Methodology, Risks and Drivers

Load Forecasting Methodology

AESO 2024 Long-Term Outlook

MAY 2024

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Load Forecasting Methodology

Overview

The methodology, centered around an econometric model, analyzes the interplay between electricity load and socioeconomic, environmental and calendar-related factors. Forecasts are generated at various levels of granularity, providing an understanding of consumption patterns.

The methodology incorporates evolving load components such as electric vehicles (EVs) and building heating and cooling electrification, alongside economic indicators like gross domestic product (GDP) and oil sands production. This integration enables a holistic approach to forecasting, accounting for dynamic shifts in consumption patterns and economic conditions.

Load Forecasting Methodology

A comprehensive methodology has been utilized to project the province's future electricity consumption patterns. At the core of this methodology lies an econometric model designed to capture the intricate relationships between electricity load and a range of crucial socioeconomic and environmental variables as well as calendar related variables. This model is used to analyze and forecast data that is organized into hierarchical structures. This model predicts electricity consumption patterns at multiple levels of aggregation, ranging from Alberta Internal Load (AIL) down to individual points of delivery (PODs) or substations. At the highest level there is AIL which accounts for load that is served by grid-connected generation and distribution-connected generation (equal or greater than five megawatts [MW]), load served by behind-the-fence (BTF) generation, and load from Medicine Hat.

After forecasting electricity consumption at both AIL level and the finer granularity of individual points of delivery, the reconciliation process ensues. This process is undertaken to harmonize the projected load at the top level (AIL) with the detailed load predictions at the bottom level (PODs). A data request was sent to distribution facility owners (DFOs) by the AESO to obtain their load forecasts at the substation level, covering potential load transfers among substations in both historical and future contexts. The AESO utilizes the responses from DFOs to integrate load transfers into its forecasts, while also focusing on reviewing substations where significant disparities exist between AESO and DFO forecasts.

The load forecasting methodology utilized a comprehensive historical training period from 2018 to 2022 to draw from an extensive dataset including historical load and weather data, macroeconomic insights sourced from the Conference Board of Canada (CBoC), S&P Global's (IHS Markit) oil sand production projections and a number of user defined variables to account for Alberta specific items (i.e., COVID-19, wildfire disruptions, etc.). To address potential multicollinearity among key economic indicators like GDP, population and employment, an economic index was created and integrated as a variable within the model. Multiple econometric models were developed and evaluated to ensure optimal forecasting accuracy, with the best-performing model selected for predictions.

During the forecasting period, a fiftieth percentile (P50) typical weather year was utilized. This typical weather year was generated through a probabilistic analysis of 21 years of weather data in Alberta, providing a robust foundation for weather-related projections. The weather profiles employed in the probabilistic forecast were evaluated according to their summer and winter load peaks. Two years positioned in the middle for summer and winter load peaks were chosen, and the P50 typical weather year was formed by combining six months from each of these selected years. The economic index, oil sands projections and weather years, along with other variables mentioned above, are consistent across the Reference Case and the High Electrification scenario. Over the ensuing 20 years, the model generates hourly load forecasts for AIL, resulting in a crucial output referred to as base AIL.

To assess the impact of future temperature variations and economic conditions, a probabilistic model has been created. The results of this model have been utilized as an input for Resource Adequacy modeling.[1] In this probabilistic model, 25 weather years from 1998 to 2022 are considered alongside five different economic scenarios.

In addition to the base AIL load forecasted by the explained model; the methodology encompasses specialized load components tailored to address the dynamic shifts in electricity consumption patterns through the forthcoming energy transition. These load modifications consider the emergence of evolving loads that were not present in the past, at a level that is projected to be in future. These loads including EVs, building heating and cooling electrification, hydrogen production load and new projects play a substantial role in the future. Furthermore, the methodology is designed to incorporate the influence of energy efficiency and distributed energy resources, recognizing their capacity to counterbalance and offset electricity demand.

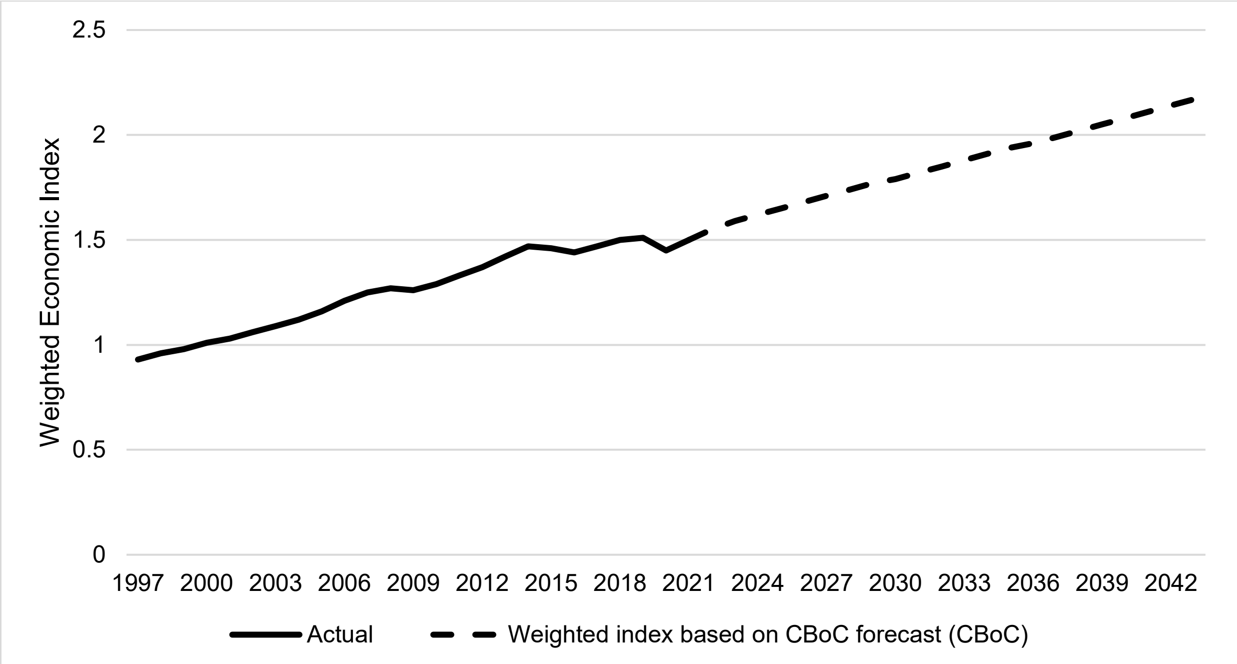
Alberta Gross Domestic Product (GDP), Population, Employment, and Oil Sands Outlook

Alberta's electricity demand is intricately linked to its GDP, population and employment levels. The size and activity of the economy, the number of residents and the extent of employment directly influence energy consumption patterns. As the GDP grows, more businesses and industries require electricity for their operations. A larger population and more people in the workforce result in increased residential and commercial energy needs. GDP, population, and employment data used is consistent across the Reference Case and High Electrification scenario.

Between 2021 and 2022, Alberta experienced a strong post-pandemic recovery, characterized by robust economic growth, including approximately five per cent expansion in GDP in 2022. This growth trajectory continued with estimated GDP growth rates of 2.4 per cent in 2023, based on data from the CBoC. The 2024 LTO utilizes a composite index reflecting real Alberta GDP, employment figures and population estimates from CBoC's 20-year provincial economic outlook. For specific regional insights in the Edmonton and Calgary planning areas, data is drawn from CBoC's metropolitan economic forecast reports. Worth noting, adjustments made in a prior LTO to account for energy efficiency impacts have been omitted in the 2024 LTO due to the implementation of a new energy efficiency estimation methodology. (Refer to the Energy Efficiency section below for more information).

[1] For more information on the Resource Adequacy outcomes modelled in the 2024 LTO see the Additional Insights section.

Figure 1: Macroeconomic Index



Oil Sands Outlook

The correlation between oil sands production and electricity consumption in Alberta is notably high due to the significant influence of industrial load within AIL. The substantial industrial load is largely attributed to the oil sands production and energy sectors operating within the region. Given that these industries rely heavily on electricity for their operations, fluctuations in oil sands production directly impact electricity consumption patterns. Notably, the considerable industrial demand arising from oil sands production and energy sectors emerges as a dominant catalyst driving the province's electricity load.

The 2024 LTO integrated oil sands production data from S&P Global's (IHS Markit's) Q3 2022 outlook data for the forecasting period and Government of Alberta's Economic Dashboard for the training period.[2] In comparison to the outlook used for the 2021 LTO (Q3 2020), the new projection closely aligns until 2027. However, deviations emerge thereafter, with the new projection indicating lower production beyond 2027 compared to Q3 2020. According to the Q3 2022 outlook, oil sands production is expected to peak in the early 2030s, followed by a stabilization period before gradual decline. This updated projection provides insights into the future trajectory of Alberta's oil sands production, signaling a shift in the industry's outlook beyond the approaching decade. The oil sands outlook applied in the Reference Case is identical to the High Electrification scenario.

[2]Summary of S&P Global's oil sands outlook that is used in the 2024 LTO can be found here: https://www.spglobal.com/commodityinsights/en/ci/research-analysis/longterm-oil-sands-outlook.html. The Government of Alberta's "Alberta Economic Dashboard" non-conventional oil production data can be found here: Alberta Economic Dashboard | Oil production

System Load:

System load represents the total electric energy billed to transmission consumers in Alberta and Fort Nelson, British Columbia, encompassing transmission losses.[3] It is noteworthy that system load differs from the AIL metric by excluding behind-the-fence load (BTF load), a component of AIL. BTF load is typically supplied by on-site generation, also known as BTF generation. These sites are commonly situated within industrial complexes, predominantly comprised of oil sands and petrochemical facilities, many of which are configured as cogeneration plants. Additionally, a select number of distribution-connected generation facilities, large university campuses and the City of Medicine Hat also serve as hosts for BTF load and generation sites.

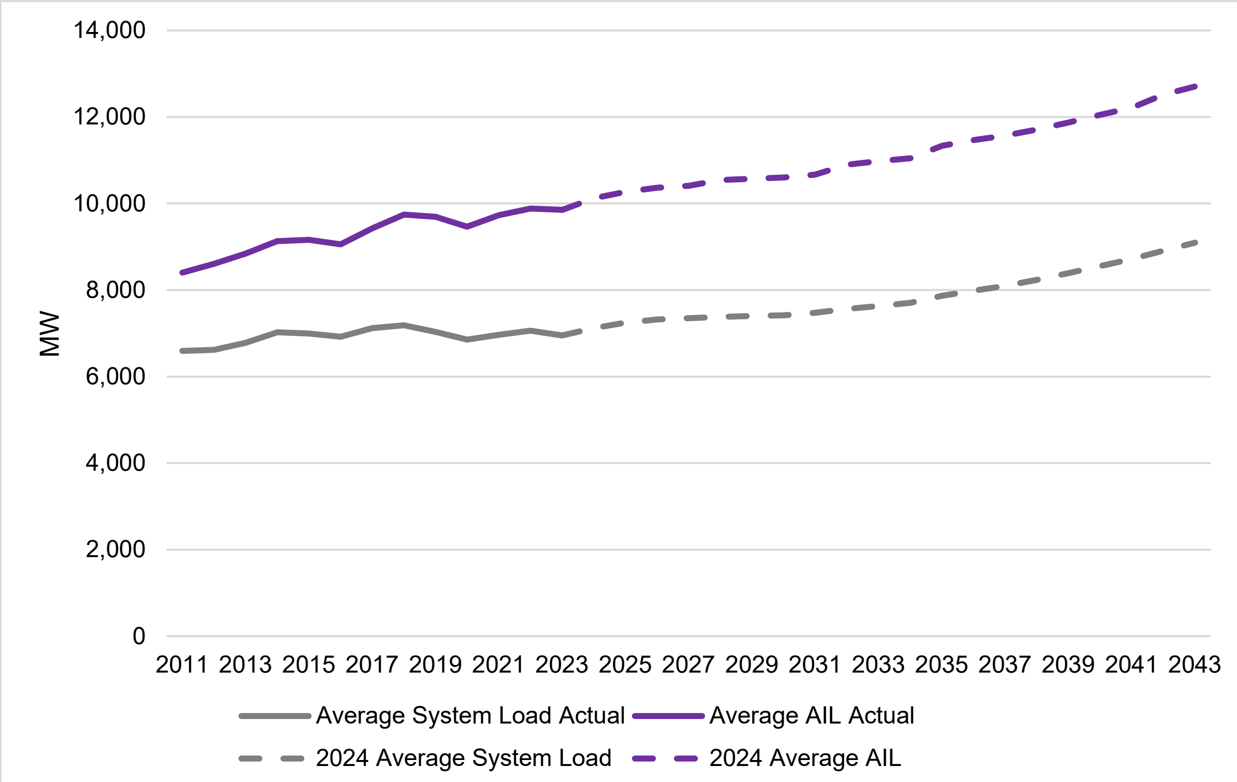
The average system load has increased by 5.4 per cent since 2011, reaching 6,951 MW in 2023. Additionally, the system load to AIL ratio decreased from 78 per cent in 2011 to 71 per cent in 2023. Various factors may influence the system load to AIL ratio in the future, including the load supplied by on-site generation, distributed energy resources (DER), oil and gas production, and the electrification of transportation and building heating and cooling. While there has been a decreasing trend in the system load to AIL ratio in the past, it seems that due to the significant increase in AIL attributed to electrification such as EVs and building heating and cooling load, both integral parts of the system load. This ratio is projected to stabilize over the near term and increase in the long term, reaching approximately 74.5 per cent by 2043.

The AIL forecast is utilized for predicting the system load. As outlined in the Load Forecasting Methodology section, the forecasted AIL comprises two components: baseload and load modifiers. These modifiers encompass evolving loads such as EV load, building heating and cooling electrification, hydrogen production load, new projects and others. They represent loads that were not prevalent in the past but are projected to become significant in the future. It is assumed that the system load to base AIL ratio will remain constant in the future, maintaining its 2022 and 2023 value of 71 per cent. To incorporate the impact of load modifiers, each modifier is examined individually, and their loads are divided between BTF and system load. For instance, while 100 per cent of the EV load is allocated to the system load, only 20 per cent of the hydrogen production load is attributed to the system load, with the remaining 80 per cent expected to be served by on-site generation.

The graph below illustrates both the forecasted system load and AIL under the Reference Case. The compound annual growth rate (CAGR) for average AIL is approximate 1.2 per cent and average system load is 1.3 per cent from 2024 to 2043. The AESO anticipates a lower CAGR for the initial 10 years (2024-2034) and a higher CAGR for the subsequent years after 2034, influenced by electrification.

[3] For system access service provided in accordance with the ISO tariff under Rates DTS, FTS, and DOS.

Figure 2: Average AIL and System Load Actuals and Forecasted Values (MW)



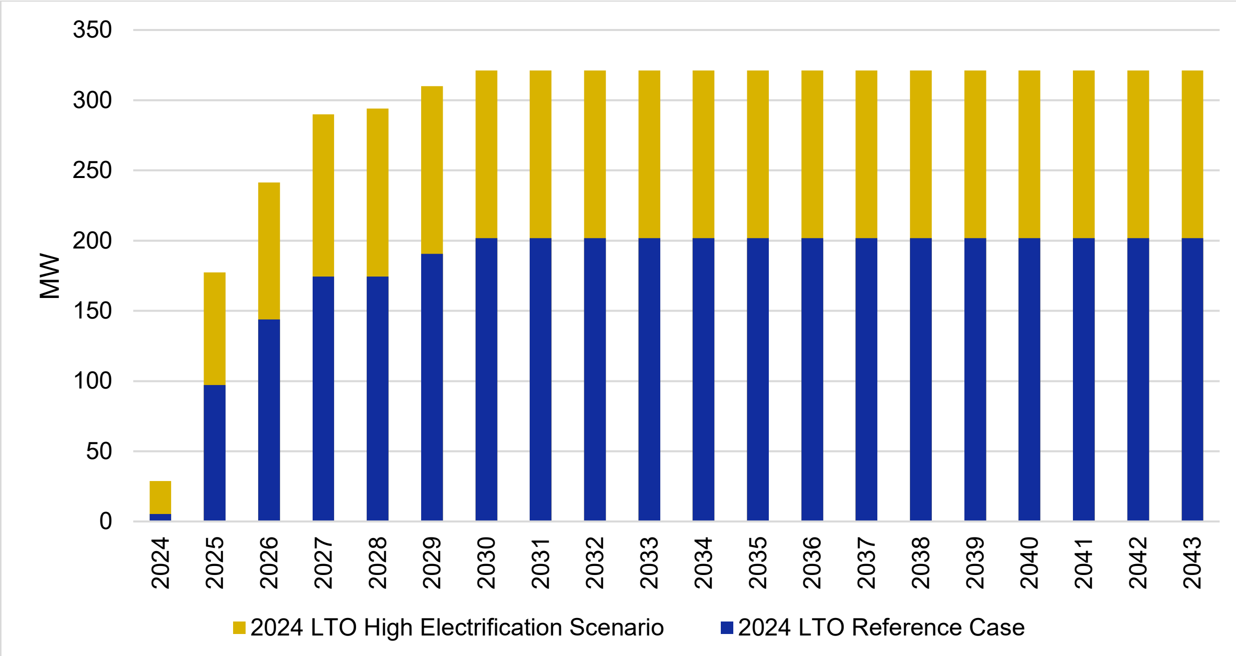
Load Project Inclusion

Specific load and Rate Demand Transmission Service (DTS) contract change projects from the AESO project list are selected as additional load modifiers. The purpose is to capture possible near-term growth in energy consumption by 2029 that the base AIL forecast is not able to fully capture.

Projects included in the 2024 LTO have been selected based on their likelihood of reaching completion. The ultimate determination of whether a project merits inclusion in the load forecast is shaped by a combination of factors, including the project's status, progress trajectory during the assessment, anticipated impact on the load forecast and alignment with the AESO's inclusion criteria. The reference case accounts for future load additions including pipeline electrification, and various industrial developments, alongside other projects. The additional projects selected for the high-electrification scenario address load projects in earlier stages of connection to account for the upper limit of load growth.

Load projects are expected to increase by an hourly average of 202 MW in the reference case, and 321 MW in the High Electrification scenario by 2030 and beyond.

Figure 3: Project Load Forecast



Electric Vehicles

Highlights

The forecast of EV numbers and loads relies on various assumptions designed for different vehicle types, including light-duty vehicles (LDVs), medium-duty vehicles (MDVs), heavy-duty vehicles (HDVs) and buses. Two distinct scenarios have been designed: the Reference Case and the High Electrification scenarios. The Reference Case reflects a moderate growth in EV adoption, influenced by the absence of policies and subsidies in Alberta. The High Electrification scenario integrates ambitious sales targets aligned with the federal 2030 *Emissions Reduction Plan* (ERP) target. The objective of this scenario is irrespective of zero-emission vehicle (ZEV) availability, cost parity with non-ZEV alternatives, system reliability, incentives for zero-emission commercial and institutional fleets, etc. Both scenarios incorporate managed charging profiles for LDVs and MDVs to mitigate the increase in load in the long term as the number of EVs increases significantly, requiring coordination among utilities and DFOs.

Transportation

The evolution of ZEVs, such as battery electric vehicle (BEVs), plug-in hybrid electric vehicles (PHEVs), and hydrogen fuel cell vehicles (FCVs),[4] plays an integral role in the reconfiguration of the transportation sector and paving the way toward decarbonization. The transportation sector includes various types of vehicles, such as light-duty passenger vehicles (e.g., cars, sport-utility vehicles [SUVs], minivans, and pickup trucks), freight (e.g., medium- and heavy-duty vehicles) and buses (transit, school, coach).

Several factors come into play to integrate ZEVs into the transportation system, including government policies, affordability, consumer preferences and the development of a robust charging infrastructure. In the

[4] Zero-emission vehicles

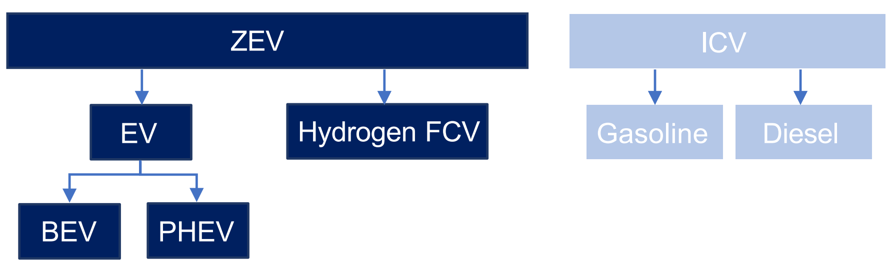
2024 LTO, two scenarios have been designed by taking several factors into consideration: the Reference Case and the High Electrification scenarios. Similar to the 2021 LTO, the AESO's EV model considers EVs in a charging state—a discharging state (i.e., vehicle-to-grid [V2G] mode) has not been modeled in either scenario.

The Reference Case incorporates moderate penetration of EVs in Alberta compared to federal targets and other jurisdictions given factors including the existing EV fleet in Alberta (historic uptake patterns), the absence of clearly defined provincial policies, unavailability of provincial subsidies, uncertainty in technological advancement, undefined charging infrastructure development plan, and that the federal target percentage of sales applies to manufacturers while it may not be uniformly applicable to all provinces.

However, aligned with the *AESO Net-Zero Emissions Pathways* report,[5] the High Electrification scenario evaluates more ambitious ZEVs penetration in Alberta. In this scenario, the projection of ZEVs targets is assumed such that policy goals announced in the ERP are achieved. This would be regardless of ZEVs availability, cost parity with non-ZEVs choices, the readiness of power systems transmissions and distributions infrastructure, public and private charging optionality, regulatory, and incentives for zero-emission commercial and institutional fleets and other factors. In other words, the policy aims to drive ZEVs adoption despite potential challenges regarding ZEV availability, infrastructure development and cost considerations.

The AESO's definition of ZEVs and internal combustion vehicles (ICVs) is represented in Figure 4. In both the Reference Case and High Electrification scenarios, our models focus on four vehicle classes (i.e., LDVs, MDVs, HDVs, and buses), described in detail next.

Figure 4: AESO's Definition of Various Vehicles



Light-Duty Vehicles

In the Reference Case, the annual percentage of new LDV EV penetrations will reach 10 per cent by 2026, 20 per cent by 2030, and 100 per cent by 2035. However, in the High Electrification scenario, the ZEVs (i.e., EVs and hydrogen FCVs) assumption is based on meeting the outlined federal policy target from the 2030 ERP for new sales requirements, i.e., 20 per cent by 2026, 60 per cent by 2030, and 100 per cent from 2035 onwards.[6]

Note the federal requirement is for ZEVs, but to test the Reference Case the AESO assumes all new light-duty ZEVs will be BEVs. Further, the current PHEV fleet in Alberta is included, but its lifecycle replacement

[5] AESO Net-Zero Emissions Pathways Report

[6] See PDF pg. 57 of the 2030 ERP and PDF pg. 34 of 2023 Progress Report on the 2030 ERP

is assumed to be BEVs to test the highest impact on the grid from EVs. Given near-term BEV availability and choices, the model assumes greater uptake of light-duty passenger cars in the 2020s, while light-duty trucks, including minivans and SUVs, will increase in prevalence in the 2030s to the car/truck ratio historically seen in Alberta with internal-combustion engine types.[7] In the High Electrification scenario, a similar assumption is made, but with the inclusion of the hydrogen FCVs. According to this assumption, a portion of annual percentage of new sales for LDVs ZEVs is allocated to hydrogen FCVs (see Table 1). This allocation is determined based on energy used for transportation in Alberta[8] and hydrogen FCV and EV efficiencies.

Table 1: Summary of ZEVs Per Cent of New Sales for Each Type of Vehicle Class in the Reference Case and High Electrification scenarios.

<table>
<tr><th>Scenario</th><th>Light-Duty Vehicle</th><th>Medium-Duty Vehicle</th><th>Heavy-Duty Vehicle</th><th>Bus</th></tr>
<tr><td>Reference Case</td>
<td><table><tr><th>Year</th><th>2026</th><th>2030</th><th>2035</th></tr><tr><td>EV* (%)</td><td>10</td><td>20</td><td>100</td></tr><tr><td>FCV (%)</td><td>0</td><td>0</td><td>0</td></tr></table></td>
<td><table><tr><th>Year</th><th>2026</th><th>2043</th></tr><tr><td>BEV (%)</td><td>1</td><td>30</td></tr><tr><td>FCV (%)</td><td>0</td><td>0</td></tr></table></td>
<td><table><tr><th>Year</th><th>2026</th><th>2043</th></tr><tr><td>BEV (%)</td><td>0.5</td><td>20</td></tr><tr><td>FCV (%)</td><td>0</td><td>0</td></tr></table></td>
<td><table><tr><th>Year</th><th>2030</th><th>2040</th></tr><tr><td>BEV (%)</td><td>20</td><td>65</td></tr><tr><td>FCV (%)</td><td>0</td><td>0</td></tr></table></td></tr>
<tr><td>High Electrification</td>
<td><table><tr><th>Year</th><th>2026</th><th>2030</th><th>2035</th></tr><tr><td>EV* (%)</td><td>19</td><td>57</td><td>95</td></tr><tr><td>FCV (%)</td><td>1</td><td>3</td><td>5</td></tr></table></td>
<td><table><tr><th>Year</th><th>2026</th><th>2030</th><th>2040</th></tr><tr><td>BEV (%)</td><td>1</td><td>31</td><td>89</td></tr><tr><td>FCV (%)</td><td>0</td><td>4</td><td>11</td></tr></table></td>
<td><table><tr><th>Year</th><th>2026</th><th>2030</th><th>2040</th></tr><tr><td>BEV (%)</td><td>0.5</td><td>12</td><td>33</td></tr><tr><td>FCV (%)</td><td>0</td><td>23</td><td>67</td></tr></table></td>
<td><table><tr><th>Year</th><th>2040</th></tr><tr><td>BEV (%)</td><td>36</td></tr><tr><td>FCV (%)</td><td>64</td></tr></table></td></tr>
</table>

*** The current PHEV fleet in Alberta is included, but its lifecycle replacement is assumed to be BEVs.**

Vehicle charging specifications (e.g., battery size, kilowatthour/kilometre [kWh/km] efficiency rates, charging duration) are based on representative battery-electric cars and trucks;[9] these are considered static over the forecast period and no assumption is made around performance changes to vehicle charging or charging infrastructure and equipment (e.g., enhancements to connector types, power ratings, etc.).

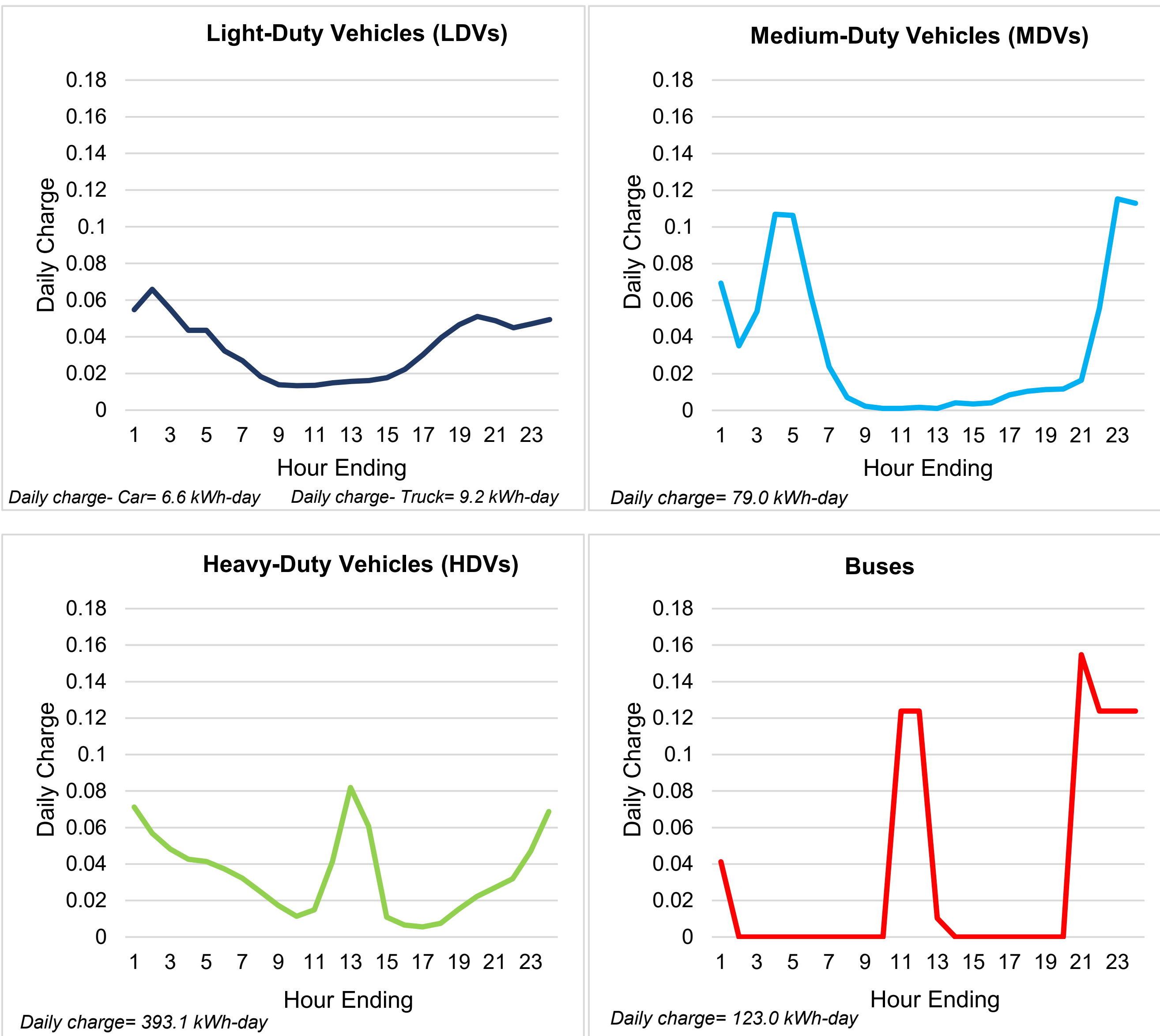
[7] The AESO estimates a 20/80 split between passenger cars and trucks, based on estimates of new sales in 2018-2022.

[8] The AESO estimates the hydrogen FCVs growth by using information related to transportation in Alberta. See pg. 5 of Khan M.A., MacKinnon C., Young C., and Layzell D. B. (2022) Techno-economics of a New Hydrogen Value Chain Supporting Heavy Duty Transport. Transition Accelerator Reports: Volume 4, Issue 5, Pg 1-52. ISSN 2562-6264. Version 2.

[9] The AESO relied on EV specifications and annual mileage intelligence produced by Dunsky Energy + Climate Advisors in an EV integration report produced for EPCOR. The AESO thanks Dunsky and EPCOR for their permission to use this data. The AESO remains responsible for data curation, transformation, error, or omissions.

Seasonal changes in driving patterns, as well as disparities between weekdays and weekends, are accounted for. No adjustments are made for holiday or non-typical driving patterns. The daily charging profiles are considered static over time and no assumption is made around changing driving behaviour over the years. A sample of charging profile used in the designed scenarios is represented in Figure 5. Further explanations regarding charging profiles will be discussed in the Managed and Unmanaged Charging Profile section.

Figure 1: Example of Daily Charging Profiles in Summer for Various Vehicle Classes*



*The daily charge includes 12 per cent of losses.

Medium-Duty Vehicles

In the Reference Case, AESO model assumes the following percentages of new MDV sales are battery-electric: One per cent by 2026 and 30 per cent by 2043. In the High Electrification scenario, the percentage of MDVs' new sales that are BEVs and hydrogen FCVs is defined according to the ERP target[10] but at a slower pace in the 2020s. In this scenario, the portion of sale percentage allocated to hydrogen FCVs is represented in Table 1.

Vehicle charging specifications are based on representative battery-electric urban delivery and utility vehicles, and these remain static. Charging profile utilized in the scenarios is shown in Figure 5 and details around it will be discussed in the Managed and Unmanaged Charging Profile section. Seasonal changes in driving patterns are adjusted in the daily profile; however, disparities between weekdays and weekends, as well as holidays, are not considered.

Heavy-Duty Vehicles

Similar to MDVs, for the Reference Case, the AESO model assumes the following percentages of new HDV sales are battery-electric: 0.5 per cent by 2026, and 20 per cent by 2043 . In the High Electrification scenario, the ERP target is expected to be met through a gradual increase during the 2020s. The fraction shared with hydrogen FCVs is shown in Table 1. Penetration of BEVs for HDVs categories is represented at a lower level, compared to the medium-duty class, to reflect this vehicle class generally requires longer duration, longer haul and heavier payload capacity. These are currently limiting factors of BEVs technology and where other zero-emission fuel sources may present greater potentials such as improved long-term cost efficiency in comparison to diesel choices.[11]

Vehicle charging specifications and daily charging needs are based on representative battery-electric short-haul trucks and these are maintained static. Given limited known-use cases of electric HDVs in Alberta, the AESO assumes this class will primarily be for short-haul regional operations that serve multiple schedules (i.e., food and beverage delivery and warehouse transportation) and therefore has a spread-out depot-based charging profile (Figure 5).[12] Similar to MDVs, charging values are adjusted by season but maintained regardless of day of week or holidays.

Buses

In the Reference Case, the AESO assumes an annual percentage of 20 per cent of new bus sales to be electric by 2030, with an increase to 65 per cent by 2040. The percentage of sales defined in High Electrification scenario is according to the federal ERP goal (see Table 1). Vehicle charging specifications and daily charging needs are based on representative battery-electric buses for each subclass and these are maintained static over the forecast period. Given the heavier presence of transit buses in the overall electric bus fleet, the charging profile has a bi-modal shape, with morning and evening peaks to reflect depot-based charging following peak-transit periods (see Figure 5).[13]

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[10] The federal ERP states a goal of 35 per cent of new sales of medium- and heavy-duty vehicles (MHDV) be ZEVs by 2030 and develop regulations for a certain subset of MHDVs sales to be 100 per cent ZEVs by 2040. See PDF pg. 57 of the 2030 ERP and PDF pg. 128 and 129 of 2023 Progress Report on the 2030 ERP.

[11] See Ledna et al (2022), Decarbonizing Medium and Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis, URL: https://www.nrel.gov/docs/fy22osti/82081.pdf.

[12] AESO blended the depot-charging profiles published by Borlaug et al (2021), heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems, URL: https://data.nrel.gov/submissions/162.

[13] The AESO adopted charging observations from a pilot study for the Edmonton Transit System feasibility, see Marcon (2016), Electric Bus Feasibility Study for the City of Edmonton, URL: https://www.edmonton.ca/public-files/assets/document?path=transit/ets_electric_feasibility_study.pdf

Hydrogen Fuel Cell Vehicles

In the path towards net zero-emission, hydrogen FCVs play a significant role, in addition to the electrification of vehicles in the transportation sector. Hydrogen FCVs can be appropriate choices for medium-duty and heavy-duty vehicles, compared to EVs with heavy batteries and limited range. In addition, they are fast fueling and more compatible with cold weather. Rather than consuming more fuel for cabin heating, they utilize the wasted heat from the fuel cell.[14] In our High Electrification scenario, the below section on Hydrogen Production incorporates the load impact results from hydrogen FCVs.

EV Share in Canada and Alberta

EV sales have been on a substantial upward trend in Canada. In 2023, the total record of EVs (i.e., BEV and plug-in hybrid) registrations was about 184,578, accounting for 10.8 per cent of total registrations.[15] The EV market share growth and adoption rates vary significantly in different provinces. Quebec, Ontario, and British Columbia, and the Territories are the first to experience rapid adoption across Canada, with about 77,083, 49,803, and 42,611 new EVs registered in 2023. Defined provincial subsidies and incentives, including rebates, tax credits, investment in developing charging infrastructure, adoption of car manufacturers, customers' preferences, competitive fuel cost and electricity prices are the main reasons for this remarkable transition in transportation in these regions.

Based on the latest updates to the Alberta Ministry of Transportation, as of March 31, 2023, the number of registered EVs (excluding plug-in hybrid and hybrid electric) stood at 9,338, a significant increase compared to March 31, 2022, with 5,680 registered EVs.[16,17] The EVs share in Alberta varies according to postal code and, therefore, Forward Sortation Area (FSA) levels [18] which are mapped to AESO planning areas[19] and demonstrated in Figure 6. This chart shows Calgary and Edmonton (with the highest populations) tend to have more EVs compared to other areas, representing about 50 per cent and 33 per cent, respectively, of total registered EVs in Alberta.

EV Number and Load

Forecasting the number of EVs and the load resulting from EV adoption in the next decades provides invaluable insights toward making informed decisions in sectors such as system planning, operation, transmission, distribution and market design. Figures 7 and 8 show the EVs number and the load forecast composition for various EVs categories (i.e., LDVs, MDVs, HDVs, and buses) in Reference Case and High Electrification scenarios, respectively.

The adoption of EV is projected to undergo exponential growth, with the number of vehicles expected to reach approximately 2.8 million by 2043 in the Reference Case. Also, the annual average of EV load is expected to increase to around 1,350 MW by 2043 (approximately 10.6 per cent of AIL), up from the 16 MW EV load in 2024 (see Figures 7 and 8). As noted in the Hydrogen Production section, the number of hydrogen FCVs (see Figure 9) has been deducted from total ZEVs in the High Electrification scenario. In this scenario, it is anticipated that vehicle number increases to approximately 2.9 million by 2043. Also, the

[14] See The Hydrogen Strategy

[15] See Table 20-10-0024-01 New motor vehicle registrations, quarterly.

[16] See Motorized vehicles registrations by fuel type as of March 31.

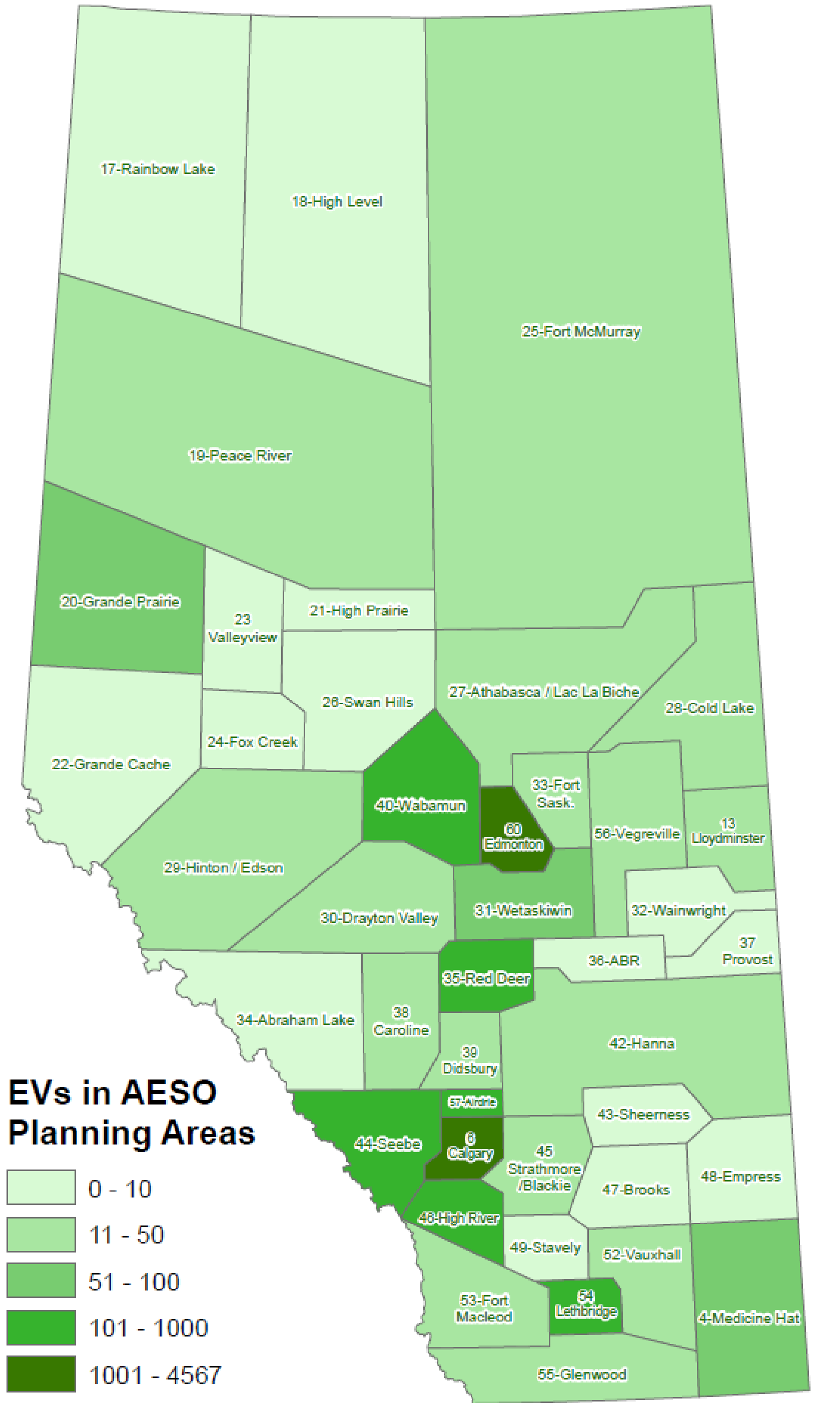
[17] This number is still a relatively small number of total vehicles registered, about 3.6 million as of March 31, 2023.

[18] Registered EVs based on postal codes are provided to AESO by Alberta Ministry of Transportation.

[19] AESO transmission planning areas

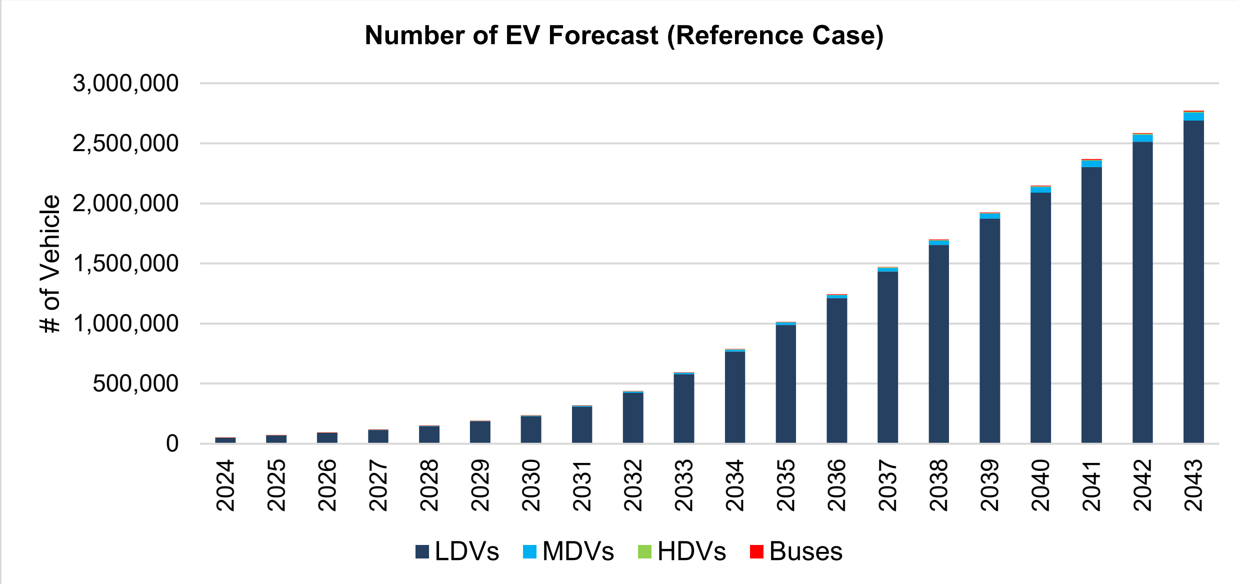
annual average load is projected to surge significantly, reaching approximately 2,000 MW by 2043, which is roughly 13.8 per cent of the AIL. This marks a notable rise compared to the 20 MW in 2024. Therefore, in the High Electrification scenario, approximately 48.1 per cent increase in average load is observed compared to the Reference Case in 2043. In both scenarios, the load forecast composition for LDVs decreased; however, the share is increased for MDVs, HDVs and buses.

Figure 2: Allocation of EV Number to the AESO Planning Area*



* Please note this chart represents the allocation of data for the year 2023.

Figure 3: Number of EV Forecast and Annual Average Load Forecast for EV in the Reference Case



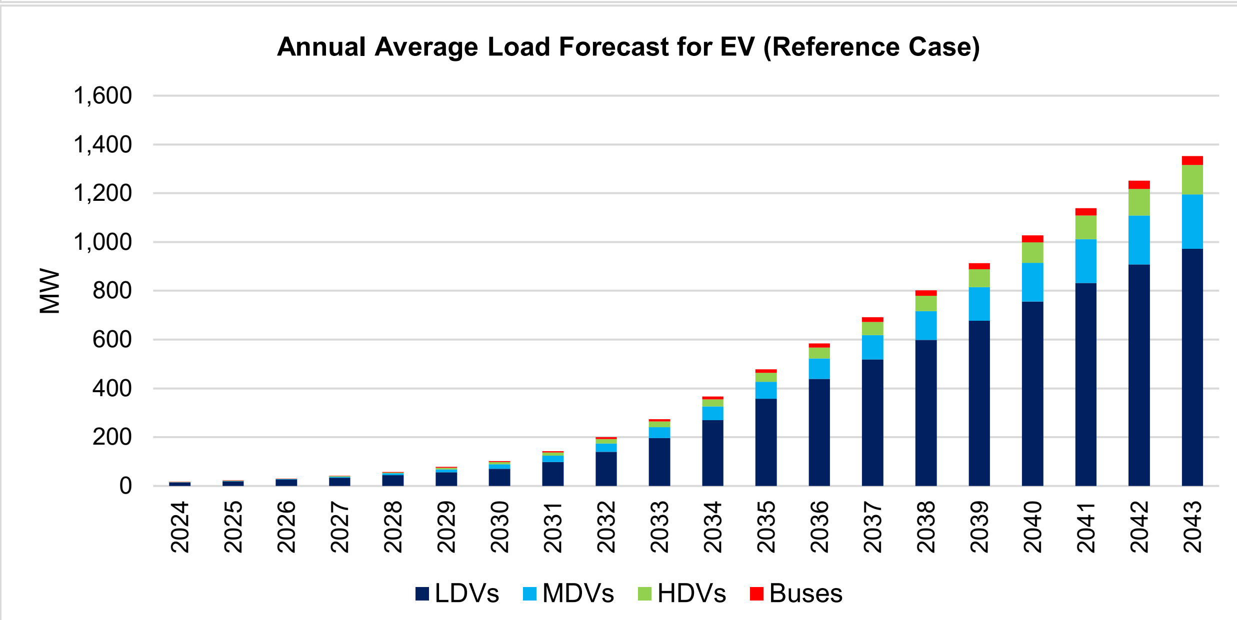
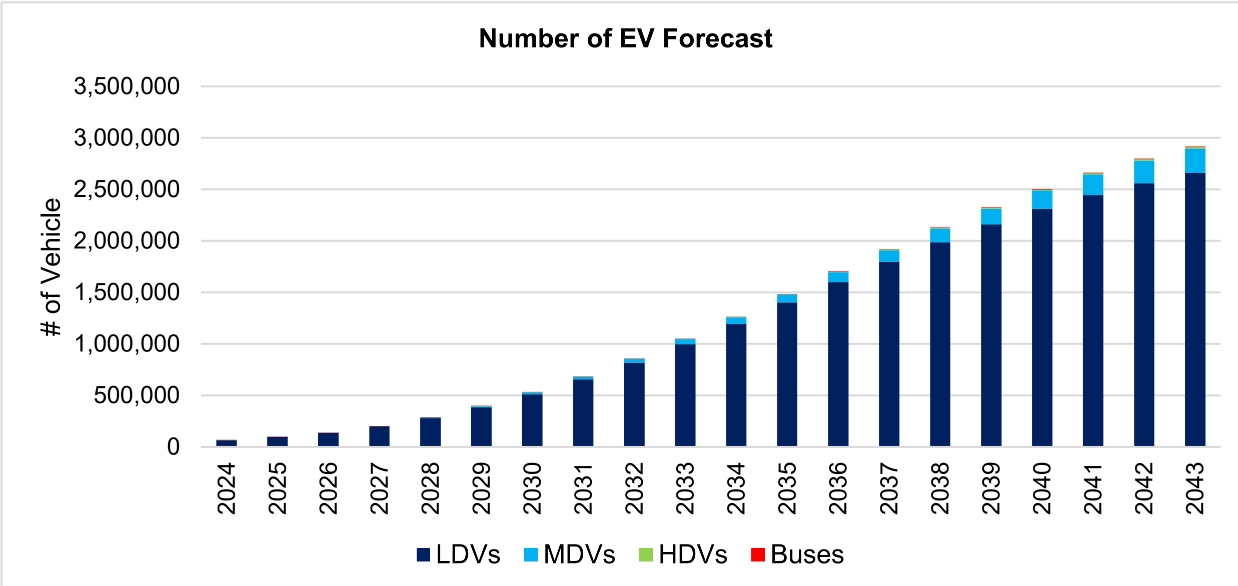


Figure 4: Number of EV Forecast and Annual Average Load Forecast for EV in the High Electrification Scenario



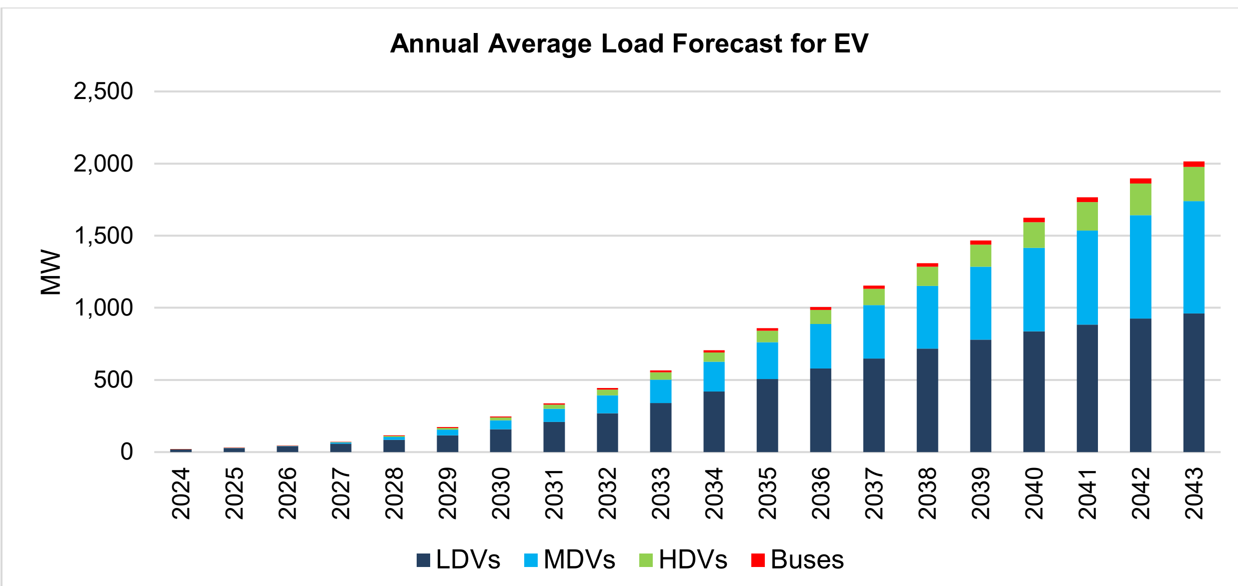
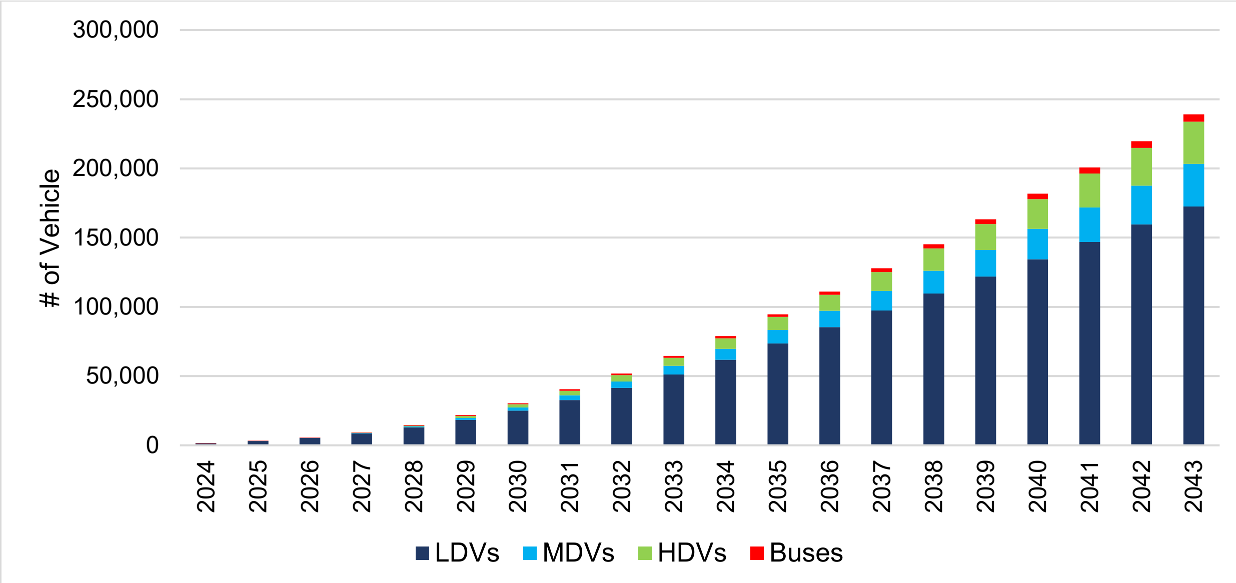


Figure 5: Number of Hydrogen FCVs Forecast in the High Electrification Scenario



Managed and Unmanaged Charging Profiles

Although accelerated EV integration in the transportation sector is a huge step towards decarbonization, grid infrastructure including system planning, reliability and operational sections, will face several challenges if the EV charging profile is not managed. To do so will require shifting the peak of the charging profile, which can optimize the charging behavior of EVs and consequently have a significant impact on the overall system load peak.

The potential and feasibility of demand flexibility can vary across different EV categories and depends on the magnitude of daily charging profile, charging time limitation and charging locations. In addition, the range of values the controlled EV charging profile offers depends on how the charging profiles for different categories are managed and coordinated. FortisAlberta and Enmax Power are DFO pioneers in running an EV charging pilot program in Alberta.[20, 21] The initiative has been designed to gather information regarding the locations and time of power drawn from the grid due to EV charging. The program could provide insights into enhancing and optimizing the grid operation while minimizing customer distribution costs.

It is worth mentioning that there are no specific plans to incentivize managed charging behaviour in Alberta. There is consensus by market participants and policy makers around the clear benefits of adopting such practices suggesting that initiatives of this nature will emerge in the future. Therefore, the AESO's assumptions regarding the results presented in Reference Case and High Electrification sections are based on managed charging profiles for LDVs and MDVs. Also, there is assumed coordination between EV owners and utilities in the managed charging profiles. Due to the limited penetration of HDVs and buses, the managed charging profiles have not been assumed for them. This section investigates how controlled and uncontrolled charging LDVs and MDVs impact the overall peak.

[20] https://www.enmax.com/NewsAndEventsSite/Documents/Charge-Up-results-news-release-April-2023.pdf

[21] https://fortisalberta.com/electric-vehicles-and-electric-vehicle-chargers/2023-electric-vehicle-smart-charging-pilot

Designing controlled charging profiles is influenced by charging infrastructure and vehicle categories. For LTO 2024, off-peak and wind-based charging have been defined. In this method, the charging pattern for LDVs centers around wind-based charging, similarly MDVs peak charging profile occurs during midnight and early morning when there is an increased potential of high wind generation.

Figure 10 compares controlled and uncontrolled charging profiles for LDVs and MDVs. The results show the distinction between the two methods remains inconsequential in both scenarios until 2030, due to the limited adoption of LDVs and even less of MDVs in that timeframe. However, the difference becomes more pronounced beyond 2030 (see Figure 11). In the managed Reference Case, the overall peak load drops by 314 MW (approximately two per cent) by 2043 compared to the unmanaged charging profile. In the High Electrification scenario, using the managed charging profile result in decreasing the peak by 1,911 MW (approximately 8.6 per cent) in 2043. Although this result signifies that managing the charging profile leads to reducing the peak load, the impact of controlling the charging profile depends highly on feasibility of managed charging profiles and optimization methods.

Figure 6: Comparison of Managed and Unmanaged Charging Profiles

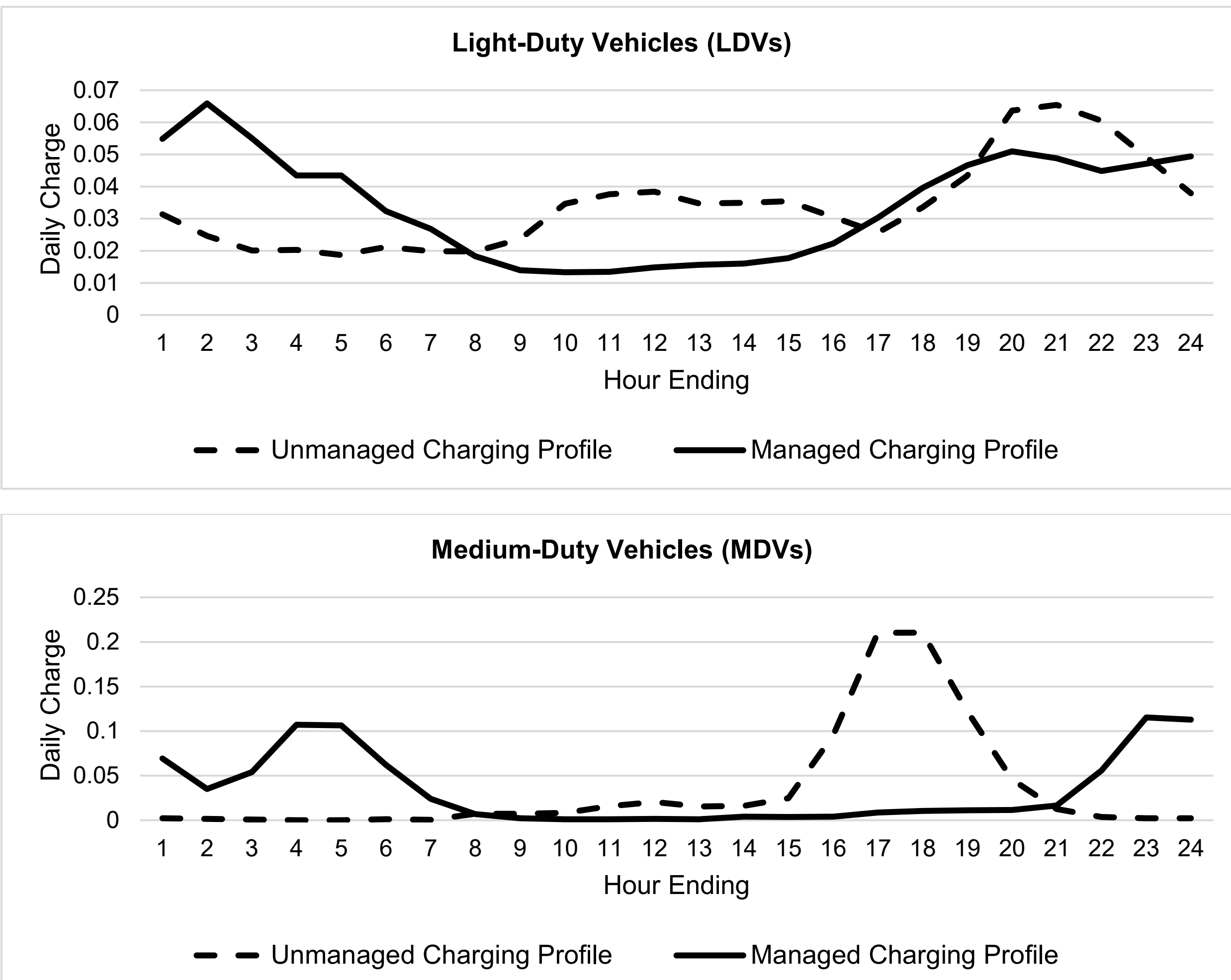
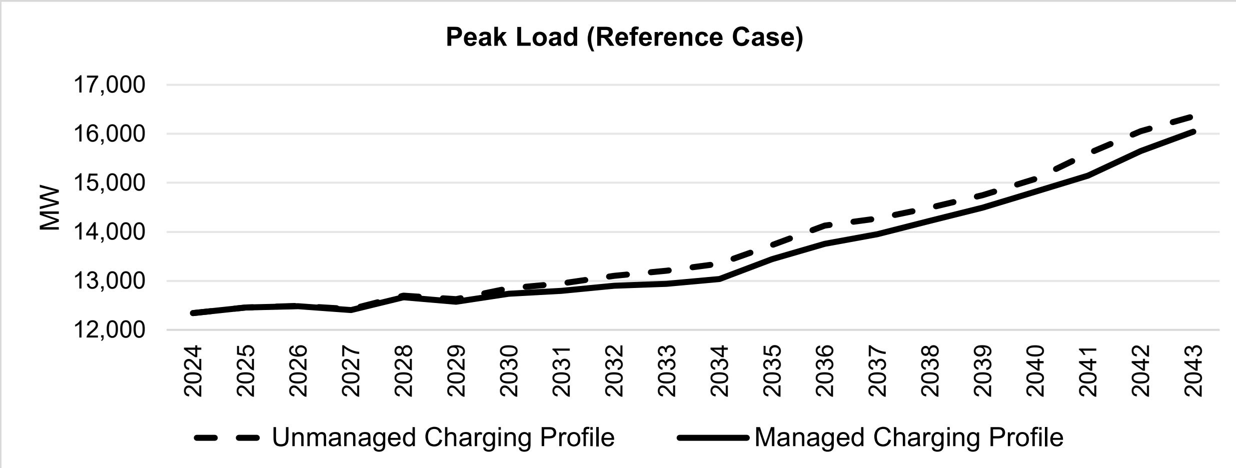


Figure 11: Impact of Managed Charging Profile on Peak Load in Reference Case and High Electrification Scenarios

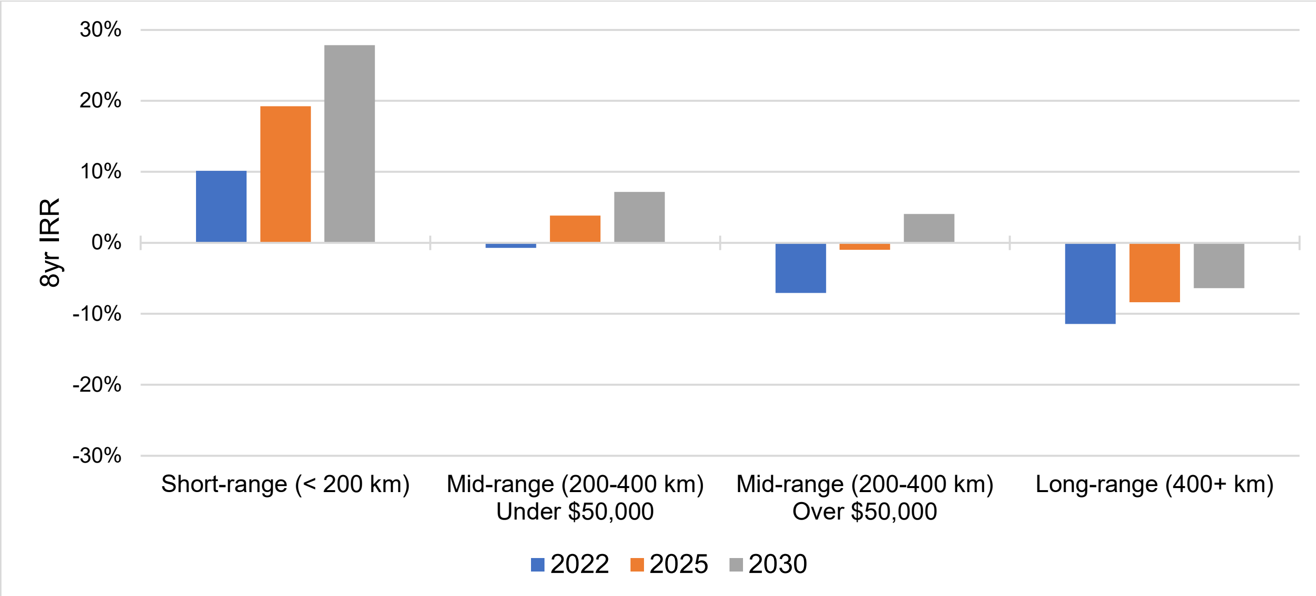


Comparison of ICVs versus BEVs

The rapid adoption of BEVs to meet federal targets, while making BEVs more affordable compared to ICVs, is challenged by factors such as governmental subsidies, gasoline prices, taxes, charger costs, electricity rates, type of vehicles, etc. The cost of vehicle ownership relies on the initial purchase price (minus applicable subsidies), fuel charges and maintenance costs. In comparing BEVs and ICVs, the high initial purchase expense is a barrier to adopting BEVs; however, the fuel cost differential is a primary benefit to BEV ownership. AESO's cost differential analysis between BEVs and ICVs includes four different LDV categories: short-range (<200 km), mid-range (200-400 km, under $50,000), mid-range (200-400 km, over $50,000) and long-range (400+ km). The analysis used different purchase years (i.e., 2022, 2025, 2030) to evaluate the viability of opting for BEVs over ICVs (see Figure 12).

In this analysis, the assumption is based on "typical" driver behavior, i.e., a daily driving profile of 55 km (20,000 km/year) and an eight-year financial lifecycle. An internal rate of return (IRR) comparison suggests that, over the eight-year financial lifecycle of the vehicles, the IRRs is more than 10 per cent in favour of switching to BEVs for short-range (<200 km) type vehicles. However, this is not the case for long-range-type vehicles, which has a negative IRR when switching to a BEV. For mid-range (200-400 km, both under $50,000 and over $50,000) vehicle types, the IRR shows an increase in 2030 compared to 2022, indicating the advantages of selecting BEVs are more pronounced in the 2030s.

Figure 12: IRR Comparison Between BEVs and ICVs for Four Vehicle Categories



Sensitivity analysis performed on the IRRs, considered two key variables: the purchase cost of vehicles and gasoline prices (pre-taxes) (see Figures 13 and 14). The initial purchase cost is affected by several factors, such as supply costs, inflation and government subsidies. Gasoline prices can vary significantly depending on factors such as governmental policies and regulations, as well as demand/supply in the market.

AESO's sensitivity analysis results indicate BEVs comparative economics rely highly on initial purchase costs and gas prices. Lower priced short-range BEVs have high IRRs (i.e., more than 10 per cent) and are most likely to see the switch from ICVs, particularly after 2025. On the other hand, higher-priced long-range vehicles BEVs remain uneconomic across different sensitivities (IRR below zero per cent) and, therefore, adoption depends on niche preference. Mid-range vehicle economics significantly depend on initial cost and gas price outlooks which are subject to considerable uncertainties. Adoption of this category will be higher for vehicles under $50,000, especially under favorable scenarios of lower purchase costs (or availability of more subsidies) and higher gas prices and from 2030 onwards.

Based on this analysis, Alberta is expected to have moderate (not aggressive) BEV adoption of LDVs unless cost parity with ICVs improves. This will require more attractive purchase costs, increases in public subsidies and/or sustained higher gasoline prices. Therefore, the Reference Case target in the LTO 2024 is lower compared to the Net Zero model to reflect this economic reality. In the High Electrification scenario, the assumptions are more in line with favourable cost parity conditions and therefore higher adoption levels. It is important to note factors beyond those evaluated by the AESO, such as supply chain challenges, available EV charging infrastructure – on the road and residential –, increased cost of electricity, etc., add uncertainty around the future of EV adoption and its economics.

Figure 13: IRR Sensitivity Analysis Based on Vehicle Purchase Cost

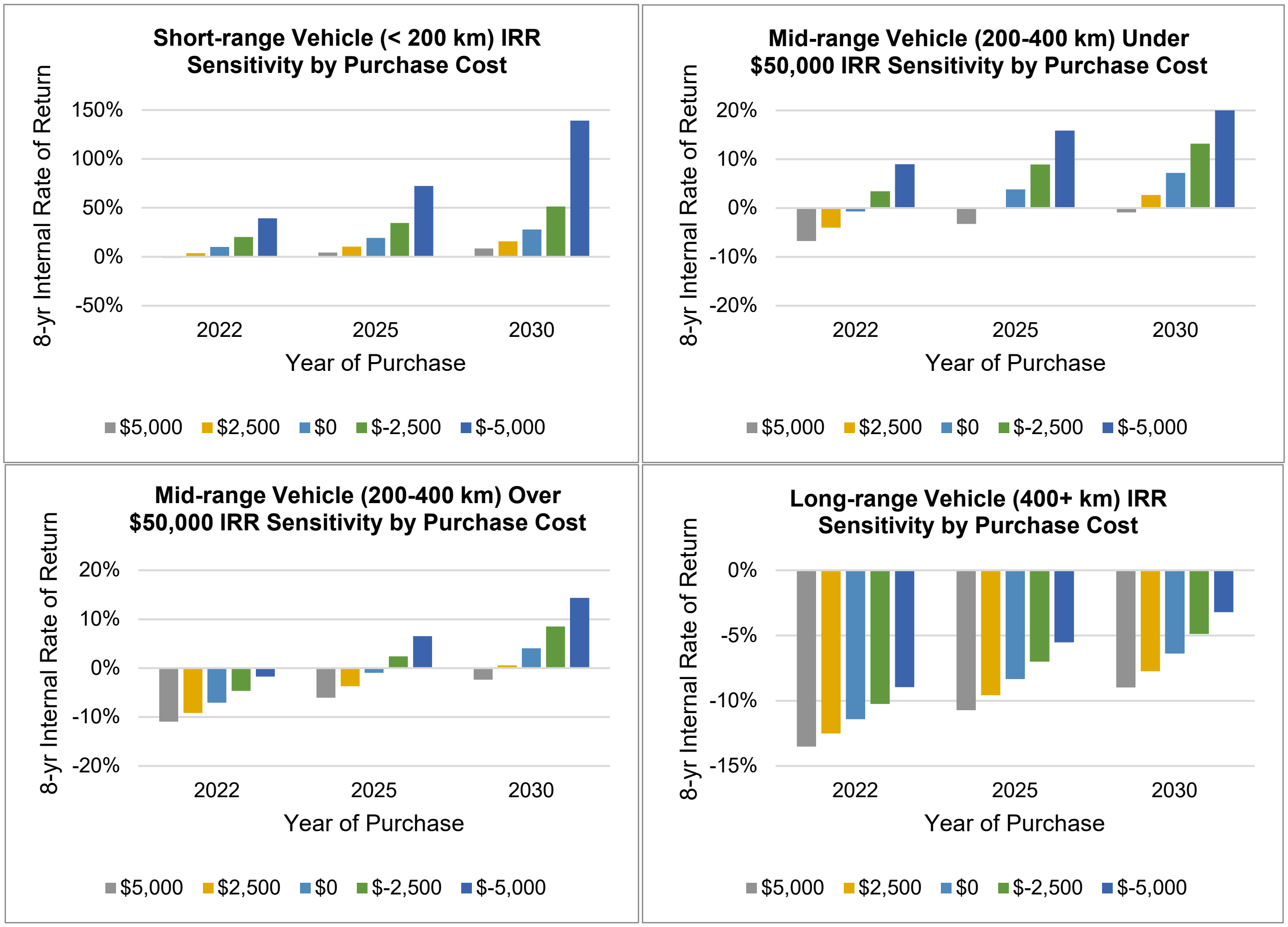
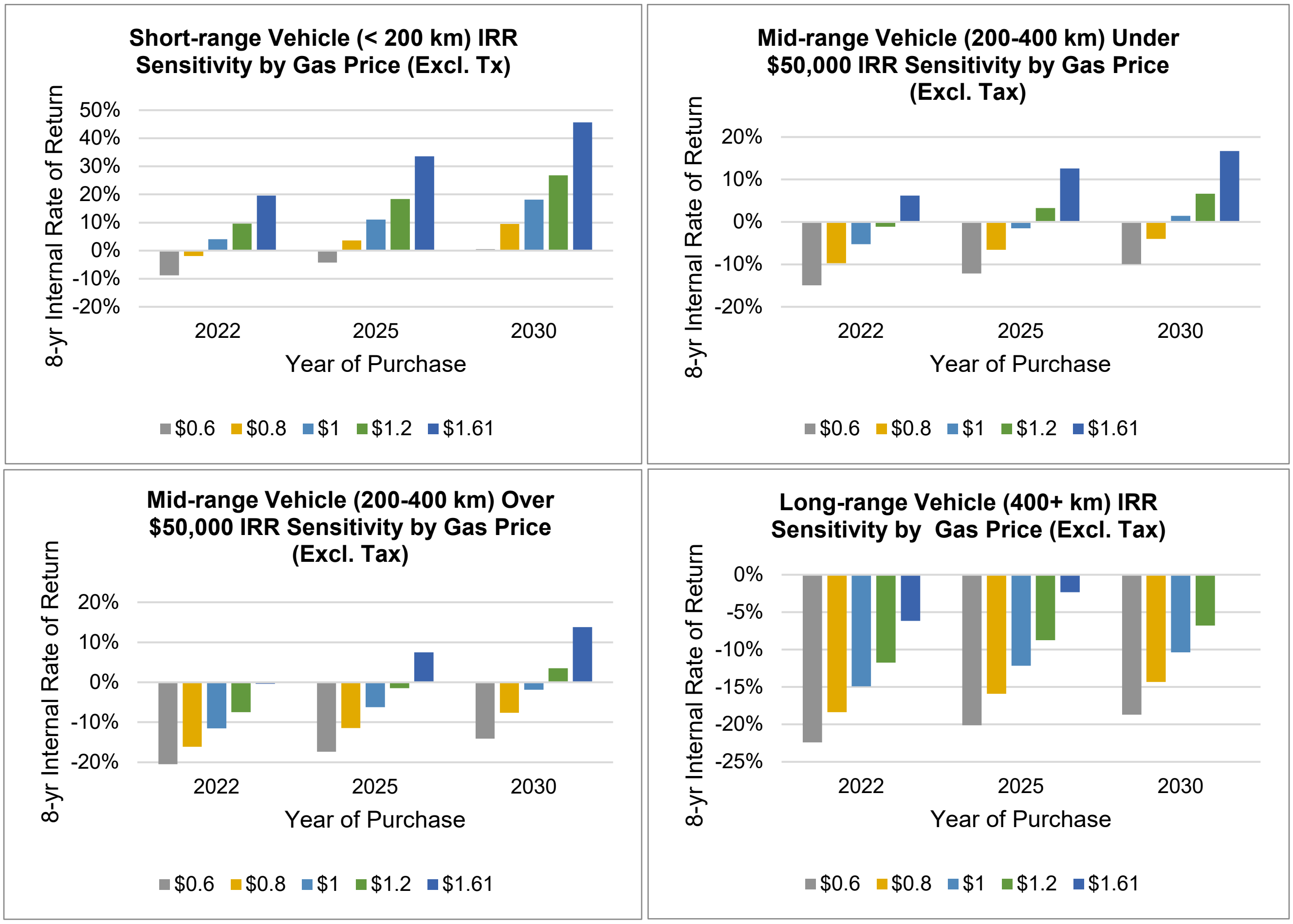


Figure 14: IRR Sensitivity Analysis Based on Gas Prices (Pre-Taxes)



In conclusion, the forecast of EV numbers and loads relies on various assumptions designed for different vehicle types, including LDVs, MDVs, HDVs and buses. Two distinct scenarios have been designed: the Reference Case and the High Electrification scenarios. The Reference Case reflects a moderate growth in EV adoption, influenced by the absence of policies and subsidies in Alberta. The High Electrification scenario integrates ambitious sales targets aligned with the ERP target. The objective of this scenario is irrespective of ZEV availability, cost parity with non-ZEV alternatives, system reliability, incentives for zero-emission commercial and institutional fleets, etc. Both scenarios incorporate managed charging profiles for LDVs and MDVs to mitigate the increase in load in the long term as the number of EVs increases significantly, requiring coordination among utilities and DFOs.

Building Electrification

Canada's building sector is accountable for 18 per cent of Canada's greenhouse gas emissions (GHG), encompassing more than 16 million dwellings and about 480,000 commercial and public buildings. This percentage includes the electricity-related emissions caused by building electricity consumption. As more than 78 per cent of building emissions come from space and water heating systems,[22] the decarbonization of heating and cooling is a significant factor for the federal government in reaching the 2030 ERP target of emission reduction and net zero in 2050.

The implementation of net-zero solutions for building cooling and heating electrification occurs at different paces among jurisdictions and can be challenging due to the lack of clear regulatory direction. These include lack of low-carbon oriented building codes for both new and retrofit buildings, limited government incentives/grants to enable fuel switching or enhance energy efficiency, etc.[23]

The AESO's electrification model assumptions are detailed in AESO Net-Zero Emission Pathways report,[24] which closely align with those in the 2024 LTO. While expanding upon the Net Zero report assumptions, the LTO 2024 building electrification strategy also integrates the modeling of cooling systems and daily consumption profiles. The AESO's daily consumption profile results from the heating and cooling of buildings derived from the National Renewable Energy Laboratory (NREL).[25]

Due to the significant impact of the residential sector on electrification models and research limitations, AESO's model assumes a daily profile related to the residential sector, specifically focusing on typical single-family detached homes. In alignment with the Alberta climate, the model considers the data associated with an area characterized by climate zone 7A (i.e., very cold). Also, heat pumps with heating and cooling functionalities as well as building envelopes are included in the model assumptions.

Figure 15 demonstrates space heating and cooling seasonal profiles. This figure shows heating peaks occur during the early morning and late evening, aligning with off-peak hours which have a lower energy demand. On the other hand, cooling demand synchronizes with on-peak demand. This observation underscores that the impact of heating systems is less pronounced than cooling on the overall peak.

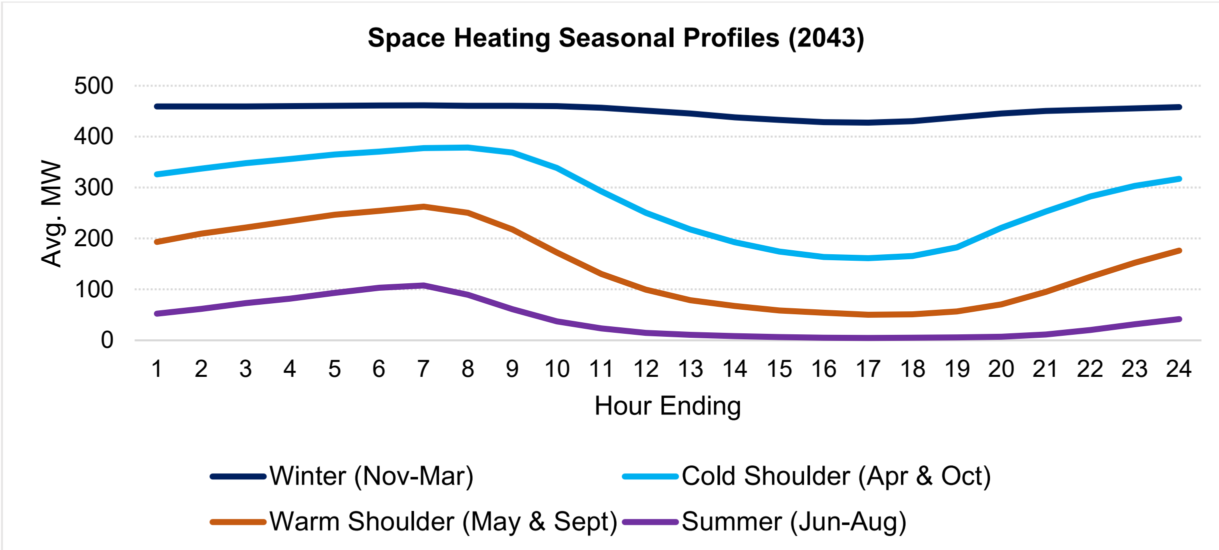
[22] See https://natural-resources.canada.ca/energy-efficiency/green-buildings/2 4572

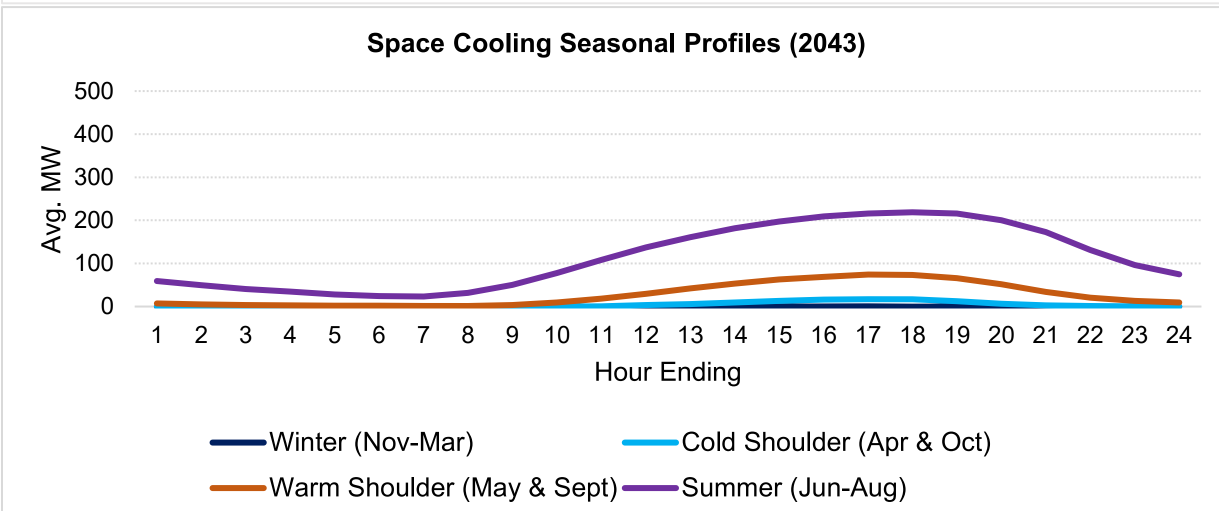
[23] For an analysis of regulatory and investment barriers to decarbonize buildings, see Pembina (2020), Achieving Canada's climate and housing goals through building retrofits, URL: https://www.pembina.org/reports/federal-buildings-recs-2020.pdf

[24] See Net Zero Report pg. 19 & 20.

[25] See https://resstock.nrel.gov/

Figure 15: Space Heating and Cooling Seasonal Profiles

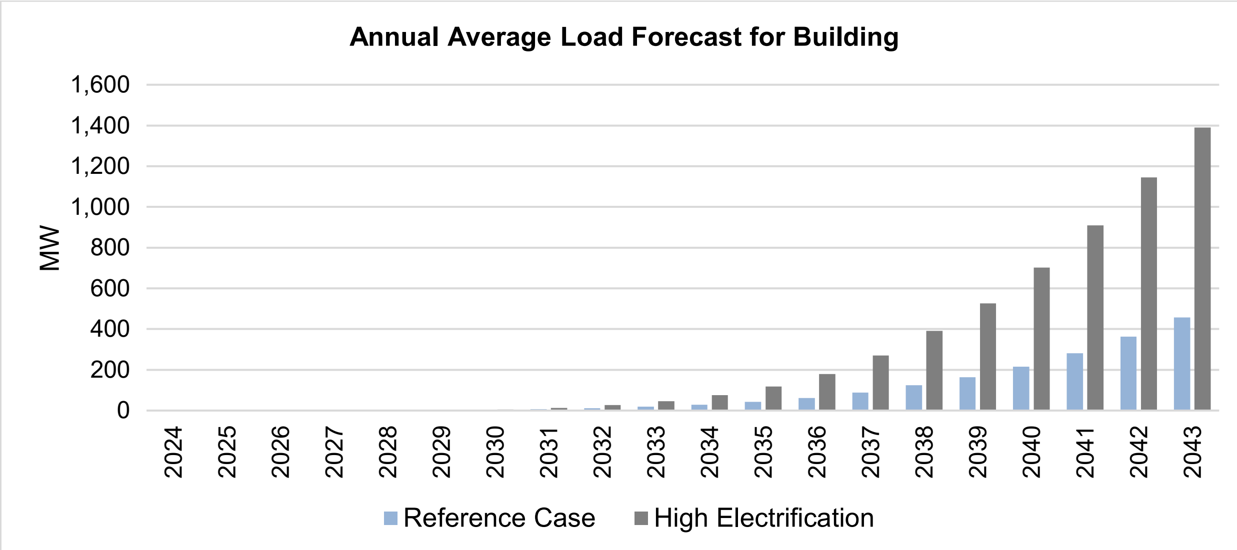




In the AESO's Reference Case for building electrification, the uptake starts in 2030, and heat pump installation is modelled on an adoption curve that assumes the first 10 per cent adoption level occurs in 2040 and continues increasing to 18 per cent by 2043. However, in the High Electrification scenario, heat pump penetration begins earlier, in 2028, and the first 10 per cent adoption level by 2035 enroute to 54 per cent by 2043.

In the Reference Case, the annual average demand for building heating/cooling rises from approximately zero MW in 2024 to 458 MW (roughly 3.6 per cent of AIL) by 2043. Likewise, under the High Electrification scenarios, the annual average load increases from zero MW in 2024 to 1,389 MW (approximately 9.5 per cent of AIL) by 2043. It is expected that the peak load rise from zero MW in 2024 to 833 MW (about five per cent of AIL) in 2043 in the Reference Case. Moreover, in the High Electrification scenario, this value is projected to surge from zero MW in 2024 to 2,401 MW (about 12 per cent of AIL) in 2043. Also, results show a higher peak and average loads of 1,568 MW and 931 MW in the High Electrification compared to the Reference Case, in 2043 (see Figures 16 and 17).

Figure 16: Annual Average Load and Peak Load Forecasts for Building in Reference Case and High Electrification Scenarios



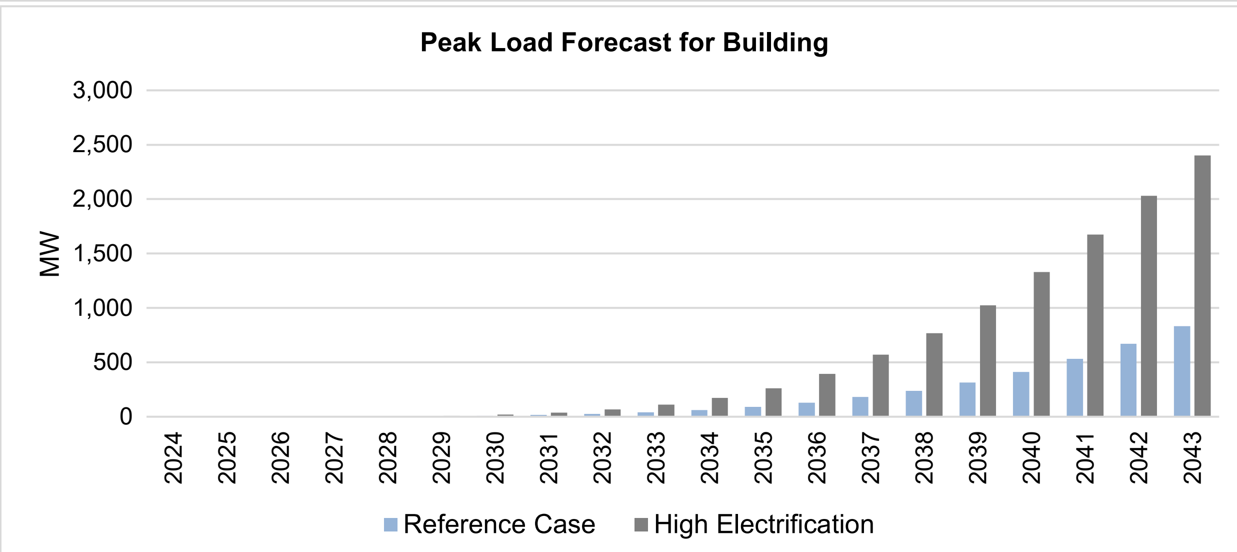
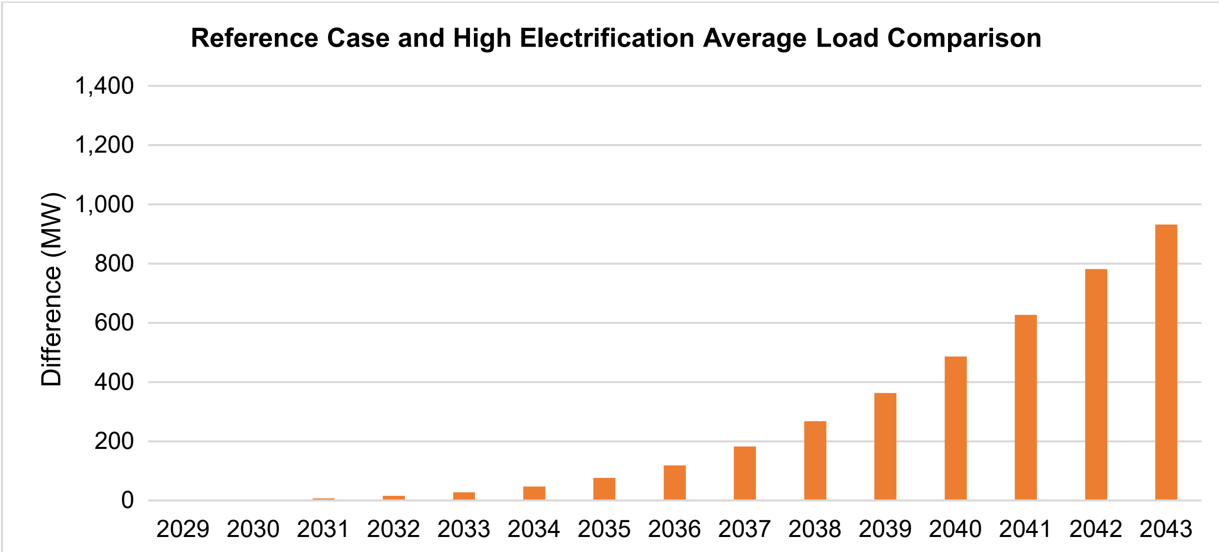
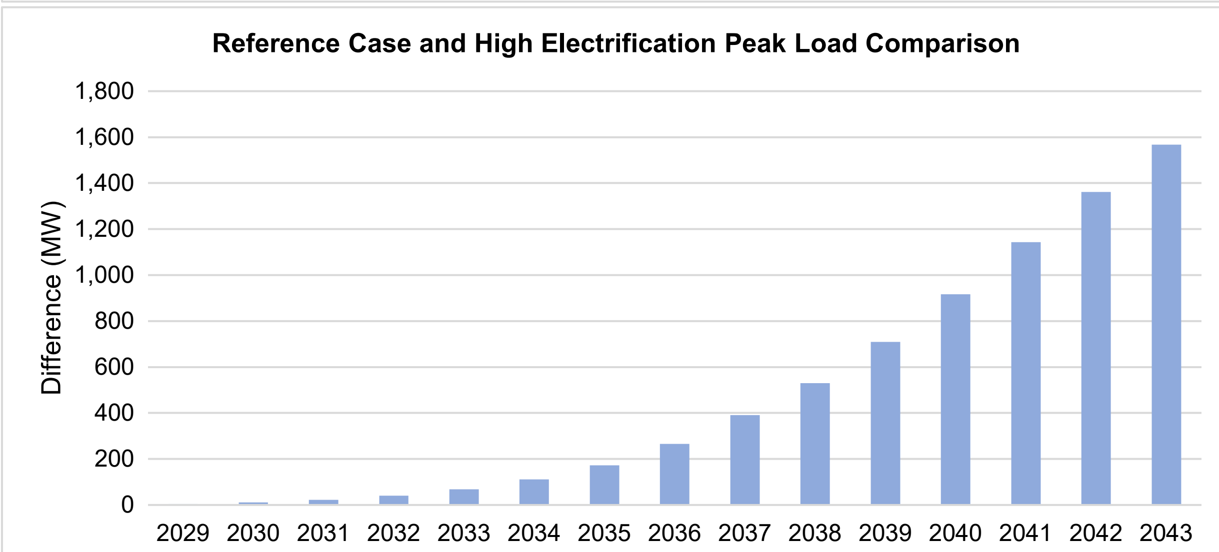


Figure 17: Comparison of Annual Average Load and Peak Load Between Reference Case and High Electrification Scenarios During the Forecasting Year





Hydrogen Production

In Alberta, large industrial facilities represent a significant portion of electricity consumption. To achieve decarbonization in these facilities, various approaches can be taken. Here, we will explore increasing the utilization of clean energy carriers like hydrogen, especially if their production can be accomplished through low-carbon methods such as carbon capture, utilization and storage (CCUS) or other advanced technologies.

Alberta's hydrogen roadmap calls for hydrogen integration in many sectors of energy, including transportation and industrial load.[26] Hydrogen can serve as a viable input fuel for combustion in various sectors dominated by large industrial emitters, including heavy oil upgrading, oil refining, chemical production and forestry operations. There is also an interest in integrating hydrogen fuel cells in the transportation sector, specifically for medium and long-haul duty vehicles. This subject is explored in more detail in the High Electrification scenario.

The AESO's industrial load model incorporates the energy demand impact of hydrogen production, electrification of heavy industries and CCUS adoption at cogeneration facilities. In this module, the specific focus is on assessing the incremental energy consumption related to hydrogen production. Assuming methane reforming technologies, such as steam methane reforming with CCUS (SMR+CCUS) and autothermal reforming (ATR) with CCUS (ATR+CCUS), being the economically preferred hydrogen production processes. Both named technologies consume natural gas, water and electricity as part of their processes.[27]

To estimate additional hydrogen production in industrial facilities, the AESO looks at Alberta's near-term major hydrogen projects (included in AESO's project list[28]) through 2030. Further production post-2030 is estimated based on observed trends in project announcements, construction timelines and existing infrastructure.

The High Electrification scenario integrates hydrogen use in the transportation and industrial sectors. Given Alberta's growing focus on hydrogen production and the potential advantages of adopting fuel cells and electric battery cells for medium to large-sized vehicles, decarbonization of Alberta's transportation sector is projected to generate demand for hydrogen fuel.

Hydrogen utilization in the transportation sector in this scenario is integrated with the existing hydrogen production for industrial applications. This additional production is calculated using the allocated number of sales of hydrogen fuel cells for each vehicle type which is described in more detail in the EV methodology portion of this section.

Figure 18 below shows that cumulative hydrogen production in Alberta is expected to reach 2.2 million-metric tonnes (MT) by 2043 in the Reference Case and reaches 2.3 million MT by 2043 in the High Electrification scenario.

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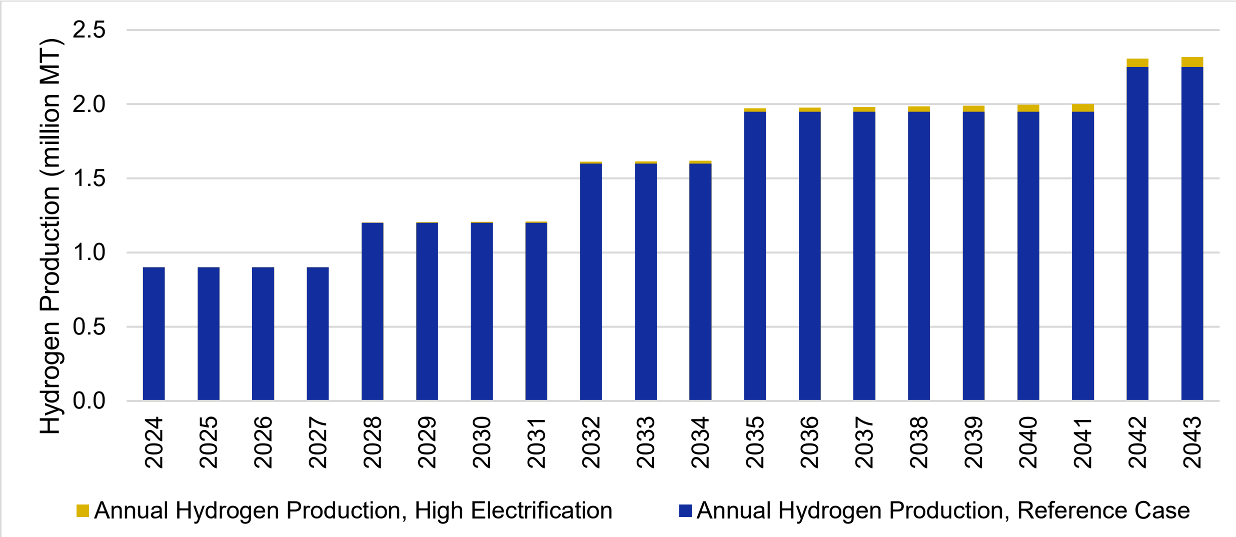
[26] Alberta Hydrogen roadmap

[27] For more information regarding hydrogen production processes see the Technical Drivers section.

[28] AESO's most recent connection project list can be found here.

Figure 18: Cumulative Hydrogen Production Outlook



The unit energy consumption for hydrogen production at industrial sites will depend on the type of technology used and the share of each utilized in producing hydrogen with CCUS. ATR is expected to be the dominant technology to produce hydrogen, considering the types of technology of announced projects by 2030, and it is an economically preferrable technology as it requires slightly less natural gas and water inputs than SMR units. Facilities that use ATR plus CCUS technology to produce hydrogen are assumed to consume four kWh per one kilogram (kg) of hydrogen produced, whereas SMR plus CCUS units are expected to consume two kWh per one kg of hydrogen produced.[29] This energy can either be used from the grid or be generated on site to take advantage of cogeneration opportunities in the production process.[30] Additionally, we consider various energy losses occurring within the hydrogen production process, fuel cell conversion and hydrogen compression and storage.

Figure 19 illustrates that additional average hourly load due to hydrogen production reaches approximately 553 MW by 2043 in the reference case and 579 MW in the High Electrification scenario. Increased hydrogen production to meet fuel demand for FCVs is the primary reason for higher load in the High Electrification scenario.[31]

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[29] Units of electricity use are based on National Renewable Energy Laboratory (NREL) [H2 production modelling assumptions].

[30] For more information on hydrogen production processes considered in the 2024 LTO see the [Technology Drivers section].

[31] For more information on hydrogen use assumptions for FCVs, refer to EV Methodology" Module (page 2) or pg. 5 of Khan M.A., MacKinnon C., Young C., and Layzell D. B. (2022) Techno-economics of a New Hydrogen Value Chain Supporting Heavy Duty Transport. Transition Accelerator Reports: Volume 4, Issue 5, Pg 1-52. ISSN 2562-6264.

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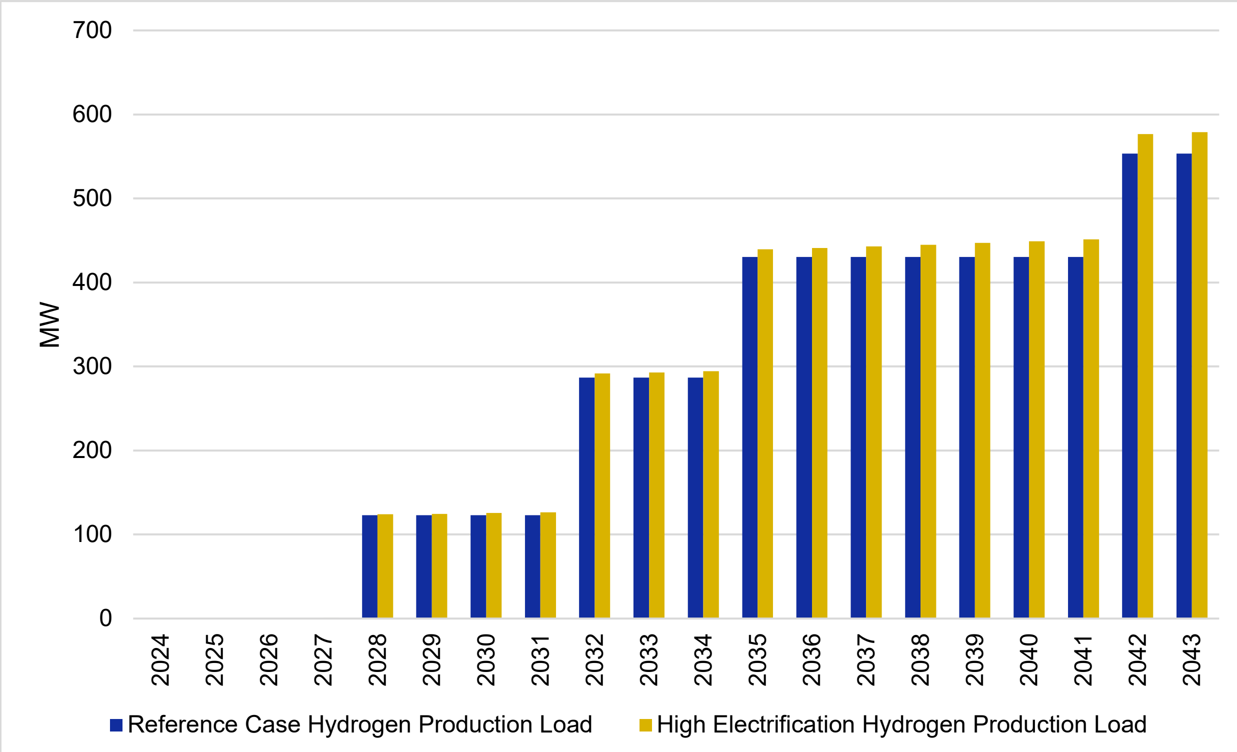
Figure 19: Annual Average Load from Incremental Hydrogen Production in Alberta



Heavy Industry Electrification Load

The 2023 LTO's High Electrification scenario addresses growth in load from heavy industry. This scenario assumes the ERP[32] targets are met.

CCUS technology plays a key role in decarbonization as it captures carbon dioxide from industrial processes or power plants and transports these emissions underground. Since CCUS requires electrical energy, load from adopting CCUS is accounted for in this forecast.[33] The industries contained in the forecast include chemical, cement, and pulp and paper industries as these are significant contributors in Alberta's economy and have potential for decarbonization through electrification and CCUS adoption. The auxiliary load from CCUS in cogeneration plants within the oil sands is factored into the generation forecast and therefore is separate from this module.

As outlined by the ERP, electricity's share in equipment stock in heavy industry is expected to increase by two per cent by 2030 for the chemical and pulp and paper industries, and one per cent by 2030 for the cement industry. After 2030, the model assumes that electrification of capital stock will continue at the same pace until 2040 and 2050.

The forecast draws from multiple sources to inform assumptions on the per cent of overall electricity demand used by equipment, the per cent of carbon dioxide emissions that will be abated by CCUS and the load required to capture these emissions across industries. To align with ERP electrification targets for

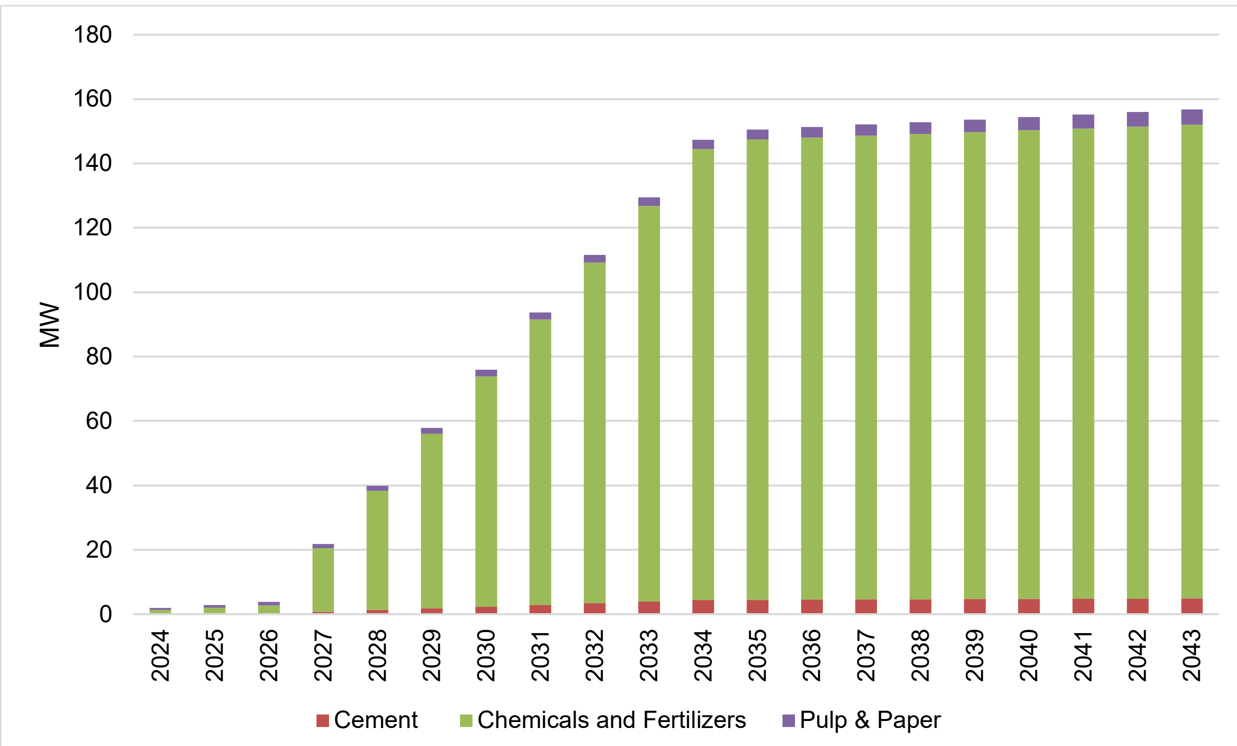
[32] For more information on Canada's Emissions Reduction plan, refer to En4-460-2022-eng.pdf (publications.gc.ca).

[33] For more information on CCUS see the Technology Drivers Section.

capital stock, the percentage of electricity used in cement, chemical, and pulp and paper plants for industrial processes was isolated from electricity used for heating and cooling, lights and other purposes.[34] Moreover, the forecast aligns with the International Energy Agency's (IEA) assumptions on the percentage of emissions reductions that will come from CCUS for the industries addressed in this report.[35]

As these heavy industries electrify and gradually adopt emissions abatement technologies such as CCUS, they are expected to increase load by an hourly average of 157 MW by 2043, which is a relatively small portion of overall load. Figure 20 demonstrates that as CCUS technology advances in the late 2020s to mid-2030s, load increases significantly. Since the chemical and pulp and paper industries consume more electricity than the cement industry, implementing ERP electrification targets and adopting CCUS have a more pronounced effect on additional load.

Figure 20: Heavy Industry Load Forecast by Industry Type, High Electrification Scenario



[34] For more details on emissions captured by CCUS in each industry see: https://www.iea.org/reports/transforming-industry-through-ccus. For more details on percentage of load from manufacturing processes see https://www.eia.gov/consumption/manufacturing/data/2018/index.php?view=data#r5.

[35] Transforming Industry through CCUS – Analysis - IEA

Energy Efficiency

Overview

Energy efficiency refers to the adoption of measures by energy consumers to achieve the same tasks or outcomes while consuming less energy or achieving more tasks with same energy consumption. Assumptions regarding energy efficiency are consistent across the Reference Case and the High Electrification scenario.

Electrification serves as an incentive for energy efficiency through multiple avenues. Firstly, modern electric appliances are intentionally engineered to surpass the energy efficiency of older equivalents. Secondly, incorporation of technologies to improve energy efficiency in residential and commercial buildings, such as upgrading to proper installation, and improving ventilation and lighting can reduce electricity consumption overtime.

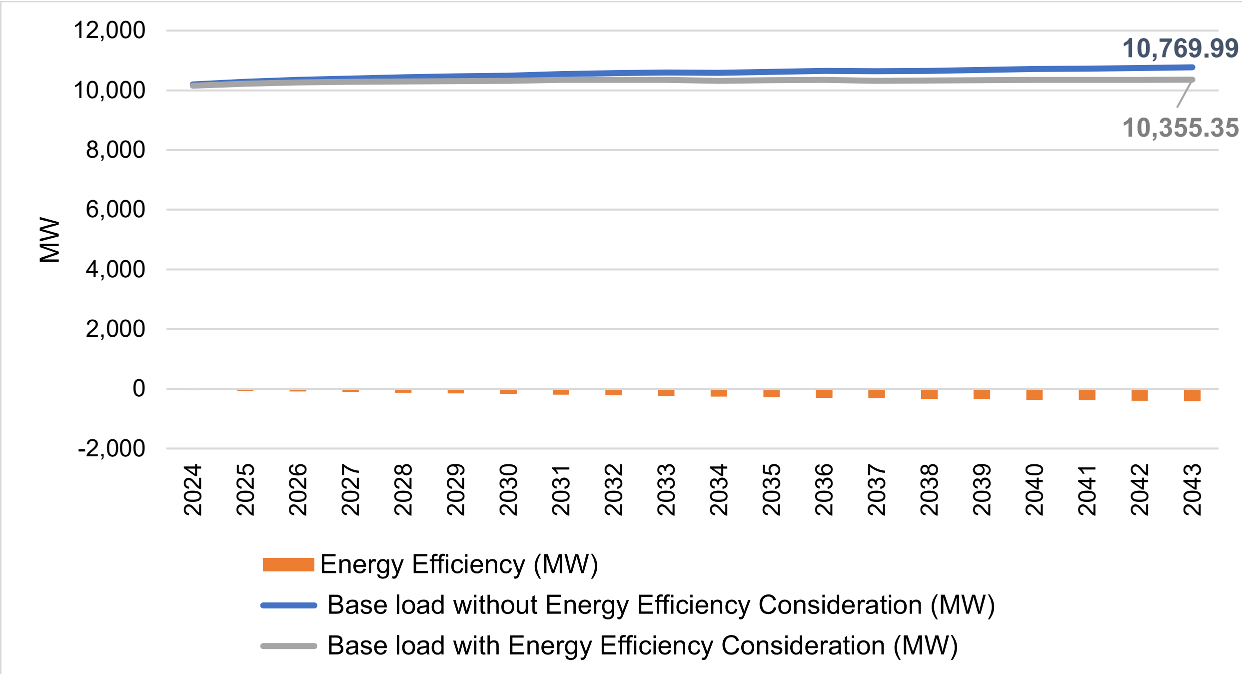
Since electrification efforts are now more pronounced than before, driven by decarbonization efforts, the AESO has introduced a new approach to estimating energy efficiency in 2024 LTO load forecast. This methodology is focused on cumulative avoided load in residential and commercial sectors. The reduced load is defined as a percentage of the baseload forecast[36] that would be avoided because of energy efficiency improvements. Note that baseload does not account for load modifiers such as EV charging, hydrogen, and building electrification load and DERs. While the percentage of load offset due to energy efficiency increases, baseload is rising in parallel. This causes a cumulative effect of load reduction due to energy efficiency overtime, which is evident in Figure 21 below.

This approach is based on the study of historical trends, which suggest that energy efficiency improvements in residential and commercial sectors are more pronounced than the industrial sector in Alberta. Electrification in the industrial sector can also lead to gains in energy efficiency. However, the assumption of energy efficiency in this sector is embedded in the modeling of industrial load and is not accounted for here to avoid double counting.

This approach suggests that due to energy efficiency improvements, the total baseload forecast will decrease by 0.4 per cent in 2024, up to 3.8 per cent in 2043. This can be translated into an hourly average baseload reduction of 42 MW in 2024 to 415 MW in 2043. Coincident to the annual peak hour, energy efficiency reduces load by 51 MW in 2024 to 440 MW in 2043.

[36] Baseload forecast refers to AIL net of load modifiers including, EV charging load, hydrogen production, heavy industry load and DER offset.

Figure 21: Baseload Average Hourly Forecast with and without Energy Efficiency



Distributed Energy Resources

DER, especially solar, are becoming increasingly important in meeting Albertans' electricity needs. As explained in the AESO's DER Roadmap, this type of technology includes any distribution-connected resources that can potentially supply energy onto the interconnected electric system and includes installation at sites with demand as well as independent generation developments connecting to the distribution system.[37]

The 2024 LTO forecast for DER is based on the five-MW threshold. DER less than five MW are forecast based on the historical trend and continue to offset load as the capacity rises. Assumptions about the DER energy profiles, and geographical allocation are consistent to the 2021 LTO.[38] The forecast methodology used to predict capacity for DER greater than or equal to five MW is described in the section on Generation Forecast Methodology.[39]

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[37] AESO's DER roadmap can be found here: DER-Roadmap-2020-FINAL.pdf (aeso.ca)

[38] More information about DER energy profiles and geographic allocation assumptions refer to page 13 and 14 of the 2021 Long Term Outlook: 2021-Long-term-Outlook.pdf (aeso.ca)

[39] For more information on solar generation methodology for assets above five MW see the Generation Forecast Methodology section.

DER Forecast Methodology:

The DER methodology predicts the total installed capacity of rooftop solar. Some key inputs in this model include population, number of dwellings by type across major urban centers and number of small and medium-sized businesses.[40] These inputs estimate the number of potential households that will install solar panels. The model uses number of dwellings data to estimate the proportion of the population that resides in different types of residences such as single-family homes, apartments, “other dwellings”, etc. The population forecast in combination with the ratio of population to type of dwelling provides an estimate of potential residential sites that could install DER solar. Estimating the potential residential sites creates an upper boundary of eligible homes and commercial buildings available to install solar panels.

The economic component of the DER solar model features inputs such as installation and operating costs, subsidies, inflation and avoided energy, transmission and distribution costs for each service territory among other variables. As each rooftop solar unit generates electricity, it offsets electricity costs that households must pay to use electricity from the distribution system. How much cost can be offset for the household determines its internal rate of return and payback period in which installing rooftop solar will pay for itself. Based on these economic factors, households will decide whether to install solar panels on the potential residential sites estimated above. The effect of these economic factors is evident in Figure 22 as the strong increase in rooftop solar adoption from 2024 to the early 2030s is driven by decreasing capital costs of solar.

Rooftop solar generation is estimated using the annual capacity of DER solar for a given year and combining this with a representative hourly solar generation profile (2011 winter months and 2003 summer months).[41] After estimating hourly DER solar generation in MW, this value is subtracted from the hourly load in the forecast. Finally, the geographic allocation of solar panels reflects financial considerations of different service territories, and population density of towns and cities in the province.

While not as prominent as DER solar growth, wind and gas DER see a gradual incline in installed capacity over the forecasting period. Considering the land required to build a wind turbine, adoption has historically been slow, and this trend is likely to continue. As such, the wind DER forecast projects the past trend of wind adoption into the future and assumes that these assets are built in the same planning areas as existing small wind generation. Wind generation is estimated using the same synchronized weather profile as DER solar generation. Like wind, gas DER also has limited adoption potential in residential households; however, in this outlook installed capacity of gas is assumed to grow consistently to past trends within industrial POD. Generation of DER gas units is based on historical metered generation.

Results

The DER outlook for the 2024 LTO is consistent across the Reference Case and High Electrification scenario as the latter scenario examines the extent of peak loads, therefore, offsetting elements such as DERs are not modified. The forecast results illustrate that solar DER remains dominant, as its adoption outpaces wind and gas as it does not face the same land restrictions as these resources. This is seen as the total installed capacity of solar DER has grown significantly as it increased by 69 MW from the end of 2022 to 234 MW in 2023. Furthermore, installed capacity of solar DER is anticipated to rise in the long term to reach 841 MW by 2043. In contrast, the installed capacity of wind and gas DER increases from 34 MW

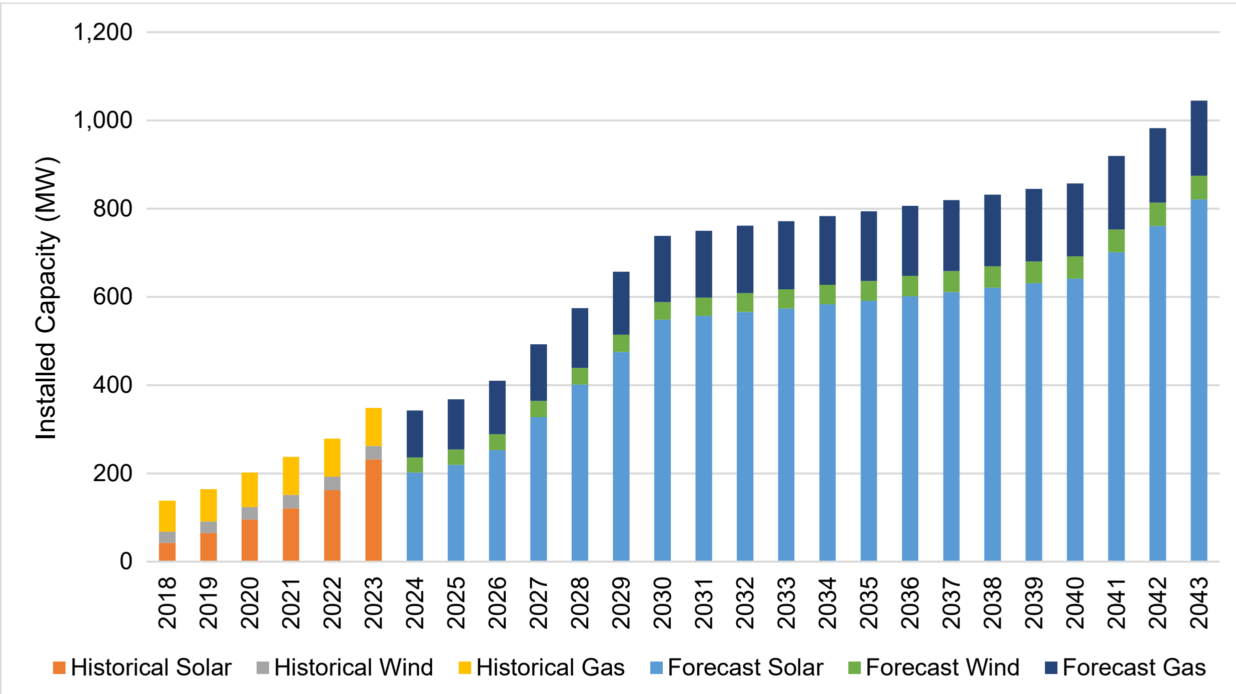
[40] Population data provided by CBOC. Number of Dwellings in major urban centers, including Calgary and Edmonton are based on the 2021 Census provided by Statistics Canada. The number of small and medium sized businesses is pulled from Statistics Canada, Canadian business counts.

[41] Winter months are January to April and November to December; summer months are May to October.

and 107 MW in 2024 to 54 MW and 170 MW in 2043 respectively.[42] The offsetting effect of DER solar generation on peak is not anticipated to change significantly over time as annual peaks occur during the winter months when there is less sunlight.

Note that the historical growth of solar DER outpaced the 2024 LTO DER forecast partly due to lack of visibility on data of additional capacity of microgeneration in historical data in 2022 and 2023. Due to this, higher capacity of solar DER was reported after finalizing the DER installed capacity forecast.

Figure 22: Installed Capacity of DER Resources



[42] Inputs of the Solar DER model is reflective of early 2023 historical Solar DER installed capacity. Note that in 2023, stronger than average growth has been experienced in solar DER adoption such that actual DER in the beginning of this year is higher than forecasted DER in 2024.

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