Improving the value of wind energy through geographic diversity of wind farms

by

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Abstract

Wind farms are often concentrated geographically as they are cited in areas with strong resources. While this maximizes energy generation, it can decrease the value of that energy, particularly as the relative amount of wind increases in the overall system. Wind energy is growing rapidly in Alberta, and this research evaluates the potential to increase the value of the energy for new wind farms by building them in regions with lower annual wind speeds but less correlation to the rest of the fleet to capture higher market prices. The research identifies a trend between the deviation of the location's potential generation output from the fleet's average and the average annual energy revenue for a wind farm at that location based on data from existing wind farms. This trend is applied to predict the average annual energy revenue, payback periods, and internal rate of return for twelve candidate wind farm sites in the northern portion of the province. This prediction suggests that these locations have competitive payback periods between 5 and 9 years and internal rates of return between 15% and 33%. Alberta's electricity market was also simulated with seven of these candidate locations added as potential new wind farms using Energy Exemplar's Aurora software. The simulation built wind energy capacity at each of the seven hypothetical sites, for a total of 4727 MW of a possible 7000 MW. The simulation was also repeated with renewable energy emissions credits removed, and although there was significantly less wind energy built, two of the hypothetical sites had capacity built for a total of 1020 MW, and made up a larger portion of the wind energy additions, suggesting that geographically diverse wind farms may be economical in Alberta's electricity market.

Preface

This thesis is an original work by T. Pawlenchuk. This research has been conducted as part of a research collaboration led by Professor A. Leach in the Department of Economics and Law, University of Alberta with T. Weis and B. Fleck in the Deparment of Mechanical Engineering. The funding for this research has been provided by Future Energy Systems at the University of Alberta.

"A strong renewable energy industry is good for our environment and our economy."

- Roy Cooper

To my beautiful wife and daughter.

Acknowledgments

This research has been completed with the support of many people who have guided and encouraged me throughout the process.

I want to specifically thank my advisors, Dr. Tim Weis, Dr. Andrew Leach, and Dr. Brian Fleck, for advocating for me and guiding me through this journey culminating in this thesis. I could not have made it this far without their expertise and support. I have learned and grown so much throughout this process and will be forever grateful for their guidance and instruction.

I am also eternally grateful to my loving wife and daughter, who have supported me through the long hours and challenges that have arisen. They have been my biggest fans, and I am excited to make them proud.

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Chapter 1

Introduction

On April 22, 2021, Canada's Prime Minister Justin Trudeau announced that Canada will enhance its emissions reduction target under the Paris Agreement to reduce greenhouse gas emissions to 40-45% of 2005 levels by 2030 [1]. This goal is highlighted in Canada's Clean Electricity Regulations (CER), which focuses on moving the country to net-zero electricity emissions by 2035 while ensuring grid reliability and affordability for homeowners and businesses [2].

At the time of the Paris Agreement, electricity was the economic sector with the third most greenhouse gas emissions in Canada, behind only the oil and gas sector and the transportation sector. Within the electricity sector, Alberta and Ontario contributed the most greenhouse gas emissions, making up 42% and 28% of Canada's electricity greenhouse gas emissions at the time (Figure 1.1). While Ontario has been able to decrease its overall greenhouse gas emissions by 27% since 2005, Alberta's overall greenhouse gas emissions have increased by 8.2% in the same time period. Most of this increase has been due to the expansion of oil and gas operations [3]. While Alberta has been able to reduce the greenhouse gas emissions from electricity and heat production (as shown in Figure 1.1), Alberta now makes up about 53% of Canada's greenhouse gas emissions in this economic sector [4].

There are many pathways for Alberta to reduce or offset the greenhouse gas emissions produced within the province. One vital contribution is the expansion of wind energy in the province to generate electricity and thus offset the greenhouse gas emissions that would have been produced had fossil fuel generators been used. As of August 2022, there was the equivalent of more than double Alberta's installed wind capacity seeking connection to Alberta's grid [5]. A study by Berrington-Leigh and Ouliaris estimates that onshore wind could deliver over half of Canada's 2010 energy demand [6].

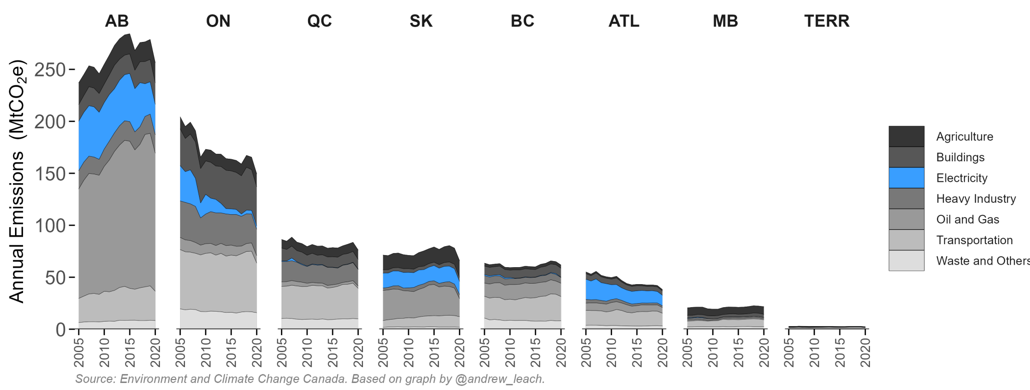


Figure 1.1: Canadian greenhouse gas emissions by province, with electricity emissions highlighted in blue (Mt CO2eq)

Wind energy is playing an increasingly large role in Alberta as its electricity sector looks to lower its greenhouse gas emissions. Much of Alberta has a strong wind regime relative to other provinces, as shown in Figure 1.2 [7]. As evident in this figure, the regions with the best wind regimes are in the southern portion of the province. The potential wind energy that can be produced at a particular location is proportional to the wind speed cubed. This means that relatively small differences in average wind speeds can significantly alter the available wind energy at that location [8, 9]. This has resulted in wind energy developers seeking out the strongest wind resources to increase their annual energy yields, resulting in the clustering of historic wind farms in the southwest of the province. Going forward it is not practical to concentrate the entire provincial wind fleet at a single location with the highest average wind speeds due to technical and political constraints, as well as the nature of Alberta's electricity market which sends a discouraging market signal. This research looks at the limitations and opportunities presented by potential wind farm locations in other locations in Alberta to improve revenues from the electricity market despite potentially having lower energy yields.

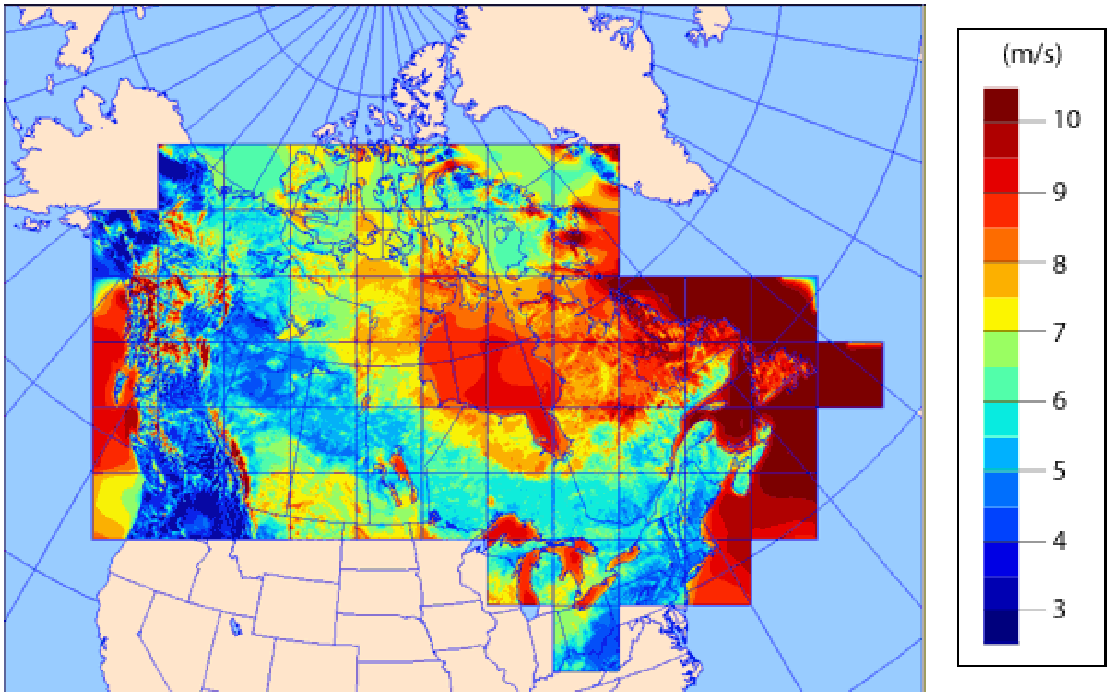


Figure 1.2: Average annual wind speed at 80 m above ground level. (Source: Environment Canada)

Historically, wind energy in Alberta has been concentrated in the southwestern corner of the province. This region experiences relatively high mean annual wind speeds making it a good location for wind energy. As variable renewable generators, these wind farms must offer the energy generated into the electricity market at $0/MWh [10, 11]. With the market price of electricity dictated by supply and demand [12], these wind generators that use the same wind regime to generate power historically flood the market with energy at similar times and drive the price down. This price cannibalization is known in Alberta as the "wind discount" [11].

Despite the lower annual wind speeds, more geographically diverse locations may prove to be economical choices for new wind farms, as the wind energy available at these locations may be able to bid into the market at times when few other renewable energy options are able to, thus capturing more frequent premium prices (or less frequent surpressed prices). These premium prices may be able to offset the lower energy output from these locations. Yet if too many wind farms are built at these alternative locations, the amount of energy bidding into the market at $0/MWh will increase, and the capture price may decrease to the point that these plants lose their economic viability. Therefore an optimal balance would have to be found to achieve maximum value at these locations.

1.1 Objectives

The purpose of this research is to determine how a more geographically diverse wind fleet could improve the viability of new wind farms in the province given Alberta's energy-only electricity market. This work will model Alberta's electricity market, and with the proper inputs allow the simulation to forecast when and what resources to build to determine the optimal future market share of each of these technologies. To accomplish this goal, this research will utilize and build on previous research conducted by Natalia Vergara Bonilla in 2020 pertaining to Alberta's climate patterns and wind energy production as a part of her Master's Thesis with the University of Alberta, as well as research completed by William Noel in 2021 to map Canada's wind energy fleet [13].

The thesis is structured into five main chapters as follows:

In Chapter 2, (literature review) background information on wind energy is presented, along with an exploration of the mechanics of Alberta's electricity market. This includes an analysis of how wind energy affects the market. This will also include looking into literature for approaches that have historically been used to plan the implementation of wind energy and will analyze the applicability to Alberta's market. Chapter 3 explores the relationship between current wind farms and the average revenues to identify traits that are important to citing new wind farms. Twelve potential sites are selected and analyzed based on the work in this chapter, and these sites are compared to each other to assess which sites hold the most potential to be economical in Alberta's electricity market.

Chapter 4 discusses how a model of Alberta's electricity market was developed. Three simulations are run with the market forecast from the year 2020 to the year 2040: one simulation with no changes to the market to act as a baseline, one simulation with the hypothetical sites identified in Chapter 3 included as possible wind farms to add to Alberta's wind fleet, and the final simulation with the hypothetical sites included, and renewable energy emissions credits removed to assess how these credits affect the results. The results of the three scenarios are analyzed and compared.

Finally, Chapter 5 summarizes the work done for this thesis, the contributions this work adds to the field, and identifies areas for future work.

Chapter 2

Literature Review

2.1 Introduction to wind energy growth

The Alberta Government released the Climate Leadership Plan in 2015 with the goal to have 30% of Alberta's electrical energy come from renewable sources by 2030 [14]. The following year this goal was reinforced with legislated targets to meet 15% by 2022, 20% by 2025, and 26% by 2028 [15]. By 2018, about 10% of Alberta's electricity was generated from renewable sources [16].

In 2022, the Alberta Electric System Operator (AESO) published an analysis of three potential supply and demand combinations that may lead to a net-zero future by 2035 by focusing specifically on electricity in Alberta. Net-zero in this report is defined as a combination of zero- or low-emissions technologies paired with offsets and credits that have a calculated emissions outcome equivalent to zero greenhouse gas emissions [17].

The three scenarios in this report include:

- A scenario where thermal units continue to dominate Alberta's market and the emissions are offset.
- A scenario with high growth in renewable energy and energy storage displaces thermal units.
- A scenario with high market saturation of renewable energy and energy storage

with the lowest amount of thermal-based supply additions.

Each of these scenarios includes forecasting a significant amount of wind energy additions, with the least optimistic being the first with wind energy almost doubling in capacity with an increase of just under 2,000 megawatts (MW), and the last scenario building the most with over 7,700 MW of wind energy being added [17].

This report concludes by stating that all three scenarios have the potential to approach net-zero emissions, and all but one of these approaches can achieve net-zero emissions. However, the costs are likely to escalate as the emissions approach zero. While the costs for each scenario vary, the report found that the total costs between the scenarios are within five percent of each other [17]. Due to the similarities between scenarios, as well as the high degree of uncertainty in the model and significant risk, the report does not identify the optimal scenario or rule out any of the scenarios. Although AESO's report presents the overall market responses and risks for each scenario, it does not elaborate on the specifics of where such a large increase in wind energy capacity should be built.

2.2 Wind energy in Alberta

Canada has a huge potential to meet its electricity with wind and solar energy. Tong et al. found that Canada ranked second out of forty-two countries for its ability to meet electricity needs from solar and wind sources [18]. Onshore wind alone has an area of approximately 240,000 square kilometres identified as high potential [6]. Yet despite this, wind and solar generation have had less growth than almost any other G2 country [19]. Alberta has some of the best and most accessible onshore wind resources in the country, as shown in Figure 1.2 [7].

That is not to say that there has been no wind energy growth. The first wind farm in Canada was built in Alberta in 1993 with an installed capacity of 16 MW [7]. Since then, wind energy in Alberta has grown in capacity to over 2 gigawatts, making it the third largest wind market in Canada [20]. Since 2010, more wind energy capacity has been built in Canada than any other form of energy [21].

In 2020 and 2021, 134 MW and 358 MW of wind energy came online in Alberta respectively, with another 1,400 MW of wind energy under construction at the end of 2021 [20]. While these installments are impressive, there is still plenty of room for growth. In 2020, 9.6% of Alberta's electricity internal load was met by wind power with an installed capacity of about 1,800 MW. By comparison, 76.6% of Alberta's electricity internal load was met by electricity generated using combustible fuels [22, 23].

2.2.1 Potential for wind energy in Alberta

In his study, Jacobson found that aggregated wind energy output (over the region) in cold climates strongly correlated with aggregate building heat loads, and identified Canada as the country with the strongest correlation [24]. This indicates that as Canada transitions to electrified building heating systems, wind energy could be an excellent candidate to meet this increased demand. This is especially applicable to Alberta as Alberta set new record demand levels twice in December 2022 due to extreme cold weather. While one of the days the new record was set experienced low winds, the first day the high winds significantly reduced the need for fossil fuel generation [25]. However, the second day demonstrates the need for consistent wind energy output with less variability to reduce the strain on the system.

2.2.2 Wind energy as a cost-competitive solution

Alberta has an energy-only electricity market design similar to Texas, where electricity suppliers rely almost exclusively on revenues from the energy market to make a profit [26]. One notable exception is the sale of emissions offset credits, available to suppliers whose emissions are below the government-set limit based on the prevailing carbon price. Wind and solar energy, producing no emissions, can potentially generate sufficient revenue through the sale of these offsets to cover generation costs.

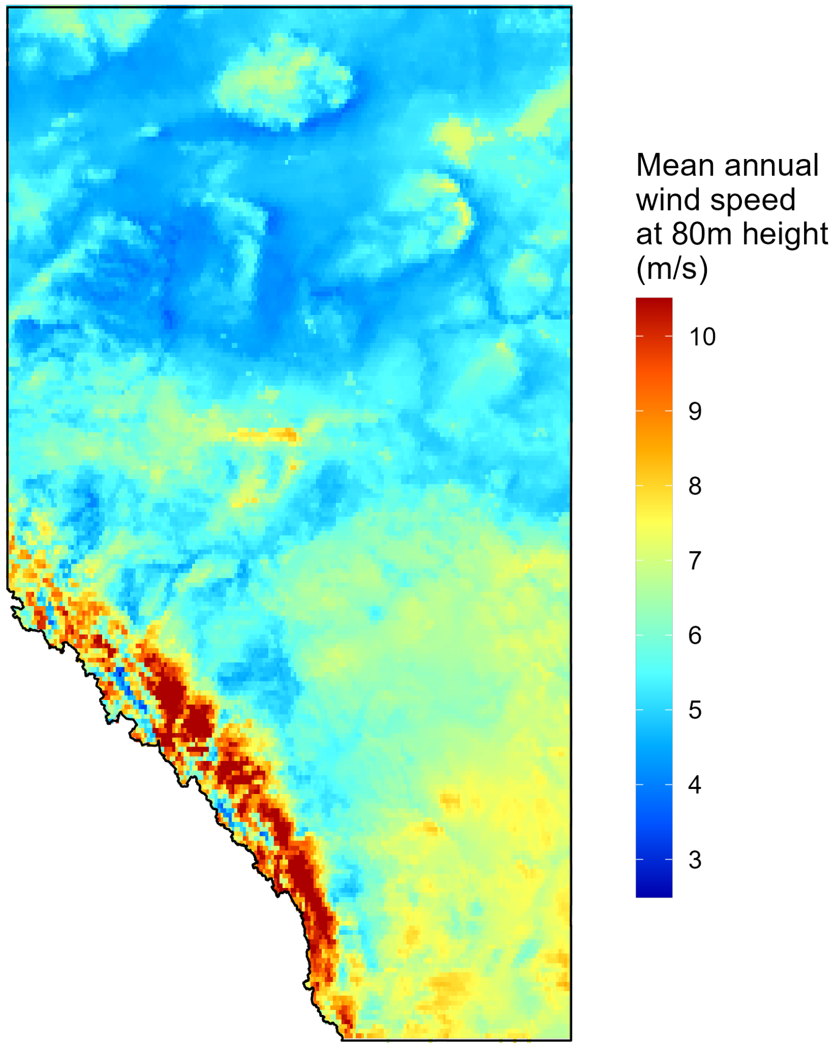


Figure 2.1: Annual mean wind speeds at 80 m above the ground. Ideal wind speeds shown in green with areas with wind speeds above the cut-out speed or below the cut-in speed for wind turbines shown in red. Source: Canada Wind Atlas [27].

However, relying on income through these credits is not sustainable for two primary reasons. The first is that these credits have value based on the demand for emission offsets, and as renewable energy penetration increases, the supply of credits will increase and lower the price. The second is that as government policies increase emission restrictions and taxes, suppliers will retire or convert emitting generators, which reduces the demand for these credits [28]. Alberta's carbon pricing policy, the

Technology Innovation and Emissions Reduction Regulation [29] allocates emissions performance credits to wind energy at a rate of 0.37 t/MWh, as this is the rate of emissions that would have otherwise been allocated to new generation units entering into the market [5]. As the saturation of renewable energy in the market increases, the rate of emissions performance credits allocation is likely to drop, which would reduce the value of these credits that wind farms would receive for their energy production. New wind energy projects must therefore be profitable based increasingly on the electricity market price alone, and less on emissions credits.

In 2006, AESO limited the then potential wind power capacity to 900 MW due to anticipated challenges in system integration. At the time, over 11,000 MW worth of potential wind projects had applied to connect to the grid, despite the lack of any serious government policies or incentive programs present to encourage wind energy. Instead, consumer demand and economics drove the growth of wind energy in the province [30].

Onshore wind currently has one of the lowest levelized costs of energy compared not only to other renewables, but to most fossil fuel electricity generation, and in the future is expected these costs will continue to decline [31, 32]. Due to their strong wind resources and ease of construction Alberta and Saskatchewan have the lowest levelized cost of energy (LCOE) for wind energy in Canada [32]. Wind energy cost-effectiveness has been increasing due to increasing size, operating speeds, and efficiencies, and that trend is expected to continue [32]. The cut-in wind velocity for current wind turbines is about 3.5 m/s (12.6 km/h), while the cut-out wind velocity is about 25 m/s (90 km/h), while annual average wind speeds of about 6.5 m/s measured at 80 m heights are often considered potentially commercially viable [32]. As shown in Figure 2.1, much of the province has potentially viable wind resources, although in practice access to transmission lines, distance from loads and land use constraints limit where wind farms are able to be built.

2.3 Alberta's electricity market

Alberta's electricity market operates on a merit order to set the wholesale price for electricity, with suppliers offering bids between \$0/MWh and \$1000/MWh for their electricity to the AESO, which dispatches the lowest priced electricity offers at the bottom of the merit order first, and moves up the merit order until the demand is satisfied [11, 26]. The highest priced offer dispatched sets the System Marginal Price (SMP) for the electricity. This SMP is determined on a minute-to-minute basis, and the average of the SMPs over each hour is used to calculate the pool price [12, 28]. The pool price multiplied by the amount of electricity dispatched gives the revenue earned by that plant. The average market price that a power generation unit earns is called the capture price [33].

$$\text{Revenue (\$)} = \text{Dispatch (MWh)} \times \text{Pool Price (\$/MWh)} \tag{2.2}$$

This approach ensures that all of the available renewable energy will be dispatched, as renewable energy offers into the market at \$0/MWh because there are no marginal costs involved. As the renewable energy supply approaches the market demand, the SMP declines as there is less energy required by the higher bidding resources [34, 35]. This results in less revenue per unit of energy dispatched, or reduced capture price, which will increase the amount of energy production required for these renewable energy plants to make a profit. The impact of these low marginal cost renewable energy sources on the SMP is called the merit-order effect [33].

2.3.1 Market effects on wind energy

As the penetration rate of renewable energy increases, the profitability of renewable energy may decrease [28]. The electricity markets in California and Texas have a higher penetration of zero marginal cost Variable Renewable Energy (VRE) technologies than Alberta, and both markets have demonstrated a "cannibalization effect" of high VRE generation undermining their unit revenues [33, 36–38].

Despite representing a relatively small portion of Alberta's electricity market, wind energy on average experienced reduced capture prices due to the cannibalization effect. As shown in Figure 2.2, wind farms earned 29% less than the average pool price in Alberta on average from 2010-2021 [7, 39]. This effect of reduced capture prices for wind energy is known as the 'wind discount'. The wind discount and how it will develop in the long term is fast becoming a key factor for investors to consider when planning new wind farms [33].

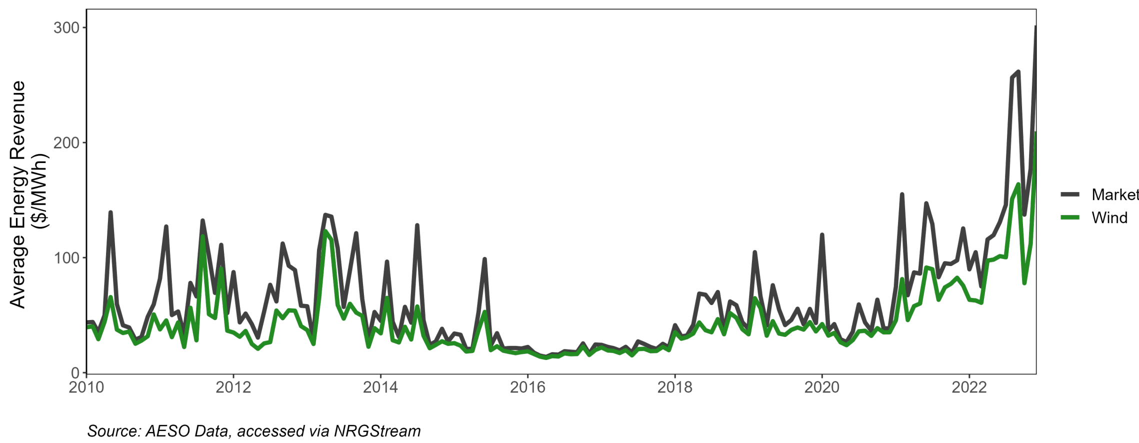


Figure 2.2: Monthly averaged prices captured by the entire market and the aggregate wind fleet.

Alberta's 'wind discount' is magnified by the variable nature of wind power, which is dependent on wind speeds. The power available in the wind is given by:

$$\frac{P}{A} = \frac{\rho_{air} v^3}{2} \tag{2.4}$$

Where

$$\begin{aligned} \text{P} =&\quad \text{wind power [W]} \\ \text{A} =&\quad \text{swept area of the rotor } [\text{m}^2] = \pi D^2/4 \\ \rho_{air} =&\quad \text{density of the air } [\text{kg/m}^3] \\ v =&\quad \text{wind velocity [m/s]} \end{aligned}$$

As wind power is proportional to the cubic of the velocity v^3, if the speed of the wind is doubled, the available wind power will increase by a factor of eight. Therefore even slight variations can cause dramatic fluctuations in wind energy output [7].

2.3.2 Geographic influences on wind energy

Owing to the cubic relationship of wind speed to generation, the geographic location has a dramatic effect on the potential output of a wind farm. This includes both time the wind energy is available and the quantity of wind energy available. Current wind turbines require a minimum wind speed (v_{cut-in}) of about 3.5 m/s and operate at a maximum wind speed ($v_{cut-out}$) of about 25 m/s. The peak power (P_{rated}) for these wind turbines is obtained with wind speeds at about 12-14 m/s (v_{rated}), as shown in Figure 2.3 [32].

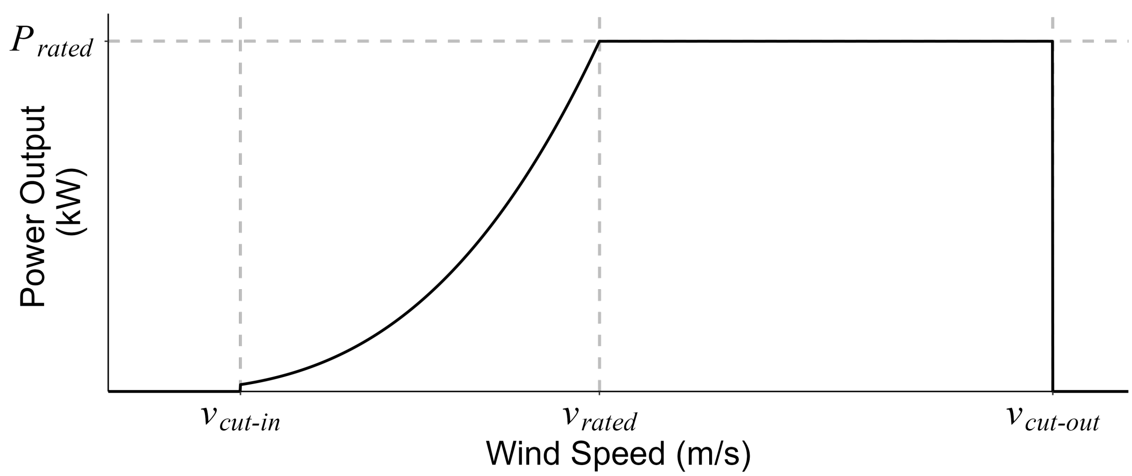


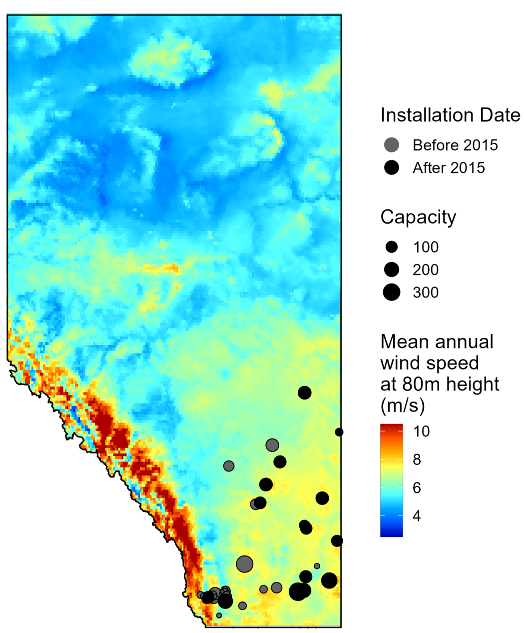
Figure 2.3: Typical wind turbine power curve.

When choosing a location for a new wind farm, the quality of the wind resource is important, but there are many other factors as well. Historically, some of the factors considered have been the electricity market, the availability of compatible land, access to transmission infrastructure, remoteness, local acceptance, and installation and maintenance expenses [40, 41].

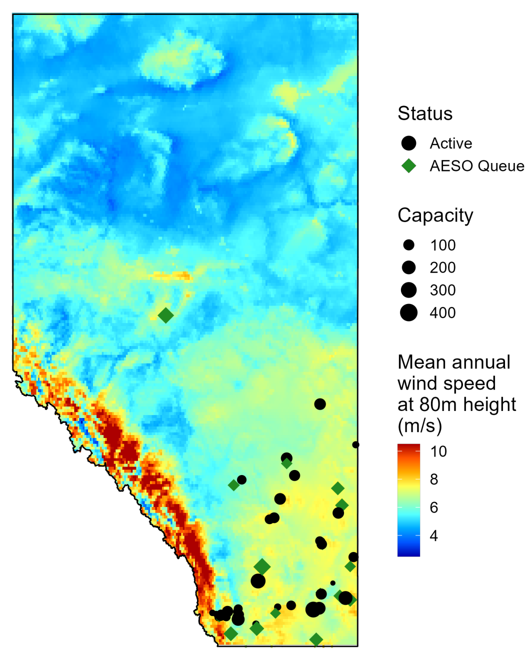
In their study, Barrington-Leigh and Ouliaris identified high-potential sites for wind development as areas being at least 5 km away from populated areas and within 75 km of a populated area and a major road network. The buffer accounts for concerns over the proximity to homes, and the range limit ensures the sites are sufficiently close to pre-existing transmission lines and to consumers. Outside of this range may result in construction/connection costs that are too prohibitive for the project to proceed [6].

2.3.3 Current geographic distribution

As shown in Figure 2.4a, most of Alberta's wind farms have historically been concentrated in the southwestern portion of the province to maximize wind energy output as the wind resource in the area is exceptionally strong. Due to this concentration of wind farms, the aggregate wind output jumps and drops dramatically as the wind speeds in the area increase or decrease [7].



(a)



(b)

Figure 2.4: a) Active wind farms in Alberta with wind energy potential map and b) active wind farms with wind farms in the AESO queue with wind energy potential map

Research conducted by Mills and Wiser found in their work that the best ways to mitigate the cannibalization effects are through increased geographic diversity of wind sites and adding low-cost energy storage to the market [42]. Recent wind energy projects within the province, both completed and proposed, are better geographically diversified, striving to achieve higher prices for the energy generated. This is evident when considering the wind farms in the AESO's project queue, as shown in Figure 2.4b, with most of the proposed wind farms being spread out away from the historical cluster.

Another benefit to building wind farms at locations with wind speeds that poorly correlate to other wind farm sites is that the variability of the aggregate wind energy decreases. This increases the overall system reliability and decreases the need for on-demand energy sources such as fossil fuels or energy storage [42]. A study conducted by Drake and Hubacek found that wind farms with weak correlation coefficients were able to reduce variation in wind fleet power output by 36% compared to the same capacity built at strongly correlated coefficients. The increase in transmission losses was minimal in comparison to the reduced variability. The results of their study proved more prominent as wind energy saturation into the market increased [43].

2.3.4 Wind energy similarities to ERCOT

The Electric Reliability Council of Texas (ERCOT) is an excellent example of the effects of wind energy on the market as this jurisdiction has the highest penetration of wind energy in the United States [44, 45]. ERCOT also has a wholesale market similar to Alberta's market that values energy based on marginal offers and has relatively little hydroelectric capacity to buffer wind intermittency, again similar to Alberta. New wind energy development in ERCOT is eligible to receive renewable energy credits [45], which are an external source of revenue available to wind energy similar to Alberta's renewable energy emissions credits [5].

Wind energy in ERCOT is able to submit offers at negative prices, which allows competition between wind farms offering energy to the market. These negative prices are possible through the external revenues available to wind energy, such as the renewable energy credits [45]. AESO limits the offers into the market at a minimum of $0/MWh [10, 11], which eliminates the competition between variable renewable energy resources.

Similar to Alberta, wind energy in ERCOT is typically anti-correlated with demand, with the highest wind energy production occurring in the winter and during off-peak hours. As such, Baldick notes that additional wind capacity contributing at these times would not significantly decrease fossil fuel usage and therefore decrease emissions [45]. Wind energy in Alberta experiences lower average revenues than the market average due to similar effects, yet the saturation of renewable energy still made up only 14.3% of net-to-grid generation in 2021 [5], compared to wind energy in Texas providing 17% of power generation in 2017 [46]. Therefore increased wind energy in Alberta will still reduce emissions, but without consideration, Alberta could similarly face an over-saturation of wind energy.

In their work, Slusarewicz and Cohan identify that deploying wind capacity strategically to minimize the occurrence of wind power being unavailable would reduce the need for fossil fuel generation or energy storage. Among the suggested strategies, spreading out wind farms was shown to increase reliability. Katzenstein et al. found that the greater the distance between wind farms, the lower the correlation coefficient [47], essentially meaning that the farther apart two wind farms are, the less likely they are to generate electricity at similar times. In thier study, Katzenstein et al. conclude that greater geographic diversity in a wind fleet reduces the high-frequency variability of wind power.

2.4 Models exploring geographically diverse wind fleets

McWilliam et al. have developed a method for optimizing the locational marginal price of a wind farm in Michigan over two historical years based on initial cost, distance to transmission lines, population density, and annual wind speeds. This was demonstrated in Alberta in their work [41]. Their work did not take the market into account, and therefore the effects of wind discount were not included. The wind speed data used was wind speed data collected 10 m above the ground and extrapolated to wind speeds at 80 m above the ground. They concluded that optimally siting potential wind farms based on geography and wind resource alone are not sufficient.

A study conducted by van Kooten et al. developed a model to simulate potential wind power output available to Alberta's electricity grid with wind turbines spread across 17 locations in the province [48]. Their model enables new resource builds and resource retirements at a macro scale, with the focus being to guide policy on climate change rather than investment decisions. This model focuses on wind power as the renewable energy option and omits the possibility of solar power.

In their model, current wind fleet capacities are maintained, but with different wind power profiles of random locations across the province. The wind data used for this data was the wind speeds at 10 m above the ground. These wind speeds aren't reliable to use when predicting wind energy output as most wind turbines have a hub height of around 100 m, and wind speeds can vary greatly between 10 m and 100 m. The research done by Kooten et al. attempts to address this using calculations to estimate the wind speeds at the hub heights, but this is at best a rough calculation greatly dependent on the terrain and vegetation in the region.

The results of this study found that some locations required no incentives to be viable, whereas other locations didn't produce enough energy to be viable without incentives. The research used historic market prices for the years matching the wind profiles, without accounting for the influence the addition of new wind farms would have on the market price [48].

Drake and Hubacek simulate the spatial distribution of offshore wind farms in the UK to determine if more distribution would lead to lower overall variations in wind power output. They argue that with greater distances between wind farms, there are fewer wind speed correlations between wind farms, which would reduce the variability of aggregate wind power generation. The four sites chosen for this study were selected to maximize the distance between the locations. The simulation concluded that by dispersing the wind farms to weakly correlated wind regimes, the variance was reduced by 36%, which increases the reliability of the system more than a combined hydro-wind power system could [43].

In another model, electricity locational marginal price (LMP) is used to compare the suitability of various locations for wind farms. The results of this study showed that the electricity market should be considered when selecting a location for a wind farm [40]. This research analyzed the spatial and temporal characteristics of LMP in Michigan from 2005 to 2007.

Another study done by Mills and Wiser found that after comparing several scenarios in the Western United States, the largest increase in the marginal value of wind energy in systems with high wind energy saturation occurred when the geographic locations of the wind sites were diversified. In this work, the geographic diversity mitigation measure cited wind plants in locations that had a minimal variance in aggregate wind production. This led to larger distances between sites compared to the reference strategy tested. Three wind penetration level scenarios were tested in this work: 20%, 30%, and 40% market saturation. The results were shown as the change in value in \$/MWh, and the geographic diversity case had the largest change in value at 10.6\$/MWh at 40% wind penetration level. For the other scenarios, the geographic diversity was the second highest change in value, behind only the strategy with price-elastic demand subject to real-time pricing. This part of their research shows that choosing geographically diverse locations becomes more important with higher wind penetration levels [42].

Mills and Wiser also ran a scenario with all the wind sites concentrated in Southern California and concluded that geographically diverse sites have less correlated wind than a group of concentrated sites and that increasing the geographic diversity reduces the frequency of extremes in wind output. There are fewer low wind output hours and fewer maximum wind output hours. This leads to higher revenues for wind energy than in the case tested with the tightly clustered wind. Comparing the two cases with or without geographic diversity, this study by Mills and Wiser found a difference of \$6/MWh favouring diversity [42].

The increase in value for the diversified sites does not however account for the increased costs associated with increased diversity, such as transmission, siting, reduced overall output, etc. Further research is required to incorporate these costs in the evaluation. The thousand diversified sites available for this study were randomly selected from a list of 30,000 30-MW wind sites in the region studied. Wind generation portfolios were available through the Western Wind and Solar Integration Study (WWSIS) and were used for this study. Therefore, this study did not evaluate unique locations that have not already been studied for wind energy in the past [42].

2.5 Forecasting wind energy development

Using various predictive methods, Dehghani-Sanij et al. looked at the potential development of wind energy in Canada's provinces and territories forecast out to 2040. The objective of this forecast is to look at the change in the LCOE for wind energy. These methods include historical compound annual growth rate and linear forecasting. While various growth rates are explored based on presumed policy interjection at provincial or territorial levels, these forecasts remain rather simplistic in nature. Their model looked solely at wind energy and did not incorporate any market effects in the forecast. Their conclusion found that the reduction in LCOE strongly depended on the quantity of installed wind power capacity, and their model predicted the lowest growth rate for Alberta, Saskatchewan, Yukon, and Nunavut [32].

Forecasting the potential output of a wind farm at a location can be a complicated matter. In their work, Bonilla et al. develop a methodology to simulate the energy production of a wind farm at a given location in Alberta within 10% error based on historical data. They use hourly averaged wind speeds provided by the Canadian Wind Atlas, along with loss coefficients to model the wind farm's performance. The model developed was designed to capture both long-term patterns as well as short-term correlations of hypothetical wind farms based on the Canadian Wind Atlas [7]. Using the power-law equation, these wind speeds can be used to approximate the wind speeds at the height of the wind turbine hub. This equation is shown in Equation 3.2. In this equation, v_0 is the wind speed measured at height h_0 meters above the ground, v_1 is the calculated wind speed at the turbine hub height of h_1 meters above the ground, while α is an exponent representing the surface roughness at the location [7].

$$v_1 = v_0 \left(\frac{h_1}{h_0}\right)^{\alpha} \tag{2.5}$$

These wind speeds can be used to calculate the potential power output of a wind turbine at a specific location using the calculated gross power output adjusted for the air density at the location, shown in Equation 3.8. The gross power is determined using the turbine-specific cut-in (v_{cut-in}) and cut-out ($v_{cut-out}$) speeds and the hourly wind speed (u^*, shown in Equation 3.7. β_i is the turbine model specific coefficients and G_{rated} is the turbine specific rated power output.

$$G_{imputed} = G_{gross} \left(\frac{T_0}{T}\right) \left(\frac{P}{P_0}\right) \tag{2.6}$$

$$G_{gross} = \begin{cases} 0 & u^* < u_{cut-in} \parallel u^* \geq u_{cut-out} \\ \sum_i \beta_i (u^*)^i & u_{cut-in} \leq u^* < u_{rated} \\ G_{rated} & u_{rated} \leq u^* < u_{cut-out} \end{cases} \tag{2.7}$$

Using an iterative process, Bonilla et al. calculated loss coefficients and found the annual energy losses totalled about 12%. This analysis, however, found that the model poorly predicted wind energy output in the Pincher Creek and Fort MacLeod areas. They concluded that this was most likely due to an improperly simulated wind boundary layer in the Canadian Wind Atlas. The work done by Bonilla et al. references a study on the influence of topography for the region by Salmon et al. that concludes that the boundary layer in this region is atypical, whereas the Canadian Wind Atlas likely uses a typical boundary layer in its' calculations [49]. With this model developed, Bonilla et al. then modelled Alberta's electricity market in Aurora with seven new wind farms imposed into the market. The wind profile for these wind farms was generated using their model. However, they concluded that there was much more work required to accurately represent both the behaviour of the wind farms in the market as well as the market itself [7].

Chapter 3

Identifying potential unique locations for wind farms

3.1 Introduction

Alberta has an energy-only wholesale market, with economic factors, competition, and policies such as the carbon tax driving the growth of renewable energy within the province. Electricity generation facilities submit hourly offers or bids to the market for their electricity. These offer blocks are dispatched from lowest to highest offers, and the last offer block dispatched sets the price all generators are paid for the electricity they generate, called the pool price [5]. Typically the offer price is a combination of fuel, facility costs, and profit margin.

Variable renewable energy (VRE) is advantaged in this market, set to bid electricity into the market at $0 [10]. This ensures all available renewable energy is dispatched, with no competition between VREs to offer into the market. The challenge with this approach is that as the saturation of VRE increases for a specific hour, fewer higher offer bids are dispatched and the pool price is subsequently lower. Historically, wind energy in Alberta has experienced this effect, known as the wind discount. This is a significant concern and potential obstacle for investors interested in building wind energy in the province.

One of the more obvious ways to negate the effects of wind discount is to generate electricity when the pool price is high, which typically correlates with when there is otherwise little wind energy being generated. In their work, Mills and Wiser found that geographic diversity in wind sites in the Western United States increases the value of wind farms. They also found that as the penetration of wind energy increased, geographically diverse locations became more valuable [42]. Drake and Hubacek found that diversifying wind farms across large areas improved the reliability of aggregate wind energy and decreased the costs for the wind fleet in the UK [43].

Alberta's geography offers a unique insight into how wind farms can generate energy at different times. Alberta is bordered on the southwest by the Rocky Mountains, which follow the border northwest until the border turns straight north. The foothills border the mountainous region, and the remainder of the province is either prairie or boreal forest. The southwest region along the edge of the mountains experiences high mean annual winds that typically originate from the Pacific and are funnelled through the Crowsnest Pass/Pincher Creek region due to the shorter mountains in the area. The result is a very strong southwesterly flow [50]. These strong winds are excellent for wind energy, which has historically drawn investors to build in the region. The large capacity of wind energy installed in the region leads to an exponential growth in wind energy supply in the market when the wind blows in the area, which results in lower energy prices when the demand remains constant.

The wind patterns in the northern part of the province are not as strongly influenced by the Rocky Mountains as they are in the south. The winds in this region are influenced more by the northwesterly arctic winds [50]. With distinctly unique sources, these wind patterns are likely to have little correlation. Wind energy farms built in this region may not have as high of capacity factors nor be as productive as the wind farms in the southwest, yet they may be able to earn higher energy prices as the supply of wind energy may be lower when they generate electricity.

Most of Alberta's wind fleet has historically been concentrated in the southwestern portion of the province. This is because historically developers have sought to maximize the capacity factor for their wind farms. This concentration of wind farms in that area causes the aggregate of Alberta's wind farms to have similar output profiles, which compounds the effect of wind discount and decreases the pool price captured by these sites [7]. Future wind farms built in the northern portion of the province could take advantage of less correlated wind profiles and could potentially capture higher prices for the energy produced than the majority of Alberta's wind fleet.

3.2 Methodology

The methodologies outlined in this research are specific to Alberta's energy-only electricity market and geography, but the principles can be applied to other markets. The first section outlines how the data was collected for the study, while the second section explains how the data was analyzed to select and compare hypothetical sites for wind farms to be built.

3.2.1 Data collection

The first criterion considered is the wind profiles for the locations. The relationship between capacity factor and capture price for active wind farms is evaluated and used as a basis for identifying potential locations.

Wind height profiles

Modern wind turbines typically have hub heights around 100 meters above the ground. The wind speeds at this height can be significantly different than the wind speeds at ground level. The power-law equation, shown in Equation 3.2, can approximate the wind speed at one height using the wind speed at a different height.

$$v_1 = v_0 \left(\frac{h_1}{h_0}\right)^{\alpha} \tag{3.2}$$

Where v_0 is the wind speed measured at a height of h_0 meters above the ground, v_1 is the desired wind speed at the desired height h_1 meters above the ground, and the exponent α represents the surface roughness at the location [51]. This equation is highly sensitive to surface roughness, which is typically determined experimentally. However, Spera and Richards show that exponent α varies with the time of day, the season of the year, the nature of the terrain, wind speed, and temperature [52]. These variables are especially problematic in Alberta, where the weather changes drastically between seasons. Thus, estimating wind speeds in Alberta using the power-law equation can lead to inaccuracies.

The data used to model potential wind farm production for various locations within the province for this research is based on hourly averaged wind speeds pulled from Canadian Wind Atlas (CWA) Modeled Historical data (HMD) and from the Government of Canada Historical Data from their weather stations. Environment and Climate Change Canada used a state-of-the-art modelling strategy based on its numerical weather prediction model to generate time series of meteorological fields at multiple heights, including 100 meters above the ground. This model covers three years between 2008 and 2010 and has a granularity of 2 km horizontal grid spacing and 10-minute time resolution [27].

Using code written for this research, the mean annual wind speed in meters per second was obtained from the CWA for all locations within Alberta to a resolution of 0.05 latitude and 0.05 longitude. This data was then used to create a map of Alberta showing the variation in annual mean wind speeds, with the location of currently active wind farms super-positioned on top.

The mean wind speeds were used to give a first estimate of the wind energy potential across the province, but the mean wind speed alone does not reflect the distribution of wind speeds, which typically results in Weibull distributions of wind speeds. The wind speed frequency distributions and typical meteorological year hourly time series are available for the CWA shown in Figure 2.4a.

A visual inspection of this map in Figure 2.4a appears to have no wind farms in the regions with the highest winds along the southwest border. This region is mountainous terrain and is mostly protected from development by national and provincial parks.

The remainder of the province's regions with the highest wind speeds have wind farms in the area. Since 2015, many of the wind farms built have been venturing into other parts of the province without wind farms, likely to attempt to capture higher prices with less correlated wind regimes. However, the active wind farms are mostly concentrated in the southern portion of the province, with no current wind farms in the northern half of the province.

Much of the northern portion of the province is uninhabited and thus with little to no infrastructure to support the construction or connection of utility-scale wind farms. Despite these obstacles, this research identifies twelve potential sites based solely on the distance from current active and proposed wind farms, being within 5 kilometres of roadways, and relatively high wind resources for the region. Siting limitations such as land use, wetland restrictions, and protected regions were not considered in the site selection. These locations are not necessarily meant to be realistic sites for wind farms in the next few years, but rather to demonstrate how diversified locations may prove economical in Alberta's electricity market.

Capacity Factor and Capture Price

The annual Capacity Factor (C_F) is used to identify the wind farm's output compared to its potential output, or its efficiency. It is defined as the ratio of the actual annual output to the rated output, as shown in Equation 3.3. The capacities and hourly output for each of the wind farms were obtained through NRGStream [39].

$$C_F = \frac{\text{Annual Output}}{\text{Maximum Potential Output}}$$

$$C_F = \frac{\frac{\text{Actual Output}}{\text{year}}}{\text{Capacity} \times \frac{\text{8760hrs}}{\text{year}}}$$

$$C_F = \frac{\text{Actual Output}}{\text{Capacity} \times 8760} \tag{3.3}$$

The term Capture Price (C_P) is often used to describe the average value obtained for the generated power. It is calculated by dividing the total revenue by the total energy dispatched by the plant for each period, as shown in Equation 3.4.

$$C_P(\$/\text{MWh}) = \frac{\text{Total Revenue (\$)}}{\text{Total Dispatch (MWh)}} \tag{3.4}$$

$$\text{Revenue (\$)} = \text{Dispatch (MWh)} \times \text{Pool Price (\$/MWh)} \tag{3.5}$$

The calculation for the revenue was given in Equation 3.5. From these equations, the revenue and therefore the C_P for a particular generation unit depend on the pool price. The pool price depends on the electricity demand and the price offered by the highest dispatched bid in the merit order. As the number of low-priced bids increases, or conversely the demand decreases, the pool price decreases. The pool prices for this study were obtained through NRGStream [39].

3.2.2 Identifying potential locations for geographically diverse wind farms

Part of this study evaluates the effect on the market as well as the financial viability of adding new wind farms in Alberta at locations that may not provide a high C_F, but where the wind output can achieve higher C_P's. Successfully identifying such locations could prove to be economical as well as smooth out the overall wind fleet output. Yet overbuilding at these locations would increase the number of low-priced bids at a time and lower the C_P for those generating units. Therefore, an optimal saturation exists of wind farms at these uncorrelated locations.

Wind profile correlations

There are a few challenges that arise with this approach that will be addressed in this research. One of the first challenges is to identify locations where a potential wind farm would experience higher wind speeds at times that do not correlate with the times that the other wind farms are experiencing significant wind speeds to avoid profit cannibalism. These locations must have enough potential wind energy to make them profitable, and the more often this wind energy is not closely correlated to the rest of the wind fleet energy output, the more profitable the wind farm becomes. As such future wind farms don't necessarily need to be built in locations with the highest potential wind energy to become profitable, so long as the wind energy they generate can capture higher pool prices.

$$r = \frac{n\sum xy - (\sum x)(\sum y)}{\sqrt{[n\sum x^2 - (\sum x)^2][n\sum y^2 - (\sum y)^2]}} \tag{3.6}$$

Pearson's correlation coefficient is used to compare the linear correlation of a particular wind farm with the rest of the wind fleet. The calculation for Pearson's correlation coefficient is shown in Equation 3.6 with x being the C_F of the individual wind farm, and y being the C_F of the entire wind fleet at that time, and n being the number of hours used in the calculation.

Table 3.1: Hypothetical sites for wind farms

Hypothetical Site	Latitude	Longitude
Anzac	56.340	-111.265
Bison Lake	57.382	-115.807
Chain Lakes	50.250	-114.176
Clear Prairie	56.724	-119.496
Falher	55.730	-117.177
Fort Saskatchewan	53.677	-113.170
Grande Cache	54.443	-119.341
Hinton	53.341	-117.472
John D'Or Prairie	58.794	-114.970
Kehewin	54.066	-110.802
Lesser Slave Lake	55.435	-115.081
Pigeon Lake	53.086	-114.187

Due to the quantity of data available, and the limited computational power available for this research, twelve proposed hypothetical sites were selectively chosen for this study, with the intent of comparing and narrowing down the list through the methods presented in this research to identify the optimal locations. The selected locations are listed in Table 3.1. These sites were chosen by observing areas in Alberta that experience relatively high mean annual wind speeds and do not contain utility-scale wind farms at the time of writing. These areas were then narrowed down by selecting one location within each region that is within 5 kilometres of existing roads. This parameter was added to reduce the prohibitive cost of adding transmission lines to the location. The most notable region that was excluded due to this parameter is the northeastern corner of the province, which has no current transmission connections to the rest of the province.

Some of the sites, such as the site at John D'Or Prairie, are in regions that are not viable for wind farms due to other restrictions, such as the availability of private land. The area around the site at John D'Or Prairie is primarily crown land which is not currently available for wind energy development at the time this research is conducted. The inclusion of these sites is to provide extreme examples of geographically diverse sites.

The selection of these hypothetical sites did not include zoning requirements, environmental restrictions, etc. Further research would be required to verify the candidacy of each of these locations prior to serious consideration for their suitability.

Using the methodology developed by Natalia Bonilla, wind profiles for each of the existing wind farms, along with the twelve proposed hypothetical sites for this study, were generated based on the hourly averaged wind speed data for each location over the course of a year [7]. While there is sub-hourly variation in wind speeds, energy generators are paid for their electricity contributions on an hourly basis. Thus averaging out the wind speeds hourly results in similar revenues compared to sub-hourly averaged wind speeds. This was done by calculating the turbine gross power generated (G_{gross}) using the following piece-wise equation:

$$G_{gross} = \begin{cases} 0 & u^* < u_{cut-in} \parallel u^* \geq u_{cut-out} \\ \sum_i \beta_i (u^*)^i & u_{cut-in} \leq u^* < u_{rated} \\ G_{rated} & u_{rated} \leq u^* < u_{cut-out} \end{cases} \tag{3.7}$$

where u^* is the hourly wind speed, u_{cut-in} and u_{cut_out} are the turbine cut-in and cut-out speeds respectively, G_{rated} is the rated output power of the turbine, u_{rated} is the rated wind speed that G_{rated} is achieved at, and β_i are the turbine model specific coefficients.

The imputed power generated ($G_{imputed}$) was calculated by adjusting for the air density using Equation 3.8

$$G_{imputed} = G_{gross}\left(\frac{T_0}{T}\right)\left(\frac{P}{P_0}\right) \tag{3.8}$$

where T and P are the temperature and pressure the turbine is operating in at the hub height and T_0 and P_0 are the standard atmospheric conditions often given for the turbine power curves.

A generic loss coefficient (L) is calculated using another piece-wise function shown in Equation 3.9:

$$L = \begin{cases} 0 & u^* < u_{cut-in} \parallel u^* \geq 1.4 \times u_{rated} \\ u_{rated}^{-1} \sum_i \alpha_i (u^*)^i & u_{cut-in} \leq u^* < 1.4 \times u_{rated} \end{cases} \tag{3.9}$$

where the coefficients (α_i) and the 'loss cut-off' factor of 1.4 are empirically derived. While this methodology is not perfectly accurate for predicting wind farm output in the southwestern portion of the province, the remainder of the province was shown to be suitable for using this methodology [7, 11]. These proposed hypothetical sites are in the northern portion of the province, therefore well away from the problematic area.

Wind farm generation index of deviation and plant average revenue

This study identified an index of deviation of each wind farm's energy generation per installed megawatt from the energy generation per megawatt of the entire wind fleet without the wind farm, as shown in Equation 3.10. This distinction of comparing the wind farm's generation per installed megawatt hour against the generation per installed megawatt hour of the wind fleet with that wind farm excluded is important, rather than compared to the entire wind fleet. By so doing, the calculated index of deviation should be independent of the capacity of the wind farm. This is especially important for larger wind farms, which would otherwise have a greater influence on the wind fleet generation than a smaller wind farm.

In Equation 3.10, x_i is the generation per installed megawatt of the wind farm at a specific hour, μ_i is the wind fleet generation per installed megawatt of all of the wind farms without the specific wind farm at that hour, and N is the number of hours used for the calculation. The generation per installed megawatt is used to identify if the wind farm and wind fleet are operating at similar capacity factors, and therefore to what extent they are correlated. For example, if the wind fleet is generating electricity equal to 50% of the installed capacity, a 100 MW wind farm generating 45 MW of energy has a lower index of deviation than an identical wind farm generating 70 MW of wind energy.

For the purposes of this study, only data from the year 2021 was used, as this is the most recent year at the time of this writing, and therefore contains the most up-to-date wind fleet. Rattlesnake Ridge Wind farm was excluded from this calculation as there are less than three months of data during 2021.

$$\sigma = \frac{\Sigma|x_i - \mu_i|}{N} \tag{3.10}$$

The plant average revenue can be used to identify energy production plants with traits that can be used in planning future energy production plants that will obtain similarly high capture prices. The plant average revenue of a wind farm built at a location can be approximated based on the IoD of the predicted C_F compared to the wind fleet C_F using the linear regression obtained from the correlation. Using this predicted average annual revenue, the payback period equation shown in Equation 3.11 is rearranged to allow the predicted capacity factor to be used to calculate the estimated payback period for wind farms built at these sites [44]. The profitability of these sites is correlated to being able to capture higher prices when there is little wind energy in the market, and therefore a potential investor would be interested in covering the costs of the investment quickly as future wind farm installations could saturate the market at similar times and thus remove the competitive advantage of this site.

Alberta's carbon pricing legislation allows wind projects to generate emissions offsets at a rate of 0.52t/MWh, and these offsets can typically be sold to other projects for less than the annual carbon price (CA$50/tonne in 2022) [5]. As the value of offsets varies according to market demand, this study simplifies the calculation by assuming the offsets can be sold for the full CA$50/tonne, which results in offset revenue of $26/MWh. The initial cost used in the calculation was CA$1.7M/MW [5], and the annual operation and maintenance cost (AOM) was estimated as 1.75% of the initial cost [44]. This equates to an estimate of $29,750/MW in annual operation and maintenance costs. Using the predicted average annual revenue, Equation 3.11 can be used to calculate the estimated payback period for wind farms built at these sites [44].

$$
\begin{aligned}
AE &= 8760\frac{\text{hrs}}{\times}C_F \\
IN &= 26\frac{\$}{\text{MWh}} \times (8760C_F) \\
&= 227,760C_F \\
P(yrs) &= \frac{IC - IN}{AE \times AR - AOM} \\
&= \frac{1,700,000 - (227,760C_F)}{(8760C_F) \times AR - 29,750} \\
&= 8 \times \frac{21,250 - 2,847C_F}{876C_F AR - 2975}
\end{aligned}
\tag{3.11}
$$

With these assumptions, the payback period for these hypothetical sites can be simplified into Equation 3.11. The resulting payback periods can be used to compare the economic viability of the various hypothetical wind farm sites.

The internal rate of return (IRR) can also be a useful metric to compare the profitability of the various sites against each other. The formula for IRR is shown in

Where,

IC is the initial cost of installation

IN is the value of the offsets or incentives

AE is the annual energy production

AOM is the annual operation and maintenance cost

AR is the average annual unit revenue

Equation 3.12, with t being the number of time periods or years for this study, and NPV is the net present value, which is set to 0 to calculate the IRR [44].

$$0 = \text{NPV} = \sum_{t=1}^{T} \frac{IN + AR \times AE - AOM}{(1 + \text{IRR})^t} - IC \tag{3.12}$$

This calculation will assume the same initial cost of installation, and assumes that the annual cash flows are a combination of the incentives, energy revenue, and the annual operation and maintenance cost. The calculation will assume an IRR with the time series starting in the year 2020, and concluding in the year 2035, or a period of 15 years. This is well below the expected lifetime of a wind farm but demonstrates the expected IRR for a wind farm at these locations by the year 2035, which is the target year for many of the government policies [2].

3.3 Results & Discussion

The results of this research are broken up into two areas. The results of the analysis using capacity factors, capture price, output correlations, and payback periods, and the results from the simulation using these hypothetical wind farm sites.

3.3.1 Results of the location analysis

Capacity Factors

From 2005 to 2021, Alberta had the highest C_F of the three provinces with the most installed wind capacity, as shown in Figure 3.1 [**noauthor˙by˙2020**, 23, 32].

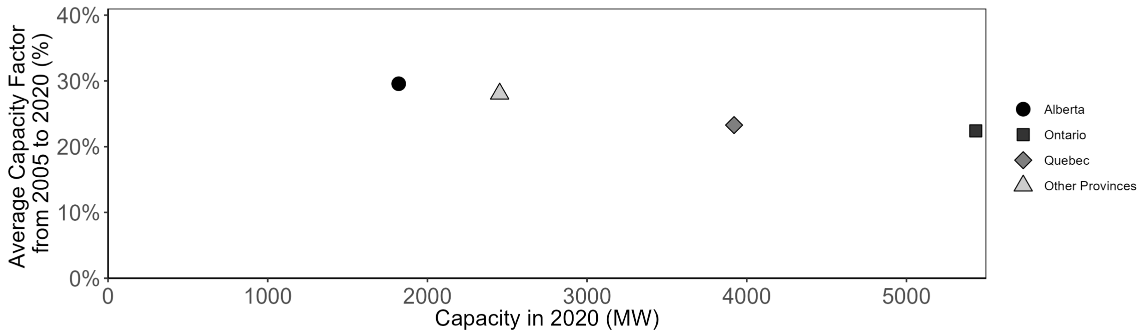


Figure 3.1: Average capacity factors by province with the installed wind capacity in 2020.

Figure 3.1 shows that higher installed provincial capacities typically lead to lower capacity factors. Newer wind turbines are able to operate at higher C_F, but the principle remains the same. In 2020, the aggregate of wind farms in Alberta had a C_F of 37% [22, 23]. While this is typically an indicator of better winds or better use of wind power [32], in Alberta the wind farms with the highest C_F tend to capture lower prices on the market, as shown in Figure 3.2.

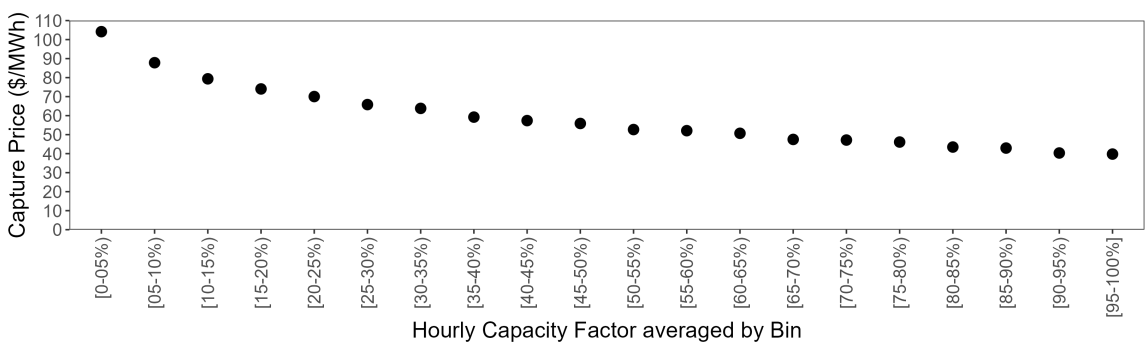


Figure 3.2: Hourly capacity factor versus capture price for wind farms in Alberta.

Pearson's correlation coefficient for wind farm sites

Pearson's correlation coefficient is calculated for each of the hypothetical wind farm sites, and plotted over a map of Alberta's mean annual wind speeds at 80 meters above the ground, as shown in Figure 3.3. This is done to show the locations of the proposed hypothetical sites compared to the active wind farms, as well as the difference in Pearson's correlation coefficient for each sight.

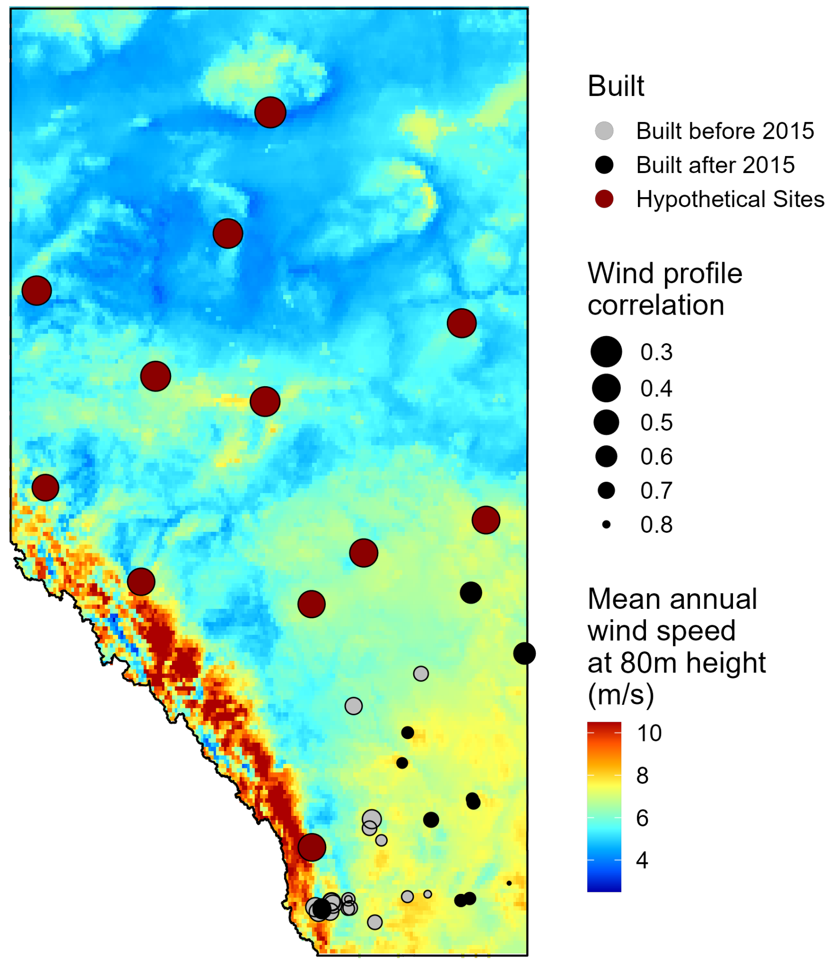


Figure 3.3: Map of Alberta showing the correlation between wind speed profiles at existing wind farm locations and potential locations identified for this research.

This preliminary test verifies that the proposed hypothetical sites are geographically diverse from the active wind farms in Alberta, and have capacity factors that in theory should not correlate strongly with the capacity factors of the rest of the wind fleet. It also shows that most wind farms built since 2015 have been built further east. This demonstrates that the industry is aware of the benefits of a geographically diverse wind fleet.

Index of deviation and the average annual revenue

The average annual revenue (AR) for each wind farm is shown in Figure 3.4 as a function of the index of deviation (IoD), and the linear regression is shown in 3.13

with an R^2 value of 0.89. This linear regression can prove useful in predicting an economic relationship which can be used to identify potential locations for new wind farms. Figure 3.4 shows this linear regression, with the 95% confidence interval to the linear regression shown in the gray band.

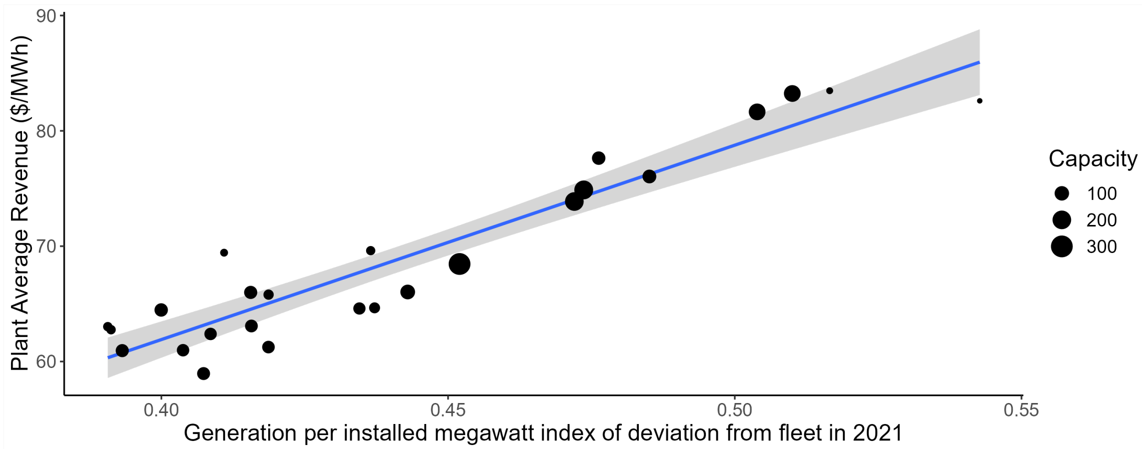


Figure 3.4: Plant average revenue and index of deviation from the rest of the wind fleet, with a 95% confidence interval shown in gray shading.

$$\begin{aligned} AR = 168.535(\$/\mathrm{MWh}) \times IoD - 5.512(\$/\mathrm{MWh}) \\ \mathrm{R}^2 = 0.886 \end{aligned} \tag{3.13}$$

The correlation between the annual average revenue and the capacity factor IoD is apparent in Figure 3.4. As the IoD increases, the expected annual average revenue also increases. The twelve selected hypothetical sites are shown with their predicted annual average revenue based on this relationship in Figure 3.5. Figure 3.6 shows the location of the various sites with their IoD. This figure confirms that the northern portion of the province has wind profiles that are not closely correlated with the southwestern portion of the province.

Estimated payback periods and IRR

Figure 3.5 shows that each of the hypothetical wind farm sites has a predicted average annual revenue of at least \$80/MWh. The resulting payback periods for the hypothetical sites were calculated and are shown in Table 3.2, with the shortest payback

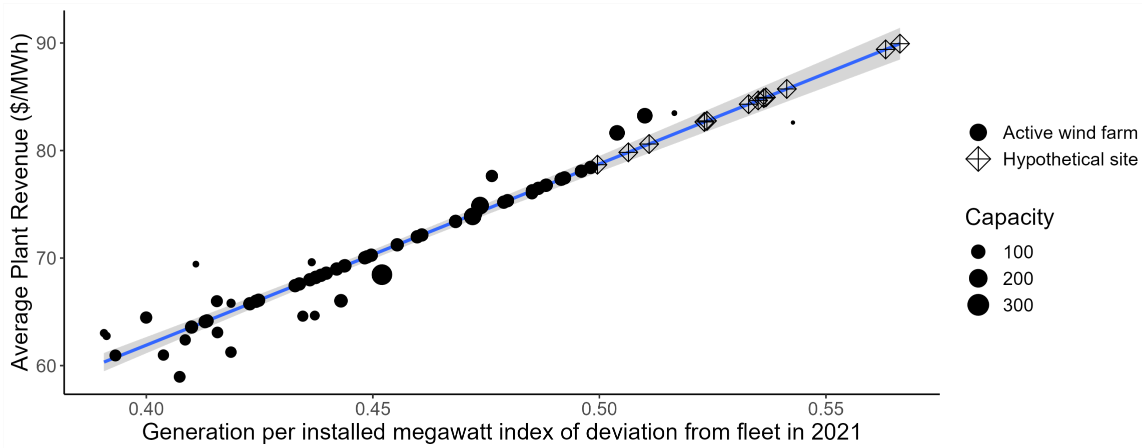


Figure 3.5: Plant average revenue and index of deviation from the rest of the wind fleet, with a 95% confidence interval shown in gray shading, with hypothetical wind farm sites shown with the predicted C_P.

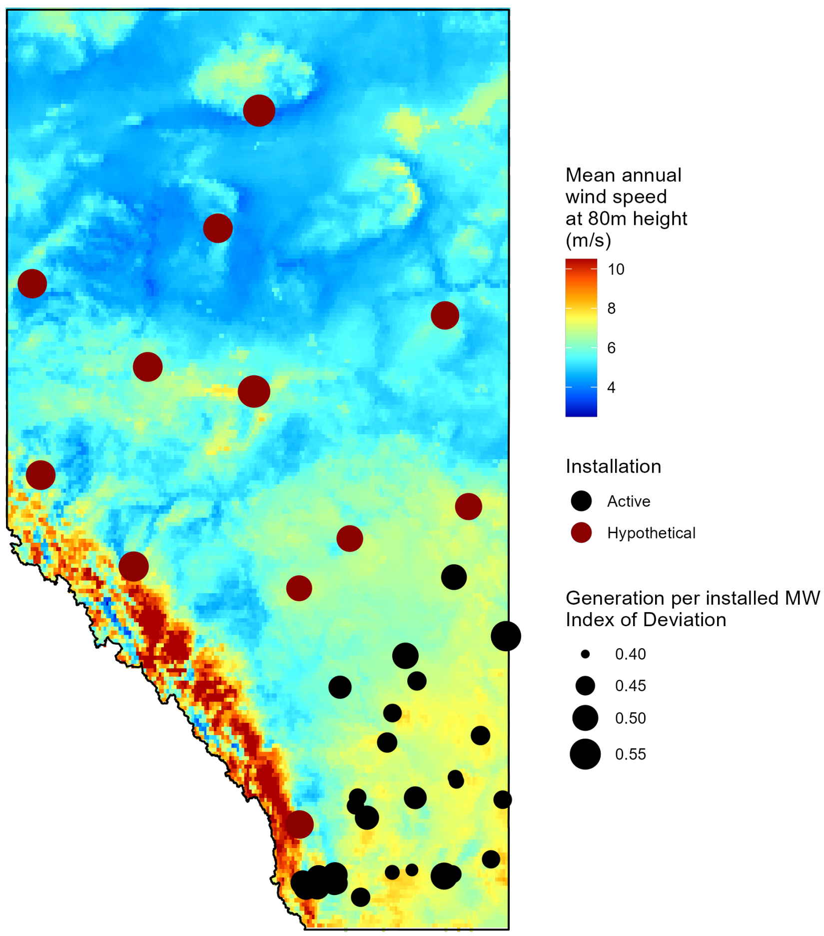


Figure 3.6: Map showing wind farm index of deviation from the rest of the wind fleet, with hypothetical wind farm sites shown in red.

period being 4.96 years, and the longest being 8.66 years. The estimated payback periods for these hypothetical sites are competitive. In their study of ten potential wind sites in Texas, an independent electricity district like Alberta, Chang and Starcher found that the shortest expected economic payback period was about 13 years. They concluded that this payback period demonstrated feasibility at these sites [44].

Table 3.2: Financial analysis for hypothetical sites

Hypothetical Site	Average Annual Revenue ($/MWh)	Payback Period (years)	IRR (%)
John D'Or	89.40	4.96	32.8
Lesser Slave Lake	89.94	4.98	32.6
Hinton	85.73	5.34	30.1
Kehewin	80.61	5.38	30.4
Pigeon Lake	78.68	5.53	29.5
Clear Prairie	84.31	5.67	28.0
Grande Cache	84.87	5.89	26.6
Bison Lake	84.66	5.91	26.5
Falher	84.95	5.99	26.0
Anzac	82.66	6.03	26.0
Fort Saskatchewan	79.83	7.30	20.4
Chain Lakes	82.76	8.66	15.8

The IRRs shown in Table 3.2 show similar results to the payback periods, with slight variation. All of the IRRs are above 15%, but the top projects have IRRs more than double those with the lowest IRRs. This indicates that there is a large discrepancy in expected returns between the projects. The only projects that have payback periods that suggest a different order of value than the IRRs are the Hinton and Kehewin sites. Both have similar metrics, but Kehewin has a slightly higher IRR than Hinton despite having a lower payback period. This indicates that while Hinton would generate the revenue to equal the initial cost sooner, by the 15-year mark, Kehewin would return higher profits overall.

These results show that although the annual average plant revenue per megawatt is high for some of these hypothetical sites, the C_F greatly affects the profitability of that site. John D'Or and Lesser Slave Lake have near identical payback periods of just under five years and IRRs of over 32% and are the most economical sites from this list according to this analysis. While still economical, Fort Saskatchewan and Chain Lakes are the least economical sites from this list, with payback periods over seven years and IRRs of under 21%.

Although all of these sites have competitive payback periods and IRRs, there were many assumptions and estimates made in these calculations. Further research would be required to accurately estimate the suitability of these sites. These financial metrics are useful however to compare the hypothetical sites against each other.

3.4 Conclusions

While the majority of Alberta's wind farms are concentrated in the southwestern portion of the province, this research suggests that there are locations in the northern portion of the province that could also prove economical. These areas can potentially capture higher prices for the electricity that they produce as the wind profiles are not correlated with the wind profiles of the majority of the wind fleet. This research estimates that the regions of John D'Or and Lesser Slave Lake have the highest potential to be economical, with payback periods of just under five years.

Chapter 4

Modelling and forecasting Alberta's electricity market with potential unique locations for wind farms

This chapter builds on the results of the previous chapter by modelling Alberta's electricity market in Energy Exemplar's Aurora software and allowing the software to forecast the development of Alberta's electricity fleet both with and without the selected hypothetical wind farm sites included. This is done to account for the influence each addition or retirement from the market exerts on the pool price profile, and how that may affect the suitability of potential sites. A simulation was also run to determine how the renewable energy emissions credits affect the outcome, and if the conclusions drawn from the other two simulations remain accurate without these credits.

4.1 Introduction

Wind energy is growing rapidly in Alberta, and much more wind energy will have to be developed if Alberta is to meet its climate targets [14]. Many conditions will have to be met for Alberta to meet these targets, with some of the most vital being economic investments in the industry. Being an energy-only market, an electricity-generating resource primarily generates revenue through the production and sale of electricity or the sale of emissions-related credits based on the electricity generated. Historically, wind energy in the province has captured lower average energy revenues relative to the market than other resources due to the geographic concentration of wind farms. This has caused the quantity of electricity generation that a wind farm is capable of producing to be less important than the value of the generation that is produced when planning future wind farms. The previous chapter explored this hypothesis and was able to show that geographically diverse locations can be potentially more economically feasible than locations in the province with the highest average annual wind speeds.

The challenge with estimating the economic feasibility of potential wind farm sites in Alberta is that Alberta's electricity market is dynamic. With each additional megawatt of electricity added to the market, the pool price potentially shifts and can drastically change the predicted capture prices. Every additional generating resource shapes the market, with larger capacity additions having a greater impact than smaller additions. Each addition could potentially shift the merit order, and therefore the capture price for that period. A hypothetical wind farm site could appear to be profitable based on historic pool prices, but when added into the system it could shift the merit order and therefore the pool price to render it unprofitable. Conversely, a small wind farm built at that site may be profitable, but as the capacity is increased, the profitability decreases until it is no longer profitable. Using a simulation the optimal size of wind farms at each location can be determined.

The first section of this chapter explains how a model of Alberta's electricity market was developed using Energy Exemplar's Aurora software package. Aurora is a software that models electricity markets on a sub-hourly or hourly basis to forecast resource allocation based on economic suitability [53]. The software requires extensive inputs such as inputs for demand, growth, current resources, potential resources, resource operating and output behaviour, fuel and maintenance costs, and bidding behaviour to name a few. The scope of the study is limited to the provincial borders of Alberta, with simplified import and export behaviour.

The second section analyzes the results of the simulation and identifies the most profitable hypothetical sites. This section compares the results to the expected results in the previous chapter.

The last section explores how geographically diverse potential sites are influenced by the carbon tax and the potential offset revenue renewable energy can generate from this. The simulation is run with the potential to build wind farms at the hypothetical sites, with one scenario without the carbon tax, and another with the carbon tax.

4.2 Model Alberta's electricity market

This research was done in collaboration with the University of Alberta's Center for Applied Business Research in Energy and the Environment (CABREE) to build a model of Alberta's electricity market by significantly updating and expanding the base case previously developed by this group. Aurora's Long Term Capacity Expansion (LTCE) functionality was used to forecast resource expansion and retirement in Alberta to determine which resources were most economical. The model built for this research was prepared to operate with a merit order dictating economic dispatch similar to Alberta's electricity market.

While this research was built upon an existing model, virtually every input was updated or altered in some way to improve the accuracy of the forecast since the last published results. The changes made to the existing model were done to better represent Alberta's electricity market. Input tables related to electricity demand, trade with other electricity markets, and electricity generating resources, both current and potential. This section outlines the parameters of this model that are pertinent to this study.

4.2.1 Energy Exemplar's Aurora software

Energy Exemplar's Aurora software package is commercially available software that is widely used to research four main areas of electricity markets: power market price forecasting, energy portfolio analysis, optimized resource expansion, and power market risk analysis. The Aurora software uses mixed integer programming (MIP) to model sub-hourly and hourly dispatch of resources to forecast future electricity prices, which resources are economic to build, which resources are economic to retire, and economic resource allocation to meet the electricity demand. Unless constrained, Aurora bases decisions on minimizing the cost of electricity generation. This software also allows for case studies with specified variations from the base case [53].

Simulation methodology

Aurora uses the inputs to create a merit order organized by offered price for electricity for each hour that is simulated. Aurora then 'dispatches' the resources from the least to the most expensive, until the demand is met. The most expensive dispatchable resource is identified as the marginal plant and its offer is set as the pool price for that hour. This approach mirrors Alberta's electricity market to provide an accurate model of this market.

The offer prices in Aurora are influenced by a number of user-inputted factors, including fuel prices, fixed and variable operating costs, start-up costs, emission prices (carbon taxes), and bidding behaviour. Each of these inputs has been adjusted to accurately portray current and forecast conditions for the resources. If the resource is set as a 'must run' resource, then the minimum capacity set for that resource is set to offer into the market at no dispatch cost, while the remainder of the capacity bids into the market as normal.

The amount of electricity being offered into the market at any given hour in Aurora is determined by the set capacity of the resource, minus the maintenance rate and forced outages. For most resources, the forced outage is a set number representing the percentage of time that the resource is unavailable to contribute to the market. Aurora offers both 'standard zonal' logic and 'long term capacity expansion' logic. For standard zonal, the model is run with the resources provided and does not make decisions about retiring or building resources. Long term capacity expansion runs an iterative version of the standard zonal to determine the optimal economic retirements and resource additions to meet the demand.

For the first iteration of the simulation, the purpose is to assess the accuracy of the model compared to Alberta's electricity market. To do this, a two-year span from 2020 to 2021 was run using the 'standard zonal' logic as it is less computationally intensive, and economic building and retiring resources are not considered. This allowed the model to run with only the inputs given, which ensures additional resources are not considered. These years were used as there have been significant changes to Alberta's electricity market in the last few years, and the accuracy of the model can easily be verified by comparing the outcomes to the historic data.

Model inputs

Aurora's simulation logic applies user-defined input tables and user-defined constraints to simulate resource dispatch and capacity expansion in the market. The user input required for this program is extensive, which allows the user to fine-tune the model to match the desired market conditions. while this research builds on an existing model that was previously developed by CABREE, many of the inputs were adjusted or replaced to improve the accuracy of the model. The changes made to the model are described in the rest of this section.

Alberta's electricity demand

Historic hourly demand was input into Aurora to provide a shaping profile for demand in future years. The historic demand used for this study was obtained directly from AESO [54]. Electricity demand from the year 2021 was chosen, as the global pandemic has changed the timing and quantity of electricity many consumers use due to the growth of remote work technology. The year 2021 also represents an ideal year, as the short-lasting effects of the pandemic had mostly worn off. As shown in Figure 4.1, 2021 had similar load levels as pre-COVID years, with a slightly different shape most noticeable in the on-peak hours [39].

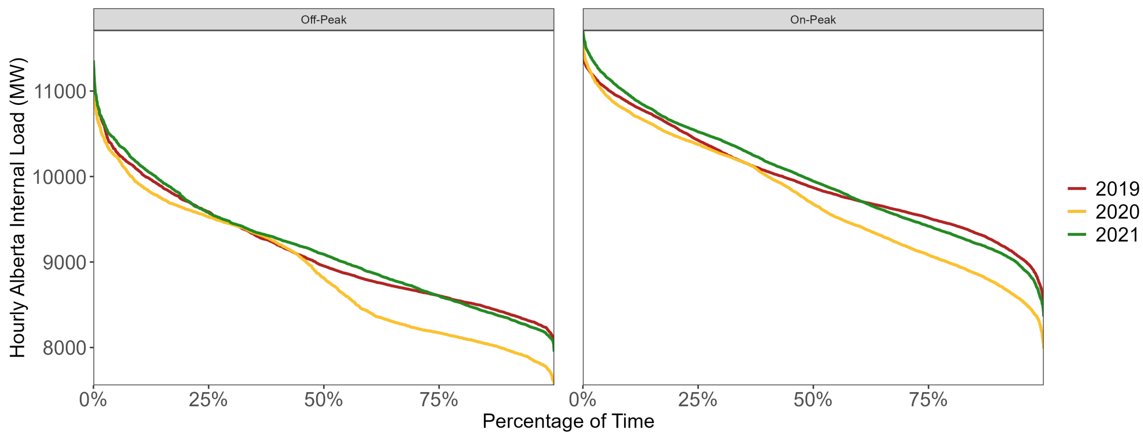


Figure 4.1: Historic Alberta load duration curve [54]

Aurora uses the hourly shaping profile that is input into the system to forecast future years. That shape was adjusted using AESO's Net-Zero Emissions Pathways Report's Alberta Internal Load (AIL) forecast [17]. The peak AIL is used to set the peak AIL for each year, and the average AIL sets the average AIL for each year. This way, the demand follows AESO's forecast with the shape set by historical demand. In this forecast, AESO is projecting an average annual growth in AIL of 1.1% from 2022 to 2040. This growth in demand accounts for the infiltration of electric vehicles into Alberta's market, as well as the decarbonization of buildings through the electrification of heating systems, improved energy efficiency in buildings, and reduced embodied carbon in construction [17].

Trade with outside electricity markets

Due to limited computational power and the complexity of modelling exterior electricity markets, for this research, the import and export of electricity into Alberta were simplified by creating two natural gas electric generators to represent each of Alberta's electricity inter-ties with other provinces. The heat rate for these resources was set to vary depending on the month to simulate a historically similar import shape profile. The exports were limited using a historical export hourly shape. The resulting trade in the simulation, though simplistic was quantitatively similar to historical levels.

Carbon tax and credits

The carbon tax is modelled to simulate the Government of Alberta's Technology Innovation and Emissions Reduction Regulation. It is set up as an annual time series starting at the equivalent of \$30 per tonne of CO_{2e}, and increasing incrementally until it reaches \$170 per tonne of CO_{2e} in 2030. From 2030 onward the carbon tax remains constant.

The carbon tax charged to an individual plant depends on the rate of emitted CO_2 and the set limit of allowable CO_2 emissions for that year, which is set as an annual time series in Aurora. These emission allocations are subject to change with new and adapting policies. This model however assumes the emission allocations remain constant for the duration of the study.

The Aurora software does not have built-in capabilities to handle carbon emissions tax credits/offsets for renewable energy, so for this study, renewable energy units that are eligible to generate credits are given negative CO_2 generating rates, which provides additional income through the carbon tax. The result is that there is a potential that resources that are eligible for these credits/offsets could bid into the market at below \$/MWh, as this additional revenue would allow these units to still break even.

While negative bids are not permitted in Alberta's current electricity market, for this study it is permitted in the model. Negative prices are permitted by the Electric Reliability Council of Texas (ERCOT), which incentives competition between wind energy sites [45]. The purpose of this research is to compare new wind farm sites to assess the viability of the selected sites in northern Alberta. Therefore, the competition between wind farm sites that negative bids allow was deemed a useful tool in this analysis.

For simplicity, this model also does not account for the decrease in emissions credit value as the saturation of renewable energy increases, nor other factors that would influence a generator to produce fewer emissions such as reputation or corporate agreements.

Electricity generating resources

Alberta's electricity market is changing rapidly. Electricity generated by coal has declined from 79% in 2002 to only 31% of generation in 2021, with plans to completely retire coal-fired electricity generation from the market within the next few years [5, 11]. The implications for this model are that the generation units available require constant updating, along with their capacities and in-service dates.

Many of Alberta's coal-fired power plants are being retrofitted to become single-cycle natural gas power plants. These have varying retrofitting schedules, emissions, and capacities that have been updated in the Aurora model. Most of these retrofitted power plants have a short life expectancy, with early retirement dates [13].

Wind and solar energy resources have been growing the most in Alberta over the last few years, with current capacities of about 2400 MW and under 1000 MW of each, respectively. There are over 6600 MW worth of wind projects projected to connect to Alberta's electricity grid, with another 11,000 MW of solar projects as well [5]. The projects with known in-service dates were added to the model as built resources that start on their appropriate day.

One of the assumptions that were made for this model is that the construction, operation, and maintenance costs are consistent for all of the new resources for each resource type. This means that a wind farm in the middle of nowhere would have the same costs as a wind farm neighbouring an existing site. The challenge of quantifying the difference in cost between potential sights was outside of the scope of this work. Keeping the location-specific costs consistent allows for better comparison of the energy value between wind farm sites.

The transmission and interconnection costs were not included among the costs for new resources as this is not a cost specific to the developer. The hypothetical sites that are simulated were specifically selected to be within 5 kilometres of existing roads to reduce the infeasibility of accessing the location. Further research could expand this study to include the transmission and interconnection costs.

The forced outage for both wind and solar energy is an hourly shape vector set to simulate the output of those resources. Solar energy follows a consistent shape that follows daylight patterns, with the only differences being in technology, such as mono-facial or bifacial, or with fixed structures or tracking systems. The forced outage for wind resources is calculated using an adapted version of the methodology developed by Natalia Bonilla [7]. Each location has a unique forced outage profile to best simulate how wind energy plays into Alberta's electricity market.

Some of the new generation units are slowly implemented into the market, with only partial capacities available until a certain date. In the model, only the resources with known implementation schedules were adjusted accordingly. Other resources have implementation schedules that were unknown when the model was created, so the model assumes an implementation schedule for these resources. One example of this is the Greengate Power Corporation's Travers Solar Project. When it first came online in March, only a small portion of the site was operational, with the remainder of the site coming online later in the year, after the simulations were being run [55]. With so many potential projects queued in Alberta, projects with uncertain in-service dates were assessed for the certainty of completion and uniqueness to decide if they should be included in the model. If a potential resource had a similar output to an existing resource, then it was not included in this model to reduce computation time.

Alberta's electricity fleet consists of 39 co-generation plants that operate in the oil and gas industry, and often produce excess electricity that is sold to Alberta's electricity market. As the main source of income for these resources is not dependent on the pool price, operating, bidding, and retirement decisions for these resources are not economically based. Due to the proprietary nature of the oil and gas production levels for these plants, only the generation contributing to the electricity market is known. Therefore, these resources were modelled differently than other resources, with the bidding behaviour set to ensure these resources generate at a minimum capacity at all times that bids into the market at \$0/MWh, and the remaining capacity bidding more aggressively. These resources were also set so that the simulation would not retire them.

$$\text{Dispatch Cost} = \text{Incremental Cost} \times (1 + \text{Bidding Factor}) \tag{4.1a}$$

The bidding behaviour for the fossil fuel-generating units was adjusted to match the bidding behaviour observed historically using a bid factor. The bid factor is a multiplication factor to the incremental cost, as shown in Equation 4.1. This bid factor is assigned to a 5% segment of the capacity for each resource type. The minimum capacity is set to -1, which effectively allows the minimum capacity to bid into the market at \$0/MWh. The bid factor increases exponentially until full capacity, with the shape of the curve set to mimic historic averages for each segment.

The bid factor was set to be constant throughout the year, with all resources within the resource type having the same bid factors. This was done as increasing complexity in the bidding behaviour exponentially increased the computational time required.

Additional assumptions made in the model

The remainder of the assumptions made for this model are

4.2.2 Assess the accuracy of the model by comparing it with historic data

The accuracy of the model was verified by comparing the simulation results using 'standard zonal' logic as it is less computationally intensive, and economic building and retiring are not considered. Only the years 2020 and 2021 were simulated so that the results could be compared against historical data for the same years. These years were used as there have been significant changes to Alberta's electricity market in the last few years, both in terms of capacity and market share.

Due to the complexity of Alberta's electricity market, limited computational resources, and external factors impossible to account for in the simulation, the expected simulation results will differ within reason of the historical data. The comparison is to verify behaviours and trends in the simulation as historically accurate, not for an exact replication of the historical data.

Three main aspects will be used to assess the accuracy of the model: the market electricity demand, resource electricity generation behaviour, and pool price behaviour. All of the historic data was obtained either through NRGStream or through Alberta Electric System Operator [39, 54].

Comparing market electricity demand

The market electricity demand is an important metric to compare the model against. The demand determines the capacity of electricity required, which affects the pool price. An inaccurate demand will require too little or too much electricity generation, and therefore set the pool price too low or too high respectively.

The simulated load duration curve is shown in Figure 4.2, with the historic load duration curves shown as dotted lines. The load duration curves were shown dating back to 2017, as the demand curve for 2020 is unique, likely due to the global pandemic.

Figure 4.2 shows that the shape of the simulated demand duration curves are similar to the historic demand duration curves, especially for 2021. This is to be expected, as

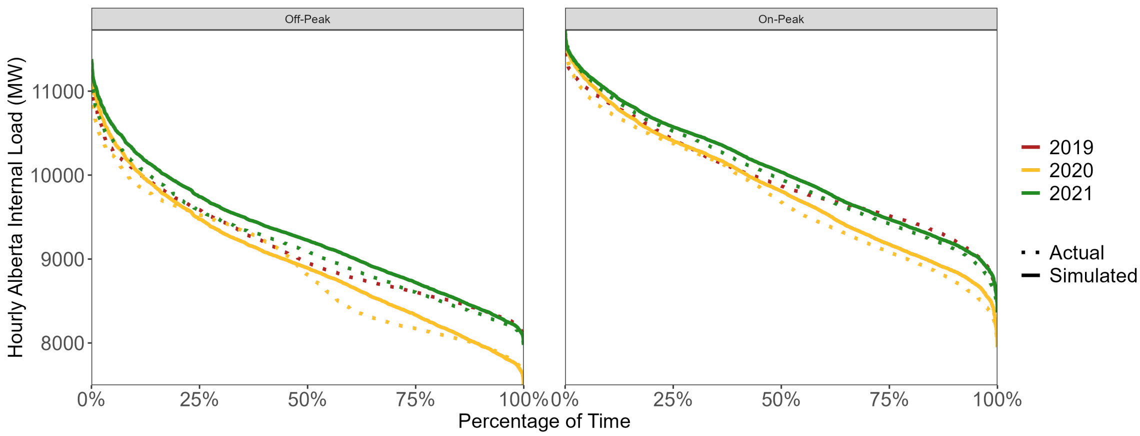


Figure 4.2: Simulated versus historic load duration curve [54]

the shape of 2021 was used as an input in the simulation, and the averages, minimums, and maximums were adjusted according to historic and forecast values [54]. Even the pandemic year demand duration curve is similar, as the peak monthly demand and average monthly demand were set according to historic data. The variation is mostly in the mid-range of the curve, which is still within acceptable limits.

Comparing resource generation

There are several metrics available to compare the resource generation between the simulation and historic values. This comparison is evaluating the accuracy by resource type rather than by individual resource. This is done to simplify the comparison, as most generating resources within the resource type bid into the market in a similar manner.

The first metric to address is to assure that the installed generation for each year in the simulation is historically accurate. This metric, shown in Figure 4.3, has little discrepancy, with the only errors being attributed to gradual changes in capacity for specific resources that were not published.

The capacity factors indicate different behaviours depending on the resource type. As renewable energy bids into the market at $0/MWh, the capacity factors for these resources indicate the accuracy of the generation output profile. In Figure 4.4, the

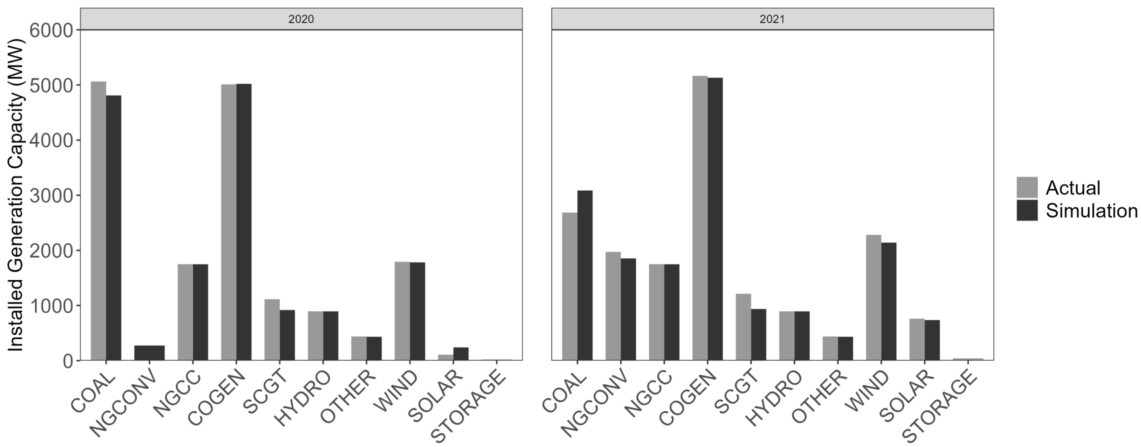


Figure 4.3: Simulated versus historic installed generation capacity by resource type [54]

renewable resources (hydroelectric, wind, and solar) have similar capacity factors as their historic counterparts.

The biggest discrepancy in Figure 4.4 is for 'other', which are mostly generating units using biomass. As shown in Figure 4.3, this type of resource makes up a relatively small portion of the market, and should therefore not affect the outcome of the simulation too drastically.

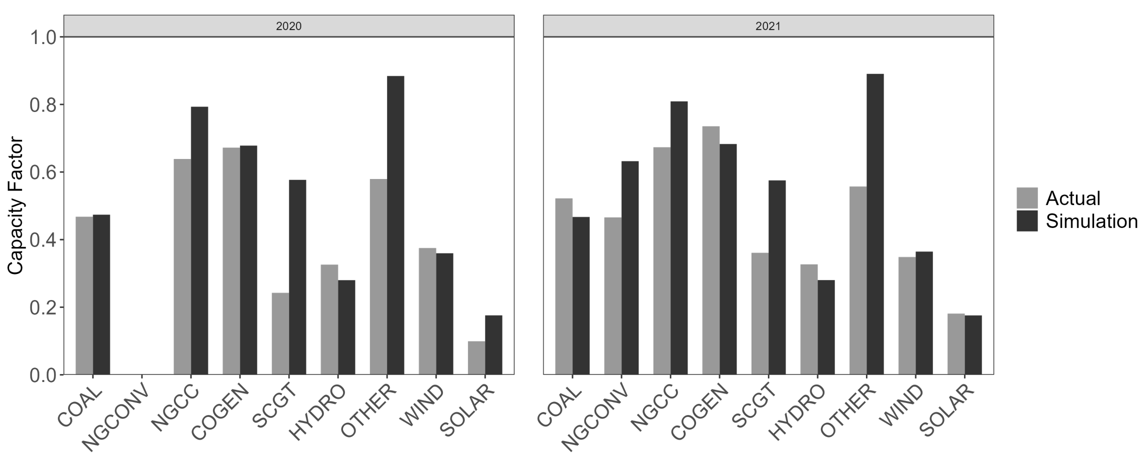


Figure 4.4: Simulated versus historic capacity factors by resource type [54]

The fossil fuel resources mostly are accurate, with simple cycle natural gas plants (SCGTs) having the greatest discrepancy. Similar to the other resource type, SCGTs make up a smaller portion of the market, however, they are often the resource that is last dispatched and therefore sets the pool price (marginal resource), so this discrepancy is flagged to be considered again in a later section.

Similar yet distinct to the capacity factors is the market share. A discrepancy between the historic market share of a resource type and the simulation could indicate that the merit order is different, and therefore the pool prices could be affected.

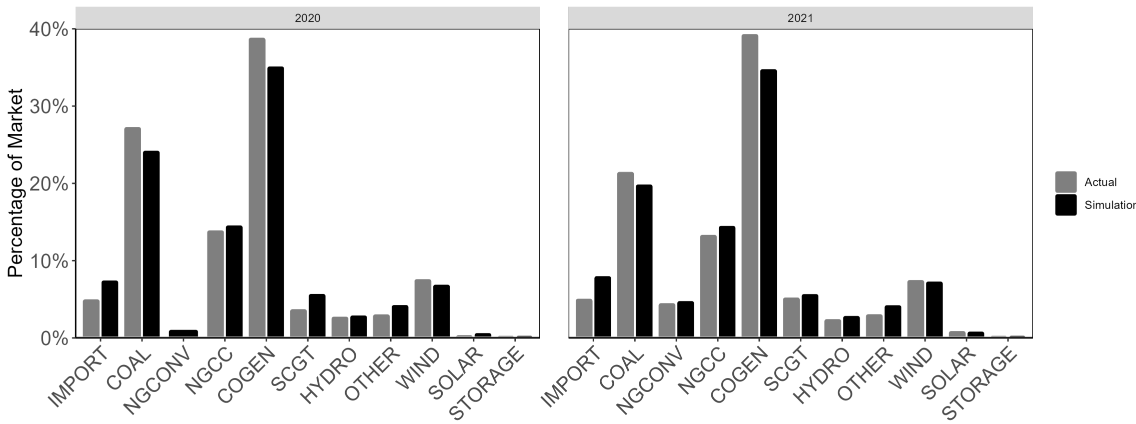


Figure 4.5: Simulated versus historic market share by resource type [54]

The market share by resource types shown in Figure 4.5 shows that the simulation is reasonably close for most resource types. The biggest discrepancies are with the coal, imports, and co-generation, yet none of the discrepancies are large enough to undermine the accuracy of the model. The imports for the simulation were simplified for the model instead of modelling the complexities of neighbouring electricity markets. As mentioned previously, the actual outputs and behaviours of co-generation sites are unknown due to the primary purpose of these units not being dedicated to the electricity market. Therefore approximations were made, and the discrepancy in imports appears to offset the discrepancy in co-generation output.

The coal market share discrepancies will have only a minor effect on the outcome of the simulation, as the later simulations forecast out to later years, and coal electricity generation units will all be retired in the next few years.

The total electricity generated by each resource type for each year is shown in Figure

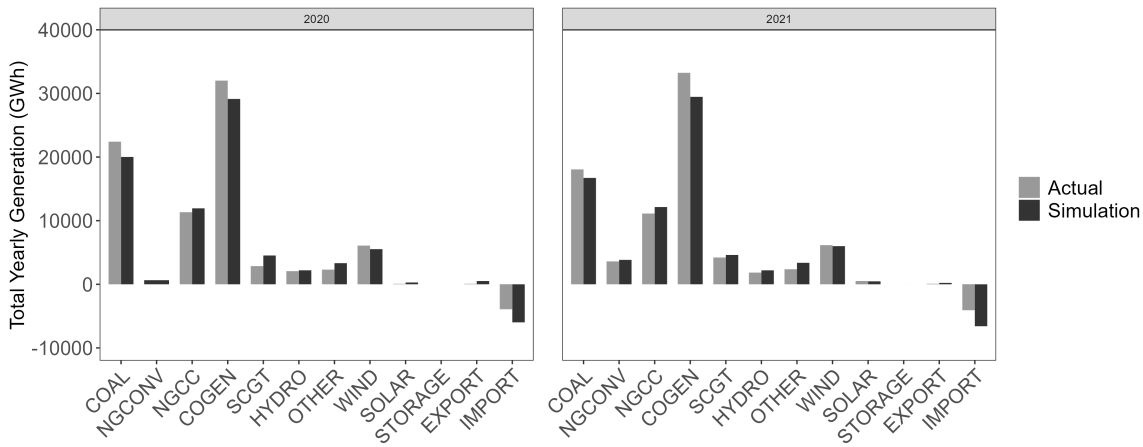


Figure 4.6: Simulated versus historic total yearly electricity generation by resource type [54]

4.6. This comparison shows few discrepancies, with the main discrepancies again in the co-generation units and the imports, with coal units slightly off.

Comparing price behaviour

The accuracy of the simulated price is heavily reliant on the resources available in the model, as the price is determined similarly to AESO through a merit order of submitted bids, with the last dispatched resource to meet demand setting the price. An accurate price portrayal, therefore, is a good indicator that the model is fairly accurate.

The price is also important for this research because the premise of geographically diverse wind farms is based on these wind farms being able to capture higher prices. If the pool price is not accurately portrayed, the benefits of building uncorrelated wind farm sites are negated.

The pool price duration curve is shown in Figure 4.7. Although the simulated price duration curve looks less smooth than the historic curve, the shape of the curve is similar, with 2020 being a noted exception due to the global pandemic. Similar to Figure 4.2, the extremes of these curves are similar, having been set by historic data. the model was unable to account for the increased mid-range prices that occurred

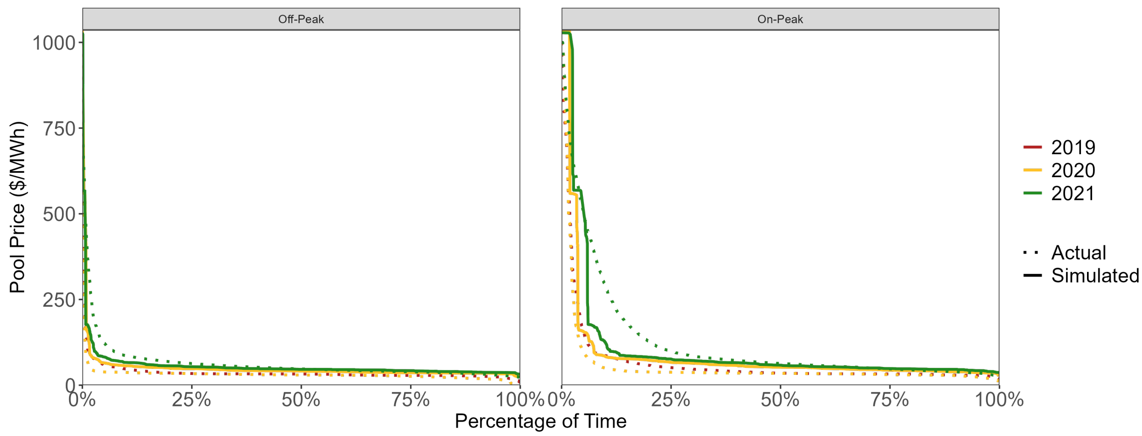


Figure 4.7: Simulated versus historic pool price duration curve by resource type [54]

during the pandemic. However, the resulting average price was similar to the historic prices for each year, as shown in Figure 4.8. The steps in the simulated curve shown in Figure 4.7 are due to the forced bidding behaviour in the model.

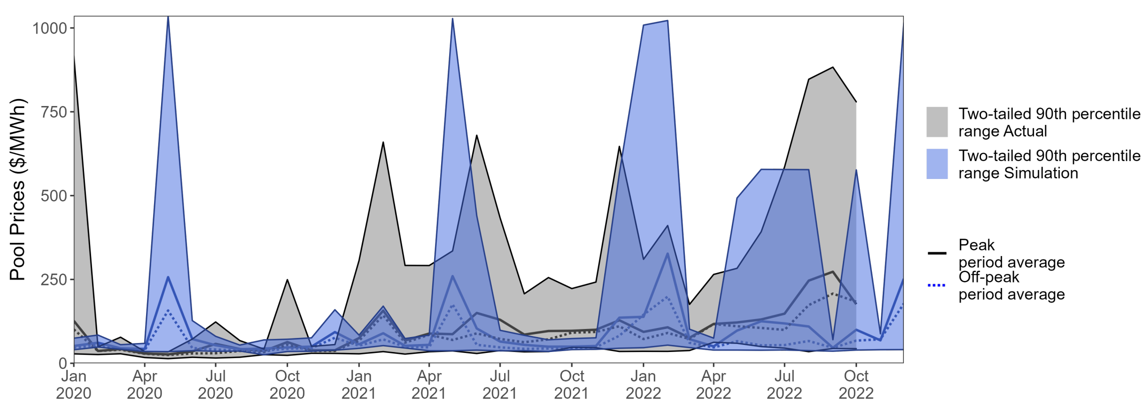


Figure 4.8: Simulated and historic monthly average pool prices with two-tailed 90th percentile range

Figure 4.8 shows the monthly averages for the pool price, along with the two-tailed 90th percentile range, with the simulated results in blue and the historical results in grey. This shows that the averages are similar, with the simulated prices typically slightly lower than the historic prices. However, there is a noticeable difference between the two-tailed 90th percentile range of the two. Especially in 2021, the simulation has tighter ranges than the historic data, with only one month being the exception. The low end is fairly similar between the two, with just the high end varying. This means that the simulated pool price didn't vary as much as the historic data, which was also evident in Figure 4.7.

While this may lead to inaccurate forecasts for this research, it will cause the simulation to err on the side of caution, as new variable renewable energy resources would not generate as much revenue due to the lower simulated pool prices than in the actual market. This would likely lead to the simulation not building as many renewable resources as what may actually happen. The hypothetical sites for wind farms potentially could be affected the most, as the premise of building wind farms at these remote sites is to capture the higher prices due to the uncorrelated nature of the wind regimes in these regions. The simulation doesn't experience as many high prices, which would lead to a smaller gap between the profitability of the hypothetical sites compared to actual sites. If the simulation does select to build at these locations, they are potentially more profitable than the simulation suggests.

4.3 Alberta's market with hypothetical wind farm sites

This section explores which of the hypothetical wind farm sites from the previous chapter might be built in Alberta's electricity market given the chance. This section also explores when these resources would be built and to what capacity. The results of this simulation with the hypothetical wind farm sites were compared against an identical simulation without the hypothetical wind farm sites included to explore how the inclusion of the hypothetical wind farm sites affects the market pool prices. A third simulation was also run to show how the results would change if there were no renewable energy credits available, therefore assessing how suitable these sites are as the market demand and conversely, the value of the renewable energy emissions credits diminishes.

Aurora's 'Long Term Capacity Expansion' logic was used for these simulations to forecast the market prices and resource allocations. The simulations were run from 2020 to 2040, but only the results up to the year 2035 were considered. This extended run allowed Aurora to simulate resource additions that would prepare for the proceeding five years. All of the figures for this section will only show the results up to the year 2035. The year 2035 was chosen to coincide with the long-term forecasts and goals in both the AESO Net-Zero Emissions Pathway report [17] and Canada's Clean Electricity Regulations [2].

Due to the increased run times and large file size, the simulation was run every second week of each month throughout the duration of the study. This decision was made in consultation with Energy Exemplar, the parent company of the Aurora software. They advised that the behaviours and trends should be accurate with only one week run a month, so long as every hour in that week is simulated. With more time and resources, this study can be repeated to simulate every week, but the conclusions drawn from the study should remain constant.

4.3.1 Including hypothetical wind farm sites in the model

This section uses the sites identified in the previous chapter as suitable locations for wind farms. Of the twelve sites identified, only the seven shown in Table 4.1 were used in the simulation. The two hypothetical wind farm sites with payback periods greater than seven years were excluded from the simulation as they were the least likely to be built. There were four sites that had internal rates of returns (IRRs) that were within one percent and within less than half a year in the payback period. These four sites were simplified to just one of the sites to represent the four to reduce redundancy and computation time. The remaining seven were used in the simulation as likely candidate locations for wind farms that were sufficiently unique from each other.

The hypothetical sites removed from the study were along the western border of the province or relatively close to other sites. The site at Hinton is the only remaining site

Table 4.1: Selected hypothetical sites for wind farms to be added to the model

Hypothetical Site	Latitude	Longitude
Anzac	56.340	-111.265
Bison Lake	57.382	-115.807
Hinton	53.341	-117.472
John D'Or Prairie	58.794	-114.970
Kehewin	54.066	-110.802
Lesser Slave Lake	55.435	-115.081
Pigeon Lake	53.086	-114.187

along the western border as it had the highest potential of these sites, and should give an indication of the optimistic potential of a wind farm in this area. The remaining two removed sites at Falher and Fort Saskatchewan were in the vicinity of Lesser Slave Lake and Pigeon Lake respectively, and had higher payback periods and lower IRRs than Lesser Slave Lake and Pigeon Lake, and were therefore removed from the study as well.

This reduction in sites evaluated simplified the simulation, which exponentially decreased the required run time. It also allowed the analysis to more accurately verify the suitability of wind farm sites in northern Alberta by increasing the distance between sites and simulating the sites with the highest potential.

The proposed seven hypothetical wind farm sites for this study were added into the model as potential new resources capable of being added to the model as early as the year 2020, with each site having a potential installed capacity of up to 50 MW. These sites were modelled so that duplicates could be built, up to a maximum of 6 a year (for an annual total of 300 MW), and a total maximum for the duration of the simulation of 20 installations at 50 MW each (for a total installation of 1000 MW). This was done as many of the current wind farms coming online are up to 300 MW, and 1000 MW was considered a reasonable ceiling to allow the resources to build freely.

Table 4.2: Selected sites for wind farms from the AESO queue to be added to the model

AESO Queue Site	Latitude	Longitude
Buffalo Atlee Cluster	50.746	-111.024
Buffalo Plains	50.384	-112.774
Buffalo Trail	49.878	-110.522
Bull Trail	49.810	-110.220
Castle Meridian	49.476	-114.018
Forty Mile	49.118	-111.207
Invenergy Schuler	50.390	-110.222
Lone Pine Wind	51.805	-113.598
Northern Lights Joss Wind	54.759	-115.567
Old Elm	49.310	-112.93
Oyen	51.454	-110.459
Paintearth	52.183	-112.062
Riplinger	49.220	-113.681
Sharp Hills	51.750	-110.580
Stirling	49.577	-112.387
Winnifred	49.936	-111.089

There were also 16 other wind farms available for the simulation to be built, shown in Table 4.2. These additional wind farms represent wind farms at locations that are currently in the AESO queue as sites that have been proposed for wind farms by industry [56]. To maintain consistency and remove bias, the predicted wind energy output profile was generated using the same methods as for the hypothetical sites. These sites were given names to represent the matching projects in the AESO queue but were allowed to build much higher capacities than their counterparts. This is to ensure that the results accurately depict how the hypothetical sites would compare in a market with other competing sites that have similar restrictions. Throughout the remainder of this work, these sites will be referred to as "AESO Queue Sites".

4.3.2 Built wind farms at hypothetical sites

The locations the simulation chose to build are shown on the map in Figure 4.9, and with the build schedule of the hypothetical locations shown in Figure 4.10. In total, 12,233 MW of wind energy was built in this simulation, with about 38% (4727 MW) of that built capacity built at the hypothetical sites. Considering all the sites built in the simulation, Figure 4.9 shows that there is significant geographic diversity between the locations, with the largest capacity being found in the northern half of Alberta or along the eastern border of the province.

Each of the hypothetical wind farm sites had at least some capacity building, with John D'Or Prairie, Lesser Slave Lake, and Kehewin building the maximum capacity allowed. This confirms the analysis done in Chapter 3, as that analysis named these three sites as being in the top four most economic sites. Of these three sites, John D'Or Prairie built the fastest, having built the maximum allowable annual capacity (300 MW), until the total maximum (1000 MW) was reached in 2023, with the exception of only building 100 MW in 2022. Wind energy was built at Lesser Slave Lake similar to John D'Or Prairie until 2023, which built half of the allowed annual capacity, leaving the remainder of the total maximum capacity to be built in 2024. Kehewin built the maximum annual capacity for the first three years, with the remainder of the maximum total capacity being built in 2025 and 2028.

The analysis in Chapter 3 showed that there was little difference between the remaining sites, with the difference in payback periods and IRRs being less than one year and 5% respectively. Of this group, the most capacity installed was Pigeon Lake with over 700 MW, and the least installed capacity was at Bison Lake with 100 MW.

Over 86% of the capacity built at these hypothetical sites was built within the first five years of the simulation, with almost 60% of the total installed capacity being built

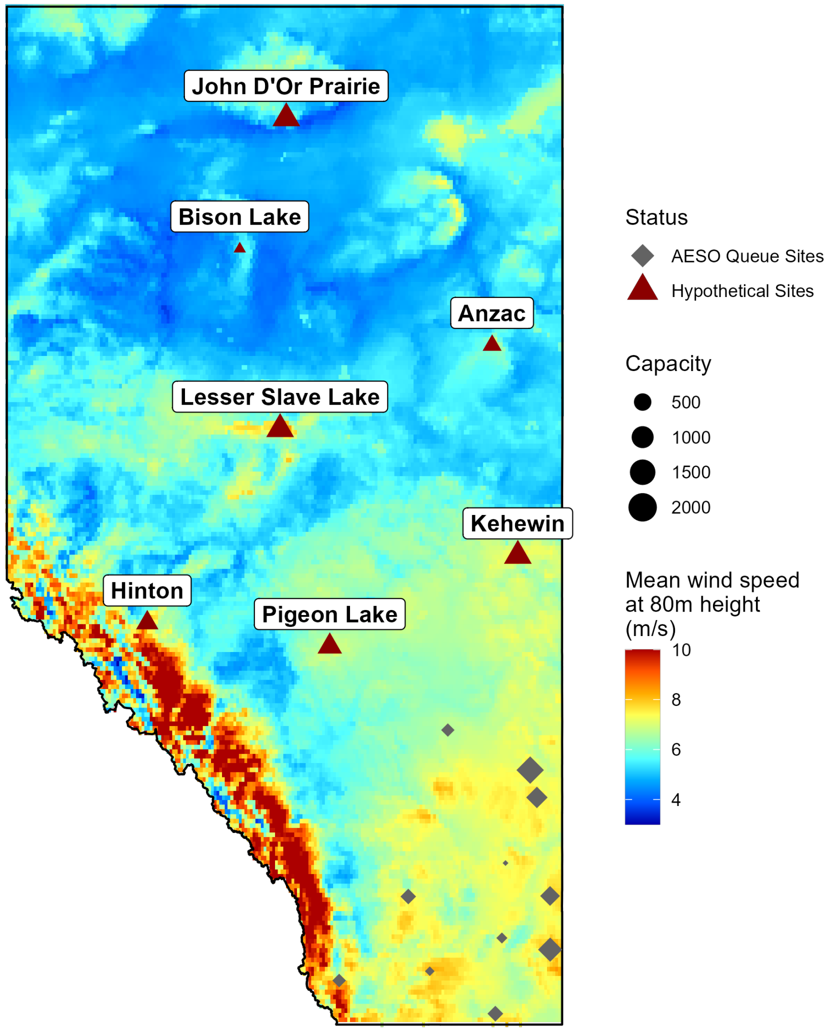


Figure 4.9: Simulated build locations for new wind farms with hypothetical sites labelled

in the first two years. This strengthens the hypothesis that these sites are economical now, with Alberta's current electricity market. The 'cannibalism effect' does not need to become more pronounced for these hypothetical wind farm sites to be competitive compared to more traditional locations in southern Alberta.

These results are important as they show that the simulation built as much as allowed at these three locations, and over half of that capacity was installed before the end of 2022, the year this simulation was run. This shows that the most economic time to build wind farms at these sites is now, not after southern Alberta has reached its limit of wind capacity.

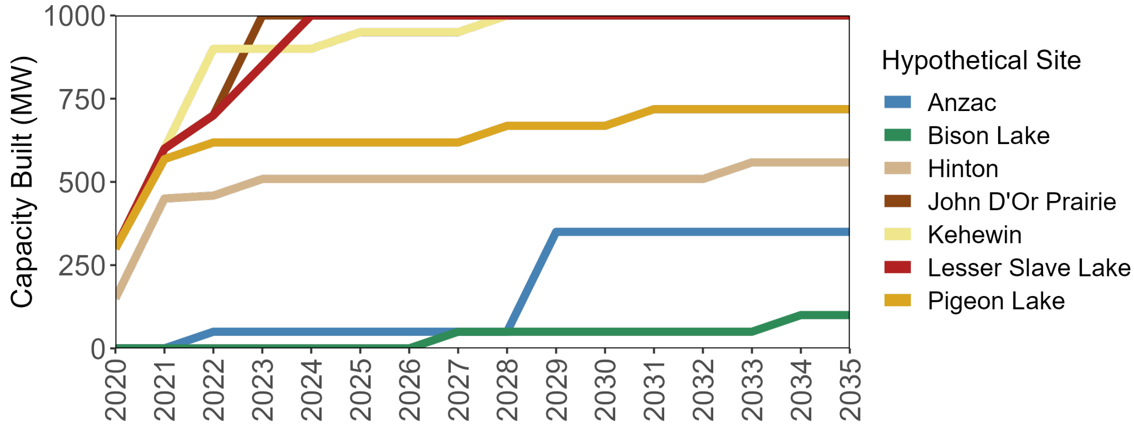


Figure 4.10: Hypothetical site build schedule and capacity

It is also interesting to compare the capacity factors for the hypothetical wind farm sites against the capacity factors of the other wind farms available to be built in the study. Figure 4.11 shows the annual average capacity factors for the hypothetical sites, along with the wind farm sites from the AESO queue that the simulation chose to build in the background. From this figure, it is clear that the hypothetical sites have about the same or lower capacity factor as half of the other sites that were built by the simulation.

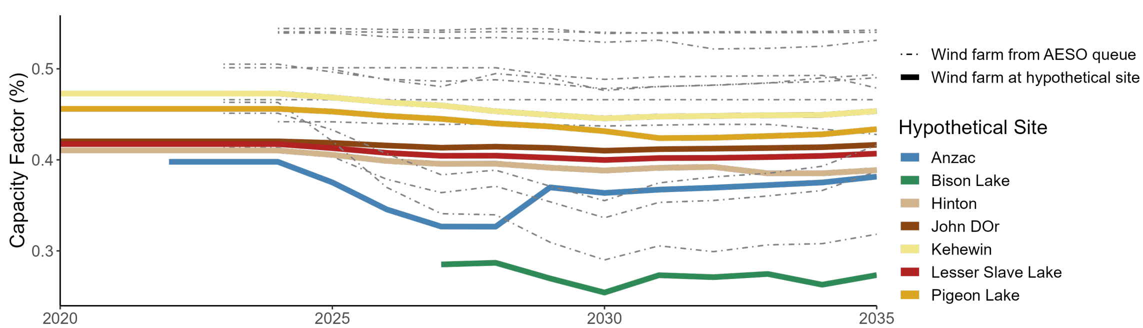


Figure 4.11: Simulated and historic annual average capacity factors.

The fastest site to reach the maximum capacity (John D'Or Prairie) only had the third-best capacity of the hypothetical sites and a much lower capacity than most of the installed wind farms. This shows that in this scenario, the quantity of wind being produced is less valuable to the wind farm than other factors.

The capacity factor is still important, with the two hypothetical sites with the least installed capacity having the lowest capacity factors of the group. Therefore, the value of the wind farm site is a combination of factors including, but not limited to, the capacity factor.

Figures 4.12 and 4.13 show the average annual revenues and the generation per installed megawatt index of deviation for the wind farms built by each simulation. Figure 4.12 is shown for comparison of what the simulation would predict with the base case, and Figure 4.13 shows the results with the hypothetical wind farm sites. The hypothetical sites returned higher average annual revenues than all of the other wind farms built except the wind farm built at the Paintearth site. While the index of deviation for these sites tends to vary, there is a slight pattern shown in Figure 4.13, with the hypothetical sites with the highest index of deviation also returning the highest average annual energy revenues.

Bison Lake is shown in Figure 4.13 to have the highest average annual energy revenues by a wide margin over the closest competitor, and the highest index of deviation. This is in contrast to the results shown in Figure 4.11, which shows Bison Lake having the lowest capacity factor by a wide margin. Therefore, the energy that the wind farm at Bison Lake is able to generate in this simulation is able to capture higher prices and revenues than the other sites. This could in part be because there was the least capacity built at this location, reducing the competition to drive the pool price down.

Both Figure 4.12 and 4.13 show most of the wind farms earning negative average annual revenue. This is because of the way the renewable energy credits were implemented into the model, with the revenue coming from the electricity market, rather than from an external market. This results in negative pool prices, which will be addressed in the next section. While the pool price is not likely to charge to produce energy, these charts demonstrate a compared value between wind farm sites that is valuable to this study.

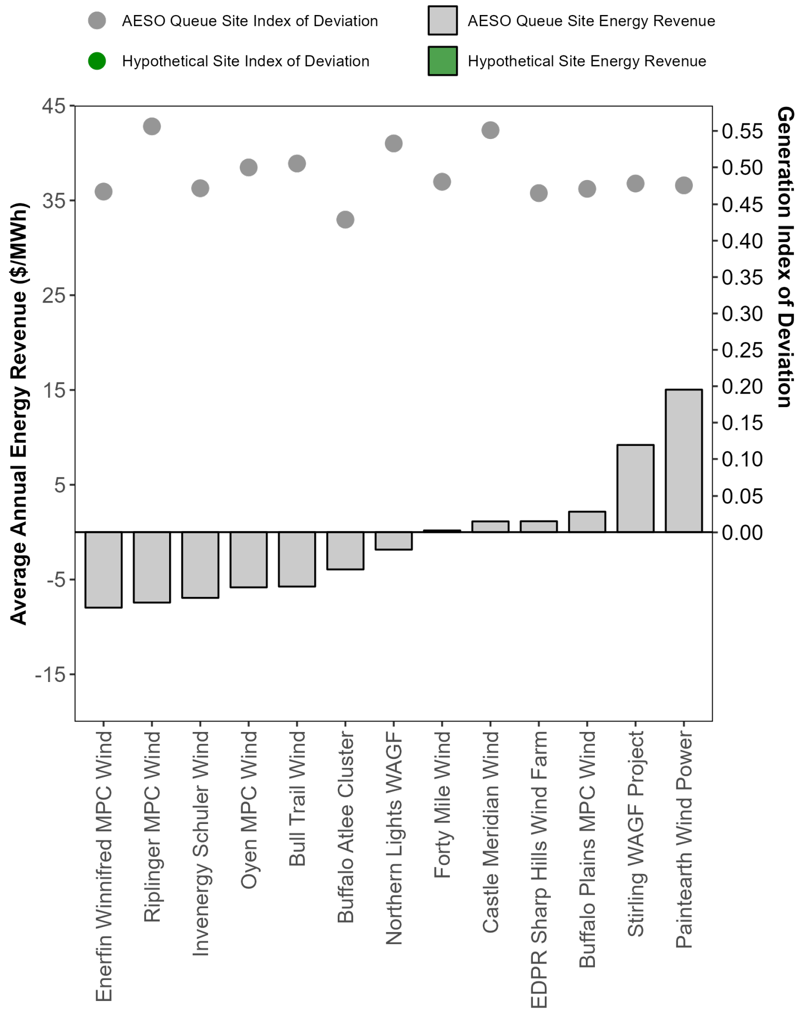


Figure 4.12: Simulated annual average revenue with the average annual generation index of deviation for simulation without hypothetical wind farm sites.

4.3.3 Pool price variation

As the saturation of renewable energy in the market increases, the market prices for electricity are likely to change [5]. This is the nature of Alberta's current electricity market. Wind and solar energy bid into the market at $0/MWh, and with increasing $0/MWh bids, the merit order shifts and the marginal resources have reduced offers. There are scenarios where the pool price drops to $0/MWh.

As stated earlier, the way renewable energy credits are modelled in the simulation allows for the pool price to become negative. While this is not likely to happen,

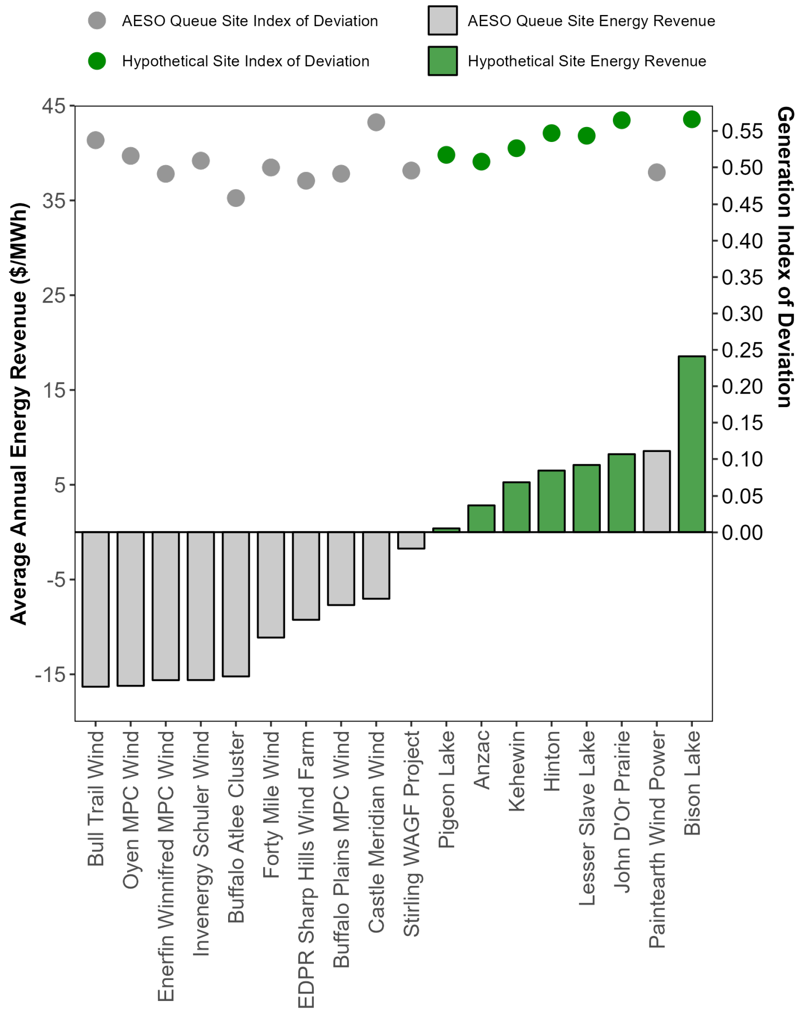


Figure 4.13: Simulated annual average revenue with the average annual generation index of deviation for simulation with hypothetical wind farm sites. Green columns identify hypothetical sites.

as the price drops toward $0/MWh, the contributing generators would earn little to no revenue for the output that would cost in the form of equipment wear and maintenance, effectively becoming a negative revenue for the generators.

An interesting observation about this simulation, therefore, is how the pool price is influenced by the inclusion of these hypothetical sites. Figure 4.14 shows the pool price decline over the duration of the study in each study, with the price dropping below zero regularly for the last half of the simulation for both simulations with renewable energy credits. Both simulations result in similar monthly averaged pool prices. The

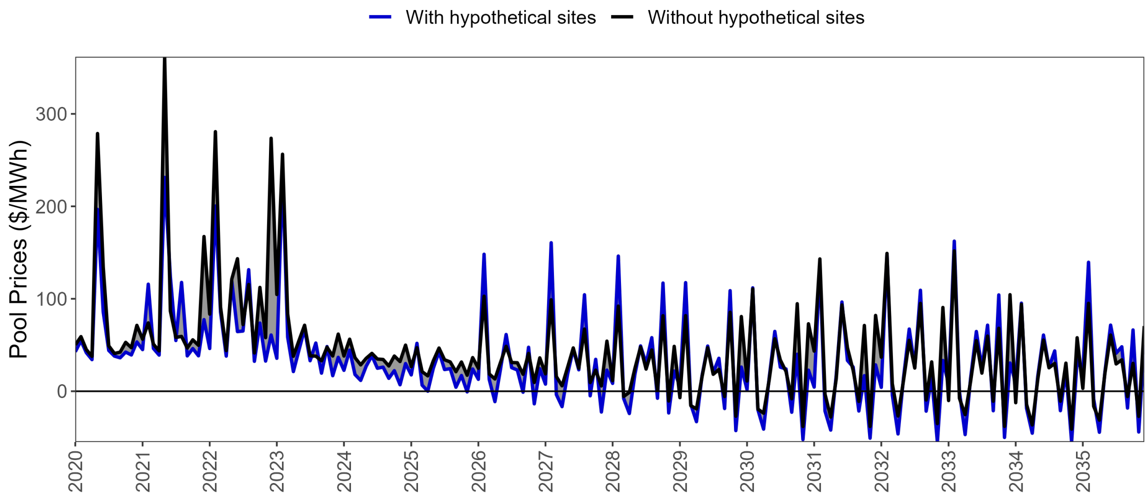


Figure 4.14: Simulated monthly average pool prices. Black results show without hypothetical sites and blue results show with hypothetical sites, with the shaded region highlighting the difference between the two.

simulation without the hypothetical sites included has higher monthly average prices most of the time until about the year 2026. From 2026 to about 2030, the simulation with hypothetical sites included regularly had more extremes in prices, whether that be high-priced peaks or low-price valleys. For the remaining five years, the monthly averaged prices were quite similar, with the simulation with hypothetical sites having slightly higher peaks and lower valleys. Throughout the study, the simulation with the hypothetical sites included regularly had slightly lower monthly averaged prices in the valleys. These results indicate that the inclusion of these hypothetical wind farm sites would likely not change the overall pool price drastically.

Another important result from the simulation is to compare how the variability of wind energy output changed with the inclusion of the hypothetical sites. Figure 4.15 shows how the inclusion of hypothetical wind farms into the simulation reduced the wind energy output variability. There are less hours near 100% capacity factor, but more hours with at least some wind energy produced.

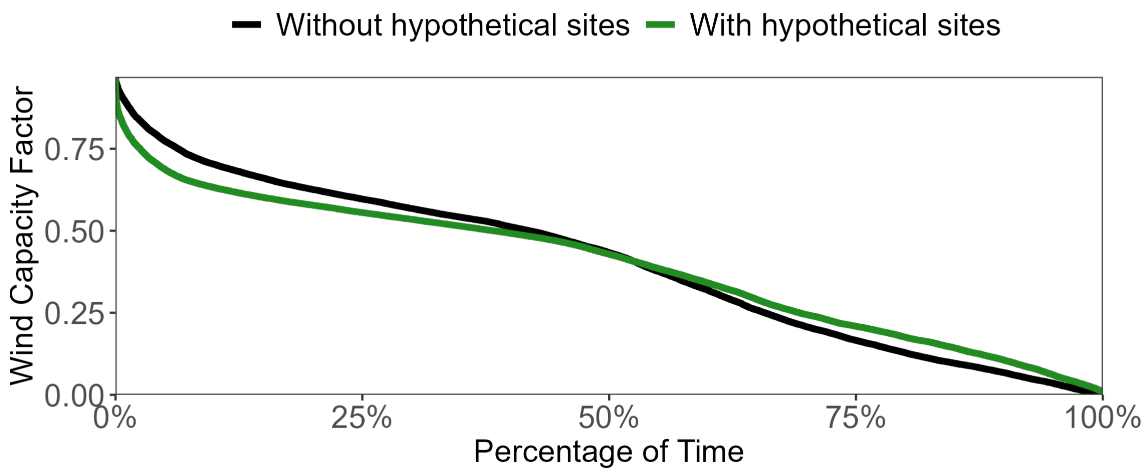


Figure 4.15: Annual wind capacity factor duration curves.

4.4 The effect of the renewable energy credits on the hypothetical wind farms

This section explores how the results of the previous section depend on or are inhibited by renewable energy credits.

Alberta's carbon pricing policy, the Technology Innovation and Emissions Reduction Regulation [29], allows wind energy to generate emissions performance credits at a rate of 0.37t/MWh, which represents the emissions that would have otherwise been allocated to emission-generating sites [5]. In the model, this is set up as a steadily declining rate to simulate the declining value of these credits as the carbon tax and the saturation of lower emission resources increase. The value of these credits is calculated by multiplying this rate by the carbon price for that year.

Currently, these emissions performance credits can generate an amount of revenue for wind farms significant enough that the pool price captured for the energy is less relevant to the financial viability of the site. However, this may change as the benchmark rate that these emissions performance credits are collected is set by the emissions rate that new generating resources in the market would otherwise produce. As the contributors to the market shift to lower-emitting technologies, the benchmark rate will lower resulting in fewer emissions performance credits available to wind

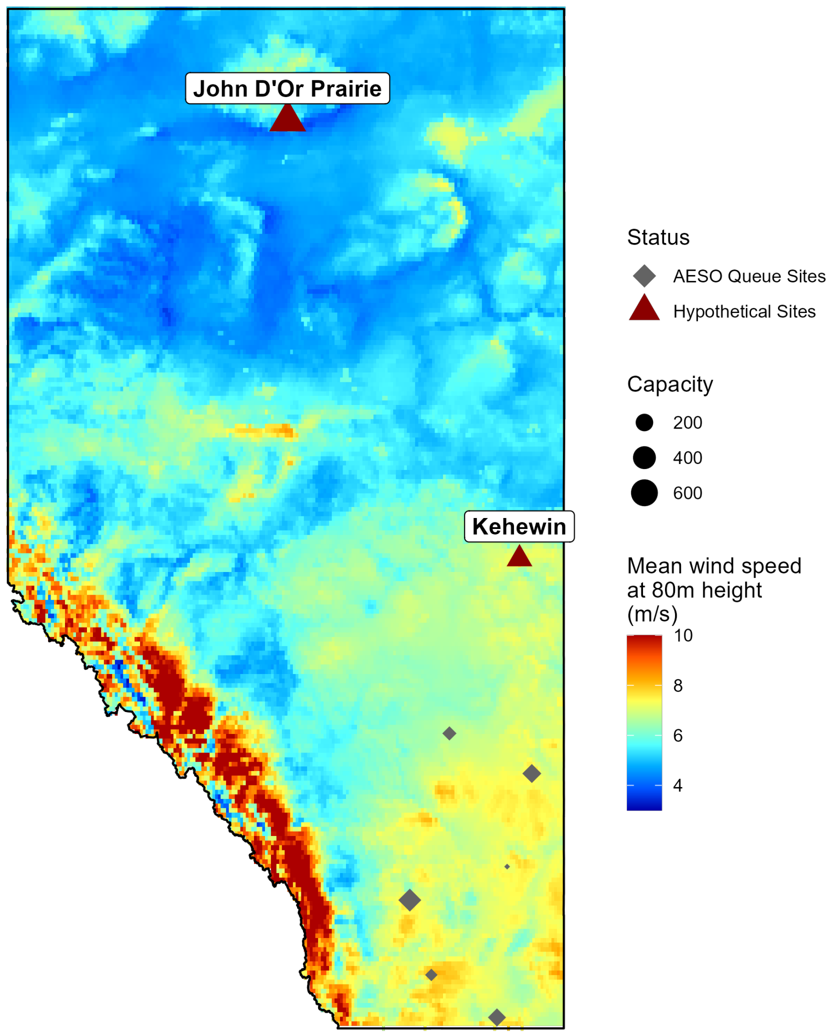


Figure 4.16: Simulated build locations for new wind farms with hypothetical sites labelled in the scenario with no renewable energy emissions credits

farms.

This section of the research simulates Alberta's electricity market with these emissions performance credits removed to assess if the hypothetical wind farm sites are more or less profitable than more conventional sites compared to the emissions performance credits. The carbon tax is still implemented for emitting resources in this scenario; only the additional revenue to wind and solar energy resources is removed.

Figure 4.16 shows the resulting build locations in the simulation with the renewable energy emissions credits removed. This image illustrates the reduction in wind fleet capacity expansion in Alberta compared to Figure 4.9. However, this figure does show

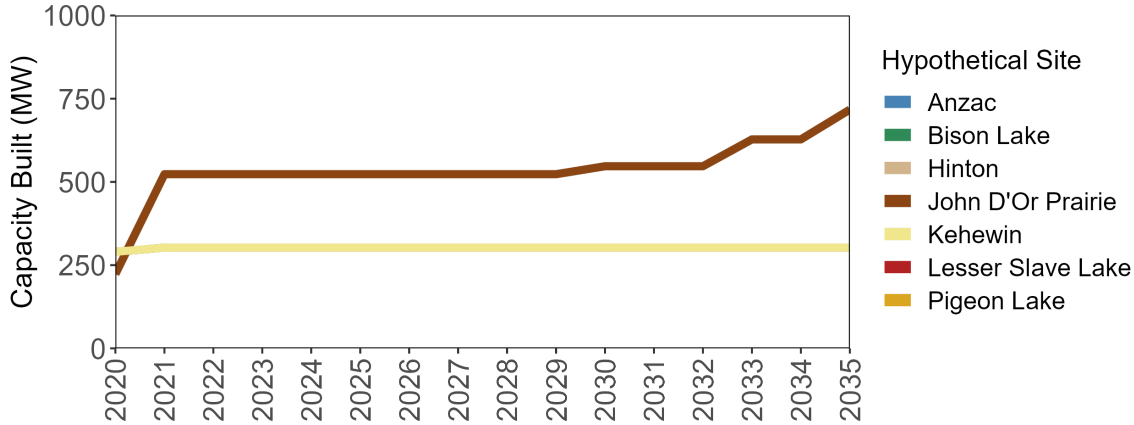


Figure 4.17: Hypothetical site build schedule and capacity in the scenario with no renewable energy emissions credits

that of the wind farms built, two of the hypothetical wind farms were built, which made up 43% of the newly installed wind energy capacity in the system. Figure 4.17 shows that most of the installed capacity built at these hypothetical sites was built in the first two years, with only a portion of the capacity at the John D'Or Prairie site built in the last five years of the simulation. The total capacity built at these hypothetical sites was 1020 MW.

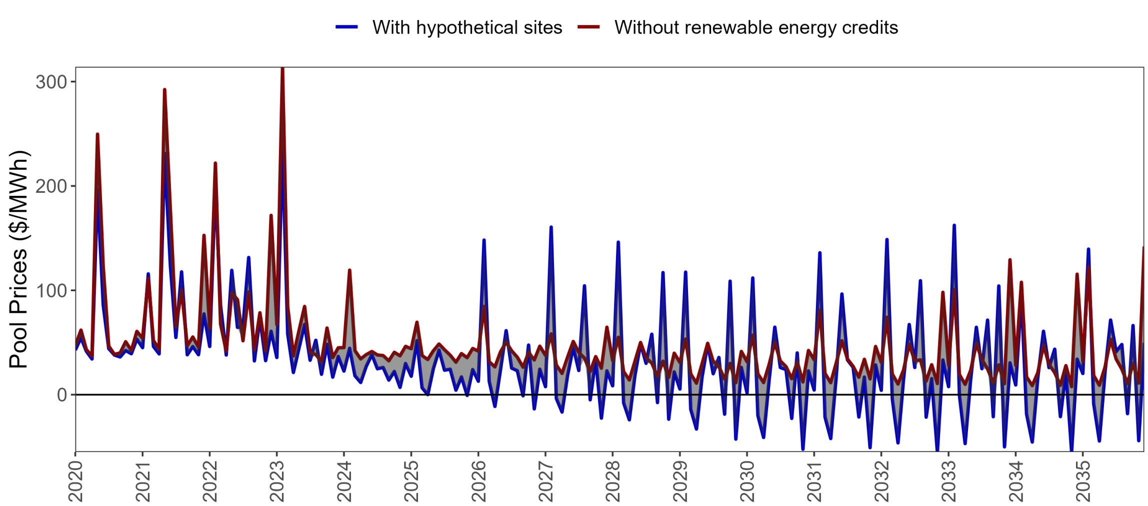


Figure 4.18: Simulated monthly average pool prices. Red results show hypothetical sites and no renewable energy credits while blue results show hypothetical sites with renewable energy credits.

Both Figure 4.18 and Figure 4.19 show that without the renewable energy emissions credits, the pool price does not go below \$0/MWh, and therefore the revenues are positive.

Figure 4.18 shows that with the renewable energy emissions credits, the monthly averaged pool prices are much more variable than in the simulation without the renewable energy emissions credits, especially from the year 2026 onward. This is likely due to the much greater wind energy capacity in the simulation with renewable energy credits, which leads to greater fluctuations in the supply of energy into the market.

The resulting average annual energy revenue shown in Figure 4.19 shows that three hypothetical sites that the simulation used to build wind farms had the highest average annual energy revenue of the wind farms that were built. This figure also demonstrates a clear trend between the average annual energy revenue and the IoD. As the IoD increases, the average annual energy revenue increases as well. In Figure 4.12 this trend appears non-existent, and this trend is only slightly apparent in Figure 4.13. This shows that the offsets do affect both the average annual energy revenues and the economic decisions made by the simulation. Therefore, as the value of the offsets decreases, building wind farms at locations with higher capacity factor indices of deviation will become increasingly more valuable.

4.5 Conclusions

A model was successfully built for this research to simulate a forecast of Alberta's electricity market with hypothetical wind farm sites included in the model, as well as an identical simulation scenario that removed the renewable energy emissions credits. The simulation with the hypothetical wind farms demonstrated that these geographically diverse wind farms could be economic and even competitive in Alberta's electricity market. In this simulation, the algorithm built 4727 MW of a potential 7000 MW of wind energy at the hypothetical sites, making up about 38% of the added

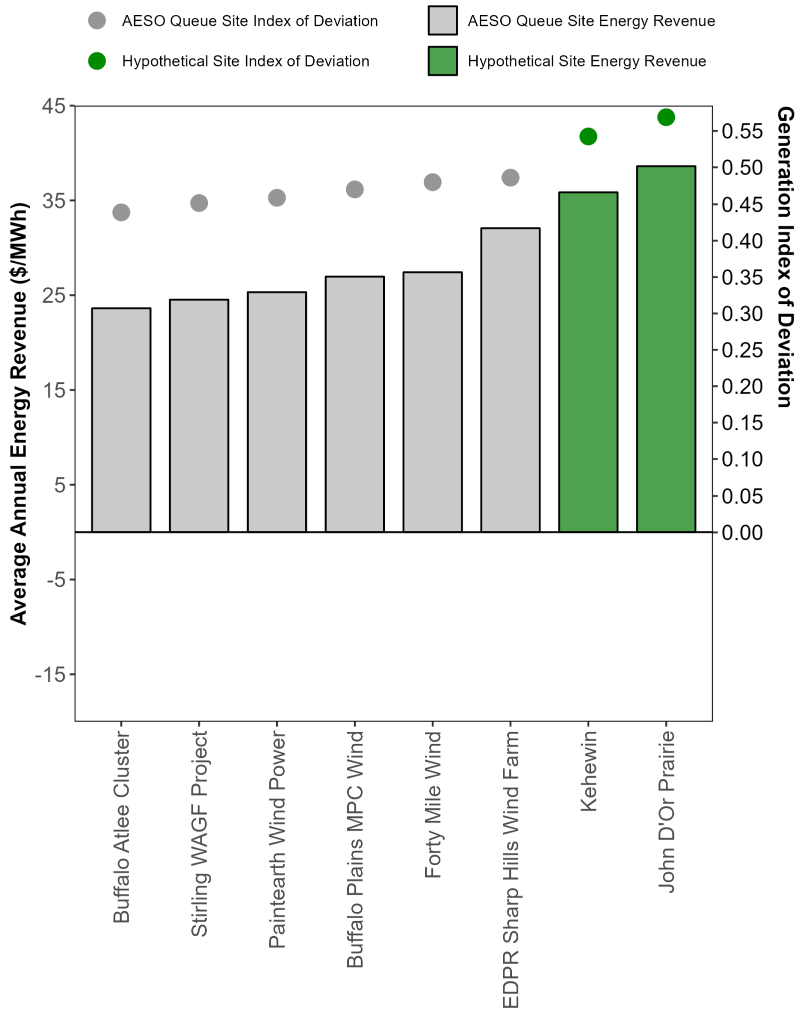


Figure 4.19: Simulated annual average revenue with no renewable energy emissions credits, with the average annual generation index of deviation. Green columns identify hypothetical sites.

wind fleet. Three of the hypothetical wind farm sites built as much wind capacity as permitted, with the fastest build reaching the limit within the first three years of the fifteen-year study. Potentially more capacity would have been built at these locations if it had been permitted.

All seven of the hypothetical locations built at least 100 MW. The hypothetical site that built the least capacity, Bison Lake, had the lowest average annual capacity factor and the highest average annual energy revenue of any of the wind farms built in the simulation. This suggests that these hypothetical sites are ideal candidates for wind energy, and in turn that a more geographically diverse wind fleet would prove economical.

In the case with no renewable energy emissions credits, the simulation still identified two of the hypothetical sites as ideal locations to build wind farms, making up 43% of the total wind fleet that was added to the market. In this case, the hypothetical wind farm sites made up almost 5% more of the built wind fleet than the scenario with the renewable energy emissions credits included.

Both of the forecast simulations suggest that a geographically diverse wind fleet is economic in Alberta's electricity market compared to a geographically concentrated wind fleet. The geographic diversity becomes more competitive as the renewable energy emissions credits reduce or are removed altogether, providing an ideal solution in a future where the value of these credits diminishes due to oversupply.

Chapter 5

Conclusion

5.1 Summary

The main goal of this thesis was to determine if a more geographically diverse wind fleet in Alberta would prove more economic than a wind fleet concentrated in a geographic area. Alberta's wind fleet historically has been concentrated in the south-western portion of the province. This region in the foothills experiences exceptionally high mean annual wind speeds as the shorter mountains in the area funnel the winds that typically originate from the Pacific through this area.

This concentration of wind farms in the region has highly correlated energy output profiles that flood the market when the wind speeds pick up in the region. Alberta's deregulated electricity market typically experiences lower pool prices during these times of high winds in those areas, and higher prices when the wind in this region slows and the wind energy output diminishes. These lower prices for the energy the wind farms produce are further reduced when additional wind energy capacity is built in the region as the influx of supply is also increased.

A potential solution that was explored in Chapter 3 is to diversify the geographic locations of the wind farms in Alberta. These diversified locations could potentially capture higher pool prices for the energy generated, which could offset the lower capacity factors of these locations. This chapter calculated an index of deviation to quantify how often and to what extent each wind farm's potential capacity factor compared to the capacity factor of the remainder of the wind fleet. When compared with the wind farm's average annual energy revenue, a clear correlation was identified with an R^2 value of 0.886.

This relationship was used to predict the average annual energy revenue for twelve hypothetical candidate sites in the northern portion of the province that were selected based on proximity to infrastructure and mean annual wind speeds in the region. The average annual energy revenue was then used to estimate payback periods for each site based on the predicted capacity factors for each location. The payback periods ranged from just under five years to eight and a half years, with John D'Or Prairie and Lesser Slave Lake having the most competitive average annual energy revenues and payback periods.

Chapter 4 built a model of Alberta's electricity market and forecast the economic expansion of the wind fleet with seven of the hypothetical wind farm sites included. This simulation built 4727 MW of a possible 7000 MW of wind energy at these locations, with capacity building at each site. The average annual energy revenues for these sites were higher than all the other wind farms built except one, indicating that these sites are excellent candidates for wind energy despite the less ideal wind regime than the current wind fleet. The pool price on average remained similar to the simulation without the hypothetical wind farms included.

Finally, a last simulation was run to identify how removing the renewable energy emissions credits would affect the build-out of wind energy in the province. The result was a drastic reduction in the amount of wind energy built in the province, from 12,233 MW down to 2,361 MW. Yet, despite the reduced expansion of the wind fleet, the wind farms built at the hypothetical locations accounted for over 43% of the added wind energy, a 5% increase over the simulation with the renewable energy emissions credits.

These results suggest that greater geographic diversity in the wind fleet could potentially prove economic for new wind farms. These results could greatly increase the potential area that can be used for wind energy, and decrease the burden on the southwestern portion of the province to invest a larger percentage of available land for future projects.

5.2 Future Considerations

The following is a list of recommendations for future work to further explore this topic and better incorporate the results of this study:

- The hypothetical sites simulated for this research were done selectively based on mean annual wind speed alone and did not consider land availability, siting requirements, environmental restrictions, etc. Future work could take the location-specific requirements into account and compare more locations that the twelve selectively chosen for this work.

- Alberta's electricity market is intricate and complex, rendering it challenging to model. While this work was able to build a model that reasonably replicated historic data, the model could be further refined to better incorporate the bidding behaviour of electricity generators, which could potentially better represent the high variability of Alberta's pool price. The premise of this work is based on the economic feasibility of wind farms at the hypothetical locations, and the conclusion relies heavily on the behaviour of the pool price. The simulations run for this work had fewer price spikes than what has been historically observed. Therefore, the resulting conclusions for this work are conservative, with these locations potentially being much more economic than shown in this work.

- This model assumed that each new wind farm added to the system had the same wind turbines with ratings. Future work could explore how using different or specialized wind turbines could prove beneficial for each site, and how that may affect the conclusions from the study. As well, further development in the model to better emulate how wind regimes vary over time could be beneficial.

- The model used for this work does not account for various external factors that drive investment decision-making, such as the economic value of companies presenting a green energy reputation, corporate power purchase agreements, the market decline of renewable energy emissions credits, and the decline in carbon emissions allocations. Future work could incorporate these factors to increase the accuracy of the analysis.

- This research only introduced how a geographically diverse wind fleet in Alberta could reduce wind energy output. Future research could explore in more depth how the overall wind energy output variability may be stabilized with the addition of more geographically diverse wind farm sites.

- Increasing or decreasing other non-dispatchable renewable energy such as solar and energy storage penetration can potentially greatly affect the effectiveness of geographically diverse wind fleets. This includes the addition of standalone resource sites as well as pairings, such as energy storage paired with wind energy. Future work should repeat these simulations with the penetration of renewable energy varied to study this sensitivity.

- If Alberta's electricity market were to change to no longer be an energy-only market, the financial incentive of a geographically diverse wind fleet could be greatly undermined. Future studies should focus on the market stability and reliability a geographically diverse wind fleet may offer.

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Appendix A: RStudio Code

A.1 Important RStudio code snippets with calculations

Listing A.1: RStudio code used to make calculations in Chapter 3

```
Ch3_IOD <- function(year1,year2) {
  # Plots the plant average revenue as a function of the index of deviation
  # of the generation per installed megawatt from the rest of the fleet of that
  # resource type, and calculates the predicted plant average revenue based on
  # the calculated revenue.

  # Set a minimum number of contributions into the market to be considered
  limit <- 2232

  # Filter data for plant_type and date considered, calculate index of deviation,
  # and fill in missing data.
  alberta_samp <- sub_samp %>%
    filter(Plant_Type == "WIND",
           time >= as.POSIXct(paste0(year1,"/01/01"),"%Y/%m/%d",tz = "MST"),
           time <= as.POSIXct(paste0(year2,"/12/31"),"%Y/%m/%d",tz = "MST")) %>%
    subset(., select = -c(he,date,Latitude,Longitude,
                          Demand,AIL,NRG_Stream,
                          Plant_Fuel,Plant_Type,GHG_ID,CO2,Heat.Rate,
                          co2_est,AESO_Name,Revenue,Price)) %>%
    na.omit() %>%
    group_by(ID) %>%
    filter(n() >= limit) %>%
    ungroup() %>%
    group_by(time) %>%
    mutate(fleet_CF = sum(gen)/sum(Capacity),
           other_CF = (sum(gen)-gen)/(sum(Capacity)-Capacity),
           deviance_CF = abs(Cap_Fac-other_CF),
    ) %>%
    ungroup() %>%
    group_by(ID) %>%
    summarize(IOD = sqrt(mean(deviance_CF)),
              Capacity = median(Capacity),
              Latitude = median(as.numeric(Latitude)),
              Longitude = median(as.numeric(Longitude)),
    ) %>%
    mutate(Installation=case_when(grepl("CRR2",ID)~"post2019",
                                  grepl("CYP",ID)~"post2019",
                                  grepl("FMG1",ID)~"post2019",
                                  grepl("HHW1",ID)~"post2019",
                                  grepl("HLD1",ID)~"post2019",
                                  grepl("JNR",ID)~"post2019",
                                  grepl("RIV1",ID)~"post2019",
                                  grepl("RTL1",ID)~"post2019",
                                  grepl("WHE1",ID)~"post2019",
                                  grepl("WHT",ID)~"post2019",
                                  grepl("WRW1",ID)~"post2019",),
```

```
        Installation=case_when(is.na(Installation)~"pre2019",
                               TRUE~"post2019"))

# Filter data for plant_type and date considered, Calculate the plant average
# revenue per megawatt
alberta_Price <- sub_samp %>%
  filter(Plant_Type == "WIND",
         time >= as.POSIXct(paste0(year1,"/01/01"),"%Y/%m/%d",tz = "MST"),
         time <= as.POSIXct(paste0(year2,"/12/31"),"%Y/%m/%d",tz = "MST")) %>%
  subset(., select = -c(he,date,Latitude,Longitude,Demand,AIL,NRG_Stream,
                        Plant_Fuel,Plant_Type,GHG_ID,CO2,Heat.Rate,
                        co2_est,AESO_Name)) %>%
  na.omit() %>%
  group_by(ID) %>%
  filter(n() >= limit) %>%
  summarize(Revenue = sum(Revenue),
            Rev = mean(Revenue),
            Dispatched = sum(gen),
            Capture_Price = Revenue/Dispatched,
            Capacity = median(Capacity)) %>%
  subset(.,select=c("ID","Capture_Price","Rev"))

# Combine the datasets
ab_data <- merge(alberta_samp,alberta_Price, by="ID")

# Run linear regression on the combined dataset between the plant average
# revenue and the index of deviation
equ <- summary(lm(Capture_Price ~ IOD, data=ab_data))

# Set size of text for the charts
sz = 15

# Plot the data with a scatter plot and the linear regression
ch <- ggplot(ab_data, aes(x = IOD, y = Capture_Price,
)) +
  geom_smooth(method='lm',
              show.legend=FALSE,fullrange=TRUE) +
  #stat_regline_equation(label.x=0.4,label.y=90,show.legend=FALSE) +
  #stat_cor(aes(label=..rr.label..), label.x=0.4,label.y=88,show.legend=FALSE) +
  geom_point(aes(size=Capacity,#color=Installation
  )) +
  #geom_text(label=ab_data$ID, size = sz-12,
  #          nudge_x = 0.001, nudge_y = 0.5) +
  labs(x = paste0("Generation per installed megawatt index of deviation from
                  fleet in ",year1),
       y = "Plant Average Revenue ($/MWh)") +
  theme(text = element_text(size = sz),
        axis.line = element_line(color="black", size = 0.5),
        panel.background = element_rect(fill = "transparent"),
        panel.grid = element_blank(),
        plot.background = element_rect(fill = "transparent"),
        plot.title = element_text(hjust = 0.5),
        plot.subtitle = element_text(hjust = 0.5),
        legend.background = element_rect(fill = "transparent"),
        legend.box.background = element_rect(fill = "transparent",
                                             color = "transparent"),
        legend.key = element_rect(fill="transparent"),
        rect = element_rect(fill="transparent")
  )

setwd("D:/Documents/GitHub/AuroraEval")

# Prepare data for plotting the map with the points
################################################################################
# Load in the data
# Wind Speed data from Canada Wind Atlas
# http://www.windatlas.ca/nav-en.php?no=46&field=EU&height=80&season=ANU
################################################################################
```

```r
wind_profileAA <- readRDS("WindAtlas_Data00_0.05")
colnames(wind_profileAA) <- c('Latitude', 'Longitude', 'Wind')

can_level1 = getData("GADM", country = "CA", level = 1)

WGS84 <- CRS("+proj=longlat +ellps=WGS84 +datum=WGS84 +no_defs")
canada_level1_ellipsoid = spTransform(can_level1, WGS84)
alberta_ellipsoid1 =
  canada_level1_ellipsoid[which(canada_level1_ellipsoid$NAME_1 == "Alberta"),]

################################################################################
################################################################################
# Map of Alberta with active sites
################################################################################
################################################################################
corr_map <- ggplot() +
  geom_tile(data = wind_profileAA,
            aes(x = Longitude, y = Latitude, fill = Wind)) +
  geom_polygon(data = alberta_ellipsoid1,
               aes(x = long, y = lat, group = group),
               fill = "transparent", colour = "black") +
  geom_point(data = ab_data,
             aes(x= Longitude, y = Latitude, size = IOD, color=Installation),
             shape = 16) +
  labs(size = "Generation per installed megawatt \nIndex of Deviation") +
  scale_color_manual(values = c("darkmagenta", "black"),
                     labels = c("Built since 2019","Built before 2019")) +
  scale_fill_gradientn(colors = matlab.like2(100),
                       limits=c(3.5,10), na.value="white",oob=squish,
                       name = "Mean wind speed \nat 80m height \n(m/s)") +
  scale_size(range = c(0.5,8)) +
  guides(color = guide_legend(override.aes = list(size = 5))) +
  theme(panel.background = element_rect(fill = "transparent"),
        panel.grid.major = element_blank(),
        panel.grid.minor = element_blank(),
        plot.background = element_rect(fill = "transparent", color = NA),
        axis.title = element_blank(),
        axis.text = element_blank(),
        axis.ticks = element_blank(),
        legend.background = element_blank(),
        legend.box.background = element_blank(),
        legend.key=element_rect(fill = "transparent"),
        #legend.text = element_blank(),
        #legend.title = element_blank()
  )

# Calculate the predicted average revenue, Payback Period, and the IRR for the
# hypothetical sites
hypothetical <- readRDS("SitesProfiles.RData") %>%
  mutate(time = as.POSIXct(as.character(paste0(year,"/",month,"/",day," ",
                                               hour,":00:00")),
                           "%Y/%m/%d %H:%M:%S",
                           tz = "MST"),
         gen = Capacity * Cap_Fac) %>%
  group_by(time) %>%
  mutate(fleet_CF = sum(gen)/sum(Capacity),
         other_CF = (sum(gen)-gen)/(sum(Capacity)-Capacity),
         deviance_CF = abs(Cap_Fac-other_CF),
  ) %>%
  ungroup() %>%
  group_by(ID,Installation) %>%
  summarize(IOD = sqrt(mean(deviance_CF)),
            Capacity = 100,
            CF = mean(Cap_Fac),
            Latitude = median(as.numeric(Latitude)),
            Longitude = median(as.numeric(Longitude)),
  ) %>%
  mutate(Capture_Price = linreg$coefficients[2] * IOD + linreg$coefficients[1],
```

```
    ) %>%
    filter(Installation == "Potential") %>%
    mutate(AE = CF*8760,
           IC = 1700000,
           IN = 227760*CF,
           AR = Capture_Price,
           AOM = 29750,
           Year = 2020,
           Ct = IN + AR*AE - AOM,
           years = 8*(21250-2847*CF)/(876*CF*Capture_Price-2975)
    ) %>%
    subset(., select=c(ID,Year,Ct,IC)) %>%
    group_by(ID,Ct) %>%
    complete(Year = full_seq(2020:2035,1)) %>%
    mutate(IC = case_when(is.na(IC)~0,
                          TRUE~IC),
           Cf = Ct-IC) %>%
    ungroup() %>%
    group_by(ID) %>%
    summarize(IRR = irr(Cf))

  return(list(equ,ch,corr_map,hypothetical))
}
```

Appendix B: Output Tables from Simulations

B.1 New wind farm build results for simulation without hypothetical wind farms included

New Resource ID	New Resource Name	Year Capacity Built	Number of Units Built	Number of Available Units Left Unbuilt	Capacity Built (MW)
NewWind_P1853	Buffalo Atlee Cluster	2023	1	0	49
NewWind_P2247	Buffalo Plains MPC Wind	2023	1	0	466
NewWind_P2342	Bull Trail Wind	2024	0.6	1.4	158
NewWind_P2342	Bull Trail Wind	2025	1.2	0.8	306
NewWind_P2342	Bull Trail Wind	2027	2	0	500
NewWind_P2342	Bull Trail Wind	2028	1.5	0.5	383
NewWind_P2353	Castle Meridian Wind	2024	3.1	0.9	70
NewWind_P2353	Castle Meridian Wind	2025	4	0	90
NewWind_P2353	Castle Meridian Wind	2026	4	0	90
NewWind_P2353	Castle Meridian Wind	2027	0.1	3.9	2
NewWind_P2353	Castle Meridian Wind	2039	3.6	0.4	80
NewWind_P2353	Castle Meridian Wind	2040	0.2	3.8	5
NewWind_P1567	EDPR Sharp Hills Wind Farm	2023	1	0	297
NewWind_P1567	EDPR Sharp Hills Wind Farm	2024	0.8	2.2	228
NewWind_P1567	EDPR Sharp Hills Wind Farm	2025	0.8	2.2	236
NewWind_P1567	EDPR Sharp Hills Wind Farm	2026	1	2	297
NewWind_P1567	EDPR Sharp Hills Wind Farm	2027	1.7	1.3	516
NewWind_P1567	EDPR Sharp Hills Wind Farm	2028	1	2	297
NewWind_P1567	EDPR Sharp Hills Wind Farm	2029	0.7	2.3	211
NewWind_P1567	EDPR Sharp Hills Wind Farm	2034	1	2	297
NewWind_P1567	EDPR Sharp Hills Wind Farm	2035	0.1	2.9	39
NewWind_P2137	Enerfin Winnifred MPC Wind	2025	1	2	128
NewWind_P2137	Enerfin Winnifred MPC Wind	2028	1	2	128
NewWind_P2237	Forty Mile Wind	2023	1	0	266
NewWind_P2237	Forty Mile Wind	2029	1	2	266
NewWind_P2398	Invenergy Schuler Wind	2025	0.7	2.3	112
NewWind_P2398	Invenergy Schuler Wind	2026	1	2	150
NewWind_P2398	Invenergy Schuler Wind	2027	2	1	300
NewWind_P2398	Invenergy Schuler Wind	2028	0	3	4
NewWind_P2398	Invenergy Schuler Wind	2038	1	2	150
NewWind_P1885	Joss Wind Northern Lights WAGF	2024	1.6	0.4	634
NewWind_P1885	Joss Wind Northern Lights WAGF	2025	0.8	1.2	317
NewWind_P1885	Joss Wind Northern Lights WAGF	2026	1.5	0.5	614
NewWind_P1885	Joss Wind Northern Lights WAGF	2027	0.1	1.9	34
NewWind_P1885	Joss Wind Northern Lights WAGF	2028	1.2	0.8	489
NewWind_P1885	Joss Wind Northern Lights WAGF	2031	0.7	1.3	260
NewWind_P1885	Joss Wind Northern Lights WAGF	2034	0.2	1.8	71
NewWind_P1885	Joss Wind Northern Lights WAGF	2035	0.1	1.9	38

NewWind_P1885	Joss Wind Northern Lights WAGF	2036	0	2	2
NewWind_P1885	Joss Wind Northern Lights WAGF	2039	0.6	1.4	246
NewWind_P1885	Joss Wind Northern Lights WAGF	2040	0.1	1.9	49
NewWind_P2356	Oyen MPC Wind	2024	2	0	500
NewWind_P2356	Oyen MPC Wind	2025	2	0	500
NewWind_P2356	Oyen MPC Wind	2026	1.3	0.7	332
NewWind_P2356	Oyen MPC Wind	2027	1.8	0.2	462
NewWind_P2356	Oyen MPC Wind	2029	0.5	1.5	120
NewWind_P2356	Oyen MPC Wind	2039	0.7	1.3	168
NewWind_P1704	Paintearth Wind Power	2023	1	0	150
NewWind_P1704	Paintearth Wind Power	2029	1	2	150
NewWind_P2481	Riplinger MPC Wind	2030	0.5	1.5	149
NewWind_P1719	Stirling WAGF Project	2023	1	0	113

B.2 New wind farm build results for simulation with hypothetical wind farms included

New Resource ID	New Resource Name	Year Capacity Built	Number of Units Built	Number of Available Units Left Unbuilt	Capacity Built (MW)
PotWind_007	Anzac (Potential#7)	2022	1	5	50
PotWind_007	Anzac (Potential#7)	2029	6	0	300
PotWind_006	Bison Lake (Potential#6)	2027	1	5	50
PotWind_006	Bison Lake (Potential#6)	2034	1	5	50
NewWind_P1853	Buffalo Atlee Cluster	2023	1	0	49
NewWind_P1853	Buffalo Atlee Cluster	2039	0.5	2.5	24
NewWind_P2247	Buffalo Plains MPC Wind	2023	1	0	466
NewWind_P2342	Bull Trail Wind	2024	2	0	500
NewWind_P2342	Bull Trail Wind	2025	2	0	500
NewWind_P2342	Bull Trail Wind	2026	0.9	1.1	233
NewWind_P2342	Bull Trail Wind	2030	1.2	0.8	290
NewWind_P2353	Castle Meridian Wind	2024	4	0	90
NewWind_P2353	Castle Meridian Wind	2025	4	0	90
NewWind_P2353	Castle Meridian Wind	2026	4	0	90
NewWind_P2353	Castle Meridian Wind	2034	1	3	22
NewWind_P2353	Castle Meridian Wind	2035	1	3	22
NewWind_P1567	EDPR Sharp Hills Wind Farm	2023	1	0	297
NewWind_P1567	EDPR Sharp Hills Wind Farm	2024	1.8	1.2	525
NewWind_P1567	EDPR Sharp Hills Wind Farm	2025	1.2	1.8	367
NewWind_P1567	EDPR Sharp Hills Wind Farm	2026	1	2	297
NewWind_P1567	EDPR Sharp Hills Wind Farm	2027	1	2	297
NewWind_P1567	EDPR Sharp Hills Wind Farm	2028	1	2	297
NewWind_P2137	Enerfin Winnifred MPC Wind	2025	0.3	2.7	44
NewWind_P2137	Enerfin Winnifred MPC Wind	2028	1	2	128
NewWind_P2237	Forty Mile Wind	2023	1	0	266
NewWind_P2237	Forty Mile Wind	2029	0.2	2.8	63
NewWind_P2237	Forty Mile Wind	2035	0.6	2.4	150
PotWind_003	Hinton (Potential#3)	2020	3	3	150
PotWind_003	Hinton (Potential#3)	2021	6	0	300
PotWind_003	Hinton (Potential#3)	2022	0.2	5.8	9
PotWind_003	Hinton (Potential#3)	2023	1	5	50
PotWind_003	Hinton (Potential#3)	2033	1	5	50
NewWind_P2398	Invenergy Schuler Wind	2024	1.3	1.7	193
NewWind_P2398	Invenergy Schuler Wind	2025	3	0	450
NewWind_P2398	Invenergy Schuler Wind	2026	1	2	150
NewWind_P2398	Invenergy Schuler Wind	2032	0.7	2.3	105
NewWind_P2398	Invenergy Schuler Wind	2038	1	2	150
PotWind_001	John D'Or Prairie (Potential#1)	2020	6	0	300

PotWind_001	John D'Or Prairie (Potential#1)	2021	6	0	300
PotWind_001	John D'Or Prairie (Potential#1)	2022	2	4	100
PotWind_001	John D'Or Prairie (Potential#1)	2023	6	0	300
PotWind_004	Kehewin (Potential#4)	2020	6	0	300
PotWind_004	Kehewin (Potential#4)	2021	6	0	300
PotWind_004	Kehewin (Potential#4)	2022	6	0	300
PotWind_004	Kehewin (Potential#4)	2025	1	5	50
PotWind_004	Kehewin (Potential#4)	2028	1	5	50
PotWind_002	Lesser Slave Lake (Potential#2)	2020	6	0	300
PotWind_002	Lesser Slave Lake (Potential#2)	2021	6	0	300
PotWind_002	Lesser Slave Lake (Potential#2)	2022	2	4	100
PotWind_002	Lesser Slave Lake (Potential#2)	2023	3	3	150
PotWind_002	Lesser Slave Lake (Potential#2)	2024	3	3	150
NewWind_P2356	Oyen MPC Wind	2024	2	0	500
NewWind_P2356	Oyen MPC Wind	2025	2	0	500
NewWind_P2356	Oyen MPC Wind	2031	0.5	1.6	113
NewWind_P1704	Paintearth Wind Power	2023	1	0	150
NewWind_P1704	Paintearth Wind Power	2029	1	2	150
PotWind_005	Pigeon Lake (Potential#5)	2020	6	0	300
PotWind_005	Pigeon Lake (Potential#5)	2021	5.4	0.6	269
PotWind_005	Pigeon Lake (Potential#5)	2022	1	5	50
PotWind_005	Pigeon Lake (Potential#5)	2028	1	5	50
PotWind_005	Pigeon Lake (Potential#5)	2031	1	5	50
NewWind_P1719	Stirling WAGF Project	2023	1	0	113

B.3 New wind farm build results for simulation without renewable energy emissions credits

New Resource ID	New Resource Name	Year Capacity Built	Number of Units Built	Number of Available Units Left Unbuilt	Capacity Built (MW)
NewWind_P1853	Buffalo Atlee Cluster	2023	1	0	49
NewWind_P2247	Buffalo Plains MPC Wind	2023	1	0	466
NewWind_P1567	EDPR Sharp Hills Wind Farm	2023	1	0	297
NewWind_P2237	Forty Mile Wind	2023	1	0	266
PotWind_001	John D'Or Prairie (Potential#1)	2020	4.5	1.5	223
PotWind_001	John D'Or Prairie (Potential#1)	2021	6	0	300
PotWind_001	John D'Or Prairie (Potential#1)	2030	0.5	5.5	24
PotWind_001	John D'Or Prairie (Potential#1)	2033	1.6	4.4	81
PotWind_001	John D'Or Prairie (Potential#1)	2035	1.8	4.2	89
PotWind_001	John D'Or Prairie (Potential#1)	2037	0.8	5.2	40
PotWind_001	John D'Or Prairie (Potential#1)	2038	2.9	3.1	147
PotWind_001	John D'Or Prairie (Potential#1)	2040	0.9	5.1	47
PotWind_004	Kehewin (Potential#4)	2020	5.8	0.2	290
PotWind_004	Kehewin (Potential#4)	2021	0.2	5.8	12
PotWind_004	Kehewin (Potential#4)	2039	3.8	2.2	192
PotWind_002	Lesser Slave Lake (Potential#2)	2039	6	0	300
NewWind_P1704	Paintearth Wind Power	2023	1	0	150
NewWind_P1719	Stirling WAGF Project	2023	1	0	113