

# Design and Implementation of an Electricity System Optimization Model for Remote Communities in Canada

by

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A Master of Science in Environmental Sustainability  
major research project presented to

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April 17, 2023

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Ottawa, Ontario

## Abstract

This study presents an energy system optimization model based on linear programming techniques to predict least-cost electricity generating systems for five remote communities in Quebec, Canada. The model integrates hourly electricity demand data, hourly wind speed data, and hourly solar power generation data, and considers relevant costs, to identify the optimal combination of generating technologies capable of meeting the communities' electricity demand throughout the year. To account for environmental considerations, the model was subject to two separate constraints. First, a carbon tax on carbon emissions from the system was incrementally increased. Second, carbon emissions were gradually constrained, ultimately reducing to zero allowed emissions. The results suggest that even in the absence of either aforementioned constraint, the least-cost system already incorporates wind power in conjunction with existing diesel generation, and a system with zero carbon emissions is less expensive still than a system fully reliant on diesel. Further, the results suggest that a carbon emissions constraint is a more impactful policy option to incent carbon emissions reductions than a carbon tax for the five communities studied, as the carbon tax increased system price while providing insignificant carbon emissions reductions.

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## List of Acronyms

ESOM	Energy System Optimization Model
NRCan	Natural Resources Canada
RCED	Remote Communities Energy Database
PV	Photovoltaic
SMR	Small Modular Reactor
O&M	Operations and Maintenance
SOC	State of Charge
MERRA	Modern-Era Retrospective analysis for Research and Applications
MMBtu	Metric Million British Thermal Unit
kgCO <sub>2</sub> e	Kilograms of carbon dioxide equivalent
GJ	Gigajoule

## 1. Introduction

In Canada, over 200 self-generating remote communities are reliant on the transportation and consumption of diesel to satisfy electricity and heat needs (Government of Canada, 2019). Through its Strengthened Climate Plan: A Healthy Environment and Healthy Economy, the Government of Canada committed to advance federal commitments to ensure remote communities that rely on diesel have clean energy alternatives by 2030 (ECCC, 2020). This commitment aligns with other activities in Canada, such as the federal Indigenous Off-Diesel Initiative (NRCan, 2022; NRCan, 2018). Exploring energy alternatives for remote communities additionally aligns with federal priorities to reduce national emissions by 2030 and achieve a net-zero electricity sector by 2035 (Lovekin, Moorhouse, Morales, & Salek, 2020).

The integration of non-emitting energy technologies within electricity-generating systems may be driven by federal and provincial climate policies, such as the carbon tax, that result in price increases on carbon-emitting fuels, such as diesel (Government of Canada, 2022). As of 2019, 82% of Canada's electricity is already produced using non-emitting sources (NRCan, 2019). However, many communities without connections to the main power grid remain reliant on fossil fuel-powered thermal electricity generators (Natural Resources Canada, 2018).

Remote communities suffer from increased price instability of diesel-generated electricity due to cost fluctuations driven by international, rather than regional, markets (Jones, James, & Mastor, 2017; US Energy Information Association, 2022). Price instability often imposes on territorial budgets and in some cases can require the use of emergency funds to reduce electricity prices for consumers to retain consumer energy security (Jones, James, & Mastor, 2017; Stringer & Joanis, 2023). Federal and provincial/territorial governments pay large sums of money to subsidize the costs of diesel electricity for consumers in remote communities, where without subsidies, the costs could be 10 to 30 times more expensive than in non-remote communities

(WWF Canada, 2021). However, even with subsidies, customers in remote communities still pay more than those in non-remote communities.

In 2017, consumers in Nunavut and the Northwest Territories, where many communities rely on fossil fuels for electricity, paid more than double the national average in electricity costs (Canada Energy Regulator, 2017). In 2021, after government subsidies, electricity customers in Canadian remote communities still paid four times more than that paid by customers connected to the grid (WWF Canada, 2021). These high prices are due to high costs attributed to unique requirements of remote communities, such as seasonal fuel transportation requirements from routes that include ice roads or conversely marine shipments that require melted sea ice (Jones, James, & Mastor, 2017). Reduced refueling requirements through electricity system decarbonization has the potential to improve fuel security and reduce logistics costs associated with transporting diesel in Canada's remote communities (Lovekin & Heerema, 2019; NRCan, 2018, NRCan, 2021).

In addition to high prices, diesel exhaust emits high quantities of greenhouse gas (GHG), while the transport, storage and handling of diesel can result in leaks and spills (Jones, James, & Mastor, 2017). GHGs are known to exacerbate climate change as well as cause issues for human health, while leaks and spills have historically caused damage to wildlife and water supply (Naiyer & Abbas, 2022; Government of Canada, 2022). For example, in 2021 the water supply in Iqaluit, Nunavut became contaminated following a diesel leak from an old fuel tank which rendered the city's water supply non-potable for nearly two months in 2021 (Zingel, 2022). Reducing fossil fuel dependence has the dual benefit of reducing GHG emissions while also reducing refuelling requirements, thereby lowering the occurrence of leaks and spills caused during diesel transport. A transition away from diesel dependence to non-emitting energy sources therefore has a wide

range of benefits, including but not limited to, increased energy security and stability, reduced electricity costs, as well as health benefits from reduced greenhouse gas emissions (He & Whitestone, 2022; Stringer & Joanis, 2023; Jones, James, & Mastor, 2017).

In recent years, federal and provincial net-zero commitments have increased funding for innovation and the implementation of non-emitting energy alternatives (Government of Canada, 2021). As a result of innovation in clean energy alternatives to diesel, and the declining costs of renewable energy technologies, recent work has proposed solutions for cost competitive non-emitting alternatives (NRCan, 2018; NRCan, 2020; IEA, 2020; IRENA, 2020; NRCan, 2018).

Energy system optimization models (ESOMs) are widely used to examine energy and electricity systems to inform such policy development as described above, using assumptions and constraints suited to the particular goals of the ESOM (Pedersen, Victoria, Rasmussen, & Andresen, 2021; DeCarolis, et al., 2017). Within Canada, ESOMs are not typically pursued at the local scale for remote communities on a granular time-basis (Aryanpur, O'Gallachoir, Dai, Chen, & Glynn, 2021; Wade, Wild, & Rowe, 2021; Vaillancourt, et al., 2013; Dolter & Rivers, 2018). However, remote communities in Canada have unique requirements for which different energy and electricity generation profiles may be appropriate compared to the national level (He & Whitestone, 2022; Zhang, et al., 2019; Bhattacharyya & Timilsina, 2010; DeCarolis, et al., 2017). As remote communities are not connected to the main grids, an assessment of the unique meteorological features of each community is warranted due to regional differences in wind availability, irradiance and temperature (Stringer & Joanis, 2023).

A study by Stringer and Joanis (2023) identified the optimal electricity generation (between solar and/or wind), storage (between lithium ion and/or vanadium redox-flow batteries), and implementation year (between 2030, 2040 and 2050) for electricity systems to replace or decrease

fossil fuel dependence in remote communities within Canada (Stringer & Joanis, 2023). The study used total electricity demand at an annual level, as well as average annual solar and wind data. The results of this study favoured early implementation of a combination of solar power and lithium-ion battery storage to reduce inferred costs associated with increasing fossil fuel costs into the future. However, the study aptly identified that more granular electricity data may be required to more accurately reflect the uses of remote communities.

To date, there is a lack of studies quantifying the cost to decarbonize remote communities in Canada using data at a granular level (Stringer & Joanis, 2023). This project aims to contribute to a growing area of research studying decarbonization of remote communities by developing a model using data with hourly temporal resolution. An ESOM of this nature may contribute to an evidence base in support of policy development for a range of federal and regional priorities in Canada that concern the decarbonization of remote communities. It may also help to understand which policies could be implemented to incent decarbonization of remote communities.

## 2. Model Design

A linear optimization model was developed in Julia using the JuMP optimization library. The model determines an optimal set of energy generating assets that could be installed to minimize the total cost of meeting the electricity demand for a specific remote community in Canada. The model is then applied to real-world electricity demand data for remote communities in Canada, each under a range of varying policy constraints.

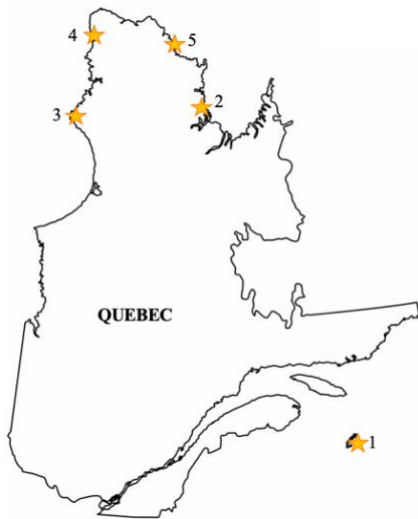
The model is designed to determine the installed capacity of various energy generators required to meet electricity demand at each hour throughout one year using real, hourly demand data for five remote communities in Canada. The model uses costs associated with each generator,

and minimizes the total system cost. The amount of carbon emissions associated with the modelled electricity produced by each generator is then calculated.

For a given remote community, an assessment of changes to system costs, installed capacities, annual generation profiles, and cumulative carbon emissions that arise from implementing various policy constraints is undertaken. Further, an assessment of the differences in the installed capacity and total cost between the five communities is undertaken to identify differences that may arise from regional wind speed and solar irradiance trends, as well as different demand profiles.

## 2.1 Community Selection

In the context of this model, a remote community is defined as one that is listed as being diesel or heavy oil reliant in Natural Resources Canada's (NRCan) Remote Communities Energy Database (RCED) (NRCan, 2018). Retrieving electricity demand information for each hour over a duration of at least one year is a limiting factor in selecting communities, as this data is difficult to obtain. However, demand data for 2017 was acquired from HydroQuebec for the Magdalen Islands and demand data for 2017 for Aupaluk, Inukjuak, Ivujivik, and Kangiqsualujjuaq was acquired from Professor Tim Weiss at the University of Alberta. Population, location, fuel source and extant capacity for the five communities studied are outlined in Table 1.



Community Name	Population (2016)	Fuel Source	Extant Capacity (kW)
1. Magdalen Islands	12,010	Diesel	67,044
2. Aupaluk	209	Diesel	780
3. Inukjuak	1,757	Diesel	3758
4. Ivujivik	414	Diesel	980
5. Kangiqsualujjuaq	942	Diesel	1975

Table 1 List of communities, population, and fuel source along with location identified on a map of Quebec, Canada.

The load duration curve for each community is shown below in Figure 1. The normalized load duration curve is a graphical representation of the demand profile experienced by the electricity system, expressed as a percentage of the maximum demand, over the year.

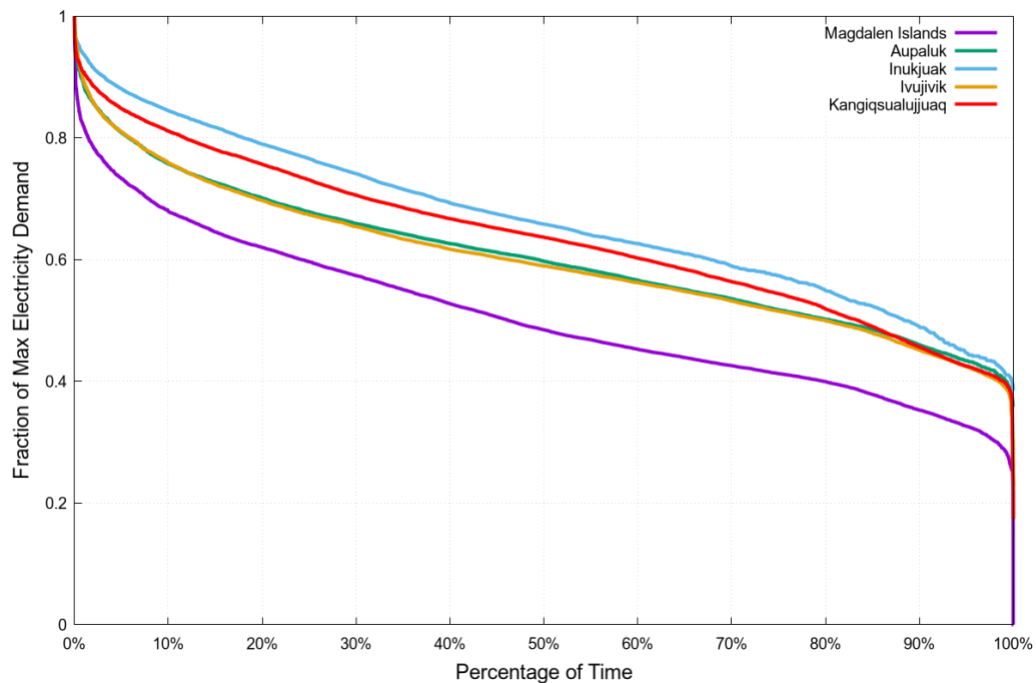


Figure 1 Normalized load duration curve for each community using 2017 data.

The Magdalen Islands power system experiences the largest demand variability, while the Inukjuak power system experiences the least demand variability. Aupaluk and Kangiqsualujjuaq have very similar demand profiles. The average load and peak load for each community is listed in Table 2 below.

<b>Location</b>	<b>Average Load (MW)</b>	<b>Peak Load (MW)</b>
Magdalen Islands	22.1	43.4
Aupaluk	0.21	0.34
Inukjuak	1.18	1.77
Ivujivik	0.27	0.45
Kangiqsualujjuaq	0.54	0.85

*Table 2 Average and peak load for each community using data from 2017.*

## 2.2 Generators and Storage

The generators selected for this model are: on-shore wind, utility solar photovoltaic (PV), 10 MW SMR, diesel, and lithium ion battery storage. The only carbon-emitting generator type included in the model is the existing diesel capacity currently installed in each community, and the model therefore restricts any emissions from new generators. Existing capacity data was retrieved from NRCan’s Remote Communities Energy Database (Natural Resources Canada, 2018). The existing capacity for each community is listed in Table 1.

Hydro power was not included due to high costs of new installation, long timelines, and other regional requirements (Stringer & Joanis, 2023). For similar reasons, pumped hydro storage is not incorporated as many remote communities are located in cold climates that do not easily facilitate the method (Stringer & Joanis, 2023). Lithium ion battery storage was selected because it is widely used in existing systems. Future work could incorporate other storage alternatives such as hydrogen production or thermal energy storage.

### 2.3 Sets and Subsets

The model uses assumptions about a set of generators relating to capital, fuel, operating and maintenance, and carbon costs to determine an optimal mix of generators to meet electricity demand. The objective function of the model is to minimize the total cost for electricity generation over one year for each community. Decision variables decided in the model include investment in generators and storage, retirement of existing diesel capacity, and hourly dispatch of the chosen generators to meet electricity demand. The notation used in the model is outlined in the following Table 3 to Table 7. Tables 3 and 4 outline the sets and subsets used to differentiate data, while Tables 5 to 7 outline the model decision variables, the exogenous parameters, and endogenous variables of the model.

Set	Symbol	Description
G	g	Set of all generators, $g \in G$ (diesel, 10 MW SMR, on-shore wind, utility solar PV).
H	h	Hours in one year, $h \in H$ (1:8760).
B	b	Set for storage, $b \in B$ (lithium ion battery).

*Table 3 Notation for sets defined in the model.*

The set G is further divided into subsets for ease of implementation:

Subset	Description
RG	Subset of all renewable generators in G (onshore wind, utility solar PV).
ETG	Subset of extant thermal generators in G (diesel).
NTG	Subset of new-build thermal generators in G (10 MW SMR).

*Table 4 Notation for subsets for the set of G defined in the model.*

## 2.4 Variables

The following tables outline model variables:

<b>Decision Variable</b>	<b>Description</b>
$CAP_g$	Installed capacity (MW) for each $g$ in $G$ .
$RET_g$	Extant generating capacity (MW) retired for $g$ in $ETG$ .
$GEN_{g,h}$	Electricity generated (MWh) for each hour and each generator type.
$CHARGE_h$	Electricity (MW) charged to the battery at each hour.
$DISCHARGE_h$	Electricity (MW) discharged from the battery at each hour.
$SOC_h$	State of charge of the battery (MWh), indicating the level of charge relative to its capacity.
$BatteryPowerCapacity_{b,h}$	The maximum rate at which electricity can be charged or discharged to or from the battery (MW) in any hour.
$BatteryEnergyCapacity_{b,h}$	The total energy capacity (MWh) of the battery.

Table 5 Notation for decision variables defined in the model.

The decision variables must be positive numbers, and are mathematically defined as:

$$\begin{aligned}
 GEN_{g,h} &\geq 0 \quad \forall g \text{ in } G, h \text{ in } H \\
 CAP_g &\geq 0 \quad \forall g \text{ in } G \\
 CAP_{NTG_g} &\geq 0 \quad \forall g \text{ in } NTG \\
 CAP_{RG_g} &\geq 0 \quad \forall g \text{ in } RG \\
 RET_g &\geq 0 \quad \forall g \text{ in } RG, g \text{ in } NTG \\
 CHARGE_h &\geq 0 \quad \forall h \text{ in } H \\
 DISCHARGE_h &\geq 0 \quad \forall h \text{ in } H \\
 SOC_h &\geq 0 \quad \forall h \text{ in } H \\
 50 &\geq BatteryPowerCapacity_{b,h} \geq 0 \quad \forall b \text{ in } B, h \text{ in } H \\
 BatteryEnergyCapacity_{b,h} &\geq 0 \quad \forall b \text{ in } B, h \text{ in } H
 \end{aligned}$$

The value of 50 MW attributed to the battery power capacity defines the power rating, which is the maximum amount of electricity that can be charged to or discharged from the battery in a given hour (Lazard, 2021; McLaren, 2016).

<b>Exogenous Variable</b>	<b>Description</b>
<b>ExistingCapacity<sub>g</sub></b>	Existing capacity (MW) in place in each remote community by 2022 for each generator ( $g \in G$ ).
<b>Demand<sub>h</sub></b>	Hourly electricity demand (MW) data for each hour over one year ( $h \in H$ ).
<b>CapitalCost<sub>g</sub></b>	Annualized capital cost (2022 \$CAD) for each generator type ( $g \in G$ ).
<b>CapitalCost<sub>b</sub></b>	Annualized capital cost (2022 \$CAD) for battery storage ( $b \in B$ ).
<b>FuelPrice<sub>g</sub></b>	Price of fuel (2022 \$CAD) for each thermal generator type ( $g \in \text{ETG, NTG}$ ).
<b>Efficiency<sub>g</sub></b>	Efficiency (%) for each thermal generator type ( $g \in \text{ETG, NTG}$ ).
<b>BatteryEfficiency<sub>b</sub></b>	Efficiency (%) of charge and discharge for a battery ( $b \in B$ ).
<b>FixedOM<sub>g</sub></b>	Fixed operating and maintenance costs (2022 \$CAD) per MW installed capacity per year for each generator ( $g \in G$ ).
<b>FixedOM<sub>b</sub></b>	Fixed operating and maintenance costs (2022 \$CAD) per MW installed capacity per year for each battery ( $b \in B$ ).
<b>VarOM<sub>g</sub></b>	Variable operations and maintenance cost (2022 \$CAD) for MWh generated for each thermal generator type ( $g \in \text{ETG, NTG}$ ).
<b>RampRate<sub>g</sub></b>	The rate per hour at which electricity generation output can increase or decrease between $h$ and $h+1$ for a given thermal generator (%/hour).
<b>MaximumCapacityFactor<sub>g</sub></b>	The maximum capacity factor (%) for each thermal generator ( $g \in \text{ETG, NTG}$ ).
<b>FuelCI<sub>g</sub></b>	Carbon dioxide (CO <sub>2</sub> ) intensity of fuel for thermal plants in kgCO <sub>2</sub> e/GJ ( $g \in \text{ETG, NTG}$ ).
<b>CarbonTax</b>	An additional cost (2022 \$CAD/tonne CO <sub>2</sub> e) applied to carbon emissions from thermal generators.

Table 6 Notation for exogenous parameters defined in the model.

<b>Endogenous Variable</b>	<b>Description</b>
<b><i>totalcost</i></b>	Total cost (million 2022 \$CAD) for supplying electricity for one year.
<b><i>capitalcost</i></b>	Capital cost (million 2022 \$CAD) for new generators for one year.
<b><i>fuelcost</i></b>	Fuel cost (million 2022 \$CAD) for thermal generators for one year.
<b><i>fixcost</i></b>	Fixed operations and maintenance costs (million 2022 \$CAD) for all generators for one year.
<b><i>varcost</i></b>	Variable operations and maintenance costs (million 2022 \$CAD) for thermal generators for one year.
<b><i>carbontaxcost</i></b>	Cost (million 2022 \$CAD) accrued via a carbon tax on fuel for thermal generators over one year.
<b><i>capacityfactor<sub>g,h</sub></i></b>	Hourly maximum capacity factor (%) for installed wind and solar ( $g \in RG, h \in H$ ), dependent on regional wind speed and solar irradiance data, respectively.
<b><i>capacityfactor<sub>g</sub></i></b>	Maximum annual capacity factor (%) for thermal generators ( $g \in ETG, NTG$ ).
<b><i>carbonemissions</i></b>	Annual carbon dioxide emissions (kgCO <sub>2</sub> e) from fuel used by thermal generators over one year.

*Table 7 Notation for endogenous variables defined in the model.*

## 2.5 Objective Function and Costs

The objective function of the model is to minimize the total cost of generating electricity to meet hourly electricity demand over the course of one year. In short, the objective function is:

$$\text{Min. total cost} = \text{capitalcost} + \text{fuelcost} + \text{fixcost} + \text{varcost} + \text{carbontaxcost}$$

The capital cost only applies to new capacity and is defined as:

$$\begin{aligned} \text{capitalcost} = & \sum_{g \in RG} \text{CapitalCost}_g \times \text{CAP}_g + \sum_{g \in NTG} \text{CapitalCost}_g \times \text{CAP}_g \\ & + \sum_{b \in B} \text{CapitalCost}_b \times \text{BatteryEnergyCapacity}_b \end{aligned}$$

Fuel cost is a variable that is only applicable to thermal generators:

$$fuelcost = \sum_{g \in NTG, h \in H} \left( \frac{FuelPrice_g}{Efficiency_g} \right) \times GEN_{g,h} + \sum_{g \in ETG, h \in H} \left( \frac{FuelPrice_g}{Efficiency_g} \right) \times GEN_{g,h}$$

The operating and maintenance (O&M) costs are split into fixed O&M costs and variable O&M costs. There are fixed costs associated with each generating technology, and the cost can be expressed as:

$$fixcost = \sum_{g \in G} FixedOM_g \times CAP_g + \sum_{b \in B} FixedOM_b \times BatteryEnergyCapacity_b$$

The variable cost refers to variable O&M costs that accrue per unit of electricity generated. Only thermal-type generators accrue these costs. Variable costs can be expressed as:

$$varcost = \sum_{g \in NTG, h \in H} VarOM_{g,h} \times GEN_{g,h} + \sum_{g \in ETG, h \in H} VarOM_{g,h} \times GEN_{g,h}$$

The carbon tax cost accounts for costs accrued from carbon emissions produced during electricity generation. In this model, a carbon tax is used to apply these costs. The carbon tax is an exogenous parameter in the model which can be changed to observe how different carbon prices affect the optimal technology mix and system cost.

$$carbontaxcost = \sum_{g \in ETG, h \in H} CarbonTax \times FuelCI_g \times GEN_{g,h}$$

## 2.6 Constraints

### 2.6.1 All Generators

Two constraints apply to all generators in the system. First, the sum of generation from all generators, plus the power available from the battery must be greater than or equal to the demand at each hour. Second, the electricity generated by each generator cannot be negative (as defined when outlining decision variables in Section 2.4).

$$\sum_{g \in G, h \in H} GEN_{g,h} + DISCHARGE - CHARGE \geq Demand_h$$

### 2.6.2 Capacity Constraints

For all generators, the installed capacity must be non-negative. For extant thermal generators (existing diesel generation), the model restricts any additional installed capacity, thus the capacity cannot exceed existing capacity. Extant capacity may be retired, and the retirement variable must be non-negative (i.e. no new capacity installed).

$$CAP_g = ExistingCapacity_g - RET_g \quad \forall g \text{ in } ETG$$

### 2.6.3 Thermal Generation Constraints

For extant and new thermal generators, the electricity generated cannot exceed the installed capacity.

$$GEN_{g,h} \leq CAP_g \quad \forall g \text{ in } NTG, g \text{ in } ETG$$

The annual capacity factor for each thermal generator type is constrained by maximum capacity factors outlined in Table 8:

$$capacityfactor_g = \frac{\sum GEN_{g,h}}{(CAP_g) \times 8760} \leq MaximumCapacityFactor_g$$

A factor of 8760 is included for the number of hours in one year..

Generator	Maximum Capacity Factor
10 MW SMR	90%
Diesel	95%

Table 8 Maximum capacity factors for new and extant thermal generators.

### 2.6.4 Renewable Generation Constraints

Power generation from renewable generators is limited by the installed capacity as well as the capacity factor, which is an endogenous value calculated by the model as a function of meteorological data. The capacity factor for wind and solar generation is discussed in more detail in Section 2.7.6 and Section 2.7.7, respectively.

$$GEN_{g,h} \leq CAP_g \times capacityfactor_g \forall g \text{ in RTG}$$

### 2.6.5 Ramping Constraints

Thermal generators are subject to ramping constraints that account for the maximum positive and negative change in generation between each hour. The constraints on ramping-up power and ramping-down power are provided, respectively:

$$GEN_{g,h} - GEN_{g,h-1} \leq CAP_g \times RampRate_g \forall g \text{ in ETG}, g \text{ in NTG}, h \text{ in } H$$

$$GEN_{g,h-1} - GEN_{g,h} \leq CAP_g \times RampRate_g \forall g \text{ in ETG}, g \text{ in NTG}, h \text{ in } H$$

The ramp rate for the SMR is set at 40% per hour based on an SMR design that has received approval from the United States Nuclear Regulatory Commission (NuScale, 2021). The ramp rate for diesel is taken from Dolter and Rivers (2018).

Generator	Ramp Rate (% per hour)
SMR (10 MW)	40.0
Diesel	25.0

Table 9 Ramp rates for new and extant thermal generators.

### 2.6.6 Battery Constraints

Constraints are applied to the battery state of charge, as well as charge and discharge capacities per hour. The state of charge is bound by the energy capacity of the battery:

$$SOC_h \leq BatteryEnergyCapacity \forall h \text{ in } H$$

Charge and discharge from the battery at each hour is constrained by the battery power capacity:

$$CHARGE_h \leq BatteryPowerCapacity \forall h \text{ in } H$$

$$DISCHARGE_h \leq BatteryPowerCapacity \forall h \text{ in } H$$

The model assumes the starting state of charge (SOC) is zero at the first hour of the year, and then calculates following state of charge values using this formula:

$$SOC_h = SOC_{h-1} + CHARGE_h \times BatteryEfficiency_b \\ - DISCHARGE_h / BatteryEfficiency_b \forall h \text{ in } H$$

### 2.6.7 Policy Constraints

Policy constraints are imposed on the model to determine their impact on the optimal generation mix and total system costs. Policy constraints include imposing maximum carbon emissions or imposing a carbon tax in varying amounts.

### 2.7 Data Processing

The following section outlines data processing. Conversions between \$USD to \$CAD use the Bank of Canada's 5-year cycle average exchange rate (2018-2022) of 1.30378 (Bank of Canada, 2023). Conversions from the currency value in \$CAD of a given year to 2022 \$CAD were completed using the Consumer Price Ratio values outlined in Table 10 for energy goods (Statistics Canada, 2023).

<b>Year</b>	<b>Consumer Price Index</b>	<b>Consumer Price Ratio</b>
2022	139.4	--
2021	128.3	1.09
2020	122.5	1.14
2019	122.7	1.14
2018	121.1	1.15
2017	118.9	1.17
2016	117.9	1.18

*Table 10 Consumer price ratios used to convert prices from \$CAD value in other years to 2022 \$CAD.*

#### 2.7.1 Capital Cost

Values for the capital cost of the 10MW SMR in \$/kW is taken from the SMR Roadmap prepared by the Canadian Small Modular Reactor Roadmap Steering Committee (Canadian Small Modular Reactor Roadmap Steering Committee, 2018). The off-grid, median capital cost value was selected. Expressed in 2018 \$CAD in the SMR Roadmap, the value was converted to 2022 \$CAD for this model. Capital costs for on-shore wind and utility solar PV are taken from Lazard (2021) and converted to 2022 \$CAD (Lazard, 2021). Capital costs from Lazard are taken as the average of the high cost and low cost values. Capital cost and lifetime values for battery

storage are the median values taken from a report by the National Renewable Energy Laboratory (NREL) that summarizes multiple, published capital cost and battery lifetime values for a 4-hour lithium ion battery (Cole, Frazier, & Augustine, 2021). The capital cost value for battery storage is converted from 2020 \$USD to 2022 \$CAD.

The capital costs for each technology are annualized over the technology lifetime ( $n$ ) using an interest rate of 4.5%<sup>1</sup> and the following equation (Purohit, 2023; Kenton, 2020):

$$\text{Annualized Capital Cost} = \frac{\text{Capital Cost} \times \text{Interest Rate}}{1 - (1 + \text{Interest Rate})^{-n}}$$

A summary of annualized capital costs is presented in Table 11. Note that the capital cost of diesel is not included as the model restricts new development of carbon-emitting generators.

<b>Generator</b>	<b>Capital Cost (2022 \$CAD/kW)</b>	<b>Lifetime (years)</b>	<b>Annualized Capital Cost (2022 \$CAD/kW)</b>	<b>Annualized Capital Cost (2022 \$CAD/MW)</b>
SMR (10 MW)	\$19,932	30	\$1,223	\$1,223,629
On-shore wind	\$1,682	20	\$129	\$129,320
Utility Solar PV	\$1,239	30	\$76	\$76,095
Battery	\$445	15	\$41	\$41,444

*Table 11 Annualized capital costs for generators used in the model.*

### 2.7.2 Operating and Maintenance Costs

Fixed and variable operating and maintenance (O&M) costs for both SMRs are taken from the SMR Roadmap (Canadian Small Modular Reactor Roadmap Steering Committee, 2018). These values are converted to CAD \$2022. The off-grid, median capital cost value was selected for each SMR. Fixed and variable O&M costs for diesel are taken from Lazard (2017) as this was the most recent report that contained values for diesel (Lazard, 2017). Values were converted

<sup>1</sup> Note that this interest rate value, and thus annualized capital cost values, are altered for one test performed by the model. This is explained further in Section 3.3.

from USD \$2017 to CAD \$2022. Fixed and variable O&M costs for on-shore wind and utility solar PV are from Lazard (2021) and are converted to 2022 \$CAD. For all values taken from Lazard, the average of the high and low cost values is used. Fixed O&M cost for battery storage is taken as the median of multiple values summarized in a NREL report and is converted from 2020 \$USD to 2022 \$CAD (Cole, Frazier, & Augustine, 2021).

<b>Generator</b>	<b>Fixed O&amp;M Cost (2022 \$CAD/kW-yr)</b>	<b>Fixed O&amp;M Cost (2022 \$CAD/MW-yr)</b>	<b>Variable O&amp;M Cost (2022 \$CAD/MWh)</b>
SMR (10 MW)	\$410.9	\$410,948	\$3.45
Diesel	\$15.3	\$15,286	\$15.29
On-shore wind	\$41.4	\$41,435	--
Utility Solar PV	\$15.9	\$15,937	--
Battery	\$22.3	\$22,255	--

*Table 12 Fixed and variable operation and maintenance costs for generators used in the model.*

### 2.7.3 Fuel Price and Carbon Intensity

The cost of diesel is taken as the fuel cost for an off-grid diesel mine from the SMR Roadmap (Canadian Small Modular Reactor Roadmap Steering Committee, 2018). The cost of nuclear fuel is taken from Lazard (2021) and multiplied by a factor of 2.4, which is the median multiplier used in the SMR Roadmap to account for additional costs due to the remoteness of operations for off-grid reactors (Canadian Small Modular Reactor Roadmap Steering Committee, 2018; Lazard, 2021). All price values were converted to 2022 \$CAD, and from dollar per MMBtu to dollar per GJ, and are outlined in Table 13. On-shore wind and utility solar PV have no associated fuel prices. The carbon intensity for diesel is taken from Dolter and Rivers (2018).

<b>Generator</b>	<b>Fuel Prices (2022 \$CAD/GJ)</b>	<b>Fuel Carbon Intensity (kgCO<sub>2</sub>e/GJ)</b>	<b>Fuel Prices (2022 \$CAD/MWh)</b>	<b>Fuel Carbon Intensity (tonnes CO<sub>2</sub>e/MWh)</b>
SMR (10 MW)	\$2.74	0	\$9.86	0
Diesel	\$33.10	72	\$119.2	0.2592

*Table 13 Fuel prices and fuel carbon intensity used in the model.*

#### 2.7.4 Thermal Efficiencies

The efficiency of thermal generators, used when calculating fuel-related costs, is the rate as a percent at which the generator converts fuel to electricity. The efficiency value for the SMR is taken from the SMR Roadmap and the value for diesel is taken from Dolter and Rivers (Dolter & Rivers, 2018; Lazard, 2021; Canadian Small Modular Reactor Roadmap Steering Committee, 2018).

<b>Generator Type</b>	<b>Efficiency (%)</b>
SMR (10 MW)	33
Diesel	35

*Table 14 Efficiency of thermal generators used in the model.*

#### 2.7.5 Storage Efficiencies

The one-way battery efficiency is the loss associated with converting electrical energy to chemical potential energy in the Li-ion battery as energy storage. Battery efficiency is set at 85% and is taken as the median value from an analysis by NREL (Cole, Frazier, & Augustine, 2021).

#### 2.7.6 Wind Data

Data for hourly wind speed (m/s) for January 1, 2021 to December 31, 2021 is taken from the GRETA Energy Project, which uses the Modern-Era Retrospective Analysis for Research and Applications (MERRA) reanalysis dataset, developed by NASA, and a 100m wind turbine hub height (McPherson, Sotiropoulos-Michalakakos, Harvey, & Karney, 2017).

To derive the equation for hourly power output as a function of wind speed, a theoretical wind turbine is used to simulate power output at different wind speeds. The wind turbine is

modelled after the 2MW ( $P^{rated}$ ) Enercon E-70 E4 that is suitable for high-wind areas (ENERCON, 2016). The modelled wind turbine in this report has a cut-in wind speed of 2.5 m/s ( $v^{cut-in}$ ), a rated wind speed of 13.5 m/s ( $v^{rated}$ ), and a cut-out wind speed of 34.0 m/s. The power ( $P$ ) at each wind speed ( $v$ ) is calculated using the equation (Dolter & Rivers, 2018). The parameter  $k$  governs the shape of the power curve and is set to 0.9.

$$P = \frac{P^{rated}}{1 + \exp - k(v - (v^{cut-in} + v^{rated})/2)}$$

A graphical representation of the power curve is seen in Figure 2. Using the wind speed at each hour in the model, an hourly capacity factor is calculated by dividing the estimated power output from the model by the rated power. This capacity factor provides a percentage of the electricity generated at a given wind speed relative to the maximum amount it could generate if it was operating at full capacity. This hourly capacity factor is used to estimate the total power output possible from the total installed wind capacity in each hour of the modelled year. To that end, the total installed wind capacity is multiplied by the capacity factor to deduce the total amount of hourly electricity generated for each wind speed.

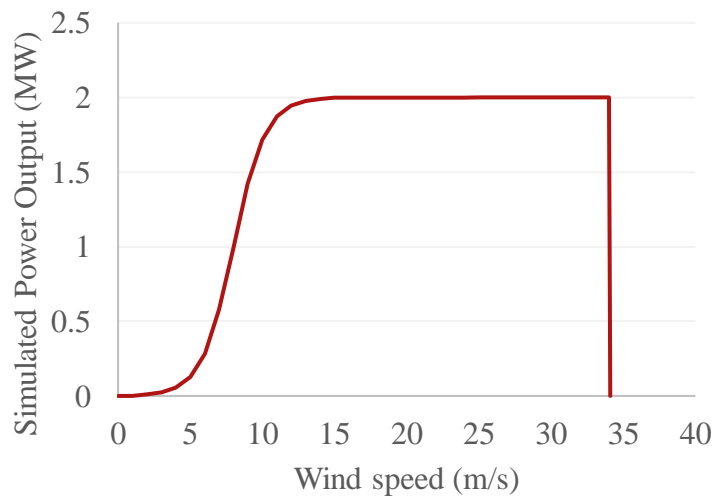


Figure 2 Simulated power profile for a theoretical wind turbine.

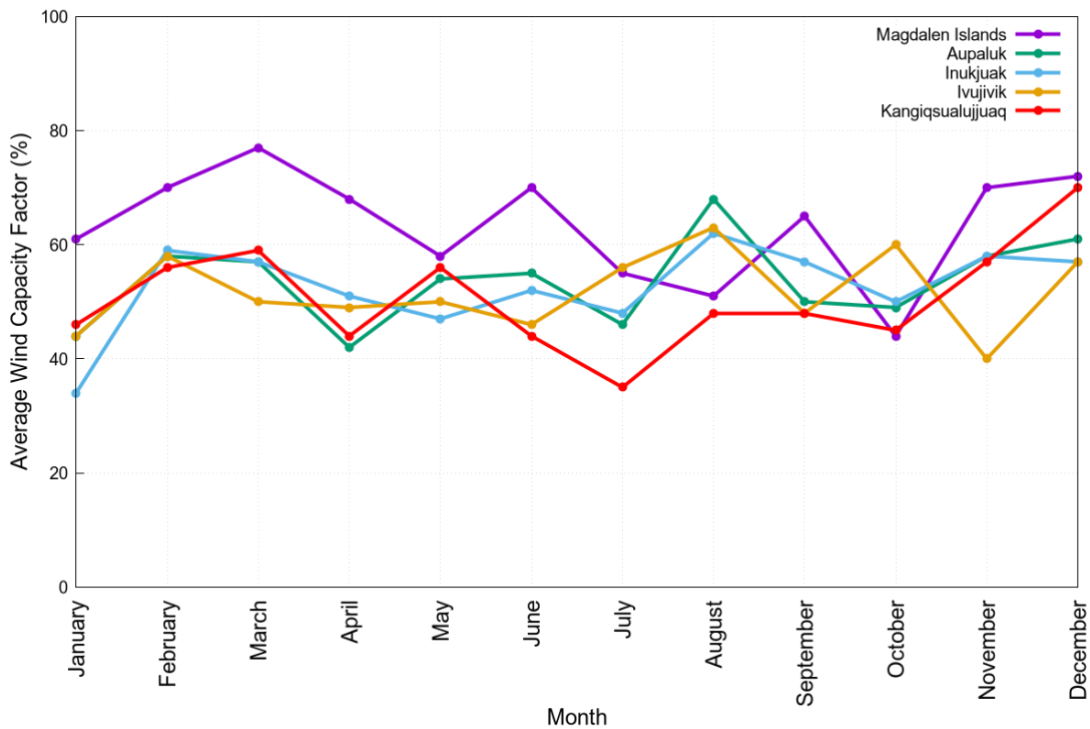


Figure 3 Average monthly wind capacity factor for each community.

The average monthly capacity factor for each community is plotted in Figure 3. Average annual wind capacity factors for Canada, the United States, and globally between 2018-2021 ranged from 23-44% (US Department of Energy, 2021; IEA, 2018). The average annual capacity factors found for the communities in this model are higher than the national and global average, and range from 51%-63%.

### 2.7.7 Solar Data

Data for power generated by solar panels is taken directly from the GRETA Energy Project (MacPherson, 2021). GRETA uses solar irradiance values from MERRA to calculate the power generation ( $W/m^2$ ) from solar irradiance, cell temperature, cell efficiency and a PV module curve. The CS6X\_320P PV model was selected for this study due to its documented ability to withstand heavy wind and snow (Canadian Solar, 2016). The following parameters in GRETA

were selected for the solar power generation calculation: polymer/thinfilmm/steel module type, open rack mount type, fixed tracking, match latitude panel tilt.

The hourly power generation is initially presented as  $Wm^2$ . This is converted to an hourly capacity factor by dividing the GRETA power generation values at each hour by the product of the nominal power generation of the CS6X\_320P PV model, which is 320 W, and the size of the panel, which is 1.9  $m^2$  (Canadian Solar, 2016). Similarly to wind, the installed solar capacity predicted by the model is then multiplied by the appropriate hourly capacity factor to calculate the solar electricity output at each hour.

The average solar power generation value and average monthly capacity factor for each month are plotted in Figure 4 for each community. The average solar capacity factor in Canada is around 15%, while in the sunniest regions in the United States, it can range from 25-30% (HydroQuebec, 2021). The average annual capacity factors for communities studied in this project are between 3-6%, and are thus much lower than the noted national averages.

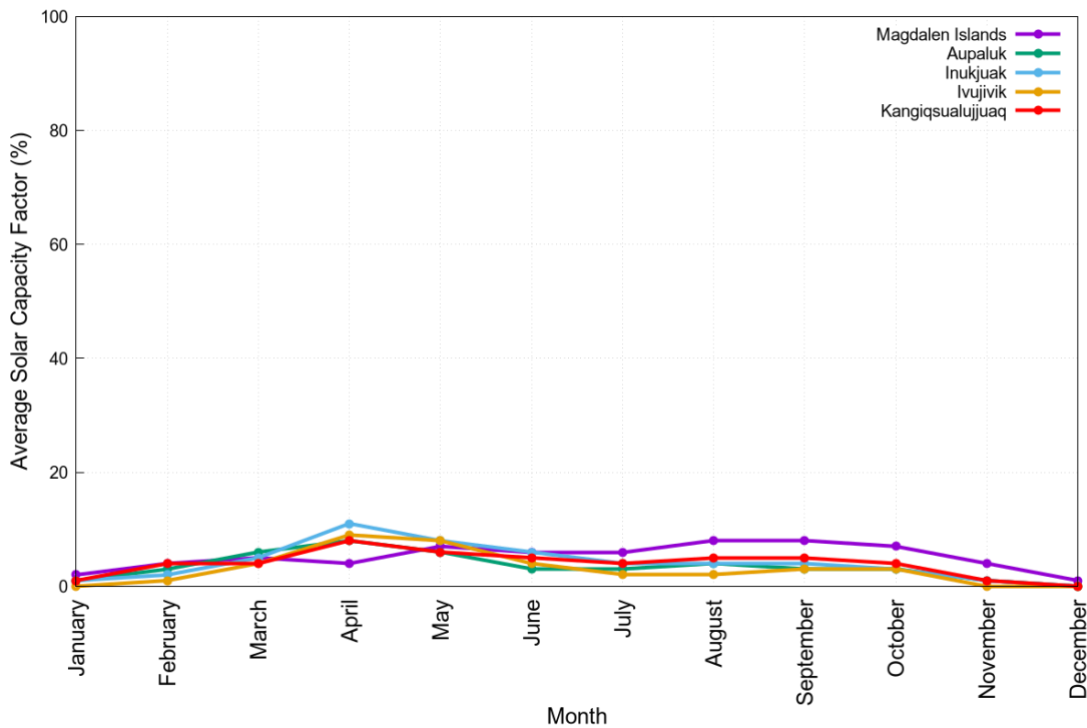


Figure 4 Average monthly solar capacity factor for each community.

For both wind speed and solar power generation data provided by GRETA for the Magdalen Islands, Ivujuvik, and Kangiqsualujjuaq values are provided for multiple grids of latitude and longitude. For example, four values were provided for each hour for the Magdalen Islands for the grid cells of (latitude, longitude) equal to (47.0, -61.25; 47.0, -61.875; 47.5, -61.25; 47.5, -61.875) and two sets of data were provided for Ivujuvik and Kangiqsualujjuaq. For these three locations, the data corresponding to the latitude-longitude location with the greatest annual capacity factor for wind and for solar were used. Data for only one set of latitude and longitude were provided for Inukjuak and Aupaluk. Note that all data is converted units of MW or MWh, as appropriate, for use in the model.

### 3. Results and Analysis

To establish the baseline electricity generation and emissions profile, the optimisation model was constrained to only use diesel to meet the electricity demand for one year. The determined diesel capacity and carbon emissions from this scenario will be referred henceforth as the baseline capacity and baseline emissions. The baseline capacity, emissions, and costs are outlined in Table 15 and Table 16 for each community.

<b>Location</b>	<b>Capital Costs (millions)</b>	<b>Fixed Costs (millions)</b>	<b>Variable Costs (millions)</b>	<b>Fuel Costs (millions)</b>	<b>Carbon Tax Costs (millions)</b>	<b>Total Cost (millions)</b>
Magdalen Islands	\$0	\$0.67	\$2.95	\$65.80	\$0	\$69.42
Aupaluk	\$0	\$0.005	\$0.028	\$0.62	\$0	\$0.65
Inukjuak	\$0	\$0.027	\$0.158	\$3.51	\$0	\$3.70
Ivujivik	\$0	\$0.007	\$0.036	\$0.81	\$0	\$0.85
Kangiqsualujjuaq	\$0	\$0.013	\$0.072	\$1.61	\$0	\$1.69

*Table 15 Costs in millions (2022 \$CAD) determined by the model for each town under baseline conditions.*

<b>Location</b>	<b>Diesel Capacity (MW)</b>	<b>Sum of real annual demand (MWh)</b>	<b>Sum of modeled annual generation (MWh)</b>	<b>Carbon Emissions (ktCO<sub>2</sub>e)</b>
Magdalen Islands	43.57	193,218	193,252	50.1
Aupaluk	0.34	1,809	1,809	0.47
Inukjuak	1.77	10,309	10,309	2.67
Ivujivik	0.45	2,374	2,374	0.62
Kangiqsualujjuaq	0.85	4,723	4,723	1.22

*Table 16 Profile of installed capacity (MW) and carbon emissions determined by the model for baseline conditions, as well as a comparison of the modelled annual generation to the real annual demand needs.*

Following the initial baseline run, subsequent analyses were conducted under two separate constraints, allowing for a mix of on-shore wind, solar, nuclear, diesel and/or battery storage technologies to satisfy hourly electricity demand. A carbon tax constraint was imposed as the first constraint, ranging from \$0/tonne CO<sub>2</sub>e to \$350/tonne CO<sub>2</sub>e increasing at \$10/tonne CO<sub>2</sub>e increments. Under this constraint, additional costs are applied to emissions associated with diesel generation by applying a carbon tax to carbon emissions. The second constraint limits the carbon emissions from baseline emissions. The baseline emissions were constrained by 0% to 100%, increasing in 10% increments. When the carbon tax is modified, there is no emission limit constraint applied, and when the emission limit is modified, there is no carbon tax constraint applied.

Interestingly, in the unconstrained scenario, the optimal energy mix includes wind generation and a reduction of diesel capacity, suggesting that introducing some wind capacity already lowers the total system cost from the baseline. Moreover, the total system costs associated with the highest carbon tax level, \$350/tonne CO<sub>2</sub>, or the 100% emissions reduction scenario, are lower than the baseline system cost that relies only on diesel. These results suggest that reducing diesel dependence could be a cost-effective solution for these remote communities.

In the following sections, the attributes associated with the optimal energy mix under the range of constraints and for each community are represented graphically. These results can be found in Figures 5-7 relate to changes in the carbon tax constraint and Figures 8-10 relate to the carbon emissions constraint.

### 3.1 Carbon Tax Constraint

Carbon tax as a policy instrument intended to decrease carbon emissions has been implemented for carbon emissions reduction across multiple jurisdictions in Canada. However, this model suggests that a carbon tax will be ineffective in reducing emissions in the studied communities.

#### 3.1.1 Costs

Figure 5 shows the costs associated with the optimized electricity generating systems at each carbon tax for each community. As the carbon tax increases, the total cost continues to rise with only a slight decrease in emissions. This rise in costs appears to be primarily due to the increasing carbon tax expenses, which fail to adequately displace the use of diesel-powered generation with non-emitting alternatives. All five communities follow a similar trend of increasing costs and relatively constant installed generator capacities through all carbon tax constraint values. This trend suggests that the carbon tax is not effective in inciting emissions reductions in these remote communities under the assumptions made in the model.

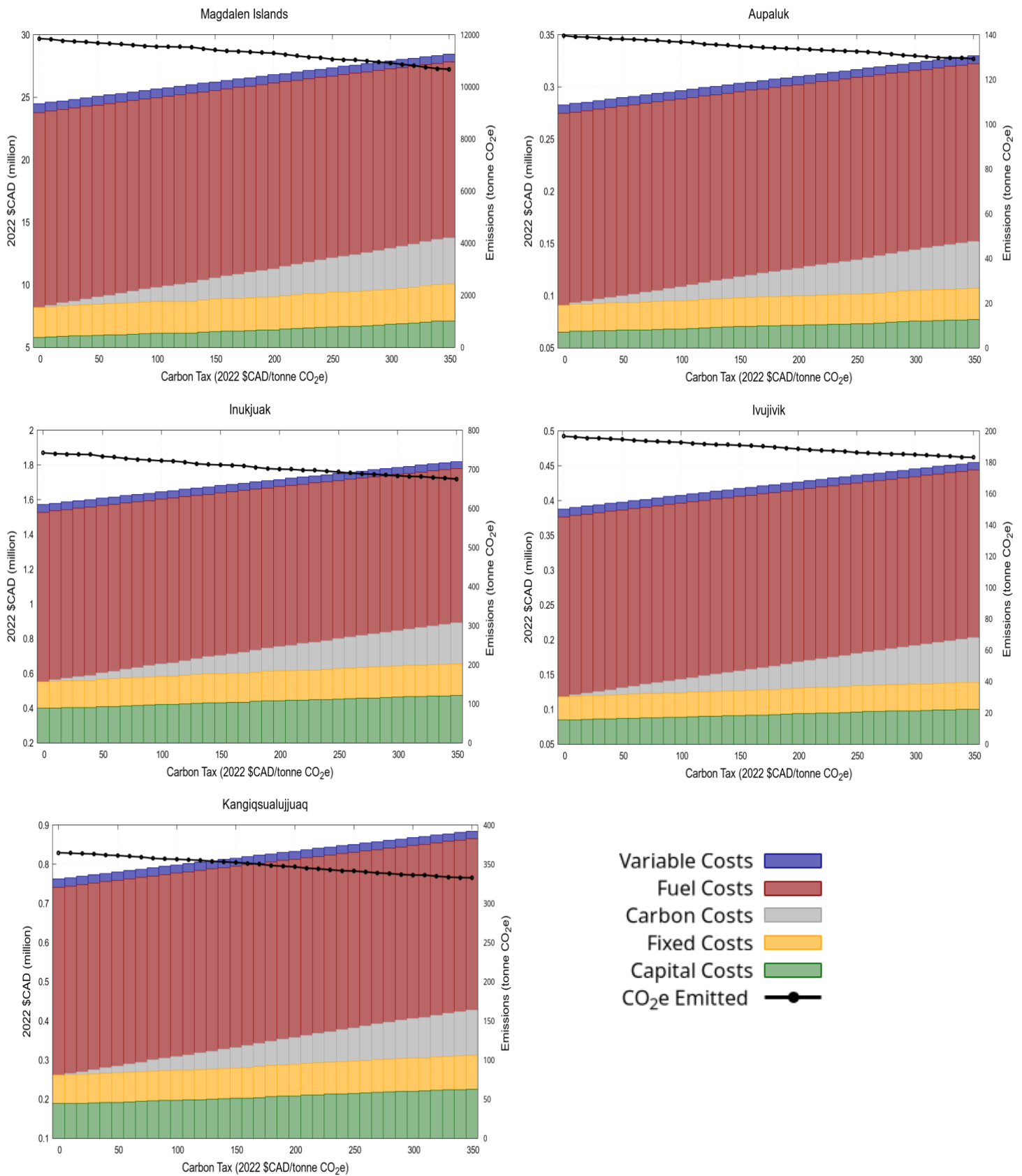


Figure 5 Total system costs in millions at each carbon tax increment. Emissions are represented by a black line.

<b>Location</b>	<b>% of baseline emissions reduced (\$0/tonne CO2 carbon tax)</b>	<b>% of baseline emissions reduced (\$350/tonne CO2 carbon tax)</b>
Magdalen Islands	76	79
Aupaluk	70	72
Inukjuak	72	74
Ivujivik	68	70
Kangihsualujjuaq	70	73

*Table 17 Percent reduction of emissions from baseline emissions due to a carbon price of \$0/tonne and \$350/tonne.*

As previously noted, there is a significant decrease in emissions from baseline levels even at a 0\$/tonne CO2 carbon price; however, increasing the carbon price to \$350/tonne CO2 does not significantly increase the emissions reductions as outlined in Table 17. When comparing the emissions reduction costs of the optimal system at a carbon price of \$0/tonne CO2 and the system at a carbon price of \$350/tonne CO2, the cost per tonne of emissions reduced is approximately 67-99% higher than the Canadian social cost of carbon, which is \$50. The costs per tonne of emissions reduced at a carbon tax \$350/tonne CO2 relative to a \$0/tonne CO2 carbon tax, and the amount of emissions reduced, is outlined in Table 18.

<b>Location</b>	<b>Cost (2022 \$CAD) per tonne CO2 reduced</b>	<b>Cost (2022 \$CAD) per tonne CO2 reduced per capita</b>	<b>Emissions reduced (tonnes)</b>
Magdalen Islands	3375	0.28	1,173.3
Aupaluk	4521	21.6	10.4
Inukjuak	3704	2.11	66.9
Ivujivik	4929	11.9	13.5
Kangihsualujjuaq	3816	4.05	32.0

*Table 18 Costs of reduction and total emissions reduced for each town at a carbon price of \$350/tonne.*

### 3.1.2 Capacity and Generation

Figure 6 shows the installed capacity at each carbon price studied and Figure 7 shows the total annual generation from each generator at each carbon price.

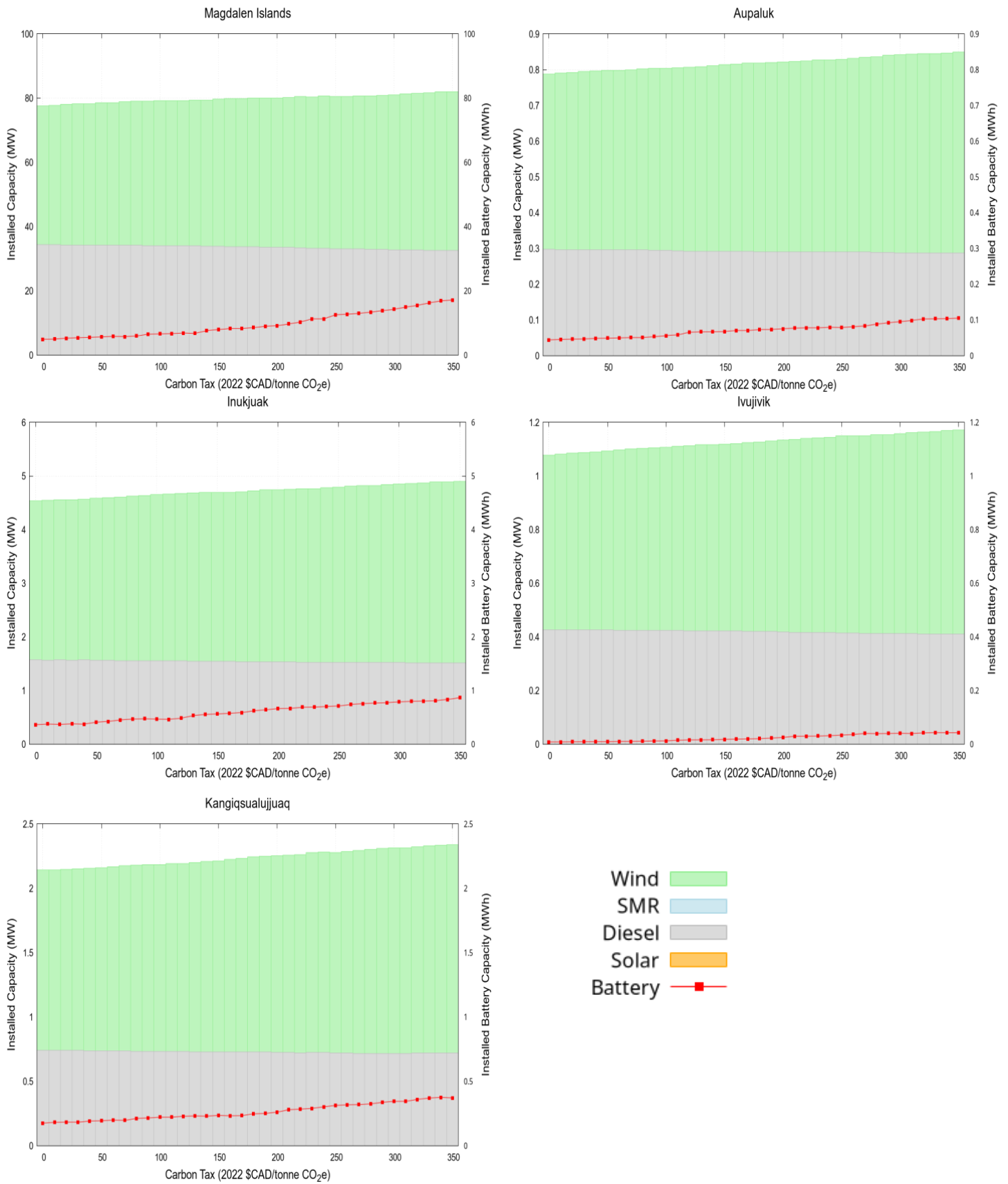


Figure 6 Installed capacity at each carbon tax increment for each community.

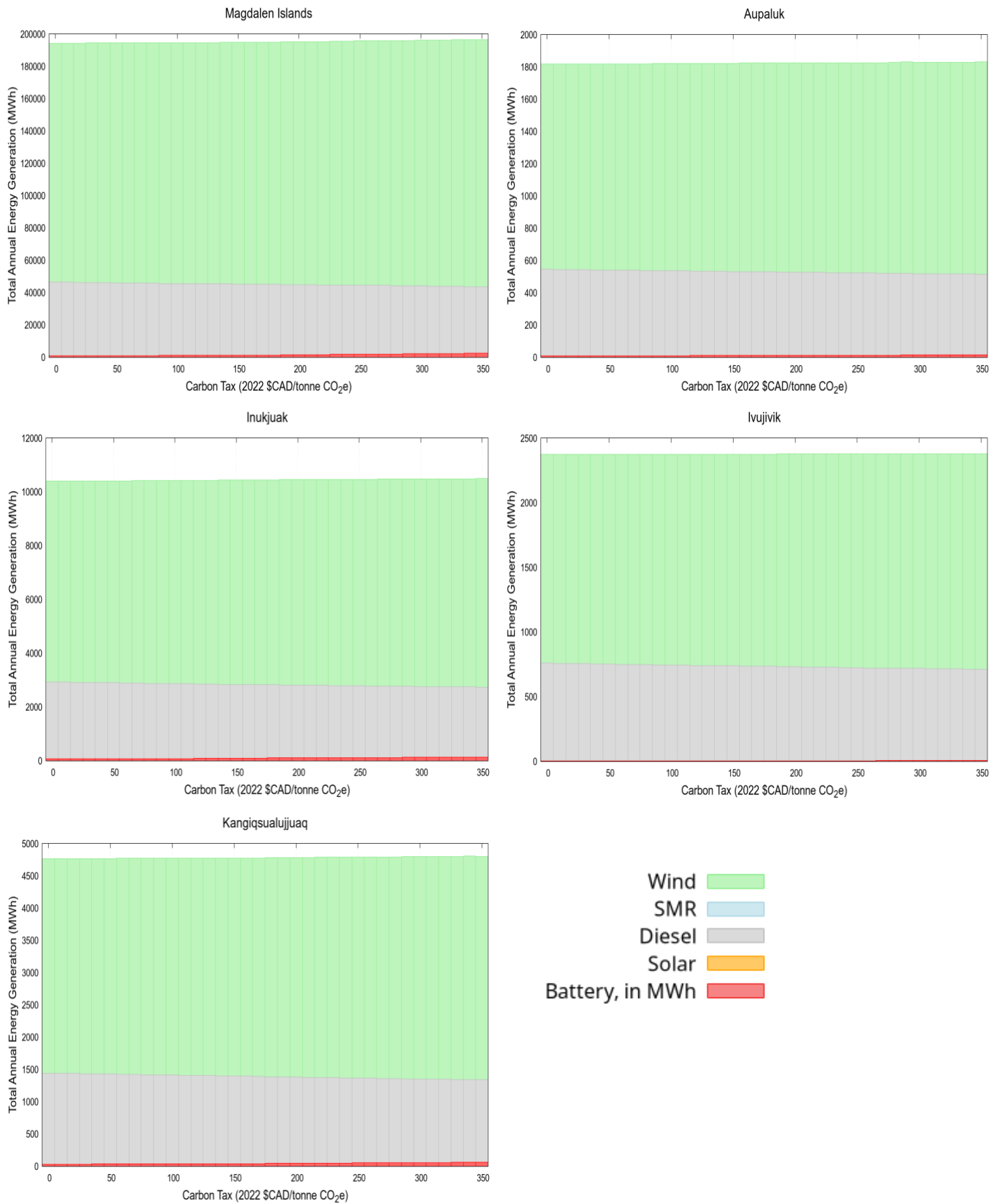


Figure 7 Contribution of each generator to the total annual generation at each carbon price for each community.

	<b>Diesel</b>		<b>Wind</b>		<b>Battery</b>	
	<i>Capacity</i>	<i>Generation</i>	<i>Capacity</i>	<i>Generation</i>	<i>Capacity</i>	<i>Discharge</i>
Magdalen Islands	-5%	-10%	+15%	+3%	+249%	+198%
Aupaluk	-3%	-7%	+15%	+3%	+137%	+111%
Inukjuak	-4%	-10%	+14%	+4%	+139%	+107%
Ivujivik	-4%	-7%	+17%	+3%	+431%	+395%
Kangiqsualujjuaq	-3%	-9%	+16%	+4%	+113%	+82%

*Table 19 Percent difference between a \$0/tonne and \$350/tonne carbon price in installed capacity and generation for diesel, wind, and battery storage.*

Table 19 presents the percent differences in capacity and generation between a \$0/tonne CO2 carbon tax and a \$350/tonne CO2 carbon tax. The model forecasts an increase of 14-17% in installed wind capacity and 113-431% of storage capacity across the five communities. Given the low capacities associated with wind and storage, a significant percent increase is not indicative of large installations of wind and storage in absolute terms. For example, although the percentage increase in battery storage is substantial, the absolute increase represents less than 0.2-1.3% of the energy demand for each community.

The contribution to the total annual generation of each technology is shown in Figure 7, and it can be seen that the major contributor to meeting annual electricity demand at each carbon tax is wind. As the carbon tax increases, wind and storage are used to supplement the 7-10% decrease in diesel generation, likely to offset costs associated with fuel and carbon tax. Communities with greater decreases in diesel capacity and generation observe greater battery storage installation, while wind capacity increases are relatively consistent across all communities. The annual generation profiles for each community do not show significant differences from one another.

The small decrease in diesel generation is insufficient to make a significant impact on emissions reduction. These findings imply that the implementation of a carbon tax alone may not induce a sufficient reduction of emissions in these remote communities. Further, the results

suggest that despite the implementation of a carbon tax, the installed diesel capacity would remain relatively unchanged, and total system costs would continue to rise, imposing a burden on the communities without achieving the desired emission reductions. As such, additional and/or different measures may be needed to reduce emissions effectively in these communities.

### 3.2 Carbon Emissions Constraint

The impact of a carbon emissions constraint offers a more cost-effective reduction of emissions compared to the carbon tax constraint for the communities studied.

#### 3.2.1 Costs

Figure 8 shows the costs associated with the optimized electricity systems at each carbon emissions constraint and Table 20 outlines the costs per tonne of CO<sub>2</sub> reduced.

<b>Location</b>	<b>Cost (2022 \$CAD) per tonne CO<sub>2</sub> reduced</b>	<b>Cost (2022 \$CAD) per tonne CO<sub>2</sub> reduced per capita</b>	<b>Emissions reduced (tonnes)</b>
Magdalen Islands	2923	0.24	11,853.2
Aupaluk	1539	7.36	139.7
Inukjuak	1667	0.95	742.1
Ivujivik	1683	4.07	196.7
Kangiqualujjuaq	1470	1.56	364.8

*Table 20 Costs of reduction and associated emissions reduced at full decarbonization, compared to baseline emissions, for each town.*

This study finds that the absolute costs required to decarbonize the Magdalen Islands is approximately twice as high as the other four communities studied, however, the cost per tonne per capita is the lowest of the five communities. When comparing the cost per tonne of CO<sub>2</sub> reduced to that in the carbon tax scenario, the cost per tonne for the Magdalen Islands is similar, while for the other four communities, the cost per tonne decreases by half upon full decarbonization under an emissions constraint.

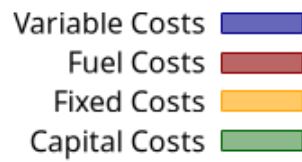
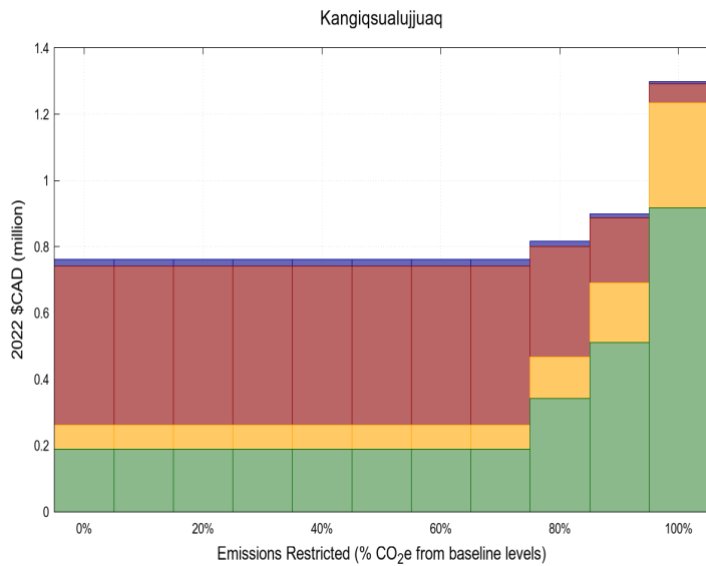
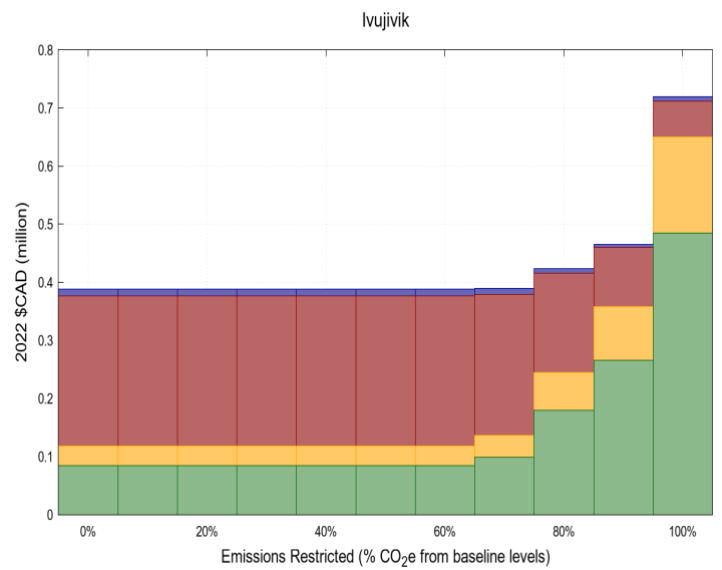
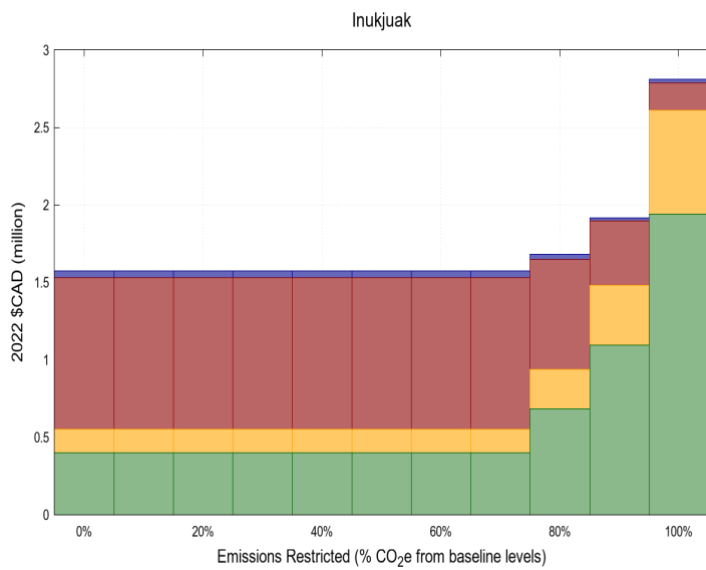
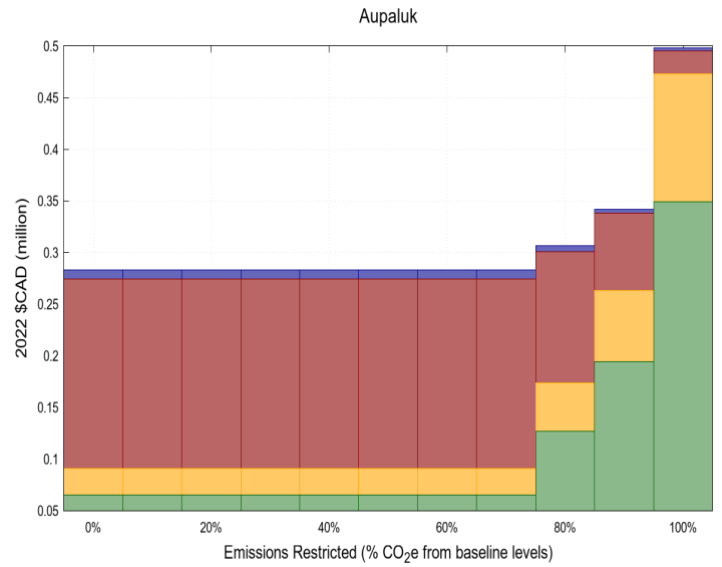
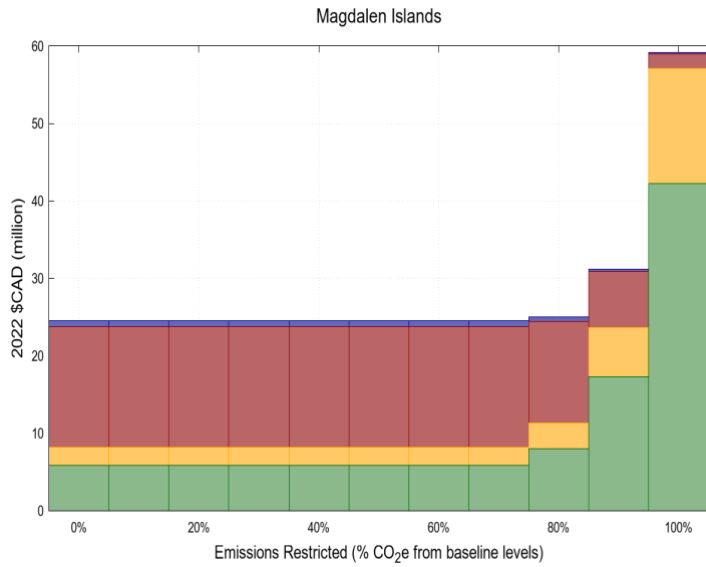


Figure 8 Total system costs in millions at each carbon emissions constraint increment for each community.

Figure 8 shows that the model suggests a significant increase in costs to achieve 100% decarbonization, with the increase beginning at 80% decarbonization. However, there is no discernible change in costs between the 0%-70% decarbonization range. This suggests that present day costs with associated non-emitting alternatives to diesel already incentivises an emission reduction of 70% without imposing a carbon emission limit.

### 3.2.2 Capacity and Generation

Figure 9 shows the installed capacity at each carbon emissions constraint studied and Figure 10 shows the total annual generation from each generator at each carbon emissions constraint.

The results of this study suggest that a mix of wind, diesel, and battery storage, can reduce system emissions up to 70% from the model's baseline emissions for all communities.

Diesel capacity remains constant until the constraint of 80-90% decarbonization, after which diesel capacity is replaced with increased nuclear and battery storage. This switch may be motivated by grid stability considerations as emissions become more constrained. Further, as diesel is replaced with nuclear, the total installed capacity of generators decreases. This behaviour can be explained by the high capital costs and low operating cost of SMRs, where the SMR should operate at relatively high capacity factors once installed.

To enhance the utility of the model, future development could assess the degree to which longer-term storage would offset the need for nuclear power. To achieve full decarbonization, the model suggests an optimal combination of battery storage, wind, and SMR for all communities.

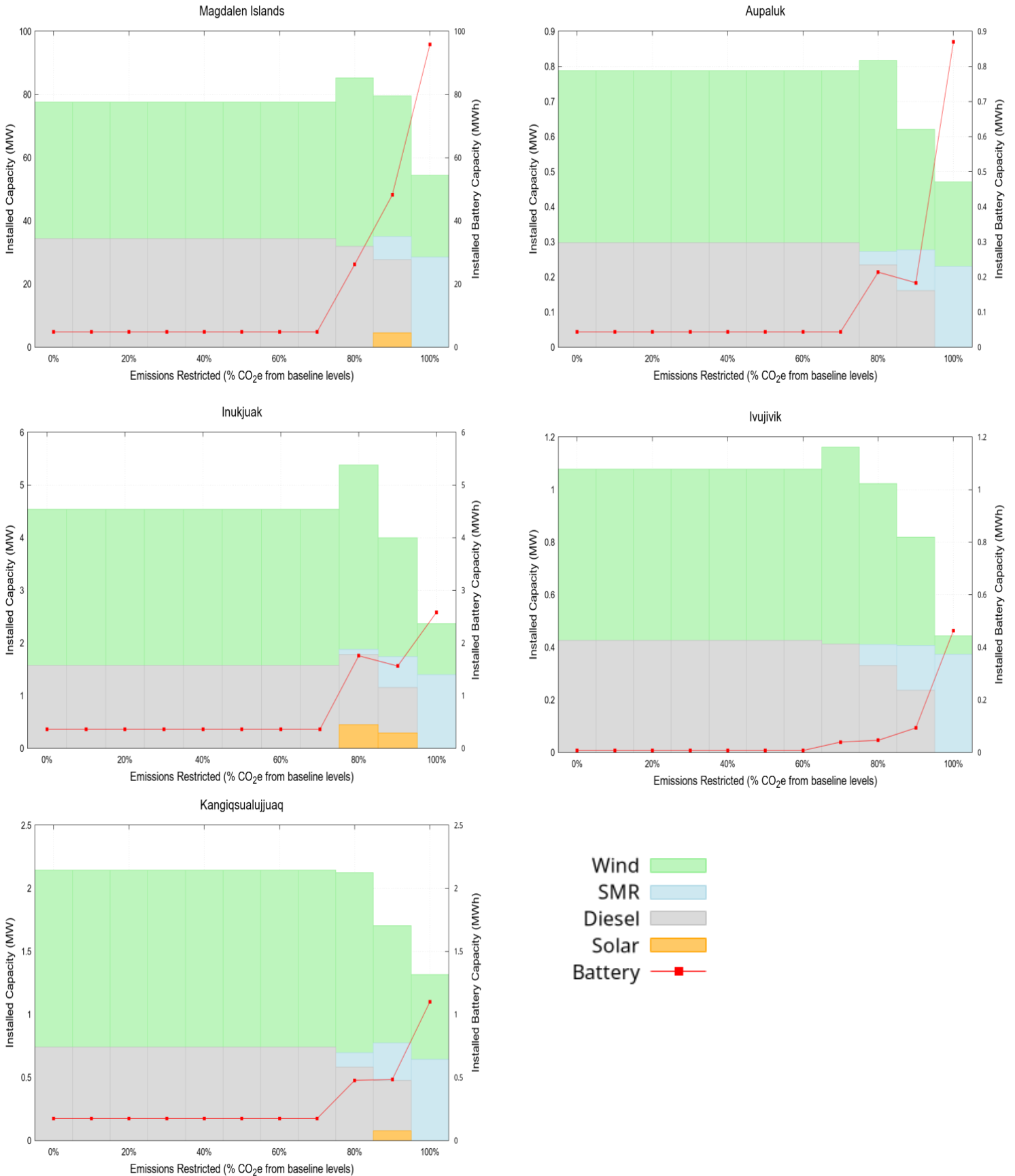


Figure 9 Installed capacity at each carbon emissions constraint increment for each community.

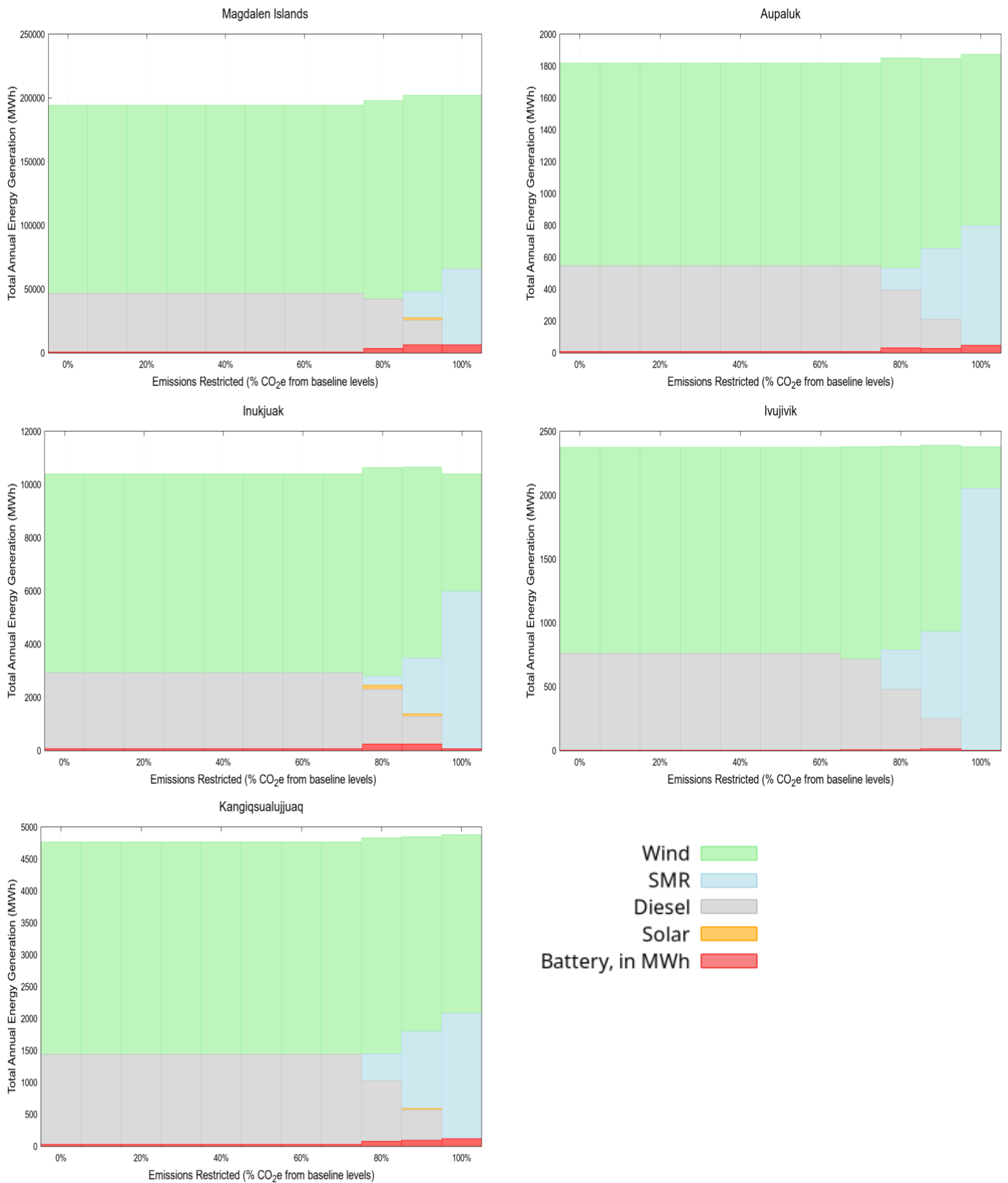


Figure 10 Contribution of each generator to the total annual generation at each carbon emissions constraint for each community.

Interestingly, no community at full decarbonization uses solar energy, although three of the five communities install a small amount of solar in the 80% or 90% decarbonized scenarios. The solar capacity factor for all communities is much lower than the national average for solar farms, at about one third of the national average, which may explain the limited reliance on this electricity source.

The present finding, that a mix of wind, nuclear/SMR and battery storage is the optimal mix for decarbonization of the remote communities studied, differs from the results of a previous report by Stringer and Joanis concerning remote communities in Canada (Stringer & Joanis, 2023). The Stringer and Joanis study, as discussed in Section 1, used annual rather than hourly data and the results of that study suggested that solar power is more favourable than wind energy in Canadian remote communities. A more geographically diverse range of communities should be studied using this model to assess the results obtained in this study for location dependence.

Ivujivik uses the lowest relative amount of installed wind capacity in the fully decarbonized scenario, as well as the lowest annual generation from wind. The low dependence on wind for Ivujivik may be attributed to the Pearson correlation coefficient between available wind power and demand. In this context, a correlation coefficient near 1 indicates that available wind power increases or decreases in tandem with demand. A correlation coefficient near -1 indicates the opposite. A correlation coefficient near 0 indicates no correlation. The correlation coefficients are detailed in Table 21. Of all five communities, Ivujivik has the most negative coefficient indicating the anti-correlation of the town's electricity demand with the available wind generation. The Magdalen Islands, with the highest positive coefficient, has the most annual generation contribution from wind. When fully decarbonized, Ivujivik relies the least on

wind power and the Magdalen Islands relies the most on wind power for total annual generation, as expected from the correlation coefficients.

<b>Community</b>	<b>Pearson Correlation Coefficient</b>
Magdalen Islands	0.208
Aupaluk	-0.007
Inukjuak	-0.041
Ivujjivik	-0.067
Kangiqsualujjuaq	0.020

*Table 21 Pearson correlation coefficient between demand and available wind power*

Ultimately, the findings of this model suggest that 100% decarbonization is more cost-effective than a 100% diesel system for electricity generation over the studied year. This finding implies that SMRs, in addition to wind and battery storage, are already cost competitive with diesel in specific situations. As previously noted, full decarbonization involves an increased reliance on SMR electricity generation, likely due to its greater reliability compared to wind energy and short-term storage. The decarbonization potential and associated costs are more optimal following a carbon emissions constraint than a carbon tax. Further, the results suggest that the optimal mix of generators being wind, battery, and SMR were not significantly impacted by the varying loads of each community, nor the differences in maximum or average loads.

### 3.3 Interest Rate Effects

The effect that interest rate, incorporated via the capital cost calculation, has on the results was analyzed. The capital costs used thus far were calculated using an interest rate of 4.5%. To assess the impact of interest rates, additional capital costs were calculated using an interest rate of 8.5%, and the model was run without a carbon tax at a 0% emissions restriction and a 100% emissions restriction. Figure 11 below shows the effects of an increased interest rate on the total system costs and optimal system capacity mix.

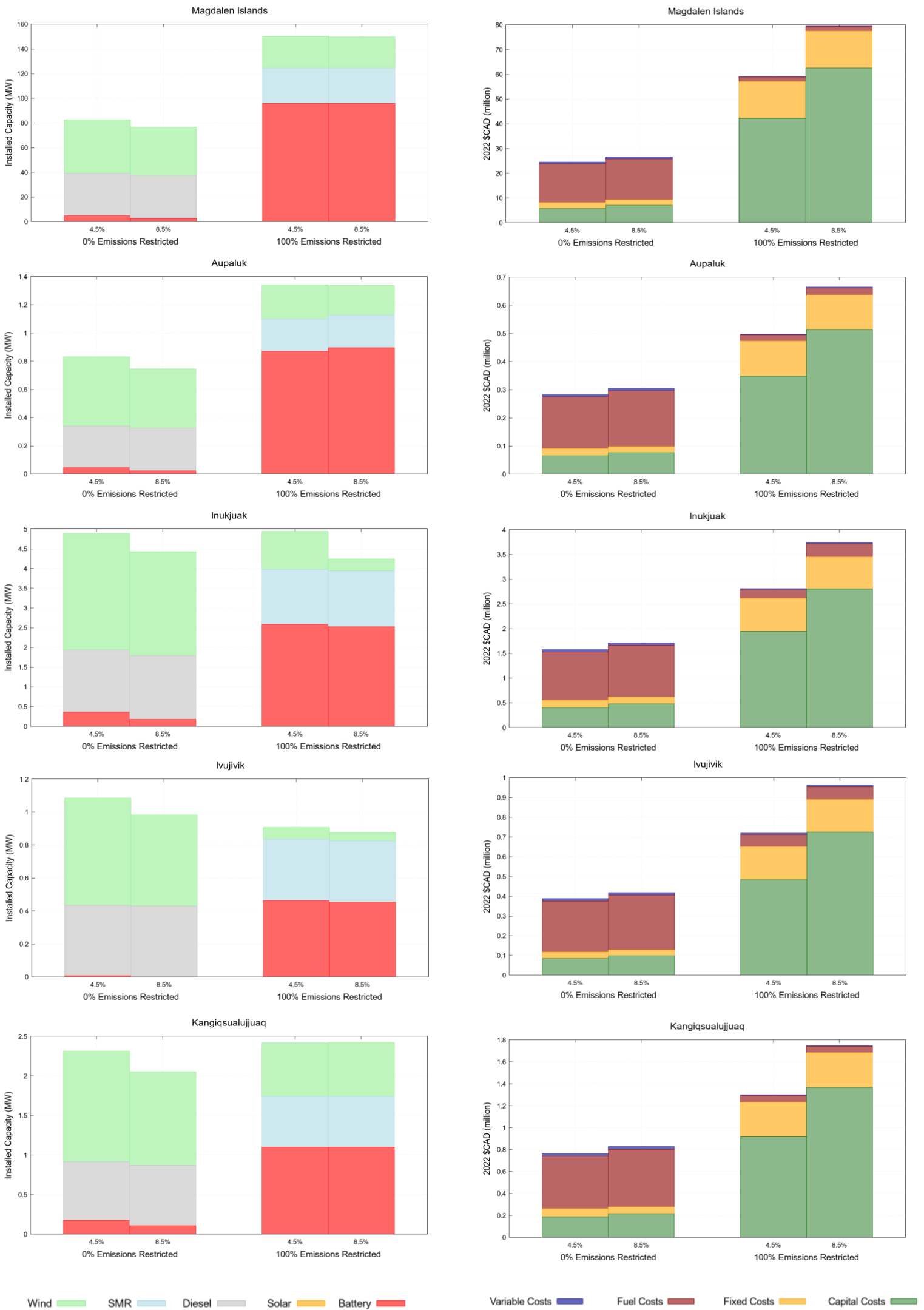


Figure 11 Column one shows the effect on capacity installed between a 4.5% and 8.5% interest rate at an emissions constraint of 0% and 100%. Column two shows the effect on total system cost between a 4.5% and 8.5% interest rate at an emissions constraint of 0% and 100%. Each row represents a given community. Note that carbon costs are not included as a carbon tax is not applied here.

Under a 0% emissions restriction, all communities undergo a decrease in wind capacity and installed battery storage when the interest rate is increased. Due to this, less diesel capacity is retired at 8.5% compared to 4.5%. The total system costs increase between a 4.5% to 8.5% interest rate for each community. The increase is minimal and comes largely from increased capital costs, for wind and battery, and increased fuel costs due to higher diesel use. The cost increase is similar in relative magnitude across all five communities. It is interesting to note that even at the high interest rate, the model still prefers some wind and battery capacity and the total system costs are less than a 100% diesel baseline system.

Under a 100% emissions restriction, there is no diesel capacity allowed in the system by merit of the constraint. The optimal generator mix for the Magdalen Islands and Kangiqsualujjuaq is essentially unchanged between a 4.5% and 8.5% interest rate. Aupaluk sees a decrease in installed wind capacity, but an increase in battery storage and Ivujivik sees a decrease in both wind and battery capacity, but the changes in both communities is minor. Inukjuak has a significant decrease in wind capacity. The significant decrease in wind for Inukjuak aligns with what was previously observed, that the community is not heavily reliant on wind power. It may be that at a 4.5% percent interest rate, wind generation is used when available due to the presence of variable O&M costs associated with SMR use, but at the increased 8.5% interest rate, this offset of nuclear O&M costs is no longer economical.

Further, under a 100% emissions constraint, all communities incur cost increases at an 8.5% interest rate that are mainly attributed to capital costs. Inukjuak has a slight increase in fuel costs, due to the heightened reliance on SMR electricity. However, the total cost increase at 8.5% interest rate for all communities is between 32-35% when compared to the 4.5% interest rate

system costs. The total system costs at an 8.5% interest rate is higher than the baseline system cost for all communities.

#### 4. Sources of Error and Future Work

The model developed in this work provides a preliminary analysis of the relative impact to costs as a result of imposing or altering policy constraints, such as carbon tax, and altering cost parameters, such as interest rates. However, there are several areas in which the model could be improved in future work to achieve greater accuracy of projected costs.

First, the model does not account for temperature impacts to battery efficiencies. Extreme temperatures impact the state of charge of lithium ion batteries. This effect has been quantified at an efficiency decrease of approximately 23% when the battery operating temperature decreased from +25 to -15 degree Celsius (Ma, et al., 2018). Many remote communities in Canada are located in areas where temperatures can drop well below zero degrees Celsius for long durations. This temperature effect on batteries is important to consider when developing models for remote communities.

Additionally, a limit on the length of time in which the battery can hold a charge is not implemented. The implemented costs of the selected battery are associated with a lithium ion battery with a charge lifetime of 4-6 hours, but this is not constrained in the model (Cole, Frazier, & Augustine, 2021). However, the observed behaviour of energy storage in the model suggests that the battery does not charge until shortly before the stored energy is needed. While this energy storage method is impractical in practice due to the unpredictability of weather and reliability requirements, within this model it moderates issues from excluding a constraint on charge lifetime. Long-duration storage batteries, along with other types of energy carriers such as hydrogen, could

be analyzed in future work to compare costs with the current lithium-ion models assessed in this analysis.

Previous papers have imposed siting constraints on generators (Dolter & Rivers, 2018). In this type of constraint, any new generators are subject to siting constraints based on available land area for infrastructure. From Dolter and Rivers (2018), wind is able to produce 2 MW/km<sup>2</sup> and solar PV is able to produce 31.28 MW/km<sup>2</sup>. A siting constraint of 11,750 MW/km<sup>2</sup> for SMRs was deduced from land requirements for a Rolls Royce SMR (Rolls Royce, 2017). However, siting constraints are not considered in the context of this model since it is proposing electricity systems for remote communities, most of which have sufficiently large land areas relative to the energy asset. It is assumed that land availability is not the constraint, and rather future work could consider issues arising from terrain suitability. For example, parameters such as slope and land use, such as water or wetlands, likely imposes a greater constraint on deployment of an electricity system than area availability. Assessments of terrain suitability can be performed in ArcGIS Pro, and may be possible to implement in Julia.

Furthermore, with clean energy alternatives being considered for deployment in remote locations, optimization models will be useful to propose solutions that satisfy demand beyond first-order electricity requirements. In these communities, diesel combustion is commonly used for co-generation, where waste heat is used as a reliable source of district heating for buildings (Lovekin, Moorhouse, Morales, & Salek, 2020). Heat generation consumes 2 to 3 times the amount of diesel used for electricity generation (Kilpatrick, 2021). In future work, hourly electricity demand could also include data for electrical heat generation to assess the potential for electric heating in the studied communities. Alternatively, the combustion of hydrogen gas as a source of thermal energy

to replace the cogeneration of diesel is a possibility if hydrogen is implemented as an energy carrier. In an ideal scenario, this heat source could work synergistically with hydrogen storage.

Additionally, costs for renewable generators and battery storage are expected to decrease significantly in future years. For example, it is projected that a cost decrease of 50% to 60% is possible for battery storage by 2030 (International Renewable Energy Agency, 2022; Cole, Frazier, & Augustine, 2021). Future work could study the effects of these decreasing costs on the projected technology mix and total costs.

Lastly, the model freely alters the installed capacity for each generator type to minimize the total cost without restrictions on the unit size of an installed energy asset. For example, if a single wind turbine has a unit size of 2 MW, the installed capacity should ideally be represented in a multiple of this unit size. As such, future work could consider a method using mixed-integer linear programming to allow only whole units of capacity to be installed or retired for each generator type, as applicable.

## 5. Conclusions

Canada's goal of achieving a net-zero electricity grid by 2030 highlights the importance of decarbonizing the electricity system. While over three quarters of Canada's electricity is already produced using non-emitting sources, remote communities that lack connection to the main power grid continue to remain reliant on fossil fuels, such as diesel, for electricity.

Decarbonizing electricity generation in these remote communities in Canada requires customized solutions that account for the unique challenges and needs of each community.

The ESOM developed in this report attempts to quantify differences in cost to decarbonize five remote communities in Canada, as well as to predict the types of technologies that could be pursued for decarbonization. This study resulted in three major conclusions. First,

the model suggests that SMRs, in addition to wind and battery storage, are already cost competitive with diesel in specific situations, as the total cost of a fully-decarbonized electricity system (at an interest rate of 4.5%) is less expensive than a system completely reliant on diesel. Further, there was no discernible change in costs between a 0% to 70% carbon emissions limit, suggesting that present day costs with associated non-emitting alternatives to diesel already incentivises an 70% emissions reduction without imposing a carbon emission constraint. Second, increasing the carbon tax from \$0/tonne CO<sub>2</sub> to \$350/tonne CO<sub>2</sub> made the total system cost more expensive without achieving significant carbon emissions reductions. This finding suggests that the carbon tax is an ineffective decarbonisation policy for these remote communities in Canada. The costs and associated emissions reductions derived in the model favour a carbon emissions limit policy. Third, the optimal generator combination for full decarbonization was similar for all five communities, consisting of a mix of wind, battery storage, and SMR. The optimal mix appears to be independent of the initial load duration, average load, and maximum load.

The overall low reliance on solar can be explained by the low capacity factors for solar power generation in each location. The high reliance on wind generation can be explained in the same way by high capacity factors, and variations between communities can be explained by the Pearson correlation coefficient. Unsurprisingly, the model installed more wind in a community if potential wind generation aligned with electricity demand.

Further, this study examined the impact of an increased interest rate on costs and installed capacity. Under a 0% emissions constraint, there is a slight cost increase and a slight decrease in wind and battery capacity observed across all five communities. For a 100% emissions reduction constraint, increasing the interest rate results in a cost increase of approximately 33%, attributed

mainly to capital costs. The installed capacity does not vary significantly for each community between the two interest rates studied, except for Inukjuak, which saw a decrease in installed wind at a higher interest rate. The decrease in wind capacity under an 8.5% interest rate for Inukjuak is potentially explained by the community having the largest, negative Pearson correlation coefficient between demand and available wind power.

Moreover, achieving net-zero emissions in Canada by 2050 means that decarbonization efforts must be extended to other sectors, including heating, for remote communities. Future work could explore the development of a system to decarbonize both electricity and heating in remote communities. Additionally, future work should incorporate demand over duration longer than one year, account for demand management, declining technology costs, and different technology types that may be used both for decarbonization and in daily life, such as EVs. Further, the work could incorporate a social analysis of the impacts of certain decarbonization technologies in remote communities to account for any community biases. Combining technical and social aspects of decarbonization will provide comprehensive and effective economy-wide strategies for decarbonization. By addressing these challenges head-on and taking a proactive approach to decarbonization, Canada can play a leading role in combating climate change and creating a more sustainable future.

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