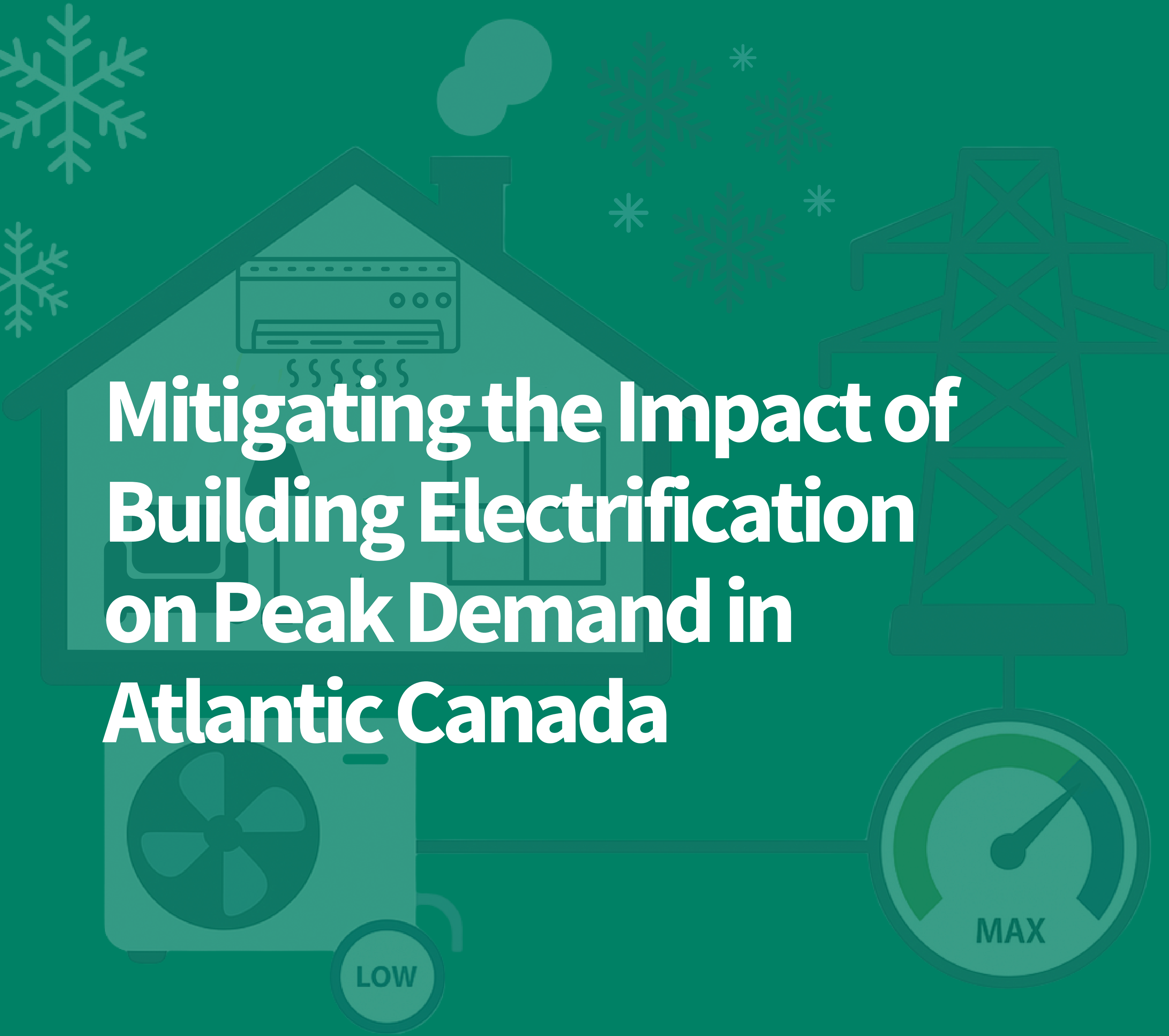
Mitigating the Impact of Building Electrification on Peak Demand in Atlantic Canada



August 2025 Modelling Report

About the Institut de l’énergie Trottier (IET)

The Institut de l’énergie Trottier (IET) was created in 2013 thanks to an exceptional donation from the Trottier Family Foundation to Polytechnique Montréal. Since then, it has been involved in every energy debate in the country. At the source of major collective reflections, the team mobilizes knowledge, analyzes data, popularizes issues and recommends fair and effective plans, simultaneously contributing to academic research and training. Its independence gives it the neutrality essential to the collaborative approach it advocates, facilitating work with the players most likely to advance the energy transition, while allowing it to be freely critical when relevant.

As the initial 10-year mandate came to an end, the Trottier Family Foundation decided to renew its confidence in the IET and made a new donation. Given the scope of the IET's activities and its status as a key player, its mandate was extended. The team will thus be able to continue offering science-based advice and enriching societal dialogue in order to advance the way we produce, convert, distribute and use energy.

About NetZero Atlantic

Net Zero Atlantic is a leading research organization incorporated under the Canada Not-for-profit Corporations Act, with its main office in Halifax and operations spanning across Atlantic Canada. Net Zero Atlantic conducts applied research and supports collaborative projects that advance the region’s transition to a carbon-neutral energy system. As an independent organization, it works closely with governments, Indigenous communities, academia, NGOs, and the private sector to provide credible, evidence-based insights that inform energy and climate decisions. Its areas of focus include energy system modelling, offshore wind, hydrogen, solar, geothermal, carbon sequestration, green buildings, and behavioural mitigation strategies.

Disclaimer

Citation

Langlois-Bertrand, S., Edom, E., Alkatheri, M., Beaumier, L., Scholtysik, S. (2025). Mitigating the impact of building electrification on peak demand in Atlantic Canada. Institut de l’énergie Trottier – Polytechnique Montréal and Net-Zero Atlantic.

Authorship team

Simon Langlois-Bertrand, PhD – Research Associate
Institut de l'énergie Trottier

Éloïse Edom, M.A.Sc. – Research Associate
Institut de l'énergie Trottier

Mohammed Alkatheri, PhD – Energy System Modeller
Net Zero Atlantic

Louis Beaumier, M.A.Sc. – Executive Director
Institut de l'énergie Trottier

Sven Scholtysik, M.Sc. – Research Director
Net Zero Atlantic

Contact

Institut de l'énergie Trottier
Polytechnique Montréal
2900, Boul. Édouard-Montpetit
2500, chemin de Polytechnique
Montréal (Québec) H3T 1J4
Web: iet.polymtl.ca
iet@polymtl.ca

Net Zero Atlantic
1209 Marginal Rd.
Halifax, NS B3H 4P8
Web: netzeroatlantic.ca
info@netzeroatlantic.ca

Executive summary

The last few years have seen an acceleration in the development and deployment of decarbonization strategies both across Canada and around the world. With the growing number of modelling studies analyzing pathways to reduce greenhouse gas emissions—especially to achieve the net-zero target by 2050, as committed by Canada and several other countries—it is now widely accepted that a large portion of energy services will shift to electricity. This transition requires a rapid and substantial transformation of the electricity supply system, which brings with it a number of planning, cost, and infrastructure challenges.

In this context, the electricity system in Atlantic Canada is under pressure from the following two major trends: the phase-out of coal in power generation and its replacement by non-emitting sources of electricity like wind and solar, which add complexity to grid planning; and the expected growth of annual and peak electricity demand following from the combination of the electrification of various energy services, such as transport and building heating, and population growth.

Together, these trends make it necessary to rapidly expand clean electricity generation and grid capacity to support decarbonization. At the same time, this must be done while keeping electricity affordable, maintaining system reliability, and avoiding unnecessary overbuild. Using **scenario-based modelling**, this report provides **region-specific insights into how residential heating electrification and population growth could affect winter peak electricity demand**. The analysis was conducted by Institut de l'énergie Trottier (IET) and Net Zero Atlantic (NZA) using the Atlantic Canada Energy System (ACES) Model—a region-specific, bottom-up capacity expansion model designed to support long-term electricity system planning.

The subsequent findings further show how this modelling approach can **inform** electrification programs, peak demand mitigation strategies, and long-term electricity system planning. The **analysis focuses on hybrid heating systems** as a transitional planning solution. Additionally, the report points to **other promising strategies** including demand-side management, energy storage, and smart energy management technologies, which were not modelled in this analysis but are important areas for future exploration.

Winter Peak Electricity Demand as an Immediate Key Challenge

The increase in winter peak electricity demand is primarily driven by building electrification and is further complicated by the transition of the electricity system away from fossil fuels, which have traditionally provided firm capacity to meet peak demand. This stands out as a key early challenge. While electrification across sectors often raises overall electricity demand without significantly affecting peak periods, space heating in buildings is highly concentrated during winter peak periods, causing sharp demand spikes that last from hours to days. This requires the electricity system to maintain enough capacity to meet demand during those short periods, even though that capacity might remain underused for the rest of the year.

Looking at the average or annual electricity use is not enough. Winter peaks, especially during very cold weather when heat pump performance declines, place significant stress on the grid. Without careful planning, these short but intense events could lead to investment in costly infrastructure that are not often used. This makes it essential to go beyond averages and develop targeted strategies to manage winter peak demand effectively.

Modelling heating strategies for winter peaks

A key strength of this analysis is the inclusion of **temperature-dependent heat pump performance**, which allows the model to capture changes in electricity demand during extreme cold. The model also examines the impacts of activating **backup heating systems** that support primary electric heat pumps, such as electric baseboards or fossil fuel units. These systems are used during the very coldest periods of the year when heat pump efficiency drops, offering insights into the actual stress on the grid and emissions under these conditions.

The scenarios used consider variations on three parameters: **the rate of population growth; the rate of electrification in the residential buildings sector**; and **whether electric baseboard heating is replaced at end of life—with possible replacements including hybrid systems (high-efficiency heat pumps paired with a fuel-based backup)**. Across these scenarios, assumptions differ on whether existing electric baseboards are replaced and on the share of new heating systems adopting electric technologies, whether for existing system replacements or to meet additional demand from population growth.

Overall, the results indicate that:

- **Electrifying residential buildings increases peak electricity demand significantly**, making it more challenging to meet this demand through grid expansion. While heat pumps help reduce the impact due to their high efficiency compared to other electric heating options, their performance drops during extreme cold weather. During these periods, backup systems such as electric baseboards (EBBs) are often activated, increasing the strain on the grid.
- Using **hybrid systems** to replace existing systems, including electric baseboards, significantly **reduces peak electricity demand**, while having **a negligible impact on total emissions** from the buildings sector. This impact on emissions is kept negligible **as long as these backup systems are used only in the coldest hours of the winter**, when temperatures are too cold for the heat pump to operate efficiently.

This suggests a trade-off: keeping a limited quantity of fossil-fuel based back-up heating systems can reduce the short-term requirements for electricity capacity expansion while only slightly increasing GHG emissions. When used selectively and framed as a **transitional solution**, hybrid systems can **ease peak demand pressures** during the shift to a **fully decarbonized electricity system**.

The need for a portfolio of approaches to peak mitigation

When considering the results, some important caveats and limitations to this analysis are worth noting. In particular, the model does not include any **cost premiums** resulting from subscribing to a refueling service, wood pellet delivery, or natural gas supply. The fixed costs associated with maintaining such distribution services for small overall quantities and frequencies may be substantial in contrast to fuel costs, which may raise the latter.

Another limitation to the analysis is that hybrid systems may imply an additional cost for the customer, despite the savings from a grid planning perspective. Importantly, even installing a hybrid system through a conversion of an existing fuel-based system into a backup for a newly installed heat pump, still involves additional installation costs – such as upgrading control systems and switching mechanisms, as well as extending the life of fossil fuel furnaces nearing the end of their useful life. However, if these systems are clearly framed and supported as transitional, time-limited solutions, targeted incentives or program design can help offset these upfront costs and avoid long-term lock-in.

Given these policy and implementation considerations, it is essential that the costs and benefits of hybrid systems be fully evaluated before deployment at scale. While the advantages of hybrid systems are noted in our results, considering their use must be done in the context of a broad societal transition toward a net-zero economy. Therefore, their use must be circumscribed to situations where (1) they offer their maximal advantage in terms of peak management and (2) they do not lead to an overall increase in the number of fuel-based systems, backup or not. In other words, **their role must be understood as a transitional strategy** for decarbonizing buildings that may offer significant cost reductions on the short and medium term, in a way that does not slow down or prevent the sector's net-zero transition.

With these caveats in mind, incorporating non-fuel-based technologies for peak mitigation in combination with hybrid systems could offer promising alternatives. These options may help avoid the challenges mentioned above, even though they are currently not widely deployed. Options range from demand-side approaches, such as smart thermostat programs that preheat homes before peak events to reduce peak load, rate-based tools (e.g., critical peak pricing), alternative heating technologies with minimal electricity demand (e.g., high-efficiency geothermal heat pumps), thermal and electrochemical storage devices (e.g., utility-scale batteries, distributed thermal accumulators), as well as power demand control technologies (e.g., smart electric panels and EV chargers). In the short and medium term, hybrid systems can create a window of opportunity to pilot and refine other peak mitigation options. This can help reduce long-term decarbonization costs by providing time to develop and scale a broader set of non-fossil peak management solutions.

A roadmap to address the winter peak challenge

This report focuses on one critical short-term challenge: how residential space heating electrification, alongside population growth, could sharply increase winter peak electricity demand. Without targeted mitigation strategies, a limited understanding of this trend could persist, risking costly overbuilds of electricity infrastructure for a few hours of extreme demand each year.

Using scenario-based modelling with the ACES Model, we find that hybrid heating systems—when deployed strategically—can significantly reduce winter peak demand while offering electricity system infrastructure cost savings. These systems are especially useful when heat pump performance drops during extreme cold. However, their contribution to peak demand management and system cost control depends on careful policy design and further assessment of the cost and feasibility of using fuel-based systems as backup for only a few hours or days each year.

Based on these findings, we recommend policymakers and utilities investigate and assess the cost and practical implications of deploying hybrid systems as a transitional tool, while ensuring incentives align with long-term decarbonization goals. Hybrid systems must be framed as short-term, peak-specific solutions—not permanent fossil-based infrastructure.

We also emphasize the importance of evaluating a broader set of mitigation strategies, including demand-side management, energy efficiency, and smart technologies. These options should be assessed with attention to technical feasibility, cost, and community acceptance across diverse regional contexts.

Overall, we propose seven recommendations for priority actions:

1. **Prioritize Winter Peak Management in Electrification Programs**
2. **Support Hybrid Heating Systems as a Targeted, Transitional Strategy**
3. **Modernize the Grid with Smart Technologies and Storage**
4. **Expand Demand Response and Tailored Load Management**
5. **Strengthen Interprovincial Coordination**
6. **Align System Replacement Policies with Net-Zero Goals**
7. **Engage Stakeholders and Build Public Readiness**

Table of Contents

1 Introduction and Purpose

The last few years have seen an acceleration in the development and deployment of decarbonization strategies both across Canada and around the world. With the growing number of modelling studies analyzing pathways to reduce greenhouse gas emissions—especially to achieve the net-zero target by 2050, as committed by Canada and several other countries—it is now widely accepted that a large portion of energy services will shift to electricity. This transition requires a rapid and substantial transformation of the electricity supply system, which brings with it a number of planning, cost, and infrastructure challenges.

Using **scenario-based modelling**, this report provides **region-specific insights into how heating electrification and population growth could affect winter peak electricity demand**. The subsequent findings further show how this modelling approach can **inform** electrification programs, peak demand mitigation strategies, and long-term electricity system planning. The following **analysis focuses on hybrid heating systems** as a key planning solution. Additionally, the report points to **other promising strategies** including demand-side management, energy storage, and smart energy management technologies, which were not modelled in this analysis but are important areas for future exploration. In addition, the report emphasizes **the value of regional and interprovincial coordination** to manage winter peaks, optimize system investments, and support shared efforts in planning, technology, and workforce development.

Pressures Reshaping the Grid

The electricity system in Atlantic Canada is under pressure from the following two major trends:

- Phase-out of coal in power generation and its replacement by non-emitting sources of electricity like wind and solar, which ad complexity to grid planning;
- Growth of annual and peak electricity demand following from the combination of the electrification of various energy services, such as transport and building heating, and population growth.

Together, these trends make it necessary to rapidly expand clean electricity generation and grid capacity to support decarbonization. At the same time, this must be done while keeping electricity affordable, maintaining system reliability, and avoiding unnecessary overbuild.

Understanding how these pressures interact—and which strategies can mitigate their impact—requires modelling. Region-specific, quantitative analysis is essential to test different pathways, identify trade-offs, and provide practical guidance for electricity system planning in Atlantic Canada.

Winter Peak Electricity Demand as an Immediate Key Challenge

In particular, the increase in winter peak electricity demand resulting from the grid's transformation under the pressures outlined above stands out as a key challenge to meet early on. While the electrification of services across sectors sometimes leads to an overall increase in electricity demand without significantly affecting peak periods, some services are highly dependent on the time of the day and the time of the year. Notably, space heating in buildings is associated with several episodes of peak demand during the coldest months of the year, each of which lasting from a few hours to several days. This requires the electricity system to maintain enough capacity to meet demand during those short periods, even though that capacity might remain underused for the rest of the year.

Looking at average or annual electricity use is not enough. Winter peaks driven by space heating place significant stress on the system and are expected to grow as more households adopt electric heat pumps. These peaks are especially difficult to manage during very cold weather, when heat pump performance declines[1] and demand rises sharply. If not carefully planned for, these short but intense events could lead to costly investments in infrastructure that sees limited use. This makes it essential to go beyond averages and develop targeted strategies to manage winter peak demand effectively.

Modelling heating strategies for winter peaks

In this report, we focus on the region's energy system transition challenge by narrowing the discussion down to a subset of the pressures outlined above, namely the combination of building electrification and population growth.

Our aim is to explore how these factors influence the electricity grid in Atlantic Canada, and how targeted efforts to reduce peak heating demand can help address these challenges.

To achieve this end, the report uses scenario-based modelling to assess how residential space heating electrification and population growth may impact winter peak electricity demand. The analysis was conducted by Institut de l'énergie Trottier (IET) and Net Zero Atlantic (NZA) using the Atlantic Canada Energy System (ACES) Model—a region-specific, bottom-up capacity expansion model designed to support long-term electricity system planning.

---

[1] *Air-source heat pumps (ASHPs) experience a natural decline in efficiency during extremely cold temperatures, due to reduced heat extraction from the outside air. This is typically measured by the coefficient of performance (COP), which falls as outdoor temperatures drop. For further detail, see:*

- *Pacific Northwest National Laboratory (2023). Performance Results from DOE Cold Climate Heat Pump Challenge Field Validation*
- *ScienceDirect (2023). Coming in from the cold: Heat pump efficiency at low temperatures*
- *Wikipedia. Air-source heat pump*

The modelling explores:

- Varying levels of residential heating electrification
- High and low population growth scenarios
- Replacement of electric baseboard systems
- Adoption of hybrid heating systems that combine heat pumps with fuel-based backup

A key strength of this analysis is the inclusion of **temperature-dependent heat pump performance**, which allows the model to capture changes in electricity demand during extreme cold. The model also examines the impacts of activating **backup heating systems** that support primary electric heat pumps, such as electric baseboards or fossil fuel units. These systems are used during the coldest periods of the year when heat pump efficiency drops, offering insights into the actual stress on the grid and emissions under these conditions.

Given this context, the next subsection outlines the specific objectives of this report and explains how the content is organized.

1.1 Objectives

We draw two main objectives for this report:

1 Assess and analyze the impact of residential space heating electrification and population growth on winter peak demand and its effects on the grid, including on the buildout of additional capacity.

2 Identify winter peak mitigation strategies and discuss their potential costs and benefits in the context of the Atlantic Canadian provinces.

To meet these objectives, the report proceeds as follows:

- Section 2 explores how electrification of residential space heating and population growth interact with winter peak demand using scenario-based modelling.
- Section 3 discusses additional options to mitigate winter peaks, including demand-side management and technology alternatives.
- Section 4 briefly highlights some supporting conditions, such as cost considerations and regional collaboration.
- Section 5 concludes with insights and priority recommendations for managing winter peaks in Atlantic Canada.

2 Electrification and Winter Peak Demand

Before turning to the analysis of residential space heating, this section offers a broader look at electrification trends across key sectors in Atlantic Canada. Electrification is central to regional decarbonization efforts, with expected shifts in how energy is used in transportation, industry, and buildings.

We then introduce a specific mitigation strategy—hybrid heating systems—and examine its effects on winter peak demand using scenario analysis with the ACES Model. This structure provides the necessary context for understanding winter peak dynamics and sets the stage for the broader mitigation options discussed in the next section.

2.1 Electrification Trends Across Sectors

Decarbonizing the economy across Atlantic Canada means, above anything else, a significant shift to electricity as the primary energy carrier used to deliver energy services. For instance, Figure 1 shows projections from the Canadian Energy Outlook (Langlois-Bertrand et al. 2024) for the four provinces to 2060: in both the net-zero (NZ) scenario considered and the reference scenario imposing no additional decarbonization efforts, electricity's share of the energy mix grows significantly (from 26% of final consumption to 42% in the reference scenario and 55% in the NZ scenario).

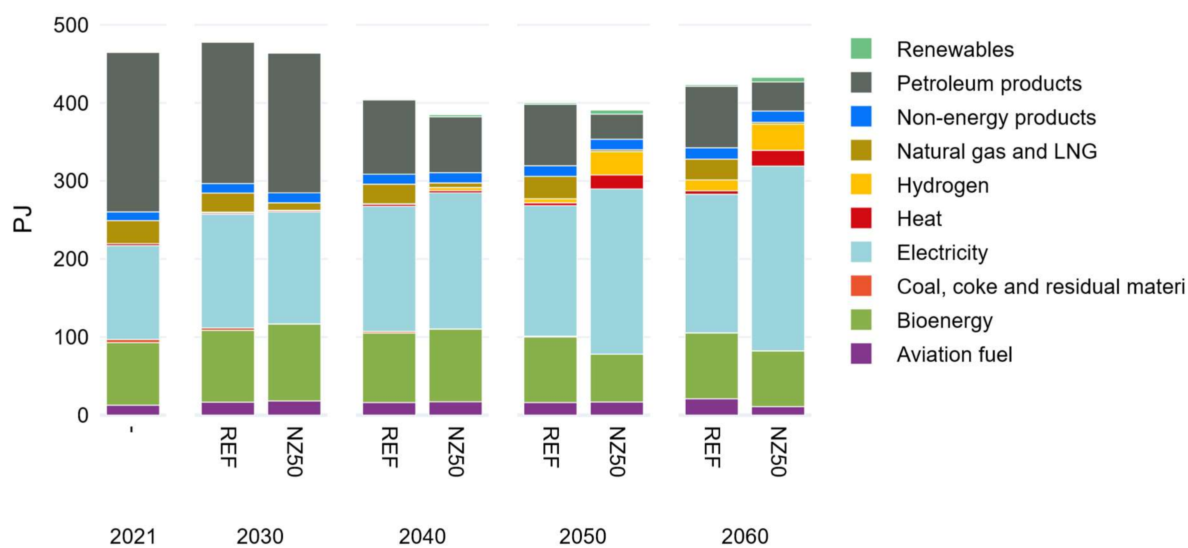


Figure 1 - Final energy consumption by source, Atlantic Canada, reference and net-zero scenarios

Source: Langlois-Bertrand et al. (2024)

In transport, this means increasing the share of electric vehicles and trucks which in turn puts upward pressure on electricity demand. In industry, this means converting a significant share of heating demand to electric technologies like electric boilers, heat pumps, and resistance heating, and using more electrically driven equipment like small compressors and pumps. In buildings, this means converting heating oil and natural gas heating systems to electric systems involving heat pumps, which also provide air cooling services in the summer. In parallel to this electrification of services across all sectors, electricity generation must also be decarbonized in New Brunswick and Nova Scotia.

The brief descriptions above are not meant to oversimplify the variety of transformations possible or even desirable in decarbonization pathways. Rather, these highlight the main trends already underway in the short term and expected over the medium to long term, offering a reference point for the analysis that follows.

In parallel with electrification and decarbonization efforts, population is also expected to grow significantly across the provinces over the next few decades. In addition, estimates differ and vary widely: therefore, population growth could add a significant upward pressure on demand for services (kms of transport, square meters of building space, etc.).

2.2 Focus on Residential Space Heating

While a brief overview of demand trends suggests an overall increase in electricity demand in the winter, in this report, we are interested in the specific insights gained by focusing on the demand resulting from the electrification of space heating in residential buildings. To ground these insights, we have also assumed different possibilities for population growth, as it relates to driving demand for space heating. As a result, we draw out the specific impact of space heating electrification with a larger population on winter peak demand.

Residential space heating is the **primary driver of winter electricity peak demand** because it is highly sensitive to cold weather and cannot be deferred. As temperatures drop, heating demand rises sharply—far more than for other residential uses like lighting, appliances, or even water heating. Unlike these services, space heating is essential for health and comfort, leaving households with **no option to delay usage** during cold spells. Electric heat pumps, which are central to building electrification, perform efficiently under normal conditions but lose effectiveness during extreme cold, just when demand is highest. In such cases, backup systems—often electric resistance heaters - are activated, further intensifying peak demand. Most existing models assume relatively high heat pump efficiency throughout winter, overlooking the impact of extreme cold events. **A key contribution of this study is to evaluate the implications of such extreme weather events—when heat pumps are unable to meet demand—on grid planning, reserve margin requirements, and overall system costs**. This is especially critical for rural or remote communities with weaker infrastructure, where outages during cold spells can have severe consequences.

While electric vehicle (EV) charging can also contribute to winter demand, especially since battery efficiency drops in cold weather and additional energy is needed to heat the cabin and battery, this load is generally more manageable. Charging can often be shifted to off-peak periods through smart charging programs or user behavior, reducing its impact on peak hours. Other contributors to electricity demand, such as industrial electrification, have a more limited or flexible effect on winter peaks. In contrast, the cumulative impact of hundreds of homes needing heat at the same time makes residential space heating one of the key challenging loads to manage in winter peak planning.

2.3 Regional Energy System Characteristics and Policy Context

As discussed in the previous section, **electrifying** residential space heating significantly increases winter peak electricity demand. However, the extent of this impact on the electricity system—and the strategies available to manage it—varies by province, depending on differences in energy mixes, infrastructure, and system design.

The energy systems across Atlantic provinces share some similarities but also present important variations. Figure 2 illustrates differences in **energy consumption by sector** across Atlantic provinces. In Nova Scotia and Prince Edward Island, industry accounts for a smaller share of total energy use (18% and 23%, respectively) compared to the national average of 53%. Newfoundland and Labrador is somewhat closer at 43%. In contrast, New Brunswick exceeds the national average, with industry comprising 55% of its energy consumption. The figure also illustrates current electricity generation by source, highlighting, for instance, Nova Scotia's continued reliance on coal—a factor that complicates its decarbonization efforts. The **planned phase-out of coal-fired power** plants by 2030 presents a particular challenge for Nova Scotia, where coal currently supplies 45% of electricity. Replacing this capacity with **variable renewable sources** like wind and solar reduces the amount of **firm, dispatchable power available**, making it more difficult to maintain grid reliability during peak winter heating periods.

At the same time, the region is experiencing a potentially increasing **peak-to-average demand ratio**.[2] This growing imbalance further intensifies the pressure on electricity infrastructure and planning. More broadly, upgrading the grid to meet both **rising demand** and decarbonization targets is complicated by the diversity of provincial energy systems, each shaped by distinct infrastructure and resource constraints. This challenge is especially pronounced in provinces where a large part of the population lives in **remote areas**—such as Newfoundland and Labrador—where low population density and geographic isolation drive up the cost and complexity of grid enhancements.

Another defining characteristic of the region is its **limited access to natural gas**. Unlike other parts of Canada, piped natural gas is only available in some urban areas of Nova Scotia and New Brunswick, further shaping the options available for heating transitions and peak management.

[2] The peak-to-average demand ratio corresponds to the ratio of the maximum power demand during the winter peak compared with the average annual power demand.

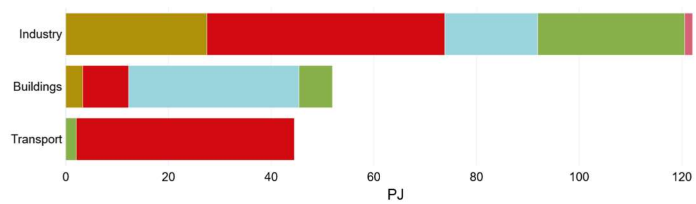
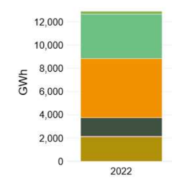
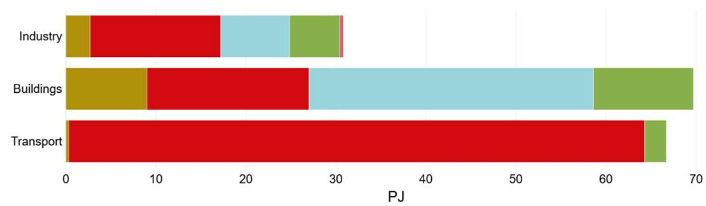
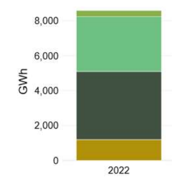
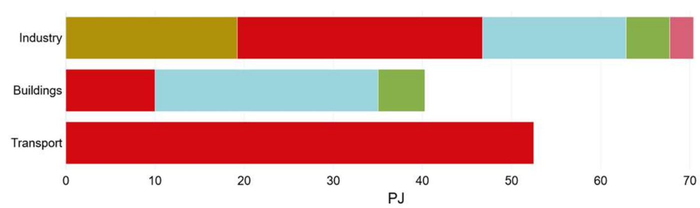
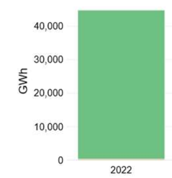
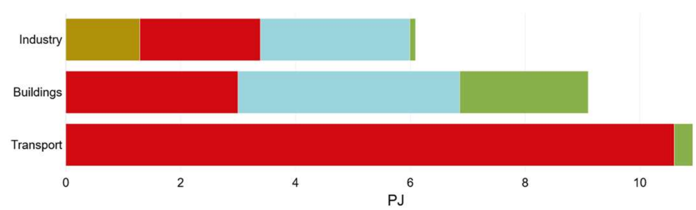
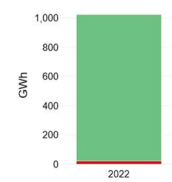
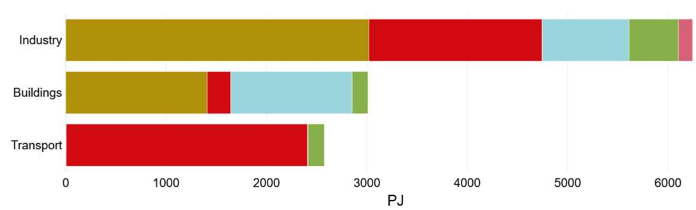
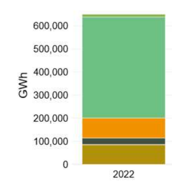
<table>
<tr><th>Province</th><th>Energy consumption by sector and by source</th><th>Electricity generated by source</th></tr>
<tr><td>NB</td><td></td><td></td></tr>
<tr><td>NS</td><td></td><td></td></tr>
<tr><td>NL</td><td></td><td></td></tr>
<tr><td>PE</td><td></td><td></td></tr>
<tr><td>CA</td><td></td><td></td></tr>
<tr><td>Legend</td><td>Other
Bioenergy
Electricity
Fuel oil & RPP
Natural gas</td><td>Bioenergy
Renewables
Nuclear
Coal
Fuel oil & RPP
Natural gas</td></tr>
</table>

Figure 2 - Energy mixes across Atlantic provinces (2022)

Source: CER (2025)

To support this transition, several **policies** have been introduced or announced to advance decarbonization in Atlantic Canada. **The Regional Energy and Resource Tables** are collaborative initiatives between the federal and provincial governments, created to accelerate low-carbon priorities across the country. These tables aim to identify and advance regional opportunities in clean energy, critical minerals, carbon management, and other sectors essential to the transition to a net-zero economy. A key priority of this effort is improving regulatory efficiency by streamlining project approvals and reducing barriers to clean energy deployment. As part of the 2030 Emissions Reduction Plan, the federal government has committed funding to support renewable energy development, contributing to its targets of reducing greenhouse gas emissions by 40–45% below 2005 levels by 2030 and achieving net-zero emissions by 2050.

Each Atlantic province also has its own policy measures to support this transition, with a strong emphasis on electrification using low-carbon electricity. These include phasing out heating oil, banning new oil furnaces in residential and commercial buildings, offering heat pump rebates, updating building codes to require net-zero-ready construction, setting renewable energy targets for the grid, and upgrading public buildings to improve energy performance.

2.4 The Role of Hybrid Heating Systems

Given that air-source heat pumps experience a significant performance drop at low temperatures, several hybridization approaches with air-source heat pumps can be considered. Specifically, a heat pump can be paired with either a backup (redundancy) system or a supplementary system. The definitions of these terms are provided in the table below.

Table 1 - Hybridization approaches to space heating systems

Term	Description	What does it mean?
Redundancy system	A second heating system (e.g., gas furnace) that takes over when the heat pump alone cannot meet demand—often fully displacing it during very low outside temperatures.	Backup system, or dual-fuel system
Supplementary system	A system that assists the heat pump, operating in tandem during peak loads or cold snaps, without fully replacing it.	Add-on system, hybrid support, load sharing, or bivalent heating system

Both approaches—redundancy and supplementary hybrid heating systems—can help reduce winter peak electricity demand by **distributing the heating load across multiple systems**. By alleviating pressure on the electric grid during cold periods, these configurations can reduce the need for large-scale infrastructure such as new power generation facilities or expanded transmission or distribution lines. This can result in significant system-wide cost savings and enable a faster rollout of electrification solutions, especially in regions where large infrastructure projects face long permitting processes, complex environmental assessments, and potential public opposition.

Distributed hybrid systems, such as those combining air-source heat pumps with backup or storage technologies, offer a **flexible and modular deployment path**. Their implementation is often simpler and quicker, particularly when compared to the timeline and complexity of centralized infrastructure investments. However, realizing this potential at scale, particularly with targets exceeding thousands of installations, requires coordinated planning and investment in workforce development. **Skilled trades and technicians** capable of installing, maintaining, and integrating these systems are in limited supply, and ramping up capacity in these areas will be essential.

Although these systems may include fossil fuel components, their usage is typically limited to short periods during the year—primarily during extreme weather events or peak demand conditions. This limited operation keeps their greenhouse gas emissions relatively low. As a transitional strategy, hybrid systems could help ensure energy reliability, and thus a household's confidence in adopting their new heating system, while electric systems and infrastructure catch up with growing demand. Nevertheless, the inclusion of fossil-based technologies presents some important challenges.

First, there is a risk of locking in fossil fuel infrastructure, leading to stranded assets that conflict with long-term climate commitments. To address this, backup systems should, where possible, be compatible with low-carbon alternatives or designed for future decommissioning as full electrification becomes feasible.

Additionally, from a social license perspective, there may be public concern that hybrid systems prolong dependence on fossil fuels. Clear communication will be necessary to emphasize their temporary role and low emissions profile, while also reinforcing their value in maintaining comfort and stability during system transition.

In summary, hybrid heating systems might offer a near-term solution for peak demand mitigation and system flexibility. However, their deployment would need to be accompanied by strong governance, transparent communication, workforce support, and a clearly defined pathway toward full electrification that aligns with climate targets.

As a result of the potential benefits outlined above, we pay special attention to the possibility of using hybrid heating systems, in a redundancy configuration, in the analysis below. We then, expand the discussion to other winter peak mitigation options available in section 3 below.

2.5 Scenario Design and Modelling Assumptions

To assess the potential impact of winter peak demand, we used the ACES Model (Box 2.1) and ran several scenarios. Our focus is on the transformation of heating systems in residential buildings stock under different population growth and electrification assumptions.

Box 2.1 – Atlantic Canada Energy System (ACES) Model Overview

The Atlantic Canada Energy System (ACES) Model is a long-term, capacity expansion energy system optimization model designed to analyze decarbonization pathways for the Atlantic provinces: Nova Scotia, New Brunswick, Prince Edward Island and Newfoundland-and-Labrador (Newfoundland and Labrador are treated as two separate regions in the model, as explained in Appendix B). The ACES Model is a bottom-up, technology-specific model that uses linear programming to determine least-cost investment and operational decisions and covers six sectors (electricity, buildings, transportation, industry, agriculture, and waste).

Electricity Demand Calculation in **the** ACES **Model**

In this study, we used a three-sector version of the ACES Model (electricity, transportation, and buildings), where electricity demand is partially endogenized. While total electricity demand is initially set using public utility load forecasts, **the model determines** electricity consumption for the building and transportation sectors based on technology adoption and energy service demands.

Their electricity consumption is endogenized, meaning:

- The model determines technology adoption levels (e.g., penetration of electric vehicles and heat pumps).
- The electricity demand from these sectors is calculated dynamically based on technology choices and energy service demands.
- To avoid double counting, the endogenized demand is subtracted from the bulk electricity forecast, ensuring that only the residual demand from non-modeled sectors (e.g., industry, agriculture, and waste) remains exogenously defined.

To maintain **realistic** system-wide demand, the residual electricity consumption from non-modelled sectors was added back exogenously, ensuring consistency with **regional electricity use patterns** while allowing the model to determine **sectoral electrification trends** and efficiency improvements to be captured.

However, in this study, we predefined the technological adoption of electric technologies for commercial buildings, residential appliances, water heating, and all transportation subsectors. This approach was taken to **isolate the impact** of residential space heating electrification from other electrification mechanisms across sectors.

Appendix B of this report contains an **extensive description** of the model's approach, including electricity generation and storage technologies, spatial representation and interconnections, interregional electricity trade, temporal resolution and representative days, building sector, transportation sector, policies considered, as well as a more detailed explanation of assumptions and considerations in the building space heating analysis.

The **list of technologies** is presented in Table 2. **Existing heating systems** are based on data from Natural Resources Canada's Comprehensive Energy Use Database (OEE 2025). The **rate of replacement** for existing heating systems is based on the following two scenario-specific assumptions: units are replaced only at the **end of their operational life**, the total existing stock is **evenly distributed** over the technology's reported lifetime. This approach helps model the gradual turnover of technologies. The assumed lifetime values for various heating systems are detailed in the ACES Model documentation[3] (NZA 2025) and the stock data is as reported in the Comprehensive Energy Use Database.

Table 2 - Space heating technologies considered in the scenarios

Existing	Replacements available
Heating oil furnace	Electric furnace
Natural gas furnace[4]	Heat pump with electric baseboard backup
Electric baseboards	Natural gas furnace
Air source heat pump	Oil furnace
Wood	Hybrid #1: heat pump with oil backup
Wood and electric dual systems	Hybrid #2: heat pump with wood backup
Wood and oil dual systems	Hybrid #3: natural gas backup

Three variables are used in the scenarios modelled:

- **The rate of population growth, which can be either high or low**. Population growth leads to an increase in floor area, which is then converted into space heating demand requirements. In the low-growth scenarios, population growth leads to a modest increase in total floor space. However, this is assumed to be approximately matched by energy efficiency improvements resulting in a flat space heating demand curve over time. In the high population growth scenarios, growth is too significant to be matched by efficiency improvements, as a result, space heating demand grows by an average of 0.8% per year across the Atlantic region.[5]
- **The rate of electrification, which can be low, medium, or high**. In the low electrification scenarios, 25% of the new heating systems sold are heat pumps by 2050; in the mid electrification scenarios, 50% of new heating systems sold are heat pumps by 2040; and in the high electrification scenarios, 100% of new heating systems sold are heat pumps by 2030. These assumptions were used to broadly align with those used in the Nova Scotia

[3] This can be found specifically within the building sector Excel workbooks (NZA 2025) https://netzeroatlantic.ca/media/1097/download

[4] Given the need for natural gas distribution infrastructure, natural gas furnaces can only be installed for buildings in the Halifax urban area, in Moncton, Saint John, and Fredericton, where natural gas distribution infrastructure currently exists.

[5] This growth rate represents the average annual increase in total space heating demand across all Atlantic provinces . The population growth assumptions used to calculate this vary by province and are based on Statistics Canada's high-growth scenario projections. The estimates are drawn from Statistics Canada Table 17-10-0057-01: *Projected population, by projection scenario, age and gender, as of July 1 (x 1,000)*. DOI: https://doi.org/10.25318/1710005701-eng

Power Integrated Resources Plan low, mid, and high electrification scenarios (NS Power 2020).

- **The option to replace electric baseboard heating at end of life**. In the high electrification context, three scenarios are considered for existing electric baseboard heaters (EBBs): existing EBBs remain in place as the primary heating system and are not replaced at end of life—only fuel-based systems are replaced by heat pumps; existing EBBs are replaced with heat pumps that use EBBs as a backup; or existing EBBs are replaced with either heat pumps with EBB backup or hybrid systems combining heat pumps with oil, gas, or wood backup.[6]

A few additional clarifications are worth noting. First, we assume that heat pumps do not operate in the coldest conditions and rely instead on a backup system (either fuel-based or EBBs) to meet heating demand. This assumption reflects the reduced performance of current air-source heat pumps in extreme cold conditions, as documented by Natural Resources Canada and the U.S. National Renewable Energy Laboratory (NRCan 2023 & NREL 2023). In the model, this transition occurs over a total (non-continuous) period of 46 hours[7] during the winter months. The model assumes these cold periods do not occur simultaneously across the Atlantic provinces.

The model accounts for slight differences in temperature profiles and timing across the region, factors that are embedded within the representative day selection, and the temperature-dependent performance of heat pumps. It captures variations in residential heating patterns that help stagger peak residential electricity demand across the region, meaning that maximum heating-related loads will occur at slightly different times in different provinces. For example, Newfoundland and Labrador, located farther north and in a different time zone, may experience peak residential space heating demand slightly earlier or later than Nova Scotia or New Brunswick. However, if a major weather event, such as a winter storm or extreme cold front, were to synchronize residential heating demand peaks across multiple provinces, the resulting stress on the regional electricity grid would be significantly amplified. Under such conditions, the impact of residential space heating electrification on winter peaks would be even more severe, and the ability to import from neighboring provinces could become highly constrained. While the model reasonably captures typical seasonal variations in residential heating demand, it may underestimate system stress during extreme events that synchronize residential electricity peaks across the region.

Second, it is important to note that a "mid-electrification" assumption is applied for transport electrification, following the approach used in NS Power's 2020 IRP. Additionally, to maintain realism, in the low and mid electrification scenarios, electric baseboard heating cannot be

[6] For the remainder of this report, the term "hybrid system" is used to refer to heating systems where an air-source heat pump is used as the main heating device while a fuel-based backup system (oil, wood or gas furnace) is installed for use only during winter peak periods (extremely cold hours).

[7] The 46-hour period is not a continuous time block but an equivalent duration derived from the representative day modelling approach. It is primarily reflected in the modeled peak winter day—January 2nd—and serves as an aggregate estimate of extreme cold conditions rather than exact hourly occurrences.

replaced by fuel-based systems: a fuel-based heater can only be chosen by the model to replace an existing fuel-based heater. Scenarios are outlined in Table 3.

Importantly, except for hybrid systems, no peak mitigation strategies (thermal storage, advanced demand response, etc.) are included in these scenarios. This exclusion reflects current data limitations: while these strategies are promising, reliable and region-specific deployment data—such as technology costs, adoption rates, and operational constraints—are not consistently available for Atlantic Canada. As a result, this modelling exercise provides a conservative reference case designed to isolate and assess the potential scale of winter peak demand growth from electrification and population trends. Section 3 of this report then considers peak mitigation strategies available today, based on other work by the IET (Edom et al. 2023, Edom and Mousseau 2025).

Table 3 - Description of scenarios

Scenario	LE-LP	ME-LP	HE-LP	HE-LP-EBREP	HE-LP-EBREP-HYB	LE-HP	ME-HP	HE-HP	HE-HP-EBREP	HE-HP-EBREP-HYB
Name										
General description	Low electrification, low population growth (reference)	Mid electrification, low population growth	High electrification, low population growth	High electrification with EB replacement, low population growth	High electrification with EB replacement and hybrid systems, low population growth	Low electrification, high population growth	Mid electrification, high population growth	High electrification, high population growth	High electrification with EB replacement, high population growth	High electrification with EB replacement and hybrid systems, high population growth
Residential space heating electrification (heat pump adoption)	Low	mid	High	high	high	low	mid	high	high	high
Transportation sector	Mid electrification									
Residential sector space heating	25% of heater new sales are HPs by 2050	50% of heater new sales are HPs by 2040	100% of heater new sales are HPs by 2030	100% of heater new sales are HPs by 2030	100% of heater new sales are HPs by 2030	25% of heater new sales are HPs by 2050	50% of heater new sales are HPs by 2040	100% of heater new sales are HPs by 2030	100% of heater new sales are HPs by 2030	100% of heater new sales are HPs by 2030
Demand Projection for space heating	Unchanged	unchanged	Unchanged	unchanged	unchanged	Growing proportionally with population growth.	Growing proportionally with population growth.	Growing proportionally with population growth.	Growing proportionally with population growth.	Growing proportionally with population growth.
HPs replacing EBBs at their end of life	No	No	No	yes	yes	No	No	No	yes	yes
Peak Mitigation: Hybrid System	No	No	No	No	yes	No	No	No	No	yes
Carbon Tax	Applied									

2.6 Peak Demand Results and System Impacts

Figure 3 shows the electricity peak load profile across the Atlantic provinces for the reference year (2022). Four curves are shown: the peak load hourly profile for a representative peak demand day (January 2nd) and a representative low demand day (June 23rd) for each of residential and total demand.[8] Even with relatively low electrification rates in residential space heating, the hourly variation during the peak day is noticeably higher compared with a summer day. The curves also show that the contribution of residential space heating to the ramp-up and maximum overall peak level experienced early in the morning is relatively limited. However, based on the projected residential load profile under large-scale electrification, space heating electrification is expected to exacerbate this ramp-up.

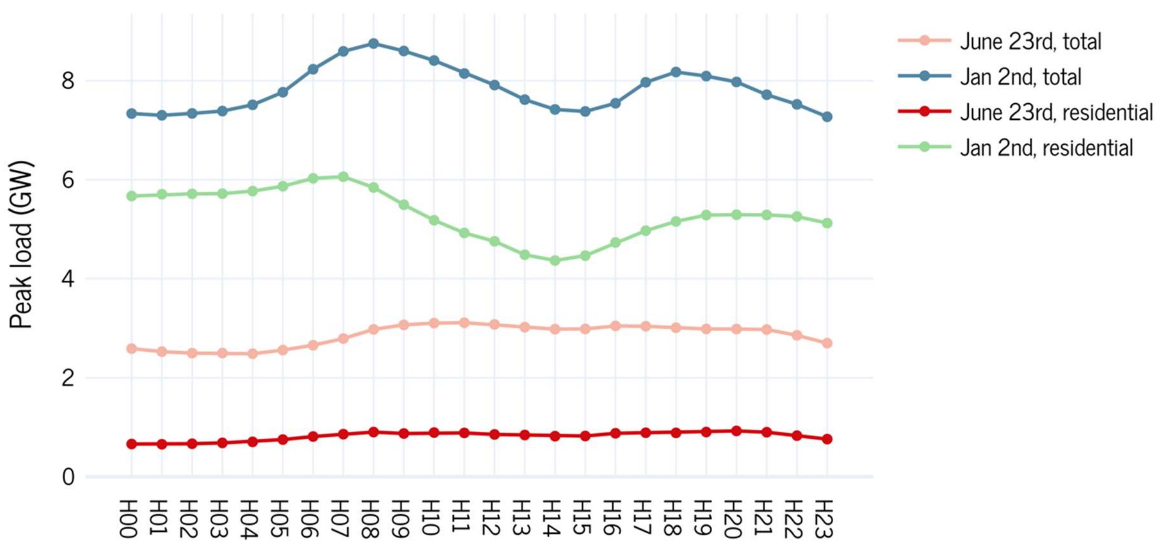


Figure 3 – Residential vs. Total Hourly peak load profile for selected representative days in the base model year (2022)

[8] In capacity expansion modelling, a representative day approach is commonly used to reduce computational complexity while capturing key system conditions. In this study, January 2nd is selected as a representative winter peak day—it may not reflect the exact peak day of the year but is chosen to simulate a high-demand, low-wind scenario that stresses system reliability and capacity needs.

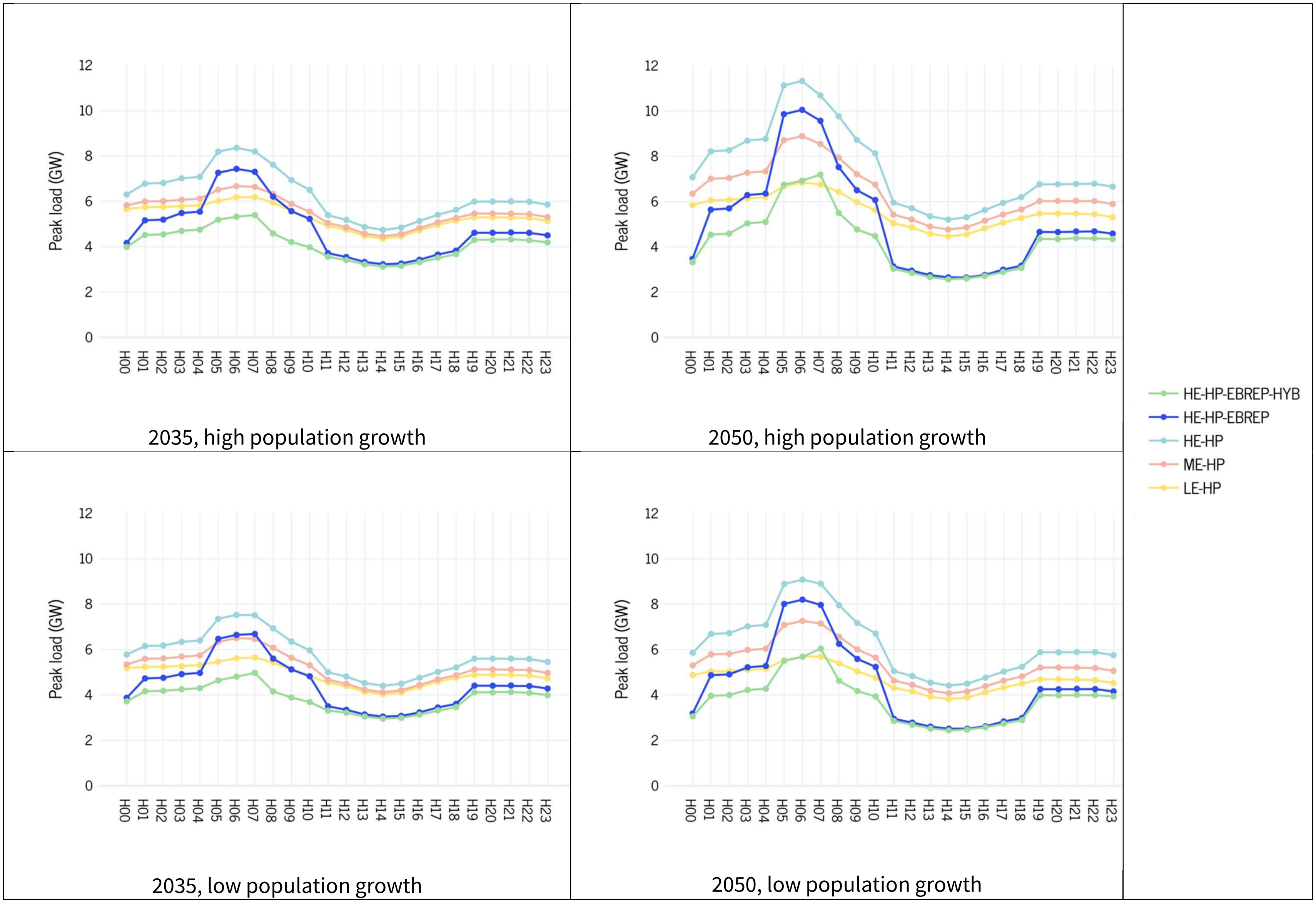


Figure 4 - Residential peak load profile evolution across time and across scenario

Figure 4 then shows how the load profile for the highest peak day (January 2nd) would have evolved in 2035 and in 2050 across scenarios for the high and low population growth group, respectively.

Here are the main observations:

- Early day residential peak demand, which represents the hours of electricity demand most exacerbated by electrification by far, is increased by 87% as a result from high electrification and high population growth (the increase is 51% in the low population growth scenario)[9]
- While the base high electrification scenario (no EBB replacement) represents by far the highest peak among both groups of scenarios, once we include the provision to replace EBB heating with a heat pump, the peak drops by 11% in 2050 (9% in the low population growth scenario), illustrating the efficiency gain even if heat pumps are assumed not to operate in peak weather. This is because the seasonal peak does not occur simultaneously across all four provinces, so the efficiency gain from heat pumps shaves some of the peak in the provinces not experiencing the coldest weather during those hours for a given day
- Even more interesting is the high electrification scenario with replacement of EBB by hybrid systems (i.e., with fuel-based backup): here, the highest total peak demand drops by 39% compared with not replacing the EBBs, and is even comparable with the low electrification scenario (LE-HP); moreover, the increased efficiency resulting from the use of the heat pump decreases demand throughout the day by almost 50% compared with either the low electrification scenario or not replacing the EBBs (HE-HP)

This last point is worth developing further, as the use of hybrid systems to manage winter peak raises at least two questions: what is the share of such systems in the scenarios; and what is the impact on GHG emissions, since fuel-based hybrid system will be emitting when they do operate. Figure 5 shows the high electrification, high population growth scenarios (where EBBs are not replaced, EBBs are replaced by heat pumps, and EBBs are replaced by hybrid systems in Figure 5a, Figure 5b and Figure 5c, respectively).

[9] Early day demand is more impacted by electrification because it aligns with the coldest hours, when heating needs are highest and heat pumps operate less efficiently. This, combined with morning routines, drives a sharp spike in electricity use compared to the evening.

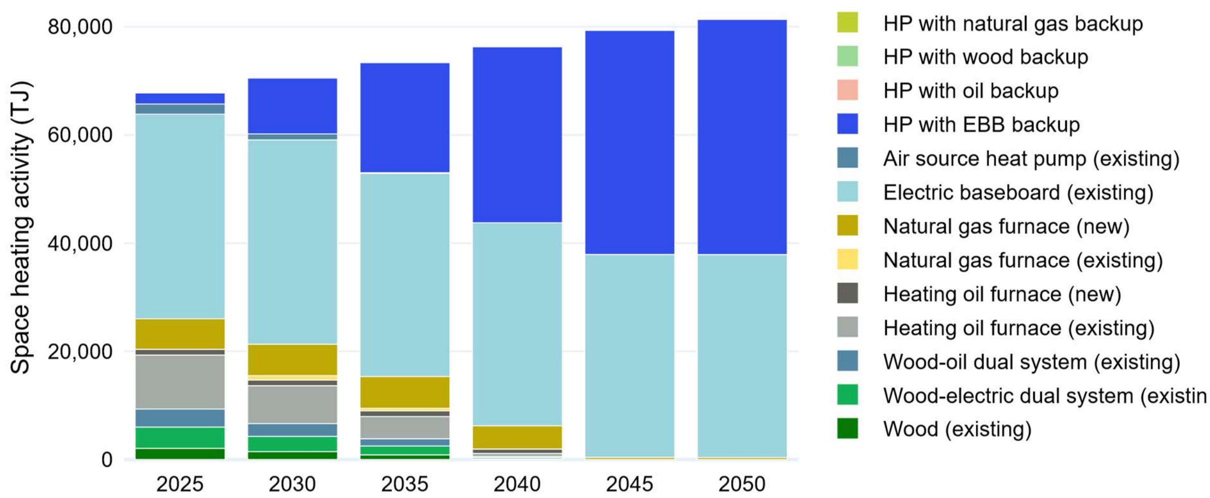


Figure 5a - Space heating technologies turnover and activity , high electrification scenario with no replacement (HE-HP)

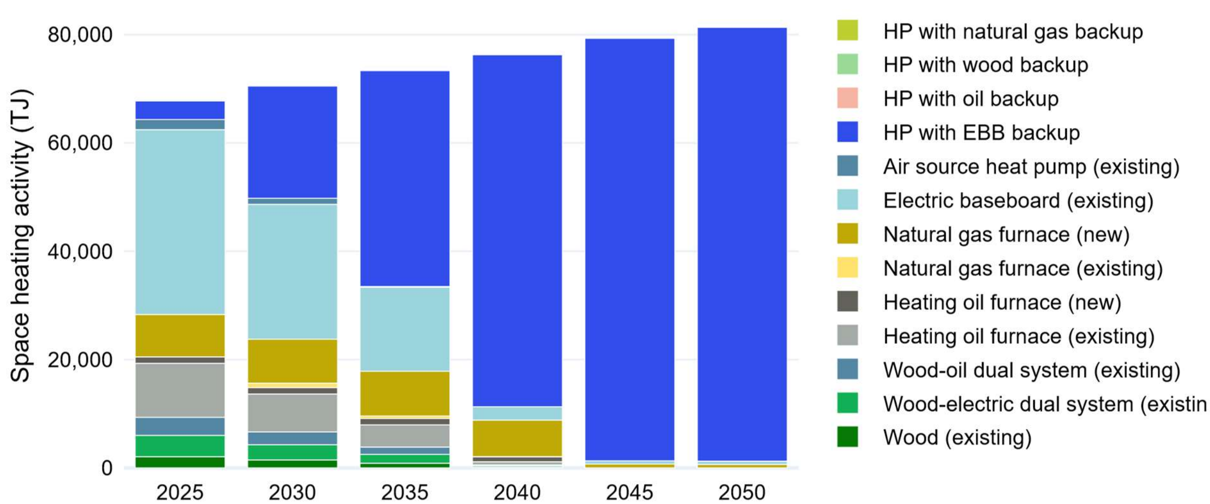


Figure 5b - Space heating technologies turnover and activity, high electrification scenario with EBB replacement (HE-HP-EBREP)

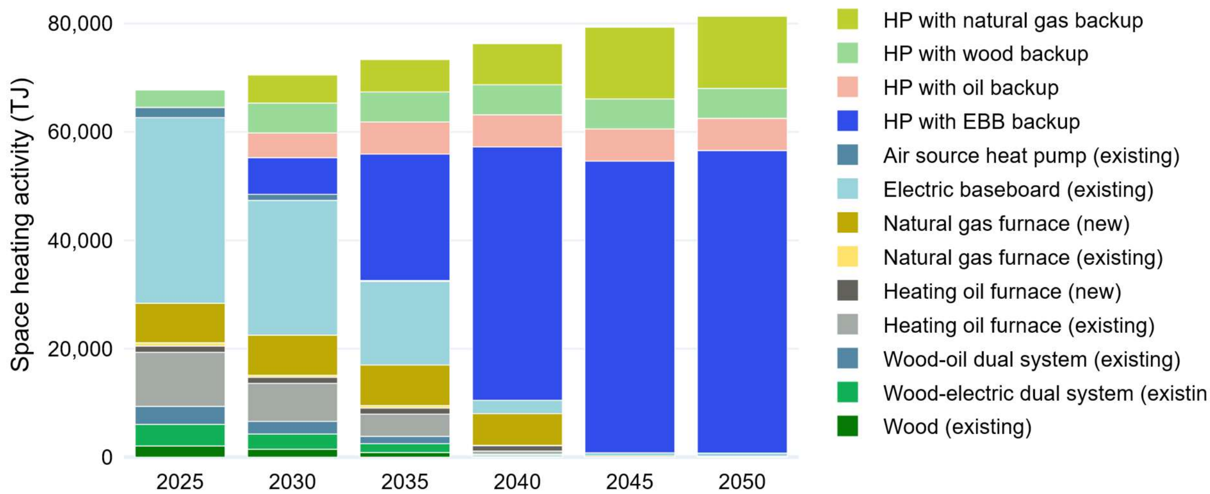


Figure 5c - Space heating technologies turnover and activity , high electrification scenario with hybrid replacement (HE-HP-EBREP-HYB)

2.7 Emissions and Trade-offs of Hybrid Systems

Hybrid systems for a given fuel are capped at 50% of the 2022 market share for that fuel. For instance, heat pumps with a wood furnace backup cannot represent more than 50% of the 2022 market share of wood furnaces. This limitation was used to introduce a degree of realism in the replacements. The adoption of heat pumps with natural gas furnace backup systems is s similarly limited by the same regional availability and capacity restrictions that apply to standalone natural gas furnaces (see footnote 3). Since both technologies draw from the same capped allowance for natural gas use, an increase in one reduces the space available for the other. In the EBREP-HYB scenarios, the model selects hybrid systems within these limits when it results in a smaller combined cost for the electricity sector and for residential buildings heating.

On the question of GHG emissions, the impact of using hybrid systems to mitigate peak is minimal. Figure 6 shows the emissions from residential buildings and the electricity production system across scenarios, for the low population growth and high population growth scenarios.[10]

[10] GHG emissions from electricity generation are negative in 2050 due to the use of BECCS (bioenergy with carbon capture and storage) with zero-carbon biomass as a feedstock. This process captures almost all of the CO_2 resulting from the biomass combustion during electricity generation. If accounting for the CO_2 captured by this same biomass from the atmosphere, the activity results in net-negative emissions. The remaining electricity generation primarily comes from renewable sources, further minimizing emission

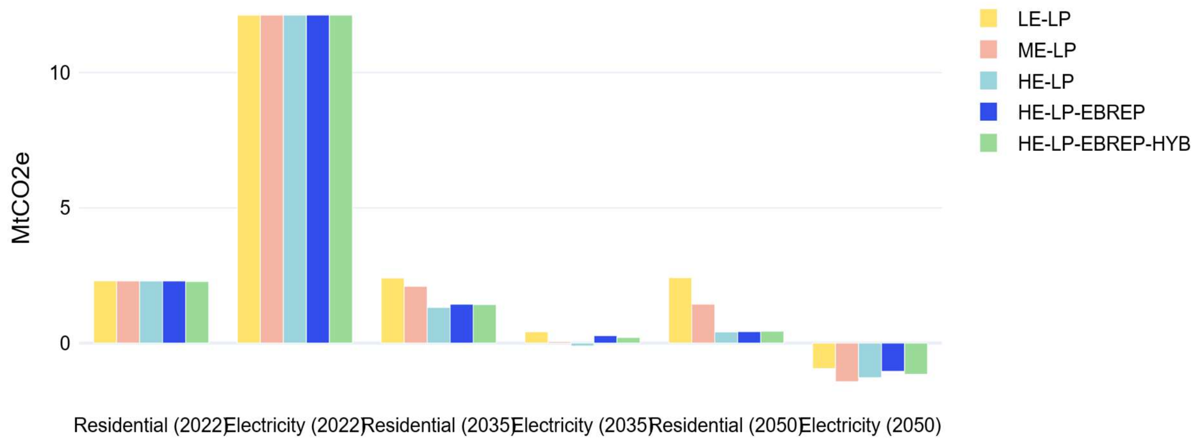


Figure 6a - Total GHG emissions in residential buildings and in electricity production, low population growth scenarios

Figure 6b - Total GHG emissions in residential buildings and in electricity production, high population growth scenarios

As expected —given that the high electrification scenario assumes nearly all residential heating is provided by electric systems - the remaining emissions from residential buildings in these scenarios are significantly lower than in low or mid electrification scenarios. For the specific scenario of high electrification with some hybrid systems replacing EBBs (HE-HP-EBREP-HYB), emissions will be higher by definition. However, the difference in emissions between these scenarios (HE-HP-EBREP-HYB or even its low population growth counterpart, HE-LP-EBREP-HYB) and the fully electric options is minimal (around 7% at most in 2050): given that in hybrid systems, the furnace or stove only operates during a very small number of hours throughout the year, the increase in emissions is very small.

Overall, the results indicate that replacing EBBs with heat pumps paired with fuel backup systems significantly reduces peak electricity demand, while having a negligible impact on total emissions from the buildings sector. We then turn to the impact of each of these scenarios on the electricity system (Figure 7).

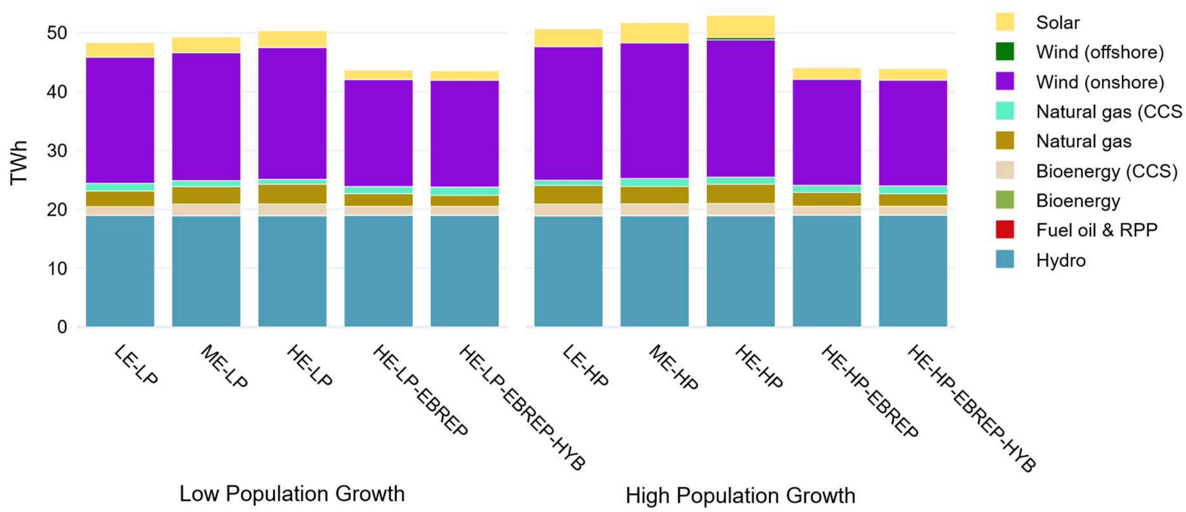


Figure 3a - Electricity generation by technology in 2050

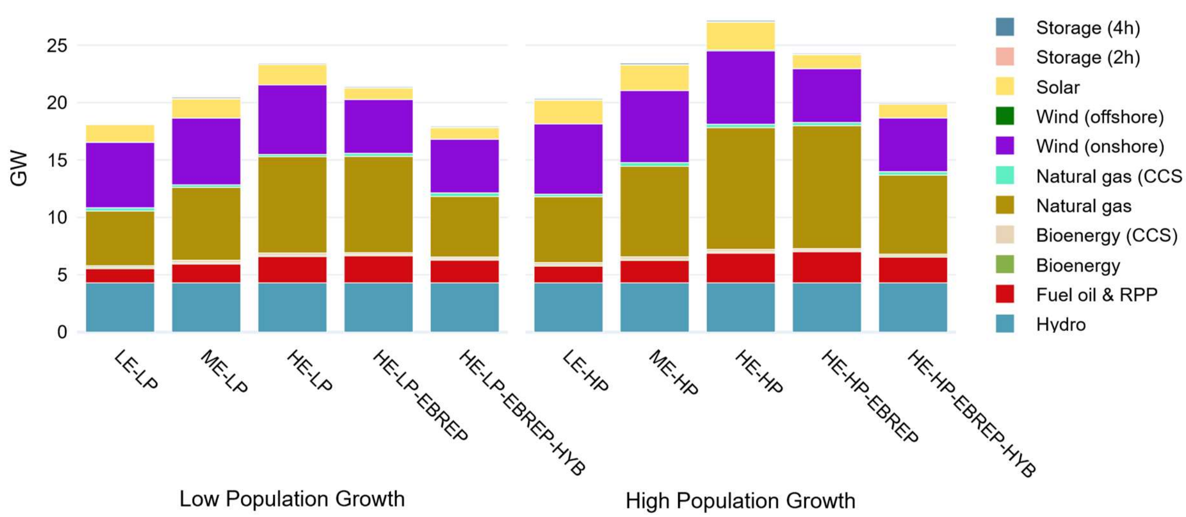


Figure 7b - Electricity capacity installed by technology in 2050

As can be seen in Figure 7a, replacing existing EBBs with heat pump systems (hybrid or not) leads to a significant reduction in electricity demand for the same service. Total demand in 2050 is 9 TWh lower in both scenarios compared with the high electrification scenario with no EBB replacement.

Figure 7b goes further, however: installed capacity is 3 GW lower in the scenario where EBBS are replaced and 7 GW lower if this replacement involves hybrid systems. In other words, the pressure put on the electricity grid buildout needs is decreased substantially through the use of hybrid systems.

Key points:

- **Electrifying residential buildings increases peak electricity demand**, making it more challenging to meet this demand through grid expansion. While heat pumps help reduce the impact due to their high efficiency compared to other electric heating options, their performance drops significantly during extreme cold weather. During these periods, backup systems such as electric baseboards (EBBs) are often activated, increasing the strain on the grid.
- **The combination of heat pumps with fuel-based peak systems** used when temperatures are too cold for the heat pump to operate efficiently, provides significant advantages in terms of electricity demand. The hybrid systems lead to both a drop in demand throughout the entire day, and a notably lower peak—representing a significant reduction compared to both high electrification scenarios (HE-HP and HE-HP-EBREP). This combination ends up requiring much smaller increases to grid capacity.
- This suggests a trade-off: keeping a limited quantity of fossil-fuel based back-up heating systems reduces the requirements for electricity capacity expansion while increasing the GHG emission slightly (around 2% more emissions than in the high electrification scenario without hybrid systems).

2.8 Caveats and Limitations

When considering the results, there are some important caveats and limitations to this analysis to note. In particular, the model does not include any **cost premiums** resulting from subscribing to a refueling service, wood pellet delivery, or natural gas supply. The fixed costs associated with maintaining such distribution services for small overall quantities and frequencies may be substantial in contrast to fuel costs, which may raise the latter.

Another limitation to the analysis is that hybrid systems may imply an **additional cost for the customer**, despite the savings from a grid planning perspective. Importantly, installing a hybrid system through a conversion of an existing fuel-based system into a backup for a newly installed heat pump, still involves additional installation costs – such as upgrading control systems and switching mechanisms, as well as extending the life of fossil fuel furnaces nearing the end of their useful life. However, these additional costs do not necessarily preclude the viability of hybrid systems as a mitigation tool. Several jurisdictions have begun to pilot hybrid systems as part of their peak load management strategies—such as Hydro-Québec's "bi-energy" program, and across parts of Europe—where policies have been designed to limit household burden through targeted rebates or rate incentives. In these cases, users with hybrid systems benefit from lower dual-fuel electricity rates during off-peak hours or in milder seasons, while utilities gain greater control over heating loads during peak winter conditions or extreme cold temperatures. In Quebec, this program is only offered to existing gas consumers, so as not to increase the number of connexions to the gas network and potentially increase emissions. When managed correctly, these programs can result in win-win outcomes: utilities avoid costly capacity investments, customers benefit from reduced rates, and fossil fuel use is limited to a small number of hours per year.

Fossil fuel providers also have a role to play. As dependence on their infrastructure is reduced under these hybrid arrangements, some jurisdictions outside of Atlantic Canada are considering regulatory mechanisms that could partially compensate for lost revenue while simultaneously encouraging these providers to transition toward low-carbon alternatives. Embedding these strategies within broader energy efficiency programs would further reduce emissions and help align peak mitigation with decarbonization goals.

Given these policy and implementation considerations, it is essential that the costs and benefits of hybrid systems be fully evaluated before deployment at scale. This includes analysis of program design, rate structures, consumer equity, including fair access and ensuring that costs and benefits are distributed fairly across income groups, and the regulatory treatment of both electricity and fuel suppliers.

While the advantages of hybrid systems are many, considering their use must be done in the context of a broad societal transition toward a net-zero economy. Therefore, their use must be circumscribed to situations where (1) they offer a maximal advantage in terms of peak management and (2) they do not lead to an increase in the number of fuel-based systems, backup or not. In other words, their role must be understood as a transitional strategy for decarbonizing buildings that may offer significant cost reductions, in a way that does not slow down or prevent the sector's net-zero transition.

With these caveats in mind, incorporating non-fuel-based technologies for peak mitigation could offer promising alternatives. These options may help avoid the challenges mentioned above, even though they are currently not widely deployed. An overview of these options is provided in section 3 below.

3 Other Mitigation Options

In the modelling presented above we focused on hybrid heating systems as one peak management solution. However, other options that could be used in combination exist. This section presents some of the main mitigation options currently utilized around the world.

3.1 Demand-Side Approaches to Peak Management

Demand side management (DSM) encompasses all measures aimed at modifying the demand profile of consumers, by shifting the timing of energy use or reducing its overall magnitude, in order to balance production and consumption (Alsalloum 2021). Demand management includes energy efficiency measures (e.g., upgrading insulation or appliances), demand response (e.g., time-of-use rates or load curtailment during extreme weather), and strategic load growth (e.g., promoting heat pump or EV adoption in ways that align with grid capacity and decarbonization goals). Each of these approaches contributes to the management of peak electricity demand. Energy efficiency and strategic load growth measures influence the medium- to long-term evolution of peak demand and have a structural impact the overall demand profile by permanently altering baseline and peak electricity needs. In contrast, demand response management provides real-time, short-term flexibility to manage peaks as they occur. Electric utilities employ combinations of these approaches to balance supply and demand. Several grid operators have been very active in developing and deploying demand-side solutions for peak demand management[11]. In cold-climate regions these peaks typically last only a few dozen hours each year, making targeted DSM solutions particularly impactful[12].

3.2 Peak Demand Management Strategies Currently in Use and their Limitations

Electric utilities typically use three main approaches to manage peak electricity demand, as displayed below in Tables 4, 5, and 6. These approaches are generally grouped into three categories: supply-oriented solutions (e.g., peaking plants), demand modulation measures (e.g., dynamic pricing), and partial transfer of supply sources (e.g., hybrid systems). The main advantages and disadvantages of these approaches are outlined below.

Table 4 - Supply-oriented approaches

	Advantages	**Limitations**
Peaking Power plant	• Offers highly dispatchable generation (rapid start-up and modulation of generation levels)	• Powered by fossil fuels (e.g., natural gas) and emits GHGs • High capital and production costs

[11] Here are a few examples : a program of interruptible water heating in Minnesota (https://greatriverenergy.com/transmission-and-delivery/demand-response/member-cooperative-load-management-programs/), or more recently, a virtual power plant experiment in California (https://investors.sunrun.com/news-events/press-releases/detail/302/sunrun-and-pge-complete-first-season-of-innovative)

[12] Given that a year is 8760 hours, the winter peak occurs about 1% of the time.

	• Adds firm capacity to the grid (it can be a capacity of several hundreds of megawatts)	
Short-term Market Purchases	• Delays the addition of new generation capacity to the system • Increases flexibility without permanent infrastructure	• Forecasting purchase prices is difficult, as they depend on market conditions (Price volatility) • Transmission infrastructure limits the quantities of energy and power blocks that can be purchased.

Table 5 - Demand modulation approaches

	Advantages	**Limitations**
Critical Peak Pricing	• Encourages off-peak usage that contributes to power system flexibility in winter peaks • Potential bill savings for consumers	• Limited control over peak demand amplitude • Shifts responsibility to consumers
Interruptible Electricity	• Provides immediate load relief • Useful in emergencies (direct contact with the consumer)	• Applicable to a limited group of consumers • Requires case-by-case contracts and may need complex compensation or regulation • Uncertainty of load relief, as load reduction not guaranteed
Energy Efficiency	• Long-term reduction in demand often based on existing, proven technologies	• Scale-up is challenging • Slow deployment pace

Table 6 - Partial transfer of supply sources approaches

	Advantages	**Limitations**
Hybrid systems (electricity-fuel based peak systems)	• Reduces peak demand during extreme-cold spells • Offers a certain level of resilience	• Risk of locking in equipment that is incompatible with long-term climate commitments ("stranded assets")

Other approaches to demand modulation measures involve pricing and load control

- **Dynamic real-time pricing and dynamic hourly pricing** are forms of pricing used primarily to manage intraday variations in demand. These pricing structures are applied year round, such as those driven by winter heating needs, are better suited for managing daily fluctuations rather than extended seasonal peaks..

- **Direct load control**, where utilities temporarily manage specific appliances or systems in participating homes to reduce demand during peak periods.

While promising, these additional demand modulated solutions are based on a voluntary commitment by customers, and may face limitations in terms of effectiveness. Barriers include limited enrollment of customers, high implementation complexity, and cost sensitivity—where the financial incentive may be too low to drive behavioral change or too high for equitable access.

3.3 Technological Solutions Supporting Fully Electrified Heating and Peak Mitigation

In addition to the strategies described above, several technologies exist to mitigate peak in an electrification strategy. These include:

- **Alternative heating technologies:** High-efficiency geothermal heat pumps, low-emission heat networks, etc. can reduce the amount of electricity required per unit of heat. The performance of high-efficiency geothermal heat pumps is higher than traditional models in cold temperatures, for instance; geothermal heat pumps, on their part, consume a very small amount of electricity and are only slightly affected by colder air temperatures; and district heating can take advantage of geothermal sources as well as waste heat recovery where available, again reducing both the need for electricity for heating space in general as well as specifically during winter peak hours;
- **Thermal and electrochemical storage devices:** Electrical thermal storage (ETS) heaters, lithium-ion batteries deployed at various scales can help shift electricity demand away from peak periods;
- **Power demand control devices**: Smart electric panels, which allow real-time control of power demand to avoid increasing a panel's amperage, and smart electric vehicle chargers, which enable vehicle-to-grid transfers, can support more precise household-level load management and active control of winter peak ramp-ups..

These approaches can be strategically deployed to support the electrification of heating systems while simultaneously helping to manage winter peak electricity demand. This can be done in combination with some of the existing strategies (like building envelope improvements or time-of-use pricing), to maximize the impact.

In this study, we have shown the impact of even high-efficiency heat pumps on winter peak demand under a high electrification scenario. Unless using a mitigation strategy like hybrid systems, the simple addition of heat pumps can lead to sharp spikes in electricity demand during extreme cold events, significantly widening the gap between peak-hour demand and average electricity consumption (see Figure). Given the caveats of using hybrid systems as a mitigation approach discussed in Section 2.7, the value and feasibility of other strategies should be assessed as soon as possible in order to develop a reduced-risk portfolio of approaches.

4 Additional Considerations

4.1 Cost Impacts

The cost analysis of different solutions for managing the winter peak demand can be approached from different perspectives, such as the consumer's or utility's, thus introducing a variability to the conclusions dependant on the point of view.

For example, some distributed energy efficiency measures are not always highly profitable for a homeowner, such as replacing electric baseboard heaters with a high-efficiency air-source heat pump, as the investment cost may not be fully paid through energy savings during the heat pump's lifetime under certain conditions. However, such a measure can be cost-effective from the power system perspective if deployed at an appropriate scale.

Analyses such as those carried out in "The Economics of Electrification in Nova Scotia" study are very useful to better understand the costs of different solutions from different perspectives (Mettetal et al. 2023). This allows, for example, a government, or an electric utility to better understand where to intervene to remove the barrier of upfront costs and support the deployment of system-relevant solutions to maintain overall cost control. This study emphasizes, among other things, that replacing oil-fired systems with high-efficiency air-source heat pumps (capable of meeting 100% of needs) is cost-effective from a system perspective, but also from a customer perspective.

4.2 Interprovincial Collaboration

The challenge of electrifying energy services in Atlantic Canada is complex and will **require significant investments** in infrastructure, technology, and workforce development. While collaboration between provinces cannot guarantee lower costs on its own, strategic coordination can help streamline strategies, optimize investments, reduce duplication of efforts, and accelerate deployment.

The Atlantic provinces share similar climate patterns and energy supply challenges. However, differences in the intensity and timing of extreme weather events, coupled with variations in provincial infrastructure, introduce important nuances. As the demand share of electrified residential and commercial buildings grows, winter peaks are expected to become more pronounced across the region. While some provinces may traditionally rely on electricity imports to help manage peak periods, a severe storm impacting multiple provinces simultaneously could cause peaks to align, straining transfer capacities and making electricity trade far more difficult exactly when it is most needed.

Strengthening interprovincial collaboration within Atlantic Canada is therefore critical to optimize electricity system investments, reinforce interprovincial transfer capabilities, and better coordinate planning for peak demand risks according to the needs of all stakeholders.

However, even enhanced regional collaboration may not be sufficient on its own. The federal Clean Electricity Strategy emphasizes the importance of building a more interconnected national grid, linking provinces and regions with complementary resources and demand profiles (NRCan 2025). Although Atlantic Canada already maintains important ties with Quebec and the U.S. Northeast, expanding and deepening interprovincial electricity grid integration—particularly across Canada and into other parts of central and eastern North America—has the potential to further diversify reliable supply options, improve resilience during extreme events, and strengthen the ability to share clean energy resources across jurisdictions. A broader and more robust interconnection strategy could provide important benefits for securing reliable and affordable electricity while progressing toward a net-zero future. However, careful evaluation of its feasibility, costs, and potential limitations will be necessary to ensure that such investments deliver the intended resilience and climate objectives.

Beyond electricity system coordination, **broader collaboration across skills, knowledge, and infrastructure development** will also be vital to successfully managing peak demand and accelerating the energy transition. Coordinated regional action could focus on:

- Developing and standardizing a portfolio of **high-performance technologies**, including hybrid heating systems, thermal energy storage, smart electric panels, and advanced cold-climate heat pumps, to better manage winter peak loads;
- Building **resilient supply chains for critical equipment** such as heat pumps, backup heating systems, thermal storage units, and smart energy management technologies and expanding regional **workforce development initiatives**, including joint training programs for installers, technicians, and system designers, to address labor shortages and ensure high-quality deployment of advanced heating and energy management systems;
- **Sharing research, modelling, and best practices** to improve demand forecasting, optimize system planning, and evaluate the performance of distributed energy solutions across different provincial contexts.
- Coordinating **policy frameworks and technical standards** to harmonize system designs, improve equipment interoperability, and reduce market fragmentation across provincial boundaries.

Together, stronger coordination on electricity system infrastructure and broader collaboration across technology development, supply chains, and workforce training will be essential pillars for securing an affordable, reliable, and decarbonized energy future for Atlantic Canada

5 Conclusions

The energy transition is already underway, and leaders across Atlantic Canada need credible, regionally grounded data to make timely and effective decisions. This report focuses on one critical short-term challenge: how residential space heating electrification, alongside population growth, could sharply increase winter peak electricity demand. Without targeted mitigation strategies, a limited understanding of this trend could persist, risking costly overbuilds of electricity infrastructure for a few hours of extreme demand each year.

Using scenario-based modelling with the ACES Model, we find that hybrid heating systems—when deployed strategically—can significantly reduce winter peak demand while offering infrastructure cost savings. These systems are especially useful when heat pump performance drops during extreme cold. However, their contribution to peak demand management and system cost control depends on careful policy design and further assessment of the cost and feasibility of using fuel-based systems as backup for only a few days each year.

Based on these findings, we recommend policymakers and utilities investigate and assess the cost and practical implications of deploying hybrid systems as a transitional tool, while ensuring incentives align with long-term decarbonization goals. Hybrid systems must be framed as short-term, peak-specific solutions—not permanent fossil-based infrastructure.

We also emphasize the importance of evaluating a broader set of mitigation strategies, including demand-side management, energy efficiency, and smart technologies. These options should be assessed with attention to technical feasibility, cost, and community acceptance across diverse regional contexts.

This study demonstrates the value of region-specific, model-based analysis in informing practical, cost-effective decisions. Region-specific models (e.g., ACES) can help policymakers, utilities, and planners to assess trade-offs and plan for a resilient, affordable, and low-carbon electricity system tailored region’s needs.

Box 5.1 – Seven Recommendations for Priority Actions

These recommendations build on both insights from this study and the existing momentum across Atlantic Canada and nearby regions. Initiatives like Efficiency Nova Scotia's heat pump programs, NB Power's retrofit efforts, and Quebec's bi-energy strategy demonstrate early action taken to try to address the issues discussed in this report. However, key gaps remain in winter peak management and planning, hybrid system deployment, and regional coordination. These recommendations aim to address some of these gaps.

1. **Prioritize Winter Peak Management in Electrification Programs.** Ensure that space heating electrification strategies are designed with winter peak mitigation in mind. Building on programs like Efficiency Nova Scotia's heat pump rebates and NB Power's Enhanced Energy Savings program, align program design, infrastructure investments, and policy incentives to both minimize peak-related grid stress and maintain end-use affordability.
2. **Support Hybrid Heating Systems as a Targeted, Transitional Strategy.** Investigate and potentially pilot hybrid heating programs where they offer infrastructure cost savings and flexibility. While Hydro-Québec's bi-energy program provides a useful model, Atlantic Canada currently lacks formal hybrid system initiatives. This presents an opportunity to assess costs, deployment constraints, and resilience benefits.
3. **Modernize the Grid with Smart Technologies and Storage.** Advance grid modernization projects, including smart panels, direct load control, and thermal/electrochemical storage, to support flexible and responsive winter peak management. Utilities in other regions, such as Green Mountain Power in Vermont, have piloted these technologies. Atlantic Canada can build on similar approaches with region-specific pilots.
4. **Expand Demand Response and Tailored Load Management.** Develop customized demand response programs for Atlantic Canada's heating patterns, supported by research and targeted implementation to manage short-term peak loads effectively.
5. **Strengthen Interprovincial Coordination.** Evaluate opportunities for interprovincial electricity collaboration to improve system flexibility during winter peaks, including imports, shared infrastructure, and coordinated load management.
6. **Align System Replacement Policies with Net-Zero Goals.** Ensure that end-of-life heating system replacements prioritize low-carbon options through regulatory and financial mechanisms that reflect long-term emissions targets. Provinces like PEI have committed to non-emitting primary heating sources by 2040; other jurisdictions can build on this by tightening replacement policies.
7. **Engage Stakeholders and Build Public Readiness.** Enhance coordination among governments, utilities, and industry to ensure market readiness. Public outreach campaigns—such as Nova Scotia's HomeWarming program and PEI's Net Zero programs—offer models to expand awareness. Targeted efforts can help encourage behavioral change, promote energy efficiency, and support broad technology adoption.

6 References

Alsalloum, H. (2021). Gestion décentralisée des interactions complexes entre producteurs et consommateurs d'énergie électrique [Thèse, Université de Technologie de Troyes ; Université Libanaise]. Online, https://theses.hal.science/tel-03808743

CER (2025). Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050. Canada Energy Regulator. Online, https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html

Edom, É, Beaumier, L., Mousseau, N. (2023). Gestion de la demande de pointe d'électricité au Québec dans un contexte de décarbonation. Institut de l'énergie Trottier.

Edom, É & Mousseau, N. (2025). Une définition intégrée de la pointe de demande d'électricité au Québec: intérêts, et avantages stratégiques et opérationnels. Institut de l'énergie Trottier.

Langlois-Bertrand, S., Mousseau, N. Vaillancourt, K., Bourque, M. (2024). Pathways for a net-zero Canada – Horizon 2060. In Langlois-Bertrand, S., Mousseau, N., Beaumier, L. (Eds.), Canadian Energy Outlook 3rd edition, Institut de l'énergie Trottier – Polytechnique Montréal. Online, https://iet.polymtl.ca/download/639/CEO3_2_SommaireExec_20240629.pdf/

Mettetal, L., Levine, M., Spencer, S., & Olson, A. (2023). The Economics of Electrification in Nova Scotia (Developed for Nova Scotia Power). Energy and Environmental Economics Inc (E3).

NRCan (2023). Heating and Cooling with a Heat Pump. Government of Canada: Natural Resources Canada. Online, https://natural-resources.canada.ca/energy-efficiency/energy-star/heating-cooling-heat-pump

NRCan (2025). Powering Canada's Future: A Clean Electricity Strategy. Government of Canada: Natural Resources Canada. Online, https://natural-resources.canada.ca/energy-sources/powering-canada-s-future-clean-electricity-strategy#a9

NREL (2023). Field Validation of Air-Source Heat Pumps for Cold Climates. National Renewable Energy Laboratory. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Online, https://heatpumpdata.energy.gov/data/studies/nrel-field-validation-air-source-heat-pumps-cold-climates-2021-2023

NZA (2025). Atlantic Canada Energy System Model. Net-Zero Atlantic. Online, https://netzeroatlantic.ca/acesmodel/documentation

OEE. (2025). Comprehensive Energy Use Database. Government of Canada: Natural Resources Canada, Office of Energy Efficiency. Online, http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

Appendix A

Decarbonization policy mix across Atlantic provinces

Nova Scotia:

- The government of Nova Scotia (NS) seeks to reduce oil heating systems by 20% in 2030 by retrofitting 60,000+ homes currently relying on oil heat with electric systems via an "off-oil" pilot program.
- The government of Nova Scotia seeks to expand programs for low-income households such as the HomeWarming program, Affordable Multifamily Housing program, Mi'kmaw Home Energy Efficiency project and a pilot program for African communities in Nova Scotia.
- Efficiency Nova Scotia (Est. 2009 via provincial legislation, operated by E1) is a program specializing in heat pump and retrofit incentives helping over 400000 Nova Scotians reduce energy use, lower utility bills, and cut GHG emissions, saving 180 million dollars and avoiding 1 million tons of CO2e emissions annually. Efficiency Nova Scotia offers a wide range of services such as heat pumps, insulation, appliance, and lighting rebates, free home retrofits for low-income families via the HomeWarming program, upgrades to business and commercial energy efficiency, and custom solutions for industrial energy management.
- The NS government has in place many standards for decarbonizing the building sector; these include banning oil furnaces in new construction as of 2025, adopting the 2020 national building code and energy code for buildings, a focus on creating a net-zero ready building stock by 2050 and encouraging the use of energy system modelling.
- The NS government has put in place many legislative pieces to attain their grid decarbonization targets (net zero by 2050), such as the Environmental Goals and the Climate Change Reduction Act and Energy Reform Act, targeting 80% renewable electricity generation and the licensing of 5 GW of OSW energy by 2030, 23 action items under the green hydrogen action plan to grow the hydrogen industry and the creation of an energy system regulator and an ISO.

New Brunswick:

- The New Brunswick (NB) government plans to phase out oil heating entirely by 2030 and collaborate with the federal government to support customers and suppliers during the shift.
- NB Power offers a variety of energy efficiency programs, such as cold-climate air-source heat pump rebates and free retrofits for low-income households via the Enhanced Energy Savings program.
- The NB government has committed to adopting the National Building and National Energy Code for Buildings to have net-zero-ready buildings and building officials trained to implement higher-tier codes by 2030.
- The NB government is actively working to support envelope upgrades (insulation and windows), heating systems upgrades and fuel switching. They are committed to increasing the capacity of residents and addressing market needs.

- NB Power has partnered with the province to offer innovative payment options to ensure affordable access to efficiency programs, including low-interest loans, on-bill financing, and pay-as-you-save models.
- The provincial government is preparing to relase a GHG action plan targeting a reduction in building emissions by 20-40% in 2030; strategies to achieve this include high-performance construction, fuel switching, and retrofits across over 900 buildings.
- To achieve net-zero electricity emissions by 2035, the NB government has developed the Clean Electricity Strategy, which outlines plans to heat homes using decarbonized solar, wind, SMRs, and hydrogen energy. To date, many interim steps have been taken to achieve this goal. This includes annual electricity efficiency and reporting targets for NB Power, ensuring adequate funding for low-income households, indigenous groups and users of non-electric heating fuels, and finally, a review of legislation relating to identifying opportunities to accelerate GHG emissions reductions and investments in reduction strategies (clean fuels, technologies, energy resources). The next steps in the plan include identifying the skills and technology gaps and investment in programs to train upwards of 300 tradespeople in skills relating to residential and commercial high-performance buildings.
- The NB government has a net-zero target by 2050, focusing on wind (1400+ MW), small modular reactors, and renewable gas integration at the forefront. NB government has also implemented a Hydrogen Roadmap, which includes 13 actions over 5 years to advance the hydrogen sector.

Prince Edwards Island:

- The government of Prince Edward Island (PE) has committed to ensuring that 90% of homes and buildings will use a non-emitting heat source as their primary heating source by 2040. The government is investing in fuel-switching rebates, targeted support to ensure low-income households can access clean heating/efficiency upgrades, policy development surrounding access to high-efficiency technologies, and programs for commercial and industrial buildings that will be key in achieving their 2040 targets.
- The government of PE has stated that all new residential homes are required to be net-zero ready, and all commercial buildings must utilize non-fossil fuel primary heating sources by 2030
- Key actions to achieve these goals include the adoption of the National Building and National Energy Codes, the introduction of stretch codes which exceed national minimums, supporting energy performance labelling, providing training and workforce development surrounding high efficiency building practices, and financial programs supporting Energy Efficiency Equipment, Energy Efficiency Programs, heat pumps and home insulations.
- The PEI government is targeting net zero-ready performance for all newly constructed government-owned buildings starting in 2025, and for all new residential construction as of 2030, with overall building sector demonstrating emissions reductions of 70% by 2030 and 95% by 2040.
- The PE government has demonstrated a commitment to decarbonization of their electrical grid, including targeting net zero by 2040 (a decade earlier than federal targets), legislative

pieces such as the Renewable Energy Act and Net-Zero Carbon Act, as well as their 2040 Net Zero Framework, which sites wind energy's vital role in achieving the targets they have set.

Newfoundland and Labrador:

- The government of Newfoundland and Labrador (NL) has committed to switching from oil-based fuel to electrical heating; through the Low Carbon Economy Leadership Fund LCELF, they have committed approximately 13 million dollars to improve energy efficiency and switch fuel oil-heated homes to electricity.
- The NL government is upgrading 47 public buildings to improve energy performance, putting minimum energy efficiency requirements for commercial buildings in place, and supporting programs that support insulation, windows, and other retrofits across both residential and public spaces.
- The NL government is working with various working groups to adopt and enhance the National Building Code and National Energy Code for Buildings to align with more stringent energy efficiency standards.
- The NL government has aligned with federal targets of achieving net zero in their electrical grid by 2050, releasing a Renewable Energy plan, Hydrogen Action plan, and the Management of Greenhouse Gas Act. Finally, the NL government signed an MOU that grants them the authority to regulate offshore wind projects in areas previously under federal jurisdiction, specifically in the Canada–Newfoundland and Labrador offshore area.

Appendix B

Atlantic Canada Energy System (ACES) Model Overview

The Atlantic Canada Energy System (ACES) Model is a long-term, capacity expansion energy system optimization model designed to analyze decarbonization pathways for the Atlantic provinces: Nova Scotia (NS), New Brunswick (NB), Prince Edward Island (PEI), Newfoundland (NFL), and Labrador (LAB). ACES Model is a bottom-up, technology-specific model that uses linear programming optimization to determine cost-effective investment and operational decisions for energy technologies. The model covers electricity, buildings, transportation, industry, agriculture, and waste sectors and evaluates energy system transitions under various policy, technology, and demand scenarios.

Built on the Temoa modelling framework, ACES Model operates as a fully open-source tool, allowing stakeholders to modify assumptions and input parameters. It incorporates spatial and temporal detail by modelling the Atlantic provinces individually and simulating system dynamics from 2022 to 2055 in five-year increments. To capture daily and seasonal variations in demand and supply, ACES Model employs seven representative days at an hourly resolution.

The model is structured to provide insights into cost-effective energy system transitions under different scenarios, supporting decision-making at regional and provincial levels.

Electricity Demand Calculation in ACES Model

In this study, we used the three-sector version of ACES Model (electricity, transportation, and buildings), where electricity demand is partially endogenized. While total electricity demand is initially set using public utility load forecasts, the model dynamically determines electricity consumption for the building and transportation sectors based on technology adoption and energy service demands.

Their electricity consumption is endogenized, meaning:

- The model determines technology adoption levels (e.g., penetration of electric vehicles and heat pumps).
- The electricity demand from these sectors is calculated dynamically based on technology choices and energy service demands.
- To avoid double counting, the endogenized demand is subtracted from the bulk electricity forecast, ensuring that only the residual demand from non-modeled sectors (e.g., industry, agriculture, and waste) remains exogenously defined.

To maintain realistic system-wide demand, the residual electricity consumption from non-modeled sectors was added back exogenously, ensuring consistency with regional electricity use patterns while allowing the model to determine sectoral electrification trends and efficiency improvements to be captured dynamically.

However, in this study, we predefined the technological adoption of electric-based technologies for commercial buildings, related residential appliances, water heating, and all transportation subsectors. This approach was taken to isolate the impact of residential space heating electrification from other electrification mechanisms across sectors.

Since the focus of this study was to determine the impact residential space heating electrification and population growth on the electric grid, we made the following assumptions:

- Commercial, residential water and other residential subsectors (e.g., appliances, lighting): The current market share of different technologies remains constant throughout the modelling horizon.
- Transportation sector: A medium electrification rate was assumed, as detailed in the scenario table.

1. Electricity Generation and Storage Technologies

ACES Model includes both existing and new generation options, classified by technology type:

- Renewables: Onshore and offshore wind, utility-scale and residential solar.
- Hydro: Existing hydro assets in Newfoundland, New Brunswick, and Labrador.
- Thermal: Coal, natural gas, and biomass with phaseout policies applied.
- Storage: 2-hour and 4-hour lithium-ion batteries, modeled with efficiency and cost data from NREL's 2022 ATB.

2. Spatial Representation and Interconnections

ACES Model represents Atlantic Canada using five distinct regions:

- New Brunswick (NB)
- Nova Scotia (NS)
- Prince Edward Island (PEI)
- Newfoundland (NFL)
- Labrador (LAB)

Electricity trade between these provinces occurs via existing transmission corridors, with the option to expand interconnections if cost optimal.

The Labrador–Newfoundland Link (LAB-NFL) is modeled separately due to its strategic role in delivering hydroelectric power from Labrador to the rest of the system. This ensures that Labrador's high hydro generation potential is accurately captured while maintaining realistic trade constraints.

The ACES Model does not include the electricity exported from Churchill Falls to Quebec, as it is already contractually allocated and unavailable for regional system optimization. However, two specific agreements—the TwinCo Block and the Recapture Energy contract—are included in the model:

- TwinCo Block: A firm 225 MW power allocation, providing 1,971 GWh per year.
- Recapture Energy: A 300 MW allocation, supplying 2,352 GWh per year.

Since these contracts ensure a fixed supply to the Newfoundland and Labrador electricity systems, ACES Models Churchill Falls as a 525 MW run-of-river hydro facility, rather than a fully dispatchable source, with its generation levels determined by contractual obligations rather than market demand

The provinces also have electricity trade links with external markets, specifically:

- New Brunswick–Quebec

- New Brunswick–Maine (U.S.)
- Labrador–Quebec

Electricity imports from Quebec are assumed to be carbon-free hydro power, while imports from New England are assigned an emission intensity based on regional generation data.

3. Interregional Electricity Trade

ACES Model incorporates both long-term price forecasts and intra-annual price variations for imported electricity.

- Annual price forecasts are based on historical wholesale electricity prices and projected cost trends from sources like the Energy Information Administration (EIA) and regional utility reports.
- Intra-annual cost variations are modeled using seasonal and hourly wholesale electricity price data, ensuring the cost of imported electricity reflects real-world market fluctuations.

4. Temporal Resolution and Representative Days

ACES Model balances model accuracy and computational feasibility by using seven representative days at hourly resolution, capturing seasonal and diurnal variations in demand and renewable energy generation. These representative days are selected using an optimization approach, ensuring they reflect key system dynamics such as:

- Peak electricity demand periods
- Wind and solar variability
- Low-resource days with high heating demand

To model intra-annual efficiency variations, the coefficient of performance (COP) for heat pumps is adjusted based on historical temperature profiles, allowing the model to capture the seasonal impact on heating energy consumption.

5. Building Sector

The building sector in ACES Model includes residential and commercial buildings, where electricity demand is largely driven by space heating and water heating. The model accounts for technology-specific energy consumption patterns and determines the optimal mix of heating technologies, including:

- Electric resistance heating
- Heat pumps
- Fossil-fuel-based heating systems

Annual end-use demands are derived from Natural Resources Canada’s Comprehensive Energy Use Database, while hourly demand profiles are taken from NREL’s ResStock and ComStock tools for the New England region, as it experiences similar weather trends.

A key feature of the model is the temperature-dependent efficiency (COP) of heat pumps, which varies intra-annually on hourly basis based on historical temperature data. As a result, heat pump electricity consumption is higher during colder months, affecting peak demand calculations.

6. Transportation sector

The transportation sector in the ACES Model is subdivided into multiple subsectors, aligning with classifications from Natural Resources Canada's Comprehensive Energy Use Database. Each subsector consists of an existing vehicle fleet and a suite of new vehicle options that compete to meet end-use demand. On-road transportation subsectors include the following options:

- Battery-electric vehicles (BEVs)
- Plug-in hybrid electric vehicles (PHEVs)
- Hydrogen fuel cell vehicles (FCEVs)
- Conventional internal combustion engine (ICE) vehicles

The off-road segment includes marine, rail, and aviation, with available fuel options such as marine gas oil, residual fuel oil, biodiesel, liquefied natural gas (LNG), and aviation biofuel.

Technology adoption is generally endogenize; therefore EV adoption is endogenized, meaning the model optimally determines the share of EVs based on cost, policy incentives, and infrastructure availability. Electricity demand from EVs is then calculated dynamically using charging profiles informed by Natural Resources Canada, which reflect most common charging behavior in home, workplace, and fast-charging behaviors.

In this study, a medium electrification rate was assumed for the transportation sector, as follow:

- Light-Duty Vehicles (LDVs): 50% of new vehicle sales are EVs by 2040
- Medium- and Heavy-Duty Vehicles (MDVs & HDVs): no EV adoption allowed.
- Buses: 5% of new vehicle sales are EVs by 2030

7. Policies Considered in the ACES Model

The ACES model integrates several key policies that influence energy system decisions, including carbon pricing, renewable portfolio standards, and fuel transition policies.

- **Carbon Pricing and OBPS**

The ACES model includes federal carbon pricing, rising from \$50/tonne CO_2e in 2022 to \$170/tonne CO_2e by 2030, then increasing 2% annually. The OBPS imposes carbon costs on generators exceeding emissions intensity limits.

- **Renewable Portfolio Standards (RPS)**

Nova Scotia requires 40% renewables until 2030, increasing to 80%, while New Brunswick maintains a 40% target. Imported clean electricity counts toward compliance.

- **Coal Phaseout and Fuel Constraints**

The model enforces the 2030 coal phaseout, eliminating coal-fired power. Natural gas imports are capped by Maritimes and Northeast Pipeline limits, ensuring realistic supply constraints.

Assumptions and Considerations in the Building Space Heating Analysis

The building space heating analysis conducted using the ACES Model focuses on evaluating electrification impacts on peak electricity demand under different population growth and heating system adoption scenarios. The study examines how the transition from fossil fuel heating and baseboard heating (EBB) to heat pumps (HPs), as well as the role of hybrid heating systems, affects grid capacity and energy infrastructure planning.

Key Assumptions:

1. **Scenario Structure and HP Replacement Strategy:**

Low and Mid Electrification Scenarios:

- HPs replace only fossil fuel heating systems (e.g., oil and gas furnaces), while EBB use remains constant.

This ensures an initial fuel-to-electric transition without impacting existing electric heating systems.

High Electrification Scenarios: Two cases are evaluated:

- HPs replace only fossil fuel systems (consistent with lower electrification cases).
- HPs replace both fossil fuel systems and EBB, allowing for a more aggressive electrification transition.

By doing this, we restrict the model from allowing fuel-based heating to replace EBB, ensuring that electrification remains the dominant transition pathway.

Additionally, existing heating systems are replaced only at the end of their operational life. The total existing stock, as reported in Natural Resources Canada's Comprehensive Energy Use Database, is assumed to be equally distributed over the technology's reported lifetime, in five-year intervals.

2. **Population Growth Considerations And Heat Demand Projection:**

The starting point for heating demand calculations was derived using NRCan's Comprehensive Secondary Energy Use Database. The calculation process involved multiplying the gross thermal requirement per square foot for each building type and vintage by the total floor area (sqft) of buildings in that category.

Two population growth scenarios (low and high) were considered, influencing heat demand projections and system-wide electricity requirements:

- **Low Population Growth Scenario:** In this case, we assumed that efficiency gains from improvements in the building envelope would fully offset the increase in heating demand associated with the low population growth. This means that, despite some expansion in total floor area, building retrofits and better insulation standards would result in a relatively stable net heating requirement over time.
- **High Population Growth Scenario:** Here, we assumed that starting heating demand would increase in proportion to the high population growth projection. Since more new buildings would be added to the stock, the total heating demand would scale with the increased building footprint, leading to higher overall energy consumption despite efficiency improvements in newer constructions.

3. **Hybrid Heating**

The model includes two categories of heat pumps based on their backup heating source:

1. HPs with Electric Baseboard (EBB) Backup – Available in all scenarios, ensuring a fully electrified heating system.
2. HPs with Fuel Backup (wood, oil, or natural gas furnaces) – Available only in hybrid scenarios, where fuel-based backup heating is considered for peak mitigation.

For oil and wood backup furnaces, their share is capped at 50% of the current market share of existing wood and oil heating systems. HPs with NG backup are only available in Halifax Urban Area, Moncton, Saint John (SJ), and Fredericton, where NG infrastructure exists.

4. Cold Climate Constraints

To account for heat pump performance limitations in extreme cold conditions, the model prevents HPs from operating for an equivalent of the coldest 46 hours per year (0.5% of the year). During these periods, backup heating systems—whether EBB or fuel-based—supply the required heat. This constraint is designed to simulate an extreme temperature drop, which, while infrequent, can occur and significantly impact heating demand. Such events might be overlooked in other models that assume non-switching heating mechanisms for HPs (i.e., relying solely on the refrigeration cycle without transitioning to electric resistance heating). This assumption can lead to underestimating peak load requirements during extreme cold conditions, resulting in an inaccurate assessment of grid stress and backup heating needs.

Uncertainties and Limitations

1. **Uncertainty in Backup System Costs and Maintenance:**

- There is significant uncertainty regarding the costs associated with backup heating systems, including installation, operational expenses, and ongoing maintenance.
- The financial burden varies depending on the type of backup system, its usage frequency, and the level of servicing required to ensure reliable operation.

2. **Heating Cost Considerations in the Analysis:**

- Differences in heating system costs are considered but only at a high level.
- The study does not conduct an in-depth financial analysis but instead prioritizes system-wide impacts on electricity demand and capacity planning.
- The modelling approach emphasizes grid implications rather than detailed consumer cost evaluations.

Primary Focus of the Analysis:

- The goal is not to determine the most cost-effective or optimal heating system from an end-user perspective.
- Instead, the study examines the impact of heating system choices on the electricity grid, particularly in terms of peak demand and capacity expansion needs.

- The focus is on understanding how different levels of heating electrification influence grid infrastructure rather than providing an economic comparison of heating technologies.