Modelling Market Impacts of Geographic Dispersion of Wind Energy in Alberta

by

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A thesis submitted in partial fulfillment of the requirements for the degree of

Master of Science

in
Engineering Management

Department of Mechanical Engineering
University of Alberta

Abstract

This thesis presents a methodology to simulate the energy production from hypothetical wind farms in Alberta in order to examine potential future market impacts of a geographically dispersed wind fleet in Alberta. The wind farms' output is simulated using the Canadian Wind Atlas (CWA) Modelled Historical data (HMD), a publicly available hourly Numerical Weather Prediction (NWP) model and calibrated to historic output from existing wind farms in the province to determine if the data available from the CWA (hourly wind speeds, temperature, and air density), were sufficient to simulate new wind farms in Alberta. A generic loss coefficient was empirically calculated to estimate power output from a wind farm compared to the manufacturer's power curve at simulated wind speeds from the CWA. By comparing modelled wind farm performance to historical market data from wind farms operating in Alberta, it was found that the CWA tends to underestimate wind speeds from 7:00 am until noon for the spring months, as well as misrepresenting wind speeds for the southwest region of the province (near communities with existing wind farms in Pincher Creek and Fort Macleod). Outside of the southwest of the province, the simulated wind farm's annual energy production, using the data from the CWA HMD, was within a percentage error between 1% to 10% for wind farms that operated over the same timeframe. By applying this methodology to regions of the province without existing wind farms, the output of new hypothetical wind farms was created in different locations in Alberta. The output of hypothetical wind farms allowed for market impacts simulations of new wind farms in Alberta using the Aurora market model from Energy Exemplar. Preliminary results from Aurora's model simulation shows that increases in wind energy development will lower market prices during periods of high wind as would be expected. This work enables future analysis examining the potential market changes of a more geographically diverse wind fleet in the province.

Preface

Some of the research conducted for this thesis forms part of a research collaboration led by Professor A. Leach and T. Weis from the Center for Applied Business Research in Energy & the Environment (CABREE) located within the Alberta School of Business at the University of Alberta. The different scenarios from chapter 4, excluding the Base Case, were designed by myself, with the assistance of Professor A. Leach. The Base Case in chapter 4 was developed by staff at CABREE. The data analysis in chapter 3 and concluding analysis in chapter 4 are my original work and the literature review in chapter 2.

Chapter 3 of this thesis is aimed to be published as N. Vergara-Bonilla, B. A. Fleck, T. Weis, A. Leach, "Calibrating the Canadian Wind Atlas Data to Historic Wind Energy Performance in Alberta" to be submitted shortly after the completion of this thesis. I was responsible for the data collection and analysis, as well as the manuscript composition. B. A. Fleck was the supervisory author and was involved with the manuscript edits. T. Weis was involved with the concept formation, assisted with the data collection and contributed to manuscript edits and composition. A. Leach assisted with the analysis and contributed to the manuscript edits.

Acknowledgments

I want to thank all the people without whom I would not have been able to complete this research and make it through my master's degree.

I want to express my sincere gratitude to my advisors, Dr. Brian A. Fleck, Dr. Tim Weis, and Dr. Andrew Leach, for the continuous support of my master studies and research, for their patience, motivation, enthusiasm, and immense knowledge. I could not have imagined having better advisors and mentors for my studies.

Thank you to my research colleagues at CABREE and at the Mechanical Engineering Department. A special thank you for the community of Stack Overflow without whom I would not have been able to conduct my data analysis, or even learned how to use R (Thanks, Dr. Leach!).
Finally, my biggest thank you to my family for all the support you have shown me through this research, the culmination of these years of distance learning. Thanks, mom and dad, for always believing in me.

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Glossary

Capacity: the maximum amount of electric power that a wind turbine or a wind farm can produce.

Demand: the amount of electricity consumed.

Dispatch: selling electricity by a power generation or distribution company to users, depending on demand.

Forced Outages: the removal from the service availability of a generating unit, in this case, wind power.

Hysteresis: the phenomenon in which the value of a physical property lags behind changes in the effect causing it.

Marginal cost: the cost added by producing one additional unit of electric power.

Pool Price: the dollar cost of a megawatt-hour of electricity at the end of a given hour paid to electricity generators for supplying electricity.

Region: an area or division having definable characteristics but no always fix boundaries.

Running cost: the amount of money required to spend regularly to keep a system or organization working.

Supply: the amount of electric power produced by generators to satisfy the energy demand.

CHAPTER 1: Introduction

Over the past decade, wind power has become one of the fastest-growing sources of new installed electricity generation in Canada [1]. Canada ranks 9th in the world for total onshore installed capacity, with 13.4 GW as of December 2019 [2], compared to the global wind fleet's 564 gigawatts (GW) of generation capacity in 2018 [3]. In 2015, the government of Alberta announced plans to increase renewable energy from approximately 9 percent of the annual generation at the time to 30 percent by 2030 [4]. While government policies change over time, increasing efforts to reduce greenhouse gas emissions, combined with the reduction in costs of wind energy systems, indicated that wind energy is likely to have an increased role in electricity generation in Alberta. This work establishes some tools to analyze how different growth scenarios for wind energy may affect Alberta's electricity market.

This work is focused on the province of Alberta but has implications for jurisdictions across and outside of Canada. Energy demand may increase by as much as 20% by 2040, compared to 2019 levels [5], and with it an increased pressure on harnessing natural resources. To meet these demands while combating climate change, renewable energy such as wind power is expected to play an increased role in electricity generation.

The Paris Agreement, whose "central aim is to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius." [6] will require new technology and capacity building frameworks [6], including increased roles for wind energy.

Alberta's electricity system transition is an interesting case study as the system is relatively isolated, has publicly available market data and is undergoing a significant set of policy changes to transition from a system that was until recently predominantly supplied by coal-fired electricity. Alberta also ranks third in Canada with 1,685 megawatts (MW) of installed capacity. The Government of Alberta's 2015 Climate Leadership Plan (CLP) included three major policy measures that directly affect its electricity system [7]:

- An increased carbon price;

- a commitment to phase out of coal-generated electricity;
- and generate 30 percent of electricity from renewable sources by 2030.

Wind power was widely expected to be the major source of new renewable energy in Alberta if it were to meet its 30% percent renewable energy target by 2030 [8]. The province's Renewable Electricity Program (REP) called for 5,000 MW of renewable energy capacity to be added by 2030 [8]. In the Alberta Wind Energy Supply Chain Study [9], the economic impact assessment assumes that approximately 4,500 MW, or about 90%, of the added capacity by 2030 could come from utility-scale wind farms, balancing with other renewable energy sources, such as solar photovoltaic (PV) and hydro.

While wind energy has significant growth potential in Alberta, some challenges may hinder its development, including how that development affects the market. To date, most of the wind power plants in Alberta have been built in the south of the province. This results in strong correlations between high and low wind production time. With no fuel costs, wind energy bids into Alberta's competitive market at 0 $/MWh resulting in an average reduction in market price during periods of high wind. As a result, Alberta's wind fleet collects on average a lower price than most other technologies in the market [10]. In order to facilitate this growth, it is valuable to understand how and if the geographic location of future wind farms may change energy prices for wind farms as well as the broader electricity fleet in Alberta. In order to do so, it is necessary to be able to simulate the behaviour of wind farms in regions of the province where historic production data does not exist. This thesis proposes a methodology to simulate potential future wind fleets with differing geographic dispersion across the province. This simulated data is used to obtain an estimate of future wind energy fleet production and changes to Alberta's energy market, including relative capture prices. Wind energy production simulations were developed using publicly available data from the Canadian Wind Atlas (CWA) and comparing it to historical market data. Future wind fleet permutations' production profiles are modelled using Aurora electric market model developed by Energy Exemplar [11] to examine impacts on pool price and variations of wind fleet price capture.

This work was supported as part of the Future Energy Systems (FES) work at the University of Alberta established in 2016 with support from the Canada First Research Excellence Fund (CFREF). [12]

1.1. Motivation

Simulating wind farms' output is not new; it is a requirement for any wind farm that is developed. Wind energy developers install wind monitoring stations and collect data at the site of potential development sites. These data are typically confidential, and models are specific to proposed wind farm layouts. Future wind farms that may be developed in areas where wind projects already exist based on market production data; however, as would be expected, wind farms tend to target the locations with the strongest wind regimes. The goal of this work is to be able to simulate wind farms in regions, which may not have the strongest wind regimes, but where wind speeds could be non-correlated to existing projects using publicly available data. This will allow for transparent and replicable results when examining hypothetical wind farm fleet configurations.

1.2. Thesis Overview

Chapter 2 provides the background information necessary for understanding the work presented in Chapter 3 and Chapter 4. This includes discussions about energy transitions, Alberta's electricity market, the basic concepts of wind energy and wind turbines, the history of wind power in Alberta, and numerical weather prediction models. A review of relevant literature on wind energy forecasting and wind farm losses are also presented. Chapter 3 contains a paper explaining the methodology created to perform the wind power forecast of non-existing wind farms across the province. Chapter 4 lays the foundation to examine the potential market impacts of geographic dispersion of wind energy in Alberta. Chapter 5 summarizes the present thesis, states its contributions, and discusses future work.

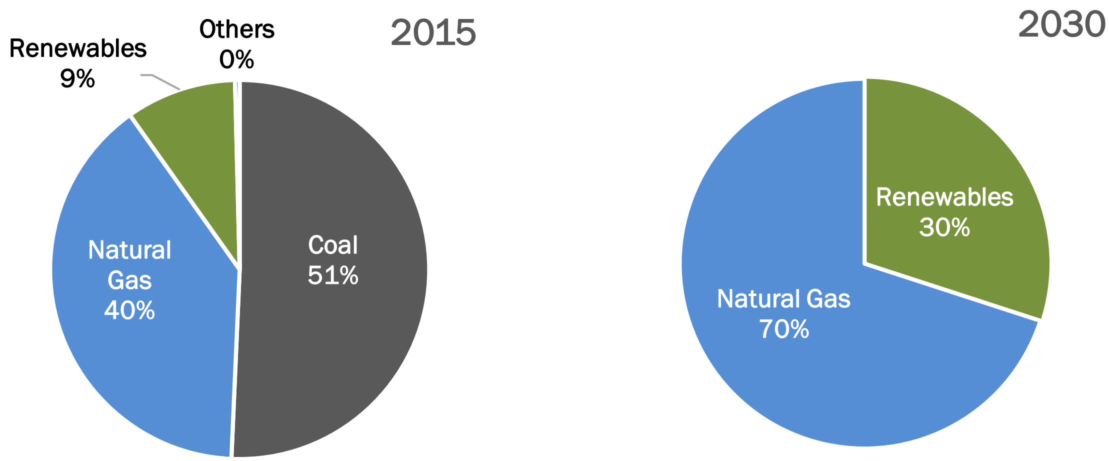
CHAPTER 2: Background and Literature Review

2.1. Energy Transitions: Alberta's renewables targets, coal phase-out, and carbon pricing.

The way societies secure energy and transform it into useful work exerts a powerful influence on their economic growth and prosperity, international relationships, and geographical structure. Significant shifts in the role of different fuels and energy conversion technologies have happened in the global energy mix in the past centuries [13]. The major challenge in the twenty-first century is to bring a new transition towards a more sustainable energy system, a system characterized by universal access to energy services, security and reliability of supply from efficient, low-carbon sources [13]. The *energy transition* concept has been widely used within energy studies and incorporated into the national energy policies in countries like Germany, Denmark, the United Kingdom, the Netherlands, the United States, China, India, and Canada [14]. The term *energy transitions* are mostly used to describe the changing composition (structure) of primary energy supply. The transition from traditional biomass fuels (wood, charcoal, and crop residues) to fossil fuels (coal and hydrocarbons) has been the most recognized and universally experienced as an example of this process [14]. Modern civilizations could not have arisen the way they have without the substantial combustion of fossil fuels. Still, this very dependence is the source of rising CO_2 emissions and the leading cause of anthropogenic global warming. This dependence is the reason why the main concern of today's energy transition is with *decarbonisation:* displacement of fossil fuel combustion by increasing reliance on carbon-free flows of renewable energy [14].

In Canada, the Pan-Canadian Framework on Clean Growth and Climate Change plan was developed to meet the emission reduction targets of the country, grow the economy and build resilience to a changing climate [15]. This plan was built on the momentum of the Paris Agreement of 2015 [6]. As mention in this framework, pricing carbon pollution is a central piece that will encourage innovation to seek out new ways to pollute less and increase efficiencies. Carbon pricing has been recognized as one of the most effective approaches to reduce GHG emissions. Carbon pricing is the government's imposition of an extra cost on activities that release CO_2 [16]. The most common mechanisms of carbon pricing are a cap-and-trade program (in which the government issues tradeable permits that allow for the emission of a certain amount of CO_2) or a straightforward carbon tax [16]. As of 2016, the provinces leading the way on this are British Columbia with a carbon tax, Alberta with a hybrid system that combines carbon levy with a performance-based system for large industrial emitters, Quebec, and Ontario with cap-and-trade systems [15]. In November 2015, the government of Alberta introduced the CLP with the scope of the provincial carbon tax and specific objectives on emissions and electricity generation [7].

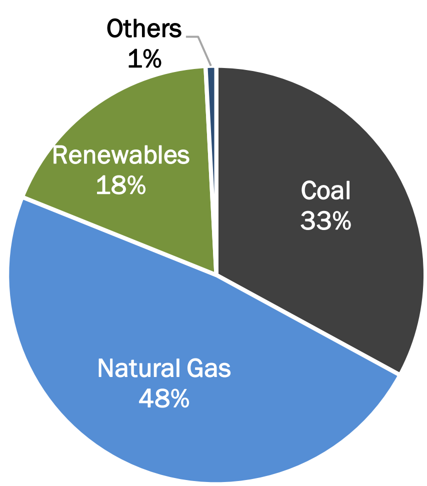
Alberta's carbon levy was launched on January 1, 2017, and it is applied to all purchased fossil fuels that produce GHG emissions when burned [17], designed to broaden the scope of pricing on GHG emissions across the province's economy and to create an incentive for action that reduces emissions. As of January 1, 2018, the levy applied to heating and transportation fuels is based on $30 per tonne CO_2e. Beginning in 2021, the federally-imposed carbon price will rise to $40 per tonne and $50 per tonne in 2022 [7]. Nevertheless, the province's carbon levy was eliminated and no longer applied on May 30, 2019 [17]. Two actions under the CLP support the phase-out of pollution from coal-generated electricity by 2030 and the generation of 30% of electricity from renewable sources by 2030, as stated in the Alberta's Renewable Electricity Act [18]. To get there, the province has a plan to add 5 GW of renewable electricity through the Renewable Electricity Program (REP) using a competitive process administered by the Alberta Electric System Operator (AESO). To meet this target, investment in Alberta's electricity system was enabled through a competitive bidding process, while ensuring that the projects would come online in a way that it would not impact grid reliability [8]. The economic impact of the successful projects will result in a new investment of at least $10.5 billion into the Alberta economy by 2030 [8]. The generation profile by energy produced as of 2015 can be seen in Figure 2-1.



Data: Alberta Utilities Commission [19]

Figure 2-1. Generation Profile by Energy Produced in 2015 vs. the expected Generation Profile in 2030.

This profile has changed with the increase of renewables into Alberta's electricity mix. In 2018, the total generation in the province was approximately 85 terawatts hours (TWh), where 18% of the total generation came from renewable sources [20]. The progress on the 2030 goal can be seen by comparing Figure 2-1 to Figure 2-2***Figure 2-2***.



Data: Alberta Utilities Commission [19].

Figure 2-2. Alberta Electric Generation (GWh) by Resource, 2018.

Alberta can keep on transforming its electricity supply from a system based on coal to one based on a diverse combination of cleaner options. One of the most feasible options to reach this goal is installing more wind energy in the province, as Alberta has one of Canada's best wind resources [21].

2.2. Alberta's Electricity Market and Wind Discount

Alberta's electricity market is based on supply, demand, and competition. Investors choose a time, location and type of generation and most financial risk is taken by the investor, not by the end consumer. Using this system, power producers and importers submit electricity supply offers to the AESO system controller. The AESO manages the power offered and distributes it across the province on an hourly basis, starting with the lowest price offers, and incrementally adding power from cheapest to most expensive until the demand is met. As the demand for electricity shifts continuously throughout the day, the system controller maintains supply and demand in balance and ensures the reliability of the system by dispatching the next eligible supply or accepting the next demand bid [22]. This supply offers and demand bids are sorted from the lowest to the highest price for each hour of the day into a list called a merit order [23]. As system demand increases, the system controller shifts up the merit order, dispatching the next eligible supply or accepting the next demand bid. If the system demand declines, the system controller dispatches down the merit order. With this system, Alberta's overall electricity needs are met by the lowest cost option when possible. Because of this system, the wholesale price of electricity has averaged $64/MWh over the last ten years [24].

Alberta has an energy-only market. In energy-only markets, generators are paid for the electricity they produce based solely on the wholesale price of electricity [25]. Therefore, in energy-only markets, such as Alberta's, the power price is set by the merit order, the electricity price fluctuations due to the merit order effect are shown in Figure 2-3. Where the sequence in which the power generation stations give power to the market, with the lowest-price offer made by the power source with the lowest running cost setting the starter point for the merit order. Electricity from renewable sources, such as wind turbines or photovoltaic installations, is sold first because of their marginal cost that equals $0, which results in it being always dispatched.

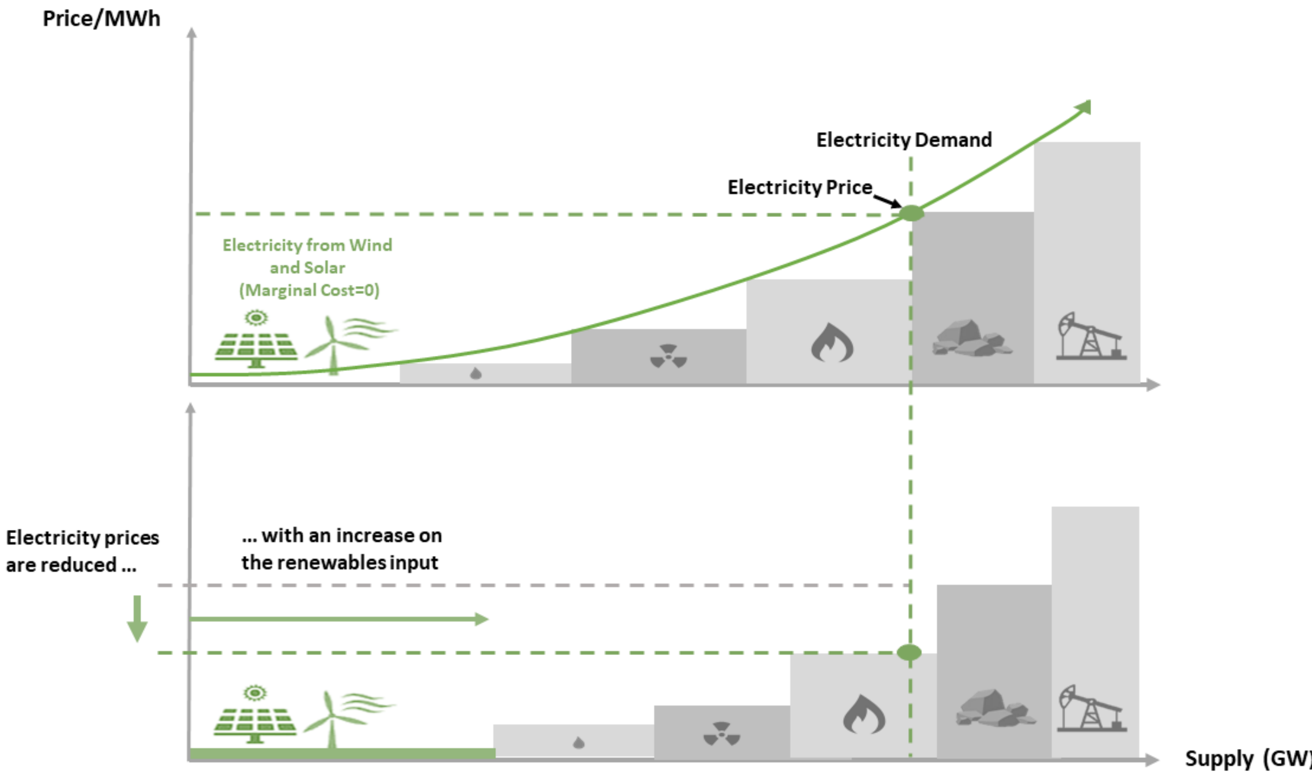


Figure 2-3. Illustration of the electricity price changes due to the Merit Order.

As of 2017, Alberta generated a total of 82.4 TWh (terawatts hour), where its primary generation came from coal (45%) and natural gas (45%), followed by wind, biomass/geothermal and hydro [26]. In 2018, Alberta generated 84.7 TWh, 48% provided by natural gas and 42% by coal. According to AESO, the demand for electricity in Alberta will grow by 1% each year for the next 20 years [27]. The hour of the day at which a generator delivers power to the grid is sometimes as crucial as the quantity of electricity offered. The revenue of this generator is a function of both the hourly pool price and the amount of electricity generated and delivered to the grid at that hour.

In Alberta, the capture rate describes how a generation facility gets high pool prices for the power it is generating. The capture rate (%) is the percentage of the average pool price in a period that a generation facility receives for the electricity that it generates [28]. Alberta wind farms experienced a lower capture rate than other sources of generation. Between 2008-2015, on average, wind farms earned $18/MWh less than the average pool price in Alberta, meaning the wind farm's average prices were 30-35% less than the average pool prices [28], this is generally known as Alberta's "wind discount."

There are two main reasons for this negative correlation and the low capture rate for wind in the province. The first one is because the majority of the wind farms in Alberta are concentrated in southern Alberta, half of them located in the Pincher Creek region. Pincher Creek is a town in the southwest of the province, and it is located east of the Canadian Rockies, about 100 km west of Lethbridge and 210 km south of Calgary.

Second, wind farms usually generate more of their power in the evening and overnight, which are period of off-peak demand when pool prices are below average. The net result of this is that large quantities of wind power generation in southern Alberta come online at the same time when the wind blows; thus, this concentration of supply pushes the pool prices lower for those hours, which means that those wind farms will receive a lower pool price.

2.3. Wind Energy Concepts

Wind energy, also known as wind power, refers to the process of creating electricity using the wind, or air flows, that naturally occur in the earth's atmosphere [29]. Obtaining electricity from wind energy is one of the methods with a higher growth rate of electrical generation in the world [30]. Wind turbines convert the kinetic energy from the moving air into electricity. The kinetic energy is caused by the uneven heating of the surface of the earth, creating motion in the atmosphere, and thus, kinetic energy with this movement [31]. The variations of different meteorological variables affect the behaviour of the wind resource, making it faster, slower, or turbulent. These variables are temperature, humidity, solar radiation and, rainfall; as well as the terrain's surface, pressure gradient force, Coriolis effect and friction [31].

The wind is air with a kinetic energy that can be transformed into useful work, in this case, electricity, via a wind turbine generator. Wind, as a resource, can generate competitive, cost-effective electricity in locations with valuable wind resources and high cost of electricity [32]. The wind speed at a given time determines the amount of power available in the wind. The power available in the wind is given by:

$$\frac{P}{A} = \frac{\rho_{air} v^3}{2} \tag{2.1}$$

where

P = wind power [W]

A = swept area of the rotor [m^2] = $\pi D^2/4$

ρ_{air} = density of the air [kg/m^3]

v = wind velocity [m/s]

Wind power is proportional to the cubic of the velocity (v^3), consequently, if the speed of the wind is doubled, the wind power will increase by a factor of eight. The density of the air, under standard conditions, is 1.225 kg/m^3 (sea level and 15°C). Power from the wind is proportional to the swept area. The energy per unit of the area available from the steady wind is shown in (*2.1*)

Table 2.1 Power per unit area available from steady wind ($\rho_{air} = 1.225\ kg/m^3$)

Wind Speed (m/s)	Power/area (W/m^2)
0	0
5	77
10	613
15	2,067
20	4,900
25	9,570
30	16,538

Nevertheless, according to Betz' Limit, no more than 59.3% of the kinetic energy of the wind can be extracted. The Betz' Limit or Betz' Law is the maximum theoretical efficiency a wind turbine can achieve, and it was first presented by the German physicist Albert Betz, in 1919. Betz concluded that no wind turbine could convert more than 16/27 (59.3%) of the kinetic energy of the wind into mechanical energy by turning a rotor. This limit is obtained as follows.

The mass flow rate of the air through the swept area of a wind turbine can be written as:

$$\dot{m} = \frac{1}{2}\rho A_t (v_u + v_d) \tag{2.2}$$

Where v_u corresponds to the wind velocity upstream of the turbine, and v_d the wind velocity downstream of the turbine in m/s. The efficiency of a wind turbine is the actual power extracted, compared to the theoretical maximum energy available:

$$\eta = \frac{\dot{E}_{Actual}}{\dot{E}_{Max\ Available}} = \frac{(P_u - P_d)A_t v_t}{1/2\rho A_t v_u^3} \tag{2.3}$$

Where:	$\dot{m} =$	mass flow rate of wind [kg/s]
	$\rho =$	density of the air [kg/m^3]
	$A_t =$	swept area of the turbine rotor [m^2]
	$v_u =$	wind velocity upstream of turbine [m/s]
	$v_d =$	wind velocity downstream of turbine [m/s]
	$v_t =$	wind velocity at the turbine [m/s]
	$P_u =$	Pressure immediately upstream of the turbine [Pa]
	$P_d =$	Pressure immediately downstream of the turbine [Pa]

Knowing that $(P_u - P_d) = \frac{1}{2}\rho(v_u^2 - v_d^2)$ and $v_t = \frac{1}{2}(v_u - v_d)$, substituting in (*2.3*)

$$\therefore\ \eta = \frac{(P_u - P_d)A_t v_t}{\frac{1}{2}\rho A_t v_u^3}$$

$$= \frac{\frac{1}{2}\rho(v_u^2 - v_d^2)A_t v_t}{\frac{1}{2}\rho A_t v_u^3} = \frac{\frac{1}{2}(v_u^2 - v_d^2)(v_u - v_d)}{v_u^3} \tag{2.4}$$

$$= \frac{1}{2}[1 + V_R - V_R^2 - V_R^3]$$

Where, $V_R = \frac{v_d}{v_u}$,

$$\frac{d\eta}{dV_R} = 0 = \frac{1}{2}\ [1 - 2V_R - 3V_R^2] \tag{2.5}$$

$$\therefore\ V_{R_{opt}} = \frac{1}{3} \text{ or } v_{d_{opt}} = \frac{1}{3}v_u$$

Substituting $V_{R_{opt}} = \frac{1}{3}$ in (*2.5*),

$$\eta_{Betz} = \frac{1}{2}\left[1 + V_{R_{opt}} - V_{R_{opt}}^2 - V_{R_{opt}}^3\right] = \frac{1}{2}\left[1 + \frac{1}{3} - \left(\frac{1}{3}\right)^2 - \left(\frac{1}{3}\right)^3\right] = \frac{16}{27} \quad (2.6)$$

Thus the Betz Limit equals 16/27 (59.3%), the explanation behind this number relays on how wind turbines harvest energy from the wind by slowing it down. Therefore, for a turbine to be 100% efficient, it would need to stop the wind, meaning the rotor would have to be a solid disk, and it would not turn, and no kinetic energy could be converted. In practice today, no more than about 45% of the available wind power can be harvested by the best modern horizontal axis wind turbines [33]. Wind turbines specifics will be further explained in the next section.

The actual power production potential of a horizontal axis wind turbine is affected by the fluid mechanics of the flow passing through a power-producing rotor at the desired location according to its wind regime and its wind variations [34]. The variations in the wind are produced with the season, the time of the day, and different weather events. Therefore, it is necessary to study the estimation of available energy in the wind and the suitability of the site where the wind farm is going to be installed. It is extremely important to understand that power is proportional to the cube of velocity and that the mean of the cube of a variable is not the same as the cube of the mean. On top of that, wind turbines have inertia and respond to changes in wind speed and direction (velocity) slowly. This means that small-scale fluctuations in wind velocity do not contribute to energy production if the time scale of the fluctuation is short; in fact, very high-frequency velocity fluctuations, both up or down, can reduce the power produced if the instantaneous wind velocity does not match the alignment and speed of the turbine at the moment of incidence. So, in some cases, the wind speed can increase, but if it happens briefly from the wrong direction before the turbine responds, it could decrease, not increase the power produced. This is why knowing the time scale of fluctuations is important for wind resource assessment.

Therefore, the analysis of wind resources focuses on several critical features of the wind data: the frequency of the wind speeds, the average annual wind speed, turbulence, vertical wind shear, and maximum gusts. The temporal wind speed variations can be divided into four categories: inter-annual; annual; diurnal; short-term (gusts and turbulence) [33], explained as follow.

- *Inter-annual variations* in wind speed occur over time scales greater than one year. It is as essential to estimate the inter-annual variability at a given location as it is to determine the long-term mean wind resource. Meteorologists conclude that it takes around five years of data to obtain a reliable average annual wind speed at a given location. The prediction of long-term average wind speed models is complicated because of the interactions of the meteorological and the topographical factors that cause these variations [33].

- *Annual* wind speed variations often occur with seasonal changes.
- The *diurnal variations* are caused, in both tropical and temperate latitudes, due to the differential heating of the earth's surface during the daily radiation cycle. A typical diurnal variation is when wind speed increases during the day and decreases during the hours from midnight to sunrise. The most considerable diurnal changes usually occur in spring and summer and the smallest in winter. However, the diurnal variation my vary with location and altitude above sea level [33].
- *Turbulence and gusts* are included in the short-term wind speed variations. Short-term variations usually mean changes over time intervals of ten minutes or less. Turbulence can be thought of as random wind speed fluctuations superposed on the mean wind speed. Turbulence can be in the form of small eddies originating from friction with the ground, or large rolls or swirls originating from the weather and meteorology, but both cause fluctuations of too high frequency to be of use for wind power generation. These fluctuations occur in three different directions: vertical, lateral (which is perpendicular to the average wind), and longitudinal (which is in the direction of the wind). Horizontal variations in velocity can be turned into power if they are low frequency (very large, slow-changing swirls kilometres in diameter), but almost any vertical velocity fluctuations cause a decrease in efficiency. A gust can be defined as discrete events within a turbulent wind field. According to [33], one way to characterize a gust is to determine its amplitude, rise time, maximum gust variation, and lapse time. Wind turbine structural loads caused by gusts are affected by these four factors.

Wind speed is also extremely dependent on the topographical and ground variations, and its direction varies over the same time scales over which wind speeds vary.

2.3.1. Wind Farm Configuration

When it is necessary to generate large quantities of power, several wind turbines can be clustered and installed together, forming a wind farm or a wind park. There are several advantages to building wind farms instead of installing single turbines. The proximity means the installation, operation and maintenance of such clusters are easier than managing scattered units, and the power transmission can be more efficient as the electricity for such sites may be transformed to a higher voltage [34]. Nowadays, wind power, as wind farms, can be classified into three main categories:

- **Off-shore wind:** the wind turbines are installed in large bodies of water, generally on the continental shelf, which is about 10 km away from the coast and about 10 m deep. These turbines tend to be larger and less obtrusive than the onshore (land-based) turbines, while wind over the sea has inherently less turbulence because there are no buildings, trees, hills or mountains there to create boundary layer turbulence. Thus they and can generate more power than land-based systems [35].
- **Utility-scale wind:** also known as onshore wind, is the land-based wind farms where the turbines' rated capacity usually ranges from 100 kilowatts (kW) up to several MW. These turbines tend to be smaller than off-shore turbines. The electricity generated by these is delivered to the power grid and then distributed to the end-user by power system operators or electric utilities.
- **Distributed or "small" wind:** formed by wind turbines below the 100 kW, used in two main areas:
    - **Autonomous** electrical systems (also known as 'stand-alone,' 'grid-isolated' or 'off-grid'), in other words, are not connected to any more extensive electrical system, and therefore are solely responsible for the control the supply of energy to their system [36].
    - **Distributed generation** systems with small wind turbine generators connected to more extensive public distribution networks, where the larger network is in charge of the overall control of the system. These are also known as 'grid-connected' or 'on-grid generation.' Municipalities, or other local government entities, private sector firms, and coordinated public sector buildings control some of these [37].

Each of these categories uses different sizes of wind turbines depending on the specifications of the site, mean wind speeds, and location. The turbine sizes, types, and how they work will be further explained in the following section.

2.4. Wind Turbines Basics

A wind turbine, also called wind energy converter, is a device that transforms the wind's kinetic energy into electrical energy [38]. The turbine will produce electricity when the wind turns the blades, which in turn spins a generator to create power. There are two main types of wind turbines, the vertical-axis wind turbines (VAWTs) and the horizontal-axis wind turbines (HAWTs). Both designs are shown in Figure 2-4 image by [39].

Vertical-axis wind turbines are comparatively rare and are commonly called the egg-beater wind turbines because of how they look. In a VAWT, the shaft is mounted on a vertical axis, perpendicular to the ground. Because of this vertical shaft, it allows the generator to be conveniently on the ground. This kind of wind turbine does not align with the horizontal wind, so there is no adjustment needed when the wind changes direction. Therefore, their designs are considered omnidirectional. Typically, a VAWT is not self-starting, and it needs energy from its electrical system to start. They generate torque as a reaction to *drag* force on the blades, which is stronger in one direction than the other. It typically uses wires for support, instead of a tower, this means the rotor elevation is lower. A lower elevation means slower wind speeds due to the roughness of the terrain, causing lower wind speeds closer to the ground. Consequently, VAWTs are generally less efficient than HAWTs. Also, they are considered less efficient because of the variation in the aerodynamic torque with a wide range in the angle of attack over a rotation of the rotor [40].

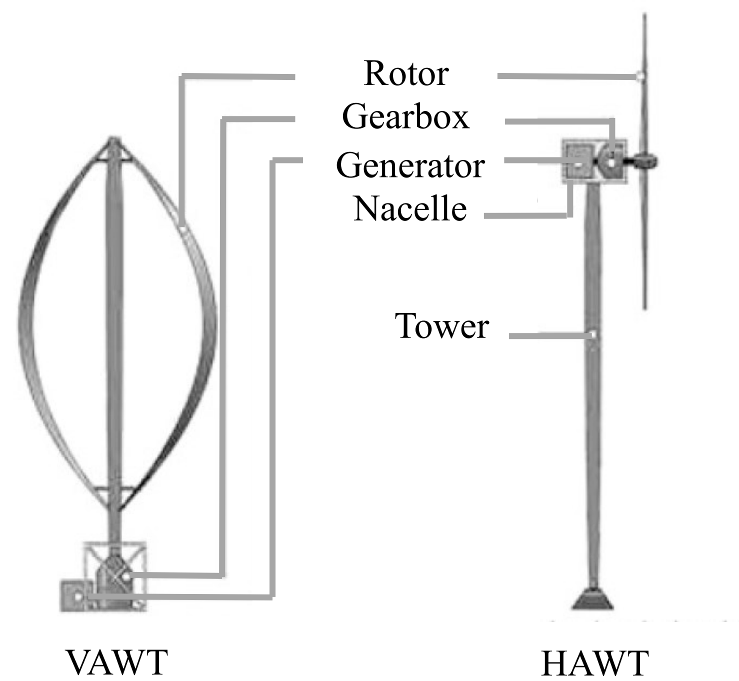


Figure 2-4. VAWT and HAWT [39]

Horizontal-axis wind turbines are much more widely used than VAWTs. This type of generator has a higher aerodynamic yield than the vertical ones, has fewer elements at ground level, and it starts autonomously [41]. These turbines are made up of several blades shaped like airfoils, used to generate a driving torque causing rotation. The torque comes from the aerodynamic *lift*, not *drag*. The number of blades used for power generation usually varies between one and four, with three blades being most common and efficient. There is a compromise between the cost, the power coefficient, and the speed of rotation of the anemometer [42].

There are three main components of a HAWT, the tower or mast, the nacelle, and the rotor. In the nacelle is the generator, which is driven by the high-speed shaft, which is connected to the low-speed shaft by a gearbox [39]. The low-speed shaft is connected to the rotor, including the airfoil-shaped blades. The blades capture the kinetic energy of the wind and transform it into the rotational kinetic energy of the turbine.

Most wind turbines operated at fixed speeds when producing electricity. For the start-up sequence of a turbine, the rotor is held stopped, and after the breaks are released, it is accelerated by the wind until it reaches the required fixed speed. At this instant, a connection to the electricity grid is made, then the network (through the generator) holds the speed constant. If the wind speed increases beyond the rated speed (the speed at which rated power is generated), the power is regulated either by stall or by pitching the blades [40]. Subsequently, the variable speed operation is introduced. This allows the wind speed and rotor to be matched, and thereby, the rotor maintains the best flow geometry for maximum efficiency. With variable speed operation, the rotor is connected to the grid at low speeds in very light winds and speeds up in proportion to wind speed [40].

Stall-regulation refers to the blade design where if the wind speeds are high, the rotational speed (or aerodynamic torque), thus power production, decreases with increasing wind speeds above specific values, usually not the same as the rated wind speed [40]. Pitch-regulation refers to the control system design that can vary the pitch angle (turn the blade around its axis) of the turbine blades to decrease the torque produced by high wind speeds [43]. This happens when wind speeds get very high (usually more than the rated speed) to slow down the turbine's rotational speed or the torque transferred to the shaft, so the rotational speed is kept constant below the cut-out speed of the turbine to prevent damage in the equipment[40].

Typically, HAWTs generate electricity at wind speeds of 4-25 m/s [44]. Once the turbine's rotor starts moving, a series of gears increase the rotation of the rotor. The most common ratio is about 90:1, with a rate of 16.7 rpm input from the rotor to 1,500 rpm output for the generator [45], at this speed, that allows the turbine's generator to produce electricity (AC). The power output of a wind turbine varies with wind speed; hence every wind turbine has a unique power performance curve. A power curve allows wind energy prediction. The power curve represents the power output as a function of the mean wind speed at hub height, as seen in Figure 2-5

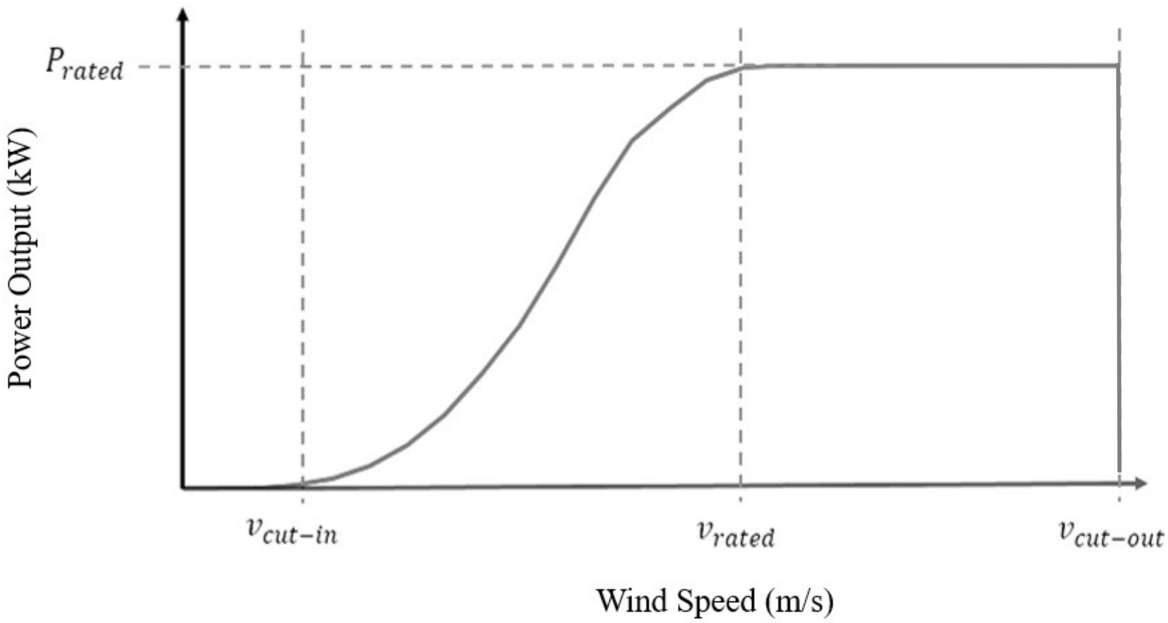


Figure 2-5. Typical wind turbine power curve.

The minimum speed at which the turbine produces useful power is known as the cut-in speed (v_{cut-in}). The rated speed (v_{rated}) is the speed at which the rated power (P_{rated}) is produced. The rated power is the maximum output power a wind turbine can generate. The cut-out speed ($v_{cut-out}$) is the maximum wind speed at which the turbine is allowed to produce power. The cut-out speed is limited by engineering design and safety constraints since any increase above the rated power causes greater unwanted loads, vibration and braking. Power curves are often publicly available and can be obtained from the manufacturer or the turbines. Worldwide, the top ten wind turbine manufacturers who had 94% of the market share in 2008 were Vestas, GE Wind, Siemens Gamesa, ENERCON, Suzlon, Sinovel, Acciona, Goldwind, and Nordex [46]. In Alberta, the manufacturers with installed commercially operating turbines are Vestas, ENERCON, GE, Siemens Gamesa, and Nordex.

2.5. History of Wind Power in Alberta

Wind as a resource has been utilized historically to facilitate human activities. Still, it was not until 1887 when Professor James Blyth from Anderson's College in Glasgow, Scotland, used the first windmill for electricity production [47]. In Canada, the history of wind traces its beginnings to

1930 when hundreds of small wind turbines, of one to three kilowatts (kW) in capacity, were built in rural areas in the western provinces to provide lighting for small farms. Years later, in 1975, Hydro-Quebec Research (IREQ) started a wind power program with an installation of a 40 kW vertical-axis wind turbine, known as an "egg beater" because of its appearance. This site is now decommissioned. In 1984, the construction of the Project Eole started on the Gaspé Peninsula, building the world's largest vertical-axis wind turbine (361 ft. height). Later, in 1986, Hydro-Quebec made the Kuujjuaq Wind Turbine demonstration project; it was a 65 kW horizontal-axis wind turbine in an off-grid system [48].

In Canada, the first commercial wind farm was commissioned in 1993 by TransAlta, near Pincher Creek in Alberta. This wind farm's maximum installed capacity was 16 megawatts (MW) with 57 turbines; it was decommissioned in the spring of 2016 [49]. In 2000, the project had an expansion with the opening of Cowley North. This new wind farm had fifteen 1.3 MW wind turbines. Thanks to the technology improvement, these fifteen turbines were capable of generating nearly as much power as the 57 turbines at the original project [50]. In 2013, Halkirk Wind Project, in east-central Alberta, was the largest wind farm running in the province. This project consists of 83 turbines, each with a capacity of 1.8 MW of power, generating a total installed capacity of approximately 150 MW. Before Halkirk, the largest wind farm in Alberta was Wintering Farms, with an installed capacity of 88 MW.

Wind energy is now utility-scale, and it has been increasing to supply a more substantial proportion of Canada's electrical demand. Currently, Alberta ranks third in the wind market in Canada, with 1,685 MW of installed capacity, following Ontario with 5436 MW and Quebec with 3,882 MW as of December 2019. Alberta has 38 projects with 957 wind turbines. Wind energy has become the lowest-cost source of new electricity in the province [51]. With the actual installed capacity, Alberta's wind farms produce enough electricity to power 431,000 average-sized homes, corresponding to approximately 8% of the province's electricity demand. As of 2018, the largest wind farm in Alberta was the 300 MW Blackspring Ridge project, situated in Vulcan County, and it is comprised of 166 Vestas V100-1.8 MW wind turbines [52].

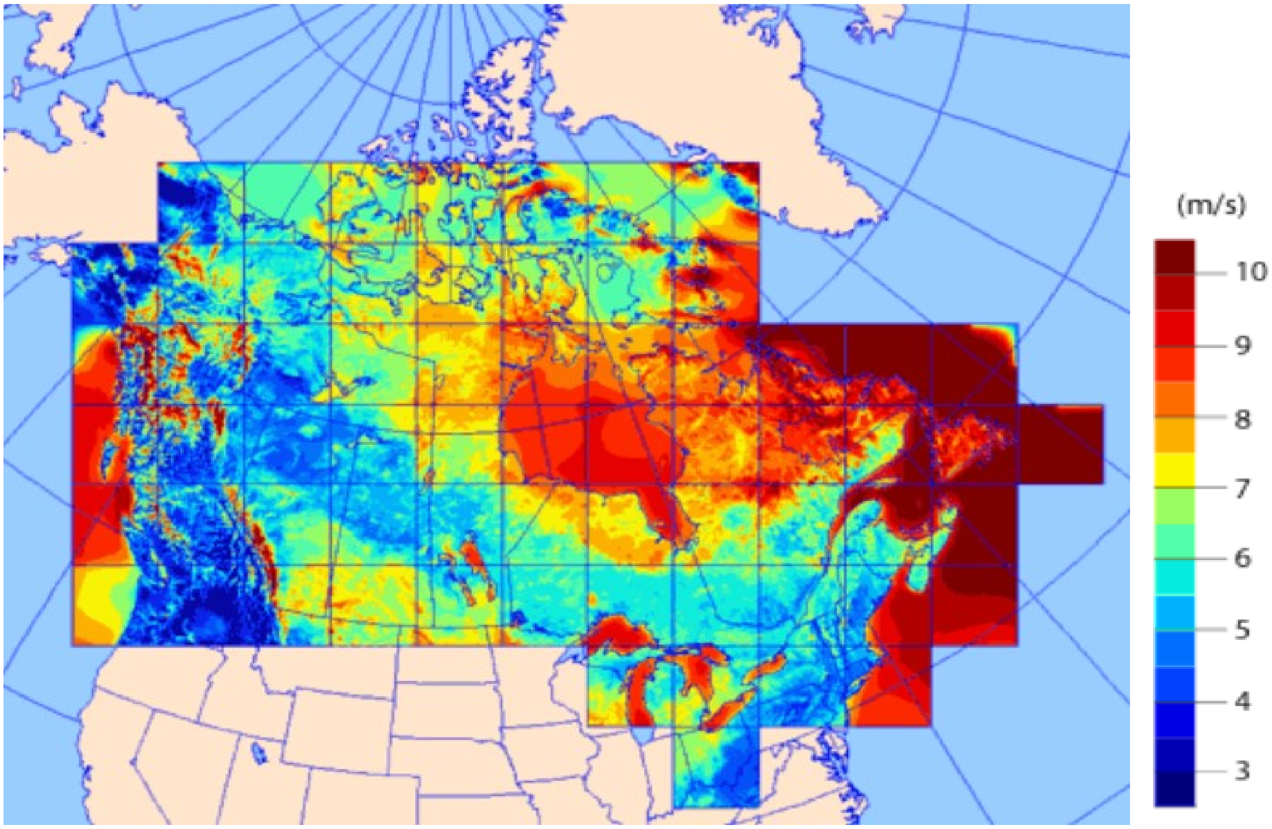


Figure 2-6. Average annual wind speed at 80 m above ground level. (Source: Environment Canada)

In Canada, one of the best and more accessible land-based wind resources is in Alberta, as can be seen in Figure 2-7. The strongest winds are present in the south of the province, where most of the existing wind farms are located. Moreover, there are some regions in the west and northwest of the with a minimum annual wind speed of 7 m/s, a speed which is generally considered to be potentially economically viable for wind energy production [21].

Current wind farms, its location coordinates, and mayor characteristics are shown in Table 2.2

Table 2.2. Utility-scale wind farms operating in Alberta as of December 2019.

Wind Farm/Site	Location (Lat, Long)		Turbine Hub Height (m)	Capacity (MW)	Built Turbines	Turbine Size (MW)	Commissioning Year	Model
Ardenville Wind	49.52	-113.41	80	69	23	3	2010	Vestas V90
Bull Creek	52.50	-110.06	80	29	17	1.7	2015	GE 1.7-103
Blackspring Ridge	50.14	-112.86	80	300	166	1.8	2014	Vestas V100
Blue Trail Wind	49.65	-113.46	80	66	23	3	2009	Vestas V90
Castle River	49.50	-114.03	50	40	60	0.66	1997	Vestas V47
Castle Rock	49.55	-113.96	64	77	33	2.31	2012	Enercon E70
Cowley Ridge North	49.56	-114.10	65	20	15	1.3	2001	Nordex N60
ENMAX Taber	49.71	-111.93	85	81	37	2.2	2007	Enercon E70
Ghost Pine	51.89	-113.34	80	82	51	1.6	2010	GE 1.6 XLE
Halkirk Wind Power Facility	52.29	-112.04	80	150	83	1.8	2012	Vestas V90
Kettles Hill	49.51	-113.80	67	63	35	1.8	2006	Vestas V80
McBride Lake Windfarm	49.59	-113.46	50	75.90	115	0.66	2003	Vestas V47
Old Man 2	49.57	-113.85	80	46	20	2.3	2014	Siemens SWT 2.3 -93
Soderglen Wind Farm	49.51	-113.49	65	71	47	1.5	2006	GE 1.5 SLE
Summerview 1	49.60	-113.77	67	66	39	1.8	2004	Vestas V80
Summerview 2	49.59	-113.73	80	66	22	3	2010	Vestas V90
Suncor Chin Chute	49.67	-112.31	80	30	20	1.5	2006	GE 1.5 SLE
Suncor Magrath	49.38	-112.95	65	30	20	1.5	2004	GE 1.5 SLE
Whitla Wind 1	49.64	-112.29	105	201.6	56	3.6	2019	Vestas V136
Wintering Hills	51.19	-112.55	80	88	55	1.6	2011	GE 1.6-82.5 XLE

2.6. Numerical Weather Prediction Models

Numerical weather prediction models are computer software programs based upon the mathematical equations of motion describing the flow of fluids [53]. These models solve the conservation of momentum, mass and energy equations by making estimates of the continuous domain (the earth) at discrete points in time and space, with spatial and temporal derivatives calculated using estimates based on differences in point values. The results are values of velocity, temperature and turbulence information on a grid of points separated in time by set time steps. According to the present state of the atmosphere, these models can simulate the passage of time, modelling the atmosphere evolving forward in time using a sequence of time steps and thereby predict a future state. The knowledge of the current state of the weather is just as valuable as the numerical model. Current weather observations serve as input to the models through a process known as data assimilation to produce outputs of temperature, precipitation, wind speed and direction, and other meteorological elements of the atmosphere [54]. Countries around the globe have their NWP models to represent the passage of time in the atmosphere corresponding to their territory. One primary application that can be obtained from the NWP is a wind atlas. A wind atlas is a meteorological tool that represents the average wind velocity and power of an area, and it is mostly used by the wind energy industry to determine the wind potential of a specific region [55]. Some countries like Canada [56], the United States [54], Greece [57], have their wind atlas obtained from their NWP models. There is a European Wind Atlas [58], which covers some countries like Belgium, Denmark, France, Germany, Ireland, the Netherlands, Portugal, Spain and the United Kingdom. The Canadian Wind Atlas is being used in this thesis.

2.7. Literature Review

In order to use the data from the Canadian Wind Atlas, a calibration method must be created. To create the method, a review of existing best practice guidelines on wind energy forecasting, how to evaluate wind profile simulations, and losses simulation was first carried out.

2.7.1. Wind Energy Forecasting

Different models for wind power forecasting have been developed during the past couple of years. According to the literature, there are various methods for predicting either wind power production or wind speeds. For the evaluation of the potential of wind in specific regions, it is required to collect systematic and on-site data on different meteorological variables, to create a more accurate forecast. According to Foley et al. [59], there are three steps in wind energy production forecasting:

I. The determination of wind speeds from a model;

II. The calculation of the wind power output forecast or prediction; and,

III. The regional forecasting or upscaling or downscaling for different time horizons.

In the literature, the forecasting methods tend to be classified according to time scales and according to different methodologies that have been used.

Time scales and methods for prediction wind power can be divided into four categories [60]–[64]:

- *Ultra-short-term forecast: from a few minutes to 1 hour ahead:* This minute forecast helps to satisfy the needs of the wind turbines' control and to stabilize the electricity quality.
- *Short-term forecast:* From one hour to several hours ahead, this hourly forecast helps to power systems to schedule at a reasonable pace and to guarantee the power quality. This forecasting method is based on NWP models. This kind of prediction tends to fulfill the needs for market dealing, operation and maintenance planning and supply security.
- *Medium-term forecast:* From several hours to one week ahead, also based on NWP models, this forecast can be used for arranging the commission and maintenance program and for scheduling optimization in a power plant.
- *Long-term forecast:* From one week to one year or more ahead, this forecast is predicted annually, and it is mainly used to study the feasibility of wind farm design and annual energy production. Since wind is intermittent and fluctuating, this kind of forecasting prediction is usually not precise, so it is recommended to be only seen as a reference.

Overall, in a wide range, the input data for wind power forecasting models can be divided into two main groups. The first group uses forecasted values from an NWP model (Section 2.6), and the second group is based upon the analysis of the historical time series of wind [59]. The models on the second group use statistical approaches to forecast mean hourly power production based on previously measured physical parameters. From Soman et al. [64] and Lange et al. [65], Table 2.3

was made to represent the power forecasting methods depending on the forecasting technique they are using.

Table 2.3. Power Forecasting Methods.

Physical Approach	Physical systems use parametrizations based on a detailed physical description of the atmosphere. The basic problem to be solved is the transformation of the wind speed given by the weather service on a coarse numerical grid to the on-site conditions at the location of the wind farm. For this, it is essential to take into consideration the horizontal interpolation from the grid point to the co-ordinate of the turbine and the transformation of the wind speed from the NWP to the hub height.
Statistical Approach	This approach is based on training with measurement data and uses the difference between the predicted and the actual wind speeds. The main idea is to derive a statistical relation between the given input from the weather prediction and the measured power output of wind farms. These systems rely entirely on data analysis, ignoring the meteorological details.
Hybrid Structures	A combination of different approaches, such as mixing physical and statistical methods or combining short-term and medium-term models, is referred to as a hybrid approach.

Ying et al. [66] propose the method of the Grid-Scale Wind Power Forecasting and the Single Farm Wind Power Forecasting. In the method for the single wind farm short-term power forecast, the wind speed is forecasted based on NWP models, and the energy transferring model was constructed, taking into account the influence of surface roughness, topography and wake effects on capturing the wind energy. For the grid-scale, they analyzed the correlation between each wind farm output and power of the entire grid, and then they selected wind farms with high correlations to the whole grid and high power forecast accuracy (Root Mean Squared Error (RMSE) < 30% and Mean Absolute Error (MAE) < 25%). Based on this, the model was constructed by the statistic approach.

Chen and Folly [67] used forecasted wind speed to convert them to the estimated wind speed at the hub height by using the power-law equation, as presented in (2.7).

$$(v_1) = (v_0)\left(\frac{h_1}{h_0}\right)^{\alpha} \tag{2.7}$$

Where v_1 is the wind speed measured at h_1 meters above ground and v_0 is the wind speed measured at h_0 meters above ground, and α represents the surface roughness exponent at a specific site. Note that this method is very sensitive to the surface roughness assumption, which is not a measured physical parameter, but a value that is assumed based on the local surroundings. Then, the estimated wind speeds at the hub height were then used to calculate the estimated wind power by using (2.8).

$$P_{real}(v) = \frac{1}{2}\rho(t)Av^3 \tag{2.8}$$

The model performed well for the very-short-term time horizon wind power forecasting, with an RMSE (%) of 5.8 and an MAE (%) of 4.2.

Zhao X. et al. [68] analyzed the evaluation methods on the uncertainty of wind power forecasting, listed as follows:

- The Mean Error (ME)
- The Mean Squared Error (MSE)
- The Root Mean Squared Error (RMSE)
- The Mean Absolute Error (MAE)
- The Standard Deviation of the Errors (SDE)
- The Normalized Root Mean Squared Error (NRMSE)
- The Normalized Mean Absolute Error (NMAE)
- The Mean Absolute Percentage Error (MAPE)

Zhao et al. concluded that different evaluation methods have different effects depending on the characteristic of the wind power forecasting system. The RMSE is more sensitive to the presence of erroneous data when compared to the MAE. Therefore is there is doubt about the quality of the evaluation set, the MAE should be preferred as the main evaluation criterion since it is more robust when confronted with large prediction errors.

2.7.2. Wind Farm Losses

To create wind power forecasts, it is necessary to undertake a series of different tasks to obtain good approximations of the energy production of a wind farm. For these, it is required to estimate or calculate a range of potential sources of energy loss. According to the European Wind Energy Association (EWEA) [69], there are six main sources of energy loss for wind farms, each of which is subdivided into more specific loss factors, as shown in Table 2.4.

Table 2.4. List of energy loss factors for wind farms.

Main sources of energy loss	Subdivision
Wake Effect	• Wake Effect Internal: the effect that wind turbines within the wind farm have on each other. • Wake Effect External: the effect that the wind turbines from neighbouring wind farms (if any) have on the wind farm being considered. • Future Wake Effect: the effect caused by wind farms that will be constructed in the vicinity in the future.
Availability	• Turbine Availability: associated with the amount of time the turbines are unavailable to produce energy. Some of the reasons for their unavailability rely on environmental conditions (icy conditions, high wind speeds), failure of particular components of the turbine, or scheduled and unscheduled maintenance [70]. • Balance of Plant (BOP) Availability: loss of power associated with the downtime of the balance of plant. BOP describes the reliability of the wind plant's components other than the turbine, such as the electrical collection system and substation [71]. • Grid Availability: loss of energy associated with the downtime of the grid connection. This happens, in an example, when the grid is unable to accept generated electricity due to a lack of capacity [70].

Electrical Efficiency	• Operational electrical efficiency: the electrical losses encountered when the wind farm is operational and will be manifested as a reduction in the energy measured by an export meter at the point of connection [72]. • Wind Farm Consumption: electrical consumption of the non-operational wind farm, such as consumption by electrical equipment within the turbines and substation.
Turbine Performance	• Generic Power Curve Adjustment: sometimes, the supplied power curve does not represent the power curve accurately, and adjustment is applied. • High Wind Hysteresis: loss of energy production due to the introduction of hysteresis into the turbine’s control algorithm to prevent fatigue loading when the turbine is shutting down and up when the wind speeds exceed the cut-off speed [72]. • Site-Specific Power Curve Adjustment: some wind farm sites can experience wind flow conditions that materially differ from the wind flow condition seen at simple terrain test sites. Therefore an adjustment needs to be applied.
Environmental	• Performance Degradation – Non-icing: the performance of wind turbines can be affected by blade degradation due to dirt or wear over the prolonged operation. • Performance Degradation – Icing: small amounts of icing on the turbine blades can change the aerodynamic performance of the machine. • Icing Shutdown: as ice accretion becomes severe, wind turbines will shut down or will not start. • Temperature Shutdown: Turbines are designed to operate over a specific temperature range; if this range is exceeded, turbines will be shut down.

	• Site Access: severe environmental conditions can influence access to more remote sites, which can affect availability. • Tree Growth: for wind farm sites located within or close to forests or other trees areas, the impact of how the trees may change in time and the effect this will cause on the wind flow over the site may affect energy production [72].
Curtailments	• Wind Sector Management: some wind farms with particularly close machine spacing may be necessary to shut down specific turbines for certain wind conditions. This is referred to as wind sector management. • Grid Curtailment: within certain grid connection agreements, the output of the wind farm is curtailed at certain times.

Multiple studies have been made in the literature on how to predict wind farm power losses for some of the mentioned factors. Torres Garcia E. et al. [73] made a statistical approach to wakes and showed the relationship that this behaviour has with the incoming wind conditions and neighbouring wakes. Their analysis filters the incoming wind conditions according to the thermal stability, wind direction and wind velocity at hub height; therefore, the wakes that were developed in periods with similar wind conditions are expected to be analogous. Lee J. and Lundquist J. [74] quantified the value of the wind farm parameterization (WFP) accounting for wake impacts on the power production of downwind turbines. Also, they found out that wake effects lead to underestimations of stable and low turbulence conditions.

Diaz-Dorado et al. [75] present a state estimation (SE) method to calculate energy losses. They concluded that losses take place in each element on the network (cables, transformers) and on the measurements (power, voltage, current). They found that for Stoavento Experimental Wind Park, in Spain, the losses represent a 2.84% of the energy generated by the turbines. Chen, Z. [76], looked at the electrical losses, exposed that harmonic disturbance, which is a phenomenon associated with the distortion of the fundamental sine wave produced by non-linearity of electrical equipment and causes power losses. Also, he mentions that reactive power is one of the significant causes of voltage instability in the network due to voltage drops in transmission lines; reactive current also contributes to system losses.

Kilpatrick [77] calculated the loss factors for a study involving the performance assessment of 23 wind farms in eight Canadian provinces over six years, spanning May 2010 to April 2016, where production losses were calculated as the difference between the wind farm actual production and the forecast production values. Losses were calculated monthly. Kilpatrick also introduced the term "cold climate loss" to indicate the additional losses incurred during the winter period compared to the summer baseline.

CHAPTER 3: Calibrating the Canadian Wind Atlas Data to Historic Wind Energy Performance in Alberta.

As discussed previously, to be able to model hypothetical wind farms, it is first critical to validate the ability to use the Canadian Wind Atlas in order to predict the output from hypothetical wind farms built in Alberta. This chapter presents an article explaining the methodology used to calibrate the publically available data from wind atlas to simulate wind farm output in Alberta. Comparing the historic market performance of existing wind farms to modelled output generated from the wind atlas were used to calibrate the methodology. This technique allows for the development of annual hourly time series for wind fleets in areas across Alberta where wind farms do not currently exist, including modelling the effects of increased geographically dispersed wind fleets.

Additional plots, which are relevant to the work but not contained in the paper manuscript, are shown in Appendix A for completeness.

Calibrating the Canadian Wind Atlas Data to Historic Wind Energy Performance in Alberta.

Natalia Vergara Bonilla, Brian A. Fleck, Tim Weis, Andrew Leach

ABSTRACT

Simulating the output of wind energy fleets is increasingly useful in order to plan and understand potential development scenarios, electricity market impacts and opportunities. This paper examines the utility of publicly available data from Environment Canada's Numerical Weather Prediction (NWP) model to simulate hourly wind farm output by validating it against historic market data in Alberta, Canada. We examine the ability to develop an hourly wind energy forecast model for generic modelled wind farms using the NWP wind data for Alberta. Market output data was compared to wind speeds published in the Canadian Wind Atlas (CWA) for six wind farms that operated over the same time frame (January 2008 to December 2010) as the historic modelled data (HMD) in the CWA. Energy losses between maximum expected and actual output were estimated in order to predict annual energy production, seasonal and diurnal patterns, as well as frequency and scale of energy output ramps of simulated wind farms. These results were then compared against historic wind energy market data in Alberta. Overall, the CWA data tended to underestimate output from 8:00 am until 12:00 pm from March to June (spring) in general, which could be taken into account. However, mismatches were so large in the southwest region of the province that the wind atlas data were unusable for predictions. Making minor adjustments for the morning hours of spring, the overall performance results of the model show an annual energy production percentage error between 1% to 10% for wind farms that operated over the same timeframe as the HMD. Comparing CWA data against wind farms outside of the HMD produced annual energy production simulations as well as aggregate output ramping events similar to actual market data suggesting the CWA data could be a basis for predictive bulk system simulations.

Keywords: wind energy forecasting; generic losses; Canadian Wind Atlas; wind fleet simulation.

3.1. Introduction

Over 65% of Canada's electricity is generated from renewable resources (mainly hydro), and Canada has a national target of producing 90% of its electricity from 'non-greenhouse gas emitting' sources by 2030, including renewables and nuclear energy [78]. Wind energy has grown from less than 1,000 MW of installed capacity in 2004 to over 13,000 MW in 2020, and will likely to continue to expand as Canada moves to meet its aforementioned target [79]. Much of this development could happen in Alberta, where Canada's only fully competitive electricity market is undergoing a major decarbonization process. The ability to simulate potential wind fleet build-out scenarios from *publicly available* data is useful in order to be able to examine as market impacts, integration issues and opportunities.

Alberta is Canada's fourth most populated province, with 4.4 million inhabitants [80] as of 2019, and has an electricity system which consumed 85 TWh of electricity in 2019 with a peak load of 11.5 GW [81]. As recently as 2014, up to 70% of the energy sold in Alberta's electricity market came from coal-fired plants, but coal-fired electricity will be completely phased out by 2030 [3]. Wind, on the other hand, is slowly being phased in and provided approximately 6% of the energy sold in Alberta's electricity market between 2014 and 2019. Alberta's wind fleet totalled 1,781 MW at the end of 2019 and is expected to increase since the government anticipates that wind energy makes up the majority of the 5,000 MW of new renewables required to reach 30% of electricity generation by 2030 [18].

In 2018, the Alberta Electric System Operator (AESO) began a process that procured approximately 1,360 MW of new wind projects to be built by 2023 through 20-year fixed-price contracts [82]. The average price for new wind projects procured during this program was less than 40 CDN/MWh [83], notably less than historic market prices, which have averaged around 50 CDN/MWh over the past decade, suggesting that wind energy is likely to continue to grow in spite of the cancellation the 30% renewables commitment in 2019. All of these significant changes occurring in Alberta make it an interesting case study.

The majority of Alberta's wind farms are clustered in the south of the province, and their correlated output tends to erode energy prices significantly when the wind is producing. For example, between the years 2010 and 2019, the average Alberta energy price was closer to 50 CDN/MWh, while the average wind fleet's capture price was 35 CDN/MWh. This discount compared to average market prices ranged as high as 41% in 2012 to a low of 10% in 2016. [10]. In spite of its low production costs, the financial success of future wind farms, as well as the ability of the province to integrate high levels of wind, may, in part, depend on more geographically diverse development in order to minimize this market price discount. This work is an effort to examine how wind data published by the Government of Canada can be used to model wind energy development scenarios in Alberta.

3.1.1. Wind Power Forecasting Methodology Classification

There are various methods for predicting the production of wind power, which are classified based on time scales. Each of the following categories has different applications, ranging between feasibility studies for wind farm design, maintenance planning, operation management, operational security in electricity markets, real-time grid operations, regulatory actions, or economic load dispatch planning, among many others [67]. Several studies within the literature divide these forecasting methods into four broad categories [60], [61], [63], [67], [68]:

- Ultra-short-term: From seconds to an hour ahead.
- Short-term: From one hour to several hours ahead.
- Medium-term: From several hours to one week ahead.
- Long-term: From one week to one or more years ahead.

Wind power forecasting models can also be divided into those who use Numerical Weather Prediction (NWP) models as an input, and those which are based on the analysis of the historical time series of wind data collected at proposed wind farm locations [59] to forecast wind farm output.

Wind farms' revenues are affected by long-term wind speeds, power demand at the time of generation as well as other market participants' behaviour, including wind farms with correlated output. The objective of this work is to develop a simulation that captures both long-term patterns as well as short-term correlations of hypothetical wind farms based on publicly-available data from the Environment and Climate Change Canada's NWP model known as the Canadian Wind Atlas (CWA) [56].

3.1.2. Numerical Weather Prediction Models

The Canadian government's ecoENERGY Innovation Initiative (ecoEII) funded a national wind model project to generate a multi-year time series of surface-layer meteorological fields based on its numerical weather prediction model GEM-LAM to support the Pan-Canadian Wind Integration Study (PCWIS) project [84]. The data from this model are publicly available and are the primary input for the methodology used in this paper (further discussed in Section 2.1).

Similar NWP models have been developed in Germany, the United States, Australia and the United Kingdom [85]. In the United Kingdom, the Met Office vertical wind profiler measurements for the British Isles is a dataset collection that contains the available 30-minute averaged wind profile data from various sites around the British Isles. The data from these sites are available for research and include parameters such as measurements of the zonal, meridional and vertical components of winds, signal-to-noise ratio (SNR) and spectral width [86].

In the United States, the Real-time Four-Dimensional Data Assimilation version of the Weather and Forecasting Mesoscale model is a mesoscale numerical weather prediction model designed for high-resolution applications, a version of it was optimized for wind energy applications for Xcel Energy [87]. The National Center for Environmental Prediction maintains several models for the public good, where only the wind speed from grids coincident with wind turbine locations are extracted [88].

3.1.3. State of the Wind Energy in Alberta

Alberta is the third-largest wind market within Canada with 38 commercial projects and 957 wind turbines totalling 1.78 GW of installed capacity as of December 2019 [51], as shown in Table 3.1. In Alberta, the majority of the wind farms have been built in the south, where the wind is the strongest, particularly in the southwest, close to the community of Pincher Creek, where Canada's first commercial wind farm was built in 1993 [89]. There are numerous sites throughout Alberta with an average annual wind speed of 6-7 m/s or higher at the height of 80 m above the ground [90], which may be suitable for development.

While the southwest of the province has some of the strongest winds, the concentration of wind farms in the area results in a strong correlation of output of the wind farms. Alberta has a competitive "energy-only" electricity market where energy prices are bid upon hourly. Wind energy sources sometimes bid at 0 $/MWh into the market and, as a result, lower the market price when they are operating. Between 2010 and 2019, the average wind market capture price was close to 35 $/MWh compared to 50 $/MWh for the entire market over the same timeframe [10].

Table 3.1. Utility-scale wind farms operating in Alberta as of December 2019.

Wind Farm Name	Location (Lat, Long)		Turbine Hub Height (m)	Capacity (MW)	Built Turbines	Turbine Size (MW)	Commissioning Year	Model
Ardenville Wind	49.52	-113.41	80	69	23	3.0	2010	Vestas V90
Bull Creek	52.50	-110.06	80	29	17	1.7	2015	GE 1.7-103
Blackspring Ridge	50.14	-112.86	80	300	166	1.8	2014	Vestas V100
Blue Trail Wind	49.65	-113.46	80	66	23	3.0	2009	Vestas V90
Castle River	49.50	-114.03	50	40	60	0.66	1997	Vestas V47
Castle Rock	49.55	-113.96	64	77	33	2.31	2012	ENERCON E70
Cowley Ridge North	49.56	-114.10	65	20	15	1.3	2001	Nordex N60
ENMAX Taber	49.71	-111.93	85	81	37	2.3	2007	ENERCON E70
Ghost Pine	51.89	-113.34	80	82	51	1.6	2010	GE 1.6 XLE
Halkirk Wind Power Facility	52.29	-112.04	80	150	83	1.8	2012	Vestas V90
Kettles Hill	49.51	-113.80	67	63	35	1.8	2006	Vestas V80
McBride Lake Windfarm	49.59	-113.46	50	76	115	0.66	2003	Vestas V47
Old Man 2	49.57	-113.85	80	46	20	2.3	2014	Siemens SWT 2.3 -93
Soderglen Wind Farm	49.51	-113.49	65	71	47	1.5	2006	GE 1.5 SLE
Summerview 1	49.60	-113.77	67	66	39	1.8	2004	Vestas V80
Summerview 2	49.59	-113.73	80	66	22	3.0	2010	Vestas V90
Suncor Chin Chute	49.67	-112.31	80	30	20	1.5	2006	GE 1.5 SLE
Suncor Magrath	49.38	-112.95	65	30	20	1.5	2004	GE 1.5 SLE
Whitla Wind 1	49.64	-11.29	105	202	56	3.6	2019	Vestas V136
Wintering Hills	51.19	-112.55	80	88	55	1.6	2011	GE 1.6-82.5 XLE

3.1.4. Wind Energy Output Losses

The expected maximum output of a real wind farm would be found by looking at the power output from the turbine manufacturer's power curve and every known or modelled wind speed over the course of the year multiplied by the number of turbines in the wind farm. In reality, the difference between the expected and actual output of a wind farm (hereafter referred to as a "loss") depends on numerous factors, including turbulence, blade soiling, and wind farm layout [91]. The principal loss factors (coefficients between 1 and 0, which characterize the fractional difference between expected and observed power, see below) in wind farms are the wake effects, the availability, the electrical efficiency; the turbine performance; the environmental losses; and the curtailments [72]. These loss factors can be subdivided, as seen in Table 3.2.

Table 3.2. Subdivision list of energy loss factors [69].

Primary Factors of energy loss	Subdivision
Wake Effects	• Internal wakes • External wakes • Future wake effects
Availability	• Turbine availability • Balance of plan availability • Grid availability
Electrical Efficiency	• Operational electrical efficiency • Wind farm consumption
Turbine Performance	• Generic power curve adjustment • High wind hysteresis • Site-specific power curve adjustment
Environmental Losses	• Performance degradation - non-icing • Performance degradation - icing • Icing shutdowns • Temperature shutdowns • Tree growth

Curtailments	• Wind sector management • Grid curtailments

Where the future wake effects refer to the impact that future neighbouring wind farms are going to have on the existing wind farms of the area, the tree growth relates to the implications of the growing flora on the wind farm's area roughness factor.

Multiple studies that predict wind farm power losses can be found in the literature. These include:

1. Power losses due to turbine wakes and their effects on power production of downwind turbines [74].
2. Power losses due to transmission and distribution [75], [76].
3. Power losses in the grid due to the annual variation of wind speeds [92], due to the wind speed variations, various nonlinear losses in wind turbines, transmission lines change the efficiency of the power system.
4. Power losses due to seasonal changes (temperature and air density), downtime losses, array losses, and icing losses [77].

These energy losses typically add up to between 10-15%, a range within the energy losses are commonly calculated by developers [75],[93]–[95]. Engineering simulations can model the individual losses and estimate the performance of a wind farm, but such simulations require detailed wind information at a proposed site as well as its layout. The aforementioned details are not available when simulating the bulk output of wind fleets across a jurisdiction like Alberta. As such, this work develops a general approximation for the combined energy losses compared to the kinetic energy available at the given wind speed published in the Canadian Wind Atlas.

3.1.5. Numerical Weather Prediction Models as Input

Environment and Climate Change Canada's CWA is a publicly available data set with 10-minute averages of winds at 80, 100 and 120 m heights above ground level over the entire country. In addition to wind speeds and direction, the CWA includes meteorological information such as temperature, pressure and precipitation. The CWA is based on a set of quadrilateral mesoscale domains, which are called "tiles" [56]. The three-dimensional mesoscale atmospheric model covers a historic modelled data (HMD) period of three years from January 2008 to December 2010 with a 2 km horizontal grid spacing [84].

For our methodology, we use the HMD as the primary input, and the wind farms are simulated as a single point located at the centroid of the actual wind farm, as stated in Table 1. The polygons in Figure 1 shows an example of the Chin Chute wind turbine locations, and the black star represents the centroid of the wind farm. The CWA grid cells are shown in grey circles, and HMD was used for the location closet to the wind farm centroid, as shown in Figure 3-1.

Figure 3-1. Location of wind atlas data with respect to wind farm layout at Chin Chute using Google Maps.

The Wind Atlas publishes speeds at 80 m, 100 m and 120 m heights. The boundary layer power law [96] was fitted at each site through the wind speeds at the three heights to extrapolate wind speed matching the nacelle height of each turbine that is installed on each wind farm.

3.2. Methodology

In order to calibrate losses, the CWA data were compared to historic market data from wind farms that were active during the HMD to compare annual energy output, seasonal variations and energy ramps (increment or decrement of energy production during a certain period). This model is not intended to predict the commercial accuracy of any specific wind farm, but rather to analyze the overall output characteristics of aggregated production of larger and geographically diverse wind fleets, including ramps, maximum outputs, seasonal and annual energy outputs. The methodology and simulation procedure are illustrated in Figure 3-2.

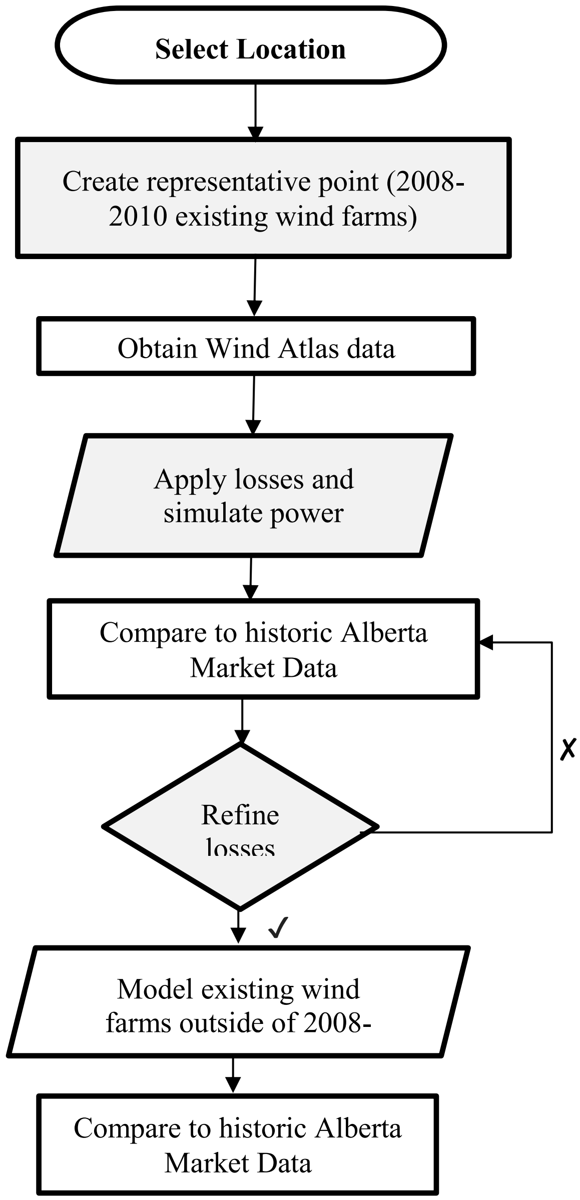


Figure 3-2. Calibration of CWA data to historical market performance flowchart.

There were six wind farms that were operational in Alberta during the entire HMD. The CWA data were collected from the representative centroid (latitude and longitude) of each farm location. Using the 10-minute wind speed data and the turbine manufacturer's power curve, the expected output was compared to observed power production data from AESO at the same time. Losses were approximated by examining the calculated differences between the expected output and the power production data. It was observed that average losses were not steady, but rather varied with time and wind speed. As such, an unsteady loss coefficient was developed, which compares fractional discrepancy between expected and observed power. Afterwards, the historical market data were compared to the simulations of the same wind farms to ensure that the annual energy production, the diurnal profiles and the hourly output ramping behaviour are comparable. These are considered as the evaluation metrics for the model.

3.2.1. Generic Loss Coefficient Development

A loss coefficient was developed comparing the expected power output to the historic market data from operating wind farms. Gross expected power output from an individual wind turbine (P_{M_i}) was calculated at 10-minute intervals by separating the manufacturer's power curve into a piecewise equation shown in (3.1).

$$P_{M_i} = \begin{cases} 0 & v_i < v_{cut-in} \\ \beta_0 + \beta_1 v_i + \beta_2 v_i^2 + \cdots + \beta_k v_i^k & v_{cut-in} \leq v_i < v_r \\ P_{M_r} & v_r \leq v_i < v_{cut-out} \end{cases} \tag{3.1}$$

Where, $v_{cut-\mathrm{in}}$ represents the cut-in speed in m/s, $v_{cut-out}$, the cut-out speed in m/s, v_r , the rated speed in m/s and, P_{M_r} represents the rated wind turbine output in MW. Once the 10-minute gross expect power output (P_{M_i}) was obtained, an air density adjustment was applied, as shown in (3.2)

$$P_{Ma_i} = P_{M_i} \left[\frac{(293\ K)(P_{atm})}{(T_{actual_i})(101.3\ kPa)} \right] \tag{3.2}$$

Where P_{Ma_i} represents the density adjusted wind turbine output. Most wind turbine's power curves are published for a constant air density value of $\rho = 1.225\ kg/m^3$ at sea level [97]. Therefore, the value for temperature is 293 K and atmospheric pressure 101.3 kPa, as it was used in (3.2).

The total expected wind farm output was calculated by summing the individual turbines' expected output and was capped at the rated wind farm maximum in cases where the sum of the power of all turbines exceeded rated farm capacity.

For each 10-minute period, the expected output (EO) was subtracted from the market data (MD) to obtain a difference. While the EO and the MD are taken from the same 3-year timeframe, in reality, there are differences between the two. These may include wind farm downtime, curtailments or local micro-climate effects, which means that the CWA wind speeds can not always be expected to match actual historic data in every interval perfectly. Instances when the relative difference between the EO and M was above 20% of the maximum wind farm output, were assumed to be data mismatches and were not used to estimate losses.

The relative power difference for the remaining data is assumed to be the first approximation of wind farm losses. Losses were grouped by 1 m/s bins over the operating range of the power curve (typically 3 m/s to 25 m/s). Losses were found to be, on average, 45% at low wind speeds (below cut-in wind speed divided by the rated wind speed) and were negligible at high wind speeds (above 140% of rated wind speed). For wind speeds in between, a loss coefficient was calculated by fitting with a 7th order polynomial regression through the resulting data. The resulting loss coefficients can be seen in Figure 3-3.

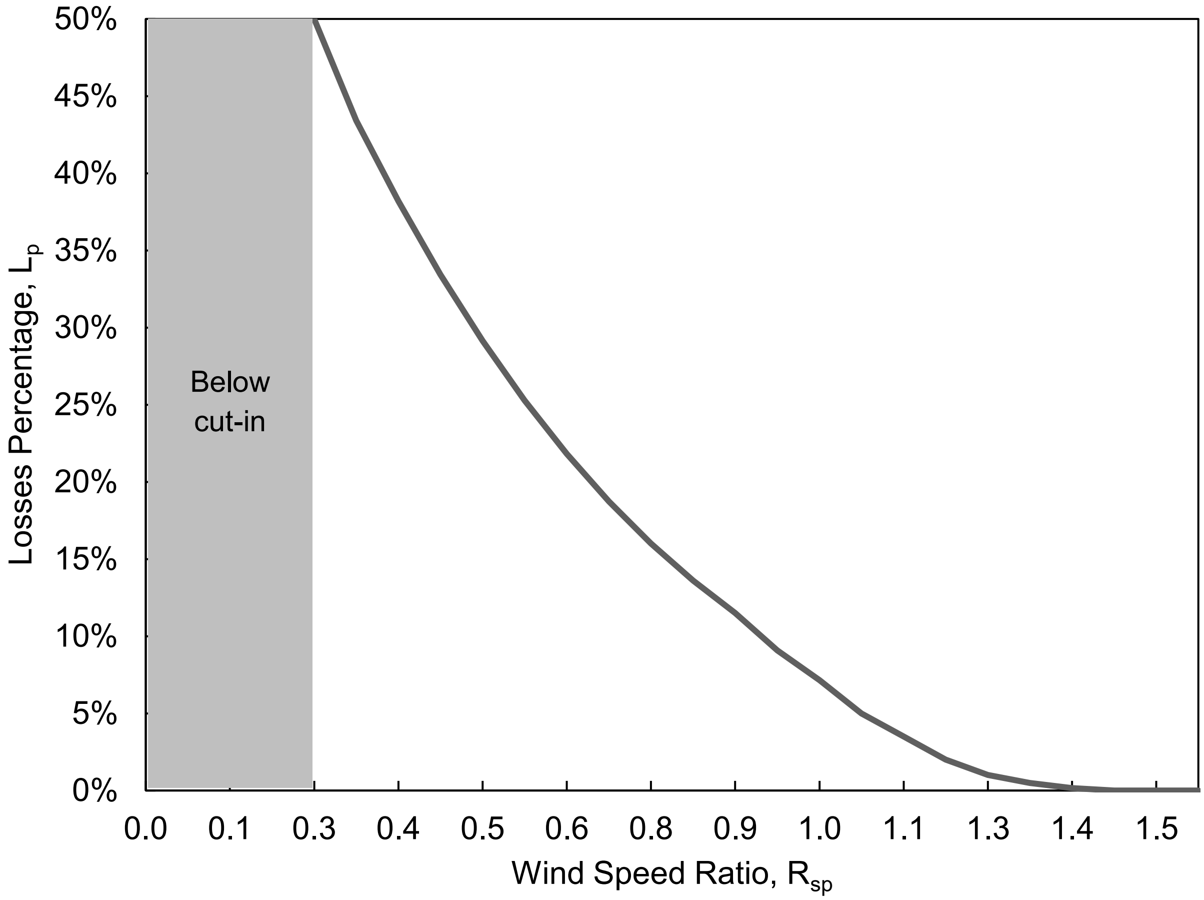


Figure 3-3. Example of empirically developed loss coefficient for ENERCON E70.

Where the wind speed ratio is calculated by dividing every wind speed (v_i) in the manufacturer's power curve over the rated speed v_r, as seen in (3.3).

$$R_{sp_i} = \frac{v_i}{v_r} \tag{3.3}$$

The loss coefficients can be calculated at any given wind speed using the piecewise function in which the losses estimated from the regression are mapped onto the specific wind speed of the manufacturer's power curve. Multiplying the specific number of built turbines on the modelled site provides expected power output at each time in (*3.4*) and (*3.5*).

$$L_{p_i} = \begin{cases} below\ cut-in & R_{sp_i} < \dfrac{v_{cut-in}}{v_r} \\ \alpha_0 + \alpha_1 R_{sp_i} + \alpha_2 {R_{sp_i}}^2 + \cdots + \alpha_k {R_{sp_i}}^k + \epsilon_i & \dfrac{v_{cut-in}}{v_r} \le R_{sp_i} < 1.4 \\ 0 & R_{sp_i} \ge 1.4 \end{cases} \tag{3.4}$$

$$\mathrm{P_{ML_i}} = \mathrm{P_{M_i} T_{wf}} \left(1 - \mathrm{L_{p_i}}\right) \tag{3.5}$$

Where in (3.4), R_{sp_i} represents the wind speed ratio calculated as in (3.3), and L_{p_i} is the percentage of losses compared to the power curve at that speed. The losses range from 45% at low wind speeds to zero when the wind farms are working at their maximum. The simulated output of the wind farm P_{ML_i} is simply the number of turbines in the wind farm (T_{wf}) multiplied by the individual turbine output P_{M_i} after adjusting for the losses as shown in equation (*3.5*).

With the values of P_{ML_i} a new power curve is created. By plotting the unaltered wind speeds from the manufacturer's power curve against the new expected power outputs with the losses applied, a new curve fitting process is being replicated as in equation (3.1). After this, the original data set is reprocessed using the new piecewise polynomial function, and the iterative method begins, where further data filtering is made as in the first iteration. Once the data are re-filtered, the process is replicated to obtain a new function each time. Iterations are repeated until the update to the loss function coefficients was under 0.03. With this calculation, the annual energy output of the simulation falls within 5% of the market data. Using the empirically calculated loss coefficients (L_{p_i}), the annual energy losses totalled 12% on average.

Figure 3-4 illustrates the duration curves comparing the simulated output to market data for the ENMAX Taber wind farm after applying the loss coefficient calculated above. We see a correlation within 5% between the number of high and low wind power generation events.

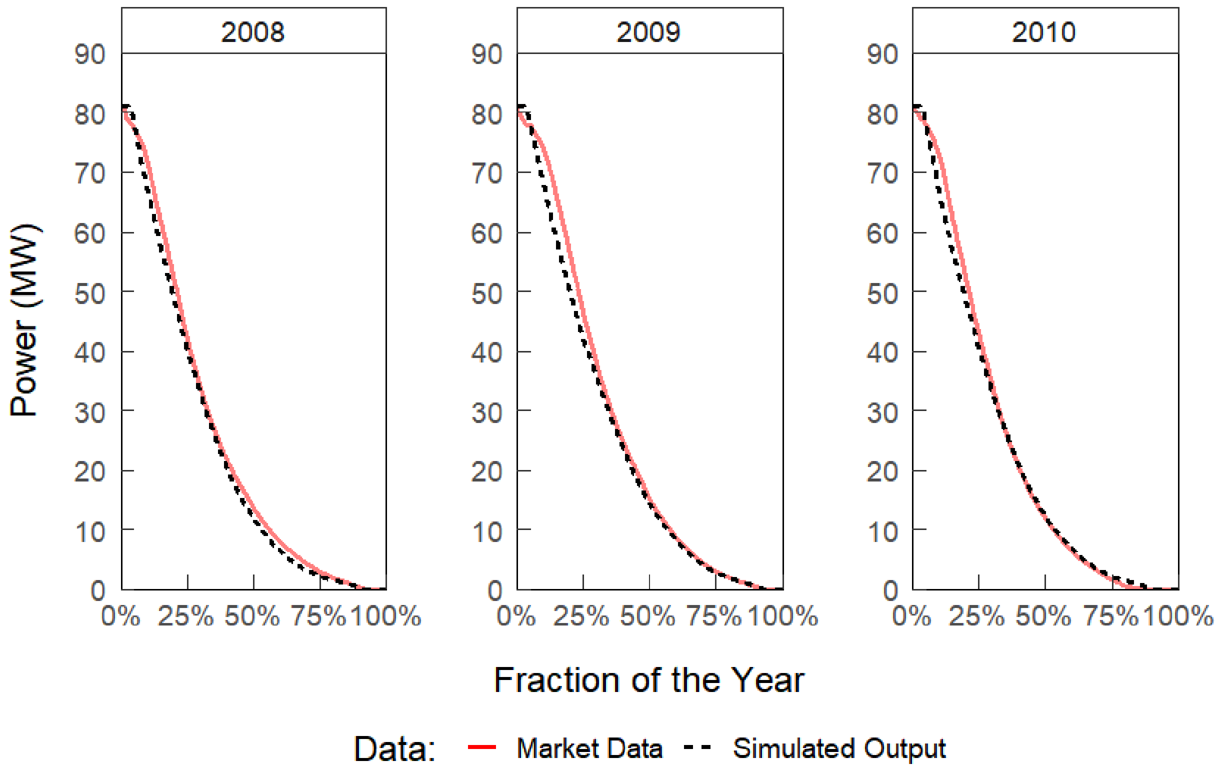


Figure 3-4. Duration curve for ENMAX Taber between the simulated output and the observed market data.

Figure 3-5 compares market data for the ENMAX Taber wind farm to expected output without losses and simulated data after the final loss coefficients were applied. On average, the difference between market and simulated data is within 10%. However, it was consistently observed that simulated data were up to 50% lower than market data between 8:00 am, and 11:00 am during the months of March to June. In order to adjust for the consistent notable under-prediction of the CWA during these hours, wind speeds were adjusted during these hours to produce power output more indicative of observed, as shown in Table 3.3. There is no physical basis for this adjustment, but it was applied to compensate for CWA data.

Table 3.3. Wind speed compensation for underprediction of wind speeds by the CWA.

Time	Wind speed compensation
8:00 am	10%
9:00 am	15%
10:00 am	10%
11:00 am	5%

This compensation, in Figure 3-5, is more notable during the hours from 8:00 am to 11:00, for March and April.

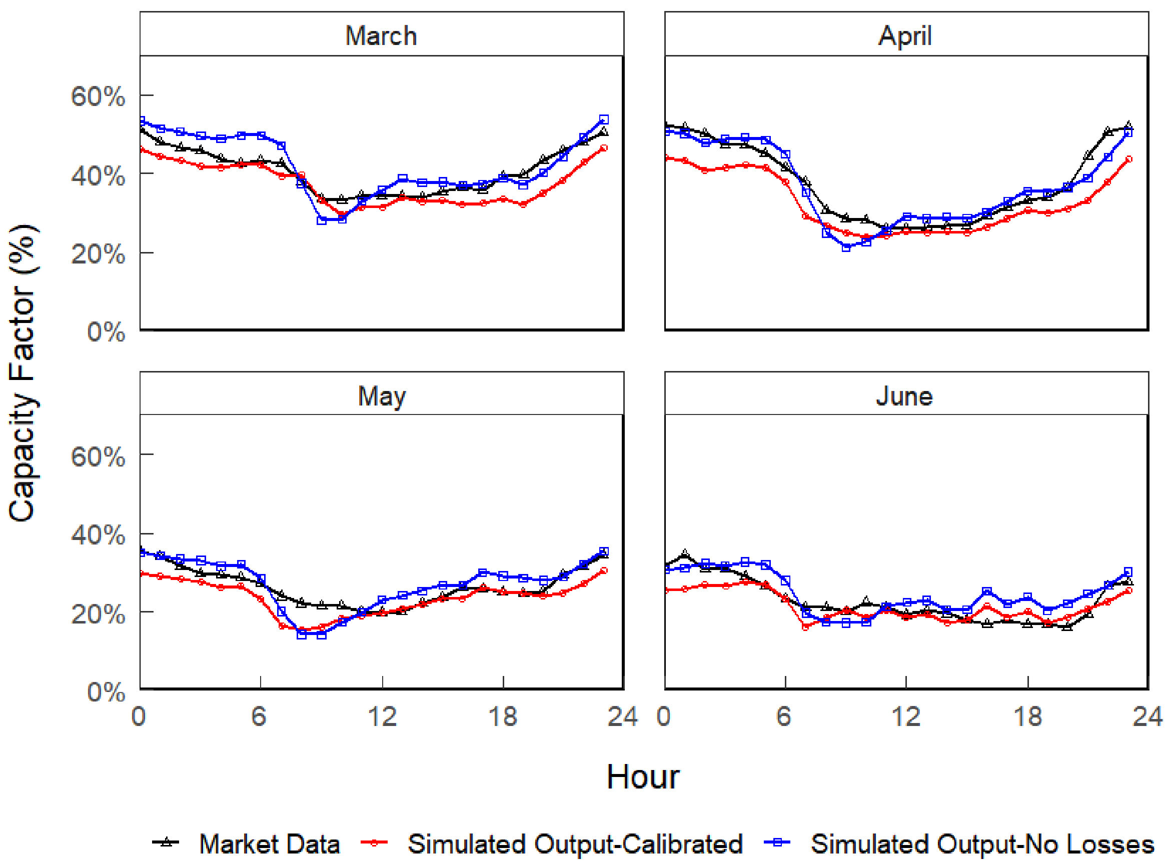


Figure 3-5. ENMAX Taber (81 MW) wind farm comparison, loss coefficient and wind speed compensation. Data from 2008-2010.

After repeating the method several times for different wind farms in Alberta and comparing the evaluation metrics (explained in Section 2.3), the difference between the losses converged, where the difference between the simulated and observed annual energy production was under the difference of 5%.

3.2.2. Evaluation Metrics and Modelled Historical Data Use Validation

Output data were simulated for all wind farms in Alberta that were operational during the 2008-2010 timeframe, which overlaps with the CWA time series. The simulated output did not compare well with wind farms listed in Table 3.4, all located in Pincher Creek and Fort MacLeod areas of the province. This discrepancy corresponds to an absolute difference higher than 20% between the AEP between the simulated and the market data of the area as well as significant diurnal pattern differences (see Section 2.3).

Table 3.4. Wind Farms located in Pincher Creek and Fort MacLeod

Location	**Wind Farms**
Pincher Creek	- Castle River
	- Castle Rock
	- Cowley North
	- Kettles Hill
	- Oldman 2
	- Summerview 1
	- Summerview 2
Fort MacLeod	- Ardenville Wind
	- Blue Trail Wind
	- McBride Lake Windfarm
	- Soderglen Wind Farm

Three key criteria were used for the evaluation of the overall simulations: the annual energy production (AEP), the diurnal profiles, and the hourly output ramping behaviour showed that the simulated data could be compared to the historical market data. These three are essential to model wind farm behaviour and to study how the rest of the market responds.

For the AEP, the simulated output and the historical market data are compared, where the percentage error ranges from less than 1% up to approximately 10%, depending on the year and the location of the wind farm. This can be seen in Table 3.5, where the AEP is compared between 2008-2010, using the CWA data for simulation and the historic market data. For this table, wind farms outside the Pincher Creek region were presented. The AEP is presented in terms of Capacity Factors (average power generated over rated peak power).

Table 3.5. Annual capacity factor and criterion comparison for the operating windfarms during 2008-2010 outside of the Pincher Creek region.

Wind Farm	Year	Capacity Factor (%)		No. of Ramps		Mean Diurnal Error (%)
		Simulated	Historic	Simulated	Historic	
ENMAX Taber	2008	30	30	2005	1947	8
(81 MW)	2009	32	32	1904	1836	6
	2010	30	29	1826	1801	6
Suncor Chin Chute	2008	38	38	1341	1315	7
(30 MW)	2009	40	39	1228	1144	9
	2010	37	30	1167	813	28
Suncor Magrath	2008	35	37	1284	1192	9
(30 MW)	2009	37	37	1169	1092	10
	2010	34	32	1121	953	12

The mean hourly diurnal profiles, as seen in Figure 3-6, were compared between the simulated hourly data and the historical market data. For each of these months, the tendency was studied, and the monthly diurnal profiles were obtained. The mean diurnal error ranges from 6 % up to 28 % for different hours of the day and month. The mean diurnal error is the average of the difference between the historic MD and the simulated data, divided by the historic MD for each month.

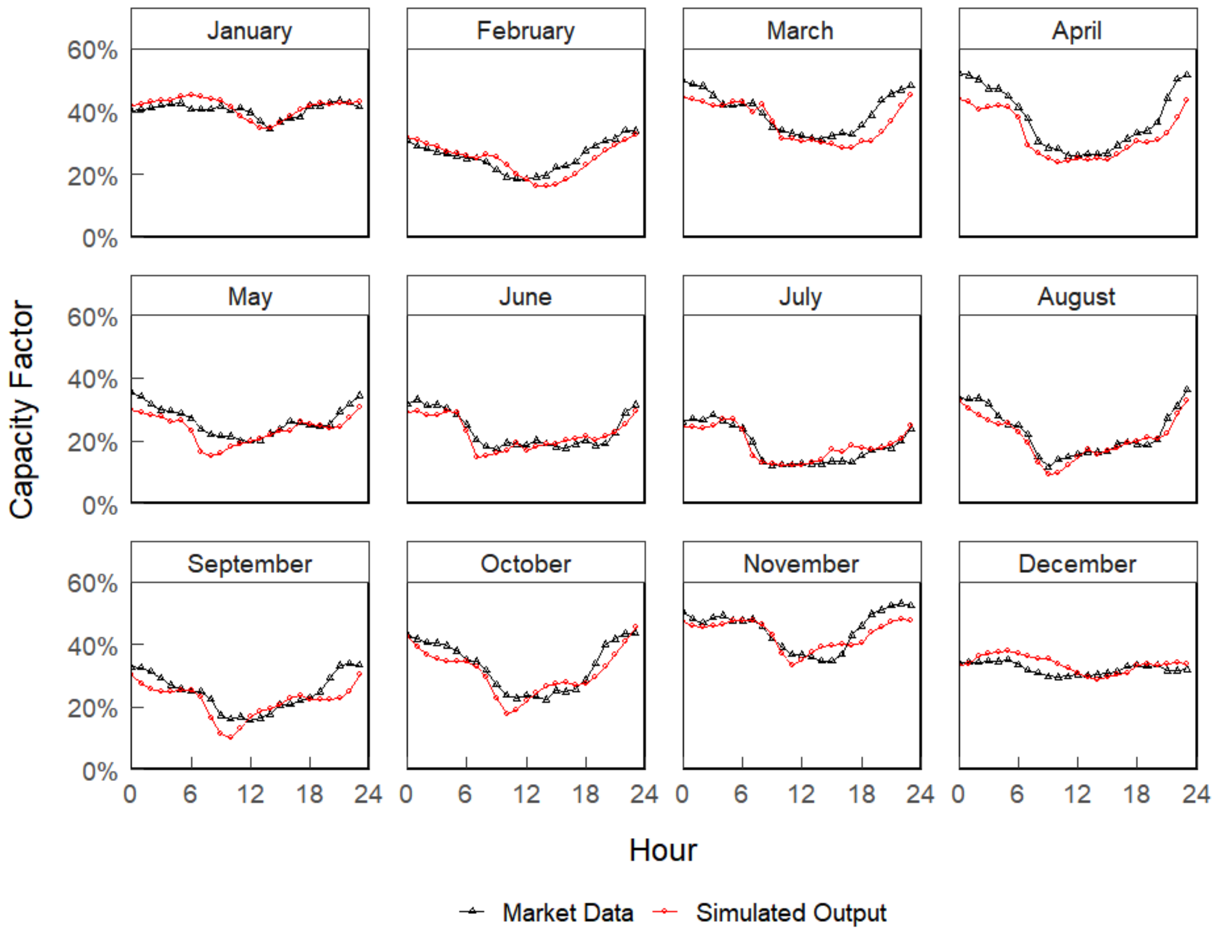


Figure 3-6. Comparison of the mean diurnal profiles between ENMAX Taber's (81 MW) simulated output and the historical market data (2008-2010).

Other generators in the electricity market respond to short-term changes in output or ramps in wind farm output. As a result, simulated data needs to mimic the hourly output ramping behaviour of actual wind farms. This metric is measured by the overall comparison of the hours that the wind farm was producing its rated output in MW, the hours at zero, and the number of ramps where the power output increased more than 70% of the rated capacity of the wind farm within no more than 2 hours. This ramping behaviour can be seen in Figure 3-7, where periods of 24 hours were plotted for eight days (October 5, 2009, to October 13, 2009).

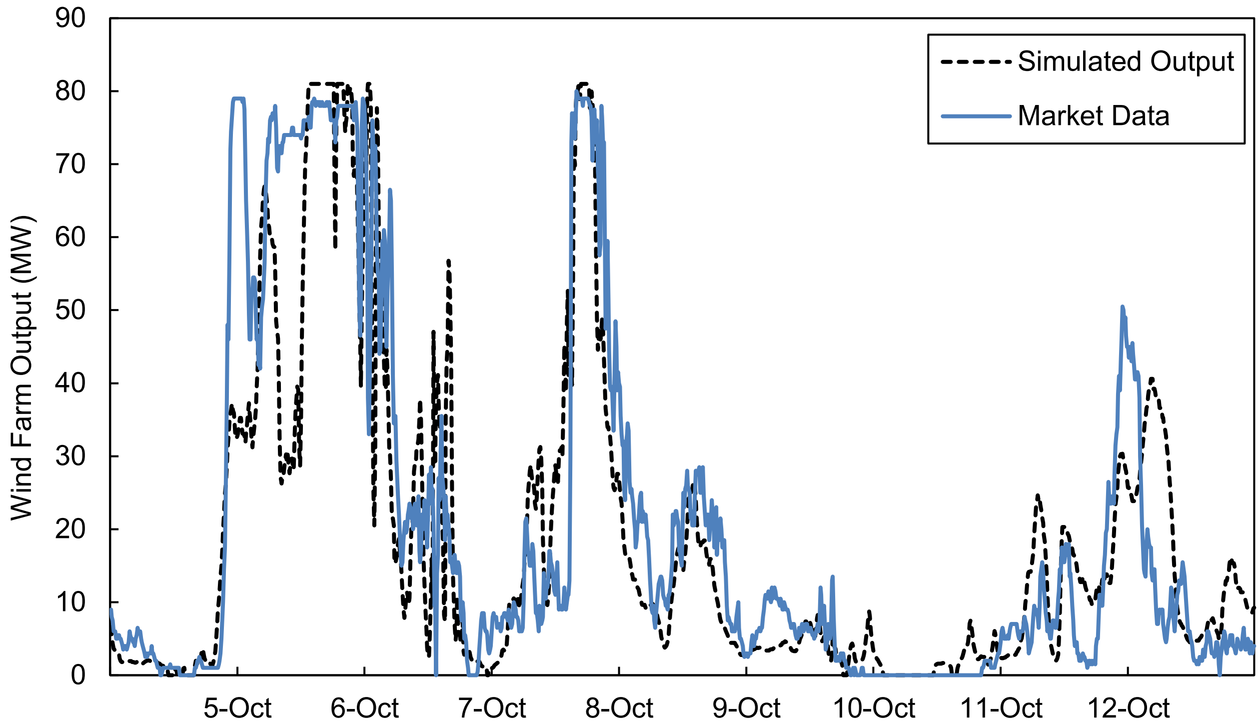


Figure 3-7. Example of hourly data comparing ENMAX Taber's wind farm in October 2009.

An example of a ramp can be seen in Figure 3-7, on October 5, the power increases from zero to 30 MW from the evening until midnight. After comparing the number of ramps between the market data and the simulation, the difference found was lower than 15%.

A visual representation between Figure 3-6 and Figure 3-7 can be seen in Figure 3-8 with a plot showing the hourly capacity factor by month, with the mean diurnal profiles overlaid. The widespread daily patterns show the variations on wind speeds during the day, and with it, the variability of wind power output.

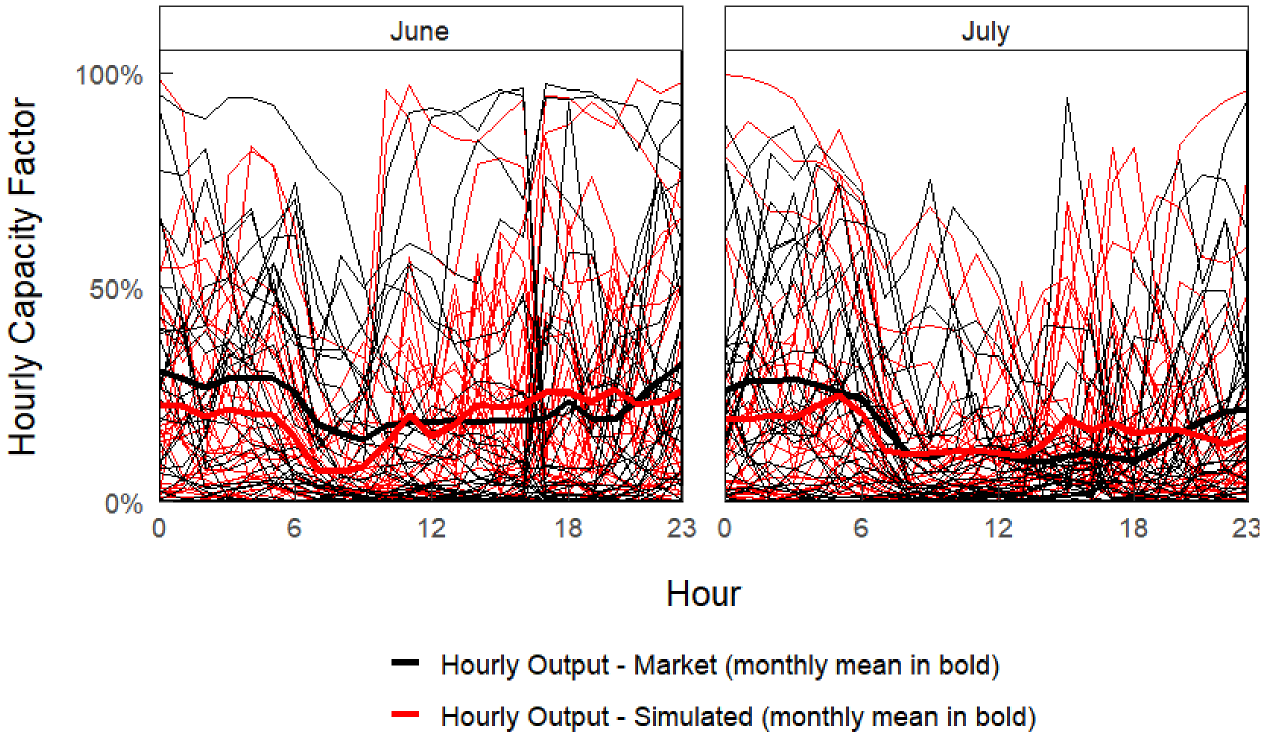


Figure 3-8. Hourly Capacity Factor for June and July (2009) for ENMAX Taber (81 MW)

Using the above evaluation rubrics, the simulated output typically falls within 10% of observed historic data. With this, hypothetical wind farms can be simulated using this generic loss function and the 10-minute data from the CWA.

In Table 3.6, wind farms outside the area of Pincher Creek and Fort MacLeod are compared used the proposed methodology. It can be seen that mean diurnal errors are higher for those wind farms who were built years after 2010. Therefore, due to wind speed variations over time, a low mean diurnal error can not be expected when comparing data from different years. A representative year was created to reduce the error associated with multi-year variations. The representative year for the CWA wind farm simulation was made by averaging 10-minute simulated output from 2008-2010 for the AEP and the diurnal profiles. For the ramping behaviour, the number of ramps of each year was obtained and averaged for the whole simulation period. A similar method was applied to develop a representative year for the MD so that the MD could be compared to the CWA representative year. For the MD, the representative year was created by averaging the hourly market measurements for all the years of available data. For the ramping behaviour of the MD, the number of ramps was counted and averaged, and later compared to the simulated output ramps.

An example of the mean diurnal profiles using the averaged year for Halkirk's Wind Power Facility (150 MW) can be seen in Figure 3-9.

Table 3.6. Metrics comparison between simulated output (2008-2010) and market data for wind farms operating outside of the CWA modelled years (excluding Pincher Creek and Fort MacLeod region).

Wind Farm	Capacity Factor (%)		No. of Ramps		Mean Diurnal Error (%)	Historic Data Period
	Simulated	Historic	Simulated	Historic		
Bull Creek (29 MW)	46	42	1287	1229	13	2016-2019
Blackspring Ridge (300 MW)	37	35	2504	2524	13	2015-2019
ENMAX Taber (81 MW)	30	31	1912	1906	11	2011-2019
Ghost Pine (82 MW)	33	27	2068	1955	24	2011-2019
Halkirk Wind Power (150 MW)	35	36	2396	2431	18	2013-2019
Suncor Chin Chute (30 MW)	35	34	1245	1102	13	2011-2019
Suncor Magrath (30 MW)	36	33	1079	1100	16	2011-2019
Wintering Hills (88 MW)	43	40	2249	2218	18	2012-2019

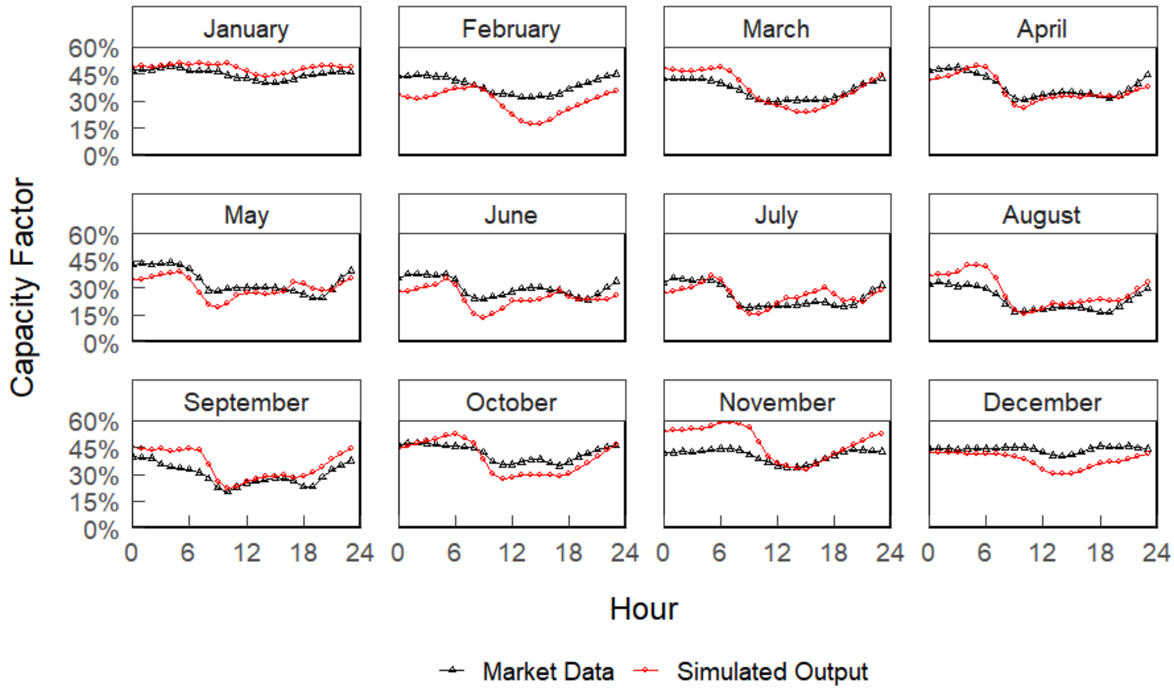


Figure 3-9. Comparison of the mean diurnal profiles between Halkirk's Wind Power Facility (150 MW) simulated output (2008-2010) and the historical market data (2013-2019).

3.2.3. Discrepancy in the Pincher Creek and Fort MacLeod Region

In the case of the wind farms of the Pincher Creek and Fort MacLeod, data were compared to show that the modelled values for these zones in Alberta are not accurate and tend to over-represent wind speeds. This over-representation is shown in the duration curves in Figure 3-10, exposing that the data from this area do not match the market data, where the AEP from the simulation was seven times higher than the reported market data. It can also be seen in Figure 3-11 that the over-prediction of wind high speeds tend to be higher in the last two quarters of the year.

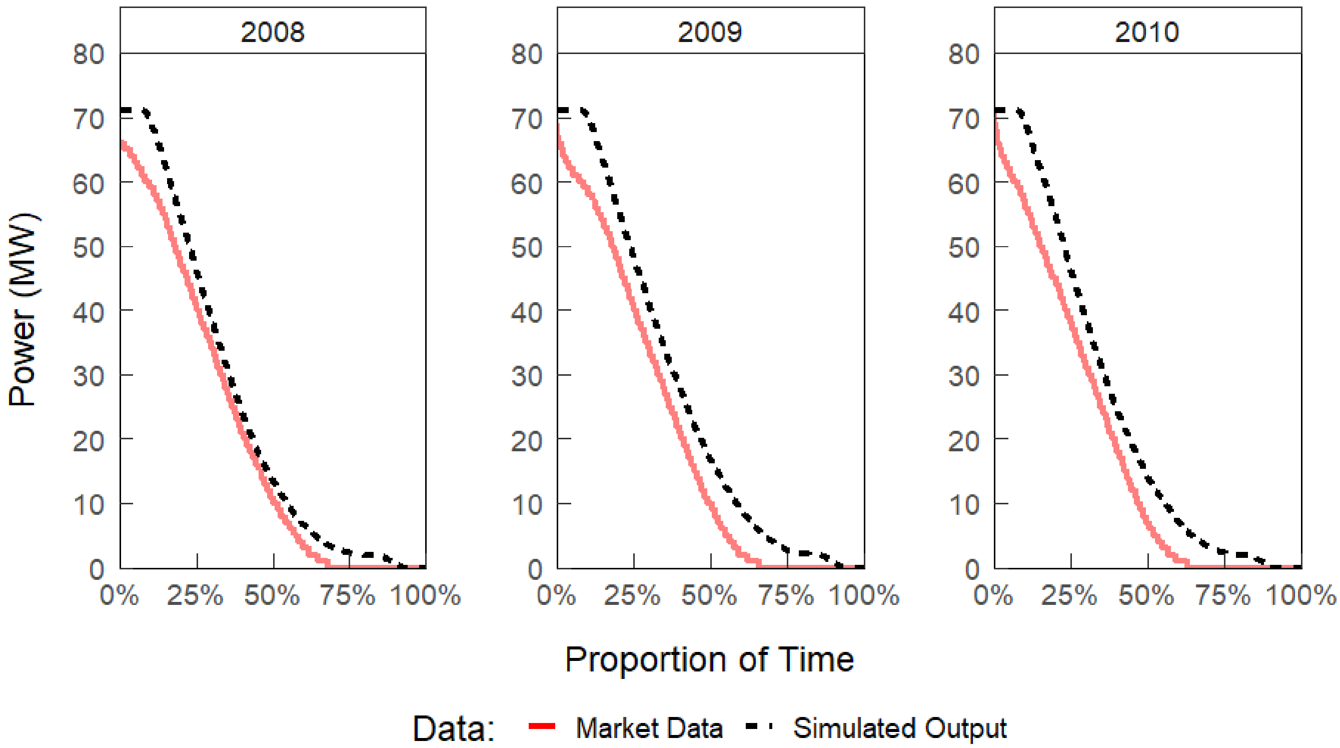


Figure 3-10. Duration curves for simulated output and the market data for Summerview (66 MW).

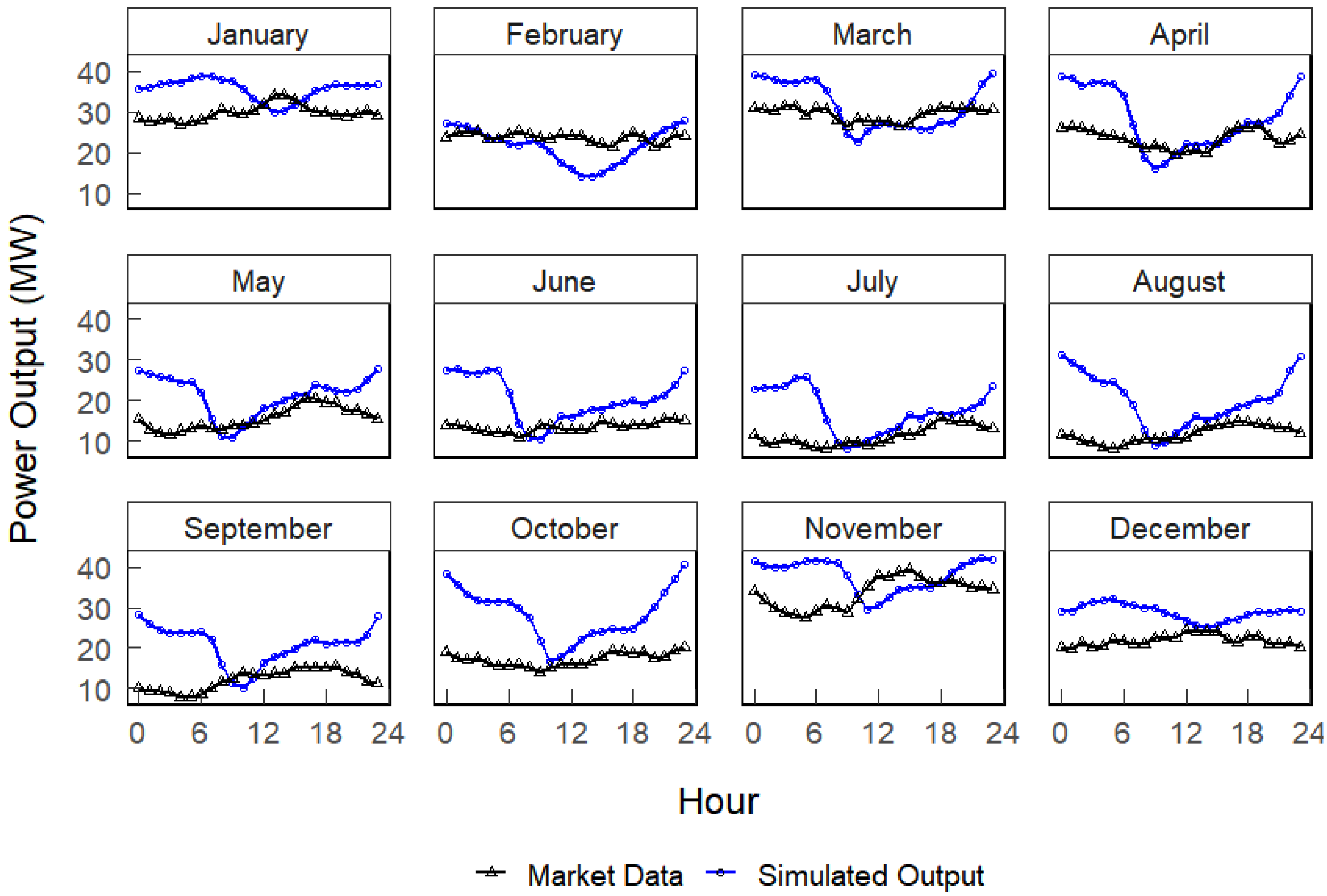


Figure 3-11. Monthly diurnal profiles for Summerview, comparison between simulated and market data. Summerview is located in the region of Pincher Creek.

It appears that the poorly correlated output is a direct result of an improperly simulated wind boundary layer in the CWA for the Pincher Creek and Fort MacLeod area. According to a study of the influence of topography on Kettles Hill by Salmon et al. [98], the boundary layer corresponding to this area is atypical due to drainage winds from the Crowsnest Pass area. The CWA may not account for this effect if it assumes a more typical boundary layer, as found in work at UCDavis [99]. However, it is outside the scope of this work to determine the source of this error.

3.3. Conclusions and Future Work

This paper presents a long-term hybrid forecast model using an NWP model as an input. From this, we have created a tool to model hypothetical or proposed wind farms in Alberta. Further, we have validated the use of the CWA for wind farm simulation. It was shown that the usage of NWP models is useful to accurately simulate hypothetical wind farms, ensuring an hourly power ramping behaviour consistent with observed wind generation facilities elsewhere. The simulated output is, on average, within 10% of historical market data.

The generic simulation of wind farm losses and the use of NWP models extend the applicability of the methodology to be applicable in different locations to cover detailed long-term simulations and to allow an analysis of diverse scenarios and their impacts of the future wind industry. The model hourly ramping behaviour for the assessment of the effects of the geographic dispersion of new wind farms on energy markets are crucial topics for power producers, electric systems operators, and energy market regulators.

The proposed methodology has many potential applications. It can be used to examine opportunities for energy storage to improve capture prices and can be used to evaluate renewable technology hybrid combinations, such as with solar. Increased geographic dispersion of the future wind projects in Alberta would increase in the average wind capture rates.

CHAPTER 4: Energy Market Modeling, Forecasting and Analysis with Aurora

This section outlines the approach used for the analysis of the market impact of geographic dispersion of wind energy in Alberta using the Aurora software package. Aurora is a sub-hourly or hourly chronological price forecasting simulation model designed to simulate a dynamic competitive electricity marketplace [100]. Supply, demand, fuel prices, and transmission links, among other factors, are fed into Aurora, which uses them to produce an optimized electric market price forecast. For this thesis, a long-term capacity expansion (LTCE) study was run in Aurora to estimate the pool price and the capture rate of wind energy from 2020 to 2030.

This chapter is divided into six subdivisions:

- Introduction to Aurora market simulation software;
- Centre for Applied Business Research in Energy & the Environment (CABREE)'s Aurora methodology and base case, including a description of the input fleet and future constraints;
- Creation of hypothetical wind farms (HWF) in Aurora.
- Wind shapes for price forecasting in Aurora;
- Cases and constraints;
- Preliminary Aurora simulation results and discussion.

4.1. Aurora Basics

Aurora is a commercially available price forecasting and analysis software based on the fundamentals of a competitive electric market [11]. The software models future electric energy prices, the market value of electric generating units, and the market value of contracts and portfolios while also analyzing the effects of market uncertainty. Aurora applies economic principles and dispatch simulations in order to model the connection between supply, transmission, and electric energy demand to forecast market prices. The operations of future and existing resources are based on a forecast of key fundamental drivers such as fuel prices, demand, hydro conditions, and the operating characteristics of new resources. Core dispatch, unit-commitment, pool pricing logic, and the LTCE capability are based on algorithms that simulate non-linear electrical systems and how resources such as hydro, supply-side, and demand-side operate to serve load. Currently, it is possible to model multiple electricity markets, zones, hubs and operating pools within a single Aurora simulation. The software is able to provide forecasts at various timescales down to individual hours, minutes, and seconds.

Aurora estimates prices by using hourly demand and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm. During a simulation run, Aurora models the operation of resources within the electric market to determine which resources are on the margin for each zone in any given hour. The software uses information on supply-side generating units and demand-side resources to build an economic dispatch for the market. Units are dispatched according to variable cost, subject to various constraints until the hourly demand is met.

For this thesis, the market chosen for simulation was the Alberta Interconnected Electricity System using the base case previously developed by CABREE. In the model, existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and later become candidates for economic retirement. The features of Aurora and the development of a representation of Alberta's electricity market are discussed in further detail in Chapter 2.

4.2. CABREE's Methodology: Base Case

In previous work, CABREE built a "Base Case" Alberta model in Aurora, which represents Alberta's electricity market based on its current configuration and existing market policies. This Base Case enables the prediction of the evolution of Alberta's market, assuming no changes to the policy framework. The base case features 134 existing resources in Alberta's electricity system; 18 corresponding to coal plants, 43 to natural gas (NG), 22 to cogeneration plants, 12 to biomass, one to solar, nine to hydro, 20 to wind, and the remainder corresponding to load control and demand-side curtailment.

For the base case, we implemented future constraints following key assumptions regarding the aforementioned plans to phase-out coal and increase the carbon price, as well as forecasted future natural gas prices. We modelled the coal phase-out constraint as either retirement of existing coal generation facilities or retrofitting them to natural gas-fired plants, depending on the publicly stated intentions of the facility owners. The carbon price was modelled as per the Government of Alberta's Technology Innovation and Emissions Reduction Regulation, increasing from \$30 per tonne CO_{2e} today to \$50 by 2023 and held constant thereafter until 2054. In the base case scenario, CABREE assumed the future growth of Alberta's wind fleet to be driven solely by the expansion of existing sites, using output wind profiles from each site to estimate the scale of expansion.

4.3. Hypothetical Wind Fleet Simulation

Using the methodology discussed in Chapter 3, I created new hypothetical wind farms (HWFs) in locations without existing wind farms to develop entirely new geographic configurations for the future Alberta wind fleet. First, I selected a location perimeter to obtain a representative point or centroid for each HWF, as was done in Chapter 3. Locations where the average historic wind speed was higher than 7 m/s, were selected to ensure each HWF had reasonable potential to be economically viable for wind energy production. Given the main objective of this thesis, I chose locations with a diverse geographic dispersion away from the current cluster of wind farms. Table 4.1 summarizes the location of the centroids, the turbine size, and the turbine model for each modelled HWF.

Table 4.1. Hypothetical Wind Farms for Alberta.

ID	Location		Size (MW)	Wind Turbine Model
	Latitude	Longitude		
HWF1	55.36	-114.91	231	GE IEC – Class II 3.2-103
HWF2	55.20	-115.15	231	GE IEC – Class II 3.2-103
HWF3	55.22	-115.77	231	GE IEC – Class II 3.2-103
HWF4	53.95	-118.53	231	GE IEC – Class II 3.2-103
HWF5	54.11	-119.41	231	GE IEC – Class II 3.2-103
HWF6	56.77	-111.21	161	GE IEC – Class II 3.2-103
HWF7	58.79	-111.09	161	GE IEC – Class II 3.2-103
HWF8	54.93	-115.76	165	GE IEC – Class II 3.2-103
HWF9	56.17	-113.27	161	GE IEC – Class II 3.2-103
HWF10	55.84	-116.73	264	GE IEC – Class II 3.2-103
HWF11	54.35	-119.79	264	GE IEC – Class II 3.2-103
HWF12	54.66	-119.84	264	GE IEC – Class II 3.2-103
HWF13	54.47	-119.26	264	GE IEC – Class II 3.2-103
HWF14	55.61	-115.62	264	GE IEC – Class II 3.2-103
HWF15	55.06	-112.03	264	GE IEC – Class II 3.2-103
HWF16	55.05	-112.82	264	GE IEC – Class II 3.2-103
HWF17	53.74	-118.13	264	GE IEC – Class II 3.2-103
HWF18	54.81	-110.87	264	GE IEC – Class II 3.2-103
HWF19	53.92	-116.99	297	GE IEC – Class II 3.2-103
HWF20	54.89	-118.69	297	GE IEC – Class II 3.2-103
HWF21	56.58	-119.79	297	GE IEC – Class II 3.2-103
HWF22	53.00	-112.26	500	Vestas V136 – 3.6
HWF23	51.69	-111.08	345	Vestas V136 – 3.6
HWF24	53.64	-112.47	345	Vestas V136 – 3.6

I created twenty-four possible HWFs in order to give Aurora a wide selection of possible sizes and locations to choose from when optimizing the model, even though it can be anticipated that not all sites will be considered feasible by the software in a given simulation run. The different models of wind turbines used in various HWFs reflect the range of turbine types that are currently being installed in Alberta; one such example is the Vestas V136 – 3.6, used in the most recently commissioned wind farm in the province (Whitla) [101]. Following location selection, I extracted the 10-minute data corresponding to the wind speeds and direction at 80 m, 100 m, and 120 m, as well as air temperature and density, from the CWA historic modelled dataset. Using the generic loss function (as described in the methodology of Chapter 3), I then post-processed the data to estimate the power output for each HWF. A map showing the location of the HWFs is provided in Appendix B.

4.4. Wind Shapes for Price Forecasting: Forced Outages

Aurora uses input factors known as Forced Outages (FO) to define the wind shapes it uses for price forecasting in the LTCE simulation. A FO defines the percentage of time the resource will be unavailable due to unscheduled outages; for each dispatch hour, Aurora de-rates the unit capacity based on the FO. After estimating the 10-min simulated power output of a given HWF, I computed the FO as shown in (4.1):

$$FO_i = \left(1 - \frac{P_{ML_i}}{P_{rated}}\right)(100) \tag{4.1}$$

Where, P_{rated} corresponds to the rated output of each HWF, and P_{ML_i}, as in Chapter 3, corresponds to the 10-min simulated output.

Next, I condensed the FO values for 2009 into the format required for Aurora by averaging the hourly FO for the third week of each month. Table 4.2 shows a sample FO for HWF22.

Table 4.2. Forced outage data sample for HWF22.

Month	Hour of the Week						
	1	2	3	4	…	167	168
January	0	0	0	0	…	0	0
February	0	0	0	0	…	99.33	100
March	96.36	95.69	91.93	90.30		68.43	78.72
April	71.81	11.42	4.71	24.01	…	0	0
May	98.63	92.56	69.20	30.97	…	65.14	47.21
June	80.75	50.37	35.69	9.03	…	100	97.80
July	94.85	98.98	100	99.89	…	85.74	89.16
August	5.29	2.35	0	0	…	2.71	2.45
September	97.38	100	100	100	…	98.91	97.70
October	0	0	0	0	…	0	0
November	100	99.40	91.64	63.11	…	64.62	76.22
December	49.16	64.64	76.44	81.00	…	0	0

As shown, each month was represented by a weekly hourly time series data set containing 168 hours of hourly FO. I selected 2009 as the sample year for CWA data extraction on the basis of a comparison between estimated and actual market capacity factors, which showed the closest alignment in that year.

4.5. Inputting Wind Profiles into Aurora

Following the FO computation, the data was input into Aurora to run the LTCE under various cases that I designed to reflect scenarios of interest. Aurora uses Input Tables to access, organize, manage, and modify all of the input data to be used in the LTCE study. As a starting point, I added the new simulated wind farms to the Input Tables by building changesets, which each represent incremental sets of data changes to the underlying database. I developed changesets for each HWF by following the following procedure:

1. Created a new wind resource by adding a row to the New Resources Table, specifying the capacity of the HWF and its associated FO.

2. Modified other limitation parameters in the Input Table, including annual maximum, overall maximum and minimum, and eligibility years. The annual maximum is the maximum number of new technology resource types that will be considered for addition to the area during an LTCE study.
3. Added a Time Series Monthly and associated Time Series Weekly tables under the FO column. The Time Series Weekly tables define the FO in the 168-hours, as shown in Table 4.2.

By following this process for each new HWF, I built up the complete changeset for input to Aurora. The different constraints and changesets created for each simulated case are presented in the following section.

4.6. Cases and Constraints

In Aurora, various combinations of changesets can be used to build different scenarios. Custom simulation constraints also require their changesets. However, in this case, modifications are needed under Aurora's Constraint Table. The constraint table defines annual constraints that affect the dispatch of resources, in this case, renewable resources. Each row within the constraint table corresponds either to energy, fuel limit, emission, or Long-Term (LT) constraints.

The primary constraint used in this thesis is an LT constraint known as the Renewables Constraint. Aurora uses this constraint to guide the build decisions that are made in the LTCE study. The constraint is defined by an LT Energy Min, which forces the model to build sufficient new renewable resources to meet the target of 30% renewables by 2030, if possible. The values used in the Renewables Constraint are shown in Table 4.3.

Table 4.3. Renewables Constraint used in the LTCE Study.

Year	Minimum energy required by year (TWh)
2022	0
2023	0
2024	20.5
2025	22.2
2026	23.8
2027	25.5
2028	27.4
2029	29.2
2030	30.8
2031	31.2
2032	31.7
2033	31.9
2034	32.2
2035	32.6
2036	33.0
2037	33.4
…	…
2054	33.4

In addition to the constraints, we defined four cases for the simulations. The first, named *Base Case*, was the case modelled by CABREE, which represents Alberta's current electric system. We built the second case, *New Wind Fleet*, based on the creation of a geographically dispersed hypothetical wind fleet. This case was defined by a changeset containing all the HWFs, as explained above. The third case, *New Wind Fleet and Constraint*, was a copy of the New Wind Fleet case, with the renewable constraint imposed upon it. The fourth case, *Base Case and Constraint*, was a copy of the Base Case with the renewable constraint added to it.

4.7. Preliminary Simulation Results

The combination of the methodology proposed in Chapter 3 and the aforementioned Aurora setup activities enabled me to run an LTCE study and a Standard Zonal study to analyze specific future scenarios in Aurora from 2020 to 2030. The objective of these studies was to predict the future behaviour of the Alberta electricity market and to estimate the future price capture rate of wind. We first ran the *Base Case* to be used as a baseline to compare the effect of future scenarios in the electricity market. The evolution of generation shares during the simulation period showed that NG is expected to make up the most significant share of the generation mix in the Base Case (See Figure 4-1). Note that we grouped other generating sources not relevant for this specific study under the “other” variable.

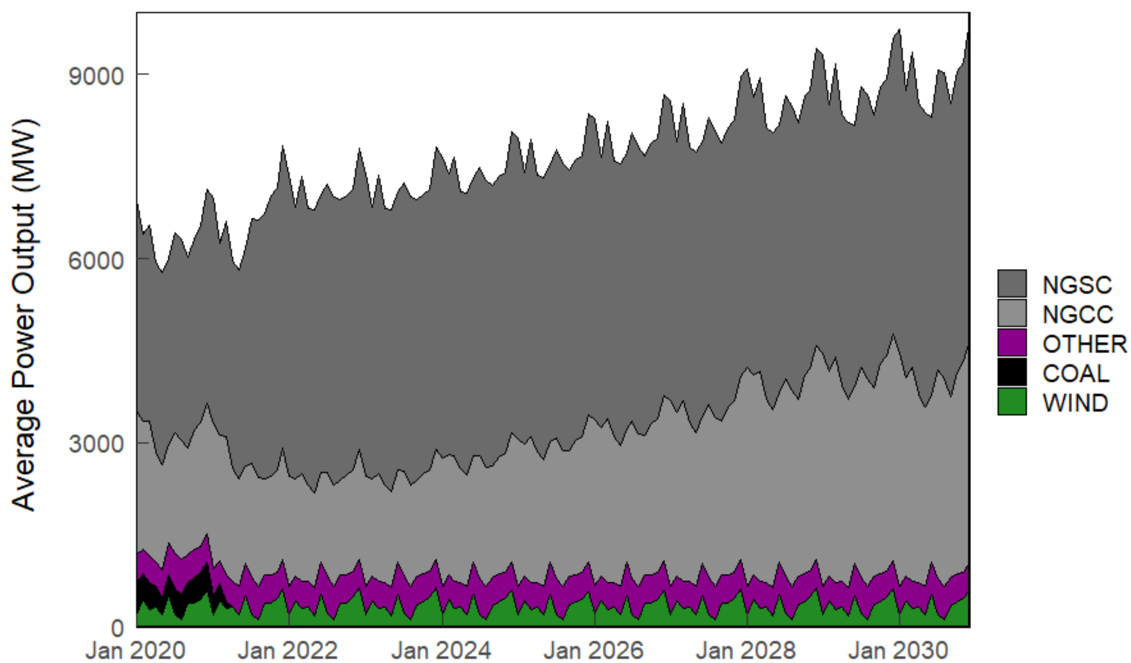


Figure 4-1. Base Case scenario monthly averaged power output generation share by fuel type.

By analyzing the generation share and revenue of each resource, we obtained an estimate of future average pool prices, on-peak prices, and off-peak prices, as shown in Figure 4-2.

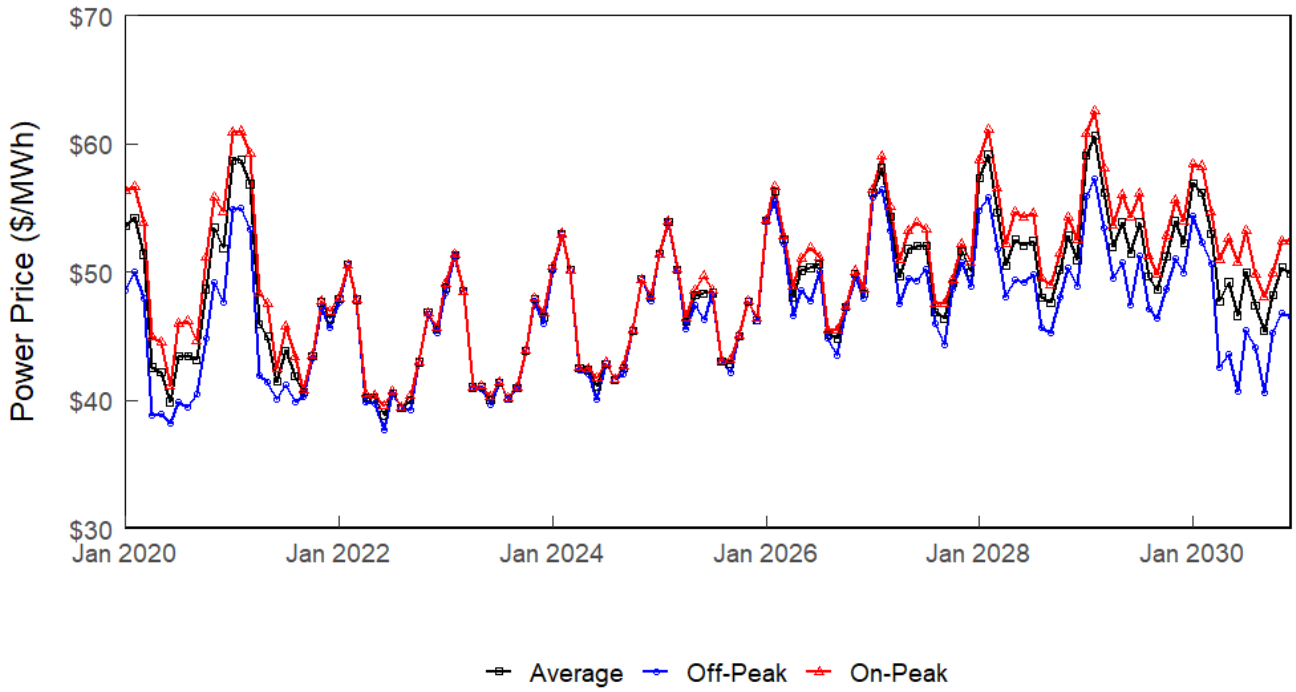


Figure 4-2. Pool price behaviour for the *Base Case* scenario in Aurora, monthly averages.

Next, we compared the *Base Case* average pool price to the average wind energy revenue, as seen in Figure 4-3. This comparison showed that a wind price discount effect was observed in the simulation as expected.

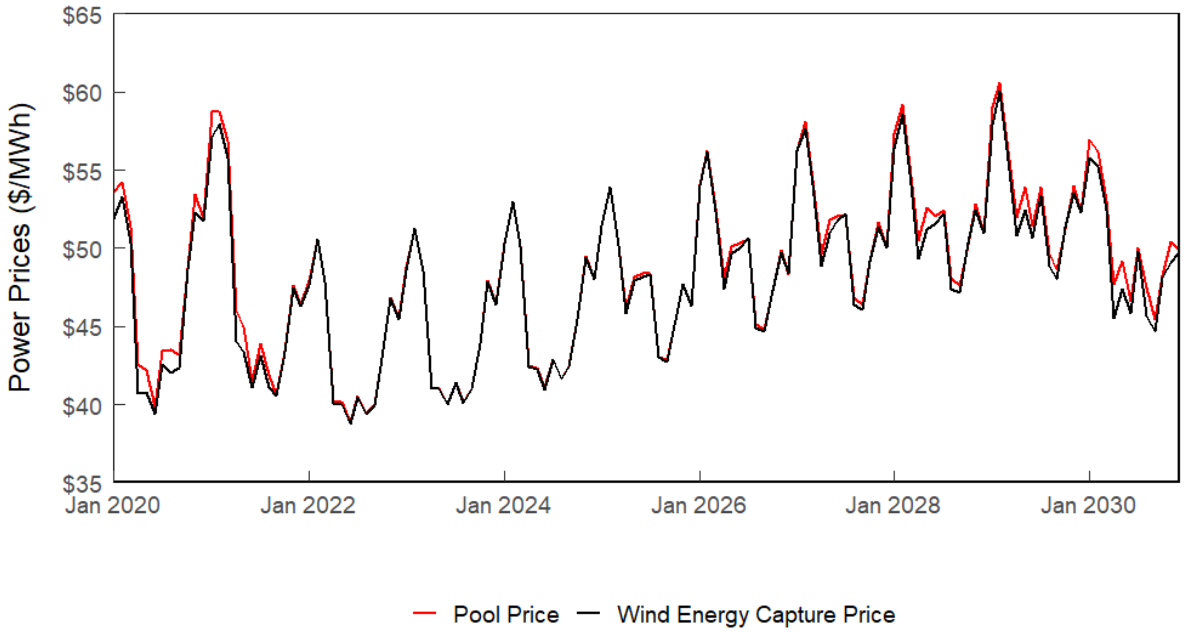


Figure 4-3. Average pool price vs average wind energy capture price (Base Case).

After analyzing the behaviour of the pool price during the simulation period, we found that there was an insufficient number of hours in the simulation where the pool price exceeded $700/MWh while the wind generation was low, compared to known historic market behaviour. We concluded that the inclusion of more hours with this situation would lead to a more accurate forecast of market behaviour.

To address one of the main thesis concerns (geographic dispersion), we created a new scenario in which we added new wind resources to the *Base Case*. This is functionally equivalent to forcing the model to build new geographically dispersed wind energy generation. Therefore we named the case *Forcing Wind.* The added wind fleet contained seven HWF with 300 MW of installed capacity each, adding a total of 2100 MW to the system. We defined the seven HWF based on the same FO, turbine models, and turbine numbers used for HWF2, HWF5, HWF7, HWF8, HWF22, HWF23, and HWF24 as described previously in Table 4.1. A map with the selected locations for the forced wind fleet is shown in Appendix B. Figure 4-4 shows the forecasted generation shares under the new scenario.

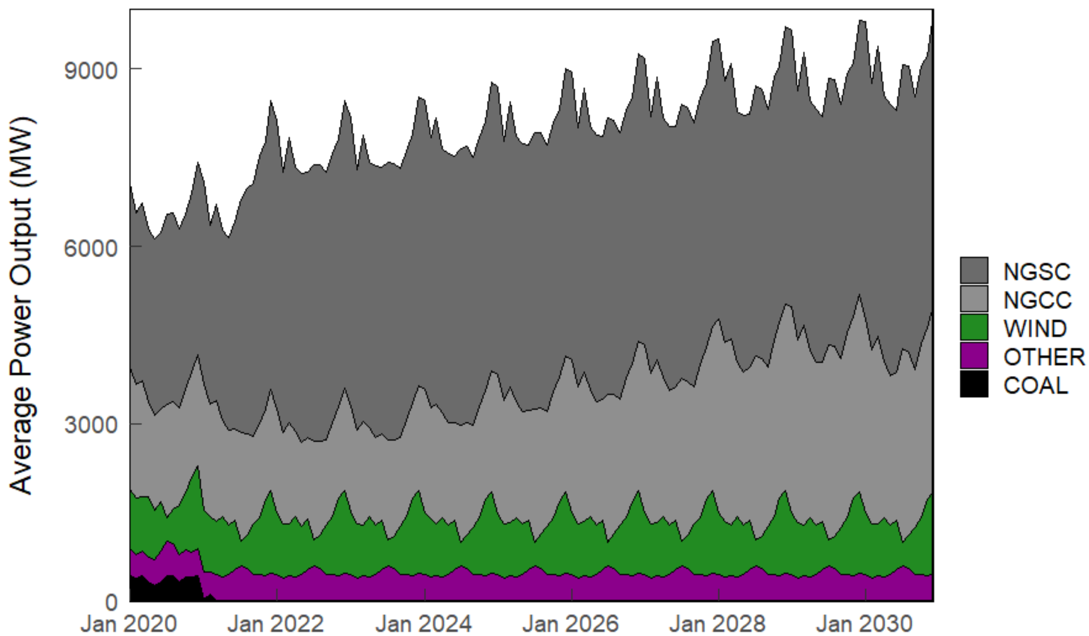


Figure 4-4. Forcing Wind scenario monthly averaged power output (MW) generation share by fuel type.

We also obtained estimates of future average pool prices, on-peak prices, and off-peak prices for this case, as shown in Figure 4-5. Even though we did not see a significant difference in the average pool price when comparing the *Forcing Wind* case (Figure 4-5) to the *Base Case* (Figure 4-2), we found that the off-peak price decreased more in the *Forcing Wind* scenario.

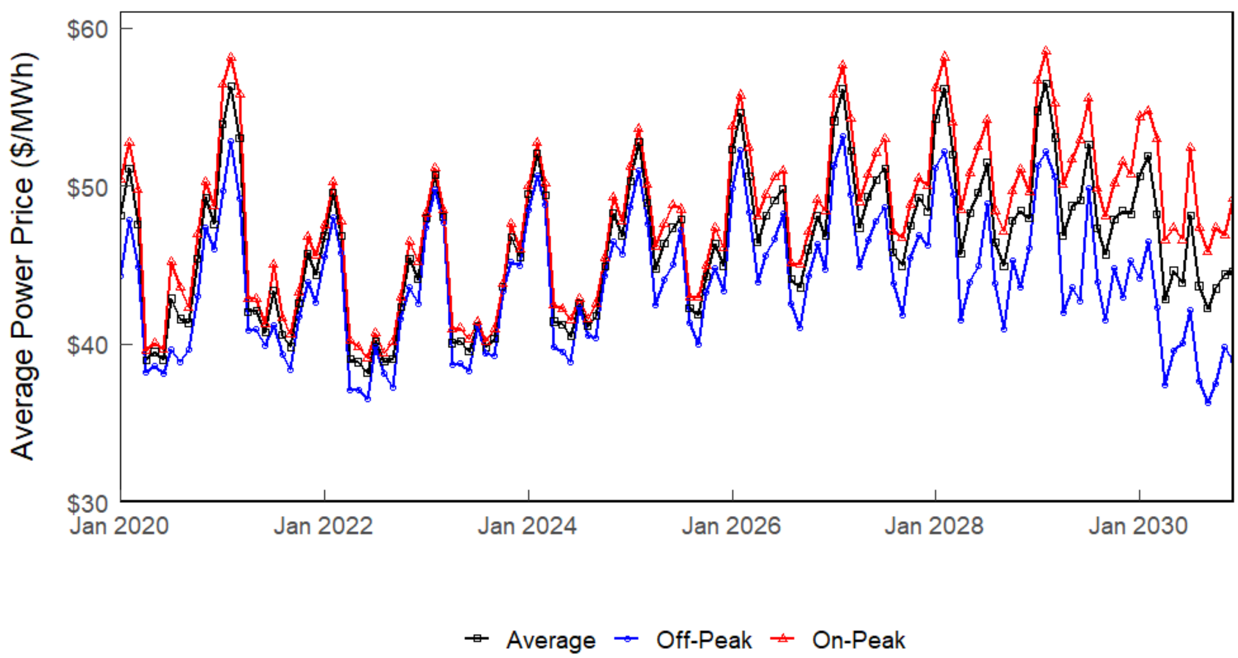


Figure 4-5. Pool price behaviour for the Forcing Wind scenario in Aurora, monthly averages.

In the same way, we compared the average pool price to the average wind capture rate, shown in Figure 4-6. While we expected to see an overall market price decrease due to the increase of wind energy in the electricity system, this was not observed. We determined that this behaviour was caused by the way NG was set up in the *Base Case* in Aurora. In the model, NG was set to produce a constant yearly amount of energy throughout the simulation, which might have caused an unexpected behaviour where NG still determined the strike price even in situations where high wind production pushed the merit order to the right.

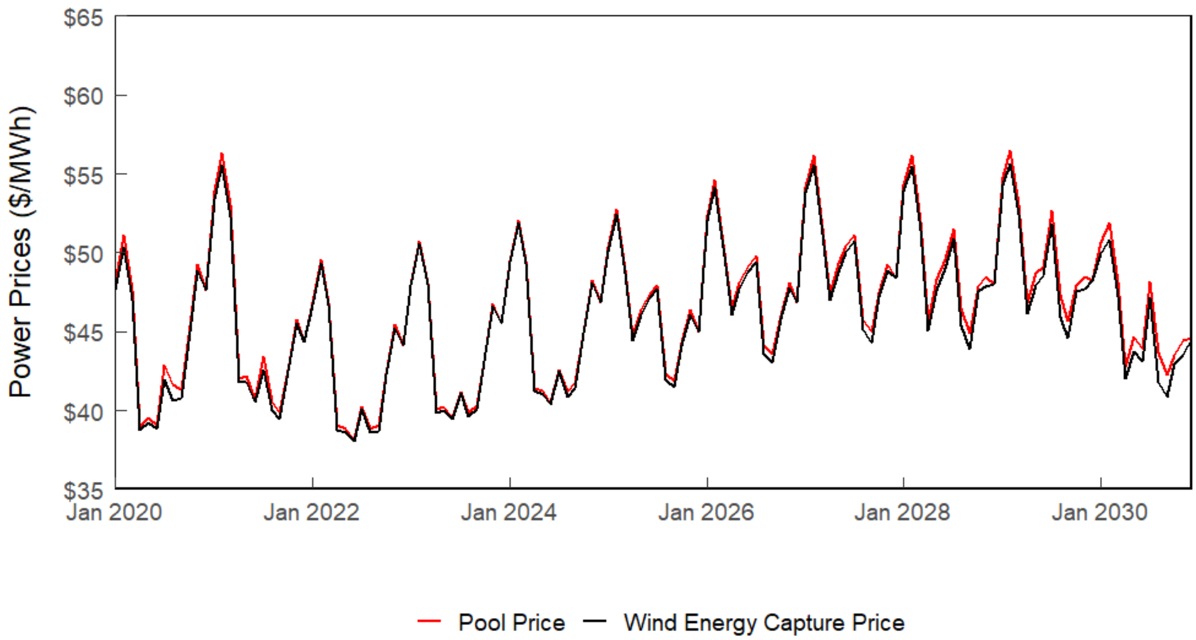


Figure 4-6. Average pool price vs average wind energy capture price (Forcing Wind).

After running these two scenarios, we created a third, named *New Dispersed Wind*, using the annual wind generation (in MWh) from the *Forcing Wind* case as a constraint. We applied the constraint into the new scenario to let the model chose where to build new wind farms while achieving the same level of wind generation as the Forcing Wind case. Figure 4-7 shows the forecasted generation shares under the New Dispersed Wind scenario, where the model chose to build five new wind farms totalling 1,500 MW. The model decided to build four wind farms of 300 MW each, corresponding to the wind profiles of HWF22, and one wind farm of 300 MW, corresponding to HWF23.

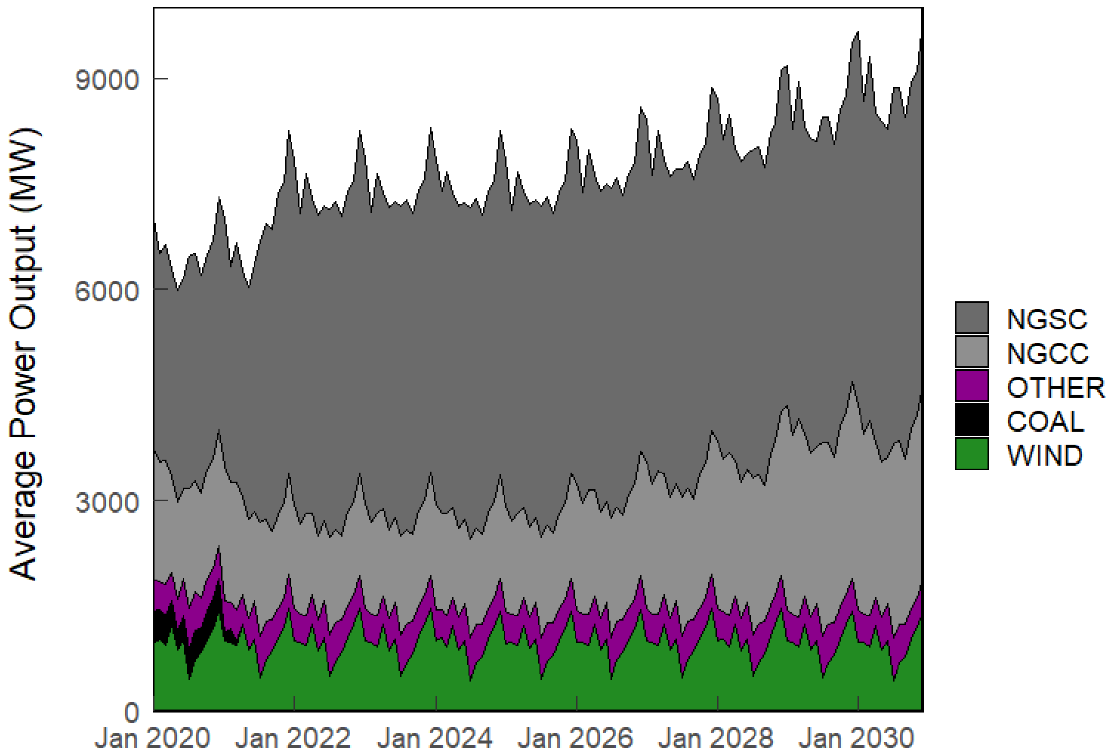


Figure 4-7. New Dispersed Wind scenario monthly averaged power output (MW) generation share by fuel type.

In Figure 4-8, we compared the *Base Case* (Existing locations), the *Forcing Wind* case (Forcing geographic dispersion), and the *New Dispersed Wind* (Geographic dispersion) scenarios. It can be seen that by letting the model chose where to build the new wind fleet, there are instances where the pool prices are higher than in the *Base Case*. A possible reason for the higher pool prices is that in this scenario the model only added wind capacity (there were no combined cycle gas power plants built.)This can be expected to cause higher-priced hours when wind output is low due to the need for the system to dispatch higher-cost plants without adequate combined cycle capacity.

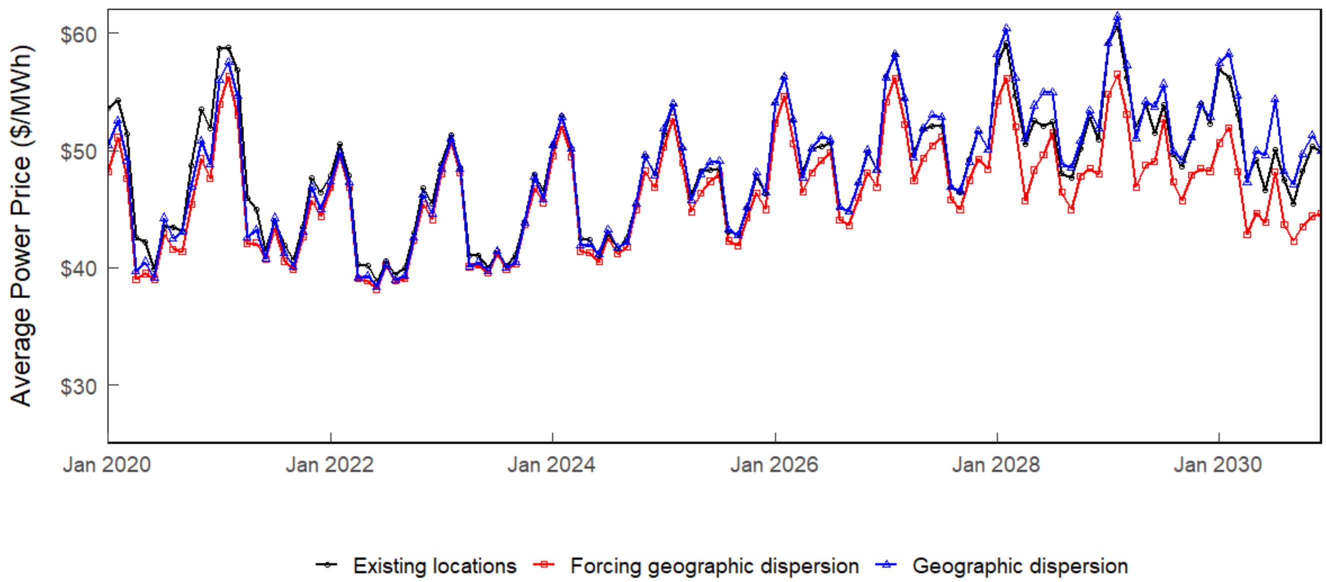


Figure 4-8. Monthly averaged pool price comparison for the three scenarios.

Figure 4-9 compares the monthly averaged wind capture price between the three modelled scenarios. It was observed that by letting the model choose the wind fleet locations the capture price of wind was closer to the average pool price.

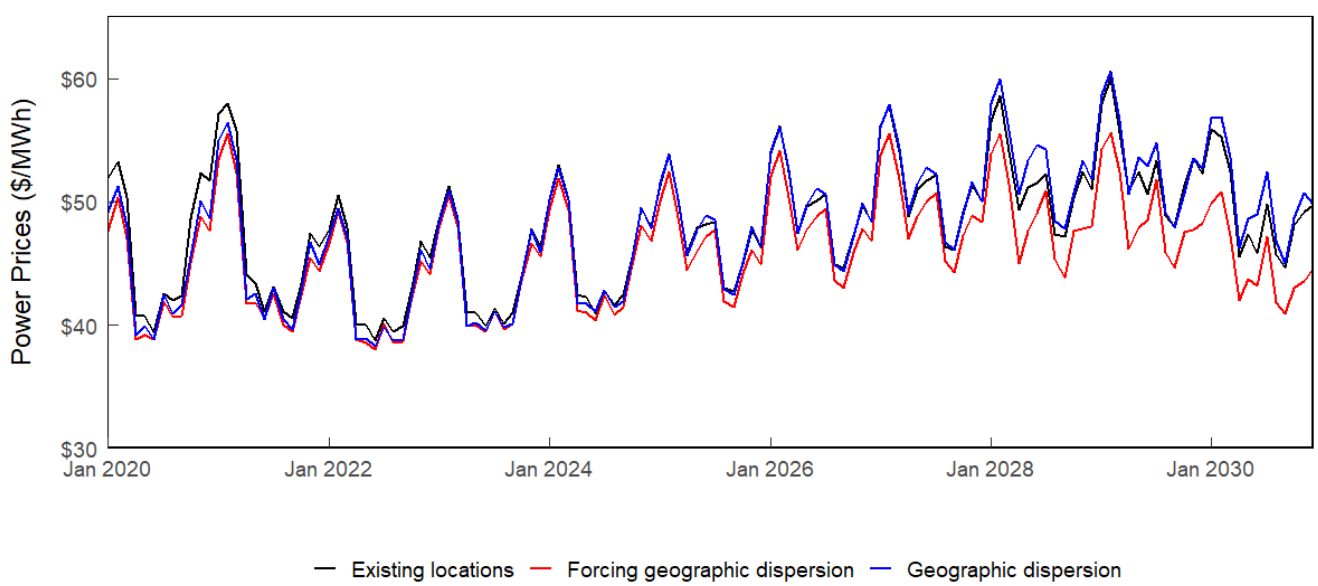


Figure 4-9. Monthly averaged wind capture price comparison for the three scenarios.

We also found that the use of only the third week of each month for the 168-hours-weekly FO (due to Aurora's data input structure) led to poor accuracy in Aurora's representation of the yearly behaviour of the HWF compared to the data from the CWA. The variability between the monthly mean profile and the weekly mean profiles in the last quarter of the simulated year (using 2009 data) can be observed in Figure 4-10, where the bold black line represents the monthly mean.

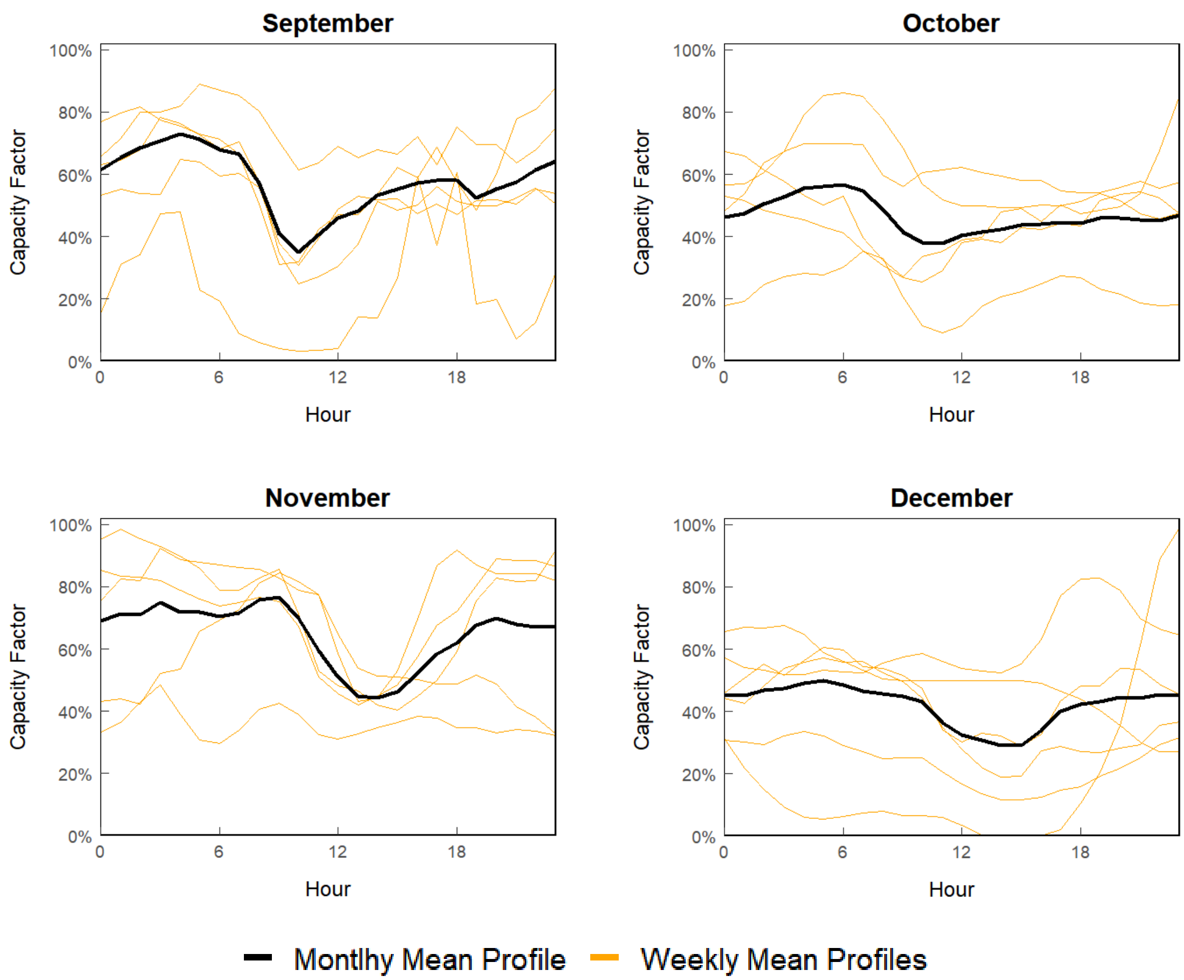


Figure 4-10. Monthly and Weekly mean profile comparison for HWF2 simulated output.

Based on these observations, we concluded that the model could be improved in future work by dynamically selecting representative weeks rather than consistently using only the third week. In order to choose an accurate week for the simulations, we propose the following specific metrics:

- Capacity Factors: the week chosen must have the closest capacity factor to the monthly average capacity factor.
- Correlation between wind farms: if the proposed HWF is close to an existing wind farm, wind shapes must follow a similar trend on wind energy production. If the HWF is within a new wind regime where there are non-existing wind farms, two HWFs must be created to analyze the correlation between them.
- Hourly ramping behaviour: the chosen week for every month must follow a similar ramping behaviour when simulating the whole year. This will help with future storage studies.

CHAPTER 5: Conclusion

5.1. Summary

The goal of this thesis was to create a methodology to simulate hypothetical future wind farms with different geographic dispersion across Alberta in order to obtain to evaluate the potential effects of differing wind configurations on the province's energy market. This information could be used to evaluate differences in relative capture prices for different wind fleet build configurations, as well as potential changes to emissions and future plant types for the rest of the fleet. Hourly wind speed time series that are published by the CWA were used to calibrate the simulated output of existing wind farms by comparing it to actual historical market data over the timeframe. The same methodology was then used to develop hourly energy production profiles for hypothetical wind farms and create fleet permutations' production profiles. Fleet configurations were modelled using the Aurora electricity market model to examine impacts on pool price and variations of wind fleet price capture. This methodology help with future decision-making strategies for location siting wind as well as other electricity generating infrastructure.

Relevant literature reviewed to assess existing best practice guidelines for wind power forecasting, wind energy power loss estimation, and to examine the studies that evaluated the different methods for wind power forecasting. It was found that while there are many studies on a specific calculation of loss factors (wake effect, transmission losses, electric losses, icing losses, etc.), none were found that provided a general calculation of wind energy loss factors. This work aims to fill that gap and presents a detailed "calibration" study with a step-by-step guide on how to use the CWA modelled historical data to predict wind power sites under consideration by using an estimated generic loss function.

To perform the calibration study, the data used were taken from the CWA modelled historical data, and the market measurements were taken from the AESO. For this study, a long-term hybrid forecast model was created using Alberta's existing wind farm locations to estimate the wind plant power output and compare it to the actual measured wind farm market output. In order to create a more predictive model, a loss coefficient was introduced to estimate power losses on a wind farm level. This is a novel algorithm introduced for the first time with this research. The CWA modelled data contain wind speeds, direction, temperature, and air density, among other variables, for the years from 2008-2010. It was found that the CWA historic modelled data tend to underestimate wind speeds from 7:00 am until noon for the spring months, sometimes misinterpreted wind speeds for the region of Pincher Creek and Fort Macleod. To validate the calibration and the CWA work, wind farms that were commissioned before 2008 and were active during the three years (2008-2010), and outside the region of Pincher Creek or Fort Macleod, were modelled and compared against the market output measurements (AESO). The calibration was then evaluated by simulating the power output for wind farms outside the CWA's timeframe and again compared to the market output. Overall, the results obtained from using the data from the CWA were capable of enabling estimation of real market output measurements when compared to existing wind farms in the province.

To analyze the market impacts of geographic dispersion of wind energy in Alberta, a model of the electricity market (CABREE's Base Case) of the province, along with different scenarios for the future, were built into Aurora. Various cases were created to model an LTCE. For the preliminary results, the *Forced Wind* case was created where a fleet of seven new wind farms (adding 2,100 MW to the electric system) was imposed into the Base Case. With this, it was possible to forecast the future electricity market from 2020 to 2030. It was found that with the methodology to predict the output of HWFs in different locations of the province from Chapter 3, and following the procedure in Chapter 4, that it is possible to model new HWF in Alberta's electricity system. This was consistent with the expected behaviour of an increase in wind energy in the province's system. However, it was found that by using only the third week of the month of hourly data to build the FO for Aurora, results do not represent the overall behaviour of wind power generation of the month. Suggestions on how to approach this are explained. Additionally, instances when the pool price increases to over $700/MWh need to be added to the Base Case on Aurora to simulate a more accurate market behaviour.

5.2. Future Work and Recommendations

Some recommendations and areas of improvement for this study are listed below:

- If the CWA is to be used as a basis for wind farm output modelling, the systematic under-prediction of morning wind speeds in the spring months should be addressed. This issue has been shared with Natural Resources Canada and Environment Canada, who developed and used the CWA. If the CWA model does not address this issue, the methodology to adjust for under-prediction used in this work could be further refined by comparing wind atlas data to weather station data.
- The significant data mismatches in the southwest of the province (Pincher Creek and Fort McLeod regions) have also been shared with the publishers of the CWA. It is outside of the scope of this work to be able to address the data mismatch. However, there are sufficient wind farms in the region whose historical output can be used to model future new builds in the region.
- In order to further refine the market impacts of new wind fleet configurations, a representative week of each month needs to be created. This representative week must reflect the monthly capacity factor, must follow typical week ramping behaviour as well as correlate to production times of other wind farms in the province. Alternatively, full-year (8760-hour) profiles could be used to recreate to better account for correlations between various wind farms' production.
- While it was outside of the scope of this work, the current Aurora market model needs to be updated to better reflect variations in bidding behaviour that tend to cause wider spreads in hourly market prices than are observed with the current model.
- The work done in this thesis lays the groundwork to examine scenarios that include maximizing future wind fleet capture prices or minimizing overall system variability.

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Appendix A

Mean diurnal profile comparison for the existing wind farms in Alberta, extra plots from Chapter 3.

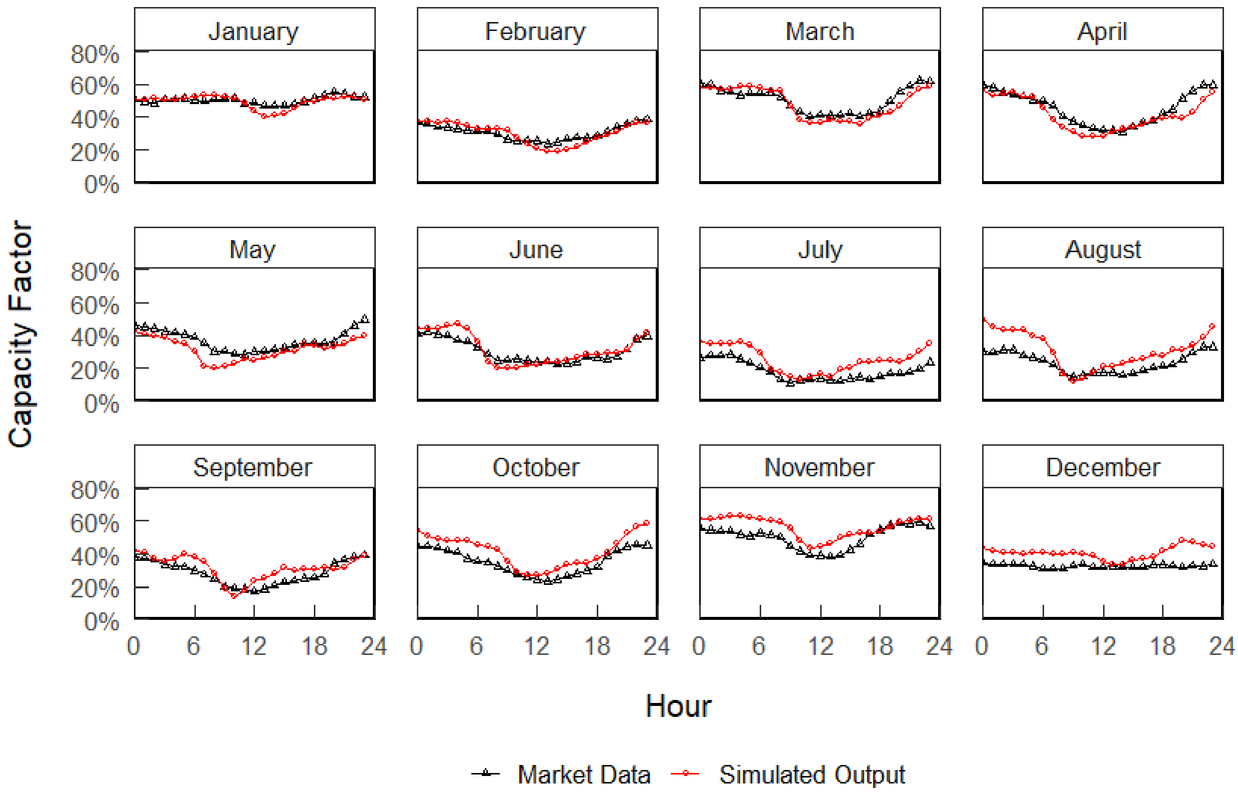

Figure A-1. Comparison of the mean diurnal profiles between Suncor Chin Chute's (30 MW) simulated output and the historical market data (2008-2010).

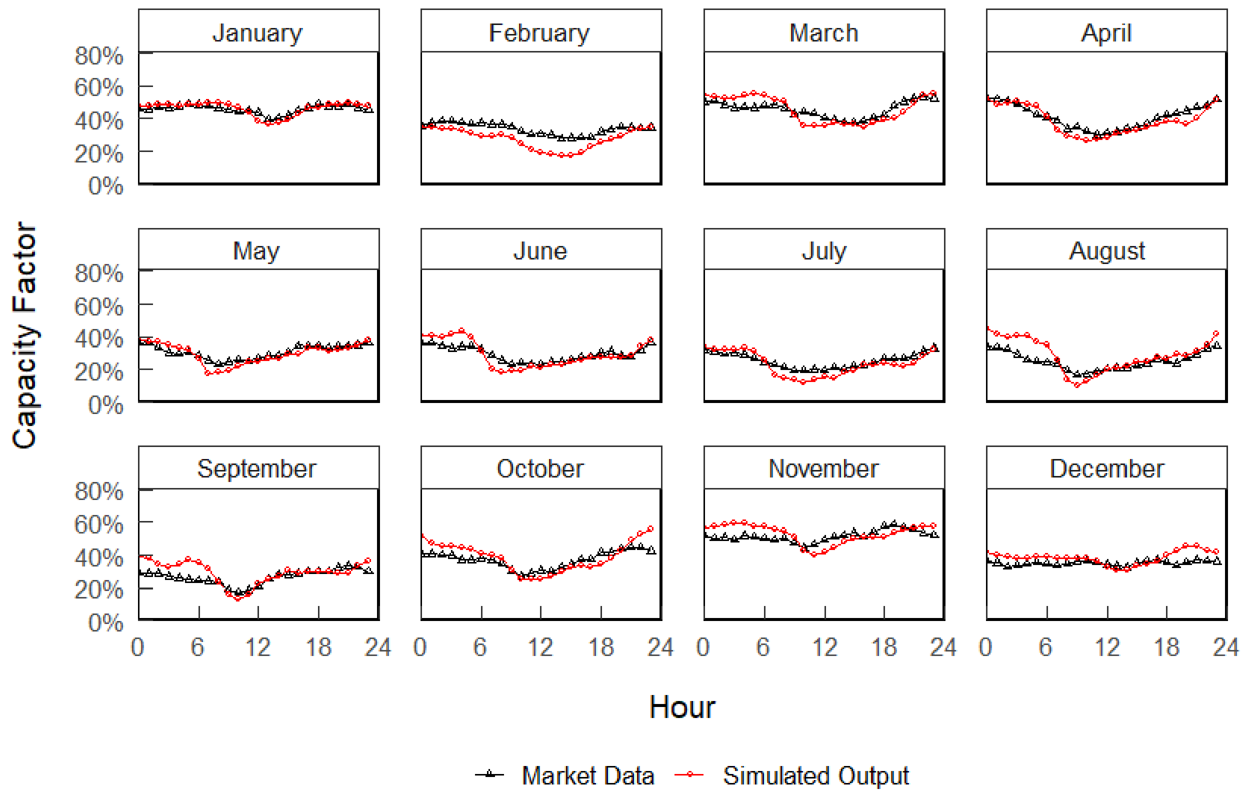

Figure A-2. Comparison of the mean diurnal profiles between Suncor Magrath's (30 MW) simulated output and the historical market data (2008-2010).

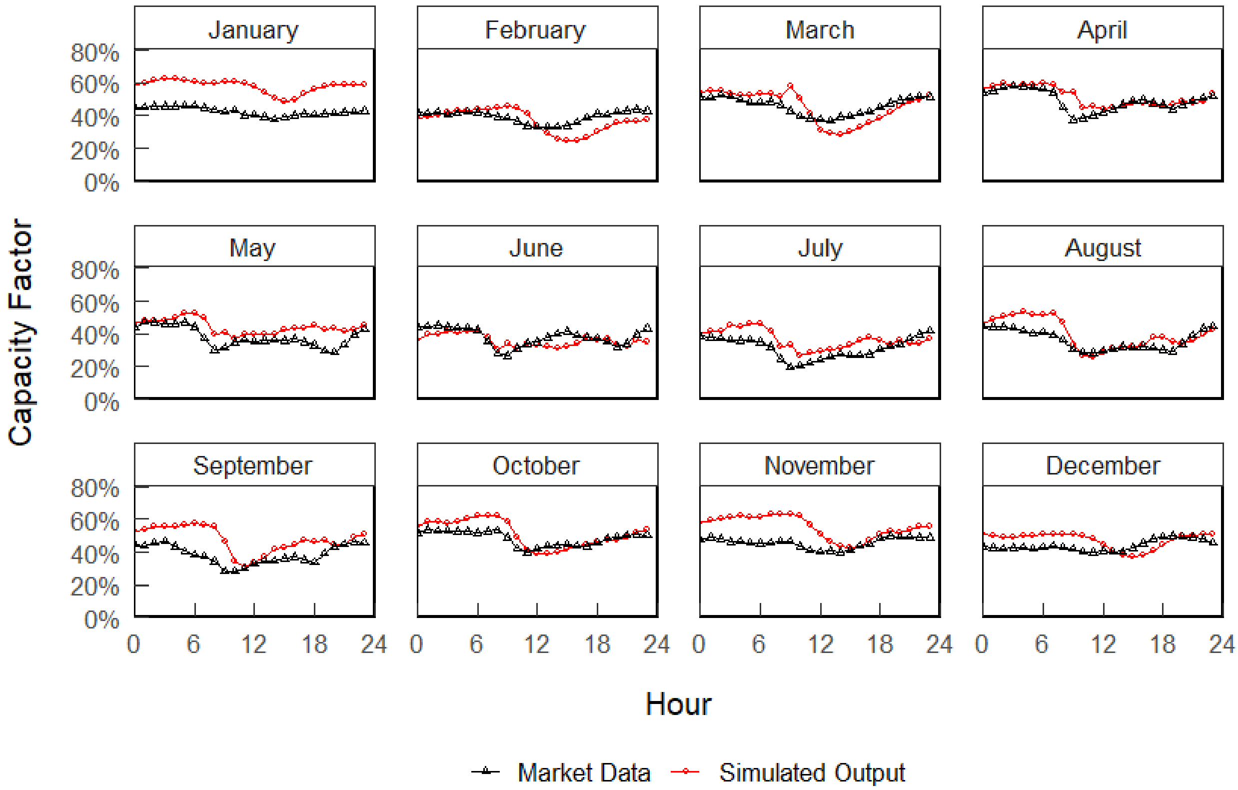

Figure A-3. Comparison of the mean diurnal profiles between Bull Creek's (29 MW) simulated output (2008-2010) and the historical market data (2016-2019).

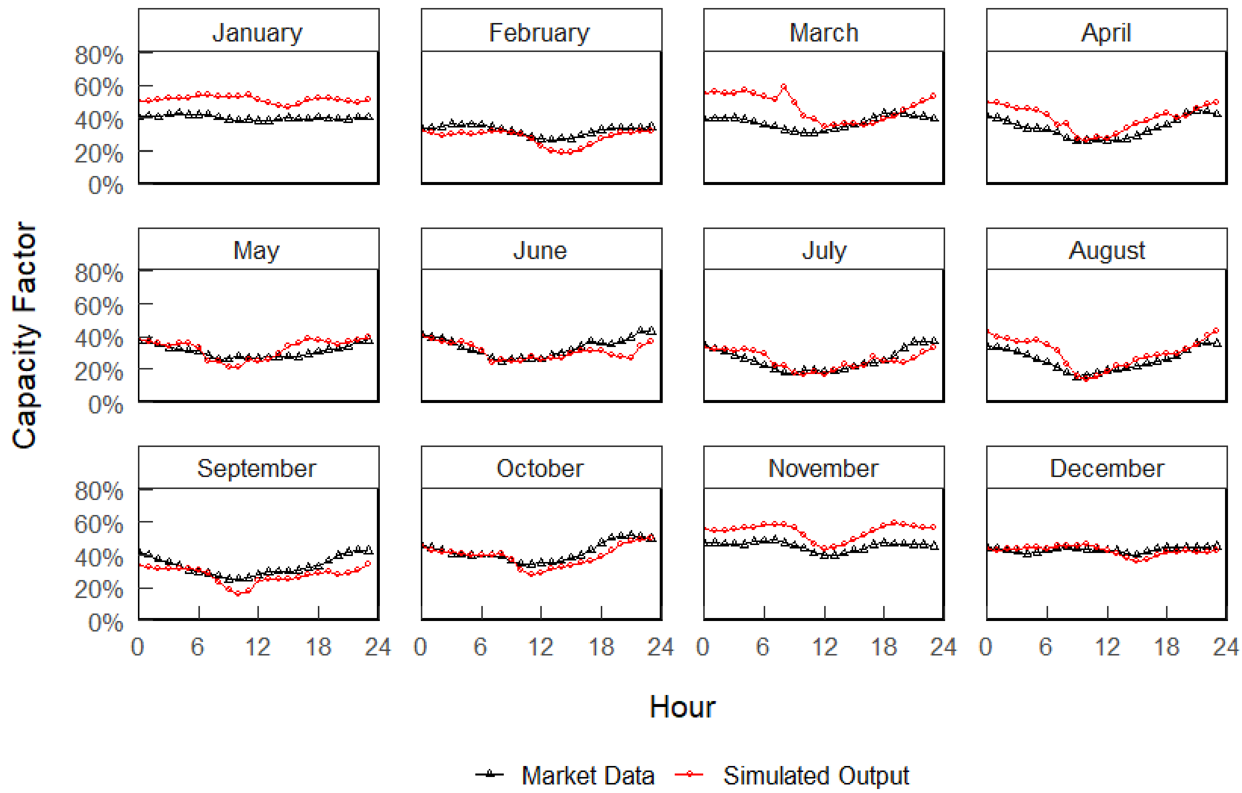

Figure A-4. Comparison of the mean diurnal profiles between Wintering Hills' (88 MW) simulated output (2008-2010) and the historical market data (2012-2019).

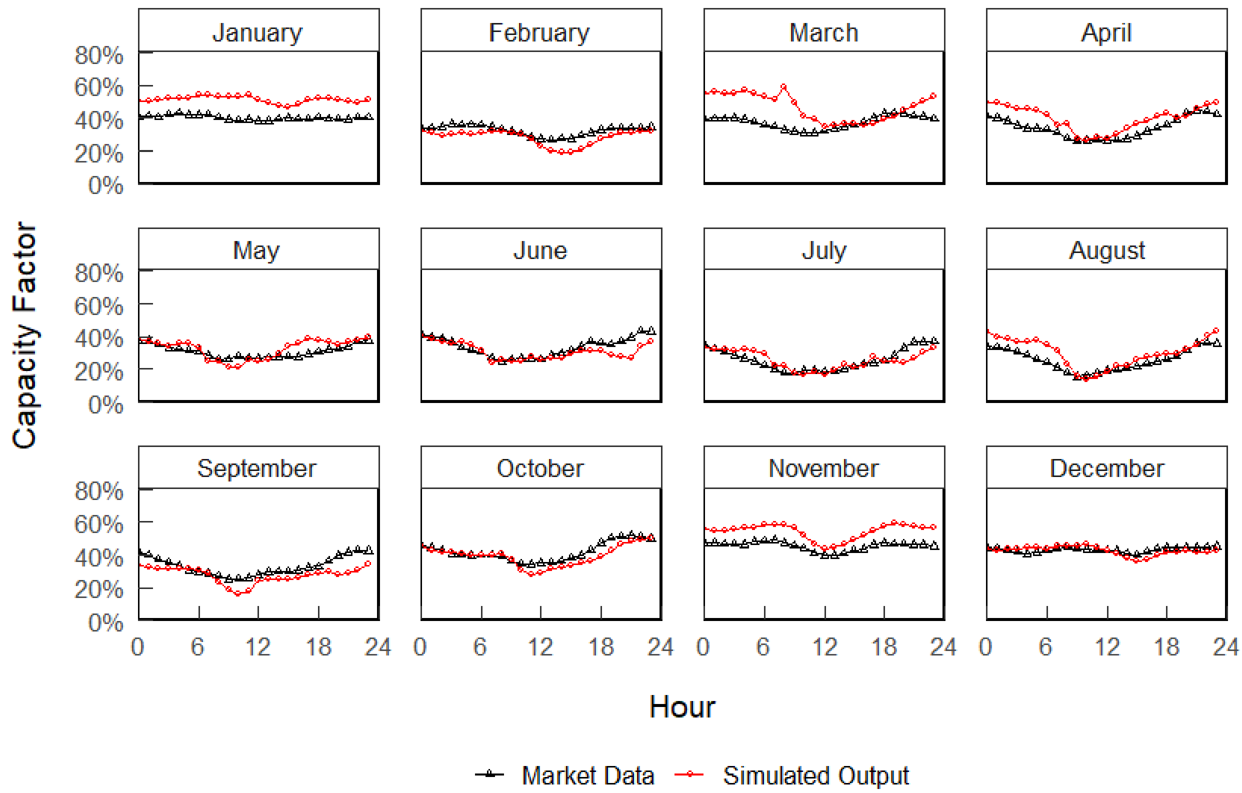

Figure A-5. Comparison of the mean diurnal profiles between Blackspring Ridge's (300 MW) simulated output (2008-2010) and the historical market data (2015-2019).

Appendix B

Map locating the proposed HWF in Alberta. This map was created by using "My Maps", from Google Maps, in it, you can see the size of the wind farm, and model of wind turbine that is being simulated.

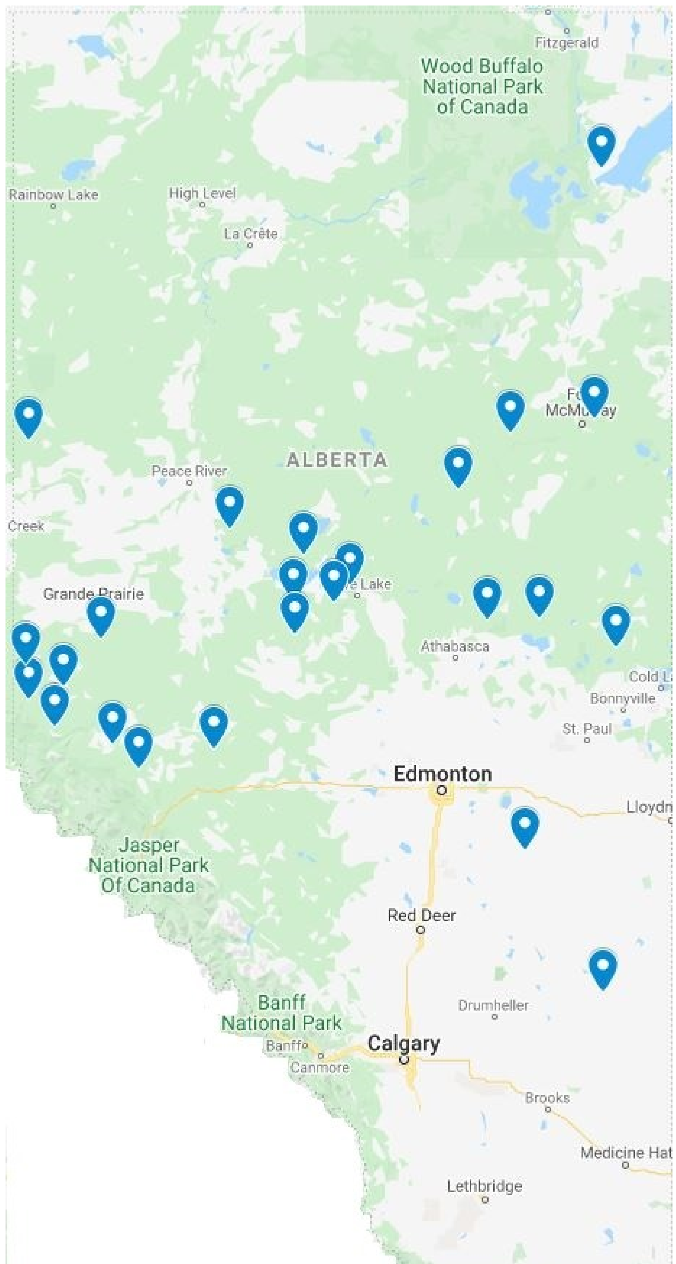

Figure B-1. HWF created for simulations in Aurora.

Link to the interactive map:
https://www.google.com/maps/d/u/0/edit?mid=1pHskHaruzh1LRCZtnLEldImK1Ew0rx6n&ll=54.538703905986836%2C-118.23872413705436&z=6

Map locating the HWF simulated in the *Forced Wind* scenario in Aurora. The selected wind farms are marked in red.

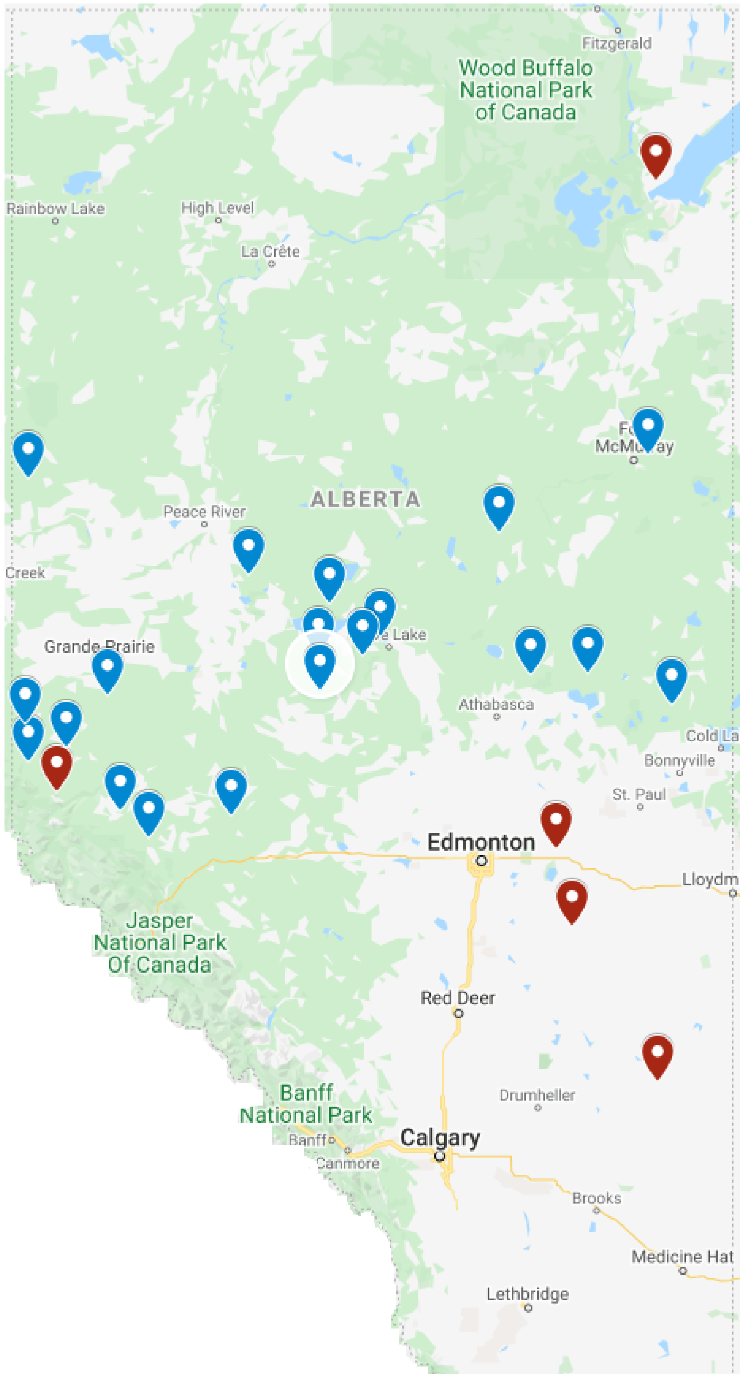

Figure B-2. Selected HWF for *Forced Wind* scenario in Aurora.