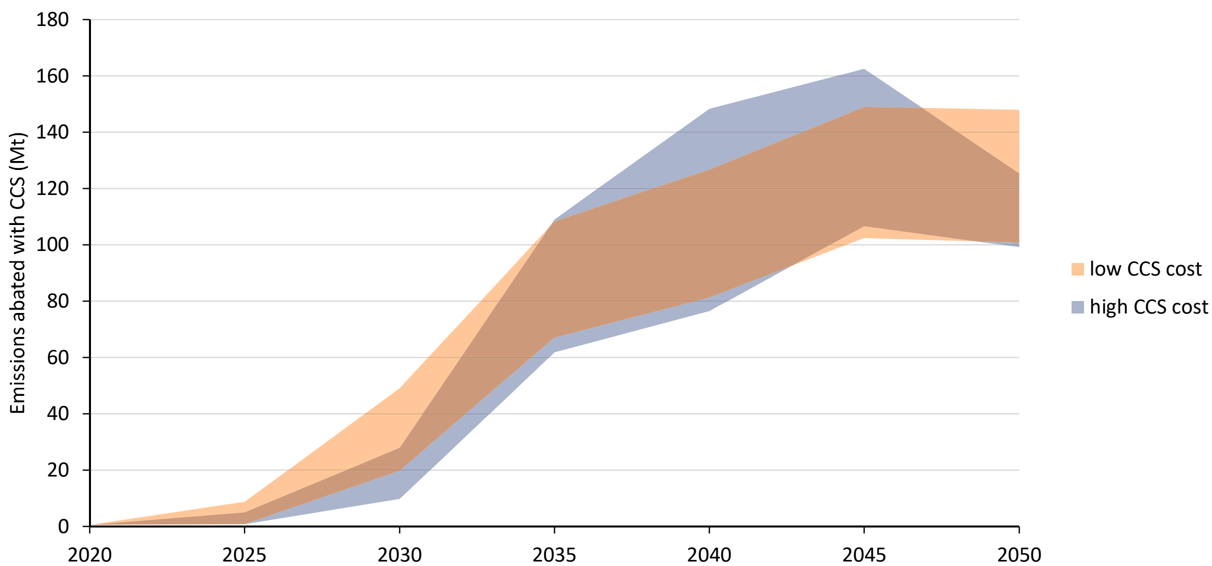
Several carbon capture, utilization and storage technologies were explored in this analysis.[94] We examined CCS on process heat, formation CO_2, cogeneration, electricity generation, and hydrogen production. Additionally, we explored the role of molten carbonate fuel cells (MCFC) and oxy-combustion gas. These technologies provide a compliance pathway to reduce emissions in many sectors of Alberta's economy.

We also explored the opportunity to use captured CO_2 for enhanced oil recovery (EOR) or for utilization in concrete, as well as the opportunity to combine CCS with RNG consumption to achieve negative emissions (bioenergy with CCS, or BECCS). These opportunities provide an additional revenue stream for CCS adopters in the province.

[93] This includes direct value-added contributions from the technology once operational, value added from building the facility (e.g., construction services, manufacturing of equipment), and indirect value added associated with service demand by the technology/sector once operational.
[94] See Section 3.2.3 and Section 3.2.4 for cost assumptions used for each technology.

CCS adoption across Alberta's economy ranges from 10-51 Mt in 2030, 77-148 Mt in 2040 and 99-178 Mt in 2050 depending on the net zero scenario. Although different CCS cost assumptions (low, reference and high) were simulated in this analysis, CCS adoption is not driven by the future cost for CCS. Figure 35 presents CCS adoption in Alberta as a range across all net zero scenarios that assume low and high CCS costs, indicating significant overlap between the two. This suggests that CCS is adopted in large amounts in Alberta under net zero policy, regardless of the cost of the technology. Even if CCS costs are high, up to 164 Mt is adopted in 2045 to abate emissions in the province.

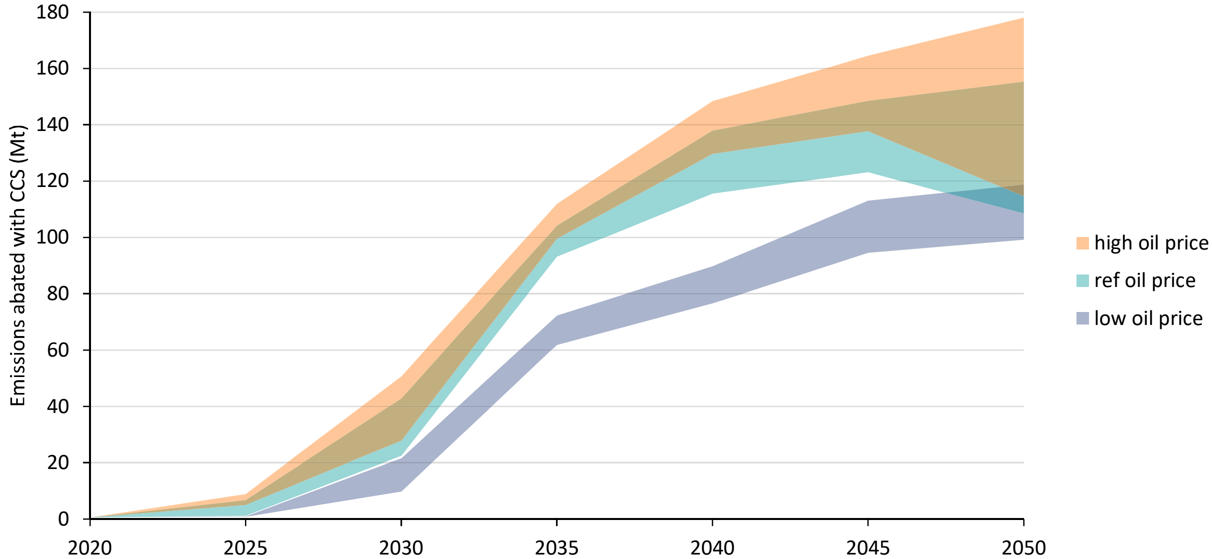
Figure 35: CCS adoption in Alberta (range across net zero scenarios)



Instead, CCS adoption is driven by demand for emissions abatement in industry, particularly the oil and gas sector. Figure 36 presents CCS adoption in Alberta as a range across net zero scenarios that assume a high, reference or low global oil price, indicating that future oil price drives the upper and lower end of the range in CCS adoption. If the global price for oil is high, CCS adoption ranges from 115-178 Mt in 2050, while if the future oil price is low, CCS adoption ranges from 99-119 Mt in 2050.

A high oil price incentivizes CCS adoption in two ways. First, higher oil prices indicate higher demand for oil and lead to greater oil production, and therefore greater investment in CCS technology to reduce emissions from oil and gas production. Second, higher oil prices create a greater incentive for oil production from EOR, which creates a market for captured CO_2 to be used for EOR (as discussed in Section 4.1.2 above).

Figure 36: CCS adoption in Alberta (range across all net zero scenarios)

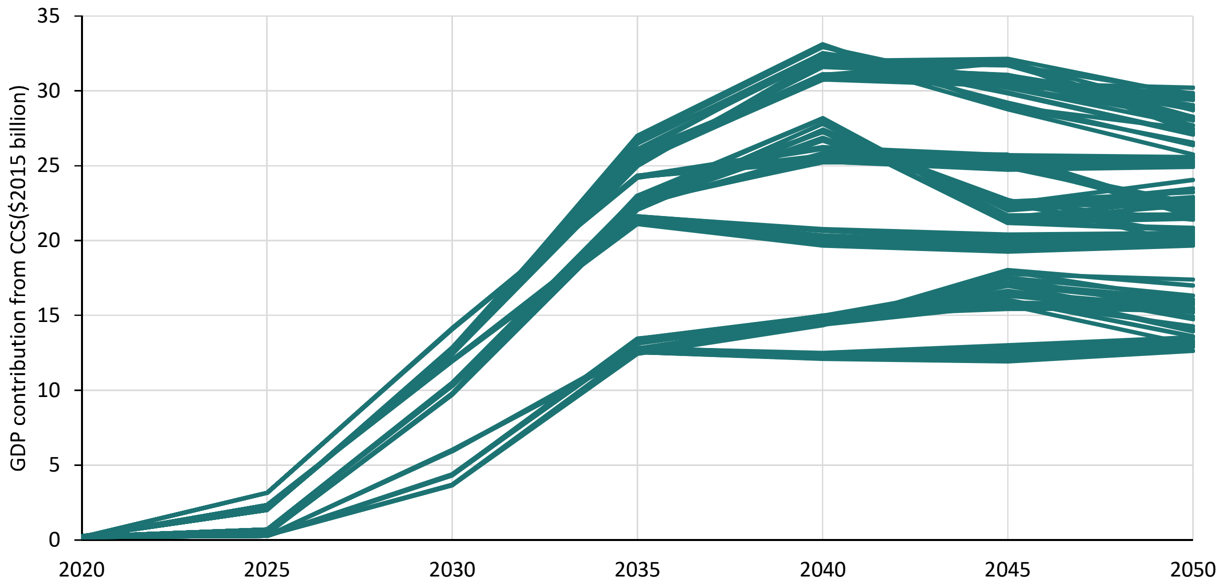


Some opportunities for carbon capture, including oxy-combustion gas turbines for electricity generation, utilization of CO_2 in concrete, and the combination of CCS with RNG to produce negative emissions (BECCS) were not identified as key opportunities in this analysis. Oxy-combustion gas turbines were not adopted in the model at the costs presented in Section 3.2.4.[95] CCU in concrete was adopted, such that by 2030 all concrete production uses CCU, but the amount of carbon sequestered in concrete (using the assumptions presented in Section 3.2.3) is minimal and does not play a significant role. Negative emissions achieved from BECCS (up to -1.7 Mt in 2050 in some net zero scenarios) were also minimal compared to other emission offset opportunities including LULUCF and DAC.

Other carbon capture opportunities, however, specifically the use of CCS for process heat (including MCFC) in industry play a significant role in Alberta's net zero energy future and facilitate economic growth in the province. Figure 37 presents the GDP contribution of CCS adoption in Alberta across all net zero scenarios. The GDP contribution of this technology ranges from $4-14 billion in 2030, $12-33 billion in 2040 and $13-30 billion in 2050 depending on the net zero scenario. This represents a significant economic opportunity for the province, including carbon capture, transport and storage. This excludes value added from EOR and other CO_2 utilization opportunities, which would provide additional GDP contributions to Alberta's economy.

[95] Note that we did not explicitly simulate oxygen consumption of this technology, likely underestimating its potential adoption.

Figure 37: GDP contribution from CCS in Alberta (all net zero scenarios)[96]



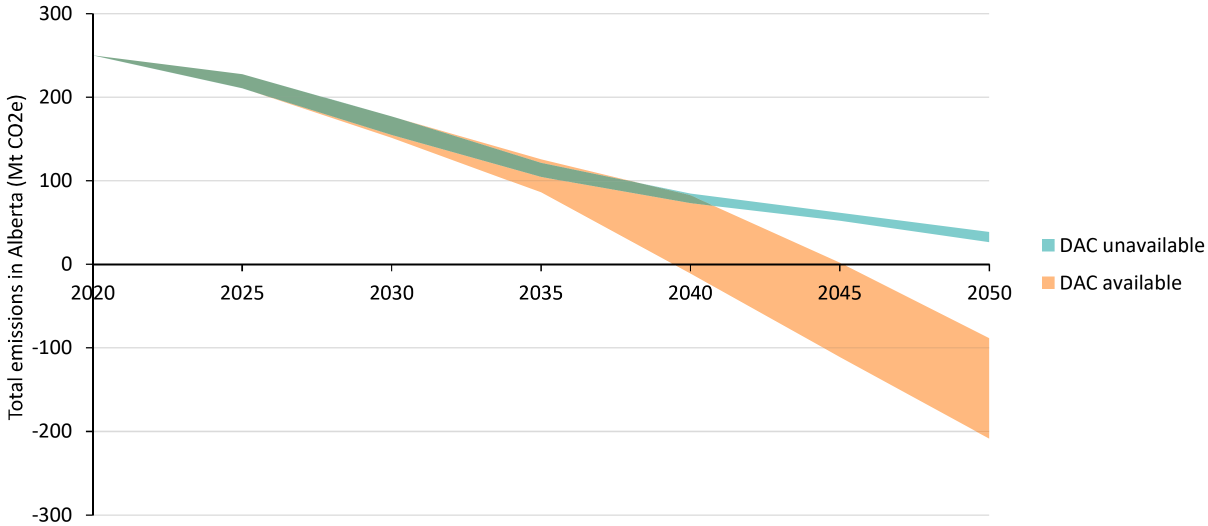
4.4.2. Direct Air Capture

Uncertainty in the future availability of a potentially important technology, DAC, is captured in this analysis by simulating net zero scenarios with and without DAC available. In scenarios in which DAC becomes a commercial technology, results indicate that this technology could play an important role in reducing emissions and provide a significant new revenue stream for Alberta in a net zero future.

Proximity to suitable CO_2 storage makes Alberta an ideal location for a DAC industry and allows the province to offset CO_2 emitted from other regions in Canada. In fact, if DAC is available, Alberta becomes a net emission sink in Canada, helping other provinces to achieve net zero by providing negative emission credits. Figure 38 indicates that Alberta's emissions range from -89 to -209 Mt in 2050 in net zero scenarios where DAC is available.

[96] This includes direct value added contributions from the technology once operational, value added from building the facility (e.g., construction services, manufacturing of equipment), and indirect value added associated with service demand by the technology/sector once operational.

Figure 38: Total emissions in Alberta (range across all net zero scenarios)

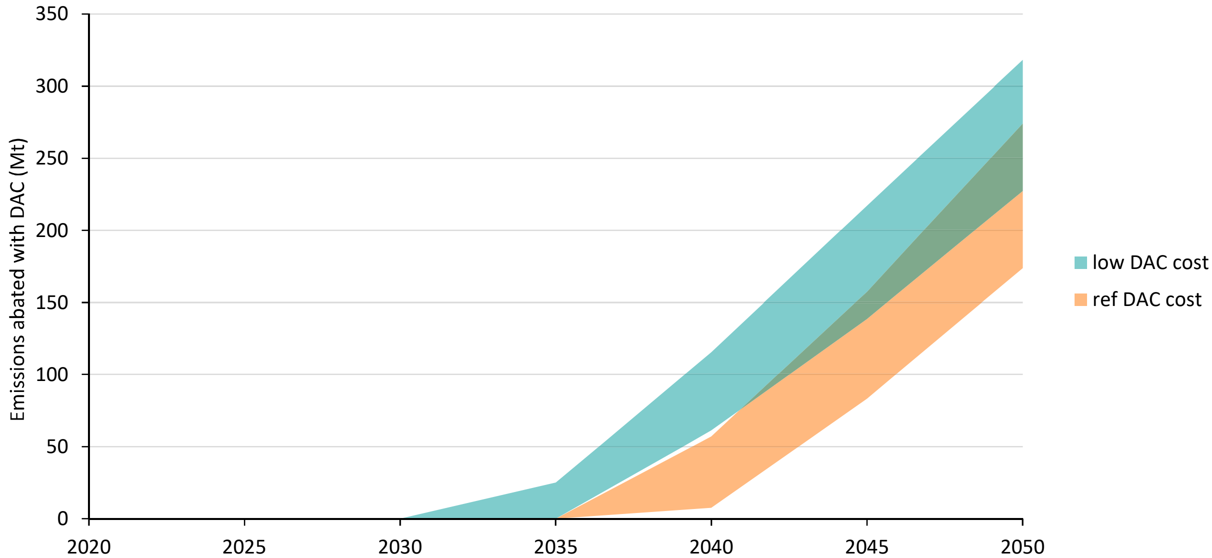


DAC allows for continued use and production of fossil fuels in Alberta and the rest of Canada by providing the ability to offset emissions. If available, DAC adoption in Alberta ranges from 8-116 Mt in 2040 and 174-318 Mt in 2050 to offset emissions that remain in Alberta and across Canada (Figure 39).

It is important to note that adoption of this technology is dependent on two key uncertainties. First, it is uncertain if the technology will become commercially available. And second, adoption relies on the incentives created by stringent climate policy that requires emissions reductions in line with net zero. For example, under an announced policy scenario with no cap on emissions at net zero by 2050, DAC technology does not become an economic abatement mechanism and is not adopted in Alberta.

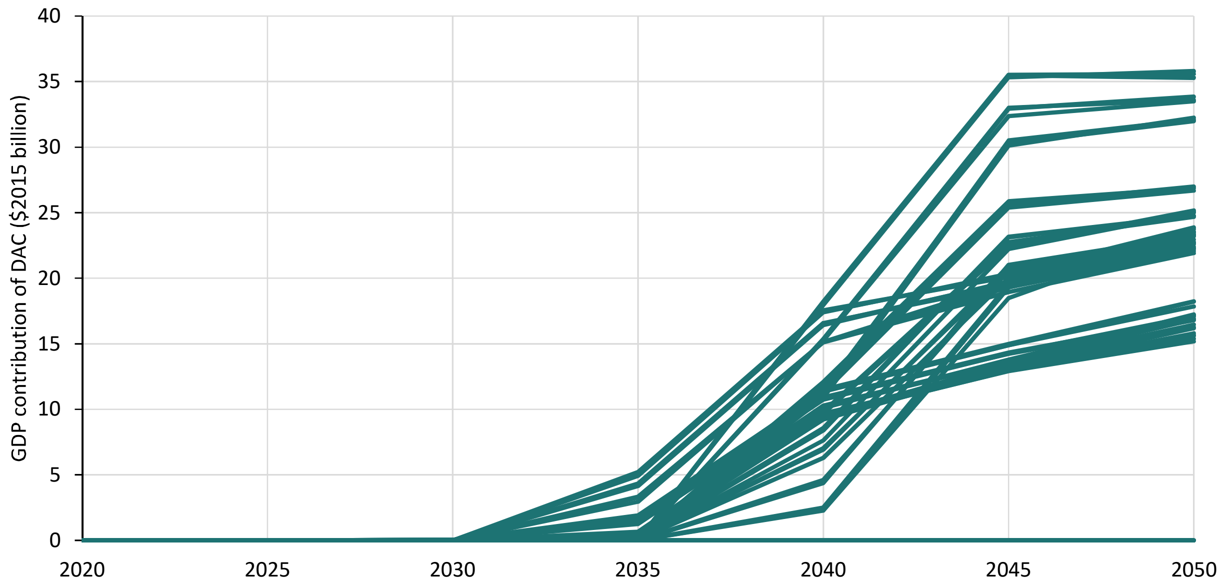
When available, and when net zero policy is implemented, DAC adoption is driven by the future cost of the technology, with the most adoption occurring in net zero scenarios where the cost of DAC declines more significantly over time, and lower adoption occurring when a reference cost trajectory is assumed (Figure 39).

Figure 39: DAC adoption in Alberta (range across all net zero scenarios with DAC available)



Many scenarios were simulated in this analysis without DAC available, in which case Alberta can still achieve net zero emissions. However, the cost of doing so is higher. This is because DAC allows for the continued use and production of fossil fuels in the province and creates a new revenue stream that directly contributes to the economy. Depending on the net zero scenario, the DAC sector contributes $2-18 billion in 2040 and $15-36 billion in 2050 to Alberta's economy (Figure 40). In addition to its direct GDP contribution, the availability of DAC allows for greater economic activity in other sectors of Alberta's economy, leading to additional GDP benefits. This suggests that the availability of DAC technology is important for minimizing the cost of achieving a net zero energy system in Alberta.

Figure 40: GDP contribution of the DAC sector in Alberta (all net zero scenarios)[97]



4.5. Hydrogen

Hydrogen is a potentially important low carbon fuel if produced with low emissions, such as via steam methane reformation (SMR) with CCS or electrolysis with renewable electricity. Demand for hydrogen increases across all net zero scenarios simulated, from virtually none in 2020 to 22-165 PJ in 2050. Hydrogen adoption is driven by the extent to which hydrogen production costs and hydrogen fuel cell vehicle costs decline over time, as indicated in Figure 41.

Figure 41 presents hydrogen adoption as a range across all net zero scenarios with low or high hydrogen cost assumptions. It indicates that if hydrogen costs come down more quickly over time, adoption of this fuel ranges from 5-9 PJ in 2030 and 75-165 PJ in 2050, while if costs come down more slowly over time, adoption is lower, ranging from 3-5 PJ in 2030 and 22-92 PJ in 2050. If hydrogen costs follow a reference trajectory, adoption falls in the middle of this range, at 49-130 PJ in 2050.

[97] This includes direct value-added contributions from the technology once operational, value added from building the facility (e.g., construction services, manufacturing of equipment), and indirect value added associated with service demand by the technology/sector once operational.

Figure 41: Hydrogen fuel adoption in Alberta (range across all net zero scenarios)[98]

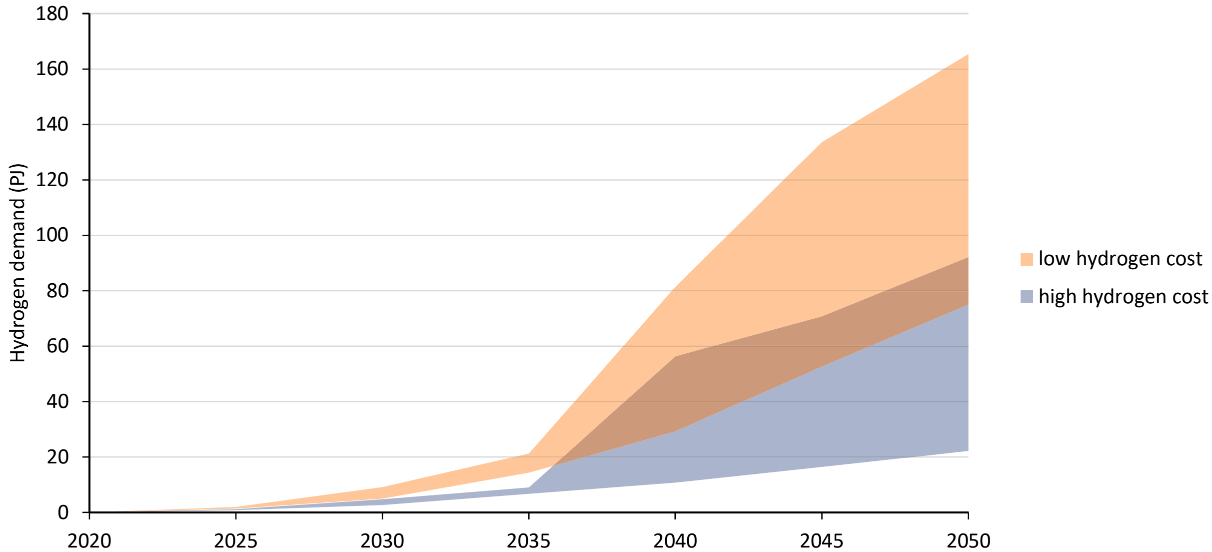
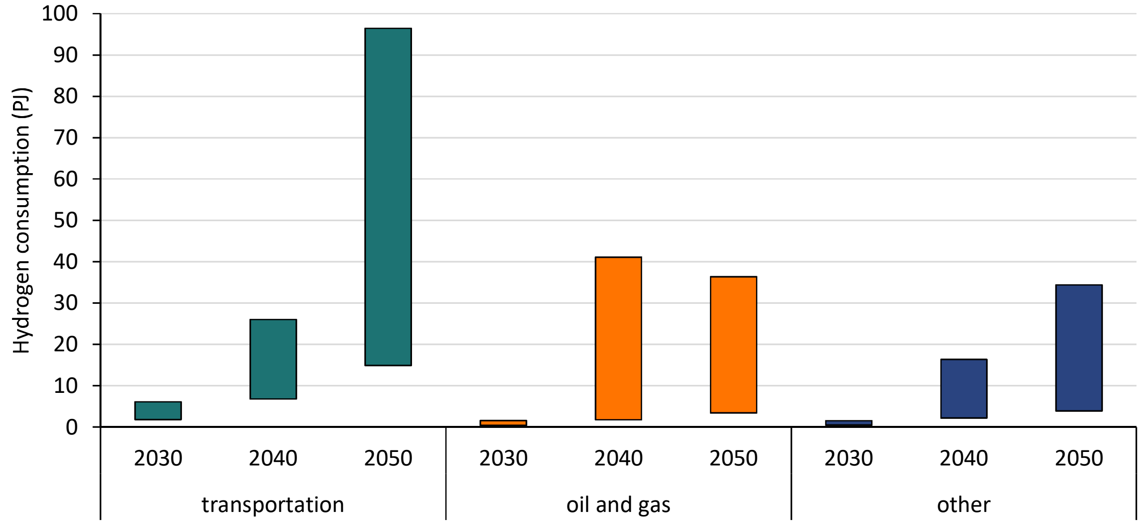


Figure 42 presents hydrogen consumption by sector as a range across all net zero scenarios simulated. Hydrogen adoption occurs mostly in the transportation sector to reduce emissions from hard-to-electrify heavy-duty transportation, with 66% of hydrogen consumption occurring in the medium- and heavy-duty transport sectors in 2050.[99] The next largest consumer of hydrogen is the oil and gas sector, which can use hydrogen blended into natural gas for process heat. This accounts for 15% of hydrogen consumption in Alberta in 2050.[100] The remaining consumption occurs across other sectors, including agriculture, waste, buildings and other industry.

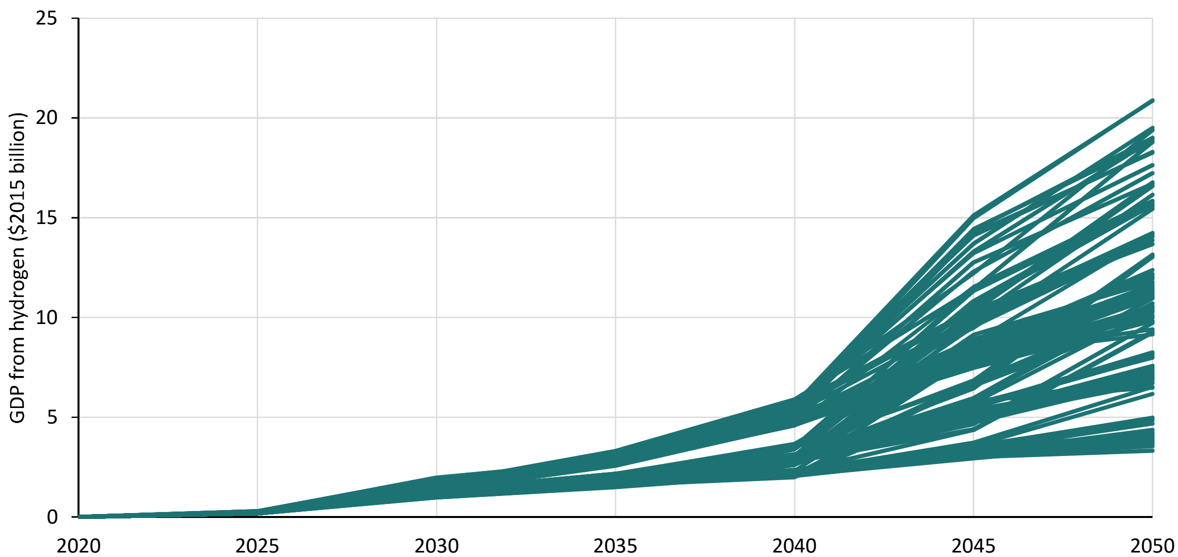
98 Hydrogen cost refers to both the cost of hydrogen production (SMR with CCS and electrolysis) and the cost of hydrogen fuel cell vehicles, as presented in Section 3.2.6 and 3.2.8.
99 A scenario with DAC available, reference oil price, and reference technology costs.
100 A scenario with DAC available, reference oil price, and reference technology costs.

Figure 42: Hydrogen consumption by sector (range across all net zero scenarios)



Production of low carbon hydrogen fuel presents an economic opportunity for Alberta in a net zero future. Figure 43 presents the GDP contribution of hydrogen fuel in all net zero scenarios simulated, which ranges from $1-2 billion in 2030 to $3-21 billion in 2050. This suggests that investment in hydrogen technologies to bring down the cost of fuel production and hydrogen fuel cells could help facilitate Alberta's net zero transition.

Figure 43: GDP contribution of hydrogen fuel in Alberta (all net zero scenarios)[101]



[101] This includes direct value added contributions from the technology once operational, value added from building the facility (e.g., construction services, manufacturing of equipment), and indirect value added associated with service demand by the technology/sector once operational.

5. Economic Implications of Net Zero for Alberta

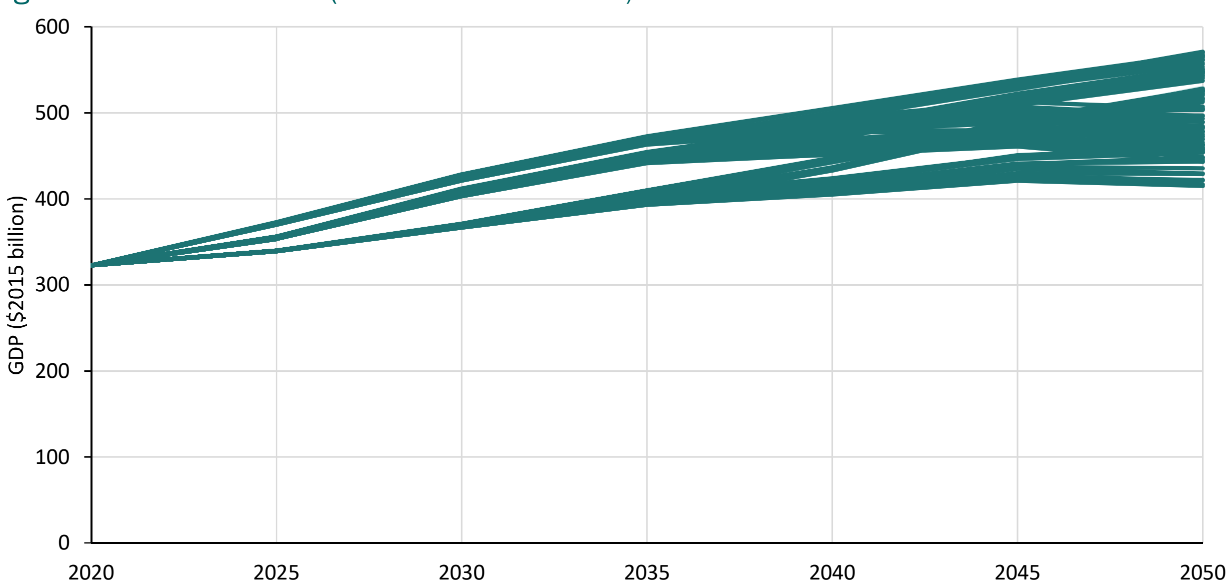
This section explores the economic implications of net zero policy in Alberta, including provincial GDP and household energy expenditure.

5.1. GDP

Alberta's economy-wide GDP increases across all net zero scenarios simulated, as shown in Figure 44. This suggests that Alberta's economy is resilient to net zero policy. The average annual GDP growth rate ranges from 0.8-1.9% from 2020 to 2050 depending on the net zero scenario.

Alberta's GDP grows most in scenarios in which the province continues to produce oil and gas and continues to consume fossil fuels, either capturing emissions with CCS or offsetting emissions with DAC. In scenarios in which DAC is available and global demand for oil is high (i.e., high oil price), Alberta's GDP increases to up to $571 billion in 2050. Alberta's economy grows least in scenarios in which global demand for oil is low, DAC is not available, and low carbon technology costs (including CCS, hydrogen, renewables and storage) are high, leading to a GDP of $415 billion in 2050.

Figure 44: Alberta's GDP (all net zero scenarios)



Two key factors that drive the difference in GDP growth across net zero scenarios are the global demand for oil and whether DAC technology is available. The impact of future global oil demand on Alberta's net zero economy is demonstrated in Figure 45, which indicates higher provincial GDP in scenarios in which we assume a high global oil price and lower GDP in scenarios with a low global oil price. If there is little global demand for Alberta's oil and gas, it is not worth investing in emissions abatement in these sectors. Instead, oil and gas production declines in the province, leading to a smaller overall economy in 2050.

However, Figure 45 also indicates significant overlap between potential economic outcomes independent of the global oil price. The overlap between these ranges is driven by DAC availability, and to a lesser extent, the cost of CCS technology.

Figure 45: Alberta's GDP under different oil price forecasts (range across all net zero scenarios)

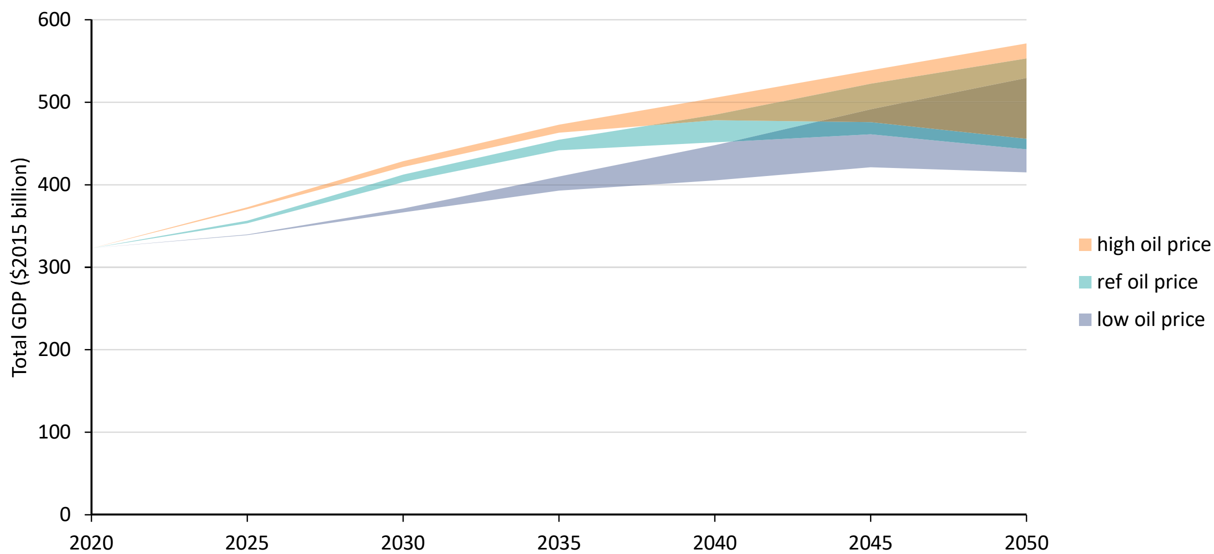
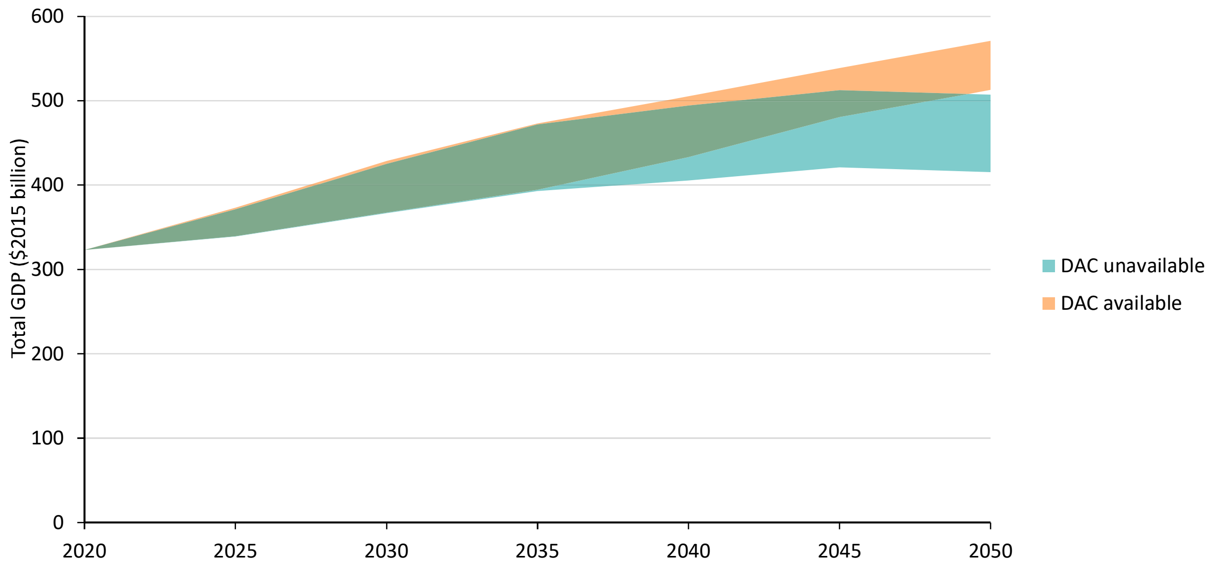


Figure 46 presents Alberta's GDP in scenarios with and without DAC technology available. It indicates that Alberta's GDP grows more after 2035 when DAC technology becomes available, relative to scenarios in which this technology is not available. When DAC is available, economy-wide GDP ranges from $513-571 billion in 2050, while GDP in scenarios without DAC available ranges from $415-507 billion in 2050. Within the ranges presented in this figure, the upper end of the DAC available range is scenarios in which both DAC and CCS are low cost and there is high demand for oil globally, while the lower end of the range is scenarios in which DAC and CCS costs are high and there is low demand for oil globally.

This indicates that even in a low oil price future, Alberta's economy can continue to grow by producing oil and gas with low emissions, given DAC and CCS are available at low cost. It suggests that investing in technologies that can allow for low-emission oil and gas production, including CCS and DAC, is particularly important for facilitating Alberta's net zero future.

Figure 46: Alberta's GDP in scenarios with and without DAC availability (range across all net zero scenarios)



5.2. Household Energy Expenditure

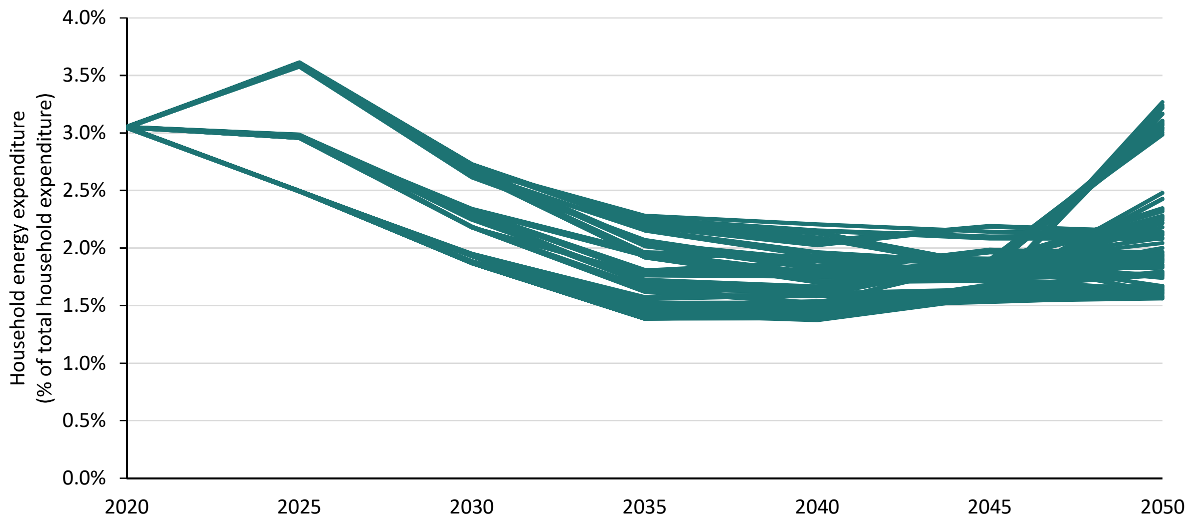
This section explores household energy expenditure as a measure of the cost of the net zero energy transition on Albertan households. Household energy expenditure includes energy costs incurred for heating, cooling, and powering homes, as well as energy use in vehicles owned by households.

As demand for clean electricity and low carbon fuels increases, so does their price. Electricity price increases in all net zero scenarios due to increased demand for electricity. Electricity prices are 55-115% higher in 2050 relative to 2020, depending on the net zero scenario, with the low and high end of this range driven by total electricity demand and by the future cost of renewables and storage. At the same time, the price of renewable fuels such as RNG and hydrogen increases as these fuels are blended into the natural gas stream, with up to 58% renewable fuel blending in buildings by 2050. RNG prices, for example, increase 2-5 times from 2020 levels by 2050 in response to increasing demand.

Despite increasing electricity and low carbon fuel prices, household energy expenditure declines as a portion of total household expenditure in most net zero scenarios (Figure 47). It declines from 3% of total household expenditure in 2020 to

1.9-2.7% in 2030, and ranges from 1.6-3.3% in 2050 depending on the net zero scenario. This decline in energy expenditure over time is a result of two factors. As personal vehicles and home heating are electrified, and as homes become more energy efficient, energy efficiency gains offset increasing costs of energy. At the same time, as Alberta's economy grows, households become wealthier and total expenditure increases.

Figure 47: Household energy expenditure as a portion of total expenditure (all net zero scenarios)



Household expenditure presented in Figure 47 is being driven by the price of gasoline and diesel for vehicles in the short term (2025) and by the price for electricity in the longer term. Expenditure in 2050 is highest in scenarios in which DAC is not available and CCS costs are high (leading to high electricity demand and driving up the electricity price), and when renewable and storage costs are high (leading to even higher electricity prices). These scenarios are reflected in the steep increase in household energy expenditure from 2045-2050 in Figure 47. When storage and renewable costs are low, and/or DAC and CCS are available at low cost, household energy expenditure is lower in 2050.

In most scenarios, net zero policy does not lead to an increase in household energy expenditure relative to current levels. Results indicate that household energy expenditure can be minimized if low carbon technologies, including DAC, CCS, renewables and storage, are available at low cost in the province.

6. Key Insights

Results of this analysis provide four key insights, summarized below.

Insight 1: The future of oil and gas production in Alberta is uncertain under net zero policy and is highly dependent on global demand for oil.

Oil and gas production has historically been an important component of Alberta's economy, but continued demand for fossil fuels is highly uncertain in a net zero emission future. Global demand for oil, simulated as an assumed global oil price in this analysis, has a significant impact on the role of oil and gas production in Alberta, driving uncertainty in the range of 2,718-6,461 thousand barrels per day and 5-11 Bcf per day in 2050 across all net zero scenarios.

However, across all net zero scenarios, continued oil and gas production is combined with adoption of methane management technologies, electrification where possible, CCS, and DAC if available to mitigate emissions. As such, lower costs of technologies like CCS and DAC are critical to improve the competitiveness of the oil and gas sector in a net zero future.

Insight 1a: Bitumen's comparative advantage in producing non-combustion commodities means it outcompetes lighter grades of crude oil in a net zero future.

Modeling of Alberta's refining sector was significantly updated for this analysis, and as such, requires further research to fully understand the extent of the role for bitumen in Alberta's net zero future. However, results of this analysis suggest that, due to its comparative advantage in producing non-combustion oil products for which demand remains under net zero policy, bitumen remains the "last barrel standing" in 2050 many net zero scenarios.

Insight 2: Alberta's net zero energy system relies on significant growth in electricity generation, including both renewables with storage and natural gas with CCS.

The electricity sector plays an important role in Alberta's net zero energy transition. The electricity grid is decarbonized by transitioning away from primarily fossil fuel towards low carbon generation. At the same time, generating capacity increases to meet growing demand across the economy. Electricity demand increases significantly across all net zero scenarios, by 46-139% from 2020 to 2050.

Across all net zero scenarios, utility generation is dominated by renewables by 2050, facilitated by storage. However, in scenarios in which DAC is not available and there is high demand for oil, natural gas with CCS is the primary source of electricity generation in 2050 across the province, driven by cogeneration with CCS and MCFC adoption in industry. This indicates investment in expansion of both low carbon generation types is important to facilitate Alberta's net zero electricity system.

Insight 3: Carbon capture technology is likely to play a transformative role in Alberta's net zero energy system.

CCS is an important technology used to mitigate emissions in Alberta's net zero energy system. It is adopted in large amounts across all net zero scenarios, with adoption ranging from 99-178 Mt across the province in 2050, driven by demand for abatement in the oil and gas sector. Most CCS adoption occurs on process heat in industry, with MCFC technology playing a potentially significant role in facilitating decarbonization of Alberta's industry.

Insight 3a: Enhanced oil recovery plays a critical role in deployment of CCS in the near term.

EOR creates a market for captured CO_2, providing an additional revenue stream for CCS adopters in the province in the near term (until 2030). As such, EOR creates an incentive for CCS, increasing adoption in the near term and helping to bring down the cost. Of the 10-51 Mt of CCS occurring in Alberta in 2030 in the net zero scenarios simulated, 8-28 Mt of captured CO_2 is used for EOR. After 2030, as increasing amounts of CO_2 are captured, the price for CO_2 declines but EOR remains an opportunity to use and store captured CO_2.

Insight 3b: If available, direct air capture technology could make Alberta's net zero transition easier and less costly.

Proximity to large quantitates of suitable storage makes Alberta ideally situated for a DAC industry. As a result, if DAC technology is available, Alberta becomes a net emission sink for Canada in a net zero future, capturing 174-318 Mt in 2050 to offset emissions that remain in Alberta and across the country.

Growth of a DAC sector in the province leads to significant economic contributions of $15-36 billion in 2050. At the same time, DAC availability allows for continued production of fossil fuels, prolonging the life of Alberta's oil and gas sector. It also allows for continued consumption of fossil fuels within the province, facilitating greater economic activity in other sectors of the economy, and avoids the need to reduce the most expensive-to-abate emissions. For these reasons combined, DAC availability can minimize the cost of achieving a net zero energy system in Alberta.

Insight 4: Alberta's economy is resilient to a net zero future. Economic growth depends primarily on future global demand for oil and the cost of carbon capture.

Alberta's GDP grows across all net zero scenarios, with the average annual growth rate ranging from 0.8-1.9% between 2020 and 2050. Alberta's economy grows most in scenarios in which the province continues to produce oil and gas and continues to consume fossil fuels, either capturing emissions with CCS or offsetting emissions with DAC.

As such, the best economic outcome for Alberta is a net zero future in which global demand for oil is high, bitumen beyond combustion allows for continued production of non-combustion oil products, CCS and DAC technologies are deployed at low cost, as are renewable electricity generation and storage technologies.

Investment to bring down the cost of technologies we know will play an important role in Alberta's net zero future – carbon capture, zero emission vehicles, hydrogen, renewables, storage - will help mitigate emissions in the province and reduce the cost of Alberta's net zero energy transition.

7. Limitations and Opportunities for Future Research

Limits to forecasting

Despite using the best available forecasting methods and assumptions, the evolution of our energy economy is uncertain. In particular, forecasting GHG emissions is subject to two main types of uncertainty.

First, all models are simplified representations of reality. Our gTech and IESD models are, effectively, a series of mathematical equations that are intended to forecast the future. This raises key questions: "are the equations selected a good representation of reality?" and "do the equations selected overlook important factors that may influence the future?".

The use of computable general equilibrium models (gTech) and linear programing models (IESD) is well founded in the academic literature. In addition, Navius undertakes significant efforts to calibrate and back-cast the model to ensure that it captures key dynamics in the energy-economic system.

However, Navius' tools do not account for every dynamic that will influence technological change. For example, household and firm decisions are influenced by many factors, which cannot be fully captured by even the most sophisticated model. The inherent limitation of energy-economy forecasting is that virtually all projections of the future will differ, to some extent, from what ultimately transpires.

Second, the assumptions used to parameterize the models are subject to uncertainty. These assumptions include, but are not limited to, oil prices, improvements in labour productivity and a stable climate. If any of the assumptions used prove incorrect, the resulting forecast could be affected.

Modeling of bitumen beyond combustion

A significant change made to gTech for this analysis was the addition of a refining module to represent the opportunity for bitumen beyond combustion in Alberta. The updates to modeling of Alberta's refining sector presented in this report are a new addition to gTech. This model improvement has a significant impact on the future of Alberta's oil sands sector compared to previous net zero analyses, and as such warrants future research. In particular, peer review of the refining module would be beneficial, as well as exploration of current limitations to our approach, discussed in more detail below.

There are some dynamics important to the role of bitumen production in a net zero future that are not yet accounted for in gTech. These include both dynamics that may overestimate and dynamics that may underestimate the role of bitumen in a net zero future.

An important limitation is that gTech is specific to Canada and the U.S., so it does not account for international demand for asphalt, including growth in international demand over time. If Alberta was to export bitumen to supply this international market, this could increase the role for bitumen and oil sands production in a net zero future. However, the model also does not account for other potential suppliers of this market, including heavy oil from Venezuela which may compete with Alberta's bitumen.

Additionally, gTech does not account for the substitutability between asphalt and concrete for road infrastructure, or using alternative feedstocks to produce asphalt, such as biocrude. If concrete is used for road infrastructure, or alternative feedstocks are used to produce asphalt, this could reduce the demand for bitumen in a net zero future.

Another limitation is that gTech does not account for the use of bitumen in producing other non-combustion products, such as carbon fibre. If demand for carbon fibre increases, the value and demand for bitumen could increase. Similarly, bitumen has a comparative advantage over lighter oils in producing sulfur, which is a biproduct of oil and gas production and an important element used in many applications, including chemical manufacturing and fertilizer production. If oil and gas production declines in a net zero future, the supply of sulfur from the oil and gas sector will decline while demand remains. As a result, supplying the sulfur market could be another important role for bitumen. Since gTech does not include carbon fibre or sulfur, this could underestimate the role of bitumen in a net zero future in the model results.

Scenario design

Significant uncertainty analysis was completed for this analysis. This includes examination of uncertainty in future oil prices and key technology costs, including DAC, CCS, hydrogen, renewables and electricity storage, resulting in modeling of over 100 possible net zero scenarios for Alberta. This analysis did not, however, explore all uncertainties in Alberta's net zero future.

For example, uncertainty in the future cost of bioenergy including RNG was not explored in this analysis. The cost and availability of RNG could have important implications for the role this fuel plays in Alberta's net zero future. In particular, the role for BECCS in Alberta is small according to this analysis but could be larger if future RNG costs are low. We also did not include the potential for third generation biofuels (algal biomass) in this analysis.

Similarly, sensitivities on the future cost of small modular nuclear reactors were not explored in this analysis. The role for this technology in Alberta is small according to this analysis but could be larger if the costs come down faster than currently expected (for example, following the “revolutionary” archetype presented in the Economy and Finance Working Group’s Roadmap[102]).

This analysis also assumes 20.3 Mt of LULUCF offsets are available in Alberta in 2050. If this is an over or under estimation of land-use offset availability, this could have important implications for the role of other negative emission technologies, including DAC and BECCS, as well as the cost of achieving net zero emissions in the province.

In addition, this analysis explores the role of hydrogen fuel based on two hydrogen production technologies – steam methane reformation and electrolysis. However, other hydrogen production technologies, including methane pyrolysis and biomass gasification, were not included in this analysis and could impact the cost and availability of hydrogen fuel in Alberta’s net zero future.

Finally, this analysis focuses on the most cost-effective pathways to net zero emissions for Alberta, simulating net zero policy as an economy-wide cap-and-trade system. In reality, the policy framework used to achieve net zero emissions will be a package of regulatory and market-based mechanisms, such as those announced in the federal *Emissions Reduction Plan (ERP)*. A more detailed review of announced policies (simulated for this analysis but not discussed in this report) in combination with net zero policy, particularly as more detail about announced ERP policies are released, could help in understanding the most likely pathway to net zero for Alberta.

[102] Economic and Finance Working Group. (2018). *SMR Roadmap*. Available from: https://smrroadmap.ca/wp-content/uploads/2018/12/Economics-Finance-WG.pdf

Appendix A: List of all current and announced policies

This appendix describes the set of policies included in the current and announced policy scenarios simulated in this analysis as explained in Section 2.3.

Current policy

The tables below describe the policies included in the current policy scenario. Table 29 describes federal policies and Table 30 describes Alberta-specific policies.

Table 29: Federal policies included in the current policy forecast

Policy	Description
Carbon Pollution Pricing Backstop[103]	This policy includes two components: (1) a carbon levy applied to fossil fuels that reaches $50/t CO_2e by 2022 and is constant thereafter in nominal terms and (2) an output-based pricing system for industrial facilities emitting more than 50 kt CO_2e annually. This policy applies to Saskatchewan, Manitoba, Ontario, New Brunswick, Prince Edward Island, Newfoundland and Labrador, the Yukon and Nunavut. Revenue raised by this policy is returned to households in each respective province/territory. Alberta has a similar output-based pricing system (TIER) for industrial facilities emitting more than 100 kt CO_2e annually. We have used the 2020 TIER compliance report[104] to estimate facility-specific benchmarks. For sectors that were either excluded from the 2020 compliance report or for which mapping to gTech sectors was not possible, a benchmark at 90% free allowances is used. We assume an annual 1% tightening rate for all sectors except for conventional oil and gas sectors and non-combustion emissions. Benchmark tightening is assumed to continue until the carbon price remains constant (2022 under the currently implemented policy). We apply TIER benchmarks to the electricity sector starting at 0.37tCO_2e/MWh and tightening by 2% annually between 2023 and 2030.

[103] Government of Canada. (2020). Pricing pollution: how it will work. Available from: https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work.html

Policy	Description
Energy efficiency regulations[105]	Federal standards exist for space conditioning equipment, water heaters, household appliances, and lighting products. Major standards include a minimum annual fuel utilization efficiency of 90% for natural gas furnaces, a minimum energy factor of 0.61 for gas water heaters and ban of incandescent light bulbs.
Green Freight Assessment Program[106]	Four-year funding program launched in 2018 with a budget of $3.4 million available for medium and heavy-duty fleet performance reviews, implementing operational best practices, installing fuel saving technologies, and purchasing alternative fuel vehicles.
Hydrofluorocarbon Controls[107]	The Canadian government was one of the signatories of the 2016 Montreal Protocol-amending Kigali Agreement on ozone-depleting substances. Canada has pledged to reduce its HFC-related GHG emissions by 15% by 2036 relative to 2011/2013 levels by revising the Regulations Amending the Ozone-depleting Substances and Halocarbon Alternatives Regulations.
Light-Duty ZEV Subsidy[108]	Light-duty vehicle subsidy available at $2,500 for short-range plug-in hybrids and $5,000 for long-range plug-in hybrids, hydrogen vehicles, and battery electric vehicles.
Regulations Amending the Heavy-duty Vehicle and Engine Greenhouse Gas Emission Regulations[109]	The national government has proposed amending the Heavy-Duty Vehicle Emissions Standard to increase the vehicle emission stringency for vehicles manufactured in model years 2018 to 2027.

[104] Government of Alberta. (2021). Alberta Industrial Greenhouse Gas Compliance. Available from: https://open.alberta.ca/dataset/c0cb77ca-fac0-4171-89af-0048e2189120/resource/3a2316ec-07df-4f07-a3e1-b3ac3c5f32cf/download/aep-alberta-industrial-greenhouse-gas-compliance-summary-2020-compliance-results-tier.pdf

[105] Natural Resources Canada. (n.d.). Canada's Energy Efficiency Act and Energy Efficiency Regulations. Available from: www.nrcan.gc.ca/energy/regulations-codes-standards/6861

[106] Government of Canada. (2020). Green Freight Assessment Program. Available from: https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-transportation/greening-freight-programs/green-freight-assessment-program/20893.

[107] Government of Canada. (2018). Canada agrees to control hydrofluorocarbons under the Montreal Protocol. www.canada.ca/en/environment-climate-change/services/sustainable-development/strategic-environmental-assessment/public-statements/canada-agree-control-hydrofluorocarbons.html

[108] Government of Canada. (n.d.) Zero-emission vehicles. Available from: https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles

[109] Government of Canada. (2018). Regulations Amending the Heavy-duty Vehicle and Engine Greenhouse Gas Emission Regulations and Other Regulations Made Under the Canadian Environmental Protection Act, 1999: SOR/2018-98. http://gazette.gc.ca/rp-pr/p2/2018/2018-05-30/html/sor-dors98-eng.html

Policy	Description
Regulations Amending the Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations[110]	New passenger vehicles and light-commercial vehicles/light trucks sold in Canada must meet fleet-wide GHG emission standards between 2012 and 2016, and between 2017 and 2025. Fleet targets for passenger cars are aligned with US regulation.
Regulations Amending the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations[111]	This policy closes coal-fired power plants by 2030 unless they emit less than 420 tonnes CO_2e/GWh.
Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity[112]	This policy limits the emissions intensity of natural gas-fired electricity generation to 420 tonnes CO_2e/GWh.
Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds[113]	Oil and gas facilities must adopt methane control technologies and practices.
Renewable Fuels Regulation[114]	Specifies a minimum renewable content of 5% for gasoline and 2% for diesel, by volume. This will become part of the Clean Fuel Regulation (CFR) once the CFR comes into force in 2022.
Zero Emission Vehicle Tax Write-Off[115]	Businesses that purchase light-, medium-, or heavy-duty ZEV vehicles (including plug-in hybrids with a battery capacity of at least 7kWh, fully electric vehicles, and hydrogen vehicles) are eligible for a 100% tax write-off. Vehicles that qualify for the federal Incentive for Zero-Emission Vehicles Program are ineligible for the tax write-off.

[110] Government of Canada. (2018). Regulations Amending the Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations. http://www.gazette.gc.ca/rp-pr/p2/2014/2014-10-08/html/sor-dors207-eng.html
[111] Government of Canada. (2018). Regulations Amending the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations: SOR/2018-263. Available from: https://laws-lois.justice.gc.ca/eng/regulations/SOR-2012-167/page-2.html#h-4
[112] Government of Canada. (2018). Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity: SOR/2018-261. Available from: https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-261/index.html
[113] Government of Canada. (2020). Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector): SOR/2018-66. Available from: https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-66/index.htm
[114] Government of Canada (2013). Renewable Fuels Regulations: SOR/2010-189. Available from: https://laws-lois.justice.gc.ca/eng/regulations/SOR-2010-189/index.html
[115] Government of Canada. (2020). Zero Emission Vehicles. Tax Write-Off. Available from: https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles

Policy	Description
Zero Emission Vehicle Infrastructure Program[116]	Federal funding available (total budget of $130 million over five years from 2019 to 2024) to partially pay for various types of charging and re-fueling stations, including medium- and heavy-duty vehicle charging and re-fueling stations.

Table 30: Alberta policies included in the current policy forecast

Policy	Description
Capping oil sands emissions[117]	Limits emissions from the oil sands to 100 Mt CO2e annually. Note this cap is not represented in gTech currently as the emissions from the oil sands are far less than 100 Mt per year in the base case. Since the policy effectively results in no change, it was removed. However, it can be put back in should that be of interest.
Renewable Electricity Act[118]	Requires that by the end of 2030, at least 30% of the electric energy produced in Alberta is produced from renewable energy resources.

Announced policy

The tables below describe the policies included in the announced policy scenario. These policies are simulated in addition to those included in the current policy scenario.

Table 31: Federal Fuel Charge

Policy	Federal Fuel Charge[119]
Stringency and timeline	The federal fuel charge is a backstop policy that applies a tax on fossil fuels in provinces that don't have an equally stringent carbon pricing system. The federal government announced that the federal fuel charge will be annually increased by $15/tCO2e after 2022 until the tax reaches $170/tCO2e in

[116] Government of Canada. (2020). Zero Emission Vehicle Infrastructure Program. Available from: https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-transportation/zero-emission-vehicle-infrastructure-program/21876

[117] Government of Alberta (2020). Capping oil sands emissions. Available from: https://www.alberta.ca/climate-oilsands-emissions.aspx#:~:text=Alberta%20will%20transition%20to%20an,to%20oil%20sands%20GHG%20emissions.&text=A%20legislated%20emissions%20limit%20on,cogeneration%20and%20new%20upgrading%20capacity

[118] Government of Alberta. (2023). Renewable Electricity Act. Available from: https://kings-printer.alberta.ca/570.cfm?frm_isbn=9780779814060&search_by=link

[119] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html

	2030 and stays constant at that level thereafter.
Sectors	All sectors except large industrial emitters
Emissions covered	Emissions-intensive trade- exposed industries are excluded from the fuel charge. Fuel charge proceeds are returned to the province in which they were collected and 100% of proceeds are returned to households.
Assumptions	As it is uncertain how provinces will change their carbon pricing systems to comply with the federal stringency increase, we assume that the federal fuel charge backstop applies to all provinces and territories.

Table 32: Output-Based Pricing System

Policy	Output-Based Pricing System[120]
Stringency and timeline	The Output-Based Pricing System (OBPS) is a tradable emissions performance standard that puts a price on industrial emissions if a facility's emissions intensity exceeds the sectoral benchmark. The federal government announced that the OBPS carbon price will be annually increased by \$15/tCO2e until it reaches \$170/tCO2e in 2030. Furthermore, sectoral OBPS benchmarks will be annually increased in stringency by 2 percentage points starting in 2023. For the TIER program, we assume that the TIER carbon price will follow the federal carbon pricing schedule and that the 1% benchmark tightening rate will continue out to 2030, after which point carbon pricing will remain at \$170/t CO2e. We apply TIER benchmarks to the electricity sector starting at 0.37tCO2e/MWh and tightening by 2% annually between 2023 and 2030.
Sectors	Large industrial emitters
Emissions covered	The OBPS applies to industrial facilities emitting more than 50 kilotonnes of CO2e annually
Assumptions	As it is uncertain how provinces will change their carbon pricing systems to comply with the federal stringency increase, we assume that the OBPS will apply to all provinces and territories. OBPS proceeds are assumed to be used to fund low-carbon industrial technologies.

Table 33: Greenhouse Gas Emissions Cap on the Oil and Gas Sector

Policy	Greenhouse Gas Emissions Cap on the Oil and Gas Sector[121]
Stringency and timeline	The federal government has announced its intention to cap greenhouse gas emissions from the oil and gas extraction sector.
Sectors	Oil and gas extraction (upstream and downstream sectors)
Emissions covered	To our knowledge, it has not yet been specified if the cap will cover upstream and downstream (natural gas distribution, refineries, LNG production) oil and gas sector emissions and if it will include both combustion and direct non-combustion emissions (e.g., methane emissions).

[120] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/2022-review-consultation.html

[121] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

Assumptions	We simulate this policy as a tradable performance standard in which the oil and gas sector is required to reduce its emissions intensity. Carbon intensity benchmarks are calculated to be consistent with the emissions cap. In line with the modeling analysis referenced in the ERP, we assume that the emissions cap will apply to total oil and gas extraction sector emissions, including direct combustion and non-combustion emissions in the upstream and downstream oil and gas sector. We assume that there are no restrictions to generating compliance credits under the OBPS and oil and gas emissions cap for the same reduction action, such as implementation of carbon capture and storage. Emissions are capped at 155 Mt in 2025 and 110 Mt in 2030.

Table 34: 75% Reduction in Oil and Gas Methane Emissions

Policy	75% reduction in oil and gas methane emissions[122,123,124]
Stringency and timeline	The federal government announced its commitment to implement regulations that will reduce methane emissions from the oil and gas sector by at least 75% below 2012 levels by 2030. This builds on the federal government's current methane regulations, which seek to achieve a 40% to 45% reduction in methane emissions in the upstream oil and gas sector below 2012 levels by 2025.
Sectors	Oil and gas extraction (upstream sectors)
Emissions covered	The current methane regulations cover upstream oil and gas emissions. To our knowledge, it has not yet been announced if the 75% reduction will apply to upstream oil and gas emissions or both upstream and downstream (including refineries, natural gas distribution, and LNG production) emissions.
Assumptions	The 75% methane reduction requirement is simulated as a regulatory requirement requiring increased uptake of abatement actions and technologies for surface casing vent flows, leaking, and venting, such as increased monitoring, flaring, and well reworking, in the upstream oil and gas sector.

Table 35: Clean Electricity Regulation

Policy	Clean Electricity Regulation[125,126]
Stringency and timeline	The federal government has stated its intention to implement a Clean Electricity Regulation (CER), which will achieve net zero emissions from electricity generation by 2035. The policy mechanisms that will be used to achieve this target have not yet been announced.
Sectors	Electricity generation
Emissions covered	The CER will cover electricity generation sold to the electricity grid. It is uncertain whether the CER will cover cogeneration providing electricity to the

[122] https://www.canada.ca/en/environment-climate-change/news/2021/10/canada-confirms-its-support-for-the-global-methane-pledge-and-announces-ambitious-domestic-actions-to-slash-methane-emissions.html

[123] https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-66/page-1.html#h-858529

[124] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

[125] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

[126] https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/achieving-net-zero-emissions-electricity-generation-discussion-paper.html

	grid.
Assumptions	This policy is simulated as a national cap in form of a tradable performance standard with regional benchmarks for the emissions intensity of utility electricity generation. Emissions intensity benchmarks are calculated to be consistent with the emissions cap. We assume that cogeneration is excluded from the CER and that there are no restrictions on generating compliance credits under the OBPS and CER for the same reduction action. We assume a national emissions cap of 39Mt in 2025, 7 Mt in 2030, and net zero in 2035 for utility generation greenhouse gas emissions while allowing for CCS for natural gas.

Table 36: Waste Methane Capture

Policy	Waste Methane Capture[127]
Stringency and timeline	The ERP states the federal government's intention to create landfill methane regulations with the goal of reducing waste emissions through waste methane capture and treatment.
Sectors	Landfills
Emissions covered	Landfill methane emissions
Assumptions	We simulate a regulatory policy which requires the uptake of abatement actions and technologies such as flaring and methane capture and utilization in landfills. We require 50% of all landfills to adapt flaring or methane capture and utilization by 2025.

Table 37: Clean Fuel Regulations

Policy	Clean Fuel Regulations[128,129]
Stringency and timeline	The federal government is developing a fuel supply standard requiring liquid fossil fuel suppliers to reduce the lifecycle greenhouse gas intensity of their fuels. The Canada Gazette Part II requires a carbon intensity reduction of 3.5 g CO_2e/MJ in 2023, increasing to 14 g CO_2e/MJ in 2030[130]. The CFR creates a credit-based compliance market which allows regulated liquid fuel suppliers and voluntary credit generators to trade compliance credits. At the end of each compliance period, regulated suppliers must present sufficient credits to comply with the reduction requirement. Credits can be produced by reducing upstream emissions associated with liquid fossil fuel production, blending low carbon fuels such as ethanol into the liquid stream, or end-use fuel switching in transport.
Sectors	Transportation
Emissions covered	The CFR will regulate gasoline and diesel suppliers.
Assumptions	**Upstream credit generation (Compliance Category 1)**

[127] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

[128] http://www.gazette.gc.ca/rp-pr/p1/2020/2020-12-19/html/reg2-eng.html

[129] Environment and Climate Change Canada. 2022. Spring 2022 Update. Available from: ECCC's Clean Fuel Standard public google drive.

[130] Government of Canada. (2022). Clean Fuel Regulations: SOR/2022-140. Canada Gazette, Part II, Volume 156, Number 14. Available from: https://www.gazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html

Credit creation through carbon capture and storage is endogenously simulated by gTech as a function of compliance costs and provincial and federal policies. All CCS projects linked to liquid fossil fuel production are assumed to be considered "additional" and qualify for CFR credit generation. CCS credit generation is pro-rated by the ratio of domestic use versus exports. For crude oil production, we assume that 20% of CCS qualifies for credit generation, as about 80% of extracted crude oil is exported[131]. For refineries, we assume that 80% of CCS can generate CFR credits, as a large share of refined petroleum products is used domestically[132]. Credit stacking under the Alberta TIER and offset program is assumed to be allowed.

We further assume that generic quantification method credits for actions such as methane conservation and refinery process improvements are created up to the 10% limit by 2030 (about 2.9 Mt CO2e worth in credits in 2030).

Fuel blending (Compliance Category 2)
Fuel blending is endogenously simulated by the model as a function of production and transportation costs as well as provincial and federal policies.

Credit generation through fuel switching in transportation (Compliance Category 3)

We use variable electricity carbon intensities based on prior gTech results. This approach accounts for the impact of electricity decarbonization driven by policies such as carbon pricing and regulations, which will impact the CFR credit market and allow for more credit generation through electrification.

We use ECCC's assumption that 10% of residential charging would be adequately metered to generate credits, growing at 2.5% per year.

Interstream credit trading
Supply of low-carbon gaseous fuels can generate gaseous credits which can be used by regulated suppliers to meet up to 10% of compliance through instream credit trading.

Credit banking
The Canada Gazette Part II Regulatory Impact Analysis (RIAS) assumes that about 3.8 Mt CO2e of banked credits will be used to comply with the CFR in 2025 and that banked credits will drop to zero in 2026 and remain at zero thereafter.

We have aligned the assumption on the number of banked credits used in each modeling period with the RIAS estimate.

Table 38: Light-Duty Vehicle Emissions Standard

Policy	Light-Duty Emissions Standard[133]
Stringency and timeline	The ERP states that the federal government plans to implement a light-duty zero emissions vehicle (ZEV) sales mandate. The ZEV mandate will require at

[131] Canada Energy Regulator. 2021. Market Snapshot: Canada's crude oil exports kept pace with production over the last decade. Available from: https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2021/market-snapshot-canadas-crude-oil-exports-kept-pace-with-production-over-the-last-decade.html.
[132] Statistics Canada. 2020. Supply and disposition of refined petroleum products, monthly. Available from: https://open.canada.ca/data/en/dataset/792aad48-1745-41dd-8424-55e49d98fa0c.
[133] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

	least 12.5% of all new light-duty vehicle sales to be ZEVs by 2026 and 50% by 2030.[134]
Sectors	Light-duty transportation
Emissions covered	We expect this policy to apply to light-duty vehicle manufacturers
Assumptions	As there are currently no details on policy design available, we assume that a policy similar to Québec's ZEV mandate will be implemented but with a delayed timeline. After a recently announced stringency increase, Québec 's ZEV mandate will require at least 17.5% low-carbon (plug-in hybrids) and zero-emission (battery electric and fuel cell electric) vehicle sales in 2026, rising to 65% in 2030 and 100% in 2035. We assume the federal policy follows the Quebec timeline but a year delayed, with a 12.5% requirement in 2026 (Quebec's 2025 target) and 50% in 2030. Each year, vehicle manufacturers need to retire a certain number of credits in compliance with these targets. Credits are generated through the sale of low-carbon and zero-emission vehicles. Vehicles with a wider electric range are thereby awarded more credits.

Table 39: Medium- and Heavy-Duty Vehicle Emissions Standard

Policy	Medium- and Heavy-Duty Emissions Standard[135],[136],[137],[138],[139],[140]
Stringency and timeline	The ERP announced plans to develop a medium- and heavy-duty ZEV sales mandate with the goal of achieving 35% ZEV sales by 2030 and 100% by 2040 in selected medium- and heavy-duty categories, based on feasibility. Furthermore, interim targets for pre-2030 years will be explored.
Sectors	Medium- and heavy-duty transportation
Emissions covered	There are currently no details on policy design available but the federal government previously expressed interest in developing a policy similar to California's Advanced Clean Trucks Regulation, which also aims to achieve 100% ZEV sales by 2040 in selected vehicle categories. California's regulation applies to manufacturers of on-road medium- and heavy-duty vehicles, excluding transit buses.
Assumptions	We assume that Canada will implement a medium- and heavy-duty emissions standard aligned with California's Advanced Clean Trucks Regulation. California's medium- and heavy-duty emissions standards require that 7% to 11% of new vehicle sales be ZEVs in 2025 and 30% to 50% in 2030, depending on vehicle weight class. Each year, vehicle manufacturers need to retire a certain number of credits in

134 Note that there could be near-term issues meeting EV deployment targets, but this is not expected to be an issue on the 30 year time-scale of this analysis.

135 https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

136 https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/healthy_environment_healthy_economy_plan.pdf

137 https://www.canada.ca/content/dam/eccc/documents/pdf/cepa/21199_HDV%20Discussion%20Document_Dec%2016_MinO%20Approved_Final_EN.pdf

138 https://www.canada.ca/en/environment-climate-change/news/2021/12/government-launches-consultations-on-commitment-to-require-all-new-cars-sold-in-canada-be-zero-emission-by-2035.html

139 https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2019/zepcert/froattb.pdf

140 https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2019/act2019/fro2.pdf

compliance with these targets. Credits are generated through the sale of low-carbon emission vehicles. For full battery electric and fuel cell electric vehicles, the number of credits generated depends on the vehicles' weight class. For plug-in electric vehicles, credit generation also depends on electric range.

Table 40: Investment Tax Credit for Carbon Capture Utilization and Storage

Policy	Investment tax credit for CCUS[141]
Stringency and timeline	Budget 2022 introduces an investment tax credit for carbon capture utilization and storage capital investments. The target of this measure is to reduce emissions by at least 15 Mt of CO2e per year. Budget 2022 states that a total of 2.6 billion dollars will be invested in direct air capture and carbon capture utilization and storage between 2022 and 2026, and 1.5 billion annually from 2027 to 2030.
Sectors	Large industrial emitters
Emissions covered	We expect that the tax credit would be available to all new carbon capture and storage, direct air capture, and for investment in equipment for transportation, storage and use.
Assumptions	This is simulated as a $2.6 billion subsidy over five years starting in 2022, and a $1.5 billion annual subsidy from 2027 to 2030.

Table 41: Canada Infrastructure Bank Spending

Policy	Canada Infrastructure Bank Spending[142],[143],[144]
Stringency and timeline	The Healthy Environment and Healthy Economy federal climate plan states that the Canada Infrastructure Bank (CIB) has a long-term investment target of $5 billion for clean power projects. It further outlines that the CIB has committed $1.5 billion for zero emission buses, $2.5 billion for low-carbon power projects, including storage, transmission and renewables, over 3 years, and $2 billion for commercial building retrofit upfront costs. The ERP mentions that CIB will receive a total of $35 billion with priorities to invest in green infrastructure ($5 billion), public transit ($5 billion) and clean power ($5 billion). CCUS funding is available to any sector wanting to implement this technology, including oil and gas.
Sectors	Transit, electricity generation, commercial buildings
Emissions covered	Buildings and other infrastructure, transit, electricity generation
Assumptions	CIB spending is simulated as a $1.5 billion subsidy for zero-emission buses, $500 million for electric charging and hydrogen refueling infrastructure (included in the “16. Funding for charging stations” policy), a $5 billion subsidy for renewable electricity generation and storage, and $2 billion for commercial high efficiency building shells and heating technologies over three years.

[141] https://budget.gc.ca/2022/report-rapport/chap3-en.html#wb-cont

[142] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/healthy_environment_healthy_economy_plan.pdf

[143] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

[144] https://cib-bic.ca/en/sectors/priority-sectors/

Table 42: Net Zero Accelerator

Policy	Net Zero Accelerator[145,146]
Stringency and timeline	A Healthy Environment and a Healthy Economy announced an investment of $3 billion over 5 years for the Net Zero Accelerator, which provides funding for development and adoption of low-carbon technologies in all industrial sectors. Budget 2021 provided an additional $5 billion over seven years for the Net Zero Accelerator.
Sectors	Large industrial emitters
Emissions covered	Funding is available to low-carbon industrial technologies.
Assumptions	The Net Zero Accelerator is simulated as an $8 billion government investment over seven years for industrial low-carbon technologies, including carbon capture and storage technologies, electrification of industrial heat production and compression, fuel switching to wood waste and hydrogen for industrial heat production, efficient electric motors, and direct air capture.

Table 43: Zero Emission Vehicle Tax Write-Off

Policy	Zero Emission Vehicle Tax Write-Off[147,148]
Stringency and timeline	Businesses can receive a 100% tax write-off when purchasing a zero-emission vehicle before 2024. The tax write-off rate declines to 75% in 2024, 25% in 2025, and 0% in 2028.
Sectors	Transportation
Emissions covered	The increased tax write-off rate is available to businesses purchasing light-, medium-, or heavy-duty on-road zero emission vehicles, including plug-in hybrids, battery electric and fuel cell electric vehicles. Vehicles that received subsidies from the iZEV program are not eligible for the tax write off.
Assumptions	The increased tax write-off for businesses is simulated as a per vehicle subsidy for medium- and heavy-duty ZEVs. Businesses purchasing light-duty ZEVs are assumed to use the federal iZEV incentive and forgo the tax write off.

Table 44: Incentives for Zero-Emission Vehicle Program

Policy	Incentives for Zero-Emission Vehicles Program[149,150,151]
Stringency and timeline	The ERP announced an additional $1.7 billion to extend the iZEV program for another three years. The iZEV program provides rebates of up to $5,000 for

[145] https://www.budget.gc.ca/2021/home-accueil-en.html
[146] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/healthy_environment_healthy_economy_plan.pdf
[147] https://www.canada.ca/en/revenue-agency/services/tax/individuals/topics/about-your-tax-return/tax-return/completing-a-tax-return/deductions-credits-expenses/line-22900-other-employment-expenses/capital-cost-allowance/classes-depreciable-properties/zero-emission-vehicles.html
[148] https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/incentives-purchasing-zero-emission-vehicles
[149] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf
[150] https://www.budget.gc.ca/efu-meb/2021/report-rapport/EFU-MEB-2021-EN.pdf
[151] https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/program-statistics

	light-duty zero emission vehicles.
Sectors	Light-duty transportation
Emissions covered	The rebate program provides subsidies to on-road light-duty plug-in hybrids, battery electric vehicles, and fuel cell electric vehicles.
Assumptions	We simulate this as a 1.7 billion subsidy, additional to historic and remaining iZEV funds for zero emission light-duty vehicles, including battery electric vehicles, plug-in hybrids, and fuel cell electric vehicles, over three years. Subsidy values are assumed to be nominal.

Table 45: Funding for Charging Stations

Policy	Funding for Charging Stations[152],[153],[154]
Stringency and timeline	The ERP states that an additional $400 million will be allocated to ZEV charging stations. In addition, $500 million in Canada Infrastructure Bank funds will be invested into improving the electric charging and hydrogen refueling infrastructure.
Sectors	Transportation
Emissions covered	Funding is available for electric charging and hydrogen fuel cell refueling network improvements.
Assumptions	This is simulated as a $900 million subsidy for light-, medium-, and heavy-duty zero emission vehicles, including plug-in hybrids, battery electric and fuel cell electric vehicles, over five years. Subsidy values are assumed to be nominal.

Table 46: Large Truck Retrofits

Policy	Large Truck Retrofits[155]
Stringency and timeline	The ERP includes a $199.6 million subsidy for retrofitting large trucks currently on the road.
Sectors	Medium- and heavy-duty transportation
Emissions covered	To our knowledge, there is currently little information regarding the retrofit actions that would qualify for funding under this policy.
Assumptions	This is simulated as a $199.6 million subsidy for efficient heavy-duty vehicles. Subsidy values are assumed to be nominal.

Table 47: Interest-Free Home Retrofit Loan

Policy	Interest-free home retrofit loan[156],[157]

152 https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf
153 https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/healthy_environment_healthy_economy_plan.pdf
154 https://www.budget.gc.ca/2021/home-accueil-en.html
155 https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

Stringency and timeline	Budget 2021 allocated $4.4 billion on a cash basis ($778.7 million on an accrual basis over five years, starting in 2021-22, with $414.1 million in future years), to the Canada Mortgage and Housing Corporation to provide interest-free loans up to $40,000 to low-income homeowners for home retrofits. The ERP announced an additional investment of $458.5 million into the low-income loan program.
Sectors	Residential buildings
Emissions covered	Funding is available to low-income households for efficiency upgrades of residential building shells and heating technologies.
Assumptions	This is simulated as a $1.2 billion subsidy ($778.7 million + $458.5 million) over seven years for efficient residential building shells and heating technologies. Subsidy values are assumed to be nominal.

Table 48: Residential Efficiency Retrofits

Policy	Residential Efficiency Retrofits[158]
Stringency and timeline	Budget 2021 included $2.6 billion for residential energy efficiency improvements over seven years.
Sectors	Residential buildings
Emissions covered	Funding is available to households for efficiency upgrades of residential building shells and heating technologies.
Assumptions	This is simulated as a $2.6 billion subsidy for efficient residential building shells and heating technologies over seven years. Subsidy values are assumed to be nominal.

Table 49: Replace Home-Heating Oil

Policy	Replace Home-Heating Oil[159]
Stringency and timeline	The Liberal Party stated on its 2021 Election Platform that it aims to accelerate electrification in home-heating and would invest $250 million to help low-income homeowners replace heating oil.
Sectors	Residential buildings
Emissions covered	Funding available to low-income households for replacing home heating with heating oil.
Assumptions	This is simulated as a $250 million subsidy over five years for electric heating technologies. Subsidy values are assumed to be nominal.

[156] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

[157] https://www.canada.ca/en/department-finance/news/2021/04/budget-2021-a-healthy-environment-for-a-healthy-economy.html

[158] https://www.budget.gc.ca/2021/home-accueil-en.html

[159] https://liberal.ca/our-platform/a-retrofit-economy-that-cuts-pollution-and-creates-jobs/

Table 50: Community Buildings Upgrade

Policy	Community Buildings Upgrade[160]
Stringency and timeline	Budget 2021 proposed to invest $1.5 billion over three years for repairs and efficiency upgrades in community buildings and for building new energy efficient community buildings.
Sectors	Community buildings
Emissions covered	Funding is available for efficiency upgrades of building shells and heating technologies in community buildings.
Assumptions	This is simulated as a $1.5 billion subsidy over three years for community and commercial efficient building shell and heating technologies. Subsidy values are assumed to be nominal.

Table 51: Low Carbon Economy Fund

Policy	Low Carbon Economy Fund[161]
Stringency and timeline	The ERP announced that $2.2 billion will be provided to the Low Carbon Economy Fund, which supports territorial, provincial and municipal governments, schools, colleges, universities, businesses, NGOs, hospitals and Indigenous organizations and communities in their effort to reduce GHG emissions.
Sectors	Territorial, provincial and municipal governments, schools, colleges, universities, businesses, NGOs, hospitals and Indigenous organizations and communities
Emissions covered	Funding is available for a variety of abatement actions and programs, including efficiency upgrades of building shells and heating technologies in community and commercial buildings.
Assumptions	This is simulated as a $2.2 billion subsidy over three years for community and commercial efficient building shell and heating technologies. Subsidy values are assumed to be nominal.

Table 52: Renewable Electricity Investments

Policy	Renewable Electricity Investments[162],[163],[164]
Stringency and timeline	The Healthy Environment and Healthy Economy federal climate plan states that $964 million over four years will be invested in renewable electricity generation. The ERP announced that an additional $600 million will be invested in renewable electricity and grid modernization and $250 million to supporting large clean electricity projects.
Sectors	Electricity generation

160 https://www.budget.gc.ca/2021/home-accueil-en.html

161 https://www.budget.gc.ca/2021/home-accueil-en.html

162 https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/healthy_environment_healthy_economy_plan.pdf

163 https://www.budget.gc.ca/2021/home-accueil-en.html

164 https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

Emissions covered	Funding available for renewable electricity generation.
Assumptions	This is simulated as a $1.8 billion subsidy ($964 million + $850 million) over four years flowing into the renewable electricity generation sector. Subsidy values are assumed to be nominal.

Table 53: Hydrogen Projects

Policy	Hydrogen Projects[165,166]
Stringency and timeline	There are two major planned government investments in hydrogen projects in Alberta. The Suncor and ATCO plant will become operational in 2028 and produce more than 300,000 tonnes of low-carbon hydrogen per year of which 20% could be used in Alberta's natural gas distribution system. Most of the remainder will be used by refineries. The Air Products project will come online in 2024 and produce 30 tonnes of liquid low-carbon hydrogen per day which will be available for the merchant market. Air products will further produce low-carbon hydrogen for refineries and electricity generation for its own operations and the grid.
Sectors	Hydrogen production
Emissions covered	n/a
Assumptions	We assume that by 2030, 24 PJ of low-carbon hydrogen, available for the merchant market and electricity production, would be produced through Air Products' project and an additional 13.5 PJ through Suncor and ATCO's project.

Table 54: Ontario Steel Plant Upgrades

Policy	Ontario Steel Plant Upgrades[167,168]
Stringency and timeline	Two major steel companies in Ontario, ArcelorMittal and Algoma, announced that they will upgrade their steel plants, which will result in greenhouse gas reductions of about 3 Megatonnes in each plant.
Sectors	Steel production
Emissions covered	Steel production
Assumptions	This is simulated as a switch to less carbon intensive forms of steel production, such as direct reduced iron steel production, and achieves about a 6 Megatonnes reduction in GHG emissions in 2030 relative to 2020.

[165] Air Products Announces Multi-Billion Dollar Net-Zero Hydrogen Energy Complex in Edmonton, Alberta, Canada
[166] Suncor and ATCO partner on a potential world-scale clean hydrogen project in Alberta | Suncor
[167] https://www.globenewswire.com/news-release/2021/11/11/2332532/0/en/Algoma-Steel-Announces-Final-Investment-Decision-for-Electric-Arc-Steelmaking.html
[168] https://corporate.arcelormittal.com/media/press-releases/arcelormittal-and-the-government-of-canada-announce-investment-of-cad-1-765-billion-in-decarbonization-technologies-in-canada

Appendix B: Model calibration

Calibration sources

To characterize Alberta's energy-economy and that of the rest of Canada and the United States, gTech and IESD are calibrated to a large variety of historical data sources. Key calibration data sources for Alberta include:

- Environment and Climate Change Canada's National Inventory Report[169]
- Statistics Canada's Supply-Use Tables[170]
- Natural Resources Canada's Comprehensive Energy Use Database[171]
- Statistics Canada's Annual Industrial Consumption of Energy Survey[172]
- Statistics Canada's Report on Energy Supply and Demand[173]
- Navius' technology database
- Canada's Energy Future 2021[174]
- Statistics Canada datasets on the electricity sector[175]

Each data source is generated using different methods, so the data sources are therefore not necessarily consistent with one another. For example, expenditures on gasoline by households in Statistics Canada's Supply-Use tables may not be consistent with fuel consumption reported by Natural Resources Canada's Comprehensive Energy Use Database. Further, energy expenditures are a function of consumption and prices, so if prices vary over the course of the year, it is difficult to perfectly align consumption and expenditures.

gTech's calibration routine places greater emphasis on some data sources relative to others. This approach means that gTech achieves near perfect alignment with data

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169 Environment and Climate Change Canada. National Inventory Report. Available from: www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/inventory.html
170 Statistics Canada. Supply and Use Tables. Available from: www150.statcan.gc.ca/n1/en/catalogue/15-602-X
171 Natural Resources Canada. Comprehensive Energy Use Database. Available from: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm
172 Statistics Canada. Annual Industrial Consumption of Energy Survey. Available from: www.statcan.gc.ca
173 Statistics Canada. Report on Energy Supply and Demand in Canada. Available from: https://www150.statcan.gc.ca/n1/en/catalogue/57-003-X
174 Canada Energy Regulator. (2021). *Canada's Energy Future 2021.* Available from: www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/index.html
175 Statistics Canada. (n.d.). *Data.* Available from: https://www150.statcan.gc.ca/n1/en/type/data?subject_levels=25%2C2504

sources receiving the highest priority weight, but alignment starts to diverge from data sources that receive a lower weight.

For this project, the datasets that will receive the highest weight are:

- Revised Environment and Climate Change Canada's National Inventory Report
- Natural Resources Canada's Comprehensive Energy Use Database
- Navius' technology database
- Canada's Energy Future 2021

Oil and gas calibration

Oil and gas production is calibrated to the 2021 version of Canada's Energy Future[176]. Production costs in Alberta are broken down into capital costs, fuel costs, intermediate goods, labour costs, and other value added (taxes, etc.). Additionally, a "secondary products" category is reported. This category accounts for the fact that a sector will produce other goods in addition to its primary output – for example, the natural gas sector will produce some oil.

Costs for crude oil production in Alberta are provided in Figure 48, and costs for natural gas production are provided in Figure 49. These costs represent input costs in the model base year (2015) but are dynamic and change by year and scenario due to changes in technology adoption, technology costs, fuel prices, policy implementation, etc. Conventional oil is disaggregated into light and heavy, and oil sands is disaggregated into integrated mining, non-integrated mining and in situ. Based on a 2019 BMO report[177], operating costs decline by 30% in oil sands mining, and 40% in oil sands in situ by 2020.

[176] Canada Energy Regulator. (2021). *Canada's Energy Future 2021.* Available from: www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/index.html
[177] BMO. (2019). *ESG, Yeah You Know Me: Innovation and the Search for 'Friendly Oil'*

Figure 48: Alberta crude oil production costs in gTech

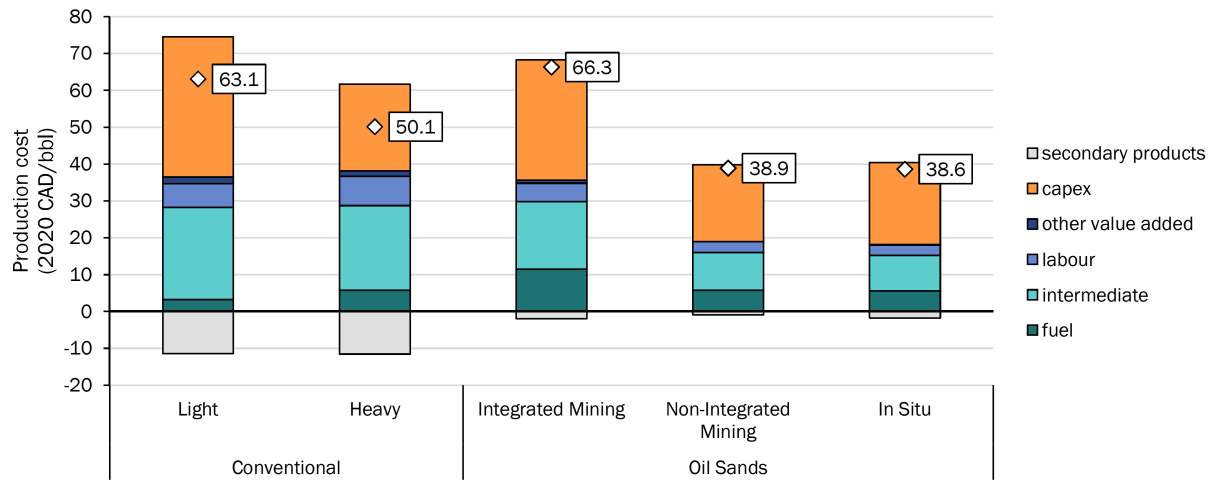
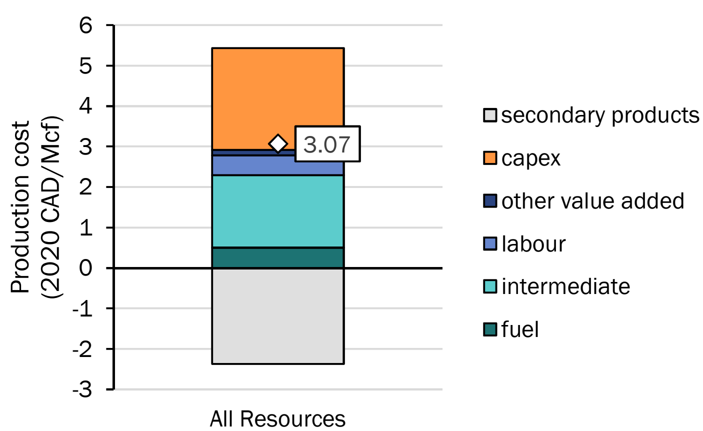


Figure 49: Alberta natural gas production costs in gTech



Appendix C: List of covered fuels, sectors, and end-uses in gTech

This appendix outlines all covered sectors, fuels and end-uses in gTech across Canada and the United States.

Table 55: Covered sectors

Sector name	NAICS code
Soybean farming	11111
Oilseed (except soybean) farming	11112
Wheat farming	11114
Corn farming	11115
Other farming	Rest of 1111
Animal production and aquaculture	112
Forestry and logging	113
Fishing, hunting and trapping	114
Agriculture services	115
Natural gas extraction (conventional)	211113
Natural gas extraction (tight)	
Natural gas extraction (shale)	
Light oil extraction	
Heavy oil extraction	
Oil sands in-situ	211114
Oil sands mining	
Bitumen upgrading (integrated)	
Bitumen upgrading (merchant)	
Coal mining	2121
Metal mining	2122
Non-metallic mineral mining and quarrying	2123
Oil and gas services	213111 to 213118
Mining services	213119
Fossil-fuel electric power generation	221111
Hydro-electric and other renewable electric power generation	221112 and 221119
Nuclear electric power generation	221113
Electric power transmission, control and distribution	22112
Natural gas distribution	222

Sector name	NAICS code
Construction	23
Food manufacturing	311
Beverage and tobacco manufacturing	312
Textile and product mills, clothing manufacturing and leather and allied product manufacturing	313-316
Wood product manufacturing	321
Paper manufacturing	322
Petroleum refining	32411
Coal products manufacturing	Rest of 324
Petrochemical manufacturing	32511
Industrial gas manufacturing	32512
Other basic inorganic chemicals manufacturing	32518
Other basic organic chemicals manufacturing	32519
Biodiesel production from canola seed feedstock	
Biodiesel production from soybean feedstock	
Ethanol production from corn feedstock	
Ethanol production from wheat feedstock	
HDRD (or HRD) production from canola seed feedstock	
Renewable gasoline and diesel production	
Cellulosic ethanol production	
Resin and synthetic rubber manufacturing	3252
Fertilizer manufacturing	32531
Other chemicals manufacturing	Rest of 325
Plastics manufacturing	326
Cement manufacturing	32731
Lime and gypsum manufacturing	3274
Other non-metallic mineral products	Rest of 327
Iron and steel mills and ferro-alloy manufacturing	3311
Electric-arc steel manufacturing	
Steel product manufacturing from purchased steel	3312
Alumina and aluminum production and processing	3313
Other primary metals manufacturing	3314
Foundries	3315
Fabricated metal product manufacturing	332
Machinery manufacturing	333
Computer, electronic product and equipment, appliance and component manufacturing	334 and 335
Transportation equipment manufacturing	336
Other manufacturing	Rest of 31-33
Wholesale and retail trade	41-45

Sector name	NAICS code
Air transportation	481
Rail transportation	482
Water transportation	483
Truck transportation	484
Transit and ground passenger transportation	485
Pipeline transportation of crude oil	4861 and 4869
Pipeline transportation of natural gas	4862
Other transportation, excluding warehousing and storage	4867-492
Landfills	Part of 562
Services	Rest of 51-91

Table 56: Covered fuels

Fuel
Fossil fuels
Coal
Coke oven gas
Coke
Natural gas
Natural gas liquids
Gasoline and diesel
Heavy fuel oil
Still gas
Electricity
Electricity
Hydrogen
Steam methane reformation
Steam methane reformation with carbon capture
Electricity
Renewable fuels (non-transportation)
Spent pulping liquor
Wood
Wood waste (in industry)
Renewable natural gas
Renewable fuels (transportation)
Ethanol produced from corn
Ethanol produced from wheat
Cellulosic ethanol
Biodiesel produced from canola
Biodiesel produced from soy
Hydrogenated renewable diesel (HDRD)
Renewable gasoline and diesel from pyrolysis of biomass
Renewable natural gas

Table 57: Covered end-uses

End use
Stationary industrial energy/emissions sources
Fossil-fuel electricity generation
Process heat for industry
Process heat for cement and lime manufacturing
Heat (in remote areas without access to natural gas)
Cogeneration
Compression for natural gas production and pipelines
Large compression for LNG production
Electric motors (in industry)
Other electricity consumption
Transportation
Air travel
Buses
Rail transport
Light rail for personal transport
Marine transport
Light-duty vehicles
Trucking freight
Off-road vehicles
Diesel services (for simulating biodiesel and other renewable diesel options)
Gasoline services (for simulating ethanol options)
Oil and gas fugitives
Formation CO2 removal from natural gas processing
Flaring in areas close to natural gas pipelines
Flaring in areas far from natural gas pipelines
Venting and leaks of methane (oil and gas sector)
Industrial process
Mineral product GHG emissions
Aluminum electrolysis
Metallurgical coke consumption in steel production
Hydrogen production for petroleum refining and chemicals manufacturing
Non-fuel consumption of energy in chemicals manufacturing
Nitric acid production
Agriculture
Process CH4 for which no know abatement option is available (enteric fermentation)
Manure management
Agricultural soils
Waste

End use
Landfill gas management
Residential buildings
Single family detached shells
Single family attached shells
Apartment shells
Heat load
Furnaces
Air conditioning
Lighting
Dishwashers
Clothes washers
Clothes dryers
Ranges
Faucet use of hot water
Refrigerators
Freezers
Hot water
Other appliances
Commercial buildings
Food retail shells
Office building shells
Non-food retail shells
Educational shells
Warehouses (shells)
Other commercial shells
Commercial heat load
Commercial hot water
Commercial lighting
Commercial air conditioning
Auxiliary equipment
Auxiliary motors (in commercial buildings)

Appendix D: List of covered fuels, sectors, and end-uses in IESD

This Appendix lists all generation and storage technologies available in IESD across Canada and the United States.

Table 58: Generation technologies available in IESD

Generation Technologies
Diesel
Coal
Petroleum coke
Single cycle gas turbine
Combined cycle gas turbine
Fossil fuel with carbon capture and storage
Oxy-combustion turbine power plants
Cogeneration
Biomass
Geothermal
Large hydro
Run-of-river hydro
Tidal
Solar
Onshore wind
Offshore wind
Nuclear
Small modular nuclear reactor
Biomass

Table 59: Storage technologies available in IESD

Storage Technologies
Flow battery
Lithium-ion battery
Seasonal storage using hydrogen

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