Pathways to Net-Zero Electricity in Alberta Under Alternative Policy Scenarios

by

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Abstract

Canada has set a goal to reach net-zero electricity. For Alberta, this remains a significant challenge. Although Alberta has achieved considerable greenhouse gas (GHG) reductions by eliminating coal and expanding its renewable fleet, a unique electricity market and the dominance of natural gas-fired generation, which accounted for over 80% of generation in 2023, has created uncertainty surrounding transition timelines and feasibility. Policies including provincial carbon pricing and carbon credit generation, federal investment tax credits to reduce the cost of low GHG projects, and a draft federal standard to limit annual GHG emissions from fossil fuel plants, will impact future electricity supply. This work uses a long-term capacity expansion and dispatch model to assess how alternative policies could shape Alberta's pathway to net-zero electricity between 2023 and 2045 within its competitive market. Results show a 75% GHG reduction by 2030 as a result of existing GHG policies. Scenarios project that tripling Alberta's 2024 wind capacity, retrofitting 75% of existing combined-cycle gas units with carbon capture, and low-use dispatchable thermal generation could enable annual GHG emissions of less than 3 Mt_{CO2e} by 2035. Draft federal standards could enable further reductions to 1 Mt_{CO2e} of annual GHG emissions by 2045. With electricity GHG emissions down from 29 Mt_{CO2e} in 2020, the goal of net-zero could be within reach. The timing and capacity of new wind and carbon capture retrofits was dependent on the value of carbon credits, removing carbon credits entirely may increase cumulative GHG emissions by 142 Mt_{CO2e}. Overall, modelling suggests existing technology can be deployed at rates already seen in Alberta to approach net-zero, but GHG reductions depend on the policy framework over the coming decades.

Preface

This research is an original work by Jessica Van Os, under the supervision of Dr. Tim Weis and Dr. John Doucette from the Department of Mechanical Engineering at the University of Alberta. Work was conducted within a research group led by Dr. Tim Weis and Dr. Andrew Leach who is cross appointed in the Department of Economics and Law. The Aurora electricity model used for this thesis was built off the work of previous students in this group including Kayla Lund, Calder Watrich, Natalia Vergara Bonilla, William Noel, Gloria Duran Castillo, and Taylor Pawlenchuk. Hydrogen fuel prices were calculated by Gloria Duran Castillo and the methodology adopted for wind energy output curves was originally presented by Natalia Vergara Bonilla. Significant changes were made to the model and input data for this thesis, as discussed in Chapter 3.

An earlier iteration of this model was used to provide results for a collaborative project with the Pembina Institute who published a 2023 report titled *Zeroing In: Pathways to an Affordable Net-Zero Grid in Alberta*. Results from the Pembina Institute collaboration are not included in Chapters 4 and 5, but some modelling inputs such as new wind and solar costs have remained unchanged.

Chapter 4 of this thesis is a paper which will be submitted for peer review and was co-authored by Dr. Tim Weis and Dr. Andrew Leach. It is included based on the initial version in June 2024.

Acknowledgements

These last two years have been transformational, and I am extremely grateful for the mentorship, opportunities, and field trips down the QEII that Dr. Tim Weis and Dr. Andrew Leach have provided me with. Their guidance and knowledge has been invaluable.

I also want to thank my family, friends, and partner for supporting me through the highs and lows of graduate school and enriching my life with laughter and memorable experiences that did not involve graphs. Without their love and patience, I would surely not be the person I am today. To my mom, thank you for telling me "you'll get it done", even when you had no idea what it was I had to get done. I got it done.

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Abbreviations

AB Alberta.

AESO Alberta Electric System Operator.

AIES Alberta Interconnected Electric System.

AIL Alberta Internal Load.

BESS Battery Energy Storage System.

BTF Behind-the-Fence.

CAES Compressed-Air Energy System.

CCS Carbon Capture and Storage.

CCUS Carbon Capture Utilization and Storage.

COPPER Canadian Opportunities for Planning and Production of Electricity Resources.

CREST Canadian Renewable Electricity Storage and Transmission Model.

DER Distributed Energy Resource.

Draft CER Draft Clean Electricity Regulations.

DSM Demand-Side Management.

E2020 Energy 2020.

E3MC Canada's Energy, Emissions and Economy Model.

ECCC Environment and Climate Change Canada.

EPCs Emissions Performance Credits.

FOM Fixed Operations and Maintenance.

FOR Forced Outage Rate.

GHG Greenhouse Gas.

H2SC Hydrogen Simple-Cycle.

HPB High-Performance Benchmark.

IEA International Energy Association.

IRA Inflation Reduction Act.

ITCs Investment Tax Credits.

LCOE Levelized Cost of Energy.

MAPLET-PS Market Penetration Modelling of Renewable Energy Technologies in Electric Power Sector.

MIP Mixed Integer Programming.

NGCC Natural Gas Combined-Cycle.

NGCC+CCUS Natural Gas Combined-Cycle with Carbon Capture Utilization and Storage.

NGConv Coal-to-Gas Converted Unit.

NGSC Natural Gas Simple-Cycle.

NPV Net Present Value.

NREL National Renewable Energy Laboratory.

PHS Pumped-Storage Hydroelectricity.

PTCs Production Tax Credits.

PV Photovoltaic.

RES Renewable Energy Sources.

SILVER Strategic Integration of Large-capacity Variable Energy Resources.

SMP System Marginal Price.

SMR Small Modular Reactor.

TIER Technology Innovation and Emissions Reduction.

VOM Variable Operations and Maintenance.

WECC Western Electricity Coordinating Council.

WECC ADS WECC Anchor Data Set.

Chapter 1

Introduction

Reaching net-zero greenhouse gas (GHG) emissions has quickly become a pivotal focus of the early twenty-first century. As the long-forewarned effects of climate change unfold [1, 2] and the reality of global agreements made by previous governments creep in [3], forming credible net-zero pathways has become increasingly important to policy makers and citizens. Cross-sectoral net-zero strategies presented by governments and organizations such as the International Energy Association (IEA) have consistently put the need for an expanded role of a low-carbon electricity sector front and centre in addition to increased energy efficiency, electrification, and the adoption of clean energy technologies across all sectors [4]. In response to rising GHG emissions and commitment to the Paris accord [5], both Canada and Alberta have established economy wide net-zero by 2050 targets [6, 7]. Canada has stated that decarbonizing electricity systems will play an important role in achieving a net-zero economy [8]. Furthermore, expedited decarbonization of the electricity sector would benefit the overall transition by directly reducing emissions while also ensuring a supply of low-carbon electricity to enable other industries decarbonization strategies. To achieve net-zero in the electricity sector, a variety of policy levers are available including direct subsidies, tax incentives, supportive market regulations, carbon pricing, and/or performance standards [9]. Implementing supportive policy on a national or sub-national level may assist the speed and cost of net-zero, but impacts can be difficult to quantify. Optimization modelling can be used to assess the impact of alternative policies and technology choices by forecasting changes to electricity systems and reporting outcomes including capacity additions, generation, and GHG emissions. This research uses a capacity expansion optimization model to forecast the evolution of Alberta's electricity system under alternative policy scenarios in the context of transitioning to net-zero in the coming decades.

1.1 Background

1.1.1 Canadian Electricity GHG Emissions

Climate change is directly correlated to increased GHG concentrations; the most prominent being carbon dioxide (CO_2), which has seen an approximate increase from 278 ppm in 1750 to 417 ppm in 2022 [10]. As global warming progresses the dangerous effects of climate change are expedited; including more frequent extreme weather events, rising sea levels, and a loss of biodiversity, which directly impacts human health, food security, habitable land, economic growth, poverty rates, and more [11]. The mid-century mark targeted by the Paris Agreement for economies to reduce greenhouse gas emissions is quickly approaching, and in response many countries have put forth net-zero commitments [12] in an effort to limit global warming to 2°C above pre-industrial levels, with the fleeting ambition to remain below 1.5°C (Article 2) [5]. Net-zero emissions is loosely defined in the Paris Agreement as a balance between anthropogenic GHG emissions and captured emissions [5]. The key is that once net-zero anthropogenic emissions is achieved, atmospheric GHG concentrations should be constant or decline over time, minimizing future risk. Unfortunately, reaching net-zero does not undo all of the cumulative damage caused by climate change over time. Thus, climate damage is dependent on emission reduction pathways [13] and there is an urgency to reduce emissions as rapidly as possible.

In 2021, Canada legislated global commitment to net-zero by 2050 through the

Canadian Net-Zero Emissions Accountability Act [6]. The *2030 Emissions Reduction Plan* was released soon after, with new milestones included to reduce economy-wide emissions 40 - 45%[1] below 2005 levels by 2030. As part of this strategy, Canada announced a clean electricity regulation meant to support the transition towards a net-zero electricity system by 2035 [15]. This was followed by the publication of draft performance based Clean Electricity Regulations in August of 2023 [8] with development ongoing [16]. While Canada's overall GHG emissions have only slowly started to decrease, Figure 1.1 shows electricity sector GHG emissions have been cut in half since 2005. This stems from the fact that coal has been nearly phased out and around 84% of the country's electricity is now generated carbon free [17]. Despite this progress, the majority of electricity GHG emissions can be attributed to only a few provinces, Alberta being the main one.

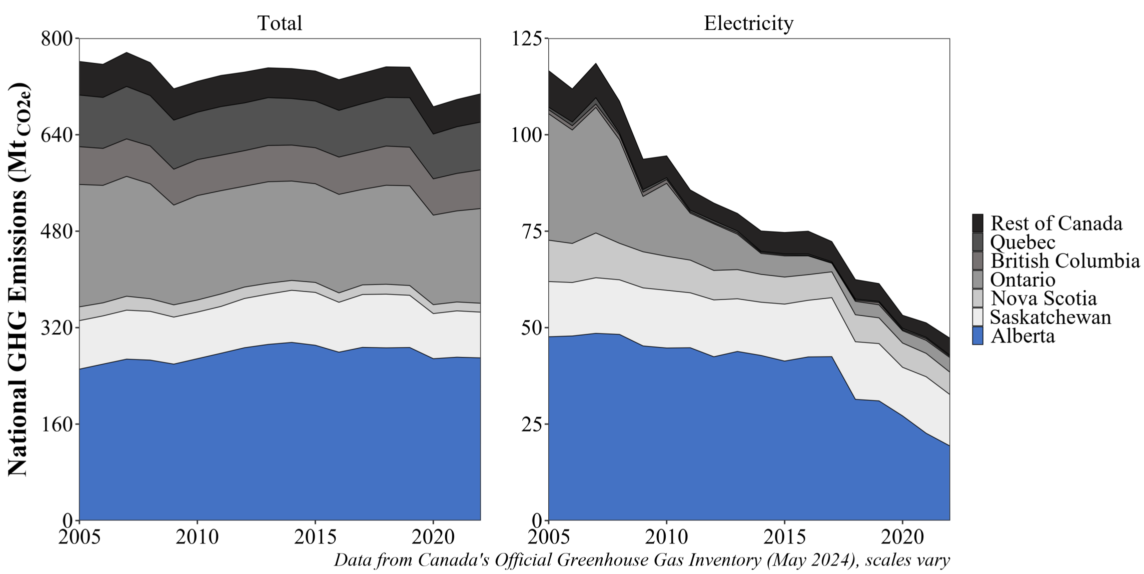


Figure 1.1: Total GHG emissions and electricity sector GHG emissions in Canada, separated by province.

Although Alberta has also cut electricity GHG emissions in half since 2005, it remains the largest source of electricity GHG emissions in Canada. Less than 20% of Alberta's electricity was generated from renewable sources in 2023 [18], while the

[1]Previous targets announced in 2015 aimed for emission reductions of 30% below 2005 levels by 2030 [14]. This new strengthened plan was announced in 2022.

majority of was sourced from the combustion of fossil fuels (predominately natural gas). The province is also Canada's largest overall emitter, largely fueled by industrial activity in the oil and gas sector. In 2022 Canada's official greenhouse gas inventory reported that Alberta was responsible for a disproportionate 38% (270 Mt_{CO2e}) of Canada's total 708 Mt_{CO2e} emissions [19], despite only housing 10% of the country's population. Decarbonizing Alberta's electricity sector is an important part of reducing the provinces overall GHG emissions and possibly enabling future GHG reductions in the emissions intensive oil and gas sector.

1.1.2 Moving to Net-Zero Electricity: Policy and Challenges

There are several existing technologies, funding mechanisms, and policies available to support a net-zero electricity transition. Since 2015, Alberta has seen a shift in its capacity mix with the growth of wind and solar alongside the decline of coal, shown in Figure 1.2. According to the Canadian Renewable Energy Association, Alberta accounted for 92% of Canada's renewable energy and storage growth in 2023 [20]. However, Alberta's natural gas fleet has also been growing, driven by a combination of new projects and coal-fired units converting to natural gas. In addition, factors related to industrial load, relatively small inter-provincial connections, and a competitive energy only market differentiate Alberta from many other regions. So although the province's electricity system is decarbonizing, consistent and substantial changes will be required to meet a net-zero goal.

Changes require investment. In the 2023 federal budget, Canada introduced a collection of financial incentives totaling over $40 billion to facilitate emission reductions in the electricity sector [21]. Incentives include low-cost financing, focused energy programs, and investment tax credits (ITCs) for eligible projects. Low or non-emitting energy projects including wind, solar, geothermal, storage, hydro, nuclear, hydrogen, carbon capture utilization and storage, and transmission are eligible to receive

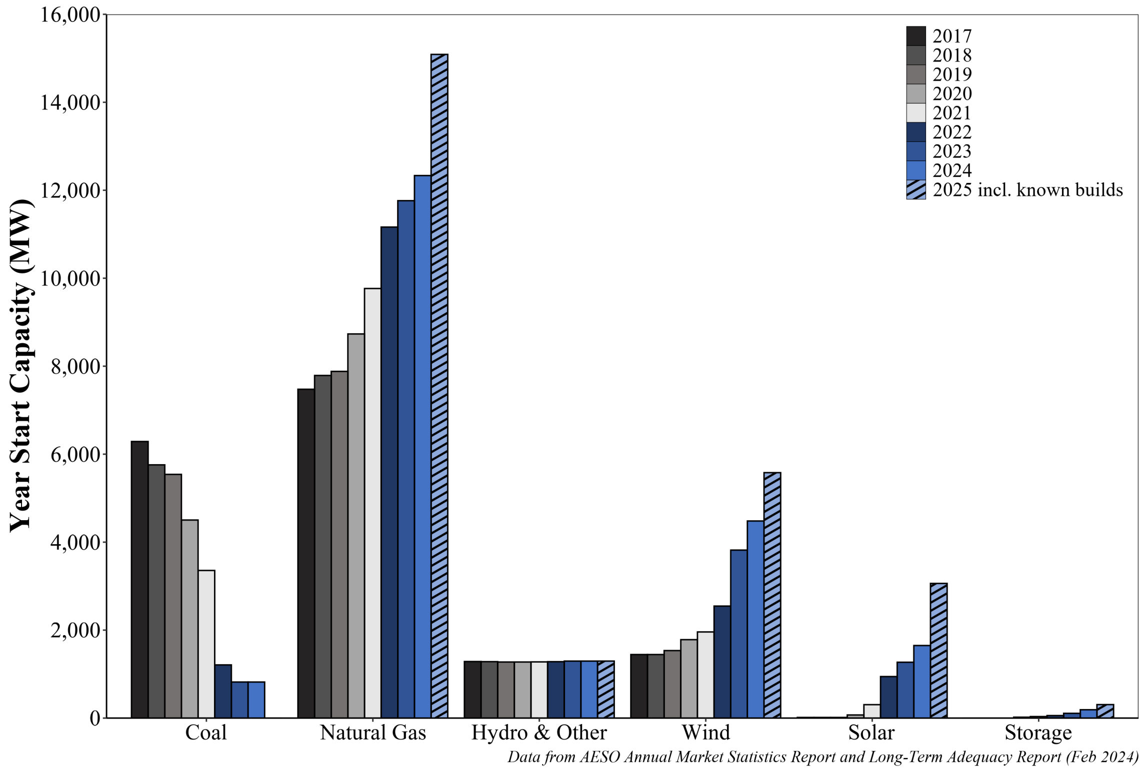


Figure 1.2: Total electricity generating capacity in Alberta at the start of each year since 2017.

refundable ITCs which effectively lower upfront capital costs[2]. Additional targeted federal funding and programs are available for remote communities and micro-scale projects. Some individual provinces also have grants or programs to support clean energy innovation and development. For instance, in 2024, Alberta is expected to announce the details of a grant program to support carbon capture, utilization and storage (CCUS) projects [22].

Climate policies are another way to drive decarbonization. Policy can help provide investment certainty and incentivize GHG emissions reductions. Some key Canadian policies that impact electricity emissions include a 2030 coal phase-out plan, natural

[2]Major electricity sector ITCs highlighted in Canada's 2022 and 2023 federal budget [21] include the Clean Technology Investment Tax Credit (30%), Clean Electricity Investment Tax Credit (15%), Clean Hydrogen Investment Tax Credit (15 - 40%), and Carbon Capture, Utilization, and Storage Investment Tax Credit (25 - 50%). The majority of ITC eligibility periods begin in 2023 and extend to 2034 with a phase out period beginning in 2032. The Carbon Capture, Utilization, and Storage Investment Tax Credit is an exception to this, extending till 2040.

gas generation regulations, and a carbon pricing system [23]. Many provinces have their own versions of these policies which must be equivalent to federal programs. Alberta uses its own provincial carbon pricing system called the Technology Innovation and Emissions Reduction (TIER) Regulation instead of the federal Output-Based Pricing System (OBPS). The systems are applied in slightly different ways but adhere to equivalent carbon price and schedule of increase. Alberta also initiated its own coal phase-out plan in 2015 which is on track for completion six years ahead of federal and provincial targets [24].

Additional policy is being implemented at the national level to support Canada's electricity GHG emissions targets, most notably federal draft Clean Electricity Regulations (CER) [25]. The draft regulations include a stringent performance standard that would require fossil fuel generation to either operate infrequently, retrofit with carbon capture, switch to clean fuels, or retire. The standards apply to all fossil fuel units that are (i) greater than 25 MW, (ii) following North American Electric Reliability Corporation Standards, and (iii) net exporters of electricity. In Alberta, there has been pushback and uncertainty surrounding timelines, flexibilities, and costs that accompany the draft electricity regulations [26]. Some of these concerns may be addressed in the final iteration of the regulation, which will consider modifications to increase flexibility surrounding GHG emissions limits [16].

1.2 Motivation

The pace and even possibility of a net-zero electricity transition in Alberta has been highly debated in public and political arenas and the impact of existing policies including the draft CER on Alberta's supply mix is uncertain. To reach national and provincial commitments, Alberta's electricity system must achieve net-zero emissions by at least 2050. However, because almost 80% of Alberta's electricity generation was supplied by emitting technologies in 2023 [18], significant transformation will be required to decarbonize Alberta's electricity system.

Long-term modelling supports decarbonization pathways by informing policy makers, stakeholders, and academics on the effectiveness of different policies and the impact of different variables in reaching net-zero. Scenario modelling is also useful to examine the impact of different features in comparable markets. Using an optimization model, this work considers how new and existing policies could impact annual capacity changes, generation, GHG emissions, and costs during Alberta's transition to net-zero GHG emissions. Further analysis was presented to examine GHG emissions outcomes under variations of Alberta's provincial carbon pricing and credit system.

1.3 Thesis Overview

This thesis is made up of six chapters, including the introduction. Chapter 2 contextualizes research with foundational knowledge on Alberta's current electricity system, supply side net-zero strategies, and capacity expansion modelling. The chapter is concluded with a review of some existing Canadian electricity models, highlighting implications for Alberta. Chapter 3 includes a methodology and overview of key model inputs. Chapter 4 is a paper that will be submitted for peer review which explores net-zero electricity pathways for Alberta under current policy and the draft Clean Electricity Regulations. Chapter 5 complements the results presented in Chapter 4 by further exploring how Alberta's industrial carbon pricing system and carbon capture utilization and storage could impact GHG emissions reductions. Finally, Chapter 6 ties everything together by summarizing key findings and areas for future work.

Chapter 2

Literature Review

2.1 Alberta's Electricity System

This section provides an overview of Alberta's electricity system, including generation, load, market structure, and provincial carbon policy.

2.1.1 Generation and Load

Before exploring decarbonization pathway modelling for Alberta's electricity system, it is important to build an understanding of the current market structure and generation trends. From Section 1.1, it is clear that Alberta's electricity system is undergoing major change. The transformation from a coal based system throughout the early 2000's, towards a natural gas dominated system with an increasing penetration of renewable energy can be seen in Figure 2.1. The Alberta Electric System Operator (AESO) *2023 Annual Market Statistics Report* [18] indicated that renewable sources including wind, solar, hydro, and biomass[3] generated approximately 19% of Alberta's total electricity in 2023, up from only 10% in 2019. From the start of 2018 to the start of 2024, Alberta added around 1.8 GW of solar and 3.2 GW of wind energy [27] to a 20.7 GW system (end of 2023). Recent growth of wind and solar, can be attributed to a combination of factors including cost reductions, corporate power purchase agree-

[3]Biomass is the main component of technologies categorized as "other" by the AESO. The remainder of "other" plants are waste heat facilities, with exception for one geothermal/natural-gas plant. The "other" group is responsible for less than 3% of annual generation [27].

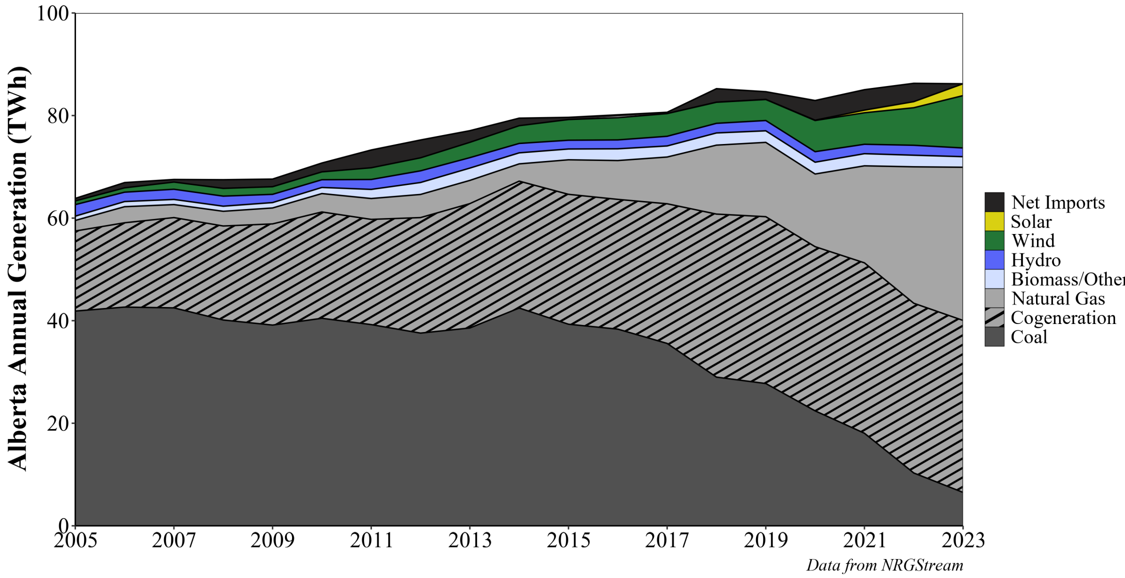


Figure 2.1: Total annual electricity generation in Alberta since 2005

ments, and favorable policies that recognize their environmental benefits. Annual generation from biomass and hydro plants has remained consistent since 2011.

Recently, Alberta has been a net energy importer rather than exporter, as shown in Figure 2.1. Interties connect British Columbia, Saskatchewan, and Montana to the Alberta Interconnected Electric System (AIES) with a transfer capacity of 1263 MW [28]. The actual transfer capacity available is often much lower than the rated capacity, due to reliability regulations and the availability of British Columbia's hydro reserves. This means Alberta is somewhat isolated, with relatively small intertie capabilities relative to provincial load, placing a reliance on provincial generation to meet demand.

Coal generation has declined from 50% of total annual generation in 2015 to only 8% in 2023. The combination of new capacity and coal plant conversions has led to natural gas growing quickly, with pure-gas generation supplying 69% of the total generation in 2023 [18]. Just over 50% of natural gas generation is provided by cogeneration technology, the other half of Alberta's gas generation comes from combined-cycle, gas-fired-steam, duel-fuel, and simple-cycle units. Gas-fired steam and the single duel-fuel unit remaining are remnants of Alberta's coal era, as many coal plants have switched to natural gas fuel. Figure 2.2 breaks down Alberta's total gas generation since 2015 by technology and the type of load served.

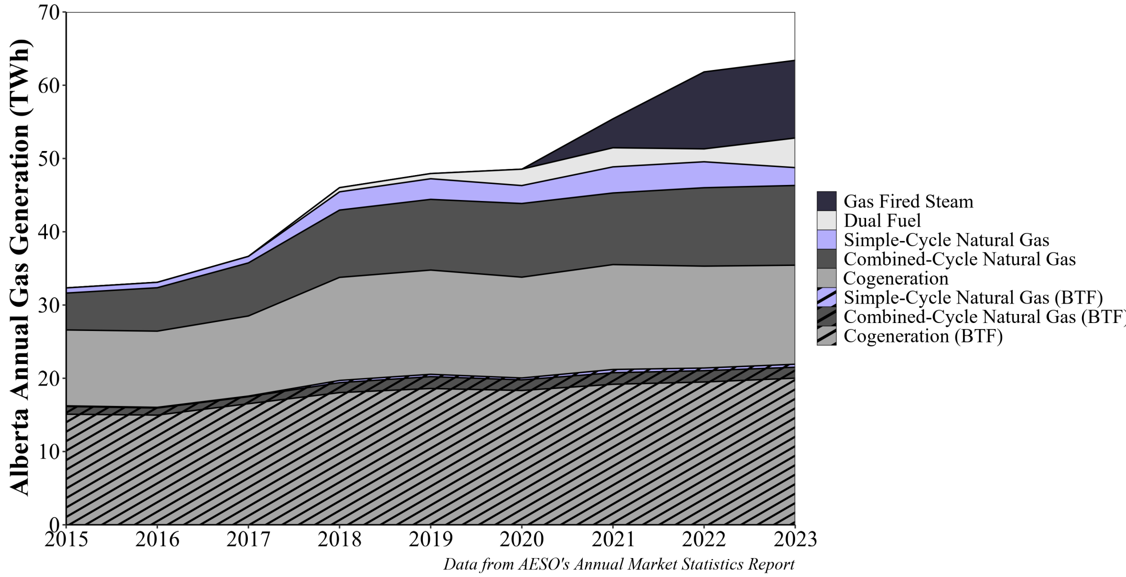


Figure 2.2: Annual natural gas electricity generation in Alberta, separated by behind-the-fence and system generation.

The energy in Figures 2.1 and 2.2, represents total annual generation; this is inclusive of all generation needed to meet Alberta Internal Load (AIL). Alberta has a strong industrial sector, mainly driven by the oil-sands, that requires significant amounts of electricity every hour. Many industrial sites also require steam (or usable heat) which is generated by burning fossil fuels. As a result, some operations have installed cogeneration plants, which can generate both heat and electricity in a single thermodynamic cycle. Electricity generated by cogeneration plants can be used on-site at the facilities or sold to the electricity grid. The portion of Alberta's load that is self supplied by on-site facilities is known as "behind-the-fence" (BTF) load. The majority of BTF load is met by natural gas generation, with a small fraction (<6%) met by other technologies. Remaining provincial load is called "system load", and it is comprised of additional industrial, residential, and commercial demand. The total load, known as Alberta Internal Load (AIL), is the sum of BTF and system load. In 2023, BTF load was 25.4 TWh, accounting for 29% of the 86.3 TWh total load [18].

Considerable industrial load in combination with northern geography leads to a distinctive hourly load profile in Alberta. Since many industrial facilities operate around the clock, Alberta experiences a less volatile load profile than some other regions. In addition, peak load has historically been set in winter during extreme cold snaps. For instance, in 2023 peak winter load reached 12,384 MW, relative to an average annual load of 9,851 MW [18]. With rising summer temperatures and an increase in air conditioning, this trend has been rivaled in recent years, resulting in peak load conditions during temperature extremes in both winter and summer. Alberta can experience tight supply conditions during extreme weather in either season. Natural gas plants are more likely to trip offline in winter but suffer a thermal de-rate during summer, while wind plants can face operational challenges such as blade icing during extremely cold temperatures [29].

2.1.2 Market

In general, electricity markets consist of four main elements: generation, transmission, distribution, and retail. For the majority of Canadian provinces, most of these elements are owned and operated by a single entity, and utility rates are based on the cost of providing service. This structure is known as a regulated or vertically integrated market. The alternative to a regulated market is a deregulated market, where private entities in one or more of the four elements compete to provide services. In Alberta, both the wholesale generation and retail markets are competitive[4], while the transmission and distribution systems are regulated. The wholesale market is managed by an independent body known as the Alberta Electric System Operator (AESO). The AESO is also responsible for grid operation, system planning, connecting generation assets to the grid, and long-term transmission expansion planning under Alberta's Transmission Regulation [31]. The regulation implies that transmission should be built to support new generation projects once they receive regulatory

[4]Although Alberta operates a competitive retail market, there is a default regulated rate option available to residential customers [30].

approval, with the goal of preventing transmission congestion. This unconstrained approach to transmission supports entrance into the competitive wholesale market.

Alberta's wholesale market is unique within Canada, since generators are only paid for energy they supply, this is known as an "energy-only" market. A separate ancillary services market is also operated to support grid stability. Some other approaches to electricity markets include an additional feature known as a capacity market. In a capacity market generators are also paid for having the ability to provide electricity, this ensures resource adequacy. Alberta's energy-only market design is predicated on the idea that tight supply conditions will result in high prices which signal the addition of new supply to meet resource adequacy needs. There are few other deregulated energy only markets, with some notable examples including the Electric Reliability Council of Texas and Australia's National Electricity Market. California's market also bears a similar design, although it includes some additional resource adequacy requirements.

Unlike regulated markets where new power plants are procured, power plants built in the decentralized energy only market require two things: (i) private investment and (ii) economic viability. This represents both a challenge and advantage for Alberta's net-zero transition. On one hand, it can be difficult to secure financing if market conditions or policies are uncertain. For example, companies may be hesitant to make major capital investments like carbon capture and storage systems without adequate assurance the investment will pay off. At the same time, the market design allows for quick development and investment based on price signals from the system.

Alberta's wholesale electricity price is determined in real-time by the AESO each hour of the day based on a merit order. Individual power plants submit offers[5] with a value between $0/MWh and $999.99/MWh every hour. The merit order is formed each minute by stacking bids in order from lowest to highest and cumulatively sum-

[5]Each plant has the option to split their capacity into multiple blocks. Up to 7 blocks may be used, each with their own offer price.

ming the accompanying capacity. Plants are then dispatched from lowest to highest offer price until demand is satisfied. Wind and solar are at the bottom end of the merit order since they offer power for $0/MWh, this means they are almost always in the market when resources are available. Plants with higher offer prices are placed farther up the merit order and less likely to be dispatched when demand is low. The final offer required to meet demand becomes the system marginal price for the corresponding minute. An hourly pool price is determined by taking the average system marginal prices over the hour. Each power plant that was deployed is compensated at the hourly pool price for the amount of electricity that it generated (in MWh). Prices may vary drastically throughout a day depending on resource availability, offer behavior, and demand. Over the past 20 years, the average annual wholesale pool price has ranged between $18/MWh - $162/MWh [27]. In theory, this system encourages competitive prices, since power plants must under-bid their competitors to remain in the market each hour. However, this has not always been the case. Market concentration has been shown to heavily influence the bidding of marginal assets, impacting power prices in Alberta [32]. While this behavior is monitored by the Market Surveillance Administrator to avoid anti-competition behavior, it is difficult to include in modelling. This is important to consider when comparing simulated results to historical prices.

2.1.3 Carbon Pricing

Industrial carbon pricing has been the backbone of Alberta's climate policy since its introduction in 2007 [33]. Since its origins, the policy has evolved to its current form, the Technology Innovation and Emissions Reduction (TIER) Regulation [34]. The TIER regulation advances decarbonization in the electricity sector in two ways. First, it makes emissions more expensive. Second, it enables the creation of emissions credits, creating a potential revenue source and incentive for low-emissions generators. Under the TIER regulation, facilities are allocated a quantity of allowable emissions per MWh of electricity generated each year. If emissions exceed the allowable amount, the facility can comply by either: (i) directly paying the industrial carbon price or (ii) purchasing credits from projects that generate credits. If a facilities emissions are lower than their allowable emissions, the facility is eligible to collect emissions performance credits (EPCs).

In the electricity sector, allowable emissions under TIER are determined according to a high-performance benchmark (HPB). The initial TIER HPB for electricity was set to 0.37 $\mathrm{t_{CO2e}}$/MWh to reflect a"good-as-best-gas" standard [35]. In 2023 the benchmark was scheduled to decrease at a linear rate of 2% of 0.37 $\mathrm{t_{CO2e}}$/MWh annually until 2030 [34] to align with further emissions reductions, as shown in Table 2.1. Multiplying the HPB by total electricity generation results in an annual allowable emissions quantity based on electricity generated. These are "free" emissions. Actual power plant emissions can be modelled as a product of plant heat rate, fuel emissions intensity, and electricity generated. Thus, the total carbon cost is the difference between total emissions and allowable emissions multiplied by carbon price, as shown in Equation 2.1. For a zero-emissions or low-emitting facility, the process remains the same, but a negative cost represents the rate at which emissions performance credits may be produced.

$$C_E = (E)(C_C)[HR(e_{fuel}) - HPB_E)] \tag{2.1}$$

Where,

C_E = emissions cost ($)
E = electricity produced (MWh)
C_C = carbon Cost ($/$\mathrm{t_{CO2e}}$)
HR = heat rate (GJ/MWh)
e_{fuel} = fuel emissions intensity ($\mathrm{t_{CO2e}}$/GJ)
HPB_E = electricity high-performance benchmark ($\mathrm{t_{CO2e}}$/MWh)

For a power plant with a high heat rate (or low efficiency) and/or an emissions insensitive fuel, the cost of carbon is higher than it would be for better performing facilities. For example, in 2024 at a carbon price of $80/$t_{CO2e}$, a typical coal plant emitting 1 t_{CO2e}/MWh would be required to pay $51.58/MWh. In comparison, a highly efficient combined-cycle natural gas plant emitting 0.37 t_{CO2e}/MWh would only pay $1.18/MWh. Meanwhile, a wind farm would be able to generate EPCs at a rate of 0.3552 t_{CO2e}/MWh amounting to a maximum value of $28.42/MWh if sold at $80/$t_{CO2e}$[6]. As the HPB decreases, emitting facilities exposure to carbon price increases while low emitting plants ability to generate credits is reduced. If facilities are not able to reduce their emissions intensity, the total cost of emissions will also increase.

Since cogeneration facilities benefit from the added efficiency of producing multiple products at once, their allowable emissions calculation is more complex, including performance benchmarks from multiple sectors. Cogeneration plants have lower emissions associated with electricity production than natural gas power plants, which means that while the HPB resembles combined-cycle emissions rates, some cogeneration plants can generate credits. The ability for cogeneration to produce EPCs will dissolve over time as benchmarks are tightened.

Renewable energy projects in Alberta may choose between collecting emissions performance credits or an alternative process of creating offset credits. Offset credits operate in a similar fashion to emissions performance credits but use a different grid factor called the Electricity Grid Displacement Factor (EGDF). The EGDF is meant to represent displaced emissions by renewable generation and is a vestige of the policy that pre-dates TIER which did not allow renewable energy to generate EPCs. Renewable energy projects are eligible to receive offsets for up to 15 years (10 years plus an additional 5 years following a project review) [36]. Once this period ends, projects may generate emissions performance credits as previously discussed. As shown in Table 2.1, the EGDF and the HPB for electricity are expected to converge by the year

[6] Generally EPCs would be sold for less than the annual carbon price, however EPCs may be held for sale in future years.

Table 2.1: Provincially outlined Electricity Grid Displacement Factor (EGDF), High Performance Benchmark (HPB), and carbon price until 2030.

Year	**EGDF (t_{CO2e}/MWh)**	**HPB (t_{CO2e}/MWh)**	**Carbon Price (\$/t_{CO2e})**
2023	0.5200	0.3626	65
2024	0.4901	0.3552	80
2025	0.4602	0.3478	95
2026	0.4303	0.3404	110
2027	0.4005	0.3330	125
2028	0.3706	0.3256	140
2029	0.3407	0.3182	155
2030	0.3108	0.3108	170

2030, thus ending the offset program. As both benchmarks decrease, the quantity of credits available to low-emissions generation will also decrease.

Both offsets and EPCs may be purchased by cross-sectoral industrial emitters to comply with the TIER regulation, however the value of these credits is limited by carbon price in a given year. This is because emitters have the option to directly pay the carbon price, so credits must be sold for less to remain competitive. Although sale prices are not publicly available, it is expected that the value of credits depends on market saturation. In a scenario with excess credits, competitive prices would likely be lower. The value of credits could also be lower if other sectors are able to reduce emissions quicker than benchmarks are tightened, which would decrease the total demand for credits.

Carbon Policy Versus the Draft CER

It is worth noting the difference between Alberta's existing carbon pricing system and the draft CER. Although both policies target the same result, emissions reductions, they approach the subject in different ways. Alberta's carbon pricing framework rewards low-emissions generation and in doing so leaves tangible emissions reductions to economics and the choices of market actors. In comparison, the draft CER is a policy rooted in the legal system that restricts power plant emissions based on a strict annual emissions intensity performance standard of 0.03 t_{CO2e}/MWh. Alternatively, the draft CER allows plants to operate for up to 450 hours per year, as long as annual emissions do not exceed 150 t_{CO2e}/year [8]. The draft CER does not impact existing carbon price systems or carbon exposure. Instead, to comply with the regulation, operators must make emissions reductions in line with the performance standards. Since carbon pricing and the draft CER work in different ways, there is potential for interactions which could impact emission reductions and electricity supply. Scenarios presented in Chapters 4 and 5 explore how existing policy and the draft CER impact technology choices and decarbonization pathways for Alberta.

2.2 Transitioning to Net-Zero Electricity

This section provides an overview of existing supply solutions and policy levers that could play a role in modelling Alberta's net-zero electricity transition. Section 2.2.1 provides an overview of wind and solar energy potential in Alberta and considers challenges associated with integrating renewable resources into the existing competitive electricity market. Section 2.2.2 explores how dispatchable power could support the integration of wind and solar resources and potentially lower net-zero transition costs. Section 2.2.3 discusses how tax credits included in the United States 2022 Inflation Reduction Act (IRA) could influence net-zero electricity supply pathways. A comparison between American and Albertan credit opportunities for low-emitting generation identifies similarities and differences, reflecting on how similar policies could impact supply pathways in Alberta.

2.2.1 Expanding Wind and Solar

Many forecasts expect wind and solar to play an important role in future net-zero electricity systems. Data from the U.S. Energy Information Administration expects

58% (36.4 GW) of new electricity generating capacity in the U.S. to be solar and 13% (8.2 GW) to be wind in 2024 [37]. This sentiment is echoed in U.S. forecasting results presented by Bistline et al. which expect solar and wind to lead capacity additions in the United States between 2022 and 2035 [38]. Wind and solar energy provide an emissions-free source of power with no fuel cost and low operating costs once developed. In addition, the declining cost of wind and solar [39] has enabled these technologies to achieve a levelized cost of energy (LCOE) that is competitive with conventional gas or coal generation [40].

At the start of 2024, Alberta's solar fleet represented 35% (1.6 GW) of Canada's installed solar capacity. Likewise, 26% (4.5 GW) of Canada's wind capacity was housed in Alberta [20]. The capacity of wind and solar in Alberta is likely to continue growing based on the AESO's project connection queue, which shows new projects at various stages of development [41]. As shown in Figure 2.3, more than 3 GW of additional wind and solar were under construction as of May 2024. The AESO

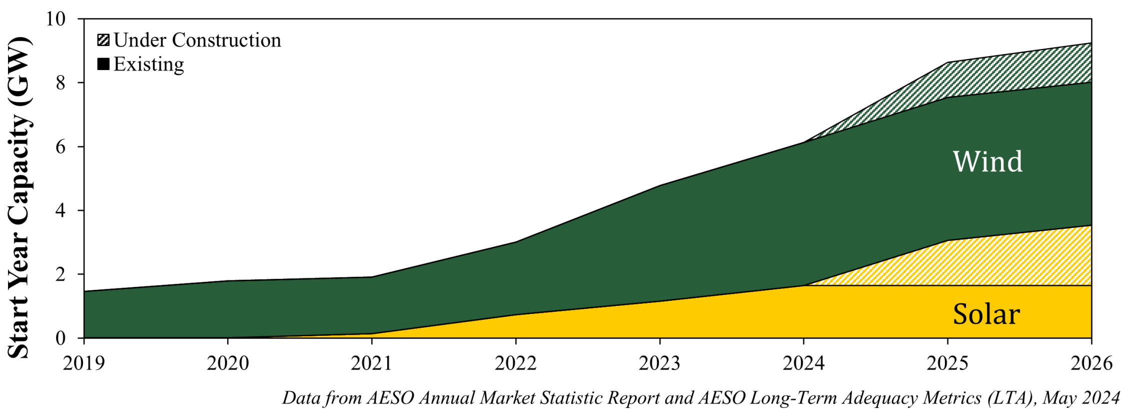
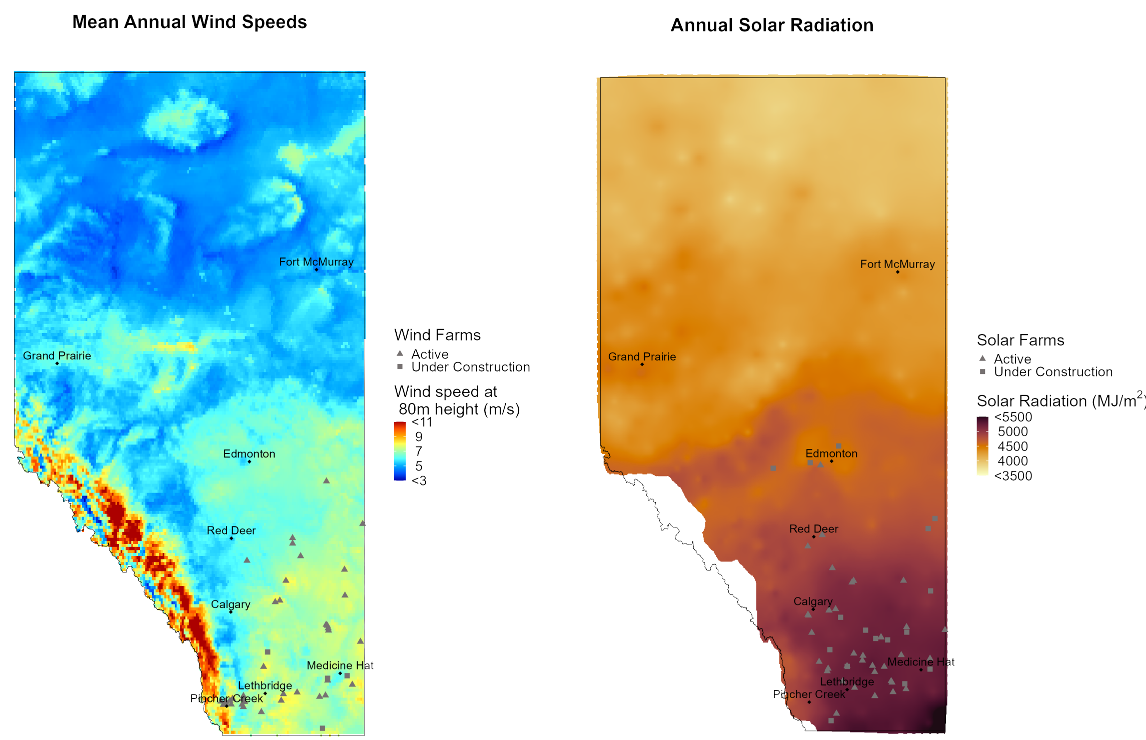


Figure 2.3: Recent growth and projected near-term wind and solar capacity in Alberta based on projects currently under construction.

project queue [41] and *Long-Term Adequacy Metrics* (LTA) report [42] show over 25 GW of potential wind and solar capacity at various stages of planning. While not all proposed projects eventually get completed, this number suggest there continues to be significant interest and available resources for further wind and solar expansion in the province.

Alberta has good potential for wind and solar generation, particularly in the southern tip of the province, as shown in Figure 2.4. The majority of Alberta's existing wind and solar have been located in these regions to maximize power potential. However, there is some location based political uncertainty surrounding new wind and solar plants in some of these prime locations. Midway through 2023, the Alberta government announced a moratorium halting new wind and solar project approvals in the province. The decision cited concerns related to reliability, reclamation, and visual landscapes [43]. This has since been followed up by proposed rules that would limit viable locations for new projects [44]. The long-term impact of these decisions is largely unknown and final location-based constraints could influence net-zero pathways for Alberta.



Wind speeds based on data from the Canadian Wind Atlas [45] and solar radiation data from the Alberta government [46] spanning 1971-2000, gaps represent areas with no data.

Figure 2.4: Map of wind and solar resources in Alberta.

Despite the benefits of wind and solar, there are challenges associated with a growing variable renewable fleet. Wind and solar plants are location constrained and weather dependent, meaning the expansion of these resources requires adequate transmission and dispatchable capacity to maintain adequate electricity supply. As a result, many papers have been written on the challenges associated with a high level of variable renewable integration in power systems [47] and the achievable penetration rate of these technologies. Research conducted by Jacobson et al. has gone so far as to claim that all electricity needs could be met by wind, water, solar, and storage only [48, 49]. Jacobson's work has been criticized by some other authors like Clack et.al., who have identified feasibility challenges, modelling errors, and inadequate representation of variable wind and solar output [50].

As shares of variable renewable output grow, additional market and system considerations arise. High penetrations of wind and solar energy have been shown to decrease electricity prices and increase system volatility [51]. Since they have no fuel cost or ability to store energy, wind and solar offer power at a price of \$0/MWh. In doing so, renewable energy is always included in the merit order, while other types of generation are pushed out of the market. This also means that when wind and solar are generating, hourly market prices are pushed down, which reduces generators earnings in a competitive energy-only market. The increased frequency of low or zero priced hours when wind and solar are generating leads to what is known as the "cannibalization effect": increasing the amount of variable renewable energy in a system decreases the incremental value associated with those resources [52].

In Alberta, wind energy has consistently earned less than other types of generation. This is often referred to as the "wind discount". In 2023, the AESO reported that wind generation received a 44% discount relative to the average pool price [18]. This phenomenon is partially due to the market depressing effects of wind energy described above, but is amplified by a highly correlated wind output from a fleet largely located in southern Alberta. In addition, wind plants continue producing power overnight when hourly power prices tend to be lower.

Solar has not yet experienced a discount relative to average pool price, on the contrary, solar energy has historically earned more than the average pool price in Alberta. While solar has the same market suppressing effect as wind, solar energy is usually available when power demand is high, during the day. In 2023, solar received an 8% premium compared to the average annual pool price in Alberta [18]. This premium is down from 25% in 2022 [53], since as solar generation increases, mid-day prices are driven down and the amount of generation required from the rest of the system is decreased. This trend has been observed frequently in the California power market which includes a high penetration of solar power [54]. The load net of solar over the course of a day is often presented graphically in what is dubbed the "duck curve". During peak sunlight hours, the system load net of solar is lower, and less generation is required from other sources. Excess renewable generation during these times is generally curtailed if it exceeds what is required to meet load or available exports [54]. At high penetrations of solar, electricity systems must be flexible enough to respond to fast changes in net load when the sun sets. With recent growth of solar energy in Alberta, the duck curve has begun to emerge, as seen in Figure 2.5.

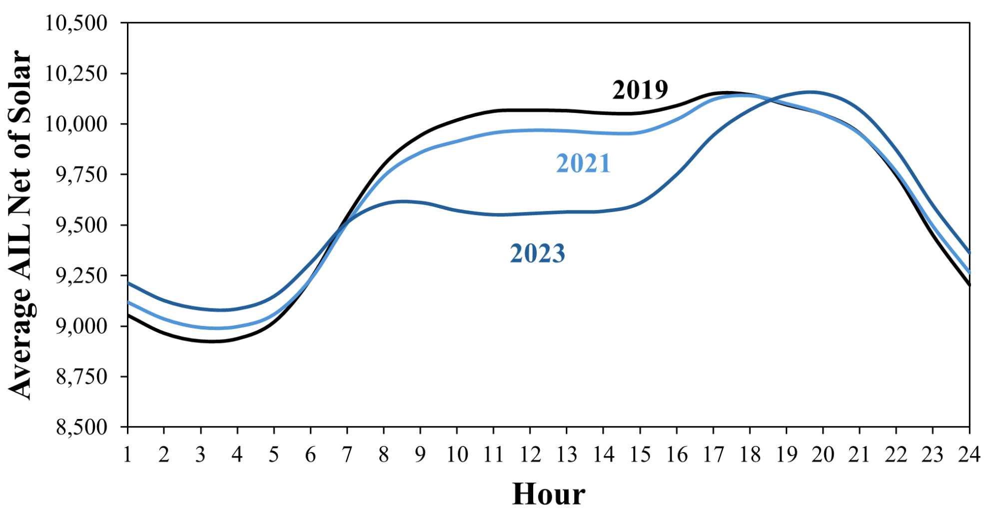


Figure 2.5: Hourly impact of solar power on average Alberta Internal Load in 2019, 2021, and 2023.

An additional consideration specific to Alberta's northern location, is the seasonality of storage. Solar generation in Alberta varies by season due to more limited winter sunlight hours. For example, using hourly data from the AESO [27] Alberta's solar fleet was calculated to have a capacity factor of 30% between March and August in 2023. Comparatively, the solar fleet capacity factor was found to be just 12% from September to February in 2023.

In summary, wind and solar are low-cost zero emissions sources of power which can be used by electricity systems. Both forms of renewable energy have seen substantial growth in Alberta since 2019, and proposed projects suggest continued appeal and opportunity for investment. However, there are challenges associated with integrating high levels of wind and solar into Alberta's existing grid, including transmission constraints, a need for adequate dispatchable supply, and reduced hourly electricity prices. Net-zero pathways presented in Chapter 4 and 5 will consider the challenge of building adequate flexible supply to support a highly renewable system and potential effects of lower power prices on capacity and supply.

2.2.2 Firm and Flexible Power Options

Flexible forms of power generation are often used to meet peak demand and respond to sudden changes in supply or demand. These technologies are also helpful to complement wind and solar generation during hours of low output or when weather conditions change quickly. Common flexible solutions to support wind and solar variability include simple-cycle plants, energy storage, peaking hydro, and/or intertie expansion. Flexible technologies like simple-cycle plants are often called "peakers" since they typically operate during peak demand when power prices are high. To maintain adequate supply as shares of variable generation increase, the system is required to have sufficient flexible capacity that can balance load.

Contrary to flexible plants, firm low-emitting technologies such as nuclear, geothermal, biomass, and thermal units with CCUS tend to operate at high levels of minimum stable generation [55]. Some large-scale hydro facilities can also be considered "firm" low-emitting resources. Firm low-emitting plants are still dispatchable, meaning they can adjust their power output and turn off and on, but generally these plants take longer to respond to load changes and cannot cycle on and off within an hour. Combined-cycle natural gas plants also follow the definition of "firm" but are not considered low-emitting.

In Alberta, biomass and hydropower are existing renewable energy sources with some ability to respond to load changes. While biomass plants are dispatchable, Alberta's biomass fleet has historically been tied to industrial facilities, with roughly 70% of average annual generation supplied behind-the-fence [27]. This means on average, Alberta's 0.4 GW biomass fleet [27] is constrained in its ability to balance variable output. Hydropower is a valuable source of zero-emissions electricity for many other provinces in Canada, providing over 60% of the country's electricity annually [56]. In Alberta, existing hydro only supplies 2% - 3% of annual generation [27], and output is often constrained based on competing factors such as water levels or flood control. While the Canadian Hydro Association has reported over 11,000 MW of technical hydropower potential remaining in Alberta [57], a high LCOE and long lead-time means new projects are unlikely in the near term. Recent large-scale hydropower projects have had a tendency to go overbudget with a long development period [58], meaning they would be difficult to develop in a competitive market. Furthermore, hydro projects require extensive environmental impact assessment studies and responsible consultation with indigenous groups before development can be considered. Thus, opportunities to expand low-emitting firm and flexible power sources in Alberta over the coming decade are primarily driven by other technologies.

A study by Sepulveda et al. [55] found that including firm low-emitting resources when modelling electricity decarbonization pathways could decrease electricity costs compared to systems comprised of renewable generation and storage only, underlining the importance of including a variety of technology options in decarbonization pathways. The capacity expansion study by Sepulveda et. al was performed for two different electricity regions in the United States, representative of the New England and Texas electricity systems. To assess the relationship between cost and the availability of firm low-emitting options, Sepulveda et al. ran multiple scenarios where each electricity system was constrained to meet an emissions limit ranging from 200 g_{CO2}/kWh to 0 g_{CO2}/kWh, both with and without firm low-emitting resources. As the emissions limit on the system was tightened, the cost of electricity increased exponentially in scenarios without firm low-emitting options. While electricity costs still increased at lower emissions limits in scenarios that included low-emitting resources, the magnitude was much lower. At an emissions limit of 0 g_{CO2}/kWh (full decarbonization), electricity costs were 10% - 62% higher in scenarios without inclusion of low-emitting resources [55].

Sepulveda et al. also found that low-emitting resources increased electricity system flexibility and reduced the need for additional generation and storage capacity. In full decarbonization scenarios with low-emitting resource options, the total generation and storage capacity required by the model was 1 - 3 times peak demand. Without low-emitting resource options, the capacity expansion model relied on an overbuild of wind and solar to meet decarbonization constraints, resulting in a final generation and storage capacity of 5 - 8 times the peak demand [55]. This occurs since wind and solar generation are not dispatchable. To replace emitting generation and maintain resource adequacy without the use of low-emitting resources, a higher generation and storage capacity was added to account for variable renewable output. Including low-emitting resource options reduced the need for additional capacity, since low-emitting resources could be dispatched when renewable output was low or supply was tight. Furthermore, since low-emitting resources are dispatchable, Sepulveda et al. note that they can consistently replace emitting generation in a carbon constrained system. In contrast, decarbonization pathways that rely on an overbuild of wind and solar may still requires some form of dispatchable power when variable output is low

[55]. Without a zero emissions constraint on the electricity system or the availability of low-emitting resources, this dispatchable power need is likely to be met by emitting generation. The study also reiterates that wind and solar tend to decrease their own value in a competitive market system, since more $0/MWh hours occur.

Results from Sepulveda et al. suggest that firm low-emitting power options such as nuclear, large-scale hydro, geothermal, biomass, and plants with CCUS are important to consider when modelling decarbonization pathways since they may decrease electricity costs [55]. In Alberta, it is unlikely new large-scale hydropower or nuclear facilities could emerge in the coming decade given long-lead times, meaning it is important to consider how other firm low-emitting technologies like gas with CCUS could impact net-zero electricity pathways. Considering Alberta's highly correlated wind fleet, the flexible emissions savings properties of firm low-emitting resources may be useful to replace emitting generation to transition to a net-zero system.

2.2.3 Policy

Around the world, policies have been developed or strengthened to support decarbonization pathways for electricity systems and economies. In the United States, a large and complex piece of policy called the Inflation Reduction Act (IRA) was introduced in 2022. The IRA aims to reduce the United States total emissions by 40% over a ten year period, with the majority of reductions expected to take place in the power sector [59]. The IRA promotes investment in electricity emissions reductions through a variety of financial incentives including investment tax credits (ITCs) and production tax credits (PTCs) [60]. Eligible low-emitting electricity projects may choose between investment tax credits that effectively lower upfront capital investment or production tax credits which are based on energy generation. Beyond this, the IRA encourages CCUS through the availability of CO_2 capture credits that are generated based on the amount of carbon captured [60]. Investment tax credits for renewable and low-emitting energy have also been used in Canada's approach, highlighted in the 2023 federal budget [21].

Recent work by Bistline et al. focuses on how the IRA could impact decarbonization in the United States electricity sector. Projections found that incentives included in the IRA could reduce the country's electricity emissions 66% - 87% by 2035 (relative to 2005 emissions) [38]. The study included results from 11 different energy optimization models from various organizations across the United States, with results presented for 2030 and 2035. In each model, a reference scenario and IRA scenario was simulated to isolate the impact of the IRA on the power sector. Most models used capital costs and fuel costs obtained from the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline[7] (ATB) report or the U.S. Energy Information Administration's (EIA) Annual Energy Outlook[8]. Since each model had its own inputs, assumptions, and structure, results from Bistline et al. presented annual capacity additions, generation, emissions, and cost outcomes in ranges to account for differences between model outcomes. The study considered renewables, fossil fuels with carbon capture and storage (CCUS), and nuclear as low-emitting technologies.

Across the models, Bistline et al. found a positive correlation between the IRA and new low-emitting capacity, with wind and solar capacity increasing to 1.4 - 6.2 times current capacity by 2035 [38]. With the IRA, annual storage capacity additions averaged 7 GW but varied significantly between models based on alternative future cost and performance assumptions, causing annual additions to range from 1 - 18 GW on average between models. The IRA caused most models compared in Bistline et al. to experience a high deployment rate of CCUS on existing coal, with an average coal CCUS capacity of 37 GW available by 2035, compared to almost none in the reference case. The deployment of CCUS on gas plants was less aggressive than it was for coal, due to the allocation of CO_2 capture credits under the IRA which contributed to

[7]The ATB report is a commonly used hub for new technology cost and plant operational characteristics [61].

[8]The Annual Energy Outlook is commonly referred to by American and Canadian modellers to populate input fuel and plant cost data [62].

increased cost sensitivity for gas with CCUS [38]. Since CO_2 capture credits included in the IRA are based on the quantity of emissions captured, coal plants experience increased revenue potential due to a higher unabated emissions rate than gas plants. The prevalence of coal CCUS in models presented by Bistline et al. is not likely to become relevant in Canada due to an output based carbon tax structure that favors lower emissions gas generation over coal.

Although Alberta does not have a credit for captured CO_2, the TIER regulation provides a similar incentive resulting from the low emissions intensity of units with CCUS which makes them eligible to generate emissions performance credits (EPCs). While the IRA approach favors emissions reductions by adding CCUS to coal powered generation, Alberta's TIER program favors fuel switching to gas plants with stronger emissions performance. Findings from Bistline et al. suggest that the available credit for captured CO_2 may help replace existing fossil fuel infrastructure with the addition of CCUS installations. The potential for a similar outcome based on credit generation by CCUS under Alberta's TIER program has not been explicitly identified in literature, but will be explored further in Chapter 5.

Annual generation presented by Bistline et al. found that by 2035, 59% - 89% of U.S. electricity was generated by low-emitting sources with the inclusion of the IRA, compared to 46% - 79% in the reference cases. Despite clean hydrogen production tax credits included in the IRA, electricity generation from hydrogen was negligible within the 2035 timeline of these scenarios [38]. Generation and capacity results from Bistline et al. show that ITCs and PTCs included in the IRA influence the growth of low-emitting generation, with wind and solar playing a substantial role. Alberta has access to investment tax credits through Canada's federal budget [21] along with EPCs that can be generated by low-emissions generation. It is possible that EPCs in Alberta could play a similar role to PTCs in the U.S. since both provide an output-based reward for low-emissions generation. An assessment of how EPCs and federal ITCs could impact supply pathways in Alberta will be explored in Chapters 4 and 5.

At higher penetrations of low-emitting generation Bistline et al. found that electricity emissions were generally lower. Relative to 2005, inclusion of the IRA allowed for a 47% - 83% electricity emissions reduction by 2030, compared to a 41% - 60% reduction in the reference case [38]. Although high-level trends and results agreed across models, result ranges showed significant variability which demonstrates the value in performing multiple studies. Few studies have been published that include up-to-date inputs for an Alberta-centric electricity model, highlighting the value of this thesis work.

2.3 Introduction to Capacity Expansion Models

Capacity expansion optimization models are tools that can be used to forecast cost optimal capacity changes to an electricity system under a provided set of policy, technology, and economic conditions. Different capacity expansion models have been used by academia, government, and the private sector to predict how electricity systems could change over time. Many of these models include tools to assess regional energy policy and recommend future actions. A large body of recent work has focused on net-zero transitions, deep decarbonization, and integrating wind and solar energy into existing systems.

In general, optimization models revolve around minimizing or maximizing one or more chosen objective function(s) by changing a selected variable [63]. For energy applications, the objective function is a mathematical statement that typically describes the overall cost of an energy system. Depending on the model, the objective function may represent costs associated with multiple energy sectors or focus on an individual sector like electricity. Equation 2.2 shows an equation for total cost which would be input into the objective function of a typical electricity system optimization model. Note that some models consider net cost, in which case revenue is subtracted from Equation 2.2. Some models may also include a transmission cost component in the objective function. Each component in Equation 2.2 represents the sum of respective costs for all power plants included in the model. By adding or removing power plants, the model can minimize the total system cost. The costs associated with each power plant are based on user defined coefficients or equations which represent costs and operational properties associated with operating each power plant. The necessary coefficients depend on model formulation, but common examples include heat rates, emissions rates, fuel costs and capital costs. Finally, models are subject to constraints which represent realistic limitations of the system and individual power plants. Examples include ensuring a balance between load and supply or enforcing operational characteristics like minimum stable generation levels. Constraints limit the quantity and type of power plants that can be feasibly added or removed over the duration of a study. Most models also include functions which optimize power plant dispatch and system generation within the larger capacity expansion optimization. By optimizing the objective function subject to constraints, optimal electricity system configurations and operations can be projected based on prescribed conditions.

$$TotalCost = C_{CC} + C_{FOM} + C_{VOM} + C_{fuel} + C_E + C_{charging} \tag{2.2}$$

Where,

C_{CC} = capital costs

C_{FOM} = fixed operations and maintenance costs

C_{VOM} = variable operations and maintenance costs

C_{fuel} = fuel costs

C_E = emissions costs

$C_{charging}$ = storage charging costs

An advantage of capacity expansion optimization models compared to high-level economic models is the ability to incorporate increased detail involving market structures, renewable resources, and technology characteristics [64]. The level of detail that can be represented in a model is a function of model structure, input data, assumptions, and computational feasibility. Two important model parameters are temporal and spatial resolution. Spatial resolution refers to the granularity used to represent geographical space. For models that involve geographical data, information is clustered together into spatial units to preserve computational abilities. A higher spatial resolution generally improves model detail while increasing computational difficulty - although complexity is also impacted by the data clustering approach taken [65]. A net-zero expansion study by Brinkerink et al. [66] found that spatial resolution is an important determinant when dealing with problems that include large amounts of renewable energy resources or transmission lines, both of which are highly dependent on location. Temporal resolution describes the level of detail included to represent time. Data is generally grouped into representative days or periods to prevent the model from running all 8760 hours of the year. Consequently, a high temporal resolution provides a more robust model at the cost of technical complexity. As explained in a 2021 paper by Bistline [67], a high temporal resolution has become increasingly relevant in policy modelling and decarbonization studies. Incorporating hourly time steps is an important part of preserving power system realism, especially concerning renewables. Using time steps that are too large fails to represent the transient nature of renewable energy and may over-estimate output and de-emphasise the importance of dispatchable power solutions [67]. Spatial and temporal resolution may be adjusted based on how many geographic regions are represented (ie: national or sub-national level), as increasing the number of regions or systems represented increases model complexity.

2.4 Existing Electricity Models

Several models have been used to forecast how Canada's electricity system could evolve into the future as a result of net-zero targets and emissions reductions policies. This section includes a review of key scenarios from seven different reports or papers which focus on decarbonizing electricity in Alberta and/or Canada.

2.4.1 Overview of Existing Models

This section provides a high-level overview of four electricity models that have been used to model decarbonization or net-zero pathways for Alberta and/or Canada.

In 2018, Dolter and Rivers presented the Canadian Renewable Electricity Storage and Transmission (CREST) Model [68] to assess the cost of decarbonizing the Canadian electricity system. The CREST model is a linear programming model that co-optimizes investment in new technology to meet demand by a selected year. The CREST objective function minimizes the annual operating cost of the entire electricity system. For the chosen year, the electricity system is dispatched each hour of everyday, giving CREST a high temporal resolution. The expansion of transmission and renewable energy is based on 2,278 spatial grid cells across Canada. Each cell is linked to average weather data which represents wind and solar potential in each location. A weakness of CREST noted by the authors is the simplified representation of dispatchable resources. Instead of using a commitment optimization framework where thermal unit output is constrained by operational characteristics like ramp rates, the model provides maximum and minimum capacity factor constraints [68]. This approach may decrease model accuracy in provinces like Alberta which are dominated by thermal generation.

A prominent capacity expansion model in the Canadian academic context is the Canadian Opportunities for Planning and Production of Electricity Resources (COPPER) model, a cost-optimal capacity expansion model developed by a research group from the University of Victoria. In 2022, the COPPER model was used to perform electricity system decarbonization research in a paper by Arjmand and McPherson [69] and a net-zero report by the David Suzuki Foundation [70]. The COPPER objective function mirrors what was used in CREST, it seeks to minimize total system cost as a sum of costs derived from investment, maintenance, energy production, and carbon emissions. The model uses representative days and periods to assess capacity expansion investments and resulting generation [69]. Results are reported in 5-year increments, which allows a dynamic optimization process. The ability to optimize and report values at incremental periods is an improvement from the CREST model which can only report results for the final year of a study. Renewable expansion and transmission system planning in COPPER is performed using the same spatial resolution as the CREST model.

Electricity system forecasting for the Government of Canada is performed by the Canada Energy Regulator and released in annual reports. Annual reports use a series of integrated economic models to forecast future scenarios for different energy sectors and analyze the impact of different macro-economic factors on Canada's energy systems. The model used by the Canada Energy Regulator is called E3MC, and within it, electricity forecasting is performed using an optimization model called Energy 2020 (E2020) [71]. Key assumptions, policy constraints, and historical patterns are supplied to E2020 from the macro-economic portion of E3MC. From here, dynamic demand projections are created and a least-cost optimization is performed to determine a supply mix that can meet projected electricity demand [71]. According to E2020 documentation, the objective function aims to minimize the total cost to the electricity system as a function of production cost (generating costs and transmission costs) [72]. Since the E2020 model is part of a broader framework which includes economy-wide inputs and cross-sectoral relationships, decisions taken by the rest of the world can influence final results for the electricity sector. For instance, electricity demand could fluctuate based on electrification pathways taken by other sectors. As a result, policy impacts over the entire economy can be evaluated at a high-level using E3MC and E2020.

Publicly available forecasting for Alberta is provided by the AESO using the Aurora capacity expansion and dispatch model [73]. Several private companies in Alberta also run Aurora models to understand how changes in policy and market conditions could impact existing assets and development opportunities, but these results are not publicly available. Every two years, the AESO publishes long-term outlook reports based on current policy and trends. The most recent report was released in May 2024 [74] with only minor changes to preliminary results that had been made available earlier [75]. In 2022 the AESO also released a *Net-Zero Emissions Pathways* report [76] which included an analysis of how Alberta's electricity system could reach net-zero by 2035. Following the AESO *Net-Zero Emissions Pathways* report, a Canadian clean energy think tank called the Pembina Institute released a different report detailing pathways to a net-zero electricity system by 2035 [77]. The modelling work in the Pembina Institute report was contributed by Van Os and Weis, in an earlier iteration[9] of the Aurora model used in this thesis. A detailed overview of Aurora and its features is presented in Chapter 3.

The Aurora capacity expansion and dispatch optimization model allows for detailed market simulations, which is useful to represent Alberta's competitive market design. In other models discussed, the total cost to the system is minimized in each hour regardless of the revenue collected by individual units. Aurora can be configured to maximize electricity system value as a function of revenue minus costs. This objective function may yield a similar result to minimizing cost, since high cost solutions will still decrease the value of the system.

In Aurora, maximum wind and solar output is defined based on hourly de-rate curves which represent historic weather conditions. Compared to COPPER, Aurora has the benefit of allowing users to choose exact locations for potential wind or solar sites based on the best available locations. Using renewable profiles which correspond to exact locations may improve results since only viable sites are considered. In contrast, renewable resource data in COPPER is averaged over grid cells representing areas in the range of 2,000 km^2 [69]. The advantage of using a grid cell approach is that the model has the flexibility to locate wind or solar sites in alternative areas

[9]Since the completion of modelling work for the *Zeroing-In* report [77], input data and assumptions have been updated to improve the University of Alberta version of the Aurora model and extend the study period to 2045, as will be seen in Chapter 4 and 5.

Table 2.2: Overview of existing models and studies reviewed.

Report/Paper Title	Results	Region	Model
Canada's Energy Future 2023 [78]	Economy	Canada	E3MC/E2020
Canada's electricity system transition under alternative policy scenarios [69]	Electricity	Canada	COPPER
Shifting Power: Zero-Emissions Electricity Across Canada by 2035 [70]	Energy	Canada	COPPER
The cost of decarbonizing the Canadian electricity system [68]	Electricity	Canada	CREST
AESO Net-Zero Emissions Pathways Report [76]	Electricity	Alberta	Aurora
AESO 2024 Long-term Outlook: Preliminary Update [75]	Electricity	Alberta	Aurora
Zeroing In: Pathways to an affordable net-zero grid in Alberta [77]	Electricity	Alberta	Aurora

and can adapt to possible transmission constraints. Similar to the COPPER model, Aurora can provide incremental capacity expansion results, which is an improvement from models with no intermediate results. The Aurora model also considers thermal plant commitment decisions to improve modelling of Alberta's fossil fuel intensive system.

Sections 2.4.2 and 2.4.3 will explore seven different publications which were based on the CREST, COPPER, E2020, or Aurora models. A summary of each paper that will be discussed along with it's corresponding model is shown in Table 2.2. Papers are classified in Table 2.2 based on regions and sectors included in final results.

2.4.2 Canadian Decarbonization Forecasting

A 2018 study by Dolter and Rivers using the CREST model [68] explored how changing carbon prices could theoretically impact Canadian electricity system decarbonization by 2025. A main result found by Dolter and Rivers was the importance of new transmission in decarbonization efforts from both and emissions and cost perspective.

When forcing the system to reach zero emissions, Dolter and Rivers found that allowing intertie capacity expansion reduced the cost of decarbonization by 26% compared to cases without additional transmission. In Alberta, Dolter and Rivers results included an additional 1,700 MW connection with British Columbia and a 9,552 MW connection with Saskatchewan [68], this represents almost 10 times current intertie capacity [28]. Dolter and Rivers found that storage and transmission play very similar roles. In cases where transmission infrastructure was expanded, there was nearly no need for additional storage, with only 28 MW added across all of Canada under a zero emissions constraint. This is because transmission and storage play similar flexibility and reliability roles for provincial systems [68]. Without transmission expansion, Dolter and Rivers found that a zero emissions Canadian electricity system required 6,475 MW of storage, with 5,177 MW added in Alberta to balance variable wind output.

Another key finding from Dolter and Rivers model was that a carbon price of $\$80/t_{CO2e}$ was deemed enough to make coal uneconomic. Once coal was retired from the system, Dolter and Rivers found that the cost to further abate emissions quickly increased [68]. While coal generation will soon be phased out of Alberta, Dolter and Rivers results suggest coal phase-out emission reductions are possible through carbon pricing alone while remaining emissions become harder and more expensive to abate. Dolter and Rivers found that even when the carbon price was increased to $\$450/t_{CO2e}$, a carbon price alone was not enough to fully retire natural gas generation and reach absolute zero emissions [68]. Gas units continued to operate in the CREST model to meet load constraints and support generation from variable renewable energy. Since CREST is a cost optimization model, this implies that even at a carbon price of $\$450/t_{CO2e}$, some natural gas units were considered more cost effective than alternative dispatchable solutions in Dolter and Rivers projections. It should be noted that CCUS options were not included in Dolter and Rivers work.

Carbon pricing results were echoed in a 2022 paper by Arjmand and McPherson

[69] which used the COPPER model to examine the effectiveness of Canada's existing carbon management policies in achieving a net-zero electricity system by 2050. All scenarios presented by Arjmand and McPherson followed federally scheduled carbon price increases till 2030 (reaching $170/t$_{\mathrm{CO2e}}$) before diverging to form alternative cases where carbon price stayed constant or increased annually at steps of $5/t$_{\mathrm{CO2e}}$, $10/t$_{\mathrm{CO2e}}$, or $15/t$_{\mathrm{CO2e}}$. The Arjmand and McPherson model included CCUS options and a suite of policy scenarios including the federal coal-phase out, carbon price schedules, and natural gas generation performance standards. Results from Arjmand and McPherson projected a significant increase in wind capacity prior to 2035, with solar beginning to play a more prevalent role towards the 2040s. This trend is similar to other forecasts which will be reviewed in Section 2.4.3 , emphasizing the important role of wind energy in Canada and Alberta's near term emission reduction pathways. Again, it was found that carbon pricing alone was not enough to reach zero emissions, despite an increase to $470/t$_{\mathrm{CO2e}}$. In the COPPER model scenarios, combined-cycle natural gas plants were retained while most simple-cycle gas technology was deemed uneconomical by 2025. While Arjmand and McPherson do not include province specific results, this does not agree with Alberta modelling by the AESO [75, 76], where simple-cycle plants continue to operate because of their ability to remain profitable when operating during high priced hours.

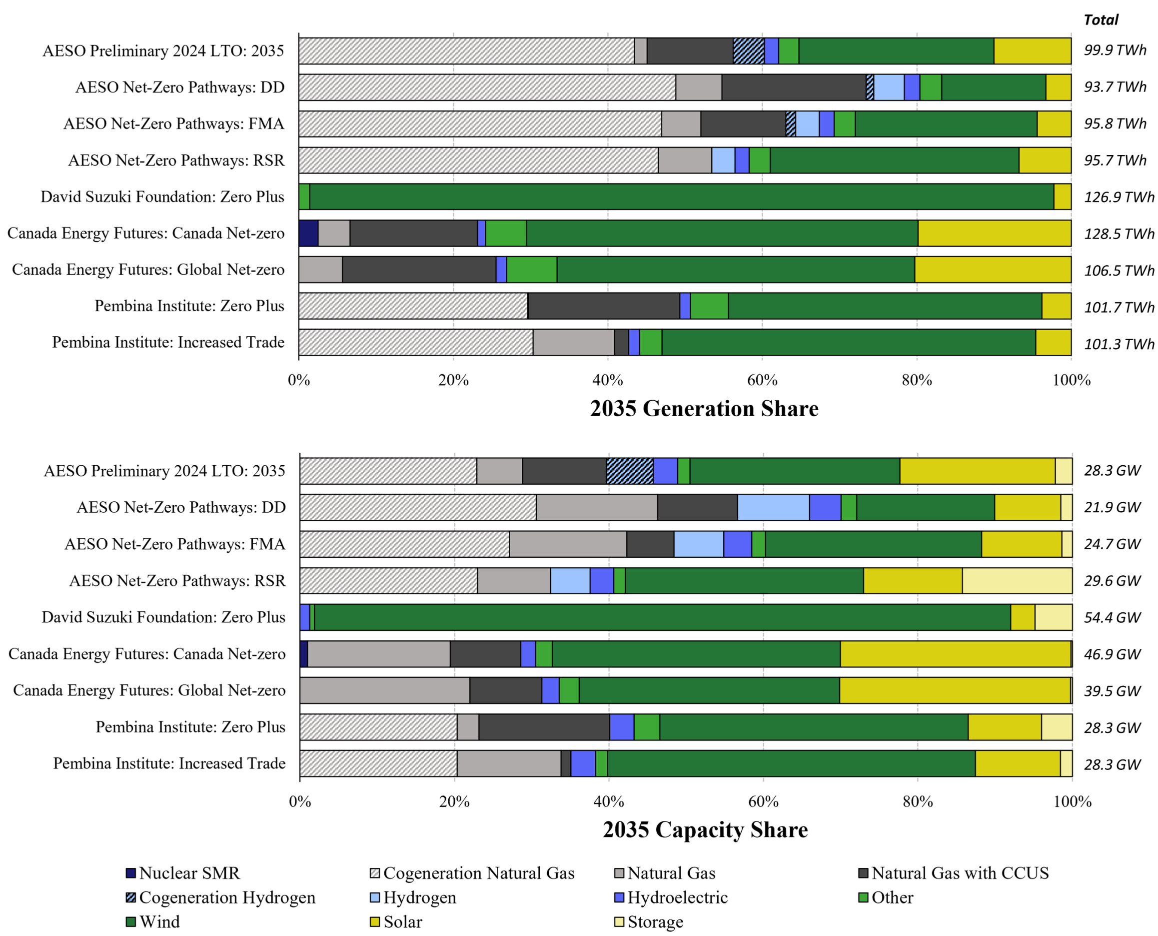
2.4.3 Net-Zero Pathways for Alberta

A handful of reports have been released detailing net-zero pathways for Alberta's electricity system [70, 76, 77]. However, there are few recent examples of academic research isolating Alberta's pathway to net-zero electricity under current policy, in part because the area is quickly evolving. For example, when reviewing a 2021 case study by Radpour et al. [79], which focused on the impacts of carbon pricing on renewable energy growth in Alberta, it was found many of the results and inputs were already outdated. Radpour et al. presented a simplified modular framework called

"Market Penetration Modelling of Renewable Energy Technologies in Electric Power Sector" (MAPLET-PS) to predict future renewable energy penetration rates based on linear capacity growth and simple pay back periods. MAPLET-PS operates by forecasting future electricity demand, iteratively predicting the market penetration and market share of renewable energy, and then evaluating generation and emissions outcomes. However, in the most extreme scenario presented, the carbon price only increased to \$105/tCO2 by 2050; this will already be surpassed by 2026. Additionally, coal energy is expected to be phased out much earlier than the year 2030 which was used in this study [79]. Overall, the linear annual capacity changes and simplified estimation of generation in Radpour et al. do a poor job of demonstrating the challenges associated with feasible hourly operation and Alberta's electricity market.

In 2022 the David Suzuki Foundation published a report titled *Shifting Power* [70] which used the COPPER model to forecast a net-zero electricity system by 2035. The definition of' zero emissions adopted in the David Suzuki Foundation report did not allow for any offsets or carbon capture and storage technologies. As a result, only wind, solar, biomass, energy storage, and intertie capacity additions could be added to meet electricity demand, while hydrogen and CCUS technologies were not included. This meant that all existing fossil fuel generation (including cogeneration) was retired by 2035 in the David Suzuki Foundation pathways. Alternative definitions, such as that taken by the AESO, define net-zero as the "combination of zero- or low-emissions technologies that may be paired with the use of offsets and credits that lead to a calculated emissions outcome equivalent to zero greenhouse gas emissions" [76]. The definition chosen has an important impact on results. As discussed in Dolter and Rivers [68], the final small incremental emission reductions in electricity systems are expected to prove the most difficult and costly to abate.

Conceptually, work by the David Suzuki Foundation highlights the ability of expanded intertie and renewable energy capacity to facilitate a net-zero transition by 2035, however, timelines for construction are likely unrealistic. In the zero plus scenario, intertie capacity for Alberta was expanded to 6.4 GW by 2035, nearly 3 times current capacity. From Figure 2.6, the David Suzuki Foundation report sees Alberta achieving zero emissions primarily through wind energy, reaching well over 40 GW of wind capacity by 2035 in the zero plus scenario [70]. To put that in perspective, between 2022 and 2023 Alberta's wind fleet capacity increased by approximately 1.3 GW [27]. This represents the largest single year wind capacity addition in the province over the last 10 years. To reach the numbers presented by the David Suzuki Foundation, Alberta would need to install roughly 3x the capacity added in 2022 in each year from now until 2035.



Natural gas cogeneration was reported as its own category if information was available, in other instances it was included with natural gas generation. Total generation values do not account for energy storage charging or intertie transfers. Data was gathered from each source [70, 75–78] and approximations were made from report figures where necessary.

Figure 2.6: Comparison of existing models capacity and generation share in 2035.

Figure 2.6 shows that compared to other net-zero forecasts, the David Suzuki Foundation zero plus scenario had the lowest solar capacity and generation share by 2035. It appears the model selected wind over solar in Alberta, likely due to cost and availability. While more solar might be expected considering the zero emission constraint included in the David Suzuki Foundation report, this result is not out of place, as most models compared in Figure 2.6 seem to agree on fairly conservative solar energy growth compared to wind in Alberta. In the David Suzuki Foundation zero plus scenario, energy storage capacity reaches close to 3 GW by 2035, which is higher than all other studies in Figure 2.6 aside from one AESO scenario.

A recent report by the Canada Energy Regulator, *Canada's Energy Futures 2023*, shows how different economy-wide energy futures could materialize in Canada in three scenarios: current measures, Canada net-zero, and global net-zero. The Canada net-zero scenario was based on Canada reaching net-zero economy-wide while the rest of the world acts slower on climate change. In contrast, the global net-zero scenario envisioned Canada, along with the rest of the world, achieving emissions in line with the Paris Agreement. In the economy-wide net-zero scenarios, the electricity sector was constrained to meet zero emissions by 2035. Results found an economy-wide net-zero scenario for Canada would require more extensive electricity infrastructure based on projected demand increases [78]. A snapshot of electricity capacity and generation shares in each of the *Canada's Energy Futures 2023* scenarios is shown in Figure 2.6, alongside results from other forecasts reviewed in this section.

A significant difference between the *Canada's Energy Future 2023* results [78] and other Alberta models presented in Figure 2.6, is treatment of cogeneration. In the *Canada's Energy Future 2023* report, electricity results aggregate cogeneration with other natural gas power plants; this simplifying assumption is common in models that include all of Canada since it enables high-level conclusions. As discussed in Section 2.1, many cogeneration units operate behind-the-fence to self-supply heat and electricity, so emissions are not entirely attributed to electricity generation and operational decisions are not necessarily tied to the electricity market price. In Alberta, where cogeneration facilities play an important role in electricity production, it is beneficial to separate these facilities into their own group when presenting modelling results, as was done in the AESO and the Pembina Institute net-zero electricity reports.

The two net-zero scenarios included in the *Canada's Energy Future 2023* report entail significant changes to Alberta's electricity system. In 2035, the Canada net-zero scenario projects that natural gas will supply 21% (26.5 TWh) of Alberta's total electricity generation, with 4% from unabated generation and the other 17% from gas with CCUS. The share of gas generation in the global net-zero scenario in 2035 was slightly higher at 26% (27.2 TWh) of total electricity generation, with 6% unabated and 20% from gas with CCUS [78]. In both *Canada's Energy Future 2023* net-zero scenarios, the capacity of unabated gas generation was 8.7 GW in 2035 while the capacity of gas with CCUS ranged from 3.7 GW (Canada net-zero) to 4.8 GW (global net-zero). Comparatively, the AESO reported that pure gas-generation provided 68.9% (59.4 TWh) of Alberta's total electricity generation in 2023, with an estimated year end capacity of 11.8 GW [18]. Numbers presented in *Canada's Energy Future 2023* report imply that roughly 1/4 of Alberta's gas fleet would retire by 2035, while remaining units either abate emissions or generate at low capacity factors to comply with net-zero constraints. Results in both *Canada's Energy Future 2023* cases agree that abated natural gas generation appears to be an important part of Alberta's cost optimal energy transition.

Scenarios in *Canada's Energy Future 2023* report further project that by 2035, renewables provide 74% (global net-zero) or 77% (Canada net-zero) of total electricity generation [78]. Alberta wind capacity reaches 17.5 GW in the Canada net-zero scenario and 13.3 GW in the global net-zero scenario. Both of these numbers are high compared to AESO forecasting scenarios [75, 76], but the global net-zero scenario falls within range of 2035 wind capacity values presented in the Pembina Institute's 2023 net-zero report. Compared to other reports, solar capacity and generation stands out in the *Canada's Energy Future 2023* model. The Canada net-zero and global net-zero scenario's included 14.0 GW and 11.8 GW of solar by 2035, which is more than double any other scenario included in Figure 2.6. This could suggest that other models are falling short in solar energy predictions, which has been the case in the past. For instance AESO's *2021 Long-Term Energy Outlook* reference case projected less than 1.2 GW of solar by 2035 [80], a benchmark which was already surpassed in 2023 [18]. Alternatively, it also could suggest that E2020 over-estimates solar output in Alberta.

In the *Canada's Energy Future 2023* Canada net-zero scenario, just over 400 MW of nuclear Small Modular Reactor (SMR) capacity was added and no additional energy storage was added in Alberta by 2035. No other forecast in Figure 2.6 included new nuclear development by 2035, although AESO's *Preliminary 2024 Long-Term Outlook* included similar capacities of SMR starting in the early 2040's [75]. Differences in timing and capacity of SMR could be due to alternative assumptions surrounding costs and flexibility. An hourly generation profile for Alberta displayed on page 70 of the *Canada's Energy Future 2023* report suggests that SMR plants are able to cycle from zero to full output in 1-2 hours [78]. Both the *Canada's Energy Future 2023* net-zero scenarios included only 90 MW of storage capacity in 2035. Every other model presented in Figure 2.6 exceeded this, with 2035 storage capacities ranging 330 - 4,156 MW by 2035.

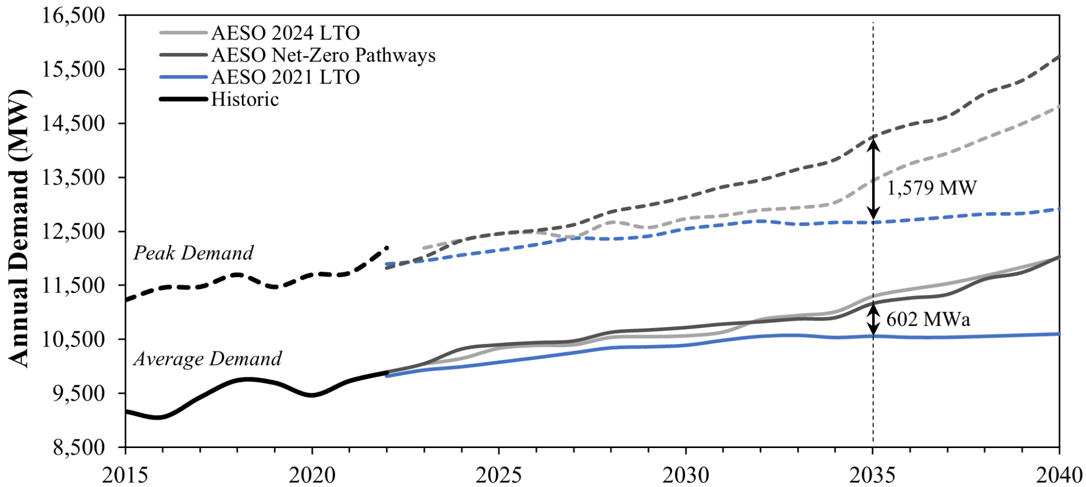
The *Canada's Energy Future 2023* report also included a current measures scenario, where results were very different from the two net-zero cases. In the *Canada's Energy Future 2023* current measures scenario, natural gas remained the dominant fuel source for Alberta, providing 79% (88.4 TWh) of electricity in 2035, with no CCUS included. Renewable energy provided the other 21% of electricity in the current measures case, with 3.8 GW of wind and 3.8 GW of utility solar by 2035 [78]. Based on Alberta's projected renewable capacity explored in Section 2.2.1, it is likely wind and solar capacity will meet or exceed these numbers within the next two years. The *Canada's*

Energy Future 2023 current measures scenario does not agree with the latest AESO scenarios [74, 75], the Pembina Institute's net-zero report [77], and work that will be presented in this thesis - all of which anticipate significant renewable energy growth under current policies.

The 2022 AESO *Net-Zero Emissions Pathways* report [76] included three scenarios: dispatchable dominant (DD), first mover advantage (FMA), and renewables and storage rush (RSR). In each scenario, changing costs, conditions, and government support prompted alternative technology mixes. The report included full carbon price exposure based on a linear decline to zero of the TIER high-performance benchmark between 2022 and 2035. The *Net-Zero Emissions Pathways* report assumed that existing cogeneration would take the required steps to meet net-zero by 2035 while continuing to supply similar levels of generation to Alberta's electricity system. The AESO definition of net-zero adopted in the *Net-Zero Emissions Pathways* report explicitly states that offsets are a requirement, implying that absolute zero emissions is not feasible for Alberta. This opinion is rooted in an anticipated cost of abating small amounts of remaining emissions and concern surrounding operational feasibility [76]. Annual emissions in 2035 for the three *Net-Zero Emissions Pathways* scenarios ranged from 3.8 - 4.8 $\mathrm{Mt_{CO2e}}$, with natural gas combined-cycle generation becoming the largest source of emissions following the retirement of coal-to-gas conversion units. This echos findings from Arjmand and McPherson that predict natural gas combined-cycle technology to become the largest remaining source of emissions in Canada following a completed coal phase-out [69].

In the dispatchable dominant scenario (DD), decarbonization pathways relied on new combined-cycle CCUS and simple-cycle hydrogen plants rather than renewable energy expansion, as seen in Figure 2.6. In the AESO dispatchable dominant scenario, only 24% of electricity came from renewable sources in 2035. The next scenario, first mover advantage (FMA), projected increased wind capacity which allowed the share of renewable generation to reach 35% by 2035. Combined-cycle with CCUS was still required, along with hydrogen simple-cycle units. The most aggressive emission reductions occurred in the final scenario, renewables and storage rush (RSR). In this scenario, 45% of electricity needs were met by renewable energy. This scenario included the largest storage fleet of all the models compared in Figure 2.6, reaching 4.2 GW in 2035. Considering slow storage adoption rates in projections from the AESO *preliminary 2024 LTO* (0.6 GW added) , *Canada's Energy Futures 2023* (0.1 GW added), or the Pembina Institute's *Zeroing In* (0.4 - 1.1 GW added), this level of storage does not seem likely to develop without added incentive.

The AESO *Net-Zero Emissions Pathways* report [76] stated that between 2022 and 2041, the added cost to reach net-zero compared to a business as usual approach from the AESO *2021 Long-Term Outlook* was estimated to be $44 - $52 billion [76], representing a 30% - 36% cost increase. However, different assumptions involving carbon price, new technology options, and demand suggest this estimate could be inaccurate. In the *2021 Long-Term Outlook* reference case, carbon price only reached $\$50/\mathrm{t_{CO2e}}$, compared to $\$170/\mathrm{t_{CO2e}}$ in the *Net-Zero Emissions Pathways* cases. This would impact the value of existing plants, competitive edge of new low-emitting plants, and total system costs. The *2021 Long-Term Outlook* considered new gas capacity but did not include a CCUS option, long-duration energy storage options, or hydrogen fuel options. In contrast, the *Net-Zero Emissions Pathways* report did not allow new gas generation, but instead included more expensive low-emitting energy options. Finally, the cases included different demand forecasts, as depicted in Figure 2.7. The peak demand in the AESO *Net-Zero Emissions Pathways* report exceeded *2021 Long-Term Outlook* peak demand by 1,579 MW. The significant growth in the AESO *Net-Zero Emissions Pathways* report was in part due to an optimistic growth in electric vehicles that includes Alberta reaching 2.6 million light-duty electric vehicles by 2041 and a resulting peak load of 15,979 MW [76]. Different demand projections make it challenging to compare costs, since systems generate different amounts of electricity as a result of factors from outside the electricity sector. More recent modelling in the



Demand projections gathered from respective AESO reports [18, 76, 80], and historic demand retrieved from the AESO's Market Statistics Report [27].

Figure 2.7: Comparison of recent electricity demand forecasts by the Alberta Electric System Operator, highlighting differences between the 2021 long-term outlook and net-zero pathways reports.

2024 Long-Term Outlook [74] appears to have addressed this gap, with a new average annual demand that resembles the net-zero pathways demand.

The AESO *Preliminary 2024 Long-Term Outlook* results included two main scenarios in response to the federal draft Clean Electricity Regulations (CER). The first was a decarbonization by 2035 scenario, which included the draft CER and full carbon price exposure by 2035. This scenario was included in Figure 2.6. The second scenario was a decarbonization by 2050 scenario which reached full exposure by 2050. Both considered the impact of investment tax credits on capital costs, a feature only otherwise included in the *Canada's Energy Futures 2023* pathways. Interestingly, both scenarios presented in the *Preliminary 2024 Long-Term Outlook* [75] achieved lower emissions than any of the *Net-Zero Emissions Pathways* scenarios [76] resulted in by 2035, with emissions of 1 Mt_{CO2e} (decarbonization 2035) and 2 Mt_{CO2e} (decarbonization 2050) in 2035.

The Pembina Institute *Zeroing-In* report published in 2023, included six scenarios which compared alternative net-zero electricity system options for Alberta [77]. All net-zero scenarios included full carbon price exposure by 2035. Cogeneration was again treated exogenously, however no assumptions were made regarding its decarbonization pathway, unlike the AESO's *Net-Zero Emissions Pathways* report. Annual emissions for the six Pembina Institute scenarios ranged from 2 - 7 Mt_{CO2e} in 2035, which is in range of the three AESO *Net-Zero Emissions Pathways* scenarios, albeit slightly higher. The majority of emissions were sourced from combined-cycle natural gas plants which were retained by the model. This report did not include federal investment tax credits for new CCUS projects or retrofit options for existing units which may have further reduced emissions. A key finding of the Pembina Institute net-zero report was that Alberta could become a net-exporter of electricity by 2035. This trend was not seen in the AESO *Net-Zero Emissions Pathways* report, however it did appear in more recent AESO *Preliminary 2024 Long-Term Outlook* scenarios. Characterizing Alberta as a net exporter of electricity could have implications for federal decarbonization pathways and provincial financial opportunities.

Since results were relatively similar across the Pembina Institute cases, only two scenarios were included in Figure 2.6. In the Pembina Institute's near-zero scenario, a constraint was used to restrict the model to net-zero emissions by 2035, with an exception for combined-cycle CCUS plants. To meet this emissions constraint, the model selected 4.8 GW of new combined-cycle CCUS capacity and 11.3 GW of wind capacity by 2035. This scenario reached a share of 51% renewable generation, which exceeds all of the AESO scenarios discussed, but remains lower than the *Canada's Energy Futures 2023* report. The second Pembina Institute scenario shown in Figure 2.6 did not include a net-zero emissions constraint but allowed Alberta's inter-provincial transmission capacity to double in 2030. Allowing increased transmission and removing the emissions constraint alleviated the need for new gas with CCUS, resulting in only 0.4 GW of combined-cycle CCUS capacity by 2035.

All modelling, aside from the David Suzuki Foundation's report [70], suggested a continued role for natural gas fired units in a cost optimal net-zero scenario. Canadian electricity decarbonization modelling suggested that combined-cycle gas units are retained by capacity expansion models despite carbon prices of over of \$400/t_{CO2e} [68, 69]. Combined-cycle gas units are difficult to remove from electricity systems as decarbonization progresses because of the flexibility role they play alongside increasing levels of variable output. As a result, both the AESO *Net-Zero Emissions Pathways* report and the Pembina Institute's 2023 net-zero report show combined-cycle natural gas becoming the largest source of electricity emissions in Alberta once coal-to-gas units were retired. Thus, reducing combined-cycle gas emissions is important to overall electricity emissions reductions. Lowered annual emissions reported in the AESO *Preliminary 2024 Long-Term Outlook* suggest that the inclusion of CCUS retrofit options may help replace emissions attributed to combined-cycle gas.

A variety of supply mixes have been proposed for Alberta to reach net-zero. The addition of gas with CCUS and wind capacity was generally a common factor of electricity transition pathways for Alberta. However, the optimal wind capacity shifted significantly between reports. By 2035, wind capacity ranged 3.9 - 9.4 GW in the AESO reports [75, 76], 11.3 - 19.3 GW in the Pembina Institute report [77], 13.3 - 17.5 GW in the *Canada's Energy Futures 2023* net-zero scenarios [78], and surpassed 40 GW in the David Suzuki Foundation report [70]. Models show mixed results concerning the role of nuclear SMR, solar, energy storage, and simple-cycle hydrogen technologies in Alberta. For example, *Canada's Energy Futures 2023* net-zero scenarios included 11.8 - 14.0 GW of solar capacity while no other model exceeded 6 GW by 2035.

2.5 Conclusions

This chapter provided an overview of Alberta's current electricity system and explored how supply options and policy incentives expected to influence the decarbonization of electricity systems in the United States could translate to Alberta. Following this, capacity expansion optimization models were introduced and seven different existing net-zero electricity system studies, based on four different models, were reviewed in the context of Alberta's electricity transition.

Wind and solar generation are low cost [40] zero emissions sources of power which have been growing quickly in Alberta, demonstrated by 1.8 GW of solar and 3.2 GW of wind added between 2018 and 2023 [27]. Proposed projects and available resources indicate continued opportunity for wind and solar expansion in Alberta [41]. However, there are challenges associated with integrating high levels of variable generation into existing electricity systems, including lower average annual power prices and a need for adequate dispatchable supply. The use of firm low-emitting resources [55] or other low-emitting dispatchable forms of power is one way to support the integration of wind and solar, reduce electricity system emissions, and potentially lower transition costs.

In the United States, tax credits available for low-emitting generation could increase shares of renewable energy and decrease electricity system emissions 47% - 83% by 2030 (relative to 2005) [38]. In Alberta, federal investment tax credits and credits for low-emissions generation may have a similar potential to reduce electricity emissions by supporting investment in low-emitting generation that can displace fossil fuel emissions. Chapters 4 and 5 consider the role for low-emitting resources in highly renewable electricity systems and discuss how the trajectory of Alberta's carbon pricing framework and the value of carbon credits could impact net-zero electricity pathways.

Existing decarbonization pathways for Canada and Alberta point towards significant emissions reductions resulting from a completed coal phase-out, followed by retirement of inefficient coal-to-gas units shortly thereafter. However, models agree that further emissions reductions after this are more of a challenge, as emitting units are retained to maintain adequate supply to support variable renewable output. Models generally expect wind to play an important role in Alberta's future system, however there is disagreement over the optimal capacity. Furthermore, many modelling results pre-exist the state of current policy. Scenarios presented in this thesis continue to examine uncertainties in future supply in Alberta's pathway to a net-zero grid.

Chapter 3

Methodology

This chapter provides a general overview of the Aurora model along with key input data and assumptions. Assumptions or input data which will be explained in detail in Chapter 4 was summarized to avoid re-iterating the same information.

3.1 The Aurora Model

Energy Exemplar's commercially available electricity system forecasting software Aurora [73] was used to carry out simulations. This optimization software is used by several private power companies in Alberta, as well as by the Alberta Electric System Operator (AESO). Aurora allows users to choose between four study types: standard zonal (optimize dispatch), portfolio (optimize a specific resource portfolio), maintenance (optimize maintenance schedules), or long-term capacity expansion (optimize future scenarios). The long-term capacity expansion study selection, used for this work, includes an integrated capacity expansion and dispatch optimization within the same interface and set of results.

3.1.1 Optimization Progress

Simulations used a mixed-integer program (MIP) optimization logic paired with gurobi solver. The MIP optimization differs from some other capacity expansion models, for example the one used by Dolter and Rivers [68] in their long-term Canadian decarbonization modelling referenced in Section 2.4.2, since both integer (0/1) and continuous values may be used as constants in optimization constraints. The MIP logic also allows for commitment optimization, an Aurora feature which optimizes the hourly dispatch of each thermal unit to minimize their total costs, given associated constraints such as up/down times and minimum stable load. The objective function in Aurora maximizes system value as a function of total resource costs minus revenue. After each iteration, the model may add or remove power plants to improve the objective function. A schematic of the entire process for each simulation is provided in Figure 3.1.

Simulations begin with a set of existing power plants and candidate new plant options. The model then dispatches the system for the entirety of the study length. During dispatch, optimization logic is used to consider commitment decisions, storage patterns, and hydro output. The dispatch optimization seeks to minimize the total cost of generating electricity while satisfying load and operational reserves. In the case that demand cannot be met, the model may relax demand or reserve constraints. For every modelled hour, the marginal cost of each plant is used to form a "dispatch cost" or "bid". By stacking dispatch costs and capacity in each hour, the merit order is created. A wholesale pool price is determined based on the marginal plant, or the last plant to offer into the market. After dispatching available plants for the entire study period, the model will assess the objective function based on real net present value (NPV). The NPV is derived based on hourly costs and energy revenue throughout the entire study, where the total cost accounts for fuel costs, variable operations and maintenance costs, emissions costs, capital cost, storage charging costs, and fixed operations and maintenance costs. Following this, the active set of plants is modified to increase the system value and a new iteration begins. These changes could include accepting a new plant with a high NPV or retiring an existing plant that is no longer profitable. A user-input constraint limits annual retirements to 3500 MW per year to avoid creating capacity retirement cliffs. Plant additions are limited on an annual

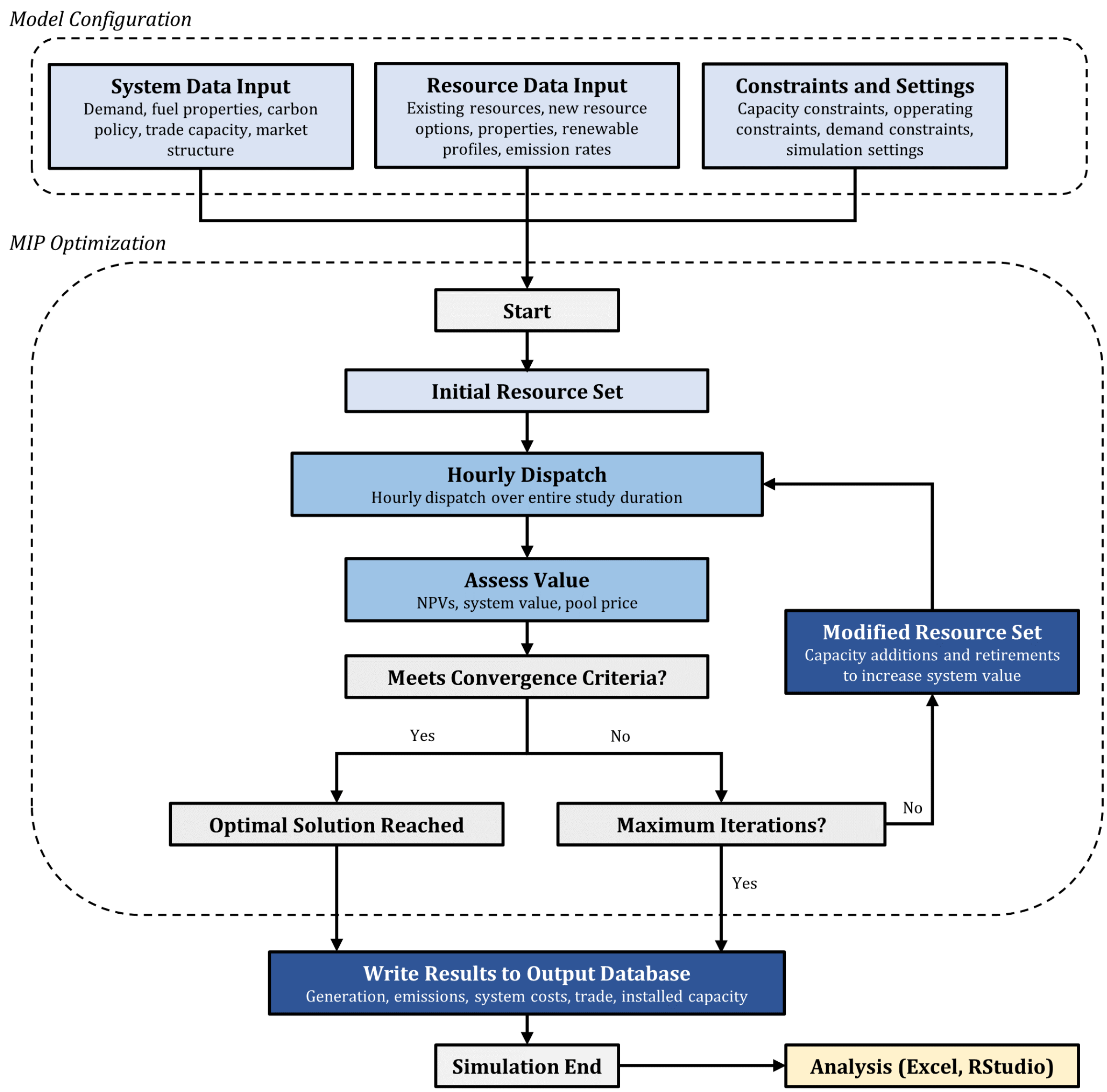


Figure 3.1: Flowchart representing the generalized Aurora simulation process.

and study long plant specific basis.

After each iteration, the system value changes based on the modified fleet. The iterative process continues until convergence is met or the model reaches a maximum number of iterations. Convergence was defined as a change of less than 1.0% in system price, but the model will begin a new iteration regardless of convergence criteria if significant fleet changes occur. The maximum number of iterations was set to 70, and after each simulation was completed, results were reviewed to ensure the model converged before reaching this metric.

Upon convergence, the software saves results to a database stored on Microsoft SQL. Outputs include fuel usage, plant output data, technology group data, GHG emissions, power prices, overall system outcomes, and optimization results. Data is automatically grouped into tables of different temporal resolutions including each hour, month, year, and the entire study. Functions and code were written in RStudio to complete post-processing, code is available on GitHub [81].

3.1.2 Technical Settings

Temporal resolution is a user defined feature in Aurora. The model was dispatched every hour of every day for one week per month. This time frame was chosen to maintain a manageable quantity of output data while remaining within a feasible overall run time of approximately 24 - 48 hours for each scenario. Although the model ran from January 2023 to December 2050, results were trimmed to 2045 to ensure a proper optimization lookback period. An hourly resolution was maintained to best represent the characteristics of renewable plants.

Based on existing configuration, the model's economic base year was defined in 2012 USD. An average annual inflation rate of 2.5% was used alongside a conversion rate of $1 CAD = $0.79 USD. Discounted values were used during the capacity expansion while results were provided in nominal Canadian dollars. To model Alberta's market structure, the price ceiling was set to $999.99/MWh while the floor was set to $0/MWh. A detailed list of technical and economic assumptions is presented in Appendix A.

3.2 General Assumptions and Inputs

This section includes general modelling assumptions and inputs, some of which will be re-iterated in Section 4.2. Unless otherwise specified, values were held constant throughout all scenarios.

3.2.1 Demand

Two main metrics were used to input future load, an annual demand forecast and an hourly demand shape. Changes in annual demand were based on average and peak Alberta internal load (AIL) values forecasted in the AESO's 2022 *Net-Zero Emissions Pathways* report [76]. The average and peak demand calculated in this report account for expected changes that would accompany an increasingly electrified economy. As such, the total change in load forecasted by the AESO includes demand growth, electric vehicle adoption, hydrogen production, electric heating, and distributed energy resources (DER)[10]. In this way, modelling indirectly accounts for electrification and possible changes to future energy demand. Annual data forecasted by the AESO spanned from 2022 to 2041. To run the simulation past 2041, average annual growth rates of 1.09% and 1.60% from the AESO net-zero report were used to extrapolate load data. Extrapolation resulted in an average load of 12,691 MW and a peak load of 17,026 MW by 2045, implying peak load grows to roughly 1.5 times the maximum AIL of 11,572 MW experienced in 2023 [18]. Extrapolation was carried out between the years 2042 and 2050. The resulting average and peak annual demand which were input into the model is visualized in Figure 3.2, along with Alberta's historic electricity demand since 2016.

Hourly load data from 2022 was taken from the AESO's market statistics dashboard [27] and used to form an hourly load profile. In each year, the hourly profile was scaled based on corresponding average and peak demand. Using the demand profile from 2022 incorporates recent trends and maintains consistency from year to year. However, possible changes in Alberta's load profile over time are not accounted for using this method.

[10]Distributed energy resources include any resources that are grid connected with the ability to supply energy to an electricity system, generally under 5 MW in capacity [82].

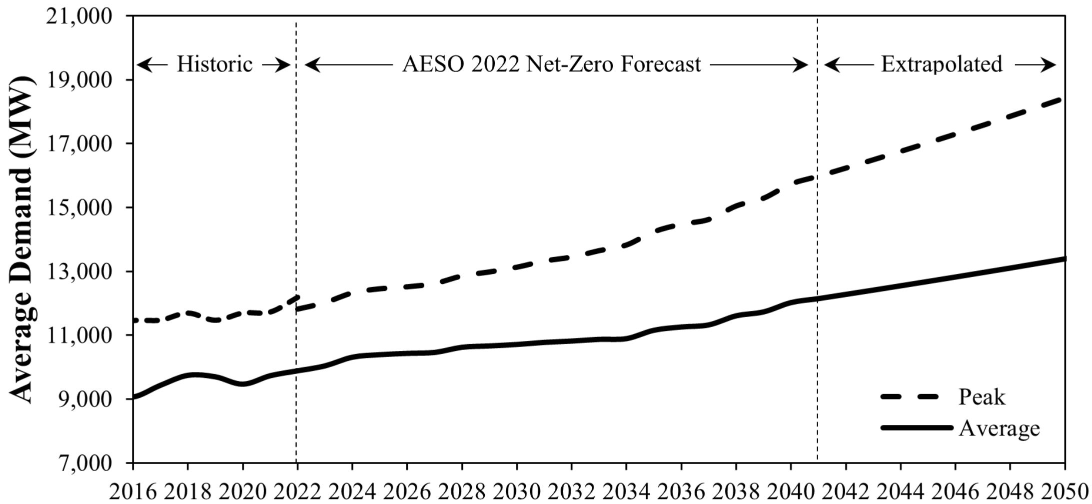


Figure 3.2: Input peak and average load for Alberta.

3.2.2 Transmission and Interties

The cost and feasibility of new provincial transmission was not considered. This is aligned with Alberta's current transmission regulations which require the AESO to develop long-term transmission plans and support the connection of new projects to the grid once they receive regulatory approval [31]. Instead, to account for limitations in new transmission, constraints were used to limit the number of new wind plants which could be built in specific locations.

To model inter-provincial connections (interties), British Columbia and Montana were joined into one zone with a maximum intertie capacity of 1,100 MW and Saskatchewan was given a maximum intertie capacity of 153 MW. Each zone was represented by a single "theoretical" gas plant which could fully supply power to its respective zone, or send electricity to Alberta. The cost of operating the two "theoretical" plants in BC/MT and SK varied monthly and was representative of the price set by a typical marginal gas plant in Alberta (i.e. the price setting plant in the merit order) based on a historical relationship between Alberta's power price, natural gas prices, and intertie flow. The resulting zone price in BC/MT and SK acted as a price signal to determine when trade with Alberta would take place. For instance, if the zone price in SK was higher than AB, it would be economic to export electricity from AB to SK. Further details describing how interties were configured is presented in Appendix A.2.1.

To represent technical limitations and outages, data from 2018 [28] was used to de-rate hourly intertie availability. Details describing the selection of 2018 as a representative year can be found in Appendix A.2.1. Intertie flow was split into four categories: Alberta exports to Saskatchewan, Alberta imports from Saskatchewan, Alberta exports to British Columbia and Montana, and Alberta imports from British Columbia and Montana. By dividing the intertie capability in each hour by the maximum capacity, a normalized hourly time series was created to shape the maximum hourly intertie availability throughout the study. Additional constraints were placed which limited imports to approximately 70% of the maximum intertie capacity of 1,263 MW. This accounts for future uncertainty and regulatory limitations, for example increased demand in BC or decreased hydro reservoirs during drought years. Although actual intertie availability varied hourly, the fractional average annual availability of each connection was as follows:

- SK to AB: 0.96
- AB to SK: 0.96
- AB to BC/MT: 0.81
- BC/MT to AB: 0.60

3.2.3 Fuel and Carbon Prices

Fuel prices were provided for coal, biomass and waste, natural gas, hydrogen, and uranium. For biomass, waste, and uranium a single default value was used. In the case of coal, since all retirements were completed before 2025, an annual fuel price for 2023 and 2024 was sourced from the April 2023 U.S. Energy Information Administration's Short Term Energy Outlook [83]. Monthly natural gas prices between 2023 - 2025 for Alberta (AECO) were obtained from Sproule's December 2023 short term forecast

[84]. Annual natural gas prices thereafter were based on baseline projections published in the Canadian Energy Regulator's *Canada's Energy Future 2023* report [78]. All hydrogen was assumed to be blue hydrogen, sourced in Alberta, with prices[11] based on a 2022 techno-economic assessment by Khan et al. [85]. Monthly variation was introduced for natural gas and blue hydrogen prices to simulate historical gas pricing trends in Alberta. Average fuel prices over the study duration are presented in 2023 Canadian dollars in Table 3.1. Additional natural gas and hydrogen price details can be found in the supplementary data in Appendix A.2.2.

Table 3.1: Average model fuel prices for study duration.

Fuel	**Average Price ($/GJ)**	**Constant**
Biomass/Waste[1]	0.07	Yes
Coal[2]	3.00	No
Hydrogen[3]	18.10	No
Natural Gas[4]	3.45	No
Uranium[1]	0.80	Yes

[1] Default database values provided with Aurora Software.
[2] Based on EIA April 2023 Short-Term Energy Outlook [83].
[3] Estimated by Duran Castillo based on techno-economic work by Khan et al. [85], shaped monthly.
[4] Short term prices from Sproule [84], annual prices from the Canadian Energy Regulator [78], shaped monthly.

The price per tonne of carbon-dioxide-equivalent was increased from $65 in 2023 to $170 in 2030 by increments of $15 annually, in accordance with Alberta's current carbon pricing schedule [86], which is compliant with Canada's *Greenhouse Gas Pollution Pricing Act* [23]. A description of how carbon pricing and emissions credits work in Alberta is presented in Section 2.1.3. In general, generators with a GHG emissions intensity greater than the annual high-performance benchmark (HPB) for electricity were charged a carbon cost for any emissions which exceeded the annual HPB. Low and non-emitting projects generated emissions performance credits (EPCs) which

[11] Hydrogen price forecasting work was completed by another graduate student Gloria Duran Castillo. Values were then verified by comparing to other forecasts, as shown in Appendix A.2.2.

were allocated based on the annual HPB and valued at 90% of the annual carbon price. Between 2023 and 2030, new wind and solar facilities received offsets based on the annual Electricity Grid Displacement Factor (EGDF) rather than the HPB. For existing wind and solar facilities, offsets were allocated based on the applicable EGDF and period as outlined in the Alberta *Carbon Offset Emission Factors Handbook* [36]. Offsets were also valued at 90% of the carbon price in the year which they were generated. For the purpose of this modelling, both EPCs and offsets were included in the objective function as a negative cost. Supplemental information regarding emissions credits and offsets is available in Appendix A.2.3.

3.3 Plant Assumptions and Inputs

3.3.1 New and Existing Plants Overview

The model was populated with an up to date list of existing power plants and projects which had publicly confirmed final investment decisions or were under construction as of January 2024. Upcoming projects were taken from the Alberta Electric System Operator (AESO) connection project reporting list [41] for projects with energization dates prior to 2026. The last listed energization date from the AESO connection reporting list for each upcoming project was assumed to be the start date. Final coal retirement and retrofit dates were also updated based on the January 2024 AESO connection reporting list.

Table 3.2 shows lifetime assumptions for existing electricity generation facilities. Existing plants could be removed from the simulation at any point following a user-defined “can drop” year. Existing wind built prior to 2015 could be considered for retirement after 20 years, while existing wind and solar built after 2015 could be considered for retirement after 25 years. If a plant was not selected for early retirement by Aurora, then it was forced to retire at its end of life. For existing plants, service lifetimes were used to determine forced retirement dates. Technology lifetimes were also informed by data from the 2023 National Renewable Energy Laboratory (NREL) Annual Technology Baseline Report [61]. In the case of existing battery storage, a 20 year end of life was assumed. While this may be on the upper end for battery storage projects, the lifetime was selected based on the maximum warranty period for a Tesla Megapack [87]. Several of Alberta's existing storage facilities, including eReserve 1, 2, and 3 (each a 20 MW facility) have used Tesla MegaPacks [88]. Gas projects were forced to retire following a 50 year end of life to account for possible refurbishment or extended operating lifetimes. The retirement dates of coal-to-gas retrofit units were staggered between 2025 to 2037, as per expected dates published in the AESO's *2021 Long-Term Outlook* [80].

Table 3.2: Lifetimes and eligible retirement date assumptions by technology type.

Type	**Can Drop (years)**	**Lifetime (years)**
Battery Storage	Anytime	50
Biomass/Other	Anytime	30
Hydro	Anytime	100
Gas	Anytime	50
Solar	25	35
Wind	20 - 25	30

Table 3.3 shows a complete list of existing capacity groups in Alberta and new capacity options available in the model. Also listed in Table 3.3 is the first year which each technology could be considered for capacity additions. For most technologies, the year 2025 was used. Capacity expansion was not considered before this since it is unlikely new large projects could attain approval and complete construction in this timeline outside of exogenously included projects. New plant options did not include coal or cogeneration, since coal is soon to be phased out and cogeneration additions depend on factors outside of the electricity sector. Thermal plant options included simple-cycle and combined-cycle plants, fueled by either hydrogen or natural gas. New wind, solar, and storage plant options could be added at fractional capacities over the

study duration. Note that not all options were selected by the final optimal solution, for instance, no scenarios included new nuclear generation. Cost assumptions for new plants are summarized in Section 4.2.8, while capital cost learning rate curves can be found in Appendix A.3.5.

Table 3.3: Existing and new options for electricity generation technologies in Alberta.

Name	**Short Name**	**Existing**	**New Option**
Coal	Coal	x	
Coal-to-Gas	NGConv	x	
Cogeneration	Cogen	x	
Hydrogen Combined Cycle	H2CC		2025
Hydrogen Simple-Cycle	H2SC		2025
Hydropower (Dammed)	Hydro	x	2026
Natural Gas Combined-Cycle	NGCC	x	2025
Natural Gas Combined-Cycle + CCUS	NGCC+CCUS		2027
Natural Gas Simple-Cycle	NGSC	x	2025
Nuclear (SMR)	SMR		2035
Nuclear (Fission)	Nuclear		2040
Other (Waste heat, geothermal)	Ot	x	
Other (Biomass)	Bio	x	2025
Solar	Solar	x	2025
Storage (Battery)	BESS	x	2025
Storage (Pumped Hydro)	PSH		2027
Storage (Compressed Air)	CAES		2026
Wind	Wind	x	2025

3.3.2 Operational Characteristics

Key operational traits assigned to dispatchable plants included outage rates, minimum stable load, up/down times, and heat rates. Operational characteristics were assigned based on typical ranges, with some variation between units for minimum stable load. Additional details can be found in Appendix A.3.2 or Chapter 4 for new plants.

Plant availability was defined based on minimum stable load, up/down times, and outage rates. Both maintenance rates and forced outage (FOR) rates were treated as a capacity de-rate which varied monthly. For example, a 100 MW plant with a forced outage rate of 10% in May, would have 90 MW available for dispatch in that month. For less flexible plants including combined-cycle, coal, nuclear, biomass/other, and coal-to-gas units, minimum up/down times were used along with a 5% commitment premium to bids following cold starts. Simple-cycle plants could cycle hourly with no premium. Only cogeneration was defined as must run, meaning cogeneration plants had to operate at minimum stable load but could ramp up when economic opportunities arose.

Typical full load heat rates were obtained from the AESO's *Preliminary 2024 Long-Term Outlook* [75] for new plant options. To capture the loss of efficiency associated with operating at partial load points, heat rate curves were introduced based on an NREL study which gathered operating data from existing facilities across the United States to form representative heat rate curves [89]. For carbon capture and storage retrofit plants, the original plant capacity and heat rate was de-rated by 10% to account for efficiency losses, this de-rate was based on the AESO's *Preliminary 2024 Long-Term Outlook* [75].

3.3.3 Bidding and Incremental Cost

Similarly to heat rates, bidding was defined based on operational load point. Bids or "dispatch costs" in Aurora are a product of hourly variable operating costs or "incremental costs" and numerical bidding values. A general formula for incremental cost is presented in Equation 3.1. In the absence of bidding behavior, this formula would dictate the price a power plant is willing to sell power for in each hour in the model. This was the case for plants that did not include bidding curves, such as hydro and storage. However, because Alberta operates a competitive market, generators may want to offer their power for more or less than marginal operating costs.

$$C_I = (C_F)(HR) + C_E\left[(HR)(e_{fuel}) - HPB_E\right] + C_{VOM} \tag{3.1}$$

Where,

C_I = incremental cost (\$/MWh)
C_F = fuel cost (\$/GJ)
HR = heat rate (GJ/MWh)
C_E = emissions Cost (\$/t_{CO2e})
e_{fuel} = fuel emissions intensity (t_{CO2e}/GJ)
HPB_E = electricity high-performance benchmark (t_{CO2e}/MWh)
C_{VOM} = variable operations and maintenance cost (\$/MWh)

To capture possible offer price increases as the electricity market tightens, bidding factors and adders were included, as shown in Equation 3.2. For all thermal and biomass/other generation, bidding curves were based on historical operation in relation to hourly pool price. Bids begin at each plants minimum capacity, and increased with load point. At minimum capacity, a bidding factor of -1 forces plants to offer at \$0/MWh. This is representative of how a generator might act if they wanted to avoid a shutdown and ensure entry into the market. Once a plant has achieved full load, bids spike towards \$999.99/MWh in an stepped exponential curve shape. Simple cycle plants were set up slightly differently. Because they could cycle on and off within an hour, a bid factor of 0 was used, setting bids to the incremental (marginal) cost to operate when offering power at minimum load. Additional steps were taken to prevent negative bidding in the case of units with CCUS, since incremental costs could be negative as a reflection of emissions performance credits. Additional details regarding bidding and heat rate curves is presented in Appendix A.3.3.

$$C_D = C_I\,(1 + B_F) + B_A \tag{3.2}$$

Where,

C_D = dispatch cost (\$/MWh)

C_I = incremental cost (\$/MWh)

B_F = bidding factor

B_A = bidding adder

3.3.4 Cogeneration

Challenges associated with modelling cogeneration will be discussed in Chapter 4. To briefly summarize, in Alberta, cogeneration facilities are generally linked to industrial sites, primarily in the oil sands, and electricity is not always the primary product of the plant. Cogeneration units self-supply a significant portion of their power, meaning that total generation is not driven by electricity prices alone. For instance, in 2023 the AESO reported that cogeneration supplied a total of 33.5 TWh, with 13.5 TWh offered into the competitive market [27]. This implies that around 60% of cogeneration went behind-the-fence (self-supply) in 2023. To account for this, cogeneration plants were constrained to must run in the model. This constraint required each plant to dispatch its minimum capacity at $0/MWh regardless of other market conditions. Above minimum capacity, when supplying electricity to the Alberta grid, bidding behavior was used to incrementally raise dispatch costs when generating above minimum capacity. Minimum capacities were selected based on the historical fraction of energy supplied to the grid and behind the fence for each unit. Just under 70% of the total cogeneration fleet was included in must run constraints to align with cogeneration capacity factors in previous years.

Since the development of cogeneration is generally dependent on industrial sites and factors outside of electricity sales, the total capacity of cogeneration was constant over the entire study (aside from known upcoming projects). This prevented the model from choosing to retire or add new cogeneration. Cogeneration was also excluded from carbon policies and GHG reporting, as the TIER regulation includes different emissions benchmarks for these facilities based on multiple end-use products and GHG allocations are not consistent across facilities or publicly available.

An estimation for total cogeneration emissions allocated to electricity generation in each modelled scenario is provided in Appendix B for completeness. For this work, cogeneration emissions were tracked based on electricity generation net of heat production benefits. Plant specific cogeneration emission rates were on average 0.30 $tCO2_2$/MWh and were estimated based on 2015 - 2017 reporting provided by the Government of Alberta under Alberta's previous carbon pricing system the Specified Gas Reporting Regulation (SGER) [90]. SGER was replaced by Alberta's current framework, the Technology Innovation and Emissions Reduction (TIER) Regulation, in 2020. Emissions allocation methodology, adapted from the accompanying technical guidance for calculating emission intensity under SGER [91], assumed a boiler efficiency of 80% and an electricity generator efficiency of 30%, attributing waste heat emissions to electricity. This approach aims to allocate a realistic GHG emission rate to electricity generation, however it differs from the methodology taken by the AESO and Environment and Climate Change Canada (ECCC), where cogeneration GHG emissions are attributed to primary sectors for each facility. Under the AESO and ECCC methodology, cogeneration units report all GHG emissions to their primary sector. Only a small portion of Alberta's electricity cogeneration fleet falls under the fossil-fuel electric power generation (NAICS 221112) category, just over 20% of capacity, estimated from Canada's greenhouse gas reporting data [92].

3.3.5 Wind, Solar, and Hydro

New wind options along with existing facilities and upcoming projects (under construction) are shown in Figure 3.3. New wind locations were based on three sources:

(i) existing projects, (ii) planned projects in the AESO connection queue [41], and (iii) proposed new diverse wind farm locations by Pawlenchuk [93]. A total of 29 project locations were available for new wind generation projects. At each location, average hourly wind speed data from the Canadian Wind Atlas [45] was used to shape maximum wind output. Wind and solar output curves were generated and input into the model by previous students Natalia Vergara Bonilla [94] and Taylor Pawlenchuk [93] . For new wind options based on existing or planned projects, an annual capacity limit of 400 MW and overall limit of 2000 MW was used. For potential sites recommended by Pawlenchuk, the overall limit was reduced to 1600 MW.

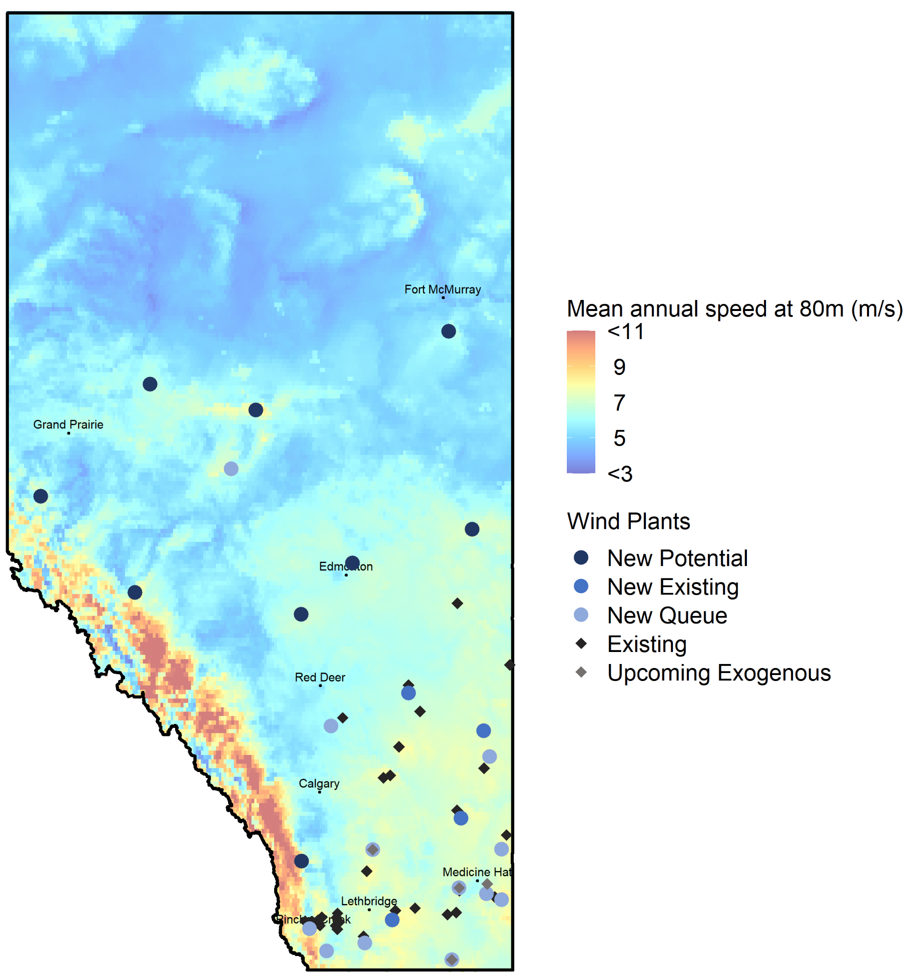


Figure 3.3: New and existing wind plant locations.

Solar profiles were based on average annual solar resource availability in Alberta and panel technology (monofacial vs bifacial, single axis vs double axis, ect.). Several new plant options with different panel configurations were included, with an annual capacity limit of 600 MW and overall capacity limit of 2000 MW per plant option. Both wind and solar plants were provided bidding factors equal to -1, forcing them to enter the merit order at $0/MWh. This is reflective of typical renewable offer behavior due to the absence of VOM and fuel costs. If wind or solar output exceed Alberta's hourly load and possible export capacity, the Aurora model may curtail additional output. Curtailed electricity does not hold any positive or negative associated costs in the objective function.

Hydro output was determined based on Aurora's hydro logic, which considers monthly availability and correlation to load. These factors were calculated based on historical data obtained from the AESO's *Annual Market Statistics Report* [27]. While dispatch costs were still used to place hydro plants in the merit order, the hydro logic ensured a minimum amount of annual and monthly generation. This reflects external factors which impact hydro output like flood control measures. Hydro resources may generate emissions performance credits, meaning dispatch costs were generally quite low in the model.

Chapter 4

Alberta's Path to Net-Zero Electricity Under Alternative Policies

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Abstract

Decarbonizing electricity systems is an important step towards overall greenhouse gas emissions reductions. Canada generates close to 84% of its electricity from low and non-emitting sources and has a stated goal of reaching net-zero electricity. Alberta poses one of the most challenging aspects to the transition as it is reliant on fossil fuels for 80% of its electricity generation, and there is significant debate surrounding how quickly a transition could occur in the province. This work uses an optimization capacity expansion and dispatch model to generate net-zero transition pathways for Alberta's electricity system considering significant policies that affect electricity supply options. Results show emissions outside of industrial cogeneration can be reduce to 83% of annual greenhouse gas emissions by 2045 based on current policies or 93% with the inclusion of draft federal electricity regulations. Results include tripling wind capacity, significant carbon capture and storage retrofits of existing gas-fired units, and expansion of low-use dispatchable generation. Emissions reductions prior to 2035 show the benefit of current policies including output based carbon pricing that credits low-emitting generation and federal investment tax credits.

4.1 Introduction

In response to growing concerns of significant climate damage [95], governments around the world have pledged to reach net-zero greenhouse gas (GHG) emissions.

Many governments are prioritizing a timely decarbonization of the electricity sector to enable other technologies and industries decarbonization strategies which often rely heavily on electrification. Government strategies to decarbonize their electricity systems and promote the development of low and non-emitting electricity generation have included financial incentives, tax incentives, and regulatory policies [9].

In 2023, Canada published draft clean electricity regulations (CER) [8] which were designed to help meet federal goals to reach net-zero electricity by 2035 [96]. The performance standards proposed in the draft CER would limit fossil fuel GHG emissions beginning in 2035. The policy is in addition to an existing carbon pricing system, coal phase-out laws, and investment tax credits for new low and non-emitting generation [21, 22]. Although Canada as a whole generates 84% of its electricity from low-carbon sources [17], Alberta is a outlier. Despite having 10% of Canada's population, Alberta contributed over 40% of Canada's estimated 47 Mt_{CO2e} electricity sector emissions in 2022 [19], a result of its fossil fuel dependent system. Due to its fossil fuel industry, the province is also Canada's top overall GHG emitter, which has placed considerable pressure on it for emissions reductions [97]. Achieving a net-zero electricity system could improve Alberta's emissions profile and support decarbonization timelines in other industries. This research uses a long-term capacity expansion and dispatch optimization model to forecast net-zero electricity transition pathways in Alberta under existing and proposed Canadian climate policies.

Alberta has made substantial strides in reducing its electricity GHG emissions in recent years. Coal, which accounted for more than 50% of the provinces electricity generation as recently as 2015, is almost fully phased out. The elimination of coal and a growing renewable fleet has allowed Alberta to cut its electricity emissions in half over the past decade, but significant investment and technological transformation is required to achieve a net-zero goal in coming years . In 2023 Alberta generated close to 80% (70 TWh) of its electricity from fossil fuels, largely natural gas. Additional factors including northern geography, a deregulated energy-only market design, and significant onsite electricity generation in its industrial base further complicate provincial emissions reduction pathways. Carbon capture utilization and storage (CCUS) has been proposed as a potential mitigation technology since 2002 in Alberta [98] but has yet to materialize in the electricity sector. Overall, the pace and possibility of a net-zero electricity transition in Alberta has been scrutinized along with the impact of existing and proposed policies.

Optimization models can be used to perform long-term capacity expansions of electricity systems. Several models have been used in literature to assess how policies including carbon pricing and coal regulations could influence the decarbonization of Canada's electricity system. In 2018, Dolter and Rivers [68] modelled the impact of carbon pricing and transmission expansion on theoretical electricity decarbonization pathways in Canada by 2025. Dolter and Rivers found a $80/$t_{CO2e}$ carbon price would deem coal units uneconomical and that cost optimal GHG emissions reductions pathways for Canada included extensive expansion of transmission and wind capacity. Pathways presented by Arjmand and McPherson in 2022 [69] showed that existing policies including carbon pricing, coal phase-out laws, and gas power plant efficiency standards could result in a 40% emissions reduction in Canada's electricity GHG emissions by 2030 and 29 GW of new wind capacity by 2035. Arjmand and McPherson found that current policies may reduce Canada's annual electricity emissions to 27 Mt_{CO2e} by 2050 and are insufficient to reach net-zero. Models by Dolter and Rivers and Arjmand and McPherson agree that even a carbon price upwards of $400/$t_{CO2e2}$ is not enough to deem all combined-cycle natural gas (NGCC) units uneconomical [68, 69], and supplementary policy would be needed to eliminate associated GHG emissions. As a consequence, continued decarbonization beyond reductions achieved through coal phase-outs may be a challenge for Alberta's gas intensive electricity system.

Long-term optimization modeling was used to forecast net-zero electricity pathways for Alberta in two publicly available reports: the first was published in 2022 by the

Alberta Electric System Operator (AESO) [76] and the second in 2023 by a clean energy think-tank called the Pembina Institute [77]. The AESO report found that Alberta could reduce it's annual GHG emissions to 3.8 - 4.8 Mt_{CO2e} by 2035, relative to 22.4 - 23.1 Mt_{CO2e} reported by the model in 2022. The net-zero pathways presented by the AESO included 3.9 - 9.0 GW of wind, 1.9 - 3.7 GW of solar, 0 - 2.2 GW of gas with CCUS, and 1.5 - 2.1 GW of hydrogen-fired generation by 2035. The lower range for wind and solar presented by the AESO net-zero report had nearly been exceeded by the end of 2023, with installed capacities of 4.5 GW wind and 1.7 GW of solar, relative to a 20.8 GW system. The AESO net-zero report concludes that between 2022 and 2041, a net-zero electricity system would cost an additional \$44 to \$53 billion (30% - 36% increase) in investment [76] relative to a reference scenario which was presented in a 2021 provincial outlook [80]. Comparing the AESO's reference scenario [80] and net-zero scenarios [76] reveals a 602 MW higher average load and 1,579 MW higher peak load in the net-zero 2035 forecast, no option for CCUS or hydrogen in the reference scenario, and a \$120/t_{CO2e} difference in maximum carbon price. Thus, the relative cost difference between a net-zero and current policy electricity system in Alberta is not clear. The Pembina Institute report [77] emphasized potential for new wind, gas with CCUS, storage, and solar capacity in Alberta to reduce annual GHG emissions to 2 -7 Mt_{CO2e} by 2035 across six different scenarios. In the Pembina Institute report, Alberta's wind fleet reached an average capacity of 13.6 GW by 2035 compared to 3.9 - 9.0 GW in the AESO net-zero report scenarios, suggesting uncertainty in optimal wind capacity for Alberta. Neither net-zero report included an option to retrofit existing gas with CCUS or build new low-use gas plants as a strategy to improve cost and GHG emissions outcomes, while both reports showed combined-cycle gas plants become a leading source of emissions by 2035.

The AESO and Pembina Institute net-zero reports preexist several policy changes which will impact Alberta's electricity system, including an updated carbon pricing framework in Alberta [34], proposed draft Clean Electricity Regulations [8], and federal investment tax credits [21]. The most recent version of Alberta's output-based carbon pricing regulation includes a 2% tightening rate between 2022 and 2030, while the AESO and Pembina Institue reports assumed a linear path to full exposure by 2035. Alternative tightening rate assumptions could significantly impact the optimal fleet mix. Including the performance standard outlined in Canada's draft Clean Electricity Regulations may also change the economics of existing gas plants by limiting operation or encouraging retrofits with CCUS. Lastly, investment tax credits included in the 2023 federal budget could impact investment in low and non-emitting technologies. The impact of tax credits on promoting the development of low and non-emitting generation has been observed in American modelling following the 2022 Inflation Reduction Act [38], but has not been explicitly identified in Canada or Alberta.

The main objective of this paper is to provide insight on pathways to net-zero for Alberta's competitive electricity market, with consideration for the impact of carbon pricing, Canada's draft Clean Electricity Regulations, and available investment tax credits on technology mix, cost, and cumulative emissions reductions to help prepare for and enable change. Scenarios compare cost optimal fleets developed under current policies as well as the draft Clean Electricity Regulations. Results include electricity generation, capacity changes, emissions, average wholesale power prices, and costs. A case study of Alberta may be useful to inform decarbonization pathways and policy in similar global electricity markets which lack developed low-emitting infrastructure.

4.2 Methodology

4.2.1 Industrial Carbon Pricing in Alberta

Alberta's carbon pricing policy, the Technology Innovation and Emissions Reduction Regulation (TIER) [34] is an output-based pricing system which includes an annually increasing cost of CO_2e while enabling the creation of emissions performance credits by low-emissions generators. The quantity of emissions covered or credits generated in the electricity sector is determined by comparing plant performance to a high-performance benchmark (HPB). The HPB was initially set to 0.37 t_{CO2e}/MWh in 2019, reflecting the performance of a new high-efficiency combined-cycle natural gas plant. Starting in 2023, the HPB is scheduled to decrease linearly by 2% of 0.37 t_{CO2e}/MWh annually, making the HPB 0.3552 t_{CO2e}/MWh in 2024 [34]. To comply with the TIER regulation, industrial sources that emit over 100,000 kt_{CO2e} per year can: (1) reduce their emissions, (2) purchase credits or offsets, and/or (3) pay the carbon price for emissions exceeding their limit. The industrial carbon price is CAD \$80/t_{CO2e} in 2024 and is scheduled both federally and provincially to increase at a rate of CAD \$15/t_{CO2e} annually to CAD \$170/t_{CO2e} by 2030 [86]. The cost of emissions in the model was determined by multiplying the difference between a plant's emission rate and the HPB by the carbon price.

Emission performance credits (EPCs) can be generated by any electricity generation technology by taking the difference between emission rate and the HPB for every MWh generated. Emissions credits can be monetized, which has provided low-emitting generation an additional revenue stream related to low or zero-emission attributes. Wind and solar projects currently also have the option to partake in a provincial offset program instead of generating EPCs. Offsets are a vestige of an earlier version of Alberta's carbon policy which are generated at a rate known as the emissions grid displacement factor (EGDF). According to the latest documentation, new projects are eligible to receive offsets for up to 15 years [36], after which, they may generate EPCs indefinitely. The 2024 EGDF is equal to 0.4901 t_{CO2e}/MWh, but since Alberta's electricity GHG emissions intensity has decreased significantly, the EGDF will linearly decrease to converge with the TIER HPB for electricity by 2030, at which point electricity offsets can no longer be generated. Offsets and EPCs can be sold to non-compliant industrial emitters interchangeably. Their value depends on carbon price, relative supply and demand of credits, and the year which they are sold

- as they may be banked for future years. This model assumes that new wind and solar projects collect offsets based on the declining annual EGDF until it converges with the HPB in 2030. Offsets and EPCs were valued at 90% of the carbon price in the year they were created.

The carbon price was assumed constant (at CAD \$170/t_{CO2e}) past 2030, while future values of the HPB were modified to model two different rates of carbon exposure, shown in Figure 4.1. The first, represents a current policy case with moderate carbon price exposure, where the HPB continues to decline at the 2% annual rate as is the plan at the time of writing this article. In the second scenario, the HPB declines linearly to 0 t_{CO2e}/MWh between 2030 and 2050. Moving towards full exposure by 2050 increases operational costs for conventional fossil fuel generation while credit generation is lowered.

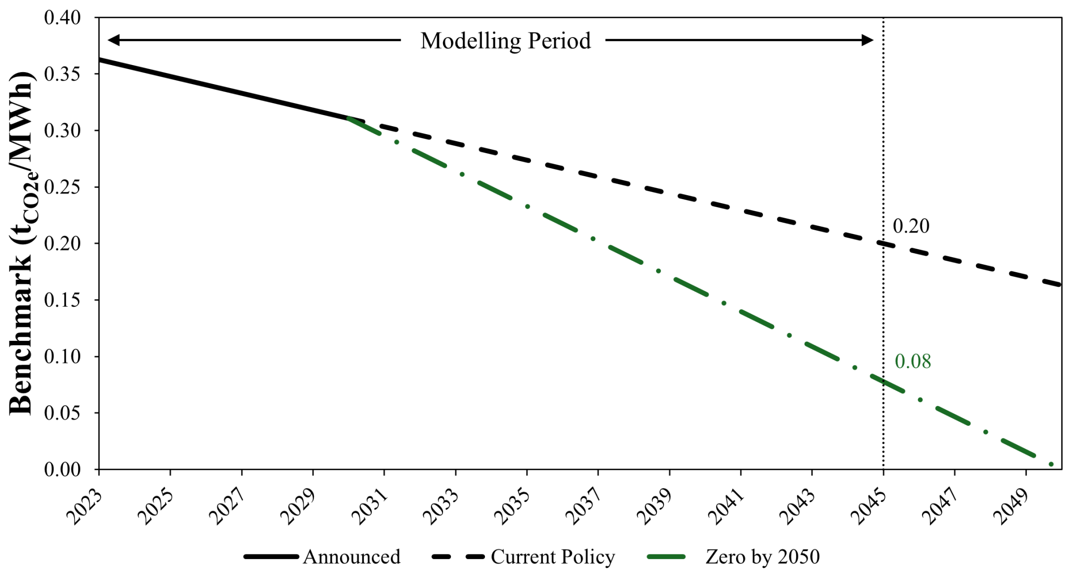

Figure 4.1: Alternative carbon policy high-performance (HPB) pathways used.

4.2.2 Emission Constraints

Canada's draft clean electricity regulation [25] includes a unit based annual emissions performance standard of 30 t_{CO2e}/GWh starting in 2035. Alternatively, plants may act as "peakers", operating below 150 kt_{CO2e} of emissions and 450 hours of operation per year. The regulation applies to all fossil fuel units that are (i) greater than 25 MW, (ii) following North American Electric Reliability Corporation standards, and (iii) net electricity exporters. For units built prior to January 1, 2025, the regulation would come into effect following a 20 year prescribed life. For units built after January 1, 2025, the regulation would begin in 2035.

The 450 hour limit in the draft CER was represented mathematically by applying an annual 5% capacity factor constraint to units starting in respective eligibility years. Additional emission constraints were not included, as earlier iterations of the model showed them to be non-binding compared to the capacity factor constraint. Fossil fuel plants were given the option to retire, act as "peakers", or retrofit with carbon capture and storage (for NGCC units). Consideration was not given to fuel blending with renewable natural gas or hydrogen. Additional provisions for emergency circumstances and a relaxed standard for new carbon capture and storage facilities included in the draft regulations were not incorporated in the model, since this is implicitly met based on constraints.

4.2.3 Scenario Design and the Model

Three main scenarios were explored as outlined in Table 4.1. The first scenario represented a current policy approach with moderate carbon price exposure. The higher HPB represents more leniency for emitting generation and higher valued credits for a longer period of time. The second scenario included the draft Clean Electricity Regulations (draft CER) and a HPB decreasing to 0 t_{CO2e}/MWh by 2050, eliminating credit generation as the grid approaches net-zero. As noted in Section 4.2.2, a 5% capacity factor constraint was applied to eligible unabated units. The final scenario, dubbed emission limit, presents an alternative approach to achieve the same goal as the draft CER. Output annual GHG emissions from the draft CER scenario were used to create a pooled annual emission limit in the emission limit scenario, constraining it to result in at most the same annual GHG emissions as the draft CER, but without the unit based capacity factor limit. The HPB was also decreased to 0 t_{CO2e}/MWh by 2050 in the emission limit scenario.

Table 4.1: Overview of the three main net-zero scenarios.

Scenario	**Carbon Exposure**	**Emission Constraint**
Current Policy	Moderate	None
Draft CER	Full 2050	5% capacity factor
Emission Limit	Full 2050	Draft CER emissions

Modelling was carried out using a commercialized mixed-integer program optimization software called Aurora [73] paired with Gurobi solver. Iterative long-term capacity expansions were performed to maximize system value (revenue minus costs), with commitment optimization logic to perform system dispatch and minimize generational costs. Although the model seeks to maximize value added by each plant, it is constrained to meet demand first. This means that the capacity expansion could retain or build uneconomical plants if they were required to meet demand reliably. In addition to demand constraints, the model includes a soft constraint to maintain a 15% reserve margin. The model operated at an hourly resolution for one week of each month of each year between 2023 and 2050[12].

4.2.4 Demand

Projected average and peak annual demand was taken from the Alberta Electric System Operator (AESO) 2022 *Net-Zero Emissions Pathways* report [76], which considers annual load changes based on electric vehicle adoption, hydrogen production, electric heating, and distributed energy resources (DER). Average growth rates of 1.09% for average load and 1.60% for peak load were calculated from the AESO net-zero report and used to extrapolate annual demand data beyond 2041. A normalized 8760 hourly demand profile was created based on real data from 2022 [27] and scaled

[12]Results were presented till 2045 to allow an adequate look-back period for the optimization.

based on annual load values.

The average demand forecasted in the AESO net-zero report falls within 200 MW of the AESO's 2024 long-term projections for the province [74], while peak load in the net-zero report exceeds the 2024 long-term outlook by an average of 713 MW between 2030 and 2041.

4.2.5 Market Structure and Pool Price

Alberta's competitive energy-only market allows hourly prices in the range of $0/MWh to $999.99/MWh. Hourly pool prices are determined by forming a merit order and selecting a marginal plant. For thermal generators, heat rate curves with prescribed bidding factors were used to vary efficiency and bids by operational load point in the model. At minimum capacity, plants operate with higher heat rates and offer energy at marginal cost or lower (based on flexibility). As load point increases, heat rates decline and plants bid much more aggressively.

4.2.6 Fuel Cost

Monthly natural gas projections spanning 2024 - 2025 were obtained from the Sproule short-term price forecast [84]. Annual natural-gas prices following 2025 were based on a 2023 forecast from the Canada Energy Regulator [78]. Future blue hydrogen prices were estimated based on values presented in Khan et al. [85], with hydrogen-fired electricity assumed to be GHG emissions free from a carbon policy point of view. Monthly price variation was introduced so that the annual gas and hydrogen prices fluctuated based on seasonal gas price patterns in Alberta, as it was assumed blue hydrogen would be derived from natural gas feedstock.

4.2.7 Transmission

To represent how the market might respond to policy signals, transmission and grid connection considerations were not included. Instead, limits were placed on the quantity of new wind and solar projects that could be added in each location, as presented in Section 4.2.9. The AESO is required to develop long-term transmission plans and identify transmission requirements with the long-term goal of unconstrained transmission in the Alberta market [31]. AESO is also responsible for transmission interconnections to support new projects once they receive regulatory approval. Since transmission costs are borne by load in Alberta, they are not associated with new projects from a developers perspective.

A total intertie capacity of 1263 MW was included, based on existing connections with Saskatchewan, British Columbia, and Montana. Zone prices in surrounding regions were based on the marginal cost of operating a single representative gas plant. The representative zone price was used as a price signal to determine when imports or exports would occur. Each intertie was de-rated hourly based on actual 2018 line capabilities [28]. This reflects fluctuations in import/export capability as a function of resource availability in other zones, maximum transfer regulations, and line outages[13]. Since the entirety of other electricity systems was not modeled, transmission expansion was not considered.

4.2.8 New and Existing Plants

Optimizations began with a complete set of existing plants. Known capacity additions under construction as of January 2024 [41] or with publicly stated final investment decisions were added exogenously. Exogenous capacity additions were added between 2023 and 2025, with one 75 MW pumped hydro storage facility added in 2026. Coal retirements were scheduled based on publicly available timing, and coal-to-gas retrofits end of life was set based on expected retirement years published in the AESO's 2021 long-term outlook [80].

Thermal plants were dispatched based on Aurora's commitment optimization logic

[13] Additional constraints were used to prevent total imports from surpassing ∼70% of the total capacity. This provided an additional layer of robustness in Alberta's capacity buildout to ensure reliable capacity needs were met within the province.

which determines optimal generation patterns based on input characteristics including up/down times, minimum capacity levels, and maintenance rates. Emission rates, heat rates, lifetimes, and other characteristics were modified for existing plants as needed - meaning existing projects operational characteristics and costs varied slightly from new projects to better reflect actual performance.

Operation and maintenance costs for new plant options are summarized in Table 4.2 (2022 CAD). For new simple-cycle and combined-cycle plants, the model was given the option to use natural gas or hydrogen fuel. The model considered five different energy storage options: three different battery storage options, pumped hydro storage, or compressed air storage. Hydrogen-fired units and gas with CCUS were considered to be low-emitting.

Table 4.2: New project costs and lifetimes.

Plant Type	**Full Load Heat Rate (GJ/MWh)**	**Efficiency (%)**	**Fixed O&M ($/kW-year)**	**Variable O&M ($/MWh)**	**Minimum Capacity**	**Lifetime (yrs)**
Hydroelectric			42.77			100
Combined-Cycle	6.79		20.20	3.65	45	30
Simple-Cycle - Aero	9.68		23.35	6.73	45	25
Simple-Cycle - Frame	10.45		10.03	6.45	40	25
NGCC with CCUS	7.52		39.53	18.28	50	30
NGCC CCUS Retrofit	7.52		39.53	18.28	40	20
Nuclear Fision	11.19		174.23	3.39		60
Nuclear SMR	10.60		136.07	4.30	50	60
Biomass (Other)	10.23		138.00	10.00	35	45
Solar			32.42			32
Battery Storage (50 MW 4 hr)		88%	57.28			20
Battery Storage (100 MW 6 hr)		88%	23.52			15
Battery Storage (100 MW 8 hr)		88%	23.52			15
Compressed Air Storage		52%	21.76			20
Pumped Hydro Storage		80%	38.05			100
Wind			71.95			30

Fixed and variable operations and maintenance costs were obtained from the AESO preliminary 2024 long-term outlook [75] with the exception of biomass costs which were based on Environment and Climate Change Canada modelling inputs [8] since the AESO did not include this option.

Capital costs for wind, solar, and storage were obtained from a 2022 report published by Clean Energy Canada using Dunksy energy [99], which used Alberta specific inputs to forecast costs between 2022 and 2035. All other capital costs were sourced from a preliminary version of the AESO's 2024 long-term outlook [75] to maintain regionalized cost projections. Initial capital costs were reduced based on normalized cost curves gathered from the NREL 2023 ATB moderate case [61]. For wind, solar, and storage, learning curves were applied starting in 2035 when projections from the Clean Energy Canada report ended. For developed technologies, including combined and simple-cycle turbines, capital costs were held constant. The change in capital cost for new projects is shown in Figure 4.2.

Based on Canada's 2023 federal budget [21], low or non-emitting electricity projects are eligible for a variety of investment tax credits (ITCs) between 2023 and 2034[14]. ITCs cover a broad range of technologies with credit values ranging from 15% - 50% based on the credit program. Alberta's Carbon Capture, Utilization, and Storage Investment Tax Credit [22] was considered in addition to federal ITCs, which provides an additional 12% credit for new CCUS built in Alberta between 2024 and 2035. ITC reductions to capital costs are depicted in Figure 4.2.

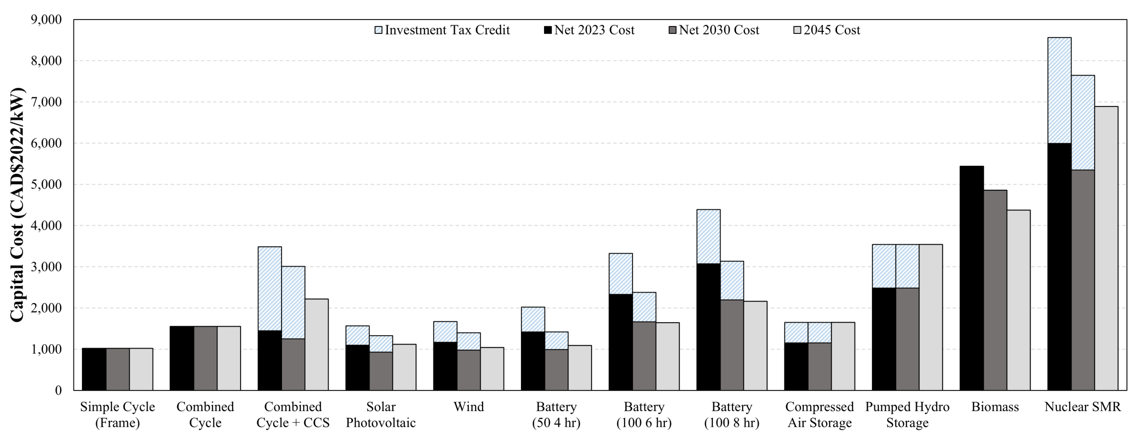

Figure 4.2: Capital cost in select years based on investment tax credits and learning rates.

[14]The Carbon Capture, Utilization, and Storage Investment Tax Credit for new CCUS equipment was interpreted from the 2023 federal budget [21] to be 50% from 2022 - 2030 and 25% from 2031 - 2040.

4.2.9 Renewables and Storage

Wind and solar output were shaped based on historic weather patterns. For solar, output was based on panel technology and available sunlight in Alberta. For wind, hourly output was location specific based on environmental data from the Canadian Wind Atlas [45] and methodology presented by Vergara Bonilla [94]. New wind capacity could be added at 29 unique locations which were selected based on existing facilities, projected facilities, and sites proposed by Pawlenchuk [93]. At each location, the model was constrained to an annual development limit of 400 MW, or a study wide limit of 1600 - 2000 MW to represent potential real world transmission build time constraints. For new wind, solar, and storage "partial builds" were enabled, meaning the expansion could add any capacity up to the overall constraint limit. Wind and solar plants offered generation at $0/MWh.

The Aurora modeling framework includes detailed hydro modeling logic. Monthly availability factors and correlation to provincial load based on 2019 data from the AESO [27] was input into this methodology to shape monthly hydro availability and dispatch. Storage plants were dispatched on a cost optimal basis and charged off the grid. Aggressive market behavior was not considered for storage technologies, meaning storage bids could not exceed marginal costs.

4.2.10 Cogeneration

The demand in this study represents Alberta Internal Load (AIL), which includes the load served on site (behind-the-fence). Historically, between 20% - 30% of AIL has been served by behind-the-fence generation [27], primarily by cogeneration plants at industrial sites. Although cogeneration plants may sell some excess power to the grid, the economics of these facilities are often tied to their primary product, mainly the oil sands in Alberta. As a result additional cogeneration was not considered for economic expansion or retirement beyond assumed projections and behind-the-fence supply was constrained using "must-run" conditions to meet industrial load, mimicking real world behavior.

Cogeneration plants were excluded from electricity based emission policy. The draft CER provisions include cogeneration facilities which are “net-exporters” of electricity (ie: they generate more electricity than they use), but this was not captured in the model as it is likely to be modified. Alberta GHG emissions from cogeneration are allocated inconsistently for different plants depending on their physical location with respect to their industrial heat load, ownership, and/or other factors. The breakdown of emissions allocated to heat and electricity is not consistent across facilities and is not publicly available. While cogeneration plants are subject to emissions pricing which has started to lead to CCUS considerations, for the purpose of this work cogeneration was treated exogenously and GHG emissions from cogeneration were not included in results.

4.2.11 Validation and Caveats

Inputs and market operation were validated by comparing hourly generation to actual 2022 and 2023 Alberta data. Further comparison was made to other publicly available Alberta forecasting reports provided by the Alberta Electric System Operator [74, 76]. While final fleet mixes differed, comparison to other forecasting work showed similar emission reductions pathways and validated the behavior of groups which did not experience significant capacity changes, such as cogeneration, biomass/other, and hydro.

It should be noted that the model dispatches plants to optimize for least cost hourly generation, while the capacity expansion maximizes system value as a sum of revenue and costs from each plant. Thus, when comparing the model to actual market results, generation and plant specific decisions will differ as the model cannot predict future private business decisions such as if companies build new plants or how they choose to dispatch them. Rather, the model is a tool to examine optimal future fleets and the impact of alternative policies on the viability of different technologies in the electricity market.

4.3 Results

Results show that current policies including industrial carbon pricing and federal investment tax credits (ITCs) allow the majority of Alberta's electricity system to decarbonize prior to 2035, achieving a nearly 80% GHG reduction relative to modelled 2023 GHG emissions. Pathways rely on an early expansion of wind and CCUS retrofits of existing combined-cycle units between 2023 and 2030, driven by available emissions performance credits (EPCs) and ITCs. between 2035 and 2045, the draft CER is able to reduce an additional 8.8 $\mathrm{Mt_{CO2e}}$ in cumulative GHG emissions relative to the current policy scenario, based on increased low-emitting generation.

Scenarios include a wind fleet three times the size of Alberta's current wind capacity, low-use dispatchable hydrogen and/or gas simple-cycle units, and low-emitting plants retrofit with CCUS. An abundance of wind generation and low-bidding firm supply causes average annual power prices to drop below $30/MWh until 2034. By 2045, 53% of all electricity was provided by renewable sources in the current policy scenario, or approximately 71% of grid generation (not including BTF). In the case of the draft CER, renewables represented 56% of total generation and 75% of grid generation in 2045.

4.3.1 Capacity

Figure 4.3 shows net annual capacity changes based on annual additions and retirements. In all cases, the optimal capacity mix relied on more than tripling Alberta's current 4.5 GW wind fleet. The current policy scenario experienced the most aggressive wind growth, with a total of 13.6 GW added between 2023 and 2045, allowing wind to reach 47% (15.8 GW) of installed capacity by 2045 once accounting for end of life retirements. In the draft CER and emission limit scenarios 11.7 GW and 13.3 GW of wind capacity was added respectively, representing 43% (13.8 GW) of installed capacity in the draft CER scenario and 46% (15.4 GW) in the emissions limit scenario in 2045. The maximum change in wind capacity across scenarios occurred in 2025, as a result of 0.4 GW in exogenous wind additions and 1.7 - 2.6 GW added by the model. Following 2025, annual wind additions did not exceed 1.4 GW in any year. Total wind additions of 13.6 GW resulting from the current policy scenario could also be achieved by adding 0.6 GW/yr over the 23 year study period. Wind capacity additions are reasonable given Alberta's previous single year record of 1.3 GW of wind added in 2022 [53].

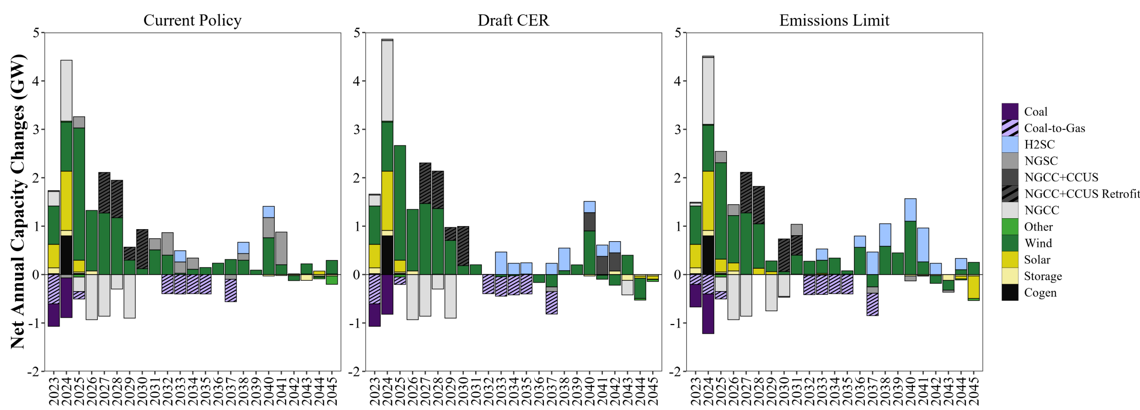

Figure 4.3: Net annual capacity changes.

A rush to build new wind capacity during the first third of the study was common in all scenarios, with 7.1 - 9.0 GW of wind capacity additions occurring before 2030 (over 50% of total wind additions). In all scenarios, installed wind capacity was 11 GW or more by 2030. This occurs for two reasons: (i) capital costs are reduced between 2025 and 2034 as a reflection of available ITCs, (ii) early development allows low-emissions projects to maximize cost reductions garnered from emissions credits. Since it was assumed that carbon price would remain constant at \$170/t_{CO2e} after 2030, the potential value of credits peaks in 2030 and decreases based on the high-performance benchmark (HPB) thereafter. In the current policy scenario, credits are valued higher between 2030 and 2045 as a result of a higher HPB relative to the other two scenarios, this enables a larger final wind capacity by 2045 by decreasing cumulative wind costs.

The current policy scenario resulted in 3.3 GW of solar by 2045, with only 0.1 GW added after 2025 (appearing in the early 2040's). In the draft CER scenario, solar reached 3.1 GW in 2045. The emissions limit scenario was a slight exception to this trend, with solar capacity reaching 3.6 GW by 2045. Although solar is eligible for the same financial incentives as wind, it did not carry the same annual value towards the system. Solar output is lower during winter months and is not reliably available at high priced times such as peak winter loads or low wind hours. For instance, in 2023 the current policy scenario resulted in a solar average capacity factor of 28% during summer months but only 8% during winter months. This is in alignment with actual 2023 seasonal solar capacity factors experienced in Alberta, calculated to be 30% during the winter and 7% in the summer [27]. The overbuild of wind also reduced the value of solar, since solar often generated in hours of excess wind and low prices. For these reasons, although solar plants remained profitable and were built, the model generally continued to operate or add alternative technologies which contributed more value to the overall system and better supported a large wind fleet via technical properties. The model also does not account for corporate power purchase agreements which have recently supported the development of some large scale solar projects in the province [100]. These reasons may explain why there is some discrepancy between simulated results and current solar growth, which has seen 1.6 GW of solar added to Alberta's system since 2020 [27].

Figure 4.4 shows the annual capacity in each scenario. In each year, a 5.3 - 7.8 GW block of thermal capacity (not including cogeneration) was part of the optimal fleet, this included natural gas simple-cycle (NGSC), hydrogen simple-cycle (H2SC), natural gas combined-cycle (NGCC), combined-cycle gas with CCUS (NGCC+CCUS), coal, and units converted from coal to gas. In 2045, the percentage of total capacity accounted for by non-cogeneration thermal technologies was 21% in the current policy scenario, 23% in the draft CER scenario, and 21% in the emissions limit scenario.

This is a shift from Alberta's current system which has just over 8 GW of unabated non-cogeneration fossil fuel generating capacity, representing nearly 40% of installed capacity.

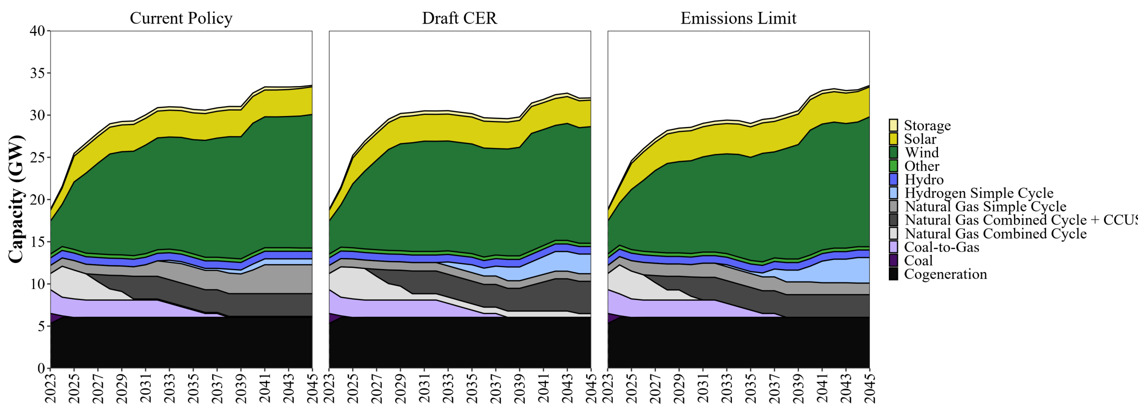

Figure 4.4: Annual system capacity.

A commonality between scenarios was the addition of simple-cycle plants, fueled by gas or hydrogen, operating as dispatchable forms of power which can take advantage of few but very high priced hours. The final capacity of simple-cycle plants was 4.1 GW, 3.2 GW, and 4.4 GW in the current policy, draft CER, and emissions limit scenarios respectively. For context, this represented 10% - 13% of total installed capacity in 2045. Hydrogen-fired simple-cycle plants first appear in 2033, as seen in Figure 4.3. In the absence of emissions constraints, 80% (~2.8 GW) of new simple-cycle plants built in the current policy scenario were gas-fired. In the draft CER scenario, all 2.3 GW of new simple-cycle plants were hydrogen fueled and existing NGSC facilities were operated within the capacity factor limit. This shows that even under stringent operating or emission constraints, these plants benefit from their flexible attributes and are not forced to retire early despite rising carbon costs. The flexibility of the emission limit scenario to operate individual units above a 5% capacity factor lead to 81% (~3.0 GW) of new simple-cycle plants being hydrogen-fired.

In each case, the model found it economic to retrofit approximately 75% of existing CCNG capacity with CCUS, representing 2.7 GW of capacity. Similarly to wind, early CCUS retrofits were supported by available ITCs and emissions credits. In the current policy scenario, following the completion of retrofits and retirements by 2030, a single NGCC plant with a capacity of 0.12 GW continued operating. In the emission limit scenario, all combined-cycle gas plants were either retrofit or retired by 2030, in part because the optimized emission allocation found it more valuable to associate pooled allowable emissions with more flexible simple-cycle natural gas plants and low emission plants with CCUS rather than retain combined-cycle plants. The draft CER scenario resulted in the highest portion of unabated NGCC plants remaining in operation, with a capacity of 750 MW (3 plants) from 2030 - 2043 and 450 MW (2 plants) by 2045, operated in a peaking style within the capacity factor constraint. The change in capacity between 2043 and 2045 is a reflection of plant specific constrains included in the draft CER.

The difference in NGCC capacity between the current policy and draft CER scenarios can be explained by the capacity factor constraint. Because operation was unconstrained in the current policy scenario, the model found it more economic to ramp NGSC units during peak hours, operating at an average annual capacity factor of 9% between 2035 and 2045. Since units were constrained to a 5% capacity factor in the draft CER scenario, less flexible combined-cycle units were dispatched alongside NGSC during peak load conditions to avoid incurring the cost to add additional units. Between 2040 and 2043, 1.1 GW of new capacity with CCUS was added in the draft CER scenario, resulting in a total capacity of 3.8 GW by 2045. This was novel to the draft CER case, as the other two scenarios did not include additional CCUS beyond units retrofit between 2027 - 2030. The selection of new CCUS in the draft CER scenario is possibly due to the combined effect of a 5% constraint on unabated generation and an alternative HPB pathway which increases GHG emissions costs, making it uneconomical to add new gas-fired units.

4.3.2 Generation

Annual generation results for the three scenarios are depicted in Figure 4.5. Prior to 2035, subtle differences in annual generation arose from different NGCC unit retirement decisions and operation. This led to an additional 18.2 TWh of NGCC generation between 2023 and 2034 in the draft CER scenario compared to the current policy scenario.

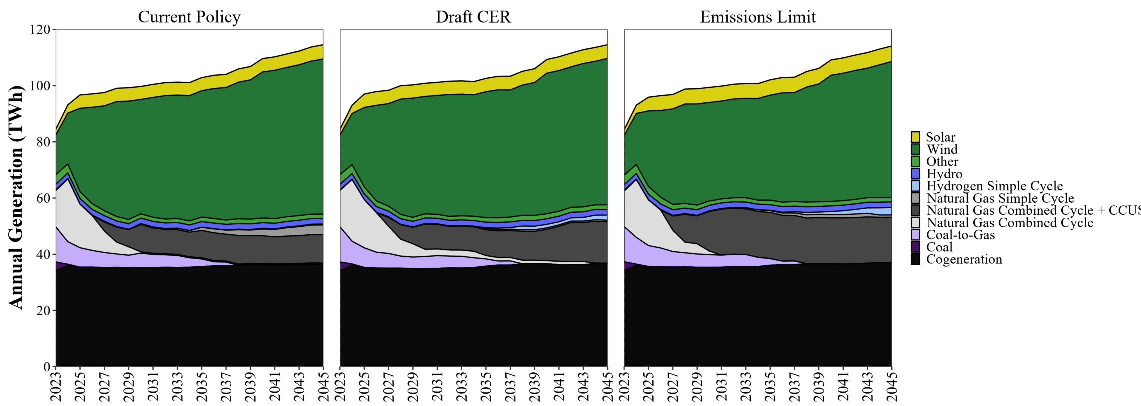

Figure 4.5: Annual generation.

Despite the increased capacity of simple-cycle plants in all scenarios, gas and hydrogen simple-cycle generation accounted for less than 4% of annual generation. H2SC generation experienced average annual capacity factors in the range of 1% - 9% while NGSC annual capacity factors ranged 1% - 11%. In the current policy scenario hydrogen-fired plants only accounted for 2.2 TWh between their emergence in 2033 and the end of the study period in 2045. Over that same time period, hydrogen-fired plants supplied 12.2 TWh in the draft CER case and 13.8 TWh in the emissions limit scenario. The operation of hydrogen-fired simple-cycle plants generally allowed for reduced generation from gas-fired simple-cycle plants, which ultimately led to reduced GHG emissions in the draft CER and emissions limit scenarios. Between 2035 and 2045, NGSC generation supplied 26.0 TWh in the current policy scenario, compared to 11.2 TWh in the emissions limit scenario and just 5.6 TWh in the draft CER scenario.

The dispatchable role of low-use hydrogen-fired plants in the draft CER scenario is visualized in Figure 4.6, which shows hourly output during four weeks of 2045. Although low use, these plants are able to capture high prices when they operate, enabling them to play an important reliability role during periods of low variable renewable output.

In all cases, the model found it economic to overbuild Alberta's wind fleet. Figure 4.5 shows an increase from wind supplying 14 TWh in 2023 to upwards of 35 TWh by 2030. The large wind fleet results in a maximum annual output of 55.2 TWh in 2045 by the current policy scenario and 52.1 TWh in the draft CER scenario. If zero-offer generation from wind and solar exceeded what was required to meet load and available exports, it was curtailed. Plants did not receive any value for curtailed generation and it was not included in total generation numbers.

An example of curtailment in the draft CER scenario can be seen in the 2030 hourly generation Figure 4.7. In the current policy scenario, which included the highest amount of wind output, wind and solar generated 1288 TWh between 2023 and 2045, of this, 193 TWh was curtailed (15%). Between 2023 and 2045, an average of 8 TWh per year of wind generation was curtailed in the current policy scenario. Curtailed power suggests that Alberta could benefit financially from expanding future trade partnerships with increased intertie capacity. It also suggests potential for further work to analyze opportunities for unused energy, such as green hydrogen production or paired renewable-storage facilities.

Although the current policy scenario resulted in a larger renewable fleet compared to the draft CER scenario, the percentage of total generation supplied in 2045 by renewable sources in the draft CER scenario was 3% higher (for a total of 56%). In the current policy scenario, during hours where wind and solar did not exceed available export capacity, unabated generation could operate and export power if economic. Since unabated generating units were constrained to a 5% capacity factor in the draft CER scenario, the optimization does not select to operate these units purely for export, which shifts the overall percentage of generation supplied by renewable sources.

Since 2017, Alberta has been a net-importer of electricity, with a maximum net flow of 4 TWh into the province in 2021 [27]. This trend has begun to change, as AESO reported that imports were roughly equal to exports in 2023 [18]. Modelled results show Alberta becoming a net-exporter of electricity starting in 2024. Between 2024 and 2045, annual imports ranged 0.8 - 2.6 TWh while exports ranged 4.7 - 7.7 TWh across scenarios. This is supported by excess renewable generation, primarily wind, which allows Alberta's generation to exceed demand requirements over 85% of hours between 2025 and 2034, and over 65% of hours between 2035 and 2045.

Storage expansion was not a key part of any scenario, only the draft CER scenario included additional storage (0.1 GW) beyond exogenous additions. This is likely a product of lengthy oversupply periods, low average wholesale power prices, capital costs, and bidding logic which dispatches storage at its marginal cost, thus preventing storage from bidding aggressively into the market. Since supply was generally in excess, storage cycling was not required or cost effective given that the wholesale pool price was $0/MWh for an average of 48% of total hours over the entire study. This makes storage a less valuable addition to the objective function of the model, since storage can not earn a substantial profit relative to its costs using arbitrage.

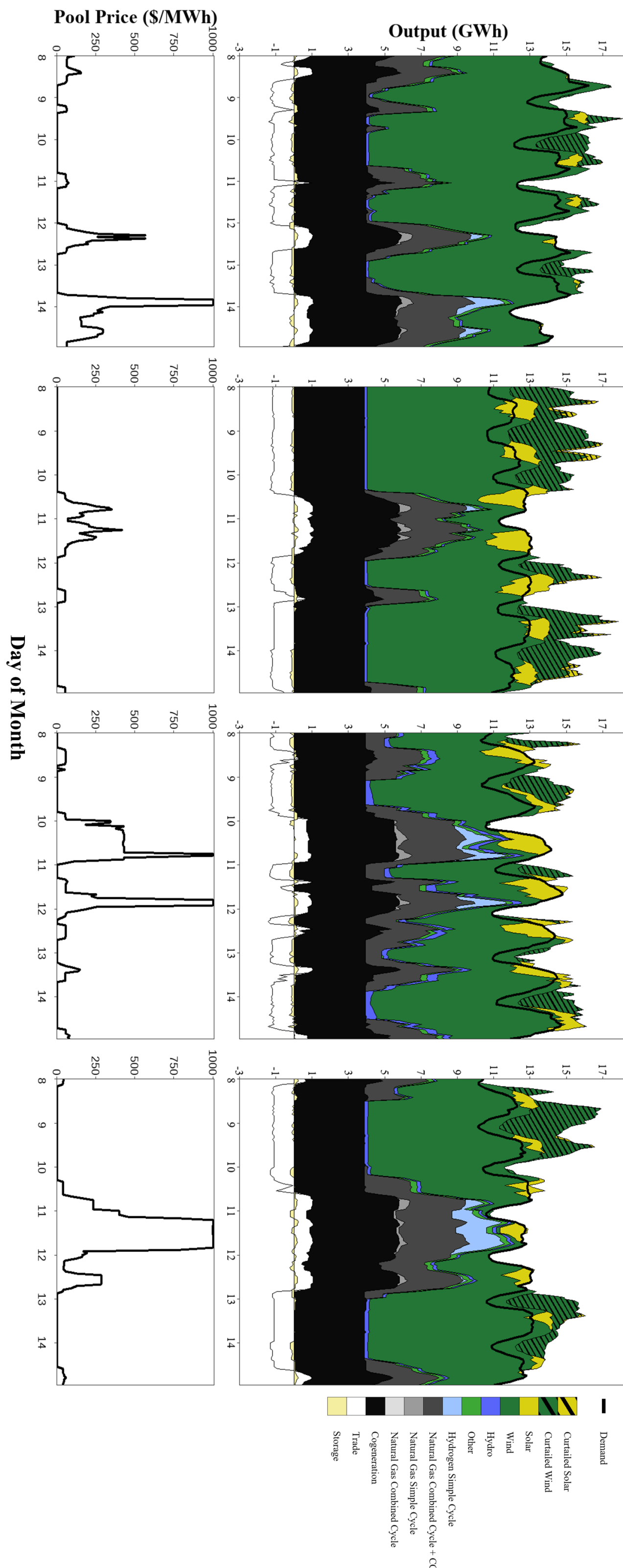

Figure 4.6: Generation and wholesale power price for four weeks in 2045 in the draft CER scenario.

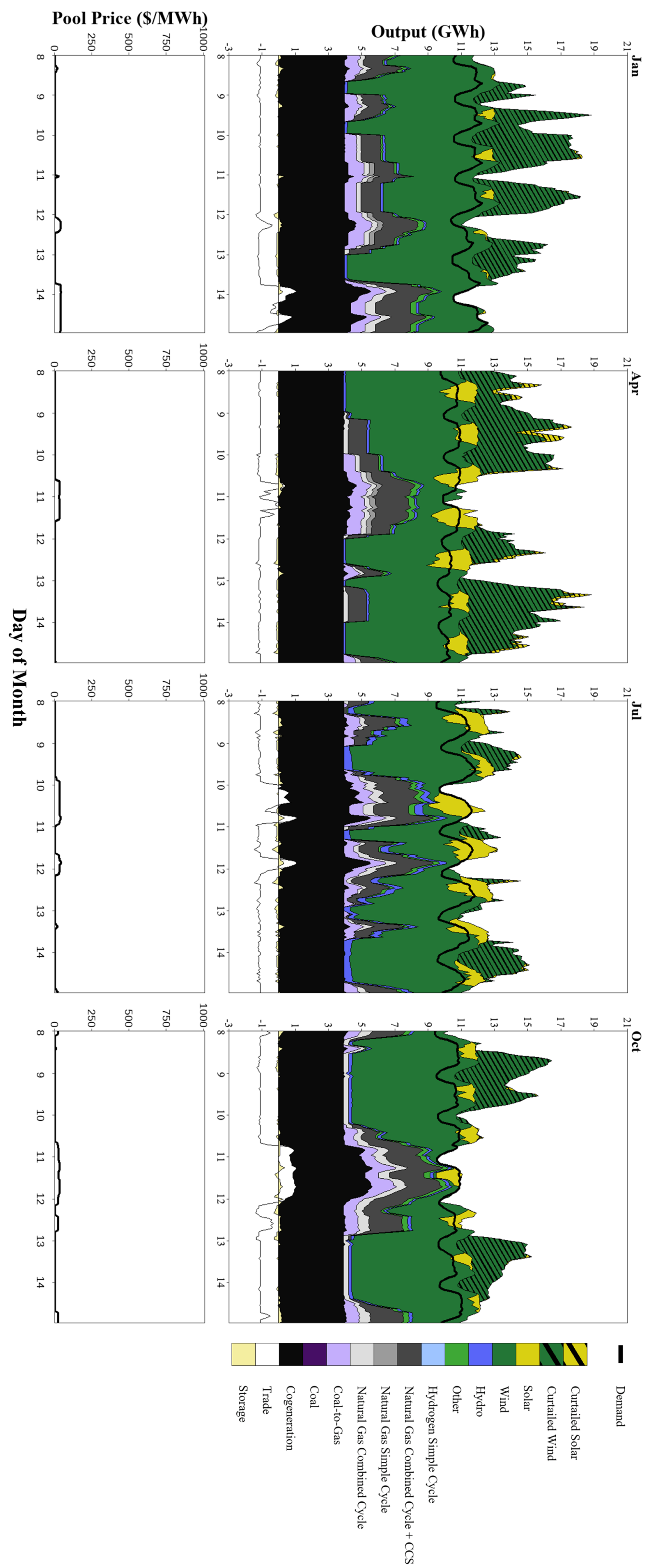

Figure 4.7: Generation and wholesale power price for four weeks in 2030 in the draft CER scenario.

4.3.3 Wholesale Prices

Figure 4.6 shows average annual pool prices for each of the three scenarios, along with historic prices since 2005. With the near-term deployment of wind and CCUS, the average annual pool price dropped below \$30/MWh until 2034. Low prices are further influenced by bidding logic, which produces less aggressive behavior when the market is not tight and also offers the self-supplied portion of cogeneration at \$0/MWh, since this generation would not be offered competitively.

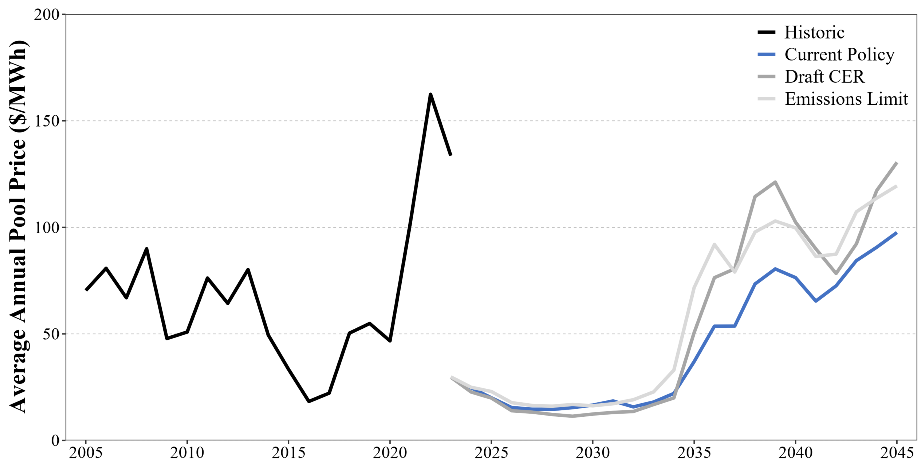

Figure 4.8: Average annual pool price for each scenario.

Following 2034, prices rose as a reflection of increased load and the growing role of peaking plants which bid more aggressively as the market tightens. The wind dominated system in combination with aggressive peaking behavior causes increased volatility in hourly pool price based on demand and available wind power, this can be seen in the hourly generation and prices chart shown in Figure 4.6. Prices increase more quickly in the case of the draft CER and emission limit scenarios as the model attempts to optimize the output of remaining unabated gas generation within provided GHG emissions constraints.

Alberta's carbon pricing system allows CCUS plants to offer power at lower prices when operating near minimum stable load. For instance, in 2030, a CCUS emission performance credit (EPC) in the model was worth an average of \$44.11/MWh (hourly rates varied based on emissions intensity). This represents a "negative cost" in the model logic, which moves CCUS plants down in the merit order. As the TIER HPB for electricity is tightened, average credit values decrease. In 2045 the model reports average EPC value for plants equipped with CCUS as \$27.15/MWh in the current policy case and \$7.57/MWh in cases where the HPB reached 0 t_{CO2e}/MWh by 2050.

Wind energy received a negative premium compared to the average price. In the current policy scenario, wind received a discount-to-pool-price equal to 18% in 2023, 34% in 2024, and 46% in 2025. Beyond 2027, the annual wind discount ranged from 51% - 73% across scenarios. Despite this, wind plants were able to remain profitable as a result of no operating costs and earned emissions credits. For wind and solar, credits were valued slightly higher than they were for CCUS, since there were no direct GHG emissions. As a result, in 2045 credits were worth \$30.57/MWh in the current policy scenario or \$11.88/MWh in the other two scenarios.

The pool price behavior reflects prescribed bidding logic which is based on historic behavior but may vary in a more renewable dominated market where traditional plants operate less. In addition, since bids were created as a function of load point, they vary from scenarios where a generator may offer below maximum capacity at a high price. In general, this should not occur often in a competitive market, however recently Alberta's market has become concentrated, leading to above average prices in 2022 and 2023. Thus, forecasted pool prices are useful to support capacity buildouts and analyze policy trends, but they are not a picture of the future. The low prices experienced between 2024 and 2035 reflect how the competitive market could respond to high penetrations of renewable energy, highlighting potential revenue concerns for new firm capacity.

4.3.4 Cost of the Draft CER Compared to Current Policy

The total cost of the draft CER scenario exceeded the current policy case by 12%. Costs reported included a summation of capital costs, fixed and variable operations and maintenance costs, net emissions cost, fuel costs, and charging costs from all plants in the system between 2023 and 2045. The majority of additional costs incurred by the draft CER scenario were derived from net emissions costs (i.e. carbon costs net of emissions credits) as a reflection of differences in future carbon pricing framework. In the current policy scenario, the HPB experienced a slower decline - meaning less money was spent by fossil fuel generators on GHG emissions and low or non-emitting generation benefited from an increased “negative” emission cost via emission performance credits. As the HPB moves towards 0 t_{CO2e}/MWh in the draft CER scenario, more emissions were exposed to carbon price while less emission performance credits were generated. This result suggest that the largest cost incurred was not a direct product of new capacity built to meet the draft CER requirements, but rather choices surrounding existing carbon pricing policy. Excluding net-emissions cost entirely, the draft CER scenario cost only exceeded the current policy scenario by 1%. Close costs outside of GHG emissions are based on a combination of 7.7% lower investment capital costs and 6.7% higher fuel costs in the draft CER scenario relative to the current policy scenario. The cost of fixed and variable operations and maintenance were largely the same based on operating similar fleets with alternative fuels.

4.3.5 GHG Emissions

Figure 4.9 shows annual GHG emissions split by technology and/or fuel. Between scenarios, annual GHG emissions were reduced 75% - 77% by 2030 and 79% - 83% by the end of 2034, with annual emissions of ≤4 Mt_{CO2e} by 2030 in all cases. Reductions are relative to annual emissions of 15.6 Mt_{CO2e} reported by the model in 2023 and do not include cogeneration emission allocations. This result suggests Alberta’s industrial carbon tax framework and accompanying federal investment tax credits to be highly effective in the near term.

Early reductions were driven by a completed coal phaseout in 2024 and increased

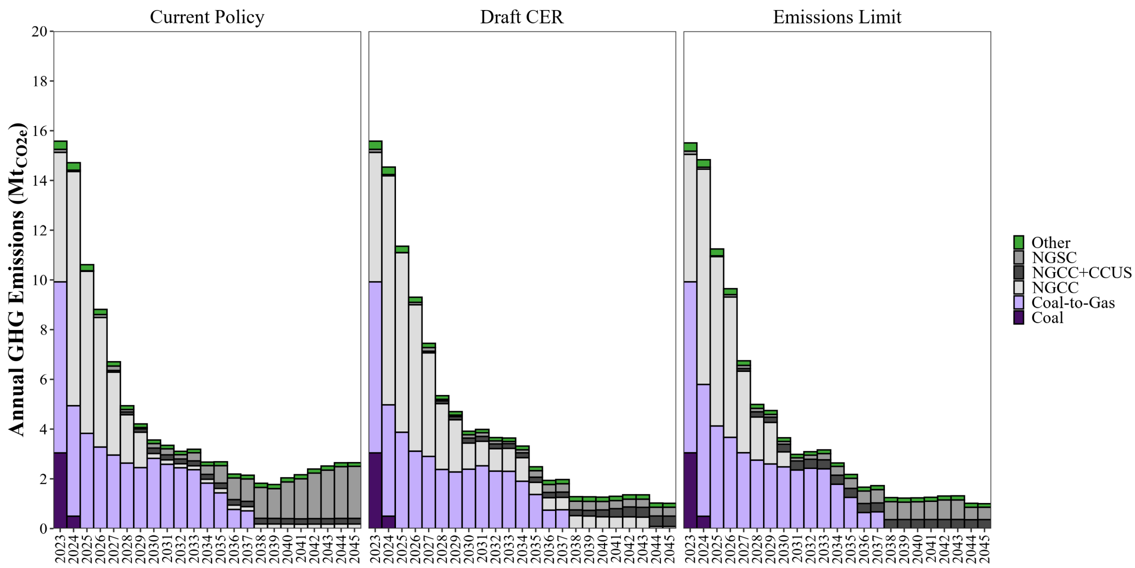

Figure 4.9: Annual non-cogeneration GHG emissions for the three scenarios.

renewable energy generation, displacing traditional fossil fuel power. Although there was some variation between scenarios, annual emissions were reduced by 5.9 - 6.8 Mt_{CO2e} between 2023 and 2026, representing a reduction of approximately 40%, as seen in Figure 4.9. Further emission reductions between 2027 and 2030 can be mainly attributed to existing NGCC units completing CCUS retrofits and continued growth of wind generation, which allows for additional GHG reductions of 5.3 - 6.0 Mt_{CO2e} by 2030 relative to 2026.

On average, the current policy scenario produced 0.4 Mt_{CO2e} less GHG emissions annually than the draft CER scenario between 2023 and 2034. This small difference in annual GHG emissions is primarily a reflection of different decisions taken by the model regarding the retirement of NGCC units between 2023 and 2025, which causes NGCC to generate an additional 18.2 TWh between 2023 and 2034 in the draft CER scenario. Combined-cycle gas represents the leading source of GHG emissions until CCUS retrofits begin in 2027; after which coal-to-gas retrofit units become the leading source of emissions until their final retirement in 2037.

Smaller GHG emission reductions spanning 2030 through to 2037 are attributed to the phased retirement of Alberta's coal-to-gas fleet. These GHG emission reductions are less noticeable than those associated with coal, early renewable energy growth, or CCUS retrofits, since coal-to-gas units operate in a dispatchable fashion and are replaced to some extent by other unabated gas generation. In the current policy scenario, unabated gas emissions from NGSC increase as peak load moves from 14.2 GW in 2035 to 17.0 GW in 2045. This results in an upwards GHG emissions trend in the current policy case, with annual GHG emissions increasing from 1.8 Mt_{CO2e} in 2038 to 2.6 Mt_{CO2e} in 2045.

The draft CER policy results in further GHG emissions reductions past 2035 and maintains lower annual emissions into the 2040's, moving from 2.5 Mt_{CO2e} in 2035 to 1.0 Mt_{CO2e} in 2045. Thus, the draft CER results in 8.8 Mt_{CO2e} fewer cumulative GHG emissions between 2035 and 2045 than the current policy scenario. The majority of remaining emissions in the draft CER scenario are attributed to unabated gas generation operating within the capacity factor constraint and emissions which are not captured by CCUS.

Overall, relative to 2023 modelled emissions, the current policy scenario results in a GHG emissions reduction of 83% and the draft CER scenario results in a 93% GHG emissions reduction. Absolute zero emissions is not reached in any case, meaning offsets would be required to account for the $\leq$2.6 Mt_{CO2e} of remaining annual emissions in 2045.

4.3.6 Investment Tax Credits

The impact of federal ITCs (which reduced capital costs) on capacity, generation, emissions, and total cost in the current policy and draft CER scenarios is depicted in Figure 4.10.

In the current policy scenario, ITCs primarily impacted CCUS retrofit decisions for existing NGCC units; ITCs enabled an additional 1.5 GW of gas-fired CCUS capacity relative to the current policy case without ITCs which only reached a capacity of 1.2 GW by 2045. As a result of increased abated capacity, the current policy case

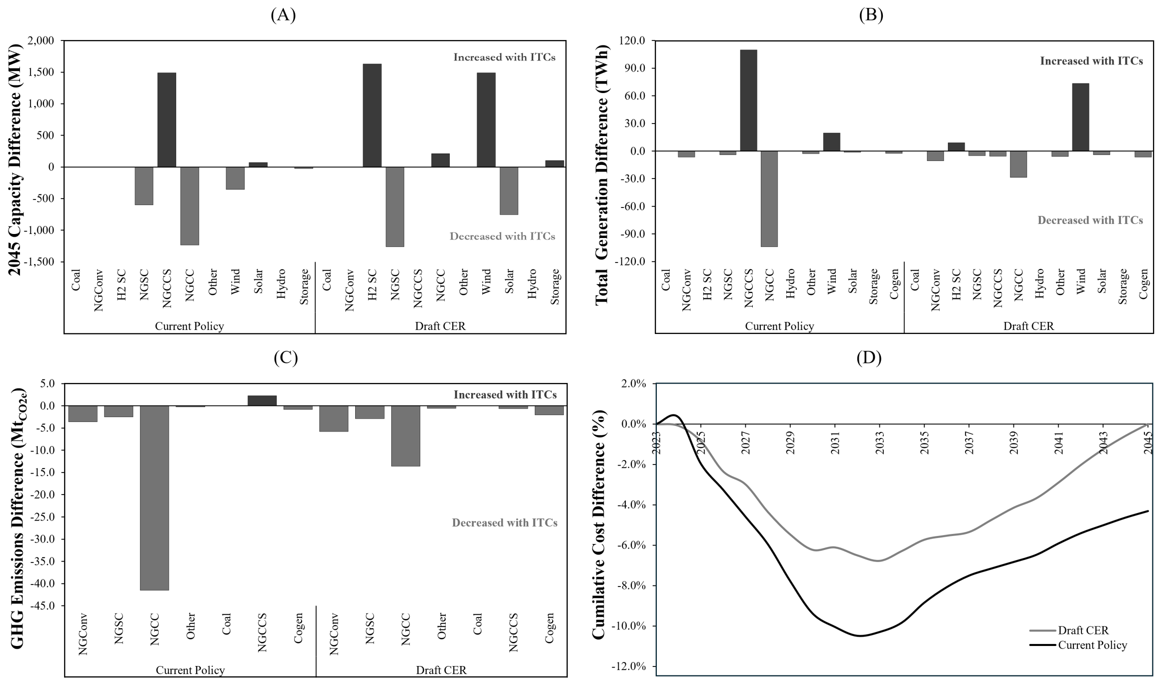

Figure 4.10: Difference between cases with and without investment tax credits on (A) final capacity, (B) cumulative generation, (C) cumulative GHG emissions, (D) cumulative cost (nominal).

with ITCs resulted in 1.2 GW less NGCC and 0.6 GW less NGSC capacity than the case which did not include ITCs. Between 2023 and 2045, the current policy case with ITCs resulted in 110 TWh more generation by plants with CCUS and 103 TWh less generation by NGCC plants than the scenario without ITCs. In the current policy scenario, the inclusion of ITCs did not significantly impact the capacity or generation of renewable energy, resulting in an additional 69 MW of solar and 356 MW of wind, which increased combined wind and solar generation by 18.3 TWh over the entire study. Thus, ITCs result in two fleets with similar operating properties but different emissions intensities under current policies.

Including ITCs in the draft CER case resulted in an additional 1.5 GW of wind but 0.8 GW less solar capacity, resulting in a 69.4 TWh increase in combined wind and solar generation overall. To balance additional wind generation in the draft CER case with ITCs, an additional 1.6 GW of H2SC relative to the non-ITC case was added, accounting for a 9.1 TWh difference in H2SC generation over the entirety of the study. H2SC units operated at very low capacity factors, as discussed in Section 4.3.2. Given that hydrogen does not appear until 2033 and the respective ITC ends in 2034, this result was likely a second order effect based on other changes to the supply mix rather than a direct result of removing ITCs. In the draft CER scenario, the final capacity of units with CCUS remained the same regardless of ITCs. This suggests that the combination of the draft CER and carbon pricing, which reached full exposure by 2050, enables additional CCUS capacity. Although 6 NGCC plants were retrofit in either draft CER scenario (representing a capacity of 2.7 GW), removing ITCs was found to reduce the incentive for retrofits to take place before 2030, since there was no associated cost savings. As a result, in the draft CER case without ITCs, 2 units (0.7 GW) were retrofit between 2044 - 2045, which caused increased cumulative emissions from respective NGCC units compared to the ITC case in which all units were retrofit prior to 2031.

Without ITCs, the current policy scenario resulted in a 70% GHG reduction relative to 2023, compared to 83% when including ITCs. Annual GHG emissions were under 5 Mt_{CO2e} from 2035 onwards, suggesting the effectiveness of Alberta's carbon pricing system in promoting low or non-emitting generation, even without ITCs. The current policy scenario with ITCs resulted in 2.0 Mt_{CO2e} less GHG emissions annually compared to the non-ITC case, representing a difference of 45.6 Mt_{CO2e} overall, primarily due to a 41.5 Mt_{CO2e} decrease in NGCC emissions. This emphasizes the importance of abating or replacing traditional NGCC units in decarbonization strategies. It also demonstrates the difficulty associated with deep emissions reductions in fossil fuel intensive electricity systems, as carbon capture solutions become less likely without cost incentives.

The draft CER scenario without ITCs reached an annual GHG emissions of 1.4 Mt_{CO2e} in 2045 and achieved a 91% reduction in GHG's relative to 2023 results, only a small divergence from the 93% reduction when including ITCs. Although the two draft CER scenarios annual emissions started to converge by 2045, this was not the case for the

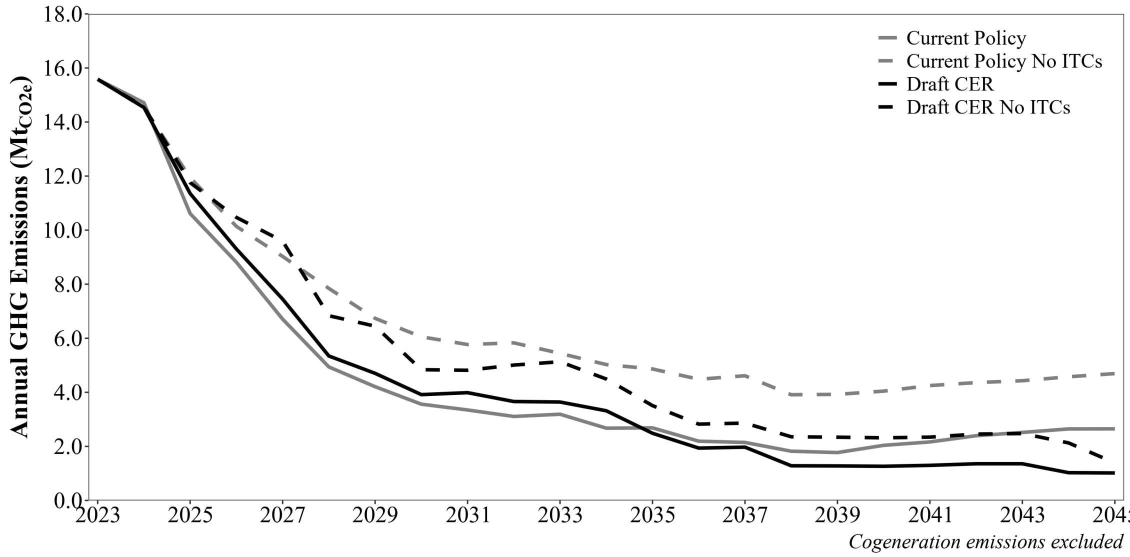

Figure 4.11: Annual GHG emissions with and without investment tax credits.

entire study period. As seen in Figure 4.11, there was an average gap of 1.0 Mt_{CO2e} annually, which contributed to a cumulative emissions increase of 23.5 Mt_{CO2e} in the draft CER scenario without ITCs. Furthermore, in the absence of ITCs, the draft CER results in a cumulative emissions savings of 25.5 Mt_{CO2e} relative to the current policy scenario without ITCs, demonstrating a higher potential for GHG emissions reductions by the draft CER in a scenario without federal subsidies for new low or non-emitting generation.

In the current policy scenario, ITCs reduced total costs by 4.3%. ITCs had the most noticeable impact on cumulative system costs prior to 2035, as demonstrated in Figure 4.10. Early system cost reductions in the ITC cases between 2025 and 2034 reflect differences in investment cost which are directly impacted by ITCs. Despite achieving additional GHG emission reductions, the draft CER scenario resulted in a $<$0.01% cost difference by the end of the study period. Although the overall cost difference was negligible, reduced capital costs from ITCs available prior to 2035 incentivised earlier investment in low and non-emitting generation, which reduced cumulative GHG emissions.

4.3.7 Limitations and Future Work

Since this model did not include the full provincial industrial carbon market, emissions credits were generated based on the annual HPB and monetized based on a value of 90% the carbon price in the year they were generated. The value of emissions credits could change over time based on the pace of sector wide decarbonization or the opportunity for banked credits to be sold in later years at higher prices.

Between 2023 and 2030, 7.1 - 9.0 GW of wind was added, resulting in annual GHG emissions of less than or equal to 4 Mt_{CO2e} by 2030. The pace of wind additions could be slowed by transmission development timelines or new provincial policies [44] that could limit new wind locations. Hourly wind output in this study was based on historical data from a single year. Future work is required to assess the adequacy of the optimal pathways developed under alternative hourly renewable output conditions.

The 2045 fleet mix in the main three scenarios included 0.7 - 3.0 GW of hydrogen-fired capacity and 2.7 - 3.8 GW of gas plants equipped with CCUS. This assumes the availability of low-emissions blue hydrogen along with accompanying industrial infrastructure by 2033, when hydrogen plants first appear. Changes in the capacity of gas-fired plants with CCUS were driven by the ability to generate emissions credits, reduced investment costs from ITCs, and (in the case of the draft CER) tightened policy which caused other thermal generation to be of less value. Recently, the most advanced carbon capture electricity project in Alberta was cancelled citing a lack of economic feasibility [101]. This reflects a gap between the optimal solution suggested by the model and actual investment decisions. If CCUS does not materialise as expected, results show continued operation of existing unabated gas infrastructure, making it more difficult to reduce emissions in line with these pathways.

Finally, future work is required to better assess cross-sectoral decarbonization pathways for Alberta's industrial cogeneration fleet. Without abatement, cogeneration could become the largest single source of GHG emissions in the electricity sector by 2035 regardless of how GHG's are allocated. Thus, the decarbonization of the electricity sector will partially depend on outcomes from codependent sectors which cogeneration facilities are tied to.

4.4 Conclusions

Many governments are targeting decarbonized electricity systems to meet net-zero targets. This paper presents a case study of Alberta, a fossil fuel dominated competitive electricity market, to assess how policies including an industrial carbon tax, the draft CER, and investment tax credits (ITCs) may impact capacity, generation, GHG emissions, and system costs. A long-term capacity expansion and dispatch optimization model was used to maximize total system value for three alternative scenarios.

By 2030, results showed that Alberta's annual GHG emissions could be reduced to 75% of 2023 modelled emissions, based on 7.1 - 9.0 GW of wind capacity additions and retrofitting three-quarters of existing NGCC capacity with CCUS. Expansion of Alberta's wind fleet to reach 15.8 GW accompanied by 2.8 GW of new low-use simple-cycle gas capacity resulted in annual GHG emissions falling 83% under current policies which included current carbon policy trajectory and federal investment tax credits. The draft CER and full carbon exposure by 2050 enabled a 93% GHG emissions reduction relative to 2023, based on a 3.0 GW hydrogen-fired simple-cycle fleet operating with an annual average capacity factor of 1% - 9% and 3.8 GW of gas-fired units with CCUS. Reductions suggest that Alberta could reach a net-zero goal in its electricity system with limited use of offsets. Results show that production based credits for low or non-emitting generation such as those included in Alberta's carbon pricing system, may enable electricity system decarbonization by promoting the development of low and non-emitting generation, while carbon costs simultaneously disincentivize emissions intensive generation.

Standards included in the draft CER scenario resulted in a cumulative GHG emissions reduction of 8.8 Mt_{CO2e} between 2035 and 2045 relative to current policies, prevented a potential increase in annual emissions during the early 2040's, and resulted in Alberta reaching an annual GHG emissions level of 1.0 Mt_{CO2e} by 2045. The 12% difference in total system costs between the current policy and draft CER scenarios was found to be mainly a function of net-carbon costs, with only a 1% difference if net carbon costs were neglected. Cost similarities between the current policy and draft CER systems suggest that the draft CER may not represent as significant of a cost challenge as other studies have predicted [76], although resource adequacy was not explored in this work. When ITCs were excluded, the draft CER scenario resulted in a cumulative emissions savings of 25.5 Mt_{CO2e} relative to current policies. This indicates that a unit-based emissions standard may be beneficial to reduce GHG's in systems that do not have access to subsidies.

Wind energy represented over 40% of installed capacity in each scenario in 2045, this allowed renewable energy to generate 53% of total generation under current policies and 56% in the draft CER scenario. Results suggest an overbuild of wind capacity is a viable low-cost net-zero strategy in regions with adequate resource availability. To maximize emission reductions, policy makers should seek solutions that support continued wind development along with complementary flexible power sources. A total of 193 TWh of curtailed renewable energy in the current policy scenario suggests a potential for future opportunities such as expanded interties, green hydrogen production, or paired storage facilities.

Average annual power prices were less than $30/MWh until 2034 in all scenarios as a result of an oversupply of wind energy and CCUS plants willing to offer power for less as a result of emissions credits. This result could suggest potential short-term challenges to the competitive market.

The cost optimal solutions used a fleet of gas-fired or hydrogen-fired simple-cycle plants which reached a capacity of 3.2 - 4.4 GW by 2045 to balance variable renewable output. Simple-cycle plants operated at high prices, with annual capacity factors of

1% - 11%, which allowed the system to maintain emissions of less than 3 Mt_{CO2e} from 2035 onwards. Including low-use dispatchable plants may help electricity systems with high variable output reduce annual GHG emissions.

Other studies have identified combined-cycle gas units as a challenge for GHG reductions [68, 69]. This work finds that incentives including emissions credits, investment tax credits, and/or strengthened policy to limit unabated emissions, enables CCUS retrofits to existing units, thus minimizing total GHG emissions from combined-cycle plants. At reduced rates of CCUS deployment, existing gas-fired generation operated more, causing an increase in cumulative GHG emissions. This is evident in the current policy case without ITCs, where unabated gas generation exceeded the case with ITCs by 103 TWh and cumulative GHG emissions were 45.6 Mt_{CO2e} higher. Thus, findings highlight the benefit of ITCs to encourage the development of low emission solutions and possibly enable the deployment of low-emitting technologies like CCUS.

Uncertainty surrounding hydrogen and CCUS present potential barriers to emissions reductions and policy compliance. Additional flexibility for existing generation when including GHG emissions performance standards or further incentive for other low-emitting supply solutions could benefit decarbonization pathways and help ensure adequate supply alongside GHG reductions.

Overall, it appears that Alberta is well positioned to make significant progress on decarbonizing its electricity sector within the next few years and could achieve a net-zero goal under current or proposed policies.

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Chapter 5

Provincial Carbon Policy and Decarbonization

Alberta's industrial carbon pricing framework provides incentive for the electricity system to decarbonize. In fact, results presented in Section 4.3.6 suggest that in the absence of federal investment tax credits, carbon pricing alone could result in annual non-cogeneration GHG emissions of less than 5 Mt_{CO2e} from 2035 onwards. As a point of reference, Canada's official greenhouse gas inventory [19] estimated that Alberta's electricity system was responsible for 19.3 Mt_{CO2e} of GHG emissions in 2022[15], down from 45.6 Mt_{CO2e} in 2015. Compared to historic annual GHG emissions, scenarios presented in Chapter 4 represent potential for substantial GHG reductions. The emissions reductions achieved in Chapter 4 are subject to the assumptions that: (i) carbon pricing continues to tighten at the current rate after 2030, (ii) emissions credits are worth 90% of the carbon price in the year they are generated, and (iii) carbon capture utilization and storage (CCUS) is available. This chapter expands on scenarios presented in Chapter 4 by exploring how these three assumptions could impact future electricity supply and GHG emissions in Alberta. For the remainder of this chapter, "credits" or "emissions credits" refers to either EPCs or offsets generated under Alberta's TIER policy.

[15]Federal inventory numbers include emissions from ∼20% of cogeneration facilities in Alberta. For reference, 2022 electricity GHG emissions presented in the AESO's 2022 net-zero report (which used the same methodology as the federal inventory) [76] amounted to 23.1 Mt_{CO2e}, with 4.6 Mt_{CO2e} allocated to cogeneration.

5.1 Introduction

In combination with the carbon price, the TIER high-performance benchmark (HPB) for electricity determines the total cost of carbon for non-compliant[16] emitting generation and the magnitude of emissions credits that can be created by low-emitting generators. If an electricity generation facility exceeds the HPB, compliance can be met by purchasing EPCs, purchasing offsets, or paying the annual carbon price for GHG emissions which exceed the allowable amount. If generators achieve an emissions intensity below the HPB, they are rewarded with EPCs, quantified by the difference between their actual emissions intensity and the annual HPB. Credits may then be banked for future years or sold to non-compliant industrial emitters across Alberta's industrial sectors. As explained in Section 2.1.3, the HPB is scheduled to decrease at a rate of 2% of 0.37 t_{CO2e}/MWh annually between 2022 and 2030 [34]. To encourage continuous technology improvement and reflect decarbonization progress, it is logical that the HPB should eventually reach 0 t_{CO2e}/MWh[17]. This would also align with federal and provincial net-zero goals.

Noting that the HPB for electricity has important implications for both the electricity system and non-compliant industrial facilities that purchase credits, several approaches could be taken to define the HPB following 2030. Continuing at the current 2% of 0.37 t_{CO2e}/MWh annual tightening rate, the HPB would reach zero by the year 2072. This would provide leniency to emitting generation and allow low-carbon generators, such as plants with CCUS, to generate EPCs until the 2070's. However, if the HPB tightening rate proved to be too slow, it could result in less of a market signal for timely and substantial GHG reductions and/or potentially cause an over saturation of emissions credits. Adopting a more aggressive tightening rate for the HPB would increase carbon price exposure for emitting generation and decrease po-

[16] Non-compliant indicates that a facility's annual emissions intensity surpassed the annual HPB.

[17] A HPB of 0 t_{CO2e}/MWh may be called "full carbon price exposure", since all GHG emissions are exposed to carbon price.

tential revenue generated from EPCs for low or non-emitting generation. As a result of increased carbon exposure, non-compliant emitting generation may potentially improve efficiency, retrofit with CCUS, limit annual operation, retire early, or increase hourly offer prices and continue operating.

5.1.1 Scenarios

The current policy scenario presented in Chapter 4 was compared to seven alternative versions outlined in Table 5.1. All scenarios included federal investment tax credits (ITCs) and did not include any additional constraints on annual GHG emissions or plant operation.

Table 5.1: Overview of key assumptions for Chapter 5 scenarios with emissions credits values and TIER HPB's.

Scenario	**TIER HPB**	**Credit Value**
Current Policy	2% decline	90%
No credits	2% decline	0%
30% credits	2% decline	30%
50% credits	2% decline	50%
70% credits	2% decline	70%
TIER 2050	Zero by 2050	90%
TIER 2035	Zero by 2035	90%
No CCUS	2% decline	90%

Section 5.2 presents four alternative scenarios where emissions credits (both EPCs and offsets) were valued at 0%, 30%, 50%, and 70% of the annual carbon price. Although it is unlikely credits would be valued at 0% of the carbon price within the next decade, a scenario which removes credits altogether can isolate how emission credits impact capacity and supply in the model. Furthermore, there are cross-sectoral factors that will impact future credit values, including future TIER high-performance benchmarks for electricity, carbon prices, emissions policy tightening in other sectors,

and industrial decarbonization progress. While the model was able to make optimal decisions based on the projected value of emissions credits over the entire study period, real life actors do not have this certainty and must make their own projections. Simulating scenarios with lower emissions credit values may help theorize what could happen if emissions credits were valued lower, either in actuality or projections.

Section 5.3 includes two alternative approaches to the future TIER high-performance benchmark (HPB) for electricity. The first included a "zero by 2050" HPB, where the HPB was linearly reduced to 0 t_{CO2e}/MWh between 2030 and 2050; this matches the assumptions taken in the draft CER scenario presented in Chapter 4. In the second scenario the HPB was reduced to 0 t_{CO2e}/MWh between 2030 and 2035, meaning that after 2035 emitting generation was fully exposed to carbon price and low or non-emitting generation could not generate emissions credits. The year 2035 was selected based on federal net-zero electricity system goals, while 2050 represents a HPB that aligns with economy wide net-zero targets.

In the optimal net-zero scenarios presented in Chapter 4, 75% of existing combined-cycle natural gas capacity was retrofit with CCUS between 2027 and 2030. While Alberta has long been a proponent of CCUS to decarbonize its industrial sectors [98, 102], very few projects have been completed [103, 104], and none at traditional electricity generation facilities. In May 2024 Capital Power, a company with 13% of Alberta's market share [105], cancelled plans to retrofit its 880 MW Genesee power plant [101], citing concerns over economic feasibility rather than technology readiness. The $15.8 billion Genesee CCUS project had previously been the most advanced CCUS electricity project in the province, with an anticipated completion date as early as 2027 [106]. The cancellation of the Genesee CCUS project, despite $5 billion in funding from Emissions Reductions Alberta [106], may signal uncertainty for future CCUS projects in Alberta's electricity market, at least in the coming decade. A final scenario was introduced in Section 5.4 to isolate potential supply and GHG emissions outcomes in the absence of CCUS.

5.2 The Value of Emissions Credits

The Aurora model was used to simulate four additional scenarios with credits (EPCs or offsets) valued at 0%, 30%, 50%, and 70% of the annual carbon price. For all scenarios, the TIER HPB for electricity was assumed to mirror the current policy approach and decline at 2% of 0.37 t_{CO2e}/MWh annually. The projected annual EPC value for renewable generation in each scenario is shown in Figure 5.1, and spans from \$0/MWh - \$30.57/MWh in 2045. Aside from the case without credits, the maximum emissions credit value is available in 2030, since the carbon price stays constant after 2030 while the HPB declines. Annual emissions credit values in Figure

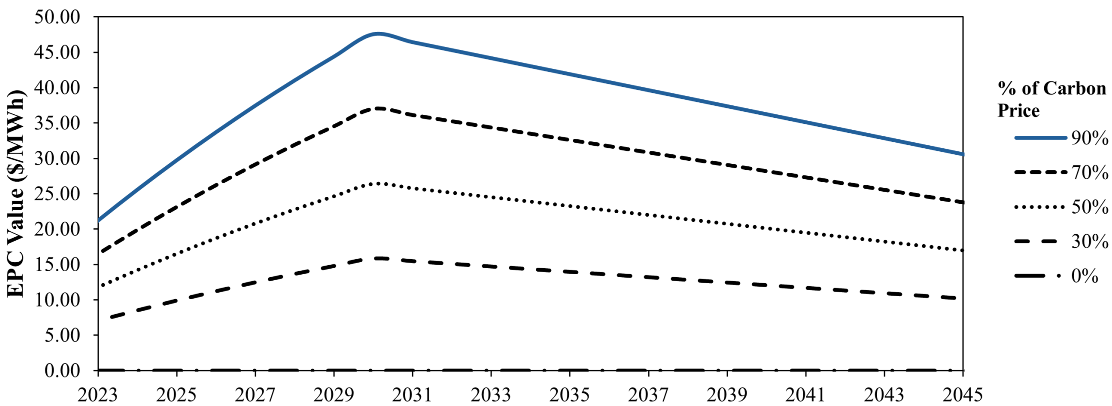

Figure 5.1: Emission performance credit (EPC) values for non-emitting generation in alternative credit value scenarios.

5.1 were slightly higher for offsets and slightly lower for low-emitting projects which receive EPCs at a lower allocation rate based on their emission intensity. Offset value was treated the same as EPCs, only offsets were generated based on the applicable Emissions Grid Displacement Factor (EGDF)[18].

[18]The EGDF is set to decrease annually between 2024 and 2030 to converge with the TIER HPB. For wind or solar projects built prior to 2023, the EDGF is constant for a 13 - 15 year period based on vintage year. Details can be found in Appendix A.2.3.

5.2.1 Capacity

Figure 5.2 shows the annual capacity of each resource group in the five alternative emissions credit scenarios. The most significant capacity changes between scenarios involved wind, combined-cycle natural gas (NGCC), and combined-cycle gas with CCUS. These changes will be discussed in further detail to follow.

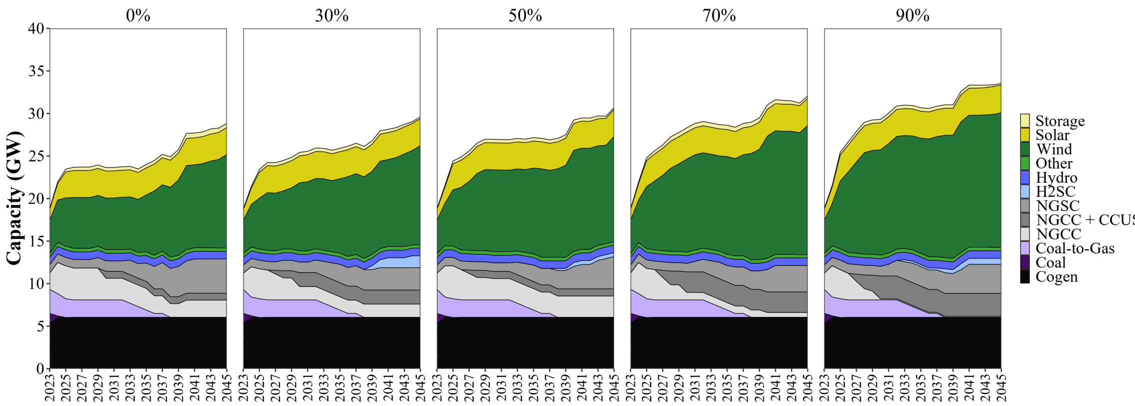

Figure 5.2: Annual capacity for the five alternative credit value scenarios.

In general, the capacity of combined-cycle gas with CCUS increased at higher emissions credit values. In all five scenarios, gas with CCUS capacity was based on retrofits to existing combined-cycle natural gas (NGCC) units and no new plants with CCUS were added. The maximum capacity of gas with CCUS occurred in the scenario with credits valued at 90% of the carbon price which reached 2.7 GW by 2045. In the scenario with credits valued at 70% of the carbon price, one less retrofit occurred relative to the 90% scenario, resulting in a gas with CCUS capacity of 2.4 GW by 2045. In comparison, the scenario with no emissions credits reached a capacity of only 0.8 GW by 2045, representing a 1.9 GW difference from the 90% value scenario. The scenarios where emissions credits were valued at 30% and 50% of the carbon price did not follow as clear of a trend, resulting in 1.6 GW of gas with CCUS in the 30% scenario and 0.8 GW in the 50% scenario. This may suggest that for credit values in this range, value added to the system by CCUS retrofits compared to value associated with original NGCC units is very similar, so either plant would have a similar impact on the value maximizing objective function (i.e. multiple thermal capacity mixes are close to optimal).

The capacity of NGCC units with and without CCUS based on credit value is also visualized in Figure 5.3, which shows the capacity of each technology at different credit values in 5 select years. Coal, coal-to-gas, and cogeneration were excluded from Figure 5.3, since retirement dates were set exogenously by the model. Although the model had the ability to retire coal-to-gas units earlier than respective end dates (spanning 2025 - 2037), this did not happen in any scenario modelled. From Figure 5.3, it can be seen that NGCC capacity changes occur as a result of retrofits taking place between 2027 - 2030. After CCUS retrofits are complete, there are no further changes to the abated NGCC fleet. This suggests that without CCUS retrofits, existing NGCC units continue to operate under current carbon pricing trajectory.

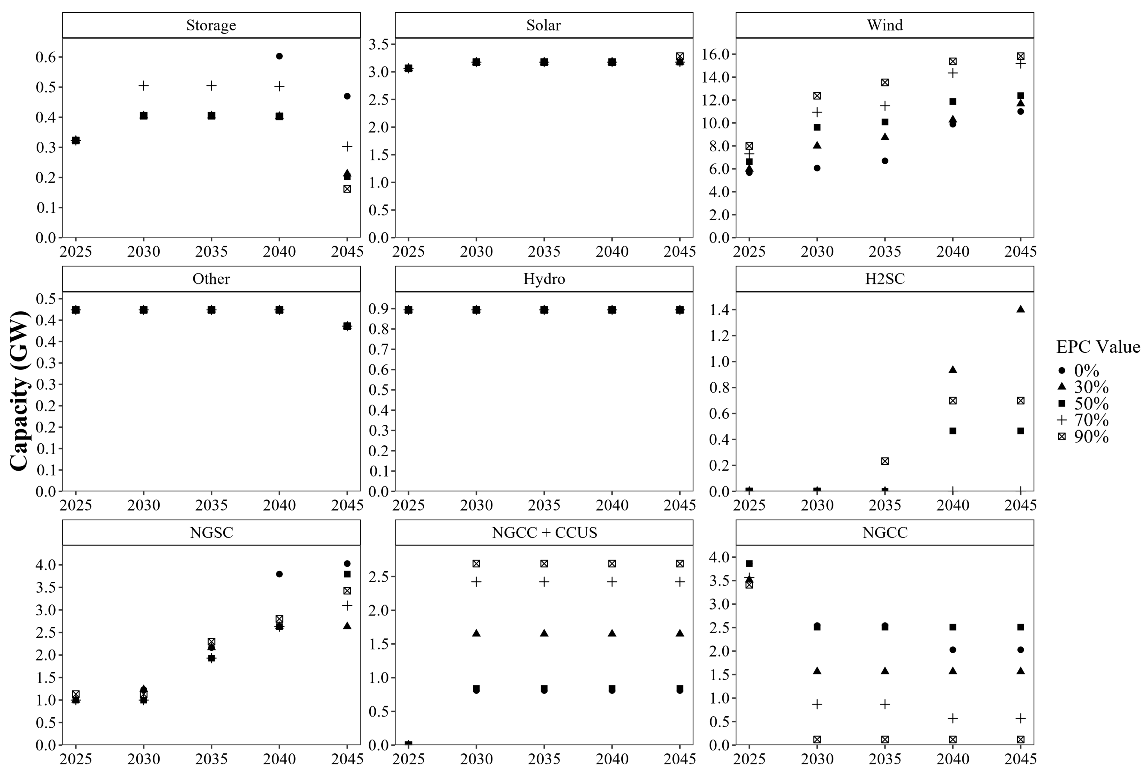

Figure 5.3: Technology group capacity in selected years by technology and credit value (scales differ).

Figure 5.3 also shows the relationship between wind capacity changes and the value of emissions credits. In general, higher credit values enabled more wind to enter the system prior to 2030. In the current policy scenario (90% credit value), wind was added at an average rate of 1.2 GW/yr between 2023 and 2030, reaching an installed capacity of 12.4 GW in 2030. Over the same time frame, average buildout rates for the 70%, 50%, 30%, and 0% cases were 1.0 GW/yr, 0.8 GW/yr, 0.6 GW/yr, and 0.3 GW/yr respectively. The scenario without emissions credits (0% value) had the slowest buildout pace and resulted in 6.1 GW of wind by 2030, around half of what was reached in the current policy scenario. Results are a reflection of both emissions credit value and the behavior of the HPB. At higher credit values, it is advantageous to add wind plants early in order to maximize cumulative cost savings, since the value of emissions credits peaks in 2030. Without emissions credits, there is no advantage associated with overbuilding the wind fleet before 2030.

In the absence of emissions credits, only 0.2 GW of new wind capacity was added outside of exogenous additions between 2023 and 2030, compared to 6.6 GW of non-exogenous wind additions in the current policy scenario. However, as load increased, wind capacity in the scenario without credits jumped from 6.6 GW to 11.0 GW between 2035 and 2045, which was the largest change in wind capacity over this time period out of all five scenarios. Considering Alberta's wind fleet capacity was 4.5 GW at the start of 2024 [27], an 11.0 GW wind fleet represents substantial growth by 2045 (about 2.5x current capacity) and suggests that wind may continue to be a low-cost supply strategy for Alberta even without emissions credit revenue.

From Figures 5.2 and 5.3 the capacity of hydrogen simple-cycle (H2SC) and natural gas simple-cycle (NGSC) appeared to shift based on the fate of other thermal units, with the final capacity of simple-cycle plants ranging from 3.1 - 4.5 GW between scenarios. However, choices between gas and hydrogen did not follow a clear trend. For instance, no hydrogen units were selected in the scenario without emissions credits, 1.4 GW of hydrogen-fired capacity was selected with 30% credit value, and the current policy scenario (90% credit value) resulted in 0.7 GW of hydrogen-fired capacity. Likewise, by 2045 NGSC capacity reached 2.6 GW in the 30% credit value scenario, 3.8 GW in the 50% credit value scenario, and 3.1 GW in the 70% credit value scenario. Thus, there was not a distinct relationship between gas or hydrogen simple-cycle units and emissions credit value.

Solar capacity was constant between scenarios where credits were valued at 0%, 30%, 50%, and 70% of the carbon price, resulting in a 2045 capacity of 3.2 GW. All of the solar growth between 2023 and 2025 was based on exogenous project additions. The current policy (90% credit value) scenario only deviated from the other scenarios between 2044 - 2045, where an additional 0.1 GW of solar was selected so that the final solar capacity reached 3.3 GW in 2045. This result suggests that emission performance credits and offsets do not have a significant impact on solar expansion in the model, which implies that solar additions are dependent on factors outside of cost. Calculating the value of solar over the entire study confirms this. By taking the total solar revenue minus cost and dividing it by total output between 2023 and 2045, the value of solar ranged from \$26.92/MWh - \$63.20/MWh. While solar value did decrease as credit value was reduced, the numbers suggest that solar plants remain profitable over the study period.

5.2.2 Generation

Figure 5.4 shows generation based on credit value for each technology summed over 5-year periods. Again, results showed a relationship between wind generation and the value of credits. By 2035, wind accounted for 44% of annual generation in the current policy scenario but only 26% in the scenario without emissions credits. Over the entire study, the current policy scenario resulted in 990 TWh of wind generation (not including curtailment), with an overall average capacity factor of 39%. In comparison, the scenario with no credits generated 656 TWh from wind, with an overall capacity factor of 43%. The difference in average capacity factor was based on curtailed wind output. As is demonstrated in Figure 5.4, the other three scenarios with 30%, 50%, and 70% credit value fell between the 90% and 0% credit value scenarios. Solar output also varied slightly between scenarios as a result of renewable curtailment in the scenarios with higher renewable energy penetrations. However, the maximum difference in solar output between the scenarios was only 7.2 TWh over the 23-year period, which represents less than 10% of Alberta's total load in 2023[19] alone.

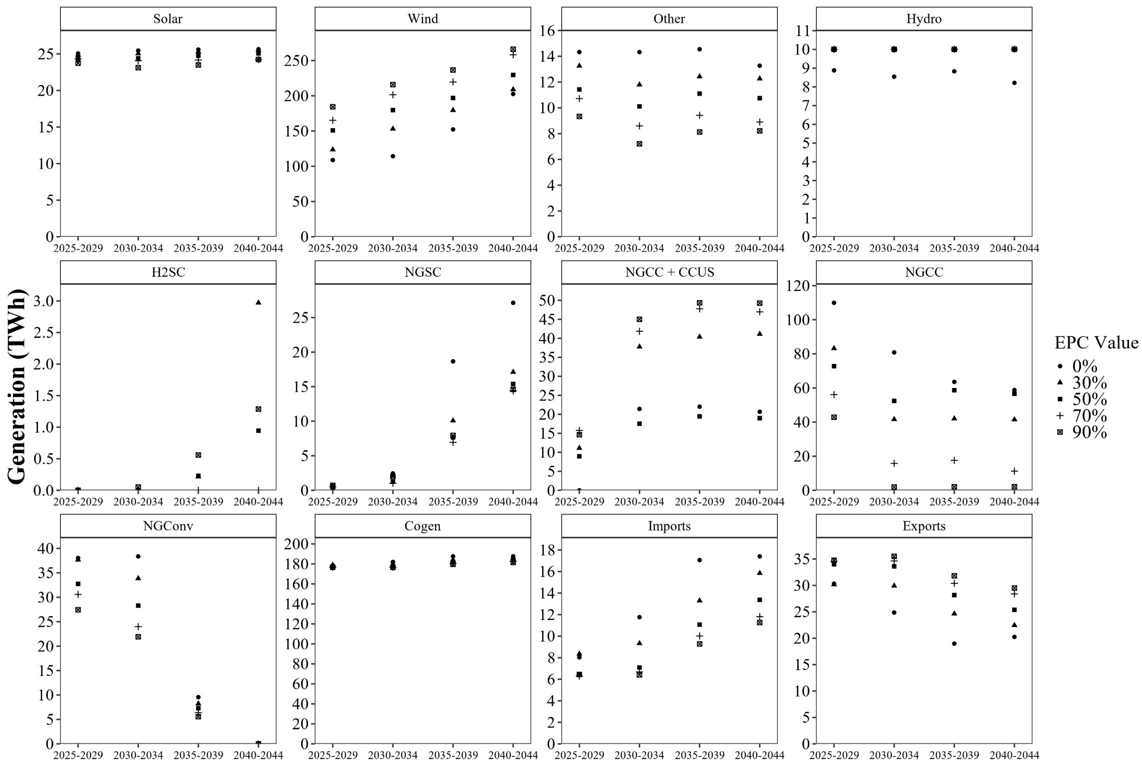

Figure 5.4: Summed generation during selected 5-year periods by technology and credit value (scales differ).

To retain a balanced system, imports increased in cases with lower credit values. Average annual net-exports in the current policy scenario were 4.4 TWh over the length of the study. Although Alberta remained a net-exporter in the scenario without credits, average annual net-exports between 2023 and 2045 were 1.7 TWh. This was a reflection of both increasing annual imports and decreasing annual exports relative to the current policy scenario which included more wind generation. Other dispatchable technologies such as biomass/other and coal-to-gas units were also used more in cases

[19] Alberta internal load (AIL) was 86.2 TWh in 2023 [18].

with lower emissions credits, as shown in Figure 5.4. For example, the biomass/other average fleet capacity factor between 2023 and 2045 increased from 48% in the current policy scenario to 77% in the scenario without credits. Similarly, during its operating period, the coal-to-gas fleet capacity factor increased from 33% to 49% when moving from 90% credit value down to 0% credit value.

Simple-cycle generation did not deviate significantly until 2035, at which point combined H2SC, and NGSC generation shifted based on capacity additions and peak load requirements. Generation by NGSC was noticeably higher in the scenario with no emissions credits, a reflection of both increased capacity and capacity factor relative to the other scenarios. Following 2035, annual average NGSC capacity factors ranged 9% - 19% in the scenario without credits, compared to a 6% - 11% capacity factor range in the current policy (90% credit value) scenario over the same period of time. The difference in NGSC output was a second order effect based on how the system shifted to adapt for alternative wind and gas with CCUS buildouts. In the case of H2SC, capacity factors and generation did not follow any clear trend. Although hydrogen-fired generation was considered zero-emissions, the high fuel costs associated with H2SC plants made them relatively intolerant to changing credit value. For example, in the 90% credit value case, H2SC units captured an average revenue of $686/MWh between 2033 and 2045.

The biggest shift in fossil fuel based generation between scenarios was operation by abated or unabated NGCC plants. Generally, in cases where emissions credits were valued higher, unabated gas generation decreased, with exception to the 30% and 50% credit value scenarios mentioned previously. Again comparing the current policy scenario to the scenario with no emissions credits, between 2023 and 2045 the total generation from NGCC was 100 TWh higher and total generation from plants with CCUS was 274 TWh lower without emissions credits. Furthermore, the average annual capacity factor of both abated and unabated combined-cycle plant groups increased when moving from 90% credit value to no credits. Between 2027 and 2045, annual average capacity factors for NGCC technologies in the current policy scenario ranged from 33% - 43%, compared to 61% - 75% in the scenario without emissions credits. Overall, because the model was less likely to select CCUS retrofits on existing units without credits to offset the cost, a deeper reliance was placed on existing gas infrastructure.

5.2.3 GHG Emissions

Annual GHG emissions for each scenario are shown in Figure 5.5. The case with no emissions credits resulted in the highest annual and cumulative non-cogeneration GHG emissions, with 8.3 Mt_{CO2e} in 2045 and 248.9 Mt_{CO2e} overall (142.4 Mt_{CO2e} higher than the current policy case which assumed 90% credit value). The 47% GHG reduction (relative to 2023 modelled emissions) achieved by the scenario with no credits is a product of coal-to-gas retirements and increased renewable generation. Without emissions credits, annual generation from gas with CCUS was 40% - 50% lower than it was in the current policy scenario, reducing the amount of displaced NGCC emissions each year. As a result, cumulative NGCC GHG emissions from the scenario with no emissions credits were 109 Mt_{CO2e} higher than in the current policy scenario.

Compared to the 90% credit value scenario (current policy approach), the scenario without credits resulted in less wind generation prior to 2035 which contributed to increased GHG emissions overall. For instance, in the year 2030, wind supplied only 22.3 TWh (23% of total generation) in the scenario with no credits, compared to 40.7 TWh (41% of total generation) in the current policy scenario. Although wind capacity starts expanding in 2036 in the scenario with no credits, peak demand and unabated gas generation also increased by this point, resulting in a plateau of annual GHG emissions ranging 7.8 - 8.8 Mt_{CO2e} between 2036 and 2045.

Each of the other four scenarios are an improvement from the case with no credits, showing that GHG reductions generally increase with credit value. Aside from the

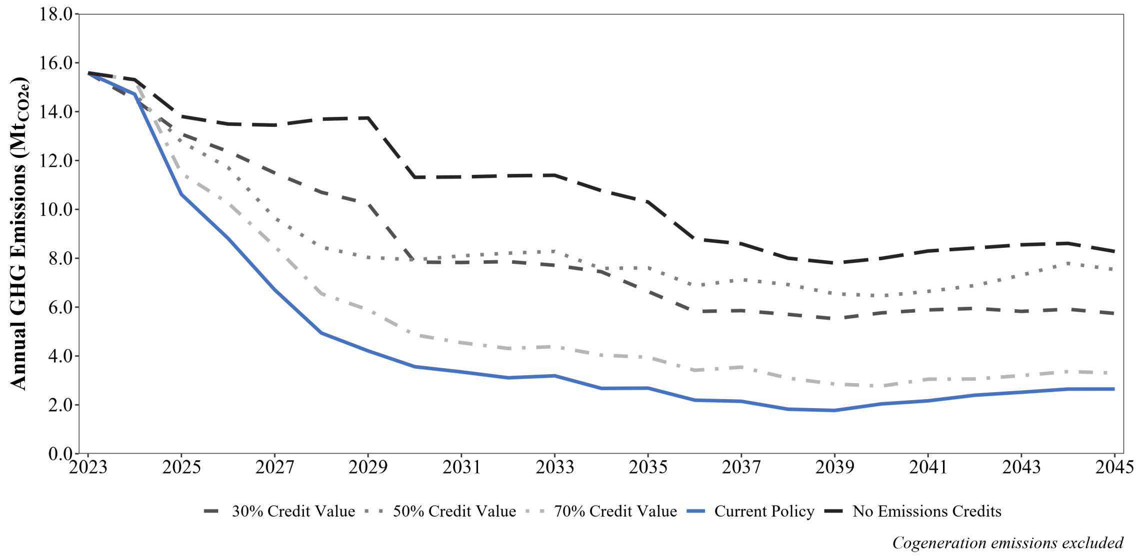

Figure 5.5: Annual emissions pathways under alternative emissions credit values.

current policy scenario, the 70% credit value scenario resulted in the lowest GHG emissions, reaching 3.3 Mt_{CO2e} by 2045 and a cumulative 131 Mt_{CO2e} overall. The 30% credit value scenario reached an annual GHG emissions of 5.7 Mt_{CO2e} in 2045 and resulted in 191 Mt_{CO2e} over the entire study. As a result of alternative retrofit decisions and thermal generation, the 50% credit value scenario resulted in cumulative GHG emissions which exceeded the 30% credit value scenario by 7.4 Mt_{CO2e}.

Figure 5.6 shows the difference in cumulative GHG emissions for each scenario relative to the current policy scenario. In each case, GHG emission differences were predominately driven by alternative CCUS retrofit decisions and resulting NGCC generation. In the scenario without credits, NGCC accounted for 76% of the cumulative 142_{CO2e} GHG emissions difference relative to the current policy scenario. In the other three scenarios, NGCC GHG emissions again accounted for over 80% of the 24.8 - 92.2 Mt_{CO2e} difference relative to the current policy scenario.

In summary, the value and availability of emissions credits was found to be a major driver of wind and CCUS deployment in these scenarios. This may be useful to consider for future carbon pricing framework decisions in Alberta since results show that maximizing credit value may reduce GHG emissions in the electricity sector

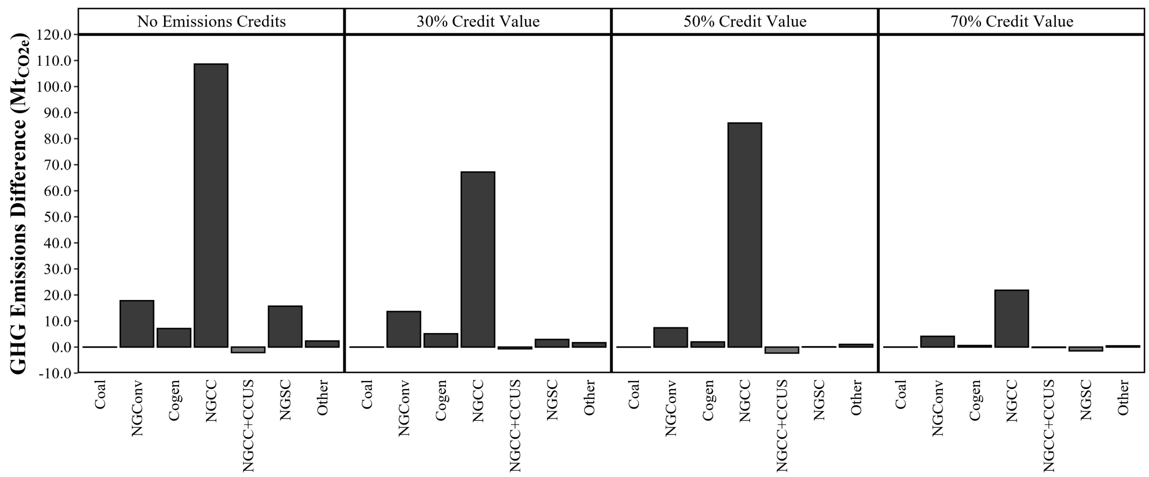

Figure 5.6: Cumulative GHG emissions comparison to current policy scenario where emissions credits were valued at 90% of the carbon price.

by enabling low or non-emitting technologies which may displace GHG emissions from traditional gas-fired generation. Thus, it would be optimal to reduce the high-performance benchmark for electricity in a way that maximizes credit value.

5.3 Varying the High-Performance Benchmark

Two alternative TIER high-performance benchmark (HPB) for electricity scenarios were compared to the current policy scenario presented in Chapter 4. The annual HPB trajectory for each scenario is visualized in Figure 5.7 and includes: (i) a HPB which follows current policy trajectory and continues to decrease at 2% of 0.37 t_{CO2e}/MWh annually, (ii) a full exposure by 2050 scenario named “TIER 2050”, and (iii) a full exposure by 2035 scenario named “TIER 2035”. The effect of tightening the HPB at a quicker rate after 2030 is twofold: total GHG emission costs are increased annually for non-compliant generation and the quantity of emissions performance credits (EPCs) obtained per MWh of low or non-emitting generation decreases annually.

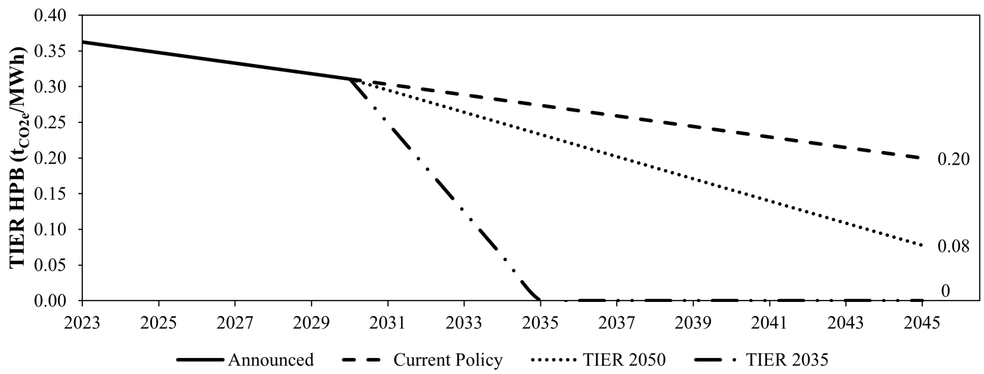

Figure 5.7: Alternative TIER high-performance benchmark pathways, with 2045 value annotated.

5.3.1 Capacity, Generation, and GHG Emissions

Net annual capacity changes (additions minus retirements) are shown in Figure 5.8 for each scenario. The current policy and TIER 2050 scenarios result in very similar capacity changes overall, with only a small shift in thermal capacity and wind capacity. Relative to the current policy scenario, the TIER 2050 scenario included an additional gas plant with CCUS (377 MW) selected by the model in 2040, an additional 233 MW of hydrogen simple-cycle (H2SC), and 440 MW less natural gas simple-cycle (NGSC). Compared to the current policy scenario, NGSC operating in the TIER 2050 scenario contributed 3.3 Mt_{CO2e} less GHG emissions between 2023 and 2045.

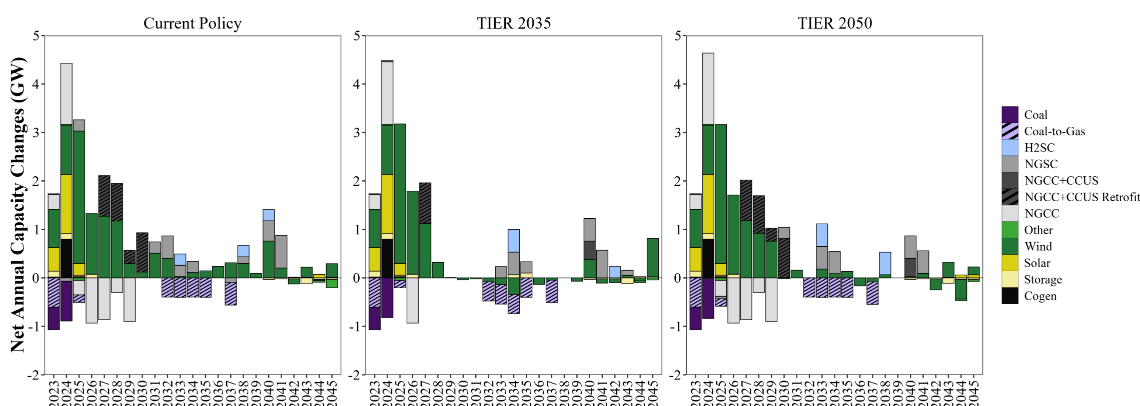

Figure 5.8: Net annual capacity changes for each TIER HPB scenario.

Considering a reduced annual HPB following 2030, the TIER 2050 scenario resulted in a wind capacity of 13.6 GW by 2045, 2.2 GW lower than the capacity presented in the current policy scenario. However, as was seen in the emissions credits scenarios presented in Section 5.2 , the majority of wind additions still happened prior to 2030, allowing the TIER 2050 scenario to reach a capacity of 12.9 GW by 2030, nearly 3 times Alberta's current wind capacity of 4.5 GW in 2024. As a result of early wind additions, the TIER 2050 system achieved a 77% reduction in GHG emissions by 2030 (relative to 2023 modelled GHG emissions), which matches results from the current policy scenario.

The scenario where the HPB was reduced to zero by 2035 showed greater variation from the current policy scenario than the TIER 2050 scenario did. Relative to the current policy scenario, the TIER 2035 scenario included 4.1 GW less wind, 1.5 GW less gas with CCUS, and 0.4 GW less NGSC by 2045. As a result, the capacity of other technology groups in the TIER 2035 scenario increased, resulting in 437 MW of storage and 2.4 GW of NGCC capacity in 2045. Between 2023 and 2030, wind capacity increased at an average rate of 1.1 GW/year in the TIER 2035 scenario, reaching an installed capacity of 11.5 GW by 2030. After 2030, there were not significant changes in the TIER 2035 system wind capacity until a 0.3 GW increase in 2040 and a 0.7 GW increase in 2045.

A full overview of annual capacity, generation, and GHG emissions for each HPB scenario is shown in Figure 5.9. The TIER 2050 scenario and the current policy scenario produced nearly identical GHG emissions and generation outcomes despite the different HPB behavior. Compared to the current policy scenario, the TIER 2050 scenario resulted in only a 1.2 Mt_{CO2e} increase in cumulative GHG emissions between 2023 and 2045. The most significant shift in generation between the current policy and TIER 2050 scenarios was in the wind group, where the current policy scenario resulted in an additional 26.0 TWh of wind generation over the 23-year period. For context, the AESO reported that wind generation supplied a total of 10.2 TWh in 2023 alone [18], which suggests that 26.0 TWh over a 23-year period likely did not substantially impact GHG emissions. Furthermore, any wind generation that was exported would not impact GHG emissions originating from Alberta's system. For all other technology groups presented in Figure 5.9, aside from gas with CCUS, no group had a variation of greater than 0.6 TWh in a single year between the current policy and TIER 2050 scenario. Although generation from units with CCUS began to increase following a 0.4 GW capacity addition in 2040 in the TIER 2050 scenario, cumulative generation from plants with CCUS was only 11.9 TWh higher than in the current policy scenario.

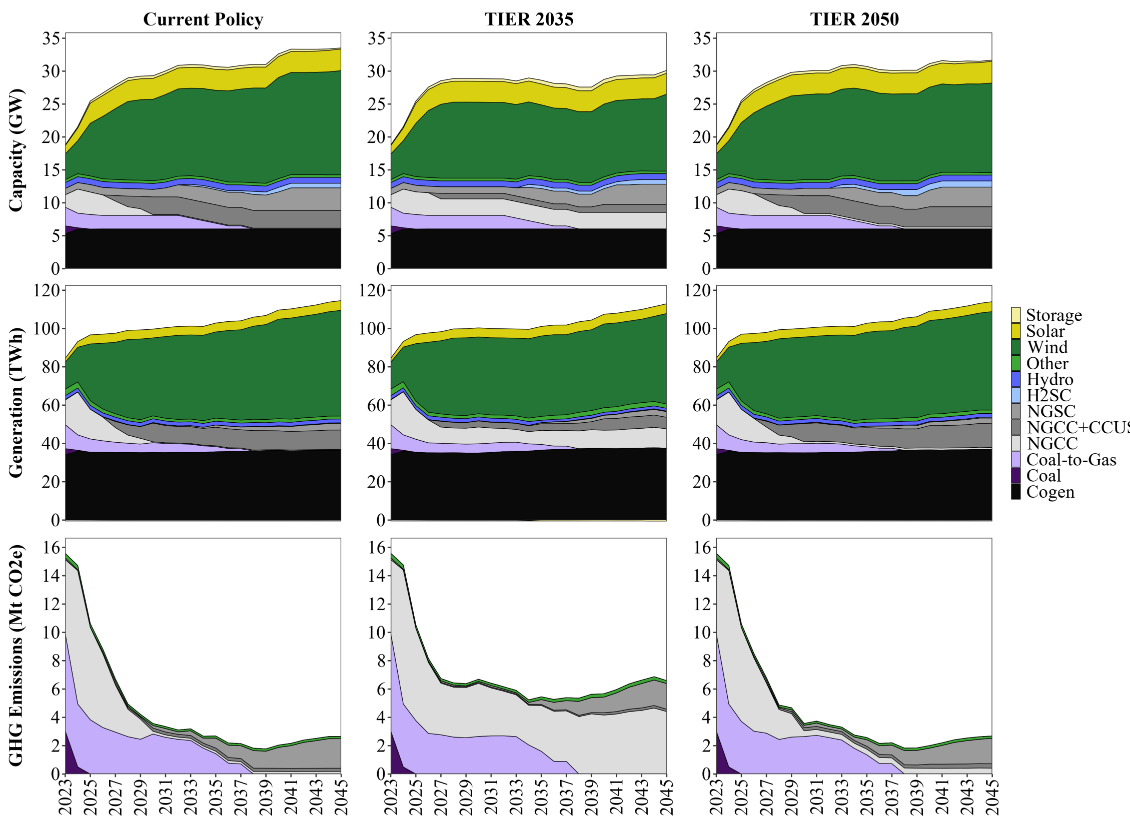

Figure 5.9: Annual capacity, generation, and GHG emissions by plant type for the three TIER HPB scenarios.

Comparing the TIER 2035 scenario with the current policy scenario, cumulative generation from only three technology groups varied by more than 12 TWh between 2023 and 2045: wind, NGCC, and NGCC with CCUS. Following the completion of CCUS retrofits in 2030, average annual generation and GHG emissions from NGCC in the TIER 2035 scenario were 8.3 TWh and 3.8 Mt_{CO2e} higher relative to the current policy scenario. Over the same 2030 to 2045 period, abated gas generation was on average 5.2 TWh lower annually in the TIER 2035 scenario. Compared to the current policy scenario, the TIER 2035 scenario resulted in a 142 TWh increase in NGCC generation and a 88 TWh decrease in gas with CCUS generation between 2023 and 2045. While wind generation only varied by 12 TWh between the TIER 2035 and current policy scenarios prior to 2035, between 2035 and 2045 the current policy scenario resulted in an additional 81 TWh of wind generation.

5.3.2 Cumulative GHG Emissions and the Fate of NGCC

Figure 5.10 shows cumulative GHG emissions for each of the three scenarios. The TIER 2050 scenario resulted in annual GHG emissions of 2.7 Mt_{CO2e} by 2045, just 0.1 Mt_{CO2e} more than the current policy scenario in the same year. Furthermore, the current policy scenario and TIER 2050 scenarios resulted in a nearly negligible annual difference of $\leq$0.5 Mt_{CO2e} each year. This was also the case for the TIER 2035 scenario prior to 2028, afterwhich, cumulative GHG emissions increased at a heightened pace relative to the current policy scenario as a result of alternative CCUS retrofit decisions. The TIER 2035 scenario resulted in a total of 166 Mt_{CO2e} GHG emissions between 2023 and 2045, with annual GHG emissions reaching 6.6 Mt_{CO2e} by 2045 (a 58% GHG reduction relative to 2023 modelled GHG's).

Overall, the TIER 2035 scenario exceeded GHG's presented in the current policy scenario by 57.7 Mt_{CO2e}. This is a somewhat counter intuitive result, as generally a quicker path to full carbon exposure is expected to provide price signals that deem traditional fossil fuels less valuable to the system which may quicken the pace of decarbonization. This happens to a degree, evidenced by the fact that emitting technology groups outside of NGCC did not experience a cumulative GHG emissions increase of more than 4.2 Mt_{CO2e} relative to the current policy scenario, despite decreased generation from wind and gas with CCUS. However, the fate of NGCC

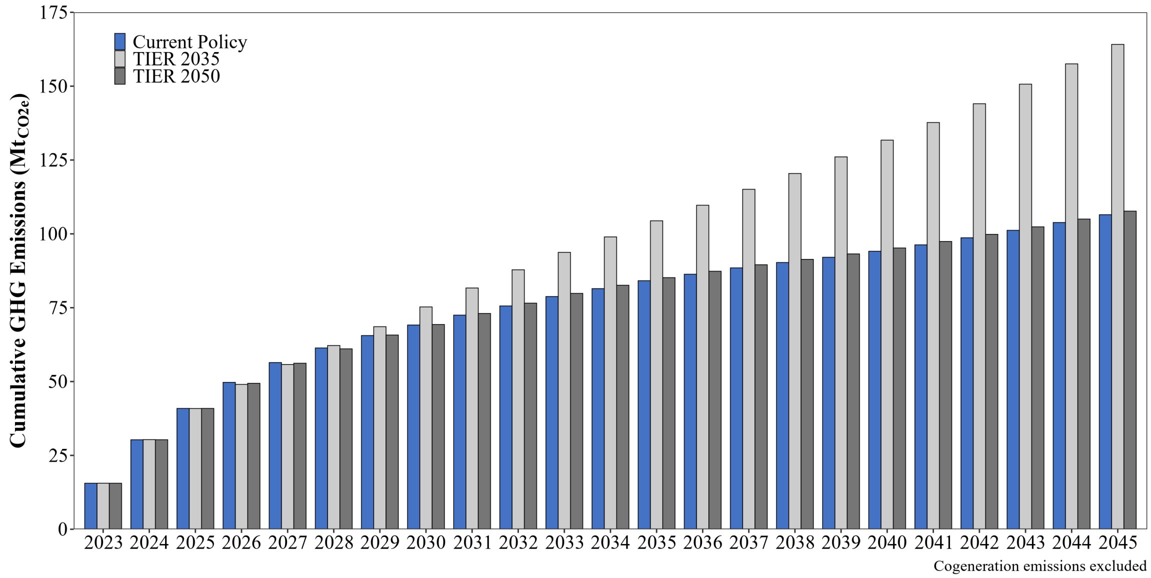

Figure 5.10: Cumulative non-cogeneration GHG emissions for the current policy scenario with alternative TIER HPB assumptions.

plants, detailed in Table 5.2 reveals that the final capacity of NGCC operating in the TIER 2050 scenario by 2045 was more than 2 GW higher than the other two scenarios which only had 0.1 - 0.3 GW remaining. This results suggests that full carbon price exposure by 2035 may not deem CCUS retrofits a more valuable choice than NGCC by 2045.

Table 5.2: Fate of combined-cycle natural gas units in the three TIER HPB scenarios.

Description	**Current Policy**	**TIER 2035**	**TIER 2050**
Units Retrofit	6	2	6
Retrofit Capacity (MW)	2,692	839	2,692
Units Retired	4	3	4
Retired Capacity (MW)	823	492	643
Units Operating	1	6	1
Operating Capacity (MW)	120	2,510	300

5.4 Wind, CCUS, and GHG Reductions

Up till this point, a total of eleven unique scenarios have been explored to various extents: three net-zero scenarios in Chapter 4, two investment tax credits scenarios in Chapter 4, four new emissions credits scenarios in Section 5.2, and two new TIER HPB scenarios in Section 5.3. Each optimal scenario included CCUS, with a final installed capacity ranging from 0.8 GW - 3.8 GW. Additions were mainly in the form of retrofits to existing units, but the four scenarios where the HPB was reduced to 0 t_{CO2e}/MWh (by either 2050 or 2035) included an additional 0.3 - 1.1 GW added in 2035 or later. Each of the eleven scenarios included a 11.0 - 16.2 GW wind fleet by 2045 and used dispatchable thermal technologies to balance generation and load during hours with low variable renewable output. A combination of abated and unabated combined-cycle plants played an important role in meeting demand during hours with low wind output. As a result, scenarios where the capacity of gas with CCUS was less than 1 GW resulted in more than 2 GW of NGCC operating by 2045. In comparison, scenarios with 2.4 GW or more of NGCC with CCUS capacity by 2045 resulted in less than 0.6 GW of NGCC in operation by 2045.

In all cases, the deployment of CCUS was driven by cost incentives or policy constraints. In Chapter 4, removing investment tax credits reduced CCUS capacity to half of what was presented in the current policy scenario, with 1.2 GW operating in 2045. In Section 5.2, removing emissions credits reduced CCUS capacity by more than two thirds of the current policy scenario, resulting in 0.8 GW by 2045. Lastly, in Section 5.3, reducing the high-performance benchmark (HPB) to 0 t_{CO2e}/MWh by 2035 resulted in 1.2 GW of gas with CCUS by 2045, roughly half the final current policy scenario capacity. The exception to this trend was the draft CER scenarios presented in Chapter 4 in which operational constraints on unabated gas generation made CCUS a key part of the net-zero solution regardless of cost incentives, the final capacity of gas with CCUS in both draft CER scenarios (with and without investment tax credits) exceeded the current policy capacity by just over 40%. From these results, a conclusion can be drawn that without cost incentives or strengthened policy, deployment of CCUS becomes less likely.

A final scenario was modelled to answer the question "what happens to GHG emissions in the electricity sector if CCUS is not available". Figure 5.11 shows annual capacity, generation, and GHG emissions in the final scenario modelled without CCUS. In the absence of CCUS, the model selected an additional 543 MW of wind, 77 MW of solar, and 962 MW of natural gas simple-cycle (NGSC) relative to the current policy approach. Furthermore, the scenario without CCUS options included 466 MW less simple-cycle hydrogen (H2SC) by 2045 than the current policy scenario. Since existing combined-cycle natural gas (NGCC) units could not retrofit with CCUS, 70% (2.1 GW) of the existing NGCC capacity in 2024[20] remained in operation by 2045, compared to just 4% (0.1 GW) in the current policy scenario. Supply changes between the current policy scenario with and without CCUS reflected this, with a 151 TWh increase in NGCC generation and a 168 TWh decrease in gas with CCUS generation between 2023 and 2045. Cumulative generation from other capacity groups changed by less than 11 TWh when excluding CCUS. Without CCUS, the system reached an annual emissions of 6.5 Mt_{CO2e} by 2045 (a 59% reduction from 2023 GHG emissions reported by the model) and cumulative GHG emissions exceeded the current policy scenario by 64.8 Mt_{CO2e} (with the scenario resulting in a total of 171 Mt_{CO2e} between 2023 and 2045).

The relationship between the capacity of gas with CCUS and GHG emissions for all modelled scenarios in select years is portrayed in Figure 5.12. As the capacity of units with CCUS increased, GHG emissions generally decreased. The most extreme cases being the two draft CER scenarios (with and without federal investment tax credits), which each reached a CCUS unit capacity of 3.8 GW and annual GHG emissions of less than 1.5 Mt_{CO2e} in 2045. Although there is some variation as a reflection of

[20] As of May 2024, the AESO reported 3.1 GW of combined-cycle gas capacity in Alberta [27].

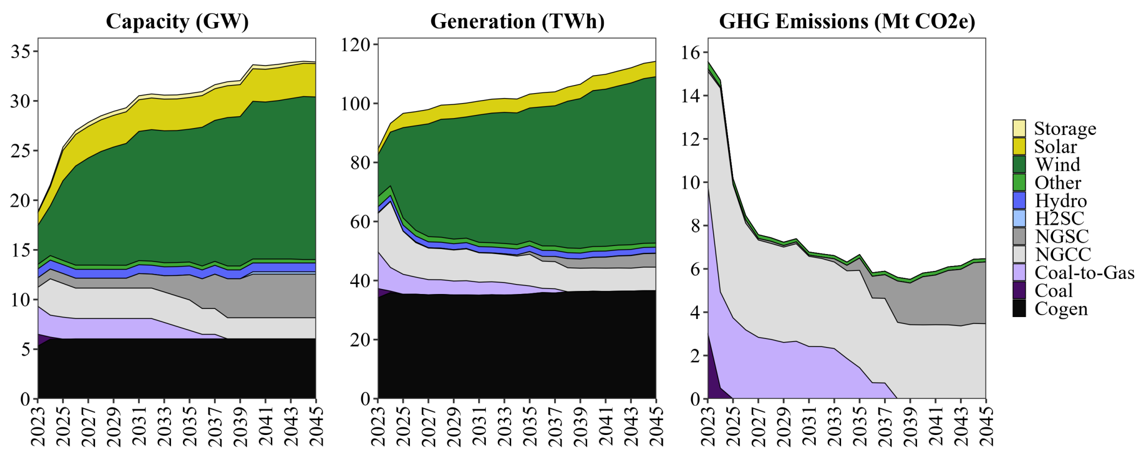

Figure 5.11: Capacity, generation, and GHG emissions results for the current policy scenario without CCUS options.

changing policy assumptions and the generation of the rest of the fleet, it is clear that the optimal pathways presented in this paper would be impacted significantly if CCUS was not available or as adept as anticipated.

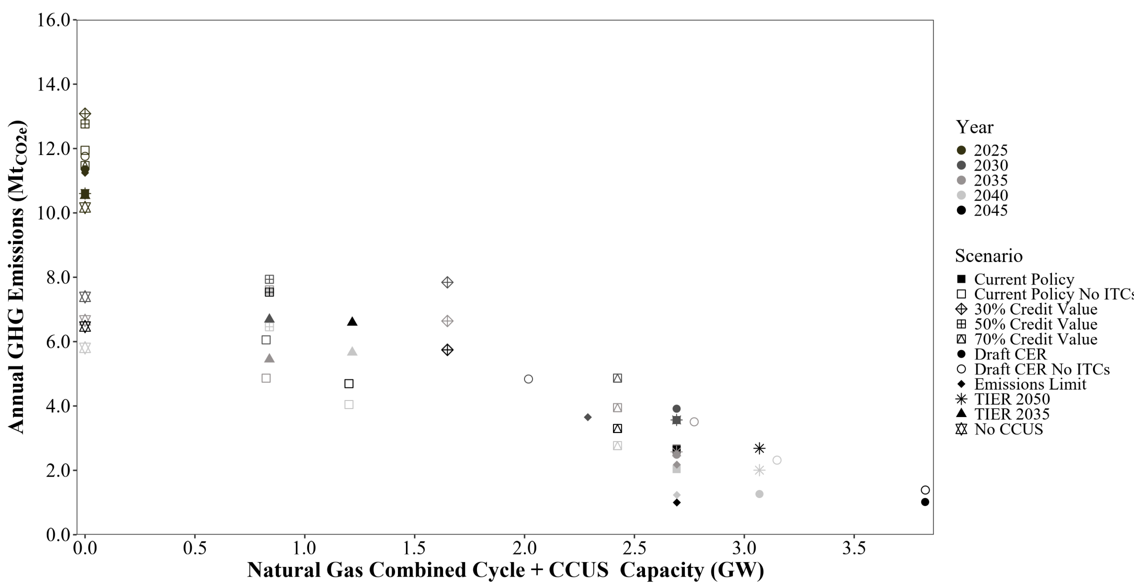

Figure 5.12: Annual GHG emissions compared to combined-cycle gas with CCUS capacity for each scenario, plotted in selected years.

Likewise, the relationship between annual wind capacity and GHG emissions is shown in Figure 5.13. For a fleet capacity of up to approximately 10.5 GW, there was a strong relationship between wind capacity and GHG emission reductions. This supports earlier findings which, when compared, show decreased cumulative GHG emissions when wind capacity additions were made earlier in the study. For example, although the TIER 2035 scenario (where the HPB was reduced to 0 t_{CO2e}/MWh by 2035) resulted in an additional 56.4 Mt_{CO2e} of GHG's between 2023 and 2045 compared to the current policy approach, cumulative GHG emissions were still lower than scenarios where emissions credits were valued at ≤50% of the carbon price. Unlike the case with no emissions credits presented in Section 5.2, the majority of wind additions took place prior to 2030 in the TIER 2035 scenario in order to maximize credit value. This resulted in the TIER 2035 scenario displacing more GHG emissions throughout the entire study period relative to scenarios presented in Section 5.2 where emissions credits were valued at 50% of the carbon price or less. For example, the TIER 2035 scenario resulted in 85 Mt_{CO2e} less GHG emissions than the scenario without emissions credits, although total generation by CCUS units was only 12.3 TWh higher. Although policies often include annual emissions targets, cumulative GHG emissions and reduction pathways are important for overall climate outcomes. These results show that the timing of wind additions, driven by emission credit value, has a significant impact on cumulative GHG emissions. In a scenario where emissions credits are devalued or no longer available, tightening the benchmark may become a more important strategy to enable cost optimal emissions reductions.

Once the wind fleet surpassed a capacity of around 10.5 GW, the relationship between wind capacity and GHG reductions was weakened. Meaning that as more wind was added past this threshold, its effectiveness in displacing GHG emissions was weakened. For instance, the case without CCUS resulted in the largest wind fleet, reaching 16.4 GW in 2045, but achieved an annual GHG emissions of 6.5 Mt_{CO2e} in 2045. In comparison, the draft CER scenario reached an installed wind capacity of 13.4 GW in 2045 but resulted in 1.0 Mt_{CO2e} of GHG's in 2045. The weaker relationship between wind and GHG reductions at higher capacities of wind reflects the multi-variable nature of deep emissions reductions. In the model, once the wind fleet has

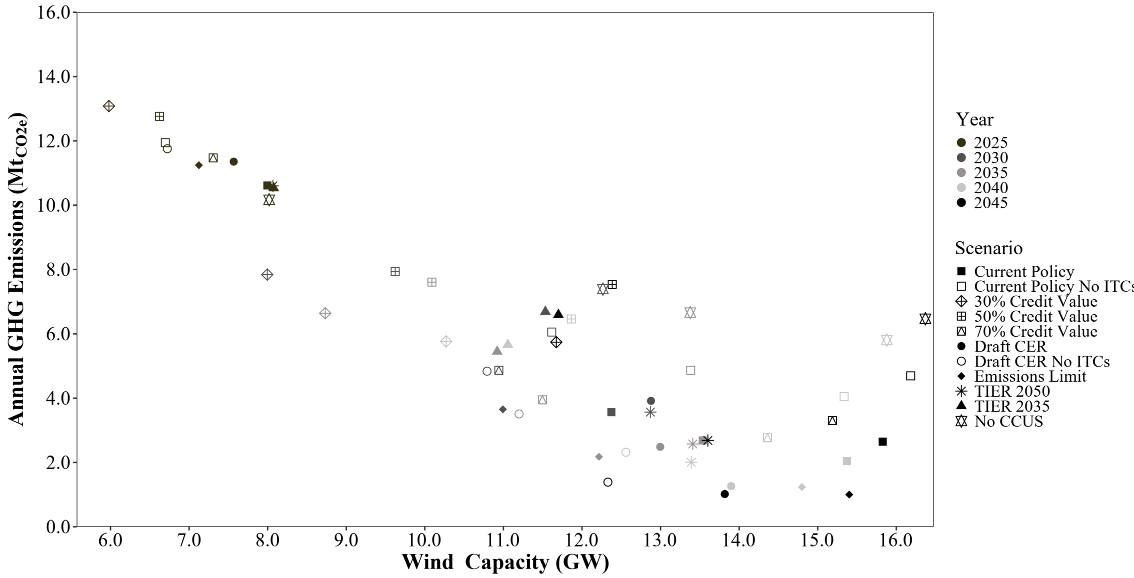

Figure 5.13: Annual GHG emissions compared to wind capacity for each scenario, plotted for selected years.

grown sufficiently large, there are an increased number of hours where wind generation surpasses load and allowable exports. When this happens, energy is curtailed instead of used to displace emissions. At the same time, because of wind's variable nature, dispatchable capacity is still required to be on "stand by" to maintain adequate supply during hours of low variable renewable output. Results showed that without low-emitting options, the system relied on unabated gas capacity and generation during hours of low renewable output which resulted in higher annual GHG emissions.

5.5 Conclusions

This chapter investigated the role of industrial carbon pricing and emissions credits in decarbonizing Alberta's electricity sector and enabling new low and non-emitting generation. Scenarios explored system outcomes when varying the annual value of emissions credits, changing the rate of carbon exposure, and removing options for carbon capture utilization and storage (CCUS). Results were compared to a current policy scenario in which emissions credits were valued at 90% of the carbon price and the high-performance benchmark (HPB) for electricity decreased at 2% of

0.37 t_{CO2e}/MWh annually, starting in 2022. Similarly to Chapter 4, each scenario included a wind fleet capacity of 11.0 - 16.4 GW by 2045, suggesting that the growth of Alberta's wind fleet to 2.5 - 3.6 times it's 2024 capacity (4.5 GW) remains part of the optimal solution regardless of emissions credits incentives.

Reducing the value of emissions credits resulted in a slower deployment of wind capacity and a lesser number of CCUS retrofits, decreasing GHG reductions. Without emissions credits, the final capacity of plants with CCUS was reduced from 2.7 GW to 0.8 GW and final wind capacity was reduced from 15.8 GW to 11.0 GW compared to the current policy scenario. As a result, the system without emissions credits was more reliant on unabated gas infrastructure and reached only a 47% reduction in GHGs by 2045 compared to a 83% reduction in the current policy scenario. Between 2023 and 2030 wind capacity was added at an average pace of 0.3 GW/yr without emission credits, compared to 1.2 GW/yr in the current policy scenario. Along with a 274 TWh decrease in abated gas generation, early differences in wind output contributed to a 142.4 Mt_{CO2e} GHG emissions increase in the scenario with no emissions credits relative to the current policy scenario. Thus, results suggest early credit availability may promote cumulative GHG emissions reductions attributed to wind displacing other generation.

The scenario which reached full carbon price exposure by 2050 produced a nearly identical result to the current policy approach, with very similar fleet mixes and only a 1.2 Mt_{CO2e} difference in cumulative GHG emissions. This is a significant finding since it shows that tightening the HPB linearly to 0 t_{CO2e}/MWh between 2030 and 2050 is feasible for Alberta. Tightening the HPB may be a useful way for policy makers to prevent an oversaturation of emissions credits and align with federal and provincial net-zero targets.

Results found that a HPB of 0 t_{CO2e}/MWh by 2035 reduced the capacity and generation of low and non-emitting technologies which were otherwise enabled by the continued generation of emissions credits after 2035. In the scenario which reached full carbon exposure by 2035, wind and gas with CCUS each contributed 93 TWh and 88 TWh less generation overall compared to the current policy scenario, resulting in a 57.7 Mt_{CO2e} increase in GHG's. Despite full carbon price exposure by 2035, 2.5 GW of combined-cycle gas capacity remained in operation by 2045. On average, combined-cycle gas units in the full exposure by 2035 scenario contributed an additional 3.8 Mt_{CO2e} in GHG emissions annually between 2030 and 2045 relative to the current policy scenario. However, a HPB of 0 t_{CO2e}/MWh by 2035 still resulted in 85 Mt_{CO2e} less cumulative GHG emissions than the scenario without emissions credits, suggesting full exposure may promote additional GHG reductions in a case where emissions credits are devalued or unavailable.

Taken together, scenarios suggest that without strengthened policy or cost incentives, CCUS deployment may proceed to a lesser extent. In the current policy scenario, units with CCUS reached an installed capacity of 2.7 GW by 2045. In comparison, removing emissions credits reduced the final capacity of units with CCUS to 0.8 GW. Reducing the HPB to 0 tCO2e/MWh by 2035 resulted in a capacity of units with CCUS of 1.2 GW by 2045. When CCUS was removed from new plant options cumulative GHG emissions increased by 64.8 Mt_{CO2e} relative to the current policy scenario, as a result of 70% of the existing 2024 NGCC fleet continuing to operate through till 2045. Thus, in the absence of CCUS retrofit options, NGCC units could become the largest source of non-cogeneration GHG emissions in Alberta's electricity system and delayed deployment of CCUS could become a significant roadblock for Alberta to reach a net-zero electricity goal.

Chapter 6

Conclusion

6.1 Thesis Summary

The objective of this thesis was to explore how alternative policies could affect Alberta's pathway to net-zero electricity. Both Canada and Alberta have economy wide net-zero by 2050 goals and have recognized the importance of decarbonizing the electricity system to both directly decrease greenhouse gas (GHG) emissions and enable electrification in other sectors. Since 2015, Alberta has rapidly transitioned away from coal and added over 5 GW of new wind and solar [27], allowing the province to reduce its electricity sector GHG emissions by over 50% [19]. However, Alberta still generates over 80% of its electricity from fossil fuels [18] and contributed over 40% of Canada's 47 Mt_{CO2e} electricity GHG emissions in 2022 [19].

This work used a long-term capacity expansion optimization model to forecast future capacity, generation, cost, and GHG emission outcomes for Alberta's competitive electricity system. Twelve different scenarios were simulated between 2023 and 2045 to understand how policies including Alberta's industrial carbon pricing framework, federal investment tax credits (ITCs), and draft clean electricity regulations (CER) could impact decarbonization pathways.

Chapter 4 presented pathways to a net-zero electricity system for Alberta and assessed the impact of Canada's draft Clean Electricity Regulations and federal investment tax credits. Results showed that under current policy, Alberta could reduce its annual GHG emissions to 2.6 Mt_{CO2e} by 2045, representing an 83% GHG reduction relative to 2023 modelled GHG emissions. The GHG reductions achieved under current policy were a result of retrofitting 75% of existing combined-cycle gas (NGCC) plants with CCUS, a wind fleet of more than three times current capacity, and low-use dispatchable simple-cycle gas and hydrogen units. With a wind fleet of 11.0 GW or more by 2030, all scenarios in Chapter 4 resulted in average annual pool prices below $30/MWh from 2023 till 2034, creating a potential challenge for the competitive market over this time period. Including the draft CER performance standards, results showed that annual emissions could be further reduced to 1.0 Mt_{CO2e} by 2045, representing a 8.8 Mt_{CO2e} cumulative GHG reduction relative to the current policy approach between 2035 and 2045. Additional GHG reductions in the draft CER scenario were driven by the deployment of low-emitting dispatchable generation, reaching 2.3 GW of low-use simple-cycle hydrogen and 3.8 GW of NGCC with CCUS by 2045.

Findings from Chapter 4 also suggest that federal investment tax credits may enable GHG emissions reductions by enabling increased penetrations of low and non-emitting generation. In the current policy scenario, including ITCs resulted in a 1.5 GW increase in gas with CCUS which contributed to a 45.6 Mt_{CO2e} cumulative GHG emissions reduction. In the draft CER scenario, including ITCs increased wind generation by 73.5 TWh, contributing to a 23.5 Mt_{CO2e} cumulative GHG emissions reduction compared to the case without ITCs.

Chapter 5 found that emissions credits may promote GHG reductions by enabling the deployment of CCUS retrofits to existing units and the growth of Alberta's wind fleet. Without emissions credits, results showed that relative to the current policy approach where emissions credits were valued at 90% of the carbon price, the final capacity of wind was 4.8 GW lower and the capacity of NGCC plants with CCUS declined from 2.7 GW to 0.8 GW. As a consequence, the scenario without emissions credits resulted in 8.3 Mt_{CO2e} of GHG emissions in 2045 and cumulative emissions exceeded the current policy scenario by 142.4 Mt_{CO2e}. Even without emissions credits, Alberta's wind fleet reached 11.0 GW by 2045, suggesting wind is an important part of the optimal technology mix. However, without emissions credits, wind additions occurred at an average pace of 0.3 GW/yr between 2023 and 2030, compared to 1.2 GW/yr in the current policy scenario, which reduced cumulative GHG emissions displacement.

Chapter 5 further explored how alternative high-performance benchmark tightening rates could impact current policy results and GHG reductions. Results found that reaching full carbon price exposure by 2050 only slightly shifted the optimal capacity mix and resulted in cumulative GHG emissions only 1.2 Mt_{CO2e} higher than what was reported in the current policy scenario. Reaching full exposure by 2035 resulted in an additional 57.7 Mt_{CO2} of cumulative GHG emissions relative to the current policy scenario, driven by a 143 TWh increase in NGCC generation. Increased NGCC generation compared to the current policy scenario reflected the removal of emissions credits after 2035 which resulted in 4.1 GW less wind capacity and 1.5 GW less CCUS retrofit capacity. However, the scenario with full carbon exposure by 2035 still resulted in 85 Mt_{CO2e} less cumulative GHG emissions than the scenario with no emissions credits, suggesting full exposure may enable additional GHG reductions in the absence of emissions credits.

Lastly, all results suggest that the deployment of CCUS may be dependent on strengthened policy or cost incentives. The 2.7 GW capacity of units with CCUS resulting from the current policy scenario was reduced by more than half without federal investment tax credits, over two thirds without emissions credits, and more than half when reaching full exposure by 2035. In comparison, including the draft Clean Electricity Regulations resulted in an additional 1.1 GW of gas with CCUS relative to the current policy scenario. In the absence of CCUS, results from Chapter5 found that 70% of Alberta's existing NGCC fleet continued to operate. Since the majority of NGCC units were retrofit with CCUS in the current policy scenario, removing CCUS options resulted in a 64.8 Mt_{CO2e} increase in GHG emissions.

Overall, results suggest that Alberta is likely to make significant progress on reducing electricity GHG emissions in the next 5 - 7 years and is on the path to net-zero under current policies.

6.2 Limitations and Future Work

In general, results could be impacted by evolving policy decisions concerning future wind sites [43, 44], the adoption of CCUS in the electricity sector, and hydrogen infrastructure development to support industrial power generation. Furthermore, in the wake of the recent Genessee CCUS project cancellation [101], variability surrounding the deployment of CCUS in Alberta's electricity market suggests that future work should focus on strategies to integrate alternative low-emitting dispatchable solutions that could play a similar role in supporting variable renewable output. A list of key limitations relative to this modelling and suggested areas for future work are listed below:

- Generally, capacity expansion studies such as this one rely on historical averages to define renewable output instead of using stochastic patterns. As a result, this work did not consider hourly resource adequacy metrics. Adequacy metrics such as expected loss of load events and unserved energy can be used to assess the adequacy of electricity systems under changing weather conditions or unplanned plant outages [107]. Future work could include steps to integrate resource adequacy assessments into the net-zero pathways presented and quantify associated risks.

- Cogeneration was treated exogenously in this thesis, however cogeneration GHG emissions will impact Alberta's ability to achieve economy-wide net-zero by 2050. Future work could explore pathways for decarbonizing Alberta's electricity cogeneration fleet based on cross-sectoral inputs and products.

- No scenario exceeded an installed storage capacity of 0.5 GW by 2045, despite the AESO reporting over 6 GW of potential storage projects proposed in Alberta as of May 2024 [42]. While storage results are logical within the context of developed scenarios (as discussed in Section 4.3.2), ideas to improve storage modelling are listed below.
  - Include the ability for storage to bid above it's marginal costs, which may improve the associated value.
  - Given the hourly curtailment of wind and solar, paired storage and renewable sites could improve the economics of both new storage and renewable sites. This could also alleviate some need for low-use dispatchable fossil fuel generation.
- Transmission was not explicitly included in this work. Strengthening location based wind constraints to better represent timelines and feasible locations would improve realism in the pathways modelled. Future work could also consider the costs of new transmission which would be necessary to achieve the net-zero pathways outlined in this thesis.
- These pathways relied on low-use gas and hydrogen simple-cycle plants to meet load constraints during peak demand. The model did not consider demand response, which could impact electricity supply requirements by shifting peak load. Including a demand response option in future work could help alleviate the strain on the system during hours of peak load.
- Given the prominence of new wind in pathways presented, future work could include a sensitivity analysis to determine how policies which could restrict new wind sites or alternative capital costs could impact wind development in Alberta.

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Appendix A: Supplementary Data

This appendix contains additional details regarding model settings, data, and assumptions presented in Chapter 3 and Chapter 4. It also includes a short expert on model validation steps which were taken.

A.1 Technical Assumptions

Key technical settings, which were held constant for all simulations, are presented in Table A.1. Where missing, default Aurora assumptions were accepted.

Table A.1: Aurora technical model settings.

Setting	**Parameter**
Study Precision	Medium (average price change <1.0%)
Minimum Iterations	6
Maximum Iterations	70
Methodology	MIP
Dispatch	Chronological (maximize system value)
Commitment	Commitment optimization
Dispatch Days in Solve	2
Lookahead Sampling	Every hour
Solver	Gurobi
Dispatch Hours	Every Hour
Dispatch Days	Every day
Dispatch Weeks	Second week

Aurora has an additional option to include planning reserve margin targets. In regulated markets, planning reserve margins are often used to define how much firm capacity is required relative to expected peak demand in each year. Since Alberta is an energy only market, planning reserve margin capacity targets were not set, instead the model was left to add/subtract resources based on value in each year.

An operating reserve represents the amount of capacity that is not being used to meet load but is available on stand-by to accommodate real-time load changes. The operating reserve margin is defined as available capacity (i.e. capacity that is not already being used to meet load requirements) divided by demand. An operating reserve margin of 15% was used in the model. The Aurora optimization model seeks to meet reserves using the most affordable plants which are not already operating at full capacity in a given hour. Power plants are first dispatched to meet demand, and then reserves are met when feasible. The model attempts to meet operating reserve constraints in all hours, however it will relax this constraint as needed in order to meet demand. To avoid infeasibility, the Aurora model also has the ability to relax demand constraints or introduce small amounts of load shedding. These features are generally discouraged in the final solution by assigning high prices (upwards of $10,000/MWh), however they are useful to ensure a smooth iterative process.

A.2 General Assumptions and Inputs

A.2.1 Interties

Each neighbouring zone, BC/MT and SK, was represented using a single theoretical gas plant. The capacity of each plant was double that of the intertie with Alberta, while zone demand was set to match the intertie capacity. This gave each simplified zone the ability to fully meet local load while also exporting power to Alberta when economic. The marginal cost to operate the representative plant in any hour was used as a price trigger to determine when imports or exports could occur. The single "theoretical plant" in each zone (BC/MT and SK) was not assigned any carbon costs or variable operation and maintenance costs. Instead, the cost of operating the plant was entirely based on fuel cost. The total fuel cost for a typical gas plant is equal to the cost of fuel ($/GJ) multiplied by the plant's heat rate (GJ/MWh). Fuel costs entered in the model were constant between AB, BC/MT, and SK, however, the heat rate used for these "theoretical" plants varied.

Theoretical heat rates were calculated with the goal of representing the cost to operate an average marginal unit in Alberta when trade took place, while at the same time considering how Alberta's pool price could relate to trade. The method adopted was based on the idea that in Alberta's fossil fuel dominated electricity system, the average hourly marginal plant would typically be a gas plant bidding near its operating costs. To calculate a "theoretical" heat rate and capture the relationship between Alberta's pool price and electricity trade, hourly pool prices spanning 2010 to 2022 reported by the AESO [108] were divided by actual gas prices reported by the U.S. Energy Information Administration [109] according to Equation A.1. Hourly heat rates were calculated when intertie flow was non-zero for four groupings: Alberta to Saskatchewan (exports), Saskatchewan to Alberta (imports), Alberta to British Columbia and Montana (exports), and British Columbia and Montana to Alberta (imports).

$$HR_T = \frac{P}{C_F} \tag{A.1}$$

Where,

HR_T = theoretical heat rate (GJ/MWh)

P = wholesale pool price ($/MWh)

C_F = fuel cost ($/GJ)

For each of the four trade categories, hourly data was grouped and the median heat rate was taken in each month to avoid data extremes. Extreme points in the data represent situations where the pool price reached a maximum or minimum as a result of more or less aggressive bidding. These situations would not represent a plant bidding at marginal cost. From here, an average of the monthly median heat rates from 2010 to 2022 was taken to estimate monthly theoretical heat rates, presented in Table A.2. These monthly heat rates were input into the model to help solidify the relationship between gas price and trade, apply more variation to monthly trade patterns, and provide a price signal for when intertie flow could take place. In most cases, monthly heat rates fall within range of typical gas-fired plants, confirming that this methodology is representative of typical marginal heat rates in Alberta. For reference, the U.S. Energy Information Administration reported that in 2022 average heat rates for gas-fired electricity generation in the United States ranged 7,596 - 11,030 Btu/kWh [110], and the AESO *2024 Long-Term Outlook* expects new combined-cycle gas technologies to achieve a heat-rate of 6,436 Btu/kWh (6.79 GJ/MWh).

Table A.2: Monthly theoretical heat rates (Btu/kWh) calculated for gas plants representing British Columbia/Montana and Saskatchewan.

Month	**AB to BC/MT**	**BC/MT to AB**	**AB to SK**	**SK to AB**
January	7,387	8,412	7,802	8,917
February	9,200	9,706	10,324	10,011
March	8,005	8,667	8,054	9,481
April	7,270	8,080	11,200	8,785
May	7,710	7,518	7,789	7,736
June	8,740	7,448	10,284	8,056
July	7,548	7,629	7,064	7,869
August	7,229	8,081	7,246	8,263
September	6,302	7,530	7,677	8,044
October	6,392	8,040	7,608	8,991
November	6,556	7,783	8,068	8,452
December	6,382	7,963	12,248	9,088

The resulting marginal cost to generate electricity in BC/MT and SK is equivalent to the theoretical heat rate multiplied by gas price. As an example, in January the theoretical heat rate for imports from Saskatchewan to Alberta was approximated as 8,917 BTu/kWh (9.41 GJ/MWh). If the average gas price in the model for this month was \$2.59/GJ, the dispatch cost in Saskatchewan for this time period would become \$24.39, meaning Alberta would not consider importing energy until the marginal zone cost (i.e. hourly pool price) exceeded this value.

Intertie availability was defined based on actual 2018 hourly data sourced from the AESO's public report on historical intertie capability [28]. The normalized hourly availability for each intertie was input into the model. Figure A.1 shows the average transfer capability available for each day in 2018. Note that a daily average is shown in Figure A.1 for simplicity, but the model uses an hourly resolution.

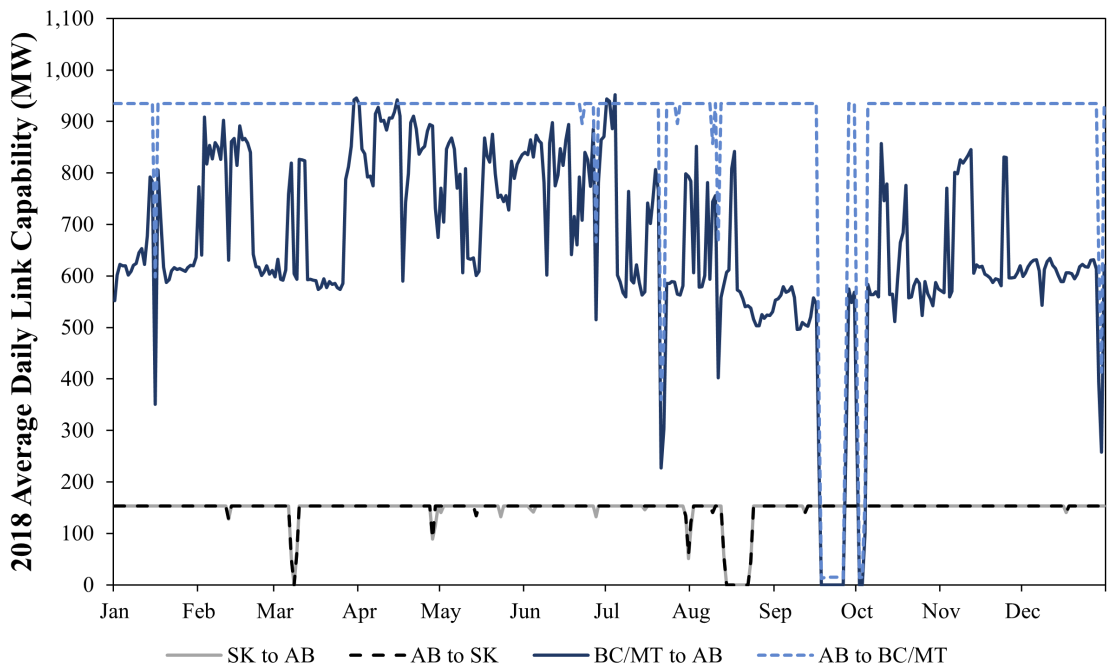

Figure A.1: Average daily intertie capability to and from Alberta based on 2018 data, with data from the AESO's public intertie reports.

To select 2018, each year of data spanning 2017 till 2021 was compared against a 5-year average (2017 - 2021). Comparison was done by plotting and analyzing the monthly link capabilities throughout the five selected years and by comparing statistics including mean link capability, standard deviation, maximum link capability, and minimum link capability. It was noted that 2020 and 2021 may have been impacted by the COVID19 pandemic, so these years were not eligible for selection. The year

2018 was found to best represent intertie availability trends between 2017 and 2021.

A comparison between the hourly data for 2018 and 5 years of data spanning 2017 - 2021 is shown in Table A.3. Values show the 2018 mean, max, and standard deviation of intertie availability for BC/MT are within a 4% difference when compared to the 5 year average used. There was more variability in the case of SK interties, resulting in a slightly higher overall availability. However, the SK connection is relatively small (only 153 MW, less than 2% of Alberta's average hourly load in 2023) so this is unlikely to have a large impact on results. More emphasis was placed on creating an accurate representation for the BC/MT connection.

Table A.3: Comparison of intertie capabilities between 2018 and 2017 - 2021.

Intertie	**Metric**	**2017 - 2021**	**2018**
SK Export	Mean (MW)	139	147
	Std Dev (MW)	43.1	29.9
	Max (MW)	153	153
	% Zero Hours	8.6%	4.0%
SK Import	Mean (MW)	139	147
	Std Dev (MW)	43.2	30.3
	Max (MW)	153	153
	% of Zero Hours	8.6%	4.1%
BC/MT Export	Mean (MW)	893	893
	Std Dev (MW)	193	192
	Max (MW)	935	935
	% of Zero Hours	2.0%	0.3%
BC/MT Import	Mean (MW)	630	658
	Std Dev (MW)	209	202
	Max (MW)	1045	1045
	% of Zero Hours	4.6%	4.5%

A.2.2 Fuel Costs

Monthly fuel prices for gas and blue hydrogen are shown in Figure A.2. Prices in Figure A.2 are presented in 2023 dollars, based on an average inflation rate of 2.5% annually. Note that separate short-term monthly forecasts were used between 2023 - 2025, which causes the different monthly pattern seen in Figure A.2. Henry hub short-term prices were obtained from the U.S. Energy Information Administration (EIA) December 2023 *Short-Term Energy Outlook* [83] while AECO (Alberta Energy Company) prices were taken from Sproule's December 2023 forecast [84]. Annual prices following 2025 were taken from *Canada Energy Futures 2023* baseline forecast for Henry Hub gas.

Monthly gas price variation for Alberta (AECO) was introduced using a monthly price adder. To estimate an adder, the historical monthly AECO prices were subtracted from the monthly price of Henry Hub natural gas between 2017 and 2021. The average monthly values were input into the model under the assumption that Alberta will continue to benefit from affordable natural gas based on its resources. This method results in average annual prices ranging from $2.59/GJ - $3.95/GJ and an overall annual average of $3.45/GJ (2023 CAD). As a point of reference, the average annual price of natural gas in Alberta presented by *Canada Energy Futures 2023* was estimated to be $3.12/GJ, ranging between $2.66/GJ - $3.66/GJ (2022 CAD) between 2023 and 2050. From this, it appears that the adder method taken aligns well with annual values, verifying the fuel prices are in a feasible range.

The cost of blue hydrogen transported via pipeline was estimated by a fellow graduate student, Gloria Duran Castillo. Assuming a higher heating value of 141,800 kJ/kg [111], average annual hydrogen prices in the model ranged CAD $2.39/kg - CAD $2.74/kg or CAD $16.87/GJ - CAD $19.35/GJ (2023 dollars). The blue hydrogen prices input in the model were verified to fall within predicted blue hydrogen ranges for Alberta and Canada. Comparatively, the Canada Energy Regulator's

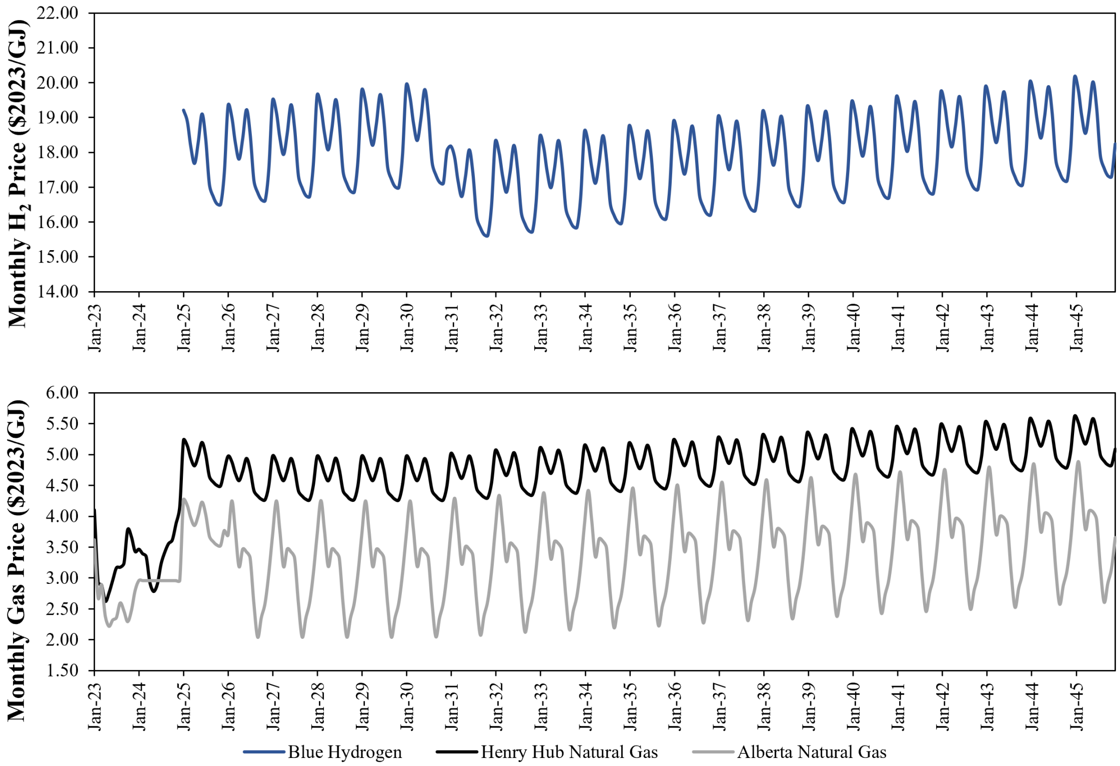

Figure A.2: Monthly prices for natural gas and hydrogen, presented in 2023 Canadian dollars.

Canada's Energy Future 2021 report [112] projected annual blue hydrogen prices in the range of USD \$1.50/kg - USD \$1.80/kg (2020 dollars) between 2030 and 2050. Assuming an average annual inflation rate of 2.5% and a conversion rate of 1 USD = 0.79 CAD, the *Canada's Energy Future 2021* report range is approximately CAD \$2.31/kg - CAD \$2.78/kg in 2023. Similarly, a 2022 study by Okunlola et al. [113] found that blue hydrogen in Alberta produced using steam-methane reforming with an 85% capture rate could be priced at CAD \$2.34/kg in 2020 dollars.

A.2.3 Emissions Performance Credits and Offsets

Emissions performance credits were generated based on the TIER high-performance benchmark (HPB) and monetized at 90% of the carbon price under current policy assumptions. The projected impact of changing the HPB can be visualized in Figure A.3, which shows how the TIER policy impacts common electricity generation plants in Alberta. For example, in 2030 at a HPB of 0.3108 t_{CO2e}/MWh and a value of 90% the \$170/tCO_2e carbon price, an EPC would be worth \$47.55/MWh in the model. Thus, as the HPB decreased, the associated credit value also decreased. Figure A.3 assumes typical GHG emissions intensities for gas-fired technologies: 0.37 t_{CO2e}/MWh for combined-cycle, 0.52 t_{CO2e}/MWh for simple-cycle, and 0.02 t_{CO2e}/MWh for combined-cycle gas with CCUS.

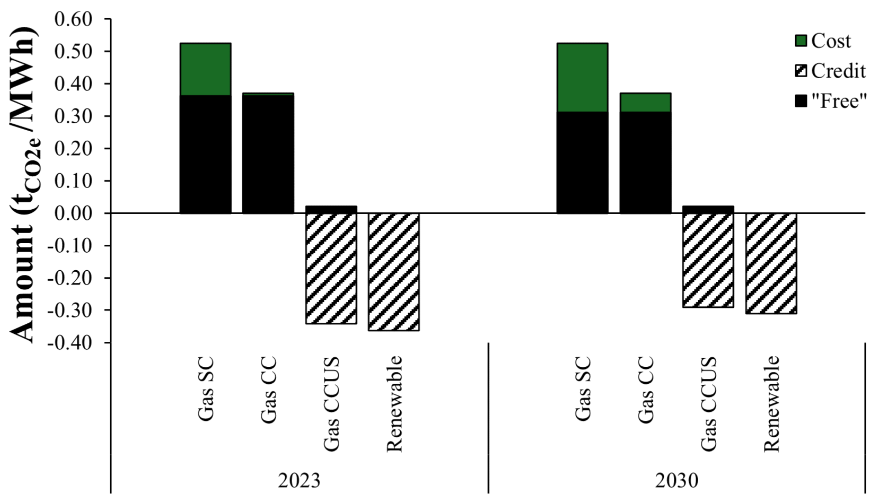

Figure A.3: Depiction of TIER HPB outcomes for simple-cycle gas (SC), combined-cycle gas (CC), gas with CCUS, and renewables in 2023 and 2030.

In the case of wind and solar, the Electricity Grid Displacement Factor (EGDF) was used where applicable instead of the HPB. EGDF values and eligibility periods were defined based on online years. For projects with a vintage year prior to 2023, a constant EGDF was used over the maximum length of eligibility, consistent with prior versions of the Alberta offset program. Following 2024, the EGDF follows the outlined schedule until it converges with the TIER HPB in 2030. After 2030, it was assumed projects would generate emissions performance credits, with no time limit. Details were sourced from the Alberta *Carbon Offset Emission Factors Handbook* [36] and are summarised in Table A.4.

Table A.4: Electricity grid displacement factor (t_{CO2e}/MWh) for wind and solar projects.

Year	Period	Handbook	EGDF
2019 or earlier	8 years + 5 bonus = 13 years	version 1.0	0.5900
2020-2022	8 years + 5 bonus = 13 years	version 2.0	0.5300
2023	10 years + 5 bonus = 15 years	version 3.0	0.5200
2024-2029	Converge with EPCs, no limit	version 3.1	varies
2030	Converge with EPCs, no limit	version 3.1	0.3108

A.3 Resource Assumptions and Inputs

A.3.1 Exogenous Additions

Annual exogenous capacity additions for each resource group are shown in Table A.5. Additions are based on projects reported in the AESO's January 2024 connection reporting list [41]. New projects labeled as stage 5 (construction) or 6 (closeout) with a project inclusion status of "yes" and completion date between 2024 - 2025 were included. An additional 75 MW pumped-hydro energy storage project was also included in 2026 based on final investment decisions.

Table A.5: Exogenous resource group additions between 2024 and 2026.

Year	Resource Type	Capacity (MW)
2024	Biomass	19
	Combined-Cycle Gas	900
	Simple-Cycle Gas	32
	Solar	1,226
	Storage	111
	Wind	1,014
2025	Cogeneration	25
	Solar	243
	Storage	29
	Wind	400
2026	Storage	75

A.3.2 Operational Characteristics

Outage Rates

Two types of outages were represented in the model, forced outage rates (FOR) and maintenance rates. Forced outage rates are unplanned events which result in a generating unit going offline for some period of time, often characterized by component failure [114]. Maintenance rates are planned outages, typically to perform safety checks or general upkeep. Table A.6 shows average annual outage rates for each generation type. It should be noted that in some instances input values varied by plant and/or month.

Outages were treated as capacity de-rates, causing a percentage of overall capacity to be unavailable. Monthly maintenance rates based on typical rates for Canada were included in the Aurora database. These were used for all thermal generation. Similarly, monthly time series from the Aurora database were used to represent a

Table A.6: Thermal plant attributes and constraints assigned in model input.

Plant Type	**FOR (%)[1,2]**	**Avg Maintenance Rate (%)[2]**	**Must Run**	**Minimum Capacity (%)**	**Min Up/Down Time[1]**
Biomass/Other	3.1	5.0	No	32/36[4]	2/4
Steam Turbine	9.2	7.3	No	20[3]	2/4
Cogeneration	5.0	4.0	Yes	46 - 91[5]	Must Run
Combined-Cycle	6.8	4.8	No	20 - 71[3]	2/6
Combined-Cycle CCS	5.0	4.0	No	40 - 50[4]	2/6
Simple-Cycle	7.5	7.3	No	31 - 87[3]	1/1
Nuclear SMR	10.0	6.7	No	50[3]	48/48

[1] From WECC anchor set V2.4.1 public data [115].
[2] From default Aurora dataset.
[3] Update of Reliability and Cost Impacts of Flexible Generation on Fossil-Fueled Generators for Western Electricity Coordinating Council [116].
[4] Adapted from 2021 form EIA-860 [117].
[5] Cogeneration minimum capacity levels were determined based on estimated BTF generation from the AESO's Annual Market Statistics Report [27].

FOR for nuclear, cogeneration, combined-cycle CCS, and simple-cycle plants. For coal-to-gas (steam turbine), combined-cycle, and biomass, flat plant specific forced outage rates (FOR) were taken from the Western Electricity Coordinating Council (WECC) regional planning groups anchor data set [115]. This data set contains detailed information specific to modelling the majority of generating plants within the WECC region, inclusive of Alberta. Where applicable, forced outage rates were updated to reflect plant specific values. If forced outage rates did not vary widely between similar plants, a single value was applied for each resource type. Values were entered as 3.1% for other/biomass plants and 9.2% for coal-to-gas steam turbine units. In the case of combined-cycle generation, forced outage rates varied between 6.3% and 6.9% on a plant specific basis. If a specific generating unit was not present in the WECC Anchor Data Set, an average value of 6.7% was applied. New plants were assigned the default monthly outage times series, since plant specific data was not available. The combined monthly outage rate for each plant type is shown in Figure A.4. It was assumed that hydrogen-fired units would adopt the same outage rates as similar natural gas facilities.

Minimum Capacities

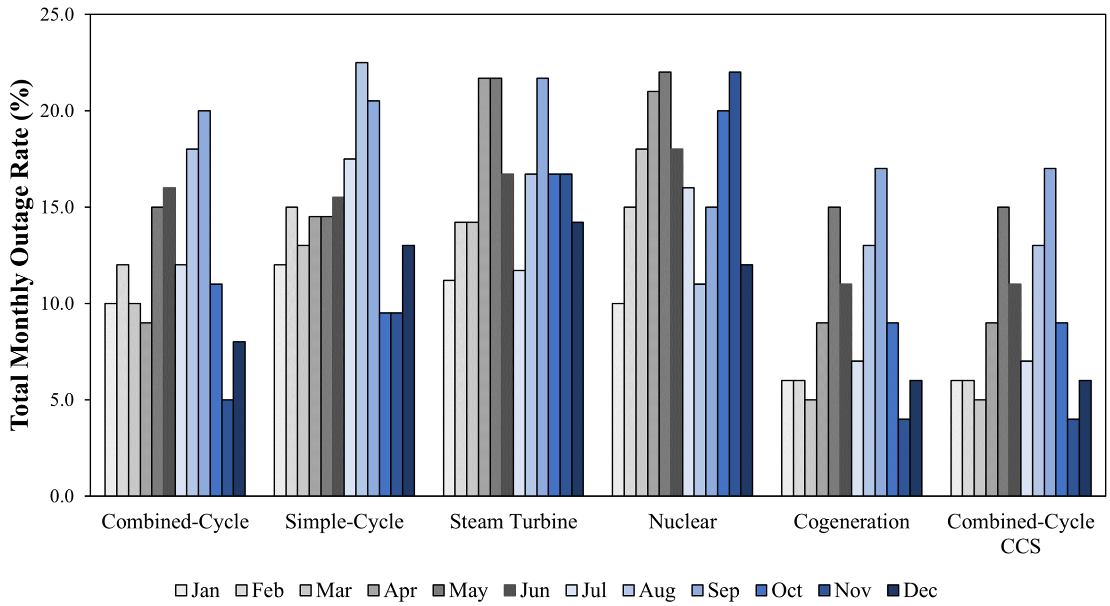

Figure A.4: Average thermal generation monthly outage rates as a combination of forced outage rate and maintenance rate.

Table A.6 outlines average operating characteristics by technology type. The minimum capacity represents the minimum stable generation level that a plant can operate at. For traditional thermal plants such as combined-cycle natural gas plants, the minimum stable generation level is based on the amount of heat necessary to efficiently generate electricity [118]. Above this level, a plant can ramp output up and down to meet load requirements. Below the minimum operating level, a plant would need to fully shut down and startup again at a later time. Table A.6 outlines the range of minim capacities used, as there was some variation between units.

Minimum capacities for combined-cycle, simple-cycle, and steam turbine natural gas units were based on the WECC Anchor Data Set (ADS) [115] as well as estimations provided in a reliability report for the Western Electricity Coordinating Council (WECC) by Kumar et al. [116]. Values vary slightly depending on the efficiency and configuration of the plant. To estimate minimum capacities for biomass/other, data was collected from the EIA's 2021 form EIA-860 [117], which compiled actual power plant performance data from plants across the United States. The minimum load presented in form EIA-860 (in MW) was divided by the rated capacity of each plant in order to get minimum load as a percentage of capacity for each plant. A total of 519 biomass (wood and/or waste type) plants were used to estimate an average minimum load point of 36%. Similarly, 252 geothermal and "other" plants were averaged to get a minimum load point of 32%.

Up/Down Times

Minimum up and down times are additional constraints which dictate the total time a plant must operate for once it has committed to run. They prevent large complex plants from unrealistically ramping from zero to full load within an hour. Up/down time constraints are fed into the commitment optimization logic of Aurora. Should a plant drop below its minimum generation level and have to shut off, the minimum down time would come into play. Similarly, if there was opportunity to supply power a few hours later, the plant would need to ramp back up to at least a minimum stable generating level. Minimum up and down times were defined based on the WECC Anchor Data Set (ADS) [115]. For new plants, general up/down times were defined based on technology type and findings in Kumar et al. [116] and the WECC ADS.

A.3.3 Heat Rate Curves and Bidding

Heat rates and offer behavior was defined for each plant based on operational load point. Each plant was segmented so that efficiency increased with load point, while the plant also offered more aggressively into the competitive market. Bid factors, as presented in Chapter 3, were originally developed by a previous student, Taylor Pawlenchuk [93]. Curves were configured to that offers increased exponentially, based on historical market data. Plants were separated into multiple segments, and simple-cycle plants were given behavior that varied monthly. Curves presented by Pawlenchuk were improved upon to incorporate CCUS and plant heat rates were updated to better diversify the fleet and accurately represent emissions. In the case of simple-cycle plants, modifications were made which prevented plants from operating under marginal costs at minimum load. Technologies including combined-cycle, coal-to-gas, coal, cogeneration, and biomass/other began offering at \$0/MWh at minimum load and increased thereafter. Figure A.5 shows an example of bidding for a simple-cycle gas plant and combined-cycle gas plant, assuming an arbitrary operating cost of \$30/MWh.

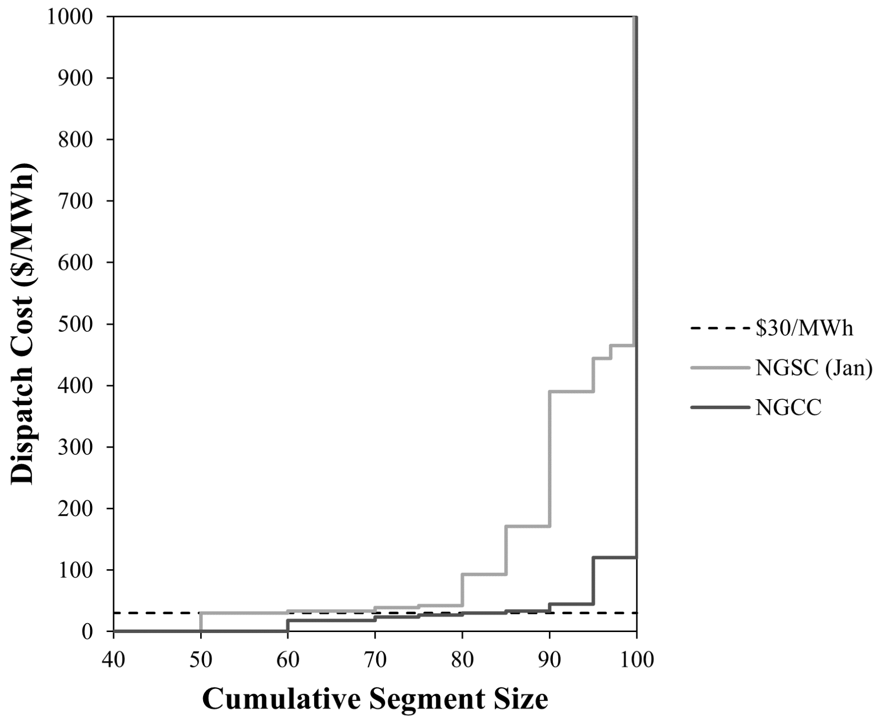

Figure A.5: Example bidding behavior for a NGSC and NGCC plant with a minimum load of 50%.

Typical heat rate curves were estimated from a National Renewable Energy Laboratory (NREL) study [89] which reviewed the impact of fossil fuel resource cycling on power system emissions. The paper included a figure which presented average heat rate curves by technology type, based on data gathered from units operating across the United States. Using the results presented in the NREL paper, data points were estimated and a second order polynomial curve was fit to each technology type. The curve was defined based on full load heat rate - meaning the heat rate of a plant

Table A.7: Example heat rates and bidding for a new NGSC plant with a marginal cost of $30/MWh, operating in January.

Cumulative Segment Size	**Heat Rate (Btu/kWh)**	**Bid Factor**	**Bid**
50	11,466	0	30
60	10,942	0.1	33
70	10,523	0.3	39
75	10,354	0.4	42
80	10,211	2.1	93
85	10,095	4.7	171
90	10,005	12	390
95	9,942	13.8	444
97	9,924	14.5	465
100	9,905	999	1000+

operating at 100% of its capacity. From here, each plant's heat rate was expanded along the corresponding technology curve. In the case of new units, typical heat rates were obtained from the AESO's *Preliminary 2024 Long-Term Outlook* [75]. Table A.7 shows an example for a simple-cycle gas plant operating with a minimum load point of 50% and a marginal cost of $30/MWh. Figure A.6 shows the result of expanding AESO typical heat rates along polynomial curves at different operational load points for different plant types. While offers (or bids) may exceed $999.99/MWh, the model includes a price cap which prevents hourly prices from exceeding $999.99/MWh.

In the case of existing plants with unique heat rates, curves were applied based on technology type, but heat rates may not match what is shown in Figure A.6. Plant specific full load heat rates were calculated from project specific turbine specifications where accessible or the Western Electricity Coordinating Council's Anchor Data Set (ADS) [115]. If no plant specific heat rate values could be obtained, AESO values were used. For CCUS retrofit options, the existing plant heat rate was modified to represent a 10% loss in efficiency.

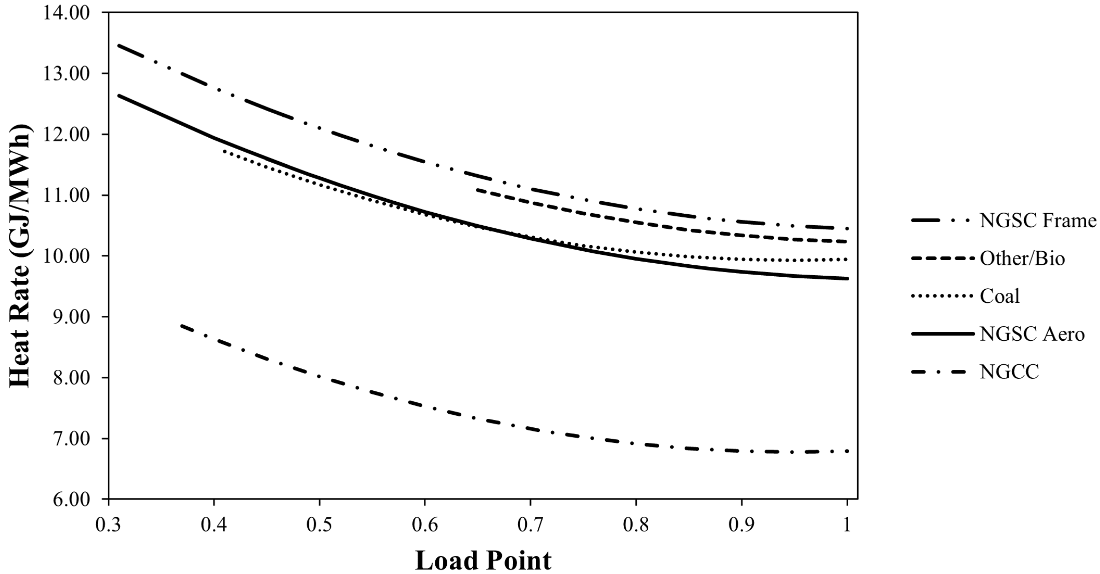

Figure A.6: Typical heat rate curves defined by operational load point.

A.3.4 Hydro

The Aurora documentation includes a complex hydro logic which shapes hourly, monthly, and annual output. Although hydro is not a major part of Alberta's electricity supply, some of these factors were configured to represent historical generation and availability. Data was collected from the AESO [27] between 2015 and 2023 to assess hydro trends. The year 2019 was chosen as a representative hydro year and targeted monthly capacity factors in the model were based on this year. Hourly data was used to create a shaping file which guided how closely hydro output followed load and price each month. For example, in spring months the correlation is low, since much more water is available and output may be based on flood control tactics rather than load following. In winter months, the correlation was higher, reflecting hydro output that is more aligned with peak load and high prices. Figure A.7 shows average monthly hydro capacity factors in Alberta between 2015 and 2023. The figure also includes a line for minimum, maximum, and 2019 average monthly hydro capacity factors.

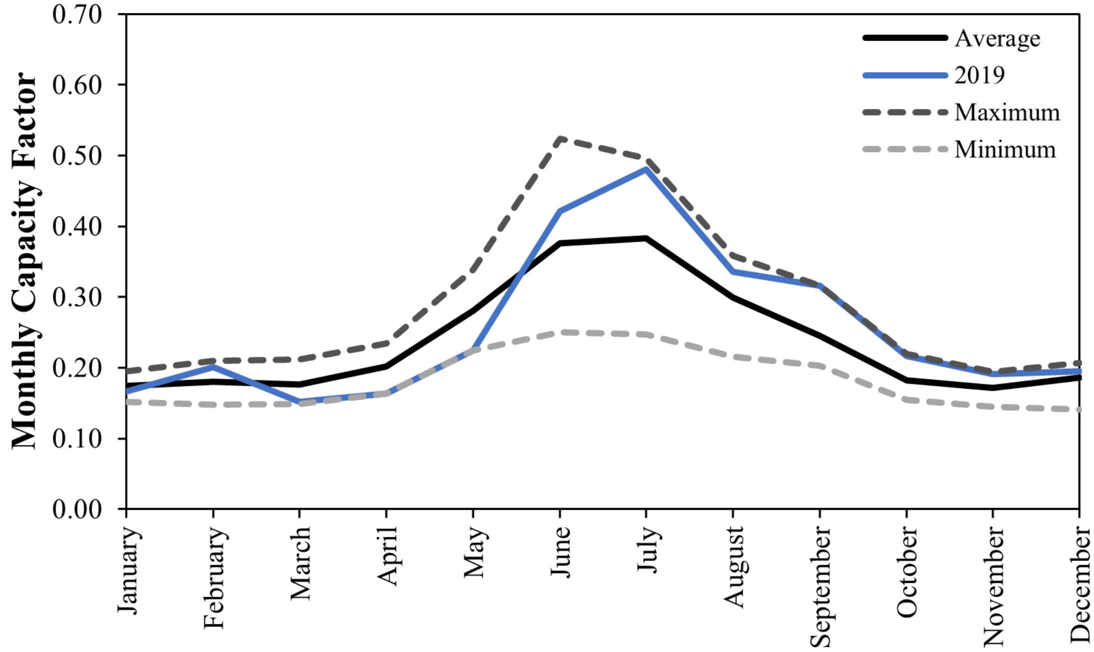

Figure A.7: Alberta average monthly hydro capacity factors between 2015 and 2023.

A.3.5 New Plant Costs

New plant costs were sourced from Clean Energy Canada (CEC) using Dunksy energy [99] and the AESO's *Preliminary 2024 Long-Term Outlook* [75]. When the AESO's *Preliminary 2024 Long-Term Outlook* was originally released, costs were presented for 2022 only. Costs were annualized based on a WACC of 9.81% (determined based on factors presented in an AESO technology cost report for Alberta [119]) and respective project lifetimes. Capital cost learning rates were normalized based on the NREL 2023 Annual Technology Baseline (ATB) report [61] moderate case. Costs sourced from CEC (wind, solar, and long-duration battery storage) were left as is between 2022 and 2035. After 2035 (when the CEC projection ended), NREL learning rates were used to further reduce costs[21]. This approach resulted in slightly lower wind capital costs during the early 2040's, reaching \$1,043/kW (2022 CAD) by 2045. In comparison, the 2023 NREL ATB cases spanned \$800/kW - \$1,038/kW (2021 USD) in 2045. Assuming a conversion rate of 0.76 USD/CAD and an average inflation rate

[21]Class 4 data was used for wind costs and class 5 was used for solar costs.

of 2.5%, this is roughly equivalent to \$1,079/kW - \$1,400/kW in 2022 CAD. Thus, the cost used in Aurora falls towards the advanced case but is not unreasonable. For costs sourced from AESO, aside from established technologies, the 2022 AESO cost was reduced based on the ATB moderate case.

Figure A.8 presents a comparison of the learning rates used by the model with other forecasts including the Clean Energy Canada report, AESO's *2024 Long-Term Outlook*, and the NREL 2023 ATB. Although initial 2022 costs remained the same, the final release of the AESO *2024 Long-Term Outlook* in May 2024 [74] did include annual learning rates which are shown in Figure A.8. As seen in Figure A.8, the biggest cost deviation between AESO assumptions and those input into the model was for nuclear SMR, where the AESO forecast included a cost reduction of approximately 50%. The AESO *2024 Long-Term Outlook* also did not include additional cost reductions for wind or solar pasts 2030.

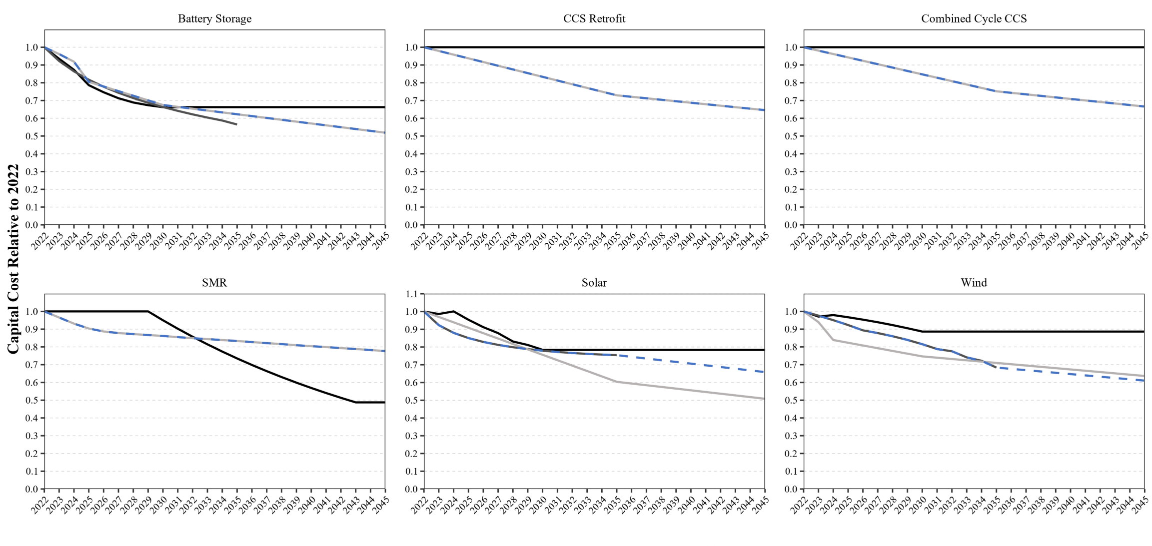

Figure A.8: Cost curves applied to each plant type and compared to other sources.

A.4 Model Validation

To validate model inputs and market operation, model outputs were compared to historical data and to recent forecasting results from the AESO. When comparing, it should be noted that the model dispatches plants based on prescribed offer behavior and estimated plant operating costs which may vary from real costs or the decisions of market actors.

A.4.1 Comparing Model Dispatch to Historical Data

Figures A.9, A.10, and A.11 compare capacity, generation, and capacity factors between the model and actual data. The model was dispatched in 2022 and 2023 at the same temporal resolution used for each simulation and compared to historical data gathered from the AESO's Annual Market Statistics Report [27]. The "gas" category presented in Figures A.9 and A.10 includes simple-cycle, combined-cycle, coal-to-gas, and dual fuel units. Capacity is presented in Figure A.9 as an average of available annual capacity. In the model, plants were given start dates corresponding to the date they were reported as active by the AESO's market updates webpage [120]. For this reason, there may be minor differences in reported annual capacity which can cause small deviations in generation.

Generation, shown in Figure A.10 also shows alignment between modelled and actual results. In general, the most significant variation was in coal, biomass/other and gas units. In the case of coal, considering that coal was phased out in 2024, it is unlikely these differences significantly impacted results. For the biomass/other fleet, these differences are again unlikely to significantly impact results, as the biomass/other fleet only makes up about 2% of Alberta's installed capacity. Differences in the gas fleet are likely a result of (i) market players bidding outside of expected patterns, (ii) higher wind fleet capacity factors displacing more expensive generation, (iii) small capacity differences, and (iv) other errors resulting from plant characteristics. Since

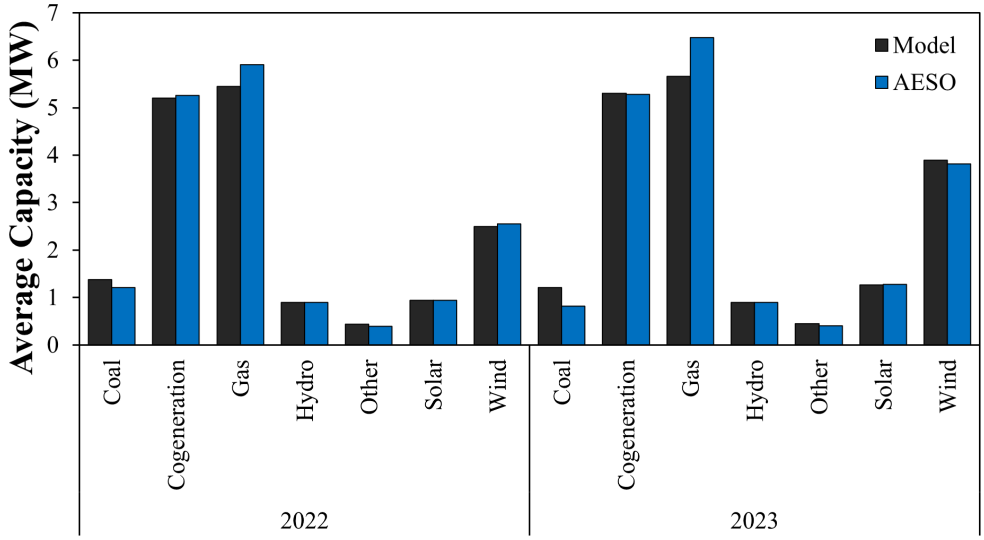

Figure A.9: Reported annual model capacity compared to AESO actual capacity.

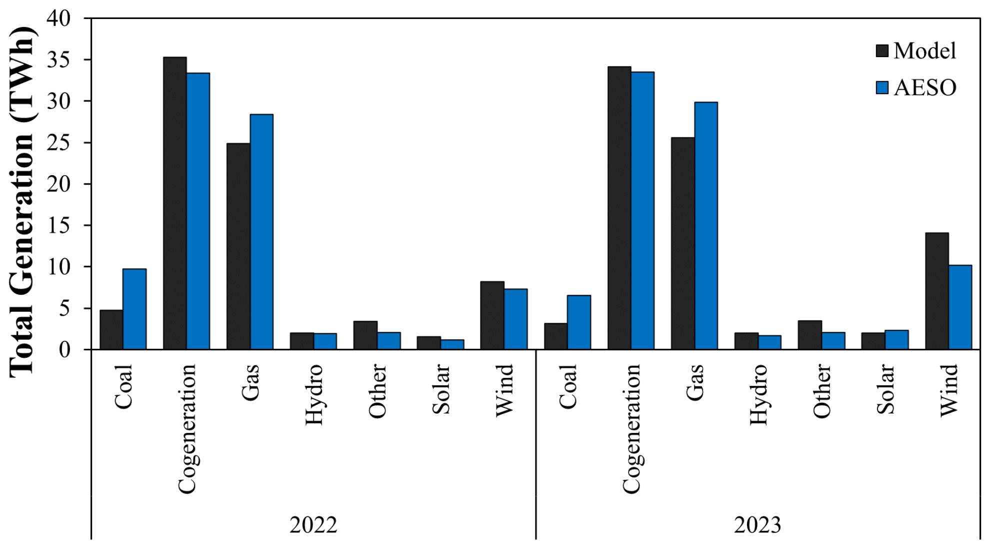

Figure A.10: Modelled annual generation compared to AESO reported actual generation.

the model considers plant bidding as a function of load point, aggressive bidding strategies by coal plants nearing their end dates was not captured.

Differences in the gas fleet operation were likely due to assumptions surrounding gas plant start dates (i.e. capacity); this is validated through a comparison of annual capacity factors calculated for each gas fleet, shown in Figure A.11. In 2022, the model resulted in an annual gas fleet capacity factor calculated[22] to be 52%, while the actual fleet capacity factor was 55%. Likewise, in 2022, the annual gas fleet capacity factor resulting from the model was 52% while the actual fleets was 53%. In addition, since plant characteristics were modified based on publicly available data and average technology data, there could be plant specific errors which contribute to slightly different annual generation or capacity factor results. Plant characteristics were likely the cause of variation for the biomass/other fleet, much of which operates behind-the-fence in Alberta. Again, it should also be noted that the optimization model dispatches plants on a cost optimal basis, which does not always reflect the decisions of individual plants in Alberta's competitive market.

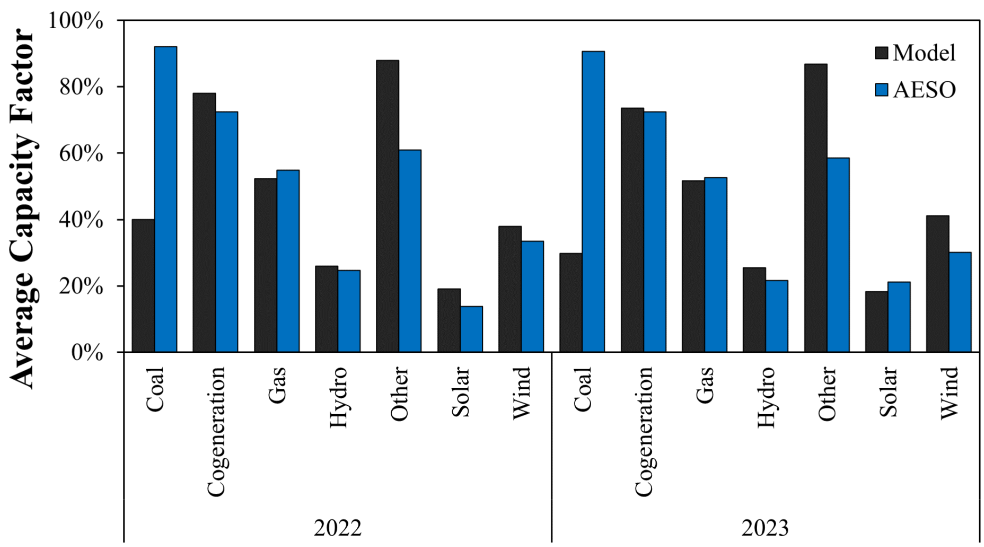

Figure A.11: Modelled annual capacity factors compared to AESO reported actual generation.

Between all scenarios modelled in this thesis, cogeneration average annual capacity factors ranged from 66% - 74%. This is in line with historical data available from the AESO's *Annual Market Statistics Report* [27]. Between 2015 and 2023 cogeneration capacity factors have ranged from 62% - 74% in the province, reporting 72% most recently in 2023. This validates that the "must run" portion of the cogeneration fleet,

[22]Calculated based on annual generation divided by annual capacity.

which was defined on a plant specific basis, was sufficient to reflect actual behavior.

Resulting annual wind and solar fleet capacity factors were compared to historical data in Table A.8. Results show that the historical data used to define wind and solar outages results in reasonable annual capacity factors, which align with previous trends for Alberta. It should be noted that lower solar capacity factors presented in Table A.8 in 2020 and 2022 may reflect new solar plants which were added to the system but not yet operating. In such cases, plants would report a capacity factor of “0”, which may cause the fleet annual capacity factor reported by AESO data to appear lower. The annual solar fleet capacity factor resulting from the model ranged from 17% - 18%.

Table A.8: Actual and modelled wind and solar fleet annual capacity factors (from current policy scenario).

Year	**Wind CF (%)**	**Solar CF (%)**
2020 Actual	39	12
2021 Actual	36	18
2022 Actual	33	14
2023 Actual	30	21
2023 Model	41	18
2025 Model	42	18
2030 Model	38	17
2035 Model	38	17
2040 Model	38	17
2045 Model	40	18

Annual modelled fleet capacity factors for wind ranged from 38% - 42%. These values are slightly above the historical 39% maximum capacity factor for Alberta’s wind fleet, reported in 2020. However, this result is expected since Alberta’s current wind fleet is quite correlated. In contrast, the model includes options for new wind plants in diverse locations across the province which reduced correlation between wind plants and increased the overall capacity factor. To ensure that wind plants were operating in a reasonable manner, the hourly fleet capacity factor was compared to actual data in Figure A.12. Figure A.12 depicts a duration curve which represents the percentage of hours per year that the wind fleet operates at a given capacity factor. From Figure A.12, the modelled wind duration curves appear to follow similar trends as historical data, indicating that the model experiences a variety of wind conditions, including near-zero wind output. Again, the model curves show slightly higher average capacity factors than actual data, which may be due to a less correlated fleet or less resource availability in the actual data presented.

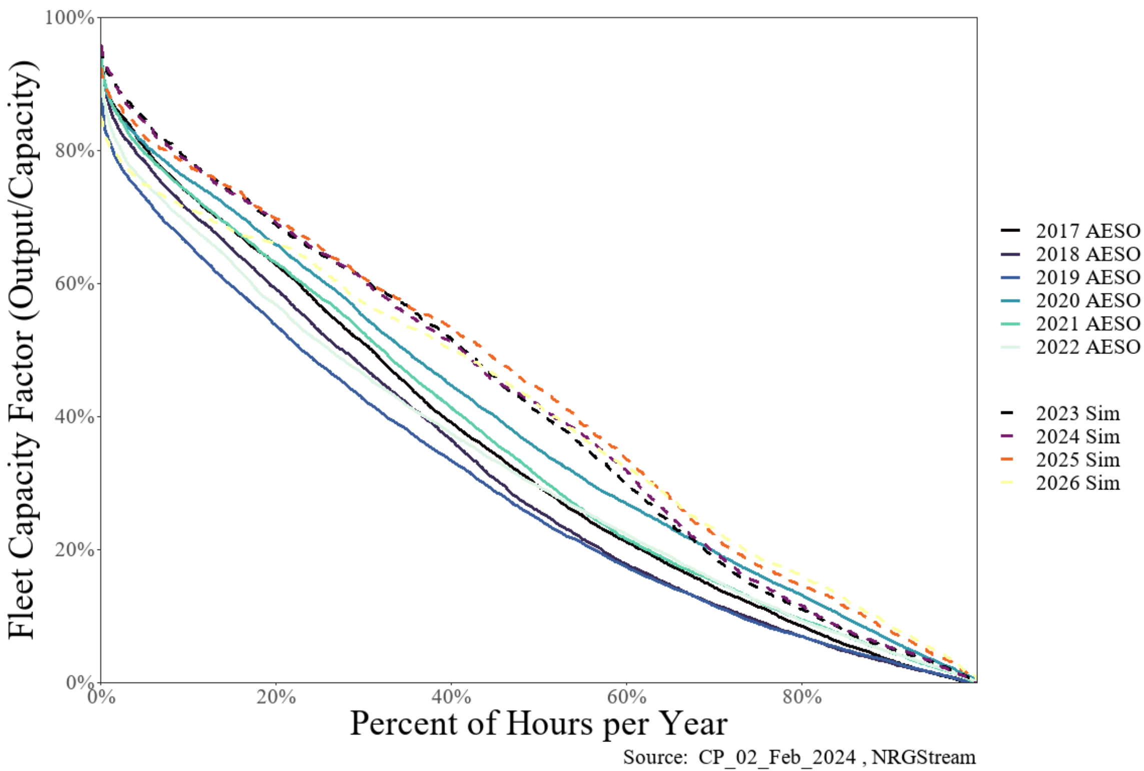

Figure A.12: Modelled wind hourly capacity factor compared to actual data.

A.4.2 Comparing to 2022 Hourly Data

Figures A.13 and A.14 show two example modelled weeks in 2022 compared to actual 2022 data. The "NRG Stream" data is simply an extract of AESO's reported hourly system data. Results show that hourly generation produced by the model reflects actual patterns, with caveats mentioned in the previous section. Figures A.13 and A.14 also help to visualize unique features of Alberta's market including the fairly consistent operation of cogeneration plants and the seasonality of solar. For instance, Figure A.13 shows the small role of solar power in January, compared to more significant output in July (Figure A.14).

There was some variation between modelled and actual simple-cycle behavior based on the bidding logic. In the model, simple-cycle gas plants were configured to start bidding at their marginal costs. In actuality, these plants may offer power below marginal costs to remain competitive, or other plants may offer higher, which would allow simple-cycle plants to enter in the merit order more frequently. Generally, in the year 2022 (show in Figures A.13 and A.14), the model selects coal-to-gas units in the place of generation which was provided by simple-cycle gas plants in the actual data.

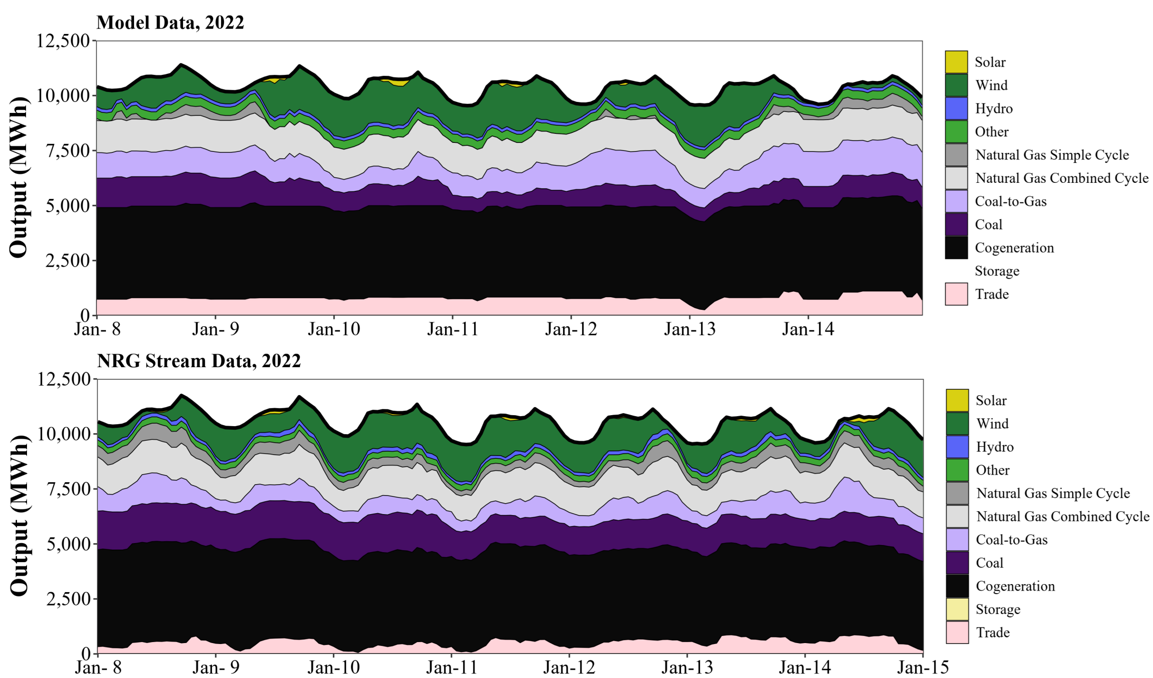

Figure A.13: Comparison between modelled and actual generation for one week in January 2022.

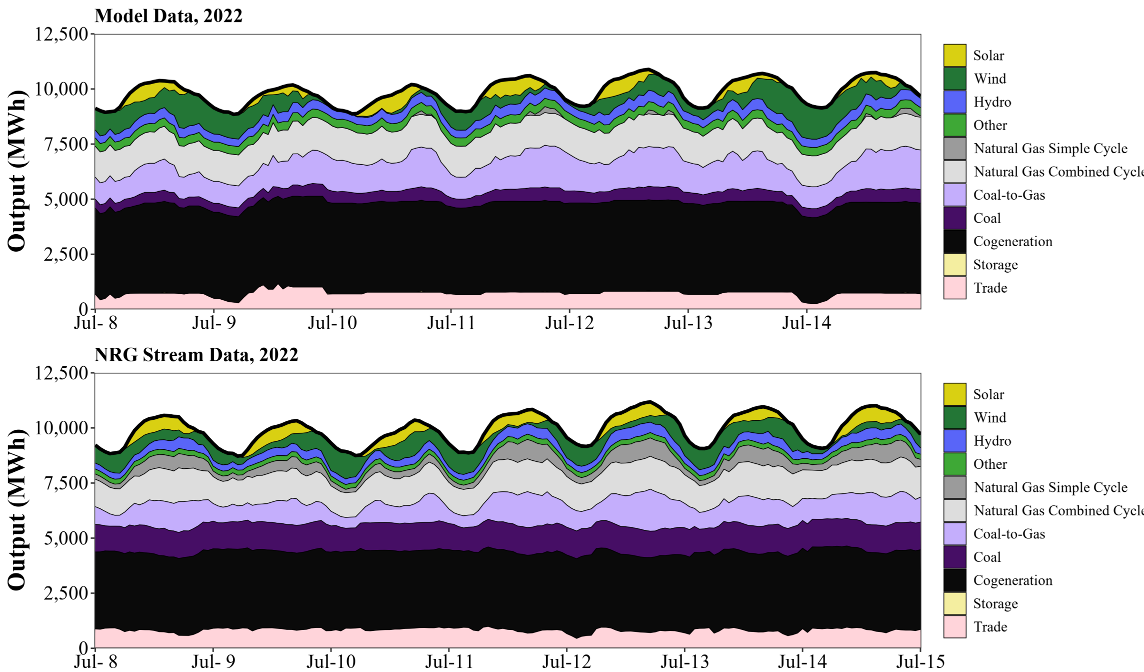

Figure A.14: Comparison between modelled and actual generation for one week in July 2022.

A.4.3 Comparison to System Operator Forecasts

The AESO released their *2024 Long-Term Outlook* in May 2024. The 2024 report included a forecast for three different future electricity systems. Figures A.15 and A.16 compare results from modelled scenarios to three of the AESO *2024 Long-Term Outlook* scenarios. The Fourth AESO scenario, a high-electrification case, was not included since it considered a dramatically different load profile. A comparison of scenarios modelled in Chapters 4 and 5 to other forecasting results may help verify findings are reasonable, as thermal groups, in particular cogeneration, show similar results.

The main difference between AESO modelling results and the results presented in this thesis is a trade off between wind fleet generation and capacity with abated gas-fired generation and nuclear SMR. The AESO report also includes some projected changes to the cogeneration fleet, either by allowing hydrogen-fired cogeneration or CCUS. Since cogeneration was exogenous in the scenarios presented in Chapters 4 and 5, GHG emissions reductions methods for cogeneration do not make a substantial difference to generation and GHG emissions results. Solar differences were explained in Chapter 4, and are based on alternative fleets. Hydro, other, and net-imports appear to be of a similar magnitude in Figure A.16.

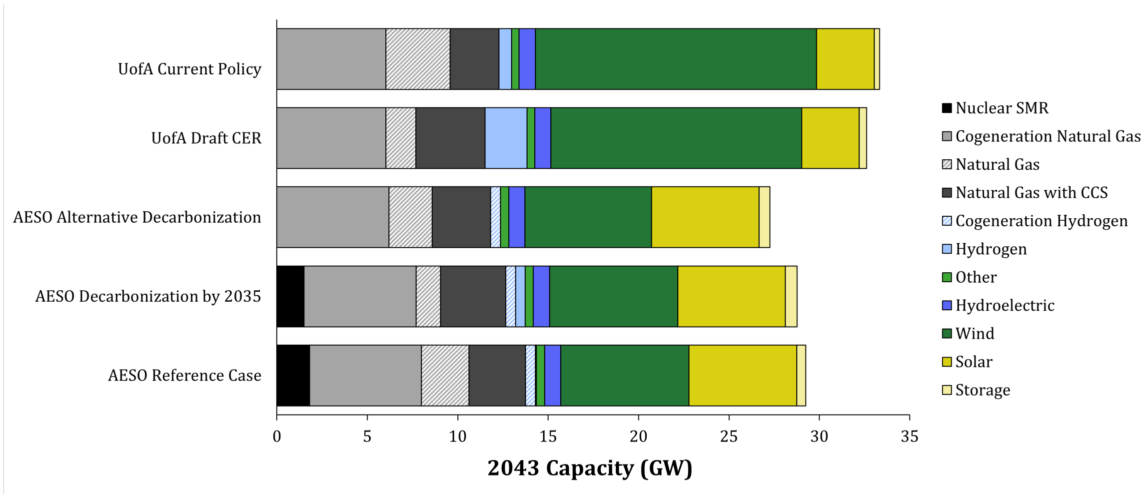

Figure A.15: Comparison between capacity expansion results from Chapter 4 and the AESO's 2024 Long-Term Outlook.

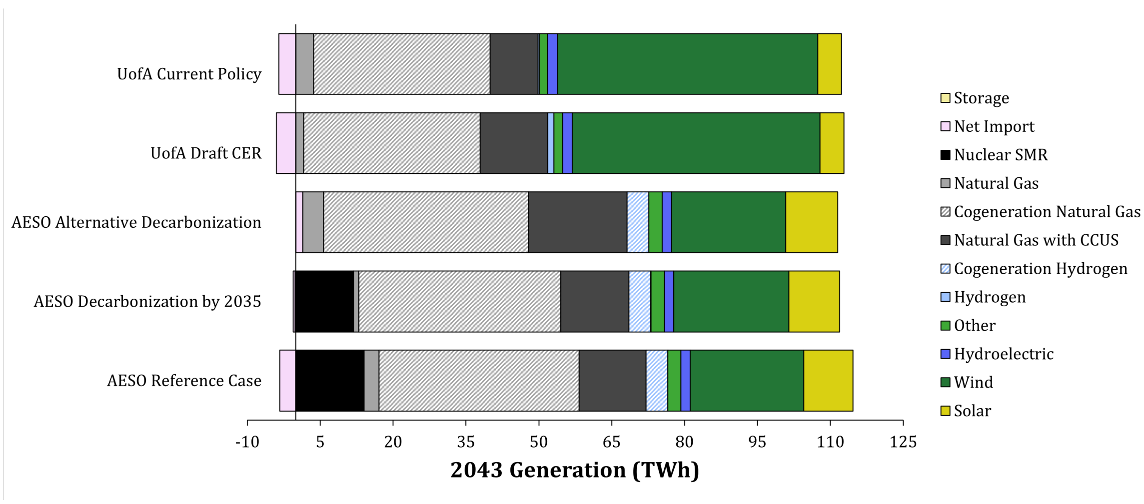

Figure A.16: Comparison between generation results from Chapter 4 and the AESO's 2024 Long-Term Outlook.

The AESO's *Preliminary 2024 Long-Term Outlook* presented two alternative decarbonization scenarios: a decarbonization by 2035 and decarbonization by 2050 scenario. The 2035 scenario was largely the same as the final release of the *2024*

Long-Term Outlook in May of 2024. However, the GHG emissions reporting methodologies differed between reports. Since the preliminary version of the report did not include cogeneration emissions, annual GHG emissions results were compared to the current policy and draft CER scenarios from Chapter 4 in Figure A.17. Although different technologies mixes are used between models, results show an alignment in projected GHG emissions trajectory.

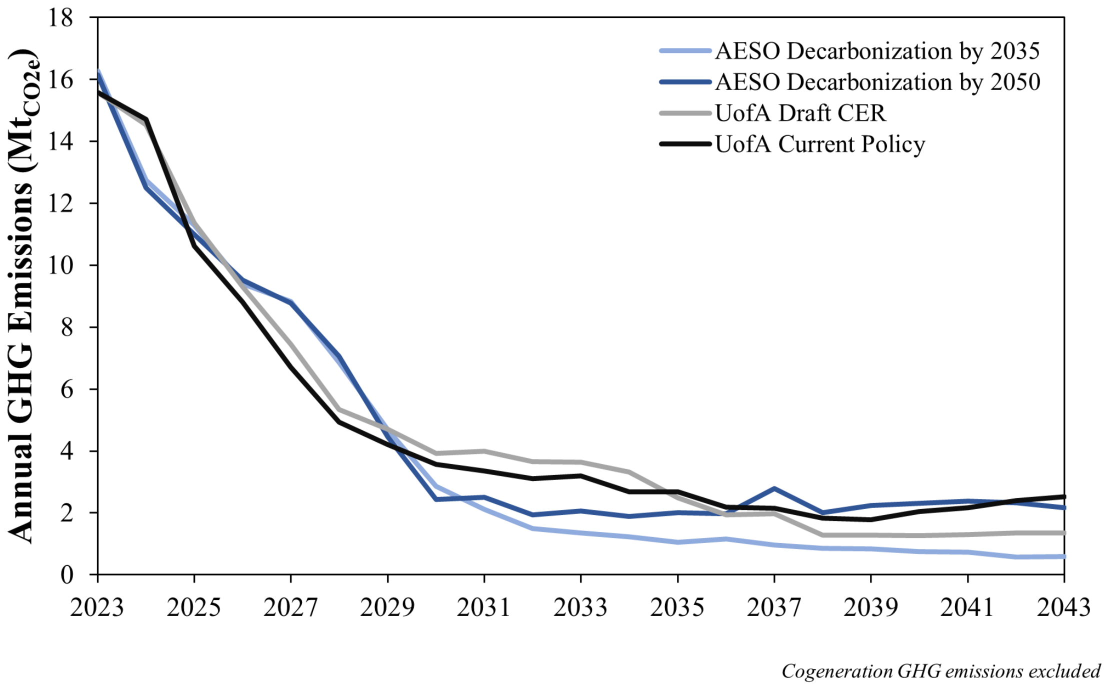

Figure A.17: Annual non-cogeneration GHG emissions from the current policy and draft CER scenarios compared to the AESO's preliminary 2024 LTO.

Appendix B: Supplementary Results

This appendix contains additional figures and tables to support findings presented in Chapter 4 and Chapter 5.

B.1 All Scenario Key Results

B.1.1 Tabulated Results

Table B.1 provides a summary of all twelve scenarios explored. Tables B.2 - B.6 shows key capacity, generation, and GHG emission results for each scenario.

Table B.1: List of all scenarios and reference to thesis section where they can be found.

Scenario	**Section**	**TIER HPB**	**Emissions Credit Value**	**Other Changes**
Current Policy	4.3	2% decline	90% of carbon price	
Draft CER	4.3	Zero by 2050	90% of carbon price	5% capacity factor constraint
Emission Limit	4.3	Zero by 2050	90% of carbon price	Constrain to draft CER annual emissions
No ITCs	4.3	2% decline	90% of carbon price	Remove ITCs
CER no ITCs	4.3	Zero by 2050	90% of carbon price	Remove ITCs
TIER 2050	5.3	Zero by 2050	90% of carbon price	
TIER 2035	5.3	Zero by 2035	90% of carbon price	
No EPCs	5.2	2% decline	None	
30% EPCs	5.2	2% decline	30% of carbon price	
50% EPCs	5.2	2% decline	50% of carbon price	
70% EPCs	5.2	2% decline	70% of carbon price	
No CCUS	5.4	2% decline	90% of carbon price	No CCUS

Table B.2: 2035 Capacity results for each scenario, given in MW.

Scenario	**NGConv**	**H2SC**	**NGSC**	**NGCC +CCUS**	**NGCC**	**Hydro**	**Other**	**Wind**	**Solar**	**Storage**	**Cogen**	**Total**
Current Policy	863	233	2,296	2,692	120	894	424	13,537	3,176	405	6,035	30,675
Draft CER	863	932	999	2,692	750	894	424	12,996	3,188	405	6,035	30,178
Emission Limit	863	233	1,642	2,693	0	894	424	12,216	3,609	405	6,035	29,014
No ITCs	863	0	2,630	824	1,819	894	424	13,383	3,176	405	6,035	30,453
CER no ITCs	863	0	1,698	2,772	990	894	424	11,199	3,176	405	6,035	28,456
TIER 2050	863	466	2,055	2,692	300	894	424	13,410	3,176	405	6,035	30,720
TIER 2035	863	466	1,931	839	2,510	894	424	10,921	3,176	571	6,035	28,630
No EPCs	863		2,164	810	2,542	894	424	6,696	3,176	405	6,035	24,009
30% EPCs	863	0	2,164	1,649	1,563	894	424	8,732	3,176	405	6,035	25,905
50% EPCs	863	0	1,931	839	2,510	894	424	10,090	3,176	405	6,035	27,167
70% EPCs	863	0	1,931	2,423	870	894	424	11,497	3,176	505	6,035	28,618
No CCUS	863	0	2,525		3,065	894	395	13,378	3,186	405	6,035	30,746

Table B.3: 2045 Capacity results for each scenario, given in MW.

Scenario	H2SC	NGSC	NGCC+CCUS	NGCC	Hydro	Other	Wind	Solar	Storage	Cogen	Total
Current Policy	699	3,427	2,692	120	894	386	15,827	3,284	162	6,035	33,526
Draft CER	2,330	901	3,823	450	894	386	13,817	3,143	263	6,035	32,042
Emission Limit	3,029	1,368	2,693	0	894	386	15,401	3,551	162	6,035	33,519
No ITCs	699	4,028	1,201	1,353	894	386	16,183	3,215	185	6,035	34,179
CER no ITCs	699	2,164	3,824	240	894	386	12,330	3,897	162	6,035	30,631
TIER 2050	932	2,987	3,069	300	894	386	13,602	3,307	162	6,035	31,674
TIER 2035	699	3,073	1,216	2,510	894	386	11,700	3,176	437	6,035	30,126
No EPCs	0	4,028	810	2,028	894	386	11,000	3,176	470	6,035	28,827
30% EPCs	1,398	2,630	1,649	1,563	894	386	11,673	3,176	212	6,035	29,616
50% EPCs	466	3,795	839	2,510	894	386	12,385	3,176	202	6,035	30,688
70% EPCs	0	3,096	2,423	570	894	386	15,187	3,176	303	6,035	32,070
No CCUS	233	4,389	0	2,133	894	344	16,370	3,361	162	6,035	33,921

Table B.4: Cumulative generation by plant type for each scenario, presented in TWh.

Scenario	**NGConv**	**H2SC**	**NGSC**	**NGCC+CCUS**	**NGCC**	**Hydro**	**Other**	**Wind**	**Solar**	**Storage**	**Coal**	**Cogen**
Current Policy	75.5	2.2	29.0	168.4	84.6	46.0	41.1	990.2	104.6	-1.4	3.6	820.8
Draft CER	73.1	12.2	7.4	187.5	109.3	46.0	42.3	962.1	105.9	-1.5	3.6	821.0
Emission Limit	77.1	13.8	13.9	284.0	79.3	46.0	42.0	847.9	117.9	-1.4	3.6	827.8
No ITCs	82.1	1.8	33.1	58.4	188.5	46.0	43.8	970.7	105.9	-1.5	3.6	823.3
CER no ITCs	83.7	3.1	12.2	192.9	137.8	46.0	48.0	888.6	110.1	-1.6	3.6	827.5
TIER 2050	74.5	3.2	23.6	180.3	96.0	46.0	42.5	964.2	105.4	-1.5	3.6	823.7
TIER 2035	76.4	2.2	22.4	80.4	227.7	39.4	49.9	897.0	108.6	-6.0	3.6	833.5
No EPCs	107.9	0.0	54.6	68.2	358.8	39.9	65.6	655.7	111.9	-4.1	3.6	842.7
30% EPCs	100.4	4.1	33.7	138.2	250.7	46.0	58.5	743.9	110.8	-1.6	3.6	836.5
50% EPCs	88.9	1.4	29.1	68.7	287.1	46.0	52.1	837.8	108.6	-1.6	3.6	826.9
70% EPCs	82.9	0.0	26.6	161.5	137.4	46.0	46.0	931.5	106.6	-5.0	3.6	822.6
No CCUS	74.7	0.5	37.3	0.0	235.3	46.0	40.5	1001.2	107.1	-1.4	3.6	820.4

Table B.5: Total GHG emissions for each scenario between 2023 - 2045, given in Mt_{CO2e}.

Scenario	**Non-Cogen Emissions**	**Estimated Cogen Emissions**
Current Policy	106.5	267.0
Draft CER	103.1	267.1
Emission Limit	98.4	269.3
No ITCs	152.1	267.8
CER no ITCs	126.5	269.1
TIER 2050	107.7	268.0
TIER 2035	164.1	271.1
No EPCs	248.9	274.1
30% EPCs	191.3	272.1
50% EPCs	198.7	269.0
70% EPCs	131.3	267.6
No CCUS	171.3	266.9

Table B.6: Annual GHG emissions for each scenario in selected years, presented in Mt_{CO2e}.

Scenario	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**
Current Policy	15.6	10.6	3.6	2.7	2.0	2.6
Draft CER	15.6	11.4	3.9	2.5	1.3	1.0
Emission Limit	15.5	11.2	3.7	2.2	1.2	1.0
No ITCs	15.6	11.9	6.1	4.9	4.0	4.7
CER no ITCs	15.6	11.8	4.8	3.5	2.3	1.4
TIER 2050	15.6	10.6	3.6	2.6	2.0	2.7
TIER 2035	15.6	10.5	6.7	5.5	5.7	6.6
No EPCs	15.6	13.8	11.3	10.3	8.0	8.3
30% EPCs	15.6	13.1	7.8	6.6	5.8	5.7
50% EPCs	15.6	12.8	7.9	7.6	6.5	7.5
70% EPCs	15.6	11.5	4.9	3.9	2.8	3.3
No CCUS	15.6	10.2	7.4	6.7	5.8	6.5

B.1.2 All Scenarios Comparison Figures

Figures B.1 and B.2 present high-level GHG emissions results for comparison between all twelve scenarios.

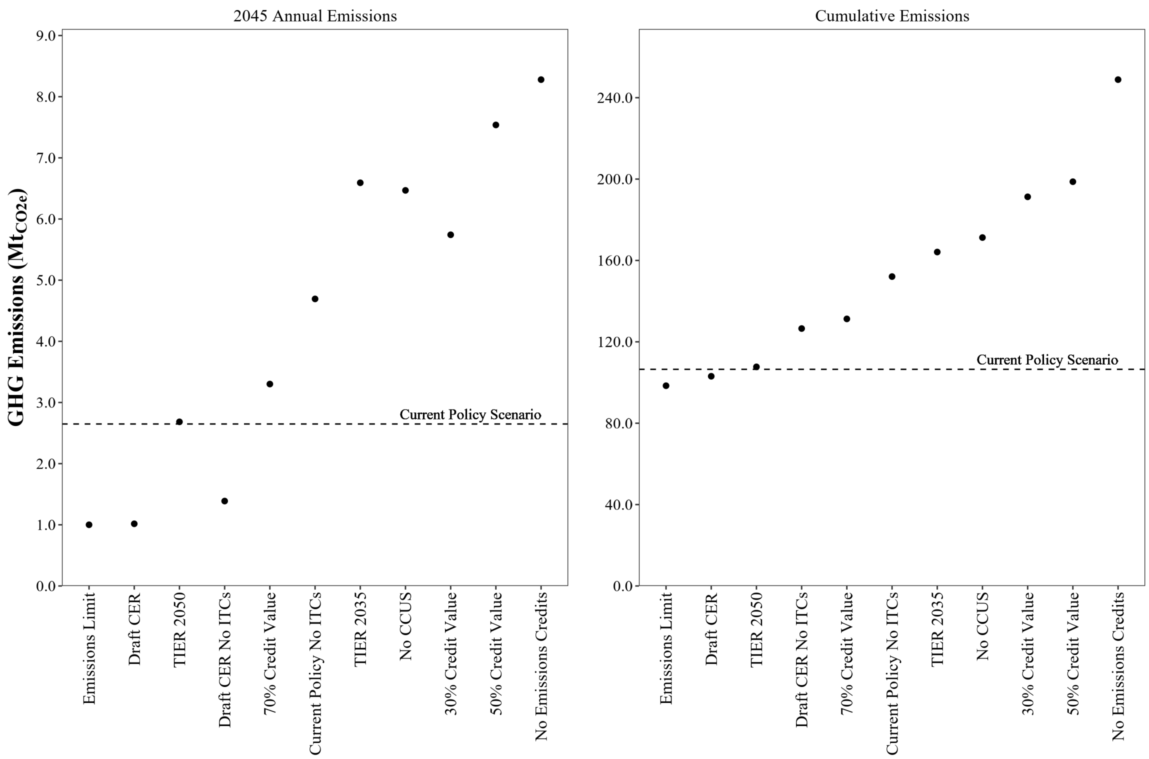

Figure B.1: Comparison between the final non-cogeneration GHG emissions of the current policy scenario and all other scenarios.

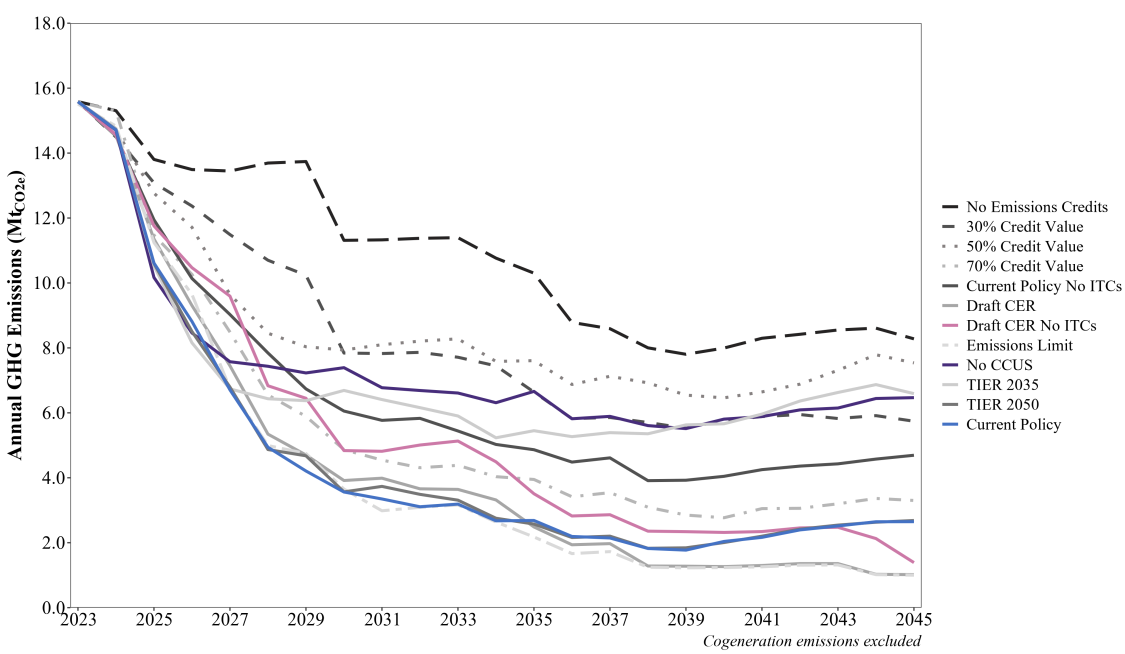

Figure B.2: Annual GHG emissions for all scenarios.

Figure B.3 presents the total cost for each scenario over the 23 year study period. Costs are summed in nominal dollars and include fixed and variable operations and maintenance costs, capital investment costs, storage charging costs, fuel costs, and net-carbon costs for all plants. Since net-carbon costs were included, scenarios with higher valued emissions credits generally resulted in a lower cost overall, since emissions credits were modelled as negative costs. It should also be noted that these costs do not include GHG emissions costs associated with cogeneration. So while cost is a useful benchmark to understand cost optimal decisions taken by the capacity expansion model, it should not be taken at face value.

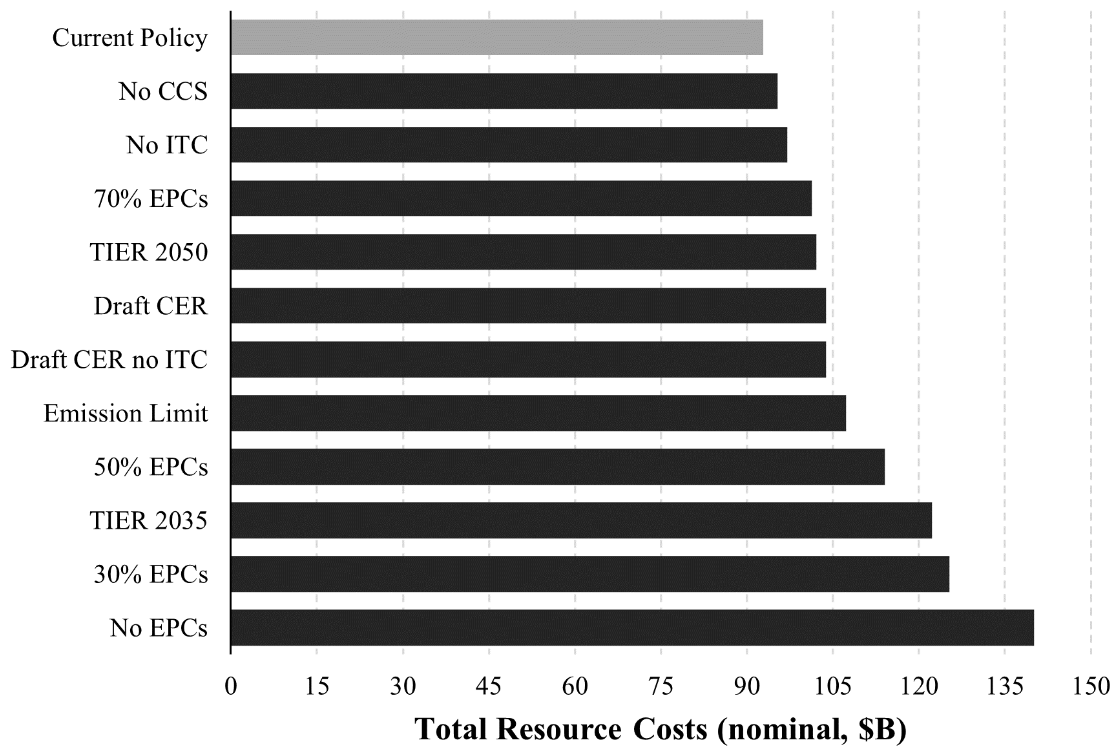

Figure B.3: Total cost for all scenarios, presented in nominal CAD.

For reference, if the total cost for each scenario is divided by the number of years, then the average annual cost is 4.0 - 6.1 billion CAD annually. In comparison, by treating the nominal costs presented by the AESO in their 2022 *Net-Zero Emissions Pathways* report [76] (net of transmission costs) in the same manner, the annual costs from AESO net-zero scenarios range from 4.5 billion CAD in the reference case to 6.6 - 6.9 billion CAD in the three net-zero scenarios. This suggests that costs resulting from the model used in this thesis are within the correct magnitude. It further suggests that the cost of a net-zero electricity system may be lower than the AESO's estimations, but it is difficult to confirm this without knowing how the AESO has accounted for emissions credits and cogeneration emissions costs in their results.

B.2 Chapter 4 Supplemental Results

Additional figures related to the results presented in Chapter 4, primarily from the current policy scenario, are included below. Recall that in the current policy scenario, Alberta's carbon pricing system continues to follow current trajectory after 2030 (i.e. the HPB continues to tighten at 2% of 0.37 t_{CO2e} annually).

B.2.1 Chapter 4 Additional Figures

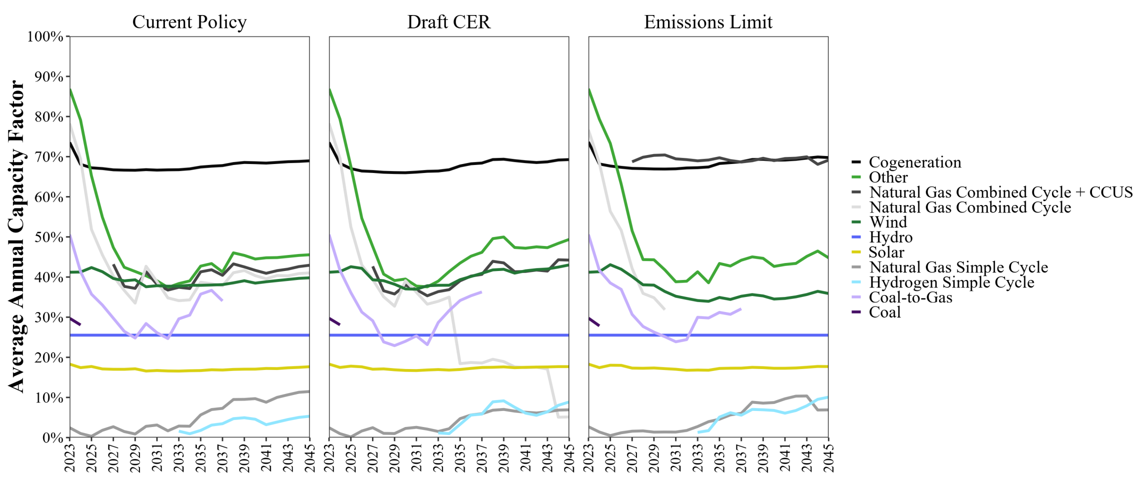

Figure B.4: Average annual capacity factors for current policy, draft CER, and emissions limit scenarios.

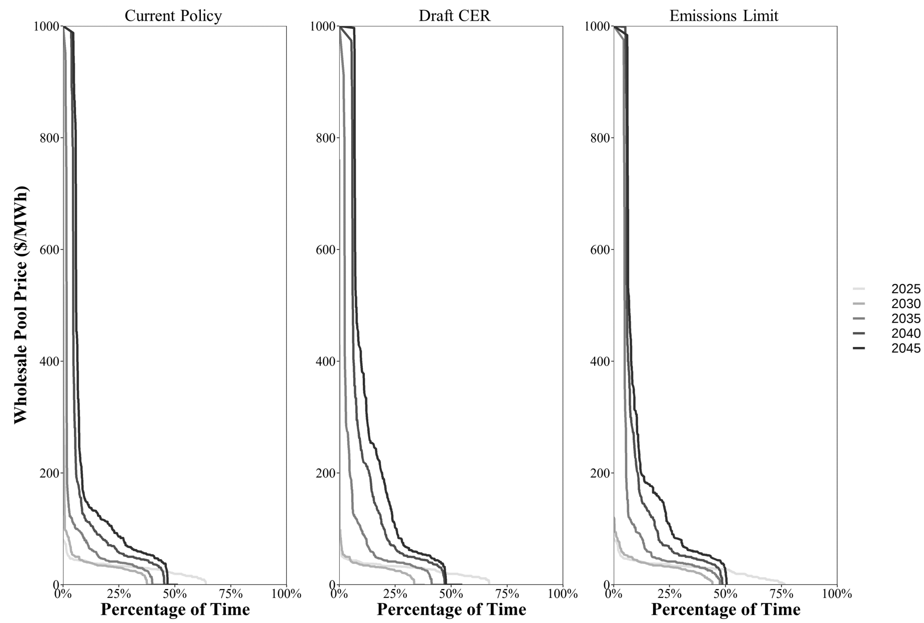

Figure B.5: Hourly price duration curves for current policy, draft CER, and emissions limit scenarios.

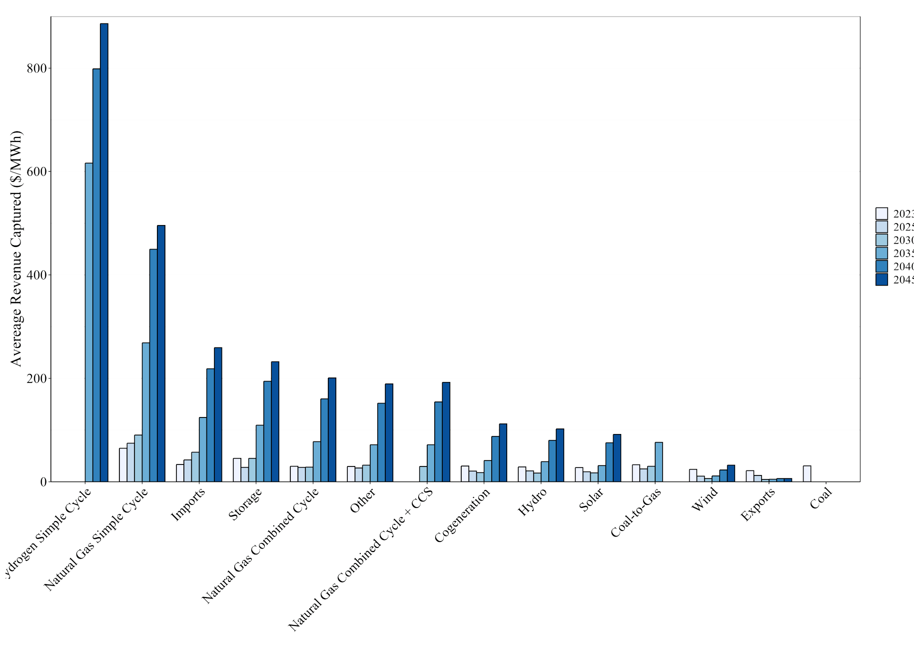

Figure B.6: Technology capture prices under current policy.

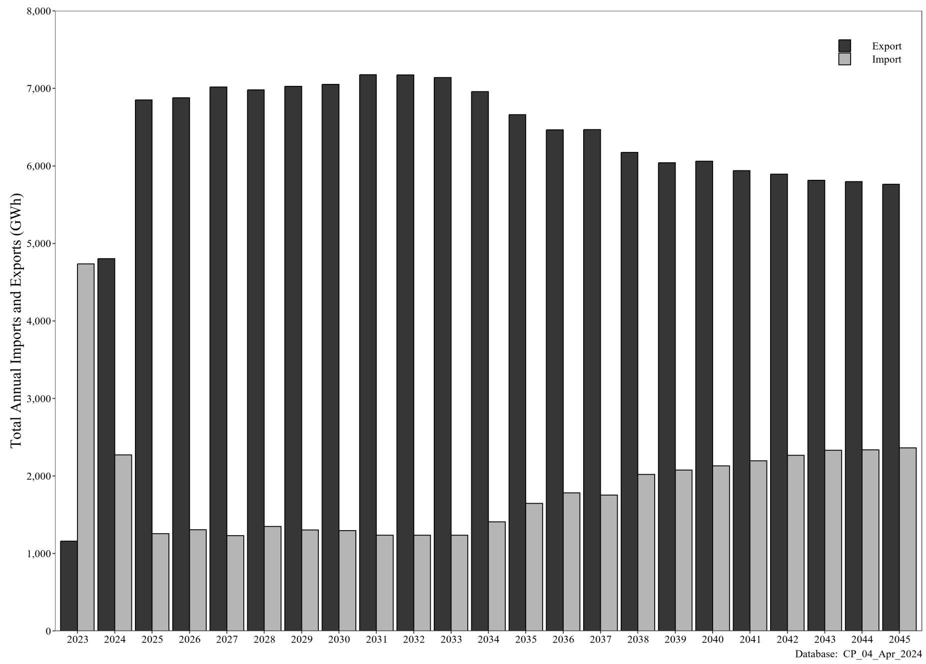

Figure B.7: Alberta annual imports and exports in the current policy case.

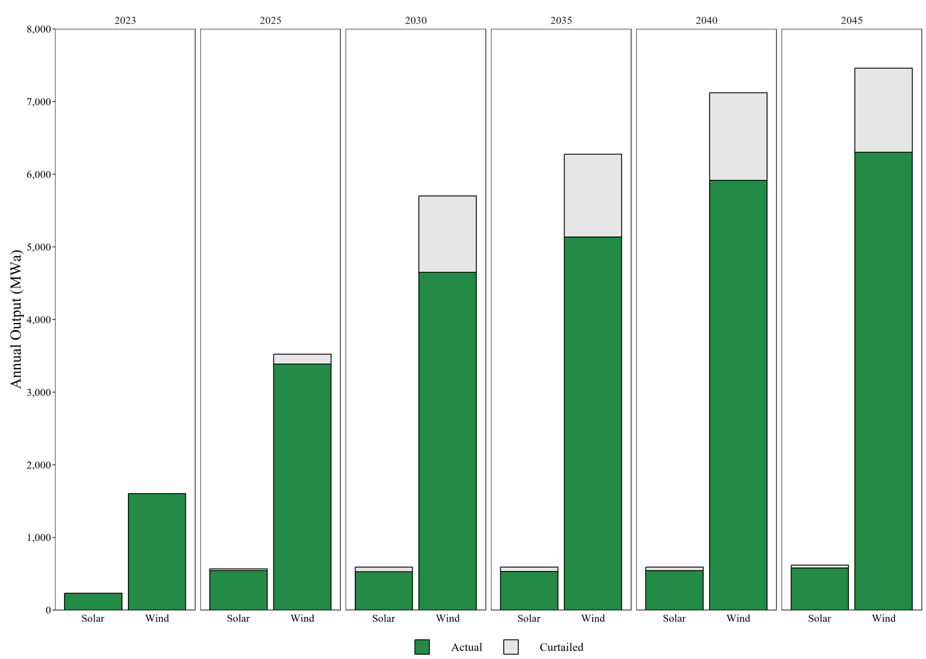

Figure B.8: Total wind and solar output as a sum of generation used by the system and curtailed generation in the current policy scenario, presented in average MW annually.

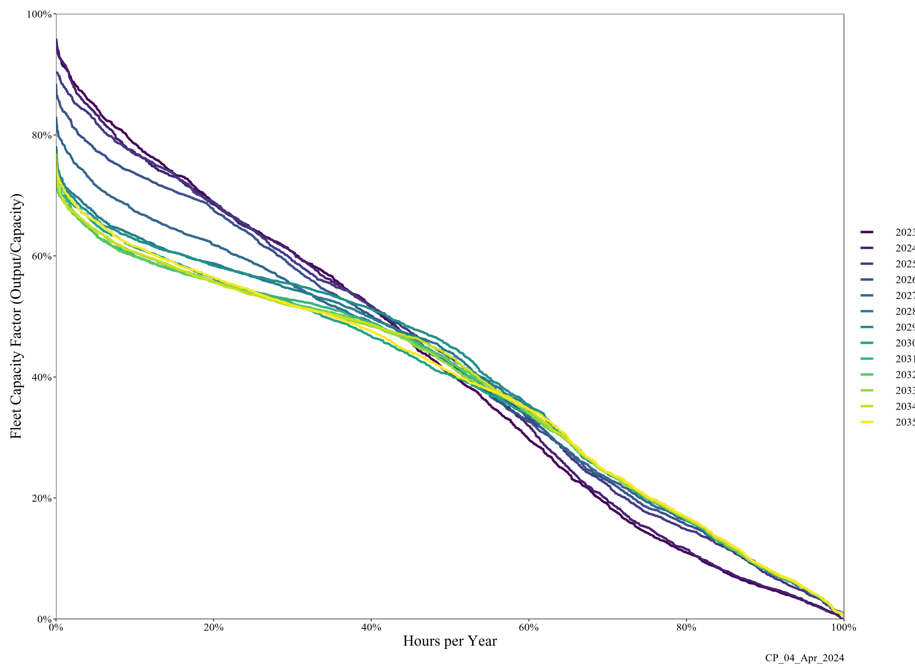

Figure B.9: Wind fleet capacity factor duration curve for the current policy scenario.

B.3 Chapter 5 Supplemental Results

Additional figures to support findings in Chapter 5 are included below.

B.3.1 Emissions Credit Value Scenarios Supplemental Results

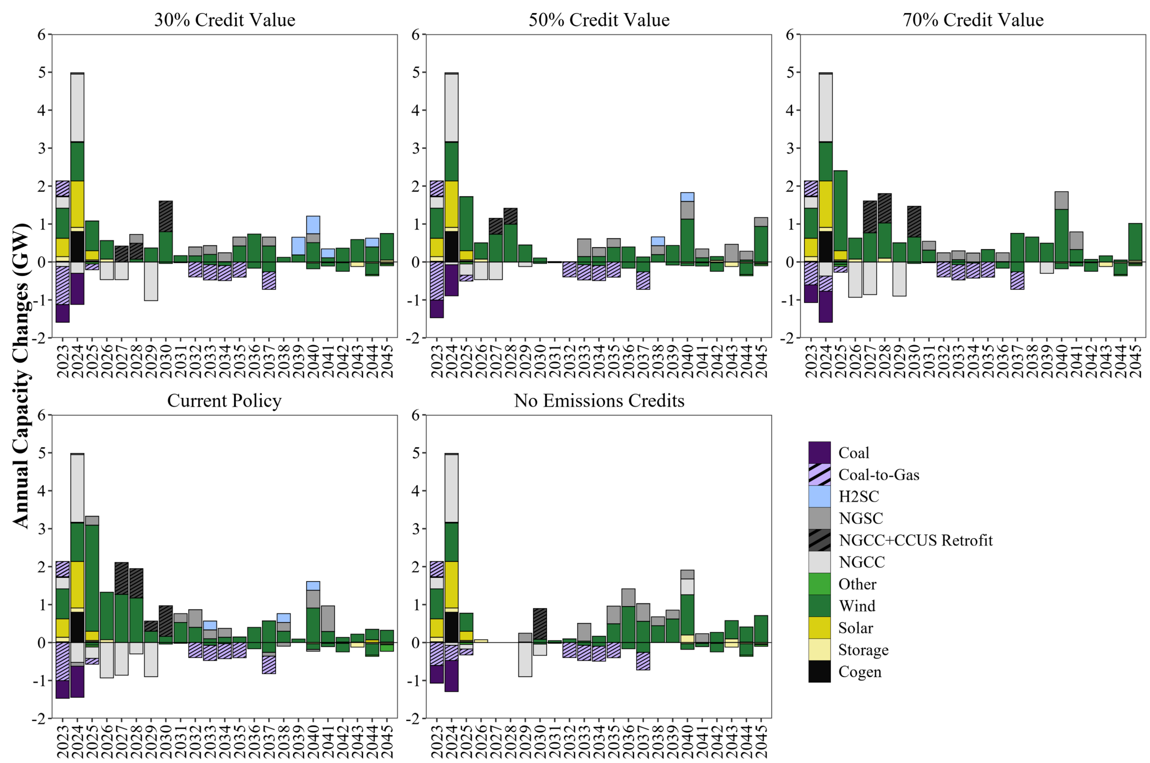

Figure B.10: Annual additions (positive) and retirements (negative) in the five emissions credits scenarios.

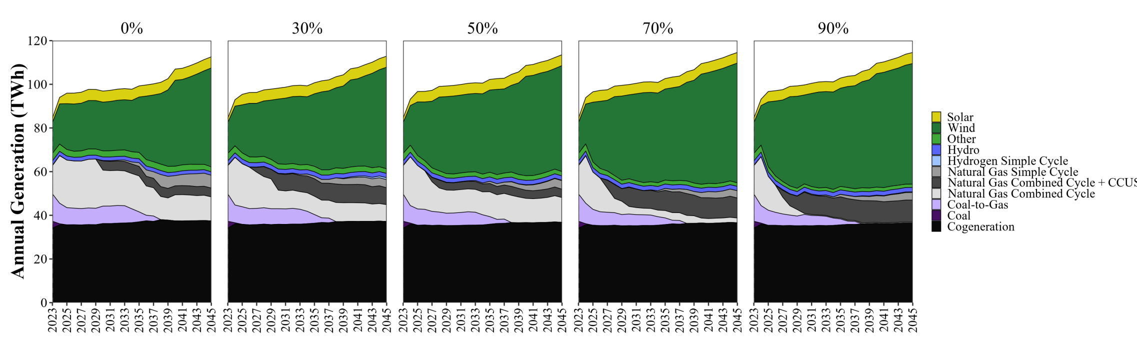

Figure B.11: Annual generation for the five emissions credits scenarios.

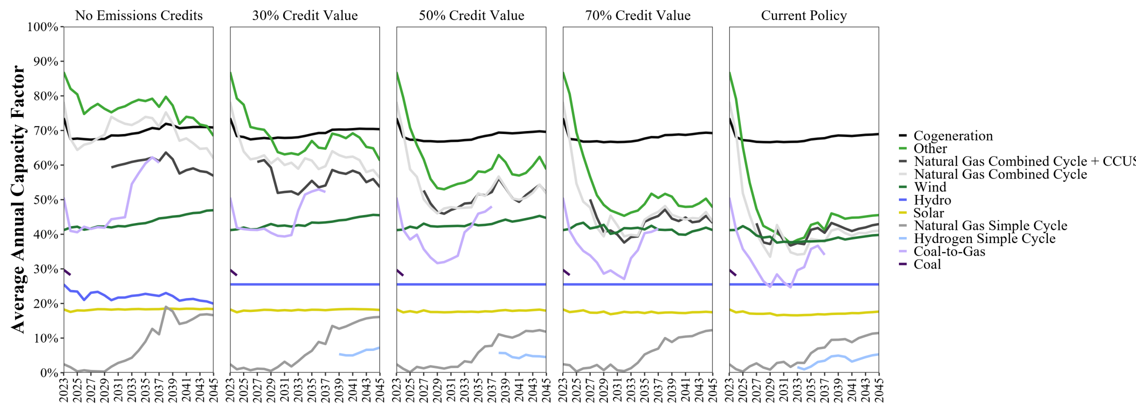

Figure B.12: Average annual capacity factors for the five emissions credits scenarios.

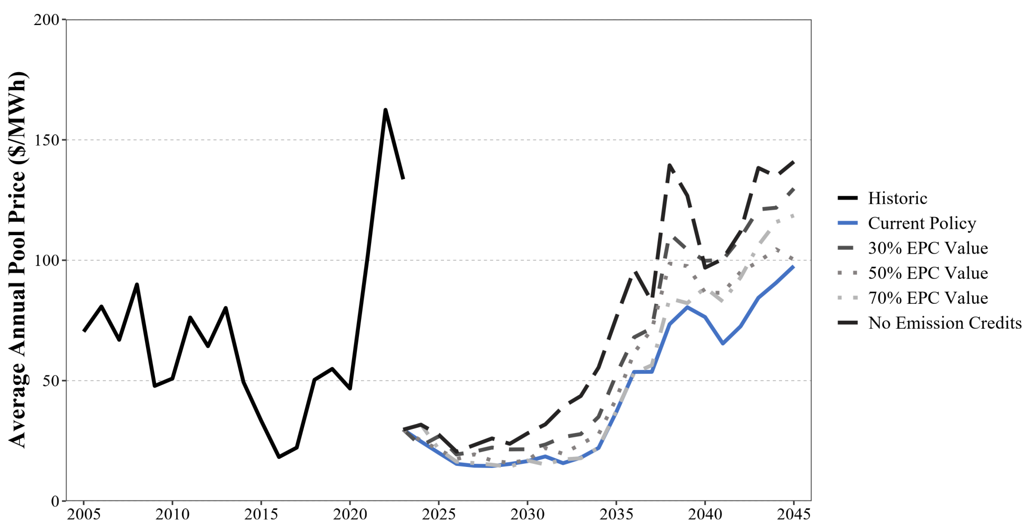

Figure B.13: Annual average pool price for the five emissions credits scenarios.

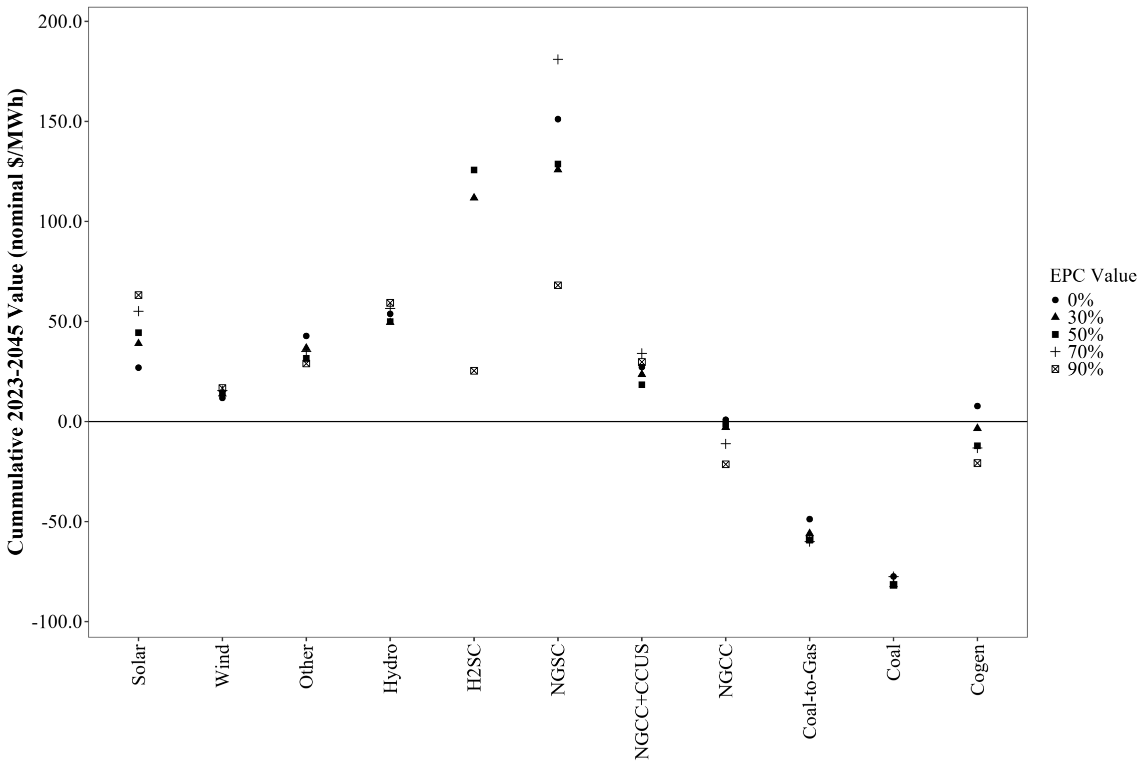

Figure B.14: Resource group value (revenue minus cost) between 2023 and 2025 in the five emissions credits scenarios.

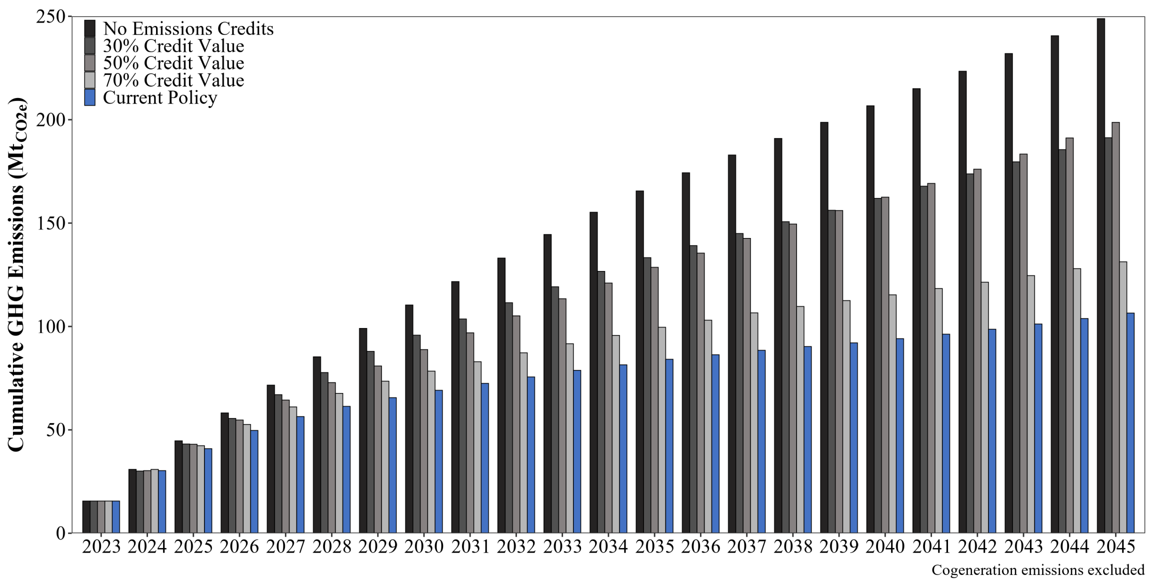

Figure B.15: Cumulative GHG emissions comparison for the five emissions credits scenarios.

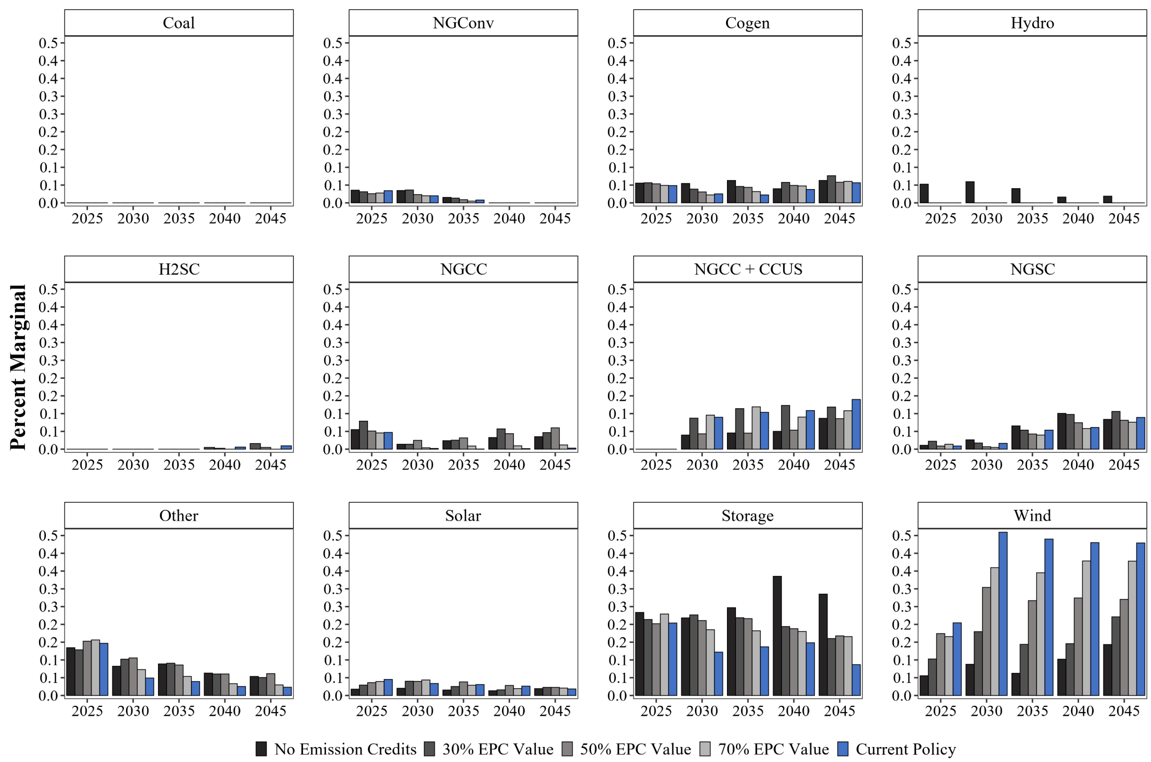

Figure B.16: Percent marginal for each resource group in select years for the five emissions credits scenarios.

B.3.2 TIER HPB Scenario Supplemental Results

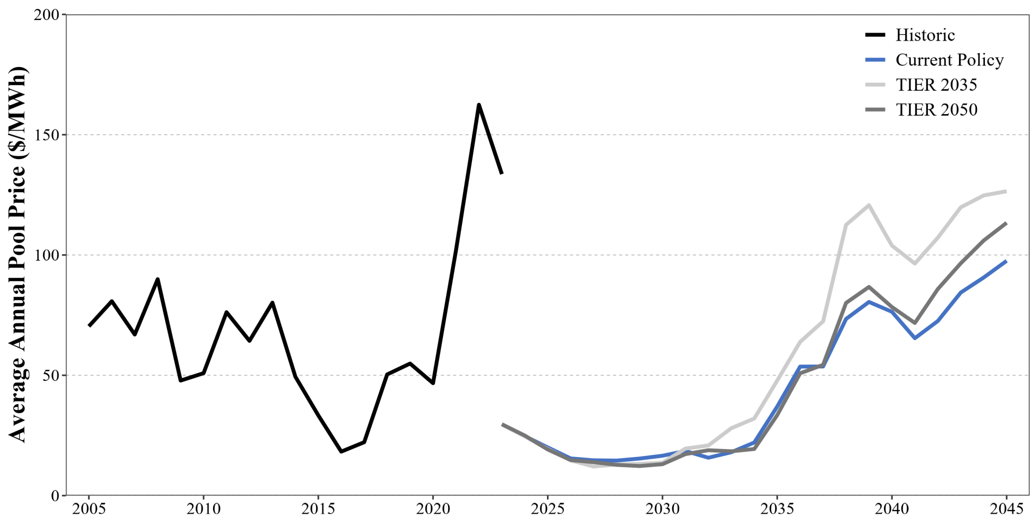

Figure B.17: Annual average pool price for the three TIER HPB scenarios.