Deep Electrification and Renewable Energy in a Remote Canadian Community

by

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Abstract

This study examines high-penetration of renewable energy options for Fort Chipewyan (an off-grid community in northern Alberta, Canada). This analysis goes beyond modelling hybrid diesel-renewable electricity supply, to also consider deep electrification scenarios that not only aim to electrify the community's heating and transportation energy demands, which can almost triple the average 35 MWh/day electricity load in a highly seasonal manner. HOMER Pro software was used to create seven different electricity use scenarios, and the outcomes were compared to optimize hybrid renewable energy technologies including solar PV, wind turbines, batteries, and hydrogen fuel cells to meet forecast electricity demand. Sensitivity analyses were conducted to verify the effects of factors such as solar radiation, wind speed, the capital cost of solar PV and wind turbines, diesel prices, and CO_2 penalty cost on the cost of electricity (COE). While the community has already installed 2.6 MW of solar PV in 2019, this research found that wind energy offers a low cost long-term renewable energy option if deep electrification goals are pursued due to the solar resource being out of sync with winter heating demands. Without heat and transportation electrification, a wind-diesel-storage system could reduce the COE by 10% (from 0.326 \$/kWh to 0.295 \$/kWh), while reducing CO_{2e} emissions by 12% (3000 tCO_{2e}) annually compared to the existing system. Additionally, adding batteries along with solar PV and wind turbines cuts annual diesel fuel costs by \$1.6 million. The findings also show that if transportation is electrified, a PV-wind-battery-diesel system can reduce CO_2 emissions by almost 16,500 tCO_{2e} annually with a resulting electricity cost of 0.291 \$/kWh. Efforts to fully decarbonize the energy system however become increasingly expensive, ranging from 3 to 6 times the current energy cost for deep decarbonization and electrification, largely due to the overbuild requirements for variable renewable energy technologies.

Preface

The work done in this thesis is an original work carried out by Tazrin Jahan Priyanka under the Supervision of Dr. Brian A. Fleck from the Department of Mechanical Engineering, University of Alberta, and co-supervision of Dr. Tim Weis from the Department of Mechanical Engineering, University of Alberta.

I was in charge of gathering, processing, and carrying out the techno-economic analysis of the raw data. I was also getting the manuscript ready for publication. The supervisory authors, Dr. Tim Weis, and Dr. Brian A. Fleck participated in editing the manuscript. Dr. Tim Weis participated in the concept generation, assisted with data collection, and helped write and edit the manuscript. A Community Energy Plan created by Green-planet Energy Analytics also served as the key source of the raw data.

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In the end, I would like to thank my loving and supportive husband Md Mashum Billal for his endless support and belief in my capability. Without you, this work would never have been possible. Thank you to my family, especially my parents, and sisters for always having faith in me.

Tazrin Jahan Priyanka

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Nomenclature and Abbreviations

ASHP	Air source heat pump
$E_{ann,served}$	Annual electrical energy served
$H_{ann,served}$	Annual heating energy served
f	Annual inflation rate
i	Annual interest rate
C_A	Annualized cost of the system
C_{batt}	Average battery capacity
$E_{average}$	Average charge curve
d	Average driving distance
ε	Average fuel efficiency
η_B	Battery efficiency
E_{BL}	Battery energy level
BAU	Business-as-usual
$CapEx_t$	Capital cost
CRF(i,n)	Capital recovery factor
$CE_{TLC/Boiler}$	Carbon emission from electric and gas boiler
CE_{st}	Carbon emission from reference system
E_{FC}	Charge curve for Fort Chipewyan
COP	Coefficient of performance
CHP	Combined heat and power
η_{con}	Converter efficiency
COE	Cost of electricity
B_E, A_E	Curve consumption coefficient
V_{ci}	Cut-in wind speed
V_{co}	Cut-out wind speed
d_{pv}	Derating factor
η_{TLC}	Efficiency of electric boiler
η_s	Efficiency of hydrogen storage
E_{TLC}	Electric boiler

EV	Electric vehicle
E_d	Electricity demand
E_g	Electricity generation
I_{elc}	Electrolyzer current
E_{elc}	Energy requirement of electrolyzer
F	Faraday coefficient
η_F	Faraday efficiency
FC	Fuel cell
GHI	Global horizontal irradiance
GHG	Greenhouse gas
HPWHs	Heat pump water heaters
E_{Heat}	Heating demand
SOC_{HC}	Home coming state of charge
SOC_{HL}	Home leaving state of charge
$T_{h,indoor}$	Hourly average indoor temperature
$T_{h,outdoor}$	Hourly average outdoor temperature
HRES	Hybrid renewable energy system
E_i	Individual charge curve
P_i	Input power of converter
η_i	Inverter efficiency
LCOE	Levelized cost of energy
n	Lifetime of the project
T_C	Module cell temperature
L_m	Monthly average envelope heat loss
$T_{m,indoor}$	Monthly average indoor temperature
I_m	Monthly average internal gains
$T_{m,outdoor}$	Monthly average outdoor temperature
G_m	Monthly average solar gains
NPC	Net present cost
i'	Nominal interest rate

x_h	Normalized hourly internal gains
n	Number of charge curve
N_{FC}	Number of EV in Fort Chipewyan
N_C	Number of total cells in series
$OpEx_t$	Operational cost
P_o	Output power of converter
$E_{FC,tank}$	Output power of fuel cell
E_{HB}	Output power of hydrogen boiler
R_{H_2}	Rate of producing hydrogen
P_{pv}	Rated capacity of the PV module
V_r	Rated wind velocity
CER	Ratio of carbon emission reduction
T_{ref}	Reference cell temperature at the standard condition
RF	Renewable fraction
P_{demand}	Required charge for EV
σ	Self-discharge rate of the battery
SAHPWHs	Solar assisted heat pump water heaters
Iref	Solar irradiation at the standard condition
PV	Solar photovoltaic
$I(t)$	Solar radiation incident on the PV
SOC	State of charge
α_p	Temperature coefficient of power
TLC	Thermal load controller
3NE	Three Nations Energy
S_h	Total hourly horizontal solar irradiation
S_m	Total monthly average horizontal solar irradiation
$E_{non-ren}$	Total non-renewable electricity from the system
$H_{non-ren}$	Total non-renewable heating generated from the system
V	Wind velocity
ZEV	Zero emission vehicle

1 CHAPTER 1: Introduction

In 2023 there were nearly 300 remote communities with a total population of around 200,000 living in Canada, many of whom are heavily dependent on diesel fuel as a reliable source of energy for generating electricity and building heating [1]. The consumption of liquid fuels in off-grid communities as the major sources of energy for electricity, heating and transportation has a significant economic impact and long-term sustainability issues in addition to potential local air quality concerns [2]. Diesel generators for electricity generation also create noise and local air pollution, and energy security can be threatened during the transportation of diesel fuels by truck over winter roads. Due to cost and sustainability concerns, the Government of Canada is targeting to replace the conventional energy generation technology with clean, reliable energy by 2030 in Canadian rural, remote, and Indigenous communities [3].

According to the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP), Indigenous people have the inherited right to autonomy to protect their culture, land and resources, and implement the laws and practices that have an impact on their daily lives [4]. Indigenous groups assert they have an innate right to autonomy because they were the first to rule Canada and did not voluntarily cede their independence to European settlers which the Canadian Constitution upholds and recognized by the federal government in 1995 [5]. Furthermore, as the severity of global warming worsens in many cases global Indigenous populations will be severely impacted by the adverse effects of climate change [6]. However, natural resource development projects in developed countries often fail to fully address the rights, livelihood, interests, and intersectionality of Indigenous people during negotiation, monitoring, and assessment processes, restricting their access to clean energy projects [7]. Indigenous people are organizing and consulting the laws of uses of resources, and profit creation from the non-governmental sectors more frequently to protect their culture, lands, resources, political, and economic prospects from the assets on lands and waters [8], [9]. This study examines a case study for a remote community which has already begun to develop its own renewable energy projects and examines potential challenges as it considers moving towards a 100% local renewable energy.

While the potential of renewable energy in remote Canadian communities has been investigated for years, and their prospective financial and environmental benefits to meet the electricity demand in remote locations [10], the majority of remote communities are still dependent on diesel fuel for electricity generation, fuel oil for heating and gasoline or diesel for vehicle use. Recent programs from the Government of Canada have made “off-diesel” a priority and few remote communities in Canada have integrated accessible renewable sources to generate electricity, create job opportunities, reduce GHG emissions, and reduce the cost of electricity while attaining energy security and autonomy [11], [12].

While reducing (or eliminating) diesel use for power generation has been a challenge on its own, heating and transportation remain heavy consumers of fossil fuels in remote communities. Collectively, the annual consumption of diesel fuel for electricity generation in remote communities in Canada is more than 90 million litres, while building heating demands two or three times more diesel fuel than that of electricity production [13]. Using waste heat from diesel generators provides an opportunity for more efficient heating in remote communities as discussed by Baidya [14], but still remains depending on a fuel input. A renewable fuel such as biomass or a biodiesel have been considered as alternatives in Canada (such as wood pallet heating system in the Northwest Territories), but can pose strains on local wood supplies, local air quality and costs [15]–[17]. The recent advent of major price declines in solar and wind energy opens the door to considering the electrification of heating systems. Furthermore, electric vehicles are becoming increasingly commercially available, and their adoption in remote communities could present a solution to virtually eliminate all fossil fuel imports through a deep electrification of heating and transportation [18]. This study looks at the challenges and the viability of deep electrification in a remote community, including examining potential technology supply options for local renewable energy generation.

The variable nature of renewable energy technologies such as wind and solar mean they require varying levels of over-capacity, technology diversity, energy storage and/or back up dispatchable generation [19]–[21]. This study examines a hybrid renewable energy system (HRES) with two or more power-generating sources, including an energy storage options to ensure reliable energy supplies throughout the course of the year [21], [22].

This study investigates the feasibility of designing different HRES scenarios for a remote community in Alberta and examines resource and storage configurations to achieve 100% renewable electric heating and evaluates the energy and ecological influence of electric vehicles

(EV) in the transportation sector of the remote community. Many remote communities have begun implementing renewable-hybrid electricity options in Canada, but this study uses Fort Chipewyan to examine how deeper decarbonization could alter the optimal technology choices.

1.1 Motivation

Canada has been examining options to reduce imported fuels into remote communities for many years including the recent Clean Energy for Rural and Remote Communities (CERRC) program [23]. Designing a hybrid renewable energy system (HRES) for isolated communities in Canada has the potential to increase reduce the dependency on energy imported into the community, lower emissions, stabilize long-term energy costs, and increase environmental sustainability and resilience. This study explores different cost minimization and deep decarbonization scenarios to investigate cost-effective energy options including diesel generators as a backup and to achieve 100% renewable electricity with and without electric heating and electric vehicle (EV) adoption. Fort Chipewyan was considered as a case study as it has been operating over 2 MW of solar photovoltaics in the community and has expressed interest in further renewable energy expansion and electrification.

1.2 Thesis overview

Chapter 2 gives the background knowledge required to comprehend the work presented in Chapter 3 and completes a literature review of similar studies. This covers topics such as discussions of renewable energy transition in Canadian rural communities, ongoing solar energy projects in the study area, a summary of renewable electric heating and electric vehicles (EV) to create sustainable communities, and a summary of global ongoing research on hybrid renewable energy technologies. Chapter 3 contains a methodology established to satisfy utility and transportation alternative fuel demand through renewable electricity. Chapter 4 examines different scenarios developed in optimization software. Chapter 5 summarizes the current thesis, outlines the contributions, and discusses future work.

2 CHAPTER 2: Background and Literature Review

2.1 Renewable energy transition in remote communities of Canada

The Royal Commission on Aboriginal People, the Truth and Reconciliation Commission (TRC), and the United Nations Declaration on the Rights of Indigenous People (UNDRIP) [24] all emphasized the importance of involving remote communities in clean energy development due to the historic issues surrounding their engagement in this area. This is particularly crucial for isolated communities, which are often adversely impacted by high energy costs and local energy scarcity. The shift towards renewable energy sources can offer remote Indigenous communities the opportunity to attain economic and political independence, promote self-reliance, achieve autonomy, and foster environmental protection while embracing their unique cultural perspectives [24], [25].

Canada relies heavily on fossil fuels, but it also generates a significant portion of its electricity from renewable sources, particularly hydropower in British Columbia, Manitoba, Labrador, and Ontario [26]–[28]. The primary energy production from various sources in 2018 [27] is presented in Figure 1, where the category of "other renewables" comprises wind, solar, wood/wood waste, biofuels, and municipal waste. However, the Canadian remote communities are far behind in electricity production from renewable energy sources. Some experts argue that promoting racial harmony and combating climate change are mutually reinforcing goals which can contribute to the democratic transition to renewable energy led by Indigenous people [29], [30], on the other hand some communities do not view a transition to renewable energy as a path to reconciliation with Indigenous peoples, even though it is not necessarily detrimental to them [29], [31]. Canada has a vast potential of renewable energy for generating electricity from solar, hydro, wind, and biomass [32]. However, some of these lands are subject to land claims by Indigenous communities [33].

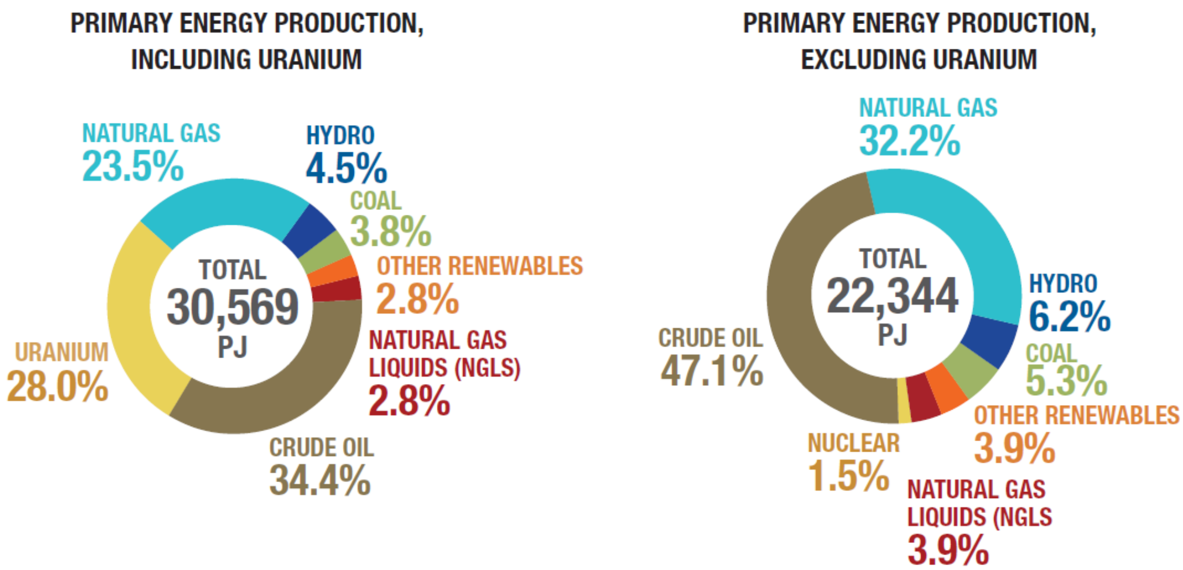

Figure 1: Primary energy production in Canada by source (2018) [27]

The Act of 1982 from Section 35 recognizes the constitutional rights of the Indigenous peoples of Canada. Among them 4.9% people [34] identified as Indigenous, with 977,230, 65,025, and 587,545 First Nations, Inuit, and Métis people respectively [34]. The legacy of colonization has resulted in Indigenous communities experiencing various forms of disadvantage, affecting almost every aspect of their well-being [35], [36] including their relationship to energy use and resources. Energy poverty is experienced by at least 170 of the 292 off-grid communities [37], with many relying on expensive diesel fuel for their energy needs where almost 500 Indigenous communities dependent on the North American Power Grid [38], [39]. Table 1 illustrates the Indigenous communities in Canada [24].

Table 1: Indigenous communities in Canada [24]

Uniqueness	Population	References
First Nations	630	[40]
Metis	8	[41]
Inuit	53	[42]

The federal and territorial governments encourage to increase the involvement of remote communities in renewable energy projects [43]–[45]. Some legislative initiatives contributes in these renewable projects, such as the Clean Energy Act (2010) and the First Nations Clean Energy Business Fund in British Columbia [46]. Similarly, in Ontario the Feed-In-Tariff (FIT) and Large Renewable Procurement (LRP) programs influence the role of First Nation communities.

2.2 Current solar energy project in Fort Chipewyan

Fort Chipewyan is home to close to 1,000 inhabitants [47], and is located approximately 150 km away from the nearest connection to Alberta's electric and natural gas grids [48], and depends on imported fuel to generate electricity as well as building heating. Diesel is transported via trucks on a winter ice road, which is open for only six weeks in the winter [48]. In order to start to reduce the diesel consumption for electricity, the community began exploring options for solar photovoltaics (PV). The Three Nations Energy (3NE) solar farm was commissioned on November 17, 2020 [49] in Fort Chipewyan.

ATCO, the local electricity utility, has collaborated with 3NE on a two-phased project to design and construct a solar farm. 3NE is operated by the Athabasca Chipewyan First Nation, Mikisew Cree First Nation, and Fort Chipewyan Métis Association. The first phase of this project comprised a 400 kW solar farm and the second phase established 2,200 kW solar farm which is jointly owned by the 3NE and operated by ATCO. The solar farm project cost $7.8 million [50] and uses 6,500 solar modules to generate 2.6 MW of electricity. The diesel facility creates approximately 760 g of GHG emissions for every kWh of electricity generated and as a result the solar farm, which reduces 800,000 litres of diesel fuel consumption and could reduce 2.1 kt of CO_{2e} emissions annually [51].

ATCO installed a 1.5 MWh of battery storage capacity in addition to this solar farm. The two solar arrays will be located near the ATCO Third Lake Generating Station [52]. While these initiatives will not replace the current diesel plant, they will reduce 25% diesel consumption in Fort Chipewyan. Without the solar project, ATCO would have needed to build 3,300 m^3 on-site diesel storage [53].

2.3 Renewable heating: Diesel to electric heating

Canadian remote communities often depend heavily on fossil fuels to meet space heating needs, resulting in high costs, local air emissions and a lack of local energy security. Renewable and alternative technologies have been explored in Canada to reduce these concerns. Hydro-Québec has piloted wind-diesel projects as early as the 1980s [54] to reduce fossil fuel shipping, storage and consumption in power generation. In some cases, grid extensions or hydroelectricity facilities were available such as in Inukjuaq and Whapmagoostui-Kuujjuarapik. In other cases, these options were not practical and more variable output technologies like wind and solar have been considered. Karanasios and Parker [55] examined prior renewable energy projects and availability of local resources in the Nunavik region of Quebec for systems that often include using diesel generators as backup supply. In addition to supply alternatives, energy demand options such as improving building insulation and other efficiency options can help to reduce, but not eliminate fossil fuel demand for building and water heating.

Yan et al. [56] performed multi-criteria decision analysis and emphasized on utilizing wood pellets combustion, waste gasification, and natural gas to select the most suitable building heating technology. They found that wood pellets combustion was the best option though it requires the pellets to be imported since there is no local supply. However, their study did not consider the use of electric heat pumps, which could also be a viable option for building heating. In Nunavik, Comeau et al. [57] conducted assessments on geothermal resources for building heating. But their study did not fully evaluate the potential of using electric heat pumps and deferrable building heating as thermal storage as practical solutions.

According to International Renewable Energy Agency (IRENA) [58], the levelized cost of electricity for onshore wind farms and concentrated solar plants has decreased by 56% and 68%, respectively. However, the intermittent nature of renewable energy resources limits the degree to which they can be relied on without either backup generation capacity or energy storage systems such as batteries or hydrogen [59]. In a study by Sezer et al. [60], concentrated solar/wind-based energy systems were analyzed and they employed a hydrogen storage to enhance the reliability and found a round trip efficiency for stored energy of 61.3%. However, none of the studies assessed the potential of using excess electricity from renewable energy sources for space heating.

This research proposes an energy system that combines wind/solar/battery energy to meet the heating demands of Fort Chipewyan with renewable energy, and it also provides a thorough analysis of the effectiveness of electric heat pumps and deferred building heating.

2.4 Adoption of electric vehicles (EV) in remote communities

To meet the net-zero targets and decrease dependency on diesel, Canada needs to decarbonize the transportation sector. The Canadian government has made a commitment to reduce carbon emissions from transportation by 18 Mt annually by 2030 [61]. One way to achieve this goal is to adopt at least 20% of Zero Emission Vehicles (ZEVs) by 2026, 60% by 2030, and 100% by 2035 [62].

Interest in EVs is growing in rural areas, but successful adoption will require overcoming challenges. Some of the specific difficulties include range reduction in cold climates, limited access to renewable energy sources, restricted grid capacity, high upfront costs, and a lack of charging infrastructure [63]. Cold temperatures can cause range loss of battery-powered vehicles, with the average driving distance dropping from 400 km to 200 km (almost 48% reduction) when the outdoor temperature falls below 0°C [64].

Additionally, the upfront cost of electric vehicles (EVs) is generally higher than internal combustion engines (ICE). The initial cost of a plug-in hybrid or electric vehicle (EV) is typically between $31,000 and $36,000, while a battery electric vehicle (BEV) generally costs over $45,000 [65]. Due to the limitations of microgrid capacity in remote communities, rapid growth of EVs may pose a significant challenge as the systems are often designed for slower, more long-term demand growth, and may also not equipped to handle the sudden increases in peak power demand that EVs can cause, potentially necessitating infrastructure upgrades to support their introduction [63]. Table 2 provides a summary of the currently available electric vehicle (EV) charging infrastructure in Alaska [66]. It offers an overview of the types of power output levels, range, and charging times required to replenish an EV battery to various levels.

Table 2: An overview of the existing charging infrastructure of EVs [66]

	Power (kW)	Typical time to full charge (hours)	Range per 30 min of charging (km)	Maximum charger use in 24 hours
Level 1	1.4	21	5	1
Level 2	7	4	20	6
Level 3	50+	8-30 mins (80%)*	161+	36

While EVs represent only a tiny fraction of new vehicle sales in the territories, the Yukon is taking the lead in transitioning to cleaner transportation due to its abundant renewable energy resources [67]. The Yukon is well-suited for electric vehicle adoption [68], unlike Nunavut, which relies heavily on diesel. The ZEV sales targets of Yukon government is 10% by 2025 and 30% by 2030 as part of its Our Clean Future [69] plan, intending to have 4,800 EVs on the road by 2030. The government needs to provide new and targeted support to northern, Indigenous, and remote communities to enable them to participate in the transition to EV and decarbonize their transportation systems. Recent announcements have acknowledged this need and have proposed to increase funding and government programs at both federal and territorial levels [61]. For instance, the Yukon government has committed funding to install 14 fast chargers in isolated locations to improve intercommunity transit [70], while the federal government will provide new funding in July 2022 to establish 72 new EV charging stations across the Northwest Territories [71]. Additionally, the Northwest Territories government plans to place EV chargers along the Yellowknife to Alberta border . However, despite these positive developments, there is still a lack of funding for infrastructure in remote communities.

2.5 Global research on hybrid renewable energy systems (HRES)

According to a case study by Ninad et al [72] in 2020, integrating centralized PV systems in small remote northern arctic communities in Canada reduces diesel fuel efficiency by 2%. They indicated that diesel generators are 50% more expensive to produce electricity than solar PV, and it was also observed that PV systems require price of 5.00 $/W or less (assuming a 1.20 $/L diesel price) to achieve economic parity. However, the study did not analyze the potential impact of energy storage systems. Vera et al [73] used HOMER Pro software to investigate and optimize the ideal combination of energy sources for the off-grid community of Sanikluaq in Nunavut. Findings showed that a 500 kW of reduction in diesel generator capacity can improve renewable penetration by 25% and decrease energy costs by 26% compared to the base case scenario. Zhou et al [74] investigated the operation and management of a wind/biomass/diesel/battery-based microgrid for a Canadian Indigenous community, and the researchers concluded that using biomass energy can reduce energy demand from diesel and peak load demand of battery banks. However, the use of biomass as an energy source raises environmental, social, and economic concerns, including biodiversity loss, reduced water quality, soil disruptions, greenhouse gas emissions, and nutrient depletion issues [75].

Saheli et al. [76] analyzed the optimal configuration of a PV/wind/diesel hybrid energy system for a single family in Winnipeg using HOMER simulation. The result showed that solar/wind energy based system offers the most cost-effective and reliable energy system for the cold climate area. However, this study neglected the potential renewable electric heating system. In addition, Romero et al. [77] investigated an optimal energy supply facility for a Canadian remote mine in the Northwest Territories utilizing the optimal mine site energy supply (OMSES) technique. Although, authors ignored the variable nature of wind energy, they stated that wind farm provides the lowest cost of energy while the size of the wind farm has a significant impact on the annual returns.

The feasibility of stand-alone renewable microgrids has been investigated in several studies, with factors such as levelized cost of electricity (LCOE), net present cost (NPC), and emissions analyzed. One study found that a PV/wind/battery-based hybrid energy system is the most feasible option for a remote community in Pakistan [78], with the potential to reduce electricity generation costs by 82% and meet 100% energy demand with 67.3% excess energy. However, the study did not include a comparative study of hydrogen and thermal storage technologies. Another study [79] evaluated the viability of heat pump water heaters (HPWHs) and solar-assisted heat pump water heaters (SAHPWHs) in Canada, finding that SAHPWHs can compensate for the cooling effect of heaters and reduce space heating and cooling load by 3% and 15%, respectively. The authors did not consider the financial implications of incorporating a heat pump into the energy system. Das et al. [80] conducted a feasibility study of a biogas/PV/diesel/wind/battery-based energy system and found that the optimal HRES could reduce carbon emissions by 59.6% and 40.5% per year compared to diesel generator-based systems and grid electricity, respectively. However, the excess electricity production from renewable energy sources was not comprehensively stated in studies that used different optimization techniques to identify the best combination of HRES.

A study from 2021 [81], investigated an off-grid hybrid renewable energy system in Western Australia. They found that a PV/wind/battery/electric boiler based system reduces the COE to 0.255 $/kWh from 0.274 $/kWh while increasing the reliability of the system to 99.92%. Additionally, in 2021, Hassan et al. [82] optimized a PV/wind/battery/micro-gas-turbine based hybrid energy system using a non-dominated sorting genetic algorithm and developed three different scenarios to meet both electrical and heating demand of a remote community in Western Australia. The results revealed that the nearly 93% renewable fraction can be achieved, and 25,220 kg/yr carbon footprints can be reduced by recovering waste heat and integrating thermal storage in the system. They found that significant excess energy from the hybrid renewable energy system increased the capacity to satisfy the electricity demand of the community consistently. However, these studies ignored the promising ability of electrification through heat pump and deferable space heating.

There are numerous studies using HOMER which concentrate on fulfilling electricity demand of remote communities though few have focused on combined heat and power (CHP). According to recent studies about CHP energy systems, the overall operational cost of a remote microgrid can be minimized controlling the ratio among the electricity output and the thermal output together with demand-side management [83]. Tang et al. [84] proposed an intraday rolling dispatch strategy for an off-grid combined heat and power (CHP) microgrid to quantify the uncertainties of renewable energy sources; they validated the model’s efficiency through case studies. Kalamaras et al. [85] investigated a PV/wind/battery/fuel cell based HRES to satisfy electricity and heating demand of an island community in Greece. They found that at 1.20 €/kW COE, the demand of CHP system can be met in reliable manner, recuperating excess energy in the system. However, the stand-alone DC system in this study neglected any emissions analysis. Eajal et al. suggested [86] that insufficient power supply or voltage due to the intermittence of renewable energy is a drawback for remote systems. The authors evaluated reliability by developing a probabilistic approach, using Bayesian networks and Monte Carlo simulations to verify the efficacy of the model. Moreover, a novel methodology was developed in 2020 to evaluate the impact of different criteria including institutional support, the possibility of microgrid expansion, and the availability of renewable resources while designing a microgrid for remote community. Finally, a hybrid microgrid was constructed for a rural community using analytical network process and experts' surveys and the result showed that PV/wind is the best combination while coupling with biomass backup gasifiers [87]. However, the authors ignored different techniques to electrify the heating and transportation sector of the communities.

Energy storage technologies play an important role in reducing energy cost, GHG emissions, and increase energy reliability. Benchaabane et al. [88] investigated the potential of compressed air energy storage to provide stable power generation system. It has been found that wind-diesel based hybrid energy system offers the best configuration to meet the electricity demand of Esker mining camp and the compressed air energy storage helps to increase lifetime and reduce maintenance cost of the system significantly. In another study [89], authors evaluated the performance of wind-diesel-compressed air energy storage based hybrid system and the results indicated that compressed air storage assists to achieve high wind fraction while reducing energy cost significantly. Kotian et al. [90] proposed a PV/wind/battery/diesel generator based hybrid energy system to satisfy electricity demand of Ramea Island using different simulation software including RETScreen, HOMER Pro, REopt, and MATLAB. The optimized model provides lower energy cost while reducing annual diesel consumption and providing high renewable penetration. Khamharnphol et al. [91] investigated an off-grid hybrid energy system for Koh Samui in the Gulf of Thailand. Although the capital and installation cost of wind turbine is higher than other components, PV/wind/battery/diesel based hybrid energy system reduces diesel consumption and provides reliable power generation in February, April, May and October. However, none of these studies utilized excess electricity to meet the space heating demand of the study area.

Hydrogen electrolysis has been proposed as a suitable form of energy storage in recent microgrid studies. Some studies have focused on utilizing excess energy for electrolysis, where the produced hydrogen is stored in hydrogen tanks and later used by fuel cells [92]–[95]. One study from 2021 [96] utilized hydrogen fuel to satisfy utility electricity and power fuel cell vehicles, buses, and trucks. The authors used a mixed-integer linear programming (MILP) model, and the result showed that hydrogen storage reduces carbon emissions by 66%-99%, while increasing cost by 30%-100% compared to a diesel reference case. It has also been observed that hydrogen fuel cells combined with a heat recovery facility can help build an effective combined heat and power (CHP) system, reducing waste energy and improving the reliability of the system [97]. The studies did not examine the economic and technological aspects of hydrogen storage in comparison to other options. Another study highlighted the impact of size and price on the energy exchange of hydrogen-based microgrids, showing that an invisible amount of energy can be generated and stored in hydrogen tanks for further trading, improving energy resilience [98]. Nonetheless, the study did not address the impact of hydrogen fuel cell technologies on the social and economic factors of off-grid communities.

Despite the fact that HRES generates a significant amount of excess electricity even after using the excess electricity for electrolysis and battery storage, Akhtari and Baneshi [99] have suggested that recovering this excess electricity can reduce cost of electricity (COE) by 7.1%, CO2 emissions by 10.6%, and increase the renewable fraction by 35%. Their suggested energy system incorporated a diesel generator and solely concentrated on the electricity needs of the community, without assessing the potential for a combined heating and power (CHP) system. In contrast, Elsaraf et al. [100] examined a PV/wind/hydro/fuel cell-based system for a remote community in Newfoundland and Labrador and found that the HRES with fuel cell could reduce diesel consumption by 71% and GHG emissions by 9000 tons, meeting 100% electricity and 63.5% thermal demand from renewable sources at a levelized cost of \$-0.0245 \$/kWh. While they provided a thorough explanation of the CHP system, they did not consider the transportation requirements of the off-grid community in their research.

A study [101] incorporated an electric vehicle (EV) station, CHP co-generation, power grid, natural gas station, and thermal energy storage water tank to reduce uncertainty in electricity and heating demand and price through a real-time energy management algorithm. The authors emphasized the potential of EV batteries as an effective energy storage solution for lowering average operational expenses. However, the varying financial limitations for EVs in remote microgrids create some discrepancies [102]. Bansal et al. [103] proposed establishing a one-stop charging station for hybrid cars, including fuel-cell and battery-based EVs, to meet charging demands in an environmentally friendly and economical way. Mosetlhe et al. [104] proposed a renewable-based hybrid refueling station for an off-grid area, where 89% of the electricity demand for hybrid cars can be satisfied by wind energy at a COE of 3.20 USD/kg but did not analyze the electricity and heating demand of the community. The studies did not examine the variations in the charging patterns of EVs between daytime and nighttime, as well as between weekdays and weekends.

In addition, Rahman et al. [105] studied a PV/wind/fuel cell based HRES that offer an attractive COE with a higher percentage of clean energy reducing GHG emissions in the system. Although the COE and percentage of renewable fraction was improved, the use of excess energy was not considered in this study. It has been also found that the EV market can be developed by establishing renewable-based charging station in workplace or study area [106]. Ganesh et al. [107] examined a scenario-based study to investigate the energy and GHG emission impact of electric vehicles on electricity and transportation facility of Alberta and the result showed that almost one-third of Alberta’s 2030 GHG emission reduction target is attainable by familiarizing electric vehicles for passenger transportation. Although, this study proposed a scenario-based hybrid simulation model for Alberta's electricity system, it completely ignored the heating system of the province which is one of the major sources of GHG emission. Additionally, Turkdogan [108] proposed a PV/wind/battery based HRES for a single family, which can reduce COE by 26.4% and offer an attractive price of hydrogen at 6.85 $/kg. Nonetheless, the research did not include the battery-powered EV and disregarded the effects of cold weather on range loss and battery capacity of EVs.

Therefore, this paper aims to suggest the optimal mix of a hybrid energy system, comprising electric heating, battery storage, and hydrogen storage, that can fulfill the power and transportation requirements of a suitable off-grid community in Alberta using renewable electricity sources.

3 CHAPTER 3: Methodology

To achieve the objectives of the current study, the method section follows some steps that include (1) examining the case study community and its background history, (2) identifying local renewable resources, (3) estimating electricity and space heating energy demand for the selected location, (4) constructing EV charging profile for designated the site, (5) developing the simulation model (i.e., techno-economic and CO_2 emissions estimation) considering different scenarios built in HOMER Pro, and (6) suggesting the most cost-effective, efficient, and environmentally sustainable scenario as the optimal HRES. Figure 2 is illustrates steps of the approach applied to obtain the goals of this study, including the assessment and data required at each step, as well as the expected result of the model.

Fort Chipewyan was used as the case study for this work as their load data and solar system performance were made available, as were details about the community's future energy plans and building data. Current energy demand (i.e., electricity and heating), as well as charging demand were modeled to estimate both current and future demand profiles. Technical specifications of system components were chosen based on currently installed or appropriately sized options and current costs were researched (i.e., initial and replacement cost, capacity, efficiency, lifetime, and renewable energy sources data). Wind and solar resources were compiled from Canadian databases, and in the case of solar was verified against the performance data from the 3NE solar farm. Finally, the techno-economic optimization was performed in HOMER Pro for different scenarios by inputting system constraints and the optimal solution was identified considering the minimum cost of energy (COE), excess energy, CO_2 emission, and a maximum renewable fraction (RF).

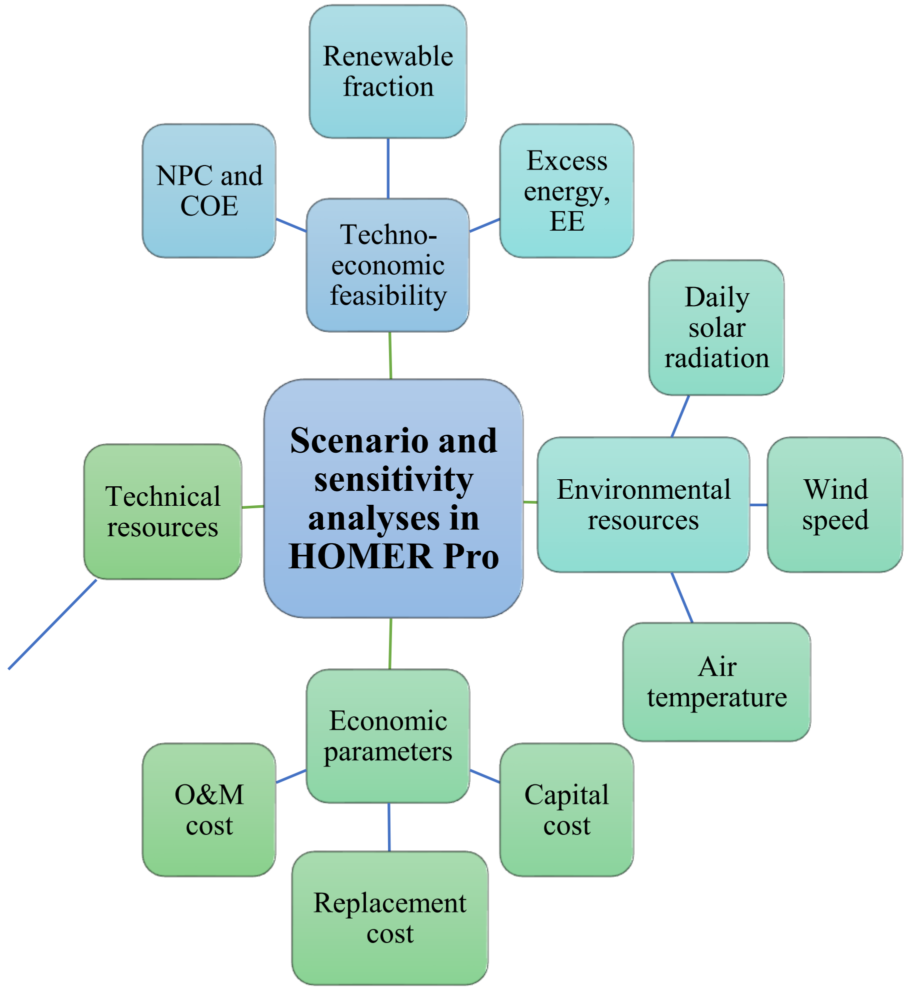

Figure 2: Inputs to the optimization model

HRESs can be flexible and scalability for different applications [109], and can include multiple sizing permutations. HOMER Pro was used to model various HRES configurations for Fort Chipewyan. HOMER Pro is a renewable energy optimization software originally developed by the National Renewable Energy Laboratory (NREL) in the USA. HOMER Pro uses hourly dispatch and renewable resource availability to investigate technical and financial options for off-grid and on-grid energy systems [110] by considering load, available resources, and different combinations of renewable energy paired with thermal generation sources and optimizes according to lowest cost of delivered energy [111]. In this study, HOMER Pro was used to investigate different load and supply scenarios as well as examine sensitivity analysis particularly with respect to future diesel fuel costs. Figure 3 shows a schematic diagram of the proposed HRES.

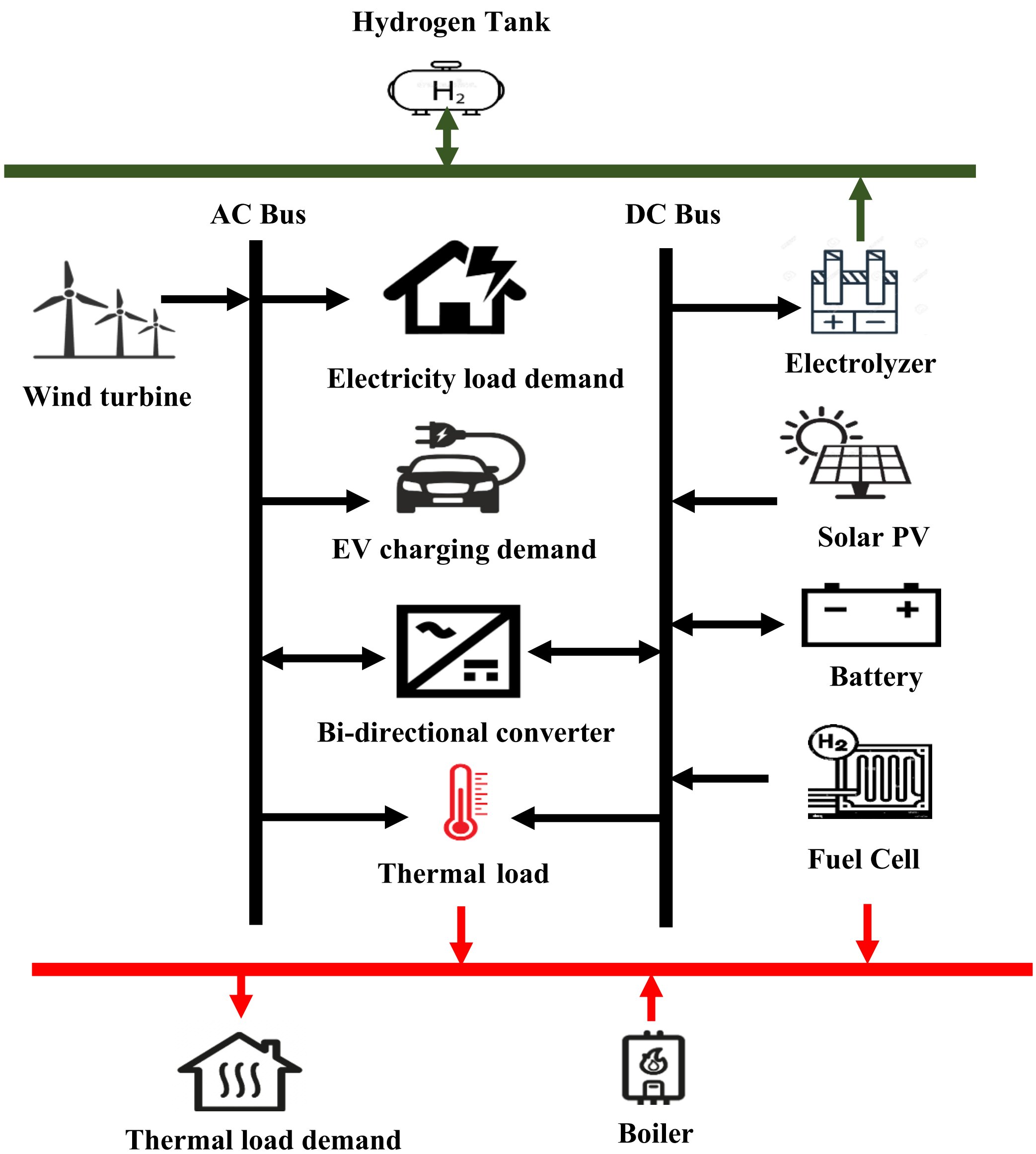

Figure 3: Schematic of the proposed HRES

3.1 Fort Chipewyan energy background

Fort Chipewyan has developed a local solar farm and is actively exploring additional ways to reduce their fossil fuels consumption. Fort Chipewyan is in the regional municipality of Wood Buffalo and is located on the northwest corner of Lake Athabasca at 58°43.2' N, 111°8.4' W and is home to almost 1000 residents living in 295 dwellings with a population density of 79.6 persons/km^2 [112]. Fort Chipewyan is seasonally accessible through two winter roads including Fort McMurray, AB (290 km) and Fort Smith, NT (140 km) whereas transportation is available during the summer season by means of air or water [113]. The Athabasca Chipewyan First Nation, the Mikisew Cree First Nation and Métis Local 12 founded 3NE in order to reduce the community's dependence on imported fuels by completing the 2.6 MW capacity solar farm project and is examining additional alternatives for further clean energy development including a local greenhouse. The studied location is completely isolated from the provincial electrical grid and prior to the development of the solar farm the ATCO Third Lake Generating Station was the only source of electricity generation which operates on four diesel-fueled generators with a total capacity of 4.58 MW. Around 2 million litres of diesel fuel is supplied by Fort Petroleum Ltd. for heating and transportation purposes [114], [115]. The purpose of this research is to investigate the possibility of combined electricity, EV charging, and building heating systems relying on 100% renewable energy sources at the selected location which will be both cost-effective and environment friendly. As this location is not easily accessible in the long winter season, grid expansion is not a feasible choice. Renewable energy sources, solar PV, wind turbines, fuel cells, and battery storage are designed in a stand-alone mode in the current study.

3.2 Estimation of electricity and thermal load profile

In this study, the daily residential and commercial electricity load data were collected from the Alberta Electric System Operator (AESO) website [116] using 1-hour time steps. This electrical load was modelled in HOMER as the 'primary load' where the scaled annual average of the load has been calculated to be 34.8 MWh/day and the annual peak load to 2.6 MW with a load factor of 0.6. Figure 4 illustrates 2021 electricity demand. Consumption is 70% higher in the winter season (September–April) compared to the summer (May-August) as the day length is shorter in winter and people increase the use of lights, and other electric appliances, including space heaters.

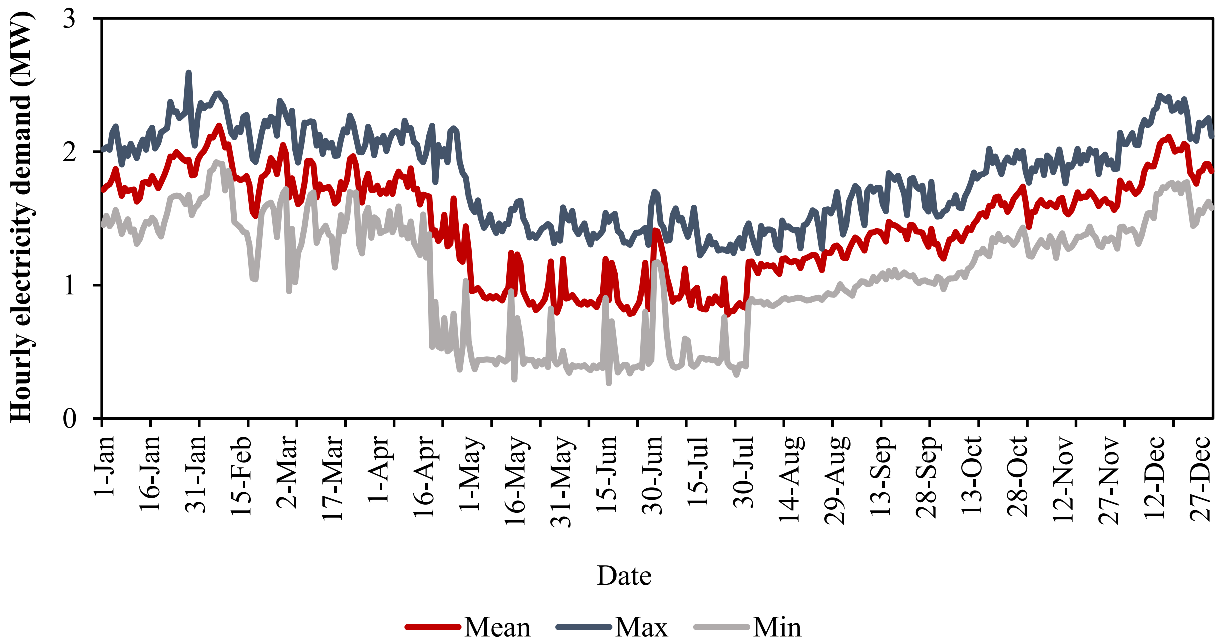

Figure 4: Hourly electricity demand at Fort Chipewyan

Hourly space heating load was estimated by developing a simulation model using HOT2000 software which is an home energy demand modeling software, created and maintained by NRCan as part of the Canadian government's EnerGuide Rating System as well as residential energy efficiency initiatives [117]. Without access to detailed building information, a typical North American home characteristics were obtained from studied literature [118] and used as a first approximation for energy use in homes. The total consumption data were verified against a 2017 community energy plan completed for the community by Greenplanet Energy Analytics [119]. Table 3 summarizes the building characteristics used in the current study.

Table 3: Sample residential building characteristics [118]

Component	Characteristic
Construction standard	R-2000
Stories	2
Livable area	210 m^2
Attic	RSI 8.6
Walls	RSI 3.5
Rim joists	RSI 3.5
Basement walls	RSI 3.5 in a framed wall. No vapor barrier.
Basement floor	Concrete slab, no insulation
Windows	Low-e, insulated spacer, argon filled, with argon concentration measured to 95%.
Window area	South facing: 16.2 m^2, Total: 35.0 m^2
Heat recovery ventilator	High efficiency (84% nominal)
Furnace	Condensing gas @ 91% efficiency

As HOT2000 calculates monthly building energy consumption, the hourly heating load is estimated using Eq. 1 [120] where, L_h denotes hourly envelope heat loss through infiltration, conduction, and ventilation, I_h is the hourly useful internal gains and G_h is the hourly useful solar gains.

$$H_h = L_h - I_h - G_h \tag{1}$$

The hourly heat loss through the envelope (L_h), internal gain (I_h) and hourly solar gain (G_h) is calculated from Eq. 2, Eq. 3, and Eq. 4 respectively [120],

$$L_h = \underline{L}_m \frac{T_{h,indoor} - T_{h,outdoor}}{\underline{T}_{m,indoor} - \underline{T}_{m,outdoor}} \tag{2}$$

$$G_h = \underline{G}_m \frac{S_h}{\underline{S}_m} \tag{3}$$

$$I_h = \underline{I}_m * x_h \tag{4}$$

Where, $\underline{L}_m$ = monthly average envelope heat loss

$T_{h,indoor}$ = hourly average indoor temperature

$T_{h,outdoor}$ = hourly average outdoor temperature

$\underline{T}_{m,indoor}$ = monthly average indoor temperature

$\underline{T}_{m,outdoor}$ = monthly average outdoor temperature

$\underline{G}_m$ = monthly average solar gains

S_h = total hourly horizontal solar irradiation

$\underline{S}_m$ = total monthly average horizontal solar irradiation

$\underline{I}_m$ = monthly average internal gains

x_h = normalized hourly internal gains

The normalized internal gain (x_h) is scaled based on the schedule of the National Building Code of Canada (NBCC) published by the National Research Council of Canada, in 2015 [121]. Figure 5 illustrates the demand for space heating load is higher in winter (October–April) as expected in a northern climate. The peak thermal load was found to be 13.5 MW along with an average heating demand of 61 MWh/day in winter.

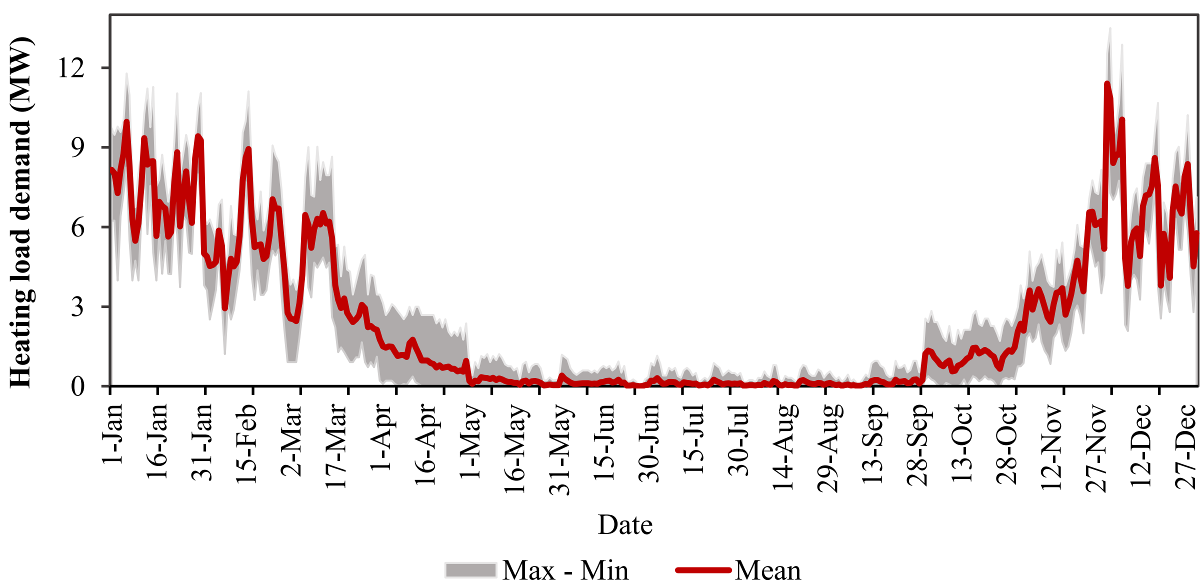

Figure 5: Estimated hourly heating demand at Fort Chipewyan

Electric thermal storage (ETS) is a distributed or dispatchable technology consisting of layers of thermal ceramic bricks storing in an insulated box [122]. This technology can be coupled with the renewable energy technologies where the furnace or boiler turns the electricity into heat and stores it in ceramic bricks. It can store the building heating load as deferrable heating to extract the heat through forced convection when it is needed, and it can also be used for peak shaving and valley filling. In this study, 70% of the total thermal load is considered to be deferrable heating, with an estimated annual scaled average of 42.6 MWh/day and a peak load of 6 MW, allowing the simulated model to store the thermal load for up to four days.

Additionally, as the wind turbines and solar PV panels generates a notable amount of excess electricity due to the intermittent nature of solar and wind resources, when the batteries are unable to consume the excess electricity, electric dump load is created in the system. Electric dump load has the potential to serve the space heating demand through an electric boiler and rest of the energy is dumped as thermal dump load. Therefore, in this study, electric dump load and deferrable building heating is considered as potential renewable heating options for the community. Table 4 is showing the monthly electric, heating, and deferrable load demand in the community of Fort Chipewyan.

Table 4: Estimated monthly electricity and heating demand in the community

Months	**Electricity demand (MWh)**	**Heating demand (MWh)**	**Deferrable load demand (MWh)**
January	1.8	7.6	5.3
February	1.9	5.5	3.9
March	1.8	3.8	2.7
April	1.6	1.1	0.7
May	1.0	0.2	0.1
June	0.9	0.1	0.1
July	1.0	0.1	0.1
August	1.2	0.1	0.1
September	1.4	0.1	0.1
October	1.5	1.1	0.8
November	1.6	3.9	2.7
December	1.9	6.9	4.8
Average	**1.5**	**2.5**	**1.8**

3.3 Electricity demand for EV

As the exact number of electric vehicles (EV) in Fort Chipewyan and their charging behavior is unknown, we modeled a synthetic but realistic charging behavior for EVs considering five different situations (including, variations between weekdays and weekends, variations in air temperature, seasonal effect on the battery capacity due to extreme cold weather in winter, variations in daily driving distance and different fuel efficiencies). There are different modeling approaches available in the literature to model the daily charging behavior of EVs depending on the vehicle aggregation method. The stochastic modeling approach is used in this study to determine the charging behavior of EVs where the mathematical model is obtained from the charging profile made by Doluweera [107]. This charging profile is developed and implemented using the programming and numeric computing software MATLAB which is extensively used by numerous engineers and scientists to analyze data, create algorithms and generate models [123]. The aggregated and average charging curve for Fort Chipewyan is calculated by Eq. 5 and Eq. 6, respectively.

$$E_{FC}(t) = N_{FC}\, E_{average}(t) \tag{6}$$

$$E_{average}(t) = \frac{1}{n}\sum_{i=1}^{n} E_i(t) \tag{7}$$

Where n refers to the number of charge curves, N_{FC} denotes the number of EVs in Fort Chipewyan, E_i refers to the individual charge curve, $E_{average}$ indicates the average charge curve and E_{FC} denotes the charge curve for Fort Chipewyan. We determined the battery capacity, fuel efficiency, and driving range of EVs by performing an EV market analysis. As the adaptation of EVs is at a growing level in the Fort Chipewyan community, we conducted an EV fleet characteristics analysis for Canada for the period of 2010-2024 and selected four electric trucks (Chevy Silverado, Tesla Cybertruck, Ford F-150, and Rivian) to model an accurate EV fleet characteristic. The average battery capacity, driving range, and fuel efficiency are calculated as 167 kWh, 605 km, and 0.28, respectively. Table 5 is representing the major technical characteristics of the designated four electric vehicles.

Table 5: Characteristics of EV fleet

Vehicle model	Year	Battery capacity (kWh)	Rated range (km)	Fuel efficiency (kWh/km)	References
Chevy Silverado	2024	200	640	0.31	[124]
Tesla Cybertruck	2022	200	800	0.25	[125]
Ford F-150	2022	131	480	0.27	[126]
R1T-Rivian	2022	135	500	0.27	[127]
Average	-	**167**	**605**	**0.28**	-

After identifying EV fleet attributes, we determined the daily travel behavior by estimating the daily driving distance, home leaving and home coming time for each vehicle. In the current study, the average driving distance by a truck is considered as 3 km/day. The travel behavior and the probability density function for different constraints are collected from U.S. 2017 National Household Travel Survey (NHTS) [128], [129]. As the freezing air temperature during the winter season increases the fuel consumption of EVs while decreasing the electrical range of a truck on a full charge significantly, the seasonal effect on battery capacity and range reduction due to extreme weather conditions is computed from [130].

It is noted that fuel consumption is more than twice on cold winter days compared to the summer season due to the required heating facilities and lower efficiency of cars [131]. For instance, 15% to 35% electric range loss can be seen due to temperature reduction between 0℃ to -25℃. In addition, we model the fuel efficiency of electric trucks in our simulations by considering the daily time-series data of air temperatures of Fort Chipewyan. It is also assumed that the average fuel consumption of the EV fleet increased from 0.28 kWh/km to 0.39 kWh/km due to cold ambient temperature. The seasonal effect on the fuel efficiency of EVs is presented in Figure 6.

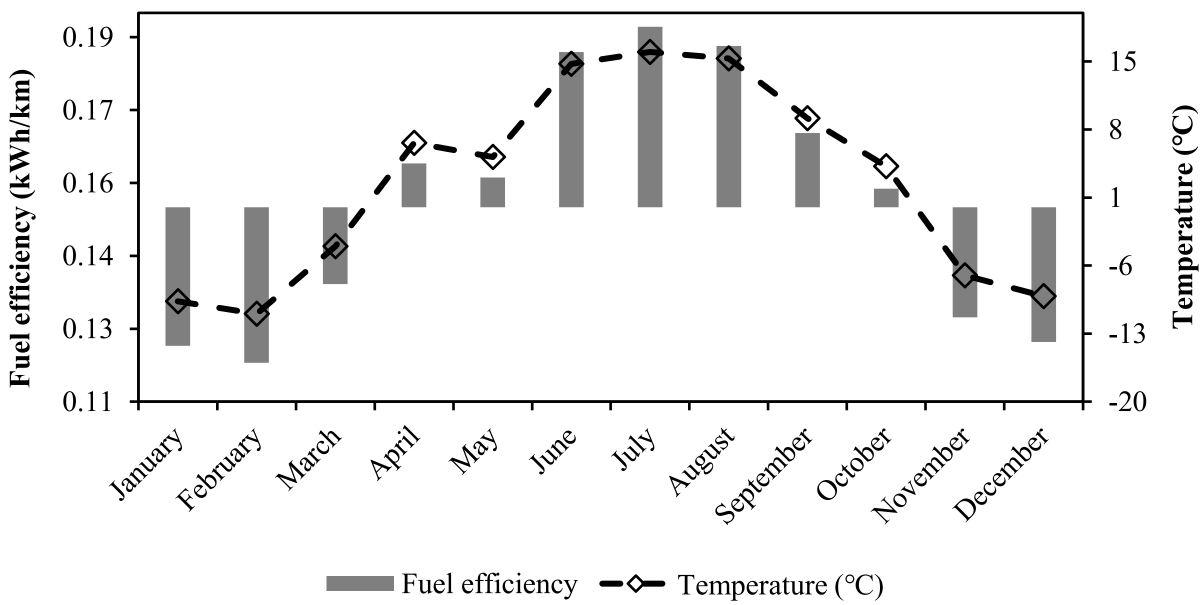

Figure 6: Seasonal effect on the fuel efficiency of EV

Furthermore, a linear correlation is considered between the energy consumption and driving distance of each vehicle by following [132]–[134]. The state of charge (SOC) refers to the percentage of level of charge remaining in the battery. The home coming state of charge (SOC_{HC}) is calculated from knowing the home-leaving state of charge (SOC_{HL}). The home coming state of charge (SOC_{HC}) and required charge (P_{demand}) for the EV battery is determined using Eq. 7 and Eq. 8 respectively, where, C_{batt} implies average battery capacity, ε denotes average fuel efficiency, and d indicates average driving distance. The efficiency of charging equipment (η) is assumed as 95% and the level two charging infrastructure is selected with 235 V voltage, 40 AMPS current, and 9.4 kW charging rate.

$$SOC_{HC} = SOC_{HL} - \left(\frac{d\varepsilon}{C_{batt}}\right) 100\% \tag{8}$$

$$P_{demand} = \frac{C_{batt}}{\eta}\left(1 - \frac{SOC_{HC}}{100\%}\right) \tag{9}$$

There are four following charging strategies available for both home and public charging.

- Uncontrolled charging: In this scenario, after the last trip, EVs begin charging instantly.
- Delayed charging: EVs delays started charging at least 4 hours after reaching home.
- Off-peak charging: It is an algorithm-based charging method. In this scenario, EVs start charging during off-peak hours, especially at night.
- Continuous charging: It assumes that vehicles start charging whenever in parking mode and that public charging stations are available at all public places.

In this study, we mainly focused on home charging and assumed that all EVs begin charging immediately after reaching home. The design framework for determining the hourly EV charging profile is shown in Figure 7.

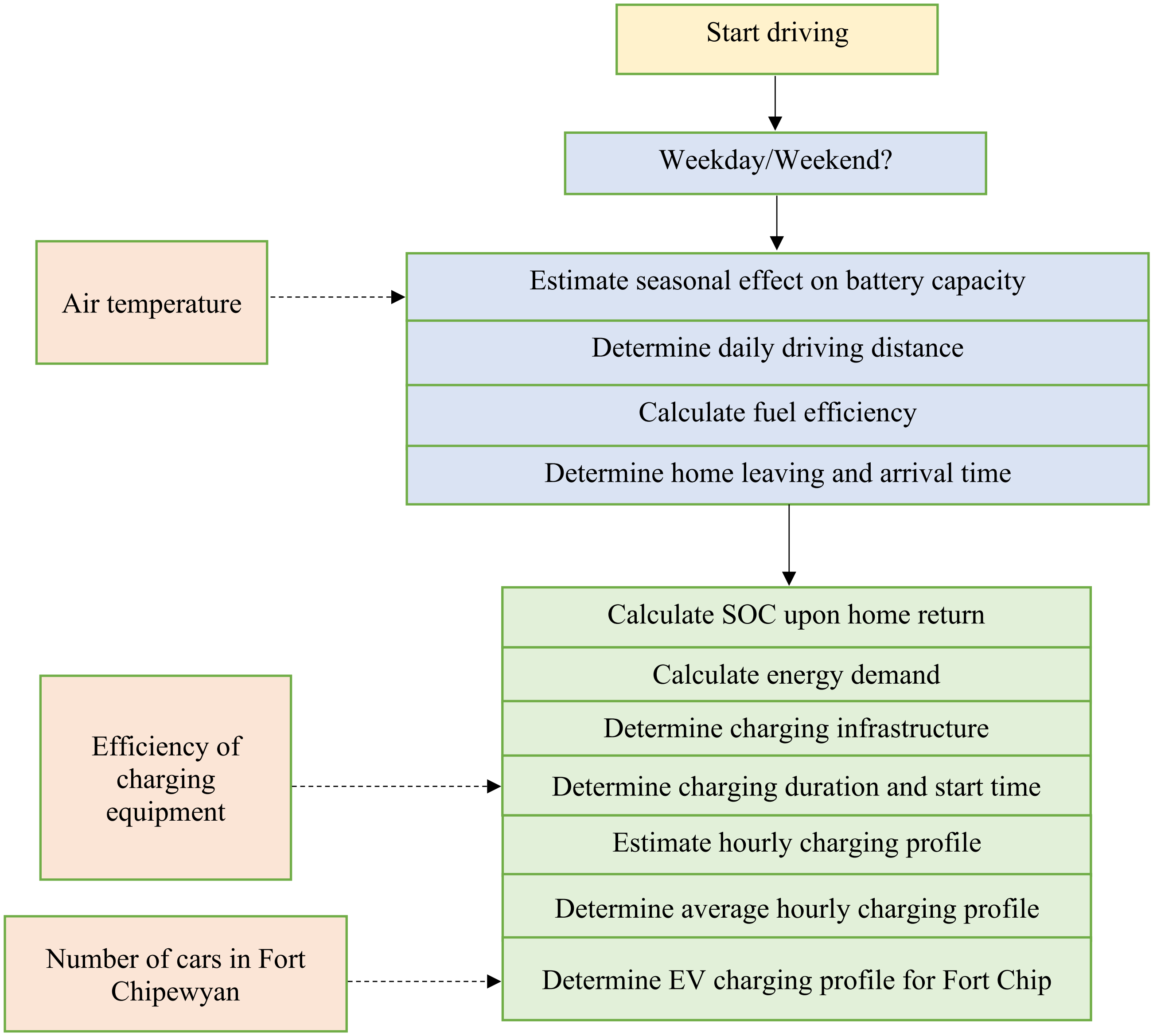

Figure 7: Design framework of hourly EV charging profile

Figure 8 is displaying the total EV charging demand for Fort Chipewyan where the estimated annual scaled average charge demand is 4.7 MWh/day with a peak load of 0.7 kW and the load factor is 0.3. Figure 8 reveals that there is a clear difference between the EV charging demand during the summer (May-August) and the winter (September-April) seasons due to the required cabin heating facility and reduced EV range in winter.

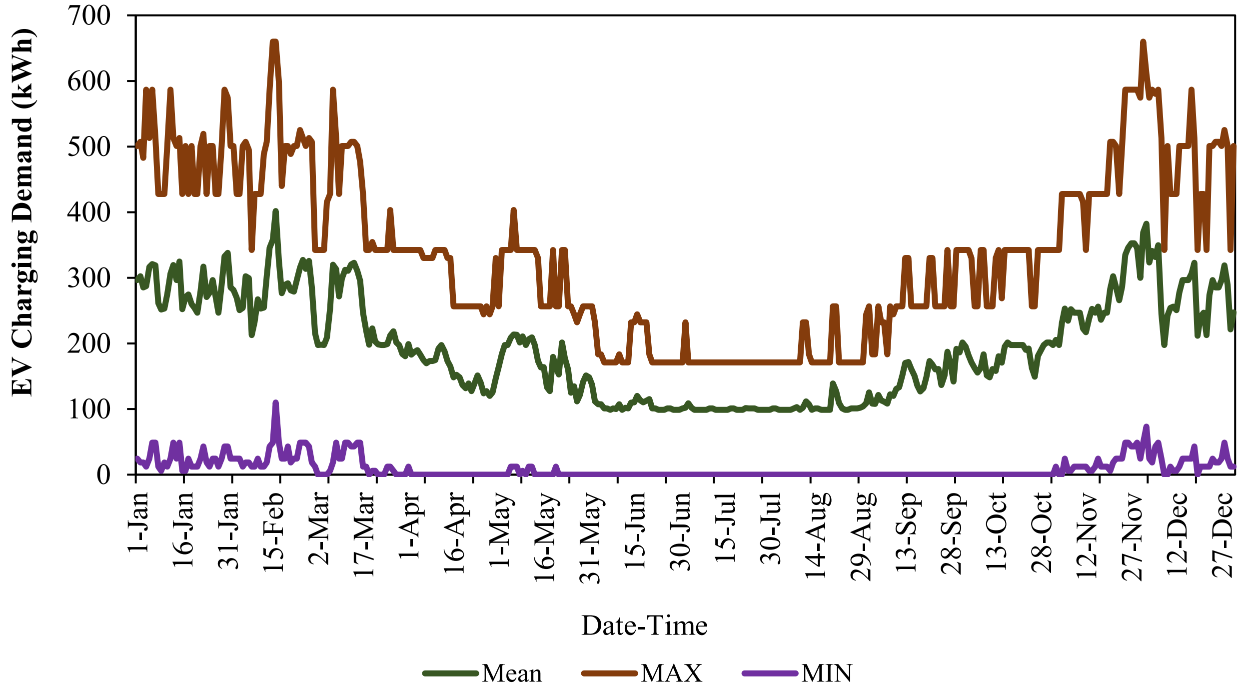

Figure 8: Simulated EV load for Fort Chipewyan

Figure 9 presents an estimate for the hourly EV charging profile assuming the 2018 gasoline consumption (approximately 2.8 million L/yr of gasoline) for cars and trucks in the community were all converted to EVs. Here, average charging demand of 26 EVs were considered that arrives home at different time of the day and start charging immediately after reaching home. The hourly EV charging profile reveals that the daily charging usually starts at 6:00 AM to 7:00 AM which continues to rise until it peaks around midnight and then declines as batteries begin to be fully charged. As different consumers begin charging at different times, a gradual increase can be seen in the average electricity consumption in the evening. In Figure 9, the peak energy consumption for one EV is nearly 11 kW, which occurs at 8:00 PM.

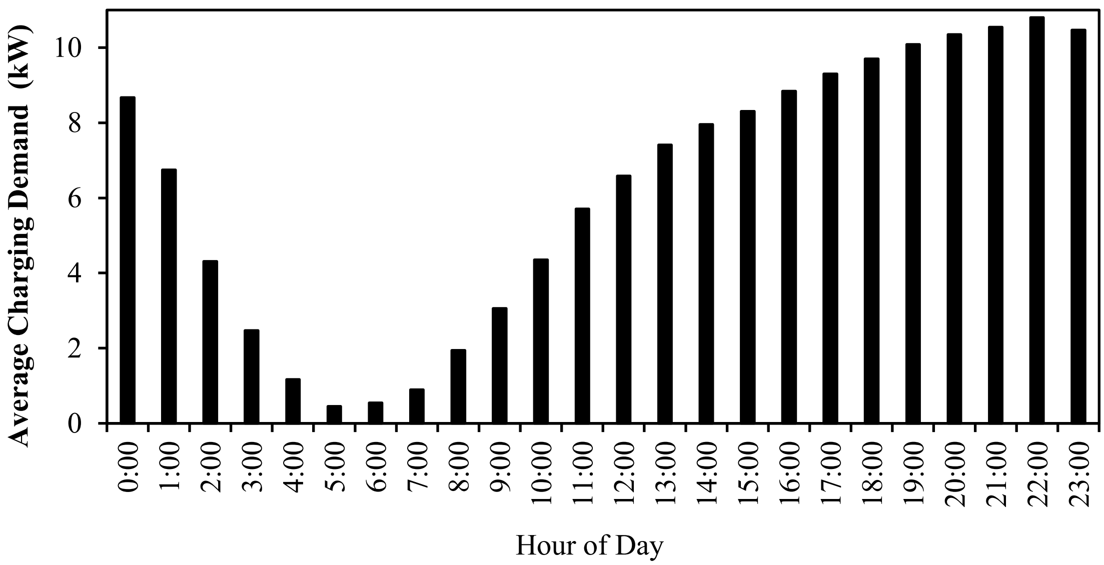

Figure 9: Hourly average EV charging profile for Fort Chipewyan

From Figure 9 and Figure 10, it can be seen that the charging demand is higher on cold winter weekdays and weekends compared to summer weekdays and weekends. Energy consumption is lower in June, July, and August and reaches a peak in December, January, February, and March, as the duration of charging is longer during winter compared to summer.

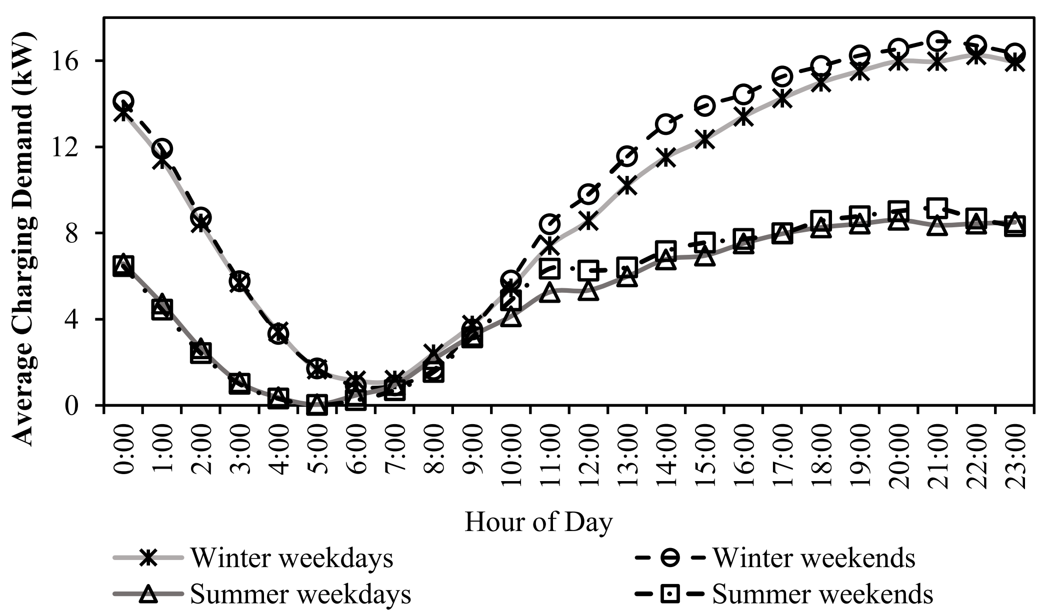

Figure 10: Day-to-Day variation in daily average EV charging profile

3.4 Renewable resource assessment

3.4.1 Solar energy

The hourly global horizontal irradiance (GHI) data has been retrieved from the Canadian Weather Energy and Engineering Datasets (CWEEDS) for the period of (2006-2017) [135]. The annual average solar radiation was assessed as 2.94 kWh/m^2/day in Fort Chipewyan with the highest clearness index of 0.630 in June which was measured at the lowest at 0.348 in December. From Figure 11 it is clear that Fort Chipewyan holds the ability to produce a significant amount of solar photovoltaic power from March to September.

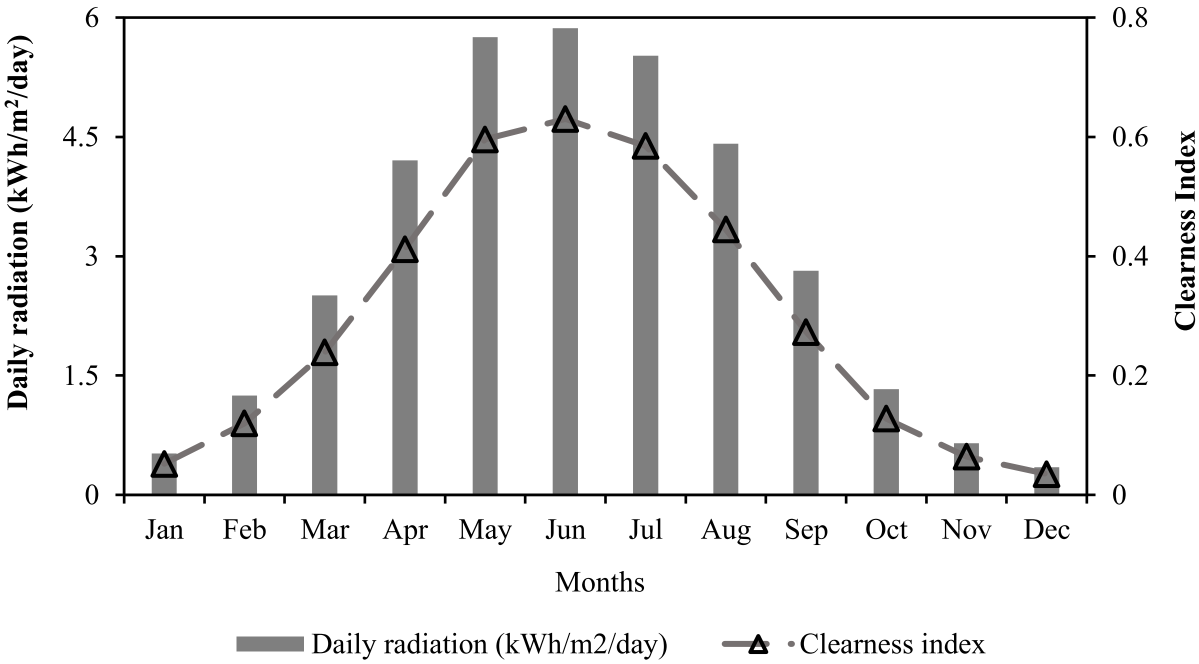

Figure 11: Monthly average solar irradiation and clearness index at Fort Chipewyan

3.4.2 Wind energy and air temperature

The hourly wind speeds and air temperature data were gathered from the Canadian Wind Energy Atlas (CWEA) database [136] and according to the latitude and longitude within the studied area, the annual average wind speed was obtained as 5.15 m/s at the height of 80 m whereas the annual average temperature was found as 1.55℃ with a monthly average range from 17.7℃ in July to -17.1℃ in January. Daily average wind velocity and average air temperature at Fort Chipewyan are presented in Figure 12 and Figure 13 respectively. The monthly average solar insulation, clearness index, wind speeds, and air temperature data has summarized in Table 6 for a better understanding of the ease of use of resources in Fort Chipewyan.

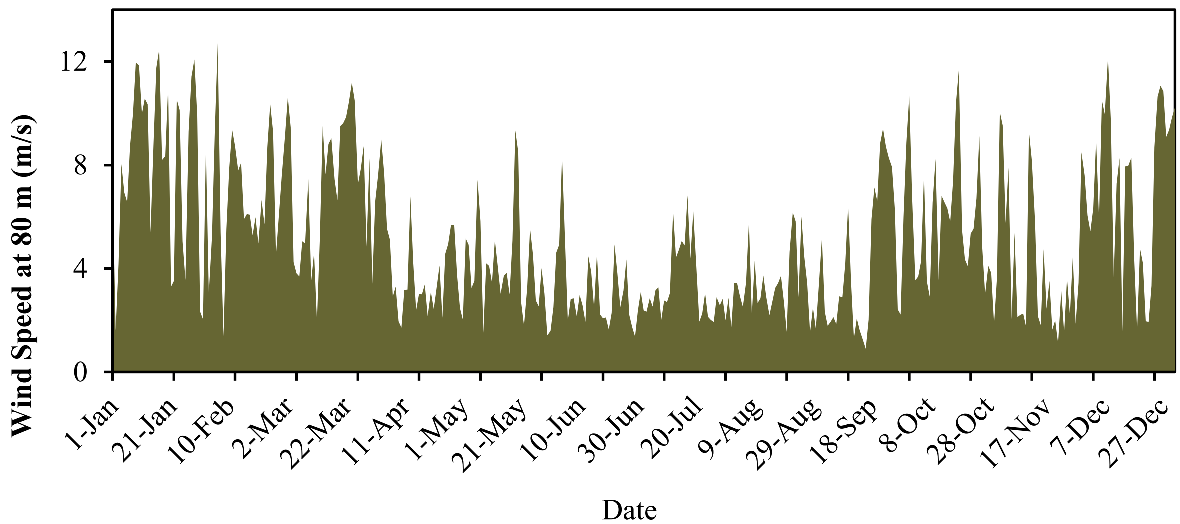

Figure 12: 10-minute averaged wind speeds at Fort Chipewyan for a typical meteorological year [136]

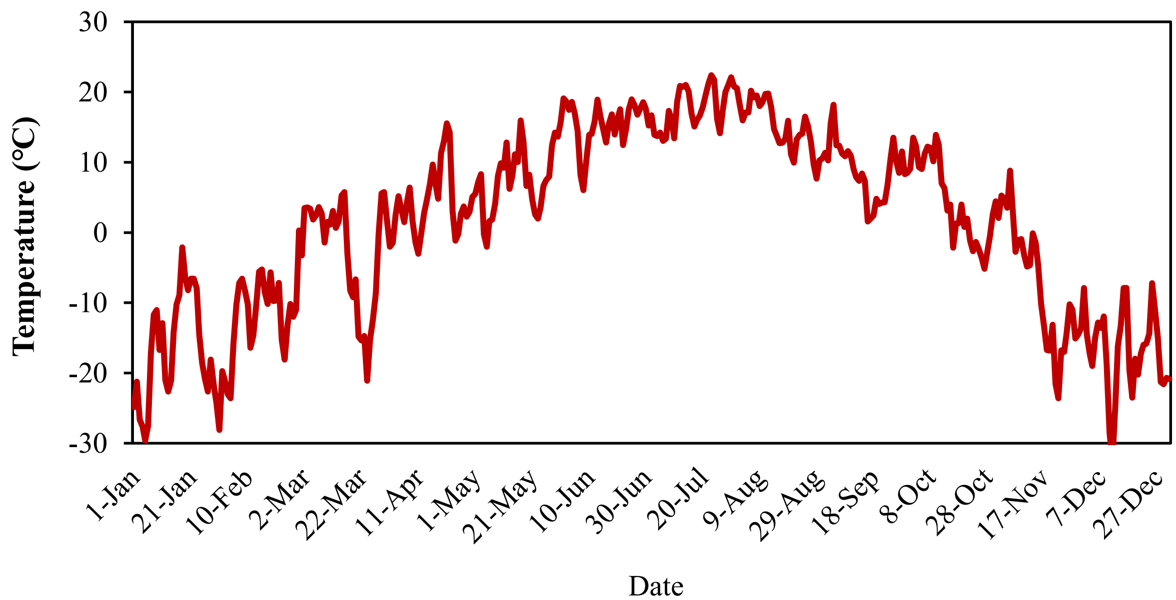

Figure 13: 10-minute averaged air temperature at Fort Chipewyan for a typical meteorological year [136]

Table 6: Summary of different environmental resources used in the study [135], [136]

Month	Clearness Index	Daily Radiation (kWh/m2/day)	Wind Speed (m/s)	Daily Temperature (℃)
January	0.05	0.5	8.2	-18
February	0.12	1.3	6.7	-12
March	0.24	2.6	7.2	-3
April	0.41	4.2	4.2	4
May	0.60	5.8	4.0	8
June	0.63	5.9	3.2	16
July	0.59	5.5	3.3	18
August	0.45	4.4	3.4	15
September	0.27	2.8	4.4	9
October	0.13	1.3	5.8	5
November	0.06	0.6	4.3	-7
December	0.04	0.3	7.2	-17
Annual Average	**0.30**	**2.9**	**5.2**	**1.5**

3.5 System architecture

3.5.1 Photovoltaic panels

An Indigenous-owned solar farm has already been established in Fort Chipewyan in which 5760 solar panels are going to replace the use of 800,000 liters of diesel fuel every year. This solar farm will provide almost 25% of Fort Chipewyan's total energy and will reduce carbon emissions by 2,376 tonnes per year [51]. In this hybrid system, a 2.6 MW generic flat plate PV was considered with 18.7% efficiency and a 95% derating factor while considering the ambient temperature. The electric energy achieved from the flat plate solar PV module is computed from Eq.9 [137]

$$P_{pv}(t) = C_{pv} d_{pv} \left(\frac{I(t)}{I_{ref}}\right)[1+\alpha_p(T_c - T_{ref})] \quad (10)$$

Here, P_{pv} refers to the rated capacity of the PV module, d_{pv} refers to the derating factor, $I(t)$ signify the solar radiation incident on the PV (kW/m2), $Iref$ indicates the solar irradiation at the standard condition (1 kW/m2). In addition, α_p states the temperature coefficient of power (-0.35 %/°C), the module cell temperature, and the reference cell temperature at the standard condition (25 ℃) are denoted by T_c and T_{ref} respectively.

3.5.2 Wind turbine

The electric power production from a wind turbine is highly dependent on the variable wind velocity. The wind power output from a wind turbine is calculated by Eq. 10 [138]

$$P_{WT}(t) = \begin{cases} 0, \ V \leq V_{ci} \ or \ V \geq V_{co} \\ T_{WT} E_r \left(\frac{V^3 - V_{ci}^3}{V_r^3 - V_{ci}^3}\right), V_{Ci} < V \leq V_r \\ T_{WT} E_r, \ V_r < V \leq V_{co} \end{cases} \tag{11}$$

V, V_r, V_{ci}, $V_{co,}$ denotes to the wind velocity, rated velocity, cut-in wind speed, and cut-out wind speed, respectively. According to the collected annual average wind speed at Fort Chipewyan was 5.15 m/s, the rated power of the wind turbine (P_{WT}) was considered as 1.5 MW for this study, and the lifetime of the turbine was assumed to be 25 years, and the hub height was 80 m without considering the ambient temperature. In the current study, the wind turbine was connected to the AC bus where the turbine loss was considered zero.

3.5.3 Battery

In this hybrid energy system, Gildemeister 250kW-4hr battery was selected with 25 years lifetime. The state of charge was considered as 100% - 0% where each string voltage was considered as 700 V. The maximum energy reservation capacity of a battery is estimated by Eq. 11 and Eq. 12 [139] where E_{BL} refers to the energy level of battery, σ denotes the self-discharge rate of the battery, η_i signifies to inverter efficiency, η_B refers to the battery efficiency and the electricity generation and electricity demand is indicated by E_g, E_d respectively.

$$E_{BL}(t) = E_{BL}(t-1) * (1-\sigma) + \left[E_g(t) - \frac{E_d(t)}{\eta_i}\right] * \eta_B \tag{12}$$

The maximum discharge capacity of a battery is determined by Eq. 12

$$E_{BL}(t) = E_{BL}(t-1) * (1-\sigma) - \left[\frac{E_d(t)}{\eta_i} - E_g(t)\right] \tag{13}$$

3.5.4 Converter

A large bi-directional converter was utilized to maintain the energy flow from AC to DC bus and DC to AC bus in this hybrid energy system. The converter was assumed to be parallel with the AC generator with a 95% efficient inverter and the lifetime was chosen as 15 years where the relative capacity and efficiency of rectifier capacity were selected as 100% and 95% respectively. The actual power output of the converter is quantified by Eq. 13 [140] where P_o, P_i indicates the output and input power of converter respectively and η_{con} refers to the converter efficiency.

$$P_o(t) = \eta_{con} * P_i(t) \tag{14}$$

3.5.5 Fuel cell

The fuel cell is a clean and efficient backup technology to convert the chemical energy of the stored hydrogen or oxygen into electricity. By utilizing stored hydrogen, a fuel cell can generate a significant amount of heat and electricity. In the current hybrid energy system, a proton exchange membrane hydrogen fuel cell (PEMHFC) has been selected to meet the electricity demand of the community where the minimum load ratio of the fuel cell was considered as 25%. Moreover, it was assumed that the fuel cell will produce electricity during the peak hours when the output power of wind turbines and solar PV panels will be insufficient to satisfy the regular electricity demand. The energy output of fuel cell (E_{FC}) is calculated using Eq. 14 [111], whereby, η_{FC} signifies the efficiency of fuel cell.

$$E_{FC}(\mathrm{t}) = E_{FC,tank} * \eta_{FC} \tag{15}$$

3.5.6 Electrolyzer and hydrogen tank

The electro-chemical process of decomposing water into hydrogen and oxygen molecules using electrical energy is called water electrolysis. This process is widely used to generate hydrogen using electricity and in most of the experiments, the output power of the electrolyzer is stored in a hydrogen tank. The rate of producing hydrogen (R_{H_2}) and energy requirement of the electrolyzer (E_{ele}) is estimated by Eq. 15 and Eq. 16 [141].

$$R_{H_2} = \frac{I_{elc} * \eta_F * N_c}{2F} \tag{16}$$

$$E_{ele}(t) = B_E * R_{H_2,n} + A_E * R_{H_2} \tag{17}$$

Here, I_{elc} refers to the electrolyzer current, η_F denotes Faraday efficiency, F signifies the Faraday coefficient, N_c the number of total cells in series in the electrolyzer and B_E and A_E refers to the curve consumption coefficient in kW/kg/h and. The energy output ($P_{H_2,tank}$) stored by the hydrogen tank is expressed by Eq. 17 [142].

$$P_{H_2,tank}(t) = P_{H_2,tank}(\text{t-1}) + \left[E_{ele}(t) - \frac{E_{FC,tank}(t)}{\eta_S}\right] * \Delta t \qquad (18)$$

Where, $E_{FC,tank}$ refers to the output power of the fuel cell and η_S indicates the efficiency of hydrogen storage.

3.5.7 Boiler and thermal load controller

Currently individual homes and buildings use heating oil and propane for furnaces and hot water heating. This combined thermal load was modelled in HOMER as a single boiler with consumption equivalent to the community's annual demand.

A 95% efficient hydrogen gas boiler was considered in this study to meet the heating demand where the fuel price and lower heating value of hydrogen gas were estimated as 2.5 $/kg and 120 MJ/kg respectively. The cost of the boiler was not calculated in this study as HOMER assumes the boiler is an existing technology in the hybrid energy system [110]. In addition, an electric boiler or thermal load controller was used in this study to generate renewable heating using excess electricity. The output power of a hydrogen boiler (E_{HB}) and electric boiler (E_{TLC}) is calculated using Eq. 18 and Eq. 19 [82] respectively.

$$E_{HB}(t) = E_{Heat}(t) - E_{TLC}(t) \qquad (19)$$

$$E_{TLC}(t) = \eta_{TLC} * P_{excess}(t) \qquad (20)$$

Where, E_{Heat} implies the heating demand in the community and η_{TLC} refers to the efficiency of an electric boiler.

3.6 Financial modeling

3.6.1 Net present cost

Net present cost (NPC) of an HRES defined as the present value of all the installation and operation costs of the system over the project lifetime which can also be considered the life-cycle cost of the HRES. Therefore, it is important to calculate NPC to determine the economic viability of any HRES. HOMER estimates NPC from Eq. 20 and Eq. 21 [143], [144] respectively, whereby C_A is the annualized cost of the system, *CRF(i,n)* is the capital recovery factor, i denotes the annual interest rate and n signifies the lifetime of the project.

$$\text{NPC} = \frac{C_A}{CRF(i,n)} \tag{21}$$

$$CRF(i,n) = \frac{i(1+i)^n}{(1+i)^n-1} \tag{22}$$

The annual interest rate is computed from Eq. 22 [145], where f is the annual inflation rate and i' is the nominal interest rate.

$$i = \frac{i'-f}{1+f} \tag{23}$$

3.6.2 Levelized cost of electricity

The levelized cost of electricity (LCOE) can be defined as the average cost of electrical energy generation from the HRES. The LCOE can be determined by using Eq. 23 [95], where $E_{ann,served}$ is the annual electrical energy served through the project lifetime.

$$\text{LCOE} = \frac{NPC*CRF(i,n)}{E_{ann,served}} \tag{24}$$

3.6.3 Levelized cost of heating

The average cost of heating energy production by HRES is called the levelized cost of heating (LCOH). The LCOH is estimated from Eq. 24 [146],

$$\text{LCOH} = \frac{\sum_{t=1}^{n}\frac{CapEx_t+OpEx_t}{(1+r)^t}}{\sum_{t=1}^{n}\frac{H_{ann,served}}{(1+r)^t}} \tag{25}$$

Here, $CapEx_t$ is the capital cost and $OpEx_t$ is the operational cost of the HRES, and $H_{ann,served}$ is the annual heating energy served through the system.

3.6.4 Carbon footprint

The ratio of carbon emission reduction (CER) is used to evaluate carbon emissions of HRES, and CER is determined by Eq. 25 [147], whereby CE_{st} refers to carbon emission from reference system and $CE_{TLC/Boiler}$ denotes the carbon emission from electric and gas boiler.

$$\text{CER} = \left(\frac{CE_{st} - CE_{TLC/Boiler}}{CE_{st}}\right) \quad (26)$$

3.6.5 Renewable fraction

The renewable fraction (RF) is defined as the fraction of renewable energy utilized to meet the total electrical and heating energy produced in the system. The RF of HRES is calculated from Eq. 26 [148], where $E_{non-ren}$ and $H_{non-ren}$ refers to the total non-renewable electricity and heating generated from the system respectively.

$$\text{RF} = 1 - \frac{E_{non-ren} + H_{non-ren}}{E_{ann,served} + H_{ann,served}} \quad (27)$$

The different technical and economical features used in the present study are reported in Table 7. The following project constraints are used in the optimization models, with all costs expressed in Canadian dollars ($):

- Nominal discount rate: 8%
- Inflation rate: 2%
- Real discount rate: 5.9%
- Project lifetime: 30 years

Table 7: Technical and economic parameters for HRES components

Components	Rated power	Capital cost ($)	Replacement cost ($)	O&M cost ($)	Lifetime
Solar module [51], [149]	1 kW	2,985/kW	2,985/kW	10/kW/yr	30 years
Wind turbine [59], [150]–[152]	1 kW	6,750/kW	5,050/kW	120/kW/yr	25 years
Battery [10], [139], [153]	1 kWh	1,620/kWh	1,200/kWh	50/kWh/yr	25 years
Converter [59], [154]	95% (efficiency)	400/kW	400/kW	10/kW/yr	15 years
Electrolyzer [155], [156]	1 kW	675/kW	340/kW	10/kW/yr	20 years
Hydrogen tank [59], [157], [158]	1 kg	775/kg	775/kg	10/kg/yr	25 years
Fuel cell [156], [159], [160]	1 kW	4,000/kW	3,400/kW	0.01/kW/hr	60,000 hours
Thermal load controller [82], [99]	1 kW	70/kW	70/kW	0/kW/yr	30 years
Diesel generator [161]	1 kW	400/kW	270/kW	0.01/kW/hr	30,000 hours

4 CHAPTER 4: Results and discussion

Seven different scenarios were generated to assess the total cost of electricity, fossil fuel consumption levels and CO_{2e} emissions while increasing renewable technologies' penetration. The scenarios are presented in Figure 14. Broadly the scenarios fall into two categories, the first being optimizing the amount of renewable energy added to the community to minimize energy costs, while the other scenarios aim to minimize emissions.

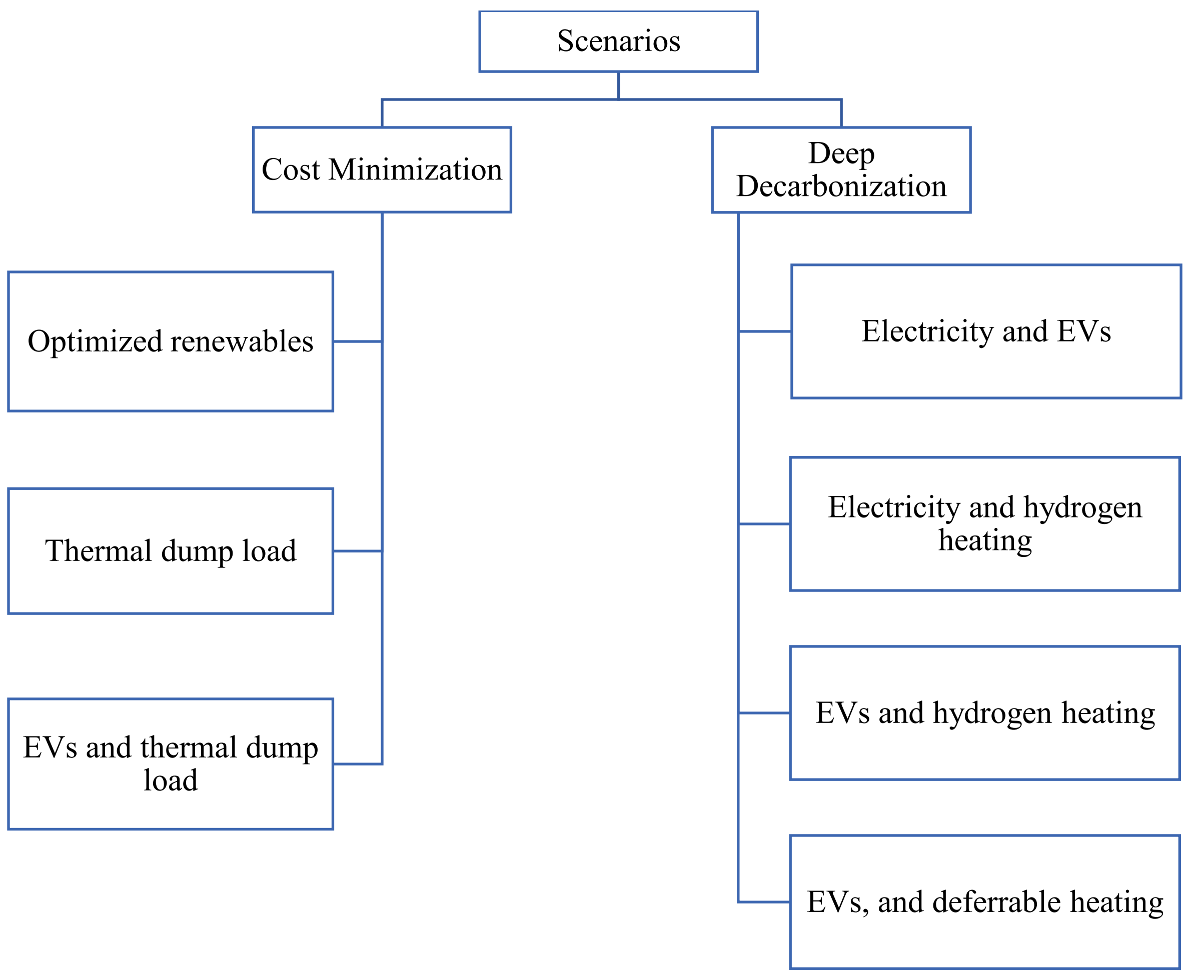

Figure 14: Scenarios considered

4.1 Scenarios

4.1.1 Existing system

The current energy system in the community consists of 4.58 MW of diesel capacity combined with 2.6 MW of solar photovoltaics. Space and water heating in the community is done using fuel oil. The annual electricity and heating demand of Fort Chipewyan is 11.3 GWh/yr and 21.4

GWh/yr respectively. Additionally, the annual electricity, heating oil and gasoline costs in the community were $1.8 million/yr, $2.4 million/yr respectively and $4.4 million in 2017 respectively.

4.1.2 Optimized renewables

This scenario takes the existing system and allows for unconstrained new wind, solar and batteries options to be selected in order minimize electricity costs. The HOMER model only adds one new 1.5 MW wind turbine to the system which reduces diesel consumption as well as costs.

4.1.3 Thermal dump load

This scenario is the same as the previous except that it allows an electric boiler to allow for surplus renewable electricity to be used as thermal supply. This would be equivalent to having a partial resistance heating ‘dump load’ in a community building such as the school or community centre. This allows for less excess renewable energy to be wasted.

4.1.4 EVs and thermal dump load

This scenario assumes a full electrification of passenger vehicles in the community as well as the electric dump load boiler from the previous scenario.

4.1.5 Renewable electricity and EVs

This scenario assumes a 100% renewable energy supply for electricity. The diesel generators have been completely removed and replaced with batteries. The load also includes the passenger vehicle fleet which is entirely converted to EVs.

4.1.6 Renewable electricity and hydrogen heating

This scenario assumes 100% renewable electricity generation from solar PV, wind turbines, batteries and hydrogen storage. A resistive heating system and hydrogen boiler is also used in this scenario to utilize the surplus renewable energy produced in the system.

4.1.7 EVs, and hydrogen heating

This scenario is same as the previous scenario except considering the deep electrification of passenger vehicles for the community.

4.1.8 EVs, and deferrable heating

This scenario assumes 70% thermal load as deferrable building heating load. Here, 100% renewable electricity is generated from solar PV, wind turbines, batteries and hydrogen fuel cell as well as electric dump load and hydrogen boiler is considered from the previous scenario.

4.2 Scenario analyses

4.2.1 Cost minimization scenarios

Table 8 summarizes the installed capacity of solar PV, wind turbine, and diesel generator, annual electricity, and heating generation, cost of electricity (COE), and the annual excess electricity production for existing system or business-as-usual (BAU) case and each of the three best scenarios. The installed solar capacity is 2.6 MW for all scenarios which produces 2.6 GWh of electricity annually whereas wind turbine generates 5.5 GWh of electricity each year in BAU with wind turbines, and BAU with thermal dump load respectively and produces 11 GWh of energy for BAU with electric vehicle charging and thermal dump load scenario. While considering EV charging demand and thermal dump load, the installed wind turbine capacity increases to 3 MW, and the diesel consumption decreases as the wind capacity increases. As a result, the diesel consumption falls to 3.4 million L/yr in EVs and thermal dump load scenario, down from 5.0 million L/yr in BAU case. It also noted that adding wind turbines in existing system decreases the COE to 0.295 \$/kWh from 0.326 \$/kWh in BAU case which is the most cost-effective energy system for the community. When the system's output exceeds the amount needed to power the load and the batteries are unable to absorb all the extra energy, excess electricity or electric dump load is created. As the amount of electricity generated by wind turbines increases, more excess electricity is created in the system, lowering the proportion of diesel-based boilers in heat generation. In BAU case and optimized renewables scenario, the diesel boiler provides all the heating, whereas, in thermal dump load, and EVs and thermal dump load scenario the electric boiler utilizes the system's generated electric dump load to provide 1.1 GWh, and 4.2 GWh of renewable heating per year. According to Figure 15, Figure 16, and Figure 17, adding 3 MW of wind turbine capacity in EVs and thermal dump load scenario decreases the diesel fuel cost to \$1.5 million/yr from \$1.8 million/yr in optimized renewables scenario. Additionally, it increases the total net present cost (NPC) of EVs and thermal dump load scenario by \$6 million at a COE of \$0.291/kWh. Therefore, wind and battery based energy systems offer a cost-effective energy system reducing diesel fuel cost significantly.

Table 8: Electricity, heating production, and installed capacity of components with excess energy generation and COE for cost minimization scenarios

Scenarios	COE ($/kWh)	Solar capacity (MW)	Wind capacity (MW)	Diesel capacity (MW)	Electricity production (GWh/yr)	Heating production (GWh/yr)	Excess energy generation (GWh/yr)
BAU (Existing system)	0.326	2.6	0	4.6	PV: 2.6 WT: 0 DG: 10.7	Boiler: 22.1	0.5
Optimized renewables	0.295	2.6	1.5	4.6	PV: 2.6 WT: 5.5 DG: 5.9	Boiler: 22.1	1.1
Thermal dump load	0.297	2.6	1.5	4.6	PV: 2.6 WT: 5.5 DG: 5.9	Boiler: 21.9 TLC: 1.1	0.9
EVs and thermal dump load	0.291	2.6	3	4.6	PV: 2.6 WT: 11 DG: 5.1	Boiler: 19.7 TLC: 4.2	1.8

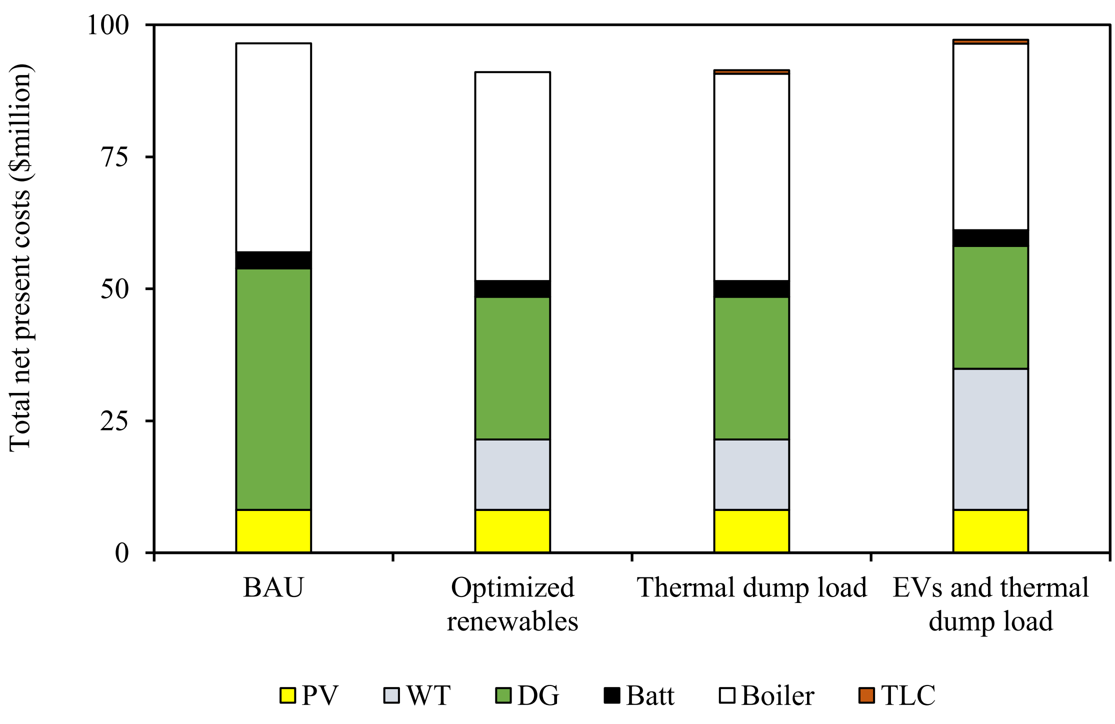

Figure 15: Total net present cost of components for cost minimization scenarios

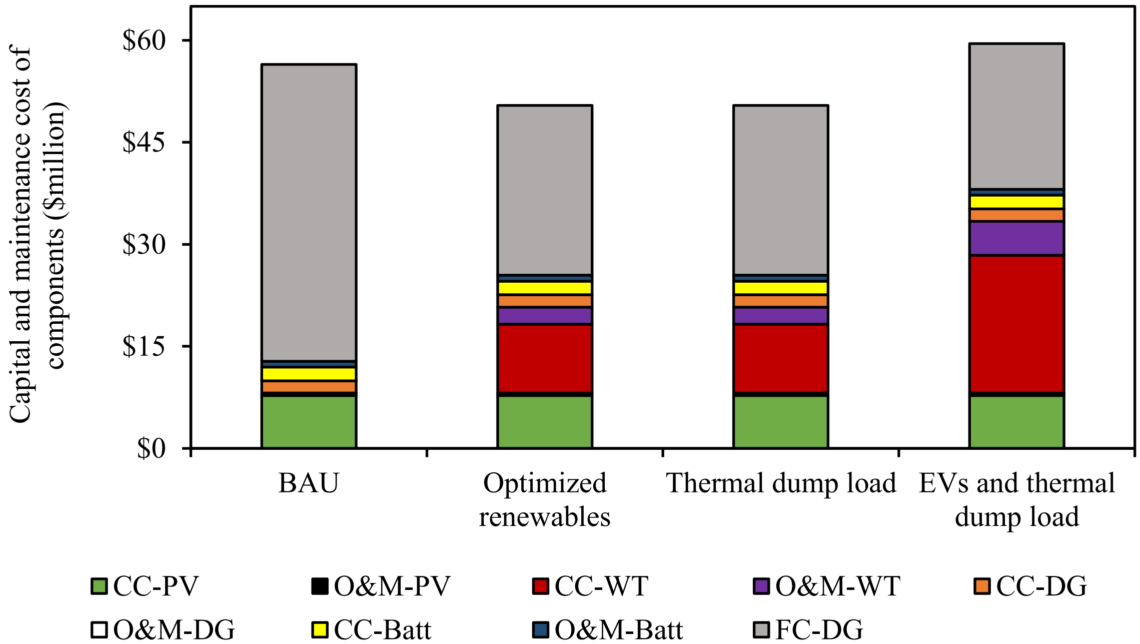

Figure 16: Capital and maintenance cost of components for cost minimization scenarios

Adding wind energy to the system appears to be able to reduce the COE by close to 10% compared to the existing system., but after allowing renewable heating into the system, it decreases to 0.291 $/kWh for EVs and thermal dump load scenario. However, incorporating battery, wind, and electric heating with solar in the energy system increases the total NPC over the optimized renewables scenario, resulting in a reduction in the diesel fuel consumption by 1.8 million L/yr compared to the BAU case. Thus, allowing thermal dump load provides an economical system compared to the BAU case. Furthermore, it is clear from Figure 17 that when considering electric heating, the optimal scenarios suggest adding 40%, and 59% additional wind capacity in thermal dump load, and EVs and thermal dump load scenario, respectively. However, the system is still incapable of providing 100% electric heating. While the optimized renewables scenario only has 19.7% of its energy coming from renewable sources, thermal dump load, and EVs and thermal dump load scenario achieve a maximum renewable fraction of 20.2%, and 32%, respectively, resulting in reductions of 23%, and 32% in CO_{2e} emissions compared to the existing system which indicate that diesel generators can be replaced by electric heating with adequate energy storage in thermal dump load, and EVs and thermal dump load scenario. Table 9 is presenting the annualized system cost and annual CO_2 emissions from cost minimization scenarios and Figure 18 and Figure

19 show the hourly dispatch of energy and daily power output of solar PV for EVs and thermal dump load scenario. Resources such as solar and wind are inconsistent and occasionally unreliable. As the cut-in wind speed is high during cloudy days, stand-alone PV or wind energy system is not sufficient to generate electricity throughout the year which can result in an oversized system increasing the total NPC and COE of the system. Therefore, it is the best solution to build a PV-wind-battery-diesel hybrid energy system for achieving better reliability.

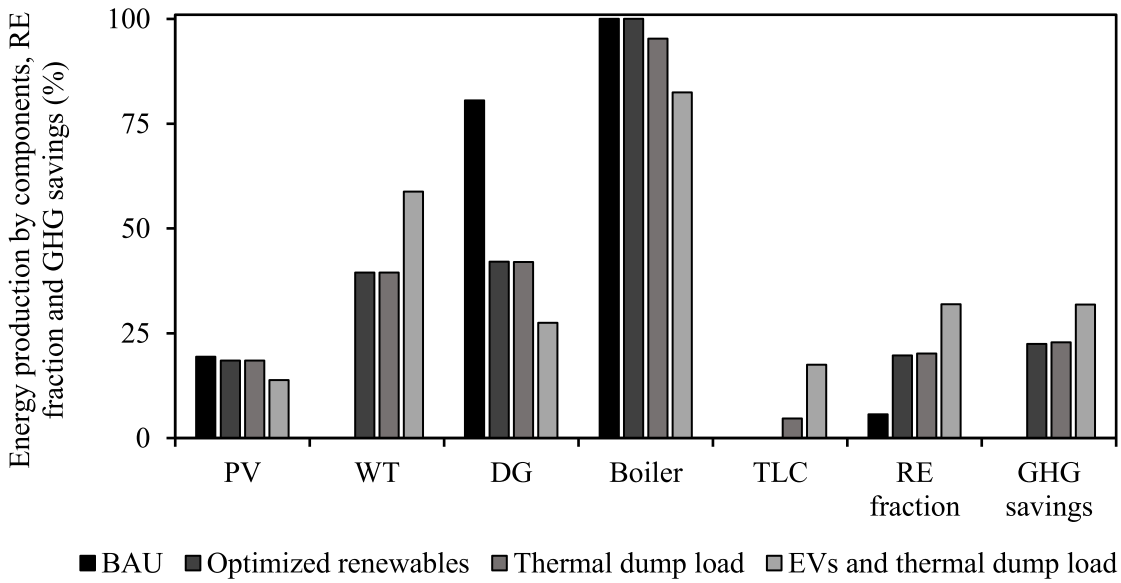

Figure 17: Electricity and heating production by components (%), the renewable fraction (%), and emissions reduction (%) for cost minimization scenarios

Table 9: Total annual system cost and CO_2 emissions for cost minimization scenarios

Scenarios	**Total annual cost (mil$/yr)**	**Total annual emissions (tCO2eq/yr)**
BAU (Existing system)	13.9	25,348
Optimized renewables	13.5	22,423
Thermal dump load	11.1	16,785
EVs and thermal dump load	7	8,875

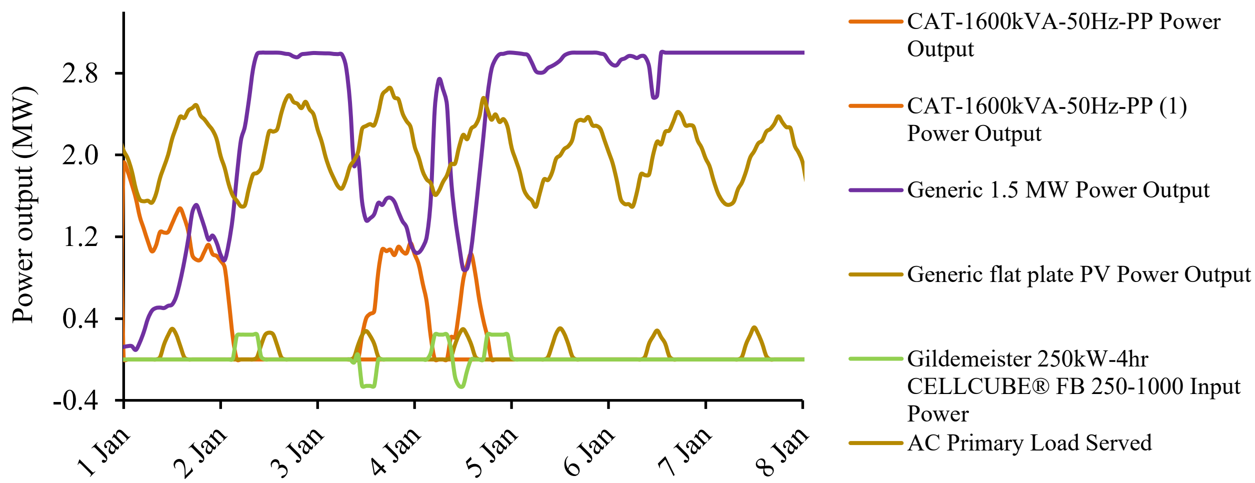

Figure 18: Hourly dispatch of energy for EVs and thermal dump load scenario

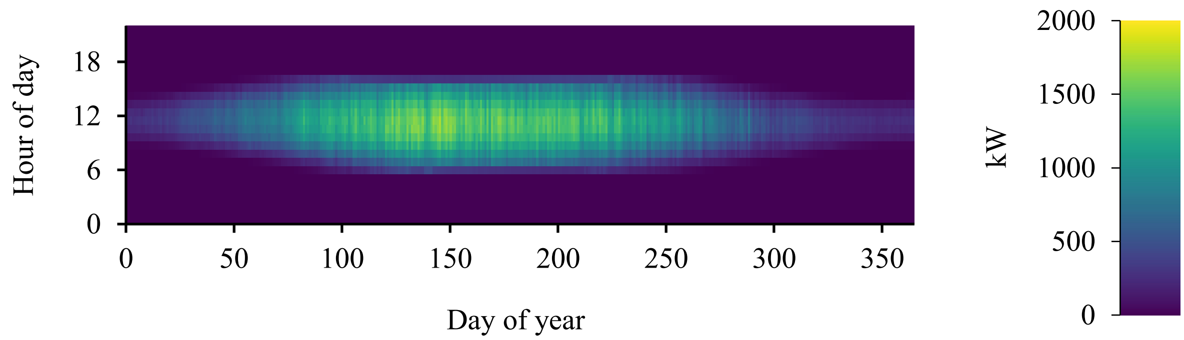

Figure 19: Daily power output of solar PV for EVs and thermal dump load scenario

4.2.2 Deep decarbonization scenarios

The annual excess energy production, installed solar, wind, and fuel cell capacity, COE, annual electricity, and heating production by system component are summarized in Table 10. Additionally, Table 11 shows the total annualized system cost and annual CO_2 emissions in the community for deep carbonization scenarios. The electricity and EVs scenario only consider the community's electricity and EV load demand. The result shows that the annual electricity generated by solar PV and wind turbines is 3 GWh and 17 GWh, respectively, with a 2 MW of fuel cell in the system, and the electricity and EVs scenario produces 0.6 GWh/yr of excess electricity as a result of the higher renewable energy production by solar PV and wind turbines. Additionally, while allowing hydrogen heating with 100% renewable electricity, a 6 MW fuel cell was incorporated into the system, increasing the system's capacity for solar and wind energy to 10 MW and 12 MW, respectively.

Table 10: Electricity, heating production, and installed capacity of components with excess energy generation and COE for deep decarbonization scenarios

Scenarios	COE ($/kWh)	Solar capacity (MW)	Wind capacity (MW)	Fuel cell capacity (MW)	Electricity production (GWh/yr)	Heating production (GWh/yr)	Excess energy (GWh/yr)
Electricity and EVs	0.96	3	4.5	2	PV: 3 WT: 17 FC: 4	Boiler: 0 TLC: 0 FC: 0	0.6
Electricity and hydrogen heating	1.63	10	12	6	PV: 10 WT: 44 FC: 3	Boiler: 0.2 TLC: 35 FC: 5	34
EVs and hydrogen heating	1.94	10.5	10.5	6	PV: 10 WT: 39 FC: 4	Boiler: 0.2 TLC: 28 FC: 6	27
EVs, and deferrable heating	1.03	7	16.5	6	PV: 7 WT: 60 FC: 8	Boiler: 0.4 TLC: 20 FC: 11	25

Table 11: Total annual system cost and CO_2 emissions for deep carbonization scenarios

Scenarios	Total annual cost (mil$/yr)	Total emissions (tCO_{2eq})
Electricity and EVs	14.6	5585
Electricity and hydrogen heating	25.7	6741
EVs and hydrogen heating	28.5	0
EVs, and deferrable heating	31.3	0

While considering the community's electricity, renewable heating, and EV charging demand in EVs and hydrogen heating scenario, the installed wind turbine capacity falls to 10.5 MW, generating 39 GWh of electricity per year, whereas solar capacity rises to 10.5 MW, producing 10 GWh of electricity annually. In addition, 70% of the total building heating load is categorized as the deferrable load in EVs, and deferrable heating scenario, where wind turbines produce 60 GWh of electricity annually, respectively. While allowing both renewable heating and EV load in the system, EVs, and deferrable heating scenario requires 6 MW more wind capacity than EVs and hydrogen heating scenario. Considering deferred load in the system, Figure 20, Figure 21, and Figure 22 indicate that EVs, and deferrable heating scenario requires only 7 MW of solar PV capacity, as 80% renewable electricity generated from wind turbines. Due to the higher capital cost of the wind turbine, it is clear from the following figures that electricity and hydrogen heating and EVs and hydrogen heating scenarios are not a cost-effective solution for Fort Chipewyan and based on deep decarbonization scenarios, it is obvious that the system needs to generate more renewable energy while allowing renewable heating and electricity for EVs. Figure 23 and Figure 24 show the hourly dispatch of energy and daily power output of solar PV for EVs and hydrogen heating scenario. As the system moves toward achieving 100% renewables for the entire system, the solar fraction gradually declines in comparison to the wind fraction. Excess installed solar PV generate a higher amount of electric dump load during the summer months while contributing little to meeting winter demands, while average seasonal wind speeds are more positively correlated to average winter loads. Consequently, wind turbines produce less excess energy as the system moves towards 100% renewable electricity and heating.

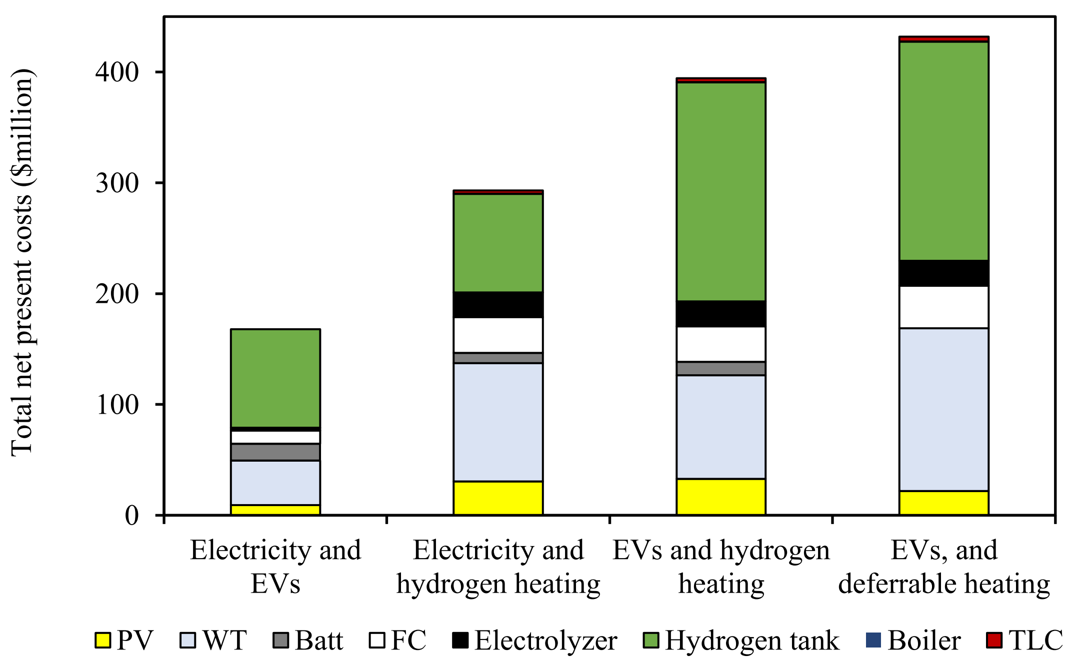

Figure 20: Total net present cost of components for deep carbonization scenarios

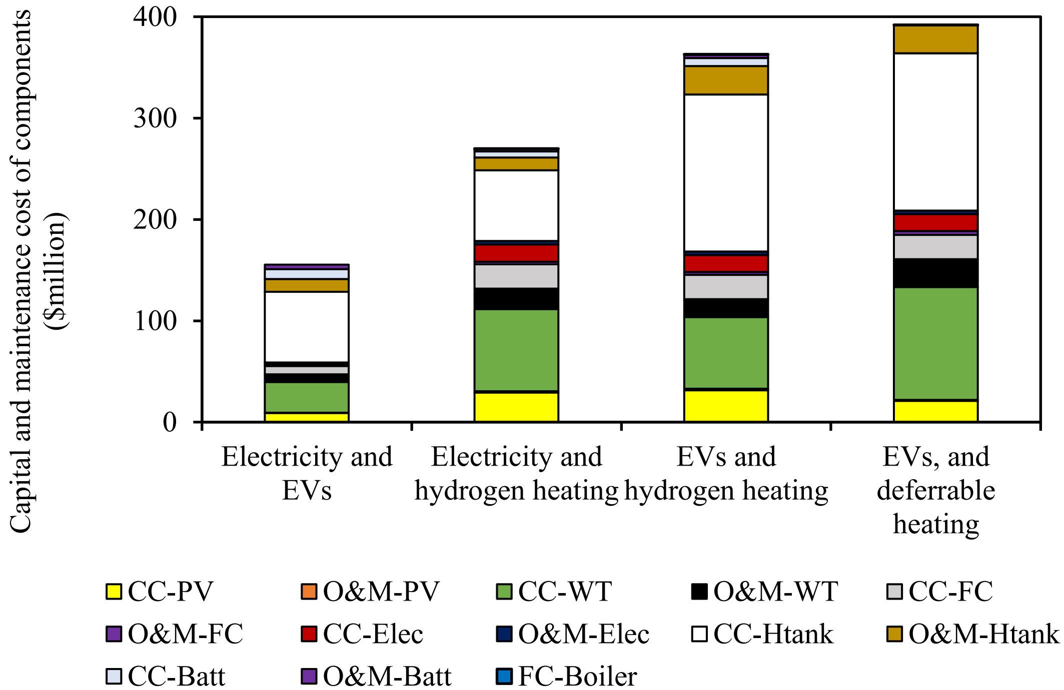

Figure 21: Capital and maintenance cost of components for deep carbonization scenarios

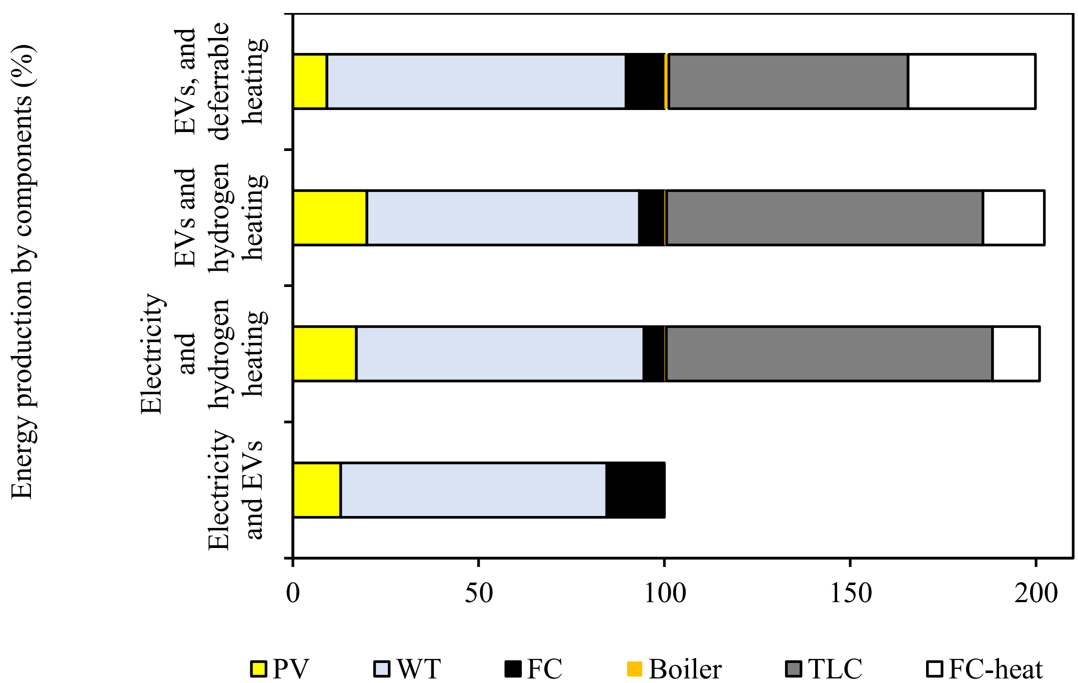

Figure 22: Electricity and heating production by components for deep carbonization scenarios

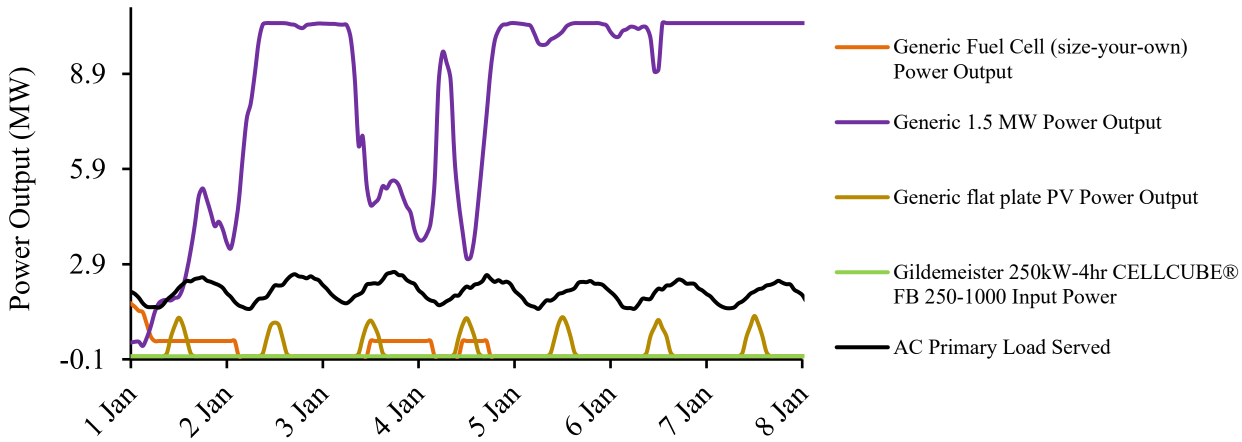

Figure 23: Hourly dispatch of energy for EVs and hydrogen heating scenario

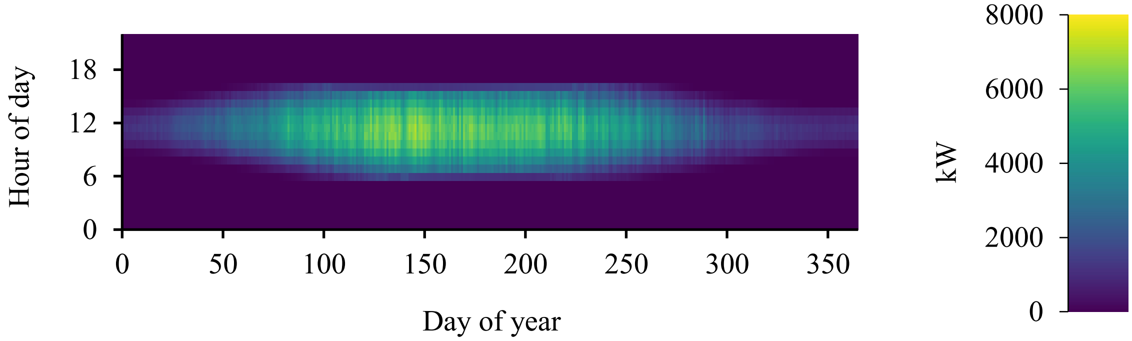

Figure 24: Daily power output of solar EVs and hydrogen heating scenario

Moreover, the COE for electricity and EVs scenario is \$0.96/kWh, while electricity and hydrogen heating and EVs and hydrogen heating scenarios each see a significant increase to \$1.63/kWh and \$1.94/kWh, respectively. The COE of Electricity and hydrogen heating and EVs and hydrogen heating scenario is expensive due to the addition of a fuel cell to the energy system and the higher NPC of wind turbines and solar PV. However, the amount of electricity and heating produced by fuel cells is extremely small. Hence, due to their high cost, it is preferable to avoid building hydrogen fuel cell systems. In Electricity and hydrogen heating, EVs and hydrogen heating, and EVs, and deferrable heating scenarios, the thermal load controller (TLC) or electric heater uses the majority of the excess electricity to generate renewable heating while the hydrogen gas boiler only produces a little amount of heat. Therefore, an electric boiler is beneficial for HRES, as it reduces the operating hours of boilers and fuel cells. It should also be noted that adding a deferrable load significantly reduces COE. Consequently, EVs, and deferrable heating scenario saves 47% in energy costs over EVs and hydrogen heating.

4.3 Sensitivity analyses

Sensitivity analyses were carried out to determine the impacts of different parameters on the COE of thermal dump load scenario and electricity and hydrogen heating scenario. For thermal dump load scenario, the CO_2 penalty cost and diesel price were changed by ±30% to examine the impact on the electricity production cost of HRES which is presented in Table 12. Diesel prices and CO_2 penalty costs were calculated using the base case values of $50/tonne and $1.2/L, respectively where for the cost minimization scenarios, the minimum renewable fraction was considered as 0%. Table 12 demonstrates that the COE rises as the price of diesel does. The system produces more electricity from renewable sources as a result of a higher NPC due to higher diesel fuel costs. At $1.56/L diesel price and $65/tonne CO_2 penalty, the COE increases by 13%, and 2% respectively, compared to the base case value. Hence, the diesel price has a significant impact and CO_2 penalty cost has a negligible impact on the COE of thermal dump load scenario. As the capacity of wind turbine increases, the COE increases nearly 25% for $0.84/L to $1.56/L diesel prices due to higher capital cost of wind turbines. Therefore, it is possible to state that the addition of wind turbines significantly increases the COE of the HRES.

Table 12: Sensitivity analysis to verify the impact of diesel price on the thermal dump load scenario

CO_2 penalty ($/tonne)	Diesel price ($/L)						
	0.84	0.96	1.08	1.20	1.32	1.44	1.56
35	0.253	0.267	0.282	0.297	0.312	0.327	0.342
40	0.254	0.269	0.284	0.299	0.314	0.328	0.343
45	0.256	0.271	0.286	0.300	0.315	0.330	0.345
50	0.257	0.272	0.287	0.302	0.317	0.332	0.347
55	0.259	0.274	0.289	0.304	0.318	0.333	0.348
60	0.261	0.276	0.290	0.305	0.320	0.335	0.350
65	0.262	0.277	0.292	0.307	0.322	0.337	0.351

The capital cost of solar PV, the capital cost of the wind turbine, wind turbine lifetime, wind speed, wind turbine hub height, and solar radiation were the six individual parameters that were chosen for sensitivity analysis of electricity and hydrogen heating scenario and varied by $\pm$30%. The initial figures for solar photovoltaics, solar radiation, wind turbine capital cost, their lifetimes, wind speeds, and hub height were 2985 \$/kW, 2.94 kWh/m^2/day, 6750 \$/kW, 25 years, 5.15 m/s, and 80 m, respectively. The outcomes of the sensitivity analysis on COE are shown in Figure 25. Figure 25 indicates that the COE of electricity and hydrogen heating scenario is significantly influenced by wind speed. The COE rises by 68% for a 30% decrease in wind speed and falls by 12% for a 30% increase in wind speed, as the COE changes from 1.44 \$/kWh to 2.73 \$/kWh for a ± 30% variation in wind speed. On the other hand, a 30% increase in wind turbine capital cost and a 30% decrease in solar radiation results in a growth in COE of \$1.77/kWh (9%), making them the second most important factor. Additionally, varying the capital cost of solar PV by ± 30% causes a 3% change in COE (from 1.58 \$/kWh to 1.67 \$/kWh). Hence, the capital cost of solar photovoltaics has a moderate impact on the COE of electricity and hydrogen heating scenario. Furthermore, increasing the lifetime and hub height of wind turbines from 25 years and 80 m to 32.5 years and 104 m reduces COE by 2% and 3% respectively. Thus, the lifespan and hub height of wind turbines have little bearing on the electricity production cost.

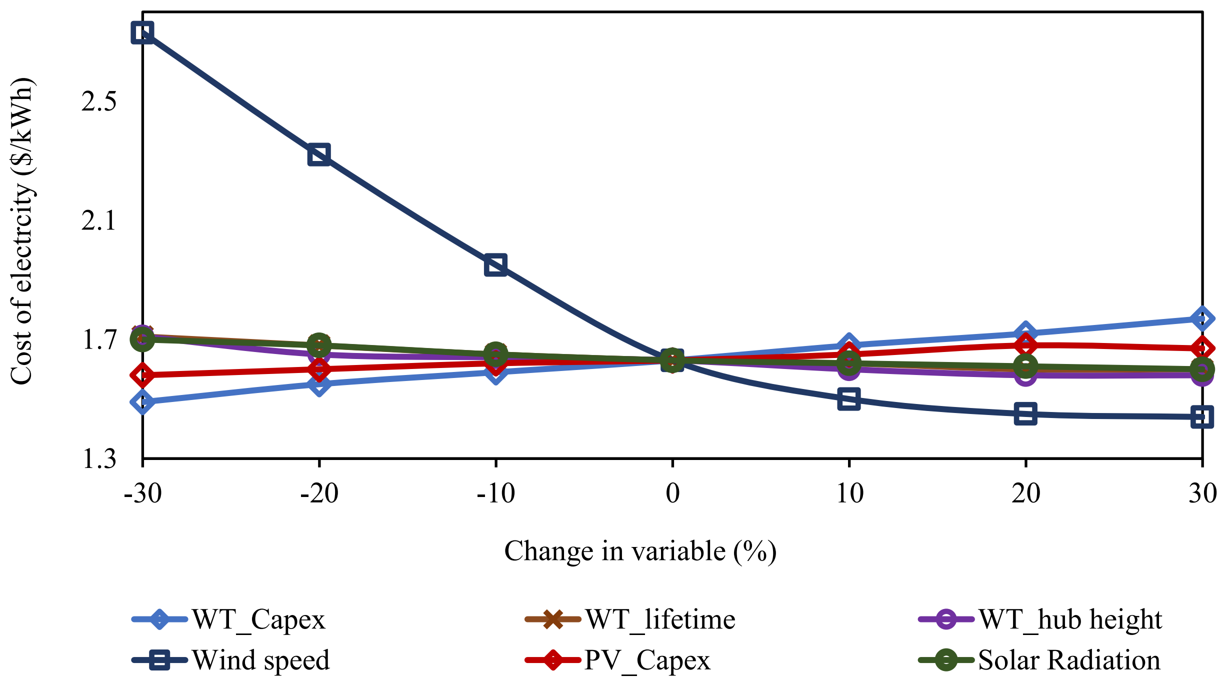

Figure 25: Sensitivity analysis to check the impact on COE of electricity and hydrogen heating scenario

Cost is an important factor in the deployment of any HRES system. Figure 26 and Figure 27 depicts a rising trend in COE with increasing renewable fraction for cost minimization and EVs and hydrogen heating scenario respectively. From Figure 26 it is obvious that COE drops as the renewable fraction increases in the system. However, the COE of the cost minimization scenarios increases again after achieving a 20% renewable fraction. As the percentage of renewable fraction increases, the optimal system requires to generate more renewable electricity and heating from solar PV and wind turbines. Therefore, the COE of the cost minimization scenarios increases with the increasing renewable energy production. Figure 27 makes it apparent that the COE is nearly constant for renewable fraction levels ranging from 60% to 80%. However, after 80% renewable energy fraction, this trend starts to rise dramatically, and a higher COE is needed to reach 100% renewable energy. Since the HRES requires a higher capacity of renewable energy sources which significantly increases the cost of energy. The optimized renewables, thermal dump load, and EVs and thermal dump load scenarios achieve 19.7%, 20.2%, and 31.9% renewable fractions at the COE of 0.295 $/kWh, 0.297 $/kWh, and 0.291 $/kWh, respectively. On the other hand, in deep decarbonization scenarios, the system's NPC is more likely to be high due to the higher capital and lower operating costs of wind turbines, solar PV panels, and hydrogen fuel cells. The diesel generator as a backup continues to be a much lower cost option than fully relying on wind and solar as illustrated by the fact the cost minimization scenarios have order of magnitude lower total energy costs than the deep carbonization scenarios. However, the increased levels of renewables and electrification of vehicles can lower overall energy costs compared to a system fully reliant on imported fossil fuels.

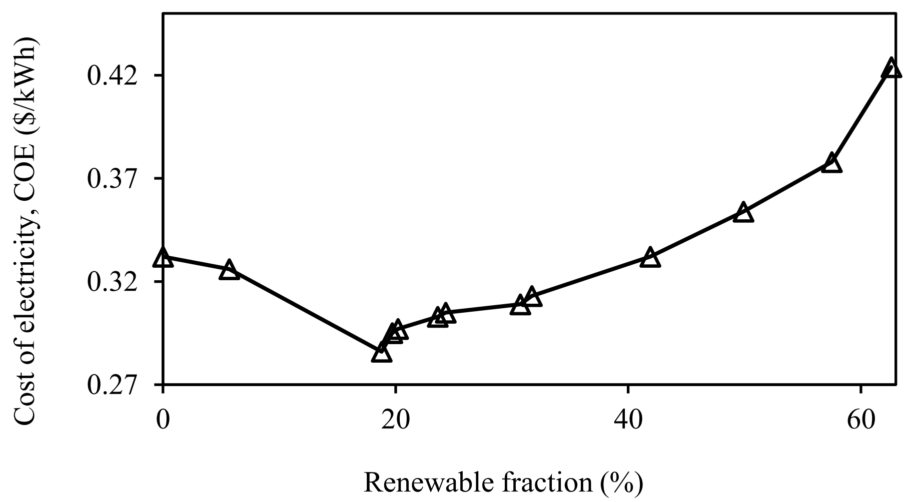

Figure 26: Increasing trend of COE with renewable fraction for cost minimization scenarios

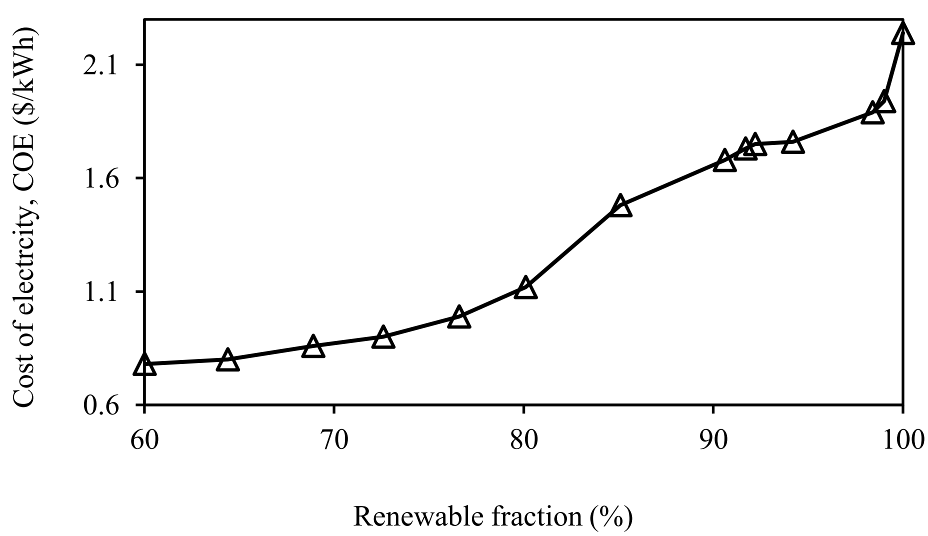

Figure 27: Increasing trend of COE with renewable fraction for EVs and hydrogen heating scenario

5 CHAPTER 5: Conclusions

5.1 Summary

The Fort Chipewyan remote community heavily relies on fossil fuels for its transportation, heating, and electricity needs which has a detrimental effect on the environment in the area. Although the community has already begun to switch to renewable energy by finishing the 2.6 MW solar farm project, more research is necessary to identify alternatives for future clean energy development. This study examines the viability of utilizing different renewable energy technologies (such as solar PV, wind turbines, batteries, hydrogen fuel cells, electric boilers, etc.) to deep electrifying the simultaneous energy needs for electricity, heating, and EV charging in the community while investigating the most cost-effective energy system for Fort Chipewyan. The feasibility study was carried out by accessing seven different scenarios, of which three were deemed to be the cost minimization scenarios that include diesel generators in the energy system, while the remaining four were considered to be deep carbonization scenarios with entirely renewable electricity and heating generation. The simulation results indicate that:

- Increasing wind turbine capacity from 1.5 MW (Optimized renewables) to 3 MW (EVs and thermal dump load) decreases diesel fuel consumption by almost 2.3 million L/yr which lowers the CO_{2e} emissions by 32% compared to the existing system. Hence, it can be concluded that the development of a PV-wind-battery-diesel energy system has the potential to significantly reduce diesel consumption in the community.
- Wind turbines play a major role by providing the majority of the system's required energy in both the cost minimization scenarios (39.5%, 39.5%, and 58.8% for optimized renewables, thermal dump load, and EVs & thermal dump load scenarios respectively) and the deep carbonization scenarios (72%, 77%, 73%, 80% for electricity & EVs, electricity & hydrogen heating, EVs & hydrogen heating, and EVs & deferrable heating scenarios respectively). As the solar PV panels produce a higher amount of excess electricity in summer, the electric boiler utilizes a negligible amount of excess electricity for space heating and dumps most of the excess energy as thermal dump load. Therefore, as the system progresses toward producing 100% renewable heating and electricity simultaneously, the optimized system requires additional capacity of wind turbines rather than solar panels due to higher power output of wind turbines in winter. As a result, wind energy has the potential to provide a promising long-term solution for remote communities like Fort Chipewyan.

- Allowing additional capacity of wind turbines in EVs and thermal dump load scenario increases the net present cost (NPC) of the system by $6 million. However, it reduces the diesel fuel cost by nearly 51% compared to the existing system. On the other hand, in EVs, and deferrable heating scenarios, the energy system does not allow batteries when all the excess energy is consumed by the electric heater and hydrogen fuel cell. Therefore, diesel generators can be replaced by electric heating with adequate energy storage system.
- In electricity and hydrogen heating scenario, the COE was 0.67 $/kWh higher than in electricity and EVs scenario while considering electric heater in the system. Accordingly, constructing an electric heater or thermal load controller can be a renewable heating option for the community and it will eventually help to achieve a 100% renewable energy system in the future.
- In electricity and hydrogen heating, EVs and hydrogen heating scenarios, which allow hydrogen fuel cells, the COE rises to 1.63 $/kWh and 1.94 $/kWh, respectively, while in electricity and EVs scenario, the COE is only 0.96 $/kWh. Although, in electricity and hydrogen heating, EVs and hydrogen heating scenario, the fuel cell contributes only 5% and 7% of the renewable electricity generation, respectively, it increases the COE of the system. As a result, building expensive fuel cell systems is a more expensive option for the community.
- With a deferrable heating load, a 100% renewable energy system is achievable at only 1.03 $/kWh for EVs, and deferrable heating scenarios, respectively, reducing excess energy generation by 7% compared to EVs and hydrogen heating scenarios. Hence, storing thermal load is a better option for Fort Chipewyan to achieve a 100% renewable energy system.
- When the EV charging demand is considered in EVs and thermal dump load scenario, the COE drops to 0.291 $/kWh and the CO_2 emissions decreases by almost 16,500 t_{CO2e} per year. On the other hand, in EVs and hydrogen heating and EVs, and deferrable heating scenarios, 100% renewable fraction is achieved at 1.94 $/kWh and 1.03 $/kWh, respectively. Consequently, while it is currently impractical, Fort Chipewyan could eventually meet its EV charging demand with renewable energy.

Finally, sensitivity analyses were performed to determine the impact of various parameters (including wind turbine capital cost, lifetime, hub height, wind speed, the capital cost of solar PV panels, solar radiation, diesel price, and CO_2 penalty cost) on the COE of the hybrid system. Diesel price was discovered to be the dominating parameter on the COE of EVs and thermal dump load scenario while wind speed was found to be the most influential factor on the COE of EVs and hydrogen heating scenario. Additionally, for EVs and hydrogen heating scenario, it was noticed that the COE is unaffected by the lifespan and hub height of wind turbines. A genetic algorithm (GA) can be used to compare study results in the future when studying the depreciation cost of components.

5.2 Future work and recommendations

The following list includes some suggestions and areas to improve future research:

- The storage of renewable energy through hydrogen is an emerging technique that could be investigated through a comparative study to assess the viability of storing hydrogen either as a liquid or gas.
- As wind speed is an important variable and wind turbines are the emerging renewable energy technologies, the community should investigate the local wind resources which can be affected by obstacles such as tall buildings or trees.
- Despite being a promising technology, the hydrogen fuel cell has a high cost of energy due to required overcapacity of renewables and high upfront costs. In order to confirm the affordability of hydrogen storage, the life cycle cost analysis can be done. Additionally, the uncertainty analysis of demand and performance for hydrogen storage can be performed to improve system's reliability.
- As the renewable heating options are expensive due to the seasonally variable nature of space heating demand, the community should investigate alternative renewable heating fuels including biomass or biodiesel resources.
- A comparative study could explore different scenario-based electric vehicle (EV) charging methods (such as delayed, off-peak, and continuous charging) and different charging infrastructure (such as level 1, level 2, and DC or fast charging) to measure the impact on the electricity system of the community.

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A. Appendix

Figure 28 presents 1.5 MW wind turbine's power output curve used in the HOMER models.

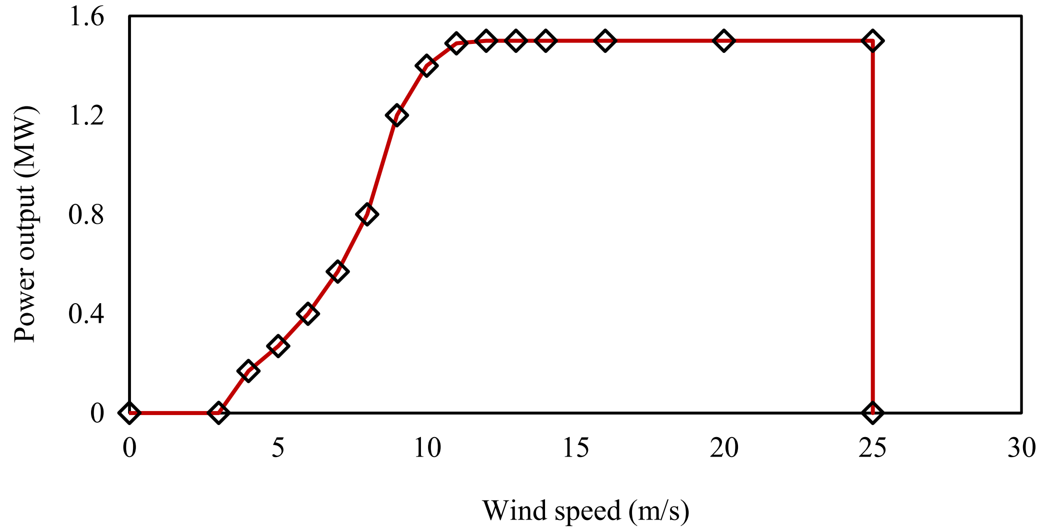


Figure 28: Wind turbine power output curve

Figure 29 presents time series chart for optimized renewables scenario.

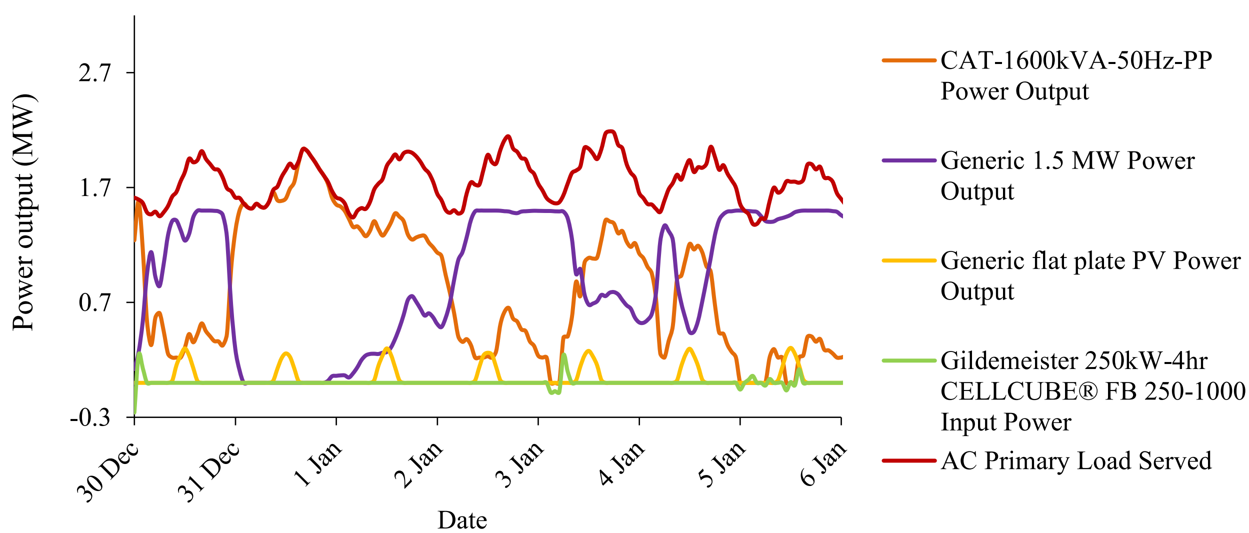
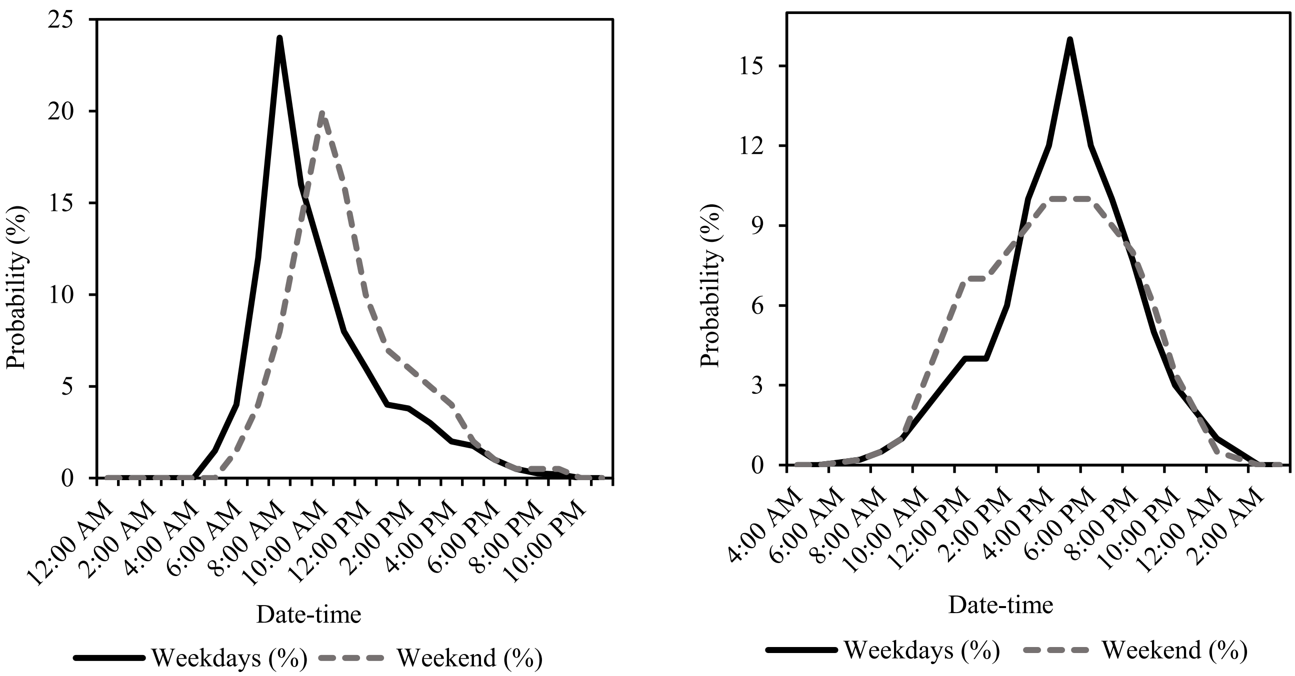


Figure 29: Time series chart for BAU+RE heat scenario

Figure 30 is showing the probability density function of daily home leaving and homecoming time on weekdays and weekends [107].



(a) (b)

Figure 30: (a) Probability density function of home leaving time, (b) probability density function of home coming time