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CLIMATE IMPACTS ON CANADA'S ELECTRICITY SYSTEMS

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Climate Impacts on Canada's Electricity Systems

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ABOUT THE CANADIAN ENERGY RESEARCH INSTITUTE – CANADA'S VOICE ON ENERGY

Founded in 1975, the Canadian Energy Research Institute (CERI) is an independent, registered charitable organization specializing in the analysis of energy economics and related environmental policy issues in the energy production, transportation, and consumption sectors. Our mission is to provide relevant, independent, and objective economic research of energy and environmental issues to benefit business, government, academia, and the public.

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Acronyms and Abbreviations

AB	Alberta
BC	British Columbia
CEAA	Canadian Environmental Assessment Agency
CERI	Canadian Energy Research Institute
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent (including all greenhouse gases)
ECCC	Environment and Climate Change Canada
EIA	Environmental Impact Assessment (Canada)
EIS	Environmental Impact Statement (US)
EPA	Environmental Protection Agency (US)
FERC	Federal Energy Regulatory Commission (US)
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GWP	Global Warming Potential
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRR	Internal Rate of Return
kt	Kilotonnes
kt/yr	Kilotonnes per year
LNG	Liquified Natural Gas
Mbpd	Million barrels per day
MBTU	Million British Thermal Units
m^3	Cubic meters
Mt	Million tonnes
Mtpa	Million tonnes per annum (Million tonnes per year)
ND	North Dakota
NEB	National Energy Board
NL	Newfoundland and Labrador
NRCan	Natural Resources Canada
OBPS	Output-Based Pricing System
ON	Ontario
PA	Pennsylvania
ROI	Return on Investment
SK	Saskatchewan
tpy	Tonnes per year
TX	Texas
US	The United States

Executive Summary

The global warming trend in Canada is, on average, about double the magnitude of the global average. As a result, there could be impacts on Canadian infrastructure that is far greater than what could be expected in other parts of the world. Electricity infrastructure that is designed by considering observed history may be vulnerable and experience outages and other physical impacts.

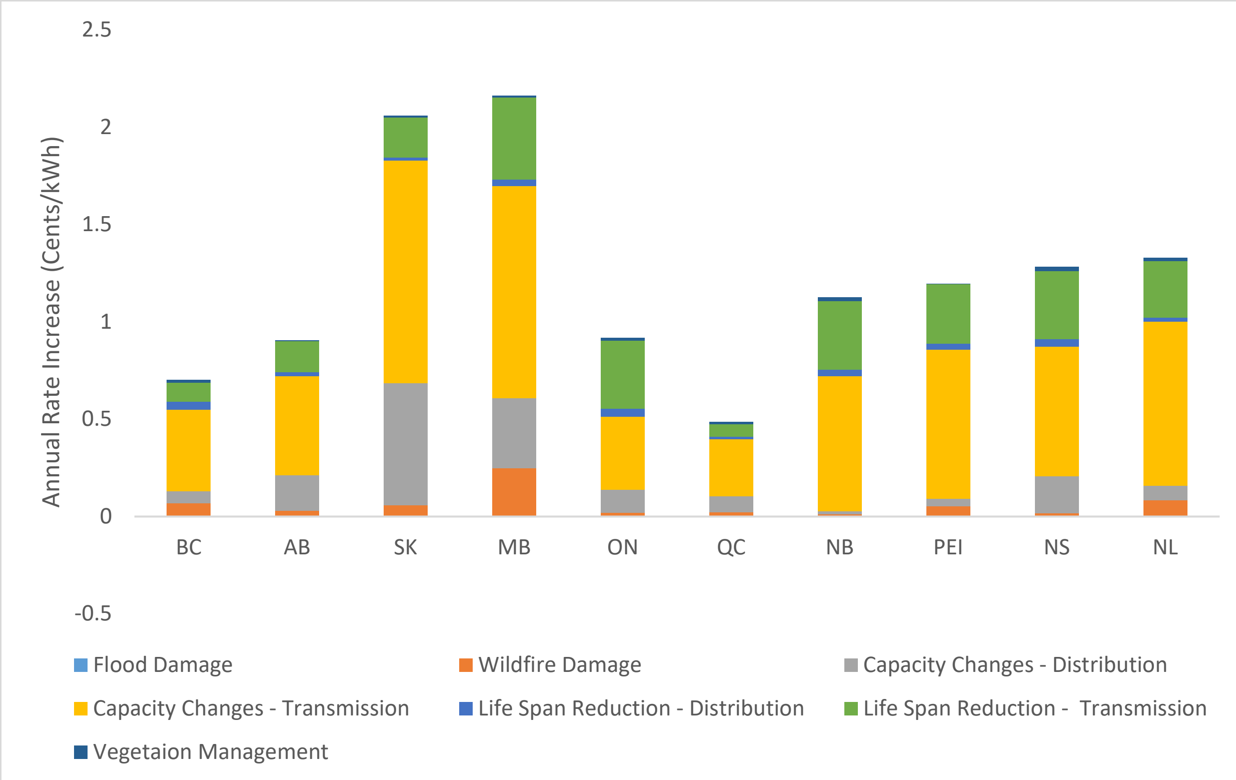
Using down-scaled climate model results, this study quantifies the magnitudes of the physical impacts of climate change on electricity systems in all Canadian provinces. Climate change induced events that can impact the Canadian electricity delivery infrastructure are identified. Climate stressor response functions are developed to assess climate change impacts of electricity delivery systems. Based on data availability, eight climate stressor response functions are used to quantify the impacts on Canada's electricity system. The eight functions are;

- Capacity change impact on transmission lines due to temperature change
- Capacity change impact on distribution lines due to temperature change
- Lifespan impact on substation/large transformers due to temperature change
- Lifespan impact on distribution transformers due to temperature change
- Vegetation management cost impact due to vegetation growth rate changes
- Wood pole lifespan changes due to rainfall and temperature effects
- Impacts from a change of wildfire occurring frequency
- Impacts from a change of flooding frequency

Regarding the impact of climate change on Canada's electricity systems, the data unavailability limits the ability to conduct full systems levels assessment of climate change impacts on other impacts. However, a qualitative assessment has been conducted on five other climate events; lightning frequency changes, high wind impacts, Storm Surge/Sea level rise impacts on coastal infrastructure, freezing rain impacts, snowfall and snow-related impacts. In addition, a thorough qualitative evaluation of the generation assets has been conducted. All the evaluations were conducted under three separate climate scenarios; net negative emissions scenario with a temperature anomaly of 1.5 ^{o}C, low emission scenario with a temperature anomaly of 2.4 ^{o}C, and high emission scenario with a temperature anomaly of 4.9 ^{o}C, by the end of the century.

The magnitude of climate change impacts varies by climate scenario, province, and type of asset, as illustrated in Figure E.1. Derating of transmission lines is the dominant climate change impact with the highest cost implications. Also, it can be seen that Manitoba and Saskatchewan are the provinces with the highest average electricity cost increase due to climate change induced impacts. By the end of the current century, the total cost of impacts of climate change induced on provincial electricity delivery systems will be about CAD$ 1 – 4.5 billion, based on the climate scenarios if no mitigation is undertaken earlier. Ontario, which has the largest power grid and most assets, will experience the highest cost burden, with around 25% of the total cost, although Ontario's rate impact remains lower comparatively.

Figure E.1: The Increase in Cost of Electricity in the Period 2096 – 2100 under High Emissions Scenario



Local/Municipal impact can deviate significantly from provincial averages for some of the climate events, particularly for events such as flooding and wildfires. Impacts are sensitive to population density, the value of assets on the ground, and local climate patterns.

The most significant climate change impact (more than 50% of combined impacts in all provinces) on electric power systems in Canada is the transmission line derating (temporary reduction of maximum available capacity) due to increased ambient temperatures. The main mitigation option to dampen the capacity loss due to increased ambient temperatures is considering the future climate change in transmission capacity planning and making regular transmission reinforcements. Transmission reinforcements could take between CAD$ 13.3 – 41.6 million annually in the next 80 years, depending on the climate scenario.

The temperature responsiveness of peak electricity demand is a major concern. In order to study this, a case study is developed to examine the temperature responsiveness of peak electricity demand of Ontario. The results show that climate change can potentially increase the demand for peak electricity generation and delivery capacity by 8 – 34% in Ontario by the end of the current century. It is prudent that the electricity system planners consider the impact of climate change on peak electricity demands to design electricity generation and delivery systems.

This analysis showed that climate change would exert pressure on electricity delivery and generation infrastructure on multiple fronts. Furthermore, those impacts will be exacerbated by the increase in peak elasticity demand due to climate change. The results also show that even if the emissions remain low, there will be upward pressure on electricity systems, challenging their ability to operate reliably and cost-effectively. Therefore, it is prudent that the electricity system planners consider the impact of climate change on electricity generation and delivery systems when designing electricity infrastructure. As illustrated in this analysis, down-scaled climate model results can provide valuable information to inform electricity infrastructure planning.

The results show that the main driver of the magnitude of physical impacts and costs is the CO_2 concentration in the atmosphere, as represented by different climate scenarios in this study. It is observed the total cost under the "High Emissions" scenario is around 4.5 times that of the "Net Negative Emissions" scenario. This observation emphasizes the importance of the Canadian and global climate change mitigation plans to ensure safe, reliable, and ultimately affordable critical infrastructure operations such as electric power systems.

Readers should note that while this analysis isolates the impact of climate change on Canada's electricity systems, it is not the only influencing factor. CERI has completed other studies[1] assessing future changes in the electricity grids. These include an impact assessment of electrification of transportation and other sectors, generation costs for decarbonization, the impacts of distributed generation, benefits and costs of increased provincial interties, and the evolution of battery storage. Together with this analysis, the sum of these reports shows an unprecedented challenge to manage the growth in Canada's systems, both technical and economic, to succeed in fostering an energy transition. Furthermore, the land-use footprint of such a growth in these systems will create a need for additional and innovative citizen consultations and regulatory decision-making.

[1] These studies can be found at the CERI website ceri.ca

Chapter 1 : Introduction

- **The warming trend in Canada is, on average, about double the magnitude of the global average**
- **Electricity infrastructure is designed by taking into account observed history may be vulnerable and experience outages and other physical impacts**
- **Using down-scaled climate model results, this study quantifies the magnitudes of the physical impacts of climate change on electricity systems in all Canadian provinces the period**

Climate change is unequivocal, and many of the observed changes are unprecedented over decades to millennia. The most well-known impact of climate change is the increase in temperature of the atmosphere and ocean. Globally, the surface temperature has risen about 0.8°C since 1880. According to the Intergovernmental Panel for Climate Change (IPCC) assessments, it is *extremely likely* that human activities caused most of the observed warming trend (Pachauri et al. 2014). According to Environment and Climate Change Canada (ECCC), both past and the future warming trend in Canada is, on average, about double the magnitude of the global average (ECCC 2019).

Along with the atmospheric and oceanic temperatures, climate change also increases the variability in weather patterns. The observed and projected changes include—but are not limited to—changes in precipitation patterns, changes in wind patterns, elevated risk of wildfires, more frequent occurrence of heat waves, stronger and frequent storms, and sea-level rise. Consequently, climate change is impacting the weather conditions in which the critical infrastructure systems—that includes the electric power systems—must operate (Burillo 2019). As our understanding of climate change evolves, studies that assess the climate vulnerability of critical infrastructure have emerged in Canada and other countries (Canadian Council of Professional Engineers 2008; CEA 2016; Fant et al. 2020; Larsen et al. 2008).

A reliable supply of electricity is critical for the functioning of modern societies. Trillions of dollars have been invested in the building and operation of electric power systems globally. Electric power systems consist of electricity generation, transmission, and distribution. Climate change can impact all sub-systems of the electric power systems. Furthermore, climate change and rising temperatures could change the electricity demand patterns, putting further stress on the electricity infrastructure. Table 1.1 summarizes some of the key climate change-induced events and their impacts on different components of electric power systems. To ensure system reliability due to natural events, planning and construction of infrastructure such as electric power systems take into account the climate by using several years of recent weather patterns (Burillo 2019). However, with prevailing climate change, the use of historical weather data to design electricity infrastructure is problematic because electric power system assets have decadal-scale lifespans. Climate projections can be used to gain insights into the electric power systems' vulnerabilities and inform investment and operations decisions.

The electricity sector is a vital part of Canada's economy. The electricity sector's contribution to Canada's economy is estimated to be about 2.5%. According to the Canadian Electricity Association (CEA), Canada's electricity sector is expected to spend approximately $350 billion between 2010 and 2030 to update ageing infrastructure with infrastructure projects across the country (CEA n.d.). Canada may face greater impacts than some other countries from climate change due to its geography. Therefore, it is prudent that our knowledge of climate change and future climate projections are used to inform electricity infrastructure investment and operations decisions for climate risk management and adaptation planning.

When considering the electricity sector, climate change can increase costs across all value-chain steps, including generation, transmission and distribution systems. On the other hand, there can be potential cost reductions. For example, precipitation changes may increase hydropower generation potential. The peak demand in the winter season could be reduced by an increase in ambient temperature. As summarized in Table 1.1, climate change impacts electricity generation include changes in resource availability and operating efficiencies, while impacts on electricity transmission, distribution, and infrastructure reduce efficiency and damage assets. Potential impacts vary by region and material importance. Costs can be increased due to damaged infrastructure, higher insurance premiums, water constraints, increased regulatory obligations, and legal liabilities. Also, revenues possibly decline through the increased frequency or duration of outages, reduced supply availability, and lower equipment efficiencies.

Table 1.1: Summary of Major Climate Change Induced Impacts on Electric Power System*

Climate Change Induced Event	Electricity Generation	Transmission System	Distribution System
Higher ambient temperature	Reduction in generation efficiency of thermal and solar photovoltaic generation, capacity derating	Capacity derating and higher line losses	Capacity derating and higher line losses, rapid equipment ageing
Precipitation changes	Changes hydropower generation capacity, lower cooling water availability for thermal generating units, lower generation efficiency due to higher moisture in solid fuels (e.g., biomass and coal)	Changes to vegetation management, damages to power lines from snow and ice	Changes to vegetation management, rapid ageing of wood poles, increased tower erosion
Increase in floods	Water inundation risk of equipment		Water inundation risk of equipment
Changes in wind patterns	Possible capacity reduction and higher variability of wind power, equipment damage	Equipment damage, changes to vegetation management	Equipment damage, changes to vegetation management
Increased fire risk (e.g., wildfires)	Equipment damage	Prolonged systems outages, equipment damage, changes to vegetation management	Prolonged systems outages, equipment damage, changes to vegetation management
Increase in electricity demand†	Possible need for peaking capacity	Increased congestion, possible need for capacity expansion	Higher system stress due to longer peak demand periods, higher maintenance requirements, possible need for capacity expansion

*The table is not an exhaustive list of climate impacts on electric power systems
†Increased demand is an indirect impact of higher temperatures and precipitation changes

A significant consideration in assessing the impacts of climate change on electricity transmission and distribution infrastructure is the rate of changes induced by climate change compared to the lifecycle of power system infrastructure replacement under "normal" conditions. The lifespan of some aspects of power system infrastructure can be up to several decades. For example, a large transformer's typical lifespan is about 40 years, and a new transmission line can take a decade to plan and permit (Beard et al. 2010). Thus, infrastructure design decisions made today will ultimately have to cope with weather conditions experienced several decades from now. In the US, ice, high winds, flooding, and lightning cause about 78% of major power interruptions to the power distribution system. A large fraction of interruptions result from extreme, low probable events (Fant et al. 2020). Thus, while short-term impacts are caused by weather, long-term impacts can be caused by climate induced reductions in the infrastructure lifespan and power line ampacity in addition to weather.

Several recent studies conducted under the auspices of the CEA and some electric utility companies have shed light on potential climate vulnerabilities of Canadian electricity infrastructure (Canadian Council of Professional Engineers 2008; CEA 2016). A survey conducted by the CEA revealed current issues in adaptation practices of CEA member companies. Findings in investment planning practices revealed a lack of diversity in investment planning, underestimated load change expectations, and low asset condition evaluation and renewal efforts. Current tools to support the integration of climate change into management practices and investment planning include the CEA's Climate Change Adaption Management Planning Guide, which outlines risk-based guidance framework and Engineers Canada's Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. A recent study by QUEST Canada assessed the impacts of climate change induced events on community-level energy infrastructure (MacKay, Nciri, and Timmins 2020). Through that study, QUEST reiterated the importance of community-level energy resilience plans to mitigate negative economic impacts from prolonged power outages and energy supply disruptions due to climate change impacts. Federal and municipal governments and system operators play an important role and are encouraged to engage stakeholders, develop and integrate climate data into planning, promote energy efficiency actions, and improve demand responses and flexibility.

Project Scope, Objectives, & Contributions

With the changing climate, the weather conditions under which the electricity infrastructure would operate are changing. Furthermore, once infrequent extreme weather events are projected to occur more often with greater strength. Therefore, electricity infrastructure designed by taking into account observed history might be vulnerable and experience outages and other physical impacts. Furthermore, changes in ambient conditions such as temperature and precipitation patterns may increase the system's losses and reduce usable capacity. These factors may impose unexpected costs on electric power systems. However, under current electricity rate structures, any costs associated with additional systems losses and responding to unplanned emergencies are, in general, recovered through the electricity rate base. In other words, all costs that would be borne due to climate change induced events will eventually be passed to electricity consumers. As such, it is plausible that climate change impacts will increase the price of electricity.

The future changes in weather patterns due to climate change and the evolution of electric power systems will vary considerably across Canada. As well, the impacts will vary in terms of complexity, magnitude, and frequency. An assessment of climate vulnerabilities and adaptation measures for the electric power systems must consider regional variations. That will require analysis that spans a vast spatial and temporal scale.

As discussed above, several studies have previously assessed the impacts of climate change on Canadian electricity systems. They make valuable contributions to our understanding of how climate change will impact the electricity infrastructure in Canada. There are a few knowledge gaps that require further assessment. Most previous studies have focused on past extreme events and costs associated with responding to them. The geographic scope of the previous studies has been narrow. Furthermore, there are gaps in assessments of electricity price impacts.

This study aims is to assess the cost of climate change impacts on the electric power systems in Canada and estimate the associated electricity retail price impacts. By building on previous studies, this CERI study contributes to filling some of those knowledge gaps. The main contributions of this study are as follows. The analysis is developed around three future climate scenarios.

1. Using down-scaled climate model results, this study quantifies the magnitudes of the physical impacts of climate change on electricity systems in all Canadian provinces between 2020 – 2100.
2. The physical impacts are then translated into economic costs and their contribution to average electricity prices in Canadian provinces.

Climate Scenarios

One of the main inputs used for this assessment is climate projections that predict the future weather conditions in Canadian provinces. Global climate models produce climate projections. Climate models are complex computer simulation models that can emulate the earth's climate system. Climate models are based on well-documented physical processes to simulate the transfer of energy and materials through the climate system (NOAA n.d.). They are used to predict changes in the climate and can be used to test our understanding of how the climate system will respond to changes in conditions.

An important condition that must be considered to predict the future climate is the past and future emissions of greenhouse gases (GHGs). Climate scientists use two sources of GHG emissions data. First, in the past, emissions inputs come from observations made at different stations around the globe.

Table 1.2: Summary of Representative Concentration Pathways (RCP)

RCP Scenario Name	Emissions Pathway	CO2 equivalent concentration (ppm)	Temperature anomaly relative to 1986-2005 (℃)	Scenario Name used in this study
RCP2.6	Decline	~490	1.5	Net Negative Emissions
RCP4.5	Stabilizing without overshoot	~650	2.4	Low Emission
RCP6.0	Stabilizing without overshoot	~850	3.0	-
RCP8.5	Rising	>1370	4.9	High Emissions

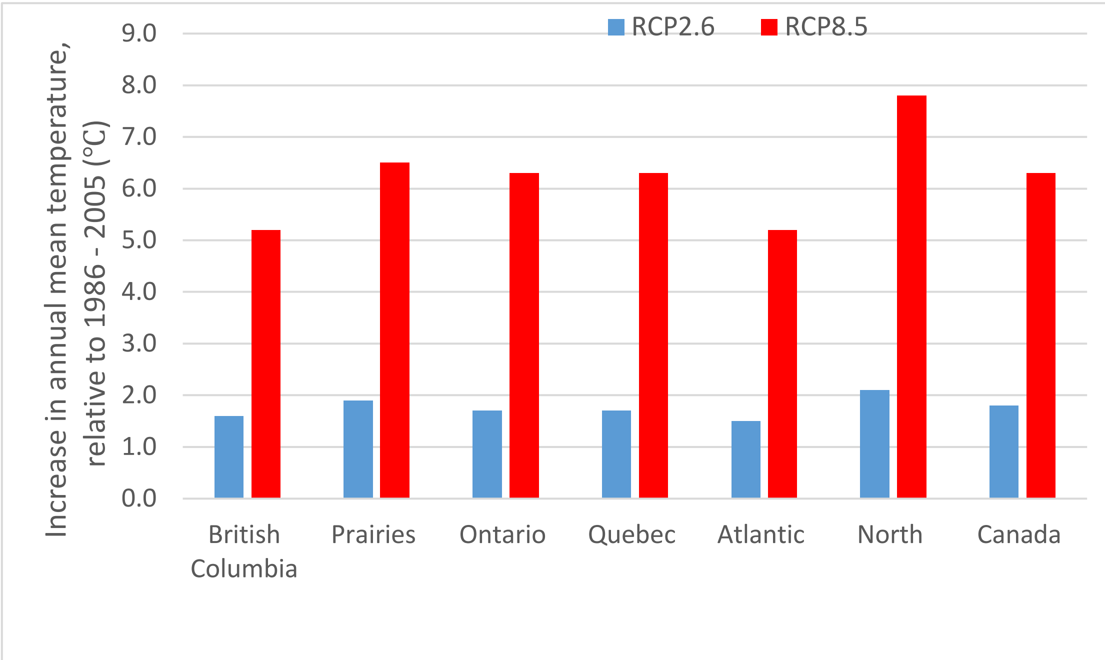
Source: OURANOS (2016)

Second, for the future, the evolution of greenhouse gases is obtained from what are called emissions scenarios (OURANOS 2016). Emissions scenarios are plausible alternative futures that are characterized by anthropogenic and natural activities. For example, how quickly the human population will grow, how land will be used, how economies will evolve, development of technology, implementation of GHG management policies, and the atmospheric conditions (and therefore, climate forcing) (NOAA n.d.). Current climate change and policy discourse are centred around four major emissions scenarios called Representative Concentration Pathways (RCP) developed under the IPCC's auspices. As summarized in Table 1.1 and Figure 1.1, RCPs provide time-dependent projections of atmospheric GHG concentration that result from alternative socioeconomic pathways. Each RCP reads to a different level of increase in global average temperature by the end of the current century (i.e., by 2100) compared to the reference period 1986 – 2005.

The future emissions pathway depends on actions taken by Canada and all other countries. For example, the global emissions trajectory would closely follow RCP2.6 if all countries implemented climate change mitigation efforts underlying the Paris Agreement. Determination of which emissions pathway would unfold over the next few decades is beyond the scope of this study. Therefore, this study is conducted under three RCP scenarios, namely RCP2.6, RCP4.5, and RCP8.5. Within this study, these scenarios are called "Net Negative Emissions," "Low Emissions," and "High Emissions," respectively. The use of three climate scenarios would produce insights into the range of plausible futures that would be observed in Canada between now and by the end of the century.

As summarized in Table 1.2, depending on the emissions scenario, the global average temperature will increase by 1.5 – 4.9 ℃. However, as shown in Figure 1.2., in Canada, the average temperature anomaly by 2100 is higher (1.8 – 6.3 ℃) than the global average and varies by region. Therefore, the impact of ambient temperature and other climate change induced events on the regional electric power sectors will vary. As the electric power systems in Canada fall within provincial jurisdictions, these regional variations must be considered by climate change impact assessments of electricity infrastructure.

Figure 1.1: Projected Change in Annual Average Ambient Temperature for Six Regions and all of Canada Area by 2081- 2100



Notes: Temperature change is relative to 1986 – 2005 period. The values shown in the figure corresponds to the median change in annual average temperature under RCP2.6 and RCP8.5.
Source: Data from ECCC (2019), Figure by CERI.

Climate projections produced by global climate models are generally too coarse regarding spatial and temporal resolutions to assess climate impacts at the electricity infrastructure level. For example, what would be the ambient temperature under which a certain electricity transmission line would operate in 2050 – 2055? Recent advancements in climate modelling have developed methods to down-scaled climate projections suitable for local and infrastructure scale climate vulnerability assessments. This study uses an ensemble of down-scaled climate projections developed by ClimateData.ca[2], covering all of Canada under the RCP scenarios considered for this study (Climatedata.ca n.d.).

Within each climate scenario, the electricity industry can adopt both mitigating and adoptive measures. Mitigating measures for this study is defined as any reactive action taken to minimize climate-related costs. This includes reinforcing existing infrastructure, maintenance cycle modifications, and repair or replace assets due to damages. Adaptive measures are defined as proactive actions taken to minimize mitigating measures and improve overall system efficiency. Adaptive actions include adopting new technology, electricity system preplanning for climate change, and supporting national low carbon

[2] Climatedata.ca is a collaboration between Environment and Climate Change Canada (ECCC), the Computer Research Institute of Montréal (CRIM), Ouranos, the Pacific Climate Impacts Consortium (PCIC), the Prairie Climate Centre (PCC), and HabitatSeven.

initiatives to reach net-negative emission scenarios. The cost assessments in this study have been conducted for mitigative approaches. Qualitative information on adaptative approaches has been discussed where necessary throughout the document.

Electricity System Infrastructure Scope

In terms of functionality, management, and ownership (in some jurisdictions), the electricity infrastructure can be split into three categories. The main categories are the generation infrastructure, transmission infrastructure, and distribution infrastructure (throughout this study, the latter two infrastructure systems are commonly referred to as the delivery infrastructure). The electricity infrastructure is built and maintained to satisfy the electricity demand of consumers in a given jurisdiction. The demand profile for electricity depends on the end-use electricity service demands of the consumers and the type of devices used by the final consumers. Electricity system operators use the generation and delivery infrastructure to satisfy consumer demand continuously.

Climate change would impact the electricity generation and delivery infrastructure and influence final consumers' electricity demand patterns. For example, when the ambient temperature is high, it is expected that the electricity used for space cooling services would increase. Electricity supply and demand must be matched within tight margins to maintain system reliability. Design and development of electricity generation and delivery infrastructure require long lead times. Electricity system planners would forecast the future demand to develop the electricity infrastructure. If unplanned, climate change-induced changes to electricity demand can put pressure on generation and delivery infrastructure. Therefore, a complete assessment of climate change impacts on electricity systems must include the impacts on generation infrastructure and delivery infrastructure and the influence on electricity demand.

This study primarily focuses on the climate change-induced impacts on electricity delivery infrastructure. Previous studies from Canada and other countries show that the delivery infrastructure would have the highest impacts due to climate change. In general, the costs associated with building and maintaining the electricity delivery infrastructure account for more than 50% of electricity rates paid by consumers. Chapter 2 describes the materials and methods used to assess the impacts on delivery infrastructure. Provincial level analysis results are presented in Chapter 3. The analysis results show that the local/municipal levels data can deviate significantly from the provincial levels data. Therefore, four municipal level case studies are presented in Chapter 4, illustrating the variations across localities.

A robust assessment of generation infrastructure requires spatially explicit and granular data on current and future electricity generation infrastructure in Canadian provinces and associated climate model results. The current study presents an assessment of generation assets and expected losses in various assets. A review of potential impacts is presented in Chapter 2, along with estimated impacts in Chapter 3. While the impacts on generation infrastructure seem comparatively small, a complete evaluation of generation infrastructure merits investigations if and when relevant data becomes available.

The impact on electricity demand due to the changes in ambient temperature is assessed as an illustrative case study in Chapter 5. The case study assesses the increase in peak demand in the province of Ontario due to climate change-induced stressors.

This study should be considered in conjunction with other CERI studies, including:

- Opportunities and Challenges For Distributed Electricity Generation in Canada
- Electricity Storage Systems: Applications and Business Cases
- Economic and Environmental Impacts of Transitioning to a Cleaner Electricity Grid in Western Canada
- Impacts of Carbon Management Policies on Canadian Electricity Prices
- A Comprehensive Guide to Electricity Generation Options in Canada
- Greenhouse Gas Emissions Reductions in Canada Through Electrification of Energy Services
- Economic and Greenhouse Gas Emissions Impacts of Alternative Transportation Scenarios for Canadian Cities

Together these studies document a challenging scenario for the development of Canada's electricity grids. Each analysis considers one element of this challenge. While the combination of these effects will be mitigated by other elements, the overall conclusion is an unprecedented build-out of Canada's electricity systems, along with significant cost implications.

Chapter 2 : Climate Change Induced Events and Analysis Methods

- **Climate change-induced events that can impact the Canadian electricity delivery infrastructure are identified**
- **Climate stressor response functions are developed to assess climate change impacts of electricity delivery systems**
- **Data unavailability limits the ability to conduct full electricity systems levels assessment of climate change impacts**

This chapter presents the details of the analytical framework developed for this study to assess the impacts on electricity infrastructure. One of the critical components of the framework is a set of stressor-response functions that will map climate change-induced events into physical impacts on electricity infrastructure. The chapter mainly describes the analysis framework for the electricity delivery infrastructure. This chapter also presents a review of impacts on generation systems.

There are two distinct types of climate change-induced events that would impact electric power systems. First, climate stressors that change continuously, such as temperature and precipitation. Second, there are intermittent climate events such as flooding and wildfire events. These intermittent climate events may be induced by changing temperature and precipitation.

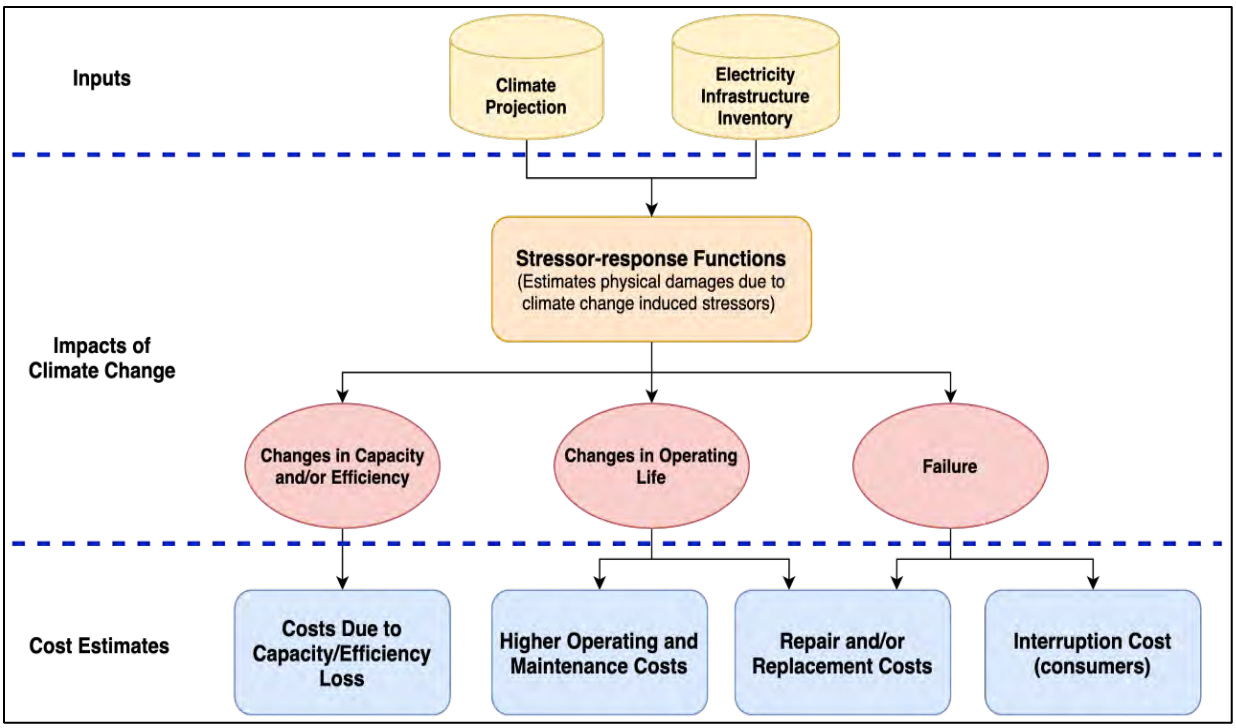
The study focuses on different climate stressors/events and the impact of each of these stressors on the electricity delivery infrastructure. Several climate stressors/events are identified for the analysis; Temperature change, precipitation change (rain and snow), wildfires, high winds, flooding, freezing rain, lightning, and storm surge/sea level rise (SLR). The climate change stressors assessed in the study have a significant impact on electricity infrastructure. However, other climate-change-induced impacts (e.g., such as ice storm frequency changes) would have significant impacts, and the current assessment excludes them for data limitations.

General Analysis Framework

To conduct the climate resiliency analysis, several generally accepted methods and industry protocols have been followed. In addition, some of these methods and protocols have been modified accordingly to Canadian conditions when necessary (Fant et al. 2020; Yue et al. 2013; CEA 2016; ECCC 2019; US Department of Energy 2016; PIVEC 2008).

We also recognize three different assets in the distribution/transmission system, distribution lines, wood poles, distribution transformers, transmission lines, and substation transformers that could be affected by the climate stressors. In addition, we recognize responses due to climate stressors and events as; capacity change, lifespan change, interruption to the power supply, and repair/replacement. All the responses are measured as cost items. It should also be noted that some of the responses may have a positive impact on the system rather than a negative impact, depending on how each stressor changes over a period of time (Fant et al. 2020; Yue et al. 2013; CEA 2016; ECCC 2019; US Department of Energy 2016). In this study, any positive changes have been analyzed. A summary of the analysis framework is illustrated in Figure 2.1.

Figure 2.1: Analysis Framework



The changes in each of the identified climate stressors under three different climate scenarios are assessed in the analysis. As discussed in Chapter 1, the three climate change scenarios are Net Negative Emissions scenario, Low Emissions scenario, and High Emissions scenario. These scenarios follow the IPCC RCP scenarios RCP2.6, RCP4.5, and RCP8.5, respectively. For each scenario, distinct representative concentration pathways (RCP) are identified in Table 2.1. Spatially down-scaled projected climate change data (e.g., temperature changes, precipitation pattern changes, etc.) required for the analysis are obtained from ClimateData.ca. The climate data used for the analysis was obtained in January - February 2021.

The potential impacts were determined based on literature and the implications of past impacts. The future costs were determined using baseline costs. The baseline used was the past 30 years (1991 - 2020), where data is available or explicitly described under each climate stressor. The analysis was conducted for the period 2020 – 2100 in five-year blocks.

Table 2.1: Climate Change Scenarios

Climate Change Scenario	RCP Scenario Name
High Emissions Scenario	RCP8.5
Low Emissions Scenario	RCP4.5
Net Negative Emissions Scenario	RCP2.6

The following sections describe the analysis methods used to assess the impacts of different climate change stressors.

Climate Change Stressors-Response Functions

There are many climate stressors. As explained in the previous section, how each of these climate stressors impacts the electricity system is different. Also, the types of assets impacted can vary by the climate stressor. Table 2.2 highlights different types of major electricity assets impacted by climate stressors

Table 2.2: Climate Stressor-Response Functions

	Asset Type						
Climate Stressor	***Transmission Lines***	***Substation/ Large Transformers***	***Distribution Lines***	***Distribution Transformers***	***Wood Poles***	***Generation Assets***	***Other Assets***
Temperature	√	√	√	√	√	√	
Rainfall					√	√	
Flooding	√	√	√	√	√	√	√
Wildfire	√	√	√	√	√	√	√
Vegetation Growth	√		√	√	√		√
Lightning	√	√	√	√			
Storm Surge/SLR*	√	√	√	√	√	√	√
High Winds	√	√	√	√	√	√	√
Freezing Rain	√	√	√	√	√		√

* Coastal Infrastructure only

A unique climate stressor–response relationship could be developed for each stressor-asset combination, translating to a unique climate stressor-response function. In this study, eight unique climate stressor-response functions were developed for quantitative analysis, and eight other climate stressor-response relationships were analyzed qualitatively, as discussed in the proceeding sections.

Air Temperature and Rainfall Effects

There are two significant effects caused by temperature changes, lifespan changes and capacity changes. Rainfall results in two major impacts, lifespan changes in wood poles and vegetation growth. Vegetation growth is discussed separately, as explained in the preceding subsection. Lifespan changes in wood poles result from rainfall and temperature and are modelled as a single effect (Fant et al. 2020; Stahlhut, Heydt, and Selover 2008; C. Wang, Leicester, and Nguyen 2008).

Capacity Changes in Distribution and Transmission Lines

Capacity change is one of the major physical effects of electricity transmission and distribution influenced by temperature. An increase in temperature can reduce the capacity. In general, most electricity systems would maintain a 10-12% capacity buffer. This buffer helps in sudden temperature events such as heat waves, which would increase both consumption and a capacity reduction in the electricity grid. Continuous increase in temperature as forecasted by climate change models will result in reducing the capacity buffer. Hence to maintain the same capacity buffer, continuous improvements are required. These improvements are mainly aimed at increasing capacity through capital investments.

The first step in this analysis is estimating the physical capacity change of the system. Using the method described by (Bartos et al. 2016), which describes the relationship between ampacity and temperature, we can estimate the future ampacity changes. Ampacity is proportional to capacity. By estimating the relative change in the future ampacity, the percentage of physical change can be derived. The values obtained can be converted to cost estimates assuming that increase in capacity requirement will drive capital investment in the distribution and transmission system.

This analysis estimates the investment cost based on current prices to reinforce existing distribution and transmission lines. The cost values used are $200,000 /km to add a new transmission line and a value of $12,500/km to add a new distribution line. These values are national averages and may vary project by project. A new transmission or a distribution line could cost as much as ten times the above value. Some of the available estimates indicate around $2 mil/km to replace an existing transmission line system (Oakville Hydro 2018; AESO 2016a; Manitoba Hydro 2013)

Lifespan/Capacity Changes in Transformers

Two main types of transformers were analyzed based on their size; distribution transformers and substation/large transformers. Both transformer lifespan and capacity can be impacted by ambient temperature.

The capacity and ambient temperature relationship has been modelled and studied by many researchers to develop empirical models. However, the agreement between models and estimation of values varies. In general, these models are fraught with uncertainty and apply only to certain local conditions and transformer types. Also, a common requirement for these models is the need for transformer-specific information (Fant et al. 2020; Sathaye et al. 2013). The literature suggests that transformer load capacity will remain above 100% until around 33°C (Xin Li et al. 2005). Canada's mean temperature values are expected to remain below 20°C throughout the century for all climate scenarios. Based on the above observations, capacity changes in transformers are not quantified in this study. Literature suggests that in warmer climates, such as in California, around 2-4% capacity change could be expected by the end of the century under high emission scenarios. However, it is unlikely that there can be a significant impact in Canada. We expect the impacts to be localized and limited to events such as sustained heatwaves.

Lifespan changes, on the other hand, is directly related to ambient temperature. Transformer cooling systems based on oil-based convective heat sinks develop "hot spots," which can damage the insulating paper that prevents short circuits. Warmer operating temperatures result in insulating paper ages faster and reducing the life of the transformer. The methods highlighted by (Stahlhut, Heydt, and Selover 2008; Sathyanarayana, Heydt, and Dyer 2009) estimate the transformer's lifespan reduction by using an empirical relationship between lifespan and ambient temperature.

For the estimate of rate and cost impacts, the current average replacement cost of a distribution transformer is used $5,000 per overhead transformer and $22,000 per pad-mounted transformer. If information is not available, all distribution transformers are assumed to be overhead transformers. Substation transformer costs are estimated for developing a new substation at an average value of $3,600,000. These values may vary largely depending on the size of the transformer (AESO 2016b; Manitoba Hydro 2013)

Lifespan Changes in Wood Poles

There are both transmission and distribution wood poles. The majority of distribution poles and lower voltage transmission towers are wood poles. There are situations where both distribution and low voltage transmission lines may occupy the same wood pole system. Hence, it becomes difficult to analyze distribution and transmission wood poles separately.

Wood pole lifespan is a function of ambient temperature and wet conditions, i.e., precipitation frequency, occurrence, and the gap between precipitation events. Woodpile life is modelled based on the fungi attack model as described by (C. Wang and Wang 2012) and used by (Fant et al. 2020).

The number of wood poles is estimated based on aerial maps and developing wood pole density for urban, rural, and suburban demographics. The results are calibrated based on available data. The cost of wood poles is based on data available in the public domain.

Vegetation Management

Canada maintains vegetation corridors of 3-75 m, depending on the size/capacity of the powerline. Vegetation management (VM) is conducted using several methods; herbicide application and trimming are the most common. Trimming and herbicide application are carried out in a VM cycle, usually ranging between 5-9 years. It has been reported that there is an increase in VM costs in recent years throughout Canada and the US. The VM cost increase could be due to climate change. In theory, VM cost changes are proportional to vegetation growth rate, whether it is an increased frequency of herbicide application or trimming (Manitoba Hydro 2019; Electric Energy Online 2006)

Climate change has two distinct interactive effects on vegetation growth, higher CO_2 concentration induced growth and high temperature-induced growth (Büntgen et al. 2019; Leahy 2019; Temme et al. 2015). Based on the literature, the following growth rate increases have been developed (Table 2.3).

Table 2.3: Vegetation Growth Rate Increment

	0 ^{0}C	**2 ^{0}C**	**4 ^{0}C**
RCP 2.6	0%	1%	2%
RCP 4.5	0%	1%	2%
RCP 8.5	1.6%	1.8%	2%

Calculating costs due to an increase in VM is based on temperature increment for each climate scenario. VM costs are assumed to be increasing relative to the vegetation growth rate. Current VM costs are estimated based on respective utility providers' websites and reports. These O&M costs could be increased VM cycle frequency, increased VM operations (labour, equipment, supplies etc.…). Vegetation-related interruption costs are not considered in the analysis, only the increment in O&M costs.

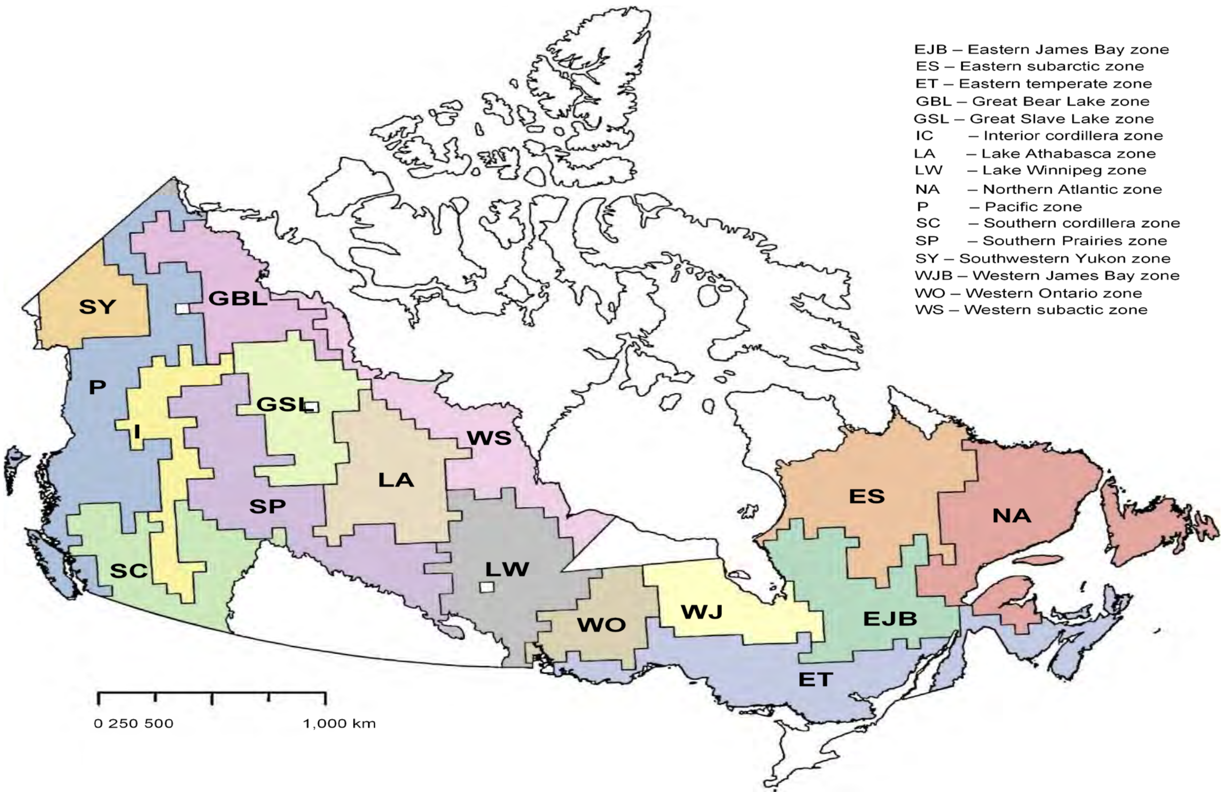
Wildfire Damages

Wildfires are recognized as one of the top two extreme climate events along with flooding. Wildfires are correlated to several other climate events, such as lightning, temperature, rainfall, change in forest cover, population growth. Research has shown that costs incurred due to wildfires can be correlated to area burned or a combination of wildfire frequency and spread days. CERI estimates the relative wildfire effect using wildfire frequency and wildfire spread days. The percentage increase in cost due to wildfire effects are calculated for each Homogenized Fire Zones (HFZ) (X. Wang et al. 2017; Natural Resources Canada 2015; Pechony and Shindell 2010; Boulanger, Gauthier, and Burton 2014; B.J. Stocks Wildfire Investigations Ltd 2013).

The baseline area burned estimation is based on wildfire areas burned between the years 1990 to years 2020. The baseline cost is based on more recent wildfire events. CERI uses wildfire costs in BC between 2008 and 2018 and the Fort McMurray wildfire in Alberta in 2017 as a proxy to calculate an average electricity cost of $85/ha. The cost includes cost due to capital equipment replacement (depreciated cost), increase in O&M, and income loss due to reduced demand and increased downtime. The final cost values are normalized for inflation. (National Forestry Database n.d.; Alberta Utilities Commission 2019; 2020; BC Wildfire Service 2020)

There are 16 HFZs (homogenized fire zones) in Canada, as presented in Figure 2.2. However, there are also areas such as southeastern AB, Southern SK, some southwest parts of MB, and Southern ON, which do not belong to an HFZ. There is no adequate data to suggest a climate-related relationship in these regions to estimate future costs due to wildfire events. Hence, wildfire costs in these regions were assumed to not change with the changing climate.

Figure 2.2: Homogenized Fire Zone (HFZ) Map



Source: (X. Wang et al. 2017)

Flooding Damages

Flooding-related damages have received significant attention in the last decade. Floods are correlated to several other climate events, such as temperature, precipitation, change in forest cover, river path changes, soil erosion, and man-made structures.

Flooding is categorized based on the frequency of occurrence, assuming that more severe events occur less frequently. Two of the most commonly used flood events are 100-year flood events and 250-year flood events, where a 250-year flood event is more severe than a 100-year flood event. In our analysis, flooding is analyzed based on the changes to the 100-year flood event frequency (Gaur 2017). Changes to the 100-year flood frequency by Gaur (2017) have been used for the analysis. However, the data available are for the nine major ecozones for Canada. According to the authors, there is considerable uncertainty in data.

The changes in flood frequency for different provinces can be estimated using the values by Gaur (2017). The baseline costs are calculated based on the average cost from flood events from the year 1970-2020. The costs are based on Disaster Financial Assistance Arrangements (DFAA) payments by the federal government for disaster events (Environment and Climate Change Canada 2009; Parliamentary Budget Officer (PBO) 2016). The costs are inflation-adjusted. We use a larger sampling time frame for flood baseline costs to increase the sample size since flooding events are not as frequent as other climate events.

Flooding analysis does not consider coastal flooding due to sea-level rise and storm surges. Different environmental factors drive coastal flooding due to sea-level rise and storm surges. Sea level rise and storm surges are analyzed separately.

High Wind Effects

High winds include high mean wind speeds and wind gusts. Wind-driven extreme events such as storms and hurricanes are not analyzed under this category. These events are driven by other climate factors and should be modelled separately.

A qualitative and quantitative approach has been followed to analyze the impact of wind effects. The percentage increase in mean wind speeds and wind gust speeds are estimated for each climate scenario.

Lightning

Predicting lightning in the future is based on a few factors, such as precipitation and the convective available potential energy (CAPE). Most scientists agree on a linear relationship between the product of precipitation and CAPE with lightning frequency (Romps et al. 2014). However, there is reasonable doubt that the relationship may not be valid for localized regions (Finney et al. 2018).

A 12% increase in lightning frequency for the years 2079 - 2088 for each 1°C temperature rise has been determined by (Romps et al. 2014). The values are comparable to details published by (Wotton, Logan, and McAlpine 2005) for Ontario.

Lightning causes interruptions to the power supply and is estimated as the cost of an interruption. Lightning-related wildfire costs are already considered under wildfire modelling. Lightning interruption costs are hard to estimate; hence the cost is presented only as an annual percentage increase.

Freezing Rain

Freezing rains can cause a significant impact on the electricity system. Freezing rain studies for Canadian conditions are limited. For this analysis, existing data from the literature to qualitatively determine the potential impact of freezing rain on Canada's electricity system is used (Lambert and Hansen 2011; Cheng et al. 2007).

SLR/Storm Surge

Sea Level Rise (SLR) and storm surges are two climate-related phenomena that are correlated. However, many other factors contribute to storm surges other than SLR, such as wind conditions, wave size, tidal patterns, isostatic rebound, and coastal geography (Stocker et al. 2013; Wahl 2017; US Department of Commerce n.d.).

The main effect of SLR is a reduction in shoreline or having to move infrastructure inwards gradually. The vertical allowance is the parameter that is directly derived from SLR. Vertical allowance is defined as the level or line where infrastructure has to be moved from the current coastline to maintain the same risk levels (Bedford Institute of Oceanography n.d.; Zhai et al. 2015). Hence, there is a direct correlation between vertical allowance and associated risk from climate change.

Many other factors also contribute to estimating exact risk and cost values from climate change. Two of the main factors are the severity and frequency of storm surge events (Zhang and Sheng 2013; Treasury Board of Canada Secretariat n.d.). A qualitative risk assessment is conducted for SLR and storm surges by carefully evaluating the available literature and data.

The current frequency and severity of storm surges are based on existing information (Treasury Board of Canada Secretariat n.d.) and, where data is not available, it was estimated based on the closest geographically available data. In addition, based on literature, the severity and frequency of storm surges are defines as follows (Treasury Board of Canada Secretariat n.d.).

Storm Surge Severity Definitions

- High Severity – Significant Damages to property and infrastructure, significant impact on power supply over a region or regions, extreme erosion and damages to base/foundations of structures.
- Medium Severity – moderate damage to property and infrastructure, power supply impacted but restored without requiring disaster management services, moderate erosion that reduces the stability of the structures but not the immediate use.
- Low Severity – In general, limited to low-level erosion and infrastructure access issues. No impact on power supply or major repairs.

Storm Surge Frequency Definitions

- High Frequency – Events occurring several times every year
- Medium Frequency – Events occurring at least once every year
- Low Frequency – Events occurring once every few years

In addition, storm surge events can be measured by the occurrence of 10- or 50-year events, similar to inland flooding. 50-year events cause more damages and cost more (Natural Resources Canada 2010) compared to 10-year events. However, flood event data is limited to local regions and academic case studies. This creates challenges for a comprehensive national assessment.

The analysis follows a 3-step method: the change in vertical allowance is determined to assess the change in risk levels from SLR; the severity and frequency of storm surges for the selected city/municipality/population center is determined, and the presence of electricity infrastructure within the vertical allowance as an infrastructure density measurement is determined.

The severity, frequency, and infrastructure density are used to determine the risk level at a municipal/city level by giving equal weights to the three parameters. This analysis is only conducted at a coastal city/municipal level, where data is available.

Snowfall and Snow Related Events

No additional cost is expected due to changes in snow accumulation. Few factors contribute to this conclusion; snow accumulation does not seem to affect the functionality of the infrastructure, and the amount of snow accumulated is expected to reduce in the future due to rising temperature levels. The other extreme snow events, such as snowstorms, need to be modelled separately. However, details on extreme snow events are limited. Hence, the extreme snow events are not analyzed at this stage.

A Review of Climate Change Impacts on Electricity Generation

Changes in the climate can significantly strain power generation. Due to the nature of climate change and the multiple components contributing to the power output of generation plants, there is a large degree of uncertainty on how climate change will impact power generation in Canada. Therefore, this section discusses the potential impacts of climate change effects on power generation in Canada, specifically for natural gas-fired simple-cycle, natural gas-fired combined-cycle, hydroelectric, nuclear, wind, and solar technologies. These technologies are the dormant current and future electricity generation technologies in Canada.

Natural gas-fired simple-cycle turbines are impacted by ambient conditions, including humidity, temperature, and pressure. High atmospheric humidity lowers the efficiency of cooling systems while ambient temperature and pressure immediately impact gas turbine performance, including the efficiency and power output. It has been reported that temperature increases linearly inhibit efficiency and power output. A 60°F (15.6°C) increase in ambient temperature results in a 1-2% reduction in efficiency and a 20-25% reduction in power output (Loew et al. 2020). However, considering the current predictions of changes in the temperature, climate change will likely have minor impacts on the total capacity and cost of simple-cycle turbines.

Furthermore, turbines are designed to operate in changing temperatures from both daily and seasonal variations. It is believed that temperature changes from climate change can be accommodated within the existing design of turbines. It is anticipated that temperature changes from climate change will have minimal impact on simple-cycle turbine power output and efficiency.

For combined-cycle natural gas plants, the cooling system is the main determinant of the technology susceptibility to meteorological conditions (Loew et al. 2020). Unlike simple-cycle natural gas plants, combined-cycle natural gas plants have steam turbines that require further cooling. The cooling system is particularly vulnerable to higher ambient temperatures and humidity compromising generation capacity. The design of the cooling system plays an important role in how capacity will be reduced in response to temperature changes.

The increase in the air temperature entering the combustion chamber also reduces the combined cycle of natural gas plant efficiency as oxygen content decreases with temperature increase. Higher ambient temperatures also result in higher pressures impacting the steam turbine outlet and reducing the power plant performance (Petrakopoulou, Robinson, and Olmeda-Delgado 2020).

Natural gas plants are also susceptible to efficiency reductions from cooling water temperature changes, overall temperature changes, and pressure increases (Loew et al. 2020; Petrakopoulou, Robinson, and Olmeda-Delgado 2020). Capacity is reduced in thermoelectric power plants by 5% with a 1.5°C increase in water temperature, 10% for a two°C increase, and 15% for a three°C increase. Efficiency is reduced by approximately 0.6-0.7% and 0.5-0.6% per 10°C ambient temperature increase for recirculating cooling systems and once-through cooling systems, respectively. A 10°C temperature increase also increases steam turbine outlet pressures by 43-48%, reducing efficiency by 0.5-0.7% for combined-cycle plants with a recirculating cooling system.

Water shortages brought on by climate change must also be considered for systems that rely on significant amounts of water for cooling (Loew et al. 2020). Technologies such as recirculating towers, dry cooling systems, and hybrid cooling systems should therefore be considered in place of once-through cooling systems in areas where water supplies are threatened. However, the effects of climate vary between different technologies. Once-through cooling systems may be impacted less by air temperature and humidity, but the technology is being phased out due to the environmental impacts of once-through cooling.

It is anticipated that rising air temperatures will minorly impact the capacity and efficiency of combined-cycle natural gas generation if cooling systems are properly designed. Under RCP4.5 and RCP8.5 scenarios, temperature and humidity conditions by the middle of the century are not significantly different (Loew et al. 2020). However, due to climate recirculating system discrepancies between locations, it is predicted that plants east of the Rocky Mountains will experience greater loss capacity than plants in western regions.

Temperature-related stresses also impact hydroelectric power systems, water availability, operational modifications, and extreme weather such as floods and droughts brought on by climate change (Wilbanks, et al., 2008). Canada, however, has an uneven distribution of water which is expected to further deviate as a result of climate change. Findings indicate hydroelectric generation potential in Canada will increase in northern regions and decrease in southern regions. For example, studies suggest that in the Great Lakes, lower water levels are predicted, resulting in lower hydroelectric power generation in addition to experiencing impacts to municipal water supply, natural ecosystems, and recreational activities (Natural

Resources Canada 2009). With increasing water flows, however, other risks also increase, including storms, floods, and sediment loading, which can compromise energy generation.

As flows originate from glacier covers and mountains in western Canada, temperature changes will likely result in shorter ice seasons and more frequent midwinter break-ups, which present both opportunities and challenges to hydroelectric power generation. In addition to availability, climate change is also expected to impact water resource demands. In the summer months, flow levels are expected to reduce compromising hydroelectric generation potential while the frequency of heatwaves is expected to increase, resulting in more energy used for cooling. Furthermore, institutional changes also impact hydroelectric power production as water resource management practices limit water use. The Niagara River Treaty, for example, allocates water between various uses to preserve the Niagara Falls scenery. This inhibits hydroelectric power generation from adapting to low flow conditions.

Overall, it is expected that Canada will gain a net increase in hydroelectric power production (Concordia University, 2019). Quebec and Ontario may experience increases in hydroelectric power, and Alberta and British Columbia may experience decreases. Quebec may see power outputs increase by as much as 15% in the summer months and 8% in the winter months. In contrast, British Columbia, Alberta, the Northwest Territories, and Nunavut may see hydroelectric power potential drops of up to 10% in certain months. Another province of particular interest is Manitoba, where hydroelectric power makes up most of the province's energy production (Cai, Huang, Tan, & Liu, 2011). Manitoba is independent of the influences of mountain ranges and large bodies of water and is generally flat in the landscape resulting in sensitivities to climate change. Potential climate change impacts include increases in precipitation rates, increases in extreme event frequency, and longer dry periods. However, it is uncertain to what extent these impacts will impact hydroelectric power generation.

Nuclear power generation is also threatened by climate change. The most significant impacts of climate change are power plant cooling and water availability (Wilbanks, et al., 2008). Nuclear power plants currently require significant amounts of water for cooling, making them particularly vulnerable to changes in the water supply. As a redistribution of water is expected due to climate change, power plants will need to adapt to anticipated changes in their respective locations, as discussed above. European data sets revealed that increases of 1°C reduce nuclear power thermal efficiency, reducing supply by approximately 0.5% (Linnerud, Mideksa, & Eskeland, 2011). Additionally, during droughts and heatwaves, cooling restraints, regulations, and water accessibility may result in production losses of over 2% with a 1°C increase in temperature.

Wind power climate impact mechanisms include wind resource changes in intensity and duration and damage from extreme weather (Wilbanks et al. 2008). Climate change predictions indicate that some areas will experience an increase in wind intensity and frequency while other areas will experience a decrease. Overall, increased variability in wind patterns is expected. Due to the uncertainty in the variability, it is hard to predict future patterns and intensity for generation and dispatch planning. These changes have a significant impact as the energy output is a function of the cube of the wind speed. Currently, there are significant discrepancies between wind pattern predictions. The Hadley Center model indicates minimal decreases in average wind speed in America, while the Canadian model suggests decreases of 10-15% by 2095. Such a decrease would result in a 30-40% decrease in wind power generation. Decreases are predicted to be more significant in the summer of northern regions of the US after the year 2050. In Ontario, climate modelling indicates a decrease in wind speed of up to 5% in southern regions between the present and 2071-2100 (Yao, Huang, and Lin 2012). Wind predictions are limited for the rest of Canada, which suggests more effort is needed in developing climate data with respect to the wind (ECCC 2019).

The future potential of solar power generation is also of particular interest in Canada. Key climate impact mechanisms for solar include insolation changes and damage from extreme weather (Wilbanks et al. 2008). One study suggested that due to increased cloud cover, solar resources could reduce up to 20% by the 2040s throughout the US and more so in the west. Globally, a 2% decrease in solar radiation is predicted, which could decrease solar cell output by up to 6%. Additionally, solar photovoltaic electrical generation efficiency reduces with an increase in temperature (Penmetsa and Holbert 2019). An increase of 1°C to 5°C can decrease the efficiency by 0.4-2% for a cell with a reference efficiency of 15%, resulting in a reduction of output power. If a temperature increase of 1.6-6.6°C is reached by the end of the century, the maximum efficiency loss would be about 3%. This value could be lower if cooling from wind is considered. However, stronger winds could deposit debris onto equipment blocking solar radiation or causing equipment damage (Solaun and Cerdá 2019).

Furthermore, greenhouse gases and aerosols in the atmosphere can also decrease solar radiation on a localized level (Wilbanks, et al., 2008). This threat can be attributed to anthropogenic activity but is difficult to quantify due to its complex nature (Solaun and Cerdá 2019). Increases in particles such as dirt, dust, and snow resulting from climate change would also reduce the solar energy output.

Another anticipated effect of climate change is the increase in the occurrence and duration of extreme weather events, including flooding, cold weather, storms, and wildfires (Ward 2013). Such events can damage infrastructure, significantly impacting all generation technologies. As such, generation plants may implement hardening measures, among other methods, to reduce impacts.

Climate change imposes potential impacts on all energy generation technologies, as explored above. Increasing temperatures, changing pressures and wind patterns, and the changes in water resources present new challenges and, in some cases, opportunities to existing technologies. However, a common theme between technologies is the limited data of climate change impacts for Canada. This suggests that a greater need for assessing local climate change impacts on electricity generation is required for planners to adapt to anticipated changes. While a degree of uncertainty is inevitable, appropriate planning may be crucial in maintaining Canada's power supply to meet growing demand.

Geographic Coverage of the Analysis

The analysis was conducted at three different geographic levels, namely, National, Provincial and Municipal. Municipal evaluations are limited to data availability and applicability of models. In addition, localized effects such as Storm Surge/SLR were evaluated at only the municipal level. Provincial-level analysis was carried out by identifying several different zones in each province, based on climate zones and infrastructure distribution. The national analysis is the cumulative results from the provincial analysis. The analysis levels for each stressor-response relationship are illustrated in Table 2.4.

Table 2.4: Stressor-Response-Infrastructure Analysis Structure

Stressor	Response	Impacted Infrastructure	Municipal Level	Provincial Level	National Level	Cost Assessment
Temperature	Capacity Loss	Distribution lines	✓	✓	✓	✓
		Transmission lines		✓	✓	✓
	Lifespan Reduction	Distribution transformers	✓	✓	✓	✓
		Substation/ Large Transformers		✓	✓	✓
	Capacity/Efficiency Reduction	Thermal/ Nuclear Generation Assets		✓		
Precipitation	Capacity Change	Hydropower Generation Assets		✓		
Temperature/ Rainfall	Lifespan Reduction	Wood poles		✓	✓	✓
Flooding impact	Capital, O&M cost, loss of income	All Infrastructure	✓	✓	✓	✓
Wildfire impact	Capital, O&M cost, loss of income	All Infrastructure		✓	✓	✓
Vegetation management cost	O&M Cost	System Impact		✓	✓	✓
Lightning interruptions	Interruptions Cost	System Impact	✓	✓		
Storm Surge/SLR	Capital, O&M cost, loss of income	Coastal Infrastructure	✓			
High winds	Capital, O&M cost, loss of income	All Infrastructure		✓		
Freezing rain	Capital, O&M cost, loss of income	All Infrastructure		✓		

Note: All/coastal infrastructure includes generation, transmission, and distribution assets where applicable

Chapter 3 : Impacts on the Provincial Electricity Systems

- **The magnitude of climate change impacts varies by climate scenario, province, and type of asset**
- **Derating of transmission lines is the dominant climate change impact with the highest cost implications**
- **Manitoba and Saskatchewan are the provinces with the highest average electricity cost increase due to climate-change induced impacts**
- **By the end of the current century, the total cost of impacts of climate change-induced on provincial electricity delivery systems will be about CAD$ 1- 4.5 billion**

This chapter presents and discusses the key results of the climate change impact assessment on electricity infrastructure in Canadian provinces.

Capacity Change – Physical Impacts

The capacity change was estimated based on the methods discussed in the previous chapter. The capacity change was evaluated as a percentage of present ampacity. A positive change in ampacity percentage represents a capacity reduction. The evaluation was conducted for all potential line sizes and conductor types. There are three main conductor types used in both transmission and distribution lines: aluminum conductor steel-reinforced cable (ACSR), aluminum conductor composite core (ACCC), aluminum conductor steel supported (ACSS). ACSR is the most common type used and is more susceptible to temperature changes. The capacity (measured as ampacity) changes for ACSR cables under different climate scenarios are illustrated in Figure 3.1, Figure 3.2, and Figure 3.3.

Figure 3.1: Change in Ampacity in ACSR Power Transmission Cables – Net Negative Emissions Scenario

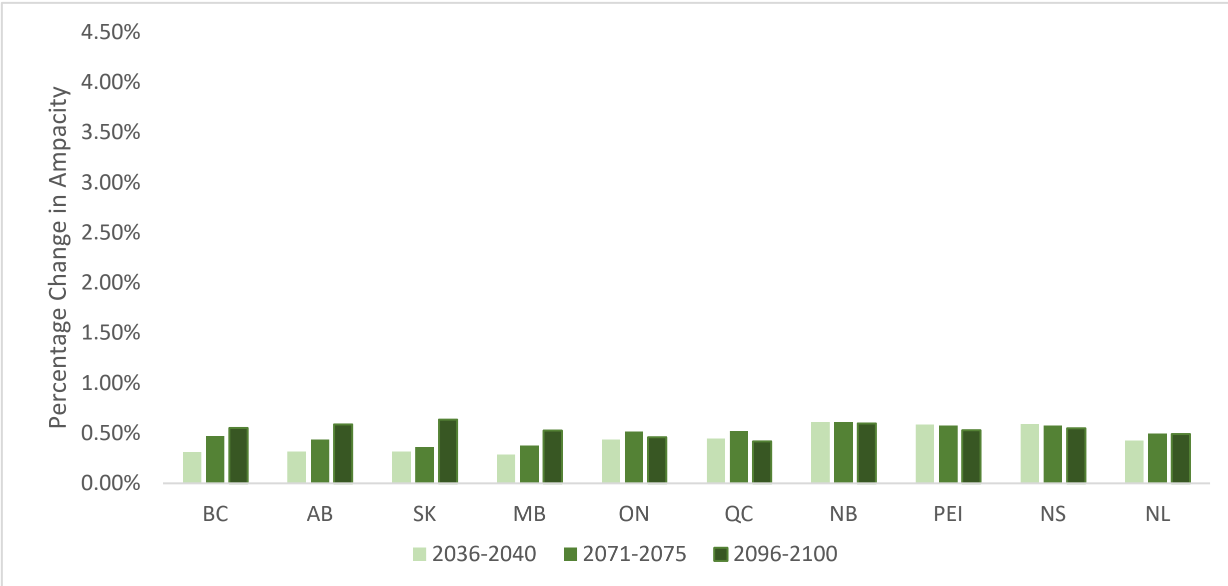


Figure 3.2: Change in Ampacity in ACSR Power Transmission Cables – Low Emissions Scenario

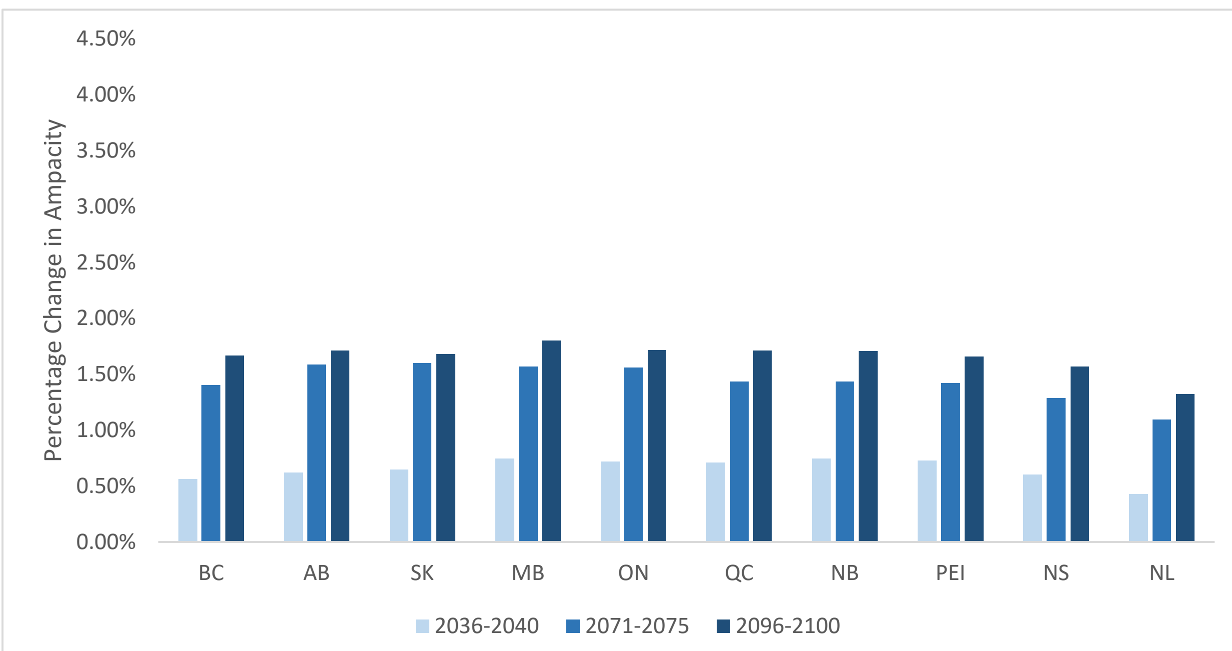
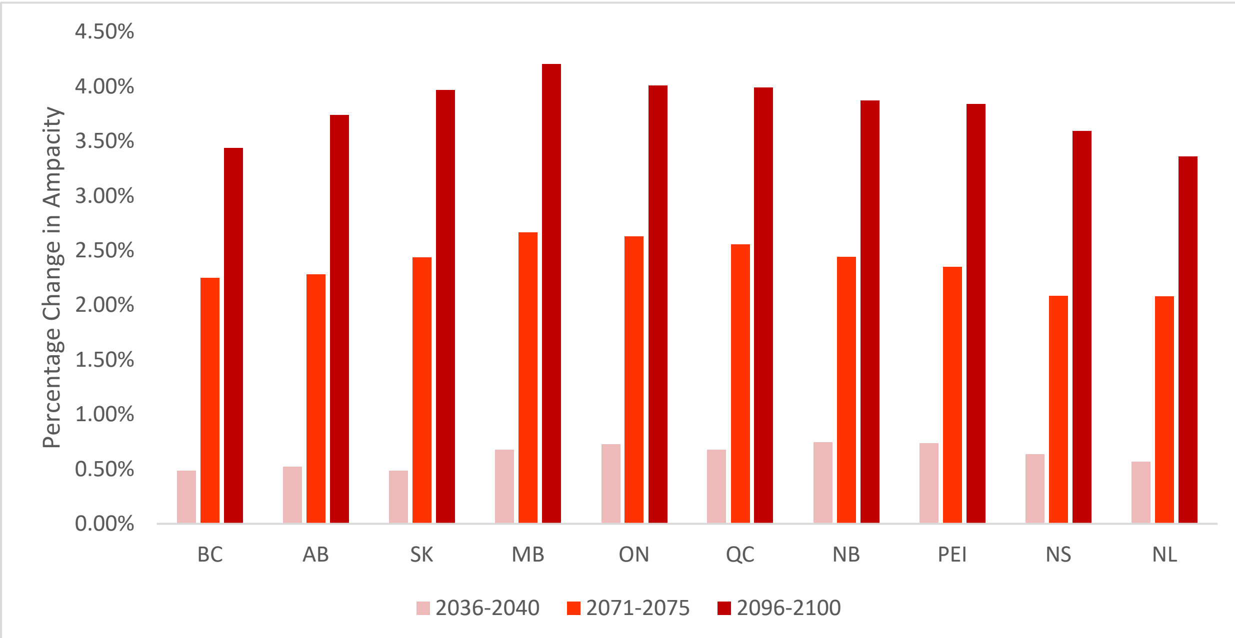


Figure 3.3: Change in Ampacity in ACSR Power Transmission Cables – High Emissions Scenario



High Emissions scenario results in a reduction of more than 4% of ampacity in MB, with other provinces showing similar results. As expected, the ampacity reduction increases with time. In the high emission scenario, a 4% increase in the transmission and distribution capacity system is required by the end of the century. The low emission scenario still yields a 2.5% reduction in capacity. All three scenarios suggest there need to be capital investments to support climate change-induced capacity reduction.

Provincial Cost Impact Analysis

Capacity Change in Distribution and Transmission Lines

Transmission lines

As discussed above, the physical impacts result in a capacity reduction in transmission lines. The cost impacts are also sensitive to the infrastructure density, i.e., amount of transmission lines in each region. The cost impact in each province has been estimated per kWh as illustrated in Figure 3.4, Figure 3.5, and Figure 3.6. The values represent the increase in residential rates of electricity at 2020 electricity prices.

Figure 3.4: Years 2036-2040 Annual Cost of Electricity Increase Due to Transmission Line Capacity Reduction

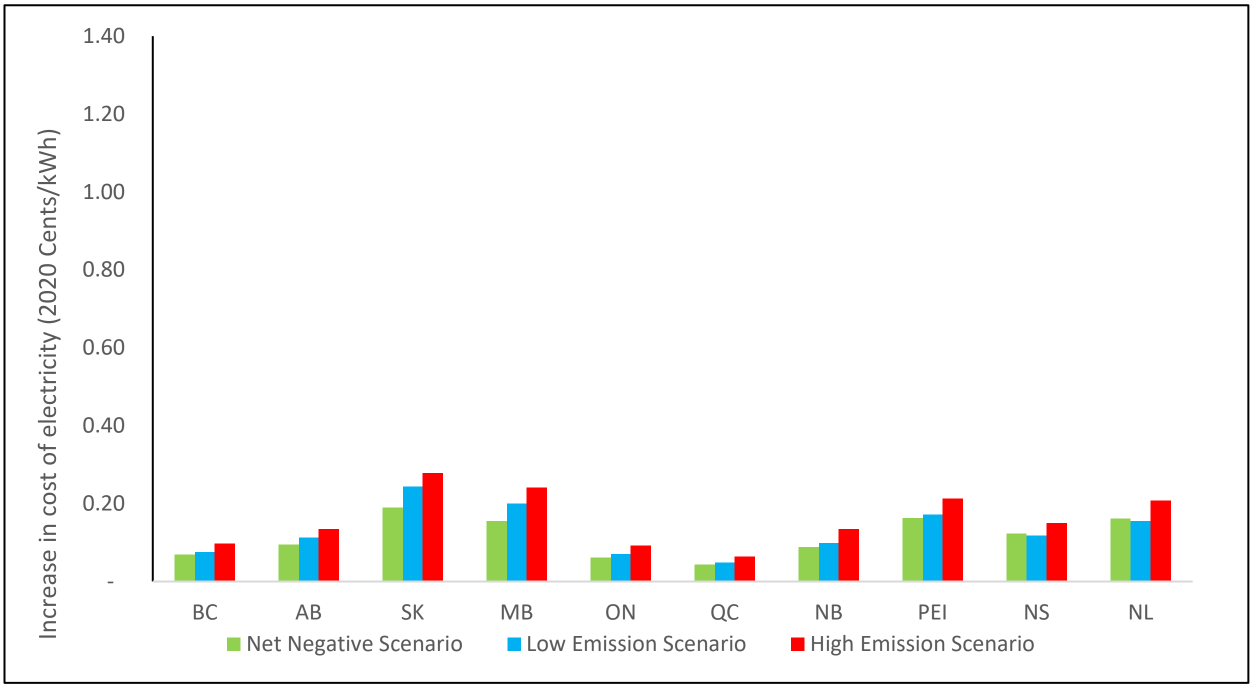


Figure 3.5: Years 2071-2075 Annual Cost Impact Due to Capacity Reduction in Transmission Lines

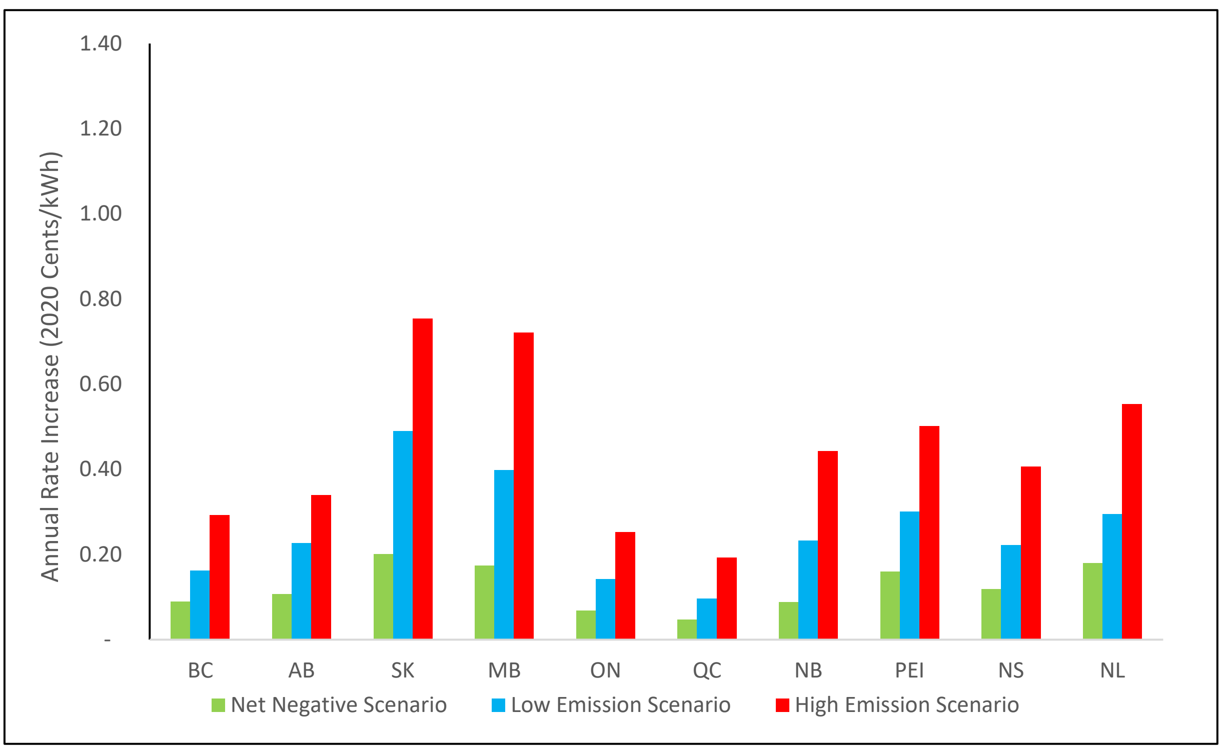
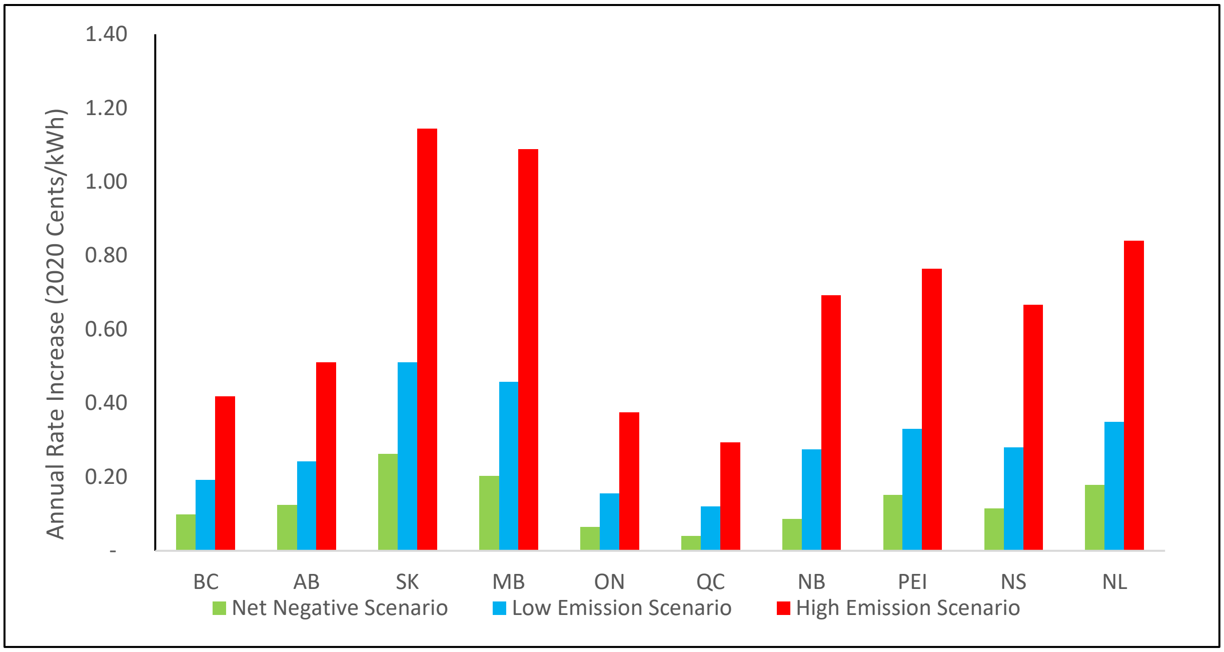


Figure 3.6: Years 2096-2100 Annual Cost Impact Due to Capacity Reduction in Transmission Lines



As expected, there is an increase in the cost of electricity for both high and low emission scenarios. The Net Negative Scenario shows a minimum or no increase in electricity cost. The highest increase is seen in SK and MB. Both these provinces have most of their assets in the southern regions, where it is more susceptible to temperature changes, resulting in a higher impact. Atlantic provinces also show relatively higher values. ON, QC, BC, and AB have the largest transmission asset sets; however, these four provinces seem to be the least impacted.

Distribution lines

As expected, cost increases due to distribution line capacity losses is relatively similar to transmission line capacity impacts. SK showed the highest impact in terms of cost incurred. Southern SK is expected to see a significant rise in temperature under the high emission scenario, with about 6 ^{0}C. Also, almost all of SKs distribution lines are in this region, resulting in a significant system-wide impact on electricity rates. The expected rise in electricity prices at retail rates is presented in Table 3.1.

Table 3.1: Expected Cost of Electricity Increase Due to Capacity Loss in Distribution Lines (2020 cents/kWh)

Province	Net Negative Scenario			Low Emission Scenario			High Emission Scenario		
	2036-2040	2071-2075	2096-2100	2036-2040	2071-2075	2096-2100	2036-2040	2071-2075	2096-2100
BC	0.01	0.01	0.02	0.01	0.02	0.03	0.01	0.04	0.06
AB	0.03	0.04	0.04	0.04	0.08	0.09	0.05	0.12	0.18
SK	0.11	0.12	0.15	0.14	0.27	0.29	0.16	0.41	0.63
MB	0.06	0.06	0.07	0.07	0.13	0.15	0.08	0.24	0.36
ON	0.02	0.02	0.02	0.02	0.04	0.05	0.03	0.08	0.12
QC	0.01	0.01	0.01	0.01	0.03	0.03	0.02	0.05	0.08
NB	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.01	0.02
PE	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.03	0.04
NS	0.04	0.04	0.04	0.04	0.06	0.08	0.05	0.12	0.19
NL	0.02	0.02	0.02	0.01	0.03	0.03	0.02	0.05	0.07

Overall, both transmission and distribution line capacity changes have an impact on electricity prices. The impacts are felt more in provinces with higher temperature increases and where the assets are located. For example, Southern ON will see a higher absolute temperature than Southern SK under all climate scenarios. However, the relative temperature increase is higher in Southern SK (6 – 7 ^{0}C), resulting in a higher impact in the region. A similar temperature rise is expected in Southern AB. However, AB's distribution and transmission assets have a bigger spread, and a significant amount of assets are in other less affected central and northern regions. Hence the rate impact is much less in AB than in SK. MB shows similar behaviour to SK, where most of its assets are located in Southern regions.

The Atlantic provinces are expected to see a relatively higher impact on the transmission system but a lesser impact on the distribution system. This is mainly due to the fact that there is a significant amount of transmission assets on the ground in these locations compared to its population. On the other hand, lower population density results in lower amounts of distribution assets. In addition, factors such as the location of generation assets and requirements of inter-provincial and inter-state transmission corridors have resulted in higher amounts of transmission assets.

Transformer Life Span Reduction

Substation/Large Transformers

Transformer lifespan reduction shows a relatively similar trend to power lines. As expected, a higher impact is seen on locations with higher temperature rises and higher amounts of assets. The highest impact is seen in MB, ON, and Atlantic Canada, as seen in Figure 3.7, Figure 3.8 and Figure 3.9. This trend was similar to transmission lines. Southern MB, Southern ON and Atlantic Canada are expected to see significant temperature rises during this century (5-8 ^{o}C), which directly contributes to lifespan reduction in transformers.

Figure 3.7: Years 2036-2040 Annual Increase in Cost of Electricity Due to Substation/Large Transformers Lifespan Reduction

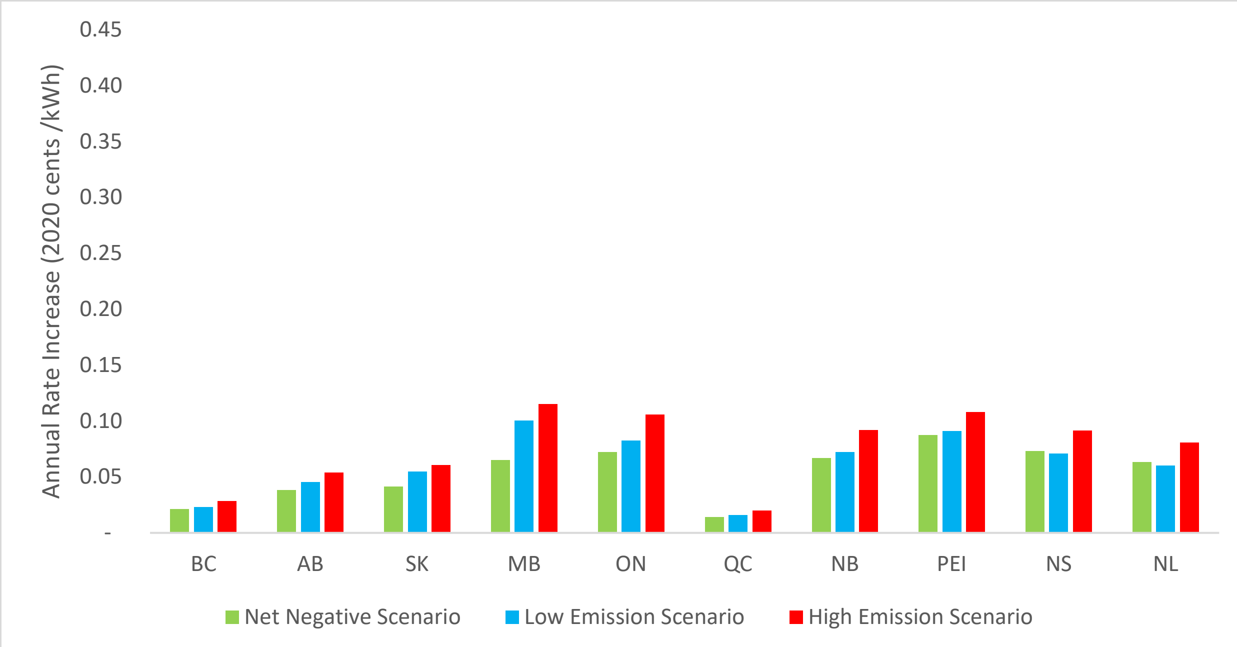


Figure 3.8: Years 2071-2075 Annual Increase in Cost of Electricity Due to Substation/Large Transformers Lifespan Reduction

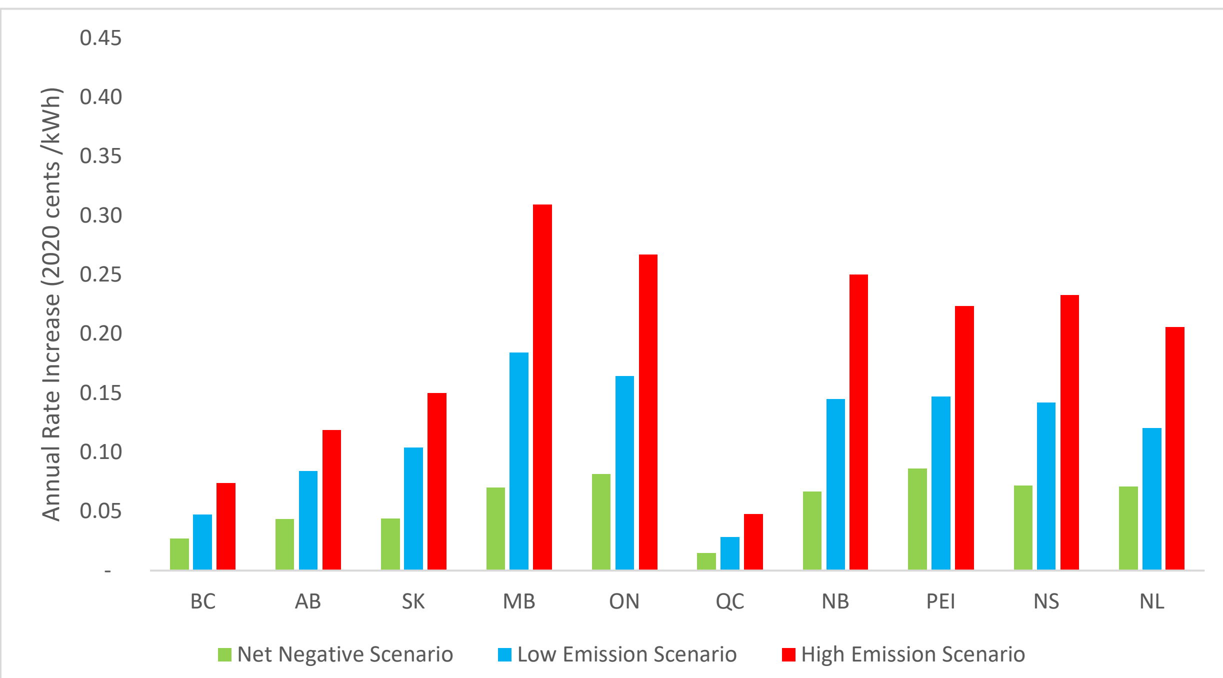
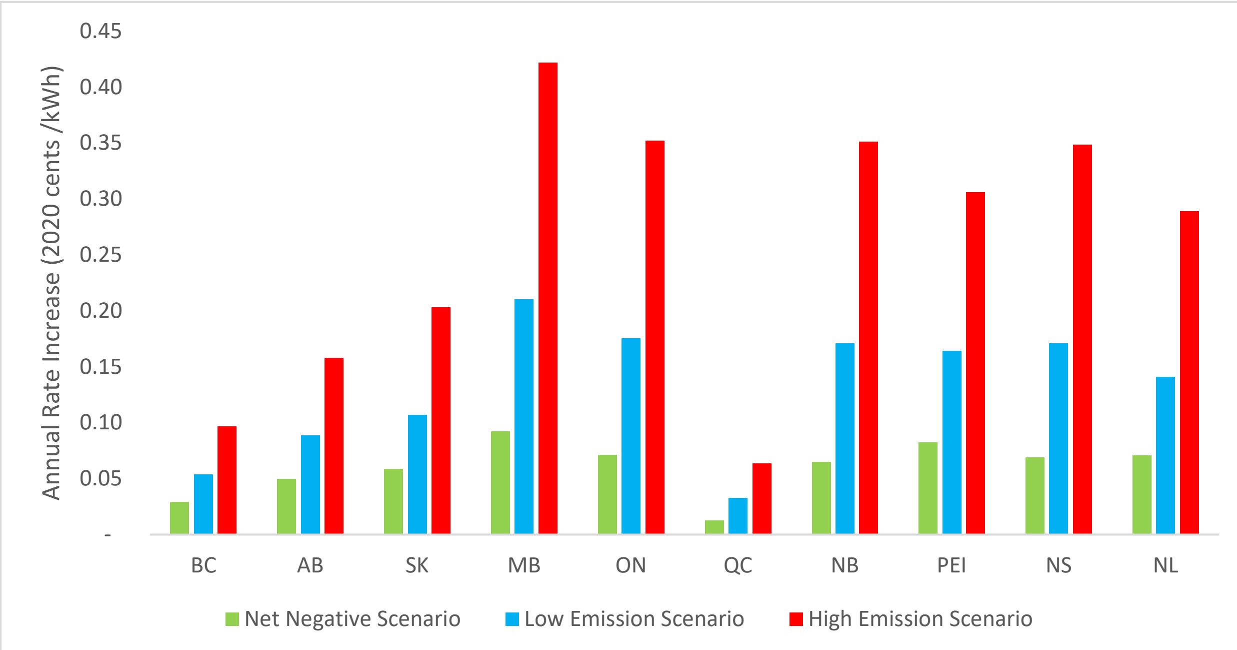


Figure 3.9: Years 2096-2100 Annual Increase in Cost of Electricity Due to Substation/Large Transformers Lifespan Reduction



Distribution Transformers

As seen in Table 3.2, the distribution transformer lifespan reduction showed a similar trend to substation/large transformers, with high impacts in MB, ON, and Atlantic provinces. In addition, BC shows significant effects in this category. BC has a considerable population spread in the southern part of the province, compared to the rest of Canada. A smaller population spread in a large region results in a significant amount of distribution assets. Currently, BC has around 300,000 overhead and underground distribution transformers. This value is almost the same as in AB, where the provincial population is only 15% less than BC. However, AB produces more electricity due to its large industrial consumer base, resulting in a lower per kWh impact.

Table 3.2: Expected Cost of Electricity Increase Due to Distribution Transformers Lifespan Reduction (2020 cents/kWh)

Province	Net Negative Scenario			Low Emission Scenario			High Emission Scenario		
	2036-2040	2071-2075	2096-2100	2036-2040	2071-2075	2096-2100	2036-2040	2071-2075	2096-2100
BC	0.006	0.008	0.008	0.006	0.015	0.017	0.008	0.028	0.042
AB	0.003	0.003	0.004	0.003	0.007	0.008	0.004	0.012	0.020
SK	0.002	0.002	0.002	0.002	0.005	0.005	0.003	0.009	0.016
MB	0.003	0.003	0.004	0.004	0.009	0.011	0.005	0.019	0.034
ON	0.005	0.005	0.005	0.005	0.013	0.014	0.007	0.025	0.041
QC	0.002	0.002	0.002	0.002	0.004	0.005	0.003	0.009	0.015
NB	0.004	0.004	0.004	0.004	0.009	0.011	0.005	0.020	0.035
PE	0.005	0.005	0.005	0.005	0.010	0.011	0.007	0.018	0.031
NS	0.005	0.005	0.004	0.005	0.010	0.013	0.006	0.020	0.038
NL	0.003	0.003	0.003	0.003	0.006	0.008	0.004	0.013	0.023

Wildfire Damages

The estimated electricity rate impact from wildfire damages is highlighted in Table 3.3. As seen from the table, MB has the highest impact from wildfire effects. Much of MB is in the Lake Winnipeg (LW) HFZ. The LW zone has seen the highest wildfire burned area in the last 30 years and is the most vulnerable to future wildfire events. Both these factors contribute to a significantly higher wildfire damage cost in MB compared to other provinces. Other provinces show relatively low impact from wildfire damages in future electricity rates.

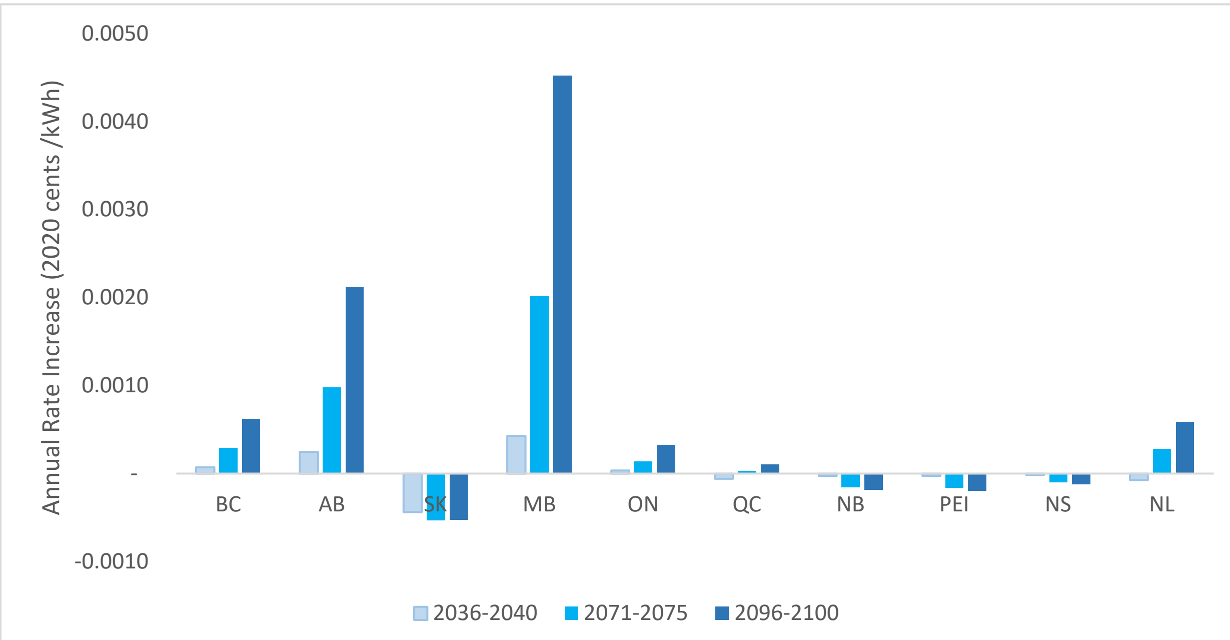
Table 3.3: Expected Cost of Electricity Increase Due to Wildfire Damages (2020 cents/kWh)

Province	Net Negative Scenario			Low Emission Scenario			High Emission Scenario		
	2036-2040	2071-2075	2096-2100	2036-2040	2071-2075	2096-2100	2036-2040	2071-2075	2096-2100
BC	0.016	0.024	0.034	0.023	0.036	0.051	0.025	0.045	0.067
AB	0.002	0.005	0.009	0.002	0.007	0.012	0.003	0.016	0.028
SK	0.002	0.008	0.015	0.001	0.012	0.024	0.004	0.032	0.059
MB	0.030	0.042	0.059	0.025	0.073	0.123	0.046	0.147	0.246
ON	0.003	0.004	0.005	0.002	0.006	0.010	0.003	0.011	0.019
QC	0.001	0.003	0.006	0.002	0.010	0.019	0.003	0.013	0.023
NB	0.005	0.004	0.004	0.005	0.007	0.010	0.005	0.008	0.012
PE	0.022	0.020	0.019	0.021	0.031	0.043	0.022	0.037	0.053
NS	0.007	0.006	0.006	0.006	0.009	0.013	0.007	0.011	0.016
NL	- 0.003	0.004	0.016	- 0.014	0.014	0.046	- 0.020	0.031	0.083

Flooding Damages

There is significant uncertainty associated with flooding models on net negative and high emission scenarios. Hence the results presented here are only for low emission scenarios. However, it should be noted that due to the nature of the relationship between precipitation and temperature, the high emission scenario may or may not yield comparative higher rate impacts. Some of the literature data suggest that flooding frequency could be higher than the low emission scenario under a high emission scenario, resulting in lower rate impacts.

Figure 3.10: Cost of Electricity Increase Due to Flooding Damage – Low Emission Scenario



As can be seen from Figure 3.10, there is a considerable variation of flooding-related rate impacts. In some scenarios, the rate impacts are lower than current due to the expected increase in flooding frequency. The flooding frequency largely depends on the ecological zones, as highlighted in the previous chapter.

MB shows the highest decrease in flooding frequency as well as the highest impact on electricity rates. The highest impacts are seen in the prairies and boreal ecological zones, including the majority of AB and MB. In real cost terms, AB has the largest impact. However, AB also has a larger population (higher electricity production/demand). The costs in AB are divided among a larger customer base resulting in a lower rate increase compared to MB, which has around half the total cost impact.

Northern SK is also in the prairies zone. However, flood frequency in Southern SK does not increase, where most of the electricity assets are located. This results in a favourable rate impact due to flooding.

Public perception is that Atlantic Canada is prone to flooding. However, it should be noted that most flooding in Atlantic Canada is based on storm surges and sea level rise (SLR). Storm surges and SLR are different climate events induced by different climate factors and discussed separately.

The above values represent an annual average rate impact from flooding. In practice, costs will occur more intermittently, with sudden rate increases as the event occurs. For example, in the prairies ecological zone, the 100-year flooding frequency is expected to reduce to a range between 30-50 years, suggesting 2-4 intermittent events in the next 100 years and rate impacts as and when these events occur.

Changes to Vegetation Management

Vegetation growth needs to be adequately maintained for the proper uninterrupted operation of the power grid. Several cost components can occur, such as interruptions due to vegetation, costs related to increased vegetation management operations, and vegetation preventive measures. The current cost estimate assumes that costs are due to increased vegetation management operations.

An increase or decrease in vegetation management costs is not expected under a Net Negative Scenario. As seen from Figure 3.12, a high emission scenario yields the highest increase in vegetation management costs. Among the impacts analyzed, vegetation management cost impact is the lowest. Of the ten provinces, the rate increase due to vegetation management is comparable, except AB and PE. Both AB and PE have lower vegetation management budgets due to the nature of vegetation (ecological zones) in these provinces, which translates to a proportionately lower impact due to climate change.

Figure 3.11: Cost of Electricity Increase Due to Vegetation Management Cost – Low Emission Scenario

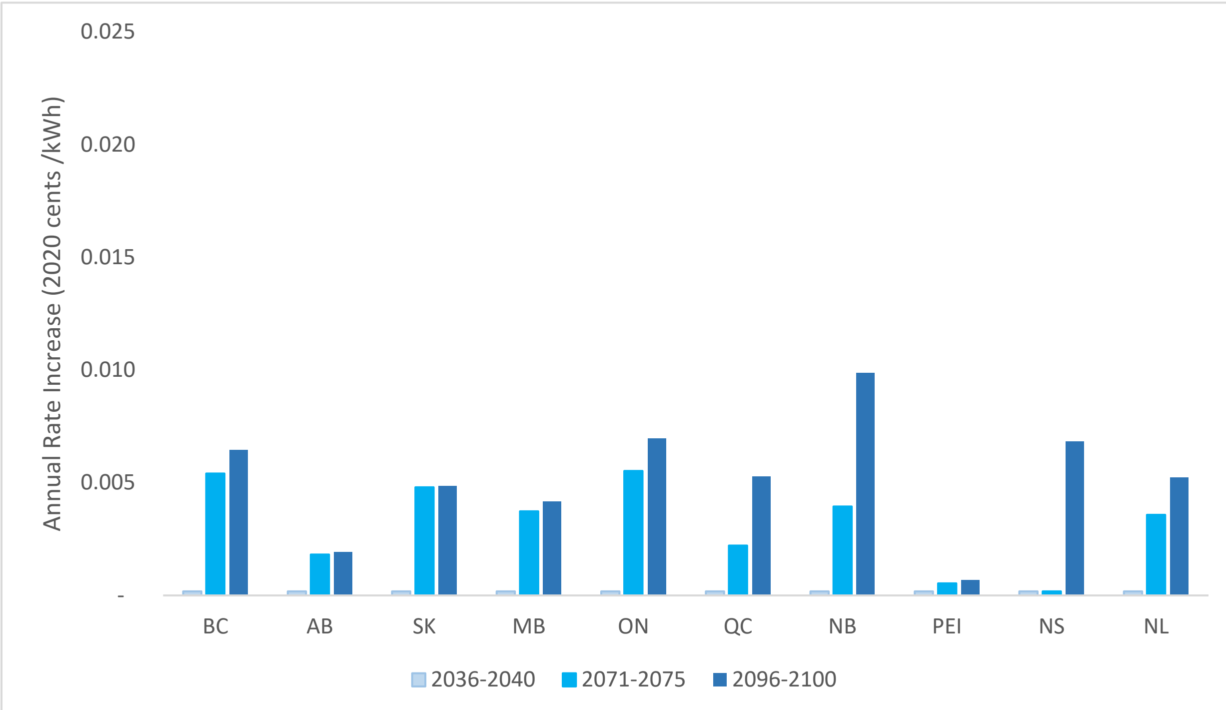
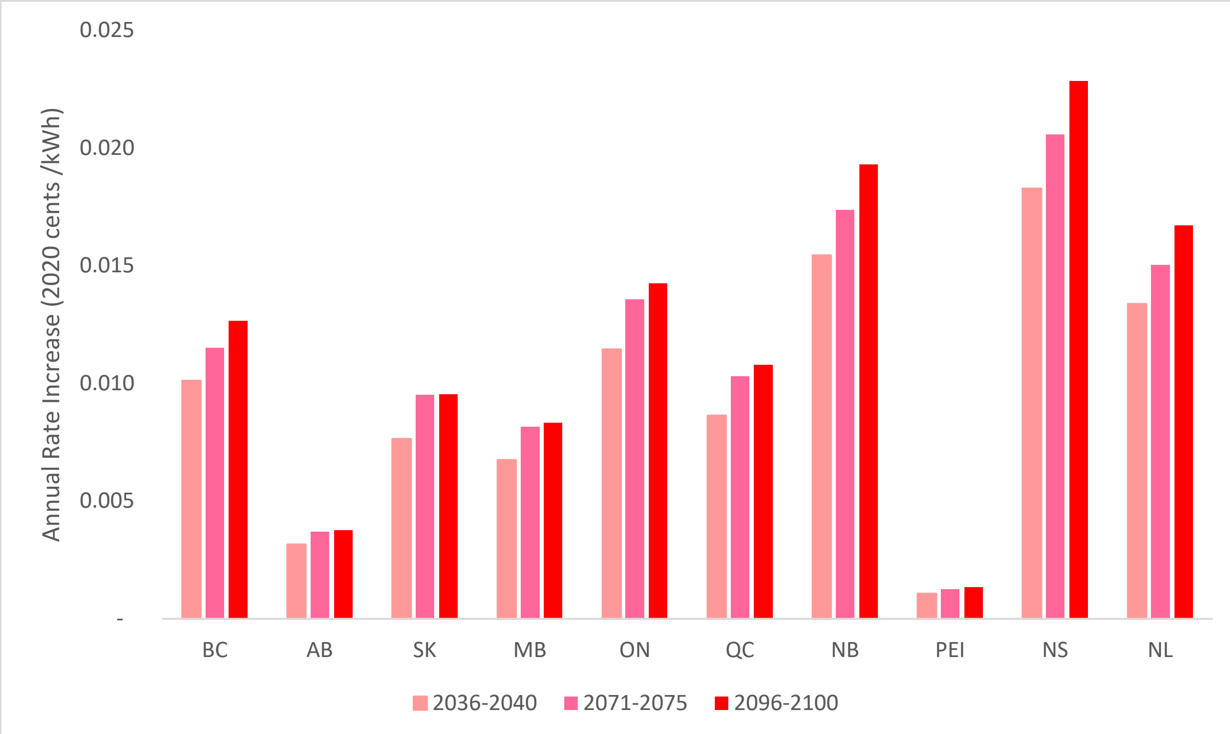


Figure 3.12: Cost of Electricity Increase Due to Vegetation Management Cost – High Emission Scenario



Wood Pole Lifespan Reduction

The results show that there is negligible impact on wood pole lifespan in Canadian conditions. Further evaluation reveals that although Canada is expected to see significant changes in temperature under low emission and high emission climate scenarios, the number of wet days is not expected to significantly impact wood pole lifespan.

While this observation is seen in most of Canada, there could be local conditions that can still impact wood pole life. For example, Vancouver Island has significantly more wet conditions. In Vancouver Island, a 1% reduction of pole lifespan for the next 40 years (until 2060) and another 9% reduction in the 40 years after (by 2100) can be seen. While these localized impacts may result in additional costs, the impact on the overall grid remains negligible.

Other Impacts

Many other climate events can affect the electricity system, as mentioned in the previous chapter. However, some of these impacts have not been studied in detail in the Canadian context and lacks modelling details for further analysis. Also, past cost impacts due to some of these climate events have not been properly estimated. These impacts have been evaluated using available data.

A summary of these climate events is highlighted in Table 3.4. Further details are available in Chapter 3 and Chapter 4.

Table 3.4: Other Climate Impacts Summary

Impact	Severity/Impact	Trend	Most Impacted Provinces
Lightning interruptions	Low	Slightly Increasing	Even Increase Across Provinces
High winds	Low-Medium	Increasing	PE, Territories
Freezing rain	Low	Varies	QC, NL
Snowfall*	Negligible	N/A	N/A
Capacity loss in transformers*	Negligible	N/A	N/A
Hydropower capacity	Negligible	Varies	BC, AB
Thermal power capacity	Low-Medium	Increasing	AB, SK
Nuclear power capacity	Low	Slightly Increasing	ON, NB

* As explained in Chapter 2

In addition to the above, we have evaluated storm surge/SLR impacts at the municipal level, as discussed in Chapter 4.

System Interruptions Due to Lightning

Lightning interruptions are expected to increase slightly throughout the century. The values show that interruption frequency increase to remain less than 1% in Canada. Some of the details are highlighted in Chapter 4 for the studied municipalities.

Impacts of Freezing Rain

Freezing rain is expected to be more frequent in northeastern Canada in the provinces of QC and NS. Moderate increases in flooding frequency is expected in the provinces of AB, MB, SK and ON. Other provinces will not see an increase by 2081-2100 (Lambert and Hansen 2011; Cheng et al. 2007). Based on the above literature, the provincial maximum values are determined as shown in Table. 3.5.

The values in the table are provincial maximums, and the average freezing rain occurrence is expected to be much lower. In addition, there is significant variability within the provinces. For example, Ontario will see an overall increase in freezing rain frequency. However, the freezing rain frequency will reduce by about 10% in southern Ontario. Based on this evidence, the freezing rain impact seems negligible, except in northeastern and western Labrador.

Hence, the expected impacts from freezing rain in Canada are minimum. This does not mean that there will not be freezing rain events in the future. However, any additional events occurring as a result of climate-related events are unlikely or extremely rare. In general, most academic studies predict a reduction in freezing rains due to freezing conditions not being met under future climate scenarios. However, there remain large uncertainties on these studies and a requirement to update with new climate data and models.

Table 3.5: Expected Freezing Rain Frequency Increase By 2081-2100

Province	Expected Freezing Rain Frequency Increase By 2081-2100 per year
BC	0
AB	0.25
SK	0.25
MB	0.25
ON	0.25
QC	0.5
PE	0
NS	0
NL	0.75
NW	0
NU	0
YC	0

Source: Lambert and Hansen 2011

Impacts of High Wind

According to the literature, the maximum percentage wind increase is expected to be less than 10% globally in the next 100 years (McInnes, Erwin, and Bathols 2011). This growth can vary from region to region. However, there are not adequate damage-related cost estimates available to determine to cost impacts. We estimate the relative increase in mean wind speeds and wind gust speeds to determine the potential for cost impact.

In the literature, for Canada, the growth in wind speeds in the far north regions are reported as the highest, with around a 5-10% increase in both low emission and high emission scenarios by 2071-2100 (Jeong and Sushama 2019), as presented in Table 3.6.

The wind gust values in Table 3.6 represent the windiest location in each province and represent the maximum risk levels in each province. However, based on data published by (Jeong and Sushama 2019), these maximum values only represent a small fraction of the whole province. The provincial averages are much lower comparatively. For example, certain parts of BC, AB, MB, NL, PE, and Territories will see a reduction of wind gusts (average and extreme values) for both low and high emission scenarios. In addition, certain areas may remain without significant changes to extreme events. (Jeong and Sushama 2019). However, all provinces will see an increase in extreme wind events by 2100, with most events occurring in QC, ON, NW, NU, and AB, for low and high emission scenarios. BC is predicted to have comparatively higher impacts under a high emission scenario.

Other wind-related ultra-extreme vents such as hurricanes and storms have not been evaluated at this stage.

Table 3.6: Provincial Average Wind Speed Changes and Mean Wind Gust Changes for Period 2070-2100

Province	Mean Wind Speed Change (RCP4.5)	Mean Wind Speed Change (RCP8.5)	Current Annual Mean Wind Guest (m/s)	2070-2100 % Increase in Wind Gust (RCP4.5)
BC	Negligible	Negligible	30	12%
AB	Negligible	Negligible	30	12%
SK	Negligible	Marginal Increase	30	8%
MB	Negligible	Marginal Increase	40	12%
ON	Marginal Increase	Moderate Increase	35	12%
QC	Marginal Increase	Moderate Increase	40	12%
PE	Marginal Increase	Moderate Increase	45	16%
NS	Marginal Increase	Moderate Increase	45	12%
NL	Marginal Increase	Moderate Increase	50	8%
NW	Significant Increase	Significant Increase	50	16%
NU	Significant Increase	Significant Increase	55	20%
YC	Significant Increase	Significant Increase	35	12%

Note: Negligible is either wind speed reducing or less than 1% increase, Marginal Increase is between 1-5% increase, Moderate Increase is 5-10% increase, and a significant increase is more than 10% increase

Data by: (Jeong and Sushama 2019)

Wind Power Generation Impact

Accurately estimating the impact on wind power generation due to climate change is challenging and fraught with uncertainty. Although overall wind speeds may increase for Canada (Table 3.6), some locations may experience a decrease in wind speeds (Yao, Huang, and Lin 2012). In addition, the increase in wind speeds is more prominent in northern Canada, where there are limited generation assets. Overall, about 5% of electricity is currently generated using wind power in Canada. Wind power capacity may increase to around 20% by mid-century, according to the CER (CER 2020b). The asset locations and construction and commencement period of new wind power projects may be a significant factor in estimating the impact on wind power generation due to climate change. The overall effect on wind energy generation due to climate change is unknown at this stage.

Impact on Hydropower Generation Assets

Around 60% of Canada's power generation is by hydropower. It is expected that this contribution will not change significantly in the future. The CER predicts a 56% hydropower contribution in 2050. The main challenge to hydropower generation is the change in precipitation patterns, as explained in the previous chapter. Canada is expected to see a net increase in hydropower capacity due to climate change. However, this will change from province to province. Table 3.7 highlights a rough estimate of the change in hydropower capacity for each province.

Table 3.7: Provincial Impacts on Hydropower Generation Assets at the end of the Century

Province	Change in Hydropower Capacity	Hydropower Contribution 2018 (%)	Overall System Capacity Impact
BC	0-10% reduction	88.7	9% reduction in capacity
AB	0-10% reduction	2.7	Negligible
SK	Minimum change	14.9	Negligible
MB	Minimum change	96.8	No Impact
ON	8-15% Increase	24.1	2-4% increase in capacity
QC	8-15% Increase	93.9	7-15% increase in capacity
NB	Unknown	18.7	Unknown
PEI	N/A	0	N/A
NS	Unknown	9.3	Negligible*
NL	0-10% reduction	95.6	10% reduction in capacity

*based on percent contribution

Source: (Cai et al. 2011; Natural Resources Canada 2017)

While the above table presents the general trend on hydro assets in each province, some assets may be impacted more than other assets due to local conditions. However, the overall impact remains relatively small.

Impact on Thermal Power Generation Assets

The major impacts due to climate change on thermal power plants were discussed in detail in Chapter 2. The major impacts that can be expected include efficiency reduction and power output reductions. Table 3.8 highlights the above impacts on the overall system.

Table 3.8: Provincial Impacts on Thermal Generation Assets

Power Plant Type	Stressor	Impact	Estimated Impact (for 1°C rise in Temperature)
Combined Cycle Natural Gas Power Plants	Cooling water temperature	Capacity change	0.4-5%
	Ambient temperature	Efficiency change	< 0.7% reduction in efficiency
		Capacity change	Negligible
Simple Cycle Natural Gas Power Plants	Cooling water temperature	Capacity change	0.4-5%
	Ambient temperature	Capacity change	< 1.5% reduction in capacity
		Efficiency change	< 0.25% reduction in efficiency

Source: (Loew et al. 2020; Petrakopoulou, Robinson, and Olmeda-Delgado 2020; NRDC 2014).

In general, heating up of cooling water could significantly impact power generation in thermal power plants. However, this depends on the technology used. Once-through cooling systems have a more significant impact from climate-related temperature increases. With new power plants adopting closedcycle cooling systems, the impacts are expected to reduce in the future. Other impacts remain relatively small. In addition, as stated in chapter 2, thermal power plants are designed to operate at varying temperatures. Recent studies have shown that power plants can regulate condenser pressures up to 35°C cooling water temperatures without compromising power output (Siswantara et al. 2018). However, the capacity will start to reduce at temperatures above 30-35 ^{0}C. With more frequent heatwaves expected and power demand rising during heatwaves, this reduction in capacity at thermal power plants could be a potential issue in balancing peak demand and supply.

Thermal power generation contribution in Canada (including coal, natural gas and oil) is around 11%. The above contribution could reduce by 15-35% by the end of the century at peak conditions. The above observations align with other studies found in the literature (Singh and Kumar 2012; Şen et al. 2018). The impact will be much higher for AB and SK, depending on natural gas resources for power generation.

Impact on Nuclear Power Generation Assets

Nuclear power plants require a significant amount of water resources for cooling. However, nuclear power plants are less impacted by the cooling water temperature than thermal power plants, with around 0.5% capacity reduction due to a change in 1°C (Attia 2015). The above values are only valid for temperatures above 15°C and below 30°C. In addition, other literature suggests that these impacts may only occur during extreme heat conditions (Linnerud, Mideksa, and Eskeland 2011).

Canada uses around 15% nuclear energy and only in provinces ON and NB. A 6°C rise in temperature could see around a 3% reduction in power output by the end of the century under a high emission scenario.

Combined Provincial Cost Impacts

Under the High Emissions scenario, the combined costs of climate change impacts on electricity delivery systems across all ten provinces are approximately 2020$ 4.5 billion per year, from 2096-2100. As expected, the Low Emissions scenario yielded lower values of 2020 C$2 billion per year. As can be seen from Figure 3.13, all values increase throughout the current century.

Provinces with larger electricity systems had more extensive climate-related losses, with ON, QC, and AB being the top 3 by a large margin (Table. 3.9). However, the normalized total cost values from SK and MN are notably higher, where the population density is much lower. The total cost impact on Atlantic provinces is low due to the relatively smaller electricity grids.

As seen from Figure 3.13, the capacity loss in transmission lines is the most significant cost contributor. Approximately 50% of the contribution is from capacity loss in transmission lines in all scenarios analyzed. In addition, capacity loss in distribution lines and lifespan reduction in transmission transformers are also significant cost components.

Figure 3.13: Total Cost Impact on Electricity Delivery Systems – All Provinces

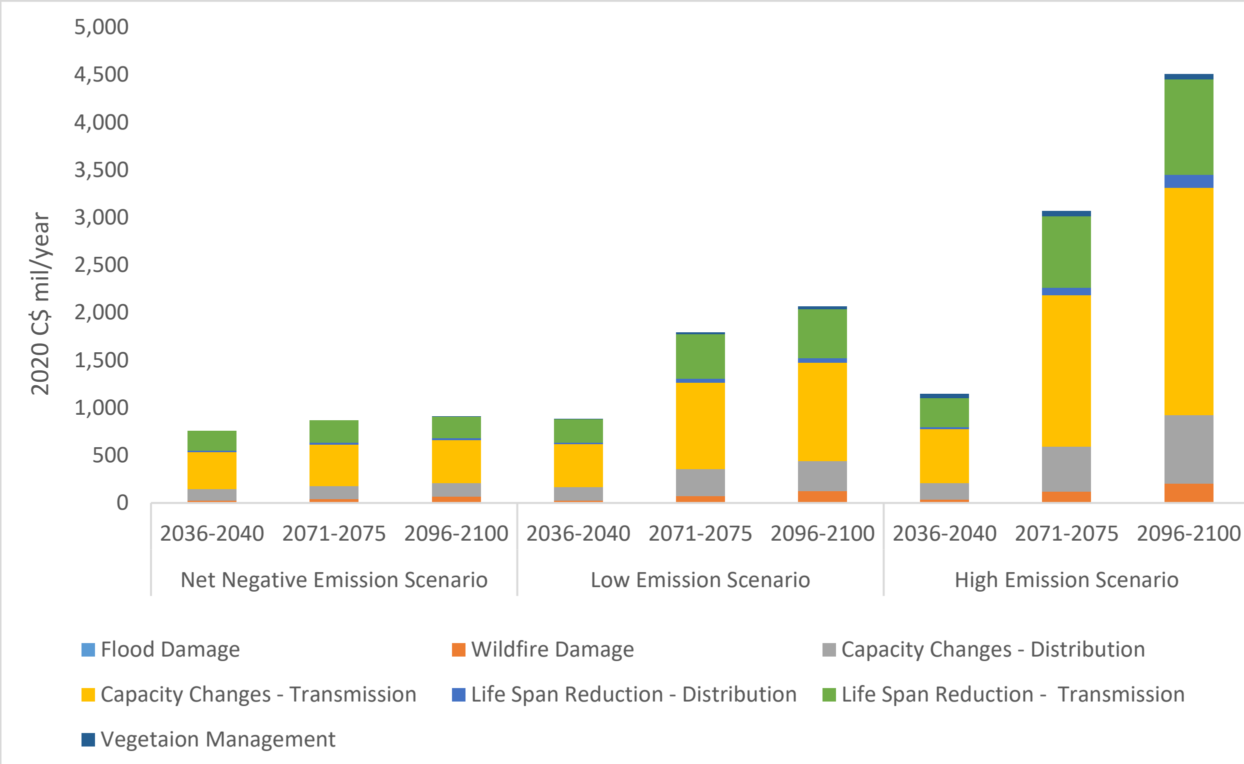


Table 3.9: Total Cost Impacts - Provincial (mill 2020 C$/year)

	Period	BC	AB	SK	MB	ON	QC	NB	PE	NS	NL
Net Negative Emission Scenario	2036-2040	70	141	74	65	211	125	22	4	25	24
	2071-2075	93	163	80	74	237	141	22	4	24	27
	2096-2100	106	193	104	90	215	124	21	4	23	28
Low Emission Scenario	2036-2040	79	168	94	83	239	143	24	4	24	22
	2071-2075	165	338	190	168	488	293	53	8	45	46
	2096-2100	200	365	201	202	534	375	64	8	57	57
High Emission Scenario	2036-2040	105	203	110	103	325	201	34	5	32	30
	2071-2075	284	505	293	302	841	567	99	12	82	86
	2096-2100	401	748	441	453	1,196	845	149	18	130	131

Impact on Average Electricity Costs and Rates

The combined cost of climate change impacts on electricity delivery infrastructure in each province is divided by the respective province's electricity demand to estimate the average cost impacts. The average cost of electricity due to climate change in the period 2096-2100 in all ten provinces is shown in Table

3.10 and Figure 3.13. As shown in Table 3.10 and Figure 3.13, SK and MB have the highest impact on average cost of electricity, with more than 2 cents per kWh. All other provinces have comparable values ranging between 0.7 cents/kWh and 1.33 cents/kWh in 2096-2100, except QC. Although QC has a larger cost impact, the average cost is lower due to its high electricity demand.

As stated in the previous section, capacity changes in transmission lines remain the largest cost contributor. Lifespan reduction in transmission transformers and capacity change in distribution lines are the next significant impacts. A notable impact can be seen from wildfire impacts in MB. As stated earlier, Lake Winnipeg HFZ has a large wildfire risk factor, where the majority of assets in MB are situated.

Figure 3.14: The Increase in Cost of Electricity in the Period 2096 – 2100 under High Emissions Scenario

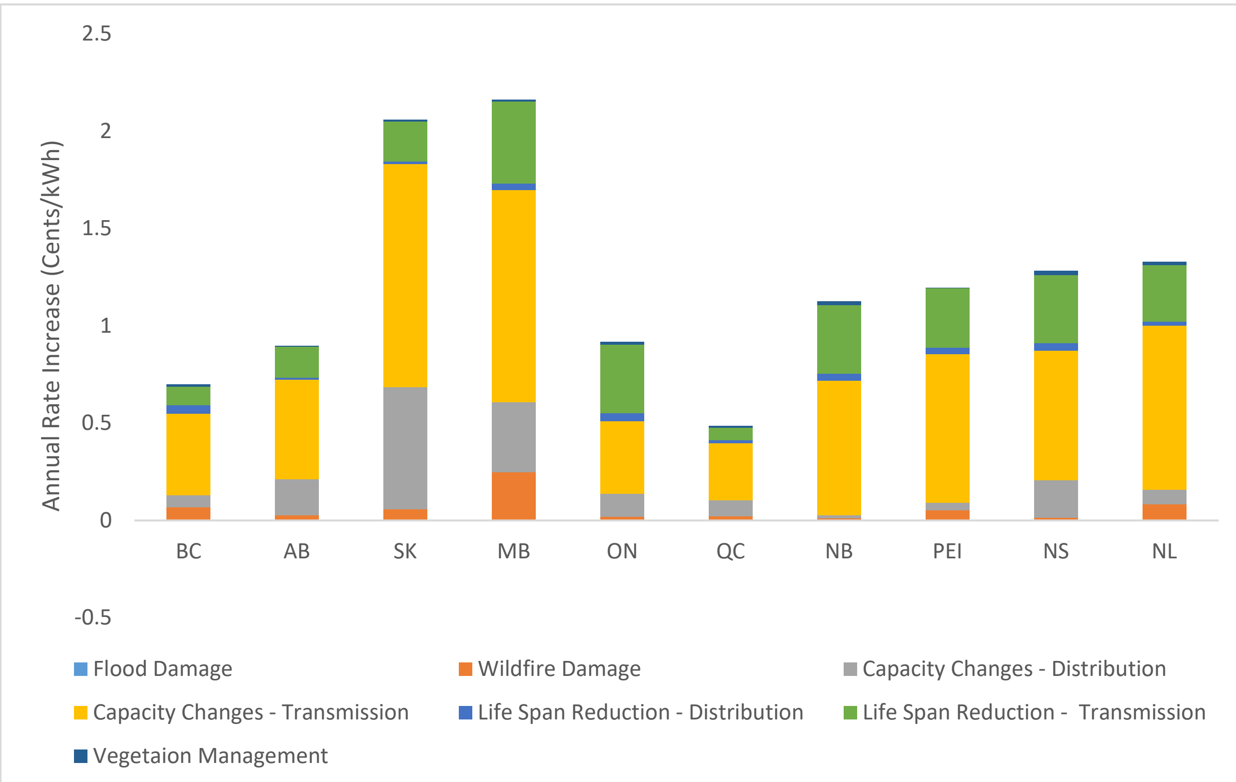


Table 3.10: Future Cost of Electricity Increase Due to Climate Change (2020 Cents/kWh)

	Period	BC	AB	SK	MB	ON	QC	NB	PE	NS	NL
Net Negative Emission Scenario	2036-2040	0.12	0.17	0.35	0.31	0.16	0.07	0.17	0.29	0.24	0.24
	2071-2075	0.16	0.20	0.37	0.35	0.18	0.08	0.16	0.28	0.24	0.28
	2096-2100	0.19	0.23	0.49	0.43	0.17	0.07	0.16	0.27	0.23	0.29
Low Emission Scenario	2036-2040	0.14	0.20	0.44	0.40	0.18	0.08	0.18	0.30	0.24	0.22
	2071-2075	0.29	0.41	0.89	0.80	0.37	0.17	0.40	0.50	0.45	0.47
	2096-2100	0.35	0.44	0.94	0.96	0.41	0.22	0.48	0.57	0.56	0.58
High Emission Scenario	2036-2040	0.18	0.25	0.51	0.49	0.25	0.12	0.25	0.36	0.32	0.30
	2071-2075	0.50	0.61	1.37	1.44	0.65	0.33	0.75	0.81	0.81	0.87
	2096-2100	0.70	0.91	2.06	2.16	0.92	0.49	1.13	1.20	1.28	1.33

Table 3.11: Relative Increase in Residential Electricity Prices Due to Climate Change Impacts on Electricity Delivery Systems in the period 2096 - 2100

Province	Residential Electricity Price (cents/kWh)	Relative Increase in Electricity price by Climate Scenario: Net Negative Emissions	Low Emissions	High Emissions
BC	15	1%	2%	5%
AB	14	2%	3%	6%
SK	22	2%	4%	9%
MB	14	3%	7%	16%
ON	22	1%	2%	4%
QC	12	1%	2%	4%
NB	22	1%	2%	5%
PE	22	1%	3%	6%
NS	20	1%	3%	6%
NL	23	1%	3%	6%

Notes: The residential electricity price forecast is obtained from CER (2020)

The increase in average costs would eventually be passed to electricity consumers, increasing the electricity rates. The increase in the average cost of electricity due to climate change must be compared against the retail electricity price forecasts to determine the relative increase in electricity prices. The construction of a long-range electricity price forecast is beyond the scope of this study. The CER provides a retail electricity price forecast up to 2050 (CER 2020a). This forecast was used for comparison purposes. For simplicity, we assumed that the retail electricity price beyond 2050 would remain the same as 2050 values.

Table 3.11 shows the relative increase in residential electricity prices due to climate change impacts on electricity delivery systems under different climate scenarios. As in the case of average cost increases, the highest relative increase in electricity prices is observed in MB & SK. All other provinces would experience comparable levels of price of electricity increases.

The reader is cautioned that these comparisons are provided only for illustrative purposes. It is difficult to make reliable long-range price forecasts due to many factors such as demographic changes, technology developments, and climate change.

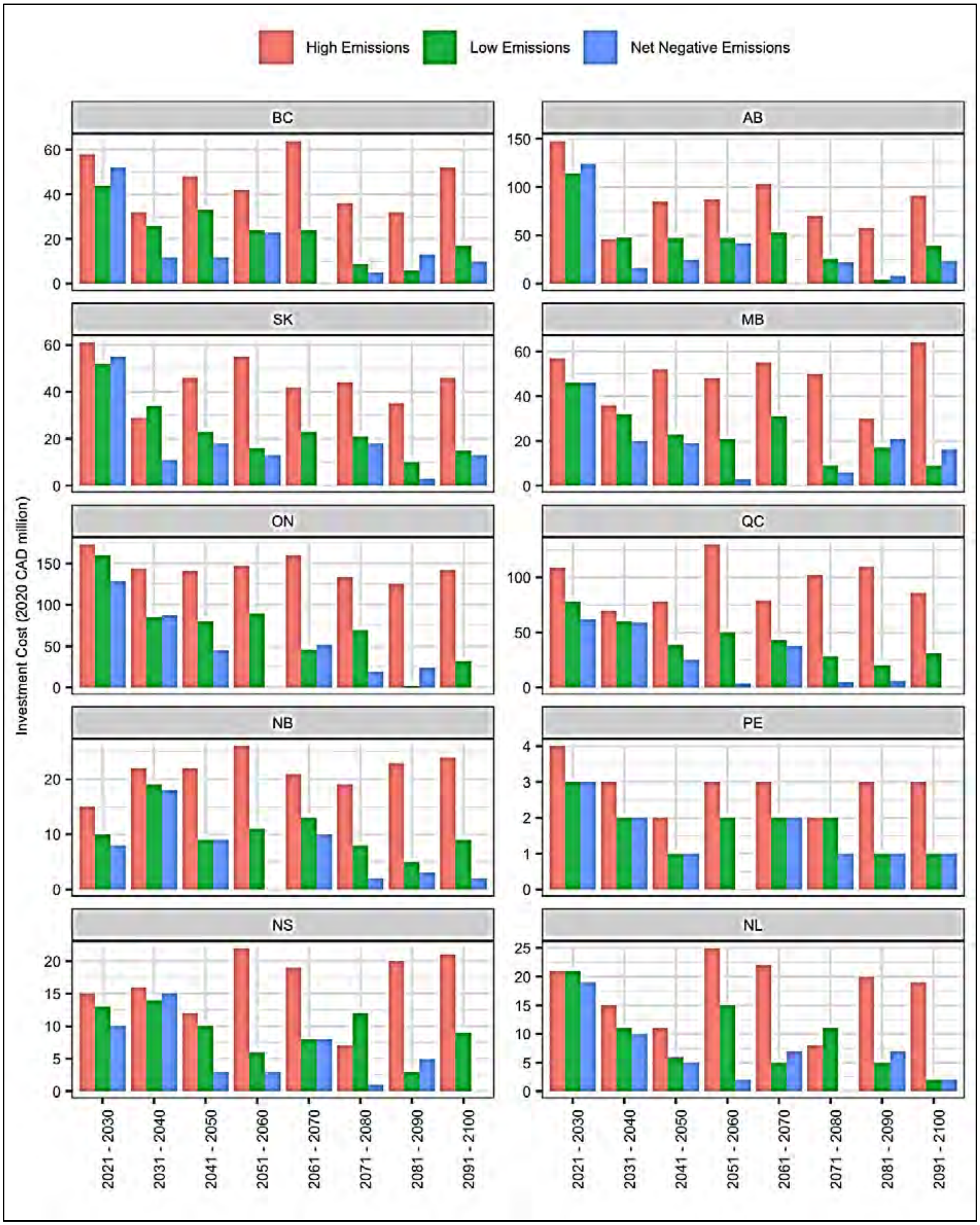
Mitigation and Adaptation Options for Transmission Capacity Loss

As discussed above, of the impacts assessed in this study, the most significant climate change impact (more than 50% of combined impacts in all provinces) on electric power systems in Canada is the transmission line derating due to increased ambient temperatures. The main mitigation option to dampen the capacity loss due to increased ambient temperatures is considering the future climate change in transmission capacity planning and regular transmission reinforcements. Figure 3.14 shows the transmission investments required every 10-year time block in the period 2021 – 2100 to mitigate the transmission capacity loss under all three climate scenarios assessed. Note that the transmission investments estimated in Figure 3.14 need to be made on top of the investments required to satisfy demand growth due to socioeconomic factors. The same results shown in Figure 3.14 are summarized and translated into an average annual transmission system investment requirement in Table 3.10. Figure 3.14 and Table 3.12 show that the required level of transmission requirements varies by climate scenario and province. The provinces with the highest investment requirements are Ontario, Alberta, and Quebec.

Table 3.12: Average Annual Transmission System Investments Required in the period 2020 – 2100 to Mitigate Transmission Capacity Loss Due to Increased Ambient Temperatures

Province	Transmission Investment Requirement (In million 2020 CAD$ per year)		
	Net Negative Emissions	Low Emissions	High Emissions
BC	1.2	1.8	3.6
AB	2.6	3.7	6.8
SK	1.3	1.9	3.5
MB	1.3	1.8	3.9
ON	3.5	5.6	11.6
QC	1.9	3.4	7.6
NB	0.5	0.8	1.7
PE	0.1	0.1	0.2
NS	0.4	0.7	1.3
NL	0.5	0.7	1.4

Figure 3.15: Transmission System Investments Required to Mitigate Capacity Loss Due to Increased Ambient Temperatures



When designing transmission systems under climate change, one of the main challenges the transmission system planners may face is the uncertainty in future climate change. The main cause of the uncertainty is the future atmospheric CO_2 concentration level and the associated warming trend. The future atmospheric CO_2 concentration level is driven by human action and beyond the control of transmission system planners. It should also be noted that reinforcing transmission systems require longer lead times and may have to go through lengthy regulatory approval processes.

As such, in addition to making regular transmission system enhancements, the electricity system operators should consider other mitigation options. Some of the other mitigation options include reconductoring congested transmission corridors and implementing novel smart-grid technologies. For example, by smart grid technologies such as dynamic ampacity systems, it is possible to determine the maximum allowable current for a given power line by using real-time electrical and environmental data, better reflecting the operating conditions (Bartos et al. 2016). This will enable greater flexibility in the way transmission systems are operated, maintained, and upgraded. The consequence is that the use of smart grid technologies will enable the higher utilization of existing transmission system infrastructure and potentially defer new transmission line investments. Emerging smart grid technologies can be implemented faster than the addition of new transmission lines providing recourse against uncertainty at the point of initial transmission line investment. For example, flexible and smart transmission technologies such as SmartValve™ systems (Smart Wires Inc. n.d.) can be added to a major transmission system in about seven months. The investment cost would be about CAD$ 6 – 9 million.

Another alternative to reduce transmission capacity loss is to adopt distributed energy generation technologies. Distributed generation would reduce/eliminate transmission requirements. In addition, by eliminating the investment requirements in transmission lines, distributed generation could become cost advantageous (CERI 2020).

Chapter 4 : Case Studies of Impacts on Municipal Level Electricity Distribution Systems

- **Local/Municipal impact can deviate significantly from provincial averages for some of the climate events**
- **Results are sensitive to population density, the value of assets on the ground, as well as local climate patterns**

Selection of Cities/Municipalities

Municipal impacts have been analyzed for four selected cities/municipalities: Vancouver, Regional Municipality of Wood Buffalo (RMWB), Oakville, and Halifax. The climate change impact on different cities is based on the geographic and climate zones where it is located. However, this an eastern coastal city, inland municipality, a western coastal city, and a city shores one of the great lakes have been selected. This selection does not represent all the climate and geographic conditions in Canada. Other cities and municipalities are to be analyzed at a later stage, depending on data availability and requirements at that time.

The analysis and cost estimate methods are as stated in Chapter 2 and Chapter 3 unless otherwise specified. Only five categories are studied at the municipal level due to data challenges and some infrastructure-stressor combinations not being relevant at the municipal level, including:

- capacity change in distribution lines
- lifespan reduction in distribution transformers
- flooding impacts
- storm surge/SLR impacts, and
- lightning impacts.

Municipal Cost Impact Analysis

Capacity Change in Distribution Lines

Capacity changes at the municipal level follow similar trends to the provincial level, with observed higher cost impacts under the High Emission scenario. The cost impacts are estimated as a percentage of the net replacement cost of the current distribution powerline assets, Figure 4.1. The increased capacity requirement will drive more capital investment, and the investment is assumed proportional to capacity change. As can be seen from Figure 4.1, the investment percentages are similar in all municipalities. The slight variations are due to the current asset base and relative temperature changes in the regions.

In actual cost values, the capital that needs to be invested in each municipality is highlighted in Table 4.1. As expected, the municipalities with more extensive electricity assets will require more capital investment.

Figure 4.1: Increase in Asset Replacement Cost – Distribution Lines – Municipal Level

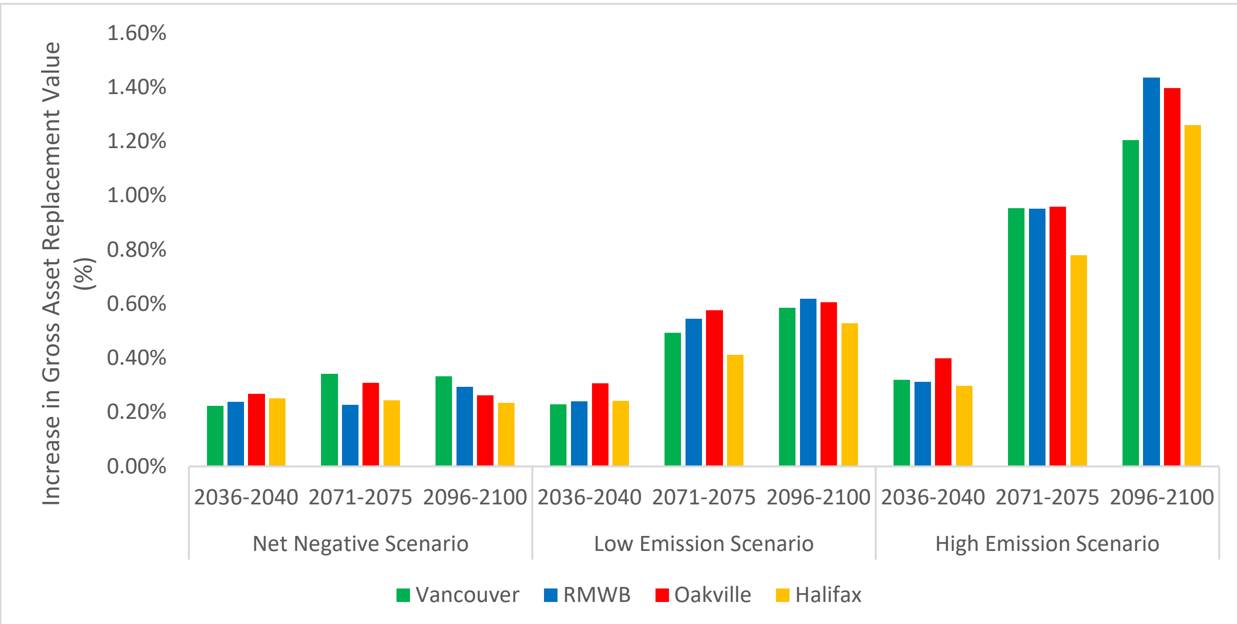


Table 4.1: Capital Investment Capacity Change in Distribution Lines – Municipal Level (C$ million/year)

	Net Negative Scenario			Low Emission Scenario			High Emission Scenario		
	2036-2040	2071-2075	2096-2100	2036-2040	2071-2075	2096-2100	2036-2040	2071-2075	2096-2100
Vancouver	0.65	1.00	0.97	0.67	1.44	1.71	0.93	2.79	3.52
RMWB	0.07	0.07	0.08	0.07	0.16	0.18	0.09	0.28	0.42
Oakville	0.22	0.25	0.21	0.25	0.47	0.49	0.33	0.78	1.14
Halifax	0.10	0.10	0.09	0.10	0.16	0.21	0.12	0.31	0.50

Lifespan Reduction in Distribution Transformers

As opposed to the capacity change in distribution lines, there is a notable difference between capital investment required due to lifespan reduction among the municipalities (Figure 4.2. Vancouver, which has the largest asset base, has the highest impact in terms of percentage investment required and actual cost values (Table 4.2). Both Oakville and Halifax have similar population densities and show similar trends. Oakville has a larger set of assets on the ground compared to Halifax, which can be correlated to a higher investment cost and investment impact. RMWB has the lowest impact among the municipalities studied.

The values are also correlated to the predicted absolute atmospheric temperature. In comparison, the capacity change in distribution lines is correlated to the relative temperature change.

Figure 4.2: Increase in Asset Replacement Cost – Distribution Transformers – Municipal Level

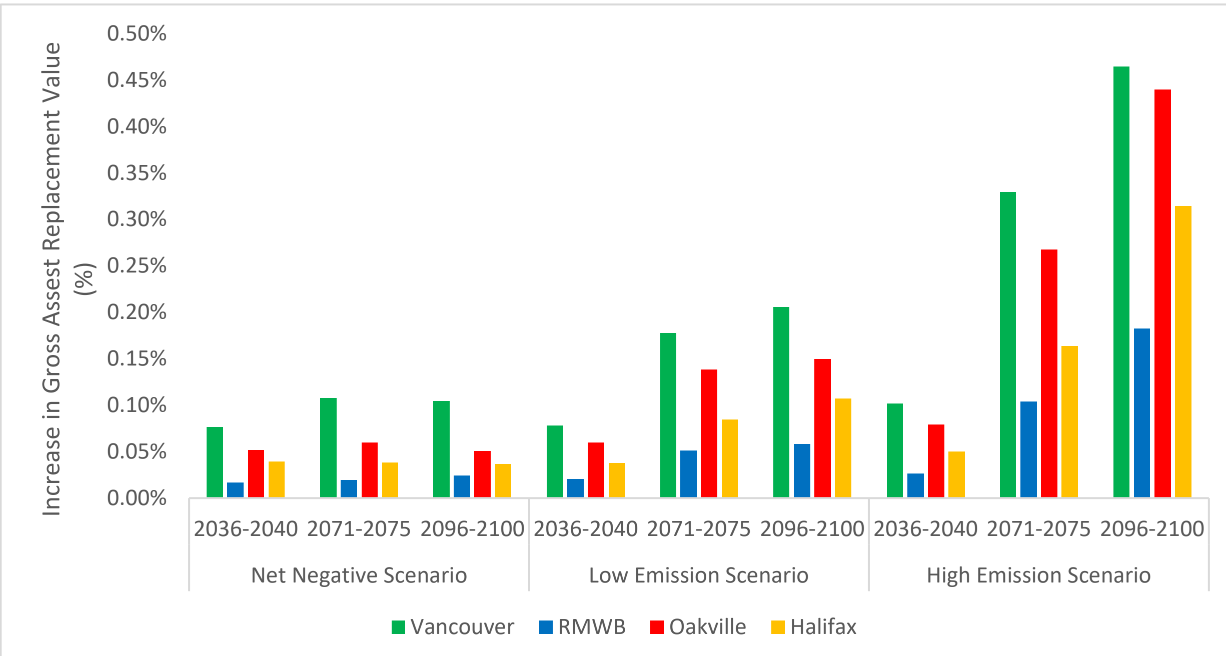


Table 4.2: Capital Investment Lifespan Reduction in Distribution Transformers (2020 C$ million)

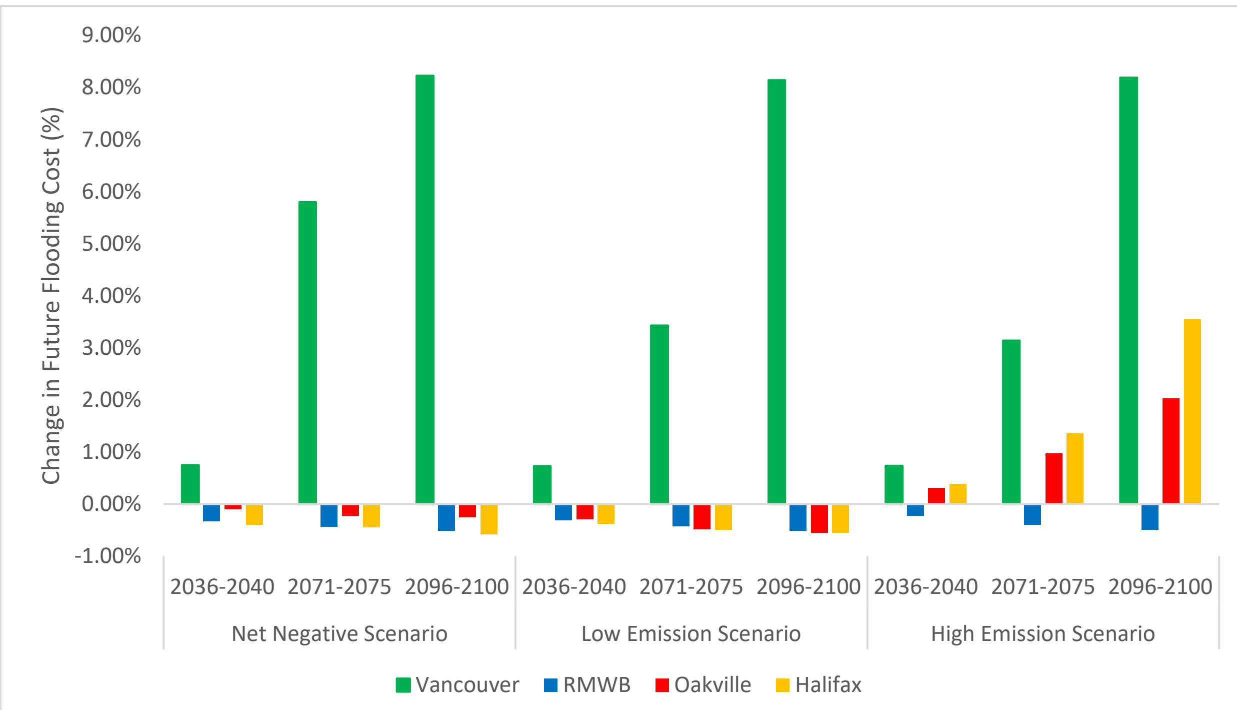
	Net Negative Scenario			Low Emission Scenario			High Emission Scenario		
	2036-2040	2071-2075	2096-2100	2036-2040	2071-2075	2096-2100	2036-2040	2071-2075	2096-2100
Vancouver	0.30	0.42	0.40	0.30	0.69	0.80	0.39	1.27	1.80
RMWB	0.01	0.01	0.01	0.01	0.02	0.02	0.01	0.04	0.07
Oakville	0.04	0.05	0.04	0.05	0.12	0.13	0.07	0.23	0.38
Halifax	0.02	0.02	0.02	0.02	0.04	0.06	0.03	0.09	0.17

Flooding Impact

Localized flooding frequencies have been based on data provided by Gaur 2017. In addition, the flooding cost for municipalities is not available. Hence, the analysis only focuses on estimating the percentage increase in flooding cost based on changes to flooding frequency, as shown in Figure 4.3.

The largest impact is seen in Vancouver, where its flooding cost can rise as high as 8% of the current cost under all climate scenarios by the end of the century. This value is much larger than the provincial average of 2.5% cost increase by 2096-2100. The highest variation in cost impact is seen in Halifax, where its costs can rise to around 3.5% of current costs under a High Emission Scenario and a negative 0.5% under a low emission scenario. Oakville shows a similar trend to Halifax. The RMWB, which is in the boreal ecological zone, will see a reduction in flood-related costs or negative values. This was explained in Chapter 2, as illustrated in Figure 2.3.

Figure 4.3: Change in Flooding Cost – Municipal Level



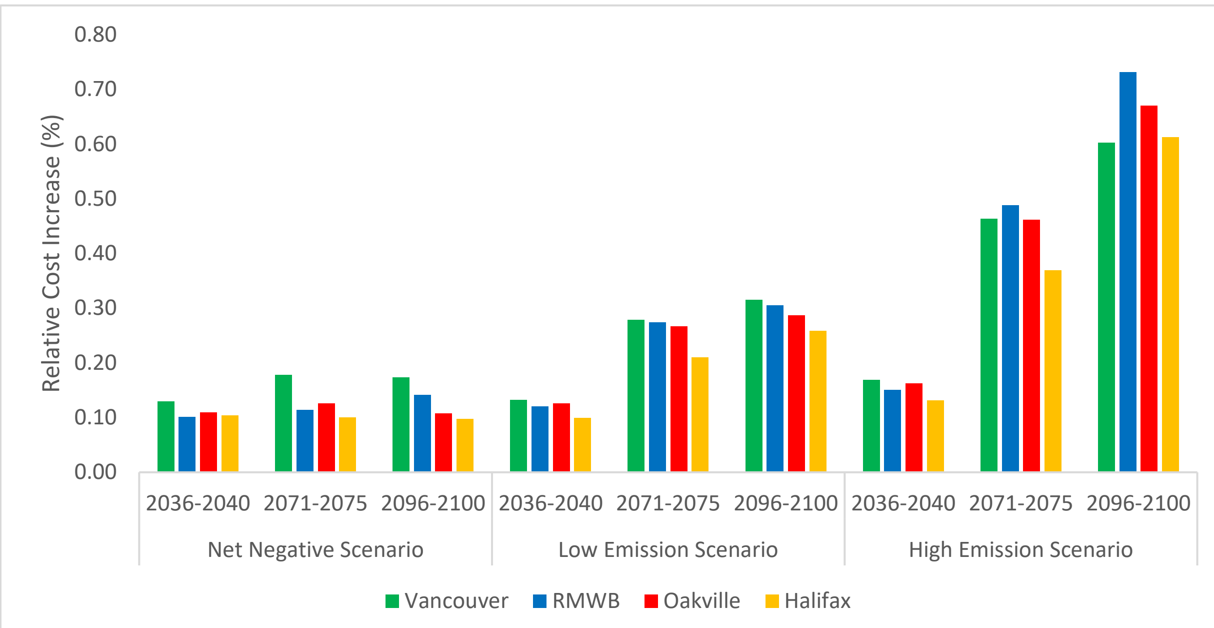
As highlighted in the previous chapter, the modelling of flooding is fraught with uncertainty. There is significant uncertainty related to the values used under both net negative and high emission scenarios. Academics are conducting further studies on this front, and once new research and details are available, these findings need to be reanalyzed to develop less uncertain results.

Lightning Interruptions

Lightning interruptions downtime costs were only estimated as a percentage cost reduction. Actual downtime costs are not available to estimate the actual cost impact.

Of the four cities analyzed, the results yield a negligible increase in annual interruption cost from lightning. In the net negative and Low Emission Scenario, the increase in annual interruption costs remained below 0.3% in each period throughout the analysis period. As shown in Figure 4.4, the interruptions cost increase throughout remained below 1%. The highest increase of around 0.7% is seen in the High Emission Scenario. Since these values are extremely low, it seems the impact from lightning interruptions is negligible.

Figure 4.4: Change in Lightning Interruptions Cost – Municipal Level



Storm Surge/SLR

Storm Surge/SLR impacts have been conducted using a qualitative approach using methods described herein for the three coastal cities, Vancouver, Oakville, and Halifax. A summary of these results is available in Table 4.3.

Vancouver

According to available data (Treasury Board of Canada Secretariat n.d.), coastal lower mainland and surrounding islands, including Vancouver, are classified as a high severity low-frequency area. This suggests that Vancouver may be subjected to damaging storm surges once every few years. The vertical allowance data suggests that there could be a potential increase in such events in the future. Furthermore, research conducted by others suggest a moderate risk to infrastructure and low risk to infrastructure access pathways in a 50 year time horizon (Fisheries and Oceans Canada 2013b)

Halifax

According to available data (Treasury Board of Canada Secretariat n.d.), islands and cities east of the Gulf of St. Lawrence are at a high-risk status from storm surges. This includes Nova Scotia, Prince Edward Island, Eastern Newfoundland, and eastern parts of New Brunswick. The coastal area towards the west of the gulf of St. Lawrence is classified as medium risk, which includes the eastern shoreline of Quebec, Western shorelines of Newfoundland, and western shoreline of New Brunswick. Halifax is classified as a high severity, medium frequency city. Furthermore, Fisheries and Oceans Canada research suggest high-risk levels for infrastructure in Halifax for both 10 and 50 year time horizons (Fisheries and Oceans Canada 2012). Halifax also reports a significant rise in future sea levels and vertical allowance. In addition, others report similar findings solidifying that there is a considerable risk in Halifax from SLR and storm surges requiring a rapid adaptation framework (Rapaport et al. 2017)

Oakville

Predicted future vertical allowance data is not available for Oakville or nearby cities. Oakville shoreline is on Lake Ontario. Nearby data suggests that Oakville may have a low severity and low frequency of storm surge occurrence, where erosion could be the main factor to be considered (Treasury Board of Canada Secretariat n.d.). However, the freshwater basin as a whole may cause medium to high risks to infrastructure both in 10 and 50-year time horizons (Fisheries and Oceans Canada 2013a). In addition, there has been a significant rise in water levels in the great lakes (NOAA n.d.).

Table 4.3: Risk Values from Storm Surge/SLR

City/Municipality	Severity of Events	Frequency of Occurrence	Infrastructure Density	Risk to Electricity Infrastructure
Vancouver	High	Low	High	***Medium***
Halifax	High	High	Medium	***High***
Oakville	Medium	Low	Medium	***Low-Medium***

Chapter 5 : Impact of Climate Change on Peak Electricity Demand: A Case Study

- **A case study is developed to examine the temperature responsiveness of peak electricity demand of Ontario**
- **Climate change can potentially increase the demand for peak electricity generation and delivery capacity by 8 – 34% in Ontario by the end of the current century**
- **It is prudent that the electricity system planners consider the impact of climate change on peak electricity demands to design electricity infrastructure**

The electricity demand is influenced by weather conditions such as ambient temperature and precipitation. In general, both high and low ambient temperatures lead to an increase in electricity demand. Over the next few decades, climate change will increase in both average and maximum daily temperatures in Canada and the rest of the world. The rising ambient temperatures can lead to higher average and peak electricity demands. The demand increases are driven by the electricity consumed by air conditioners and other devices used for space cooling. The potential increase in electricity demand, particularly the peak demand, is non-trivial. A study covering a range of world cities reported peak electricity demand increases between 0.45% and 4.6% (average 2.65%) per degree of ambient temperature increase (Santamouris et al. 2015). Similar results have been reported for different parts of the US (Burillo 2019; Auffhammer, Baylis, and Hausman 2017). It should also be noted that electricity consumption plays a role in adapting to climate change in terms of helping to adjust to heating and cooling needs in the face of temperature changes (Damm et al. 2017).

The potential increase in peak demand due to climate change has significant electricity system-level implications. Electricity generation and delivery infrastructure is typically designed for maximum demand days. Peak demand generally increases with the population and economic growth, although growth can be dampened by deploying energy-efficiency improvement and demand-side management measures. The increasing intensity of extreme heat days due to climate change can exacerbate the peak demand growth. That will lead to additional investments in peak generation capacity, transmission, or storage beyond what is demanded by demographic and socioeconomic factors (Auffhammer, Baylis, and Hausman 2017). In assessing climate change impacts on Canadian electricity systems, the CEA (2016) identifies the increased peak demand in summer, especially in large cities, due to rising temperatures in combination with the urban heat island effect as a risk for Canada's electricity systems. If system planners do not consider the influence of climate change on the peak electricity demand, the system reliability will be impacted, leading to more frequent system contingencies, including unplanned outages. As such, estimating the impact of climate change on-peak electricity demand in Canadian provinces is essential for both mitigation and adaptation planning.

In this chapter, an illustrative case study is developed to assess the impact of increased ambient temperature on peak electricity demand. The case study examines the temperature responsiveness of daily consumption and peak demand in the province of Ontario. The province of Ontario is the most populous Canadian province and has the second-largest electricity system in terms of installed generation capacity and electricity demand. The case study is developed using a high-frequency data set of electricity demand, observed weather data, and projected daily temperatures under the three climate scenarios considered for this study.

Material & Methods

The analysis framework developed for the case study follows the methods developed by Auffhammer, Baylis, and Hausman (2017). However, this analysis uses a relatively simpler mathematical framework to examine the temperature responsiveness of electricity demand. The mathematical framework used for the analysis first establishes a relationship between daily maximum temperature and electricity demand. This relationship is then used to predict the future peak and average demand in Ontario under the three climate scenarios considered for this analysis. This analysis only considers demand changes due to climate change. The other demand factors, such as the increase in population and shift away from fossil fuels, are not considered in this analysis. The main data and methods used for the analysis are as follows.

- Time series data of hourly electricity demand in Ontario in 2000 – 2019 are obtained from the Ontario Independent Electric System Operator (IESO 2021). The hourly data is processed to construct a data set of daily maximum and average electricity demand in Ontario.
- The observed daily maximum temperature in Ontario is obtained from the weather data portal provided by ECCC(2021). Daily maximum temperature data observed in a weather station in Toronto city center (weather station ID 6158350) are used as a representative provincial maximum temperature for the intents and purposes of this analysis. It should be noted that the highest electricity demand in Ontario is observed in Toronto and surrounding areas.
- A cross-examination of the daily maximum and electricity demand and daily maximum temperature revealed a non-linear relationship between them. Minimum daily electricity demands (both average and peak) are observed when the temperature falls within 15 – 18 °C. Both positive and negative temperature deviations from that range increase the electricity demand. Positive deviations (i.e., hotter temperatures) lead to higher demand increases than negative deviations.
- A regression model is fitted between the daily maximum temperature and electricity demand (both average and peak). As discussed above, the temperature responsiveness of electricity demand is observed to be non-linear. The non-linearity is captured by using regression splines. The intention was to use the daily maximum temperature as a predictor of average and peak electricity demand.
- The maximum daily temperature in Toronto, which is the representative location used for this analysis, under the IPCC emissions scenarios RCP2.6 (Net Negative Emissions), RCP4.5 (Low Emissions), and RCP8.5 (High Emissions) are obtained from ClimateData.ca (n.d.).
- The average and peak daily electricity demand between 2025 and 2100 are predicted by using the previously discussed regression model. The predicted results are used to examine the impact of rising

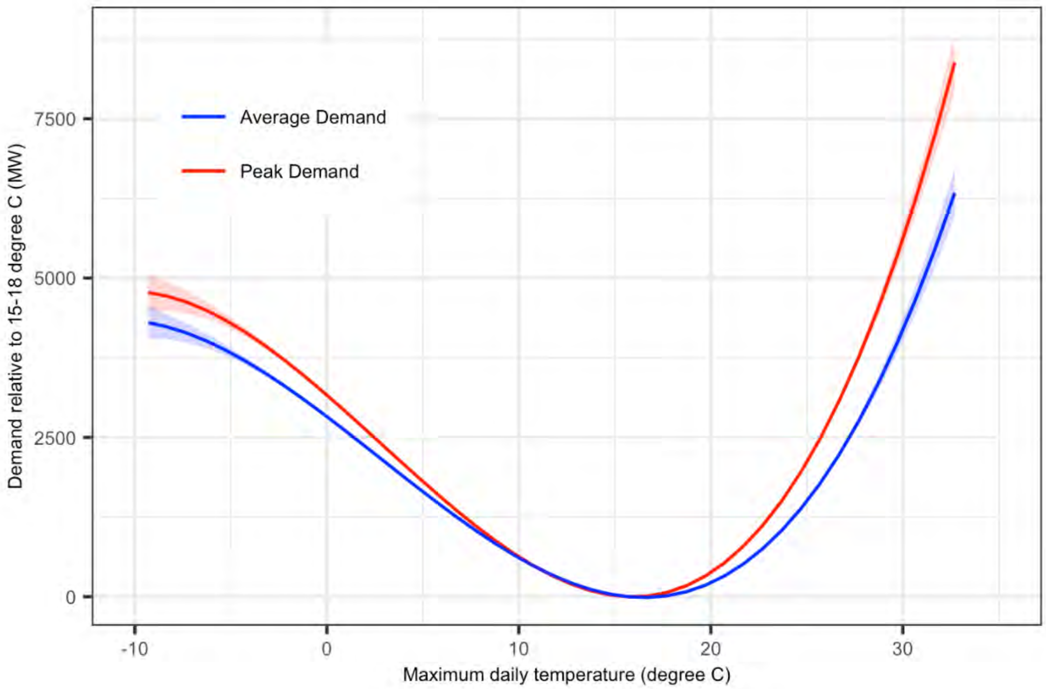
daily maximum temperature on electricity demand. The predicted demands are averaged across 25 independent climate model results.

- Although not discussed explicitly, statistical methods are employed to avoid biases that may be introduced by using climate model results in a mathematical model calibrated using observed data (Auffhammer et al. 2013).
- The use of a single reference year electricity demand data to predict the future electricity demand may appear as an oversimplification. The approach taken by this analysis holds constant economic growth, population growth, electricity infrastructure, attributes and penetration level of technology used by consumers (e.g., number of air conditioners installed per 1000 houses, the efficiency of end use devices, etc.). This means the inherent assumption is that those factors would remain at the same levels observed in 2019, and only the daily maximum temperatures would change. By taking this approach, the impact of rising ambient temperatures on electricity demand can be isolated, which is the intended purpose of this analysis.

Case Study Results and Discussion

The non-linear regression model was developed to examine the temperature responsiveness of daily electricity demand in Ontario is depicted in Figure 5.1. The figure shows the daily average demand and peak demand relative to the demand corresponds to the daily temperature range (15 – 18°C), where the lowest demands are observed. As can be seen from Figure 5.1, the peak demand is impacted far more than the average demand by the daily maximum temperature.

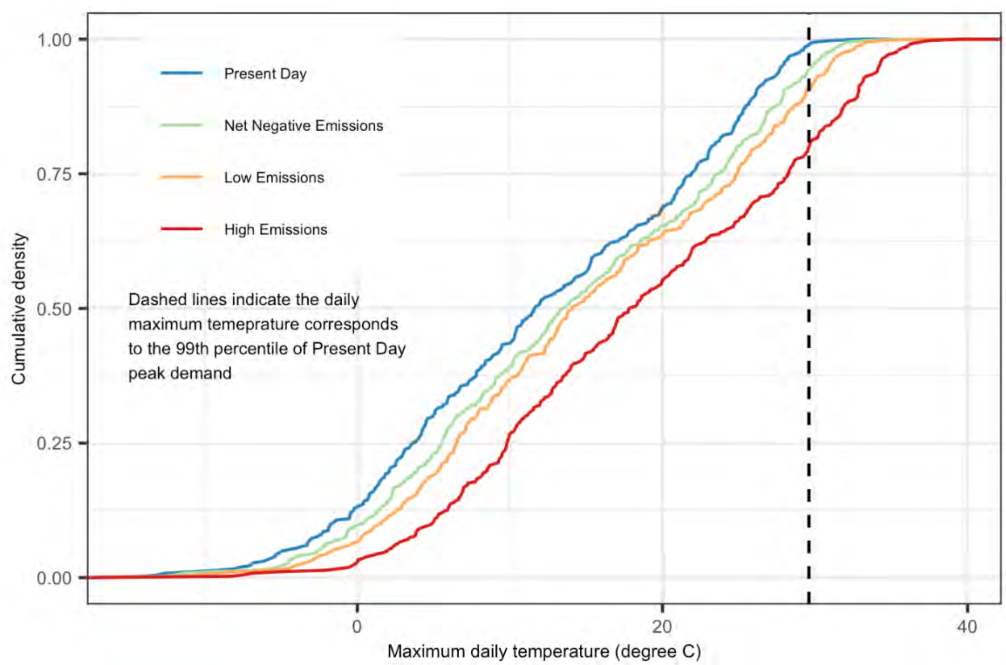
Figure 5.1: Temperature Responsiveness of Daily Electricity Demand in Ontario



Notes: The figure shows the daily average demand and peak demand relative to the lowest demand, which was observed in daily maximum temperature range of 15 – 18 °C. The responsiveness function shown here corresponds to the reference year 2019. The lowest daily peak demand observed in 2019 was 16784MW and the lowest average demand observed was 13736MW. The shades areas represent the 95% confidence interval of the responsiveness function. Figure Source: CERI

The temperature-responsive function shown in Figure 5.1 is used to predict the peak demand in Ontario by using the projected daily maximum temperatures under the three climate scenarios as the predictor. Figure 5.2 shows the cumulative probability density distributions of the current and projected daily maximum temperatures 2090 -2100. As seen from the figure, under all climate scenarios, the likelihood of higher daily maximum temperatures than the current observed values increases significantly. As such, climate change will lead to higher peak electricity demands in Ontario under all climate scenarios considered for this analysis.

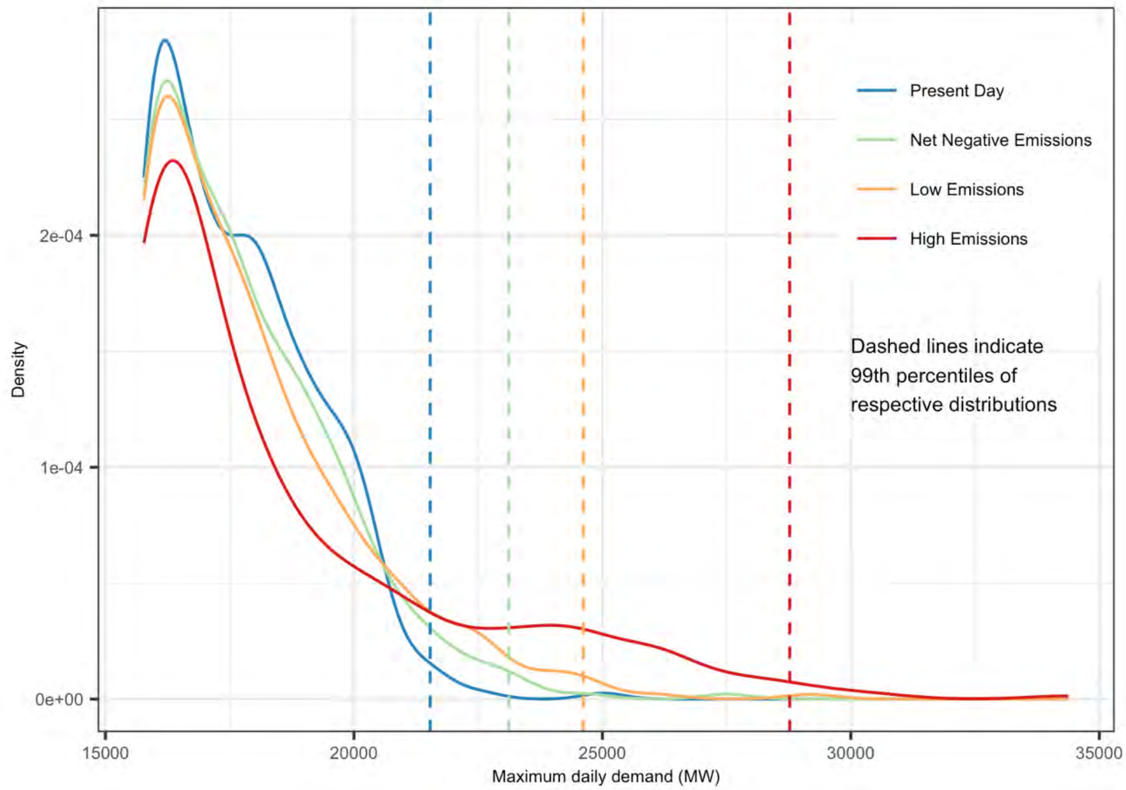
Figure 5.2: Cumulative Probability distribution of daily Maximum Temperature in Ontario in the Period 2090-2100



Notes: The "Present Day" distribution corresponds to the daily peak demand distribution in the reference year (i.e., 2019). Future daily maximum temperature projections are averaged across 25 independent climate models.

Distributions of predicted daily peak electricity demands in the 2090 – 2100 period under three climate scenarios are shown in Figure 5.3. The distribution of daily peak demand in the reference year (i.e., 2019) is also shown in Figure 5.3 and referred to as "Present Day." As shown in Figure 5.3, climate change right shifts the distributions of daily peak electricity demand. Compared to the peak demand of the reference year, the 99th percentile of the daily peak demand distributions under Net Negative Emissions scenario (RCP2.6), Low Emissions scenario (RCP4.5), and High Emissions scenario (RCP8.5) increase by 8%, 14%, and 34% respectively.

Figure 5.3: Distributions of Daily Peak Demands in Ontario in the Period 2090-2100

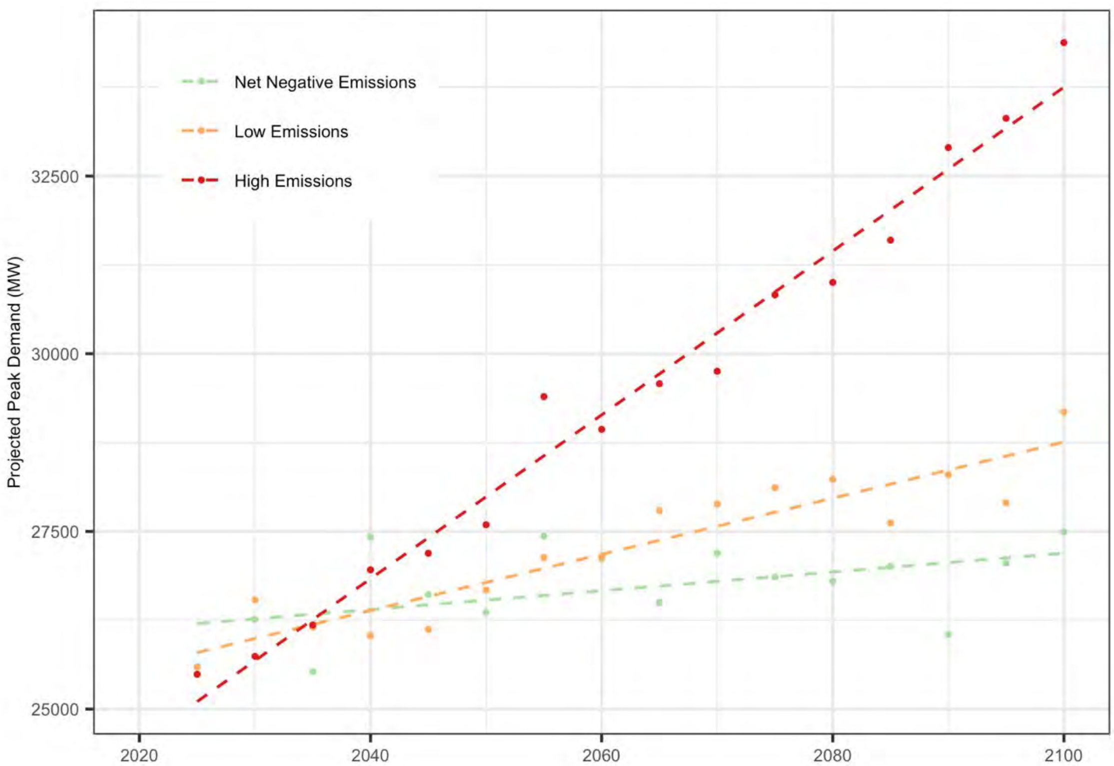


Notes: The "Present Day" distribution corresponds to the daily peak demand distribution in the reference year (i.e., 2019). Future daily peak demand projections are averaged across 25 independent climate models. Source: CERI

The electricity systems are designed to maintain high system reliability. In other words, the power systems are designed to satisfy the demand over 99% of the time. Due to climate change, the results show that electricity generation and delivery infrastructure capacities must be increased by a minimum of 8 – 34% by the end of the century to maintain system reliability. Figure 5.4 shows the growth in peak demand in the period 2025 – 2100 is due to increased daily maximum temperatures under three climate scenarios. As shown in Figure 5.4, depending on the climate scenario, climate change-driven growth in the annual peak electricity demand in Ontario varies in the range 0.1%/year (Net Negative Emissions, RCP 2.6) to 0.4%/year (High Emissions scenario, RCP8.5).

It should be noted that relative growth in the 99th percentile of peak demand (Figure 5.3) and annual peak demand growth rate (Figure 5.4) discussed here are only due to the impacts of climate change. As previously, discussed except for the daily maximum temperature, this analysis kept all factors that would influence the daily peak demand constant at 2019 levels. However, other demographic, economic, and technology-related factors would inevitably affect the daily peak demand. For example, a recent peak demand outlook produced by the IESO forecasts the annual peak demand in Ontario to grow on average at about 0.9%/year between 2020 and 2040. Climate change could potentially increase the peak demand growth rate by another 0.1 – 0.4%/year.

Figure 5.4: Projected Peak Demand on Ontario Under Different Climate Scenarios



Notes: The figure shows the predicted peak demand due to the influence of rising daily maximum temperatures.
Source: CERI

Cost Implications and Mitigation Options

As discussed above, the increase in ambient temperature increases Ontario's peak demand beyond the peak demand growth due to economic and population growth. This study estimates that the average annual peak demand growth due to the ambient temperature increase under Net Negative Emissions, Low Emissions, and High Emissions scenarios is approximately 22MW, 40MW, and 90MW, respectively.

To maintain electricity system reliability under increasing ambient temperatures, one mitigation option is installing additional electricity generation and transmission capacity. The exact generation technology choice installed in Ontario is uncertain and depends on electricity generation investors' decisions. One required characteristic of generating units used to satisfy peak demand is that they need to be dispatchable. Under current conditions[3], a lower-cost dispatchable generation technology is natural gas-

[3] Under current conditions the capital cost of NGSC is estimated to be approximately CAD$700/kW (IEA/NEA 2020)

fired simple-cycle (NGSC) units. If NGSC units are to be built to mitigate the increase in peak demand, under current costs, the average annual generation investment under Net Negative Emissions, Low Emissions, and High Emissions scenario would be CAD$15.4 million/year, CAD$ 29 million/year, and CAD$ 63 million/year, respectively.

Determining the transmission investment costs is not straightforward. A reliable estimation of transmission enhancement requirements requires electricity power system simulations that consider existing transmission systems, the location of current and future generating units, and the spatial distribution of electricity demand. A rough estimation shows that the transmission enhancement requirements under the Net Negative Emissions scenario are equivalent to adding a 138 kV transmission line to the Ontario electricity system every five years between 2025 and 2100. The associated minimum capital cost requirement will be approximately CAD$ 1.3 million per kilometre of transmission addition[4]. Similarly, under the High Emissions scenario, the transmission enhancements are equivalent to the addition of a 230kV transmission line every five years that would require a minimum investment of about CAD$ 2 million per kilometre of transmission addition. As mentioned above, determining the exact nature of required transmission enhancements needs systems-level simulations beyond the scope of this study.

Other options are available to mitigate the increase in peak demand. These include but are not limited to investment in energy storage. Strategic addition and siting of energy storage can potentially avoid or defer generation and transmission investments. If electricity storage is used as a mitigation option, the exact investment required depends on the duration of peak demand conditions and the electricity storage technology choice. If lithium-ion batteries with 4 hours of storage duration are used, under the current conditions, the annual investment requirements would be approximately CAD$ 20 million/year under the Net Negative Emission scenario and CAD$ 80 million/year under the High Emissions scenario[5].

The main observation from this analysis is that the cost implications of peak demand increase due to the rise in ambient temperature in Ontario are non-trivial.

Implications for Electricity System Planning

The illustrative case study shows that climate change would lead to higher peak electricity demand in Ontario, requiring additional system infrastructure investments to maintain system reliability. Although this analysis was limited to Ontario, given the expected changes in ambient temperatures across Canada, it is highly likely that similar results would be observed in other provinces. The case study results show that even if the emissions remain low (for example, follow RCP2.6), there will be upward pressure on peak electricity demands.

Conversely, the warming trend may decrease the peak electricity demand in electric power systems in Canada. Historic observations reveal that most electricity is consumed during the coldest hours of a given year in many provinces. In those provinces, the increase in ambient temperature may lower the peak

[4] Estimated based on the information from GE Energy Consulting (2016)
[5] Estimated assuming lithium ion battery capital cost of CAD$220/kWh (based on Cole and Fraiser (2020))

demand during winter, decreasing the infrastructure requirements to maintain system reliability. Although, a higher summer electricity demand may occur due to higher summer temperatures. It should be noted that the variation in peak demand conditions across provinces depends on the appliance choice and behaviour of electricity consumers. Both of those factors may change over time and could potentially be influenced by climate change. For example, more households may install air conditioners due to increasing ambient temperatures, leading to changes in the electricity demand profile.

Furthermore, even within a given province, intra-regional variations may exist. For example, although the peak demand in Alberta is generally observed in winter, the peak demand in the south part of the province, which includes the highly populated Calgary sub-region, is observed in summer. Since the ambient temperatures are projected to increase in all of Canada, the evolution of the electricity demand profile may deviate from what we currently anticipate based on past observations.

The case study only considered the impact of temperature on peak electricity demand. It should be noted that, as reported in Chapter 3, higher air temperatures would also reduce the capacity of electricity delivery systems. As reviewed in chapter 2, the electricity generating units may also experience capacity and efficiency reductions under higher ambient temperatures. Therefore, increasing temperatures would exert concurrent pressure on electric power systems on multiple fronts, challenging the system's reliability. Further analysis is required to assess the full system-level impacts of climate change on electricity system reliability and associated costs for the electric power systems of Canadian jurisdictions.

As discussed above, the cost implications of enhancing electricity generation and transmission systems to mitigate the ambient temperature-driven peak demand increase are nontrivial. In addition to infrastructure additions, peak demand increases can be dampened by deploying energy efficiency measures, demand-side management measures, and market-based tools such as time of use pricing. The results show that the climate change-induced events would increase the importance of those peak demand management measures.

It is prudent that the electricity system planners consider the impact of climate change on peak demands to design electricity infrastructure. Down-scaled climate model results can provide valuable information to inform electricity infrastructure planning. Overall, the electricity system will need to be enhanced to support the increased peak demand conditions across Canada.

Chapter 6 : Conclusions

Climate change is altering the weather conditions in which electric power systems must operate. The warming trend in Canada is, on average, about double the magnitude of the global average. The electricity infrastructure that is designed by considering the observed weather patterns may be vulnerable and experience outages and other physical impacts. This study used down-scaled climate model results to quantify the physical and cost impacts of climate change on electricity systems in all Canadian provinces.

This study primarily assessed the climate change impacts on the electricity delivery infrastructure in Canadian provinces, including the transmission and distribution systems. The impacts are assessed under three climate scenarios corresponding to alternative futures characterized by atmospheric CO2 concentrations and global temperature anomalies by the end of the century.

Climate change-induced events that can impact the Canadian electricity delivery infrastructure are identified through a review of climate model results and existing literature. Climate stressor response functions are developed to assess the climate change impacts of electricity delivery systems. The physical impacts are translated into economic costs to estimate the increase in the average cost of electricity in Canadian provinces in 2020 – 2100.

The results show that the magnitude of climate change impacts varies by climate scenario, province, and types of assets. The dominant climate change impact on the electricity delivery system in terms of the contribution to the increase in average cost of electricity is found to be the transmission line capacity reduction due to higher ambient temperatures. It was found that depending on the climate scenario by the end of the current century, the load-carrying capacity of electricity transmission lines would decrease by about 1% to 4.5%. The reduction in line capacity accounts for more than 50% of the average cost increase due to climate change impacts on electricity delivery systems. Other impacts that have major cost implications include distribution line derating, life span reduction of electricity delivery infrastructure and system damages due to wildfires.

It should be noted that while much of this analysis is focused on the provinces, the set of impacts would be exacerbated in the territories due to; 1) larger climate changes in northern Canada, 2) smaller populations to pay for rate base additions, 3) lower density infrastructure, and 4) higher on average costs for infrastructure development. As such, the observations regarding climate impacts on Canada's electricity systems are magnified in northern Canada.

The combined cost of climate change impacts on electricity delivery infrastructure will reach about CAD$ 1- 4.5 billion per year by the end of the current century. The associated increase in the average cost of electricity would be 0.2 cents/kWh to 2 cents/kWh by 2096 – 2100, depending on the climate scenario and province. Saskatchewan and Manitoba appear to have the highest cost of electricity increase due to climate change. The main reasons are the lower population density and geographic correlation with electricity infrastructure and areas where most adverse impacts of climate change are observed.

The study also developed a case study to examine the temperature responsiveness of peak electricity demand of Ontario. The results show that climate change can increase the demand for peak electricity generation and delivery capacity by 8 – 34% in Ontario by 2096 – 2100. Furthermore, depending on the climate scenario, the rising ambient temperatures will increase Ontario's peak demand growth rate by 0.1%/year to 0.4%/year beyond the socioeconomic factors that would lead to growth in peak electricity demand. Further analysis is required to quantify the impact on peak demand by rising ambient temperatures in other provinces.

One of the main limitations of this study is the exclusion of several climate change impacts on electricity delivery infrastructure due to data unavailability. Data at the municipal distribution system level was particularly limited. A higher level of collaboration with electricity system operators is required to produce a robust and complete set of physical and cost impact assessments.

A high-level study on the impact of climate change on electricity generation systems was conducted. The results show that there can be potential impacts on power generation infrastructure. Overall, the impacts seem to be small comparatively. However, climate change impact assessment of electricity generation systems in Canada merits a standalone study.

This analysis showed that climate change would exert pressure on electric electricity delivery and generation infrastructure on multiple fronts. Furthermore, those impacts will be exacerbated by the increase in peak elasticity demand due to climate change. The results also show that even if the emissions remain low, there will be upward pressure on electricity systems, challenging their ability to operate reliably and cost-effectively. Therefore, it is prudent that the electricity system planners consider the impact of climate change on electricity generation and delivery systems when designing electricity infrastructure. As illustrated in this analysis, down-scaled climate model results can provide valuable information to inform electricity infrastructure planning.

This analysis assumes only that one peak impact on demand. However, the move toward electrification of non-traditional sectors such as transportation and industry and the introduction of new grid-level and distribution-level generation will require significant new investment in transmission and distribution systems. CERI has completed several studies looking at each of these issues[6]. These reports include 1) decarbonize generation, 2) electrify services, and 3) introduce new technologies and business models. Together with this report, this scope of research clearly demonstrates an unprecedented challenge to managing electricity system growth. Will Canada and its provinces be able to attract sufficient capital to double the size of our grids? Will there be sufficient tradespeople and engineers to build it? Will we have enough room in our urban centres to site new substations in existing neighbourhoods to serve our electric vehicles? Will our regulatory processes be sufficiently flexible to adapt to changing circumstances? Will citizens accept the doubling of the land footprint in order to service the needs of our energy transition? And how will we afford to pay for this expansion?

As the energy transition will take decades, long-term support for similar research as noted above is necessary to provide up-to-date insight into the evolving nature of our vital electricity systems.

[6] These reports can be found at ceri.ca

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