# Forecasting Canada's Electricity Future

## Demand Growth, Key Drivers, and Implications for Provincial Planning

**Prepared for:**

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# EXECUTIVE SUMMARY

A global energy transition is underway, marked by the accelerating deployment of electro-tech – technologies that are enabling increased use of electricity to meet energy needs throughout the economy – particularly in the transportation, buildings, and industrial sectors. This report explores how utilities, system operators, and energy modellers envision electricity demand evolving in Canada in the future, the key drivers that are expected to shape this growth, and the implications for future electricity system planning.

It does this by reviewing two different types of electricity demand forecasts: (a) forecasts from provincial electricity system operators and utilities that are guiding future electricity system planning (referred to as "system outlooks" for the purposes of this report), as well as (b) key net-zero pathways studies that explore the potential demand for electricity in a carbon-neutral economy.

## Forecasts of Future Electricity Demand

By 2050, national electricity demand is projected to grow significantly across all forecasts, although the magnitude of growth varies by study and scenario. Figure ES-1 illustrates forecast electricity demand from all reviewed forecasts, including aggregated provincial system outlooks and national pathways studies, and presents them alongside data on historical electricity generation.

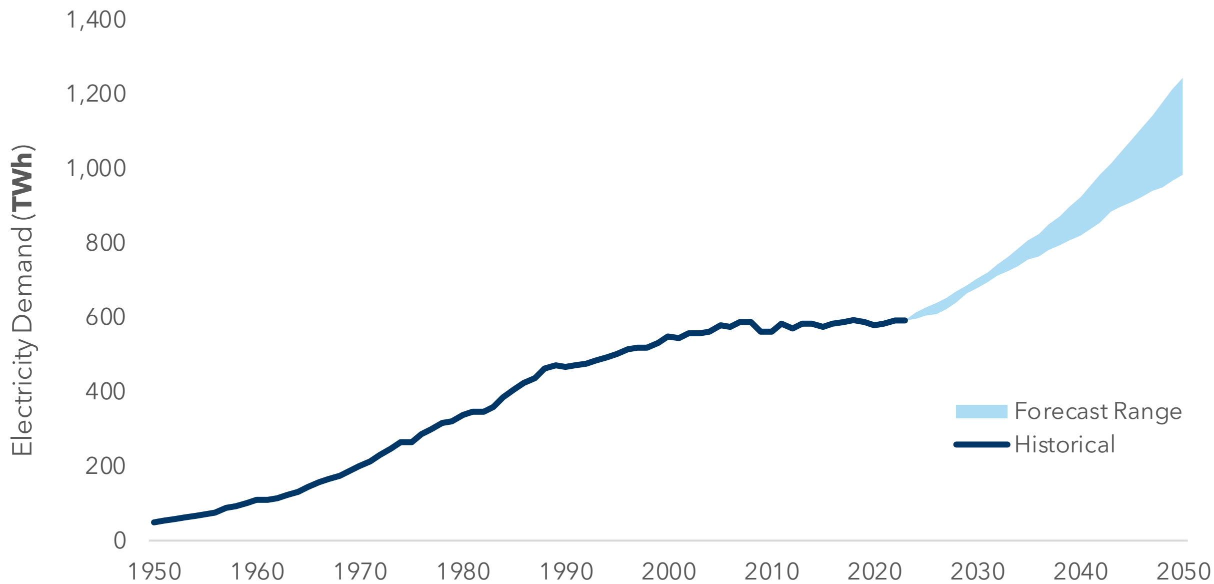


**Figure ES-1: Historical and Forecast Electricity Generation, 1950-2050.**

Even under the most conservative projections, electricity demand in Canada is expected to increase by approximately 62% between 2025 and 2050.[1] Electricity demand is expected to increase significantly in all provinces in Canada over this period, and while growth rates vary,

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[1] This estimate is based on an aggregated projection of provincial system outlooks (see Section 2.1 for a list of reviewed forecasts).

our review has also shown that provincial system operators and utilities are consistently revising their electricity demand forecasts upward over time.

Nonetheless, pathways studies and provincial system outlooks employ different methodologies, resulting in notable variations between electricity demand forecasts. Figure ES-2 summarizes projected increases in electricity demand across provinces, comparing the national pathways studies with provincial system operator and utility system outlooks.

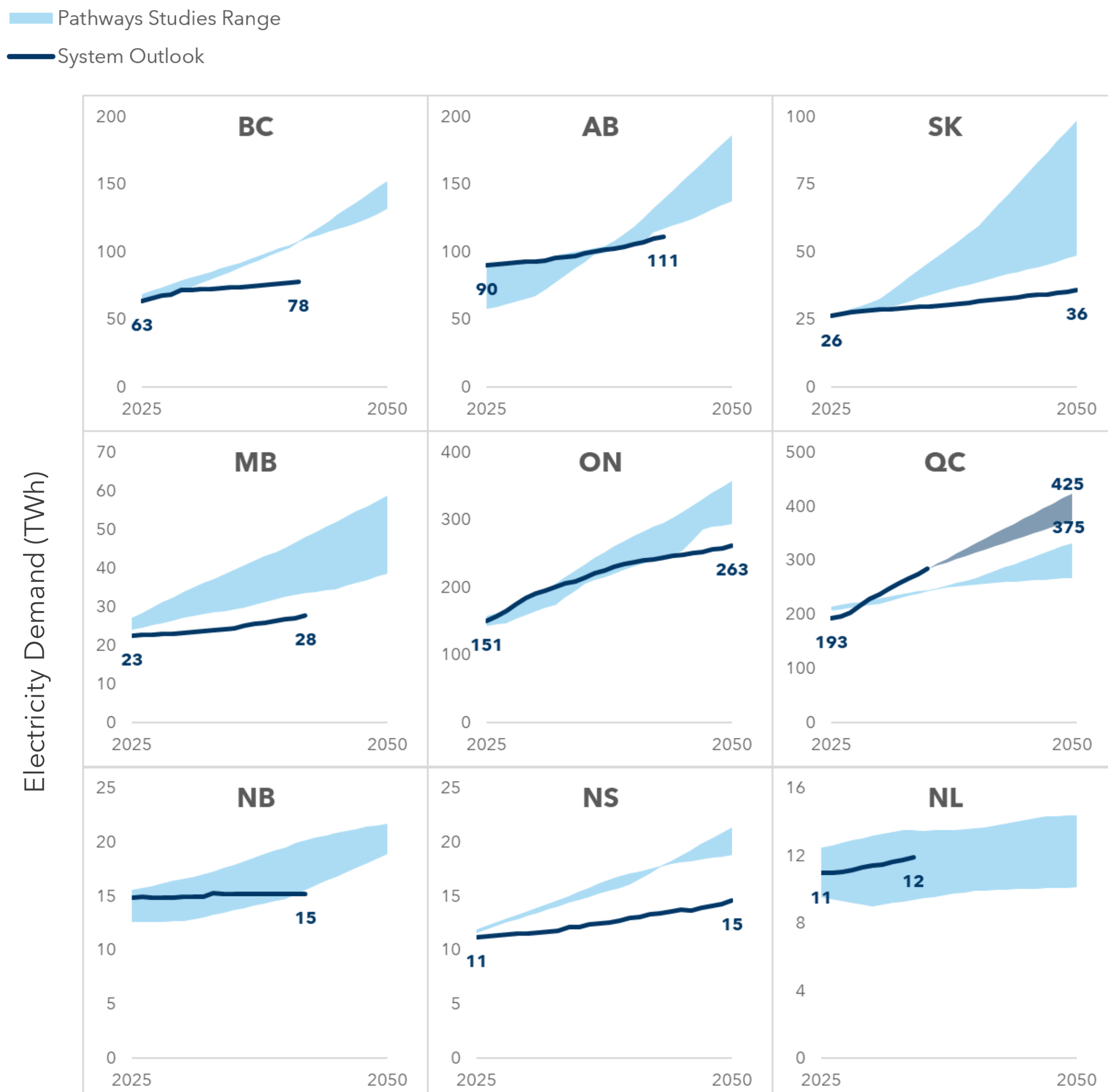


**Figure ES-2: Electricity Demand by Province, 2025-2050, system outlooks and pathway studies**

Across most jurisdictions, pathways studies consistently project more demand growth than provincial system outlooks. This divergence is expected and reflects fundamental differences in modeling assumptions. Figure ES-2 however, illustrates some interesting regional differences. For example, Western provinces show the widest divergence between the two forecast types, while system outlooks in Newfoundland and Labrador and Quebec are exceptions that see electricity demand growth consistent with or greater than that envisioned in national pathways studies.

## Drivers of Future Electricity Demand

Electricity demand growth is shaped by a wide range of underlying drivers, including traditional macro drivers like population and economic growth, technology drivers such as evolving electro-tech and demand-side resources, emerging industrial large demand loads, and relevant policy and regulatory signals. This report examined the treatment of these key drivers in the reviewed pathways studies and provincial system outlooks to assess if such studies are more likely to be overestimating or underestimating future electricity demand.

Table ES-1 shows where actual electricity demand could deviate above ("upside risk") or below ("downside risk") the forecasts presented in pathways studies and provincial system outlooks based on this assessment.

**Table ES-1: Risk Assessment by Driver**[2]

| | Driver | System Outlooks | Pathway Studies |
|---|---|---|---|
| **Macro** | Population Growth | ? **Unknown**<br>System outlooks reflect local utility insights, but data availability is inconsistent between provinces | ▲ **Upside Risk**<br>Assume lower population growth than corresponding provincial forecasts. |
| | Economic Growth | ? **Unknown**<br>Data availability is limited | ⇅ **Mixed**<br>Moderate growth expectation of 1-2%, macro volatility cuts both ways |
| **Cross-Cutting** | Net-zero by 2050 | ▲ **Upside Risk**<br>Only two provinces align demand forecast with net-zero future | ▼ **Downside Risk**<br>All pathway studies align demand forecast with net-zero future |
| | Carbon Pricing | ▼ **Downside Risk**<br>Many system outlooks include consumer carbon pricing, which has been repealed | ▼ **Downside Risk**<br>All pathways studies include consumer carbon pricing, which has been repealed |
| **Sectoral Drivers** | Transportation | ⇅ **Mixed**<br>LDV electrification generally well-captured, but MHDV and other non-road transportation assumptions vary widely. Potential change to federal ZEV mandate introduces downside risk. | ▼ **Downside Risk**<br>Assumes transportation electrification and policies consistent with net-zero by 2050. |
| | Buildings | ⇅ **Mixed**<br>Electrification assumptions are highly inconsistent across reviewed forecasts. Rates of heat pump adoption vary significantly. Strong upside risk in some provinces. | ▼ **Downside Risk**<br>Assume more ambitious electrification and policies consistent with net-zero by 2050. |
| | Industry | ▲ **Upside Risk**<br>Several system outlooks do not account for industrial load growth. Only two provinces explicitly consider new loads from data centres. | ⇅ **Mixed**<br>Studies assume growth in hydrogen production and electrification of existing industry, but do not account for near-term impact of data centres. |

[2] This table excludes demand-side management (DSM) impacts for clarity of comparison. For more information on DSM, see Section 4.4.

How to read the table:

- ▲ Upside risk = demand likely higher than forecast
- ▼ Downside risk = demand likely lower than forecast
- ⇅ Mixed = material uncertainty both ways
- ? Unknown = insufficient disclosure/consensus

## Key Findings

This review of key electricity demand drivers in pathway studies and provincial system outlooks yields the following insights:

- **Overall, system outlooks likely underestimate electricity demand growth**, with greater upside than downside risk. Most provincial forecasts assume moderate electrification and limited new industrial or digital loads. As a result, actual demand could exceed these baselines — particularly in provinces not yet accounting for data centres, clean fuel production, or electrification of existing industry. Additionally, if Canada does achieve a net-zero economy by 2050, provincial system outlooks will have significantly underestimated future electricity demand. However, results vary by province – Quebec is a notable exception, as its system outlook already reflects stronger industrial and digital load growth, as well as net-zero policy commitments.
- **Pathway studies exhibit more downside risk, driven by climate policy uncertainty.** These studies assume full alignment with net-zero by 2050, embedding rapid electrification of transport, buildings, and industry. Should policy momentum slow, these forecasts will likely overstate demand. However, pathway studies may underestimate near-term industrial growth from sectors such as data centres, which are expanding faster than emerging technologies like hydrogen and carbon capture.
- **Climate policy uncertainty impacts all forecasts.** The impacts of climate change policy on growth in electricity demand may be overstated in all studies reviewed with the recent elimination of a consumer carbon price and potential upcoming changes to the federal electric vehicle sales mandate. At the same time, conservative assumptions on the future evolution of building codes from a climate and energy use perspective may see many provincial system outlooks underestimate the future growth of electricity demand in this sector.
- **Industrial electricity demand growth is the largest single source of upside risk.** Pathway studies emphasize long-term industrial demand from decarbonization but may miss shorter-term pressures from data centres and other emerging sectors. On the system outlook side, only two provinces – Ontario and Quebec – explicitly model data-centre demand, yet of these, Ontario projects a 440% increase in data-centre electricity use by 2050, while Quebec anticipates five-fold growth in data-centre peak demand by 2035. Other emerging loads such as hydrogen, direct air capture, and large industrial electrification could also materially alter provincial demand trajectories, often with limited lead time relative to traditional planning cycles.

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# 1. Introduction

## 1.1 Context

A global energy transition is underway, marked by the accelerating deployment of electro-tech — technologies that are enabling increased use of electricity to meet energy needs throughout the economy – particularly in the transportation, buildings, and industrial sectors. Today, electricity already accounts for 34% of global useful energy — more than oil (26%), gas (22%), coal (11%), or biomass (7%) — and its share is growing rapidly.

This transition is driven by several fundamental forces: (a) economics - as emerging electricity supply, transmission, and demand technologies become increasingly cost-competitive and benefit from learning and growth curves; (b) physics - as electricity provides energy more efficiently than alternatives; and (c) politics - as increased use of electricity can enhance energy security and support decarbonization objectives. Together, these forces are reshaping energy systems worldwide, and positioning electricity at the heart of the transition.

This report reviews current thinking on how this energy transition is unfolding in Canada and its implications for Canada's future electricity demand. While electricity demand in Canada has remained relatively flat over the past two decades, the fundamental forces described above make it clear that the sector is now on the cusp of significant growth. By examining recent forecasts of future electricity demand, this report explores how utilities, system operators, and energy modellers envision electricity demand evolving in the future, the key drivers that are expected to shape this growth, and the implications for future electricity system planning.

## 1.2 Study Scope

Forecasting future electricity demand is an extremely challenging exercise as many variables must be considered and all are characterized by elements of uncertainty. In reviewing recent electricity demand forecasts in Canada, this report seeks to understand the following: (a) how is electricity demand growth being forecast across Canada, (b) to what extent do these forecasts account for the key drivers of the energy transition currently underway, and (c) what explains the differences found in electricity demand forecasts across provinces and studies?

To explore these questions, the report considers two different types of electricity demand forecasts: (a) forecasts from provincial electricity system operators and utilities that are guiding future electricity system planning (referred to as "system outlooks" for the purposes of this report), as well as (b) key net-zero pathways studies that explore the potential demand for electricity in a carbon-neutral economy. The purpose of this analysis is to better understand current electricity demand forecasts in the context of the emerging energy transition and to consider how all future electricity demand forecasts can evolve to better reflect the transition that is underway. It is not intended to serve as a "scorecard" of current provincial or utility electricity demand forecasts.

# 2. Approach

As noted above, this report examines the magnitude and drivers of forecast electricity demand growth across Canada by reviewing forecasts from both provincial electricity planning documents ("system outlooks") as well as net-zero pathways studies ("pathways studies").

It covers electricity planning across all Canadian provinces, except for Prince Edward Island (PEI).[3] Territories were also excluded from this report given their unique context and challenges related to data availability.

## 2.1 System Outlooks

In this study, we define a "system outlook" as the document that best represents the planning basis for electricity infrastructure decisions at the provincial level. These documents can include integrated resource plans (IRPs), planning outlooks, and other long-term forecasts developed by utilities or system operators. The system outlook document for each province selected for this report reflects the best available representation of the assumptions and projections that underpin provincial electricity system investments.

To begin, we identified and reviewed the most recent IRP in provinces that had them. In cases where an IRP was unavailable, we selected alternative long-term electricity planning documents, such as capital plans or system operator forecasts. Table 1 outlines the selected system outlook from each province included in this study, as well as the scenario utilized in this analysis when multiple scenarios had been developed.

**Table 1: Provincial System Outlooks Included in This Study**

| Jurisdiction | System Outlook | Organization | Short Name | Year | Scenario |
|---|---|---|---|---|---|
| **British Columbia** | Integrated Resource Plan (IRP) | BC Hydro | BC 2021 IRP | 2021 (updated in 2023) | Reference |
| **Alberta** | Long-Term Outlook (LTO) | Alberta Electricity System Operator (AESO) | AB 2024 LTO | 2024 | Reference |
| **Saskatchewan** | Future Supply Plan (Draft) | SaskPower | SK 2024 Plan | 2024 | Diverse Mix 2050 |
| **Manitoba** | Integrated Resource Plan | Manitoba Hydro | MB 2023 IRP | 2023 | Scenario 1 |
| **Ontario** | Annual Planning Outlook (APO) | Independent Electricity System Operator (IESO) | ON 2025 APO | 2025 | Reference |

[3] PEI is omitted from this analysis because it imports approximately 68% of its electricity from New Brunswick via two submarine transmission cables, resulting in limited independent electricity planning data. Government of Canada. 2024. Prince Edward Island: Clean electricity snapshot.

| Jurisdiction | System Outlook | Organization | Short Name | Year | Scenario |
|---|---|---|---|---|---|
| **Quebec [4]** | État d'avancement du plan d'approvisionnement 2023-2032 | Hydro-Québec | QC 2024 Plan | 2024 | Planned |
| **New Brunswick** | Integrated Resource Plan | NB Power | NB 2023 IRP | 2023 | Scenario B |
| **Nova Scotia** | Evergreen IRP - Updated Action Plan and Roadmap | Nova Scotia Power | NS 2023 IRP | 2023 (inc. 2024 & 2025 updates) | CE1-E1-R2 |
| **Newfoundland and Labrador** | Resource Adequacy Plan (RAP) | NL Hydro | NL 2024 RAP | 2024 | Reference |

For scenario selection, the "Reference" case was used wherever it was defined. In provinces without an explicit reference case – namely Manitoba and New Brunswick – Scenario 1 and Scenario C were selected, respectively. Manitoba's Scenario 1 represents the least deviation in key variables such as economic growth and decarbonization policy, while New Brunswick's Scenario C assumes a slower pace of decarbonization combined with more rapid technological advancement. These scenarios were deemed the most appropriate proxies for a reference case.

It is important to note that each of the system outlooks selected features a different forecast horizon (Figure 1). As a result, direct comparisons between provinces are challenging. To address this, we use compound annual growth rate (CAGR) throughout this report to allow for comparison; however, the different horizons still mean that direct comparisons should be interpreted with caution.

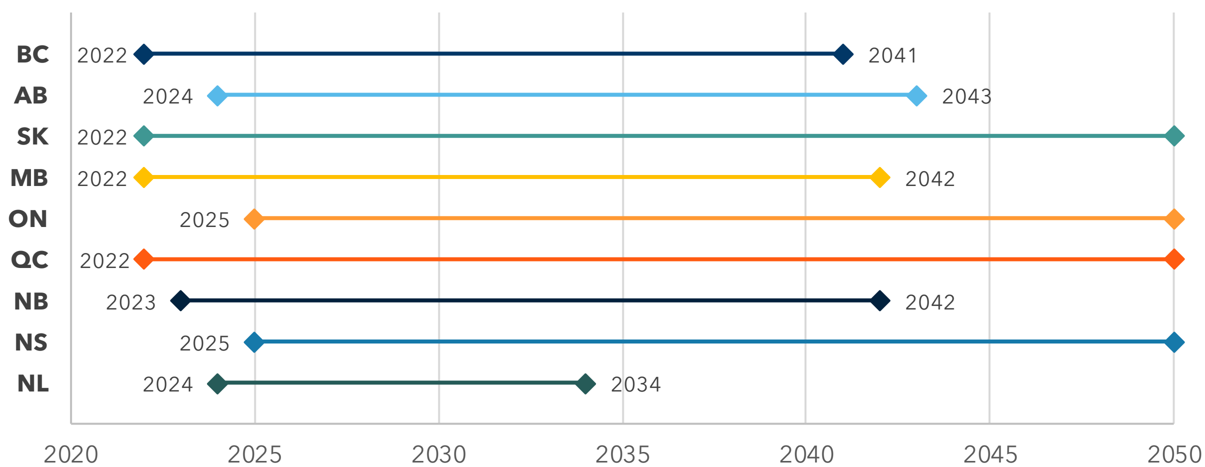


**Figure 1: Planning horizons identified in system outlooks for provincial utilities and system operators[5]**

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[4] In some cases, information from Hydro-Quebec's Action Plan 2035 was used to supplement the analysis.

[5] Planning horizon date ranges shown are based on latest utility and provincial as of October 2025. Québec planning horizon to 2050 based on total electricity demand range provided in HQ's '2035 Action Plan'. Saskatchewan's 2050 planning horizon is based on SaskPower's 'Future Supply Plan 2030 and Beyond' draft submission.

## 2.2 Pathways Studies

Pathways studies, as defined in this report, are studies that evaluate **least-cost** resource and technology pathways to net-zero emissions under various scenarios and assumptions. Often commissioned by governments, electricity system operators, or research institutions to inform policy or energy planning, these studies analyze scenarios for achieving net-zero emissions, considering energy supply, demand, infrastructure, costs, and trade-offs.

Pathways studies generally fall into two broad categories based on their modeling approach:

- **Integrated economic-electricity pathway studies,** which explicitly model end-use energy demand and its impact on electricity demand as part of a cost-optimized, economy-wide net-zero scenario. Studies in this category include the Canada Energy Regulator's (CER) Energy Futures 2023, the Institut Energie Trottier's (IET) Canadian Energy Outlook, and Manitoba's Electricity Roadmap. These studies model economy-wide energy-related emissions, which includes simulating the consumption of electricity at the end-user level. This approach connects the growth of electricity demand across the economy and the evolution of the electricity system, with each exerting influence on the other.
- **Electricity-sector-only studies**, which model net-zero electricity emissions but rely on assumed electrification trajectories rather than deriving them from integrated modeling. These include studies by IESO (Ontario) and AESO (Alberta). While these studies assume accelerated levels of electrification relative to business-as-usual as one would expect in a net-zero economy, they do not model future electricity demand but simply make assumptions about it. Pathways studies can complement the more granular system outlooks and plans developed by utilities or system operators. We conducted a comprehensive scan of pathways studies outlining electricity system evolution under net-zero scenarios. This included reports from government agencies, electricity system operators, academic institutions, think tanks, and industry organizations.

Following this review, six studies were included in the analysis (Table 2). In selecting studies to include, we prioritized recent provincial or national studies that provide disaggregated provincial projections.

**Table 2: List of pathways studies included in this analysis**

| Jurisdiction | Study | Organization | Short Name | Year | Scenario |
|---|---|---|---|---|---|
| **Canada** | Energy Futures | Canada Energy Regulator (CER) | Canada CER | 2023 | Global Net Zero |
| | Pathways for Net Zero in Canada [6] | Institut de l'énergie Trottier (IET) | Canada IET | 2024 | Global Net Zero |
| **Ontario** | Pathways to Decarbonization | IESO | ON P2D | 2022 | Net Zero |

[6] Supplemental sector-specific electricity demand data was provided by IET to complement the publicly available data from this study.

| Jurisdiction | Study | Organization | Short Name | Year | Scenario |
|---|---|---|---|---|---|
| | Cost Effective Energy Pathways | Government of Ontario (prepared by ESMIA and Dunsky Energy + Climate Advisors) | ON Pathways | 2024 | Net Zero |
| **Alberta** | Net-Zero Emissions Pathways | AESO | AB Pathways | 2022 | Net Zero |
| **Manitoba** | An Electricity Roadmap for Manitoba | Government of Manitoba (prepared by Dunsky Energy + Climate Advisors) | MB Roadmap | 2022 | Net Zero |

Studies that did not meet these criteria – such as the Canadian Climate Institute (CCI)'s Canada's Net Zero Future, the National Renewable Energy Laboratory (NREL)'s The North American Renewable Integration Study: A Canadian Perspective and the Electric Power Research Institute (EPRI)'s Canadian National Electrification Assessment – were excluded from the analysis. While these studies offer valuable national insights, they lacked sufficiently granular provincial-level data. Additionally, these studies were published in 2021 and are therefore less reflective of current policy and market conditions.

## 2.3 Why Review System Outlooks and Pathways Studies?

While this report considers forecasts from both pathways studies and system outlooks, it is important to recognize that these two categories of forecasts serve fundamentally different purposes: **pathways studies** model the theoretical least-cost pathway to achieve a specific outcome (e.g., net-zero emissions across the entire economy), while electricity **system outlooks** – including integrated resource plans (IRPs), planning outlooks, and related documents – focus on driving investment decisions within a utility's service area based on current policies, regulations, and market conditions.

Table 3 highlights key differences between system outlooks and pathways studies.

**Table 3: Provincial electricity system outlooks vs National / Provincial pathways studies**

| | System Outlook | Pathways Study |
|---|---|---|
| **Scope** | Focused on the provincial electricity system, with a granular focus on future needs under existing policy conditions. | Typically economy-wide assessment for net-zero transition which models or assumes total electricity needs to meet a net-zero scenario. |
| **Alignment with net-zero** | Mixed adherence – some align with net-zero targets | Aligned to and informed by net-zero targets and milestones |
| **Societal impacts** | GHG emissions and societal impacts may be included but to varying degrees across regions within Canada | GHG emissions focus (may incorporate other social and economic goals) |
| **Timeframe** | Long-term planning horizon, with inputs into short-term utility financial planning. Generally not aligned with net-zero milestones. | Aligned with net-zero milestones and target date (commonly net-zero by 2050) |

Although they serve different functions, both forecasts present credible perspectives on possible futures. Reviewing them together provides a more complete picture: system outlooks reflect expectations for electricity demand under current and relatively static policy and market conditions, while pathways studies operate at a higher level and explore how electricity demand could evolve in response to assumptions made about future technological capabilities and costs and the evolution of potential policy frameworks to support national decarbonization objectives.

### Study Limitations

This analysis is based on a snapshot of publicly available electricity demand forecasts as of 2025. Several provinces, including British Columbia, Saskatchewan, and Manitoba, are expected to release updated IRPs and planning outlooks soon, which may alter some of the findings presented in this report.

Additionally, not all provinces have formal IRPs. In such cases, our analysis relies on alternative electricity planning documents, such as capital investment plans or system operator forecasts. These documents vary in scope, detail, and methodological approach, making it difficult to ensure consistency across provinces.

Further, many of the system outlook scenarios included in this analysis are not official reference forecasts. Both Manitoba Hydro and NB Power develop scenario-based outlooks to explore a range of potential futures rather than to establish a single reference trajectory. Similarly, the scenario selected for Saskatchewan is based on a draft submission by SaskPower, as the release of the 2024 Long-term Supply Plan has been postponed indefinitely.[7] Accordingly, these scenarios should be interpreted as reasonable approximations of a provincial reference case.

Finally, there are several challenges associated with comparing the electricity demand forecasts produced by the range of documents considered in this report, including the fact that different studies consider different electricity demand forecast horizons and vary widely in the information provided concerning their methods, assumptions, and presentation of results.

As a result of all these factors, comparisons between jurisdictions should be interpreted with caution.

[7] SaskPower. Future Supply Plan – 2030 and Beyond. Accessed October 26, 2025.

# 3. Canadian Electricity Demand Outlook

## 3.1 National Outlook

By 2050, national electricity demand is projected to grow significantly, although the magnitude of growth varies by study and scenario. All the documents reviewed for this report envision massive growth in electricity generation to meet this demand. Figure 2 illustrates forecast electricity demand from all reviewed forecasts, including aggregated provincial system outlooks and national pathways studies, and presents them alongside data on historical electricity generation.

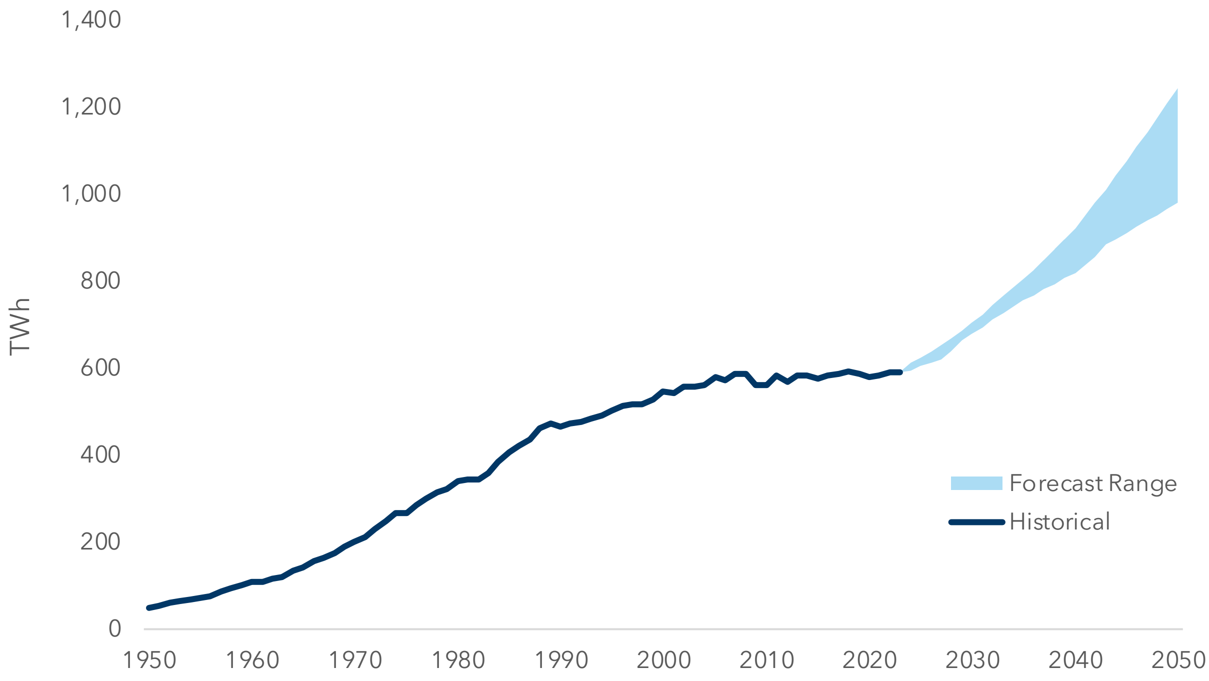


**Figure 2: Historical Generation and Forecast Electricity Demand, 1950-2050.**[8]

These projections collectively highlight a sustained upward trend in electricity demand, alongside increasing uncertainty beyond 2040. Even under the most conservative projections, electricity demand in Canada is expected to increase by approximately 62% between 2025 and 2050 to meet increased electricity demand across the Canadian economy. The forecasts of future electricity demand in Canada clearly assume that the fundamental forces driving increased electricity demand globally are relevant in Canada as well.

[8] This graph reflects the CER and IET pathways studies, as well as an aggregated forecast of provincial electricity system outlooks. As not all provincial system outlooks extend to 2050, this aggregated forecast incorporates Dunsky's internal modeling to project trends through 2050. The modeling draws on Canada's Renewable Energy Market Outlook 2025: Wind. Solar. Storage., a joint publication by the Canadian Renewable Energy Association and Dunsky Energy + Climate Advisors.

Table 4 compares projected national electricity demand growth across the national pathways studies and the aggregated provincial system outlooks. Across these sources, electricity demand is projected to grow at a compound annual growth rate (CAGR) ranging from 2.0% to 2.6%. Across all forecasts, the conclusion is consistent: electricity will play an increasingly central role in Canada's energy system over the coming decades.

**Table 4: National Demand Growth Across Reviewed Forecasts**

| Type | Region and Study | Period | Metric | Increase Across Study Period | CAGR |
|---|---|---|---|---|---|
| **Pathways Studies** | Canada **CER, GNZ** | 2023-2050 | Electricity Demand | 102% 587 → 1,187 TWh | 2.6% |
| | | | Peak Demand | 112% ~100 → 212 GW[9] | 2.8% |
| | Canada **IET, NZ50** | 2021-2050 | Electricity Demand | 99% 519 → 1,031 TWh | 2.4% |
| **System Outlooks** | Canada **Aggregated Forecasts** [10] | 2025-2050 | Electricity Demand | 62% 604 → 982 TWh | 2.0% |

[9] The CER dataset provides relative changes in electricity peak demand by province between 2021 and 2050 but does not include the underlying absolute demand values. In the absence of those base-year figures from CER, provincial starting-year peak demand values were obtained from publicly available source such as IRPs, LTOs, and utility rate applications. The CER's provincial growth factors were then applied to these baseline values to estimate 2050 peak demand, from which total demand and CAGR were derived.

[10] As not all provincial system outlooks extend to 2050, this aggregated forecast incorporates Dunsky's internal modeling to project trends through 2050. The modeling draws on Canada's Renewable Energy Market Outlook 2025: Wind. Solar. Storage, a joint publication by the Canadian Renewable Energy Association and Dunsky Energy + Climate Advisors.

## 3.2 Provincial Outlook

### 3.2.1 Projected Growth Rates in Electricity Demand Vary Significantly by Province

While electricity demand is projected to grow significantly at the national level between 2025 and 2050, there is significant variation in the expected growth rate of electricity demand between provinces. Figure 3 summarizes the range of projected electricity demand CAGR by province across all reviewed forecasts, including system outlooks and pathways studies.

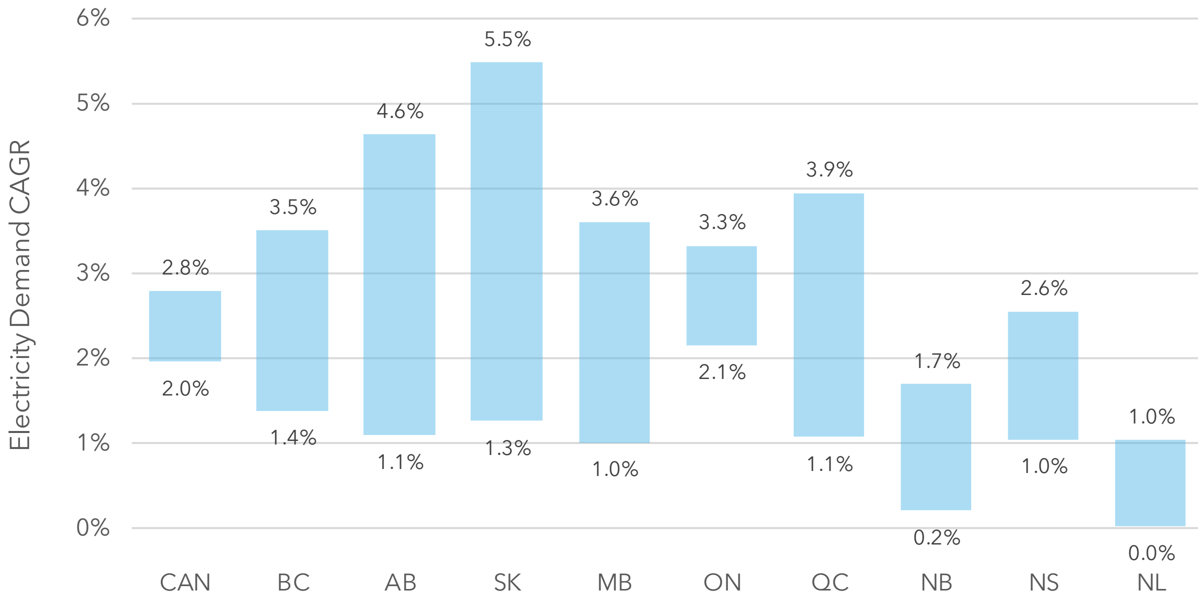


**Figure 3: Range in CAGR in Electricity Demand by province across reviewed forecasts**

As shown in Figure 3, several provinces — including British Columbia, Alberta, Saskatchewan, Manitoba, and Quebec — show a wide range of projected growth. Forecasts for these provinces range from under 2% CAGR at the low end (below the national low end) to over 3% at the high end (above the national high end). Ontario's projected CAGR range is roughly aligned with the national trend, spanning approximately 2% to 3%. By contrast, forecasts for Nova Scotia, New Brunswick, and Newfoundland and Labrador indicate slower demand growth, with upper-end CAGR values below the national estimate. Indeed, Newfoundland and Labrador is the only province where one of the demand forecasts projects no growth (0% CAGR) in this time period.

Despite variations in projections across provinces and the uncertainty surrounding long-term demand forecasts, however, the trend is clear: electricity demand is expected to increase significantly in all provinces in Canada between 2025 and 2050.

Figure 4 presents the same information as Figure 3, but illustrates the difference found in CAGR growth rates between pathway studies and system outlooks across the provinces. This makes it very clear that provincial system outlooks generally envision significantly slower CAGR in electricity demand than pathway studies. There are two clear exceptions to this finding – namely, Quebec and Newfoundland and Labrador – and the reasons for this will be examined in Section 4.3.

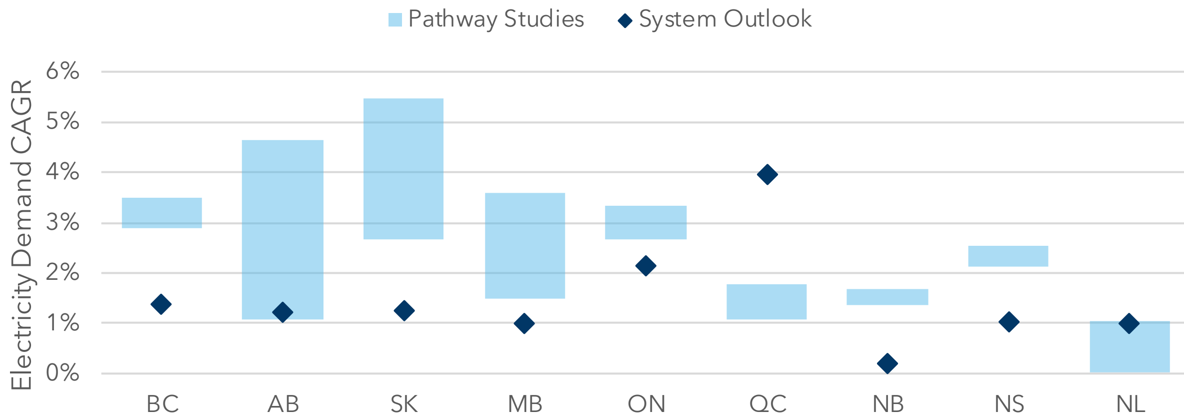


**Figure 4: Electricity Demand CAGR by Province, Pathway Studies vs System Outlooks**

Figure 5 examines the CAGR for peak electricity demand at the provincial level across pathway studies and all provincial system outlooks except Saskatchewan and Nova Scotia where this data was not available. Once again, provincial system outlooks consistently forecast CAGR for electricity demand to be lower than pathway studies except for Quebec.

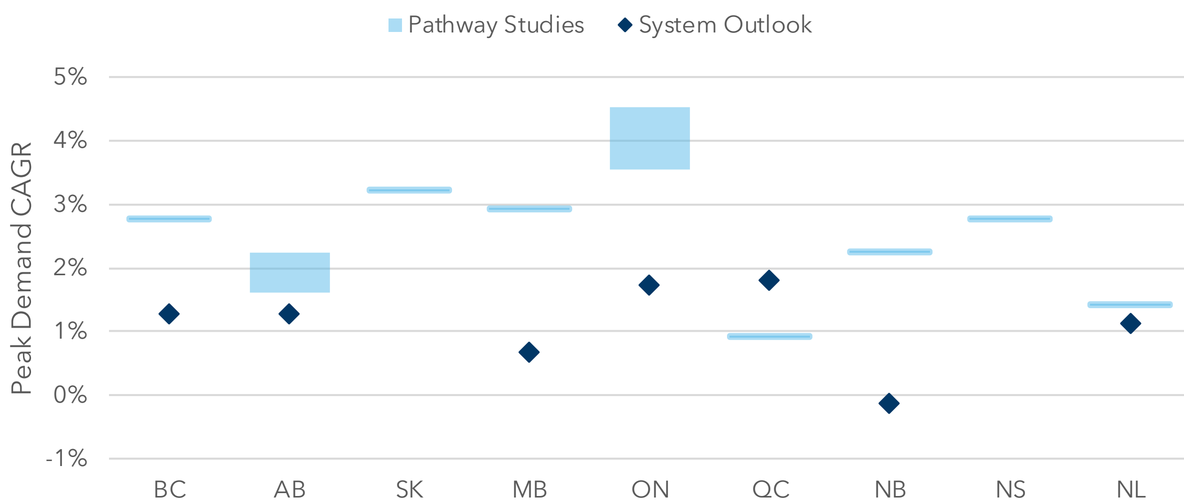


**Figure 5: Peak Demand CAGR by Province, Pathways Studies vs. System Outlooks**

As both Figures 4 and 5 illustrate, electricity demand forecasts envision significant differences in growth rates of future electricity demand in different provinces. What explains these differences? A key component of the answer can be found in how different forecasts consider and treat several major drivers of electricity demand. This will be explored in Section 5 of this report.

For more detail on CAGR by province and forecast, see the Appendix.

### 3.2.2 Provincial Demand Growth Expectations Consistently Revised Upwards Over Time

Where this report has had an opportunity to review several iterations of electricity demand forecasts in specific provinces, it has found a clear and consistent trend of provincial system operators and utilities revising their electricity demand forecasts upward in successive system outlooks. As understanding of electrification, economic growth, and decarbonization policies has evolved, projections for electricity demand have steadily increased across most provinces.

Figures 6 and 7 provide two examples to illustrate this trend, showing the evolution of total electricity demand forecasts from successive editions of the AESO's Long-Term Outlook (LTO) for Alberta and the peak electricity demand forecasts of the IESO's Annual Planning Outlook (APO) for Ontario. While all electricity demand forecasts include uncertainties that may lead to electricity demand falling short of (or being higher than) forecasted levels, it is significant that forecasted electricity demand is generally increasing with the publication of each new system outlook.

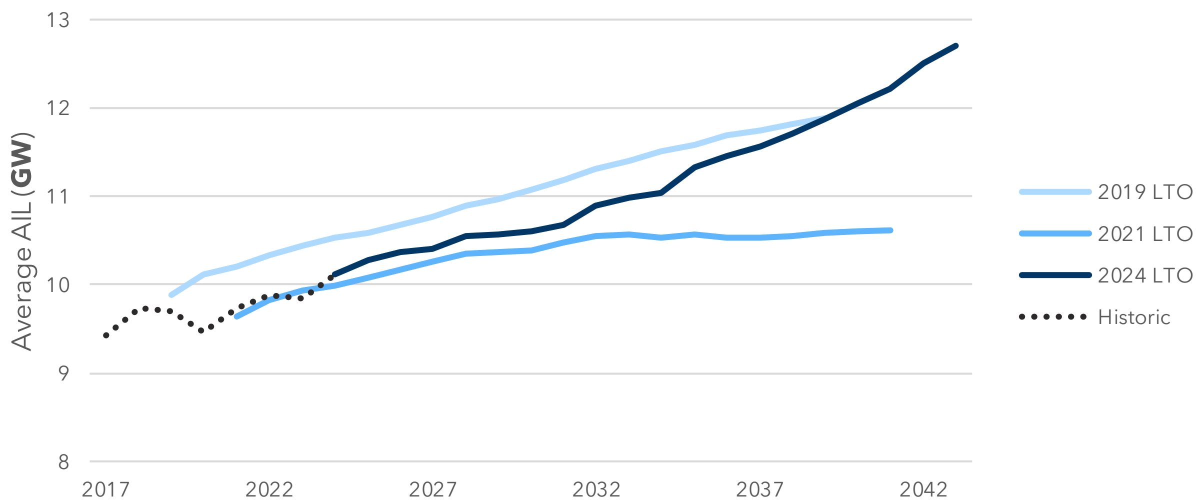


**Figure 6: Reference Case Average Alberta Internal Load forecast – AESO 2024 LTO**

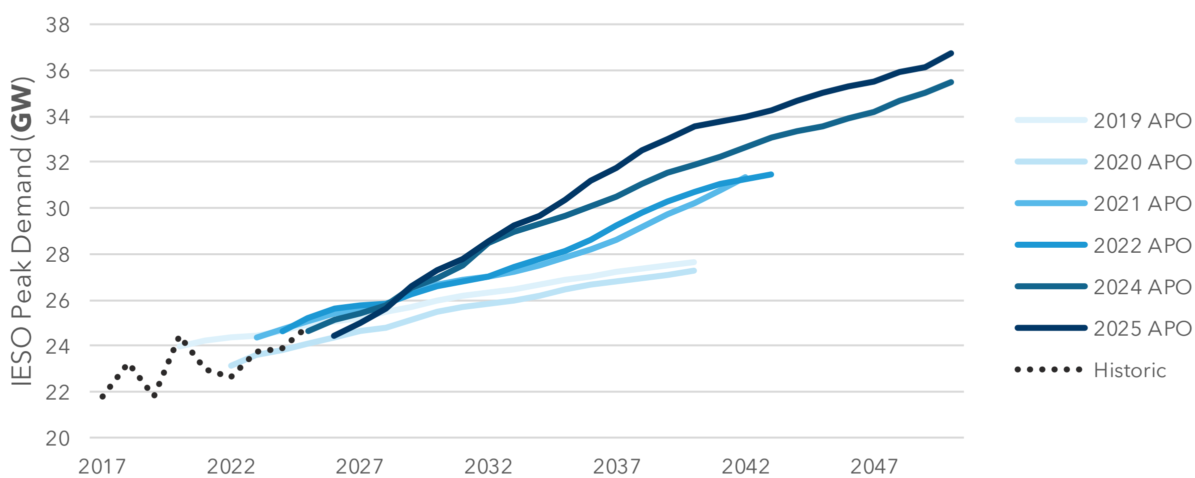


**Figure 7: Ontario Annual Planning Outlook (APO), 2019-2025**

Indeed, there is a clear trend that each new edition of these planning outlooks projects higher future electricity demand than the previous one. The temporary decline observed between the 2019 and 2020 IESO forecasts can likely be attributed to the economic slowdown and reduced electricity consumption during the COVID-19 pandemic, which temporarily dampened demand expectations. Similarly, the AESO's 2021 LTO projects lower demand relative to its 2019 edition, reflecting the near-term impacts of the pandemic on Alberta's industrial activity and energy-intensive sectors.

Since the IESO's 2020 APO and the AESO's 2021 LTO, both system operators have revised their projections significantly upward as electrification of transportation, buildings, and industry has accelerated, and as stronger policy signals for decarbonization have emerged (see Figure 6 and 7). Overall, this trend underscores a growing consensus that electricity demand growth in Canada will be substantially higher than previously anticipated, driven by the ongoing energy transition and increasing electrification across all sectors.

## 3.3 Comparing Total Provincial Electricity Demand by Type of Forecast

The different CAGR in electricity demand found in different provinces and across type of forecast leads to some notable variation between electricity demand forecasts in pathway studies and provincial system outlooks for different provinces. Figure 8 summarizes projected increases in total electricity demand across provinces, comparing the national pathway studies (CER and IET) with provincial system outlooks.

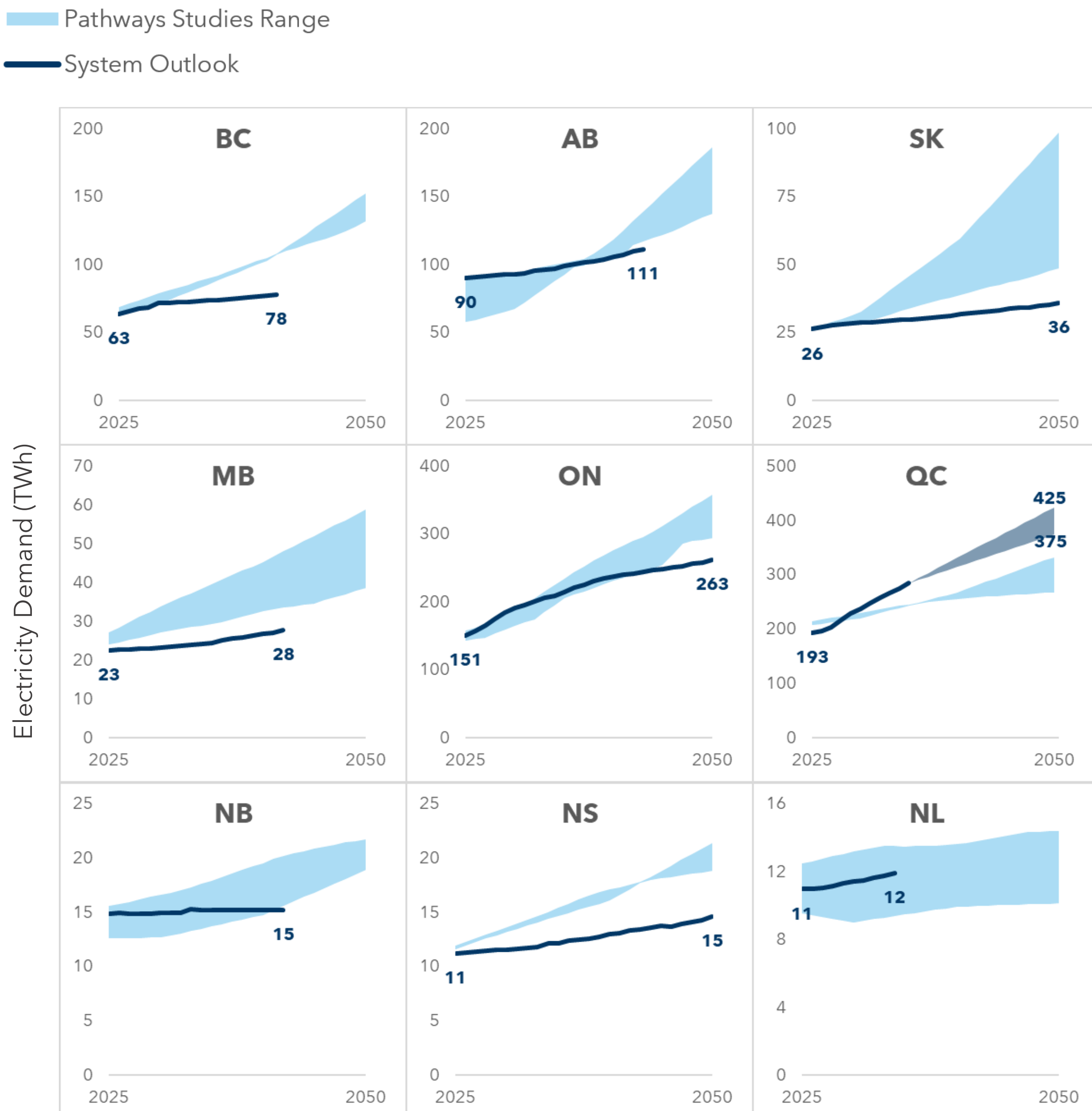


**Figure 8: Electricity Demand by Province, 2025-2050, system outlooks and pathway studies**

Across most jurisdictions, **pathways studies consistently project greater electricity demand** than provincial system outlooks. This is observed in six of nine reviewed provinces: British Columbia, Alberta, Saskatchewan, Manitoba, Ontario and Nova Scotia. In Alberta and Ontario this is primarily true after 2035, while the divergence begins much earlier in the other provinces. Electricity demand in the provincial system outlooks in both New Brunswick and Newfoundland and Labrador fall within the range envisioned by the national pathway studies, while Quebec's provincial outlook envisions significantly higher growth than national pathway studies.

The divergence found in most provinces is expected and reflects fundamental differences in modeling assumptions. Pathway studies assume economy-wide electrification aligned with achieving net-zero emissions by 2050, whereas provincial system outlooks typically focus on expected outcomes based on current policies and market conditions. As a result, the provincial system outlooks are more conservative.

As illustrated in Figure 8, however, Quebec and Newfoundland and Labrador are significant exceptions to this trend. Why? First, they are the only two provinces that explicitly align their system outlook reference case with a high-electrification, net-zero future. Quebec also makes much more aggressive assumptions related to industrial load growth and economic growth than most provinces, while in Newfoundland and Labrador, the national pathway studies assume a shrinking population while the provincial system outlook does not.

The next section will dive more deeply into the treatment of key drivers of electricity demand in different forecasts, reviewing the assumptions of each pathway study and provincial system outlook.

# 4. Demand Drivers

Electricity demand growth is shaped by a wide range of underlying drivers, and forecasts of electricity demand must consider many factors or variables including traditional macro drivers like population and economic growth, technology drivers such as evolving electro-tech and demand-side resources, emerging industries and large demand loads, and relevant policy and regulatory signals. This section provides an overview of each of these key factors that can influence future electricity demand, followed by a province-by-province review of how these factors are reflected in individual forecasts.

## 4.1 Macro Drivers

Macro drivers are the fundamental socioeconomic factors that shape electricity demand projections, such as population growth and economic growth. Together, these drivers set the baseline trajectory for electricity demand.

### 4.1.1 Population Growth

Population growth is typically represented as an assumed annual percentage growth rate and may also be reflected through related indicators such as housing starts.

Figure 9 summarizes the assumed population CAGR across reviewed forecasts, including pathway studies and provincial system outlooks. There are two blue lines for pathway study assumptions: one reflects the full 25-year horizon, while the other is normalized to align with its respective provincial system outlook.

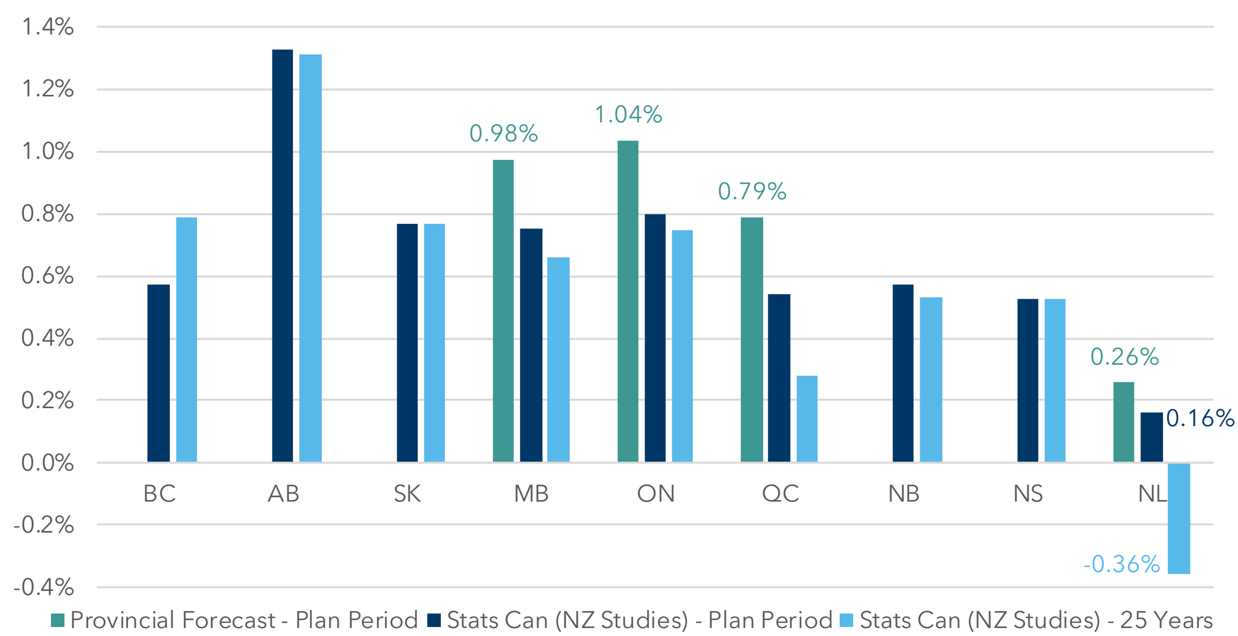


**Figure 9: Population CAGR Assumptions**

Not all provincial system outlooks disclose their underlying population growth assumptions. However, where comparisons are possible, **pathways studies generally assume lower**

**population growth than the provincial forecasts** for the same regions and periods. As illustrated in the earlier discussion on electricity demand, changes in the CAGR across forecasts can have a major impact on assumed population levels over the time period considered by these forecasts. This difference has implications for electricity demand forecasts because future electricity demand will be higher if the population is greater.

Further analysis is required, as only four of nine provinces disclose their population growth assumption, but it seems apparent that national pathways studies would forecast higher future electricity demand if they used the population growth assumptions found in provincial system outlooks.

Notably, Newfoundland and Labrador is the only province modeled with a shrinking population across any forecast. Both the IET and the CER's pathways studies assume a population decrease of 0.36% annually over the next 25 years. In contrast, the province's own plan focused on a shorter 10-year horizon and projects modest annual population growth of 0.26%. As a result of the population decline assumed in its net zero study, the CER report forecasts negative electricity consumption growth across the residential and industrial sectors through 2050.

### 4.1.2 Economic Growth

Economic growth is another core driver of electricity demand, typically expressed as an assumed increase in gross domestic product (GDP). In some cases, forecasts may also incorporate related indicators, such as growth in disposable income. These assumptions capture broad, economy-wide trends that influence electricity consumption across the residential, commercial, and industrial sectors. Importantly, this section does not include sector-specific drivers – such as the emergence of new industries (e.g., hydrogen production or data centres) – which are addressed separately in Section 4.3.3: Industry.

Table 5 summarises economic growth assumptions across forecasts. Not all forecasts include GDP as a key input; therefore, this assumption may be either not applicable or not disclosed. In such cases, "No data" is shown in Table 5.

**Table 5: Economic Growth Assumptions**

| Study | Annual GDP Growth | Details |
|---|---|---|
| | **Pathways Studies** | |
| **Canada** CER | 1.26% | |
| **Canada** IET | 1.62% | IET GDP growth based on CER's Canada Energy Future 2021 Report |
| **MB** Roadmap | -0.02% | The annual impact of a net zero scenario on GDP is slightly negative until 2040, but positive after 2040, showing a period of transition followed by recovery. |
| **ON** P2D | No data | |
| **ON** Pathways | 1.67% | Growth decelerates until 2030, after which a rebound is expected followed again by a slight deceleration of GDP increase. |
| **AB** Pathways | N/A | Over the longer term, provincial economic growth is expected to be moderate due to the combination of an aging population and a slowdown in oil production post 2030 |

| Study | Annual GDP Growth | Details |
|---|---|---|
| | | **System Outlooks** |
| **BC** 2021 IRP | No public data | BC Hydro utilizes Conference Board of Canada's (COB) provincial outlook reports to derive its GDP growth assumptions. While the document highlights of recent annual versions of the COB reports don't publish GDP growth expectations, the 2022 publication from the organization outlined a **1.7%** annual real GDP growth assumption between 2022 and 2045 for BC. |
| **AB** 2024 LTO | No public data | Similar to BC, the AESO utilizes the COB's provincial outlook report to derive its GDP growth assumptions. Unfortunately, details regarding AB's forecasted GDP growth were not listed in any of the document highlights of historical COB reports. |
| **SK** 2024 Plan | No data | |
| **MB** 2023 IRP | 1.30% | |
| **ON** 2025 APO | No data | IESO does not use GDP as input into its modelling but rather focuses on residential household count, commercial floor space and industry specific growth plans & activities for forecasting electricity growth.<br><br>The IESO also indicated that the relationship between industrial sector GDP output and industrial sector electricity demand use is often weak. |
| **QC** 2024 Plan | 1.50% | Assumes annual real salary growth of 1.1%, job growth of 1.0% and 1.5% real GDP growth. |
| **NB** 2023 IRP | No data | No assumptions shared. IRP notes that about 21% of total provincial electricity sales are closely tied to provincial GDP. |
| **NS** 2023 IRP | No data | |
| **NL** 2024 RAP[11] | No data | Assumes 0.89% annual increase in disposable income. |

Table 5 reveals a wide variation in how different Canadian pathway studies and system outlooks approach economic growth assumptions in electricity demand forecasting. Among pathways studies, the key determinant is GDP growth, and the Canada Energy Regulator (CER) assumes annual GDP growth of 1.26%, while the IET study adopts a slightly higher rate of 1.62%, referencing the CER's 2021 projections.

In contrast, system outlooks at the provincial level illustrate a mix of approaches and data availability. Some provinces, like Manitoba and Quebec, outline explicit GDP growth assumptions of 1.3% for Manitoba, and 1.5% for Quebec (which also includes related indicators like salary and job growth).

While British Columbia and Alberta rely on external sources like the Conference Board of Canada for their economic outlooks, they do not disclose specific GDP growth figures in their IRPs or appendices.

Ontario diverges from the GDP-based approach entirely, focusing instead on sector-specific metrics like household count and commercial floor space, citing a weak correlation between industrial GDP and electricity demand. Several provinces such as Saskatchewan, New Brunswick, Nova Scotia do not describe the data being used while Newfoundland and Labrador provides an alternative indicator of disposable income growth.

[11] Electric Vehicle electricity demand from NL Hydro's 2023 Long-Term Load Forecast

While all pathways studies and system outlooks consider the impact of projected economic growth on future electricity demand, the different approaches utilized to reflect economic growth in different studies and the wide diversity in data transparency among those studies makes it very challenging to determine whether or not different approaches in this area can explain some of the differences in estimates of future electricity demand across these forecasts.

## 4.2 Cross-Cutting

We define cross-cutting drivers as economy-wide policy assumptions that influence electricity demand across multiple sectors and regions. In this context, they include measures such as carbon pricing and policy commitments to achieve net-zero emissions by 2050.

Cross-cutting policy assumptions across forecasts are outlined in Table 6.

**Table 6: Cross-Cutting Policy Assumptions**

| Region and Study | Economy-Wide Net-Zero by 2050 | Carbon Pricing |
|---|---|---|
| **Pathway Studies** | | |
| **Canada**<br>CER | ✓ | ✓ |
| **Canada**<br>IET | ✓ | ✓ |
| **MB**<br>Roadmap | ✓ | ✓ |
| **ON**<br>P2D | ✓ | ✓ |
| **ON**<br>Pathways | ✓ | ✓ |
| **AB**<br>Pathways | ✓ | ✓ |
| **System Outlooks** | | |
| **BC**<br>2021 IRP | **No** | **Likely**<br>IRP is aligned with government policy objectives |
| **AB**<br>2024 LTO | **No** | ✓<br>Including consumer carbon tax and provincial TIER carbon pricing |
| **SK**<br>2024 Plan | **No** | No data |
| **MB**<br>2023 IRP | **No** | ✓<br>All scenarios |
| **ON**<br>2025 APO | **No** | **✓ - Industrial**<br>Provincial Emissions Performance Standards (EPS) program |
| **QC**<br>Action Plan 2035 & 2024 Supply Plan Progress Report | ✓ | **Likely**<br>Plan is aligned with government policy objectives |
| **NB**<br>2023 IRP | **No** | ✓ |
| **NS**<br>2023 IRP | **No** | ✓ |
| **NL**<br>2024 RAP[12] | ✓ | ✓ |

By definition, net-zero pathway studies adopt a predetermined outcome of net-zero emissions by 2050 and then rely on energy and economic modeling to project a pathway that

[12] Electric Vehicle electricity demand from NL Hydro's 2023 Long-Term Load Forecast

is consistent with that outcome.[13] These studies also model a range of current, announced and hypothetical policy measures to ensure that emissions fall in line with the net- zero trajectory.

Despite the prevalence of net-zero targets and policies across Canada few utilities and system planners are currently fully integrating net zero-aligned policy assumptions into their provincial system outlooks.[14] On the demand side, only two utilities – Hydro-Québec and NL Hydro – explicitly align their reference case with assumptions on electricity demand associated with a high electrification, net-zero future. Several other utilities and system operators, including Manitoba Hydro, AESO, and IESO, include a high-electrification scenario that is intended to reflect increasing electricity demand from a net zero future, but these scenarios are not considered in this analysis.[15]

Carbon pricing, encompassing both the consumer-facing fuel charge and industrial large-emitter programs, is reflected across most of the reviewed forecasts. Pathway studies and most system outlooks incorporate both forms of pricing, as the federal consumer carbon price remained in effect until its repeal in 2024. The latest Ontario APO is the exception, as it was published in 2025, after the repeal of the consumer fuel charge.

Canada's industrial carbon pricing systems remain in place and continue to drive electrification in energy-intensive sectors. However, the repeal of the federal consumer carbon price in 2024 removes an important incentive for households and businesses to switch from fossil fuels to electricity. As a result, there may be some downside risk to projected electricity demand growth in provinces where residential and commercial electrification had been partly driven by consumer carbon pricing.

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[13] CER 2023. https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/scenarios-and-assumptions/

[14] Eight of nine provinces – all except Ontario – included in this analysis have a provincial net zero by 2050 target.

[15] The IESO does not model net zero as part of its 2024 APO, but references a separate IESO study—Pathways to Decarbonization—that modeled a net-zero economy and electricity system by 2050.

## 4.3 Sectoral Drivers

Sectoral drivers are specific trends and factors that influence electricity demand within individual sectors of the economy. In the transportation sector, the primary example is the adoption of electric vehicles (EVs). For buildings, future electricity demand will be influenced by the electrification of space heating and cooling, adoption of electric appliances, building codes and policies, and energy efficiency measures. For industry the decarbonization of existing industries through electrification, and the introduction of new electricity demand loads such as data centres and hydrogen production are the main factors influencing electricity demand.

### 4.3.1 Transportation

For both pathway studies and system outlooks, the core factor determining future electricity demand in the transportation sector is the increased adoption of EVs across all segments of the transportation sector. Most of the forecasts reviewed assume that 100% of light-duty vehicles sold in 2035 will be electric and that the vast majority of LDVs on the road in 2050 will be electric. Some also assume at least partial electrification of medium- and heavy-duty vehicles (MHDV) on the road in that timeframe. Additionally, some studies assume that electrification of other transportation including rail and off-road vehicles also contributes to increasing electricity demand in the sector.

Table 7 summarizes transportation electrification assumptions across forecasts.

**Table 7: Transportation Electrification Assumptions Across Reviewed Studies**

| Region / Study | LDV Electrification | MHDVs / HDVs Electrification | Other Information |
|---|---|---|---|
| **Pathways Studies** | | | |
| **Canada** CER | 100% LDV sales by 2035 | 100% HDV sales by 2040 (where feasible) Tech mix remains uncertain (H2, battery) | Passenger fleet electrification is policy and cost-driven (battery cost decline, incentives, carbon pricing)<br>Freight: electricity >90 TWh (2050), $H_2$ 5 MT by 2050 |
| **Canada** IET | 95%+ LDV on the road by 2050 | Outcomes hinge on infrastructure & policy choice (battery, H2, catenary) | Rail fully decarbonized by 2050 (electric, H2). Agriculture electrifies strongly. |
| **MB** Roadmap | 100% of LDV sales by 2035 | 100% HDV sales by 2040 (where feasible). HDV buses and freight are mostly (~75%) electric. | Biofuels, hydrogen, and RNG in hard to electrify HDV segments. Biofuels in particular play an important role in agricultural, industrial and other off-road vehicles. |
| **ON** P2D | 100% LDV sales by 2035 | 100% of municipal transit commission buses electrified by 2040. | Assumed increased bus fleet, and electrical charging demand, of 10% higher than baseline forecasts. Other electric mobility electrical charging demand increased to be equivalent of 5% of light duty battery electric vehicles.<br>Rail transportation as a whole, electricity demand to be 20% higher than baseline forecasts |
| **ON** Pathways | 100% LDV by 2050 | HDV "shifts" towards BEVs, Buses | Other transportation modes – including rail, marine, and off-road transport – leverage a mix of electrification, biofuels and hydrogen. |

| Region / Study | LDV Electrification | MHDVs / HDVs Electrification | Other Information |
|---|---|---|---|
| | | predominantly electrified | |
| **AB** Pathways | 100% LDV sales by 2035 | Aligns with Federal ERP targets – buses 100% electric by 2040, MDVs 30%, and HDVs 20% | LMHDV sensitivities across scenarios with a "Slower adoption rate" which would decrease average load by 300 MW while a "Higher adoption rate" would increase average load by 365 MW by 2035. |
| **System Outlooks** | | | |
| **BC** 2021 IRP | 100% LDV sales by 2040 | No province-wide mandate; bus electrification (TransLink, BC Transit) | Voluntary TOU subscription; 50% of EV charging shifted to off-peak |
| **AB** 2024 LTO | 100% LDV sales by 2035 | MHDV: 30% sales by 2043; Bus: 65% by 2040 | |
| **SK** 2024 Plan | No data | No data | |
| **MB** 2023 IRP | ~65% LDV sales by 2045<br>Framed as "scenario inputs" rather than deterministic forecasts. | 30% MDV, 15% HDV by 2045<br>Bus: ~90% by 2040 | EV adoption is identified as a major driver of long-term load growth.<br><br>Electrification of buses assumed in all scenarios suggests strong policy/market certainty compared to trucks, which vary more across scenarios. |
| **ON** 2025 APO | 100% LDV sales by 2035 | 23% of MHDV stock by 2050 | High uncertainty in MHDV technology mix. Transportation electrification covers EVs and rail. |
| **QC** Action Plan 2035 & 2024 Supply Plan Progress Report | 100% LDV sales by 2035 | Support programs exist but no quantified HDV adoption | No details on adoption but explicitly earmarks 24 TWh of new supply for transport electrification & building electrification by 2035. |
| **NB** 2023 IRP | LDV stock grows from 3k in 2023/24 to 151k in 2042/43 | No MHDV electrification | 80% LDV charging at home, 20% GS sales<br>MHDV charging as GS, industrial Dx or Tx sales |
| **NS** 2023 IRP | No data | No data | Not explicitly mentioned; EV adoption assumed as part of electrification scenarios, which adds ~200 MW of peak demand by 2030 (from EVs + heating) |
| **NL** 2024 RAP | 100% new LDV sales by 2035 | MHDV and bus electrification modeled in all scenarios | Assume 50% of home charging of LDV will be shifted from evening peak to overnight; unmanaged would add 70-150 MW |

For light-duty vehicles (LDVs), four provinces – Alberta, Ontario, Quebec, and Newfoundland and Labrador – model the federal government's zero-emissions vehicle (ZEV) sales targets (or equivalent provincial targets) that mandate 100% of light-duty vehicle sales to be zero-emissions by 2035. British Columbia assumes this target will be met in 2040. In Newfoundland, the reference case projects significant EV growth, with more than 80,000 light-duty EVs on the road by 2034, accounting for over 20% of total LDV stock. This projection can be considered aggressive relative to current EV registration trends in the province. Comparatively, Manitoba Hydro's IRP baseline scenario has a much more relaxed pace for EV adoption (65% LDV sales by 2045), with only its high electrification scenario assuming EV adoption on pace with the federal ZEV sales target.

Pathways studies generally assume more rapid and extensive electrification of LDVs than provincial system outlooks. All reviewed pathways studies are aligned with the federal ZEV sales target, resulting in a nearly fully-electrified LDV fleet by 2050.

Of note, in September 2025 the federal government announced a temporary pause and review of the Electric Vehicle Availability Standard "to ensure it continues to reflect market realities, remains effective for Canadians, and does not place undue burden on automakers". The review may result in significant changes to the original policy, including the annual sales targets and the 2035 target.[16] Potential weakening of the federal LDV targets will likely slow the pace of EV adoption and electricity demand growth in the transportation sector across the country.

Only four provinces (Alberta, Manitoba, Ontario and Newfoundland and Labrador) model MHDV adoption. The electrification of buses and public transit is considered within most provinces.

Pathways studies generally adopt more ambitious assumptions for MHDV electrification than provincial system outlooks. For instance, the Manitoba Roadmap and CER studies assume 100 percent electrification of heavy-duty vehicle sales where technically and economically feasible, while the Ontario P2D and Alberta Pathways studies project fully electrified bus fleets by 2040. Pathways studies also extend electrification assumptions beyond on-road vehicles to include agricultural, off-road, and rail segments, which are rarely addressed in provincial system outlooks.

To illustrate how these assumptions translate to impact on transportation-related electricity demand, Figure 10 illustrates both the increase and total transportation-related electricity demand over the time horizon for each study.

As Figure 10 illustrates, all reviewed forecasts show increasing demand in the transportation sector. Pathway studies envision rapid growth in transportation-related electricity demand across all provinces. Significantly, this growth is much higher than that considered in the provincial level system outlooks that present this data. British Columbia, Quebec, Nova Scotia, and Saskatchewan do not provide transportation-sector demand data in their system outlooks. Quebec does not report transportation-sector electricity demand in energy terms but does provide projections for its impact on peak load, forecasting an eighteenfold increase to 3.3 GW by 2035.

More details on the forecast evolution of electricity demand in the transportation sector across all reviewed studies can be found in the Appendix.

[16] Prime Minister Carney launches new measures to protect, build, and transform Canadian strategic industries. September 5, 2025.

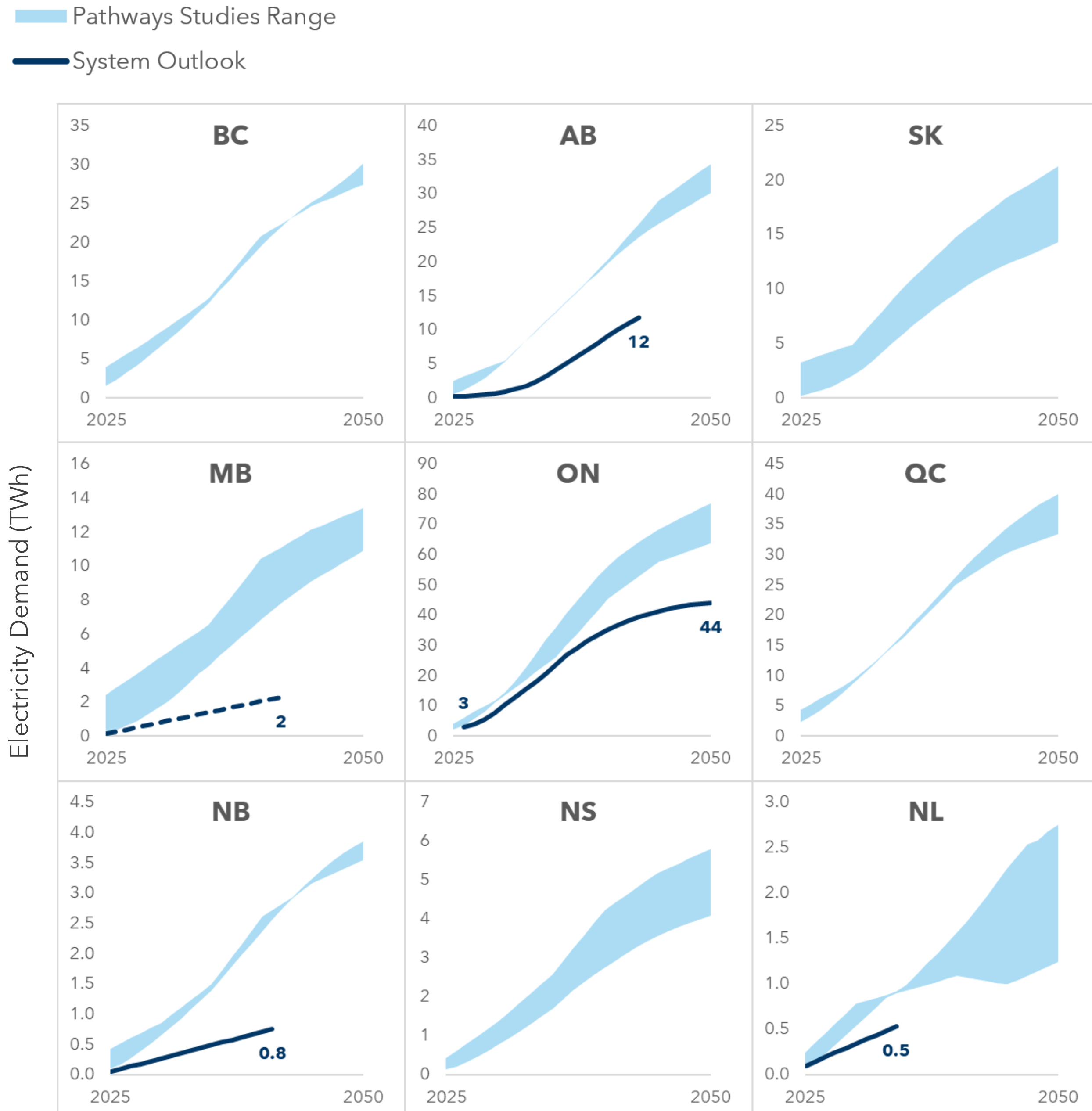


**Figure 10: Electricity Demand Growth in the Transportation Sector by Province in Pathway Studies and System Outlooks**

## 4.3.2 Buildings

Future electricity demand in buildings will be shaped by several factors, including rates of building electrification, applicable building codes and policies, and energy efficiency, among others.

Accordingly, future electricity demand forecasts must consider the deployment of heat pumps and electric appliances (stovetops, clothes dryers) that are replacing traditional fossil fuel-based equipment. They must also consider the evolution of building codes and regulations. For example, the National Energy Code for Buildings (NECB) sets technical requirements for energy efficient design and construction of large buildings, while the National Building Code (NBC) covers low-rise residential buildings. Both codes now include tiered performance standards, with the highest tier aligned to net-zero energy-ready goals by 2030. Additionally, Minimum Energy Performance Standards (MEPS) such as the EnerGuide Rating System establish baseline efficiency requirements for different building types.

Table 8 summarizes the assumptions made about the buildings sector in the reviewed pathway studies and system outlooks.

**Table 8: Buildings Assumptions Across Reviewed Forecasts**

| Region / Study | Electrification | Building Codes and Policy |
|---|---|---|
| | **Pathway Studies** | |
| **Canada** CER | HPs in ~50% RES & COM buildings by 2050; adoption tied to replacement cycles; ccASHP complimented by backup; some gas/oil furnaces remain to 2050; water heating lags space heating<br><br>HP costs -15% by 2030 and -40% by 2050; residual fossil emissions in buildings reduced by blending RNG (13%) & $H_2$ (7%) | MEPS, NECB/NBC, BC Step Code, NZE-ready by 2030; NZ by 2050; existing rebates and tax credit continues |
| **Canada** IET | Near-total HP adoption; water heating lags due to limited policy support; challenge is logistical and regulatory, not technological<br><br>NG in buildings is almost entirely displaced by electricity, | Strengthened codes & efficiency standards; fossil phase-out in buildings; regulatory streamlining of retrofits; affordability grants, existing rebates and tax credit continues |
| **MB** Roadmap | Natural gas systems are replaced by electric heat pumps (including GSHPs and ASHPs).<br><br>Electricity represents 85% energy consumption.<br><br>While the share of electricity in overall energy consumption increases, actual electricity consumption decreases (-8%), due to EE and fuel switching. | Aligned with current building codes at the time. |
| **ON** P2D | Electrification of heating contributes significantly to load growth. | |
| **ON** Pathways | 100% HP adoption (mix of ASHP, GSHP) by 2030 for Toronto, 2035 for rest of Ontario for both new and existing residential & commercial buildings | |

| Region / Study | Electrification | Building Codes and Policy |
|---|---|---|
| | Water heating: 100% adoption of electric powered heat pumps by 2030 for Toronto, 2035 for rest of Ontario for both new and existing residential & commercial buildings | |
| **AB** Pathways | Buildings largely electrified ranging between 60-80% by 2050 depending on scenario.<br><br>Final energy consumption decreases significantly between 2019 and 2050, driven by electrification, improved envelopes for both new and retrofit buildings, and controls. | Aligned with current building codes at the time. |
| **Canada** CER | Assumes 100% HP adoption by 2050 for residential, commercial and industrial customer classes with S curve adoption | Directional alignment with (not-yet-published at the time) national net-zero by 2050 buildings strategy |
| | | |
| | **System Outlooks** | |
| **BC** 2021 IRP & 2025 IRP Technical Advisory Committee[17] | HPs primary solution, adoption accelerates after 2025 with ASHP becoming standard by 2030s. Residential space heating shares:<br><br>**Electric Heating**<br>2024 (Actual): 50%<br>2050: ~58.5%<br><br>**Heat Pump**<br>2024 (Actual): ~8.5%<br>2050: 20% | NZ-ready building code 2032; CleanBC accelerates low-carbon heating by 2030; municipal bans on fossil heating in new builds; incentives in 2020s → regulatory compliance in 2030s |
| **AB** 2024 LPO | Building electrification is gradual, long-term load driver; HP not singled-out, but implied as primary technology<br><br>ITC indirectly supports affordable operation of electric heating | Baseline decarbonization policy by 2050; building codes not modeled beyond federal backstop; no aggressive provincial policy assumed; no bans on fossil heating; TIER benchmark + carbon pricing erode fossil heating competitiveness |
| **SK** 2024 APO | No data | No data |
| **MB** 2023 IRP | Space heating shares by 2043:<br><br>50% NG, 41% electric, 2% GSHP; no dual fuel; new-build use NG; existing customer keep NG furnaces | Electrification not a top priority, gas heating remains dominant |
| **ON** 2025 APO | HP adoption: 2.5% → 6.3% of households by 2050 | Toronto Green Standards (2030); provincial/federal incentives continue; supportive provincial policy environment for new builds |
| **QC** 2024 Plan | Most homes already use electric heating (~85% space and ~95% water)<br><br>~700k high-efficiency systems (HP, Smart Thermostat & WH) by 2035; increasing the share of Québec homes with such equipment from 3% to 25%. The share of homes with HPs in 2022 | Strong supporting programs are maintained (rebates for ASHP + weatherization, higher incentives for GSHP, free smart thermostats and dynamic rates, dual-fuel incentives and rates) |

[17] BC Hydro. 2025 Integrated Resource Plan Technical Advisory Committee – Meeting #5 – July 2025.

| Region / Study | Electrification | Building Codes and Policy |
|---|---|---|
| | was 10% and is expected to be notably higher today.[18] | |
| **NB** 2023 IRP | Most homes already use electric heating (~70% space and >90% water); HPs replaces electric baseboards, coldest day often require backup heat | Heating oil phase out; accelerated adoption of NBC/NBEC |
| **NS** 2023 IRP | HP adoption main peak driver; base case = gradual growth; ~200 MW peak growth by 2030; base case assumes no hybrid switching | |
| **NL** 2024 RAP | ~61% of electric-heated homes adopt ASHPs by 2034, informed by historical HP adoption trends and survey data | Oil-to-Electric program continues to drive HP adoption; policy & programs are important drivers for electrification |

In British Columbia, Manitoba, Quebec, New Brunswick, Nova Scotia, and Newfoundland and Labrador, fuel switching from fossil fuel boilers and furnaces to electric heat pumps is the primary mechanism for increasing electricity demand in the buildings sector by 2030-2035. In Alberta and Ontario heat pumps are modelled as key drivers of long-term electrification, where adoption is much more gradual and associated with building standards and incentives and equipment replacement cycles. [19]

Pathways studies generally envision a faster, more comprehensive electrification of buildings than provincial system outlooks. Most assume that electric heat pumps – air-source, ground-source, and cold-climate models – become the dominant heating technology across residential and commercial sectors by mid-century. In the IET and Ontario Pathways studies, near-universal heat pump adoption is achieved by 2030–2035, including in existing buildings, supported by extensive retrofitting and regulatory streamlining. The CER scenarios project that roughly half of all residential and commercial buildings use heat pumps by 2050, with adoption constrained mainly by equipment turnover rates rather than technological barriers.

A key distinction between pathways studies and provincial outlooks is that pathways assume electrification as a central decarbonization lever, while system outlooks often treat it as an outcome contingent on policy or market evolution. Pathways studies also include complementary decarbonization options, such as limited roles for renewable natural gas (RNG) or hydrogen blending for residual fossil heating demand.

While the increased electrification of space heating and cooling is envisioned in all reviewed electricity demand forecasts, the assumptions underlying those forecasts reveal that a broad range of policy approaches are being considered to achieve that outcome.

For example, only two jurisdictions (British Columbia and New Brunswick) assume aggressive building codes and policies. The adoption of net zero-ready building codes by 2032 and municipal bans on fossil heating in new builds in British Columbia and the accelerated adoption of NB and NBEC in New Brunswick contribute to the rapid growth of heat pumps in buildings. Alberta has the least aggressive buildings codes and policies, going no further than federal regulations and no consideration for the phase-out of fossil fuel heating.

[18] Natural Resources Canada. Residential Sector – Quebec – Table 21: Heating System Stock.
[19] IESO. 2025. APO Engagement Webinar.

Other provinces like Quebec, Nova Scotia, and Newfoundland and Labrador, rely on incentives for off-oil or fuel switching programs. For example, in Newfoundland, NL Hydro assumes that 71% of homes currently using oil heating and with expiring tanks will convert to electric heating. Overall, they project that approximately 38% of all available oil-to-electric conversions will be completed by 2034 – a relatively ambitious assumption compared to other provincial system outlooks.

Pathways studies generally assume stronger and earlier policy signals driving building electrification compared to provincial system outlooks. The CER and IET studies link electrification outcomes to strengthened building codes, enhanced retrofit programs, and ongoing financial incentives such as federal tax credits and rebates. These studies assume that codes evolve toward net-zero energy-ready performance by 2030, and that regulatory

**Seasonal Peak Impacts**

These differences in policy ambition and approach also shape how jurisdictions are planning to prepare for expected increases in winter peak demand arising from increased electricity use for space heating. New Brunswick and Nova Scotia both identify winter peak growth as a key planning constraint, with heat pumps driving capacity needs and influencing reserve margin decisions and highlighting the need for system flexibility. In Manitoba, dual-fuel systems will help manage peak loads, while Quebec cites flexible pricing and demand-side measures as tools to manage winter peaks.

Figure 11 illustrates how these assumptions translate to impact on building-related electricity demand.

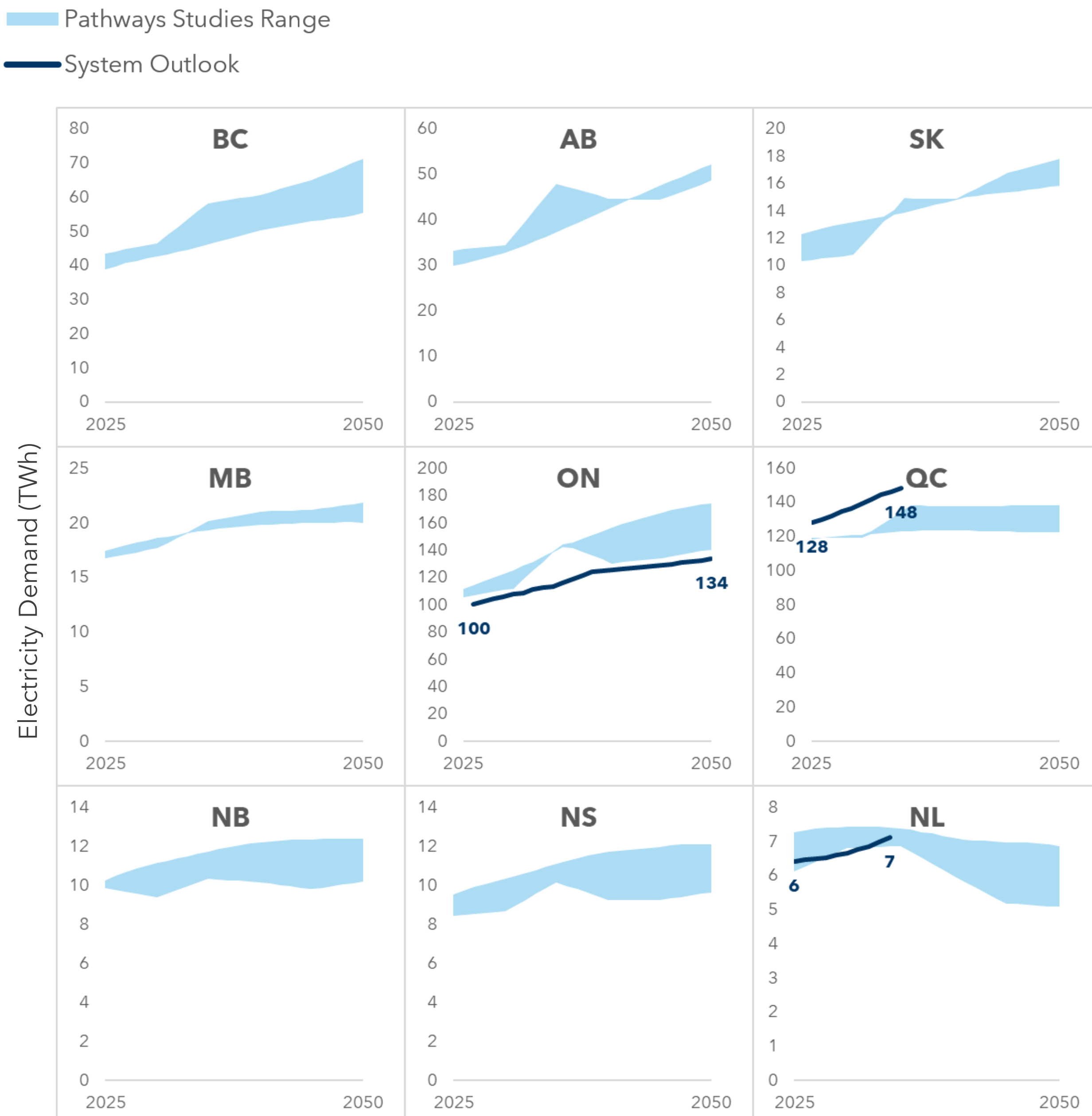


**Figure 11: Electricity Demand Growth in the Buildings Sector by Province in Pathway Studies and System Outlooks**

Across all forecasts, electricity demand in the building sector is not expected to grow as quickly as in the transportation sector. This is partly because buildings are already relatively electrified, particularly in provinces where electric space and water heating are common. In contrast, transportation electrification is still in its early stages, with widespread adoption of EVs expected to drive a significant new source of demand. Additionally, ongoing improvements in building energy efficiency – including enhanced insulation, building envelope performance, and energy codes – help moderate growth in overall consumption. Finally, the shift from less efficient electric resistance heating or air conditioning to high-efficiency heat pumps reduces incremental electricity requirements per unit of heating or cooling delivered. As a result, most forecasts show a more gradual increase in electricity demand from buildings, compared with the steeper trajectory projected for transportation.

Most provincial system outlooks do not provide detailed electricity demand projections for the buildings sector. New Brunswick, Nova Scotia, British Columbia, Saskatchewan, and Manitoba include little or no information on this sector in their outlooks. In contrast, Newfoundland and Labrador, Ontario, and Quebec present some level of detail. In Ontario's system outlook, projected electricity demand in buildings grows more slowly than in pathway studies, reflecting relatively conservative building electrification assumptions, such as heat pump adoption reaching only 6.3% of households by 2050. In Newfoundland and Labrador, pathway studies indicate a decline in building-sector demand, potentially linked to assumptions of a shrinking population over the forecast period. Quebec's system outlook, by contrast, shows higher demand growth than pathway studies. Finally, while Alberta's system outlook does not present a full demand trajectory for buildings, it estimates that electrification will add approximately 4 TWh of demand by 2043, equivalent to about 4% of total electricity use.

In those jurisdictions that provide data on electricity use in both residential and commercial buildings, growth rates relative to the baseline are expected to be similar in these two segments. More details on the forecast evolution of electricity demand in the buildings sector across all reviewed studies can be found in the Appendix.

### 4.3.3 Industry

Electricity demand in the industrial sector is shaped by the decarbonization and electrification of existing industries, as well as the emergence of new electricity-intensive activities.

Many industries are shifting away from fossil fuels and adopting electric alternatives for key processes such as heating and manufacturing. This transition is driving up electricity use across a wide range of sectors including mining and pulp and paper. At the same time, new loads such as data centres and hydrogen production facilities are adding significant demand to the grid. These developments are reshaping industrial electricity use and contributing to overall growth in demand.

Table 9 summarizes industrial demand growth assumptions across forecasts.

**Table 9: Industrial Demand Growth Assumptions Across Reviewed Studies**

| Region / Study | Existing Industry | Data Centres | Clean Fuel Production |
|---|---|---|---|
| **Pathway Studies** | | | |
| **Canada** CER | ~74% oil production decrease from 2021-2050; down to 1.3 MMB/d<br><br>~66% natural gas production decrease from 2021-2050; down to 5.5 Bcf/d; LNG Exports of ~ 2 Bcf/d from 2026-2044, 0.3 Bcf/d thereafter | No data | Hydrogen Electricity Demand grows from 0 TWh in 2021 to 198 TWh in 2050 |
| **Canada** IET | Doubling of electricity consumption in mining, pulp and paper, and other industrial sectors | No data | Energy consumption in the Hydrogen segment grows from 77 PJ in 2021 to 507 PJ in 2050 (21 $TWh_e$ to 141 |

| Region / Study | Existing Industry | Data Centres | Clean Fuel Production |
|---|---|---|---|
| | DAC Elec Demand: 2030 = 2.4TWh, 2050 = 66 TWh<br><br>~96% oil production decrease (2030-2050)<br>~90% natural gas production decrease (2030-2050) | | $TWh_e$). This excludes consumption associated with energy production. |
| **MB** Roadmap | Already largely electrified. Additional electrification, with electricity replacing ~58% of NG consumption as well as meeting demand from growth in energy consumption. | No data | Small role for hydrogen and RNG.<br><br>Hydrogen production triples its contribution to overall energy mix but remains small at 6%. |
| **ON** P2D | Broad substitution of NG fuel to electricity, roughly 20% of current levels by 2050. | No data | Hydrogen production assumed to be outside of Ontario (no impact on Elec demand) |
| **ON** Pathways | The industrial sector is largely electrified, and electricity accounts for the largest share of final energy consumption in 2050 (44%) | No data | Hydrogen production increases significantly, particularly post-2035, totalling ~25 TWh in 2050. |
| **AB** Pathways | Study notes that the extent to which electricity will play a role in the decarbonization pathway to heavy industries, particularly with respect to magnitude and pace, remains uncertain.<br>AESO assumes heavy-industry electrification will be maintained in line with the historical relationship observed with economic and energy sector growth. | No data | The production of hydrogen is expected to increase industrial load in Alberta.<br>Incremental Industrial load from hydrogen production expected to increase from ~10 MW in 2022 to ~500 MW in 2035 |
| **System Outlooks** | | | |
| **BC** 2021 IRP | From 2021-2026 the Plan targets a 2,800 TWh of load growth in the industrial sector, in part driven by electrifying existing industrial loads (e.g. natural gas/LNG, mining, forest products, pulp and paper)<br>Assume oil & gas sector load growth (including LNG); declines in forestry sub-sector. | 2021-2026 load growth partially assumed due to attracting new loads from data centres | 2021-2026 load growth partially assumed due to attracting new loads from green hydrogen and cleantech sectors |
| **AB** 2024 LTO | Heavy industry load shown as 0 MW across LTO study period.<br><br>Oil production expecting to peak in early 2030s, followed by a stabilization period before gradual decline. | Incremental data center load/demand was not modelled in the 2024 LTO.<br><br>Does not model additional load from new industrial projects that are not yet "known" | Hydrogen production load grows from 1.1 TWh / 125 MW in 2028 to 4.8 TWh / 550 MW in 2043. |
| **SK** 2024 Plan | No data | No data | No data |
| **MB** 2023 IRP | No industrial load growth. | No data | No data |

| Region / Study | Existing Industry | Data Centres | Clean Fuel Production |
|---|---|---|---|
| **ON** 2025 APO | Mining & Metals electricity demand grows 79% between 2026-2050 (24 TWh to 44 TWh).<br><br>Other industrial electricity demand grows 45% from 2026-205 (20 TWh to 29 TWh) .<br><br>Growing Chemicals, EV production and other industrial demand to materialize in late 2020's. Some demand attrition to materialize in automobile production ICE manufacturing declines. | Data Center electricity demand grows 440% from 2026-2050 (3 to 14 TWh) | No data |
| **QC** 2024 Plan | Grows from 63 -93 TWh from 2022 to 2035, surpasses residential demand by 2033.<br><br>Growth is primarily driven by the steel industry, melting & refining (7 - 17 TWh), a 147% increase along with petrol & chemicals from (5 -15 TWh), a 200% increase.<br><br>Aluminum and Paper & Paste make up more than 50% of industrial load in 2022 but are flat through 2035 (decreasing to 40% of total industrial load). | Data center peak demand to increase from 127 - 664 MW from 2022 to 2035 | No data |
| **NB** 2023 IRP | Includes unallocated growth factor of 0.5% applied annually to account for additional industrial load growth (including electrification). | No data | Does not take into consideration potential large, new loads such as hydrogen/ammonia production, the emergence of other new industries or firm export sales. |
| **NS** 2023 IRP | No data | No data | No data |
| **NL** 2024 RAP | No data | No data | No data |

Across jurisdictions, industrial electricity demand is expected to grow due to electrification of existing industries and the emergence of new sectors.

Among provincial system outlooks, Quebec and Ontario show the most detailed projections for electrification of existing industries. Quebec's industrial demand is projected to rise 46% by 2033, driven by steel, chemicals, and refining, while Ontario anticipates strong growth in mining and metals (79%) and other industrial loads (45%) between 2026 and 2050. British Columbia's plan highlights significant load growth from electrifying traditional sectors like mining and pulp and paper.

Other provinces assume relatively limited electrification of existing industries. Manitoba's scenario 1 assumes no industrial load growth, while New Brunswick applies a conservative growth factor of 0.5% per year. Alberta's long-term outlook shows no electrification of heavy industry.

**Pathway studies generally project moderate to significant electrification within existing industrial sectors**, though the pace and magnitude of change vary by region. The IET study further expects a doubling of electricity consumption across mining, pulp and paper, and other industrial segments, alongside growing electricity use for direct air capture (DAC). Manitoba and both Ontario studies foresee further electrification of already electricity-intensive industries, with Manitoba replacing up to 58% of natural gas use with electricity and Ontario P2D projecting that natural gas consumption in industry will fall to 20% of current levels by 2050. At the same time, pathway studies generally assume declines in industrial output as part of the broader decarbonization transition. Nationally, the CER and IET studies both project sharp reductions in fossil fuel production, with natural gas output falling by roughly 66–90% and oil production by 74–96% by 2050, respectively.

In terms of new and emerging industries, **none of the reviewed pathway studies explicitly account for electricity demand from data centres**, despite their status as a rapidly growing source of industrial load.[20] Similarly, most provincial system outlooks omit data centres, with two primary exceptions: Ontario and Quebec. In these provinces, data centres are projected to contribute substantially to industrial electricity demand: Ontario anticipates a 440% increase in data centre electricity use by 2050, while Quebec expects peak demand from data centres to grow fivefold by 2035. The absence of data centre assumptions in most pathway studies and system outlooks indicates that total industrial electricity demand could be underestimated. It is worth noting that the Ontario and Quebec system outlooks are among the most recent forecasts included in this study. Future updates to other provincial outlooks are expected to incorporate higher electricity demand associated with data centre growth.

Hydrogen is considered in every reviewed pathways study, and is expected to increase electricity demand in all forecasts except Ontario's P2D (which assumes hydrogen production will occur outside the province). On the system outlook side, Alberta is the only province with an emphasis on hydrogen, with demand from hydrogen production reaching 4.8 TWh by 2043. Other provinces (British Columbia and New Brunswick) have noted some consideration of hydrogen, though specific figures are not provided.

Figure 12 illustrates how these assumptions translate to impact on industry-related electricity demand.

[20] A recent IEA report finds that data centres are projected to drive more than 20% of the growth in electricity demand between now and 2030 in advanced economies.

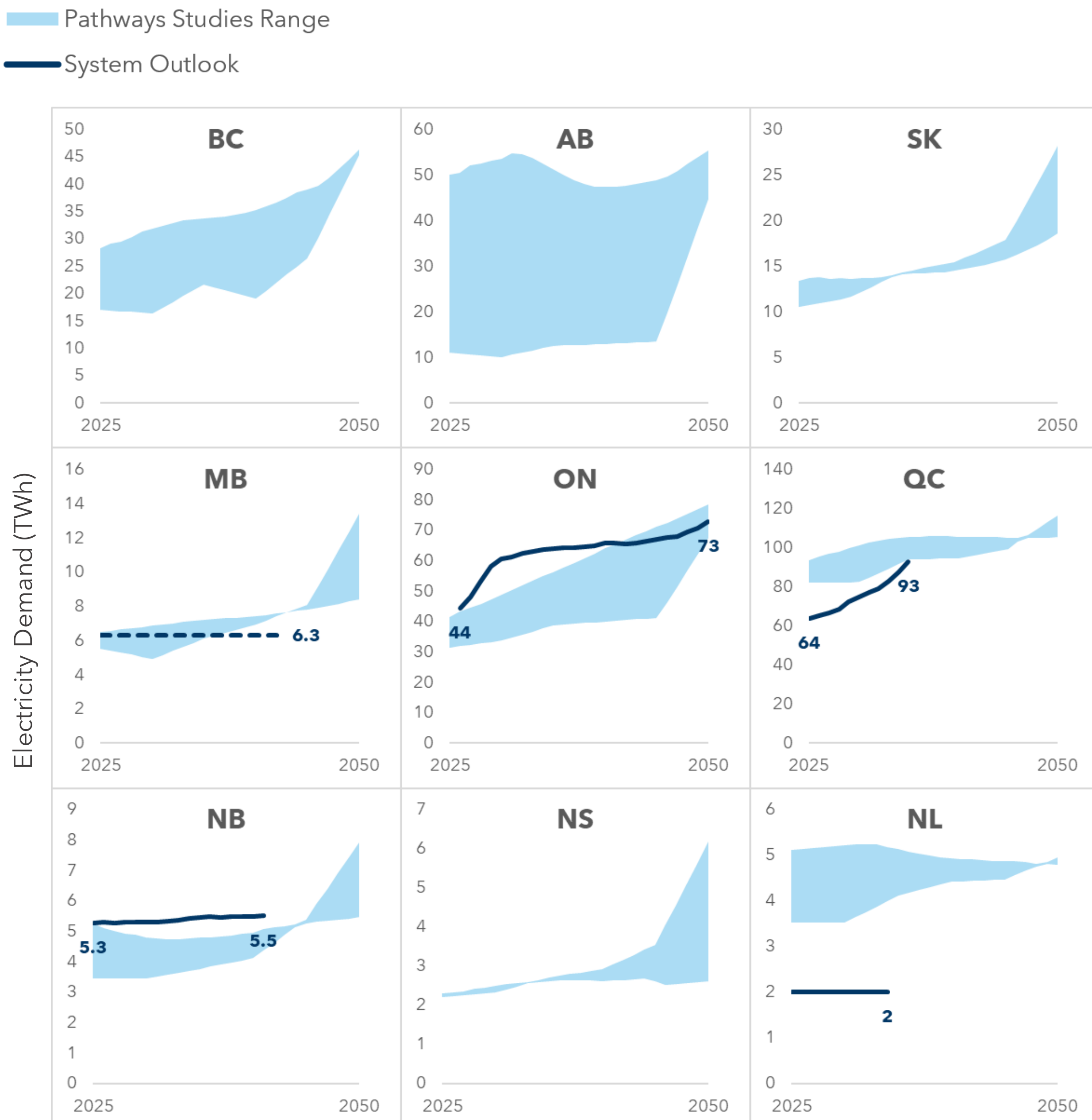


**Figure 12: Electricity Demand Growth in the Industrial Sector by Province in Pathway Studies and System Outlooks[21]**

Only five provincial system outlooks present electricity demand forecasts for the industrial sector. Newfoundland and Labrador, Manitoba, and New Brunswick all show minimal or no industrial load growth in their system outlooks.

[21] In provinces where 2025 industrial demand varies widely (e.g., Alberta, Newfoundland and Labrador, Quebec), the differences reflect variations in how studies classify electricity use between industrial and commercial sectors.

Across national pathway studies, general industrial electricity demand is projected to grow at a compound annual growth rate (CAGR) of 1.0–1.3%. When accounting for emerging net-zero industries – particularly green hydrogen (CER) and direct air capture (IET) – the projected CAGR increases substantially to 2.0–2.7%. The IET study shows relatively modest growth through 2025–2040, followed by a sharp acceleration in the 2040s, driven by the large-scale deployment of decarbonization technologies. In contrast, the CER forecast presents a steadier, more evenly distributed increase in industrial electricity demand over time.

For provincial system outlooks, the most recent and detailed forecasts – Ontario and Quebec – show higher rates of industrial demand growth than national studies. Ontario projects a 2.6% CAGR from 2025–2050, with faster growth early in the forecast period (see Figure 11), while Quebec projects a 3.5% CAGR from 2025–2035.

Provincial system outlooks that are not explicitly considering the emergence of such new loads (i.e., all except Ontario and Quebec) are likely underestimating future growth in electricity demand, though the timing and scale of these new loads will vary regionally. Pathway studies similarly appear to underestimate data-centre growth, but this may be partially offset by their more aggressive assumptions for hydrogen production and electrification of existing industry.

However, these drivers differ significantly in both timing and maturity. Data centres represent a proven, commercially deployed technology with rapid near-term growth already underway across multiple provinces. In contrast, green hydrogen and DAC are more nascent technologies, with large-scale deployment expected only in the longer term – primarily in the 2040s – as costs decline and enabling infrastructure develops. Consequently, pathway studies may be underestimating near-term industrial load growth driven by more mature sectors like data centres, despite accounting for potential longer-term, still-developing technologies such as hydrogen and DAC.

Further details on projected industrial electricity demand across all reviewed studies are provided in the Appendix.

## 4.4 Demand-Side Management

While demand-side management (DSM) is likely to play an important role in determining future electricity supply needs in Canada, its role in the creation of electricity demand forecasts can vary significantly across jurisdictions, depending on how it is defined and modelled within system studies. In some cases, DSM is modelled as a standalone resource with specific targets or scenarios, while in others it is simply an assumption embedded within broader load forecasts or presented as a policy lever to influence consumption patterns. This variation makes it challenging to consistently assess DSM's impact on electricity demand.

Another challenge in interpreting DSM trends across jurisdictions is differences in assumptions about what constitutes DSM. In some system outlooks, there is overlap with building-sector energy efficiency measures, as actions related to improved insulation, appliance upgrades, and heating system retrofits are sometimes categorized under buildings rather than DSM. This ambiguity complicates efforts to isolate DSM impacts from other measures.

For the purposes of this analysis, DSM includes measures such as demand response, distributed solar, battery storage, EV managed charging, and other distributed energy resources (DERs) that can shift or reduce electricity consumption.

Table 10 summarizes DSM assumptions across forecasts.

**Table 10: Demand-Side Management Assumptions Across Reviewed Studies**

| Region / Study | Treatment of DSM and EE in Resource Planning | Demand Response | DER & Others |
|---|---|---|---|
| **Pathways Studies** | | | |
| **Canada** CER | EE embedded in load forecast, not as resource | Implied for winter peaks, not specified | DERs (e.g. EV managed charging, distributed resources) assumed necessary for peak management in net-zero grid by 2035 |
| **Canada** IET | Aggressive retrofits/EE reduce demand ~19% by 2050, but only as a load modifier | DSM/DR assumed critical for peak management, not quantified | High DER integration (EVs, HPs, solar/storage). |
| **MB** Roadmap | EE embedded in load forecast as a resource. EE (incl. retrofit & HVAC control measures) reduces demand in buildings by 26% by 2050, in addition to energy savings from the shift to heat-pumps | DR assumed critical for peak management, not quantified | Inclusion of rooftop solar PV 0.4TWh), and storage (1.4GW) technologies. Other DERs such as managed charging, V2G and V2B assumed necessary. |
| **ON** P2D | Assumes the maximum level of demand reduction based on the cost-effective conservation and demand management potential that was identified in the 2019 Achievable Potential Study.<br>11.7 TWh of energy savings, ramping up over the study time frame, reaching a total of | Demand response installed capacity = 5,936MW in 2035 and 6,744MW in 2050 | Incremental DERs can potentially exist up to levels identified in the IESO's 2022 Distributed Energy Resource Achievable Potential Study |

| Region / Study | Treatment of DSM and EE in Resource Planning | Demand Response | DER & Others |
|---|---|---|---|
| | 22 TWh of energy reduction by 2035. | | |
| **ON** Pathways | Includes to the extent possible, all economically feasible EE potential | DR assumed critical for peak management, not quantified. | Rooftop PV = ~7GW and battery storage = ~5GW installed capacity in 2050. |
| **AB** Pathways | EE included as load-modifying driver (historical trend; sensitivity at 3x historical rate). DSM only included as sensitivity to shift EV charging. | Included as a reliability-enhancing reserve in sensitivity analysis. | DERs below 5 MW (solar, wind, gas) explicitly modeled as offsets to AIL. (5 TWh in 2041) |
| **System Outlooks** | | | |
| **BC** 2021 IRP | DSM (EE + DR) is BC Hydro's "first resource"; not endogenously modeled and treated as inputs | TOU & CPP rates; residential & commercial DR Programs; industrial curtailment | DERs: solar, batteries, EV smart charging (~170 MW) |
| **AB** 2024 LTO | DSM/EE only mentioned as potential load modifiers; not modeled or treated as resources<br>EE + DER partly offset load growth, but electrification dominates | No DR modeled | Not in load forecast unless already known/committed |
| **SK** 2024 LTSP | DSM/EE discussed in engagement feedback but not modeled; purely qualitative at this stage. | No data | No data |
| **MB** 2023 IRP | Only Efficiency MB baseline EE embedded; no DSM resource modeling | Minimal DR role | No DER modeled |
| **ON** 2025 APO | DSM embedded in demand forecast | DR (ICI, Peak Perks) included as load modifiers | Included in net demand outlook, but not quantified as resource capacity |
| **QC** 2024 Plan | EE embedded in demand forecast; DR included as fixed MW capacity. Both treated as resources, not dynamically modeled.<br><br>21 TWh EE savings; 2.5 GW peak reduction from EE + load shifting (rates, DR); 100k retrofits target | 1M households in flexible pricing + load shifting programs to reduce peaks | Inclusion of thermostats, EV charging<br><br>Small-medium enterprise cut 10% demand |
| **NB** 2023 IRP | DSM strengthened to offset electrification; DR critical for winter peaks; fixed capacity assumptions. | DSM/DR critical for winter peak reliability | |
| **NS** 2023 IRP | DSM/EE included via EfficiencyOne forecasts and avoided-cost analysis; DR fixed via pilots. No endogenous modeling. | E1 rebates & DSM programs continue; TOU pilot cut peaks 11–13%; CPP ~18%. | |
| **NL** 2024 RAP | ECDM embedded in load; not treated as a resource | Capacity Assistance (~130 MW) modeled explicitly; other DR not specified | Wind-to-$H_2$ projects may interconnect, not treated as DER |

| Region / Study | Treatment of DSM and EE in Resource Planning | Demand Response | DER & Others |
|---|---|---|---|
| | | | 140 GWh savings from takeCHARGE ECDM |

Across Canadian jurisdictions, DSM and energy efficiency (EE) are usually embedded within load forecasts rather than modelled as explicit, selectable resources in electricity system planning. This approach simplifies modelling by treating DSM and EE as assumptions that reduce demand, rather than as resources with defined costs, performance, and adoption trajectories. Accordingly, most jurisdictions recognize DSM and EE as important planning tools but do not dynamically model them. Saskatchewan, for example, qualitatively discusses DSM but does not include it within their modelling.

Similarly, while most utilities view DERs as essential for grid flexibility and decarbonization, they are typically analyzed through scenario assumptions or qualitatively, rather than being dynamically modelled as part of the resource mix.

This approach to the development of system outlooks may need to evolve going forward as demand response is gaining traction, particularly for managing winter peaks and ensuring system reliability. Several provinces, including British Columbia, Quebec, New Brunswick, and Nova Scotia have implemented or piloted DR programs such as flexible pricing, load shifting, and time-of-use (TOU) rates. Newfoundland and Labrador is unique in explicitly modelling DR as a firm capacity resource.

Pathway studies place greater emphasis on DSM and EE than most provincial outlooks, recognizing their role in achieving net-zero outcomes. Both the CER and IET studies incorporate significant energy efficiency improvements that materially reduce load. The IET analysis assumes aggressive retrofits and efficiency measures that reduce demand by roughly 19% by 2050, while the CER integrates efficiency implicitly through lower projected load growth. Both also identify demand response and DERs – including managed EV charging, heat pumps, and behind-the-meter storage — as essential for managing peak demand and maintaining reliability in a highly electrified, decarbonized grid. However, DSM is generally represented as a load adjustment, not a dispatchable system resource, limiting insight into its potential contribution to system balancing or cost optimization.

# 5. Key Takeaways

This review of pathways studies and provincial system outlooks demonstrates that there **is broad directional consensus that electricity demand will grow substantially.** Across both pathways studies and aggregated provincial system outlooks, national electricity demand roughly doubles by 2050 (CAGR ~2.0-2.6%), with every dataset pointing up and uncertainty widening after ~2040. It is also worth noting that provinces have been revising forecasts upward in successive outlooks.

A high-level review and comparison of the results across different pathways studies and provincial system outlooks illustrate some important differences in the treatment of key sectoral demand drivers that will play a critical role in determining future electricity demand. While electricity demand forecasts always have a meaningful degree of uncertainty associated with them, an assessment of the different approaches used to consider the key drivers of future electricity demand in the pathways studies and provincial system outlooks reviewed can help provide some insight as to whether or not such studies are more likely to be overestimating or underestimating future electricity demand.

Table 11 assesses where actual electricity demand could deviate above ("upside risk") or below ("downside risk") the forecasts presented in pathways studies and provincial system outlooks.

**Table 11: Risk Assessment by Driver** [22]

| | Driver | System Outlooks | Pathway Studies |
|---|---|---|---|
| **Macro** | Population Growth | **? Unknown**<br>System outlooks reflect local utility insights, but data availability is inconsistent between provinces | **▲ Upside Risk**<br>Assume lower population growth than corresponding provincial forecasts. |
| | Economic Growth | **? Unknown**<br>Data availability is limited | **⇅ Mixed**<br>Moderate growth expectation of 1-2%, macro volatility cuts both ways |
| **Cross-Cutting** | Net-zero by 2050 | **▲ Upside Risk**<br>Only two provinces align demand forecast with net-zero future | **▼ Downside Risk**<br>All pathway studies align demand forecast with net-zero future |
| | Carbon Pricing | **▼ Downside Risk**<br>Many system outlooks include consumer carbon pricing, which has since been repealed | **▼ Downside Risk**<br>All pathways studies include consumer carbon pricing, which has since been repealed |
| **Sectoral Drivers** | Transportation | **⇅ Mixed**<br>LDV electrification generally well-captured, but MHDV and other non-road transportation assumptions vary widely. Potential change to federal ZEV mandate introduces downside risk. | **▼ Downside Risk**<br>Assumes transportation electrification and policies consistent with net-zero by 2050. |

[22] This table excludes demand-side management (DSM) impacts for clarity of comparison. For more information on DSM, see Section 4.4

| | Driver | System Outlooks | Pathway Studies |
|---|---|---|---|
| | Buildings | ⇅ **Mixed**<br>Electrification assumptions are highly inconsistent across reviewed forecasts. Rates of heat pump adoption vary significantly. Strong upside risk in some provinces. | ▼ **Downside Risk**<br>Assume more ambitious electrification and policies consistent with net-zero by 2050. |
| | Industry | ▲ **Upside Risk**<br>Several system outlooks do not account for industrial load growth. Only two provinces explicitly consider new loads from data centres. | ⇅ **Mixed**<br>Studies assume growth in hydrogen production and electrification of existing industry contribute to long-term demand growth, but do not account for near-term impact of data centres. |

How to read the table:

- ▲ Upside risk = demand likely higher than forecast
- ▼ Downside risk = demand likely lower than forecast
- ⇅ Mixed = material uncertainty both ways
- ? Unknown = insufficient disclosure/consensus

As illustrated in Table 10, a review of the treatment of key electricity demand drivers in pathways studies and provincial electricity systems outlooks provides us with the following insights:

- **Overall, system outlooks likely underestimate electricity demand growth**, with greater upside than downside risk. Most provincial forecasts assume moderate electrification and limited new industrial or digital loads. As a result, actual demand could exceed these baselines – particularly in provinces not yet accounting for data centres, clean fuel production, or electrification of existing industry. Additionally, if Canada does achieve a net-zero economy by 2050, provincial system outlooks will have significantly underestimated future electricity demand. However, results vary by province, and Quebec is a notable exception, as its system outlook already reflects stronger industrial and digital load growth, as well as net-zero policy commitments.
- **Pathway studies exhibit more downside risk, driven by climate policy uncertainty.** These studies assume full alignment with net-zero by 2050, embedding rapid electrification of transport, buildings, and industry. Should policy momentum slow, these forecasts will likely overstate demand. However, pathway studies may underestimate near-term industrial growth from sectors such as data centres, which are expanding faster than emerging technologies like hydrogen and DAC.
- **Climate policy uncertainty impacts all forecasts.** The impacts of climate change policy on growth in electricity demand may be overstated in all studies reviewed with the recent elimination of a consumer carbon price and potential upcoming changes to the federal ZEV mandate. At the same time, conservative assumptions on the future evolution of building codes from a climate and energy use perspective may see many provincial system outlooks underestimate the future growth of electricity demand in this sector.
- **Industrial electricity demand growth is the largest single source of upside risk.** Pathway studies emphasize long-term industrial demand from decarbonization but may miss shorter-term pressures from data centres and other emerging sectors. On the system

outlook side, only two provinces – Ontario and Quebec – explicitly model data-centre demand, yet of these, Ontario projects a 440 % increase in data-centre electricity use by 2050, while Quebec anticipates five-fold growth in data-centre peak demand by 2035. Other emerging loads such as hydrogen, direct air capture, and large industrial electrification could also materially alter provincial demand trajectories, often with limited lead time relative to traditional planning cycles.

# Appendix: Detailed Data Tables

## Total Demand

**Table A1: Provincial Electricity Demand Growth Across System Outlooks and National Pathways Studies [23]**

| Region | Study | Type | Period | Metric | Increase Across Study Period | CAGR |
|---|---|---|---|---|---|---|
| BC | **2021 IRP** | System Outlook | 2024-2041 | Electricity Demand | 1.3x \| 62 → 78 TWh | 1.4% |
| | | | | Peak Demand | 1.2x \| 11 → 14 GW | 1.4% |
| | **CER** | Pathways Study | 2021-2050 | Electricity Demand | 2.3x \| 58 → 132 TWh | 2.9% |
| | | | | Peak Demand | 2.2x | 2.8% |
| | **IET** | | 2020-2050 | Electricity Demand | 2.8x \| 54 → 152 TWh | 3.5% |
| AB | **AESO LTO 2025** | System Outlook | 2024-2043 | Electricity Demand | 1.3x \| 89 → 111 TWh | 1.2% |
| | | | | Peak Demand | 1.3x \| 10 → 13 GW[24] | 1.2% |
| | **CER** | Pathways Study | 2021-2050 | Electricity Demand | 1.8x \| 75 → 138 TWh | 2.1% |
| | | | | Peak Demand | 1.9x | 2.2% |
| | **IET** | | 2020-2050 | Electricity Demand | 3.9x \| 48 → 187 TWh | 4.6% |
| | **Pathways** | | 2022-2041 | Electricity Demand | 1.2x \| 87 → 106 TWh | 1.1% |
| | | | | Peak Demand | 1.4x \| 12 → 16 GW | 1.6% |
| SK | **2024 Plan** | System Outlook | 2025-2050 | Electricity Demand | 1.4x \| 26 → 36 TWh | 1.3% |
| | | | | Peak Demand | No data | |
| | **CER** | Pathways Study | 2021-2050 | Electricity Demand | 2.1x \| 23 → 49 TWh | 2.7% |
| | | | | Peak Demand | 2.5x | 3.2% |
| | **IET** | | 2020-2050 | Electricity Demand | 5x \| 20 → 98 TWh | 5.5% |
| MB | **2023 IRP** | System Outlook | 2022-2042 | Electricity Demand | 1.2x \| 23 → 28 TWh | 1.0% |
| | | | | Peak Demand | 1.1x \| 4 → 5 GW | 0.7% |
| | **CER** | Pathways Study | 2021-2050 | Electricity Demand | 1.9x \| 21 → 39 TWh | 2.2% |
| | | | | Peak Demand | 2.3x | 2.8% |
| | **IET** | | 2020-2050 | Electricity Demand | 2.9x \| 20 → 59 TWh | 3.6% |
| | **Roadmap** | | 2025-2050 | Electricity Demand | 1.4x \| 27 → 39 TWh | 1.5% |

[23] The CER dataset provides relative changes in electricity peak demand by province between 2021 and 2050 but does not include the underlying absolute demand values. In the absence of those base-year figures from CER, provincial starting-year peak demand values were obtained from publicly available source such as IRPs, LTOs, and utility rate applications. The CER's provincial growth factors were then applied to these baseline values to estimate 2050 peak demand, from which total demand and CAGR were derived.
[24] Average Alberta Internal Load

| Region | Study | Type | Period | Metric | Increase Across Study Period | CAGR |
|---|---|---|---|---|---|---|
| ON | **2025 APO** | System Outlook | 2026-2050 | Electricity Demand | 1.7x \| 158 → 263 TWh | 2.1% |
| | | | | Peak Demand | 1.5x \| 24 → 37 GW | 1.7% |
| | **CER** | Pathways Study | 2021-2050 | Electricity Demand | 2.4x \| 136 → 330 TWh | 3.1% |
| | | | | Peak Demand | 3.6x | 4.5% |
| | **IET** | | 2020-2050 | Electricity Demand | 2.7 \| 134 → 358 TWh | 3.3% |
| | **P2D** | | 2025-2050 | Electricity Demand | 1.9x \| 153 → 294 TWh | 2.7% |
| | | | | Peak Demand | 2.4x \| 25 → 60 GW | 3.5% |
| | **Pathways** | | 2021-2050 | Electricity Demand | 2.4x \| 138 → 332 TWh | 3.1% |
| QC | **2024 Plan** | System Outlook | 2025-2035 | Electricity Demand | 1.5x \| 193 → 285 TWh | 3.9% |
| | | | | Peak Demand | 1.2x \| 45 → 53 GW | 1.8% |
| | **CER** | Pathways Study | 2021-2050 | Electricity Demand | 1.4x \| 197 → 267 TWh | 1.0% |
| | | | | Peak Demand | 1.3x | 0.9% |
| | **IET** | | 2020-2050 | Electricity Demand | 1.7x \| 195 → 332 TWh | 1.8% |
| NB | **2023 IRP** | System Outlook | 2023-2042 | Electricity Demand | 1.0x \| 14.6 → 15.2 TWh | 0.2% |
| | | | | Peak Demand | 0.97x \| 3.2 → 3.1 GW | -0.1% |
| | **CER** | Pathways Study | 2021-2050 | Electricity Demand | 1.6x \| 13 → 22 TWh | 1.7% |
| | | | | Peak Demand | 1.9x | 2.2% |
| | **IET** | | 2020-2050 | Electricity Demand | 1.5x \| 13 → 19 TWh | 1.4% |
| NS | **2023 IRP** | System Outlook | 2025-2050 | Electricity Demand | 1.3x \| 11 → 15 TWh | 1.0% |
| | | | | Peak Demand | No data | |
| | **CER** | Pathways Study | 2021-2050 | Electricity Demand | 1.8x \| 10 → 19 TWh | 2.1% |
| | | | | Peak Demand | 2.2x | 2.8% |
| | **IET** | | 2020-2050 | Electricity Demand | 2.1x \| 10 → 21 TWh | 2.6% |
| NL | **2024 RAP** | System Outlook | 2023-2034 | Electricity Demand | 1.1x \| 11 → 12 TWh | 1.0% |
| | | | | Peak Demand | 1.1x \| 2.1 → 2.4 GW | 1.1% |
| | **CER** | Pathways Study | 2021-2050 | Electricity Demand | 1.3x \| 11 → 14 TWh | 1.0% |
| | | | | Peak Demand | 1.5x | 1.4% |
| | **IET** | | 2020-2050 | Electricity Demand | 1.0x \| 10 → 10 TWh | 0.0% |

## Transportation

**Table A2: Magnitude of Transportation-Related Electricity Demand Increases Across Reviewed Studies**

| Region | Study Period | Increase in Transportation-Related Electricity Demand Across Study Period | CAGR | Transportation-Related Electricity Demand (% of Total) at End of Study Period |
|---|---|---|---|---|
| **Pathways Studies** | | | | |
| **Canada** CER | 2023-2050 | 79x \| 2.7 → 214 TWh | 18% | 214 TWh (21%) |
| **Canada** IET | 2021-2050 | 103x \| 2.0 → 206 TWh | 17% | 206 TWh (18%) |
| **MB** Roadmap | 2020-2050 | 1,791x \| ~0 → 9.4 TWh | 29% | 9.4 TWh (57%) |
| **ON** P2D | 2023-2050 | No data | No data | No data |
| **ON** Pathways | 2019-2050 | 117x \| 0.6 → 67 TWh | 17% | 67 TWh (44%) |
| **AB** Pathways | 2022-2041 | 135x \| 0.08 → 11 TWh | 29% | 11 TWh (10%) |
| **System Outlooks** | | | | |
| **BC** 2021 IRP | 2024-2041 | No data | No data | No data |
| **AB** 2024 LTO | 2024-2043 | 86x \| 0.14 → 12 TWh | 26% | 12 TWh (11%) |
| **SK** 2024 Plan | 2025-2050 | No data | No data | No data |
| **MB** 2023 IRP | 2022-2043 | ~0 → ~2.3 TWh | 44% | ~2.3 TWh (8%) |
| **ON** 2025 APO | 2026-2050 | 11x \| 3 → 44 TWh | 12% | 44 TWh (17%) |
| **QC** 2024 Plan | 2025-2035 | 18x (capacity, not energy) | 30% (capacity, not energy) | 3.3 GW (7% of capacity, not energy) |
| **NB** 2023 IRP | 2023-2042 | 5x \| ~0.15 → ~0.75 TWh | 9% | ~0.75 TWh (5%) |
| **NS** 2023 IRP | 2025-2050 | No data | No data | No data |
| **NL** 2024 RAP[25] | 2023-2034 | +0.5 TWh | N/A (baseline not defined) | 0.5 TWh (6%) |

[25] Electric Vehicle electricity demand from NL Hydro's 2023 Long-Term Load Forecast

## Buildings

**Table A3: Magnitude of Building-Related Electricity Demand Increases Across Reviewed Studies**

| Region | Study Period | Increase in Building-Related Electricity Demand Across Study Period | CAGR | Building-Related Electricity Demand (% of Total Electricity) at End of Study Period |
|---|---|---|---|---|
| **Pathways Studies** | | | | |
| **Canada** CER | 2023-2050 | **RES & COM Electricity:**<br>1.5x \| 317 → 474 TWh<br>**RES & COM Fossil Fuel:**<br>66% decrease \| 447 → 151 $TWh_{eq}$ | **RES & COM Electricity:**<br>1.5%<br><br>**RES & COM FF:**<br>-3.9% | **RES & COM:** 40% |
| **Canada** IET | 2021-2050 | **RES & COM Electricity:**<br>1.5x \| 321 → 466 TWh<br>**RES & COM Fossil Fuel:**<br>97% decrease \| 379 → 11 $TWh_{eq}$ | **RES & COM Electricity:**<br>1.3%<br><br>**RES & COM FF:**<br>-11.5% | **RES & COM:** 45% |
| **MB** Roadmap | 2020-2050 | **RES & COM Electricity:**<br>11% decrease \| 16.4 → 14.6 TWh<br>**RES & COM Fossil Fuel:**<br>85% decrease \| 13.8 → 2.1 TWh | **RES & COM Electricity:**<br>-0.4%<br><br>**RES & COM FF:**<br>-6.3% | **RES & COM:** 85% |
| **ON** P2D | 2023-2050 | No data | No data | No data |
| **ON** Pathways | 2019-2050 | **RES & COM Electricity:**<br>1.4x \| 98 → 138.7 TWh<br>**RES & COM Fossil Fuel:**<br>100% decrease \| 186 → 0 TWh | **RES & COM Electricity:**<br>1.1%<br><br>**RES & COM FF:**<br>-100% | **RES & COM:** 40% |
| **AB** Pathways | 2022-2041 | **Heating systems[26]:**<br>112x \| 0.02 → 2 TWh | **Heating systems[27]:**<br>28% | 2% |
| **System Outlooks** | | | | |

[26] The AESO's building electrification model assumes uptake beginning in 2030, reflecting the slow pace of building retrofits, current policy uncertainty around the federal net-zero building code, and expected improvements in cost parity between electric heat pumps and gas boilers.

[27] From 2030 to 2041

| Region | Study Period | Increase in Building-Related Electricity Demand Across Study Period | CAGR | Building-Related Electricity Demand (% of Total Electricity) at End of Study Period |
|---|---|---|---|---|
| **BC** 2021 IRP | 2024-2041 | No data | No data | No data |
| **AB** 2024 LTO | 2024-2043 | **RES & COM Electricity:** Incremental building electrification adds 4 TWh by 2043 | No data | **RES & COM:** Incremental building electrification is 4% of total demand in 2043 |
| **SK** 2024 Plan | 2025-2050 | No data | No data | No data |
| **MB** 2023 IRP | 2022-2043 | No data | No data | No data |
| **ON** 2025 APO | 2026-2050 | **RES & COM**: 1.3x \| 100 → 134 TWh **RES**: 1.2x \| 51 → 63 TWh **COM**: 1.4x \| 50 → 71 TWh | **RES & COM:** 1.2% **RES:** 0.9% **COM:** 1.5% | **RES & COM:** 51% **RES:** 24% **COM:** 27% |
| **QC** 2024 Plan[28] | 2025-2035 | **RES & COM**: 1.2x \| 128 → 150 TWh **RES**: 1.2x \| 77 → 89 TWh **COM**: 1.2x \| 51 → 61 TWh | **RES & COM:** 1.6% **RES:** 1.5% **COM:** 1.7% | **RES & COM:** 60% **RES:** 36% **COM:** 24% |
| **NB** 2023 IRP | 2023-2042 | No data | No data | No data |
| **NS** 2023 IRP[29] | 2025-2050 | No data | No data | No data |
| **NL** 2024 RAP[30] | 2023-2034 | **RES & GS (incl. EV):** 1.1x \| ~6.3 → ~7.2 GWh **RES & GS (excl. EV):** 1.1x \| ~6.3 → ~6.7 GWh | **RES & GS (incl. EV):** 1.2% **RES & GS (excl. EV):** 0.6% | **RES & GS (incl. EV):** 78% **RES & GS (excl. EV):** 73% |

[28] Sector-level data derived from projected sales by sector, adjusted by T&D loss factors.
[29] Data retrieved from NS Power's 2022 Evergreen IRP Draft Assumptions.
[30] Data retrieved from NB Power's 2023 Long-Term Forecast Report.

## Industry

**Table A4: Magnitude of Industry-Related Electricity Demand Increases Across Reviewed Studies**

| Region | Study Period | Increase in Industrial-Related Electricity Demand Across Study Period | CAGR | Industrial-Related Electricity Demand (% of Total) at End of Study Period |
|---|---|---|---|---|
| **Pathways Studies** | | | | |
| **Canada** CER | 2023-2050 | 1.3x \| 226 → 301 TWh<br>+$H_2$: 2.2x \| 226 → 499 TWh | 1.1%<br>+$H_2$: 3.0% | 25%<br>+$H_2$: 42% |
| **Canada** IET | 2021-2050 | 1.5x \| 184 → 270 TWh<br>+DAC: 1.8x \| 185 → 336 TWh | 1.3%<br>+DAC: 2.1% | 26%<br>+DAC: 33% |
| **MB** Roadmap | 2020-2050 | 1.6x \| 7.2 → 11.2 TWh | 1.5% | 58% |
| **ON** P2D | 2023-2050 | No data | No data | No data |
| **ON** Pathways | 2019-2050 | 2.2x \| 35.5 → 79.5 TWh<br>+$H_2$: 0 → 9.8 TWh | 2.6% | 44%<br>+$H_2$: 5% |
| **AB** Pathways | 2022-2041 | $H_2$: 57x \| 0.13 → 7.42 TWh | $H_2$: 24% | $H_2$: 7% |
| **System Outlooks** | | | | |
| **BC** 2021 IRP | 2024-2041 | No data | No data | No data |
| **AB** 2024 LTO | 2024-2043 | Heavy industry: +0<br>$H_2$: +4.8 TWh | Heavy industry: 0%<br>$H_2$: +4.8 TWh | Heavy industry: N/A<br>$H_2$: 4% |
| **SK** 2024 Plan | 2025-2050 | No data | No data | No data |
| **MB** 2023 IRP | 2022-2043 | +0 MW | No data | No data |
| **ON** 2025 APO | 2026-2050 | 1.7x \| 44 → 73 TWh (excluding data center)<br>Data Center: 4.7x \| 3 → 14 TWh<br>1.8x \| 47 → 86 TWh (with data center) | 2.1% (excluding data center)<br>Data Center: 6.6%<br>2.6% (with data center) | 28% (excluding data center)<br>Data Center: 5%<br>33% (with data center) |
| **QC** 2024 Plan | 2025-2035 | 1.5x \| 64 → 93 TWh | 3.5% | 40% |
| **NB** 2023 IRP | 2023-2042 | ~1.05x \| ~5.3 → 5.5 TWh | 0.2% | ~36% |
| **NS** 2023 IRP | 2025-2050 | No data | No data | No data |
| **NL** 2024 RAP | 2023-2034 | 1.0x \| ~2 → ~2 TWh | 0% | 18% |

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