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# A Wind Offset Paradox: Alberta's Wind Fleet Displacing Greenhouse Gas Emissions and Depressing Future Offset Values

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**Abstract:** The introduction of a significant industrial carbon price in Alberta, Canada, has precipitated major changes in its electricity market, both for fossil fuel generators, which has resulted in a rapid transition from coal to natural gas, as well as for renewable energy projects, which can monetize emission offset credits. Coal, which generated close to half of the electricity in the province in 2016 before the major changes were introduced, had fallen to less than 8 percent by the end of 2023 and was completely phased out by June 2024. Conversely, wind energy grew from 6 to 12 percent of the annual supply, in part due to the increasing value of the carbon credits whose value is connected to the deemed greenhouse emissions they are displacing. As wind energy increased in penetration, it lowered its own market price, which was discounted from the average market price by 10–43 percent, but in turn increased the relative importance of its offset. This paper examines the evolution of emissions displaced by wind energy in Alberta by considering 10 years of historical merit order data and creating a counterfactual scenario where historical wind generation is replaced by next-in-merit units. On average, coal made up 84 percent of the marginal energy and 93 percent of the marginal emissions in 2018. As the coal capacity declined, natural gas units replaced coal on the margins, jumping from 21 percent of next-in-merit generation in 2020 to 84 percent in 2023. Alberta uses a deemed emissions displacement factor, which is a combination of historical build and operating margins that declined from 0.65 $tCO_2e$/MWh in 2010 to 0.52 $tCO_2e$/MWh in 2023. Using the counterfactual scenario, an alternative offset value is considered, which had a maximum difference of 57 percent (9 CAD/MWh) of increased value over the actual historical offset. However, the counterfactual rate of emission offsets fell to near parity with the deemed grid displacement factor by 2022 as natural gas became increasingly dominant in the market. As the carbon price is scheduled to increase from 65 CAD/$tCO_2e$ in 2023 to 170 CAD/$tCO_2e$ by 2030, the provincial offset could reach a maximum value of 53 CAD/MWh in 2030 but begin to decline thereafter as the carbon price drives decarbonization, thereby lowering displaced emissions in either method of calculation. The introduction of significant carbon pricing into a thermally dominated electricity market resulted in more emissions being displaced by renewable energy than they were credited for in the short term, but the resultant decarbonization of the grid decreases the long-term value of emission offsets.

**Keywords:** electricity market; emission offsets; carbon pricing; wind; marginal emissions; Alberta

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# 1. Introduction

Alberta is home to some of the largest oil reserves in the world [1], and the industrial activities tied to its oil sands make the province responsible for over one-third of Canada's greenhouse gas (GHG) emissions despite accounting for only 12 percent of the national population [2]. On a national scale, Alberta is the top emitter of greenhouse gases, and while oil and gas industries are the largest sources of GHG emissions in Alberta, up until recently, the electricity sector's heavy reliance on coal rivaled oil sands' extraction GHG emissions [3]. However, recent provincial and federal climate change policies, combined with the technology progression of clean electricity generation and historically low natural gas prices, have contributed to a 53 percent reduction in electricity-related emissions between 2005 (the first full year of mandatory emission reporting for large emitters in Alberta) and 2022 [4,5]. This significant reduction in emissions occurred despite a 31 percent increase in electricity demand during the same period [6,7], driven by the transition from coal-fired electricity to natural gas and the expansion of the renewable energy sector.

In Canada, each province has jurisdiction over its own electricity generation and distribution. Alberta's competitive energy-only electricity market is unique in Canada, where the hourly price of electricity is based only on supply and demand, resulting in a single, uniform pool price [8]. Prices are moderated solely through market competition, as no offer price-buffering systems are implemented [8]. Generation facilities are required to offer their entire available capacity each hour, and the only restrictions on offer prices are a price floor of 0 CAD/MWh and a cap of 999.99 CAD/MWh. Alberta's deregulated market results in higher wholesale price volatility when compared to other Canadian provinces [9]. The highly volatile nature of prices has rewarded operational flexibility in generation technologies, but the lack of long-term price certainty can also make the market less attractive to technologies without the ability to dispatch their generation, such as wind or solar [8], and these technologies have often relied in part on additional revenues available from regulated or voluntary carbon credits.

This paper examines the changing nature of displaced energy from Alberta's wind fleet during a period of transition within the electricity market, characterized by an increasing carbon price and a rapid transition from coal, by considering the hourly merit orders over the past 10 years. Publicly available market data were collected from the Alberta Electric System Operator (AESO) to examine the marginal units displaced as a result of wind energy to determine changes in emissions and propose a novel, counterfactual method to calculate carbon offsets. Carbon offsets are an additional revenue stream for wind generators. This work was performed to examine whether or not an alternative offset value calculation could enhance price certainty for wind energy generators. Financial stability for wind energy farms enhances their competitiveness in the market compared to natural gas plants, enables more effective financial planning despite the variability inherent in wind energy production, and supports further development and wind energy capacity expansion. Financial support for wind energy can contribute to achieving emission reduction objectives as part of the ongoing energy transition in Alberta.

## 1.1. Alberta's Changing Electricity Generation

Alberta had a population of 4.8 million [2] and an electricity demand of 86 TWh [10] in 2023, both of which have been growing by close to 1 percent year-over-year for the past decade, although the electricity demand growth is expected to slow, plateauing around 91 TWh by the mid-2030s. Coal power plants, industrial cogeneration (COGEN)—largely from oil-sands operations—and, more recently, natural gas combined cycle (NGCC) plants have together generated close to 90 percent of Alberta's electricity in the past decades [11]. Generating around 40 TWh annually, coal accounted for about half of the electricity market in the early 2000s, while renewable energy (mostly hydro) generated less than 4 percent [12]. Alberta added new coal units in 2005 and 2010, despite introducing one of the first industrial carbon pricing systems in the world in 2007. By 2014, coal generation had peaked at 54 TWh, although its market share had shrunk to closer to 60 percent, as shown in Figure 1, largely as a result of much of the load growth being met by an increase in natural gas-fired generation. As mentioned, Alberta has had an industrial carbon pricing regime since 2007, which required a 12 percent reduction in emission intensity, and non-compliance resulted in a 15 CAD/t$CO_2$e penalty. The stringency of the carbon pricing system was increased in 2016 and 2017 and then overhauled in 2018, resulting in a 77 percent (22 TWh) drop in annual coal generation by the end of 2023 (comparing 2018 to 2023). Further, of the 19 coal units operating in 2015, only 2 units remained operational in 2023, both of which were retired and converted to natural gas (NGCONV) by June 2024, 6 years ahead of a federally mandated coal phase-out [13]. An increase in simple cycle gas turbine (SCGT) dispatch units, which are typically considered "peaking plants", and coal units co-fired with natural gas ("dual fuel" units) in a transitional period have also accompanied the broader coal phase-out. Co-fired units have the ability to operate using either coal or natural gas or both [14]. Note that AESO's dual fuel units have been categorized as natural gas conversion units in this analysis, for simplicity.

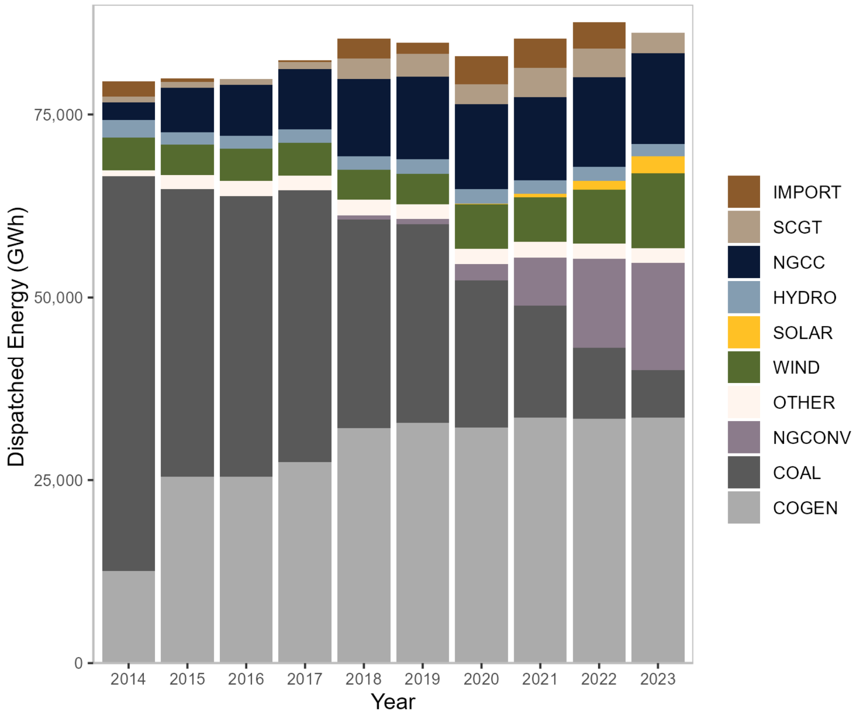


**Figure 1.** Annual total energy generated by plant type in Alberta. Data source: AESO [10].

Alberta's electricity demand is heavily influenced by its large industrial sector, and as a result, has had an average load factor of 82 percent for the past decade [6] and a winter peak. In addition to the 18.3 TW of installed generation capacity, Alberta has approximately 1.2 TW of intertie capacity linking the market to British Columbia and Saskatchewan, as well as the American state of Montana, and has been a net importer of electricity since 2017, although imports account for less than 5 percent of the market [10]. In addition to being almost two-thirds of Alberta's load, the industrial sector in Alberta self-supplies much of its own electricity in "behind-the-fence" heat and electricity cogeneration configurations. Behind-the-fence generation averaged 2900 MW in 2023 and represented almost 30 percent of Alberta's electricity load (larger than either the commercial or residential demand) [10,15].

*1.2. Alberta's Electricity Market*

Despite historically operating as a regulated electricity market, Alberta has never had provincially owned utilities, and only three utilities dominated Alberta's market until market reforms began in 1996 [12,16]. While the transmission and distribution systems remain regulated, Alberta's wholesale market became deregulated in 2001 [17]. The Alberta Utilities Commission approves new generation after safety, environmental, and design standards have been met but does not regulate the location, facility type, or rate of return; rather, owners' investment risks are recouped only through the competitive "energy-only" market. A single hourly equilibrium price is managed by the AESO, and energy is dispatched via an economic merit order. This merit order organizes electricity generation offers by ascending price, creating a cumulative supply–demand curve that dynamically adjusts to meet provincial demand. At each minute, the system marginal price is determined by the offer price of the last unit dispatched to meet demand, and this unit is referred to as the marginal unit. At the end of each hour, a single hourly pool price is calculated from the average of the preceding 60 system marginal prices. This pool price is paid to all generators deemed "in-merit", which consists of those dispatched to produce electricity.

There are three broad categories of generator offers: those that offer at the price floor to ensure they are dispatched, those that are considered "price-takers" as they offer at or near their marginal cost, and those that often offer above their marginal cost and are considered "price-makers" [8]. Generators must offer for all available output, but it can be in up to seven different price–volume pairings every hour, and there are no restrictions on offer prices beyond a floor and ceiling price, as previously mentioned. For instance, there is no mechanism to automatically adjust offers if they stray from the marginal costs or drastically vary. One issue with this freedom-of-offer strategy is that coordinated extraction strategies are more easily carried out (whether intentional or not) [8]. Non-dispatchable energy, such as wind, is required to offer its energy at 0 CAD/MWh, and as a result, its presence in the market tends to have a price-suppressing effect since it can displace higher-priced offers. Consequently, the 0 CAD/MWh offers from wind energy generators lower the wind energy fleet's own capture price, as can be seen in Figure 2.

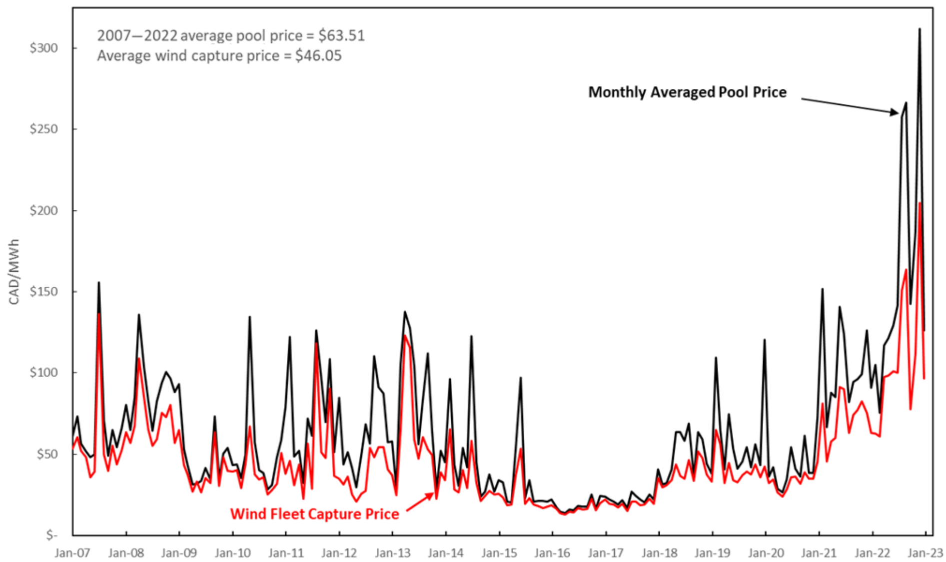


**Figure 2.** Alberta monthly wholesale electricity prices (2007–2022). Data are publicly available from the AESO.

Oversupply in capacity tends to result in lower prices, as can be seen in Figure 2 between 2016 and 2018 shortly after an 800 MW combined-cycle gas plant (Shepard Energy Center) entered the market on the heels of a softening in demand due to a global drop in oil prices [18]. On the other hand, tight markets and/or increases in market power can lead to high prices, as has been the case in recent years [19,20]. The all-time low average monthly market prices in 2016 and highs in 2022 in Figure 2 illustrate Alberta's market volatility (on a monthly basis). The black line in this figure is the monthly average pool price, while the red line is the wind fleet capture price, which typically shows a discount compared to the average price. The wind fleet capture price is the average price that wind energy generators receive for the electricity they produce and sell into the market, reflecting the timing and market conditions under which wind power is generated; it is the wind fleet revenue weighted by the generated wind energy. More discussion on the wind fleet's discounted capture price is available in Section 4.1.

## 2. Background and Theory

### *2.1. Greenhouse Gas Policy and Carbon Pricing in Alberta*

This section provides background to the carbon pricing policies that have been historically followed by Alberta's electricity market. These are the policies that introduced carbon offsets, which provide additional revenue for wind generators. The analysis performed in this paper will compare the historical method of determining offset values, as outlined here, to a counterfactual method, which will be described in the methodology in Section 3.

#### 2.1.1. Specified Gas Emitters Regulation (SGER)

Facing significant domestic and international pressure about the growing emissions from its oil sands, Alberta introduced the Specified Gas Emitters Regulation (SGER) in 2007 making it the first GHG pricing initiative in North America [21]. This policy applied only to regulated large final emitters (LFEs) in the province, defined as facilities that emit more than 100,000 $tCO_2e$/year. Each year, the government allocated 88 percent of the LFEs' baseline emissions intensity as "free emissions" with the intent of reducing the financial burden on individual companies while retaining the marginal price signal. Facilities were then required to comply through any combination of physical emission reductions, purchasing and retiring emissions credits, or payments into a technology fund [22]. Technology fund prices were set at 15 CAD/$tCO_2e$, which also provided a de facto ceiling on the value of tradeable emissions credits.

Emissions credits, formally called emissions performance credits (EPCs), could be generated from LFEs that outperformed their reduction requirements, or offsets could be created from actions or facilities that prevented emissions from occurring, such as new wind energy generation [23]. The technology fund price and free emission allocations were kept stagnant until their stringencies were increased in 2016 to 20 CAD/$tCO_2e$ and 85 percent, respectively, and then again in 2017 to reach 30 CAD/$tCO_2e$ and 80 percent. This increased both the demand and value of offsets, which will be discussed further in Section 2.2.

#### 2.1.2. Carbon Competitiveness Incentive Regulation (CCIR) and Technology Innovation Emissions Reduction (TIER) Regulation

The Carbon Competitiveness Incentive Regulation (CCIR) came into effect in January 2018, superseding the SGER [24]. At the beginning of 2020, the CCIR was transformed into the Technology Innovation Emissions Reduction (TIER) regulation, which is the approach currently followed by the province for carbon pricing. TIER for the electricity sector is largely the same as CCIR and will be discussed henceforth in this paper as TIER for simplicity. TIER keeps many of the core principles of SGER in place, notably, the emission intensity approach, as well as compliance options; however, free emission allocations are no longer electricity facility-specific, but rather based on a sector-wide standard [25] pegged at 0.37 $tCO_2e$/MWh (or "good-as-best-gas") tightening at 2 percent each year starting in 2023 [26].

The fund payment price was 30 CAD/$tCO_2e$ in 2018 and increased to 40 CAD/$tCO_2e$ in 2019 until the newly elected government reduced it back to 30 CAD/$tCO_2e$ to match the federal government's carbon pricing schedule. Subsequently, the fund price increased by 10 CAD/$tCO_2e$ until 2022 (50 CAD/$tCO_2e$), after which annual increases of 15 CAD/$tCO_2e$ will continue until attaining a final price of 170 CAD/$tCO_2e$ in 2030 [27]. These scheduled increases match the federal Greenhouse Gas Pollution Pricing Act carbon pricing schedule that was adopted in 2020, which acts as a policy backstop should provinces not implement an equivalent system such as TIER [26,28]. The average carbon cost for a coal generator with a 1.0 $tCO_2e$ /MWh emission intensity was in the order of 1.8 CAD/MWh under the original SGER, which increased to 3.0 CAD/MWh and 6.0 CAD/MWh in 2016 and 2017, respectively, and then jumped to 18.9 CAD/MWh when TIER was implemented in 2018. This jump in carbon cost shows the specific impact of these policy changes for a relatively high GHG-emitting energy generator. Additionally, while coal had slowly been losing its market share due to the growth in natural gas-fired generation, TIER resulted in a significant acceleration of this trend, as can be seen in Figure 1, specifically looking at the years 2018–2023.

### *2.2. Emissions Offset Creation and Value*

Within SGER and TIER, wind energy facilities can generate and trade greenhouse gas emission credits and offsets. The value of emission offsets for wind energy projects is based on a deemed "Electricity Grid Displacement Factor" (EGDF) representing the quantity of $CO_2$ displaced for every MWh of electricity generated from a wind (or other renewable) energy project. The EGDF is revised at least every five years and calculated using an equal weighting of build and operating margins over the previous revision period, where operating margins are calculated based on the percentage of time each unit type is on the margin and build margins are based on new generation that entered the market during that period [29]. Equation (1) describes this relationship. The specific methodology and calculations for the build margin and operating margin are available online through the Alberta Emission Offset System [29].

$$\text{EGDF} = \frac{\text{Build Margin} + \text{Operating Margin}}{2} \tag{1}$$

The EGDF was originally established at 0.64 $tCO_2e$/MWh and had slowly declined from 0.59 $tCO_2e$/MWh in 2015 to 0.52 $tCO_2e$/MWh in 2023. For projects initiated before 31 December 2023, projects were able to use the specified EGDF for that respective year for the entire duration of the offset crediting period [30]. For projects initiated on or after 1 January 2024, the EGDF will not be consistent over the total crediting period and will decrease every year until 2030 when the offset program will merge with the TIER performance benchmark value [30], which is scheduled to tighten by 0.0074 $tCO_2e$/MWh (2 percent of 0.37 $tCO_2e$/MWh) annually after 2022 until reaching 0.3108 $tCO_2e$/MWh [31]. For 2023, the EGDF value was 0.52 $tCO_2e$/MWh for electricity grid displacement from renewable generation [30]. Table 1 summarizes some of the EGDFs that were followed and are expected to be followed while the offset crediting program remains established. This table also shows how the value of carbon offsets is directly related to the evolving cost of carbon emissions since they are a product of the EGDF and the carbon price.

Offset crediting periods are ten years long, with the option to apply for a five-year extension [32]. A project is eligible to apply for a credit period extension if they are able to demonstrate the project's financial need for continued emission offset generation and that it meets all offset system requirements [33]. The limit of 15 years to receive offset credits for one project is to ensure "additionality" in the market, meaning new emission reductions (i.e., those that are beyond business as usual) are being rewarded [32]. Subject to finding a buyer, offsets offer a predictable revenue stream to counterbalance the volatility of the deregulated market, thereby enabling access to initial capital or potentially lowering financing rates [34]. LFEs who may want to purchase the offsets are not limited to the electricity sector, and often include oil and gas companies, although bilateral contracts are not publicly disclosed, so their exact value is unknown, so the technology fund price ceiling provides an estimation. For the purpose of this analysis, a 10 percent commercial discount was assumed compared to the annual technology fund carbon price as an estimate of any offset value for the same year.

**Table 1.** Historical Electricity Grid Displacement Factors in Alberta [30,35,36].

| Year | EGDF ($tCO_2e$/MWh) | Carbon Price (CAD/$tCO_2e$) | Maximum Offset Value (CAD/MWh) |
|---|---|---|---|
| Pre-2015 | 0.64 | 15 | 9.60 |
| 2015 | 0.59 | 15 | 8.85 |
| 2016 | 0.59 | 20 | 11.80 |
| 2017–19 | 0.59 | 30 | 17.70 |
| 2020 | 0.53 | 30 | 15.90 |
| 2021 | 0.53 | 40 | 21.20 |
| 2022 | 0.53 | 50 | 26.00 |
| 2023 | 0.52 | 65 | 33.80 |
| 2024 | 0.49 | 80 | 39.21 |
| 2025 | 0.46 | 95 | 43.72 |
| 2026 | 0.43 | 110 | 47.33 |
| 2027 | 0.40 | 125 | 50.06 |
| 2028 | 0.37 | 140 | 51.88 |
| 2029 | 0.34 | 155 | 52.81 |
| 2030 | 0.31 | 170 | 52.84 |

### *2.3. Growth of Wind in the Alberta Market*

Unlike most Canadian provinces, renewable energy in Alberta has generally occupied less than 10 percent of the electricity market and has typically depended, at least in part, on additional out-of-market mechanisms for revenues or revenue certainty. Wind energy's growth in the early 2000s was aided by a ten-year 10 CAD/MWh federal incentive and, additionally, an ability to sell $CO_2$ offsets after 2007 [22,37]. Wind energy reached 5 percent of Alberta's generation by the year 2015, but its growth was largely stalled until 2019 when its market price discount (exacerbated by the correlated output from wind farms largely located in the southwest of the province) eroded long-term investor confidence [38]. In order to create price stability for new renewable energy projects, the provincial government established a Renewable Electricity Program (REP) in 2018, which procured over 1300 MW of wind energy at an average price of nearly 38 CAD/MWh [39] through 20-year contracts for differences but retained the wind farms' emissions credits [12]. The program was canceled in 2019 after a change in government, but wind energy has continued to grow after the introduction of significant carbon prices [12]. By 2022, wind was the second largest installed plant-type capacity in Alberta, serving about 8 percent of the annual load in that year [6]. As of 2023, Alberta had the second largest installed wind capacity in Canada behind only Ontario [40], and wind is one of the lowest-cost electricity supply options.

Nonetheless, the annual wind output in Alberta grew by 192 percent from 2014 to 2023, as shown by a similar trend with averaged hourly data in Figure 3, in part due to its continued ability to sell offsets and the rising carbon price [41]. However, as the wind output increases, not only does its discount from average market prices increase but it also contributes to the decarbonization of Alberta's grid, lowering the value of new offsets available for new projects. The results of this work examine the changes in generator types in the market and emissions displacement from wind energy as the carbon price has evolved and what that might mean for future emissions and offset values.

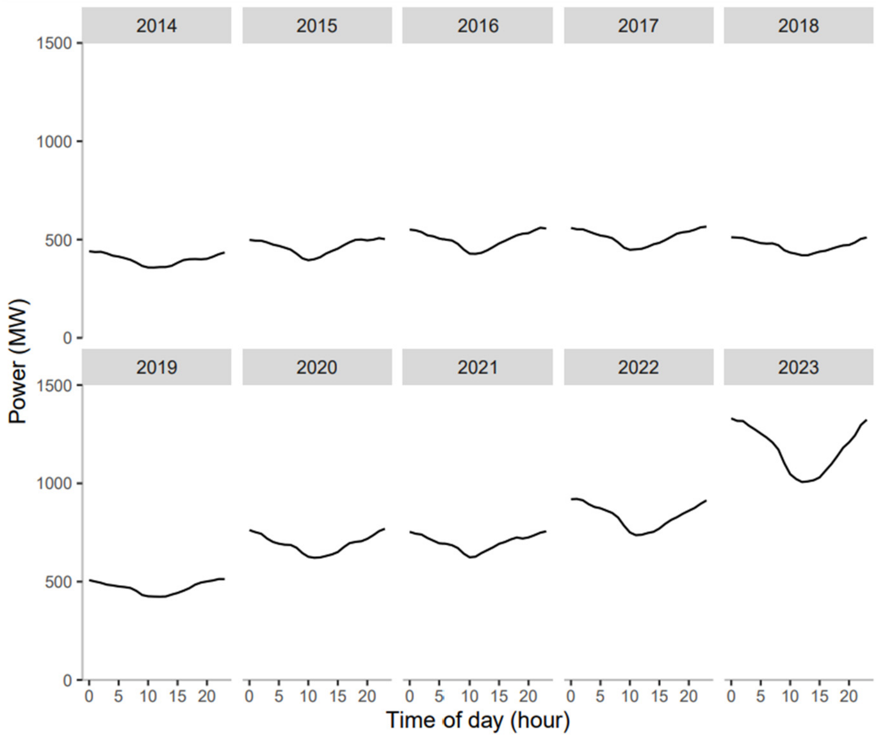


**Figure 3.** Daily average generation from Alberta's wind fleet.

## 3. Methodology

Hourly historical merit order data are publicly available from the AESO. The AESO data were collected using NRGStream, which is a database for North American energy markets and a commercial data aggregation service that offers market solutions to its customers. These data were blended with AESO metered volumes for wind generation data, among other calculations, to create the dataset used for this analysis. The final dataset includes all offer volumes, prices, and hourly settlements. GHG emissions data were collected from facility-level compliance reporting to the province of Alberta for SGER and CCIR/TIER policies between 2009 and 2023. Compliance data provide annual averages for facilities, and no attempt to model dynamic emissions based on loading or ramping was made. Where gaps in GHG data existed, such as with small-scale facilities, the Canadian Federal Greenhouse Gas Emissions Reporting Program data were inserted. Where additional data gaps existed, similar unit emissions were assumed for cases where units are exempt from the programs, such as for small generating units or plants that are in their initial stages that had not yet disclosed emission levels, or the average emission intensity for that particular technology grouping was inserted. Where only partial information on a unit's emission behavior was available, previous years with known emission intensities were used. Finally, some facilities with multiple generating units report their emissions collectively, and in these cases, each unit was assigned the same intensity as the overall facility.

The methodology used in this paper attempts to put a reasonable emission rate on all electricity that was offered into the market, but it should be noted that overall emission numbers are different than numbers reported by AESO due to the different treatment of cogeneration facilities, which includes some facilities but excludes others. Alberta has a large contingent of industrial combined heat and power (CHP) facilities where emissions are “shared” between electricity and heat generation. For the emissions attributable to an incremental unit of electricity for all natural gas CHP facilities, 0.30 t/MWh was used as a representative number, which assumes an 80 percent efficient boiler, as is the case in the SGER guidelines [42], as well as a 30 percent efficient electricity generator. Furthermore, all wasted heat is attributed to electricity emissions. So, for 1 GJ of input fuel, 0.3 GJ is consumed for electricity generation. Using a boiler efficiency of 80 percent, Equations (2) and (3) show the fuel attributable to both heat and waste. The emission intensity of natural gas fuel was assumed to be 0.0561 $tCO_2e/GJ$. Equation (4) displays the final emissions intensity (EI) for electricity production for all cogeneration facilities in this study. It is worth noting that cogeneration facilities report their emissions to the federal government differently, with some reporting all emissions entirely attributed to oil and gas and others entirely to the electricity sector, and so the universal 0.30 $tCO_2e/MWh$ assumption allows for simplicity. Additionally, no behind-the-fence generation is considered in the study data.

$$(1\ \text{GJ} - 0.3\ \text{GJ})0.8 = 0.56\ \text{GJ attributable to heat per unit of fuel} \tag{2}$$

$$1\ \text{GJ} - 0.3\ \text{GJ} - 0.56\ \text{GJ} = 0.14\ \text{GJ attributable to waste per unit of fuel} \tag{3}$$

$$\text{EI}_{\text{cogeneration, elec.}} = \frac{\frac{0.0561\ \text{tCO}_2\text{e}}{\text{GJ}}(0.3\ \text{GJ} + 0.14\ \text{GJ})}{0.0833\ \text{MWh}} = 0.30\ \text{tCO}_2\text{e}/\text{MWh} \tag{4}$$

## 4. Results and Discussion

The results of this research are discussed in the following sections. The first section discusses the market price cannibalization effect on Alberta’s wind fleet capture price resulting from increased penetration of wind energy. This shows an increasingly discounted wind capture price between 2016 and 2023. The subsequent section presents the counterfactual analysis results for the emissions from the energy generation units that were displaced by wind energy in the electricity market. By quantifying these displaced emissions, an alternative offset value for wind energy generators is calculated. The alternative offset suggests having a higher value compared to the historical, deemed offset value, up until the marginal fleet decarbonizes significantly.

### *4.1. Wind Energy’s Historical Impacts in the Market*

Wind energy in Alberta has a market price-depressing effect as it offers its energy at 0 CAD/MWh, lowering the hourly price the most when wind output is the highest. López Prol et al. describe the phenomenon of variable renewables entering the market and ultimately diminishing their own value as the “cannibalization effect” [43]. Wind energy’s cannibalization effect or “discount” in Alberta is discussed in AESO’s 2022 Annual Market Statistics report [6] and can be calculated by taking the hourly electricity pool price and multiplying it by the hourly wind output that hour and dividing by the total annual energy generated from the entire wind fleet. This capture price calculation is shown in Equation (5), where $E_{\text{Wind},t}$ is the total wind fleet’s energy generation during hour $t$ (MWh) and Pool price$_t$ is the market pool price during hour $t$ (CAD/MWh).

$$\text{Annual wind capture price} = \frac{\sum_{t=1}^{8760} (E_{\text{Wind},\ t})(\text{Pool price}_t)}{\sum_{t=1}^{8760} (E_{\text{Wind},\ t})} \tag{5}$$

The fleet average prices for wind energy compared to the market average are shown in Table 2 and illustrate how wind’s discount ranged from 10–43 percent over the past decade. While wind energy grew in Alberta during the study period, there were also other significant market forces that contributed to the low-price periods during 2017–2020, including a period of oversupply and the COVID-19 lockdowns in 2020. Increased concentration in market control in 2021 and 2022 led to high overall prices, and despite wind generation and its associated discount being at their highest levels, on average, the wind fleet captured its highest average prices. In 2023, prices declined in part due to a 900 MW gas plant (Cascade units 1 and 2) coming online and wind's total market share increasing by four percent compared to the year prior. Nonetheless, if market prices return to their historical norms and the discount continues to grow, it may present significant future financing problems for new wind projects.

**Table 2.** Average annual wind discount compared to average Alberta wholesale price.

| Year | Average Market Price (CAD/MWh) | Wind Average Price (CAD/MWh) | Wind Discount Average (%) |
|---|---|---|---|
| 2014 | 49.08 | 32.55 | 33.7 |
| 2015 | 32.84 | 22.32 | 32.0 |
| 2016 | 18.27 | 16.43 | 10.1 |
| 2017 | 22.14 | 19.52 | 11.8 |
| 2018 | 50.58 | 39.03 | 22.8 |
| 2019 | 54.86 | 39.53 | 27.9 |
| 2020 | 46.71 | 33.69 | 27.9 |
| 2021 | 102.56 | 70.11 | 31.6 |
| 2022 | 167.44 | 105.71 | 36.9 |
| 2023 | 134.04 | 75.84 | 43.4 |

Hydro and biomass do not experience the discount that wind does in Alberta's market despite being renewable, as seen in Figure 4 (biomass makes up the majority of AESO's 'other' category), as they have some degree of dispatchability and are not forced to make zero-dollar offers. Furthermore, wind's discount is exacerbated by its tendency to generate, on average, 20 percent more energy overnight when prices are lower [38]. Trends in premiums or discounts to the average market price for the other major technologies in Alberta's fleet are shown in Figure 4 and align with the AESO 2023 Annual Market Statistics report [10], but further discussion is available in Section 4.3. An increasing market discount results in offsets playing a larger role in project viability.

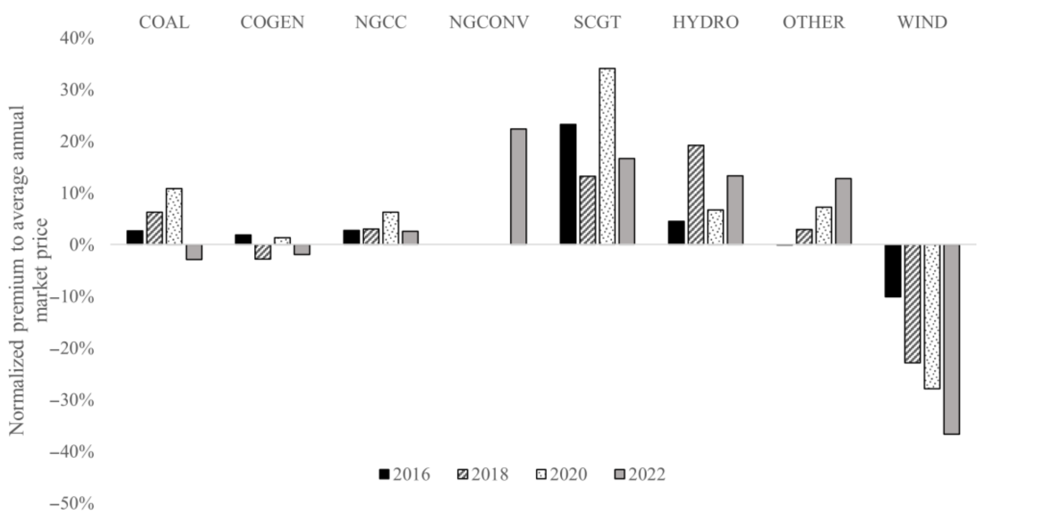


**Figure 4.** Average market premium for different generation types in Alberta between 2016 and 2022.

## *4.2. Counterfactual Scenario*

Counterfactual scenarios were created by removing all wind energy offers from each hour and assuming the rest of the merit order remained unchanged. This compiles the marginal units and their associated emissions that were next in line to dispatch had there been a sudden drop in wind energy output, but it does not consider how the fleet's installed capacity would have developed in the absence of wind energy development.

The potential value of an offset depends, in part, on the carbon price, as well as the emission displacement factor that is credited to a unit of wind energy generation. This section examines an alternative method for considering displaced emissions resulting from wind energy generation by looking at the emissions associated with the generators that were not dispatched in each hourly merit order when wind energy was operating. The "counterfactual displaced energy" (i.e., the displaced energy) is found by removing all wind generation from actual historical merit orders and filling that generation with the units that were next-in-merit, which is illustrated by Equation (6). The resulting counterfactual energy generation share is shown in Figure 5. In this figure, the outline of the graph in each year is the average wind generation, and the fill corresponds to the proportion of generation coming from the next-in-merit sources (i.e., the counterfactual generating fleet).

$$E_{\text{counterfactual}} = \sum_{0}^{E_{\text{Wind}}} E_{\text{Next-in-meritoffers}} \text{ for each hour} \tag{6}$$

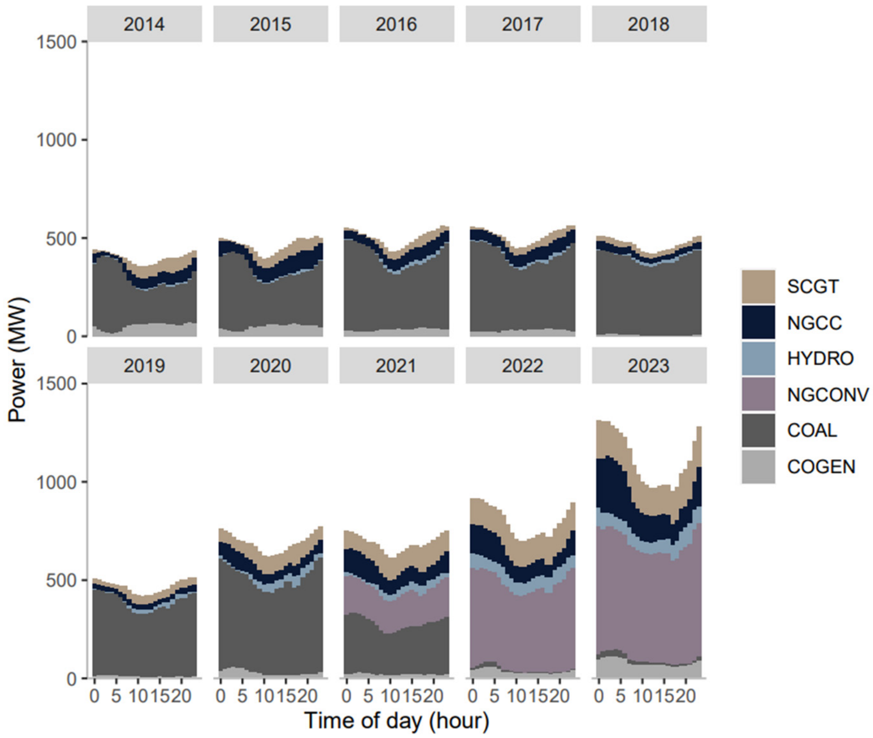


**Figure 5.** Average expected generation displaced by Alberta's wind fleet.

As wind energy output is highly variable, AESO posts both seven-day-ahead and 12 h forecasts [44], which market participants use when developing their offers, and so merit-order offers are made with the expected wind generation in mind. The displaced energy therefore represents energy that would have been dispatched had there been a sudden and complete loss in wind speeds at any given hour, but not necessarily what would have been dispatched if the wind fleet did not exist at all. This model is not an attempt to re-imagine how merit-order offers would have been made but rather to examine what was in fact next in the merit order and, thus, the energy that was actually available every hour that wind energy was produced over the past decade.

From 2014 to 2015, the counterfactual displaced energy is similar to the average fleet mix shown in Figure 1 with the renewable resources removed, as would be expected given that coal and natural gas have non-zero dispatch costs. When Alberta's carbon costs began increasing in 2016, coal's share of counterfactual displaced energy increased from 64% to 74%, despite the fact that coal's actual overall generation had slowly begun to decline. By 2018, when coal generation had declined by approximately 25 percent from its 2014 peak to less than one-third of the overall market, it represented over 84 percent of the energy displaced by wind generation, which can largely be attributed to the significant carbon costs forcing higher bids. By 2021, coal units that had been converted to natural gas began to represent a large share of displaced energy (15 percent), as would be expected due to their lower efficiencies and higher carbon costs, and the decline in remaining coal capacity. The shift from coal to natural gas is clear: in 2020, the natural gas resources (SCGT, NGCC, and NGCONV) collectively represented 21 percent of marginal energy, but by 2023, they accounted for 84 percent. Figure 6 shows the changing marginal energy generation fleet alongside the SGER and TIER program years, thus summarizing the above discussion.

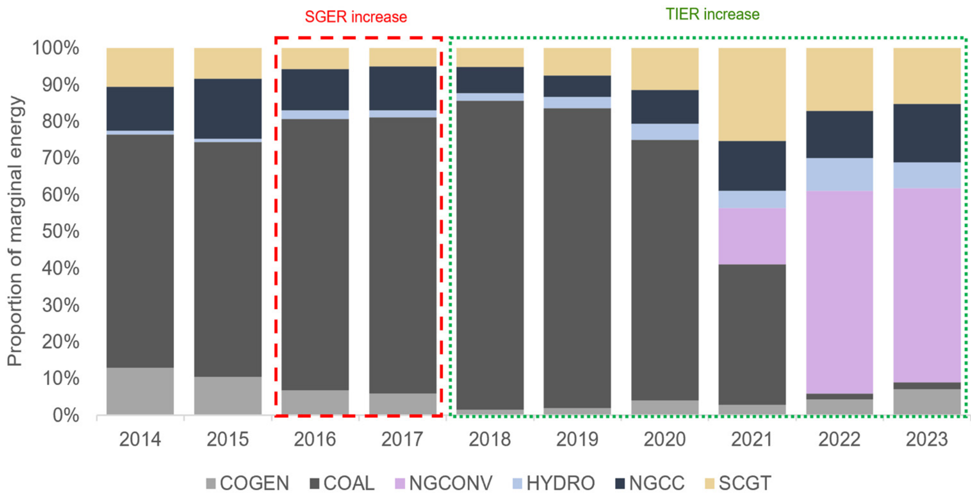


**Figure 6.** Annual proportion of energy displaced by wind in Alberta.

Alberta has limited hydroelectric capacity, most of which operates with little annual year-over-year water retention and supplies roughly 200 GWh, representing approximately 2–3 percent of annual generation. Much of the capacity is in run-of-river units and/or in systems that are dispatched as part of river management, irrigation, and flood control. A limitation to this study's generation replacement methodology may occur if energy from a hydro facility that was out of merit would actually have been available in a subsequent hour had it been dispatched. In most years, the displaced hydro represents a small fraction of the overall energy, and therefore, while the limitations in the analysis are noted above, no changes were made to the results to attempt to correct for either. In 2022, hydroelectricity represented 9 percent of the displaced energy, a notably higher number than previous years. This is likely to have been the result of a change in offer control for some of these assets but only represents, on average, 71 MW out of the 894 MW of installed hydro capacity and, therefore, does not likely suggest a physically impossible amount of dispatched energy.

The average hourly historical market generation with wind energy replaced with the equivalent counterfactual displaced energy is illustrated in Figure 7. Cogeneration's share is mostly stable due to its "baseload" tendencies and must-run operation for industrial activities, but it is again clear that higher-emitting generators such as coal and natural gas units are being displaced by wind. In the most recent years, the converted natural gas share is most noticeably displaced by wind, as seen in Figure 7, but with actual wind generation included in the mix for comparison.

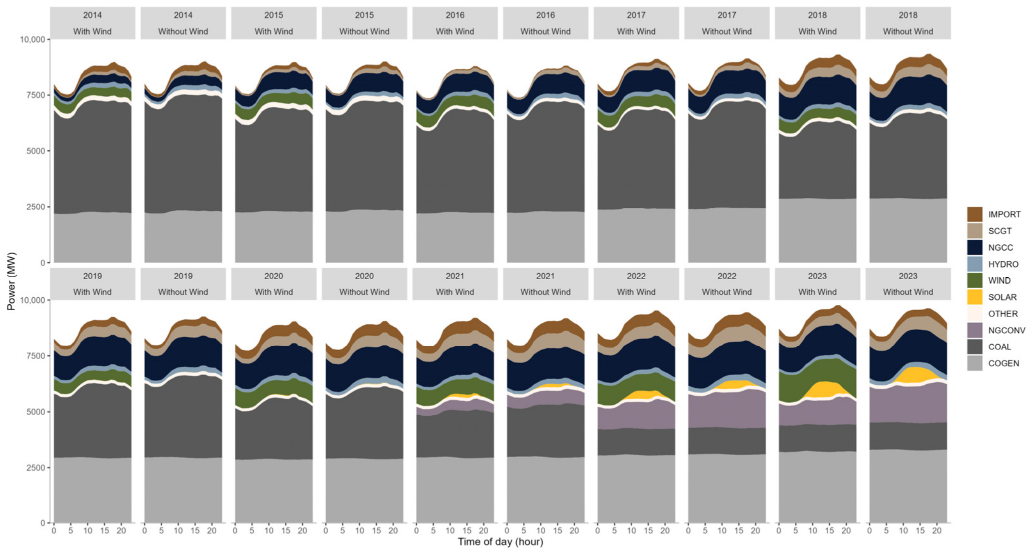


**Figure 7.** Average Alberta electricity market with wind output replaced with next-in-merit energy.

### *4.3. Displaced Greenhouse Gas Emissions*

As recently as 2017, Alberta's electricity system was responsible for 60 percent of all of Canada's electricity generation GHG emissions [15]. Alberta's electricity market GHG emissions peaked in 2014, with study data showing 52 $MtCO_2e$/year, and declined by around 39 percent to just under 32 $MtCO_2e$/year in 2023, largely due to a major reduction in coal [6], despite total demand increasing by about 8 percent. The total emissions found in this analysis differ from those reported by the AESO because of discrepancies in how emissions are treated, particularly with cogeneration units. This analysis calculates all emissions from all electricity offered into the market without behind-the-fence considerations.

Each plant participating in the market reports its respective emission intensity factor, but the average emission factors for each technology are shown in Table 3 for context. These average emission factors were used to replace empty emission intensities in the dataset, depending on the technology, as outlined in the methodology. Renewable energy, including biomass, was considered to have zero emissions, which is consistent with TIER reporting, while other non-biomass smaller-scale generation in the "other" category are small and neglected for simplicity.

**Table 3.** Average assumed GHG emission factors for each generation technology.

| **Technology** | **Acronym** | **Emissions Factor ($tCO_2e$/MWh)** |
|---|---:|---:|
| Coal | COAL | 1.00 |
| Coal to Gas Converted | NGCONV | 0.69 |
| Cogeneration | COGEN | 0.30 |
| Combined Cycle Natural Gas | NGCC | 0.42 |
| Simple Cycle Natural Gas | SCGT | 0.60 |
| Hydro | HYDRO | 0 |
| Other | OTHER | 0 |
| Solar | SOLAR | 0 |
| Wind | WIND | 0 |

The emissions displaced by wind energy in the counterfactual scenarios can be calculated by multiplying the plant emissions factors by their marginal energy, and these results are shown in Figure 8 Between 2013 and 2023, 39 MT of cumulative marginal emissions were not emitted due to the presence of wind in the market, which is in the order of one full year of total electricity sector emissions. Coal makes up the majority of these counterfactual displaced emissions, increasing from 82 percent of all marginal emissions in 2014 to 93 percent in 2018. After 2018, the proportion of coal emissions on the margin decreases, reaching only 3 percent by 2023. While the total displaced emissions from wind were roughly commensurate with its energy generation in 2014 (approximately 5–6 percent), its displaced emissions grew faster than its relative generation of annual generation after 2017. Wind's displaced emissions reached approximately 4.4 $MtCO_2e$ in 2020, which corresponds to over 13 percent of the entire grid's emissions, while wind accounted for less than 8 percent of the energy generation. However, as coal generation began to decline, the displaced emissions in 2022 fell back to 2016 levels (3.8 $MtCO_2e$), despite wind energy generation having nearly doubled over the same timeframe, although the displaced emissions from wind still represented 12 percent of total electricity sector emissions. With the increase in wind generation in 2023, this trend was reverted again since the counterfactual scenario showed that 5.3 $MtCO_2e$ were displaced, or nearly 17 percent of total emissions, which surpasses wind's 12 percent generation share.

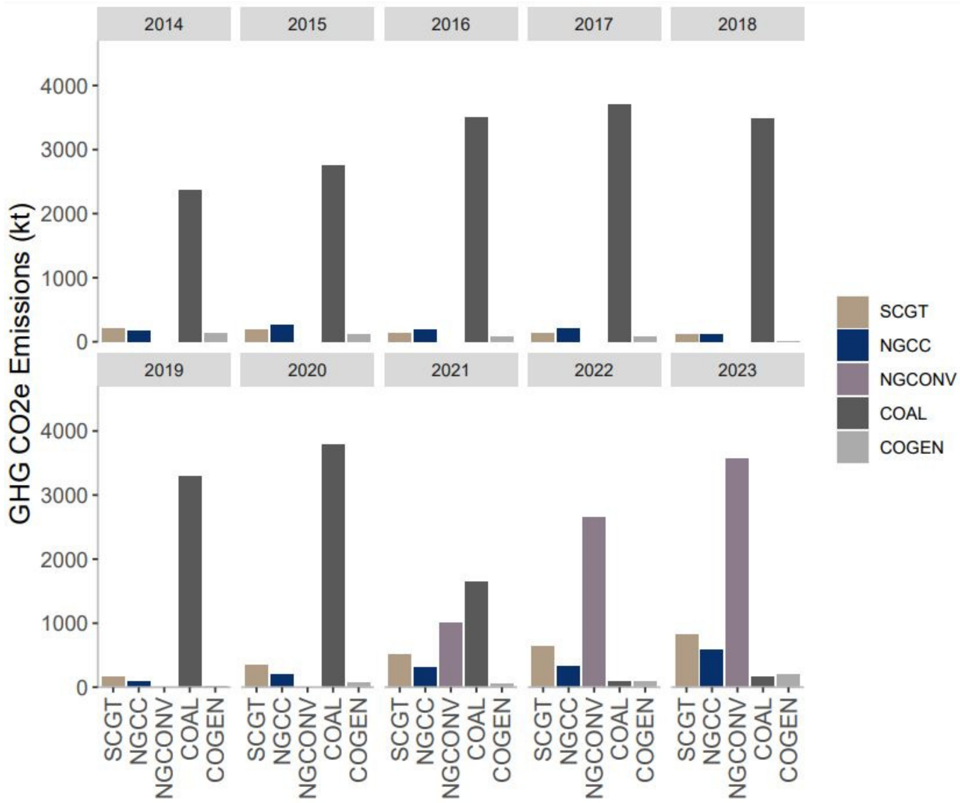


**Figure 8.** Counterfactual emissions from units displaced by wind generation in Alberta.

The significant changes in carbon pricing in recent years have not only resulted in major changes to the electricity system but also major changes to renewable energy systems such as wind energy. The increase in carbon price increases the potential value of any offsets that wind energy projects can monetize. On the other hand, as higher-emitting generation sources are displaced, the overall volume of displaced emissions decreases. The true EGDF is calculated by an equal weighting of the emissions rate from units built in the previous 5 years and the emissions rate of annual marginal units (the price-setting unit in the merit order each hour) [29].

As the increasing carbon price drives new builds toward lower-emission sources while resulting in high-emitting units operating more frequently on the margins, build and operating margins from 2018–2020 were found to be 0.23 and 0.80 $tCO_2e/MWh$, and the government set an overall EGDF of 0.52 $tCO_2e/MWh$ for 2023 [29]. Historically, the EGDF was reviewed every five years; however, as a result of the rapid changes in grid intensity, a schedule was set forth beyond 2023 by the government of Alberta as outlined in Table 1. Table 1 also illustrates that despite the increasing carbon price, the maximum value of offsets begins to plateau around 50 CAD/MWh. In 2018, the government of Alberta awarded contracts for differences to multiple wind energy projects where average prices were around 39 CAD/MWh [45], although the AESO has reported that new merchant wind energy projects might have a levelized cost of energy between 50 and 62 CAD/MWh [46]. Despite the unusually high price years of 2021–2023, wind energy's average market revenue over this study period is closer to 45 CAD/MWh (29 CAD/MWh if 2021–2023 are excluded) using the data from Table 2, suggesting that the offset is likely of consequential value to many wind energy projects.

The offset value found using the actual EGDF is shown in Figure 9 (light grey color) stacked on top of the average wind capture price (grey) and compared with the total average market price (red). The counterfactual displaced emissions are also used as a hypothetical alternative method of calculating an offset value in place of the actual EGDF, which considers real-time changes to emissions (stacked in Figure 9 in black). Recall that the counterfactual offset is calculated by normalizing the displaced emissions by wind output and multiplying by the in-year carbon price. For consistency, a 10 percent discount to the maximum price is applied to both offset calculations. This adjustment reflects a more favorable price compared to TIER fund payments, which generators might otherwise choose to pay instead of purchasing offsets. While this estimate serves as a ceiling value for the offset, the actual discount applied to offsets is not publicly disclosed, introducing a limitation to the analysis. The two offset calculations are shown in Equations (7) and (8) where EI is the emission intensity ($tCO_2e/MWh$) of the next-in-merit generating unit considered in the counterfactual generation fleet and CP is the carbon price ($CAD/tCO_2e$).

$$\text{Historical offset} = \text{EGDF}(\text{CP})(90\%) \tag{7}$$

$$\text{Counterfactual offset} = \frac{\sum E_{\text{Next-in-merit offers}}(\text{EI})}{\sum E_{\text{Wind}}}(\text{CP})(90\%) \tag{8}$$

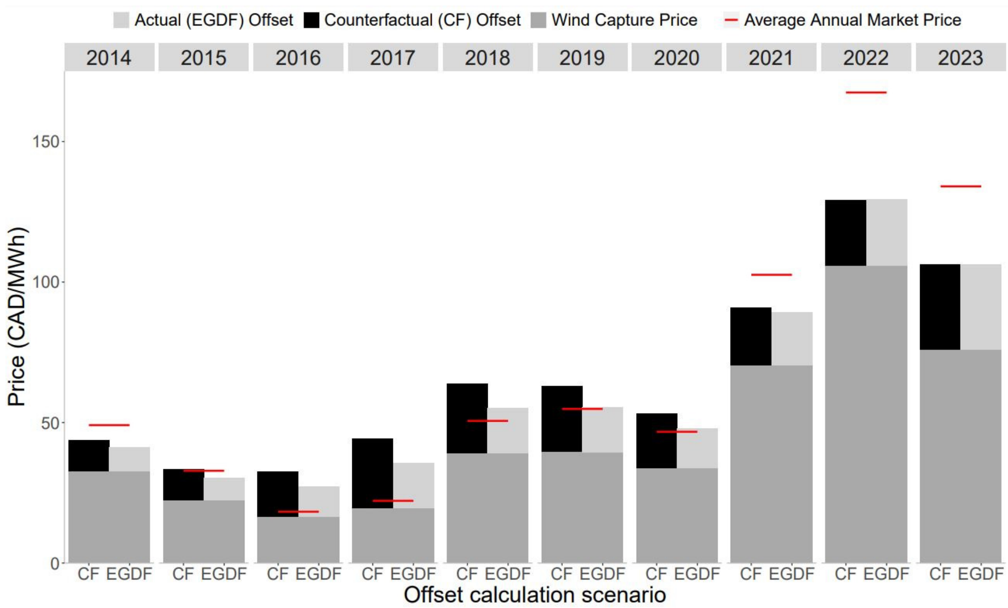


**Figure 9.** Comparing a counterfactual offset value to the provincial policy offset value for wind.

Overall, Figure 9 shows how the value of emission offsets can close the gap between the wind capture price and the average market price, and in some years (2016 to 2020 inclusive), wind farm revenues per MWh could have gone from a discount to the average market price to a premium. Excluding 2022 and 2023, the counterfactual method of calculating displaced emissions is more valuable than the actual historical EGDF, ranging from 10 to 57 percent increases. This difference peaks in 2017 through 2019 when the increases in carbon prices resulted in more coal offered higher in the merit order. As coal began to be physically phased out in Alberta, the difference in the two methodologies decreased; the counterfactual method in 2023 is only very slightly better than the offset based on the EGDF and is actually lower in 2022, even though this difference is only in the order of cents per MWh.

Using the historical EGDF, the 54.5 TWh of wind energy generated over the study period was credited for displacing 30.5 Mt$CO_2$e. Assuming actual wind offsets could be monetized for 90 percent of their in-year carbon price, they had a cumulative value of CAD 1.00 billion, or 18 CAD/MWh representing an additional 35 percent of revenue above the market value (wind's capture price) of the energy generated over the same timeframe. Using the counterfactual methodology, 38.7 Mt$CO_2$e of emissions were displaced, with a value of CAD 1.19 billion using the same assumptions or 22 CAD/MWh. To put this into perspective, consider a new 100 MW wind farm with a 40 percent capacity factor that generated 350,000 MWh/year. Its offsets would have been valued at 5.6 million CAD in 2017 using the actual EDGF but would be closer to 8.7 million CAD if using the counterfactual offset methodology compared to the 6.8 million CAD value of its energy generated at wind's average capture price in that same year. This increased offset value could have helped maximize wind energy revenues.

## 5. Conclusions

This study looked at Alberta's market during a coal phase-out transition period precipitated by significant increases in carbon pricing. This analysis illustrates how carbon pricing increases marginal emissions displaced by wind energy in the short term, but as the carbon price phases out higher-emitting sources, it can potentially lower revenue streams associated with the offsets for the same wind energy projects. By considering the counterfactual case of crediting wind energy with emissions that were displaced from hourly merit orders, the value of wind energy credits could be as much as 57 percent higher than a methodology that includes recent builds and the marginal generating unit.

However displaced emissions are calculated, there is an observation that permanently displacing high-emitting sources of emissions lowers the emission displacement value for each unit of energy generated by technologies such as wind. This decrease in value occurs concurrently with increasing levels of wind energy that also erode their own average market capture price. A commensurate increase in carbon prices can help to maintain the value of emissions offsets in the short to medium term.

Using a methodology of equivalent energy from hourly merit orders captures real-time changes in bidding behavior as a result of carbon pricing and credits wind energy that displaces those emissions. This methodology is less likely to over-credit displaced emissions than a deemed displacement rate, maintaining the integrity of carbon credits. While the per MWh displaced emissions intensity declines as high-emitting electricity sources such as coal are permanently displaced, using a methodology that examines merit-order offers will ensure that the remaining peaking units that are displaced are credited to renewable energy output. However, this methodology also has a limitation because it assumes that generator offers are unchanged compared to historical offers, despite a change in the availability of wind energy generation. Integrating dynamic offers into the model, in response to the removal of wind energy generation, could be an area for future research.

Alberta is a useful case study because of the important role that an increasing carbon price has played in its off-coal transition [47]. During this transition from 2014–2023, wind energy increased from 5 percent of the annual supply to over 12 percent. Also, during this timeframe, the total annual electricity sector emissions fell from 52 $MtCO_2e$ in 2013 to 32 $MtCO_2e$ by 2023, while wind energy was credited with displacing a cumulative 30.5 $MtCO_2e$ using the Government of Alberta's emissions displacement factors. A counterfactual methodology of examining merit-order offers to determine energy and emissions displaced by wind energy during this transition was used to find that 39 $MtCO_2e$ were displaced by wind energy, representing an increase of 19 percent in the potential normalized offset value.

The methodology developed in this case study offers valuable insights and can serve as a reference for other jurisdictions navigating clean energy transitions. While each country has unique energy targets and varying access to energy resources, the global effort to achieve a net-zero electricity sector highlights the growing importance of wind energy in decarbonization. However, challenges persist in maximizing revenue potential for wind energy generators, particularly as increased wind energy penetration has led to a decrease in the wind's capture price and a decline in the value of carbon offsets.

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## Abbreviations

| | |
|---|---|
| AESO | Alberta Electric System Operator |
| CAD | Canadian dollar |
| CCIR | Carbon Competitiveness Incentive Regulation |
| $CO_2e$ | Carbon dioxide equivalent |
| COGEN | Cogeneration |
| CHP | Combined heat and power |
| EGDF | Electricity Grid Displacement Factor |
| EPC | Emission performance credit |
| GHG | Greenhouse gas |
| LFE | Large final emitters |
| NGCC | Natural gas combined cycle |

| | |
|---|---|
| NGCONV | Natural gas conversion |
| REP | Renewable Energy Program |
| SCGT | Simple cycle gas turbine |
| SGER | Specified Gas Emitters Regulation |
| TIER | Technology Innovation Emissions Reduction |

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