The Economics of Electrification in Nova Scotia

Evaluating the benefits and costs of building and transportation electrification in Nova Scotia and the implications for utility planning and program design

Developed for Nova Scotia Power

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Energy+Environmental Economics

Authors & Acknowledgements

Project Team

Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the clean energy transition. E3's analysis is utilized by the utilities, regulators, developers, and advocates that are writing the script for the emerging clean energy transition in leading-edge jurisdictions such as California, New York, Hawaii and elsewhere. E3 has offices in San Francisco, Boston, New York, and Calgary.

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Acknowledgements

This report was sponsored by Nova Scotia Power, who provided input and certain assumptions for the analysis. The specific assumptions provided by the utility, including certain cost data, are noted within the report body. Modeling and analysis for this study was conducted in 2021-2022. As such, inputs and assumptions reflect the best available data provided by public sources and the utility at that time.

The report conclusions are our own.

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Acronym Definitions

Acronym	Definition
AMI	Advanced metering infrastructure
ASHP	Air source heat pump
BCA	Benefit-cost analysis
BEV	Battery electric vehicle
ccASHP	Cold-climate air source heat pump
CO2	Carbon dioxide
DCFC	Direct current fast charging
E1	EfficiencyOne
E3	Energy & Environmental Economics, Inc.
ER	Electric resistance
EV	Electric vehicle
GHG	Greenhouse gas
ICE	Internal combustion engine
IPCC	Intergovernmental Panel on Climate Change
L2	Level 2
LEV	Low-emissions vehicle
LDV	Light-duty vehicle
MD/HD	Medium- and heavy-duty vehicles
MW	Megawatts
NPV	Net present value
O&M	Operations and maintenance
PCT	Participant Cost Test
RIM	Ratepayer Impact Measure
RNG	Renewable natural gas
SCT	Societal Cost Test
TOU	Time-of-use
U.S.	United States
V1G	Managed or smart charging
V2B	Vehicle-to-building
V2G	Vehicle-to-grid
VGI	Vehicle-Grid Integration
ZEV	Zero-emission vehicle

Executive Summary

Nova Scotia has established a formal goal to transition to net zero carbon emissions by midcentury[1], in alignment with Canada's federal target and targets set by other climate-leading nations. Achieving this goal requires rapid transformation of the way Nova Scotians produce and use energy in buildings, transportation, and industry. Coordinated near-term action across the economy will be essential to meeting Nova Scotia's goals at low cost, as shown in studies of Nova Scotia and across North America**.**

A common finding of economy-wide net zero carbon pathways studies is the need to accelerate **electrification of transportation and building end-uses** to reduce carbon emissions in those sectors[2]. In addition to reducing carbon emissions, electrification can reduce consumers' total energy bills and improve public health. Nevertheless, accelerating customer adoption of electrified technologies requires overcoming various hurdles, including high up-front costs and the need for enabling infrastructure to drive adoption, as well as ensuring a reliable electric grid to support substantial load growth. Electrification can also have a significant impact on the need for new electricity infrastructure, requiring careful planning to minimize these impacts and ensure a seamless transition.

Nova Scotia Power engaged Energy and Environmental Economics, Inc ("E3") to assess questions related to its' approach to initiatives aimed at electrification. This study supports Nova Scotia Power with an assessment of key potential "beneficial electrification" measures. For purposes of this study, we follow the definition proposed by the Regulatory Assistance Project: *"to be considered beneficial, or in the public interest, electrification must meet one or more of the following conditions, without adversely affecting the other two:*

> *1. Saves consumers money over the long run;*
>
> *2. Enables better grid management; and*
>
> *3. Reduces negative environmental impacts"*[3]

Key study questions to inform Nova Scotia Power, policymakers, and stakeholders in developing electrification strategies and planning include:

- **Jurisdictional Scan:** What role is electrification playing in helping jurisdictions across North America make progress toward Net-Zero?
- **Economics:** What are the benefits and costs of adopting key electrified technologies—electric vehicles and heat pumps for this study—from the perspective of adopters, ratepayers, and the province?

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[1] Environmental Goals and Climate Change Reduction Act defines Net-Zero in Nova Scotia as "balancing greenhouse gas emissions with removals and other offsetting measures" (Bill No. 57, "Environmental Goals and Climate Change Reduction Act", 2021)

[2] See Nova Scotia Power's Phase 1 Pathways Report, available here: https://irp.nspower.ca/files/key-documents/scenarios/20200225-revised-E3_NSPI_Pathways_Study.pdf

[3] Beneficial Electrification: Ensuring Electrification in the Public Interest. https://www.raponline.org/wp-content/uploads/2018/06/6-19-2018-RAP-BE-Principles2.pdf

+ **Utility Planning & Program Recommendations:** What are the aggregate impacts of electrification on Nova Scotia Power's electricity sales and peak demands over time, and how should the utility proactively plan for these to minimize the cost of serving new electrification loads? What program design elements should Nova Scotia Power, or partners, put in place to encourage and enable beneficial electrification in the near term?

Analysis Highlights

+ Electric vehicles reduce carbon emissions, save customers money, and produce average ratepayer savings. However, higher up-front costs, insufficient infrastructure, range anxiety, and other factors are challenges to adoption and realizing benefits at scale.
+ Time-of-use rates and vehicle-grid integration (V1G and V2G) offer opportunities to reduce customer costs, integrate load flexibly, and manage peak impacts.

+ Adoption of cold-climate heat pumps by fossil and electric resistance residential customers reduce carbon emissions and provide significant provincial benefits. The consumer economics currently are favorable for many residential customers, though outcomes depend on current fuel prices and electricity rates, existing heating system, heat pump sizing and performance, and rebates.
+ Winter peak impacts on the electricity system from cold-climate heat pumps can be mitigated by encouraging hybrid (mini-split) systems and best-in-class performing heat pumps.

Study Context

To align with Nova Scotia's Environmental Goals and Climate Change Reduction Act, which sets greenhouse gas (GHG) emissions reduction targets of 53% below 2005 emissions by 2030 and net-zero by 2050, Nova Scotia Power is proactively planning for a future that requires a significant energy supply transformation and potentially equally large-scale shifts in energy demands. In 2019, E3 worked with Nova Scotia Power to develop a deep decarbonization pathways analysis that included an array of economy-wide decarbonization scenarios highlighting the central role of the power sector in all deeply decarbonized futures. In 2020, Nova Scotia Power filed its 2020 Integrated Resource Plan, which included electrification assumptions based on the Pathways Study scenarios. Given the significant planning implications, the IRP identified electrification as a key action item for the utility to assess through a subsequent electrification strategy.

This report provides E3's assessment of key considerations for Nova Scotia Power as it supports provincial electrification and provides outputs from supporting analyses E3 developed on behalf of Nova Scotia Power.

Scope of Analysis in this Report

As noted above, this report provides results from two key analyses. To assess the cost-effectiveness of electrification[4], E3 analyzed the **marginal costs and benefits** of building and transportation electrification from three key perspectives:

- **Participant Cost Test (PCT):** What are the total benefits of adopting an electrified technology relative to the costs over the technology lifetime, from the perspective of adopters (electric vehicle or building owners)?
- **Ratepayer Impact Measure (RIM):** What are the costs and benefits to all non-participating ratepayers – will average utility rates increase or decrease from marginal adoption?
- **Societal Cost Test (SCT)** from the perspective of Nova Scotia: What are the costs and benefits, inclusive of non-monetized externalities, of adopting the electrified technology to the province as a whole?

Marginal cost-benefit analysis asks: What are the incremental benefits and costs of an additional electric vehicle or heat pump on Nova Scotia's Grid? This serves as a complement to IRP PLEXOS analysis of the total impacts of electrification loads on the grid.

The cost-benefit analysis is done on a *marginal* basis – reflecting the incremental costs and emissions associated with serving electric load from a new electric vehicle or heat pump by the marginal generator in each hour of a given year, based on the adoption year and expected usage patterns over the equipment lifetime. Marginal costs and emissions rates were provided by Nova Scotia Power from modeling scenarios of a mid-electrification trajectory. Marginal costs could change significantly over time depending upon the pace and scale of electrification, the changing mix of resources used to provide energy, notably increased renewable penetration, and demand side interventions to manage new load. Because Nova Scotia Power is greening its grid over time, sales-weighted averages of marginal emissions from electrification fall over time and for adoption in future years. The design of new or additional carbon policies will also influence marginal costs and emissions rates through their impact on the portfolio over time. In addition, energy prices will continue to affect the marginal costs of electrification as well as the costs of relying on the counterfactual fuels. In this study, because the electricity marginal costs reflect the 2020 IRP, they reflect energy market prices and projections at that time.[5]

Electrification *at scale* will also generate **system-level load and peak load impacts**. In parallel to the above, E3 developed a set of electrified load shapes under scenarios that reflect different customer technology choices, their performance characteristics and utility load management strategies. For these scenarios, unless otherwise noted, the results shown exclude the additional impacts of energy efficiency measures,

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[4] We note that this study is focused on building heat pumps and electric vehicles. Other energy-consuming sectors with potential for electrification (e.g., industrial sector) and other off-road transportation end uses were not included in this study.

[5] We note that given different data sources for different energy inputs (e.g., electricity from Nova Scotia Power, gasoline from Canadian Futures, and oil based on benchmarking to local sources and scaling using public forecasts), they may reflect somewhat different energy price conditions and future assumptions. Future energy prices are an important source of uncertainty in this study, and any differences across the different projections are an inherent limitation on this work. E3 worked with NSP to evaluate some price sensitivities as part of internal modeling, and this will be an important area for NSP's ongoing tracking as it monitors and supports electrification in this province.

for example those introduced through codes and standards or those developed by EfficiencyOne (E1). Studies by E3 and others across North America demonstrate that coupling electrification with investments in energy efficiency (e.g., building shells, weatherization) is critical to ensuring cost effective decarbonization. Analyses presented in the appendix demonstrate the potential benefits of illustrative building shell energy efficiency measures on building load and peak impacts.

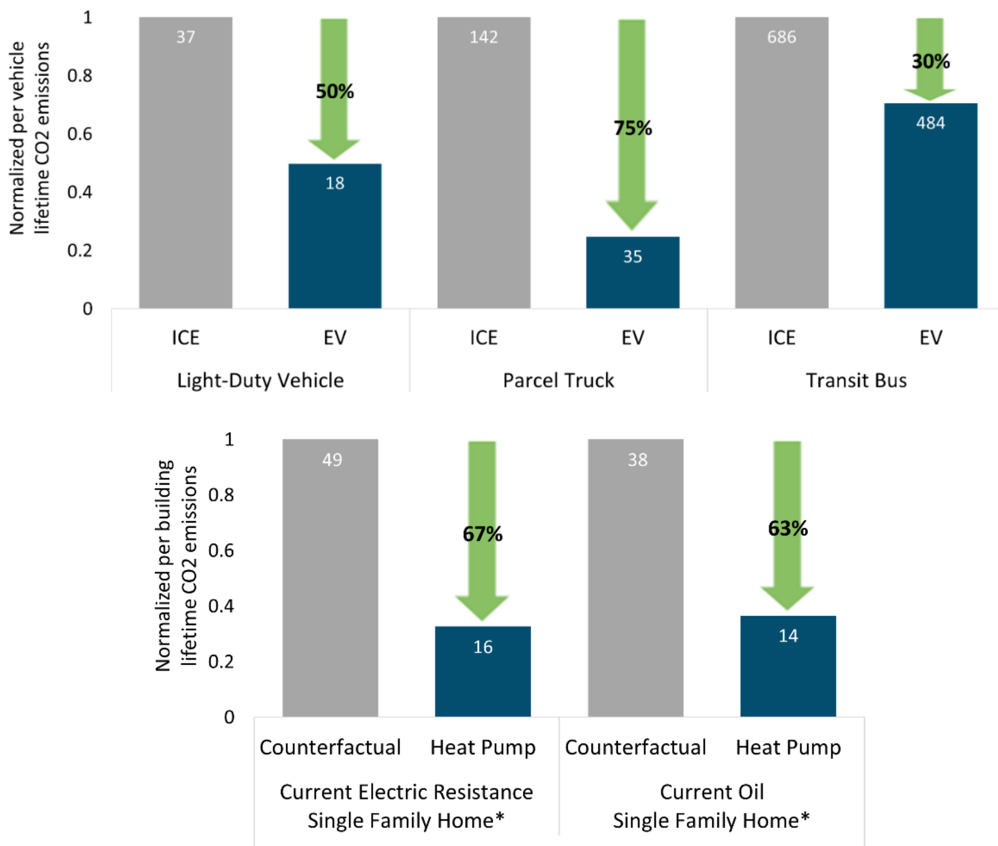
Key Analysis Findings

The analysis generated several findings related to electrification in Nova Scotia.

Key Finding 1: Building and transportation electrification reduces emissions in Nova Scotia.

In all transportation and building electrification scenarios evaluated, incremental CO_2 emissions from electricity generation to meet vehicle charging and building loads were lower than the offset emissions from fossil fuel end uses. For example, adoption of a light-duty vehicle today reduces emissions by almost 20 tons (about 50%) over the vehicle lifetime compared to an internal combustion vehicle. Results for several technologies evaluated are shown in Figure ES-1 below. Emissions benefits also increase with time, as the electric grid becomes greener through coal-fired generation phase out and investments in wind and clean imports.

Figure ES-1. Lifetime CO_2 emissions savings for electrified transportation and building investments by representative customers, adopted in 2022 (Lifetime CO_2 in tonnes shown in bar)

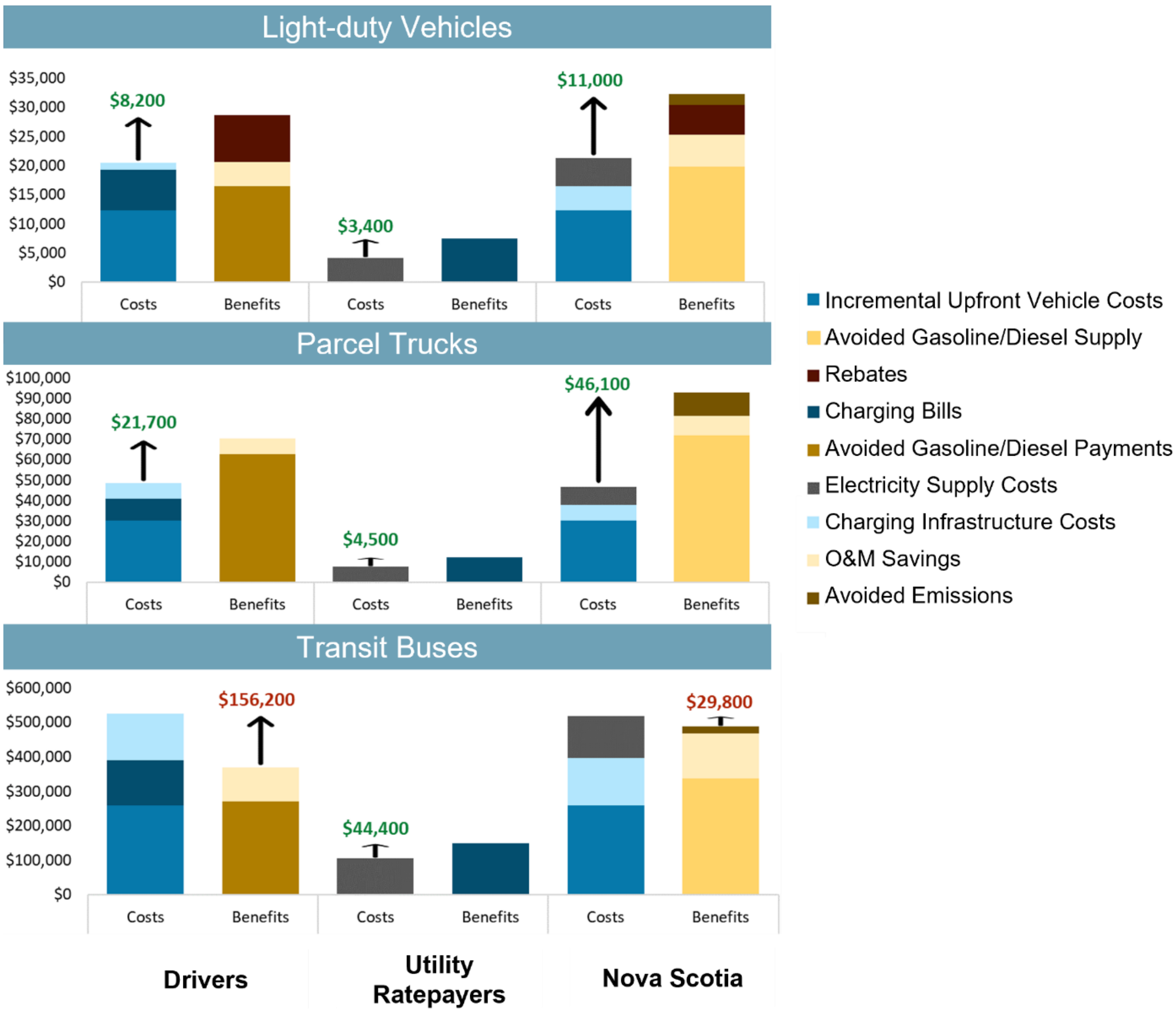


Notes: Normalized per vehicle/home CO2 emissions over the lifetime of the selected vehicle or building, with total emissions labeled within the bar in tonnes (metric). The emissions for ICE vehicle and fossil or electric resistance buildings are normalized to 1 and electrified transportation and buildings are scaled to their relative counterfactual. (*) Buildings graph assumes all-electric current heat pump performance (coefficient of performance of 2.7 at -8°C). The representative fuel oil customer modeled in the figure above has slightly lower emissions than their ER counterpart given the oil heat pump was a larger size (2 ton vs. 0.5 ton) and operating at a higher COP on average.

Key Finding 2. Most transportation electrification investments produce benefits that exceed costs from the perspective of drivers, utility ratepayers and Nova Scotia.

While electric vehicles have higher up-front costs today, drivers benefit from existing rebates, avoided gasoline purchases, and lower maintenance costs over time. Driver benefits are slightly greater when drivers adopt time-of-use rates and drivers respond to the rates by shifting their charging to off-peak periods. Likewise, utility ratepayers benefit as electricity sales exceed the cost of supplying electricity. From the provincial perspective, Nova Scotia benefits not only from the net cost savings and the influx of federal rebate dollars, but also from the societal value of avoided emissions, which grows over time. Similar dynamics underpin the analysis of adopting parcel trucks and transit buses in the province, as presented in the report body; light duty vehicles and parcel trucks generate net benefits today, and transit buses are expected to yield net benefits by mid-2020s. Finally, the economics of adopting electric vehicles are expected to improve with forecasted battery cost declines, enabling light-duty electric vehicles to achieve cost parity with combustion-based vehicles over time, though significant near-term supply chain uncertainties exist.

Figure ES-2. Net present value of costs and benefits of adopting light-duty vehicle in 2022, assuming managed charging with load management using vehicle-grid integration



Notes: The benefit estimates vary across scenarios based on rates, fuel costs, incentives, and marginal electricity costs. Results have been rounded to the nearest $100. The figure above assumes (not exhaustive): managed charging with VGI to smooth loads, TOU electric rates, base gasoline and diesel prices, and a 12-year vehicle lifetime. Light-duty vehicles receive a $3,000 provincial rebate and $5,000 federal rebate.

Key Finding 3. While building electrification yields net benefits for Nova Scotia, policy may be required to encourage adoption of dual-fuel and highest performing equipment that minimizes peak impacts and avoids adverse impacts to electric ratepayers.

The economics of building electrification from the customer perspective can be more uncertain than a similar transportation analysis, dependent on current and uncertain future fuel prices and electricity rates, building type and size, counterfactual heating system, and technology choice. This study evaluated a selected set of representative electric heat pump options— including “current” or “average” performance cold-climate air source heat pumps, “best-in-class” cold-climate air source heat pumps, and “hybrid” or dual-fuel mini-split air source heat pumps, which rely on retaining fuel back-up—from the perspective of representative current electric resistance, fuel oil, wood, and natural gas customers. Broadly, the economics for mini-split and current performance heat pumps are more favorable, with selected conversions generating net positive benefits today and many choices being strongly net positive for participants by 2030. Dual-fuel mini-split systems, in which an air source heat pump is paired with back-up fuel oil, offers particular advantages by reducing fossil usage through electrification of most load, while minimizing peak impacts and therefore electric infrastructure needs through switching to fossil back-up for the coldest hours. Given currently high fuel prices, the customer economics of best-in-class heat pump adoption also appear economic and can reduce peaks, given the operating cost savings from using a more efficient appliance. That said, current performance all-electric heat pumps adopted at scale would generate higher system peak impacts than best-in-class heat pump adoption. This trade-off requires careful consideration: the economics are highly uncertain and will be influenced by the marginal cost to serve large amounts of new load, as well as the rate of heat pump technology cost decline, the influence of high fuel prices on future electricity rates, rate design, oil prices, and other important variables. Finally, we note that although not within scope for this study, existing research suggests that electrification is likely to remain a cheaper option than decarbonized fuel for most homes. Similar, although not evaluated here, the economics of new construction are much better than retrofits, and these costs should be evaluated in future work.[6,7,8]

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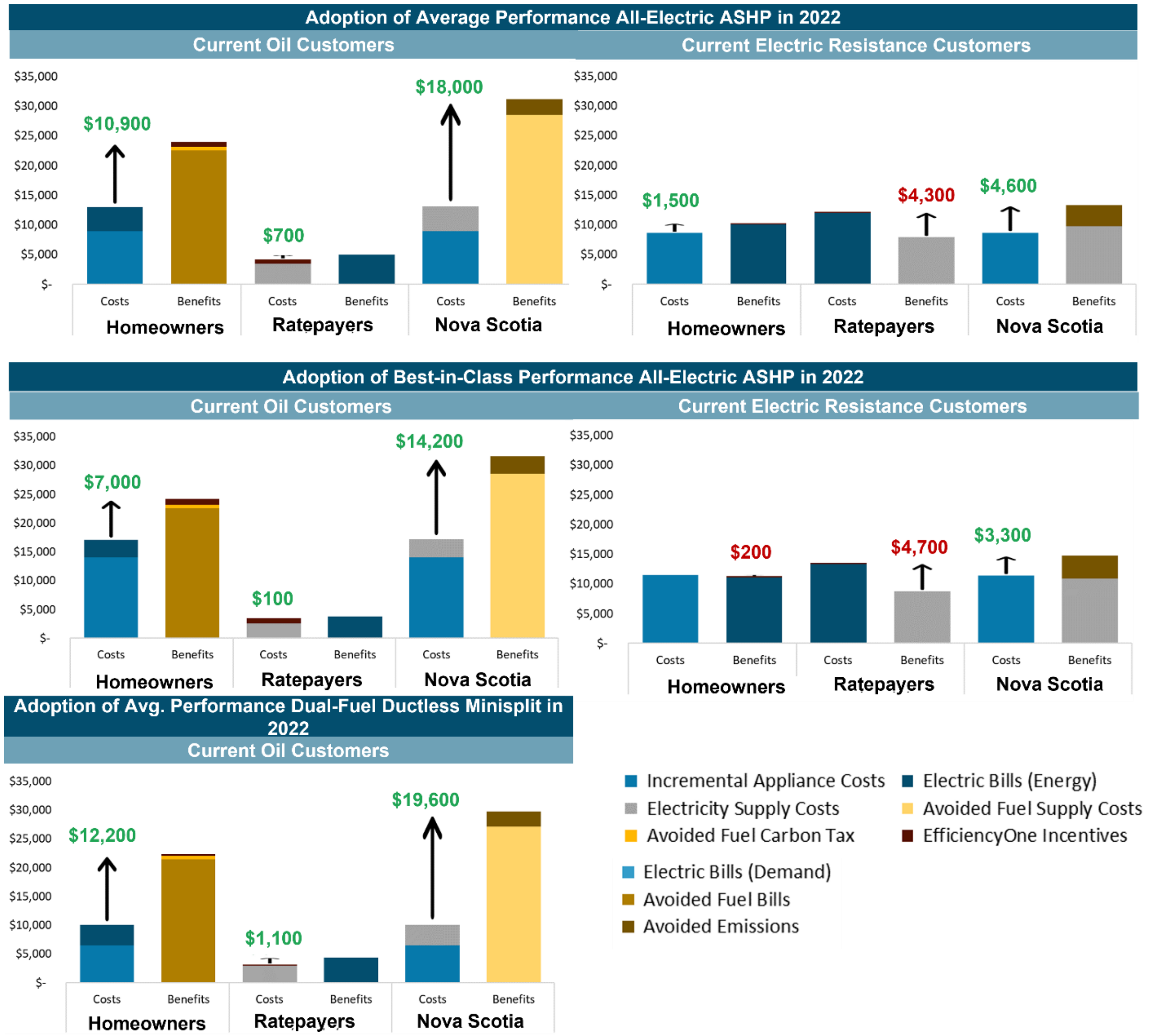
[6] Maryland Commission on Climate Change, “Building Energy transition Plan: a roadmap for decarbonizing the residential and commercial building sectors in Maryland,” November 2021, https://mde.maryland.gov/programs/air/ClimateChange/MCCC/Commission/Building%20Energy%20Transition%20Plan%20-%20MCCC%20approved.pdf (pg. 7)

[7] E3, “Financial Impact of Fuel Conversion on Consumer Owned Utilities and Customers in Washington, May 2022, https://www.commerce.wa.gov/wp-content/uploads/2022/06/Financial-Impact-of-Fuel-Conversion-on-Consumer-Owned-Utilities-and-Customers-in-Washington-Final-Report.pdf (pg. 3)

[8] Massachusetts D.P.U. 20-80, The Role of Gas Distribution Companies in Achieving the Commonwealth’s Climate Goals: Independent Consultant Report, Technical Analysis of Decarbonization Pathways, March 2022, https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Decarbonization%20Pathways.pdf

Figure ES-3. Net present value of adopting heat pump technologies for selected cases

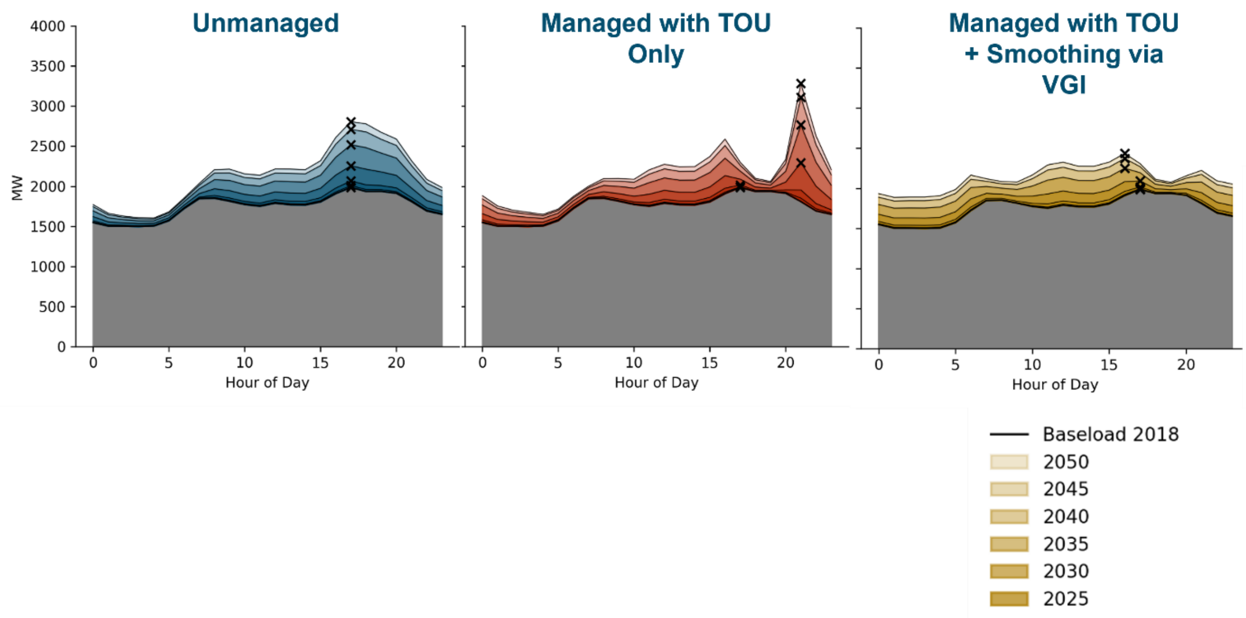


Notes: Results shown here are the costs and benefits for a single-family home on a flat rate. Adoption of heat pumps amongst current electric resistance customers presents a net ratepayer cost as the more efficient system reduces bills more than estimated electric supply costs. The incremental appliance cost of a heat pump compared to electric resistance counterfactual system is lower than utility bill savings. Switching to a heat pump from a fuel oil system creates net benefits for the homeowner. Mini-split customers are assumed to maintain their non-electric heating system for use during peak periods, leading to ratepayer savings in that scenario. Retail fuel oil prices in 2022 are assumed to be $5.56/therm ($2.03/L) and electricity rates are $0.1622/kWh. In 2022, the cost of a best-in-class heat pump installed in single family home currently using fuel oil is $16,000; the cost of an average performance heat pump is $10,869; and the cost of the dual-fuel mini-split is $6,500 (not including furnace replacement). See section 9.2 for detailed BCA assumptions.

Key Finding 4. Utility actions to manage transportation loads will be crucial to minimizing costs and achieving ratepayer benefits.

In the transportation sector, time of use rates and aggregating and smoothing loads to avoid "rebound peaks" will be valuable as adoption advances; unmanaged transportation electrification, assuming typical driver behavior under scenarios consistent with 100% EV sales by 2035, could generate over 1000 MW of evening peak load in Nova Scotia by 2050 (as shown in Figure ES-4 below). Simulations that incorporate driver responses to Nova Scotia Power's current time-of-use (TOU) rate shift load out of peak hours but create a strong rebound in charging demand when the off-peak period begins. A version of "smart" programs to complement TOU rates will likely be needed to avoid unintended consequences of "rebound" peaks at the beginning of off-peak hours. These programs can be enabled through technologies that provide vehicle-grid integration (VGI), which allows utilities to communicate with home technologies and coordinate charging load to when electricity supply costs are lowest.

Figure ES-4. Peak winter weekday loads from 2025-2050 with increasing light-duty vehicle loads



Note: VGI in the figure above reflects the assumption that the utility is managing and shifting charge to flatten overall load impacts.

Key Findings 5. Encouraging adoption of advanced building technology such as high performance all-electric heat pumps and dual-fuel heat pumps will be essential to mitigate peak load impacts. Equally important will be coupling new heat pumps with continued building shell and other energy efficiency measures.

Current performance heat pumps can generate incremental coincident peak impacts of over 1000 MW (non-coincident impacts can be even larger, at over 1100 MW by 2050). Building enough generation, transmission, and distribution capacity to serve this load could be costly. High performance heat pumps as modeled in the Best-in-Class scenario could reduce coincident peak impacts by almost 70 percent, significantly reducing the need for new firm generating capacity (see Figure ES-5 and Figure ES-6 below).

While the cost-benefit analysis estimates slightly lower ratepayer benefits from the adoption of best-in-class heat pumps, this finding is sensitive to estimates of the marginal electricity supply costs, inclusive of generation, transmission, and distribution. When electrification occurs at scale, the marginal cost to serve load from new heat pumps could trigger significant new investments in generation, transmission and distribution as heat pumps add new load to existing winter peaks when adopted in buildings currently using fossil fuels for heating; this in turn would reduce ratepayer benefits of current performance heat pumps, adding urgency to the need to incentivize best-in-class heat pumps and dual-fuel heat pumps to reduce the peak load impact. Increased wintertime peak loads are especially challenging on the Nova Scotia Power system, which in the future will need to in large part rely on peaking facilities fueled by either natural gas (with associated carbon costs) or a clean substitute such as green hydrogen to meet system peaks. (Note that net ratepayer impacts will depend on utility revenues, a function of rate design, from electrified load relative to the costs to serve that load.)

Figure ES-5. Noncoincident peak impacts of building electrification: 1-in-10 impacts increasingly important to consider as electrification is pursued at scale

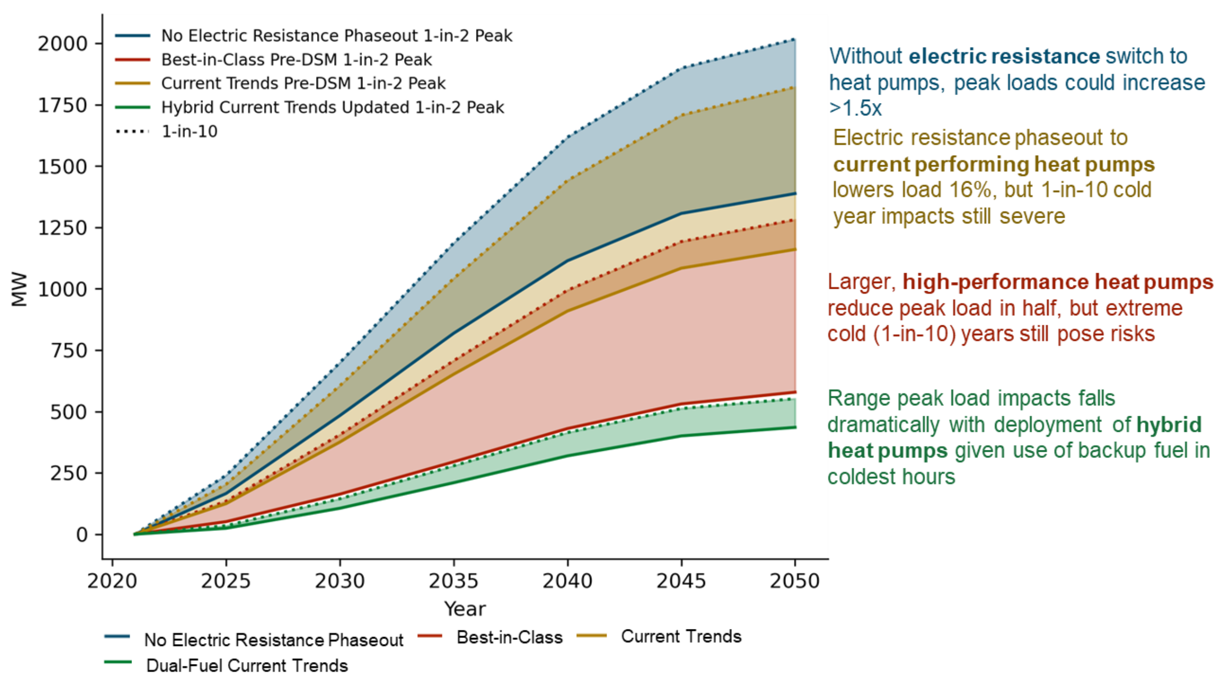


Figure ES-6. Components of non-coincident peak impacts from building electrification

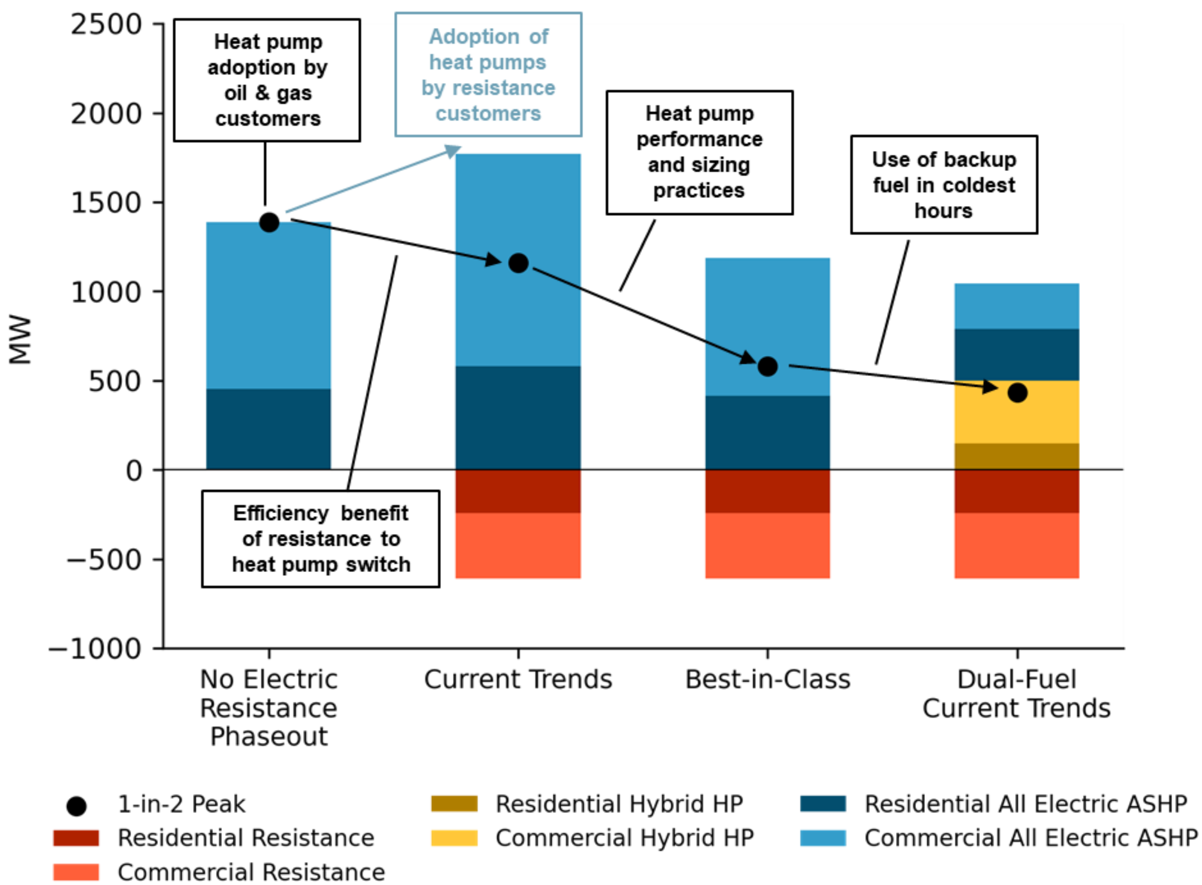
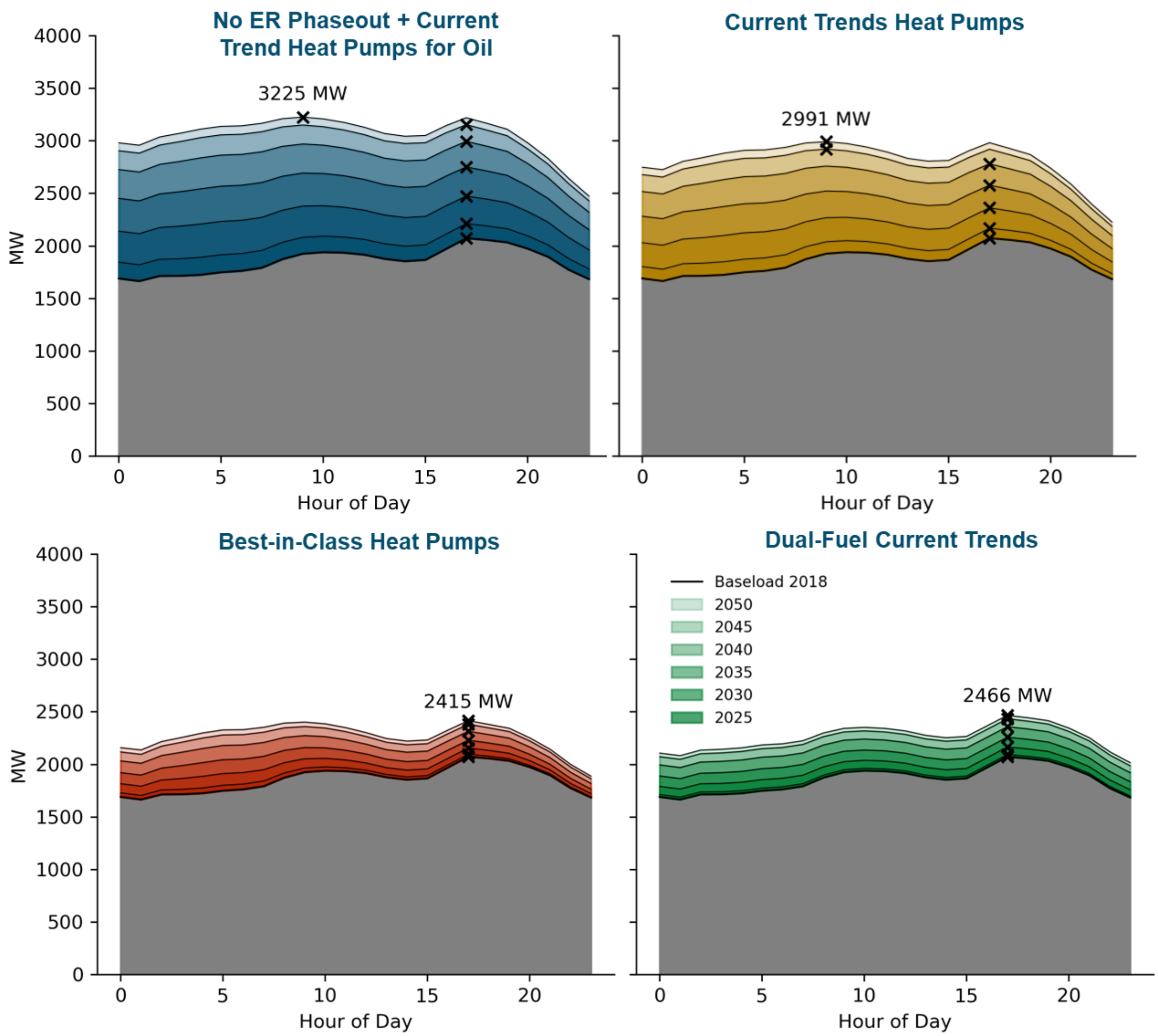


Figure ES-7. Peak winter weekday loads from 2025-2050 with increasing building heating loads (buildings plus system load peak impact)



Recommendations for Nova Scotia Power

Electrification has the potential to provide significant benefits to Nova Scotians by reducing total energy expenditures and lowering the province's overall emissions footprint. However, realizing the full benefits of electrification will require actions from a range of parties, with no one group, stakeholder, or the utility able to drive the transformation alone. In Nova Scotia, Nova Scotia Power plans, operates, maintains, and balances the majority of the grid assets needed to power widespread electrification and therefore is well positioned to proactively identify and support initiatives to advance electrification, particularly those to meet reliability, affordability, and equity goals. Nova Scotia Power should proactively collaborate with its partner, E1, to identify and prioritize investments with the greatest customer and societal benefits. Nova Scotia Power should also work with other partners and stakeholders, particularly E1, to execute on these recommendations. The recommendations below highlight key utility actions for Nova Scotia Power as it implements its electrification strategy. We note that these recommendations are derived both from the analysis as well as from the jurisdictional scan and E3's broader experience working on utility electrification across North America.

Short-term Actions, Customer Programs & Capital Investments

Recommendation 1. Design and promote increasingly dynamic rate structures that encourage adoption and minimize costs, including expanding current time-of-use rates to the full year and gradually moving to rates that reflect the marginal cost to serve load.

+ **Implement dynamic rate design[9]:** Transportation loads in particular are a flexible source of new load for utilities across North America. Better alignment of retail rates with the marginal costs to serve load lowers costs to ratepayers and provides EV adopters opportunities to shift their charging to lower cost hours (e.g., periods of renewable generation). More efficient rate structures reflect the costs of interconnection, capacity, and energy services by time of day, while appropriately compensating customers who can provide system services (e.g., energy, load flexibility) themselves. Rate designs that encourage shifting can reward users through lower rates during these lower cost times, improving the economics for adopters and helping avoid the need for costly infrastructure upgrades. While today, the most common utility rate design is a time-of-use rate, these do not realize the full benefits associated with home/vehicle to grid integration, and more dynamic price signals that vary with grid conditions will provide even stronger incentives for shifting load. The SDG&E Grid Integration Rate (GIR) piloted from 2018-2020 is a good example that included day-ahead hourly prices with adders for system and distribution peak hours. SDG&E reports indicate that the GIR rate was effective at shifting charging from peak hours in early evening to outside of the peak period.[10] Another example, though based on a much larger jurisdiction with a carbon-neutral target, is New York's Smart Home Demonstration Projects, designed to demonstrate how alternative rate structures with customer price signals can optimize value for the customer and the system. Customers were given home energy management technologies and signed onto a rate structure reflective of day-

[9] The conceptual ideal multi-part rate design includes: 1) a dynamic hourly energy rate that is low in most hours of the year when zero/low variable cost resources are abundant and on the margin; 2) a long-run marginal cost-based coincident demand charge or hourly allocation of long-run marginal capacity costs that encourage reducing and shifting load out of a relatively small number of hours driving new investments in generation, transmission, and distribution capacity; and 3) non-bypassable customer charges designed for equity that recover remaining embedded and unavoidable fixed costs.

[10] Despite the program's success, challenges included software customizations. It was also noted that because direct charging control was not included in the project, VGI could not be utilized to its fullest capacity for renewable integration and distribution system management. For more information see: https://www.sdge.com/sites/default/files/regulatory/SDG%26E%20FINAL%20Power%20Your%20Drive%20Research%20Report%20April%202021.pdf. Initial filing available here: Microsoft Word - Application Testimony Chapter 5 - Rate Design_CF_final.docx (sdge.com)

ahead hourly locational-based marginal prices.[11] While this type of pilot would likely require larger investments, it's useful to consider as an "aspirational" longer-term goal.

- In this instance, E3 does not believe that submetering or installing a second meter for EVs is necessary to support EV adoption in the near-term. These options have generally been costly, and have faced implementation challenges, including for submeters, challenges related to accuracy and the ability to do utility-grade metering for billing. This may change in future years as more VGI and particularly V2G opportunities are implemented. In the immediate future, E3 believes it's more important to focus on whole-home rate designs that reflect the costs of supply.

+ **Drive customer transition:** A transition to more dynamic rates requires significant customer outreach and education and should be implemented gradually to ensure customers can adjust their behavior and avoid abrupt bill changes. Pilot programs and opt-in rate designs allow customers to transition at their own pace and directly experience benefits over time. Nova Scotia Power is advancing opt-in Time Varying Pricing (TVP) and Critical Peak Pricing (CPP) pilots for this purpose, with an interim report currently filed with the Board[12]. This approach is aligned with E3's recommendation that Nova Scotia Power start with opt-in and transition to opt-out once benefits and successful customer outreach strategies are well established. California's transition to default, opt-out TOU rates has taken over five years and was hampered by early customer complaints and confusion. At the same time, customers with EVs and PV have generally been positive about opt-in TOU rates.[13]

- **Leverage advanced metering infrastructure (AMI) to manage loads for the benefit of all customers:** AMI, or smart meters, which measure and record electricity usage data at least hourly, are required for more dynamic rate designs and demand response programs. AMI enables widespread adoption of TOU rates, which are a good starting point for encouraging load to shift from on- to off-peak periods. However, TOU rates do not facilitate customer responsiveness to the specific hours with the highest or lowest costs and GHG emissions and can cause secondary peaks at the start of the off-peak period. As customers adopt more flexible DER such as energy storage, EVs and electric water and space heating, more dynamic rate and load management strategies will be needed to maximize their value for both Nova Scotia Power and the customer. Enabling more dynamic strategies for flexible electrification technologies will require work in several areas, including cost-effective communications, metering and interconnection requirements.

- **Vehicle Grid Integration (VGI):** An early use case will be VGI, which includes managed one-way charging (V1G) as well as two-way charging and discharging, including vehicle-

[11] NY Smart Home Rate Demonstration Projects - LPDD

[12] M09777: Time Varying Pricing Pilot Program Nova Scotia Power Interim Report, July 29, 2022

[13] This approach can also be taken a step further to drive electric adoption by offering electric rates specifically for all-electric customers who adopt heat pumps. At the same time, care must continue to be taken to ensure that rate designs do not generate cost shift.

to-grid (V2G) and vehicle-to-building (V2B) services. VGI services are broadly categorized as “passive” (e.g., responding to a TOU rate) and “active” (e.g., providing a verified response to a dispatch signal). Passive V1G services are feasible today and widely adopted with AMI. Active and V2G strategies require more enabling technology and policy changes, but also have potentially significant incremental value if those challenges can be addressed in the coming years. E3 recommends that Nova Scotia Power continue its roll out of TOU and CPP rates, and quickly scale existing investments in V1G with AMI, while finishing the Smart Grid NS pilot that includes V2G technology.

Recommendation 2. Work with E1 to provide rebates to help customers overcome high up-front costs of electrification, with the utility focused on technologies that provide ratepayer benefits.

+ **Spur electrification with ratepayer benefits:** Rebates can help customers overcome electrification first-costs. While the government should support adoption aimed at achieving the societal goals and benefits of electrification, the utility role should be distinctly focused on encouraging technologies with better RIM (ratepayer impact measure) test results. EVs and oil-to-heat pump conversions will yield net revenues to the utility and thus ratepayers, due to an increase in sales relative to the cost to serve new loads. These revenues can help fund incentives or rebate mechanisms that increase adoption and create benefits to Nova Scotia, while at the same time reducing upward pressure on electricity rates. As shown in the BCA analysis, electrification of certain buildings and transportation segments generate ratepayer benefits that are less than the incremental cost of electrification from the participant perspective. For certain customers, ratepayer funded rebates will be insufficient to incentivize electrification.[14] Thus, non-ratepayer sources of funding will be needed to support near-complete levels of electrification without negatively impacting non-participating ratepayers.
    - **Transportation rebates:** Despite net benefits for participants over the lifetime of the vehicle, electric vehicles of all classes are still expected to have incremental up-front costs until the early to mid-2030s, with a payback period estimated at three years for light-duty vehicles. Because electric ratepayers benefit from EV adoption through lower average electric rates, a portion of ratepayer benefits associated with electric vehicles could be used to support adoption through up-front vehicle or charging infrastructure incentives.
    - **Space heating rebates:** Payback periods for heat pumps can take several years. For existing oil customers, hybrid dual-fuel heat pumps (i.e. mini-splits) are typically already cost-effective, and encouraging adoption of dual-fuel heat pumps with new rebates could generate provincial benefits through avoided fuel and emissions. Without rebates,

[14] This is partially driven by the large magnitude of lifetime net costs. For example, transit buses adopted in 2022 face a lifetime net cost of over $156,000 as seen in Figure ES-3, which is greater than an amount that could be recovered without impacting non-participating customers. This is also driven by the financing structures that may be required to support low-income adoption of appliances or vehicles with high upfront costs; even if customers can achieve lifetime net savings, further reductions to upfront costs may be needed to increase accessibility of electrified devices to some customer types.

conversion to all-electric systems for current oil customers is slightly costlier today given the incremental up-front system cost, but societal benefits are achievable and ratepayer benefits could support all-electric heat pump incentives. For electric resistance homes, adoption of current performance all-electric heat pumps is cost effective today and generates significant societal benefits through avoided electric supply and emissions. Although not directly evaluated in this study, new construction is expected to have better economics than retrofits and should be prioritized in programs and policy.

- **High performance heat pumps**: While the highest performing ("best-in-class") heat pumps are more costly to customers and therefore provide somewhat lower societal benefits even with technology cost declines, the benefits associated with avoiding electrification peak impacts are expected to grow as electrification is pursued at scale. In other words, while the costs of meeting incremental loads with new capacity may be reasonable on the margin, meeting this new peak growth over time and in aggregate may require more expensive capacity (e.g., hydrogen-ready combustion turbines, significant penetrations of grid-scale batteries) and distribution system upgrades (e.g., transformer replacements, line reconductoring, voltage upgrades, etc.). Thus, increasingly incentivizing these systems is likely to be valuable (particularly for electric resistance customers where fuel back-up is not an option).

- **Water heating:** Like space heating, converting customers to heat pump water heaters generates significant societal benefits, including reductions in emissions and lowering total energy bills; however, for electric resistance customer conversions, which do not result in lower electric rates for non-participants, public funds should be used to pay for rebates for electric heat pump water heaters.

Recommendation 3. Support development of infrastructure "backbone" for electric vehicle charging to improve geographic coverage and fill gaps where third parties may have less incentive to invest.

+ **Create infrastructure backbone:** A robust electric vehicle charging network will be required to address range anxiety and support adoption of electric vehicles. Electric utilities like Nova Scotia Power have broad experience developing electricity infrastructure projects and have an ability to fund investments with revenues earned through rates when benefits are clear, and to work with partners, such as third-party charging providers, to facilitate investments in charging solutions. In addition, given it manages the distribution network, the utility can ensure that chargers are built in a way that leverages the existing distribution network at least cost and in a manner that maximizes customer benefits. E3 recommends that Nova Scotia Power focus its efforts on building a backbone of public chargers and a broader network of make-ready charging infrastructure to support third-party chargers in meeting customer locations and driver needs.

  - **Invest in make-ready investments in high-traffic locations:** E3 encourages Nova Scotia Power and its' partner E1 to invest in make-ready charging infrastructure, including infrastructure to support Level 2 chargers at public locations, multi-unit dwellings, and workplaces, and in high-traffic spots where distribution network capacity is readily available. Similar make-ready infrastructure programs have been implemented by utilities across North America and have played a key role in building out charger networks.[15] These make-readies can enable third party chargers, leveraging their private investment in the province, and help steer charging providers toward locations that are the less constrained and thus lower cost interconnection points.

- **Invest in full charging infrastructure to fill charging gaps:** Beyond supporting third-party charging providers and building owners in make-ready investments, Nova Scotia Power should invest in full charging infrastructure, including both EVSEs and make-ready infrastructure, in locations where charging gaps are likely to exist due to lower third party incentives for investment.[16] For example, private providers are likely to have less compelling business cases to build chargers in areas with lower average household incomes, disadvantaged communities, and rural communities, where concentrations of EVs are currently low. Private providers also have lower incentives to serve multi-unit dwellings, where access and utilization are lower than other public charging locations but where charging access is critical for facilitating EV adoption. Utilities across North America have also begun filling in charger gaps through investments in full charging infrastructure. By filling these gaps with a mix of DCFC and Level 2 chargers, Nova Scotia Power can help enable widespread and equitable adoption of EVs.

Recommendation 4. Support cost-effective grid modernization and panel upgrades, as well as all-electric ready new construction, to ensure the utility doesn't become a bottleneck to electrification.

+ Grid modernization and panel upgrade investments are necessary to enable electrification but can increase near-term rate pressure and so should be carefully evaluated.[17] All new construction should be built to accommodate future electrification. This "electric-ready" construction has electrical panels and services sized to accommodate electric appliances and vehicles. Electric-ready construction can be mandated by government through energy and building codes. Building new construction to be electric-ready can avoid the expensive costs of retrofitting infrastructure. In existing buildings, where retrofits are needed, upgrades are likely to increase rate pressure. Electrical upgrades can require utility permits and approval, which has been slow and created bottlenecks in other jurisdictions. Nova Scotia Power can help avoid these bottlenecks by streamlining the process for evaluating upgrades and issuing permits. Given its role as the electrical inspection authority within its service territory, the utility can also

[15] Examples include Eversource and National Grid, which have implemented make-ready programs to support public, multi-unit dwelling, and workplace charging. Hawaiian Electric Co. (HECO) has also implemented make-ready charging infrastructure programs. Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) have both implemented make-ready charging infrastructure programs for medium- and heavy-duty vehicles.

[16] Utilities in North America that have implemented full charging infrastructure have included costs in their rate base. Examples include San Diego Gas & Electric's rate base cost recovery of 3,500 L2 chargers in its Power Your Drive program and Southern California Edison's rate base cost recovery of chargers at 1,500 sites as part of its Charge Ready program to help jumpstart EV adoption in their service territories.

[17] To ensure equitable access to electrified technologies, one strategy may be to prioritize undersized panels and panels for low-income and/or disadvantaged communities.

help facilitate appropriate procedures up front and prioritize timely inspections to ensure this doesn't slow down electrification. E3 also recommends that the utility identify ways to more efficiently and cost-effectively support distribution system and service upgrades. For example, Nova Scotia Power may develop plans for coordinating investments in higher amperage service conductors by having a program in place to proactively schedule and complete the associated upgrades in a coordinated fashion that can both minimize certain costs that can be shared (e.g., road closures) and accelerate the overall pace at which upgrades can be completed.

Long-Term Strategy and Planning

Recommendation 5. Fully incorporate electrification strategy findings, including peak impacts and mitigation strategies, into utility planning models.

- **Model impacts on resource needs and costs**: Reliably serving electrification loads will be a defining challenge for Nova Scotia Power in coming decades. While many programs and initiatives described above could help to mitigate this impact (e.g., smart charging, dual-fuel heat pumps), Nova Scotia Power should continue to model the impacts of electrification on the generation portfolio through its IRP Evergreening process and beyond, enabling the utility to proactively plan a mix of generation and demand-side resources to meet the system's capacity needs at least cost and while maintaining emissions constraints. An ongoing emphasis in Nova Scotia Power's planning should be evaluation of the potential electricity cost savings associated with peak mitigation strategies.
- **Model impacts of electrification on reliability:** High levels of electrification will change the timing and shape of Nova Scotia Power's peak loads and may increase load's weather sensitivity. This in turn may affect the ability of variable and energy limited resources to provide capacity and could potentially increase the required planning reserve margin. At the same time, flexible electric vehicle loads may provide reliability benefits, and Nova Scotia Power should consider modeling the reliability benefits managed load can provide relative to unmanaged loads. We recommend Nova Scotia Power evaluate the potential for different DER programs to provide effective capacity contributions through robust reliability modeling (e.g., using a loss-of-load model); this modeling could also inform a comparison of the ability of different DER programs to provide cost-effective alternatives to supply side investments (e.g., batteries).
- **Evaluate the impacts of electrification on equity and affordability**. Electricity system planners are increasingly playing a role in assessing the potential impacts of electrification and other decarbonization investments on energy affordability. Metrics to assess affordability include monthly or annual energy bills, energy costs that incorporate both bills and upfront costs, and energy bills as a fraction of household income. While electric rates are a useful gauge for how the costs of electricity for customers change over time, applying electric rates to customer loads is needed to determine the actual impacts of electrification on customers' total energy bills and costs. Understanding the affordability implications of electrification can help inform provincial planning and determine where additional provincial support will be needed. Affordability also extends beyond electricity; affordability metrics should consider the offsetting reductions in natural gas, fuel oil, gasoline and diesel expenditures as building and transportation end uses

are converted to electricity, as well as the up-front cost premiums associated with electrified equipment and appliances.

Recommendation 6. Advance public-facing distribution planning process to support electrification.

+ **Proactive distribution system planning:** Utility planners need to manage an increasingly complex distribution system proactively and effectively. Pre-planning is needed to identify areas where significant load growth is expected and the upgrades that might be needed if various scenarios play out with electrification, and to coordinate with those investments. E3 recommends that Nova Scotia Power proactively identify needed transmission and distribution facilities to ensure that customers do not experience delays in upgrading to electrified equipment. At a high level, this involves building out spatially explicit load forecasts under key electrification planning scenarios, and typically using commercially available tools to allocate expected load growth at the substation level. The next steps often involve evaluating the ability to shift load away from overloaded areas and adding capacity in the most constrained areas of the distribution system. Ideally, more detailed modeling of customer equipment that can shift load, providing benefits to the grid through load management, is pursued as another step in distribution planning, as this can potentially reduce the size of needed transmission and distribution investments. A formal distribution system planning process that includes such non-wires alternatives will also enable stakeholder engagement and public participation to help identify the most pressing issues to customers and identify areas that are in need of utility investment in order to ensure a reliable, resilient grid and help the province meet long-term goals.

Partnerships & Customer Engagement

Recommendation 7. Electrification at scale requires concerted effort and coordination across diverse organizations and interests with complementary expertise. Nova Scotia Power should continue to proactively build partnerships with these other key stakeholders.

+ **Key partnerships are likely to include the following:**

  - **Efficiency One:** Support E1 in accelerating building shell and other efficiency measures to reduce customer bills when switching to electrified space and water heating. Coordinate and support E1 in promoting heat pump adoption among current electric resistance customers, consistent with utility remit under the Public Utilities Act. Bill 228 expands "electricity efficiency and conservation" activities to include "strategic electrification of energy end uses currently powered by fossil fuels in a manner that reduces overall greenhouse gas emissions and electricity costs." [18] As the utility, Nova Scotia Power should work with E1 on prioritizing electrification programs and initiatives.

[18] Bill 228, which received Royal Assent on November 9, 2022, adds "strategic electrification of energy end uses currently powered by fossil fuels in a manner that reduces overall greenhouse gas emissions and electricity costs" to the mandate of Nova Scotia's electricity efficiency and conservation franchise holder.

- **Government:** Nova Scotia Power should engage in ongoing collaboration helping encourage 1) electric-ready building codes and other building policies that encourage beneficial electrification; 2) enable the deployment of charging stations; 3) identifying underserved communities and investments needed to ensure equitable access to electrified mobility and heating.

- **Third Party EVSE Providers:** Work to collaborate on improving the process of interconnection and developing additional public and workplace charging infrastructure. The utility role may complement third-party charging companies by filling in 'gaps' in coverage in underserved areas.

- **Equipment Manufacturers:** Collaborate on education, outreach, and innovation.

- **Transit/Bus Owners and Operators:** Work to develop electrification pilots and support education on model types, capabilities, and limitations.

- **Consumer Advocates:** Collaborate to understand broad impacts on underserved communities. Pursue outreach and potential programs to help overcome first-cost hurdles.

- **Supporting customer education and training:** Despite growing awareness of transportation electrification options, many consumers as well as building and vehicle fleet managers and operators have insufficient information in considering electrification options. Customer engagement is needed to identify where and when on the grid loads will materialize.

- **Supporting technical contractor training**: Lack of knowledge of the benefits and capabilities of heat pumps by contractors may drive up contractor mark-up. Training contractors and developing public lists of contractors with expertise in heat pump retrofits can help make customer adoption easier and cheaper.

Recommendation 8. Support an equitable transition through programs directly aimed at lower income or disadvantaged communities.

+ **Identify underserved communities and prioritize investments to ensure equitable access:** Without intentional program design, electrification at scale is expected to pose challenges that disproportionately impact lower-income and disadvantaged communities. For example, these customers may be less able to self-fund capital investments required for building electrification, and on the transportation side, they may live in communities with less access to charging infrastructure. It will be critical for Nova Scotia Power and E1 to work with provincial and local governments to identify underserved communities and investments needed to ensure equitable access to electrified mobility and heat. For example, these could include lower income households or areas, communities with disproportionate health or pollution burdens, or rural areas with less infrastructure. In addition to including equity-related analysis in utility planning (e.g., by estimating energy burden as noted above), the utility should pursue specific initiatives to address equity-related challenges. One approach best-in-class utilities are taking is to set specific targets for electric vehicle charging infrastructure in disadvantaged community or multi-family housing units. For example, a specific challenge in Nova Scotia relates to communities currently served by radial transmission lines. These communities have lower reliability and less ability to integrate new large electric loads without major upgrade costs. For widespread electrification, these customers will require upgraded supply. Thus, the costs of supporting investments in these communities – relative to the potential achievable electrification net benefits – should be a priority to evaluate, and investments in these areas could be considered on the basis of promoting equitable access to electrification benefits in the province.

1. Introduction

1.1 Motivation

Economy-wide decarbonization modeling in Nova Scotia and in jurisdictions across North America demonstrates that electrification of transportation and most buildings is a "safe bet" strategy for achieving Net Zero. Electrification is generally lower cost than other decarbonization strategies and the technologies for electrification of transportation and buildings are commercially available today. In conjunction with power sector decarbonization and energy efficiency, electrification is critical to achieving the province's decarbonization goals.

This study provides Nova Scotia Power, policymakers, and stakeholders insight into the economics of electrification today, the system-level load impacts, and recommendations for the utility to support electrification to reduce emissions and costs for Nova Scotians.

1.2 Objectives

The objective of this report is to answer the following questions to inform Nova Scotia Power, provincial policymakers, and other stakeholders on the development of electrification programs that help the province meet its decarbonization goals and provide benefits to the province. These questions include:

+ **Jurisdictional Scan:** What role is electrification playing in helping jurisdictions across North America make progress toward Net Zero targets?
+ **Economics:** What are the benefits and costs of adopting key electrified technologies – electric vehicles and heat pumps -- from the perspective of adopters, ratepayers, and the province?
+ **Utility Planning & Program Design Recommendations:** What are the aggregate impacts of electrification on Nova Scotia's electric sector sales and peak demands over time, and how should the utility proactively plan for these? What approaches can Nova Scotia Power and E1 pursue to facilitate beneficial electrification?

The above questions evaluate marginal near-term electrification initiatives. To assess electrification at scale, E3 developed a set of electrified load shapes under scenarios that reflect different customer technology choices, their performance characteristics and utility load management strategies.

1.3 Report Contents

The study is organized as follows:

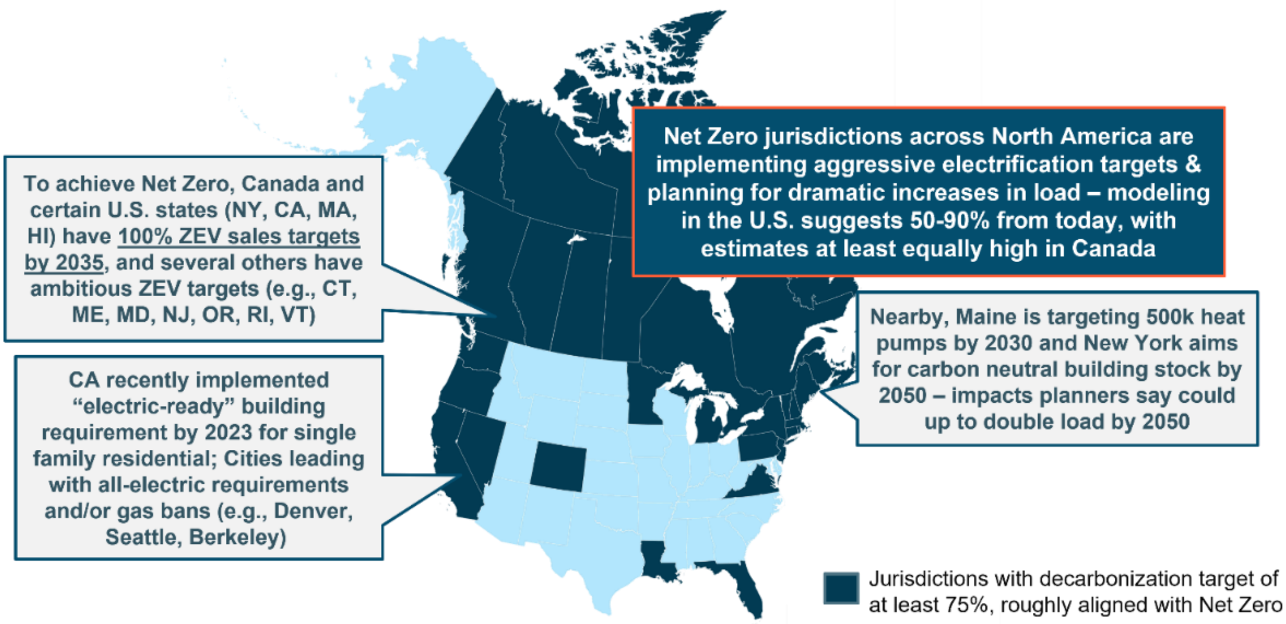
+ Section 2 of this report provides an overview of electrification initiatives across North America.
+ Section 3 assesses the impacts of electrification on Nova Scotia Power's system if electrification occurs at the pace required to meet the midcentury decarbonization goals.
+ Section 4 assesses the benefits and costs of electrification for the utility and the province.
+ Section 5 concludes and provides recommendations for the role of the utility.

2. Context: Net Zero and the Role of Electrification

2.1 Net Zero and the Role of Electrification

In its Special Report on the impacts of potential global warming, the Intergovernmental Panel on Climate Change (IPCC) reports that GHG emissions must be reduced to Net Zero globally by 2050 to avoid global warming greater than 1.5 degrees Celsius.[19] Consistent with the IPCC findings, Nova Scotia has set an economy-wide Net Zero target by 2050, consistent with Canadian federal policy and a growing number of U.S. states (see Figure 2-1).

Figure 2-1. Net Zero targets and example electrification goals in North America



Transportation and buildings are major emissions sources across North America; in Nova Scotia, they represent about 44% of all emissions.[20] To decarbonize these sectors, existing modeling in Nova Scotia and across North America identifies high levels of electrification as part of a feasible, cost-effective

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[19] IPCC Special Report: https://www.ipcc.ch/site/assets/uploads/sites/2/2019/05/SR15_SPM_version_report_LR.pdf

[20] Canada Energy Regulator, Provincial and Territorial Energy Profiles – Nova Scotia, https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-nova-scotia.html#:~:text=GHG%20Emissions,-Nova%20Scotia%27s%20GHG&text=Nova%20Scotia%20emissions%20per%20capita,14%25%20(Figure%206).

strategy to reduce emissions.[21] These studies also demonstrate that electrification must be pursued in parallel with energy efficiency and conservation, as well as aggressive power sector GHG reductions. In addition to reducing fossil fuel reliance and emissions in transportation and buildings, many electrification studies demonstrate opportunities for significant customer and ratepayer benefits.

To support economy-wide decarbonization, policymakers in many Net Zero jurisdictions are setting electrification targets and pursuing policies to accelerate sector transformation. The following sections provide a high-level overview and examples of recent policy, costs, and emerging utility actions to support electrification[22]. The last section discusses the implications for Nova Scotia Power.

2.2 Transportation Electrification

2.2.1 Recent Policies

Transportation policies to align with Net Zero targets are emerging across North America. To date, at least 13 states—California, Colorado, Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Vermont, and Washington—plus the District of Columbia, have adopted California's low-emission vehicle (LEV) and zero-emission vehicle (ZEV) standards requiring manufacturers to sell a certain number of ZEVs per year. Other states like Minnesota, New Mexico, Nevada, and Virginia have plans to adopt California's standards in the next several years as well.[23] California's ZEV standards are the most ambitious in the U.S. – an executive order from 2020 requires 100% zero-emission passenger vehicle sales by 2035, and recent regulatory proposals may require 35% passenger ZEV sales in 2026, increasing to 68% in 2030 and reaching 100% by 2035[24]. This target (100% electric light-duty cars and passenger truck sales by 2035) is also now mandated in all of Canada[25], and is a goal in New York and Massachusetts.

For medium- and heavy-duty (MD/HD) vehicles, the most aggressive policies require 100% zero-emission vehicles in select fleets such as transit fleets or school buses by 2030 or 2035. Canada has set a target of 35% of MD/HD vehicle sales being ZEVs by 2030, with targeted vehicle types achieving 100% of sales by 2040. Several jurisdictions, including 14 U.S. states, have set 100% zero emission MD/HD sales targets in 2050. The most aggressive policy to date is a California target for all MD/HD vehicles on the road to be

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[21] For example, see NSPI Pathways (link above); or
Dion, J., A. Kanduth, J. Moorhouse, and D. Beugin. 2021. Canada's Net Zero Future: Finding our way in the global transition. Canadian Institute for Climate Choices., Canadas-Net-Zero-Future_FINAL-2.pdf (climatechoices.ca).

[22] This discussion is a high-level overview and not meant to be exhaustive, given the breadth of emerging activities occurring in this space.

[23] California Air Resources Board. "States that have Adopted California's Vehicle Standards under Section 177 of the Federal Clean Air Act." https://ww2.arb.ca.gov/sites/default/files/2022-05/%C2%A7177_states_05132022_NADA_sales_r2_ac.pdf.

[24] California Air Resources Board. Public Hearing to Consider the Proposed Advanced Clean Cars II Regulations. Staff Report: Initial Statement of Reasons. ACC II ISOR (ca.gov)

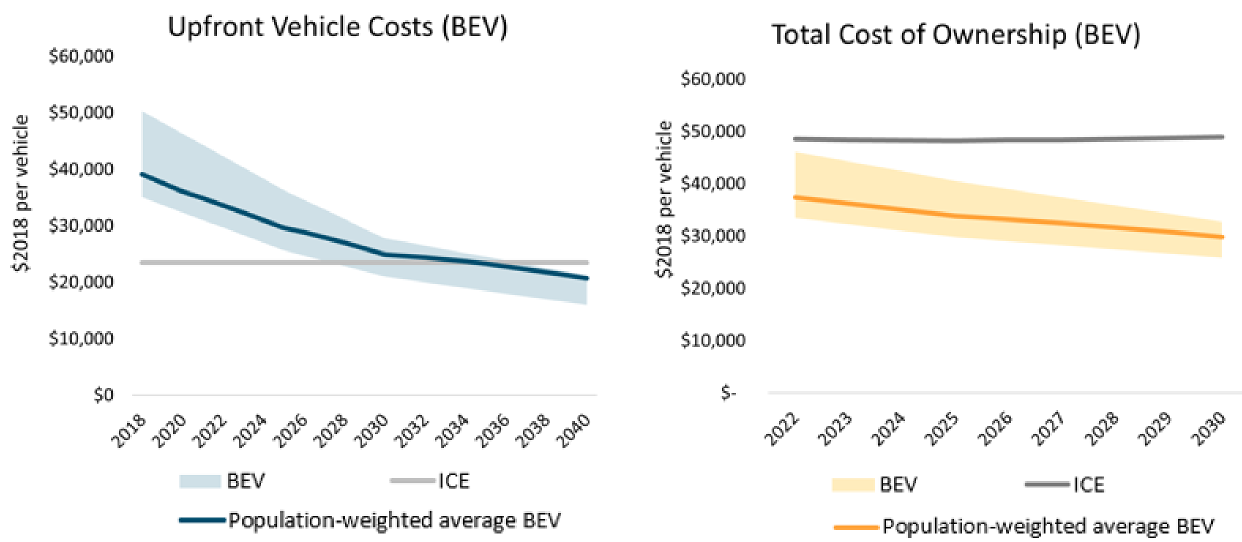
[25] Government of Canada, News Release, "Building a Green Economy: Government of Canada to Require 100% of Car and Passenger Truck Sales to be Zero-Emission by 2035 in Canada". https://www.canada.ca/en/transport-canada/news/2021/06/building-a-green-economy-government-of-canada-to-require-100-of-car-and-passenger-truck-sales-be-zero-emission-by-2035-in-canada.html.

zero emissions by 2045.[26] More stringent policy, however, has been widely acknowledged as necessary to achieve GHG goals.

2.2.2 Costs

The economics for EVs are improving quickly and some models of EVs are expected to reach cost parity with ICE vehicles by the late 2020s. The average light-duty EV, in considering an average of vehicle ranges, is forecasted to reach cost parity by the mid-2030s. Upfront vehicle costs for a light-duty BEV compared to an ICE vehicle are shown in below.

Figure 2-2. Upfront vehicle cost and total cost of ownership forecasts of battery electric vehicle compared to internal combustion vehicle



Note: Upfront cost estimates for BEVs and ICE vehicles are derived from the International Council on Clean Transportation (ICCT) and E3 calculations. Total cost of ownership for BEVs and ICE vehicles include upfront vehicle costs and lifetime O&M costs. For BEVs, total cost of ownership also includes charging bills, charging infrastructure costs, and rebates. For ICE vehicles, total cost of ownership includes gasoline costs. Total cost of ownership is only shown through 2030 given our analysis only proceeds through vehicles adopted in 2030. The lower range of BEV upfront costs and total cost of ownership represents costs for short-range (150 miles) BEVs and the upper range shown represents long-range (400 miles) BEV costs. Solid lines for the population-weighted average BEV costs represent the average upfront costs and total costs of ownership based on the portion of short- and long-range BEVs adopted in Nova Scotia in each year.

2.2.3 Example Utility Actions

Most utilities within Net Zero jurisdictions are proactively planning for transportation electrification. The utilities with the most advanced planning for transportation electrification have aligned strategic goals

[26] California Executive Order N-79-20: https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf

and targets with transportation policies and have instituted V1G or managed charging pilot programs. Most utilities within Net Zero jurisdictions are initiating policies and programs to support transportation electrification; recent examples of utilities with robust plans include BC Hydro[27], Hydro-Québec[28], Seattle City Light[29], Hawaii Electric Co.[30], and Southern California Edison[31].

Jurisdictions increasingly also offer transportation electrification rate designs. The jurisdictions with EV rates have tended to be the areas with the highest levels of EV adoption. There is a mixture between EV rates that apply to an entire house versus those that apply only to the charging load that is on a separate meter. Rates proposed and adopted thus far have been primarily time-of-use (TOU) rates, designed to capture general variations in the utility's cost of service over time. While an advancement from flat rates, TOU rates do not capture real-time variation in electricity supply costs. Options for dynamic EV rates include a rate that follows the car with clear managed charging incentives, credits for not charging on-peak, demand charge mitigation, and multi-part rates with a dynamic real-time energy charge.

Managed charging has been recognized as critically important to minimizing peak impacts of EV charging and concentrating charging, when possible, in lower-cost hours. Managed charging, also called "V1G" and "smart charging", refers to charging that may shift load to different hours within the same charging session. If unmanaged, charging would begin as soon as the driver plugs in their vehicle, often aligned with an evening system peak load in Nova Scotia. Managed charging uses signals such as rates to optimize for a charging outcome such as minimizing charging costs to assess times in which the vehicle is parked will be best to charge. Managed charging can be "passive" (e.g. responding to a TOU rate) or "active" (e.g. providing a verified response to a dispatch signal). TOU rates can enable a basic form of managed charging in which drivers shift charging to off-peak periods when possible. Utilities can enable more effective managed charging by offering more dynamic rates that better capture hourly variations in electricity prices. Charge management requires and leverages advanced metering infrastructure (AMI).

EVs can also participate in V2G charging; in addition to charging from the grid, vehicles can then sell energy stored in their battery back to the grid. With V2G charging, EVs can act as a battery and provide services to the grid while still satisfying charging requirements. To incentive effective V2G charging, utilities must offer export rates that compensate customers for the value of electricity supplied back to the grid. Utility development of rates for vehicle exports are nascent. Some jurisdictions have export compensation rates used for other demand-side technologies that could be applied to vehicles, such as New York's Value of Distributed Energy Resources (VDER) tariff.[32] More broadly, utilities must also ensure that there is a market mechanism in place to enable V2G participation. In the U.S., FERC Order 2222 requires

[27] BC Hydro's Electrification Plan: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/electrification/Electrification-Plan.pdf.

[28] Hydro-Québec Strategic Plan 2022-2026: https://www.hydroquebec.com/about/strategic-plan.html.

[29] Seattle City Light Transportation Electrification Strategic Investment Plan: https://www.seattle.gov/documents/Departments/OSE/ClimateDocs/TE/SCL-Transportation-Electrification-Strategic-Investment-Plan-2021-2024-w-attachments.pdf.

[30] Hawaii Electric Co. Electrification of Transportation Strategic Roadmap: https://www.ethree.com/wp-content/uploads/2018/04/201803_EOT_roadmap.pdf.

[31] Southern California Edison Company's Charge Ready Pilot Quarterly Report: https://www.sce.com/sites/default/files/custom-files/2021%20Q1%20Report%20.pdf.

[32] New York State Energy Research and Development Authority (NYSERDA). The Value Stack: https://www.nyserda.ny.gov/All-Programs/ny-sun/contractors/value-of-distributed-energy-resources.

independent system operators (ISOs) or regional transmission organizations (RTOs) to design market models that enable DER participation, including V2G. However, in FERC jurisdictions not covered by an ISO or RTO, it is up to the utility to ensure that market models are in place that enable V2G.

Direct control programs have also begun to emerge from preliminary pilots to larger programs. V2G programs have been mostly implemented as pilot programs, such as the PG&E and General Motors V2G pilot[33], JUMPSmartMaui[34], and SDG&E's V2G pilot school bus program[35]. In both V1G and V2G programs, cost-benefit analysis has been used to support regulatory approval of programs, with a large focus on ratepayer impacts and ensuring that non-adopting ratepayers are not harmed by program adoption. Cost-benefit analysis of proposed programs has also been used to determine prioritization.

Utilities have cited uncertainty regarding EV availability and customer enrollment as barriers to managed charging programs. EV programs to date have been siloed from other distributed resources and loads, but some utilities are expanding time-varying EV rates and managed load programs beyond EVs to be technology agnostic. Demonstration of cost-effectiveness, including in avoiding cost-shifting to ratepayers who do not electrify, has played an important role in utilities receiving regulatory approval for pilots and full-scale programs that support electrification.

Utilities to date have played an important role in the support, facilitation and, in some cases, the installation and ownership, of EV chargers. Utility charging infrastructure ownership models have varied; some jurisdictions have received regulatory approval for full ownership of chargers while others have only gained regulatory approval for the ownership up to the "make-ready" component of chargers. Figure 2-3 depicts the various utility ownership models for charging infrastructure. (e.g., HECO partnerships with Nissan and BMW increased EV sales substantially in its service territory)[36].

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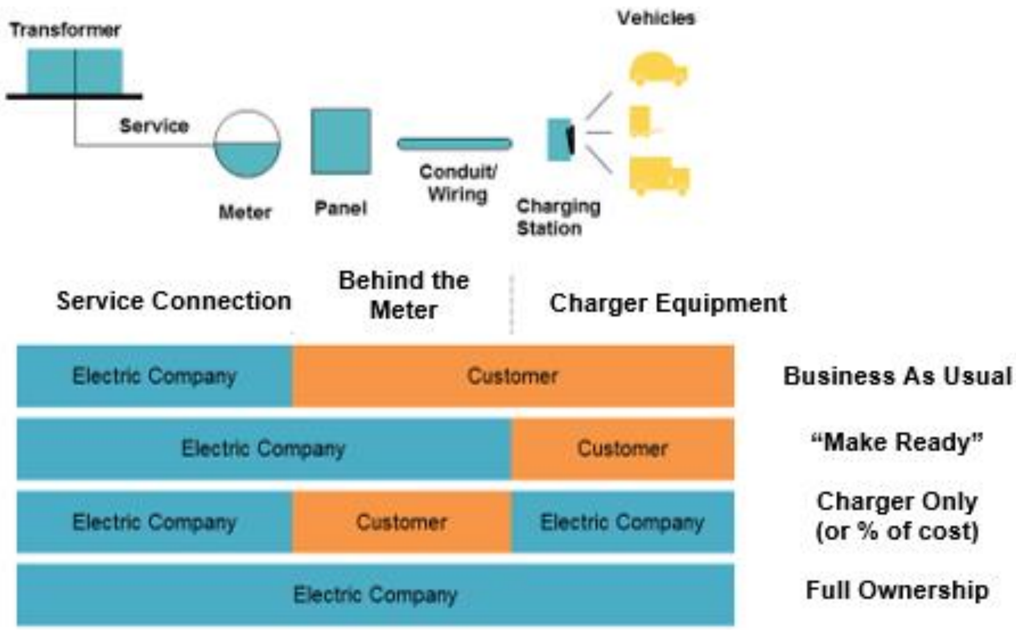
[33] Pacific Gas & Electric News Release. "PG&E and General Motors Collaborate on Pilot to Reimagine Use of Electric Vehicles as Backup Power Sources for Customers." https://www.pge.com/en_US/about-pge/media-newsroom/news-details.page?pageID=c77a4e23-f8fc-4774-9786-0dba87a203db&ts=1646754047003.

[34] "The New Smart Grid in Hawaii: JUMPSmartMaui Project." https://social-innovation.hitachi/en-us/case_studies/the-new-smart-grid-in-hawaii-jumpsmartmaui-project/.

[35] San Diego Gas & Electric News Release. "Vehicle-to-Grid Pilot: Leveraging Big Batteries on Electric School Buses to Support the Grid." https://www.sdgenews.com/article/vehicle-grid-pilot-leveraging-big-batteries-electric-school-buses-support-grid.

[36] HECO Transportation Roadmap. https://www.ethree.com/wp-content/uploads/2018/04/201803_EOT_roadmap.pdf

Figure 2-3. Potential utility ownership models for EV charging infrastructure[37]



Partnerships have proven to be useful in accelerating electrification. For example, several utilities have built partnerships with vehicle manufacturers and third-party charging companies to accelerate EV sales and charger installations.

2.2.4 State of the Market and Challenges

The state of the market for EVs has changed drastically over the past several years. CALSTART and the California Air Resources Board (CARB) publish an annual update on the technology and market readiness of EVs. In the latest update, released in October 2022, electric LDVs were classified as in the "early market" technology level, indicating full commercialization and widespread availability. Electric MDVs and HDVs vary in technology level depending on the specific vehicle type. The latest update identified some MD/HD vehicle types, such as long-haul trucks, drayage trucks, shuttle and school buses, and refuse vehicles, as being in or near the early market technology level. Other MD/HD vehicle types, such as transit buses, cargo vans, and medium-duty trucks, range from early demonstration to early market entry technology levels. [38]

EVs have represented a growing portion of the global vehicle fleet. Globally, there are nearly 20 million electric LDVs on the road, which represent about 1.5% of the global vehicle fleet. EV sales are steadily increasing and reached 9% of all LDV sales in 2022.[39] China and Europe have been leaders in EV adoption

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[37] Image was adapted based on an Edison Electric Institute (EEI) graphic.

[38] CALSTART and California Air Resources Board, "Methods for Assessing Technology and Market Readiness for Clean Commercial Transportation": https://calstart.org/wp-content/uploads/2022/10/assessing_technology_and_market_readiness_october_2022.pdf

[39] Bloomberg New Energy Finance. "Electric Vehicle Outlook 2022 Executive Summary." https://about.bnef.com/electric-vehicle-outlook/

to date and combined represent approximately 80% of the global EV stock. In Canada, in 2021, there were nearly 250,000 light-duty EVs registered, with about 61% being BEVs and 39% being PHEVs. In Nova Scotia, there were approximately 1,200 light-duty EVs registered in 2021, with a lower portion (51%) being BEVs relative to Canada as a whole. There were only several electric MDVs or HDVs registered in Canada and none registered in Nova Scotia in 2021.[40]

All this said, while the market for EVs is growing quickly, there are still challenges that the province will need to continue to evaluate and alleviate to achieve the high levels of EVs required for net-zero. In addition to the up-front cost barrier noted above, other challenges include customer awareness and education about EV performance, as concerns related to range anxiety and battery reliability in cold weather have been mitigated in many of the latest models. In addition, as global demand for electric vehicles accelerates, supply has struggled to keep up with demand, with wait times on the order of several months.[41] These wait times are only partially attributable to demand, as the industry has also suffered from pandemic and demand-related shortages of key inputs (e.g., lithium[42], computer chips[43]). It's expected that over the coming years, as manufacturing capacity grows, the availability of electric vehicles will increase to meet demand. Finally, as noted above, insufficient charging infrastructure remains a challenge, despite the over 150 public charging stations across Nova Scotia as of this report.

2.3 Building Electrification

2.3.1 Recent Policies

The most aggressive policies to support building electrification currently under discussion are for all-electric new construction mandates. California, New York, and Massachusetts have discussed adoption of an all-electric new construction mandates, but no mandates have been adopted to date.[44] California has implemented an "electric-ready" building requirement by 2023 for single-family residential new construction.[45] At the city-level, several cities have adopted all-electric requirements for new construction and/or bans on new gas connections, including Denver, Seattle, and Berkeley.[46][47] Adoption of these types

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[40] Statistics Canada, "Vehicle registrations, by type of vehicle and fuel type": https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310030801&pickMembers%5B0%5D=1.4&cubeTimeFrame.startYear=2020&cubeTimeFrame.endYear=2021&referencePeriods=20200101%2C20210101

[41] https://www.am-online.com/news/market-insight/2022/10/25/lead-time-for-ev-orders-is-getting-longer-data-shows

[42] https://www.mckinsey.com/industries/metals-and-mining/our-insights/lithium-mining-how-new-production-technologies-could-fuel-the-global-ev-revolution

[43] https://www.businessinsider.com/why-is-there-chip-shortage-car-companies-electronics-supply-chain-2021-2

[44] Tom DiChristopher. 2022. "To drive building electrification, Massachusetts proposed energy code changes." *SP Global.* *https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/to-drive-building-electrification-massachusetts-proposes-energy-code-changes-68854724*

[45] California Energy Commissions. *2022 Building Energy Efficiency Standards Summary.* https://www.energy.ca.gov/sites/default/files/2021-08/CEC_2022_EnergyCodeUpdateSummary_ADA.pdf

[46] Tom DiChristopher. 2022. "Gas Ban Monitor: Denver tackles retrofits; Pacific Northwest movement grows" *SP Global.* https://www.spglobal.com/marketintelligence/en/news-insights/blog/research-brokers-accelerate-their-coverage-of-electric-vehicles

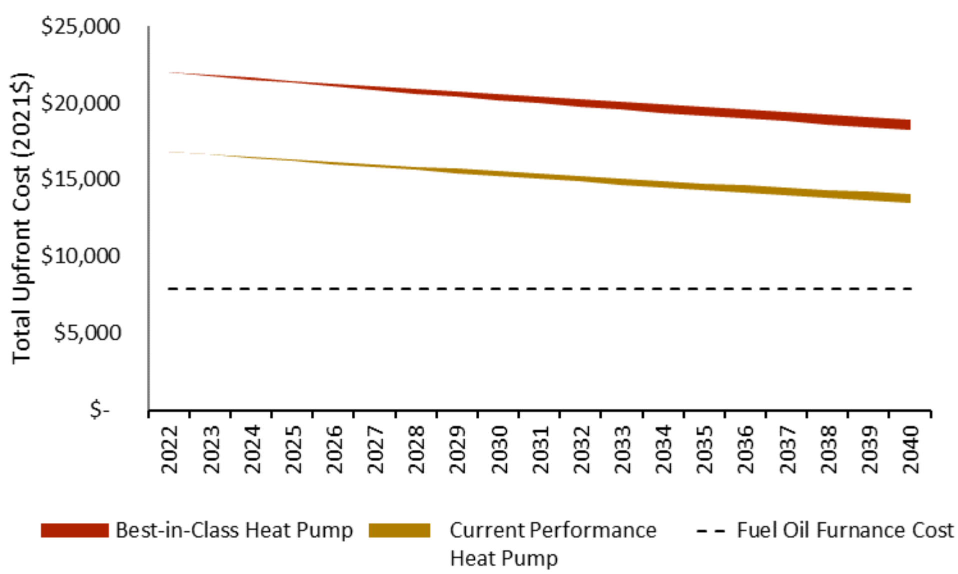
[47] City of Berkeley Municipal Code. Chapter 12.80 Prohibition of Natural Gas Infrastructure in New Buildings. https://berkeley.municipal.codes/BMC/12.80

of mandates as well as other aggressive measures, such as stretch/reach building codes and ways to overcome existing barriers to building electrification, such as cost and workforce development, are widely believed to be necessary to reach GHG targets.

2.3.2 Costs

The upfront cost of installing a ducted heat pump is higher than fossil fuel heating systems in most jurisdictions, but the incremental cost can vary significantly based on heat pump type and market maturity in the region. Figure 2-4 shows the upfront costs of heat pumps for a single-family home compared to the cost of a fuel oil boiler in Nova Scotia. In many jurisdictions, all-electric new construction is cheaper than building new mixed-fuel, but in retrofit applications, the incremental cost of heat pumps is often greater than like-for-like replacement of existing heating equipment. In cold climates, heat pumps have a significant upfront cost hurdle relative to oil systems but may pay back over time under certain circumstances, such as if coupled with efficiency, favorable rate designs, or incentives. The economics of heat pumps are also more favorable when customers are replacing an existing air conditioning unit or installing air conditioning in conjunction with heating system upgrades. Partial electrification of space heating through hybrid dual-fuel systems can have a lower total cost of ownership compared to an incumbent heating system in retrofit applications particularly in the commercial sector.

Figure 2-4. Incremental upfront cost of a ducted 2-2.5 ton ccASHP adopted in a single family home retrofit showing projected range in costs based on technology learning curves[48]



Notes: The current performance heat pump has a coefficient of performance of 2.7 at -8°C and the best-in-class heat pump has a COP of 3.3 at -8°C.

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[48] Current heat pump costs in Nova Scotia were developed based on NS Power's experience. Equipment cost decline trajectories were developed based on data from the National Renewable Energy Laboratory's *Electrification Futures Study*: *End-Use Electric Technology Cost and Performance Projections through 2050.*

Despite the high incremental upfront costs of heat pumps, electrification at scale is typically cheaper than the widespread use of decarbonized gas. The supply of renewable natural gas (RNG) is limited such that more expensive, and yet to be fully commercialized fuels such as green hydrogen and synthetic natural gas would be required to meet decarbonization goals. Given that Nova Scotia's natural gas distribution network serves only a small share of buildings, decarbonization through RNG is unlikely to be a viable pathway for the province at the scales required to achieve Net Zero.

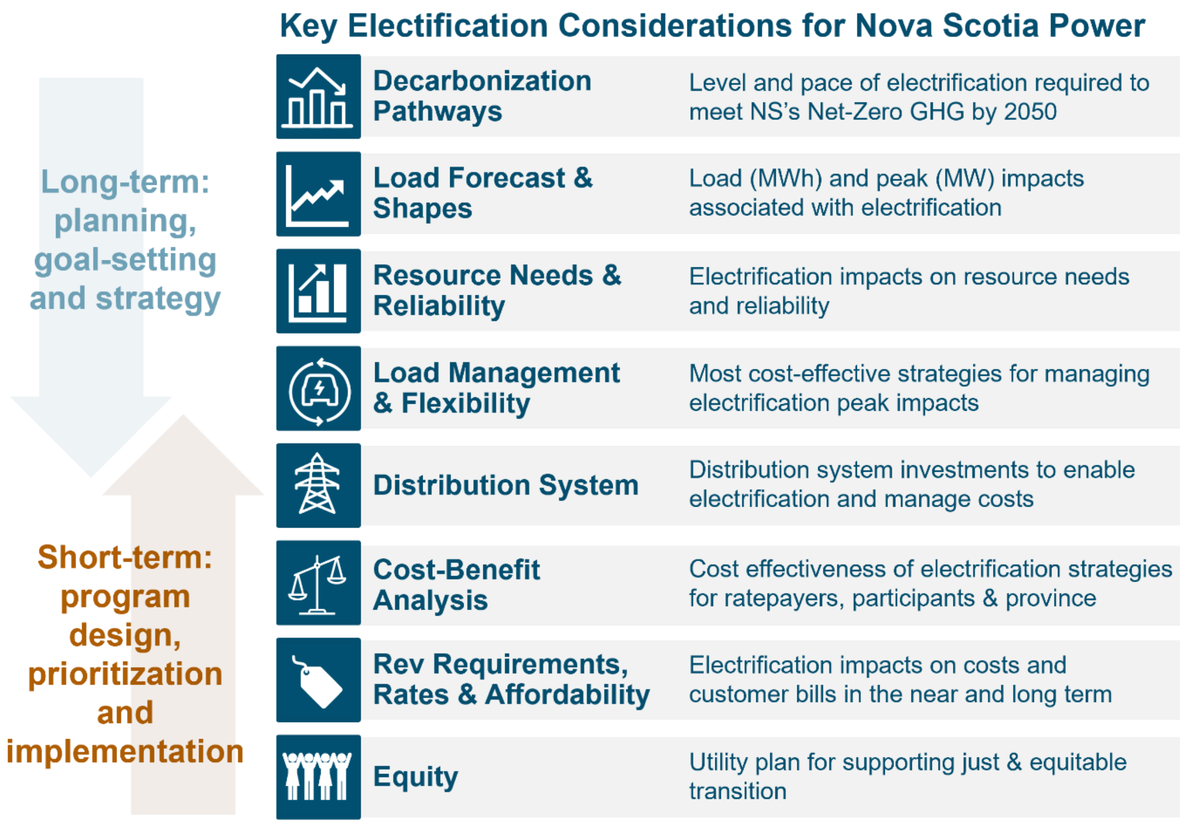
2.3.3 Example Utility Actions

In many jurisdictions with Net Zero targets, utilities have adopted programs, incentives, and customer education programs to support building electrification. It is increasingly common practice for utilities and/or jurisdictions to provide heat pump rebates, for example, BC Hydro, Hydro-Quebec, National Grid, and Xcel, often with separate rebates for space and water heating. Utilities have also adopted programs to support all-electric new construction, retrofits of existing buildings, and purchases and usage of smart thermostats. Utilities have also supported rebate programs for retrofits in low-income and social housing. While many jurisdictions have used ratepayer funds to support heat pump rebates, state or provincial funding, local taxes, and carbon fee programs can also support rebate funding.[49] The Sacramento Municipal Utility District is one example of a utility that has partnered with private contractors to perform whole home performance evaluations that include recommendations for both efficiency and electrification options. Some utilities have also tried to attract new energy-intensive industries and companies to their service territory through favorable rates for these customers.

2.4 Role of the Utility in Electrification

Achieving widespread benefits from electrification requires a range of important short-term programs and long-term planning activities. Utilities play a critical role in supporting adoption, enabling interconnection, and ensuring a just and equitable transition. Looking ahead, utilities must also plan for the contribution of electrification to system peak demand and the future grid required to serve substantial load growth load. Key utility considerations are outlined in Figure 2-5 below. Finding of this jurisdictional scan are incorporated into the overall recommendations presented in the executive summary.

Figure 2-5. Key electrification considerations for Nova Scotia Power



Note: Decarbonization Pathways assessment was developed by E3 for the utility in 2019; resource needs and reliability, distribution system, and revenue requirements and rates impacts represent ongoing work by the utility; affordability and equity planning may be incorporated into future work.

3. System Load Impacts

3.1 Overview of E3's Electrification Load Shape Modeling

This section describes E3's modeling of the potential aggregate load impacts of building and transportation electrification when pursued at the pace and scale required to align with existing provincial Net Zero policy. For transportation and buildings, E3 developed multiple scenarios potentially consistent with Net Zero, which vary in terms of increases in energy sales and peak demand. These results provide an indication of the level and shape of electrification that could materialize as the region decarbonizes. The modeling approach, scenarios and results are described below.

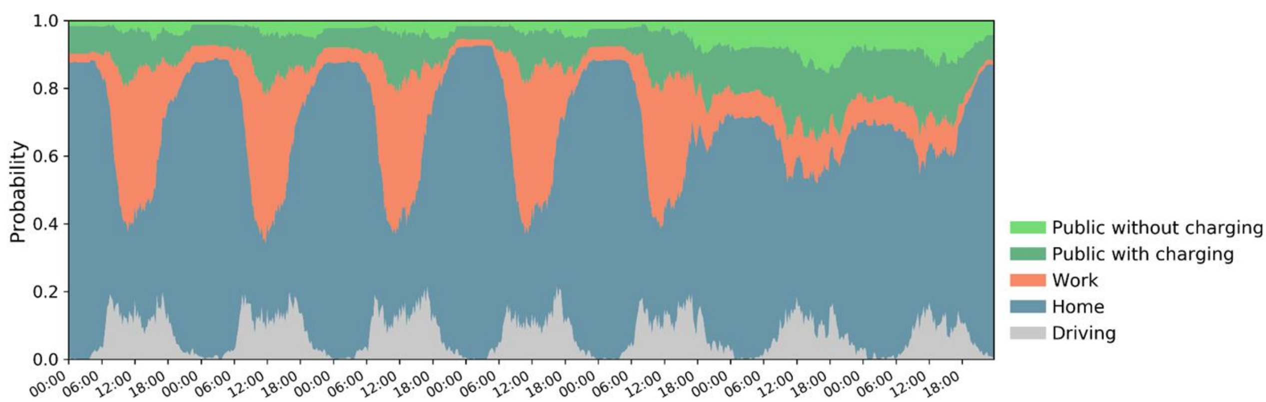
We note that these results focus on two key carbon-emitting sectors – buildings and transportation – but exclude potential additional electrification from other sectors, including the industrial and non-road transportation sectors.

3.2 Transportation: Load Shape Modeling

3.2.1 Overview of E3's EV Load Shaping Tool

To calculate electricity bills and supply costs for EV charging, E3 developed a forecast of potential EV charging loads consistent with achieving Nova Scotia's policy goals. Charging loads depend on several factors, including vehicle type, charging access, and the driving behavior of drivers. To model charging behavior, E3 utilized its bottom-up model, which simulates driving and charging of thousands of representative EV drivers. Driving behavior is captured using travel survey data and converted to 15-minute driving patterns though a Markov-Chain Monte Carlo method. Figure 3-1 below shows an example of LDV weekly driving patterns expressed as the probability that a driver is at a given location or is driving.

Figure 3-1. LDV weekly driving pattern from Markov-Chain simulation



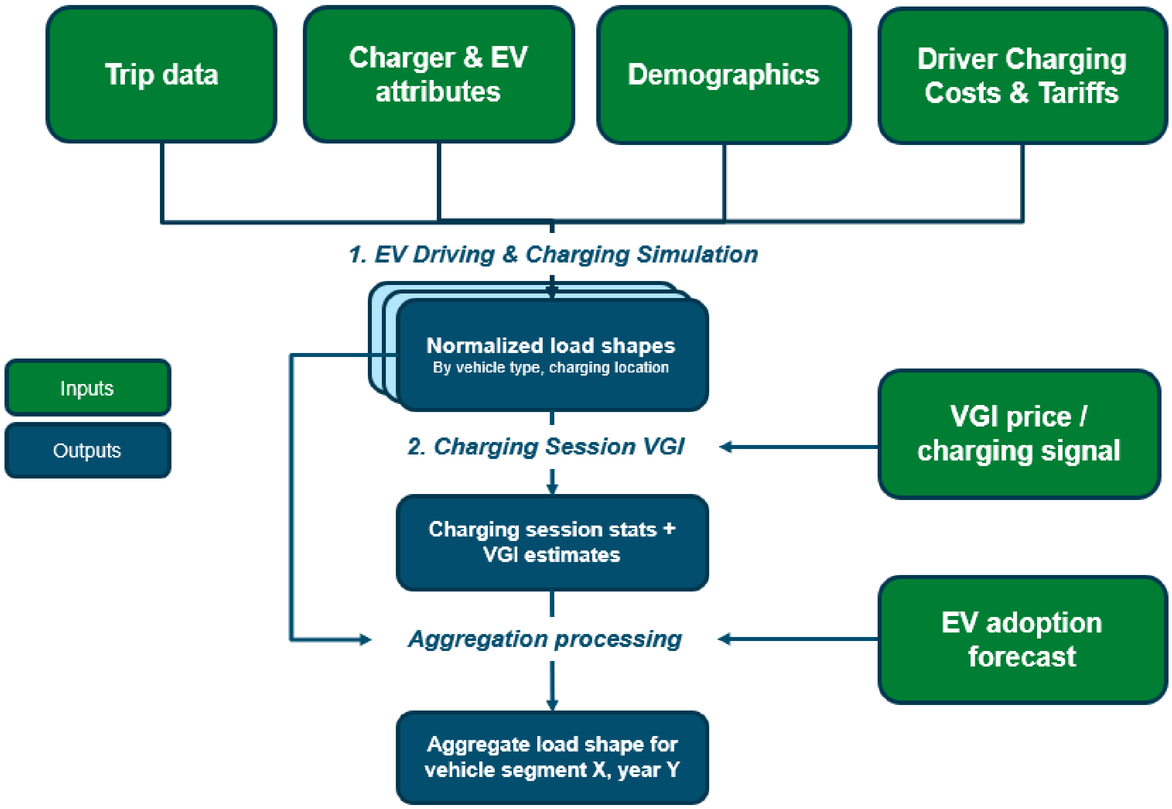
The driving population is characterized by drivers' EV type and access to charging. For light-duty vehicles (LDVs), the model assumed four EV types (short and long-range plug-in hybrid and short and long-rang battery electric vehicle) and six charging access types (a combination of access to residential, workplace, and public charging), resulting in 24 combinations or customer types. Loads for each customer type get weighted by the percentage of drivers forecasted to represent that customer type. The final load shape therefore captures the potential diversity of driving behavior, EV types, and charging access across that may be expected in Nova Scotia by drivers as electric vehicle sales targets are achieved.

Charging loads that feature drivers that plug in and begin charging immediately upon arrival at their destination reflect an unmanaged charging scenario. In this scenario, drivers still choose the location of their charging based on the relative electric rates at each location (for example, if a driver has the choice given their driving patterns and charger access to choose between more expensive public charging or less expensive residential charging, they will choose the less expensive residential charging). However, the timing of charging at a given location does not take into consideration any time-varying prices of electricity in the “unmanaged” charging scenario. In a “managed” charging scenario, drivers can shift the timing of their charging at a given location to minimize costs of charging based on time-varying electric rates. A third charge management type, charge management with Vehicle-Grid Integration (VGI), assumes drivers shift their times of charging to minimize charging costs, but also features an aggregator’s involvement to smooth peaks in charging that occur at transitions between peak and off-peak rate periods.[50]

Figure 3-2 below provides an overview of the inputs and outputs of the EV Load Shape Tool.

[50] The charging loads resulting from each charge management type are combined with electric rates and electricity supply costs to calculate total bills and electricity supply costs for EV charging in Section 4 of this report.

Figure 3-2. Overview of E3 EV Load Shape Tool



Charging loads are developed separately for each vehicle class, including LDV, MDV, and HDV.

3.2.2 Key Modeling Inputs

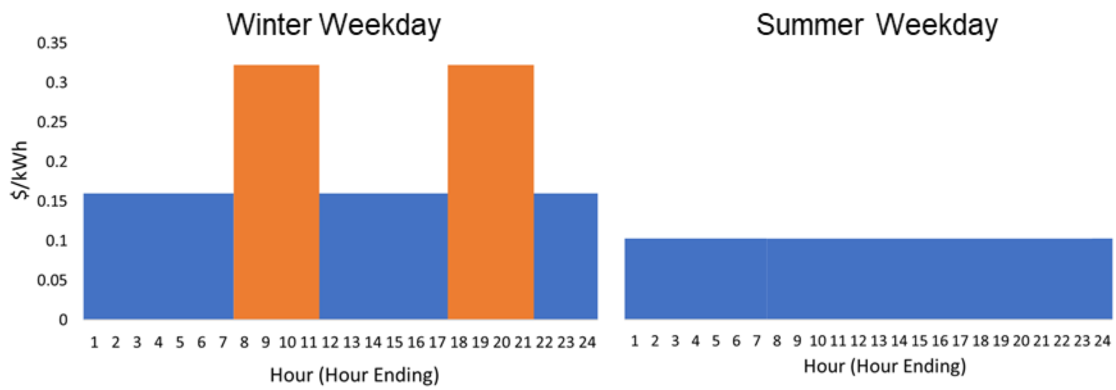
To develop the transportation load shapes, key inputs into the E3 EV Load Shape Tool include:

- Annual Vehicle Miles Travelled (VMT): the miles or kilometers an average LDV, transit bus, and parcel truck per year
- Range: the range, in kilometers, of an EV battery
- EV efficiency: the efficiency of the conversion from kWh charged to kilometers driven by a vehicle. EV efficiency varies by outdoor temperature.
- Number of EV chargers: EV charger availability informs the ability for EVs to charge at each location
- Charger access: the portion of EV population that has access to residential and workplace chargers (all EVs are assumed to have access to public charging)
- Charger parameters: key charger inputs include rated charger power in kW and charger efficiency

Additional detail on inputs used in the E3 EV Load Shape Tool are provided in Appendix Section 6.

In managed charging scenarios, charging is shifted based on the assumed electric rates at each charging location (residential, workplace, and public charging locations). For residential charging, 100% of drivers charge with Nova Scotia Power's new domestic TOU rate, shown in Figure 3-3.

Figure 3-3. Nova Scotia Power domestic TOU pilot rate



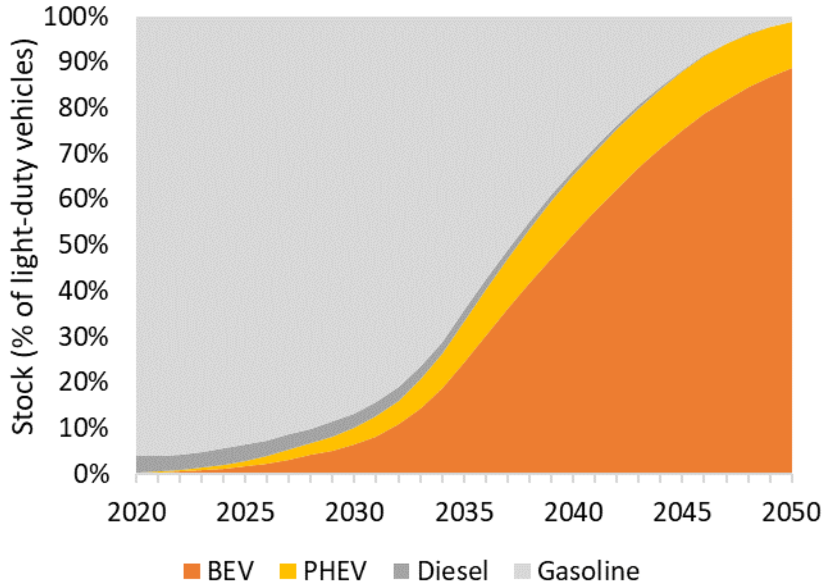
For workplace charging, 20% of workplace charging is assumed to be free in 2030 and the remaining 80% of workplace charging is on Nova Scotia Power's pilot General TOU rate. For public L2 and DCFC, 100% of drivers charge with Nova Scotia Power's public charging rates ($1.50/hour for public L2 and $15/hour for public DCFC). For transit busses and parcel trucks, 100% of managed charging is assumed to be on Nova Scotia Power's pilot General TOU rate.

3.2.3 Transportation Scenarios

E3 modeled four scenarios for EV load shapes based on the access to rates and level of EV charge management, in order to evaluate potential impacts on load and system peak. [51] All scenarios assume adoption of light duty electric vehicles in line with 100% electric vehicle sales by 2035. The adoption forecast is reported in Figure 3-4 below.

[51] Load forecasts and shapes were also developed for transit bus and parcel truck vehicles using the same tool, though these categories comprise a smaller portion of load in Nova Scotia. Those load shapes are leveraged in the BCA in Section 4.

Figure 3-4. Light-duty electric vehicle stock across scenarios (% of stock)



The scenarios then layer on assumptions related to TOU responsiveness and load management. First, scenarios vary based on how responsive drivers' charging is to time-of-use electric rates. TOU responsiveness indicates that charging that is shifted based on time-varying electric rates, to the extent possible given vehicle driving patterns, to reduce charging costs (i.e., drivers charge when electric rates are lower and avoid charging when electric rates are higher). The percentage of TOU responsiveness indicates the percentage of Nova Scotia vehicles that have charging managed based on TOU rates.

Scenarios also vary in their assumptions related to charge management, with some scenarios assuming the use of aggregation or vehicle-grid integration (VGI). Aggregation/VGI indicates external involvement, such as by an aggregator or utility, to smooth charging demands. Without aggregation/VGI, a large spike in charging occurs immediately when an off-peak TOU period begins; aggregation/VGI helps to smooth and distribute that charging across lower TOU rates in a way that minimizes spikes in charging load.

The four scenarios modeled include:

- The **Unmanaged Charging** scenario provides a "high peak" counterfactual to understand what would happen if future electric load impacts were not managed or shifted in some way.
- The **Blended** scenario reflects a "central" case in which 70% of customers manage their charging using the TOU, and those with managed charging have that charge managed, or smoothed.
- The **Managed with TOU** scenario is designed to maximally reduce charging during the peak TOU hours, but does not smooth out "rebound" effects that may occur after the TOU period ends.
- The **Managed with VGI Aggregation** scenario demonstrates the full value that a future TOU combined with load management through VGI aggregation could provide. In this scenario, all customers are fully responsive to the TOU rate, and all charge is further managed, or smoothed, using VGI.

A summary of the scenario assumptions are shown in Figure 3-4 below.

Figure 3-5. System-level light-duty EV load shape scenarios

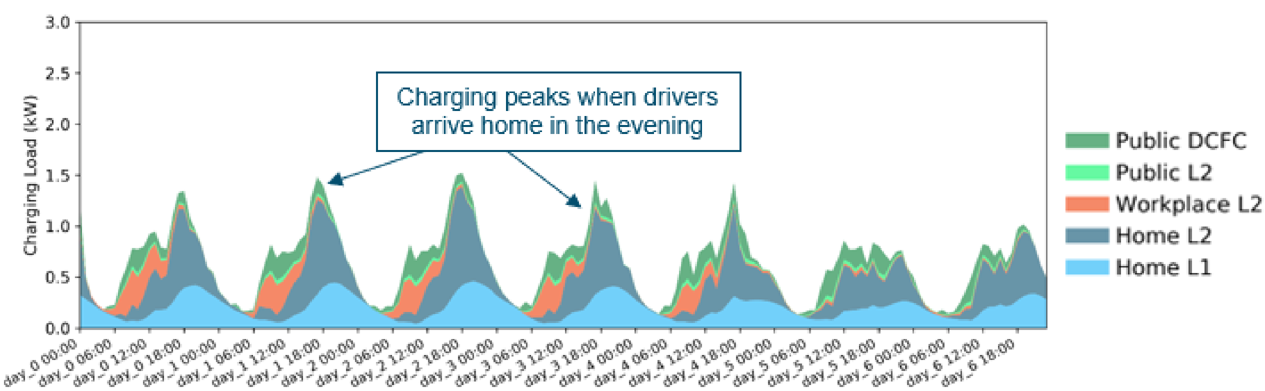
	Unmanaged Charging Scenario	Blended (Unmanaged and Managed with VGI) Scenario	Managed with TOU	Managed with VGI Aggregation
Access to Residential Charging	100% access to public; 77% access to residential	100% access to public; 77% access to residential	100% access to public; 77% access to residential	100% access to public; 77% access to residential
Time of Use Responsiveness	None	70% TOU responsive	100% TOU responsive	100% TOU responsive
Aggregation/Load Management with VGI	None	All those responsive to TOU (70%) are managed through VGI aggregation	None	100%

3.2.4 Results: EV Scenario Load Forecast and Shapes

Hourly load forecasts

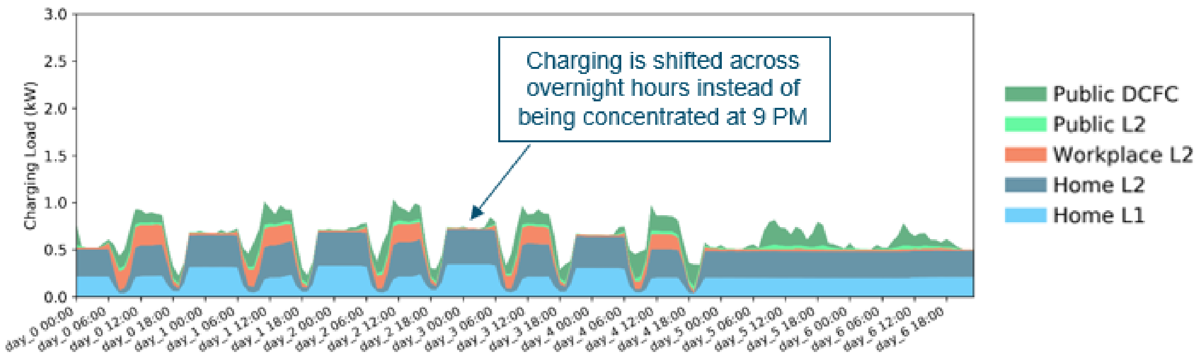
Load forecasts were developed at an hourly level for a full year for each scenario identified in Section 4. Load forecasts across the entire LDV population are averaged to give a per vehicle profile. Figure 3-6 below shows an hourly charging profile for one LDV vehicle with unmanaged charging.

Figure 3-6. Hourly LDV unmanaged charging profile (winter, one week)



Unmanaged charging features large amounts of charging in the early evening hours, when drivers typically arrive home from work and begin charging their EV. The Nova Scotia Power TOU rates have peak periods from 7-11 AM and 5-9 PM and therefore, managed charging shifts charging out of these hours as much as possible, illustrated in the hourly profiles in Figure 3-7 below.

Figure 3-7. Hourly LDV managed charging with VGI profile (winter, one week)



Hourly charging profiles are used as an input to the total load forecast provided in Section 3.4 and in the cost-benefit analysis to calculate the utility bills and electricity supply costs to serve EV load.

3.3 Buildings: Load Shape Modeling

3.3.1 Overview of E3's Building Load Shaping Tool

E3's RESHAPE model is designed to simulate diversified system-level building electrification load shapes. System diversity is captured in the model through a regionally specific sample of buildings representing the housing stock and fuel mix, temporal and spatial variability in temperature, and the mix of heat pump technologies adopted.

3.3.2 Key Assumptions

The residential building stock in Nova Scotia was characterized using data from Natural Resource Canada (NRCAN), Nova Scotia Power, and the U.S. Energy Information Agency (EIA) Residential Energy Consumption Survey (RECS). Data from E1 on the average heating demand per household was used to determine the total residential service demand across the province. The share of homes using fuel oil, natural gas, electricity (resistance and heat pumps), or wood as their primary heating fuel was determined from Nova Scotia Power provided data. NRCAN data on provincewide space heating fuel consumption and building stock was used to adjust the per household annual service demand of single family and multifamily homes by fuel type to capture variation in service demand in the building stock. E3 used a sample of homes in New England in the RECS dataset adjusted and scaled for Nova Scotia's residential fuel mix in the RESHAPE model to represent the provincial housing stock. The assumed annual service demand for the 2009 weather year by fuel type is summarized in Table 3-1.

Table 3-1. Residential building stock fuel mix

Fuel	% of Households	Annual Heating Demand (kBtu/household)
Electric Resistance	20%	44,529
Natural Gas	4%	33,294
Heat Pumps	31%	44,682
Fuel Oil	33%	35,411
Other (including Wood)	12%	90,493

The commercial building stock in Nova Scotia was categorized using data from Nova Scotia Power, EIA's Commercial Energy Building Survey (CBECS), and Heritage Gas. Nova Scotia Power provided data on the number of small and general commercial customers that are not all-electric and all-electric and their space heating energy intensity (kWh/m^2). Combined with floor area estimates for a typical small and medium/large commercial customer derived from CBECS, E3 estimated the space heating demand of non-electric and electric customers in the province. The provincewide service demand is summarized in Table 4-2 A sample of buildings from the New England region of the CBECS dataset was scaled according to the fuel mix derived from the Nova Scotia Power and Heritage Gas data to represent the commercial heating service demand fuel mix in the province. Commercial heating demand was allocated to counties in Nova Scotia according to employment data from Statistics Canada.

Table 3-2. Commercial building stock fuel mix

Fuel	% of Commercial Customers	Annual Heating Demand (kBtu/m^2)
All- Electric	30%	126
Not All-Electric	70%	151

To capture the impact of weather on building electrification loads, E3 modeled building loads under a 1-in-2, or median weather year, and a 1-in-10, or 90th percentile, weather year. The RESHAPE model was run with county-level resolution to capture variation in weather across the province. The population weighted average minimum morning (7 AM – 9 AM) and evening (12 PM – 7 PM) in each weather year modeled is showed in Table 3-3.

Table 3-3. Weather year assumptions

Weather Year	Year	Evening Temperature (ºC)	Morning Temperature (ºC)
1-in-2	**2018**	-14.5	-16.5
1-in-10	**1988**	-22.9	-18.6
1-in-40	1979	-21.2	-20.3

Notes: Weather data was sourced from the National Oceanic and Atmospheric Administration's (NOAA) National Centers for Environmental Prediction (NCEP) North American Regional Analysis (NARR) dataset. Weather was sampled from NARR for each county in Nova Scotia using its geographic centroid. Values shown in this table represent the minimum temperature from the population weighted average of the county temperature profiles

RESHAPE models various base, mid, and best-in-class performance all-electric heat pumps as well as dual-fuel hybrid heat pumps. Heat pump performance data is sourced from manufacturer reported data provided by the Northeast Energy Efficiency Partners (NEEP) in its *Cold Climate Air Source Heat Pump Product List and Specifications.* Detailed assumptions on heat pump performance and sizing assumptions can be found. The mix of heat pump technology is varied between scenarios modeled.

In this analysis, base and mid performance all-electric heat pumps are sized according to standard building industry practice to have a heat pump balance point temperature—the temperature below which the supplemental device would begin to serve heating demand—of 20ºF/-7ºC. Best-in-class or high performance all-electric heat pumps were oversized such that the heat pump could serve the heating demand at 99th percentile historical minimum temperature from 2000 to 2018, approximately 6ºF /-14ºC. Dual-Fuel heat pumps were sized to have a heat pump balance point temperature of approximately 30ºF/-1ºC. Heat pumps are modeled such that below the balance point temperature both the heat pump and supplemental device both contribute to meeting the service demand.

3.3.3 Building Scenarios

In all scenarios modeled, E3 assumes that 100% of sales of heating equipment are heat pumps by 2030 resulting in nearly all residential customers and 96% of commercial customers having heat pumps by 2050. Most scenarios assume that current electric resistance customers will adopt heat pump, but E3 modeled a **No Electric Resistance Phaseout** scenario that considers the impact to Nova Scotia Power's system when current resistance customers do not adopt more efficient heating systems.

E3 modeled several scenarios that explore the system impacts under current trends in electrification, improvements in heat pump technology, and the use of mini split or dual-fuel hybrid heat pumps amongst current fuel oil, natural gas, and wood customers.

- The **Current Trends** scenario assumes all heat pumps adopted are all-electric ducted ASHPs with 30% of those being base performance, 40% mid performance, and 30% high performance. This scenario reflects Nova Scotia Power's current focus on moving electric resistance customers to moderately high performing heat pumps and assumes fuel customers adopting heat pumps would not retain their current heating system for backup in coldest hours. E3 also modeled two iterations of this scenario. In the "with DSM" iteration, current resistance buildings receive a building shell improvement when adopting a heat pump ("with DSM") and in the "pre-DSM" scenario there are no shell improvements assumed; this scenario is used for Nova Scotia Power's system modeling when DSM programming is added later based on information from E1.

- The **No Electric Resistance Phaseout** scenario assumes the same mix of heat pumps are adopted amongst current fuel oil, natural gas, and wood customers as the Current Trends scenario but assumes that current electric resistance customers do not adopt heat pumps. This scenario represents a future in which electrification continues but Nova Scotia Power stops its efforts to switch resistance customers to more efficient devices.
- The **Best-in-Class** scenario assumes all heat pumps adopted are all-electric high performance heat pumps that are sized larger. This scenario represents a focus on deploying the high performing heat pumps which would require policy support and/or market transformation. E3 also modeled two iterations of this scenario. In the "with DSM" iteration, all buildings receive a building shell improvement when adopting a heat pump ("with DSM") and in the "pre-DSM" scenario there are no shell improvements assumed.
- The **Current Trends Hybrid** scenario assumes that current resistance customers adopt 30% base, 40%, mid and 30% high performance all electric heat pumps and current fuel customers adopt dual-fuel heat pumps. Dual-Fuel heat pumps are mid-performance and are modeled as mini-split systems such that in the coldest hours both the heat pump and supplemental heating system contribute to meeting the building's heating demand.

The mix of heat pumps adopted in each scenario are shown in Figure 3-8 and Table 3-4.

Figure 3-8. Residential building stock across scenarios (% of housing stock)

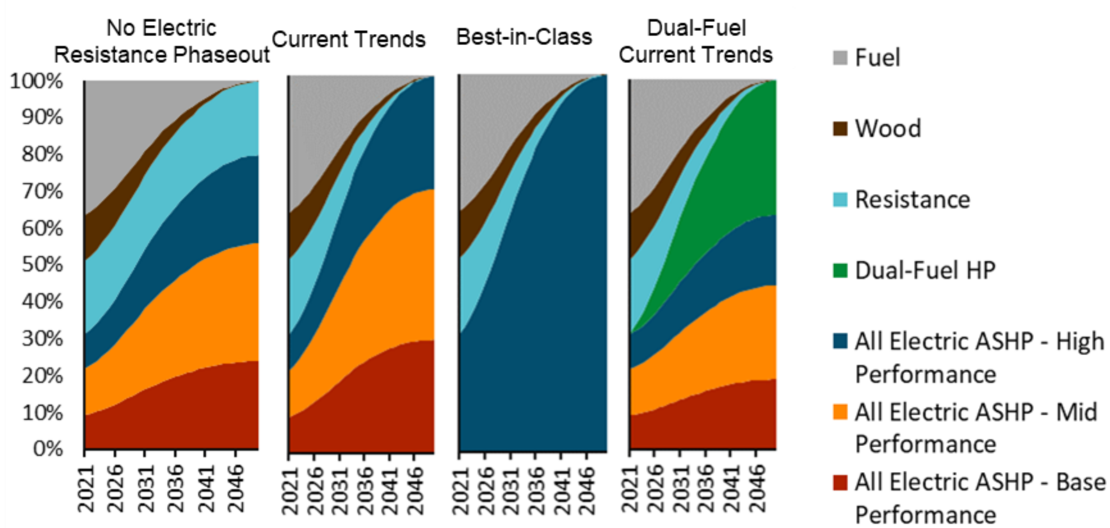


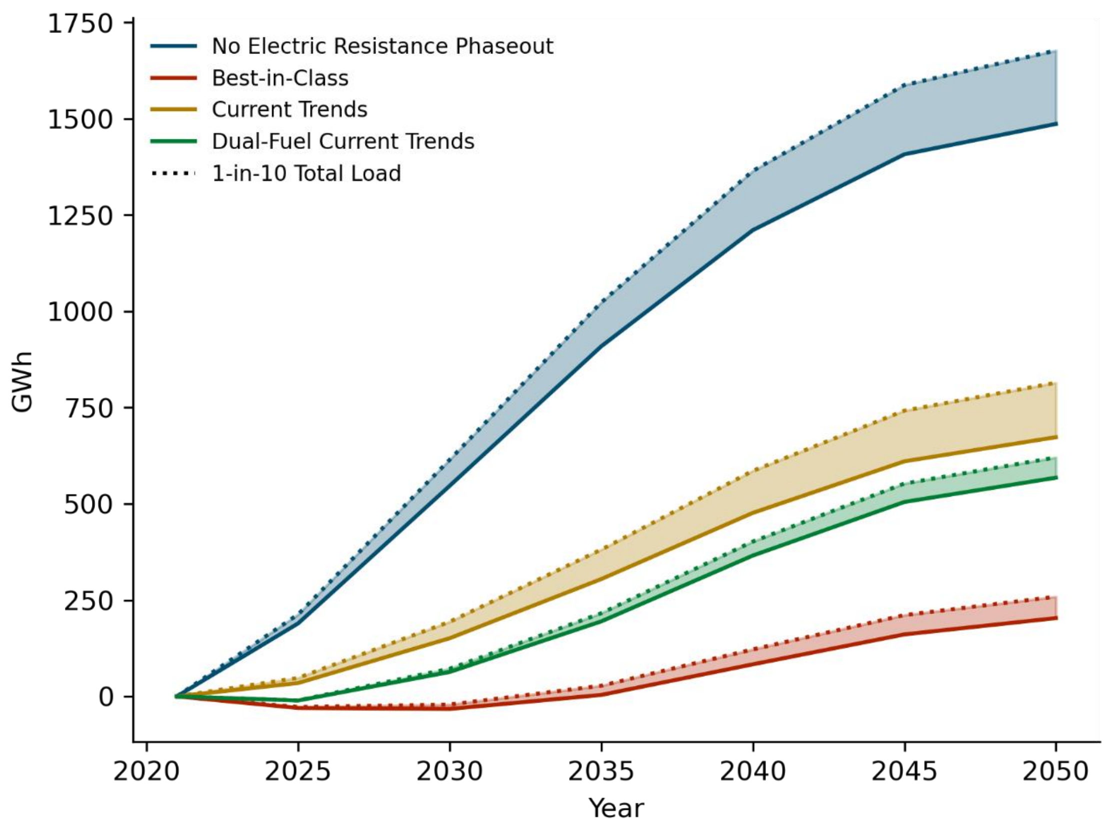
Table 3-4. Building scenario design

	No Electric Resistance Phaseout	Current Trends All-Electric	Best-in-Class	Current Trends Dual-Fuel
Today's gas and oil heating buildings	Adopt **ASHP**	Adopt **ASHP**	Adopt **ASHP**	Adopt **mini-split systems** and retain fuel back-up
Today's electric resistance buildings	Retain **ER** heating system	Adopt **ASHP**	Adopt **ASHP**	Adopt **ASHP**
Heat pump performance	ASHPs are 30% base; 40% mid; 30% high performance	ASHPs are 30% base; 40% mid; 30% high performance	ASHPs are 100% high performance	ASHPs are 30% base; 40% mid; 30% high performance; Mini-split systems are 100% mid performance
Heat pump sizing	ASHPs sized to serve full heating demand in 93-95% of hours	ASHPs sized to serve full heating demand in 93-95% of hours	ASHPs sized to serve full heating demand in 99% of hours	ASHPs and mini-splits sized to serve full heating demand in 93-95% of hours
Building shell improvements	No shell improvements	No shell improvements	No shell improvements	No shell improvements

3.3.4 Results: Building Scenario Load Forecast and Shapes

While annual load growth is expected to be modest from building electrification, peak load impacts could potentially be large. Under the **Current Trends Pre-DSM** scenario, buildings are expected to add 673 GWh of load in a 1-in-2 weather year to Nova Scotia Power's system in 2050 which is approximately 6% of current annual load. The adoption of heat pumps amongst current electric resistance customers offsets approximately 814 GWh of load growth from fuel switching. In the **Best-in-Class Pre-DSM** scenario, annual load growth is expected to be approximately 70% lower than the Current Trends scenario due to the uptake of high-performance heat pumps.

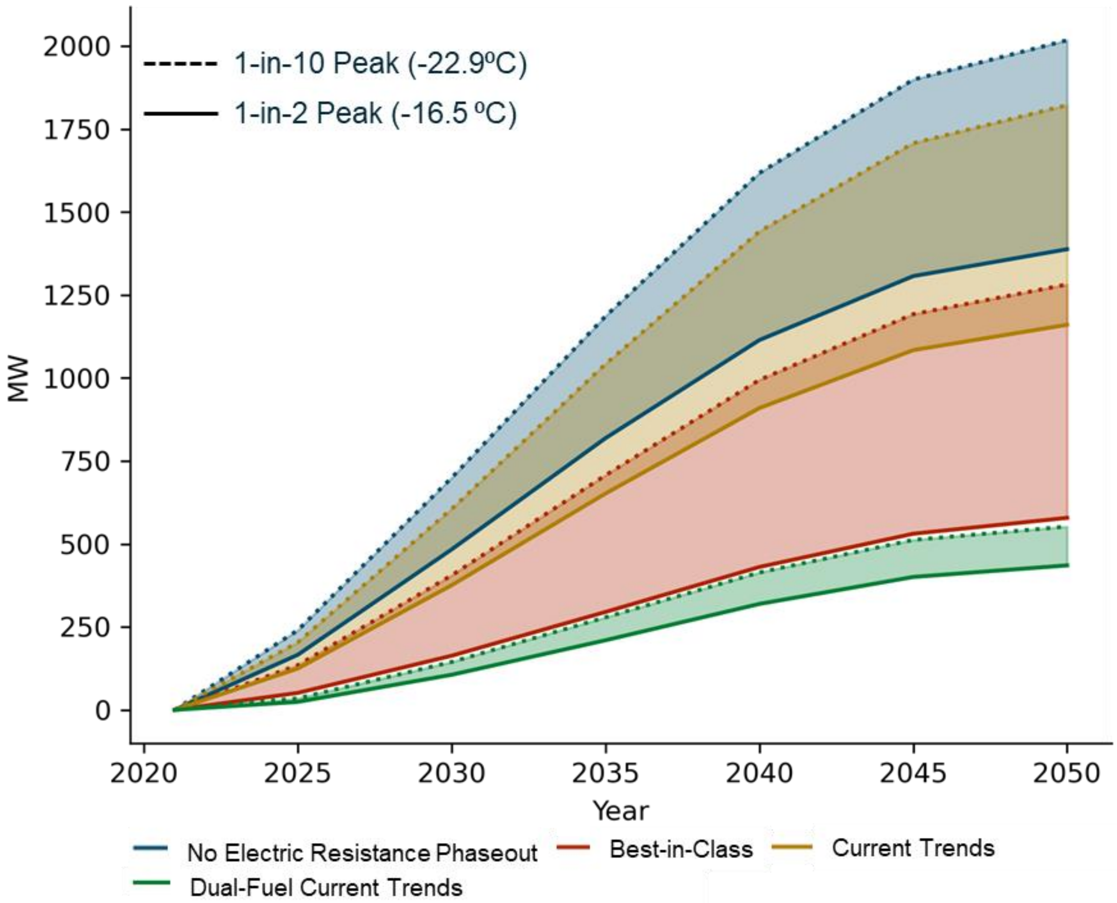
Figure 3-9. Incremental annual load growth from building electrification



Note: Scenarios show are pre-DSM.

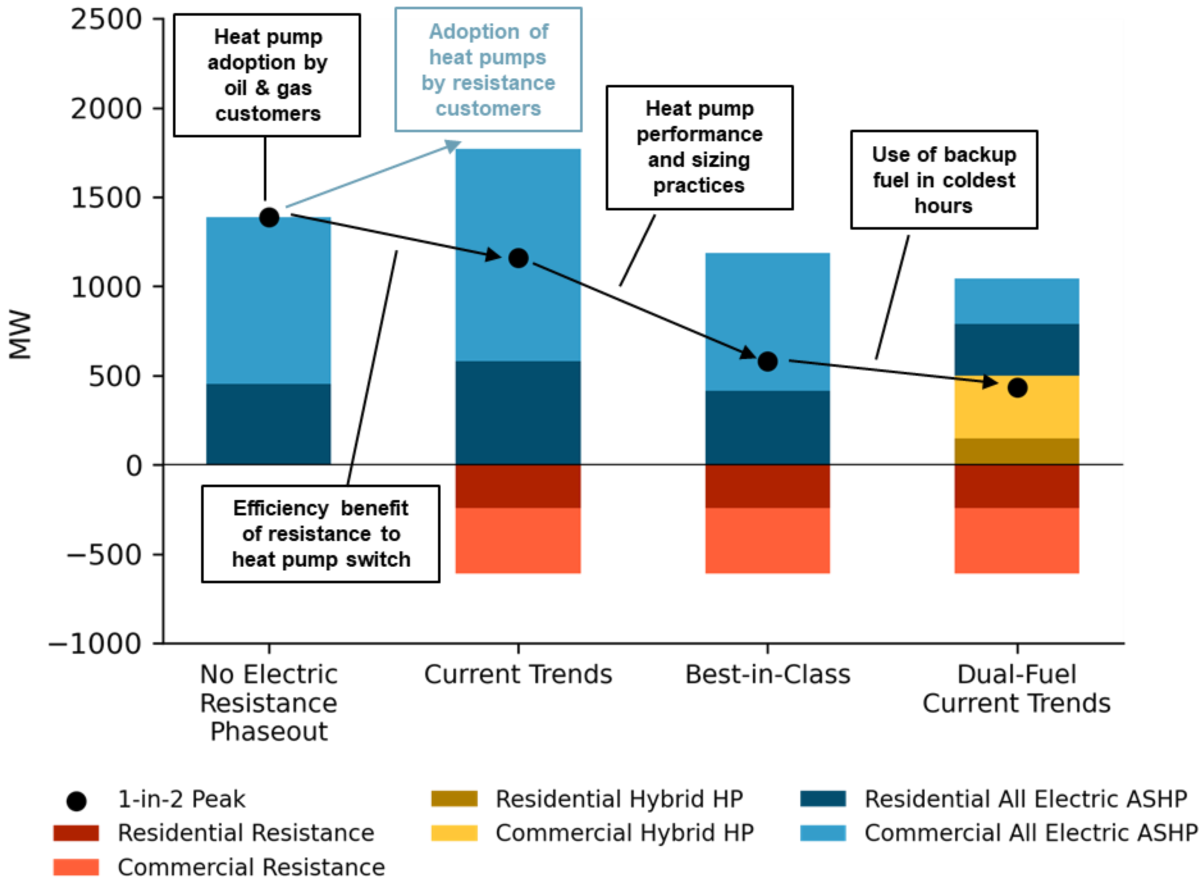
Electrification of buildings is significant peak load impacts given the declining efficiency of heat pumps in cold temperatures and greater coincident of heating loads with NS Power's existing system peak load. Under the **Current Trends Pre-DSM** scenario, the non-coincident peak of buildings incremental building loads is expected to reach 1160 MW in 2050 under a median or 1-in-2 weather year and 1822 MW in an extreme 1-in-10 weather year. The use of backup fuel systems in the **Current Trends Dual-Fuel** scenario could significantly reduce peak load impacts. The non-coincident peak impacts of incremental building electrification scenario is 436 MW in a 1-in-2 weather year.

Figure 3-10. Incremental non-coincident buildings peak demand forecast



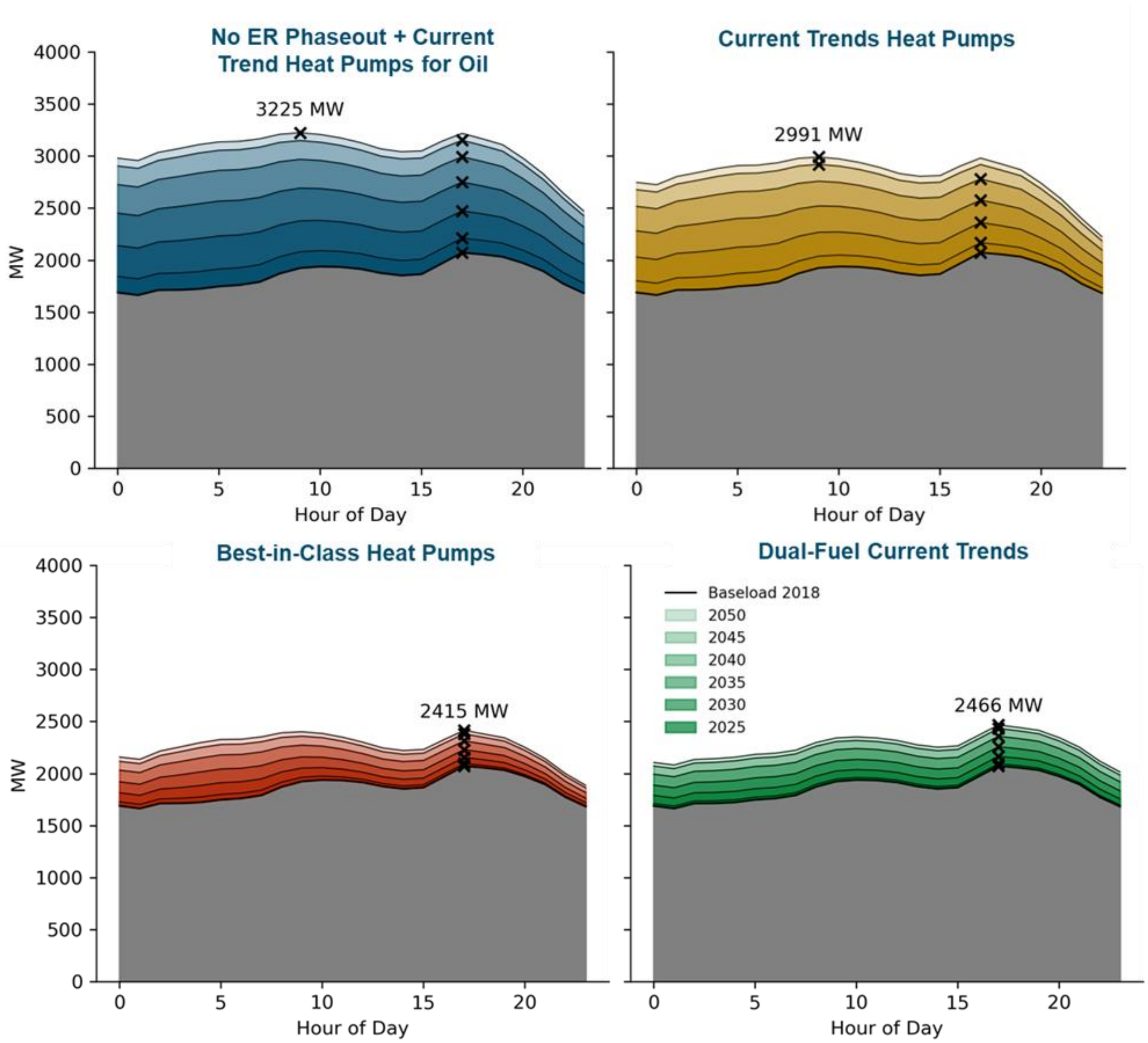
Note: Scenarios show are pre-DSM.

Figure 3-11. Contribution to incremental non-coincident peak load by sector



Note: Scenarios show are pre-DSM.

Figure 3-12. Peak day load growth

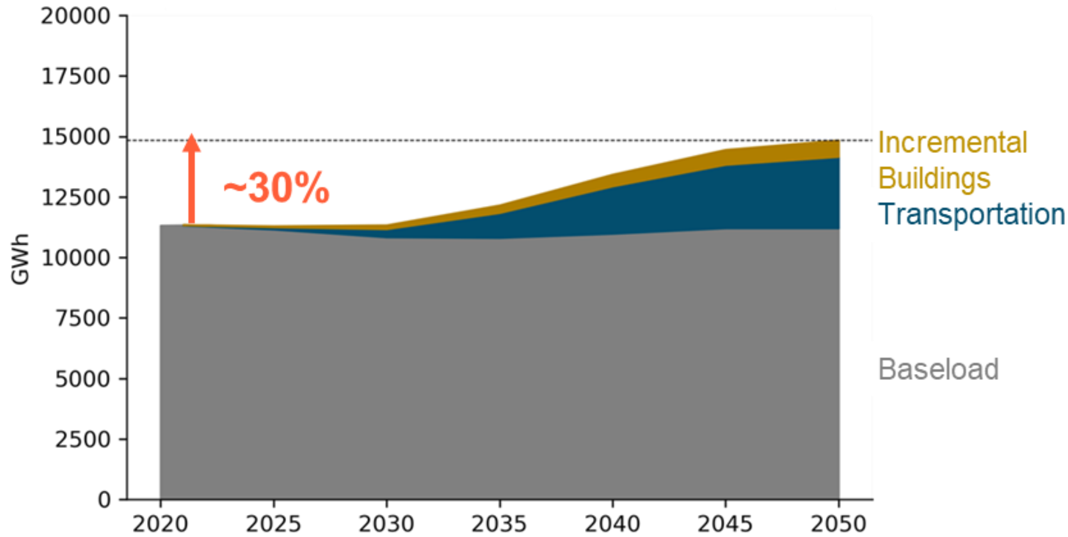


Note: Scenarios shown are pre-DSM.

3.4 Combined Electrification Load Impacts

Considering both transportation and buildings, electrification will generate significant electric load and peak impacts. Transportation loads are forecasted to make up a larger portion of annual load. Incremental building loads are lower in Nova Scotia relative to expected incremental loads in other jurisdictions given the existing portion of electric resistance customers in Nova Scotia as well as the high levels of heat pump adoption assumed in Baseload.

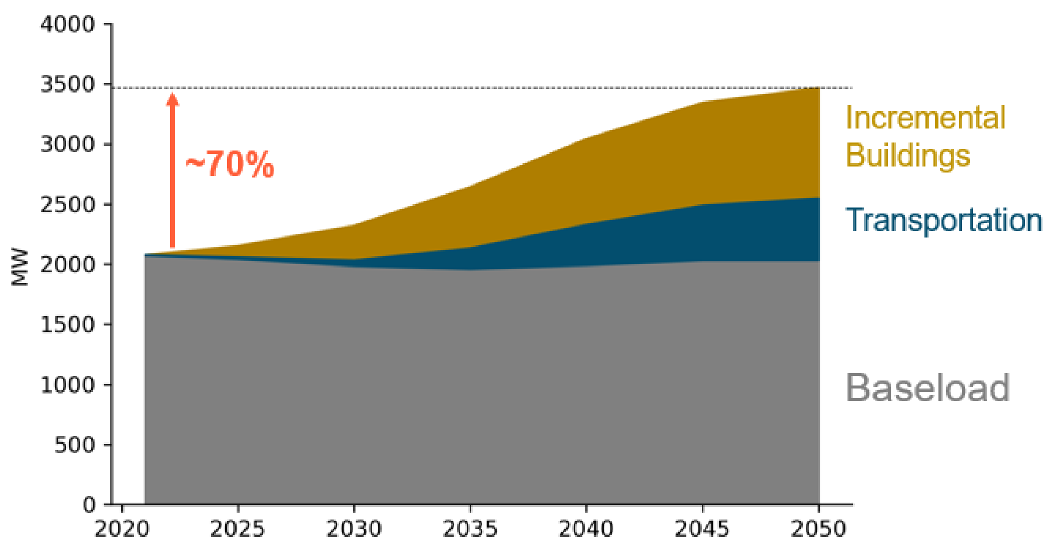
Figure 3-13. Annual loads from transportation and building electrification under the Current Trends All-Electric buildings scenario and Blended (managed/unmanaged) transportation scenario



Note: Reflects Current Trends All-Electric buildings scenario and Blended transportation scenario.

Buildings, however, are expected to disproportionately contribute to peak load given the high demand during cold winter days, when system peaks are likely to occur.

Figure 3-14. Annual peak load contribution from incremental transportation and building electrification under the Current Trends All-Electric buildings scenario and Blended (managed/unmanaged) transportation scenario



Note: Reflects Current Trends All-Electric buildings scenario and Blended transportation scenario.

4. Benefit-Cost Analysis Modeling

4.1 Overview of Benefit-Cost Analysis Modeling

E3's Benefit-Cost Analysis (BCA) approach assesses the marginal benefits and costs of heat pump adoption for representative heat pump technologies and building segments. The analysis presents the economics of marginal adoption for representative heat pumps and EVs using available data and assumptions described below. These results provide an indication of the economics for average customers within Nova Scotia, though individual customers and building types may have different outcomes. As discussed below, the results are sensitive to several uncertain assumptions and modeling limitations, notably capital costs, fuel prices, and electricity supply costs. The capital cost information for electric vehicles derived from the International Council on Clean Transportation, with E3 adjustments (see Figure 2-2 for details). The capital cost information for heat pumps and the electricity supply costs were provided by Nova Scotia Power. The fuel prices were benchmarked to local sources. More details on these assumptions is provided in Appendix 7.2.

4.2 Benefit-Cost Analysis Model

E3's Benefit-Cost Analysis (BCA) Model calculates the costs and benefits associated with transportation and building electrification. Costs and benefits in the E3 BCA Model are organized by perspective, using standard "cost tests" typically performed in evaluating electricity sector demand-side investments.[52] The three perspectives analyzed in this BCA are:

+ **Participant Cost Test (PCT):** What are the costs and benefits to the vehicle driver, fleet owner, or building owner – Is the total cost of EV ownership higher or lower for the driver? Is the total cost of installing and operating a heat pump over its lifetime higher or lower for the homeowner or business than a fossil fuel heating system?
+ **Societal Cost Test (SCT) from the perspective of Nova Scotia:** What are the costs and benefits to the region or province – do EVs and heat pumps provide net benefits for the province? This perspective includes the value of externalities, specifically carbon emissions.
+ **Ratepayer Impact Measure (RIM):** What are the costs and benefits to all non-participating ratepayers – will average utility rates increase or decrease?

The BCA Model estimates the annual stream of costs and benefits associated with electrified technology adoption. To facilitate comparison, the model makes assumptions about how to weigh impacts in the future to today and uses those weights to estimate the net present value of each cost and benefit stream. The PCT uses a 9% nominal discount rate, the SCT uses 3%, and the RIM uses 6%. The higher discount rate for the participant cost test reflects the higher borrowing costs typically facing private borrowers (and

[52] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects: http://www.calmac.org/events/SPM_9_20_02.pdf.

likewise, the higher return on private capital); the ratepayer impact measure relies on the utility's discount rate (approximately); and the societal discount rate reflect societal trade-offs between consumption today and consumption in future periods. These discount rates are used to estimate the net present value (NPV) results shown below.

4.2.1 Cost and Benefit Categories in Transportation BCA

The model considers significant and measurable categories of benefits and costs. A brief description of each estimated cost/benefit component included in the transportation BCA is provided below:

- **Incremental EV cost:** EVs generally have a higher upfront purchase cost than an equivalent ICE vehicle. The incremental EV cost is the difference between the upfront cost of an EV and an equivalent ICE vehicle in a given adoption year.
- **Federal and provincial EV purchase incentives:** The federal EV tax credit and provincial EV rebate are applied to LDV in applicable years.
- **EV operating and maintenance (O&M) savings:** EVs generally have lower O&M costs than ICE vehicles on a per mile basis. The EV O&M savings represent the difference between the lifetime O&M costs for EVs and ICE vehicles.
- **Vehicle fuel savings:** EVs offer savings from the avoided gas or diesel costs that would be incurred to satisfy an average vehicle's lifetime Vehicle Miles Travelled (VMT).
- **Electricity supply costs for EV charging:** The marginal utility cost of supplying EV charging load over the vehicles' lifetime. These utility costs include the marginal energy, generation capacity, transmission capacity, and distribution capacity costs.
- **Charging infrastructure costs:** All costs beyond the customer meter for installing electric vehicle supply equipment (EVSE).
- **Electricity bill for EV charging:** The revenue collected by the utility from the sale of all energy used for EV charging or the electricity bill paid by the EV owner for all charging over the vehicle lifetime. This is the EV equivalent of ICE vehicle gasoline costs. The revenue collected by the utility is not always the same as what the driver pays for charging their EV in public and workplace locations and therefore PCT and RIM values may be different.
- **Avoided emissions:** An estimate of the monetized benefit of emissions avoided, calculated as the net of avoided emissions from not combusting gasoline or diesel in an ICE vehicle and the emissions associated with the energy used for EV charging.

Table 4-1 below categorizes the key costs and benefits included in each perspective. The cost perspectives are based on the perspectives outlined in the California Public Utility Commission (CPUC) standard practice manuals for cost effectiveness of demand side resources.[53]

[53] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects: http://www.calmac.org/events/SPM_9_20_02.pdf.

Table 4-1. Cost and benefits associated with each cost test perspective for transportation electrification

Cost/Benefit Component	PCT	SCT	RIM
Incremental upfront EV cost	Cost	Cost	
Federal EV purchase incentives	Benefit	Benefit	
Provincial EV purchase incentives	Benefit		
EV O&M savings	Benefit	Benefit	
Vehicle fuel savings	Benefit	Benefit	
Electricity Bill for EV charging	Cost		Benefit
Electricity supply costs for EV charging		Cost	Cost
Charging infrastructure costs	Cost	Cost	
Avoided emissions		Benefit	

4.2.2 Cost and Benefit Categories in Buildings BCA

The cost and benefit streams considered in the buildings BCA are summarized in Table 4-2 and include the upfront incremental cost of the appliance, incremental electricity bills, avoided fuel oil or natural gas bills, incremental electricity supply costs, avoided fuel supply costs, utility incentives, and emissions savings.

Table 4-2. Cost and benefits associated with each cost test perspective for building electrification

Cost/Benefit Component	PCT	SCT	RIM
Incremental Electricity Bills[1]	Cost		Benefit
Incremental Appliance Cost	Cost	Cost	
Avoided Fuel Bills	Benefit		
Utility Incentives	Benefit		Cost
Electricity Supply Costs[2]		Cost	Cost
Avoided Fuel Supply Costs		Benefit	
Avoided Emissions		Benefit	

1. Incremental electricity bills are a cost to participants switching from fuel oil or natural gas to heat pumps but a benefit for current electric resistance customers adopting heat pumps.

2. The adoption of heat pumps amongst current fuel customers presents electricity supply costs from both the SCT and PCT perspectives, but the adoption of heat pumps amongst current electric resistance customers presents a net benefit.

A brief description of each cost/benefit component included in the building BCA is provided below:

- **Incremental appliance cost:** This is the additional capital cost required to purchase a heat pump compared to the alternative in-kind replacement of existing heating equipment in the year a heat pump is adopted. E3 modeled heat pump adoption in retrofit applications for this report.
- **Incremental electric bills:** This is the additional revenue the customer would pay and the utility would collect from customers who adopt heat pumps over the equipment's lifetime. For customers who switch from electric resistance to a heat pump, this would present a bill savings for the participant and a loss in revenue for the utility.
- **Avoided fuel bills:** This is the cost the fuel oil, natural gas, and wood customers avoid paying for heating fuel from electrifying over the lifetime of the equipment. This includes the commodity cost and delivery cost paid by the consumer.
- **Electricity supply costs:** The marginal utility cost of supplying EV charging load over the vehicles' lifetime. These utility costs include the marginal energy, generation capacity, transmission capacity, and distribution capacity costs.
- **Avoided fuel supply costs:** The commodity cost of fuel delivered to the customer. While avoided fuel bills consider both the commodity and delivery costs that customers pay, the avoided fuel supply costs include only the commodity cost of the fuel. From the societal perspective, delivery costs are an in-province transfer of funds and therefore do not present a net cost or benefit.
- **Avoided Fuel Carbon Tax:** The cost of carbon fees association with the purchase of fuel oil or natural gas for heating. Avoided fuel carbon taxes are included in the PCT as they represent a portion or the customer's fuel bills that are avoided adopting a heat pump, but the taxes are not included in the SCT. The SCT takes the perspective of Nova Scotia and the taxes represent an in-province transfer.
- **Avoided emissions:** The monetized benefit of emissions avoided, calculated as the net of avoided emissions from not combusting fuel for heating and the emissions associated with the electricity used by the heat pump.

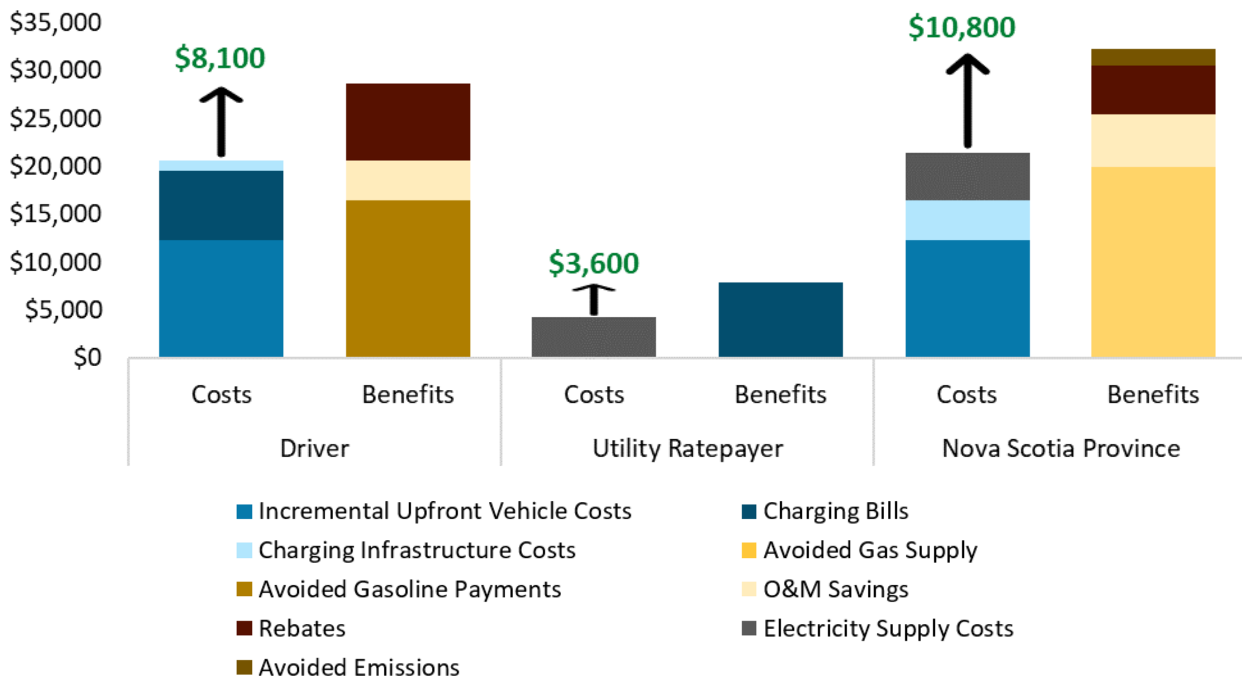
The buildings BCA models the economics of heat pump adoption for both water heating space and space heating mini-split. A current performance ducted all-electric heat pump, a best-in-class (high performance) ducted all-electric heat pump, and a dual-fuel mini-split with fuel backup (hybrid) are modeled. The BCA model also includes the option to analyze the shell improvement adopted alongside the best-in-class heat pumps. The model considers retrofit applications in single-family and multi-family homes as well as small commercial buildings that current use wood, fuel oil, natural gas, or electric resistance for space heating. Representative heating load shapes for each segment were developed as part of the Load Shape Analysis. Additional detail on the E3 BCA Model and inputs can be found in Appendix Section 6.

4.3 Transportation Benefit-Cost Analysis Results

4.3.1 Light-duty Vehicle BCA Results

Electric light-duty vehicles (LDVs) have greater lifetime benefits than costs from the perspectives of drivers, utility rate payers, and the province. The net present value (NPV) of lifetime costs and benefits for an electric LDV adopted in 2022 and with unmanaged charging is shown in Figure 4-1 below.

Figure 4-1. NPV cost-benefit analysis for LDV adopted in 2022 with unmanaged charging



Driver costs for electrifying an LDV include incremental upfront vehicle costs relative to a comparable ICE vehicle, which are sizable in 2022. Driver costs also include bills for charging load and costs borne by drivers to purchase and install residential chargers. Driver savings are made up of avoided gasoline costs[54], a $3,000 provincial rebate, a $5,000 federal rebate, and operating and maintenance (O&M) savings.

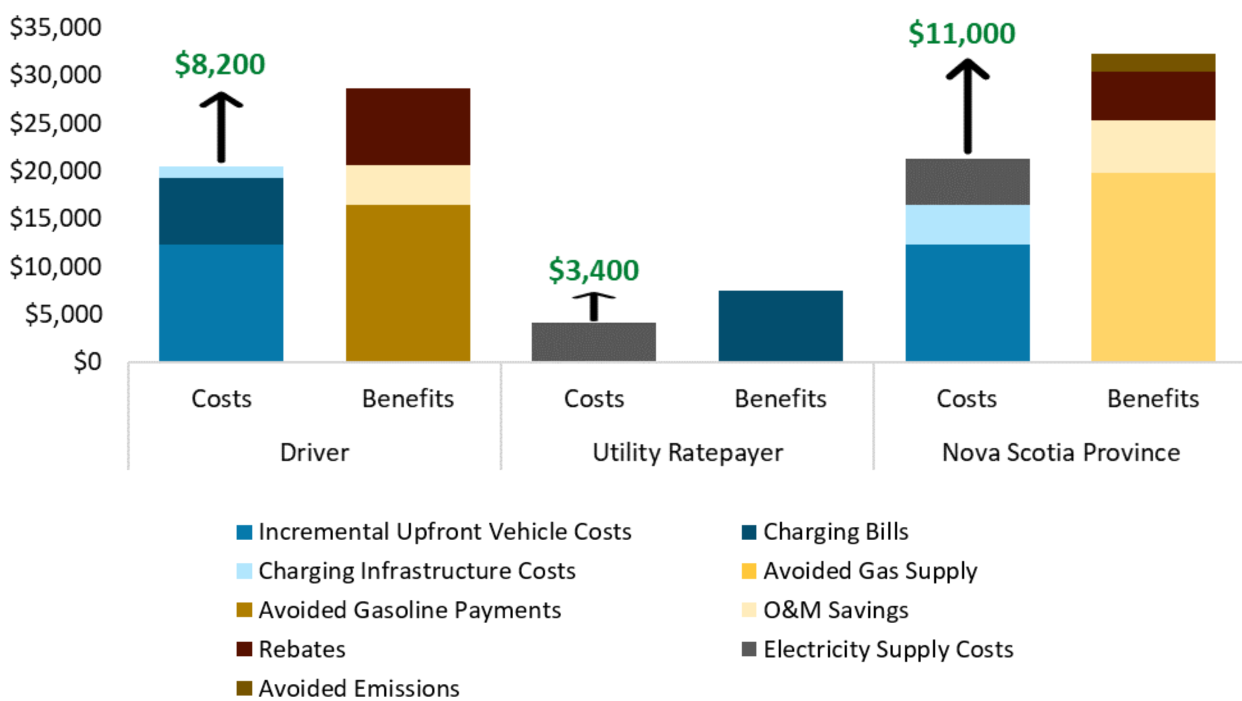
Utility ratepayer benefits are larger than costs, meaning that revenues collected by the utility are larger than the electricity supply costs to serve charging load. This result indicates that average utility rates would decrease with the additional EV charging load.

Costs and benefits from the provincial perspective include many of the same cost components as the driver perspective but are valued at a lower discount rate than from the driver perspective[55], which results in different cost and benefit values. Another difference between the driver and provincial perspective is the exclusion of the carbon tax in gasoline in the provincial perspective; the provincial perspective does not include revenues collected from the carbon tax component of gasoline prices as a benefit since the transfer of tax revenue is assumed to stay within the province. The provincial perspective also includes a monetized value of emissions savings as a benefit which can be considered if desired. The federal rebates are assumed to provide benefits (net inflows) into the province, while the provincial rebates are assumed to be a transfer within the province.

[54] All LDV are modeled with base gasoline prices as detailed in Appendix 9.1.4.
[55] Costs and benefits from the driver perspective are discounted at 9% while provincial costs and benefits are discounted at 3%.

Costs and benefits from each perspective for an electric LDV adopted in 2022 with managed charging with VGI is shown in Figure 4-2. As discussed in Section 3.2, managed charging with VGI represents charging schedules in which drivers shift their charging to lower-cost hours when possible and any spikes in charging are smoothed by an aggregator. In this study, LDV drivers manage home charging against Nova Scotia Power's Domestic TOU rate and manage workplace charging against Nova Scotia Power's General TOU rates. Given the short time duration typically spent in public charging locations, drivers are not typically able to manage public charging to TOU rates.

Figure 4-2. NPV cost-benefit analysis for LDV adopted in 2022 with managed charging with VGI



Drivers achieve about $100 more in net savings by managing charging with VGI compared to having unmanaged charging. Increased net savings stem from savings in charging bills; drivers are able to save about $30 per year in bill savings (undiscounted) by shifting their charging to lower-cost hours. Saving opportunities are lower than may be seen in other jurisdictions since the new Nova Scotia Power Domestic and General TOU rates only offer time-varying rates in winter months. Therefore, drivers only have opportunities to save on their bills in winter months. Net savings for drivers under managed charging are also reduced due to an incremental ~$100 NPV charging infrastructure cost to enable managed charging. Appendix 10 provides a breakdown of BCA results for EVs adopted in 2030.

Summary results for each cost-benefit analysis test under different charge management scenarios are shown as cost-benefit ratios in Table 4-3 below. A ratio greater than 1 indicates that NPV benefits are greater than costs for that perspective. A ratio less than 1 means that NPV benefits are lower than costs.

Table 4-3. Summary of cost-benefit analysis results for light-duty vehicles

	2022			2030		
Charging Scenario	**PCT**	**RIM**	**SCT**	**PCT**	**RIM**	**SCT**
Unmanaged	1.4	1.8	1.5	2.5	1.7	2.7
Managed w/ TOU and VGI	1.4	1.9	1.5	2.5	1.7	2.7

All cost tests show positive results in both 2022 and 2030 for all charge management scenarios. Improvements in LDV driver and societal perspective results over time are primarily driven by decreases in incremental upfront costs between 2022 and 2030; as the incremental upfront cost declines, it becomes more economic for drivers to adopt EVs. Positive ratepayer perspective results indicate that for all years and all charging scenarios, electricity supply costs to serve charging load are lower than the utility revenues collected from charging load.

The emissions savings from electrification of LDVs under each charge management scenario are shown in Table 4-4.

Table 4-4. Estimated lifetime emissions savings per electrified light-duty vehicle, 2022 and 2030

	CO2 Emissions Savings (MMT)	
Charging Scenario	**2022**	**2030**
Unmanaged	17	20
Managed w/ TOU and VGI	19	21

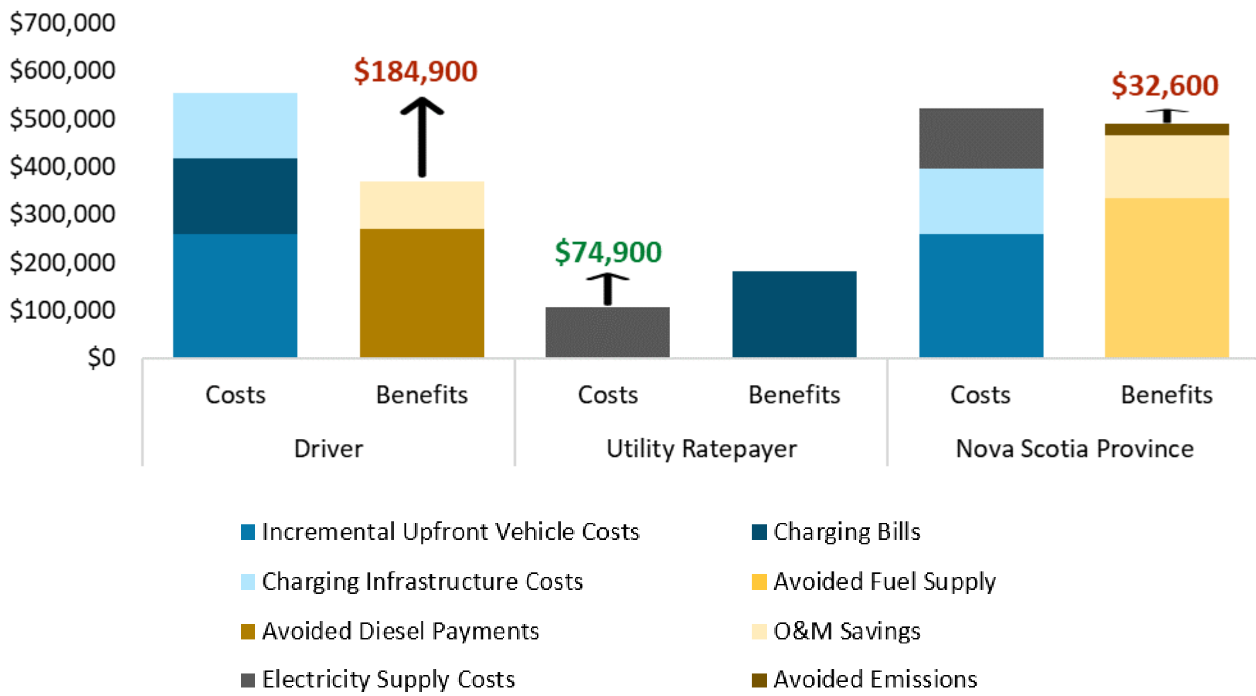
All electric LDVs achieve emissions savings relative to ICE vehicles in 2022 and 2030.

4.3.2 Transit Bus BCA Results

This study models transit busses as a representative heavy-duty vehicle (HDV), which is classified as a vehicle weighing 15 tonnes or more.[56] The net present value (NPV) of lifetime costs and benefits for an electric transit bus adopted in 2022 and with unmanaged charging is shown in Figure 4-3. below.

[56] Transport Canada: https://tc.canada.ca/en/corporate-services/policies/road-transportation-0.

Figure 4-3. NPV cost-benefit analysis for a transit bus adopted in 2022 with unmanaged charging



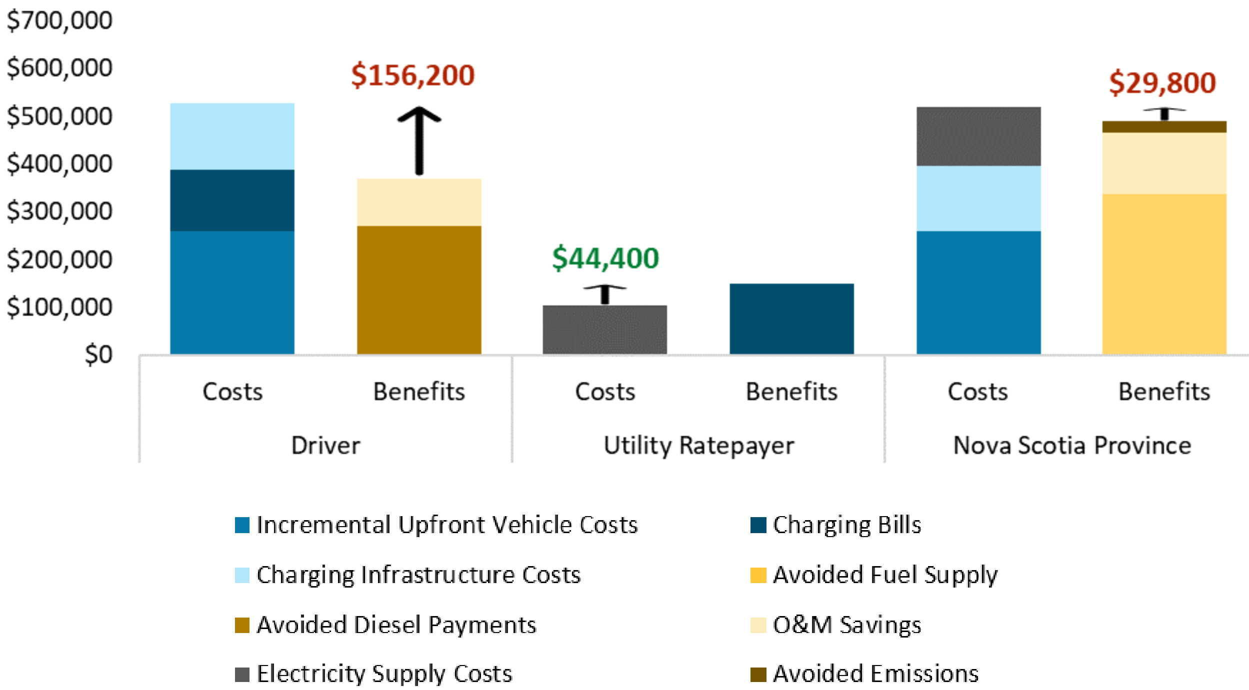
Transit busses adopted in 2022 have net costs from the vehicle driver/owner and provincial perspectives. Net costs are driven by large incremental upfront transit bus costs and high charging infrastructure costs per bus. There are no rebates included as benefits for transit busses which could serve to mitigate this cost difference if available. Although savings from avoided diesel costs[57] and O&M savings are large, they are not large enough to make up for the high upfront and charging infrastructure costs.

From the ratepayer perspective, benefits are larger than costs, which indicates that the utility receives sufficient revenue to cover the electricity supply costs of transit bus charging. Therefore, utility rates would decrease as a result of additional transit bus charging load.

BCA results for a transit bus adopted in 2022 with managed charging with VGI is shown in Figure 4-4.. Charging is managed against Nova Scotia Power's General TOU rate for all transit bus depot charging.

[57] All transit busses are modeled with base diesel prices as detailed in Appendix 9.1.4.

Figure 4-4. NPV cost-benefit analysis for a transit bus adopted in 2022 with managed charging with VGI



Managed charging reduces charging bills for a transit bus owner by about $3,750 per year, which helps reduce the net cost for a transit bus adopted in 2022. The Nova Scotia Power General TOU rate only offers time-varying rates in winter months and additional savings could be unlocked under a rate with year-round time-varying rates. Managed charging offers greater bill savings for transit bus owners than savings in electricity supply costs, which causes the net benefit in the ratepayer perspective to decrease.

A summary of transit bus cost-benefit analysis ratios are shown in Table 4-5.

Table 4-5. Cost-benefit analysis results for transit busses

	2022			2030		
Charging Scenario	**PCT**	**RIM**	**SCT**	**PCT**	**RIM**	**SCT**
Unmanaged	0.7	1.7	0.9	0.8	1.5	1.2
Managed w/ TOU and VGI	0.7	1.4	0.9	0.9	1.3	1.2

Transit bus driver/owners have net costs in both 2022 and 2030 for all charge management scenarios, primarily driven by high incremental upfront costs and high charging infrastructure costs per vehicle. Transit busses also have net costs from the provincial perspective in 2022 but results shift to net benefits by 2030 due to reduced vehicle upfront costs and increases in diesel costs that get discounted at a lower rate than from the transit bus owner perspective.

The emissions savings from light-duty vehicle electrification under each charge management scenario are shown in Table 4-6.

Table 4-6. Lifetime emissions savings per electrified transit bus, 2022 and 2030

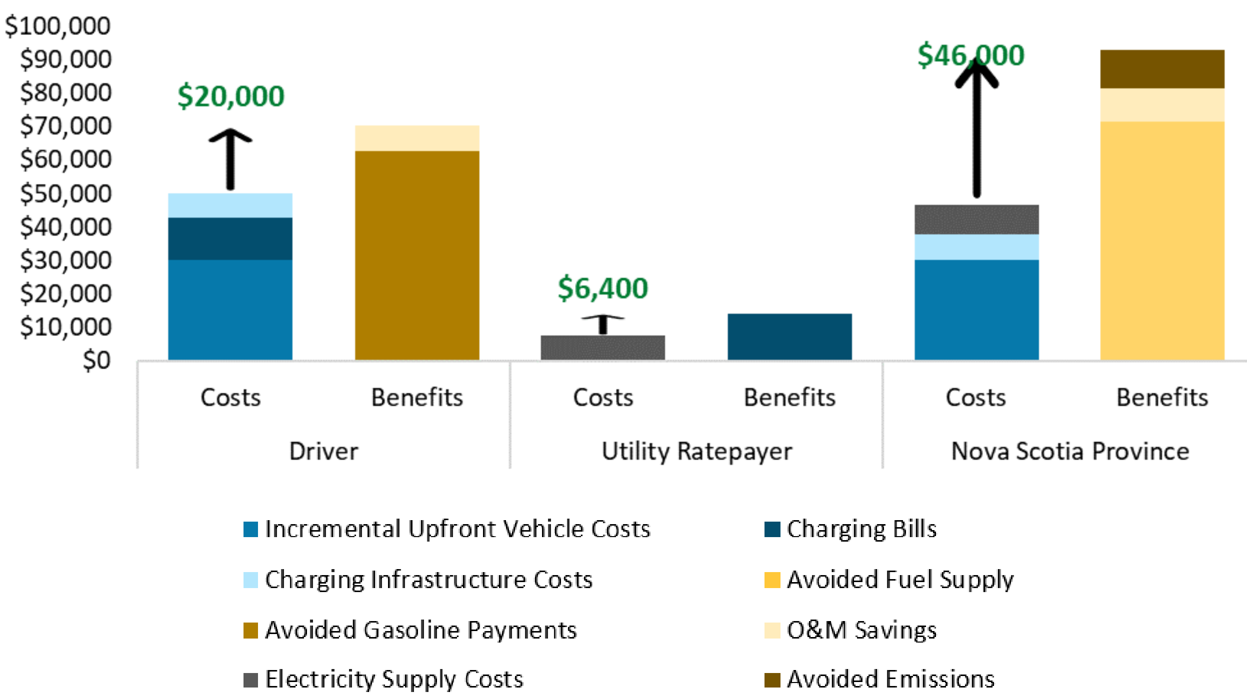
	CO2 Emissions Savings (MMT)	
Charging Scenario	**2022**	**2030**
Unmanaged	204	278
Managed w/ TOU and VGI	203	267

All transit busses achieve emissions savings relative to ICE busses in 2022 and 2030.

4.3.3 Parcel Truck BCA Results

This study models parcel trucks as a representative medium-duty vehicle (MDV), which is classified as a vehicle weighing between 4.5 tonnes and 15 tonnes.[58] The net present value (NPV) of lifetime costs and benefits for an electric parcel truck adopted in 2022 and with unmanaged charging is shown in Figure 4-5. below.

Figure 4-5. NPV cost-benefit analysis for a parcel truck adopted in 2022 with unmanaged charging



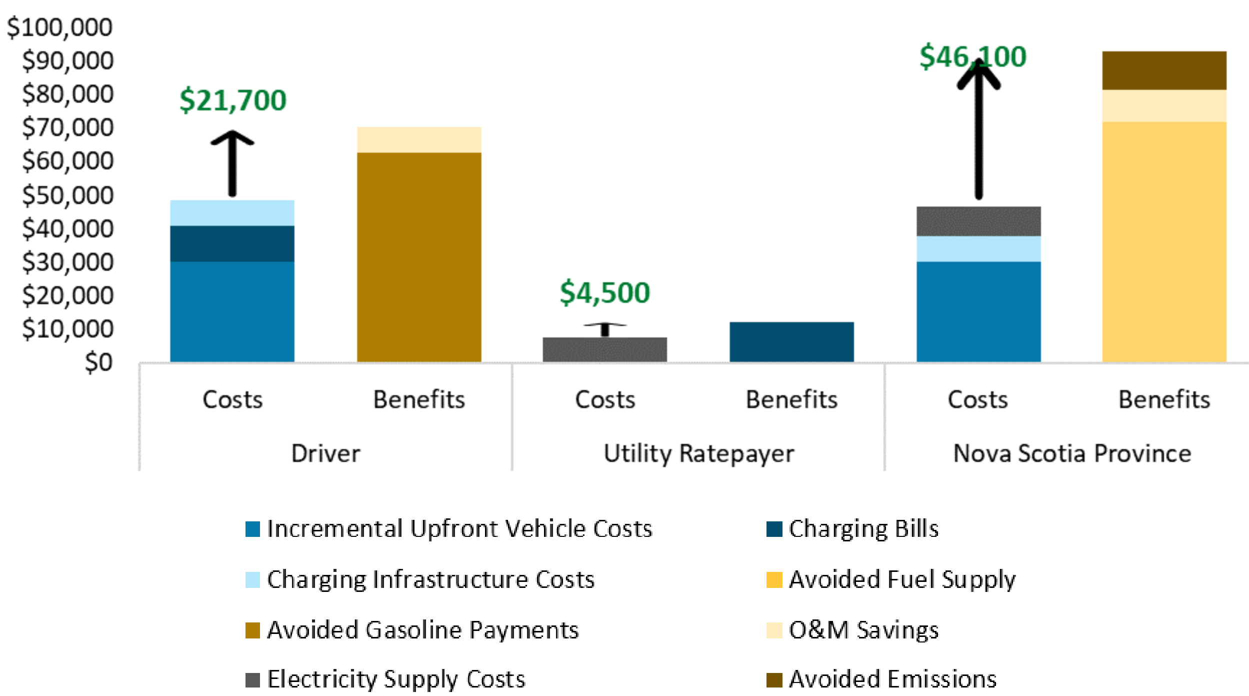
[58] Transport Canada: https://tc.canada.ca/en/corporate-services/policies/road-transportation-0.

Parcel trucks adopted in 2022 with unmanaged charging have net benefits from the parcel truck driver/owner, ratepayer, and provincial perspective. Net benefits from the parcel truck owner and provincial perspectives are largely driven by savings from avoided gasoline[59] and O&M. Relative to transit busses, parcel trucks have much lower incremental upfront costs compared to a comparable ICE vehicle, which helps to keep costs low. In addition, parcel trucks have chargers with much lower power levels (assumed 7.2-15 kW chargers instead of 100-200 kW chargers for transit busses), which results in lower charging infrastructure costs for parcel trucks.

As seen with LDVs and transit busses, parcel trucks also have ratepayer benefits larger than costs, which indicates that the utility receives revenues greater than the costs of supplying electricity to serve charging load and that utility rates will decrease as a result of parcel truck charging load.

BCA results for a parcel truck adopted in 2022 with managed charging with VGI is shown in Figure 4-6.. Charging is managed against Nova Scotia Power's General TOU rate for all parcel truck charging.

Figure 4-6. NPV cost-benefit analysis for a parcel truck adopted in 2022 with managed charging with VGI



With managed charging, a parcel truck driver/owner can reduce charging bills by about $220 per year, which helps increase net benefits for electric parcel trucks adopted in 2022. The Nova Scotia Power General TOU rate only offers time-varying rates in winter months and additional savings could be unlocked under a rate with yearlong time-varying rates. Managed charging offers greater bill savings for parcel truck owners than savings in electricity supply costs, which causes the net benefit in the ratepayer perspective

[59] All parcel trucks are modeled with base gasoline prices as detailed in Appendix 9.1.4.

to decrease. Net benefits remain positive, though, indicating that utility rates would still go down due to parcel truck charging load.

A summary of parcel truck cost-benefit ratios are shown in Table 4-7.

Table 4-7. Summary of cost-benefit analysis results for parcel trucks

Charging Scenario	2022			2030		
	PCT	RIM	SCT	PCT	RIM	SCT
Unmanaged	1.4	1.8	2.0	3.0	1.6	4.5
Managed w/ TOU and VGI	1.5	1.6	2.0	3.3	1.4	4.5

The emissions savings from parcel truck electrification under each charge management scenario are shown below.

Table 4-8. Lifetime emissions savings per electrified parcel trucks, 2022 and 2030

	CO2 Emissions Savings (MMT)	
Charging Scenario	2022	2030
Unmanaged	109	105
Managed w/ TOU and VGI	107	102

All electric parcel trucks achieve emissions savings relative to ICE vehicles in 2022 and 2030.

4.4 Building Benefit-Cost Analysis Results

Table 4-9 summarizes the results of the building electrification BCA for a select configuration of representative buildings adopting heat pumps for space heating. In general, the customer economics of heat pumps in single family homes are favorable. Given current assumptions and fuel prices, the adoption of a current performance heat pump is cost effective for the representative homeowner modeled in 2022, driven by large avoided fuel oil or electricity bills, depending upon the home's current heating fuel. The adoption of best-in-class heat pumps, which could play a significant role in mitigating system peak load impacts from widespread electrification, also are cost effective from the participant's perspective under many modeled scenarios, or will become cost-effective in the next few years as technology improves. While best-in-class heat pumps are cost effective on a lifetime net present value basis, the incremental cost of a best-in-class heat pump over a current performance heat pump is approximately $5,000 in 2022 for a single-family home. Thus, additional policy or incentive support may be necessary to encourage adoption of best-in-class heat pumps. The adoption of heat pumps in single-family homes provides net benefits to Nova Scotia through avoided fuel supply costs and avoided emissions. There are also ratepayer benefits where the adoption of heat pumps generate new load and therefore incremental fixed cost recovery for Nova Scotia Power.

The results of the building electrification BCA are highly sensitive to the fuel oil price forecast, electricity rates, and incremental appliance costs. Given the rise in fuel oil prices in 2022, heat pump adoption provided large customer and societal benefits that may diminish if oil prices fall in the future (see Section 9.2.3 for fuel oil price assumptions). The BCA is also highly sensitive to the upfront capital costs of heat pumps and counterfactual electric resistance or fuel oil heating systems. Capital cost assumptions were developed based on Nova Scotia Power's experience supporting it customers (see Section 9.2.1). Finally, we note that the marginal electricity generation prices reflect the energy prices as they were modeled for Evergreen IRP Scenario 3.1C, and thus may not reflect recent dynamic changes in fuel prices.

Table 4-9. Summary of Building Electrification Cost Benefit Analysis Results

Sector	Heat pump type	Counterfactual Fuel	2022		
			PCT	RIM	SCT
Single Family	**Current Performance**	**Electric Resistance**	Benefit	Cost	Benefit
		Fuel Oil	Benefit	Benefit	Benefit
	Best-in-Class	**Electric Resistance**	Cost	Cost	Benefit
		Fuel Oil	Benefit	Benefit	Benefit
	Dual-Fuel Mini-split	**Fuel Oil**	Benefit	Benefit	Benefit

4.4.1 Residential Space Heating

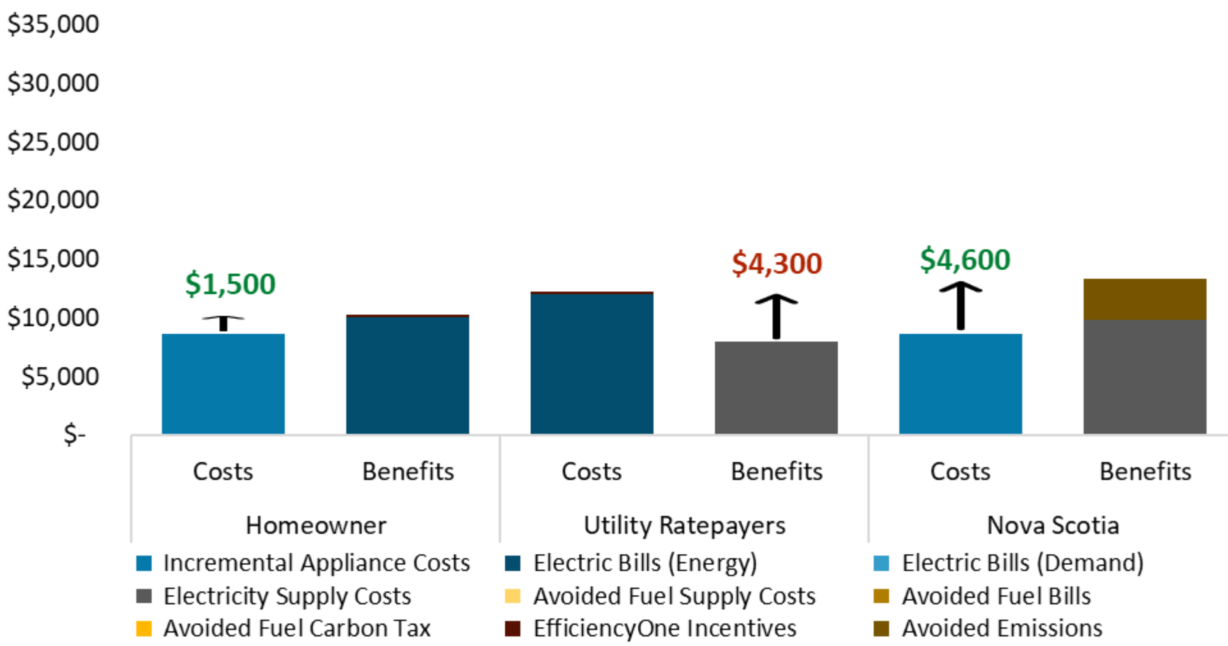
The economics of heat pump adoption in single-family homes depends significantly upon the counterfactual heating system and heat pump type adopted. The economics of heat pump adoption from the participant perspective are expected to improve over time as the upfront capital costs decline. In all scenarios, heat pump adoption provides positive societal net benefits given driven by avoided fuel supply or electricity supply costs as well as avoided emissions.[60]

As shown in Figure 4-7, adoption of current performance all-electric heat pumps amongst customers who currently use electric resistance heating systems provides homeowners and society with net benefits. For homeowners, the electric bill savings significantly outweigh incremental upfront cost of adopting a heat pump, and for the province, the avoided electricity supply costs are also greater than the upfront capital

[60] The study also performed a preliminary review of representative small commercial buildings. The results suggested significant participant and societal benefits from commercial heat pump adoption. However, there is significant heterogeneity in building types and customer heating needs, it's hard to draw broad conclusions without detailed review.

cost. The switch from electric resistance to heat pumps is an efficiency measure that reduces the revenue collected by the utility more than the avoided electricity supply costs which creates a net cost from the ratepayer's perspective.

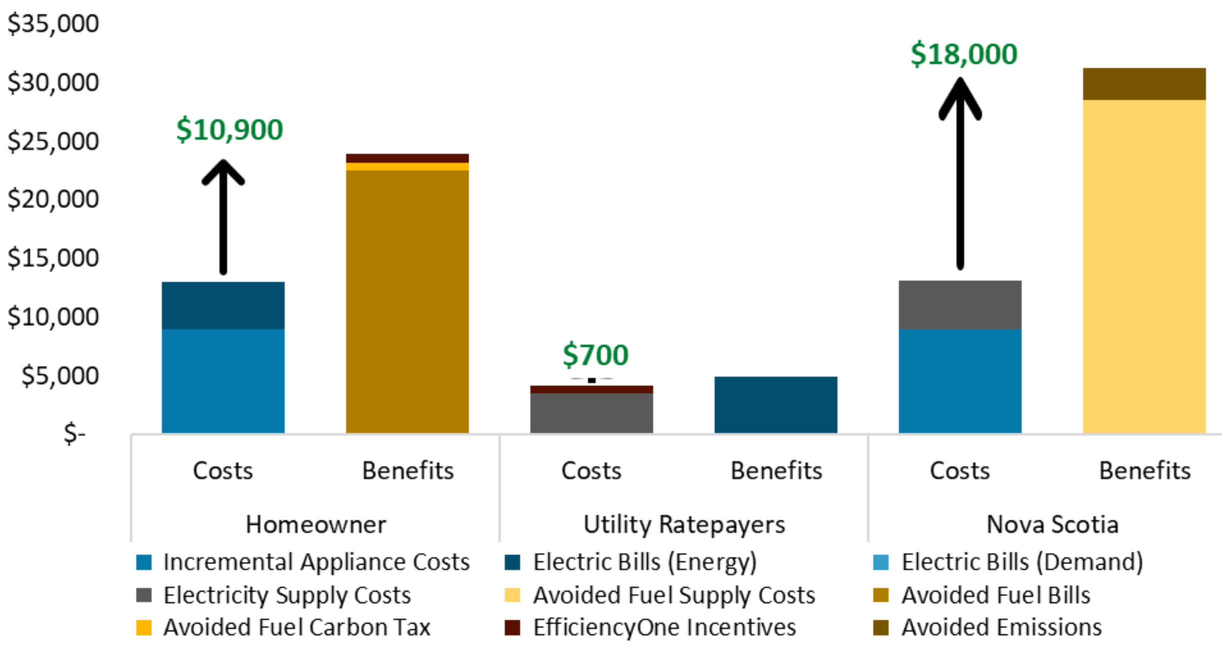
Figure 4-7. NPV cost-benefit analysis for a current performance ducted ASHP adopted in 2022 in a single-family home currently using electric resistance[61]



The adoption of an all-electric current performance heat pump amongst customers who currently use fuel oil to heat their home is also cost effective (see Figure 4-8The upfront capital cost and increase in electric bills is less than the avoided fuel bills. Adoption of heat pumps amongst current fuel oil customers presents net benefits to Nova Scotia, through large, avoided fuel supply savings and avoided emissions. For ratepayers, electrification of heating in current fuel oil homes presents net benefits as electricity supply costs are lower than the amount paid in bills by the customer.

[61] Analysis assumes customers are on a flat rate.

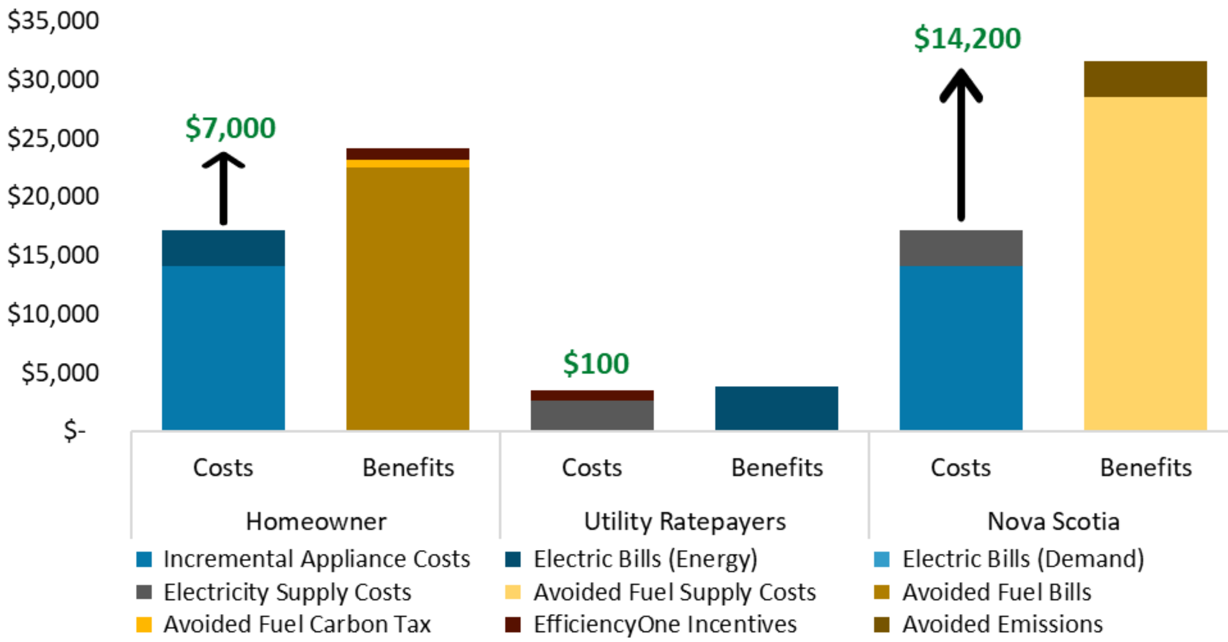
Figure 4-8. NPV cost-benefit analysis for a current performance ducted ASHP adopted in 2022 in a single-family home currently using fuel oil.[62]



The adoption of best-in-class ducted ASHPs is cost-effective. For participants, the upfront cost premium for a higher performance system is greater than the reduction in bill savings customers would see from upgrading from the current performance system, reducing the net benefits to the homeowner. The higher upfront cost also reduces the societal net benefits, but the adoption of best-in-class performance heat pumps is still cost effective from the perspective of the province. Ratepayer benefits decrease because the higher performance heat pump lowers the amount of new load served by the utility.

[62] Analysis assumes customers are on a flat rate.

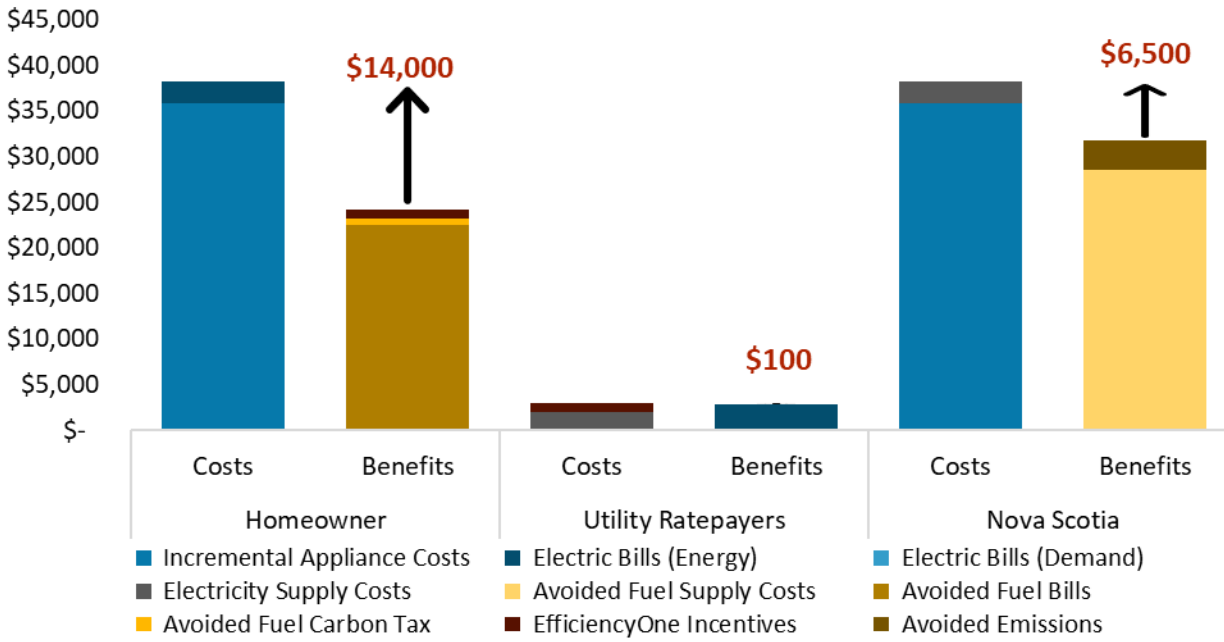
Figure 4-9. NPV cost-benefit analysis for a best-in-class performance ducted ASHP adopted in 2022 in a single-family home currently using fuel oil[63]



The inclusion of shell improvements alongside the adoption of a best-in-class heat pump in a current fuel-oil home is not cost effective from either the participant or societal perspective (see Figure 4-10). The upfront cost of the shell improvement is much greater than the reduction in incremental electric bills and electricity supply costs it provides.

[63] Assumes customers are on a flat rate.

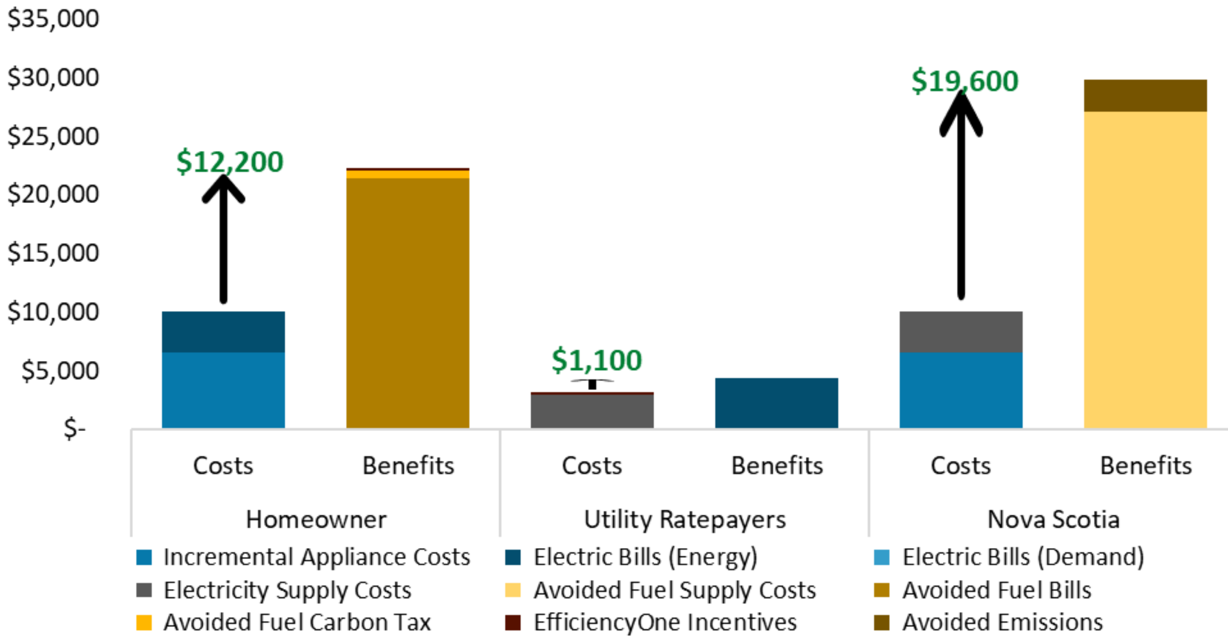
Figure 4-10. NPV cost-benefit analysis for a best-in-class performance ducted ASHP and shell improvement adopted in 2022 in a single-family home currently using fuel oil[64]



The adoption of dual-fuel mini-split systems amongst current fuel oil customers presents positive net benefits for homeowners, ratepayers, and the province. The fuel cost savings achieved through the adoption of the mini-split are greater than the incremental cost of adopting a heat pump resulting in net lifetime benefits of approximately $12,000 for the participant. From the societal perspective, the avoided fuel supply costs and avoided emissions costs drive large societal benefits of about $20,000. A significant reduction in emissions is still achieved with the adoption of ductless mini-splits since the backup fuel system is used only in the coldest hours and most of the heating demand is electrified. Ductless mini-split adoption also has net ratepayer benefits driven by an increase in customer electric bills. The use of backup fuel during the coldest hours reduces the incremental capacity costs to serve the new electrified customer compared to the current performance ducted all-electric heat pump that uses electric resistance backup in the coldest hours.

[64] Assumes customers are on a flat rate.

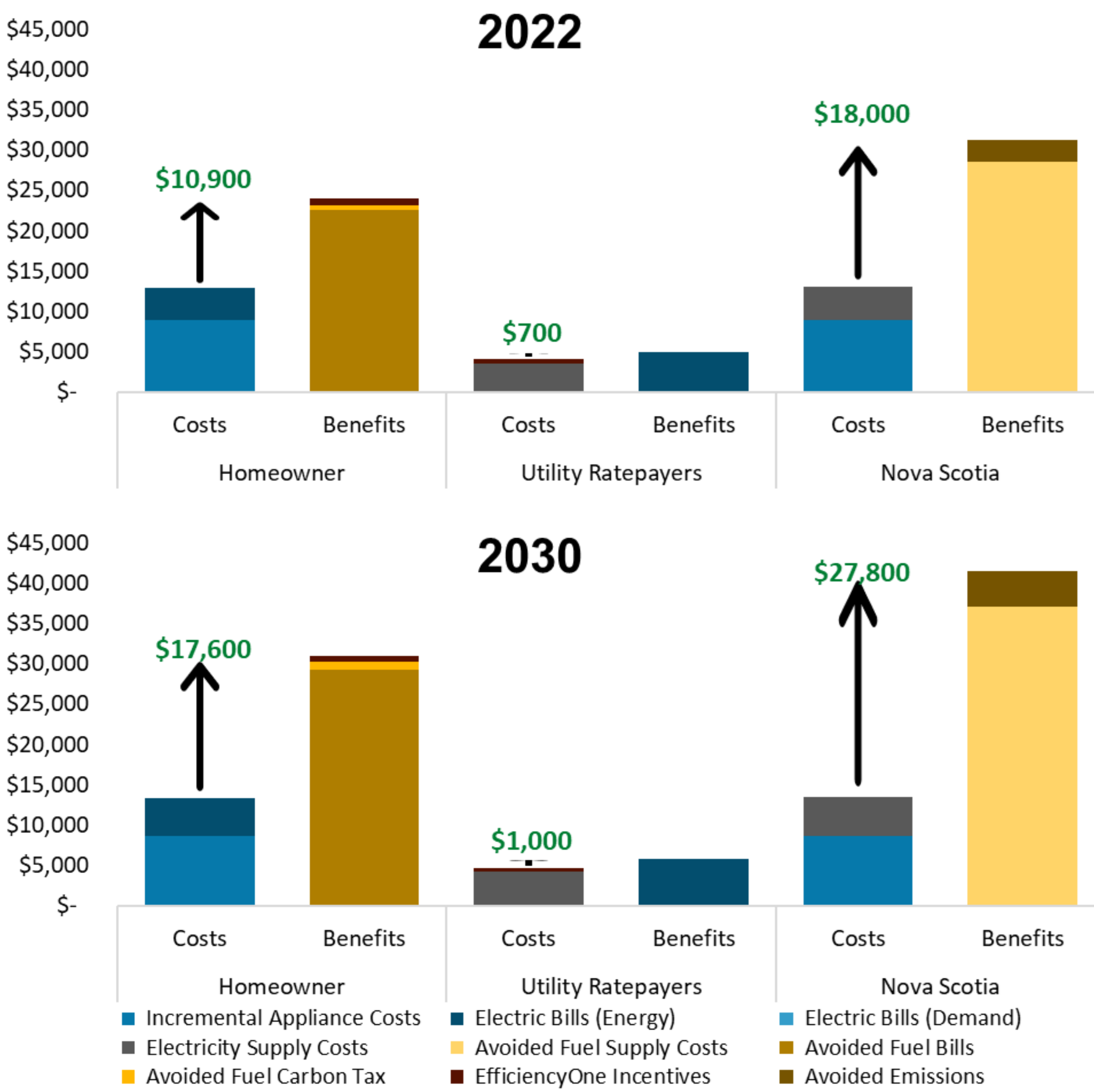
Figure 4-11. NPV cost-benefit analysis for a dual-fuel ductless mini-split adopted in 2022 in a single-family home currently using fuel oil [65]



The incremental cost of heat pumps is expected to decline such that heat pump adoption will become more cost-effective from the customer perspective in the future. The societal benefits of heat pump adoption are also expected to increase in the future as appliance costs decrease and the electricity grid becomes cleaner creating greater potential avoided emissions benefits.

[65] Assumes customers are on a flat rate.

Figure 4-12. NPV cost-benefit analysis for a ducted current performance heat pump adopted in 2022 and 2030 in a single-family home currently using fuel oil (assuming rapid technology improvement)[66]



[66] Assumes customers are on a flat rate.

4.5 Limitations of the Results

The cost-benefit analysis presents the economics of representative heat pumps and EVs adopted for the marginal unit adopted using the best available assumptions available today regarding capital costs, fossil fuel costs, and electricity supply costs. There are several limitations to the methodology used in this study in assessing the economics at scale across the province from all three perspectives considered.

This analysis models the economics for representative buildings and vehicles. While the buildings in this analysis reflect an average home or small commercial building in Nova Scotia, the cost of electrifying, including both capital and operation costs, could vary significantly across the building stock. Similarly, the infrastructure and vehicle cost assumption, particularly for the parcel truck and transit bus modeled, could vary significantly depending on usage and transportation demands.

The economic evaluation of electrifying is also highly sensitive to assumptions regarding future fossil fuel prices. If the cost of gasoline, diesel, or fuel oil rise more than assumed in this analysis, the benefits of electrifying could increase. The converse is also true: if electricity prices are higher than modeled, the benefits of electrifying will fall. In addition, we note that given different data sources for different energy inputs (e.g., electricity from Nova Scotia Power, gasoline from Canadian Futures, and oil based on benchmarking to local sources and scaling using public forecasts), they reflect somewhat different energy price conditions/points in time, and future assumptions. Future energy prices are an important source of uncertainty in this study, and any differences across the different projections are an inherent limitation on this work.

The cost-benefit analysis considers the economics for the marginal vehicle or heat pump adopted and does not consider how the adoption of electric vehicles and buildings at scale could impact those marginal costs.[67] The marginal electric sector costs and emissions used in this analysis were provided by Nova Scotia Power and reflect a mid-electrification trajectory. Those marginal electric sector costs will change over time and are a function of the pace and scale of electrification, as well as demand side management. Even though the marginal electric sector costs used in this analysis could change significantly in the future, this analysis is still useful as it focuses on the adoption of EVs or heat pumps in the near term, which can be well represented by Nova Scotia Power's marginal cost assumptions, and is focused on the economics for a single marginal unit adopted.

[67] Instead, the utility separately will use the aggregate load forecasts to evaluate electrification at scale in its PLEXOS modeling.

5. Conclusions & Implications for Nova Scotia Power

Across North America, electrification is a core pillar of strategies to decarbonize the economy, and it has substantial participant and societal benefits, as well as ratepayer benefits under many circumstances. This study and the supporting analysis generated several key findings for Nova Scotia Power as it supports provincial electrification.

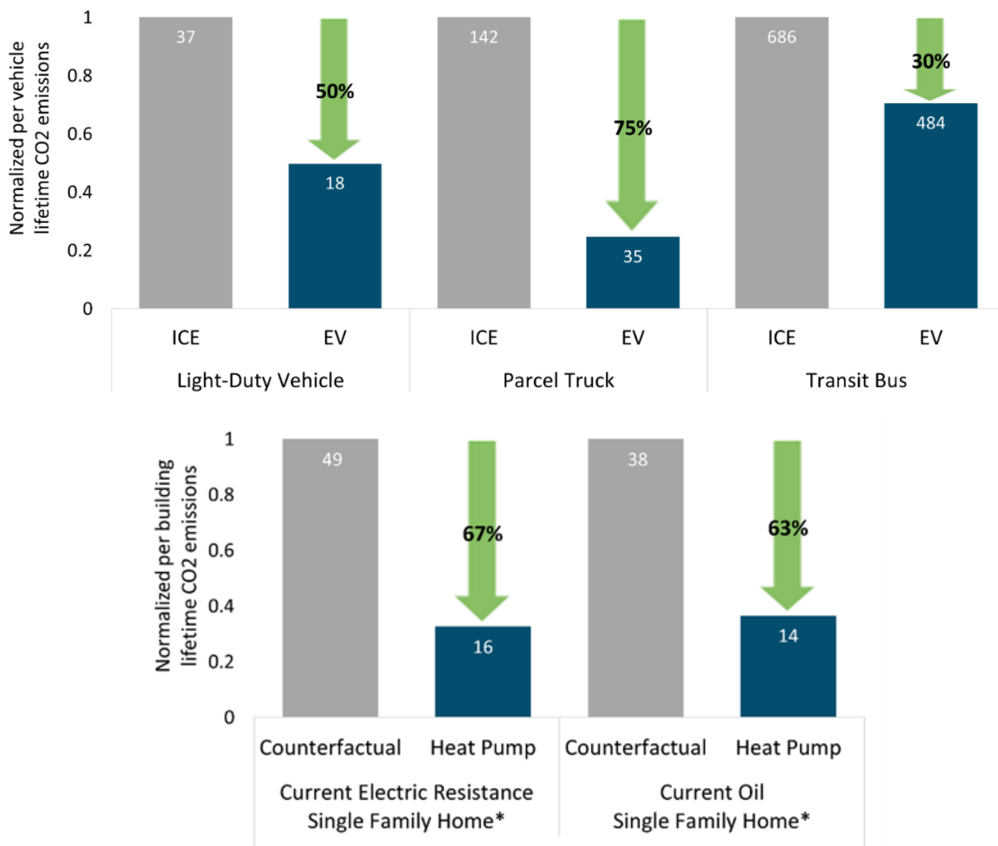
5.1 Key Analysis Findings

The analysis generated several findings related to electrification in Nova Scotia.

Key Finding 1: Building and transportation electrification reduces emissions in Nova Scotia.

In all transportation and building electrification scenarios evaluated, incremental CO_2 emissions from electricity generation to meet vehicle charging and building loads were lower than the offset emissions from fossil fuel end uses. For example, adoption of a light-duty vehicle today reduces emissions by almost 20 tons (about 50%) over the vehicle lifetime compared to an internal combustion vehicle. Results for several technologies evaluated are shown in Figure 5-1 below. Emissions benefits also increase with time, as the electric grid becomes greener through coal-fired generation phase out and investments in wind and clean imports.

Figure 5-1. Lifetime CO_2 emissions savings for electrified transportation and building investments by representative customers, adopted in 2022 (Lifetime CO_2 in tonnes shown in bar)

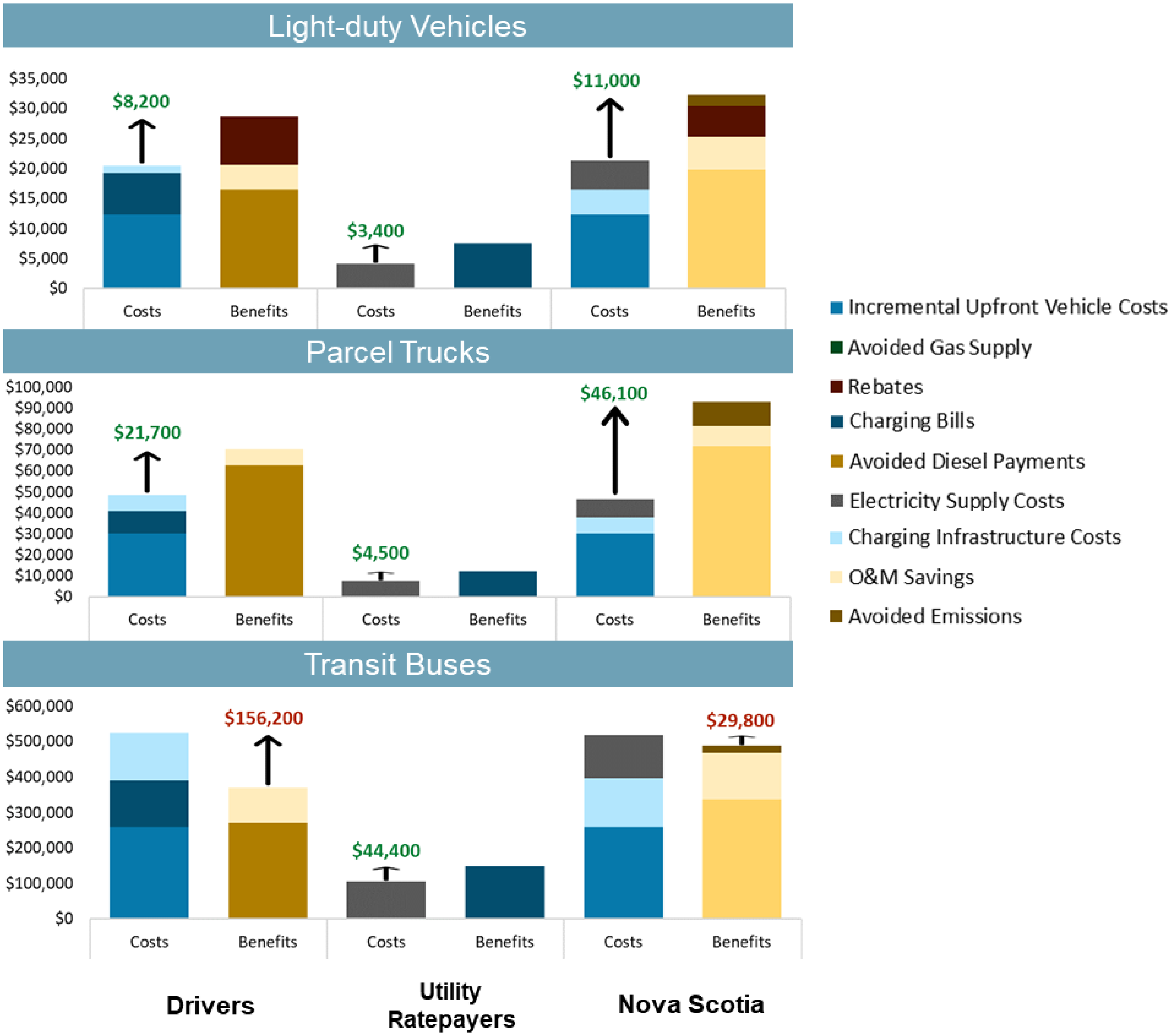


Notes: Normalized per vehicle/home CO2 emissions over the lifetime of the selected vehicle or building, with total emissions labeled within the bar in tonnes (metric). The emissions for ICE vehicle and fossil or electric resistance buildings are normalized to 1 and electrified transportation and buildings are scaled to their relative counterfactual. (*) Buildings graph assumes all-electric current heat pump performance (coefficient of performance of 2.7 at -8^{o}C). The representative fuel oil customer modeled in the figure above has slightly lower emissions than their ER counterpart given the oil heat pump was a larger size (2 ton vs. 0.5 ton) and operating at a higher COP on average.

Key Finding 2. Most transportation electrification investments produce benefits that exceed costs from the perspective of drivers, utility ratepayers and Nova Scotia.

While electric vehicles have higher up-front costs today, drivers benefit from existing rebates, avoided gasoline purchases, and lower maintenance costs over time. Driver benefits are slightly greater when drivers adopt time-of-use rates and drivers respond to the rates by shifting their charging to off-peak periods. Likewise, utility ratepayers benefit as electricity sales exceed the cost of supplying electricity. From the provincial perspective, Nova Scotia benefits not only from the net cost savings and the influx of federal rebate dollars, but also from the societal value of avoided emissions, which grows over time. Similar dynamics underpin the analysis of adopting parcel trucks and transit buses in the province, as presented in the report body; light duty vehicles and parcel trucks generate net benefits today, and transit buses are expected to yield net benefits by mid-2020s. Finally, the economics of adopting electric vehicles are expected to improve with forecasted battery cost declines, enabling light-duty electric vehicles to achieve cost parity with combustion-based vehicles over time, though significant near-term supply chain uncertainties exist.

Figure 5-2. Net present value of costs and benefits of adopting light-duty vehicle in 2022, assuming managed charging with load management using vehicle-grid integration



Notes: The benefit estimates vary across scenarios based on rates, fuel costs, incentives, marginal electricity costs. Results have been rounded to the nearest $100. The figure above assumes (not exhaustive): managed charging with VGI to smooth loads, TOU electric rates, base gasoline and diesel prices, and a 12-year vehicle lifetime. Light-duty vehicles receive a $3,000 provincial rebate and $5,000 federal rebate.

Key Finding 3. While building electrification yields net benefits for Nova Scotia, policy may be required to encourage adoption of dual-fuel and highest performing equipment that minimizes peak impacts and avoids adverse impacts to electric ratepayers.

The economics of building electrification from the customer perspective can be more uncertain than a similar transportation analysis, dependent on current and uncertain future fuel prices and electricity rates, building type and size, counterfactual heating system, and technology choice. This study evaluated a selected set of representative electric heat pump options— including "current" or "average" performance cold-climate air source heat pumps, "best-in-class" cold-climate air source heat pumps, and "hybrid" or dual-fuel mini-split air source heat pumps, which rely on retaining fuel back-up—from the perspective of representative current electric resistance, fuel oil, wood, and natural gas customers. Broadly, the economics for mini-split and current performance heat pumps are more favorable, with selected conversions generating net positive benefits today and many choices being strongly net positive for participants by 2030. Dual-fuel mini-split systems, in which an air source heat pump is paired with back-up fuel oil, offers particular advantages by reducing fossil usage through electrification of most load, while minimizing peak impacts and therefore electric infrastructure needs through switching to fossil back-up for the coldest hours. Given currently high fuel prices, the customer economics of best-in-class heat pump adoption also appear economic and can reduce peaks, given the operating cost savings from using a more efficient appliance. That said, current performance all-electric heat pumps adopted at scale would generate higher system peak impacts than best-in-class heat pump adoption. This trade-off requires careful consideration: the economics are highly uncertain and will be influenced by the marginal cost to serve large amounts of new load, as well as the rate of heat pump technology cost decline, the influence of high fuel prices on future electricity rates, rate design, oil prices, and other important variables. Finally, we note that although not within scope for this study, existing research suggests that electrification is likely to remain a cheaper option than decarbonized fuel for most homes. Similar, although not evaluated here, the economics of new construction are much better than retrofits, and these costs should be evaluated in future work.[68,69,70]

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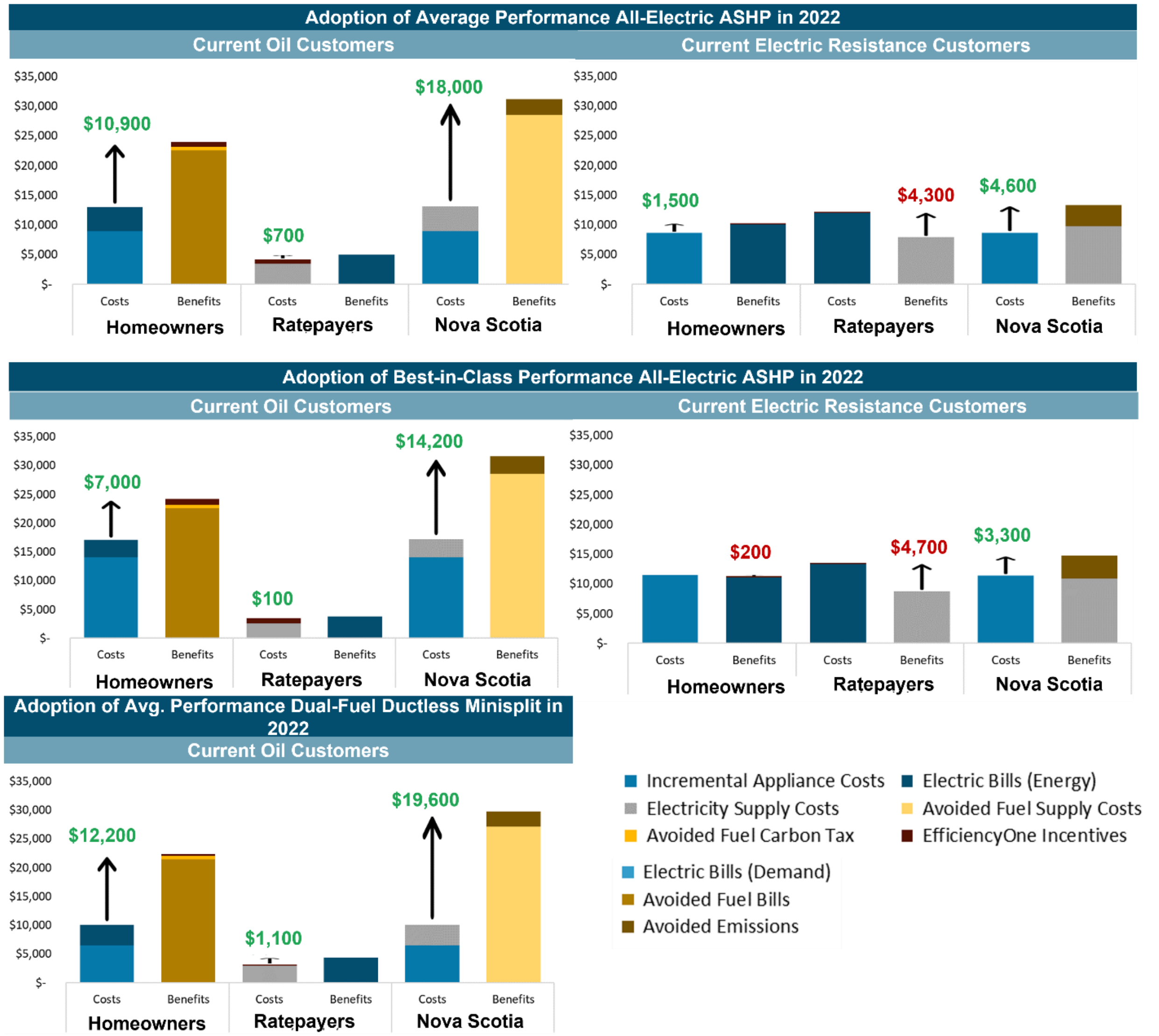
[68] Maryland Commission on Climate Change, "Building Energy transition Plan: a roadmap for decarbonizing the residential and commercial building sectors in Maryland," November 2021, https://mde.maryland.gov/programs/air/ClimateChange/MCCC/Commission/Building%20Energy%20Transition%20Plan%20-%20MCCC%20approved.pdf (pg. 7)

[69] E3, "Financial Impact of Fuel Conversion on Consumer Owned Utilities and Customers in Washington, May 2022, https://www.commerce.wa.gov/wp-content/uploads/2022/06/Financial-Impact-of-Fuel-Conversion-on-Consumer-Owned-Utilities-and-Customers-in-Washington-Final-Report.pdf (pg. 3)

[70] Massachusetts D.P.U. 20-80, The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals: Independent Consultant Report, Technical Analysis of Decarbonization Pathways, March 2022, https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Decarbonization%20Pathways.pdf

Figure 5-3. Net present value of adopting heat pump technologies for selected cases

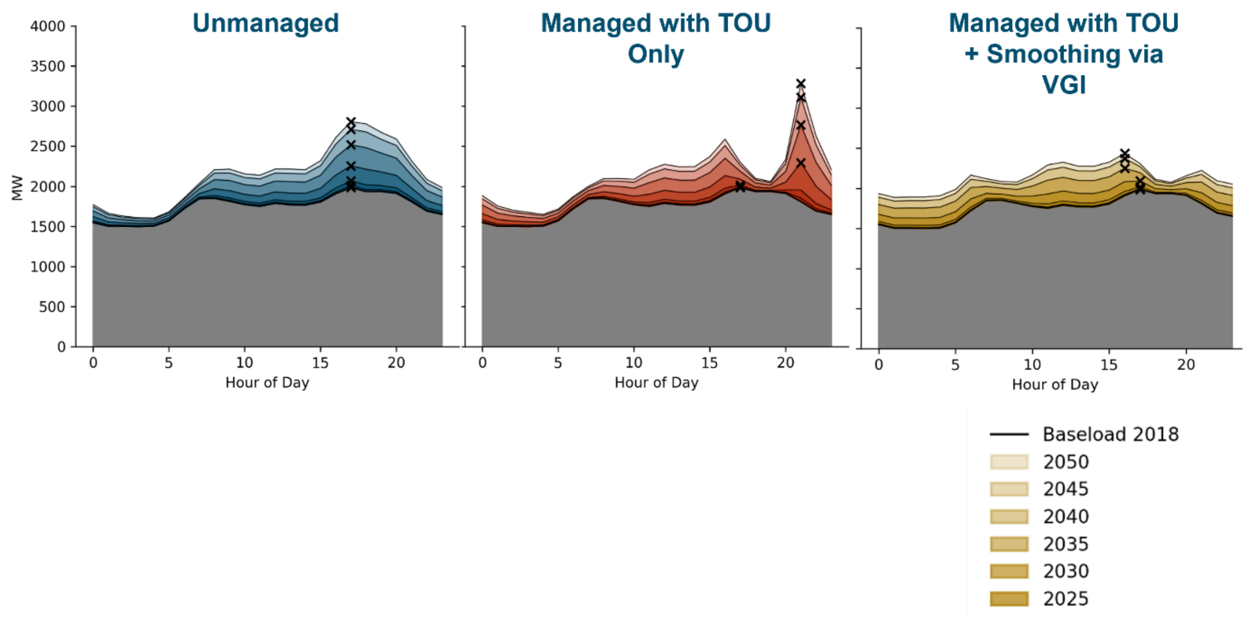


Notes: Results shown here are the costs and benefits for a single-family home on a flat rate. Adoption of heat pumps amongst current electric resistance customers presents a net ratepayer cost as the more efficient system reduces bills more than estimated electric supply costs. The incremental appliance cost of a heat pump compared to electric resistance counterfactual system is lower than utility bill savings. Switching to a heat pump from a fuel oil system creates net benefits for the homeowner. Mini-split customers are assumed to maintain their non-electric heating system for use during peak periods, leading to ratepayer savings in that scenario. Retail fuel oil prices in 2022 are assumed to be $5.56/therm ($2.03/L) and electricity rates are $0.1622/kWh. In 2022, the cost of a best-in-class heat pump installed in single family home currently using fuel oil is $16,000; the cost of an average performance heat pump is $10,869; and the cost of the dual-fuel mini-split is $6,500 (not including furnace replacement). See section 9.2 for detailed BCA assumptions.

Key Finding 4. Utility actions to manage transportation loads will be crucial to minimizing costs and achieving ratepayer benefits.

In the transportation sector, time of use rates and aggregating and smoothing loads to avoid "rebound peaks" will be valuable as adoption advances; unmanaged transportation electrification, assuming typical driver behavior under scenarios consistent with 100% EV sales by 2035, could generate over 1000 MW of evening peak load in Nova Scotia by 2050 (as shown in Figure 5-4 below). Simulations that incorporate driver responses to Nova Scotia Power's current time-of-use (TOU) rate shift load out of peak hours but create a strong rebound in charging demand when the off-peak period begins. A version of "smart" programs to complement TOU rates will likely be needed to avoid unintended consequences of "rebound" peaks at the beginning of off-peak hours. These programs can be enabled through technologies that provide vehicle-grid integration (VGI), which allows utilities to communicate with home technologies and coordinate charging load to when electricity supply costs are lowest.

Figure 5-4. Peak winter weekday loads from 2025-2050 with increasing light-duty vehicle loads



Note: VGI in the figure above reflects the assumption that the utility is managing and shifting charge to flatten overall load impacts.

Key Findings 5. Encouraging adoption of advanced building technology such as high performance all-electric heat pumps and dual-fuel heat pumps will be essential to mitigate peak load impacts. Equally important will be coupling new heat pumps with continued building shell and other energy efficiency measures.

Current performance heat pumps can generate incremental coincident peak impacts of over 1000 MW (non-coincident impacts can be even larger, at over 1100 MW by 2050). Building enough generation, transmission, and distribution capacity to serve this load could be costly. High performance heat pumps as modeled in the Best-in-Class scenario could reduce coincident peak impacts by almost 70 percent, significantly reducing the need for new firm generating capacity (see Figure 5-5 and 5-6 below). While the cost-benefit analysis estimates slightly lower ratepayer benefits from the adoption of best-in-class heat pumps, this finding is sensitive to estimates of the marginal electricity supply costs, inclusive of generation, transmission, and distribution. When electrification occurs at scale, the marginal cost to serve load from new heat pumps could trigger significant new investments in generation, transmission and distribution as heat pumps add new load to existing winter peaks when adopted in buildings currently using fossil fuels for heating; this in turn would reduce ratepayer benefits of current performance heat pumps, adding urgency to the need to incentivize best-in-class heat pumps and dual-fuel heat pumps to reduce the peak load impact. Increased wintertime peak loads are especially challenging on the Nova Scotia Power system, which in the future will need to in large part rely on peaking facilities fueled by either natural gas (with associated carbon costs) or a clean substitute such as green hydrogen to meet system peaks. (Note that net ratepayer impacts will depend on utility revenues, a function of rate design, from electrified load relative to the costs to serve that load.)

Figure 5-5. Noncoincident peak impacts of building electrification: 1-in-10 impacts increasingly important to consider as electrification is pursued at scale

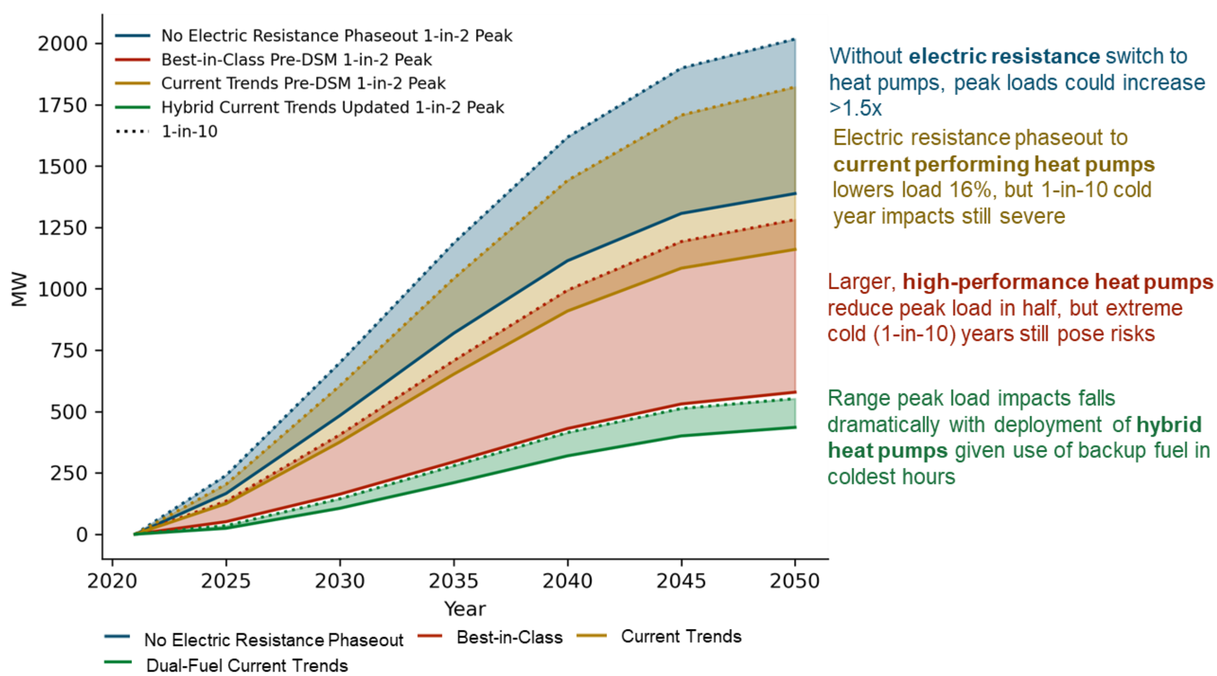


Figure 5-6. Components of non-coincident peak impacts from building electrification

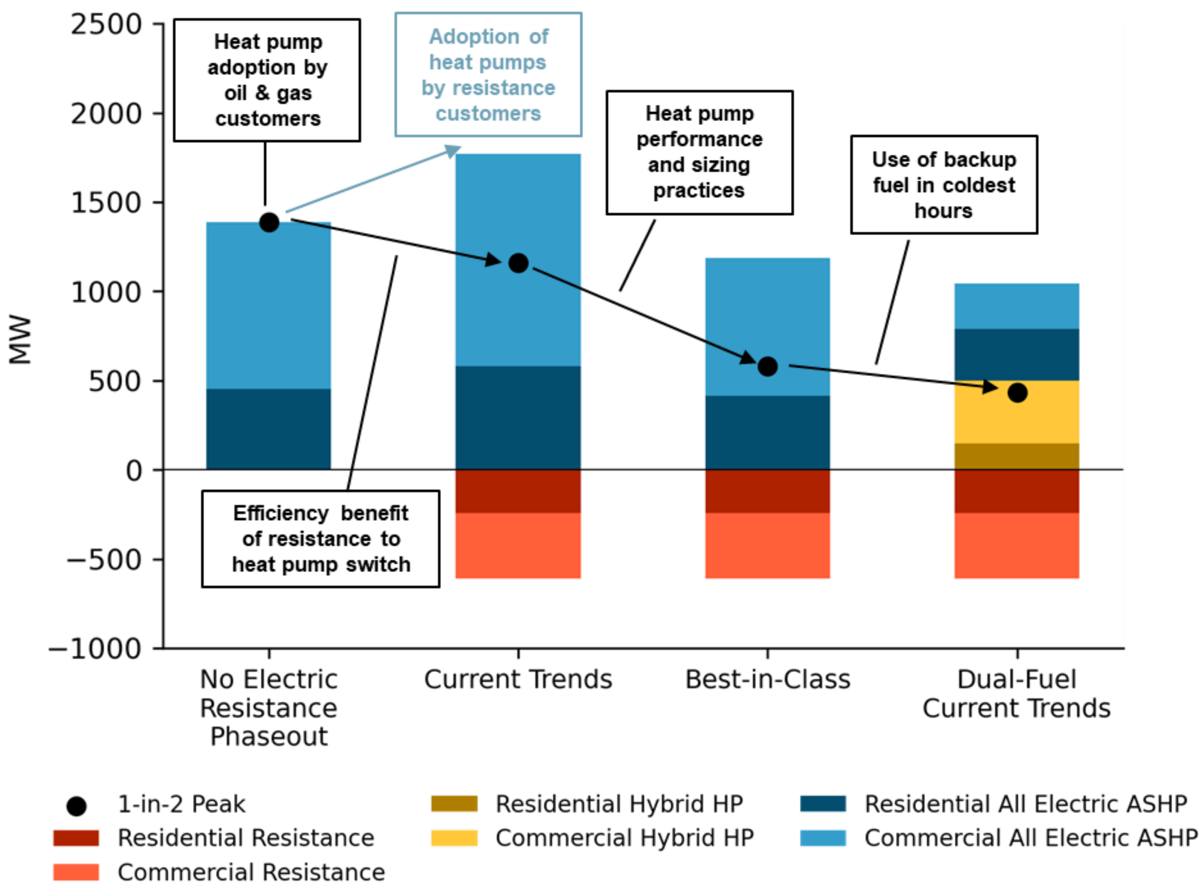
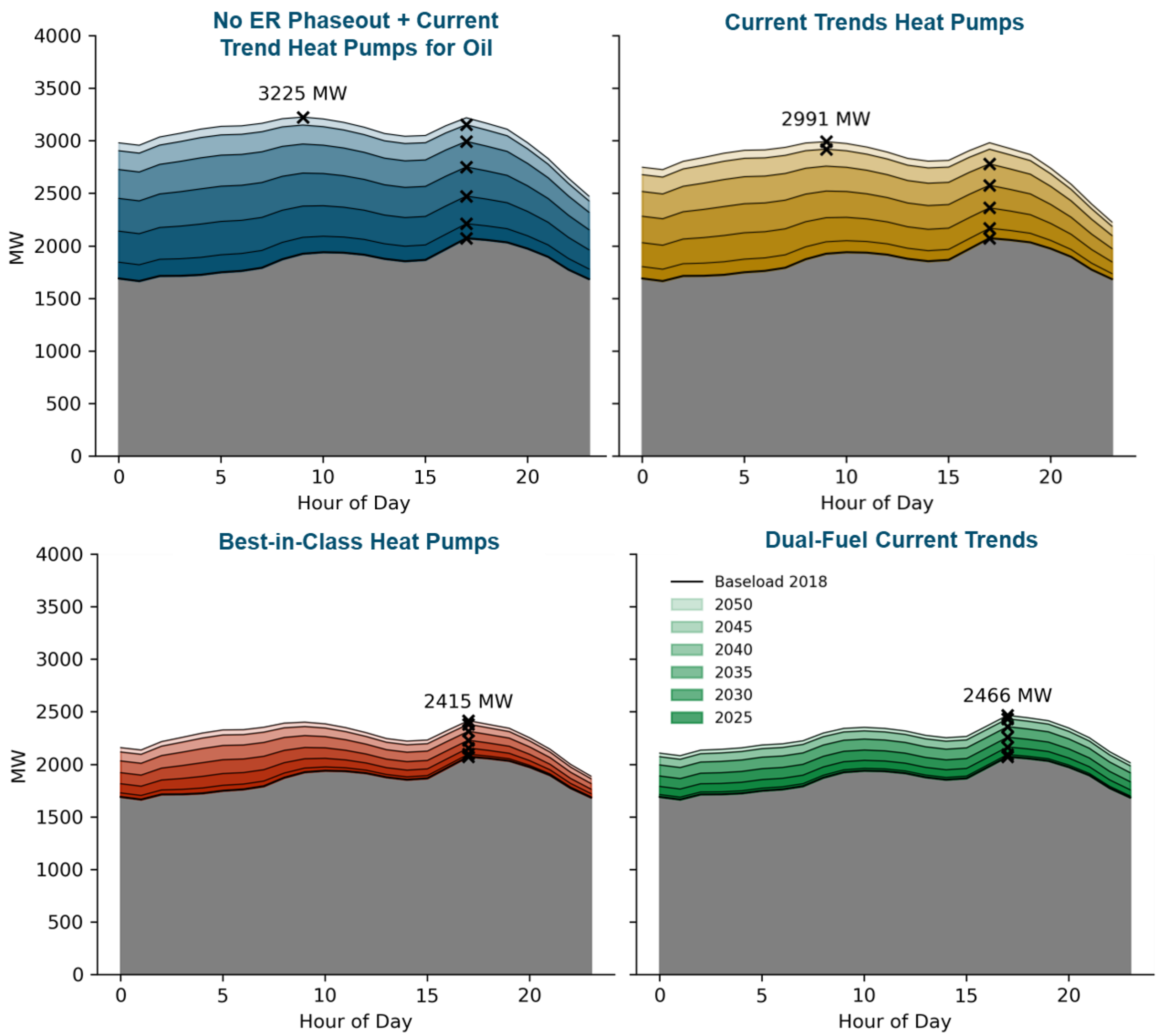


Figure 5-7. Peak winter weekday loads from 2025-2050 with increasing building heating loads (buildings plus system load peak impact)



5.2 Recommendations for Nova Scotia Power

Electrification has the potential to provide significant benefits to Nova Scotians by reducing total energy expenditures and lowering the province's overall emissions footprint. However, realizing the full benefits of electrification will require actions from a range of parties, with no one group, stakeholder, or the utility able to drive the transformation alone. In Nova Scotia, Nova Scotia Power plans, operates, maintains, and balances the majority of the grid assets needed to power widespread electrification and therefore is uniquely positioned to proactively identify and pursue initiatives to support electrification, particularly those to meet reliability and equity goals. The recommendations below highlight key utility actions for Nova Scotia Power as it executes on its electrification strategy. We note that these recommendations are derived both from the analysis as well as from the jurisdictional scan and E3's broader experience working on utility electrification across North America.

Short-term Actions, Customer Programs & Capital Investments

Recommendation 1. Design and promote increasingly dynamic rate structures that encourage adoption and minimize costs, including expanding current time-of-use rates to the full year and gradually moving to rates that reflect the marginal cost to serve load.

+ **Implement dynamic rate design[71]:** Transportation loads, and to some extent new building loads, are a flexible source of new load for utilities across North America. Better alignment of retail rates with the marginal costs to serve load lowers costs to ratepayers and provides EV adopters opportunities to shift their charging to lower cost hours (e.g., periods of renewable generation). More efficient rate structures reflect the costs of interconnection, capacity, and energy services by time of day, while appropriately compensating customers who can provide system services (e.g., energy, load flexibility) themselves. Rate designs that encourage shifting can reward users through lower rates during these lower cost times, improving the economics for adopters and helping avoid the need for costly infrastructure upgrades. While today, the most common utility rate design is a time-of-use rate, these do not realize the full benefits associated with home/vehicle to grid integration, and more dynamic price signals that vary with grid conditions will provide even stronger incentives for shifting load. The SDG&E Grid Integration Rate (GIR) piloted from 2018-2020 is a good example that included day-ahead hourly prices with adders for system and distribution peak hours. SDG&E reports indicate that the GIR rate was effective at shifting charging from peak hours in early evening to outside of the peak period.[72] Another example is New York's Smart Home Demonstration Projects, designed to demonstrate how alternative rate structures with customer price signals can optimize value for the customer and the system. Customers were given home energy management technologies and signed onto a rate structure reflective of day-ahead hourly locational-based marginal prices.[73]

    - In this instance, E3 does not believe that submetering or installing a second meter for EVs is necessary to support EV adoption in the near-term. These options have generally

[71] The conceptual ideal multi-part rate design includes: 1) a dynamic hourly energy rate that is low in most hours of the year when zero/low variable cost resources are abundant and on the margin; 2) a long-run marginal cost-based coincident demand charge or hourly allocation of long-run marginal capacity costs that encourage reducing and shifting load out of a relatively small number of hours driving new investments in generation, transmission, and distribution capacity; and 3) non-bypassable customer charges designed for equity that recover remaining embedded and unavoidable fixed costs.

[72] Despite the program's success, challenges included software customizations. It was also noted that because direct charging control was not included in the project, VGI could not be utilized to its fullest capacity for renewable integration and distribution system management. For more information see: https://www.sdge.com/sites/default/files/regulatory/SDG%26E%20FINAL%20Power%20Your%20Drive%20Research%20Report%20April%202021.pdf. Initial filing available here: Microsoft Word - Application Testimony Chapter 5 - Rate Design_CF_final.docx (sdge.com)

[73] NY Smart Home Rate Demonstration Projects - LPDD

been costly, and have faced implementation challenges, including for submeters challenges related to accuracy and the ability to do utility-grade metering for billing. This may change in future years as more VGI and particularly V2G opportunities are implemented. In the immediate future, E3 believes it's more important to focus on whole-home rate designs that reflect the costs of supply.

+ **Drive customer transition:** A transition to more dynamic rates requires significant customer outreach and education and should be implemented gradually to ensure customers can adjust their behavior and avoid abrupt bill changes. Pilot programs and opt-in rate designs allow customers to transition at their own pace and directly experience benefits over time. Nova Scotia Power is advancing opt-in Time Varying Pricing (TVP) and Critical Peak Pricing (CPP) pilots for this purpose, with an interim report currently filed with the Board[74]. This approach is aligned with E3's recommendation that Nova Scotia Power start with opt-in and transition to opt-out once benefits and successful customer outreach strategies are well established. California's transition to default, opt-out TOU rates has taken over five years and was hampered by early customer complaints and confusion. At the same time, customers with EVs and PV have generally been positive about opt-in TOU rates.[75]

    - **Leverage advanced metering infrastructure (AMI) to manage loads for the benefit of all customers:** AMI, or smart meters, which measure and record electricity usage data at least hourly, are required for more dynamic rate designs and demand response programs. AMI enables widespread adoption of TOU rates, which are a good starting point for encouraging load to shift from on- to off-peak periods. However, TOU rates do not facilitate customer responsiveness to the specific hours with the highest or lowest costs and GHG emissions and can cause secondary peaks at the start of the off-peak period. As customers adopt more flexible DER such as energy storage, EVs and electric water and space heating, more dynamic rate and load management strategies will be needed to maximize their value for both Nova Scotia Power and the customer. Enabling more dynamic strategies for flexible electrification technologies will require work in several areas, including cost-effective communications, metering and interconnection requirements.

    - **Vehicle Grid Integration (VGI):** An early use case will be VGI, which includes managed one-way charging (V1G) as well as two-way charging and discharging, including vehicle-to-grid (V2G) and vehicle-to-building (V2B) services. VGI services are broadly categorized as "passive" (e.g., responding to a TOU rate) and "active" (e.g., providing a verified response to a dispatch signal). Passive V1G services are feasible today and widely adopted with AMI. Active and V2G strategies require more enabling technology and policy changes, but also have potentially significant incremental value if those challenges can be addressed in the coming years. E3 recommends that Nova Scotia

[74] M09777: Time Varying Pricing Pilot Program Nova Scotia Power Interim Report, July 29, 2022

[75] This approach can also be taken a step further to drive electric adoption by offering electric rates specifically for all-electric customers who adopt heat pumps. At the same time, care must continue to be taken to ensure that rate designs do not generate cost shift.

Power continue its roll out of TOU and CPP rates, and quickly scale existing investments in V1G with AMI, while finishing the Smart Grid NS pilot that includes V2G technology.

Recommendation 2. Work with E1 to provide rebates to help customers overcome high up-front costs of electrification, with the utility focused on technologies that provide ratepayer benefits.

+ **Spur electrification with ratepayer benefits:** Rebates can help customers overcome electrification first-costs. While the government should support adoption aimed at achieving the societal goals and benefits of electrification, the utility role should be distinctly focused on encouraging technologies with better RIM (ratepayer impact measure) test results. EVs and oil-to-heat pump conversions will yield net revenues to the utility and thus ratepayers, due to an increase in sales relative to the cost to serve new loads. These revenues can help fund incentives or rebate mechanisms that increase adoption and create benefits to Nova Scotia, while at the same time reducing upward pressure on electricity rates. As shown in the BCA analysis, electrification of certain buildings and transportation segments generate ratepayer benefits that are less than the incremental cost of electrification from the participant perspective. For certain customers, ratepayer funded rebates will be insufficient to incentivize electrification.[76] Thus, non-ratepayer sources of funding will be needed to support near-complete levels of electrification without negatively impacting non-participating ratepayers.
    - **Transportation rebates:** Despite net benefits for participants over the lifetime of the vehicle, electric vehicles of all classes are still expected to have incremental up-front costs until the early to mid-2030s, with a payback period estimated at three years for light-duty vehicles. Because electric ratepayers benefit from EV adoption through lower average electric rates, a portion of ratepayer benefits associated with electric vehicles could be used to support adoption through up-front vehicle or charging infrastructure incentives.
    - **Space heating rebates:** Payback periods for heat pumps can take several years. For existing oil customers, hybrid dual-fuel heat pumps (i.e. mini-splits) are typically already cost-effective, and encouraging adoption of dual-fuel heat pumps with new rebates could generate provincial benefits through avoided fuel and emissions. Without rebates, conversion to all-electric systems for current oil customers is slightly costlier today given the incremental up-front system cost, but societal benefits are achievable and ratepayer benefits could support all-electric heat pump incentives. For electric resistance homes, adoption of current performance all-electric heat pumps is cost effective today and generates significant societal benefits through avoided electric supply and emissions.

[76] This is partially driven by the large magnitude of lifetime net costs. For example, transit buses adopted in 2022 face a lifetime net cost of over $156,000 as seen in Figure ES-3, which is greater than an amount that could be recovered without impacting non-participating customers. This is also driven by the financing structures that may be required to support low-income adoption of appliances or vehicles with high upfront costs; even if customers can achieve lifetime net savings, further reductions to upfront costs may be needed to increase accessibility of electrified devices to some customer types.

Although not directly evaluated in this study, new construction is expected to have better economics than retrofits and should be prioritized in programs and policy.

- **High performance heat pumps**: While the highest performing ("best-in-class") heat pumps are more costly to customers and therefore provide somewhat lower societal benefits even with technology cost declines, the benefits associated with avoiding electrification peak impacts are expected to grow as electrification is pursued at scale. In other words, while the costs of meeting incremental loads with new capacity may be reasonable on the margin, meeting this new peak growth over time and in aggregate may require more expensive capacity (e.g., hydrogen-ready combustion turbines, significant penetrations of grid-scale batteries) and distribution system upgrades (e.g., transformer replacements, line reconductoring, voltage upgrades, etc.). Thus, increasingly incentivizing these systems is likely to be valuable (particularly for electric resistance customers where fuel back-up is not an option).

- **Water heating:** Like space heating, converting customers to heat pump water heaters generates significant societal benefits, including reductions in emissions and lowering total energy bills; however, for electric resistance customer conversions, which do not result in lower electric rates for non-participants, public funds should be used to pay for rebates for electric heat pump water heaters.

Recommendation 3. Support development of infrastructure "backbone" for electric vehicle charging to improve geographic coverage and fill gaps where third parties may have less incentive to invest.

+ **Create infrastructure backbone:** A robust electric vehicle charging network will be required to address range anxiety and support adoption of electric vehicles. Electric utilities like Nova Scotia Power have broad experience developing electricity infrastructure projects and have an ability to fund investments with revenues earned through rates when benefits are clear, and to work with partners, such as third-party charging providers, to facilitate investments in charging solutions. In addition, given it manages the distribution network, the utility can ensure that chargers are built in a way that leverages the existing distribution network at least cost and in a manner that maximizes customer benefits. E3 recommends that Nova Scotia Power focus its efforts on building a backbone of public chargers and a broader network of make-ready charging infrastructure to support third-party chargers in meeting customer locations and driver needs.

    - **Invest in make-ready investments in high-traffic locations:** E3 encourages Nova Scotia Power and its' partner E1 to invest in make-ready charging infrastructure, including infrastructure to support Level 2 chargers at public locations, multi-unit dwellings, and workplaces, and in high-traffic spots where distribution network capacity is readily available. Similar make-ready infrastructure programs have been implemented by utilities across North America and have played a key role in building out charger networks.[77] These make-readies can enable third party chargers, leveraging their private investment in the province, and help steer charging providers toward locations that are the less constrained and thus lower cost interconnection points.

- **Invest in full charging infrastructure to fill charging gaps:** Beyond supporting third-party charging providers and building owners in make-ready investments, Nova Scotia Power should invest in full charging infrastructure, including both EVSEs and make-ready infrastructure, in locations where charging gaps are likely to exist due to lower third party incentives for investment.[78] For example, private providers are likely to have less compelling business cases to build chargers in areas with lower average household incomes, disadvantaged communities, and rural communities, where concentrations of EVs are currently low. Private providers also have lower incentives to serve multi-unit dwellings, where access and utilization are lower than other public charging locations but where charging access is critical for facilitating EV adoption. Utilities across North America have also begun filling in charger gaps through investments in full charging infrastructure. By filling these gaps with a mix of DCFC and Level 2 chargers, Nova Scotia Power can help enable widespread and equitable adoption of EVs.

Recommendation 4. Support cost-effective grid modernization and panel upgrades, as well as all-electric ready new construction, to ensure the utility doesn't become a bottleneck to electrification.

+ Grid modernization and panel upgrade investments are necessary to enable electrification but can increase near-term rate pressure and so should be carefully evaluated.[79] All new construction should be built to accommodate future electrification. This "electric-ready" construction has electrical panels and services sized to accommodate electric appliances and vehicles. Electric-ready construction can be mandated by government through energy and building codes. Building new construction to be electric-ready can avoid the expensive costs of retrofitting infrastructure. In existing buildings, where retrofits are needed, upgrades are likely to increase rate pressure. Electrical upgrades can require utility permits and approval, which has been slow and created bottlenecks in other jurisdictions. Nova Scotia Power can help avoid these bottlenecks by streamlining the process for evaluating upgrades and issuing permits. Given its role as the electrical inspection authority within its service territory, the utility can also help facilitate appropriate procedures up front and prioritize timely inspections to ensure this doesn't slow down electrification. E3 also recommends that the utility identify ways to more efficiently and cost-effectively support distribution system and service upgrades. For example,

[77] Examples include Eversource and National Grid, which have implemented make-ready programs to support public, multi-unit dwelling, and workplace charging. Hawaiian Electric Co. (HECO) has also implemented make-ready charging infrastructure programs. Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) have both implemented make-ready charging infrastructure programs for medium- and heavy-duty vehicles.

[78] Utilities in North America that have implemented full charging infrastructure have included costs in their rate base. Examples include San Diego Gas & Electric's rate base cost recovery of 3,500 L2 chargers in its Power Your Drive program and Southern California Edison's rate base cost recovery of chargers at 1,500 sites as part of its Charge Ready program to help jumpstart EV adoption in their service territories.

[79] To ensure equitable access to electrified technologies, one strategy may be to prioritize undersized panels and panels for low-income and/or disadvantaged communities.

Nova Scotia Power may develop plans for coordinating investments in higher amperage service conductors by having a program in place to proactively schedule and complete the associated upgrades in a coordinated fashion that can both minimize certain costs that can be shared (e.g., road closures) and accelerate the overall pace at which upgrades can be completed.

Long-Term Strategy and Planning

Recommendation 5. Fully incorporate electrification strategy findings, including peak impacts and mitigation strategies, into utility planning models.

+ **Model impacts on resource needs and costs**: Reliably serving electrification loads will be a defining challenge for Nova Scotia Power in coming decades. While many programs and initiatives described above could help to mitigate this impact (e.g., smart charging, dual-fuel heat pumps), Nova Scotia Power should continue to model the impacts of electrification on the generation portfolio through its IRP Evergreening process and beyond, enabling the utility to proactively plan a mix of generation and demand-side resources to meet the system's capacity needs at least cost and while maintaining emissions constraints. An ongoing emphasis in Nova Scotia Power's planning should be evaluation of the potential electricity cost savings associated with peak mitigation strategies.
+ **Model impacts of electrification on reliability:** High levels of electrification will change the timing and shape of Nova Scotia Power's peak loads and may increase load's weather sensitivity. This in turn may affect the ability of variable and energy limited resources to provide capacity and could potentially increase the required planning reserve margin. At the same time, flexible electric vehicle loads may provide reliability benefits, and Nova Scotia Power should consider modeling the reliability benefits managed load can provide relative to unmanaged loads. We recommend Nova Scotia Power evaluate the potential for different DER programs to provide effective capacity contributions through robust reliability modeling (e.g., using a loss-of-load model); this modeling could also inform a comparison of the ability of different DER programs to provide cost-effective alternatives to supply side investments (e.g., batteries).
+ **Evaluate the impacts of electrification on equity and affordability**. Electricity system planners are increasingly playing a role in assessing the potential impacts of electrification and other decarbonization investments on energy affordability. Metrics to assess affordability include monthly or annual energy bills, energy costs that incorporate both bills and upfront costs, and energy bills as a fraction of household income. While electric rates are a useful gauge for how the costs of electricity for customers change over time, applying electric rates to customer loads is needed to determine the actual impacts of electrification on customers' total energy bills and costs. Understanding the affordability implications of electrification can help inform provincial planning and determine where additional provincial support will be needed. Affordability also extends beyond electricity; affordability metrics should consider the offsetting reductions in natural gas, fuel oil, gasoline and diesel expenditures as building and transportation end uses are converted to electricity, as well as the up-front cost premiums associated with electrified equipment and appliances.

Recommendation 6. Advance public-facing distribution planning process to support electrification

+ **Proactive distribution system planning:** Utility planners need to manage an increasingly complex distribution system proactively and effectively. Pre-planning is needed to identify areas where significant load growth is expected and the upgrades that might be needed if various scenarios play out with electrification, and to coordinate with those investments. E3 recommends that Nova Scotia Power proactively identify needed transmission and distribution facilities to ensure that customers do not experience delays in upgrading to electrified equipment. At a high level, this involves building out spatially explicit load forecasts under key electrification planning scenarios, and typically using commercially available tools to allocate expected load growth at the substation level. The next steps often involve evaluating the ability to shift load away from overloaded areas and adding capacity in the most constrained areas of the distribution system. Ideally, more detailed modeling of customer equipment that can shift load, providing benefits to the grid through load management, is pursued as another step in distribution planning, as this can potentially reduce the size of needed transmission and distribution investments. A formal distribution system planning process that includes such non-wires alternatives will also enable stakeholder engagement and public participation to help identify the most pressing issues to customers and identify areas that are in need of utility investment in order to ensure a reliable, resilient grid and help the province meet long-term goals.

Partnerships & Customer Engagement

Recommendation 7. Electrification at scale requires concerted effort and coordination across diverse organizations and interests with complementary expertise. Nova Scotia Power should continue to proactively build partnerships with these other key stakeholders.

+ **Key partnerships are likely to include the following:**

  - **Efficiency One:** Support E1 in accelerating building shell and other efficiency measures to reduce customer bills when switching to electrified space and water heating. Coordinate and support E1 in promoting heat pump adoption among current electric resistance customers, consistent with utility remit under the Public Utilities Act. Bill 228 expands "electricity efficiency and conservation" activities to include "strategic electrification of energy end uses currently powered by fossil fuels in a manner that reduces overall greenhouse gas emissions and electricity costs." [80] As the utility, Nova Scotia Power should work with E1 on prioritizing electrification programs and initiatives.

  - **Government:** Nova Scotia Power should engage in ongoing collaboration helping encourage 1) electric-ready building codes and other building policies that encourage beneficial electrification; 2) enable the deployment of charging stations; 3) identifying

[80] Bill 228, which received Royal Assent on November 9, 2022, adds "strategic electrification of energy end uses currently powered by fossil fuels in a manner that reduces overall greenhouse gas emissions and electricity costs" to the mandate of Nova Scotia's electricity efficiency and conservation franchise holder.

underserved communities and investments needed to ensure equitable access to electrified mobility and heating.

- **Third Party EVSE Providers:** Work to collaborate on improving the process of interconnection and developing additional public and workplace charging infrastructure. The utility role may complement third-party charging companies by filling in 'gaps' in coverage in underserved areas.

- **Equipment Manufacturers:** Collaborate on education, outreach, and innovation.

- **Transit/Bus Owners and Operators:** Work to develop electrification pilots and support education on model types, capabilities, and limitations.

- **Consumer Advocates:** Collaborate to understand broad impacts on underserved communities. Pursue outreach and potential programs to help overcome first-cost hurdles.

- **Supporting customer education and training:** Despite growing awareness of transportation electrification options, many consumers as well as building and vehicle fleet managers and operators have insufficient information in considering electrification options. Customer engagement is needed to identify where and when on the grid loads will materialize.

- **Supporting technical contractor training**: Lack of knowledge of the benefits and capabilities of heat pumps by contractors may drive up contractor mark-up. Training contractors and developing public lists of contractors with expertise in heat pump retrofits can help make customer adoption easier and cheaper.

Recommendation 8. Support an equitable transition through programs directly aimed at lower income or disadvantaged communities.

+ **Identify underserved communities and prioritize investments to ensure equitable access:** Without intentional program design, electrification at scale is expected to pose challenges that disproportionately impact lower-income and disadvantaged communities. For example, these customers may be less able to self-fund capital investments required for building electrification, and on the transportation side, they may live in communities with less access to charging infrastructure. It will be critical for Nova Scotia Power and E1 to work with provincial and local governments to identify underserved communities and investments needed to ensure equitable access to electrified mobility and heat. For example, these could include lower income households or areas, communities with disproportionate health or pollution burdens, or rural areas with less infrastructure. In addition to including equity-related analysis in utility planning (e.g., by estimating energy burden as noted above), the utility should pursue specific initiatives to address equity-related challenges. One approach best-in-class utilities are taking is to set specific targets for electric vehicle charging infrastructure in disadvantaged community or multi-family housing units. For example, a specific challenge in Nova Scotia relates to communities currently served by radial transmission lines. These communities have lower reliability and less ability to integrate new large electric loads without major upgrade costs. For widespread electrification, these customers will require upgraded supply. Thus, the costs of supporting investments in these communities – relative to the potential achievable electrification net benefits – should be a priority to evaluate, and investments in these areas could be considered on the basis of promoting equitable access to electrification benefits in the province

Technical Appendices

6. Appendix: Detailed Transportation Load Modeling Assumptions

6.1 E3 EV Load Shape Tool Inputs and Assumptions

6.1.1 Light-duty vehicle (LDV) charging loads inputs and assumptions

LDV are assumed to drive on average 17,427 km/yr[81]. The 2030 vehicle parameters assumed are show in Table 6-1 below:

Table 6-1. 2030 vehicle parameters

EV type	Average Range (km)	% of vehicle population
BEV	475	77%
PHEV	68	23%

EV efficiency for each vehicle type is adjusted daily in the model based on historic Nova Scotia temperature data.

The number of residential chargers are based on the assumption that 75% of drivers have access to residential charging. The number of workplace and public charger ratios are developed using EVI Pro Lite and the assumption that 34% of drivers have access to workplace charging.[82] Charger parameters for each charger location and charger type modeled are shown in Table 6-2 below:

Table 6-2. 2030 charger parameters

Charger type	Rated charger power (kW)	Charger efficiency (%)	Charger : EV ratio	# of Chargers
Residential L1	1.6	90%	1 : 1	25,607
Residential L2	11.4	90%	1 : 1	33,444
Workplace L2	6.6	90%	1 : 21.8	3,465
Public L2	6.6	90%	1 : 29.5	2,561
Public DCFC	175	85%	1 : 44.8	1,686

[81] https://oee.nrcan.gc.ca/publications/statistics/cvs/2009/appendix-1.cfm?graph=11

[82] Nova Scotia 2016 Census Data, NREL EVI-Pro2 Input Presentation, Aug 2020

Note that the actual maximum power draw is dependent on vehicle type and may be lower than listed in Table 6-2 for some EV types.

6.1.2 Medium-duty vehicle (MDV) and heavy-duty vehicle (HDV) charging loads inputs and assumptions

Transit buses were selected given their predictable driving schedules and consistent depot charging; long-haul trucking driving patterns often span beyond the Nova Scotia province and have inconsistent locations for charging. Transit buses are assumed to drive 62,888 km/yr.[83] Parcel trucks are used to represent MDV charging loads. Parcel trucks are assumed to drive 22,779 km/yr.[84]

Vehicle parameters for transit buses and parcel trucks are shown in Table 6-3 below:

Table 6-3. 2030 MD/HD vehicle parameters

EV type	Average Range (km)
Transit bus	670
Parcel truck	442

The efficiencies of transit buses and parcel trucks are adjusted daily based on historic Nova Scotia temperature data. Transit buses have a slightly different relationship to temperature than LDV and parcel trucks.

All parcel trucks and transit buses are assumed to have their own charger. Charger parameters for transit buses and parcel trucks are given in Table 6-4 below:

Table 6-4. 2030 MD/HD charger parameters

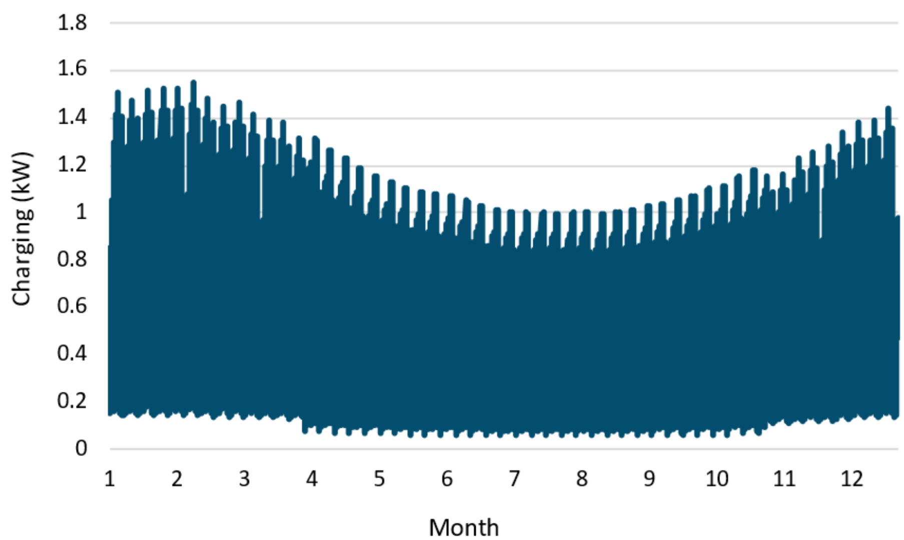
Charger type	Rated charger power (kW)	Charger efficiency (%)	Charger : EV ratio	# of Chargers
Transit bus charger	100-200	90%	1 : 1	601
Parcel truck charger	7.2-15	90%	1 : 1	956

[83] https://oee.nrcan.gc.ca/publications/statistics/cvs/2009/appendix-1.cfm?graph=11
[84] https://oee.nrcan.gc.ca/publications/statistics/cvs/2009/appendix-1.cfm?graph=11

6.2 Additional E3 EV Load Shape Tool Results

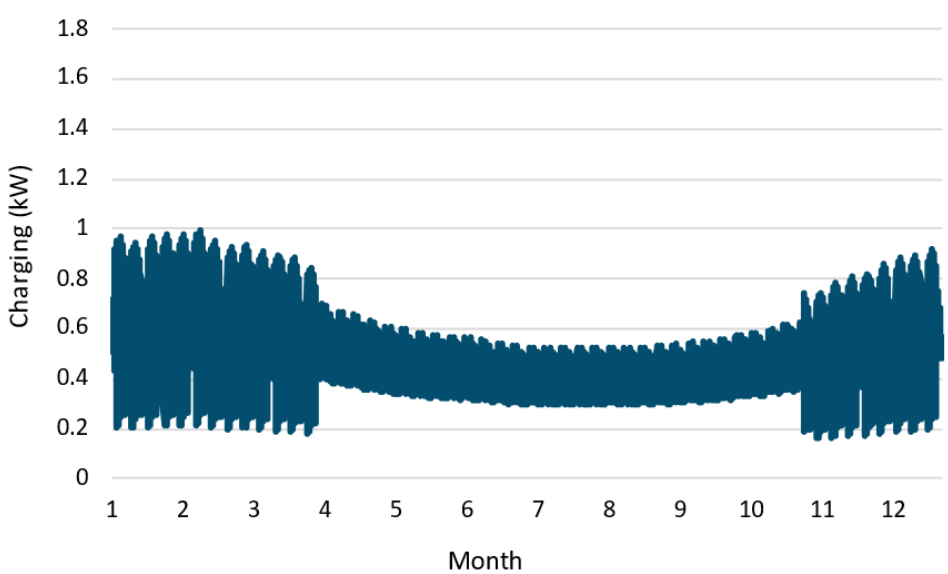
Charging profiles vary by temperature and therefore fluctuate throughout the year. A per vehicle charging profile for an unmanaged LDV is shown in Figure 6-1 below.

Figure 6-1. Annual unmanaged LDV charging profile



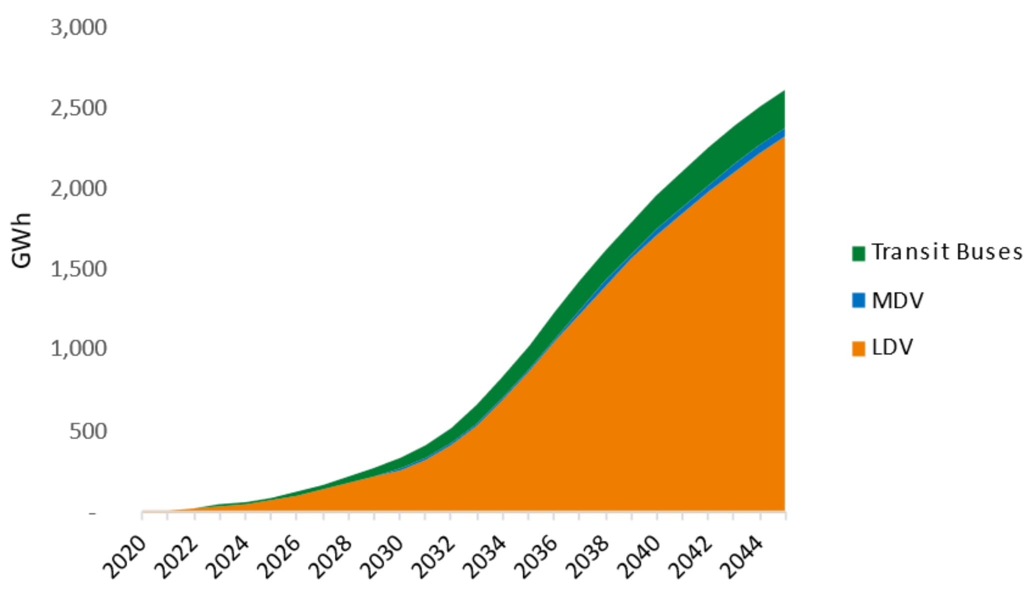
Per vehicle annual charging is shown for a managed vehicle with VGI in Figure 6-2 below.

Figure 6-2. Annual managed with VGI LDV charging profile



Based on modeling in E3's EV Load Shape Tool, LDVs in Nova Scotia are forecasted to increase load by about 260 GWh by 2030, with an additional about 80 GWh from transit buses and parcel trucks. Incremental transportation loads by vehicle class are shown in Figure 6-3 below.

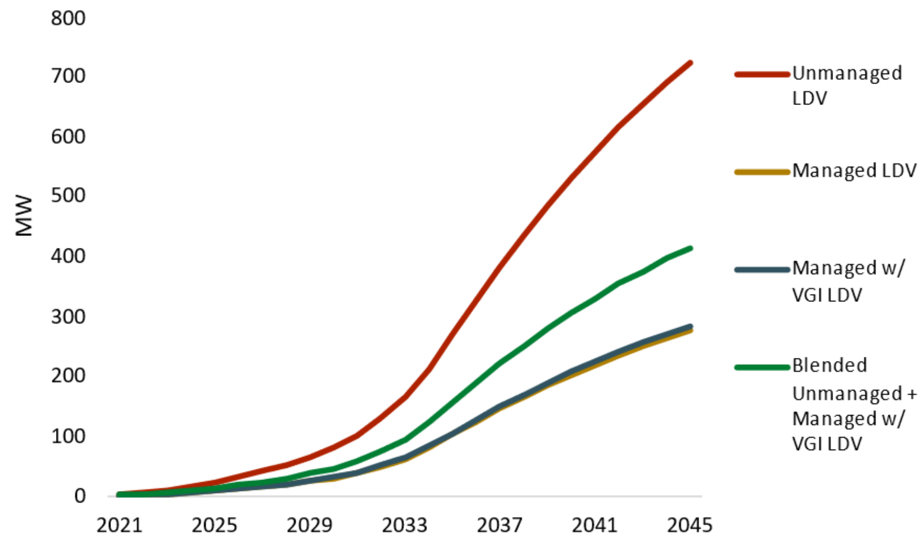
Figure 6-3. Incremental transportation loads, 2020-2045



Electrified transportation, including LDVs, transit busses, and parcel trucks, represents approximately 3% of Nova Scotia's total load in 2030 and 15% by 2040.

Unmanaged charging has a much greater total contribution to coincident peak load compared to managed charging. Figure 6-4 below shows the LDV contribution to Nova Scotia coincident peak load under different charge management scenarios.

Figure 6-4. LDV contribution to coincident peak load, 2021-2045

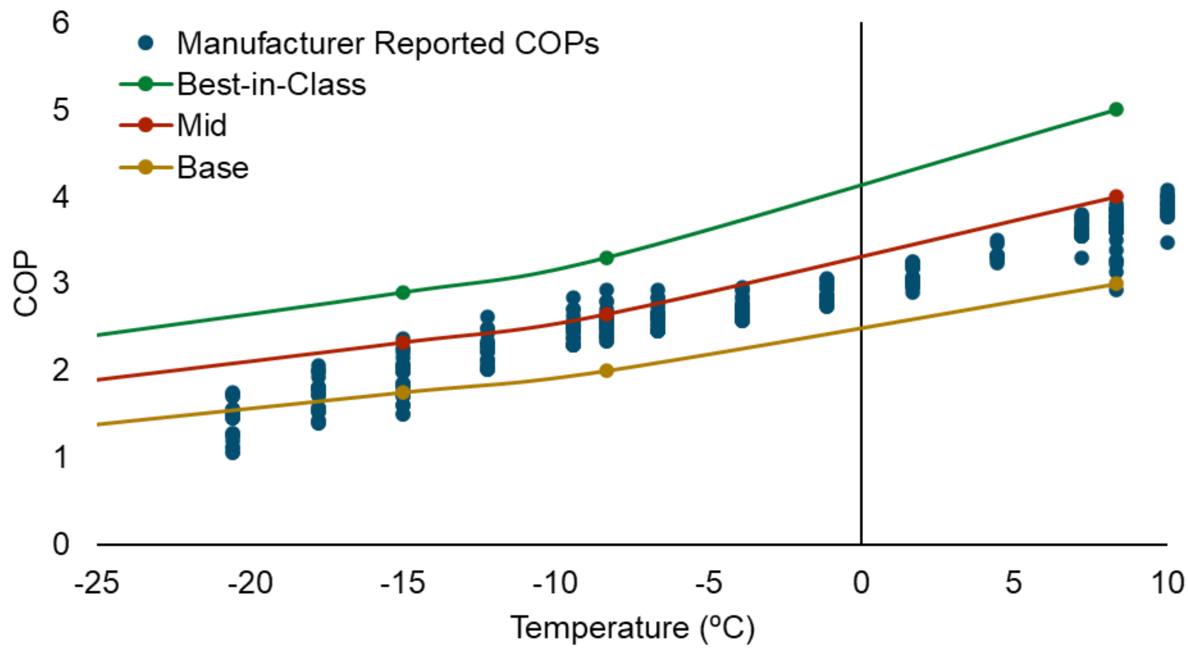


7. Appendix: Detailed Building Load Modeling Assumptions

7.1 Coefficient of Performance (COP) Assumptions

E3 uses manufacturer reported data on the performance of ccASHPs provided by NEEP in its *Cold Climate Air Source Heat Pump Product List and Specifications*. Data from the NEEP database is used in RESHAPE as shown in the base, mid, and best-in-class curves in Figure 7-1. . E3 corroborated the NEEP data with publicly available manufacturer reported data from Amana, Goodman, Day and Night, and Rheem ("Manufacturer Reported COPs" in Figure 7-1.).

Figure 7-1. RESHAPE COP curves



7.2 Heat Pump Sizing Assumptions

Base and mid performance all-electric heat pumps are sized according to standard practice to have a heat pump balance point temperature—the temperature below which the supplemental device would begin to serve heating demand—of 20ºF/-7ºC. Best-in-class all electric heat pumps were oversized such that the heat pump could serve the heating demand at 99th percentile historical minimum temperature from 2000 to 2018. Dual-fuel heat pumps were also sized to have a heat pump balance point temperature of approximately 20ºF/-7ºC. For dual-fuel systems, heat pumps are modeled such that below the balance point temperature both the heat pump and supplemental device both contribute to meeting the service demand.

7.3 Shell Improvement

E3 modeled building electrification scenarios with "DSM" and "Pre-DSM." In scenarios with DSM, buildings adopting heat pumps also receive a building shell improvement. E3 used the building simulation software EnergyPlus to determine the percent reduction in annual service for existing buildings that receive a shell retrofit (see Table 7-1). E3 simulated a prototype residential and commercial building in Nova Scotia with pre-DSM (existing) and DSM (new construction code) building envelopes. The building simulations used slightly lower R-values than prescribed by the code because retrofits are unlikely to achieve the insulation levels of new construction and most buildings would comply with the code on a performance-based approach targeting other measures (lighting, plug loads, heating equipment) to be compliant. Details on the building envelopes modeled in EnergyPlus are in Table 7-1.

Table 7-1. Shell improvement in DSM building scenarios

Sector	% Reduction in Annual Service Demand
Residential	23%
Commercial	14%

Table 7-2. EnergyPlus simulations building details

Sector	Building Type	Wall Assembly R-Value ($ft^{2*}h*R/Btu$)	Roof Assembly R-Value ($ft^{2*}h*R/Btu$)	Glazing Assembly U-Value ($Btu/ft^{2*}h*R$)	Infiltration (cfm/sf)
Residential	Pre-DSM – Existing	15.4	22.2	0.52	0.223
	DSM – New Construction Code	20.4	32.2	0.35	0.112
Commercial	Pre-DSM – Existing	15.4	22.2	0.52	0.223
	DSM - New Construction Code	20	32	0.35	0.12

8. Appendix: System Load Impacts with Demand Side Management

As discussed in Section 3, electrification at scale could potentially have large impacts on system peak loads. Many studies have demonstrated that coupling energy efficiency investments such as weatherization and building shell improvements coupled with electrification is critical for achieving cost-effective decarbonization. Thus, E3 modeled system load impact under building electrification scenarios that include demand side manage (DSM) strategies like shell improvements.

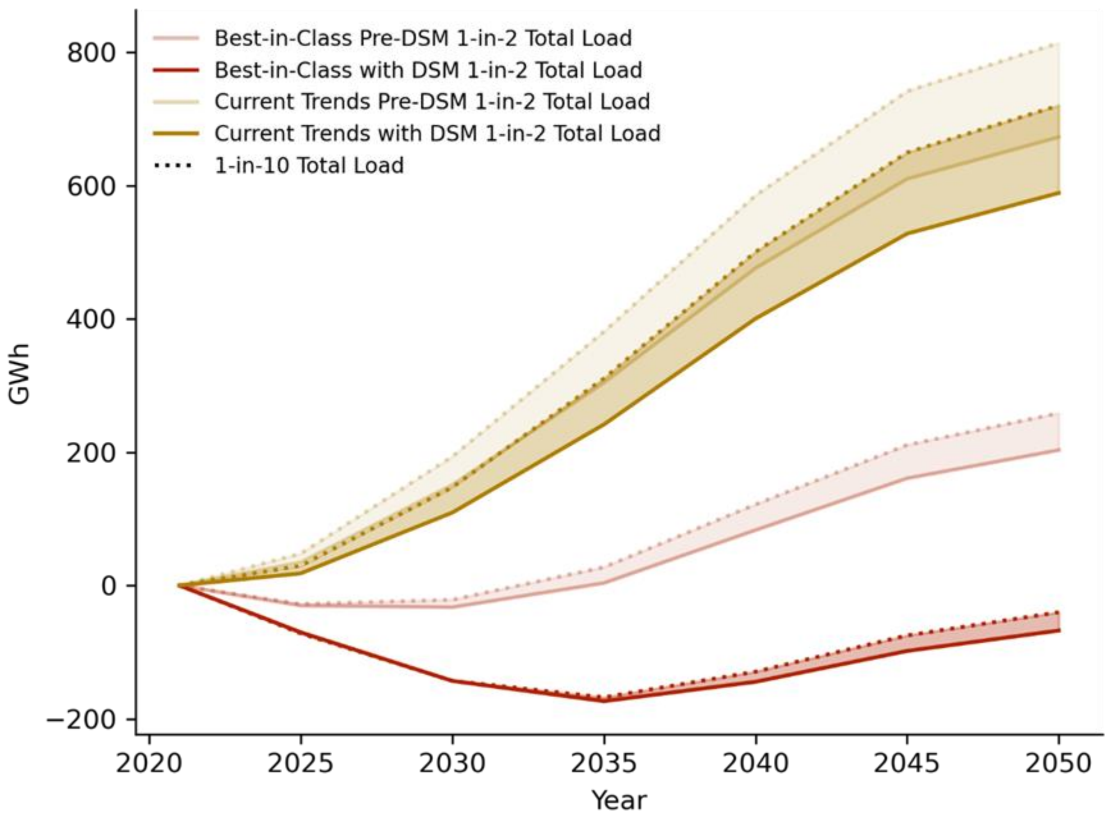
As summarized in Table 8-1, E3 modeled scenarios building upon the **Current Trends All-Electric** and **Best-in-Class** Pre-DSM. The Current Trends scenario with DSM models the adoption of shell improvements amongst current electric resistance customers adopting heat pumps. In the Best-in-Class scenario with DSM, all buildings receive a shell improvement when adopting a heat pump. In both scenarios, residential buildings that receive a building shell improvement reduce their annual heating service demand by 23% and commercial buildings reduce their annual heating service demand by 14%. The expected impact of building shell improvements was estimated using building simulation software as described in the Appendix: Detailed Building Load Modeling Assumptions.

Table 8-1. Building scenario design with DSM

	Current Trends All-Electric		Best-in-Class	
	Pre-DSM	With DSM	Pre-DSM	With DSM
Today's gas and oil heating buildings	Adopt **ASHP**		Adopt **ASHP**	
Today's electric resistance buildings	Adopt **ASHP**		Adopt **ASHP**	
Heat pump performance	ASHPs are 30% base; 40% mid; 30% high performance		ASHPs are 100% high performance	
Heat pump sizing	ASHPs sized to serve full heating demand in 93-95% of hours		ASHPs sized to serve full heating demand in 99% of hours	
Building shell improvements	No shell Improvements	Current resistance customers receive shell improvements	No shell improvements	All buildings receive a shell improvement

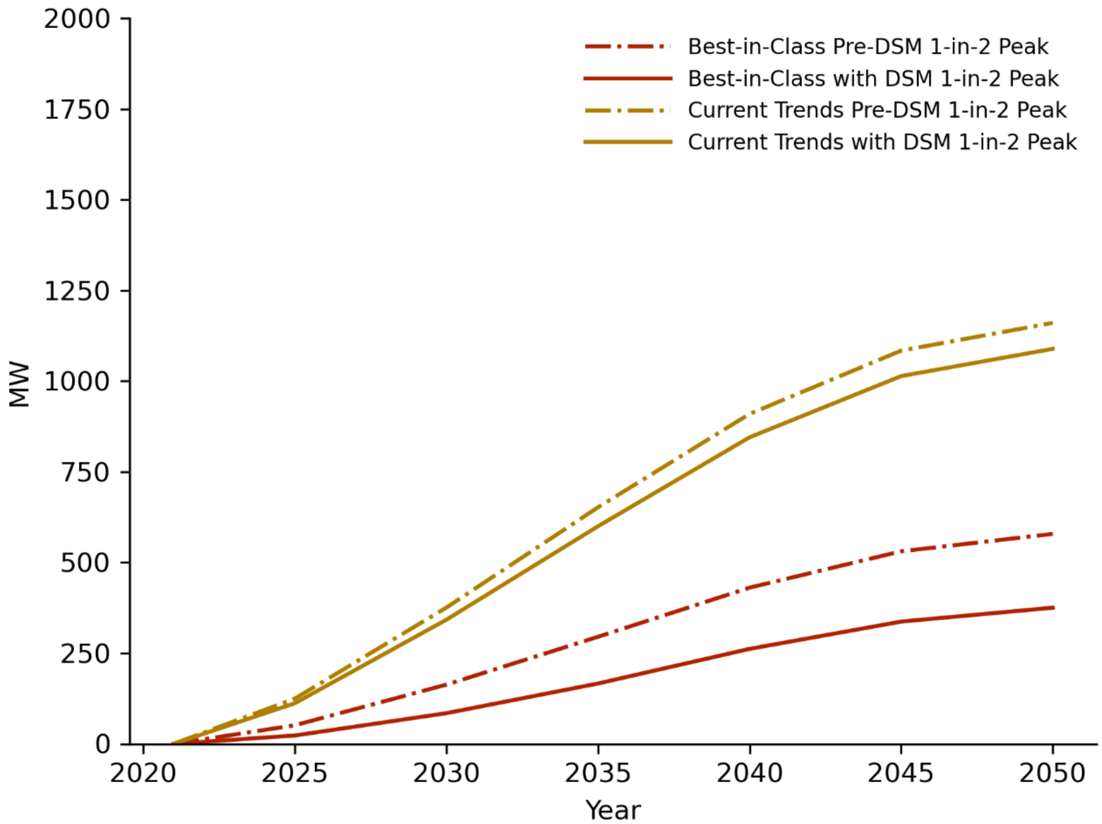
The adoption of shell measures amongst current electric resistance customers switching to heat pumps in the Current Trends Scenario with DSM could reduce the incremental annual load growth by 12% in 2050. The larger scale deployment of shell measures in the Best-in-Class with DSM scenario shows that incremental annual load from electrification could be negative as the increase in new load severed by fuel oil customers adopting heat pumps is lower than the efficiency savings from electric resistance customers adopting heat pumps and shell improvements.

Figure 8-1. Incremental annual building electrification load with DSM



In the Current Trends with DSM scenario, the incremental buildings non-coincident peak load is expected to reach approximately 1,088 MW by 2050, a 6% compared to the Pre-DSM scenario. In the Best-in-Class with DSM, where all customers receive a shell improvement, DSM is expected to reduce peak impacts by 35% in 2050.

Figure 8-2. Non-coincident peak of incremental building electrification loads with DSM



9. Appendix: E3 BCA Tool Inputs and Assumptions

Inputs used for the transportation benefit-cost analysis in E3's BCA Tool are detailed below.

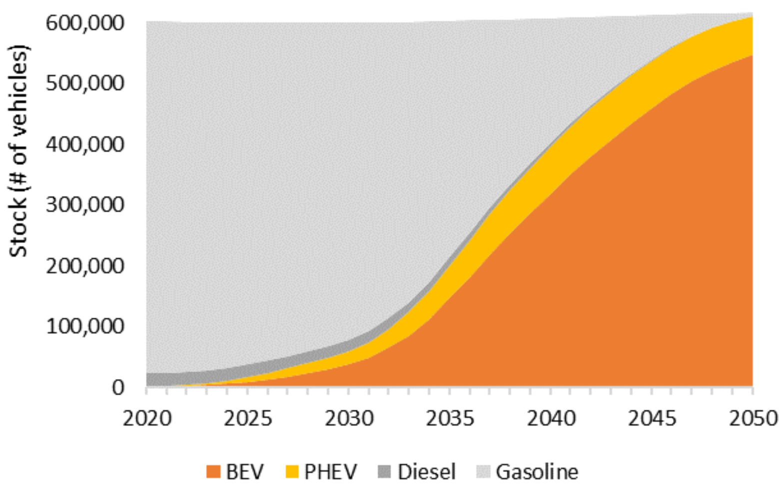
9.1 Transportation

9.1.1 EV Adoption

EV adoption and stock estimates were developed in E3's PATHWAYS stock rollover model.

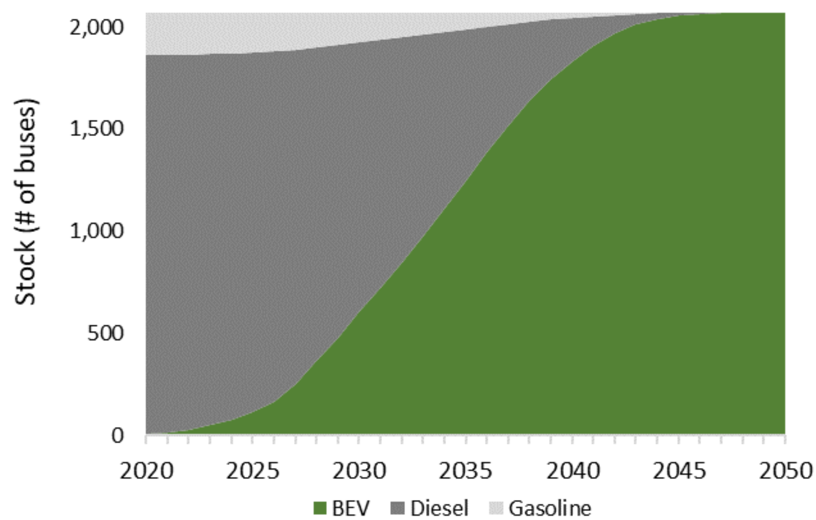
LDV adoption forecasts were developed based on the assumption that 100% of LDV sales will be electric by 2035. The base case of EV adoption follows a "slow sales ramp" scenario, which reaches 30% electric LDV sales by 2030.

Figure 9-1. LDV stock by type, 2020-2050



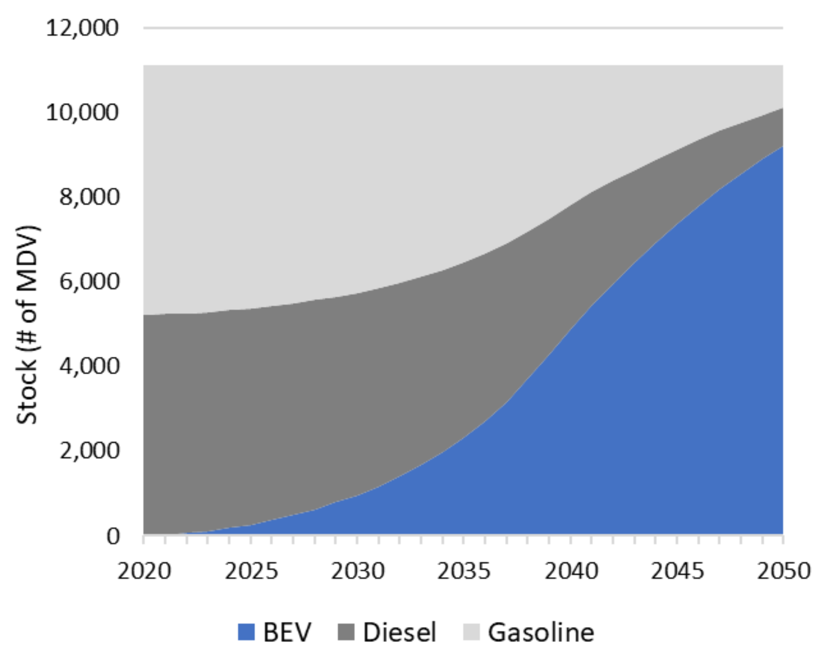
Transit bus adoption forecasts were developed based on the assumption that 100% of transit bus sales are electric by 2030. This marks an accelerated transition to electrification compared to LDV given the faster transition potential for transit busses that results from consistent routes and environmental and health benefits.

Figure 9-2. Transit bus stock, 2020-2050



Parcel truck adoption forecasts were developed based on the assumption that over 90% of parcel truck sales are electric by 2040.

Figure 9-3. Parcel truck stock, 2020-2050



9.1.2 EV Purchase Incentives

There are several upfront purchase incentives that are included for LDV. A federal EV tax credit of $5,000 for BEVs and long-range PHEVs and $2,500 for short-range PHEVs was included. Funding for the federal EV tax credit was guaranteed through March 31, 2022 at the time of the analysis and therefore, only 25% of the federal tax credit was included for vehicles purchased in 2022 and no tax credit was modeled for vehicles adopted starting in 2023. Tesla BEVs and PHEVs are not eligible for the federal tax credit. In 2020, Tesla made up 54% of EV purchases; therefore, 54% of vehicles purchased in 2022 were assumed to not be eligible for the federal tax credit. The federal tax credit was also averaged for the proportion of new vehicle purchases estimated to be BEV or long-range PHEV and the proportion of new vehicle purchases estimated to be short-range PHEVs.

In addition to the federal EV tax credit, a $3,000 provincial rebate was included for LDV purchased in all years modeled.

There are no EV purchase incentives assumed to be available for transit buses or parcel trucks in all years modeled.

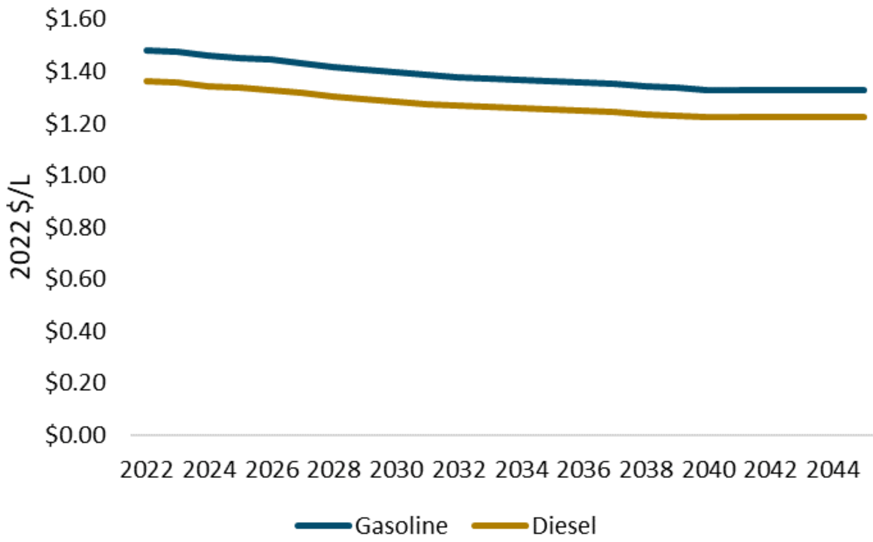
9.1.3 EV O&M Savings

EVs generally have lower lifetime operating and maintenance (O&M) costs than an equivalent ICE vehicle. A per mile O&M savings, determined separately for each vehicle class, is applied to the vehicle class average lifetime Vehicle Miles Travelled (VMT).

9.1.4 Vehicle Fuel Price Forecasts

Vehicle fuel savings represent the avoided gasoline or diesel costs that would be incurred by an equivalent ICE vehicle to satisfy an average lifetime VMT. To calculate avoided gasoline or diesel, a forecast of ICE fuel economy for each vehicle type is used. LDV fuel economy projections are informed by NREL and transit bus and parcel truck fuel economy estimates are based on estimates from UC Davis, the U.S. Energy Information Administration (EIA), and the U.S National Household Travel Survey (NHTS). Gasoline and diesel price forecasts from the Canada’s Energy Future 2018 report for Nova Scotia are used with fuel economy projections to determine annual and lifetime vehicle fuel savings. Gasoline and diesel price forecasts and given in Figure 9-4 below.

Figure 9-4. Gasoline and diesel price forecast



9.1.5 Marginal Electricity Supply Costs for EV Charging and Buildings

Electricity supply costs represent the costs that utilities must pay to provide the electricity used for EV charging. There are four components that make up electricity supply costs: energy, capacity, distribution, and transmission.

Energy supply costs reflect the cost for the utility to purchase electricity needed to serve EV charging in a given hour. Costs of electricity are determined by the hourly short run marginal cost of energy. The marginal cost of energy is forecasted through 2045. These were provided by Nova Scotia Power.

Annual capacity costs are from Nova Scotia Power and based on the cost of a combustion turbine. Annual distribution and transmission supply costs are derived from Nova Scotia's 2023-2025 Demand Side Management Plan.[85] Annual capacity, distribution, and transmission supply costs are allocated to hourly costs using the Peak Capacity Allocation Factor (PCAF) method.[86] The PCAF method allocates the annual capacity, distribution, and transmission costs to the hours each year with the highest net load. These hours with the highest net load reflect the times at which utility capacity and the distribution and transmission systems are most likely to be constrained and require upgrades. Net load is calculated by netting out imports, hydro, and wind production from gross Nova Scotia Power load. Nova Scotia Power load netted of imports, hydro production, and wind production are forecasted through 2045. The top 500 highest net load hours each year are used to calculate PCAF values, which are each top hour's load as a percentage

[85] 2023-2025 Demand Side Management Plan: https://www.efficiencyone.ca/2023-2025-demand-side-management-plan/

[86] The PCAF method was first developed by PG&E in their 1993 General Rate Case and have been used by California and many other jurisdictions to allocate capacity, distribution, and transmission costs for planning purposes.

over all top 500 hours' load. Hourly capacity, distribution, and transmission costs are allocated by applying PCAFs to annual costs.

9.1.6 Charging Infrastructure Costs

Current and future charging infrastructure cost assumptions were sourced from ICCT and are summarized in Table 9-1. The analysis assumes that the charging infrastructure cost from the driver's perspective only includes the cost of home chargers and that 39% of drivers will have access to home L2 chargers, 35% will have access to a home L1 charger, and 26% will have no home charging access. From the province's perspective, the charging infrastructure costs from the adoption of an LDVs also includes the cost of workplace, public, and DCFC chargers to support those vehicles. To allocate the cost of those charger to the adoption of a single vehicle, E3 assumes that there are 23 EVs on the road per workplace L2 charger, 33 vehicles per public L2 charger, and 54 vehicles per public DCFC charger. The charging infrastructure cost for the adoption of an MDV vehicle is equivalent to that of a workplace L2 charger in Table 9-1 and the infrastructure cost for a transit bus charger is equivalent to a DCFC charger for both the participant and societal perspectives. When analyzing the cost and benefits of managed charging, E3 included an incremental upfront cost of $130 CAD in 2022.

Table 9-1. Charging infrastructure costs (nominal CAD)

Charger	2022	2030
Home L1	$0	$0
Home L2	$2,568	$2,358
Work L2	$7,465	$6,855
Public L2	$7,465	$6,855
DCFC	$137,279	$126,060

9.1.7 Avoided Emissions

E3 calculated avoided emissions for the adoption of both electric vehicles and heat pumps as the avoided emission from the reduction in fossil fuel combustion net of the marginal increase in electric sector emissions. Hourly electric sector marginal emissions rates were provided by Nova Scotia Power through 2050 based on IRP modeling. Table 9-2 summarizes the emissions rates for avoided transportation fuels.

Table 9-2. Emissions rates from transportation fuels (tonnes/liter)

Tonnes/Liter	Gasoline	Diesel
CO_2	2.30×10^{-3}	2.91×10^{-3}
NO_x	8.40×10^{-7}	1.35×10^{-6}
PM10	1.64×10^{-7}	2.42×10^{-7}
SO_2	6.74×10^{-9}	1.20×10^{-8}

Table 9-3 summarizes the emissions rates for avoided fuels used for space heating.

Table 9-3. Emissions rates for space heating fuels (tonnes/therm)

Tonnes/Therm	Fuel Oil	Natural Gas	Wood
CO_2	0.0074	0.0053	0
NO_x	5.83×10^{-6}	3.89×10^{-6}	7.47×10^{-6}
PM10	1.32×10^{-7}	6.20×10^{-7}	4.53×10^{-6}

9.2 Buildings

9.2.1 Heat Pump Capital Costs

E3 developed capital cost assumptions for heat pumps in collaboration with Nova Scotia Power. Based on their experience supporting heat pump adoption, Nova Scotia Power reported that the typical cost of installing a 2.5 ton best-in-class all-electric in a single-family home currently using fuel oil is $16,000 and that the cost of installing a 1.5 ton mini-split in an equivalent home is $6,500. E3 generated capital cost assumptions for other building segments based on the average heat pump sized for that segment in the system load impact analysis and the cost per ton implied by Nova Scotia Power's reported experience. E3 developed counterfactual system costs based on analysis conducted from data sources in New England adjusted for prevailing labor rates in Nova Scotia.[87] The analysis also supported E3's assumptions regarding the cost premium for a best-in-class heat pump compared to the average performance system.

[87] Massachusetts D.P.U. 20-80. February 2020. "The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals: Independent Consultant Report. https://thefutureofgas.com/content/downloads/2.15.22%20-%20DRAFT%20Independent%20Consultant%20Technical%20Report%20-%20Part%20I%20(Decarbonization%20Pathways).pdf

Table 9-4. Appliance costs in 2022[88]

Sector	Counterfactual Fuel	Counterfactual System Cost ($)	Average Performance Heat Pump Cost ($)	Best-in-Class Performance Heat Pump Cost ($)	Shell Cost ($)	Mini-split Cost ($)
Single-family	**Fuel Oil**	$7,940	$10,869	$16,000	$21,725	$6,500
	Natural Gas	$4,394	$10,869	$14,400	$21,725	$6,500
	Wood	$5,111	$6,793	$11,200	$21,725	$6,500
	Electric Resistance	$1,059	$6,793	$9,600	$21,725	N/A
Multi-family	**Fuel Oil**	$6,307	$9,511	$12,800	$6,354	$6,500
	Natural Gas	$2,644	$8,152	$12,800	$6,354	$6,500
	Electric Resistance	$766	$6,793	$9,600	$6,354	N/A
Small Commercial	**Fuel Oil**	$10,385	$38,043	$56,000	$326,766	$17,333
	Natural Gas	$4,509	$32,608	$49,600	$326,766	$15,167
	Electric Resistance	$17,400	$14,945	$22,400	$326,766	N/A

9.2.2 Heat Pump Cost Declines

E3's BCA models heat pump costs declining in the future to study the evolving economics of heat pump adoption over time. E3 derived technology cost learning rates from heat pump cost projects from NREL's *Electrification Futures Study*: *End-Use Electric Technology Cost and Performance Projections through 2050*.[89] The learning rates for air source heat pumps and heat pump water heaters are summarized in Table 9-5. E3 applied these learning rates to the equipment portion of their 2022 capital cost estimates. The labor portion of the heat pump capital cost is assumed to remain constant in real dollars. It is also assumed that the cost of counterfactual electric resistance or fossil fuel heating system remains constant in real dollars.

[88] The heat pump sizing varies based on the empirical estimates of average heating demand by home type. While electric resistance customers were assumed to have smaller heat pump (0.5 tons), existing fossil customers were assumed to adopt heat pumps between 1.5-2.5 tons, depending on the particular scenario design. We note that for the load shape analysis, mini-splits were sized up to create a more "apples-to-apples" comparison with all-electric systems, but for the CBA analysis, mini-splits are sized and costed smaller than all-electric systems (as reflected above).

[89] Jadun, Paige, Colin McMillan, Daniel Steinberg, Matteo Muratori, Laura Vimmerstedt, and Trieu Mai. 2017. Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-70485. https://www.nrel.gov/docs/fy18osti/70485.pdf.

Table 9-5 Heat pump equipment cost learning curves

End use	Time period	Moderate (Real %/year)	Rapid (Real %/year)
Space heating	2020-2030	-0.85%	-1.47%
	2030-2040	-0.93%	-1.47%
	2040-2050	-1.03%	-1.73%
Water heating	2020-2030	-1.99%	-3.97%
	2030-2040	-2.03%	-0.95%
	2040-2050	-0.95%	-1.05%

9.2.3 Fuel Price Forecasts

Wood pellet costs were sourced from Massachusetts Department of Energy Resources and are estimated to cost $2.63/therm (CAD) in 2021.[90] The model assumes that the cost for pellets reported in Spring 2021 by the MA DER will remain constant in real dollar terms into the future.

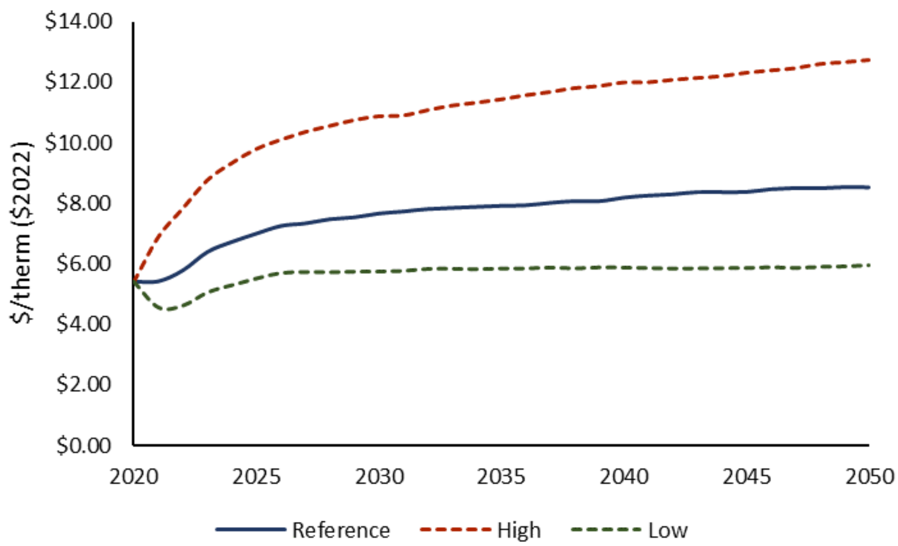
E3 identified four sources reporting residential retail fuel oil prices in Nova Scotia in fall of 2022 including Scotia Fuels (as of October 2022)[91] and Statistics Canada (October 2022).[92] The average retail fuel oil prices was $5.56/therm. The forecasted trend from U.S. Energy Information Agency's Annual Energy Outlook 2022 (AEO) distillate fuel oil price forecast for the New England region was applied to the benchmarked price of $5.56/therm to develop a forecast of future fuel oil prices.

[90] https://www.mass.gov/info-details/massachusetts-home-heating-fuels-prices#modern-wood-heating-prices-

[91] https://www.scotiafuels.com/

[92] Statistics Canada, Monthly average retail prices for gasoline and fuel oil, by geography, https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000101&pickMembers%5B0%5D=2.7&cubeTimeFrame.startMonth=06&cubeTimeFrame.startYear=2022&cubeTimeFrame.endMonth=12&cubeTimeFrame.endYear=2022&referencePeriods=20220601%2C20221201

Figure 9-5. Residential fuel oil price forecast



E3 estimated the delivery component of the retail fuel oil price to be $1.07/therm for residential customers and $1.30/therm for commercial customers in 2022. E3 estimated the delivery component based on the rate structure Scotia Fuels reports their competitors use and the difference in retail and wholesale prices reported in New England by the U.S. Energy Information Agency. E3 assumed the delivery component of the retail fuel oil price will remain constant in real dollar terms in the future. E3 subtracted the delivery cost from the retail fuel oil price forecast to determine a wholesale fuel oil supply cost.

E3 modeled natural gas rates paid by customers as having two main components: delivery charges and commodity charges. E3 used public Heritage Gas rate sheets to estimate current commodity and delivery rates for residential and commercial customers. The historical growth rate in the delivery charges found in rate sheets dating from August 2018 to December 2021 was applied to the current Heritage Gas delivery rates to develop a delivery price forecast. AEO's natural gas commodity price forecast for New England was applied to Heritage Gas's current commodity charges to develop a commodity price forecast for Nova Scotia.

Figure 9-6. Natural gas delivery costs

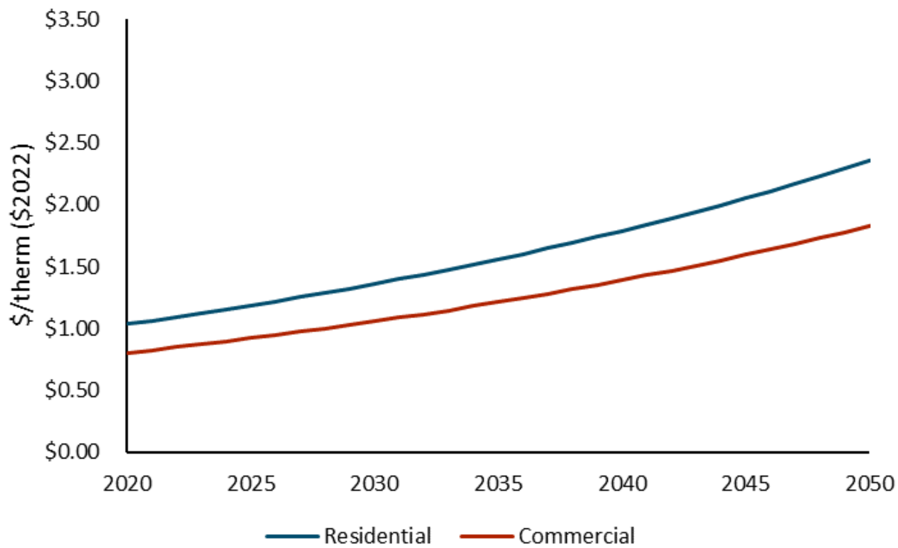
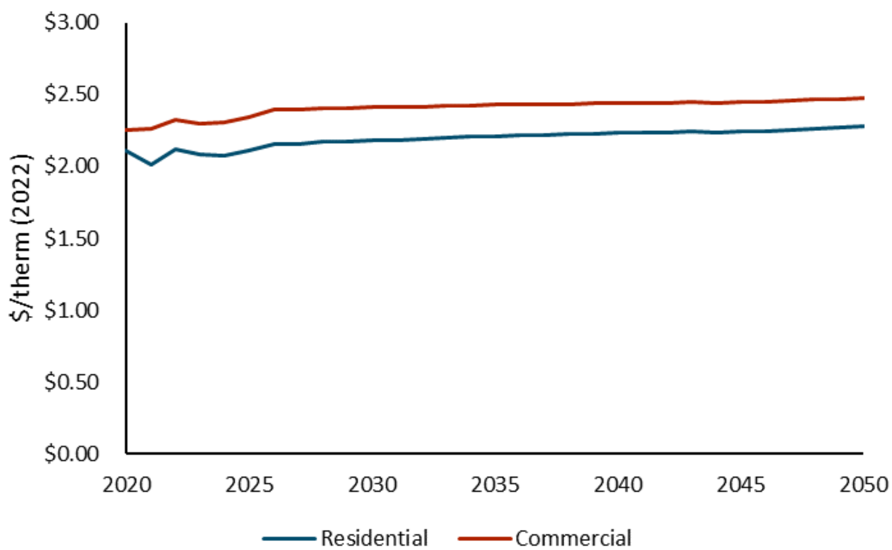


Figure 9-7. Natural gas commodity costs



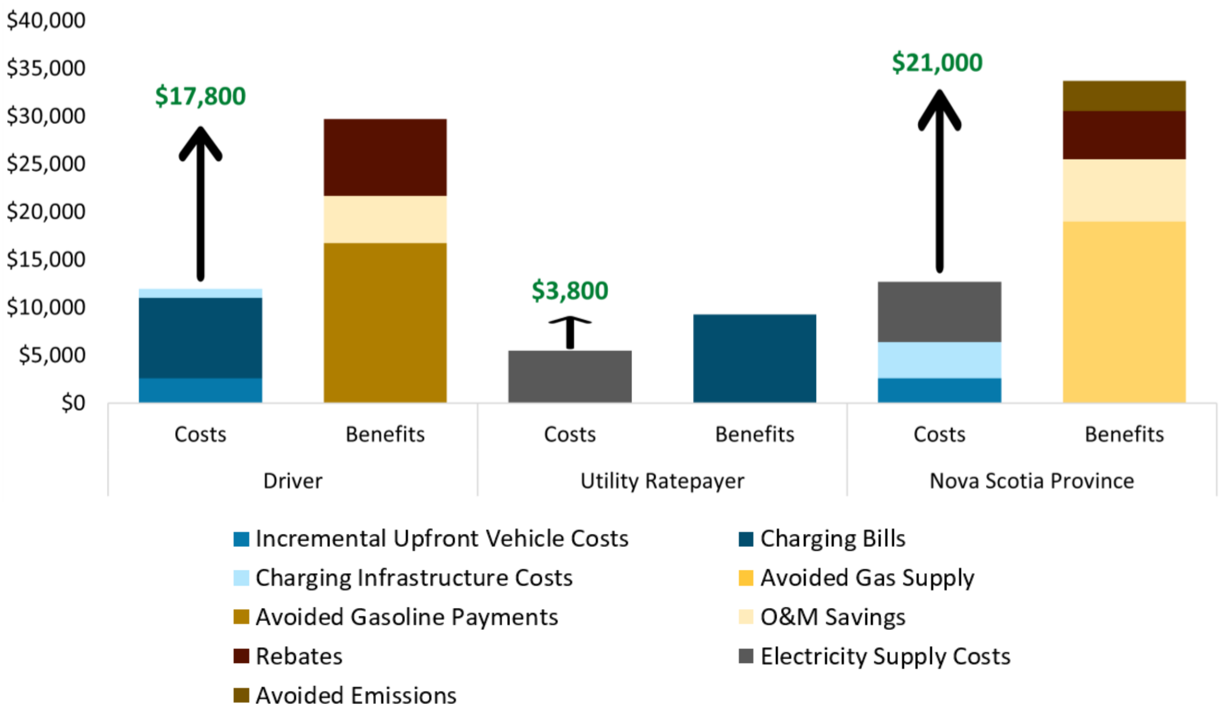
10. Appendix: Additional BCA Results

10.1 Transportation BCA Results for 2030

10.1.1 Light-duty Vehicles

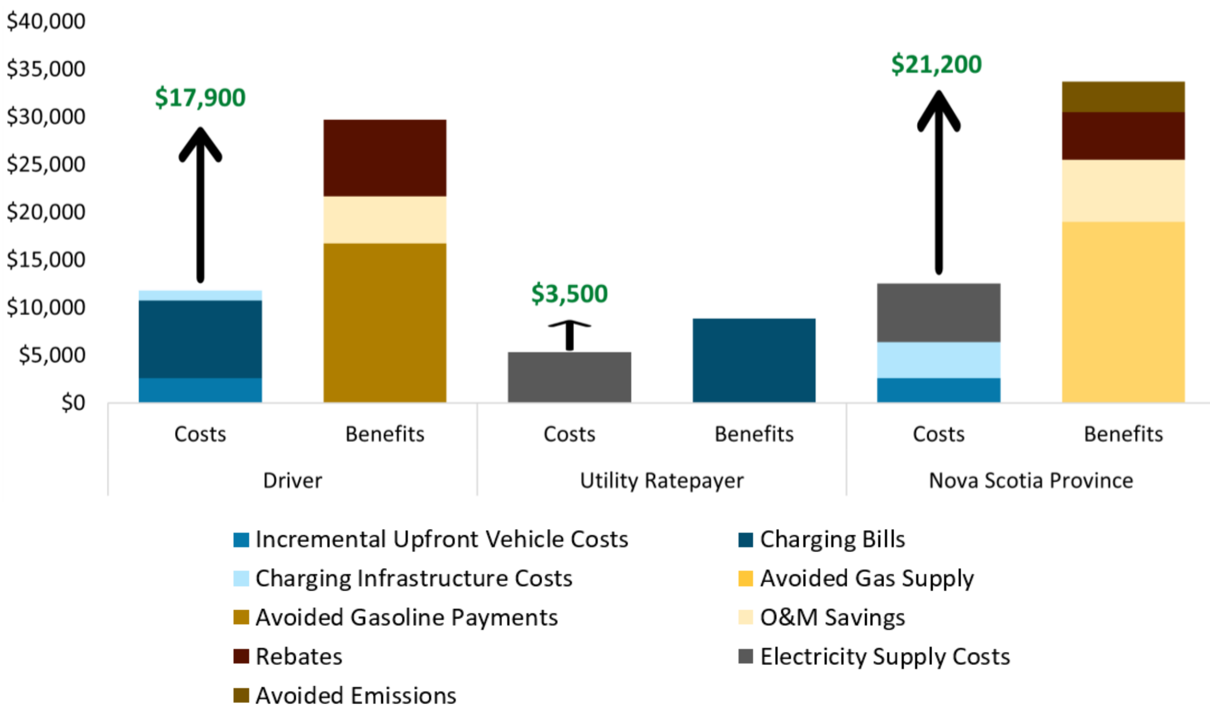
Cost-benefit breakdowns are also shown for EVs adopted in 2030. Figure 10-1. shows cost-benefit analysis results for an EV adopted in 2030 with unmanaged charging.

Figure 10-1. NPV cost-benefit analysis for LDV adopted in 2030 with unmanaged charging



Drivers see even larger savings for an EV adopted in 2030, primarily due to lower incremental upfront costs that result from reductions in upfront EV purchase prices over time. Rebates are assumed to remain available through 2030.

Figure 10-2. NPV cost-benefit analysis for LDV adopted in 2030 with managed charging



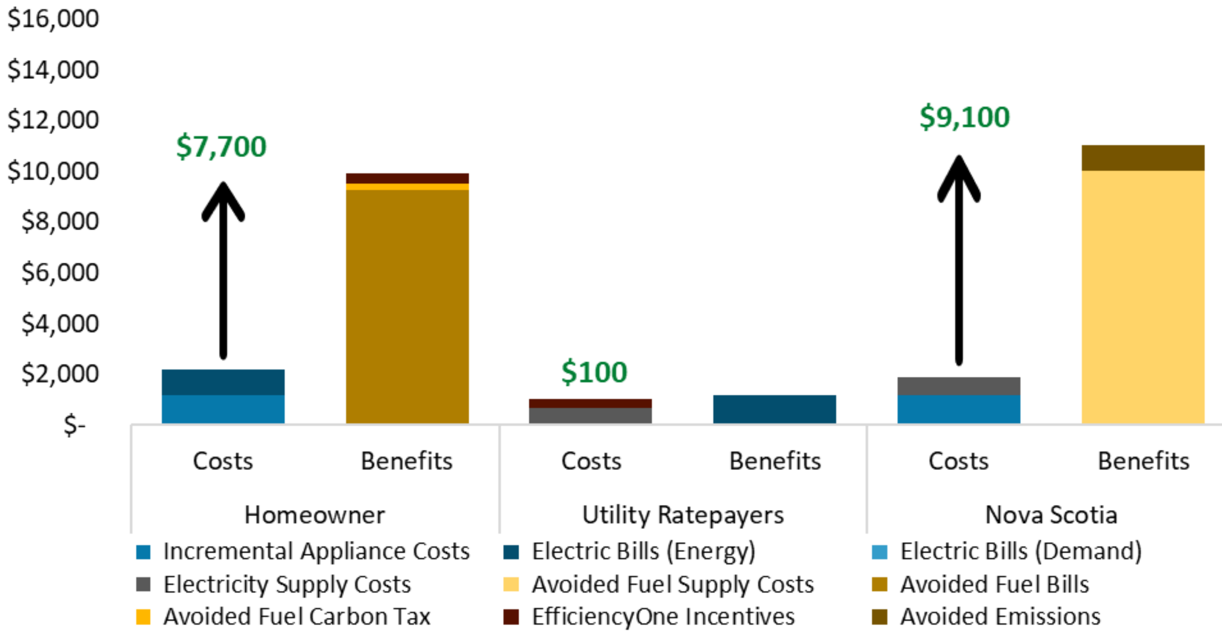
Similar to 2022, drivers who adopt an EV in 2030 achieve bill savings from managing charging with VGI although savings are muted by time-varying rates only being in winter months.

10.2 Additional Buildings BCA Results for 2022 (Residential Water Heating)

10.2.1 Residential Water Heating

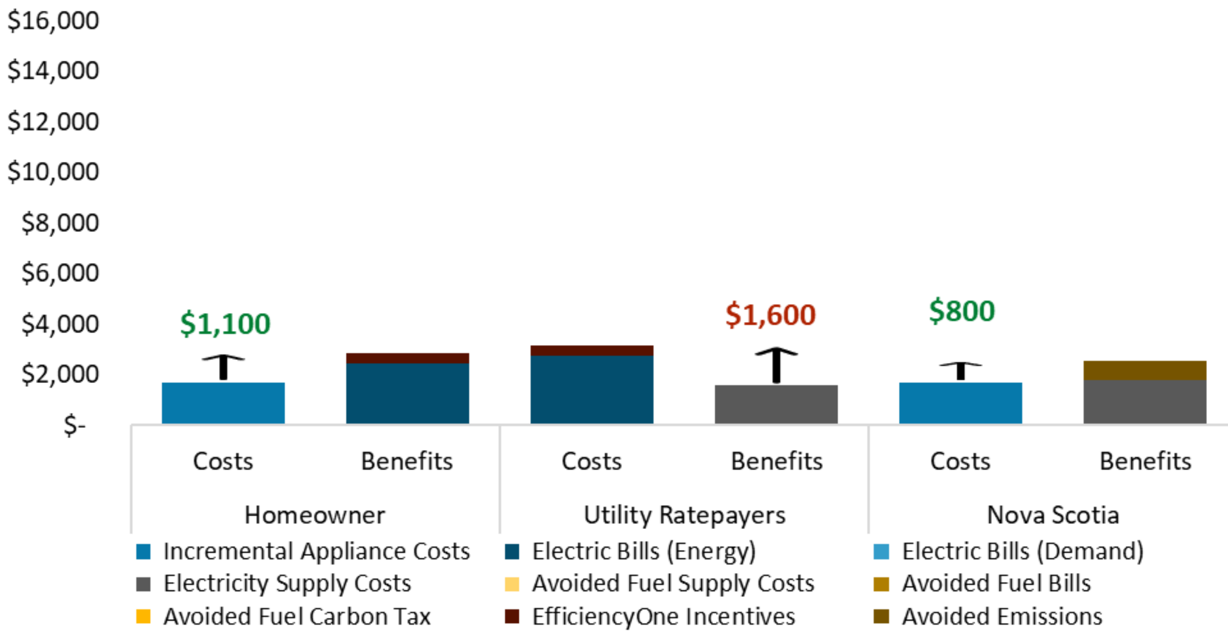
Electrification of water heating presents net economic benefits to participants, ratepayers, and Nova Scotia. Figure 10-3 shows the results of the cost-benefit test for the adoption of a heat pump water heater (HPWH) in 2022 for a residential customer currently using fuel oil. The net lifetime benefits for the customer are approximately $7,700, which is driven by large, avoided fuel bills that outweigh the incremental cost of the heat pump and incremental electricity bills. For the ratepayer, the electrification of water heating has net benefits as the cost for NS Power to serve the new load is less than the increase in revenue. Thus, the electrification of water heating puts downward pressure on rates. The net lifetime benefits of HPWH adoption present societal benefits are more than $9,000 which is driven by avoided fuel oil supply costs.

Figure 10-3. Costs and benefits of residential HPWH adoption in 2022 amongst current fuel oil customers[93]



[93] Assumes customers are on a flat rate.

Figure 10-4. Costs and benefits of residential HPWH adoption in 2022 amongst current electric resistance customers[94]



94 Assumes customers are on a flat rate.