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November 5, 2025

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Re: Newfoundland and Labrador Hydro – 2025 Capital Budget Supplemental Application – Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Additional Information – 2025 Energy Solutions Potential Study

On October 8, 2025, Newfoundland and Labrador Hydro ("Hydro") received correspondence from the Board of Commissioners of Public Utilities ("Board") requesting that Hydro file the Conservation and Demand Management ("CDM") Potential Study in advance of its planned filing in December 2025.[1] Hydro has attached the 2025 Energy Solutions Potential Study prepared by Posterity Group ("2025 Potential Study") to this correspondence. The report represents a joint effort by both Newfoundland Power Inc. ("Newfoundland Power") and Hydro (collectively "the Utilities").

It is not common for the Utilities to file a potential study without an accompanying five-year plan. The Utilities are in the process of developing a five-year plan, based upon the findings of the 2025 Potential Study. While the enclosed study provides valuable information, it should not be considered independent of the CDME Plan, which is intended to be complete in December of this year.

All CDM programs that will be included in the Utilities' CDME Plan will be based on local market research, stakeholder consultation, and estimates of long-term energy and demand impacts as determined by past program offerings, in combination with the results of the 2025 Potential Study.

2025 Potential Study Results – Context

The 2025 Potential Study evaluates the potential for energy efficiency, electrification, and peak demand management activities to be undertaken by the Utilities under their joint energy efficiency partnership, takeCHARGE. The study reflects a forecast period of 15 years to 2040 for the Island Interconnected System; however, only the first five years inform the development of the 2026–2030 CDME Plan.

The 2025 Potential Study assessed three levels of energy efficiency potential: Technical, Economic, and Achievable.

[1] The parties had agreed as part of the Settlement Agreement reached in the *Reliability and Resource Adequacy Study Review* proceeding to file the study in December 2025 as part of the 2026–2030 Joint Utility Conservation, Demand Management and Electrification Plan ("CDME Plan").

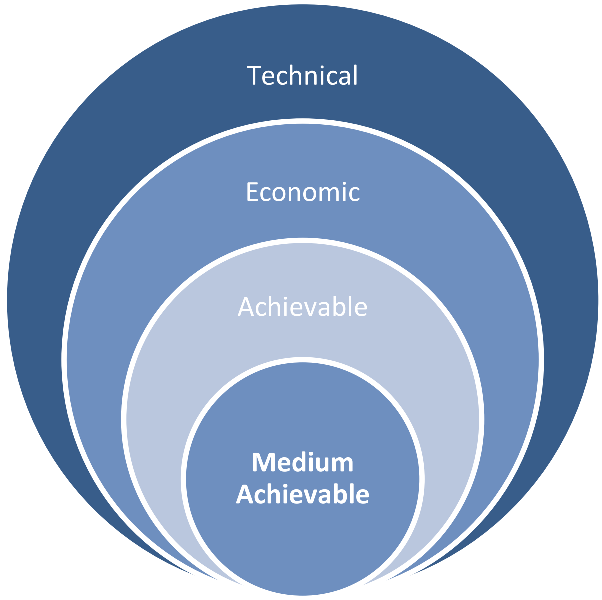

Figure 1: CDM Potential Scenarios

Technical Potential is an estimate of the technically feasible energy and demand savings potential, ignoring cost-effectiveness or market acceptance. In essence, it is a theoretical maximum amount of potential, ignoring all market constraints and consumer behaviour.

Economic Potential is an estimate of the energy and demand savings potential for measures that pass the cost-effectiveness screening criteria in the study. For the study, that includes any measures that received a 0.8 or higher on the Total Resource Cost ("TRC") test.[2] This potential also ignores consumer and market behaviour.

Achievable Potential is an estimate of the energy and demand savings potential considering feasible adoption rates of cost-effective measures over the study period. Achievable Potential considers market barriers, customer payback acceptance, and awareness of energy efficiency measures, among other factors, making it the most relevant of the three types of potential.

The Achievable Potential includes three levels of savings, as shown in Exhibit 2 of the attached report. The results presented in the 2025 Potential Study focus on a subset of Achievable Potential, more specifically, the **Medium Achievable Potential** scenario, which is forecast based on incentive levels of 50% of the incremental retrofit cost.[3]

Using the Medium Achievable Potential scenario to inform the CDME Plan ensures the Utilities' CDM programming is sufficiently broad while still meeting cost-effectiveness tests as established by the Board. Consideration of scenarios with higher energy or capacity savings would not be cost-effective and would therefore not be consistent with the Utilities' statutory obligation for least-cost, environmentally responsible, and reliable service.

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[2] The Board's established cost-effectiveness guidelines include a TRC score of 1.0 or higher. As an initial screening criteria, the 2025 Potential Study examines any measures that receive a TRC score of 0.8 or higher as to not rule out potential programs that could become cost-effective upon further analysis.

[3] For example, if the base case technology choice was $500 and the targeted energy-efficient technology cost $700, the incremental retrofit cost is $200. This scenario assumes an incentive of 50% of that cost (i.e., $100). Higher incentive levels increase program costs, which must be considered in the context of cost-effectiveness testing.

Medium Achievable Potential Scenario Summary

Table 1 summarizes and compares the forecast savings from energy efficiency outlined in the Medium Achievable Potential scenario versus CDM program savings included in Hydro's 2024 Load Forecast Slow Decarbonization scenario, as filed in the 2025 Build Application.[4] Hydro's forecast incorporates Newfoundland Power's 2023 General Rate Application forecast CDM savings in the first four years of the forecast. Estimates of longer-term CDM program savings are based on historical and current trends of CDM programs and customer uptake.

Table 1: **Cumulative Capacity and Energy Savings by Year from Energy Efficiency Medium Achievable Scenario vs. Hydro's 2024 Slow Decarbonization Load Forecast**

Year	2025 Potential Study Cumulative Evening Peak Demand Savings Available[5] (MW)	2025 Potential Study Cumulative Energy Savings Available[6] (GWh)	Hydro 2024 Load Forecast (Slow Decarbonization)[7] CDM Cumulative Demand Savings[8] (MW)	Hydro 2024 Load Forecast (Slow Decarbonization)[7] CDM Cumulative Energy Savings (GWh)
2025	7	32	4	19
2026	11	50	8	39
2027	15	74	12	59
2028	21	106	17	79
2029	28	145	20	91
2030	36	185	22	103
2031	43	220	24	114
2032	48	248	26	125
2033	53	270	28	136
2034	56	287	30	144
2035	59	299	32	152

Table 1 shows that Hydro's 2024 Slow Decarbonization Load Forecast already includes a significant amount of energy and capacity savings from utility CDM programming. In addition to the amounts shown in Table 1, Hydro's 2024 Slow Decarbonization Load Forecast also includes an approximate 150 GWh and 28 MW of energy and capacity savings by 2035, to account for the natural adoption of heat pumps in electrically heated homes.

When comparing Hydro's 2024 Load Forecast to the 2025 Potential Study, it is important to note that the full potential outlined in the Medium Achievable Potential scenario should not be assumed to be achievable. As noted in the attached report, the Medium Achievable Potential scenario has been

[4] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025.
[5] "Newfoundland Power and Newfoundland and Labrador Hydro – Energy Solution Potential study – Final Report," Posterity Group, May 5, 2025, exh. 111.
[6] The difference between reference and medium consumption. "Newfoundland Power and Newfoundland and Labrador Hydro – Energy Solution Potential study – Final Report," Posterity Group, May 5, 2025, exh. 3.
[7] Hydro's application seeks approval of new generating capacity outlined in the Minimum Investment Expansion Plan, based on the Slow Decarbonization 2024 Load Forecast results.
[8] Excludes savings from electric vehicle ("EV") demand management programs.

developed with a screening criteria of 0.8 TRC or higher and therefore would not be cost-effective in its entirety. The Utilities' plan for the Island Interconnected System will be developed based upon a selection of programs included in the Medium Achievable Potential scenario and will appropriately target a lower savings level in order to achieve a portfolio of CDM programming that passes the Board's established cost effectiveness guidelines (TRC of 1.0 or higher).

The 2025 Potential Study also explored other methods for enabling demand response on the Island Interconnected System. Table 2 shows the peak demand reduction by sector and resource type that may be achieved by 2040.

Table 2: Summary of Peak Demand Reduction by Sector and Resource Type (MW)[9]

Sector	Energy Efficiency	Electrification	TOU[10] Rates	CPP[11]	Utility-Driven Equipment	Thermal Storage w/TOU
Residential	36.9	-2.6	4.8	7.9	7.6	1.6
Commercial	25.5	-1.6	1.1	1.5	11.1	3.5
Industrial	9.3	-0.1	0.3	0.3	0.7	-
EV	-	-	4.7	-	41.0	-
Total	**71.7**	**-4.3**	**10.9**	**9.7**	**60.4**	**5.1**

It should be noted that Hydro already assumes EV demand management in its long-term load forecast.[12] Therefore, the EV peak demand reduction in Table 2 should not be considered an additional reduction to what is already accounted for in Hydro's 2024 Load Forecast. It is also important to note that some of the resources outlined in Table 2 are mutually exclusive, and capacity benefits are not additive. For example, customers would either be offered TOU or CPP time-varying rates—not both.

The results in Table 2 have not been screened for cost effectiveness, and therefore, capacity benefits cannot be assumed. For example, the 2025 Potential Study concluded that:

> [t]he TOU and CPP electricity rate design measures are not cost-effective, due to the high program costs associated with the installation and operation of the [Advanced Metering Infrastructure] infrastructure *(sic)* required to administer them.[13]

Conclusion

It is Hydro's position that the 2025 Potential Study does not change the need for Bay d'Espoir Unit 8 and the Avalon Combustion Turbine, totalling approximately 300 MW of additional capacity, as outlined in the 2025 Build Application. Hydro has already reflected an appropriate level of energy and demand savings from CDM programming and energy efficiency in its 2024 Slow Decarbonization Load Forecast, which is the basis for the 2025 Build Application. This position is consistent with the Settlement Agreement from the *Reliability and Resource Adequacy Study Review* proceeding, where it was agreed

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[9] *Supra,* f.n. 6.
[10] Time of Use ("TOU").
[11] Critical Peak Pricing ("CPP").
[12] The EV charging demand reduction at peak in 2035 in the 2024 Slow Decarbonization Load Forecast was assumed to be 26 MW.
[13] "Newfoundland Power and Newfoundland and Labrador Hydro – Energy Solution Potential study – Final Report," Posterity Group, May 5, 2025, Executive Summary, p. xxxiii.

that Hydro's load forecast and reliability planning analysis demonstrated that additional capacity is required for the Island Interconnected System.[14]

The Utilities plan to complete their five-year CDME Plan in December of 2025. That plan will outline the planned takeCHARGE CDM programs for the Island Interconnected System from 2026 through 2030, informed by the Medium Achievable Potential scenario as outlined in the attached report.

The full potential outlined in the 2025 Potential Study should not be assumed to be economically viable, as not all programs meet the cost-effectiveness criteria established by the Board. The Utilities' CDME Plan for the Island Interconnected System will select initiatives and programming that appropriately target a lower savings level in order to achieve a portfolio that meets the Board's guidelines.

Hydro maintains that CDM measures are important to consider as a supply option to meet the Reference Case requirements, and the 2025 Potential Study and subsequent CDME Plan will help inform the next steps and the next Resource Adequacy Plan.

In summary, the Minimum Investment Required Expansion Plan is a holistic approach to system reliability, and the resource options put forward in the 2025 Build Application form the basis on which future CDM programming can build and be considered in the next Resource Adequacy Plan.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

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[14] *Reliability and Resource Adequacy Study Review* proceeding, Settlement Agreement, att. 1, item. 9.

Newfoundland Power and Newfoundland and Labrador Hydro

Energy Solutions Potential study

Final Report

Date: May 5, 2025

Western Brook Pond, Gros Morne National Park
Photo by Dave Shipley

Newfoundland Power and
Newfoundland and Labrador Hydro

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Contents

List of Exhibits

Definitions

Customer Accounts: Number of Newfoundland Power and Newfoundland and Labrador Hydro customer accounts. This report refers to 'customer accounts' rather than customers because there may be multiple customer accounts associated with one customer.

Advanced Metering Infrastructure: An integrated system of sensors and equipment for enhanced energy metering.[1]

Addressable Peak: The peak hour consumption in the demand response windows that can be shifted outside the window without creating a new peak hour.

Base Year: The first year of a forecast period and is based on historical data provided by the Utilities.

Battery Electric Vehicle (BEV): Vehicle powered solely by a rechargeable battery pack that produces zero tailpipe emissions.[2]

Behind-the-Meter: Energy that originates from a source other than the publicly owned and operated power grid.[3]

Bounce-Back Effect: The phenomenon that can occur when energy consumption and peak demand increase after a demand response resource is called.

Cost of Conserved Energy (CCE): Annualized incremental capital and operations and maintenance cost of the upgrade measure divided by the annual energy savings achieved, excluding any administrative program costs. The CCE represents the cost of conserving one kilowatt hour of electricity and can be directly compared to the cost of supplying one new kilowatt hour of electricity.

Critical Peak Pricing (CPP): An electricity rate structure that encourages customers to shift electricity use from periods of unusually high demand. During CPP events, customers pay critical peak pricing rates.

Customer or End-User Payback Acceptance: Customer or end-user willingness to invest in an energy or demand savings measure based on how long it will take to recoup their initial investment.

Direct Current Fast Charging (DCFC): DCFC chargers convert utility-supplied alternating current power to direct current power and charge electric vehicles directly with the direct current power.

Electricity Conservation and Demand Management (ECDM): A strategy used by utilities to reduce electricity consumption and peak demand.

End Use: The final purpose for which energy is used. For example, space heating, water heating, or industrial process heating.

Electrically Heated Dwelling/Building, Non-Electrically Heated Dwelling/Building: In the residential and commercial sectors, a dwelling or general service building that primarily uses electricity for space heating heat (>50% of the fuel share for space heating) is considered an electrically heated dwelling/building. A dwelling/building that has an electricity space heating fuel share <50% is considered

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[1] "Advanced Metering Infrastructure," Manitoba Hydro, Available: https://www.hydro.mb.ca/articles/2022/04/advanced_metering_infrastructure/ (Accessed Jan. 21, 2025).
[2] "Light and medium-duty vehicle registrations: Interactive dashboard," Statistics Canada, Available: https://www150.statcan.gc.ca/n1/pub/71-607-x/71-607-x2022023-eng.htm (Accessed Feb. 29, 2024).
[3] "Behind the Meter," Electricity Canada, Available: https://tinyurl.com/324mkhpd (Accessed Jan. 21, 2025).

a non-electrically heated dwelling/building. Electrically heated dwellings/buildings may have other fuels serving the space heating end use, but electricity comprises at least 50% of the fuel share.

Electric Vehicle Supply Equipment (EVSE): Electric vehicle supply equipment supplies electricity to an electric vehicle. Other terms for EVSE include charging station or charging dock. EVSE include the electrical conductors, related equipment, software and communications protocols that deliver electricity efficiently and safely to the vehicle.[4]

Energy Curtailment Program: Program offered by Newfoundland Power that incentivizes commercial rate 2.3 or 2.4 customers to reduce their demand on the IIS on request during the winter peak period.[5]

Exogenous: Relating to external factors.

External Advisory Committee (EAC): External stakeholder Study participants. External stakeholders included including retailers, property managers, representatives from industry associations and the provincial government, and others. External stakeholders were consulted in May 2024 during the achievable potential workshops.

Fuel Share: Ratio of a specific end use load that is met by a particular fuel. For example, if 90% of the space heating load in large offices is met by electric equipment, the electricity fuel share for space heating in large offices is 90%.

Heavy-Duty Vehicle (HDV): On-road vehicle with a gross vehicle weight of more than 11,793 kilograms.[2]

Internal Combustion Engine (ICE) Vehicle: Vehicle powered by an internal combustion engine that burns fuel (e.g., gasoline or diesel) to generate the power required to propel the vehicle.

Light-Duty Vehicle (LDV): Vehicle with a gross vehicle weight less than 4,536 kilograms.[2]

Level 1 (L1): Level 1 equipment provides charging through a 120-Volt alternating current outlet.[6]

Level 2 (L2): Level 2 equipment provides charging through a 208-Volt or 240-Volt alternating current outlet.[6]

Medium-Duty Vehicle (MDV): Vehicle with a gross vehicle weight between 4,536 kilograms and 11,793 kilograms.[2]

Multi-Unit Residential Building (MURB): A residential building that contains two or more units.

Other Industrial: The segment that includes all industrial facilities not categorized as large industrial, manufacturing, fishing and fish processing, water and wastewater, mining and processing, or pulp and paper.

Participant Cost Test (PCT): A metric to evaluate the cost-effectiveness of a measure based on the participant's costs and benefits.

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[4] "Electric Vehicle Supply Equipment System," NEMA, Available: https://www.nema.org/membership/products/view/electric-vehicle-supply-equipment-system (Accessed Aug. 9, 2024).
[5] "Energy Curtailment Program" Newfoundland Power, Available: https://www.newfoundlandpower.com/Business-Services/Rates-and-Services/Curtailment-Program (Accessed Jan. 22, 2025).
[6] "Charger Types and Speeds," U.S. Department of Transportation, Available: https://www.transportation.gov/rural/ev/toolkit/ev-basics/charging-speeds (Accessed Aug. 9, 2024).

Peak Demand: The single highest hour of system demand, typically occurring on the coldest day of the winter.

Plug-In Hybrid Electric Vehicle (PHEV): Vehicle with an internal combustion engine and a high-capacity battery that can be recharged using a wall outlet or charging equipment, by the ICE, or through regenerative braking.

Program Administrator Cost (PAC): A metric to evaluate the cost-effectiveness of a measure based on the program administrator's costs and benefits.

Reference Adoption: The adoption level for a measure if there is no program activity in the marketplace.

Reference Case: Represents the baseline forecast period against which new potential can be calculated.

Replace on Burnout (ROB): Measure that is replaced at the end of its useful life.

Retrofit (RET): Measure that is implemented immediately.

Saturation: For most end uses, saturation is the extent to which an end use is present in a segment. For some specific end uses that are associated with appliances, saturation is defined as the average number of appliances per unit.

Sector: Grouping or category of customers, buildings, or vehicles by type: residential, commercial, industrial and transportation.

Segment: Grouping or category of buildings (e.g., single-family detached in residential, large offices in commercial). Segments reflect the main purpose of the building and helps to differentiate between energy use intensity or patterns across building types within a sector.

Simple Payback: The duration of time to recover the cost of a project based on cumulative savings, without accounting for the time value of money. Calculated from the perspective of an end use and presented in units of years. For example, a measure that costs $600 and results in energy savings valued at $200 annually has a simple payback of 3 years (i.e., $600 ÷ $200/yr = 3 years).

Single-Family Detached: A dwelling unit with walls and roofs independent of any other building.[7]

Size Factor: The change in average number of units per customer account. Size factor is primarily used to reflect the forecast change in production volumes in industry.

Stock Average Efficiency: Average efficiency of equipment serving the tertiary load for that end use.

Tertiary Load: The useful energy delivered to an end use. In the context of the Study, tertiary load is the amount of energy required to be delivered as an end use service, for example, heat delivered by a heat pump to a residential dwelling.

Time-of-Use (TOU) Rates: An electricity rate that reflects the cost of producing electricity at different times of day based on demand. TOU pricing has two or more periods. These periods may include on-

[7] "Eligible Property Types," Natural Resources Canada, Available: https://natural-resources.canada.ca/energy-efficiency/home-energy-efficiency/canada-greener-homes-initiative/eligible-property-types (Accessed Feb. 27, 2025).

peak, when energy demand and cost is high, mid-peak, when energy demand and cost is moderate, and off-peak, when energy demand and cost is low.[8]

Time-Variable Rate (TVR): An electricity rate that varies depending on time of day.

Total Resource Cost (TRC): A metric to evaluate the cost-effectiveness of a measure based on both the participants' and utility's costs and benefits.

Unit Energy Consumption (UEC): The amount of energy used by each end use per unit.

Units: The sector-specific unit of analysis: dwellings in the residential sector, square feet in the commercial sector, and production capacity in the industrial sector.

Vehicle Telematics: Method of monitoring cars, trucks, equipment and other assets using global positioning system (GPS) technology and on-board diagnostics to plot the asset movements on a computerized map.[9]

Vehicle to Load (V2L): Applications use vehicle battery power as a backup source for localized loads within a site.

Vehicle to Building (V2B): Applications enable feeding battery power from the vehicle to serve end uses in the building and are expected to primarily serve for building resilience but may also reduce building peak power demand.

Vehicle to Grid (V2G): Applications enable feeding battery power from the vehicle back to the grid during peak periods.

Vintage: A grouping of facilities based on their age.

[8] "Electricity Prices and Costs," Hydro One Networks Inc, Available: https://bit.ly/4jvPEom (Accessed Aug. 9, 2024).
[9] "What is Telematics," Geotab, Available: https://www.geotab.com/blog/what-is-telematics/ (Accessed Aug. 9, 2024).

Acronyms

a.m.	Before noon
AMI	Advanced Metering Infrastructure
ASD	Adjustable Speed Drive
BEV	Battery Electric Vehicle
BTM	Behind-the-Meter
CDME	Conservation, Demand Management and Electrification
CED	Customer, Energy and Demand
CEUS	Commercial End Use Survey
CPP	Critical Peak Pricing
DC	Direct Current
DCFC	Direct Current Fast Charging
DHW	Domestic Hot Water
DLC	Direct Load Control
DR	Demand Response
EAC	External Advisory Committee
EC	Electronically Commutated
ECDM	Electricity Conservation and Demand Management
ECP	Energy Curtailment Program
EMIS	Energy Management Information System
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
GEB	Grid Interactive Efficient Buildings
GWh	Gigawatt hour
HDV	Heavy-Duty Vehicle
HVAC	Heating, Ventilation, and Air Conditioning
ICE	Internal Combustion Engine
ICEV	Internal Combustion Engine Vehicle
IIS	Island Interconnected System
kW	Kilowatt
kWh	Kilowatt hour
kVA	Kilo-Volt-Ampere
LD	Light-Duty
LDV	Light-Duty Vehicle
L1	Level 1
L2	Level 2
MDV	Medium-Duty Vehicle
MHDV	Medium-and Heavy-Duty Vehicle
MUN	Memorial University of Newfoundland
MURB	Multi-Unit Residential Building
MW	Megawatt
MWh	Megawatt hour
NAICS	North American Industry Classification System
NEW	New Construction
NLH	Newfoundland and Labrador Hydro
NP	Newfoundland Power

PAC	Program Administrator Cost Test
PCT	Participant Cost Test
PHEV	Plug-In Hybrid Electric Vehicle
p.m.	After noon
RET	Retrofit
REUS	Residential End Use Survey
ROB	Replace on Burnout
SFD	Single-family detached home
TCO	Total cost of ownership
TOU	Time-of-Use
TRC	Total Resource Cost
TRM	Technical Reference Manual
TVR	Time-Variable Rate
UEC	Unit Energy Consumption
VFD	Variable Frequency Drive
VKT	Vehicle Kilometre Travelled
VT	Vehicle Telematics
V2L	Vehicle to Load
V2B	Vehicle to Building
V2G	Vehicle to Grid
ZEV	Zero-Emissions Vehicle

Executive Summary

The Energy Solutions Potential Study (the Study) evaluates the potential for energy efficiency, electrification, and peak demand management activities led by Newfoundland Power and Newfoundland and Labrador Hydro (the Utilities) from 2025-2040.

Posterity Group Consulting (PG, the Study Team) completed the analysis and reporting for the Study, in collaboration with the Utilities and their stakeholders. This collaboration included the provision of customer data, inputs to the measure analysis, and participation in achievable potential workshops.

The Study relied on the Utilities' knowledge of their customer base; the best available research and data available to the Utilities; internal and external stakeholder feedback; extensive original research; and the Study Team's professional judgement. The results in this report reflect rigorous analysis and estimate the opportunities available to the Utilities.

Study Scope

The Utilities' energy conservation activities under the takeCHARGE brand have historically focused on energy savings but are increasingly considering demand management technologies and their potential to reduce or shift peak demand. Accordingly, the Study scope examines opportunities for energy efficiency, fuel switching and to deploy demand response (DR) resources including managed electric vehicle (EV) charging to manage peak demand on the Island Interconnected system (IIS). The Study scope is summarized in in Exhibit 1.

Exhibit 1: Study Scope

Study Period

- **Base Year**: 2023 base year
- **Forecast Period**: 2024-2040
- **Measure Application**: 2025-2040

Geographical Coverage

- **Includes:** The IIS, both Utilities' customers
- **Excludes:** Labrador Interconnected & Isolated Diesel Generation Systems

Sectors

- **Four Sectors:** Residential, commercial, industrial, & transportation
- **Transportation sector**: Personal & fleet EVs

Measures

- **Types**: Efficiency, fuel switching, & DR
- **DR:** Time-variable rates, EV managed charging, thermal storage, and others.

Given the emphasis on demand management, the Study Team was asked to examine the impact of all measure types for three peak periods:

1. **Peak Hour:** The single highest hour of IIS demand, typically occurring on the coldest day in the winter. Depending on the Study year, the single hour peak can occur in the morning or the evening.
2. **Morning Peak Period:** The four-hour period in the morning with the highest average IIS demand, defined as 7 a.m. to 10:59 a.m.
3. **Evening Peak Period:** The five-hour period in the evening with the highest average IIS demand, defined as 5 p.m. to 9:59 p.m.

EV Forecast Scenarios

EV adoption represents both a large potential load and an important opportunity for load management. Because future EV adoption is uncertain and Newfoundland-specific data on recent EV registration trends is limited, the Study Team modelled three EV adoption scenarios:

1. The **Natural Adoption Scenario**, the lowest adoption scenario, which estimates EV adoption based on current incentives, with fleet vehicle and bus adoption in this scenario aligned with global forecasts for all countries.
2. The **Intermediate Scenario**, which includes EV uptake beyond the Natural Adoption scenario consistent with additional market interventions such as Provincial vehicle rebates and accelerated build-out of charging infrastructure.
3. The **Government Targets Scenario**, the highest adoption scenario, in which aggressive Federal Government targets for sales of Zero Emissions Vehicles by 2030, 2035, and 2040 are met.

Efficiency Savings Potential

The Study Team assessed technical, economic, and achievable efficiency potential for a range of efficiency measures in the residential, commercial, and industrial sectors. Measures are included in the economic and achievable potential if their total resource cost (TRC) test benefit/cost ratio is 0.8 or higher.

The achievable potential includes three levels of savings, as shown in Exhibit 2.

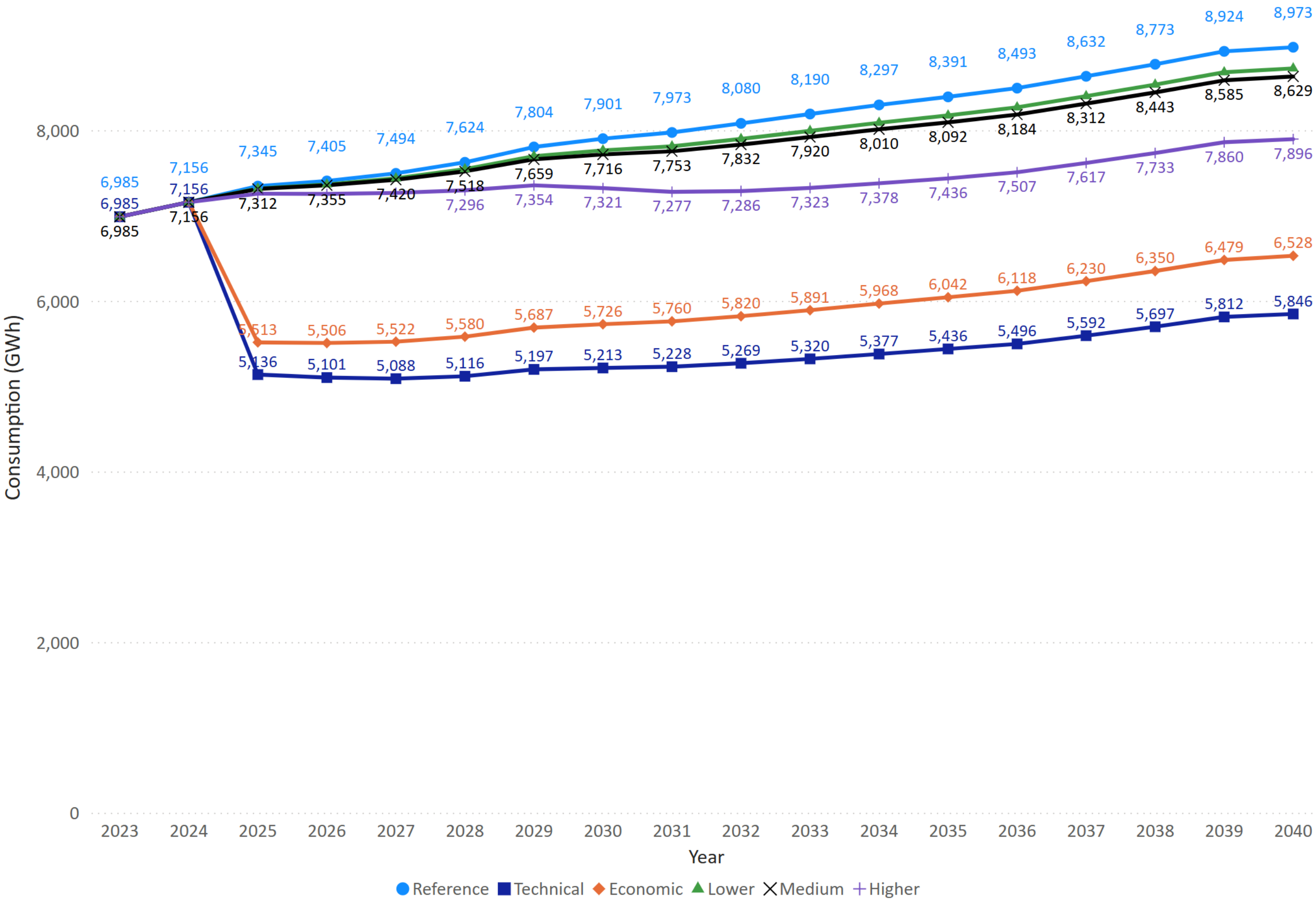
Exhibit 2: Achievable Potential Scenarios Summary

Scenario	Incentive Level	Non-Incentive Costs[10]
Lower	25% of incremental cost	25% of measure-level incentive costs
Medium	50% of incremental cost	
Higher	100% of incremental cost	

[10] While 25% is a standard estimate used for the purposes of this Study, non-incentive costs would vary from program to program.

Exhibit 3 shows annual consumption in the reference case and by potential scenario.[11] The difference between the reference case consumption and the consumption in each potential scenario represents cumulative potential savings. For example, savings in 2025 represent potential for measures adopted that year, whereas savings in 2040 represent savings for measures adopted that year, plus the savings for all measures adopted between 2025 and 2039, provided they did not reach end of life in that period.

Exhibit 3: Annual Consumption by Scenario - Efficiency

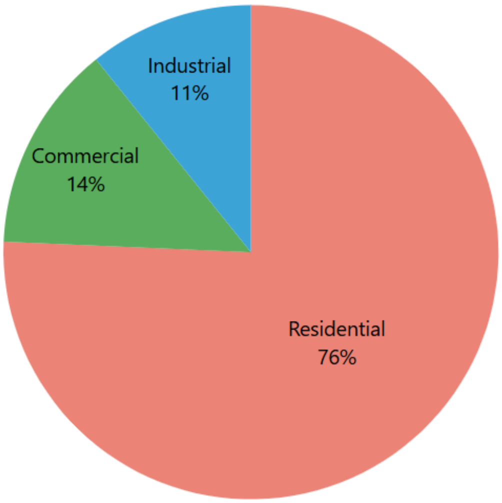


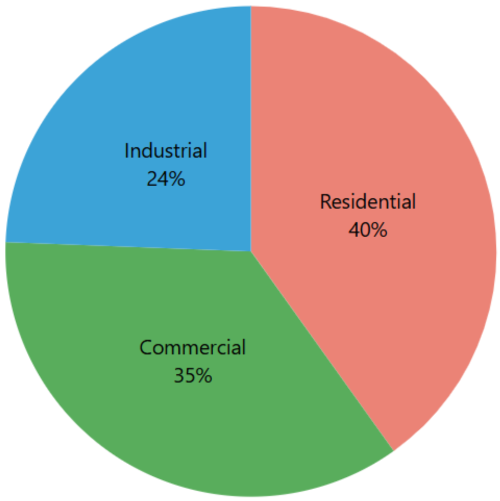
The difference in consumption between the lower and medium achievable potential scenarios is approximately 100 GWh by 2040, while the difference in consumption between the medium and higher achievable potential scenarios is approximately 700 GWh by 2040. This suggests that doubling the incentive between the lower and medium achievable scenarios has a smaller impact on measure adoption than doubling the incentive between the medium and higher achievable scenarios.

[11] The reference case in Exhibit 3 includes intermediate scenario EV consumption.

Exhibit 4 shows medium achievable potential energy savings by sector in 2025 (32 GWh) and 2040 (344 GWh). In both milestone years, the highest potential exists in the residential sector. The 2025 potential savings allocation by sector is directionally consistent with recent electricity conservation and demand management (ECDM) program results, in which residential sector programs contributed 88% of total energy savings in 2023.

Exhibit 4: Medium Achievable Potential Energy Savings by Sector, 2025 (left) and 2040 (right)

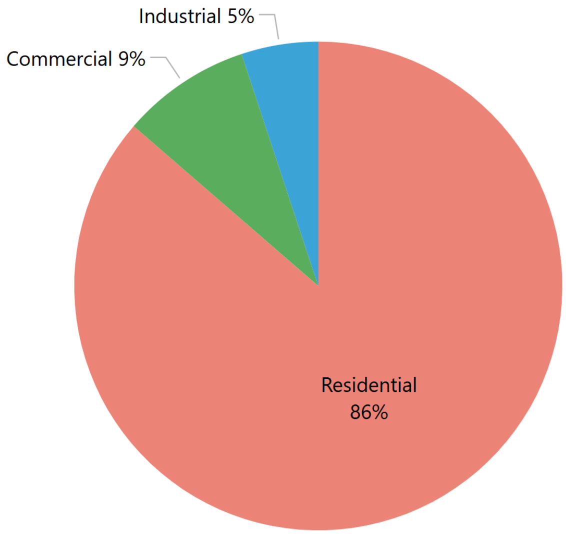


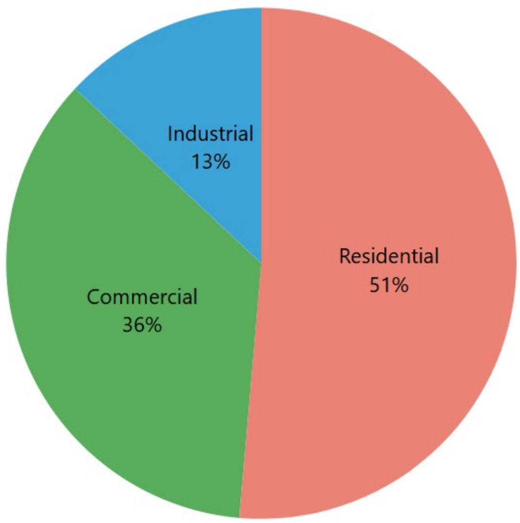


By 2040, potential savings by sector are more consistent with the reference case electricity consumption forecast by sector: the residential sector is forecast to contribute 54% of reference consumption and 40% of medium achievable savings; commercial 34% of consumption, 35% of savings; and the industrial sector contributing higher relative savings levels with 12% of reference consumption and 24% of savings.

Exhibit 5 shows medium achievable potential savings for the peak hour by sector in 2025 (7.7 MW) and 2040 (71.7 MW). Peak savings by sector are directionally consistent with energy savings by sector.

Exhibit 5: Medium Achievable Peak Demand Reduction Potential by Sector, 2025 (left) and 2040 (right)





Conclusions from the efficiency potential analysis include:

- In the residential sector, **home energy reports** offer the most energy savings potential and peak demand savings in 2025 because they are broadly applicable. By 2040, home energy reports remain among the top ten measures by annual and peak hour demand savings, but by 2040, **equipment measures that affect space heating** (e.g., central air source heat pumps, ductless mini-split heat pumps, and heat recovery ventilators) also offer substantial savings.
- Commercial sector savings in 2025 are dominated by **indoor lighting** measures, but their contribution to potential savings for the sector drops from 52% in 2025 to 26% in 2040. The decrease is attributable to high (60%) reference adoption of interior LED lighting, and the introduction of Natural Resources Canada's Amendment 18 that mandates LED lighting starting in 2028.[12] By 2040, **equipment measures that affect space heating** (e.g., electric furnace to air source heat pump, baseboard heating to ductless mini-split heat pump) offer substantial savings, as do **whole-building new construction** measures.
- In the industrial sector, annual and peak demand savings by end use remains relatively consistent between 2025 and 2040, which suggests a broad-based opportunity for cost-effective conservation. Measures targeting the **other motors** and **pumps** end use represent four of the top ten efficiency measures in both 2025 and 2040. **Energy management information system** is among the top ten measures in 2025 and 2040 because it is broadly applicable and targets all industrial sector end uses.

[12] "Amendment 18," Natural Resources Canada, Available: https://natural-resources.canada.ca/energy-efficiency/energy-efficiency-regulations/amendment-18 (Accessed: Dec. 3, 2024).

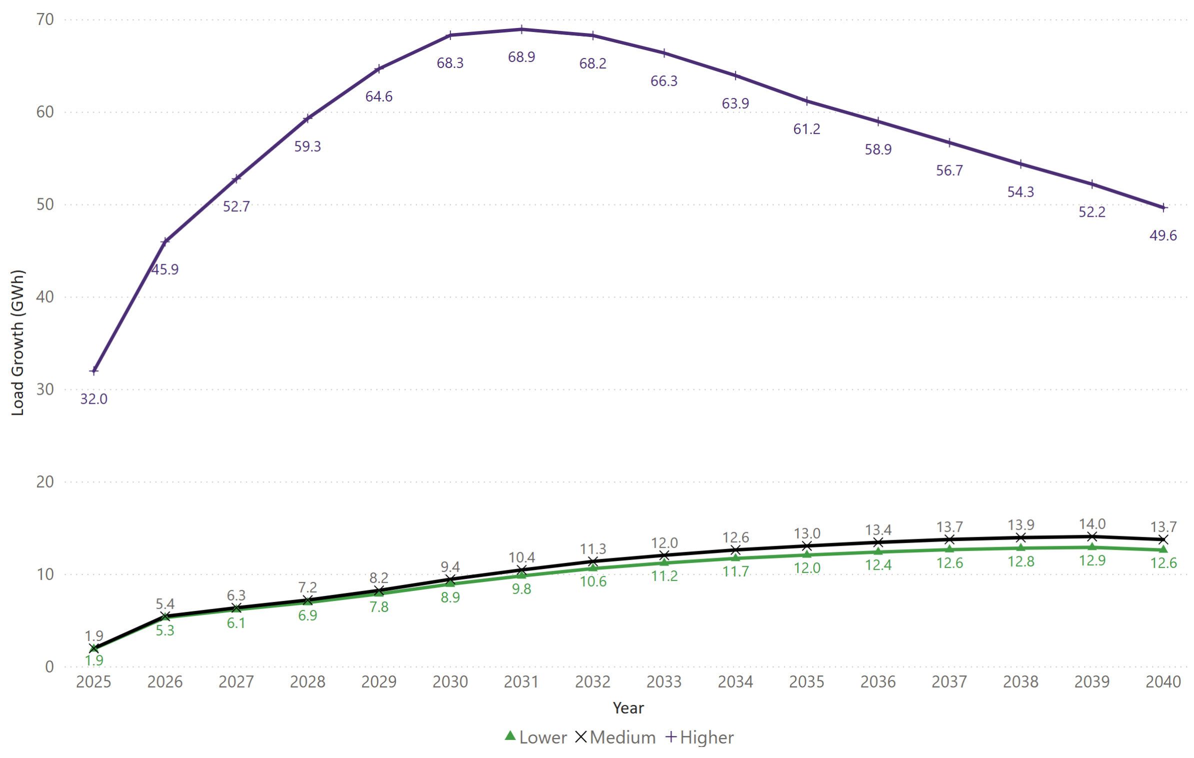
Fuel Switching and Off-Road Electrification Potential

The fuel switching analysis examines the potential for IIS customers to switch from fossil to electric space heating, water heating, and cooking. It also explores the electrification potential for select off-road vehicles. The fuel switching and off-road electrification potential assessment mirrors the efficiency potential assessment in structure and economic screening criteria:

- Three levels of fuel switching and off-road electrification savings potential are assessed: technical, economic, and achievable.
- The total resource cost (TRC) test is used to screen fuel switching and off-road electrification measures, and measures are included in the economic potential if their benefit-cost ratio is 0.8 or higher. In addition, three residential sector fuel switching measures (oil furnace to cold climate air source heat pump, oil furnace to air source heat pump (partial switch), and oil furnace to electric furnace.) These measures are being adopted in the Oil to Electric program administered by the Utilities even though they may not be cost-effective.
- The achievable potential includes lower, medium and higher scenarios, with incentive levels of 25%, 50% and 100% of incremental cost, respectively.

The cumulative impacts of fuel switching and off-road electrification in the lower, medium and higher achievable potential scenarios are shown in Exhibit 6.[13]

Exhibit 6: Fuel Switching and Off-Road Electrification Impacts by Achievable Scenario



[13] The decrease in load growth from fuel switching from 2031 to 2032 in the higher achievable potential scenario is driven by forecast space heating conversions in the Oil to Electric program, and natural fuel switching from oil to electricity included in the reference case which erodes the impact of these space heating conversions.

Conclusions from the fuel switching and off-road electrification potential analysis include:

- By 2040, measures in the higher achievable potential scenario cause 49.6 GWh of load growth, compared to 13.7 GWh and 12.6 GWh in the medium and lower scenarios, respectively. Reference case consumption is forecast to be roughly 9,000 GWh in 2040, so this growth represents an **increase of less than one percent of annual consumption for all scenarios**. Fuel switching potential is limited in all three sectors **because of the high relative fuel share of electric space heating in the base year and natural electrification that occurs in the reference case**.
- By 2040, approximately **5,600** incremental **residential sector dwellings** are forecast to be heated electrically or have electric water heating compared to 2025. This forecast includes the 3,000 space heating fuel switching projects expected to be completed under the Oil to Electric program in 2025. An incremental **1.1 million** additional **square feet** of commercial sector floor area are forecast to be heated electrically in 2040 compared to 2025 in the medium achievable scenario.
- The electrification of **forklifts** and **Zambonis** is expected to have a very small effect, adding approximately 0.3 GWh of electricity consumption to the IIS by 2040.
- By 2040, the peak impacts of the fuel switching and off-road electrification measures in the higher achievable potential scenario for the residential sector and in the medium achievable potential scenario for the commercial and industrial sectors are forecast to be 14.8 MW during the morning peak and 14.3 MW in the evening peak.

Demand Response Potential

Exhibit 7 shows the demand response resources examined in the Study: electricity rate design, equipment demand response, and customer curtailment.

Exhibit 7: Summary of Demand Response Resources

Demand Response Resources

- **Electricity Rate Design**
  Customers opt into one of two time-variable rates at their discretion: time of use or critical peak pricing.
- **Equipment Demand Response**
  Utility has direct load control of customer end use equipment including thermostats, water heaters, EV chargers, and thermal storage systems during on-peak times.
- **Customer Curtailment**
  Select customers curtail their energy use when one of the Utilities issues a request for curtailment.

Like for efficiency and electrification, the Study Team assessed three levels of demand response savings potential for each resource shown in: technical, economic, and achievable. However, the demand response potential assessment differs in the following ways:

- Measure-level incentives and non-incentive program costs are not varied, so there is only one achievable potential scenario. Throughout this section, this scenario is referred to as the medium achievable potential scenario.
- Participation rates are based on research and consultation with the Utilities. The only demand resource response currently in market in Newfoundland is customer curtailment, so there are no historical savings to benchmark against for the electricity rate design and equipment DR measures.
- The Program Administrator Cost (PAC) test is used to assess cost-effectiveness of the DR measures because utilities typically pay all incremental equipment costs in a DR program, and because incentives to participants are typically an expense to the utility over and above the incremental equipment costs. This differs from efficiency programs where the incentives usually cover a portion of the participant's incremental costs for the efficiency upgrade.[14]

[14] Conservation Potential Study, Final Report (Volume 2 – Appendices)," Dunsky Energy Consulting (2019).

Electricity Rate Design

The Study includes two opt-in electricity rate design measures: time-of-use (TOU) and critical peak pricing (CPP). Exhibit 8 shows the rate structures for these measures in the Study. These rate structures are representative, and neither is currently offered or under specific consideration by the Utilities.

Exhibit 8: TOU and CPP Rates

Season	Peak	Time	Residential ($/kWh)[15]	Commercial ($/kWh)	Industrial ($/kWh)
December to March	On-peak	Morning Peak Evening Peak	$0.24	$0.17	$0.18
	Off-peak	Hours Outside of Peak Periods	$0.06	$0.04	$0.04
December to March	Critical Peak	Critical Peak Events	$0.55	$0.83	$0.85
	Off-Peak	Hours Outside of Critical Peak Periods	$0.06	$0.07	$0.07

Substantial investment in Advanced Metering Infrastructure (AMI) would be required to implement time-variable rates for NP and NLH customers, estimated at approximately $80 Million over four years

The frequency and duration of the TOU and CPP peak events are as follows:

- **TOU:** The TOU on-peak rate is modelled as being in effect during the morning (4 hours) and evening (5 hours) peak periods on weekdays from December to March (i.e. a total of 89 days per year).
- **CPP:** The critical peak rate is modelled as being in effect during critical peak events, as determined by the Utilities. The Study Team assumes events are called 12 times per year during the morning and evening peak periods for the purposes of the analysis.

[15] The residential rate applies to "at home" personal EV charging.

Exhibit 9 shows the medium achievable potential peak demand reduction potential for the electricity rate design measures by sector, excluding savings from EV TOU.

Exhibit 9: Medium Achievable Peak Demand Reduction– Electricity Rate Design (2040)

Measure	2029 Winter Peak Hour Reduction (MW)	2029 Winter Morning Average Peak Reduction (MW)	2029 Winter Evening Peak Average Reduction (MW)	2040 Winter Peak Hour Reduction (MW)	2040 Winter Morning Average Peak Reduction (MW)	2040 Winter Evening Average Peak Reduction (MW)
CPP	0.34	0.34	0.33	9.77	9.40	9.35
TOU	0.22	0.22	0.21	6.23	6.09	5.98

The following observations can be made on Exhibit 9:

- **CPP** shows **higher savings potential than TOU** because peak events are less frequent, and the on-peak retail rate is higher.
- The 2040 peak hour demand reduction potential for the rate design measures (6.23 MW for TOU, 9.77 MW for CPP) is **less than** for the efficiency measures (71.7 MW) in 2040.

Exhibit 10 shows the medium achievable PAC results by sector for the electricity rate design measures, none of which pass the PAC due to high costs associated with AMI installation and operation.[16]

Exhibit 10: Medium PAC Cost-Effectiveness Test Results – Electricity Rate Design

Measure	Residential	Commercial	Industrial
CPP	0.19	0.39	0.43
TOU	0.12	0.29	0.39

A TOU rate can have a larger effect on EV charging compared to any other end use in the residential, commercial and industrial sectors because EV charging is flexible.[17] The Study Team modelled two EV TOU participation scenarios, defined as follows:

- **Opt-in participation scenario**: Reflects a 15% participation rate, which matches the one used for the residential sector TOU measure.
- **Opt-out participation scenario**: 100% of EVs are on a time-of-use rate.

[16] The PAC results reflect costs and benefits incurred during the four-year AMI meter installation period and the 20-year smart meter lifetime. These measures assume an opt-in rate structure where participation ramps up to a maximum of 15% in the later years of the study.

[17] The impact of a TOU rate on EV charging depends on the number of EVs participating in the TOU rate.

Exhibit 11 shows demand reduction potential for the opt-in and out-out EV TOU scenarios during the morning and evening peak periods, and for the peak hour. The 51.60 MW peak hour reduction from EVs based on an opt-out TOU rate in 2040 is more than eight times higher than the TOU rate reduction potential from the residential, commercial, and industrial sectors combined (6.23 MW), which highlights the flexibility of EV charging loads and the value to the IIS of managing the load.

Exhibit 11: Medium Achievable Peak Demand Reduction - EV TOU[18]

Measure	2029 Winter Peak Hour Reduction (MW)	2029 Winter Morning Peak Reduction (MW)	2029 Winter Evening Peak Reduction (MW)	2040 Winter Peak Hour Reduction (MW)	2040 Winter Morning Peak Reduction (MW)	2040 Winter Evening Peak Reduction (MW)
Opt-In EV TOU	0.10	0.12	0.72	4.69	0.77	4.36
Opt-Out EV TOU	1.12	1.38	7.24	51.60	9.62	48.39

Exhibit 12 shows the medium achievable PAC results by sector for the TOU measure. Three results are shown for the residential sector: excluding EVs, including EVs with opt-in participation, and including EVs with opt-out participation.[19] The PAC is less than 1 for all sectors, though the **residential sector** result **including EVs with opt-out participation** exceeds the **PAC screening threshold of 0.8**.

Exhibit 12: Medium PAC Cost-Effectiveness Test Results – Electricity Rate Design with EV TOU

Measure	Residential (Excl. EVs)	Residential (Incl. EVs, Opt-In)	Residential (Incl. EVs, Opt-Out)	Commercial	Industrial
TOU	0.12	0.20	0.95	0.29	0.39

[18] Reductions in load can be higher for the morning or evening periods when compared to the peak hour because the system peak hour doesn't coincide with the highest EV load. The value for the peak hour is the value that the overall system peak is reduced by.

[19] The results reflect costs and benefits incurred during the four-year AMI meter installation period, and the 20-year smart meter lifetime.

Equipment Demand Response

The Study's equipment DR measures are split into three categories: utility-driven, EV managed charging, and thermal storage with TOU. Each thermal storage measure has a utility-driven version and a thermal storage with TOU version. The measures are modelled at the following frequency and peak event durations:

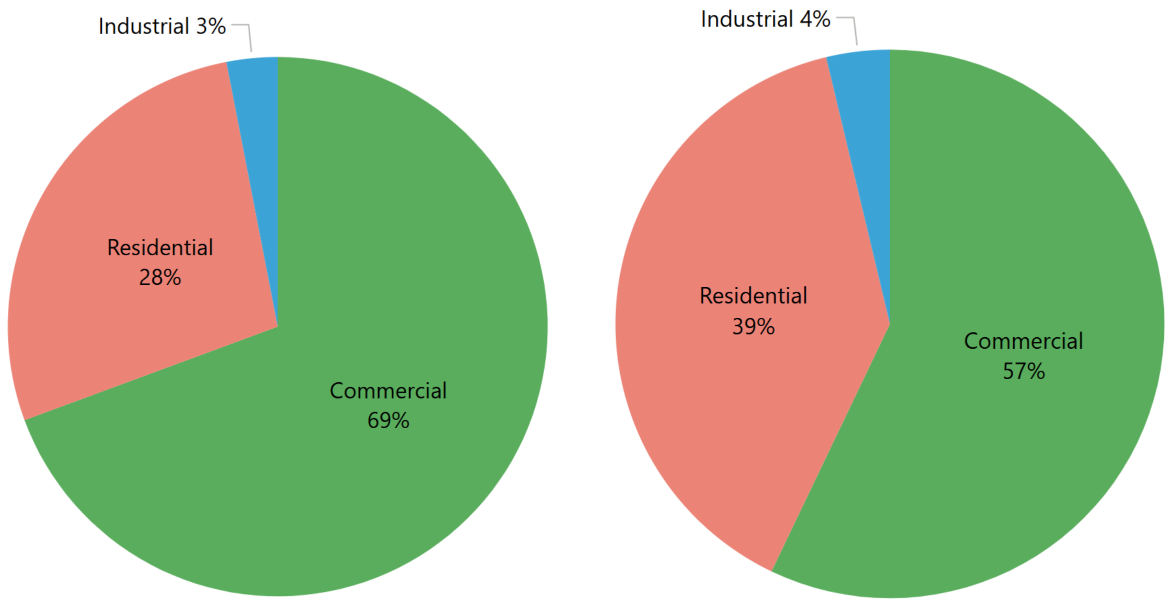
- **Equipment DR Measures (Utility-Driven):** The utility shifts customer load 12 times annually, for four hours during the morning peak period and five hours during the evening peak period.
- **EV Managed Charging:** The utility shifts customer EV charging for five hours during the evening peak period. Managed charging programs are not modelled at a system wide scale until 2029 (coinciding with the introduction of TOU rates).[20,21]
- **Equipment DR Measures (Thermal Storage with TOU):** Customers shift load off the peak periods on weekdays from December to March, for a total of 89 events per year.

[20] EV managed charging measures are modelled without TOU rates. Studies show that with sufficient equipment and enrolment incentives, participation in managed charging programs does not depend on TOU rates.
[21] "PG&E Electric Vehicle Automated Demand Response Study Report," Opinion Dynamics, Available: https://opiniondynamics.com/wp-content/uploads/2022/03/PGE-EV-ADR-Study-Report-3-16.pdf (Accessed Feb. 24, 2025).

Utility-Driven Equipment DR

Exhibit 13 shows the medium achievable potential peak reduction for the utility-driven measures by sector in 2031 (12.2 MW) and 2040 (19.4 MW), excluding the impacts of EV managed charging. The commercial sector shows the most peak demand reduction in both milestone years. The proportion of peak demand reduction attributed to the residential sector increases from 28% in 2031 to 39% by 2040, as participation in residential measures increases.[22]

Exhibit 13: Medium Achievable Demand Reduction Potential by Sector, 2031 (left) and 2040 (right) – Utility-Driven Equipment DR



Conclusions from utility-driven equipment DR potential analysis include:

- In the residential sector, the **smart circuit breakers or smart panel** measure shows the highest peak demand reduction in 2031 (1.4 MW) and 2040 (4.0 MW). This measure impacts most end uses and is broadly applicable. Of the measures targeting the **space heating** end use, the **smart thermostat or switch for baseboards or furnaces** measure shows the highest peak demand reduction in 2040 (0.8 MW). This measure has no incremental cost to the customer and a large opportunity comprising both homes with electric baseboard heating and electric furnaces.
- The commercial sector **backup generation at peak hours** measure shows the highest peak demand reduction by 2040 (4.0 MW). This measure assumes customers have an existing generator, has a small incremental cost and offers relatively high savings (80%). **Thermal storage and heat pump heating** shows the highest peak demand reduction for measures that target **space heating** (1.0 MW in 2031 and 1.5 MW in 2040). This is driven by a higher technical applicability for heat pumps in the commercial sector than other space heating systems.

[22] 2031 is a milestone year for reporting because it is the first year all utility-driven measures show peak savings.

- **All configurations** of **thermal storage** measures in the residential and commercial sectors are **cost-effective** under the PAC screen. Market barriers to adoption could include lack of familiarity with thermal storage, aesthetic considerations for room units, and space constraints.
- The peak demand reduction potential in the **industrial** sector is more evenly distributed across end uses compared to the residential and commercial sectors. Measures targeting the **other motors**, **HVAC fans and pumps**, and **process cooling** end uses offer the highest peak demand reduction potential.

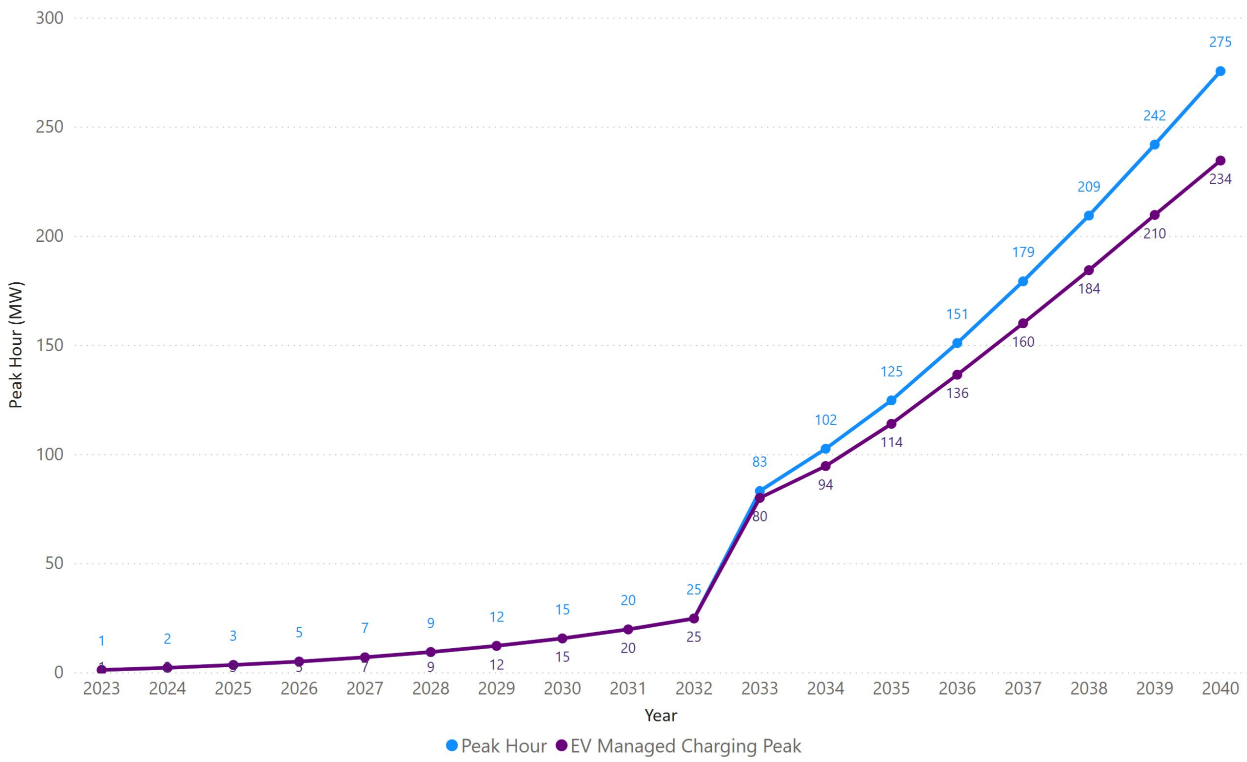
EV Managed Charging

Exhibit 14 shows that peak demand from EV charging is forecast to increase from 1 MW in 2023 to 275 MW by 2040 in the intermediate forecast scenario. This change is driven by the adoption of approximately 162,000 fleet and personal EVs.

In 2033, EV charging causes the IIS peak to switch from morning peak to evening peak. Shifting personal EV at-home charging could reduce the IIS peak. The opportunity to managed fleet EV charging is more limited than for personal EVs based on their duty cycles. However, certain fleet vehicles will have duty cycles that can accommodate managed charging.

Savings from the managed charging measures reach a maximum reduction demand potential of approximately **41 MW** by 2040. This corresponds to a roughly 15% decrease in the EV load during the system peak hour in 2040.

Exhibit 14: Annual EV Peak Hour Demand (MW) – Managed Charging



Thermal Storage with TOU Equipment DR Measures

The thermal storage with TOU equipment measures offer **5 MW** of peak hour demand reduction potential by 2040. Savings for the thermal storage with time-of-use measures are higher than the equivalent utility-driven measures because participation is assumed to be higher when a time-variable rate is involved. All configurations of residential and commercial sector thermal storage measures with TOU are cost-effective under the PAC screen.

Customer Curtailment

The Study Team examined curtailment potential among three customer groups:

- **Existing and prospective Energy Curtailment Program (ECP) participants**: NP's ECP offers an incentive to commercial customers to reduce their demand upon request during the winter peak period.
- **Large customers:** The Utilities may enter short-term or long-term capacity assistance contracts with large commercial or industrial sector customers.

Exhibit 15 shows curtailment potential by customer group. Curtailment potential is not varied annually in the Study.

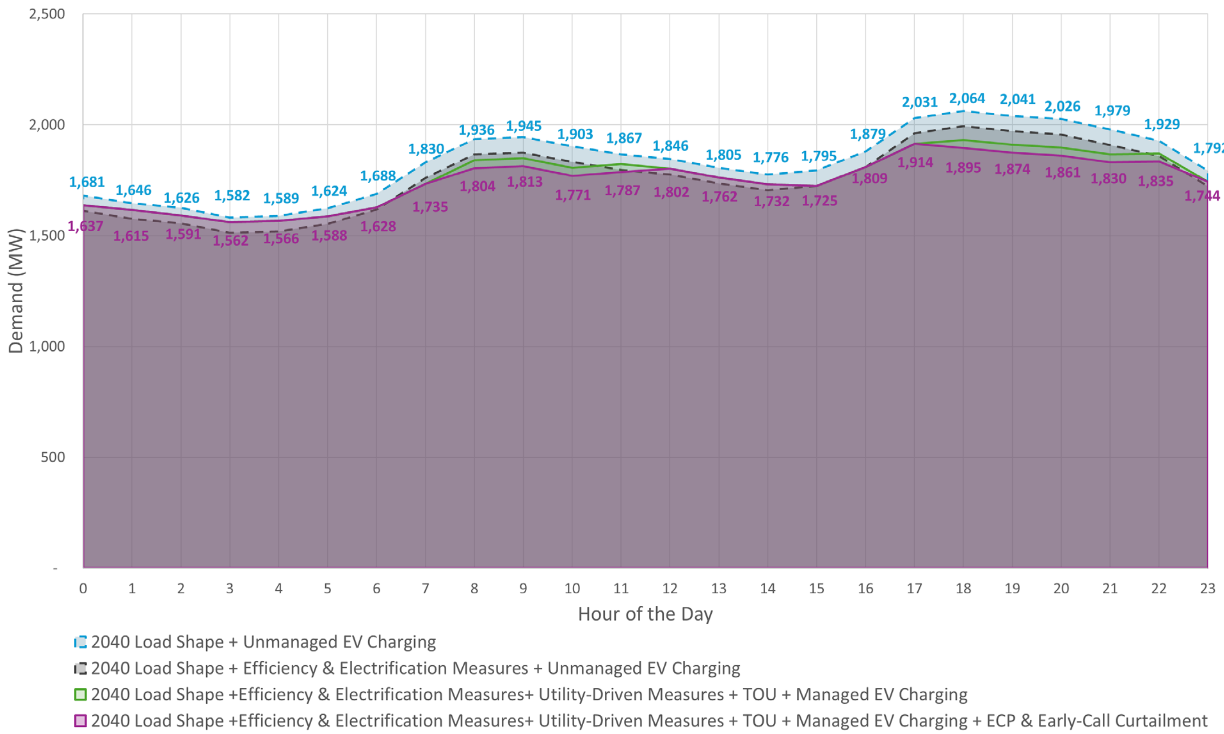
Exhibit 15: Curtailment Potential Results (all years)

Customer Group	Curtailable Load/Customer	Number of Customers	Total Curtailment
2.4 Existing ECP participants	500 kW/participant	24	12.0 MW
2.4 New ECP participants	300 kW/participant (30% of peak demand)	8	2.4 MW
Large Customer Contracts	Contract-Specific	3	120.6 MW
	Total	**35**	**135 MW**

Summary of IIS Peak Day Load Shape Impacts

In the base year, the IIS peak occurs in the morning. By **2040**, the IIS peak is expected to shift to the evening, driven in part by unmanaged EV charging in the intermediate scenario. Exhibit 16 shows the impact of combinations of demand response resources on the IIS peak day load shape.

Exhibit 16: Standard and Resulting Peak Day IIS Load Shapes (2040)



The Study findings reveal the following impacts on the IIS load curve:

- Excluding existing curtailment contracts, **energy efficiency** measures show the highest potential to reduce IIS peak. For example, in 2040, the efficiency measures reduce the winter morning and evening peaks by 70 MW and 69 MW, respectively. In contrast, the utility-driven measures reduce the winter morning and evening peaks by 23 MW and 18 MW, respectively. The TOU electricity rate design measures reduce the winter morning and evening peaks by 6 MW each.
- After the efficiency and electrification measures, the utility-driven equipment DR measures, and managed EV charging are applied, the evening peak period starts at **5 p.m. and ends at 10:59 p.m**. This **lengthens** the evening peak period **by one hour** compared to the reference load shape.
- When the ECP and the early-call curtailment are applied during the evening peak period (i.e., 5 p.m. to 9:59 p.m. denoted by the purple load shape), the peak hour occurs at **5 p.m.**, **one hour earlier** than in the reference load shape.
- For each combination of demand response resources, the addressable peak is equal to the peak reduction. This is because the peak demand is reduced in all cases (i.e., the resources do not create a higher peak than the original peak).

Conclusions

The major conclusions drawn from the study analysis include:

- **Energy Efficiency Potential**: The Study identifies opportunities for energy efficiency across the residential, commercial, and industrial sectors:
    - In the residential sector, measures that affect space heating offer the most potential savings. In the early years of the forecast period, these savings are dominated by envelope measures including air sealing and insulation, but by the end of the forecast period, equipment-based measures including heat pumps and HRVs offer the most potential savings. In addition, home energy reports offer residential sector savings throughout the Study period.
    - Initially, lighting measures dominate the commercial sector potential savings, but their savings potential decreases over time as LED lighting becomes saturated and federal lighting standards are introduced. By the end of the forecast period space heating measures including heat pumps and air sealing offer the most potential savings due to their broad applicability.
    - In the industrial sector, there is a broad-based opportunity for cost-effective conservation across end uses.
- **Impact of EVs**: The Study includes three forecast EV scenarios to explore a range of possible futures: natural adoption, intermediate and government targets. The results presented in the Study focus on the intermediate scenario:
    - In the intermediate scenario, the adoption of approximately 160,000 EVs will cause EV charging to increase from an estimated 9 GWh in 2023 to 1,000 GWh by 2040, and peak period demand to increase from an estimated 1 MW in 2023 to 275 MW by 2040. In 2033, EV charging causes the IIS peak to switch from morning peak to evening peak.
    - Consideration to EV managed charging can mitigate the impacts of EV charging on the IIS peak. By 2040, shifting personal EV charging could reduce the IIS peak by 41 MW. The opportunity to manage fleet EV charging is more limited than for personal EVs based on their duty cycles. However, certain fleet vehicles will have duty cycles that can accommodate managed charging.
- **Fuel Switching and Off-Road Electrification Potential**: Fuel switching potential is limited in the residential, commercial and industrial sectors because of the high relative fuel share of electric space heating in the base year.
    - In the higher achievable potential scenario, 49.6 GWh of load growth due to end-use electrification is forecast by 2040, compared to 13.7 GWh and 12.6 GWh in the medium and lower achievable potential scenarios, respectively. Nearly all this load growth is due to end-use fuel switching in the residential, commercial, and industrial sectors.

- **Demand Response Potential**: The Study assesses demand response potential opportunities across three measure types: electricity rate design, equipment demand response, and customer curtailment.
  - The TOU and CPP electricity rate design measures are not cost-effective, due to the high program costs associated with the installation and operation of the AMI infrastructure required to administer them.
  - Several configurations of thermal storage measures are cost-effective for the residential and commercial sectors, with and without TOU rates. Market barriers to adoption could include lack of familiarity with thermal storage, aesthetic considerations for room units, and space constraints.
- **Overall Impacts on IIS Peak Day Load Curve**: In the base year, the IIS peak occurs in the morning. In 2040, the IIS peak is expected to occur at 6 p.m., driven in part by unmanaged EV charging in the intermediate scenario. The Study findings reveal the following impacts on the IIS load curve:
  - Excluding existing curtailment contracts, energy efficiency measures show the highest potential to reduce IIS peak. For example, in 2040, the efficiency measures reduce the winter morning and evening peaks by 70 MW and 69 MW, respectively. In contrast, the utility-driven DR measures reduce the winter morning and evening peaks by 23 MW and 18 MW, respectively. The TOU electricity rate design measure reduces the winter morning and evening peak by 6 MW.
  - After the efficiency and electrification measures, the utility-driven equipment DR measures, and managed EV charging are applied, the evening peak period starts at 5 p.m. and ends at 10:59 p.m. This lengthens the evening peak period by one hour compared to the reference load shape.
  - When the ECP and the early-call curtailment are applied during the evening peak period the peak hour occurs at 5 p.m., one hour earlier than in the reference load shape.
  - For each combination of demand response resources, the addressable peak is equal to the peak reduction. This is because the peak demand is reduced in all cases (i.e., the resources do not create a higher peak than the original peak).

1 Introduction

The Energy Solutions Potential Study (the Study) assesses the near term and long-term potential for energy efficiency, electrification, and peak demand management activities led by Newfoundland Power and Newfoundland and Labrador Hydro (the Utilities). The Utilities have jointly offered customer energy conservation information and programming under the takeCHARGE energy conservation brand since 2008. The Utilities have historically focused on energy savings but are increasingly considering demand management technologies and their potential to reduce or shift peak demand.

Study Scope

The Study scope is summarized as follows:

- **Study Period**: The base year in the Study model is 2023. The forecast period is 2024-2040. Measures are applied against the reference case starting in 2025.
- **Geographical Coverage**: The Study's geographical scope is the Island Interconnected System (IIS). The Labrador Interconnected System and the Isolated Diesel Generation System are not in scope. The Study includes both Utilities' customers.
- **Sector Coverage**: The Study includes four sectors: residential, commercial, industrial and transportation. The industrial sector includes Newfoundland and Labrador Hydro's six large industrial customers and both Utilities' large customers in the general service rate class. The transportation sector includes personal and fleet EVs.
- **Measures**: The Study examines the potential for efficiency, fuel switching, and demand response measures. Marine and off-road electrification are addressed at a high-level. The demand response measures include time-variable rates, EV managed charging, and thermal storage, among others.

Uses for the Study

The Study will support resource planning, and inform the planning and design of potential electrification, energy efficiency, and demand management programs and initiatives for the Utilities. It provides an estimate of the relative size of energy savings and demand reductions measures but is not intended to serve as a program design document.

Data Sources

The Study relies on the Utilities' knowledge of their customer base, the best available data, and inputs based on extensive research and the Study Team's professional judgement. The results in this report reflect rigorous analysis and provide an estimate of the opportunities available to the Utilities. The Study's data sources are summarized as follows:

- **Utility Customer Data**: The Utilities provided 2023 residential, commercial, and industrial sector customer billing data to inform the Study base year.
- **Long-Term Forecasts**: The Study uses Newfoundland and Labrador Hydro's general service and residential forecasts to inform the reference case.
- **End-Use Surveys**: The Utilities' 2022 Residential and Commercial End-Use Surveys are used to inform end use saturations and fuel shares. An end use survey asks utility customers about the characteristics, equipment, appliances and behaviours that drive energy use in buildings. End

use surveys can support potential studies, provide data to support program design, and support electricity load forecasting.[23]

- **Economic Data**: The Study uses 2023 marginal costs and electricity retail rates, and discount rates to assess cost-effectiveness.
- **Stakeholder Groups**: An external advisory committee of stakeholders provided input at two key steps in the Study workflow: measure identification and achievable potential. This input included desktop review of a list of measures and participation in achievable potential workshops.
- **Publicly Available Data Sources**: Data from publicly available Federal and Provincial websites was collected to inform Study inputs, including the transportation sector EV forecasts, for example.

By integrating these sources, the Study reference case considers the impacts of existing policies, but it does not account for potential future policies. Appendix A provides more details on the data sources and assumptions used in the Study.

Report Structure

The Study is organized and presented as follows:

- Section 2 explains the approach.
- Section 3 profiles the base year and reference case.
- Section 4 identifies the measures and presents cost-effectiveness test results.
- Section 5 presents efficiency savings potential by sector, for energy and peak.
- Section 6 shows fuel switching and off-road electrification potential by sector.
- Section 7 presents demand response potential for electricity rate designs, equipment-based measures, and customer curtailment.
- Section 8 shows the conclusions.

[23] Cadmus Group, "Ontario Residential End-Use Survey," Available: https://ieso.ca/-/media/Files/IESO/Document-Library/research/Ontario-Residential-End-Use-Survey.ashx, (Accessed: March 18. 2025).

2 Approach

Exhibit 17 shows the major analytical steps for the Study and summarizes each one. The base year and reference case were modelled using Posterity Group's Navigator™ Energy and Emissions Simulation Suite (Navigator). Navigator was also used to estimate technical, economic, and achievable potential. The Methodological Approach in Appendix A provides the detailed Study approach.

Exhibit 17: Study Major Analytical Steps

Step	Approach Summary
1. Develop Base Year Energy Use & Peak Demand	• Profile base year energy use using 2023 residential, commercial, and industrial sector customer billing data from the Utilities. • Use end-use peak factors to convert annual electric energy use to electric demand. Modify the peak factors so that peak demand in the base year aligns with the actual 2023 IIS peak. • Determine the base year vehicle stock for the transportation sector using historical vehicle registrations and data on active electric vehicle (EV) stock. Multiply vehicle stock by vehicle efficiency and annual vehicle kilometers travelled to determine annual energy consumption per vehicle.
2. Develop Reference Case Energy Use & Peak Demand	• Create a reference case that represents the baseline against which new potential can be calculated and is calibrated to NLH's long-term forecasts. Use end-use peak factors to convert annual electric energy use to electric demand. • Because EVs are emerging and future adoption is uncertain, create three forecast scenarios instead of one reference case: natural adoption, intermediate, and government targets.
3. Characterize Measures & Programs	• Develop measure list for each sector. Ensure coverage by end use and measure type (efficiency, fuel switching, off-road electrification, and demand response) • Characterize measures: energy and peak impacts; applicable segments; costs and cost-effectiveness.
4. Estimate Technical & Economic Potential	• Estimate the hypothetical technically feasible energy and demand savings potential for the IIS. • Estimate the potential for all cost-effective measures applied in technically feasible applications.
5. Estimate Achievable Potential	• Develop generic adoption curves based on customer payback acceptance and typical market diffusion patterns. Apply curves to each measure in the economic potential to create a simplified achievable potential. • Develop realistic achievable potential by soliciting feedback from stakeholders, input from the Utilities, jurisdictional research, and historical program data from the Utilities.

The rest of this section is structured as follows:

- Section 2.1 presents the model structure.
- Section 2.2 defines the Study base year and explains the scope of the reference case forecast.
- Section 2.3 defines the peak periods and summarizes the method to develop electric peak end use profiles for the base year and reference case.
- Section 2.4 list the types of measures characterized in the Study.
- Section 2.5 defines the potential scenarios.
- Section 2.6 lists caveats and limitations.

Readers are encouraged to consult Appendix A – Methodological Approach for details of the Study approach.

2.1 Model Structure

The Study includes four sectors: residential, commercial, industrial, and transportation. This section shows the model structure for each sector, including segments, end uses, vintages, and rate classes. This information provides important context for readers to understand the rest of this report.

Exhibit 18 shows the residential sector model structure by segment, end use, vintage and rate class. Residential segments are divided by electric and non-electric space heating. This differentiation is important for the reference case and potential assessment, because customer account growth (i.e., the number of customer accounts) and measure applicability vary by space heating fuel. Exhibit 18 also shows two EV charging end uses: battery electric vehicle (BEV) charging and plug-in hybrid electric vehicle (PHEV) charging.

Exhibit 18: Residential Sector Segments, End Uses, Vintages and Rate Classes

Segments (8)	End Uses (20)	Vintages (6)	Rate Classes (1)
• Apartment, electric space heat • Apartment, non-electric space heat • Attached, electric space heat • Attached, non-electric space heat • Other and non-dwellings • Single-Family Detached (SFD), electric space heat • SFD, non-electric space heat • Vacant and partial	• BEV Charging • Clothes Dryer • Clothes Washer • Computer and Peripherals • Cooking • Dehumidifier • Dishwasher • Freezer • Hot Tubs • Lighting • Other Electronics[24] • PHEV Charging • Refrigerator • Small Appliance and Other • Space Cooling • Space Heating • Television • Television Peripherals • Ventilation • Water Heating	• Pre-1965 • 1965 to 1979 • 1980 to 1989 • 1990 to 1999 • 2000 to 2012 • Post-2012	• 1.1

[24] Includes miscellaneous small electronics such as gaming consoles and tablets.

Exhibit 19 shows the commercial sector model structure by segment, end use and rate class. Some segments are differentiated by size (e.g., offices, non-food retail). This differentiation is important for the potential assessment portion of the Study because measure applicability varies by building size. Exhibit 19 also shows six EV segments (personal EV private charging, personal EV public charging, fleet light-duty vehicle (LDV) depot charging, fleet medium-duty vehicle (MDV) depot charging, fleet heavy-duty (HDV) depot charging, and fleet bus depot charging) and two EV end uses (BEV charging and PHEV charging).

Exhibit 19: Commercial Sector Segments, End Uses and Rate Classes

Segments (23)	End Uses (17)	Rate Classes (5)
• Arena	• BEV Charging	• 2.1
• Fleet Bus Depot Charging	• Computer Equipment	• 2.3
• Fleet HDV Depot Charging	• Computer Servers	• 2.4
• Fleet LDV Depot Charging	• Food Service Equipment	• Street Lighting
• Fleet MDV Depot Charging	• General Lighting	
• Food Retail	• High Bay Lighting	
• Healthcare	• HVAC Fans & Pumps	
• Large Accommodation	• Misc Equipment	
• Large Non-Food Retail	• Other Plug Loads	
• Large Office	• Outdoor Lighting	
• Large Other Building	• PHEV Charging	
• Non-Building	• Refrigeration	
• Personal EV Private Charging	• Secondary Lighting	
• Personal EV Public Charging	• Space Cooling	
• Restaurant	• Space Heating	
• School	• Street Lighting	
• Small Accommodation	• Water Heating	
• Small Non-Food Retail		
• Small Office		
• Small Other Building		
• Street Lighting		
• Universities and Colleges		
• Warehouse		

Exhibit 20 shows the industrial sector model structure by segment, end use and rate class. The large industrial segment includes only NLH's six large industrial customers.

Exhibit 20: Industrial Sector Segments, End Uses and Rate Classes

Segments (7)	End Uses (12)	Rate Classes (5)
• Fishing and Fish Processing • Large Industrial • Manufacturing • Mining and Processing • Other Industrial • Pulp and Paper • Water and Wastewater	• Air Compressors • Conveyors • Fans and Blowers • General Lighting • HVAC Fans & Pumps • Other • Other Motors • Process Cooling • Process Heating • Process Specific • Pumps • Hydrogen	• 2.1 • 2.3 • 2.4 • IND-1

Exhibit 21 shows the transportation sector model structure by ownership type, vehicle type, and powertrain.[25] Two EV charging end uses are modelled for the transportation sector, BEV charging and PHEV charging.

Exhibit 21: Transportation Sector Vehicle Segmentation

Ownership Type	Vehicle Type	Powertrain
Personal	LDV	BEV
	LDV	PHEV
Fleet	Bus	BEV
	HDV	BEV
	LDV	BEV
	LDV	PHEV
	MDV	BEV

[25] Electric micro-mobility was excluded from the Study because its impact is limited and due to a lack of Newfoundland-specific data. Hybrid electric vehicles, referring to vehicles that have both an electric motor and an internal combustion engine but are not plugged in, were also excluded from the Study. This is because their batteries charge through regenerative braking and by the internal combustion engine rather than plugging in and being supplied by the electricity grid.

2.2 Base Year and Reference Case Energy Use

This section explains the scope of the Study base year and reference case energy use forecast.

Base Year Electric Energy Use

Base year (2023) electric energy use is calibrated to historical customer billing data provided by the Utilities for the residential, commercial, and industrial sectors. Base year electric energy use for the transportation sector reflects historical vehicle registrations, data on active EV stock, vehicle efficiency and annual vehicle kilometers travelled. It was not possible to calibrate the transportation sector base year because the Utilities do not identify EVs in their historical customer data.

Reference Case Energy Use

The Study reference case (2024-2040) forecasts electricity consumption and peak demand based on exogenous conditions that follow a business-as-usual scenario. That is, it represents the baseline against which new potential can be calculated. Reference case energy use for residential, commercial, and industrial sector reference case forecasts is calibrated to NLH's long term forecast and has the following characteristics:

- It reflects current consumption patterns and known future changes, including expected customer growth, and current and known future changes to codes and standards.
- It considers the natural turnover of equipment and appliances, and changes in space heating and water heating fuel shares.
- It excludes conservation from ECDM activities carried out after 2023 and forecast electric vehicle load.
- It accounts for distribution losses in the 'losses and company use' segment in the commercial sector.

The Study Team created three forecast EV scenarios instead of a single reference case for the transportation sector because EVs are an emerging technology and future adoption is uncertain. This approach provides a range of possible futures for EV adoption in Newfoundland, which is expected to be influenced by government policy and other factors. The forecast EV scenarios are defined as follows:

- The **Natural Adoption Scenario** estimates EV adoption based on current incentives. MHDV and bus adoption in this scenario aligns with global forecasts for all countries, recognizing that Newfoundland will lag adoption in leading jurisdictions.
- The **Intermediate Scenario** includes EV uptake beyond the natural adoption scenario, consistent with additional market interventions like vehicle rebates and accelerated build-out of charging infrastructure for LDV, and/or more favorable EV capital cost declines for MDV and HDV.
- In the **Government Targets Scenario**, Federal Government targets for sales shares of LDVs and MHDVs being ZEVs by 2030, 2035, and 2040 are met. In the natural adoption and intermediate scenarios, the Federal Government targets are not met.

Energy use in each EV scenario reflects the forecast stock in each scenario, vehicle efficiency, and annual vehicle kilometres travelled.

2.3 Base Year and Reference Case Peak Demand

This section presents peak period definitions for the Study and explains the scope of the base year and reference case peak demand forecast.

Peak Period Definitions

Three peak periods are defined in the Study:

- **Peak Hour:** The single highest hour of IIS demand, typically occurring on the coldest day in the winter. Depending on the Study year, the single hour peak can occur in the morning or the evening.
- **Morning Peak Period:** The four-hour period in the morning with the highest average IIS demand, defined as 7 a.m. to 10:59 a.m. for Newfoundland.
- **Evening Peak Period:** The five-hour period in the evening with the highest average IIS demand, defined as 5 p.m. to 9:59 p.m. for Newfoundland.

Base Year Peak Demand

The Study Team used load profiles for each peak period to convert annual electric energy consumption to hourly demand for the residential, commercial, and industrial sectors. Base year peak demand is calibrated to the Utilities' estimate of IIS peak hour demand.

The Study Team also completed a peak day analysis to estimate demand in the hours outside of the peak hour. For the morning and evening peak periods, the Study Team determined the average demand during each period and calibrated the space heating peak factors to align the total with the average demand.[26] The peak day analysis is discussed in further detail in section 7.1.

Base year peak demand for the transportation sector uses 8760 load shapes for each combination of vehicle type and charging location. These load shapes are applied against base year annual energy consumption to determine demand in each hour of the year.

The Study Team identified the day that included the peak hourly EV load, then overlayed that day's 24-hour load shape onto the reference peak day load shape for the residential, commercial and industrial sectors. The overall IIS peak hour is identified based on the resulting aggregated load shape that reflects peak demand for all sectors.

Reference Case Peak Demand

The Study Team used calibrated peak factors from the base year in each year of the reference case forecast. Therefore, for each combination of end-use and building type, the reference case peak load scales with annual energy consumption for the residential, commercial, and industrial sectors. Aggregating the resulting end-use peak loads provides the forecast single peak hour or average peak demand for each year in the reference case.

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[26] The Study Team adjusted peak factors for the space heating end use in the residential and commercial sectors for the morning and evening peak period calibration because overall demand is driven by space heating in those sectors. The peaks for each period in the industrial sector are the same because overall demand is not driven by space heating.

Like the base year peak demand, reference case peak demand for the transportation sector relies on 8760 load shapes for each combination of vehicle type and charging location. The Study Team applied the load shapes against forecast annual reference case consumption to determine hourly demand in each reference case year.

2.4 Measure Characterization

The Study Team assessed the energy savings and peak demand reduction potential for measures in three categories:

1. **Efficiency**: Measure that uses electricity more efficiently than the base case measure.
2. **Fuel Switching**: Measure that uses electric equipment to replace a base case measure that uses another fuel (i.e., oil, propane, or wood). This category also includes measures that use-off road electric equipment (i.e., forklifts, Zambonis) to replace a base case off-road measure that uses propane.
3. **Demand Response**: Measure that uses less electricity during the peak period but has minimal or no impact on annual electric energy consumption. The demand response (DR) measures are further classified as follows:
    - **Electricity Rate Design**: Customers opt into a time-of-use (TOU) or critical peak pricing (CPP) electricity rate at their discretion. This includes TOU rates for EVs.
    - **Equipment DR**: The utility has direct load control (DLC) of customer end use equipment (e.g., water heater smart switch, smart thermostat) during on-peak times. These measures are modelled with opt-in participation and with current rates (i.e., they are not modelled with time variable rates (TVR)).
    - **EV Managed Charging**: Measure that enables utilities to influence charging periods for vehicles via connected hardware and controls. Managed charging measures can be valuable to an electric utility because they can reduce the peak demand associated with EV charging. Peak demand is a main driver of infrastructure investment needs and costs borne by utility ratepayers.
    - **Thermal Storage with TOU**: Customers shift electricity use off peak based on TOU rates only using electric thermal storage (ETS) systems.

In addition, the Study Team determined what market conditions would be required to support the natural adoption, intermediate and government targets scenarios defined in section 2.2.[27] This included an examination of the following transportation sector measures:

- **Adoption Incentives**: Payments to vehicle operators that offset the incremental cost of adopting EVs.
- **Charging Infrastructure**: Charging infrastructure costs include port costs and associated installation costs. Costs exclude distribution system upgrades to host charging loads.

Lastly, the Study Team completed a qualitative assessment of emerging measures transportation sector measures:

- **Emerging Measures**: Connected hardware and controls that enable vehicle batteries to feed energy back to specific loads, dwellings or the grid and allow the Utilities to influence the magnitude and timing of this energy flow.

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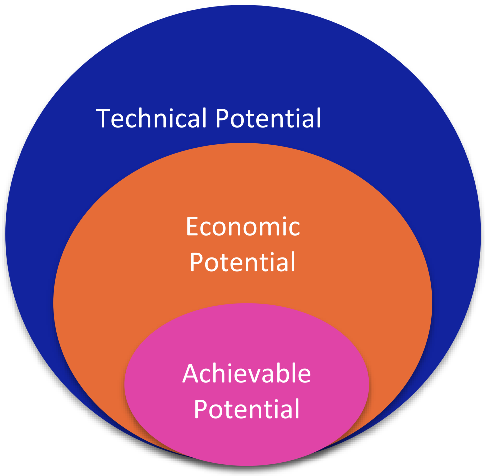
[27] In the Study, charging infrastructure refers to the ports required to support electric vehicle charging in the Transportation sector.

2.5 Potential Assessment

The Study assesses three levels of savings potential: technical, economic, and achievable, described as follows:[28]

1. **Technical Potential:** An estimate of the technically feasible energy and demand savings potential, ignoring measure cost effectiveness or market acceptance.
2. **Economic Potential:** An estimate of the energy and demand savings potential for the measures in the technical potential that also pass the cost effectiveness screening criteria established for the Study. The total resource cost (TRC) test is used to screen efficiency measures. Measures are included in the economic potential if their benefit-cost ratio is 0.8 or higher.[29]



3. **Achievable Potential**: An estimate of the energy and demand savings potential considering feasible adoption rates of cost-effective measures over the study period. Achievable potential considers market barriers, customer payback acceptance, and awareness of energy efficiency measures among other factors. The achievable scenarios are defined as follows:
   - **Lower**: Incentive is 25% of incremental cost for ROB measures and 25% of full cost for RET measures.
   - **Medium**: Incentive is 50% of incremental cost for ROB measures and 50% of full cost for RET measures.
   - **Higher**: Incentive is 100% of incremental cost for ROB measures and 100% of full cost for RET measures.

In all three achievable potential scenarios, non-incentive costs are set to 25% of the measure-level incentive. While 25% is a standard estimate used for the purposes of this Study, non-incentive costs would vary from program to program.

[28] "Foreword" Independent Electricity System Operator, Available: https://www.ieso.ca/-/media/Files/IESO/Document-Library/conservation/APS/2019-Achievable-Potential-Study-Foreword.pdf (Accessed Dec. 11, 2024).
[29] This ratio was selected instead of 1.0 to allow more measures to be screened into the economic and achievable potential scenarios. The economic potential does not consider incentive or non-incentive program costs.

2.6 Caveats and Limitations

Forecasting and modelling are integral to this Study. Both activities require assumptions and engineering estimates based on extensive research and the professional judgement of the Study Team. The Study Team has made diligent efforts to ensure that any assumptions were in line with the Utilities' knowledge of their customer base and informed by the best available information. The results in this report should therefore be interpreted as estimates.

The Study reference case is calibrated to NLH's 2023 long-term forecasts. The following data sources inform the Study reference case:

- Newfoundland and Labrador Hydro's (NLH) general service forecasts for their customers and for Newfoundland Power's (NP) customers.[30]
- NLH's residential forecasts for their customers and for NP's customers, based on the historic relationship between new customer accounts and housing starts, which inherently reflects demolitions or rebuilds.[30]
- Residential and commercial end use survey results, used to estimate the rate of natural adoption of new, more efficient technology.

By integrating these sources, the Study reference case considers the impacts of existing policies, but it does not account for potential future policies. Any differences in stated values or summations in this report are due to rounding unless otherwise noted.

[30] The General Service forecast for NP's customers was derived using an econometric equation driven by GDP, non-residential building investment, forecast CDM savings, and a forecast for heating degree days.

3 Base Year and Reference Case

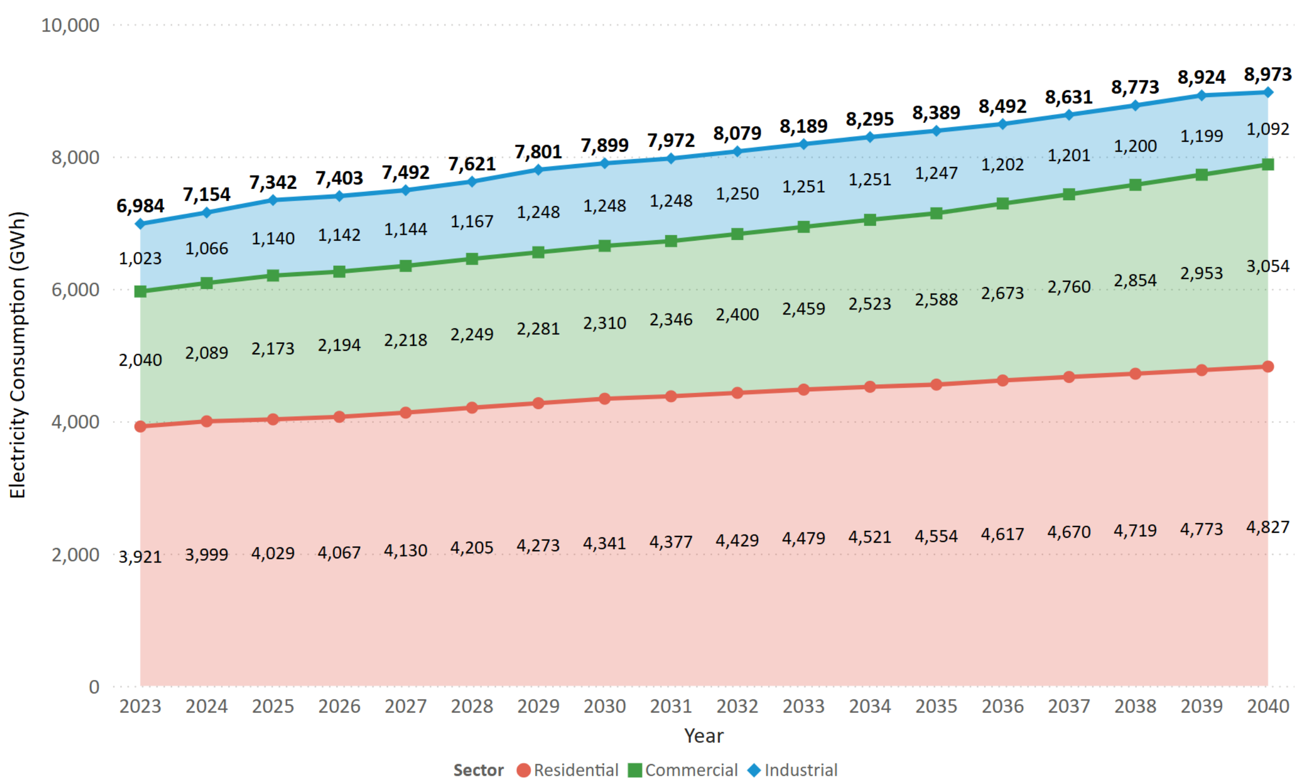
This section shows base year and reference case energy consumption and peak demand at the system-level and by sector. It is structured as follows:

- Section 3.1 shows system-level base year and reference case results.
- Sections 3.2, 3.3, and 3.4 show results by segment, customer accounts and end use for the residential, commercial, and industrial sectors. Results are presented by segment, customer accounts and end use.
- Section 3.5 shows results for the transportation sector, including a comparison of the forecast vehicle stock, consumption and peak demand in the natural adoption, intermediate, and government targets scenarios.

3.1 System-Level Base Year and Reference Case

Exhibit 22 shows base year and reference case IIS electricity consumption by sector.[31] Residential and commercial sector electricity consumption includes EV charging in the intermediate scenario, as defined in section 2.2. The numerical values in bold font (e.g., 6,984) represent total annual IIS consumption.

Exhibit 22: Reference Case IIS Consumption (GWh)



Observations on Exhibit 22 include:

- Total base year electricity consumption is 6,984 GWh. The residential sector represents 56% of this total (3,921 GWh). The commercial and industrial sectors represent 29% (2,040 GWh) and 15% (1,023 GWh) of the total, respectively. In 2040, these contributions are 54% residential, 34% commercial, and 12% industrial.
- Electricity consumption is forecast to increase by 1,989 GWh (28%) between 2023 and 2040. The adoption of 160,699 EVs caused by incentives or more charging infrastructure for LDVs in the

[31] Electricity consumption from losses and company use is excluded. Losses and company use contribute 350 GWh and 458 GWh to IIS electricity consumption in 2023 and 2040, respectively. IIS consumption including losses and company use is 7,334 GWh in 2023 and 9,431 GWh in 2040.

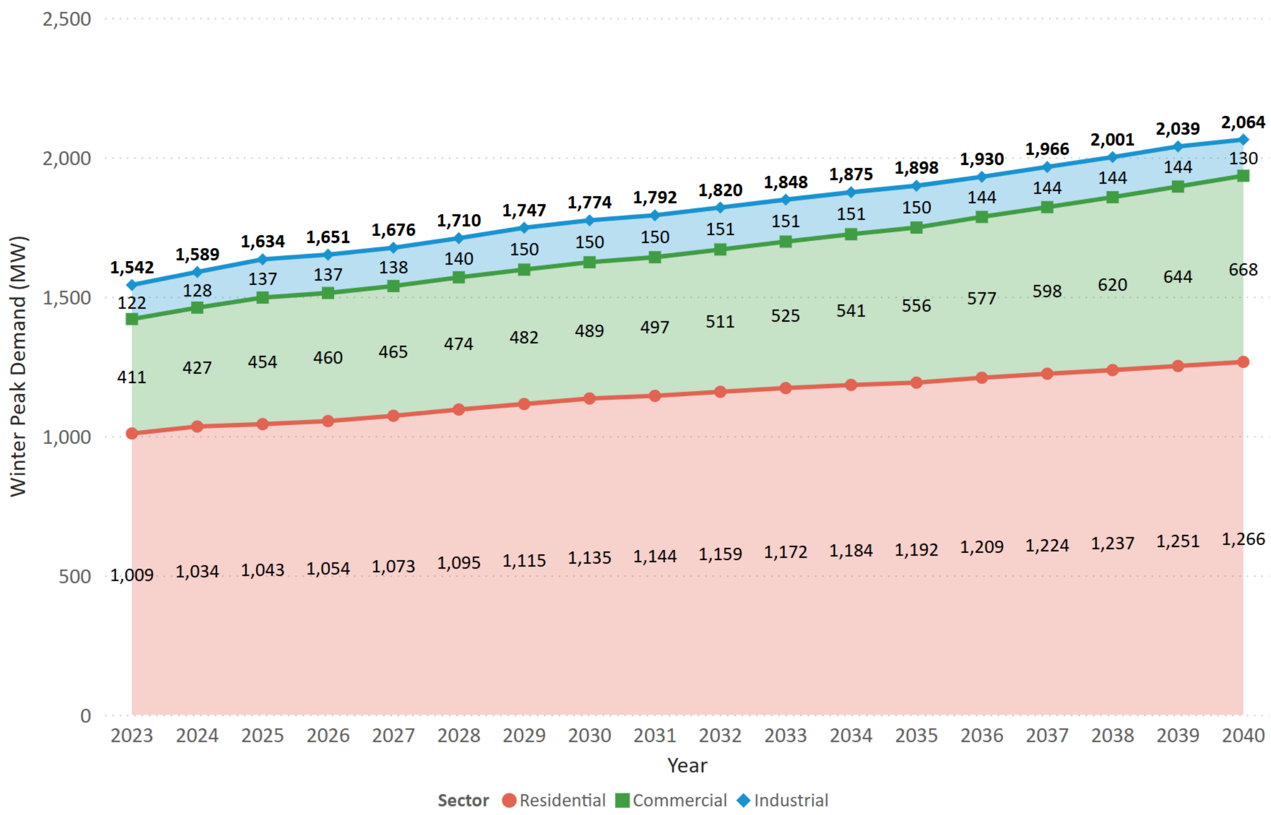
intermediate scenario accounts for 991 GWh of this increase.[32] The rest of the increase is driven by:

- Space heating electrification in the residential and commercial sectors, and,
- An increase in customer accounts in the residential and commercial sectors, and in small and medium customer accounts in the industrial sector.

Exhibit 23 shows base year and reference case winter peak demand (i.e., the single highest hour of system demand, which typically occurs on the coldest day of the winter) by sector for the IIS, including the contributions of EV charging in the intermediate scenario.[33] The numerical values in bold font (e.g., 1,542) represent total annual IIS peak demand.

From 2023 to 2032, the IIS peaks in the morning. In 2033, the peak is forecast to occur in the evening, driven by the adoption of EVs in the intermediate scenario. This change to the evening peak is discussed in detail in section 7.1.

Exhibit 23: Reference Case IIS Winter Peak Demand (MW)



[32] The Study Team integrated the intermediate EV scenario because it is the middle scenario compared to the natural adoption and government targets scenarios, which bookend the EV forecast analysis.

[33] Peak demand from losses and company use is excluded. Losses and company use contribute 55 MW and 72 MW to IIS peak demand in 2023 and 2040, respectively. Total IIS peak demand including losses and company use is 1,597 MW in 2023 and 2,135 MW in 2040.

Observations on Exhibit 23 include:

- Peak demand in the base year is 1,542 MW. The residential sector represents 65% (1,009 MW) of this total, while the commercial and industrial sectors represent 27% (411 MW) and 8% (122 MW) of the total, respectively. By 2040, these contributions shift to 61% residential, 33% commercial, and 6% industrial.
- Peak demand is forecast to increase by 522 MW (34%) between 2023 and 2040. The increase to 2,064 MW by 2040 is largely driven by the adoption of 160,699 EVs between 2030 and 2040 in the intermediate scenario.

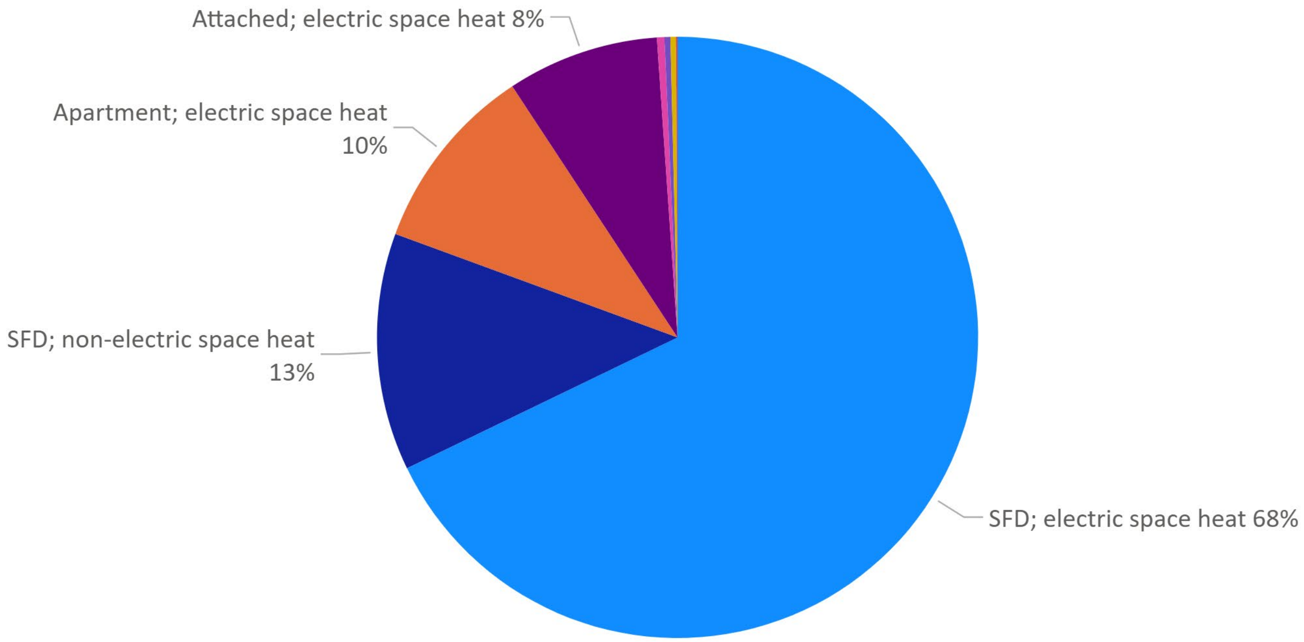
3.2 Residential Sector Base Year and Reference Case

This section presents residential sector results for the base year (2023) and the reference case forecast (2024-2040). The results presented in this section include consumption from unmanaged EV charging in the intermediate scenario.

3.2.1 Base Year Consumption by Segment, Customer Accounts, and End Use

Base year consumption in the residential sector is 3,921 GWh. Exhibit 24 shows that electrically heated single family detached dwellings (SFDs) consume the most electricity (2,660 GWh, 68%), followed by non-electrically heated SFDs (500 GWh, 13%) and electrically heated apartments (398 GWh, 10%).[34] The distribution of customer accounts by segment drives this result (see Exhibit 25).

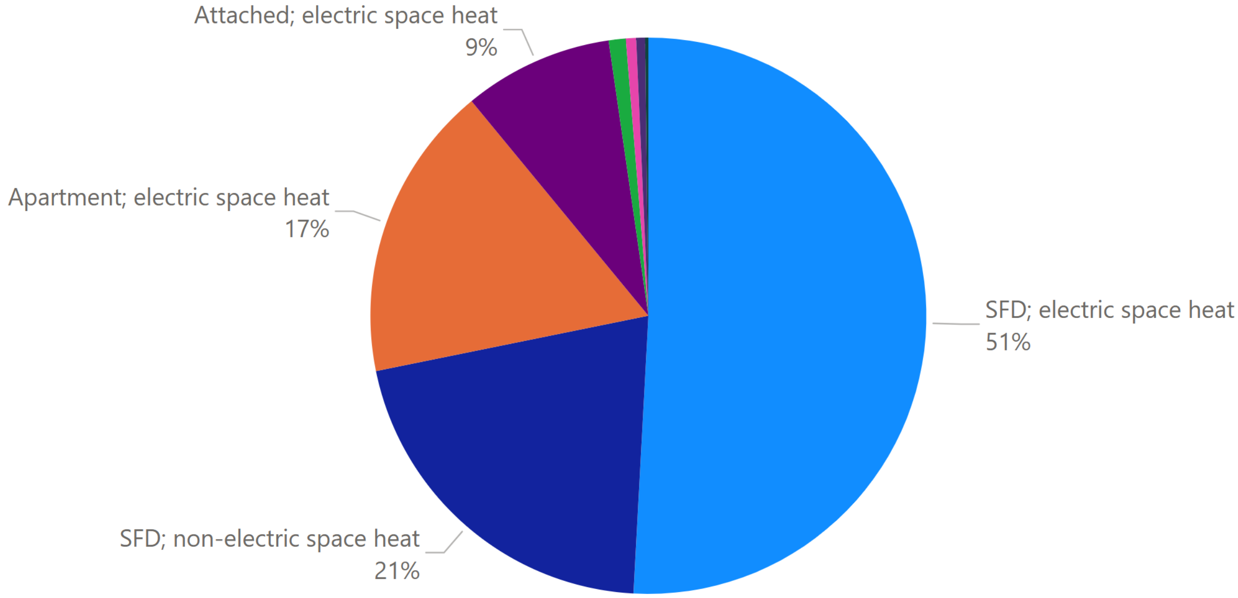
Exhibit 24: Base Year Residential Consumption by Segment



[34] Segments that contribute less than 8% to residential sector consumption are not labelled to improve readability: other and non-dwellings (0.4%), vacant and partial (0.3%), apartment; non-electric space heat (0.3%), and attached; non-electric space heat (0.08%).

The distribution of electricity customer accounts by segment is presented in Exhibit 25.[35] Most of the 259,793 base year customer accounts are in the electrically heated SFD segment (132,124, 51%), followed by the non-electrically heated SFD segment (54,434, 21%).

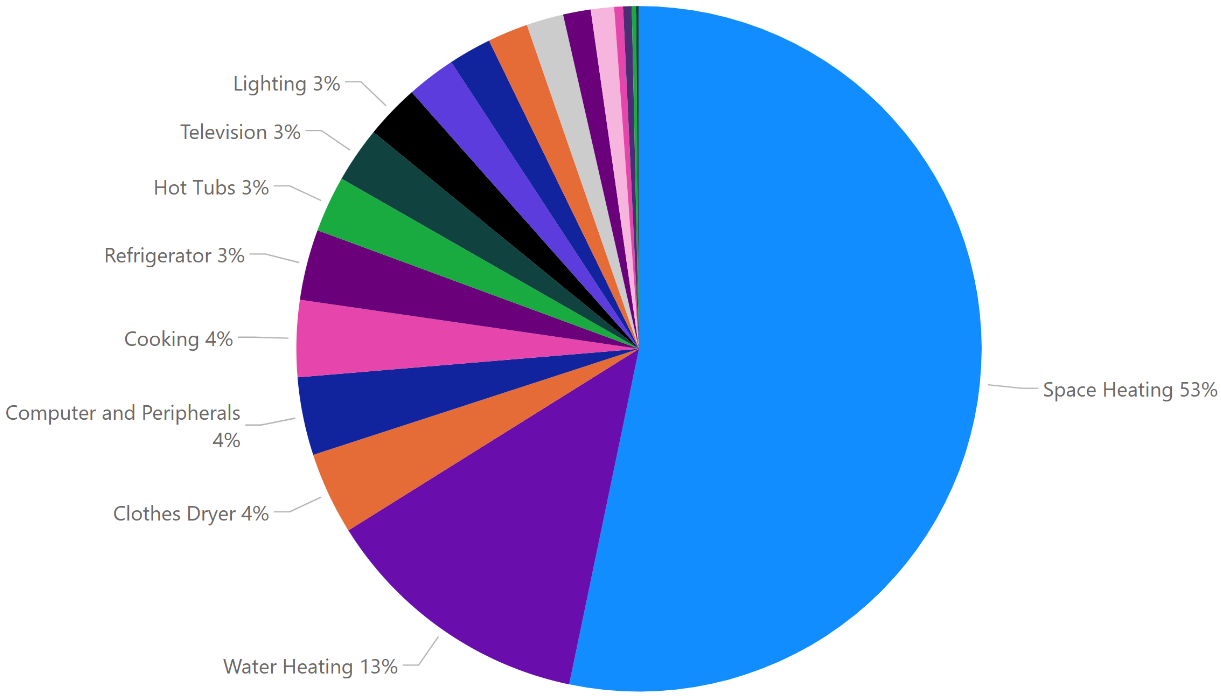
Exhibit 25: Base Year Residential Customer Accounts by Segment



[35] Segments that represent less than 8% of residential sector accounts are not labelled to improve readability: apartment; non-electric space heat (1%), other and non-dwellings (0.6%), vacant and partial (0.5%), and attached; non-electric space heat (0.2%).

Exhibit 26 shows residential sector electricity consumption by end use. Most base year electricity is for space heating (2,088 GWh, 53%) followed by water heating (504 GWh, 13%) and clothes dryers (152 GWh, 4%).[36,37] The contribution of EV charging to total base year energy consumption is 6 GWh, or 0.15%. This EV charging consumption represents 1,520 vehicles.

Exhibit 26: Base Year Residential Consumption by End Use



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[36] End uses that represent less than 3% of residential sector base year consumption are not labelled to improve readability: small appliance and other (2%), television peripherals (2%), dehumidifier (2%), freezer (2%), ventilation (1%), other electronics (1%), space cooling (0.4%), dishwasher (0.4%), clothes washer (0.2%), BEV charging (0.1%) and PHEV charging (0.03%).

[37] Television peripherals include the peripheral equipment used with televisions (e.g., DVRs, cable boxes, etc.).

Base Year Consumption per Customer Account

Dividing consumption by the number of customer accounts gives the average electricity consumption per customer account. This calculation reveals the segments with the highest or lowest energy intensities. Base year consumption, customer accounts and consumption per customer account for each segment are displayed in Exhibit 27. Highlights from this exhibit include:

- The most energy intensive segment in the residential sector is electrically heated single-family detached (SFD), which consume 20.1 MWh per customer account, followed by attached dwellings (electric space heat) at 14.2 MWh per customer account and other and non-dwellings at 10.2 MWh per customer account.
- Non-electrically heated dwellings and both electrically- and non-electrically heated apartments are the least energy intensive segments.

Exhibit 27: Base Year Residential Energy Intensity (MWh/Customer Account) by Parent Segment

Segment	2023 Consumption (MWh)	2023 Customer Accounts	2023 Average Consumption (MWh/Customer Account)
SFD; electric space heat	2,659,749	132,124	20.1
Attached; electric space heat	320,225	22,567	14.2
Other and non-dwellings	15,773	1,546	10.2
Vacant and partial	12,421	1,340	9.3
SFD; non-electric space heat	500,202	54,434	9.2
Apartment; electric space heat	397,621	44,720	8.9
Attached; non-electric space heat	3,128	487	6.4
Apartment; non-electric space heat	11,765	2,575	4.6
Total	**3,920,884**	**259,793**	**15.1**

Base Year Peak Demand

Exhibit 28 shows base year residential sector peak demand by end use. Observations for the base year include:

- Space heating is the largest (67%) residential component of peak demand. As shown in the previous section, space heating represents 53% of residential base year electricity consumption. This consumption is concentrated in the winter when the IIS system peaks on a very cold day.
- Water heating is the second largest (14%) residential component of peak demand. Water heating represents 13% of annual electricity consumption in the base year and is on during the winter peak periods.
- EV charging represents 0.1% (1 MW) of residential sector peak demand in the base year. EV charging represents 0.15% of annual electricity consumption in the base year.

Exhibit 28: Base Year Residential Peak Demand (MW)

End Use	2023 Winter Peak Demand (MW)[38]	2023 % of Winter Peak Demand
Space Heating	673	67%
Water Heating	145	14%
Cooking	28	3%
Clothes Dryer	25	2%
Computer and Peripherals	19	2%
Television	17	2%
Lighting	17	2%
Ventilation	16	2%
Hot Tubs	16	1%
Refrigerator	13	1%
Small Appliance and Other	12	1%
Television Peripherals	10	1%
Freezer	7	0.7%
Other Electronics	6	0.6%
Dishwasher	3	0.3%
BEV Charging	1.5	0.1%
Clothes Washer	1	0.1%
PHEV Charging	0.3	0.03%
Total	**1,009**	**100%**

[38] Dehumidifier and space cooling are not shown because they represent less than 0% of base year winter peak demand.

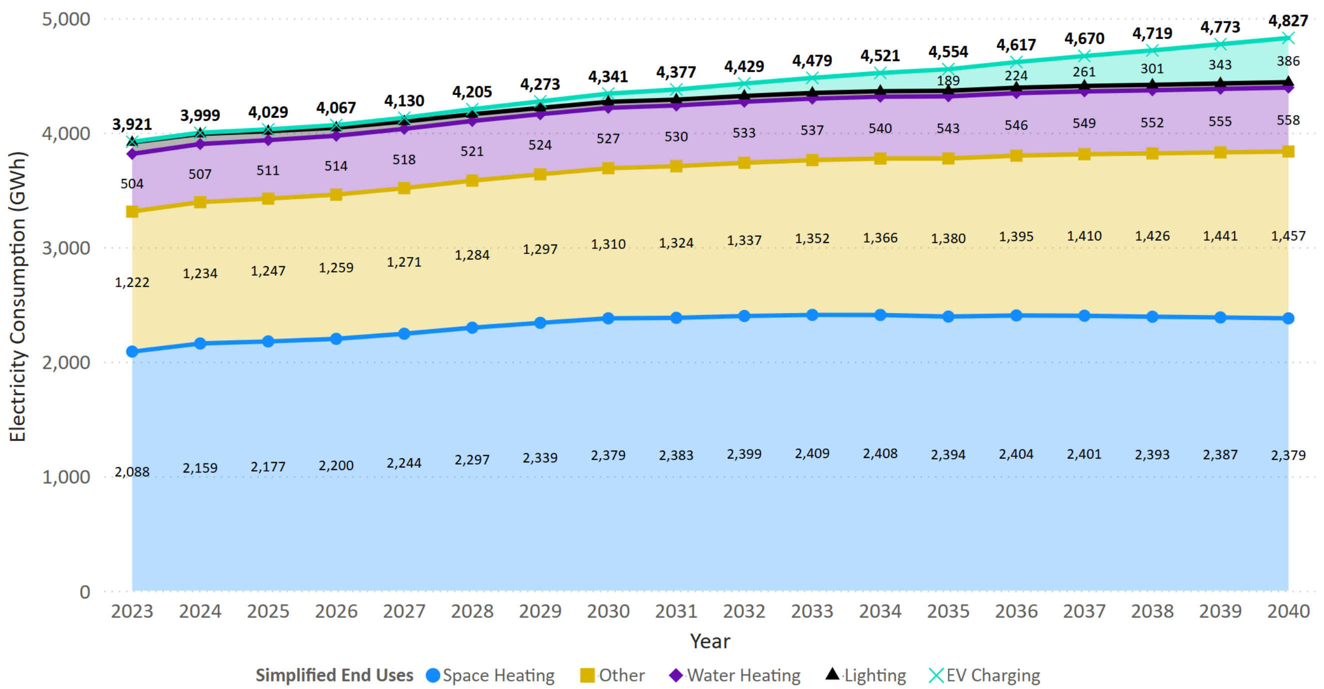
3.2.2 Reference Case Electricity Consumption and Peak Demand

This section profiles the reference case electricity consumption and peak demand forecast for the residential sector. It begins with commentary on high-level trends, then shows how consumption is forecast to change by segment, end use, and in new versus existing homes. It ends with a summary of peak demand results.

Residential Reference Case Consumption Trends

Exhibit 29 shows reference case electricity consumption for the residential sector. The contributions of space heating, water heating, lighting, and unmanaged EV charging to total consumption (represented by numerical values in bold font) are shown explicitly. The contributions of all other end uses are grouped in "Other" to enhance readability.

Exhibit 29: Reference Case Residential Consumption Forecast (GWh)



Residential electricity consumption is forecast to increase by 906 GWh (23%) from 2023 to 2040. The increase to 4,827 GWh in 2040 is explained by the following trends:

- **Space heating electrification**: The number of customer accounts with electric heating are expected to increase by 59,643 between 2023 and 2040, while the number of customer accounts without electric heating are forecast to decrease by 31,599 between 2023 and 2040.[39]

[39] Customer accounts with electric heating use electricity as their main heating source, accounting for at least 50% of their heating, while customer accounts without electric heating use less than 50% electricity for heating.

Between 2014 and 2022, the Residential End Use Survey (REUS) showed an overall increase in electrically heated dwellings from 66% to 78%.[40]

- **An increase in EV charging:** Annual EV charging consumption is forecast to increase by 381 MWh over the forecast period, caused by the adoption of 138,478 EVs.
- **An increase in residential customer accounts:** Residential customer accounts increase by approximately 11% over the forecast period. This is compounded by most new dwellings using electric equipment for space heating compared to older existing dwellings.
- **Increased saturation of space cooling**: The penetration of heat pumps is projected to grow substantially in forecast period. Between 2014 and 2022, the REUS showed that the overall heat pump penetration increased more than seven-fold (from 3.3% to 24.9%). This change is directly correlated with an increase in space cooling saturation because homes in Newfoundland rarely have stand-alone air conditioning equipment (i.e., space cooling is primarily provided by heat pumps).

Consumption by Segment

Exhibit 30 shows the change in electricity consumption by segment over the forecast period. The largest increase in consumption occurs in the electrically heated apartment segment (61%) followed by the non-electrically heated apartment segment (34%) and the electrically heated SFD segment (31%).[41]

Exhibit 30: 2023 vs 2040 Residential Consumption Forecast (GWh) by Parent Segment

Segment	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption (%)
Apartment, electric space heat	398	641	243	61%
Apartment, non-electric space heat	12	16	4	34%
SFD, electric space heat	2,660	3,496	836	31%
Attached, electric space heat	320	398	78	24%
Other and Non-Dwellings	16	15	-0.1	-1%
Vacant and Partial	12	12	-0.4	-4%
SFD, non-electric space heat	500	249	-252	-50%
Attached, non-electric space heat	3	0.5	-3	-85%
Total	**3,921**	**4,827**	**906**	**23%**

[40] With increased heat pump uptake, the average efficiency of electric space heating is projected to increase, which balances out the increase in electric space heating penetration across the IIS. Therefore, contribution of space heating consumption to the residential sector total decreases over time in the reference case.
[41] Apartments are expected to see the largest increase in consumption because they are forecast to see the largest increase in customer accounts between 2023 and 2040.

Consumption by End Use

Exhibit 31 shows the expected growth in electricity consumption by end use and highlights space cooling saturation growth trend discussed. Observations on Exhibit 31 include:

- EV charging end uses are expected to grow by 380 GWh between 2023 and 2040, caused by the adoption of 138,478 personal EVs in the intermediate scenario.
- Other electronics and television end uses grow by 106 GWh between 2023 and 2040 due to customer account growth and natural adoption.
- Space cooling consumption is expected increase by 8 GWh (50%) between 2023 and 2040, driven by the rapid adoption of heat pumps.

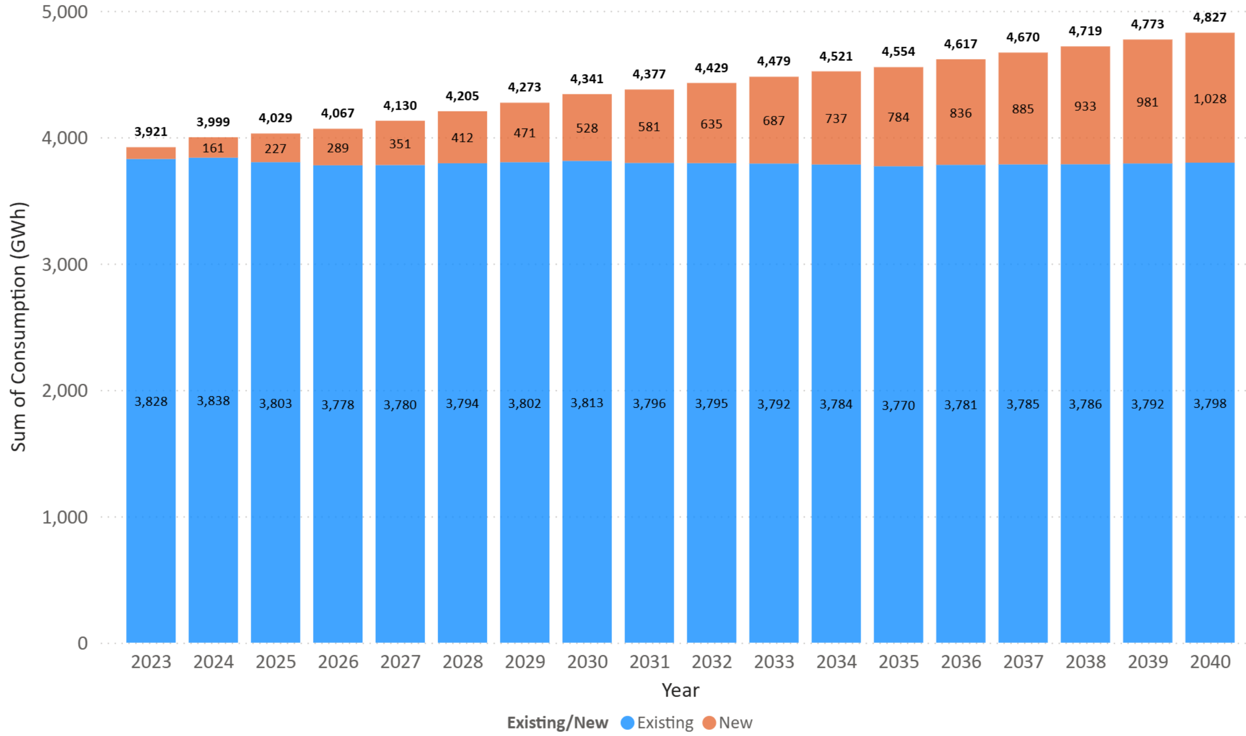
Exhibit 31: 2023 vs 2040 Residential Consumption Forecast by Parent End Use (GWh)

End Use	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption (%)
BEV Charging	5	338	333	7,164%
PHEV Charging	1	48	47	6,271%
Other Electronics	43	69	26	59%
Space Cooling	16	24	8	50%
Television Peripherals	79	114	35	44%
Television	103	148	45	44%
Hot Tubs	104	130	26	25%
Freezer	68	84	16	22%
Computer and Peripherals	144	174	30	21%
Dishwasher	16	19	3	20%
Refrigerator	130	156	26	19%
Space Heating	2,088	2,379	291	14%
Water Heating	504	558	54	11%
Dehumidifier	75	83	8	10%
Cooking	142	156	14	10%
Clothes Washer	8	8	0	9%
Small Appliance and Other	91	97	6	8%
Clothes Dryer	152	155	3	2%
Ventilation	51	40	-11	-21%
Lighting	101	47	-54	-53%
Total	**3,921**	**4,827**	**906**	**23%**

Reference Case Electricity Consumption: Existing versus New Buildings

This section compares the electricity consumption in existing versus new residential buildings across the reference case forecast. New constructions are estimated by extrapolating customer forecasts provided by NP and drawing insights from the electricity consumption growth forecasts by rate class. This leads to a decreasing stock of existing building over the reference case forecast period while new dwellings increase, which is reflected in the graph of consumption over time shown in Exhibit 32.

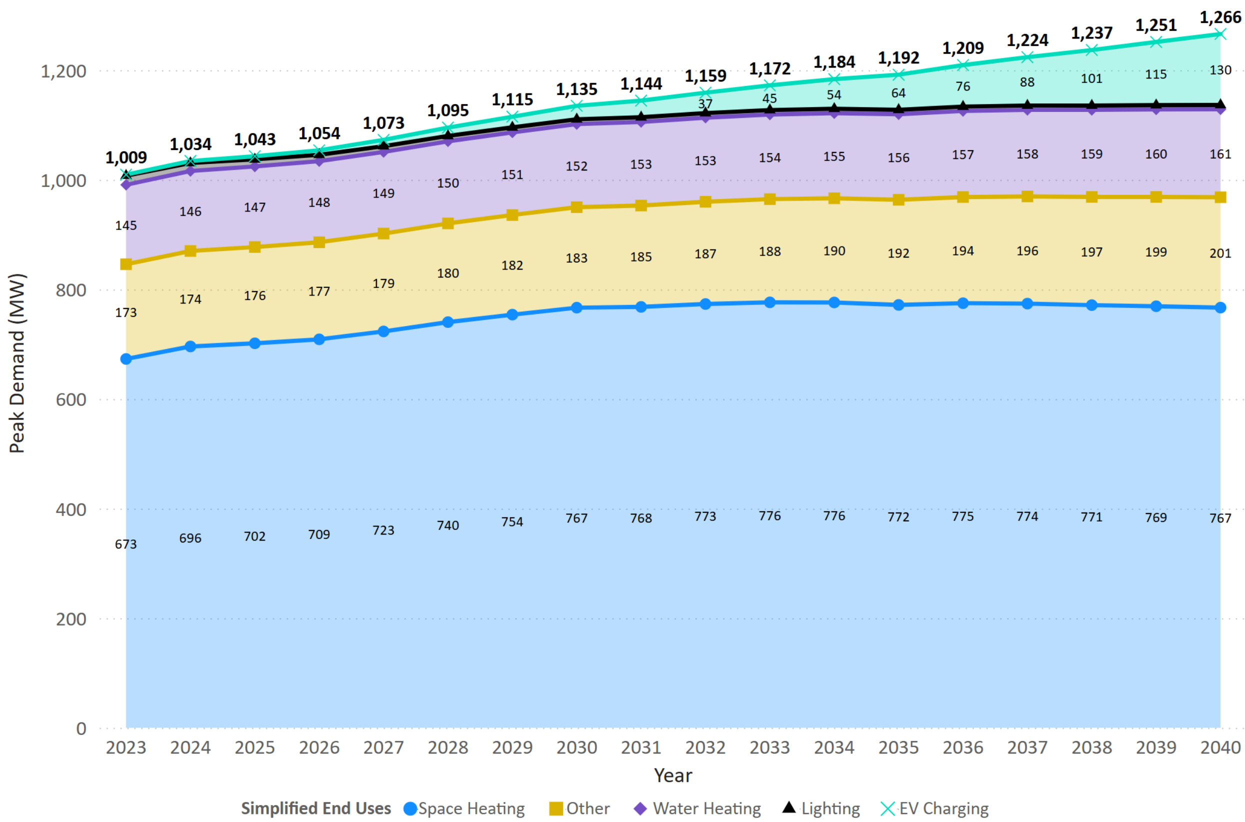
Exhibit 32: Existing vs New Dwelling Residential Consumption Forecast (GWh)



Reference Case Peak Demand

Exhibit 33 shows reference case peak demand for the residential sector. The contributions of water heating, unmanaged EV charging, lighting and space heating to total consumption are shown explicitly while the contributions of all other end uses are grouped in “Other” to enhance readability.

Exhibit 33: Residential Sector Reference Case Peak Demand (MW)



The reference case winter peak demand in the residential sector is forecast to increase by 257 MW (25%), between 2023 and 2040. The increase to 1,266 MW by 2040 is explained by the following trends:

- **Increase in space heating demand**: Space heating demand increases substantially over the forecast period (94 MW, 14%) and comprises the highest demand of all end uses. This increase is explained by the electrification trends for space heating.[42]
- **Increase in EV charging demand**: There is a substantial increase in demand for EV charging, from 1.8 MW in 2023 to 130 MW in 2040. EV charging represents 10% of residential winter peak demand by 2040.

[42] Demand increases are linearly correlated with energy consumption increases.

Exhibit 34 shows residential sector reference case peak demand for all end uses. Observations include:

- EV charging end uses have the highest peak demand growth (128 MW) over the forecast period due to the adoption of 138,478 personal EVs in the intermediate scenario.
- Peak demand increases by 59% in other electronics and by 44% in televisions and peripherals. This is due to projected increases in the saturation of these end uses during peak hours.
- In 2040, space heating contributes the most to the winter peak (61%), followed by water heating (13%), and BEV charging (9%).

Exhibit 34: Residential Sector Reference Case Peak Demand by End Use (MW)

End Use	2023 Winter Peak Demand (MW)	2040 Winter Peak Demand (MW)	Change in Peak Demand (MW)	Change in Peak Demand (%)
BEV Charging	1.5	108	107	7,164%
PHEV Charging	0.3	21	21	6,271%
Other Electronics	6	9	3	59%
Television Peripherals[43]	10	15	5	44%
Television	17	25	8	44%
Hot Tubs	16	20	4	25%
Freezer	7	8	1	22%
Computer and Peripherals[43]	18	22	4	21%
Dishwasher	2.6	3.2	0.5	20%
Refrigerator	13	15	2	19%
Space Heating	673	767	94	14%
Water Heating	145	161	16	11%
Cooking	28	31	3	10%
Clothes Washer	1.3	1.4	0.1	9%
Small Appliance and Other	12	13	1	8%
Clothes Dryer	25	26	1	2%
Ventilation	16	13	-3	-21%
Lighting	17	8	-9	-53%
Space Cooling	0	0	0	N/A
Dehumidifier	0	0	0	N/A
Total	**1,009**	**1,266**	**257**	**25%**

[43] The Study Team derived the growth in end use saturation for these end uses by comparing the 2014 and 2022 NP and NLH REUS. The annual growth in end use saturation is approximately 1.5%. This indicates customers owned more TVs, computers, and associated peripherals in 2024 than in 2014.

3.3 Commercial Sector Base Year and Reference Case

This section presents results and key findings for the commercial sector base year (2023) and reference case forecast (2024-2040). The results include consumption from unmanaged EV charging in the intermediate scenario.

Commercial sector base year and reference case results are presented by parent segment (e.g., Office, Non-Food Retail, Accommodation) and parent end use to enhance readability. A parent segment represents the sum of consumption or customer accounts in the small and large segments where applicable. For example, consumption for the office parent segment represents the sum of consumption in the small and large office segments. Parent end uses represent a combination of like end uses. Specifically:

- Indoor lighting represents general lighting, secondary lighting, and high bay lighting.
- Plug loads represents computer equipment, computer servers and other plug loads.

Section 2 - Approach provides additional details on the commercial sector model structure.

3.3.1 Base Year Electricity Consumption and Peak Demand

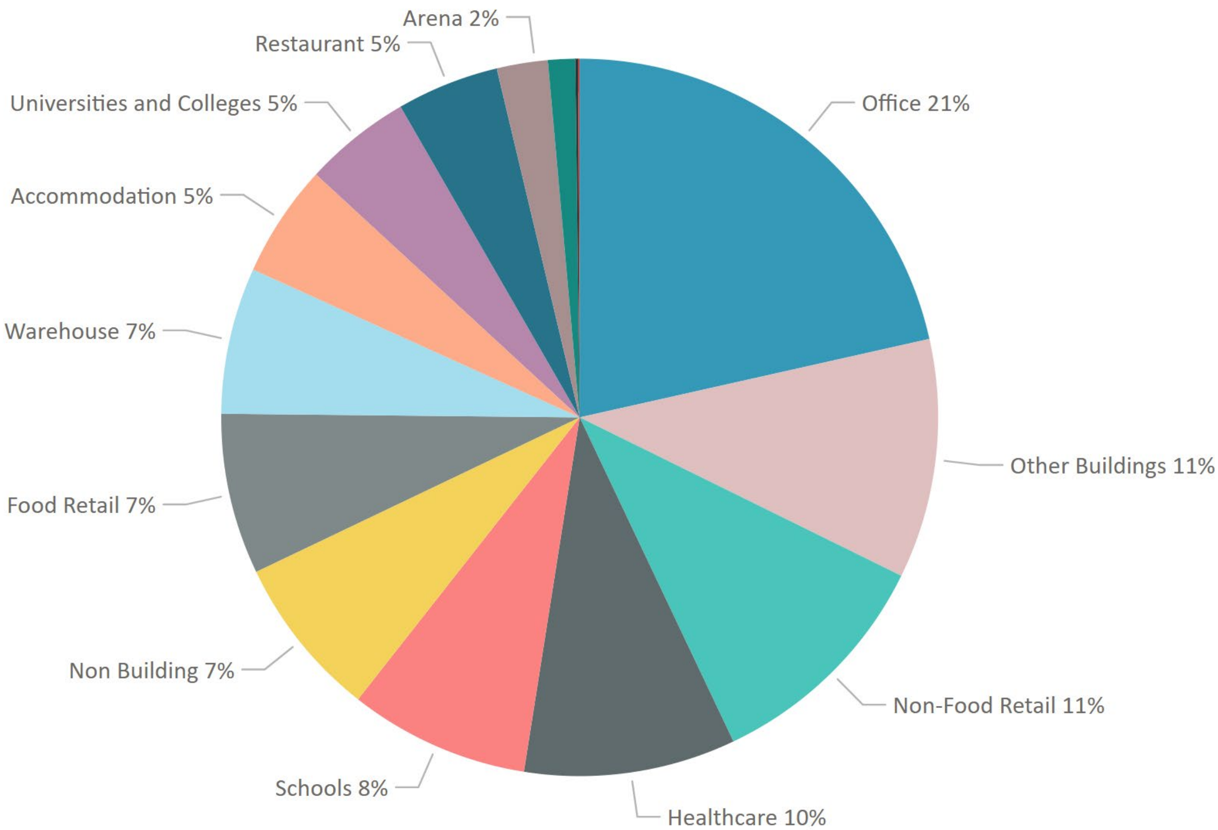
This section profiles base year electricity consumption, customer accounts, consumption per customer account, and peak demand for the commercial sector.

Consumption by Segment, Customer Accounts, and End Use

Base year electricity consumption in the commercial sector is 2,040 GWh. Exhibit 35 shows that electricity consumption is highest in the office segment (438 GWh, 21%) followed by other buildings (220 GWh, 11%) and non-food retail (218 GWh, 11%).[44] Examples of other buildings include churches, community centres, recreation complexes, and buildings that do not fit into the other parent segments.

In the base year, the EV charging segments contribute 3.9 GWh (0.2%) to the commercial sector total. This distribution of customer accounts by segment drives this result (see Exhibit 36).

Exhibit 35: Base Year Commercial Consumption by Parent Segment



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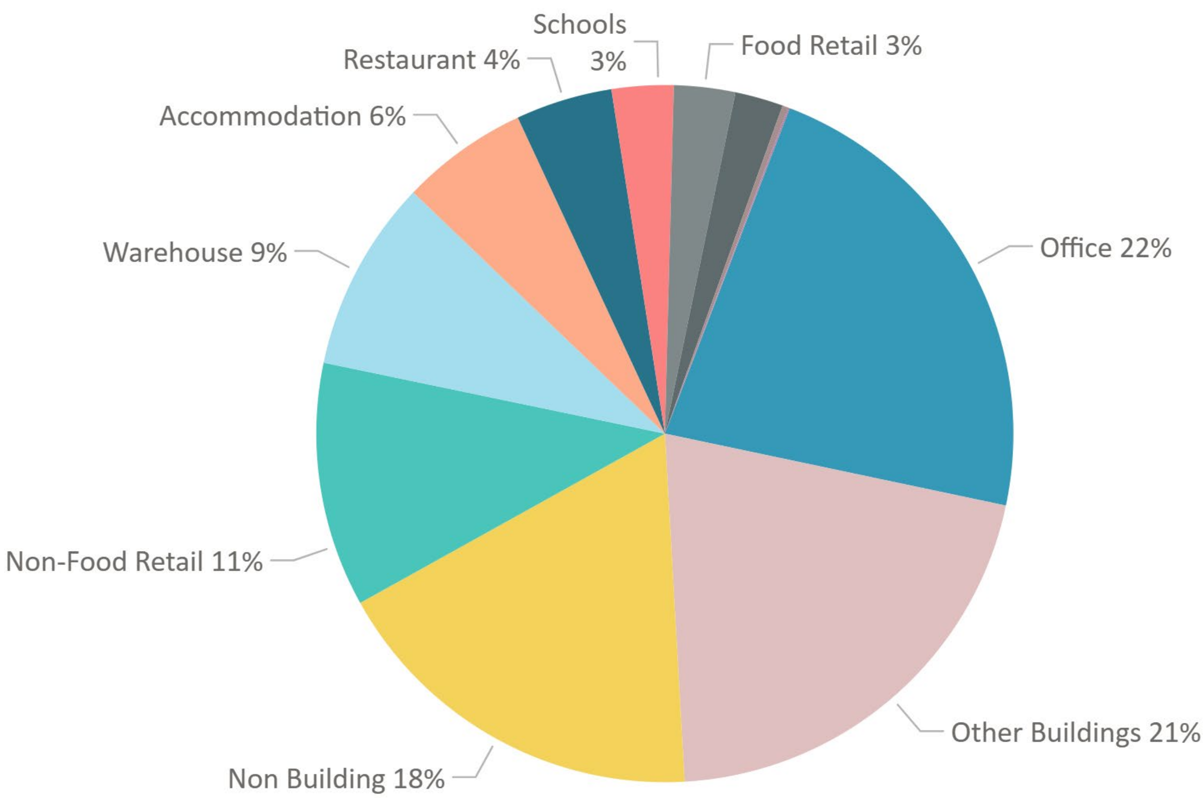
[44] Segments that represent less than 2% of commercial sector consumption are not labelled to improve readability: street lighting (1%), personal EV charging (0.1%), and fleet depot charging (0.07%).

Base year commercial sector customer accounts are presented by segment in Exhibit 36.[45] Most of the 23,733 base year customer accounts are offices (5,334, 22%), followed by other buildings (4,934, 21%) and non buildings (4,232, 18%). Non buildings include facilities like cell phone towers. Although these facilities may include a building, most of their electricity use is consumed by the unique equipment they house.

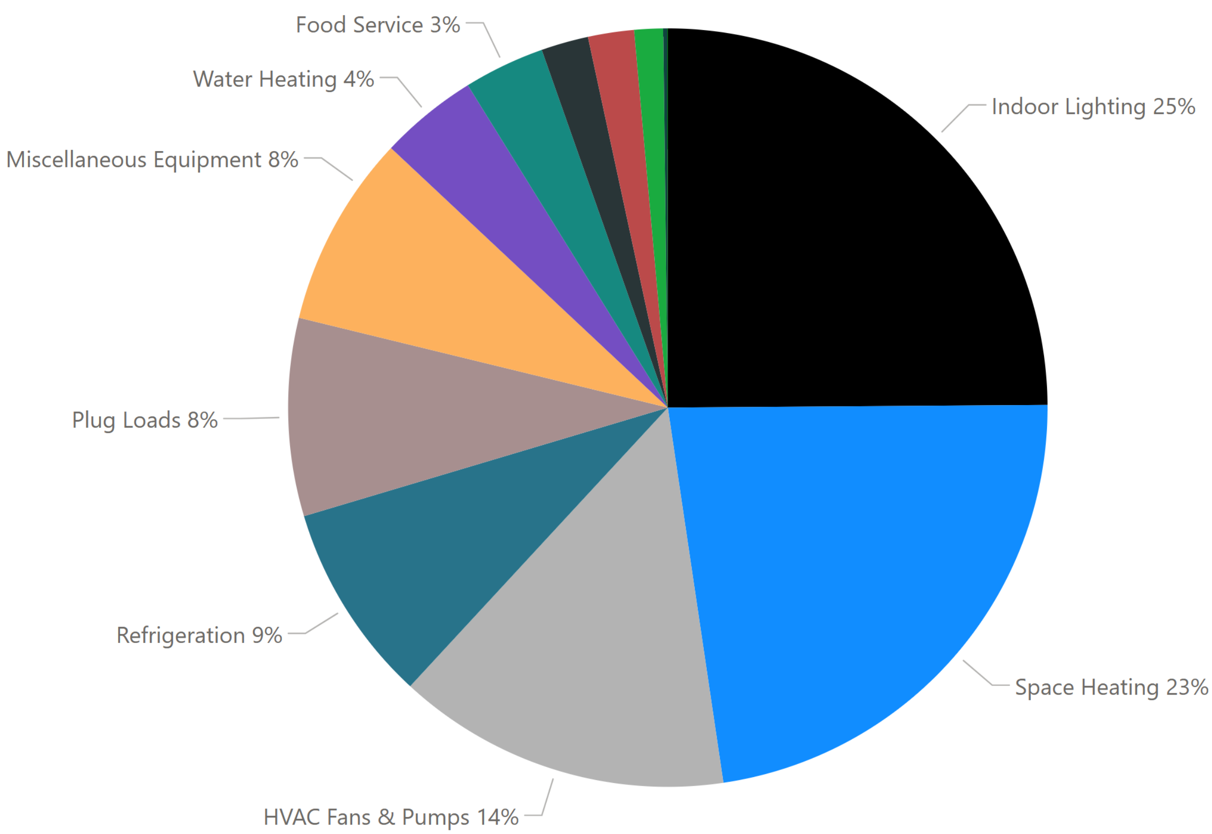
Exhibit 36: Base Year Commercial Customer Accounts by Parent Segment



[45] The street lighting segment is not presented because it includes 11,277 total customer accounts and would skew Exhibit 36. The segments that represent less than 3% of commercial sector accounts are not shown: healthcare (2%), arena (0.3%), and universities and colleges (0.07%).

Exhibit 37 shows commercial sector base year electricity consumption by end use.[46] Space heating and HVAC fans and pumps represent 37% (755 GWh) of total consumption. Indoor lighting, which includes general lighting for the main areas of commercial buildings and secondary lighting for hallways and stairwells, represents 25% (508 GWh) of total consumption.

Exhibit 37: Base Year Commercial Consumption by End Use



[46] The end uses that contribute less than 3% of base year consumption in the commercial sector are not shown to improve readability: outdoor lighting (2%), space cooling (2%), street lighting (1%), BEV charging (0.2%), and PHEV charging (0.02%).

Energy Intensity

Dividing electricity consumption by floor area (in square feet) gives electric energy use intensity. Performing this calculation by segment reveals those with the highest and lowest electric energy use intensities. Base year electricity consumption, floor area, and electric energy intensity for each segment are shown in Exhibit 38. Highlights from this exhibit include:

- In the base year, food retail buildings have the highest electric energy use intensity (54.7 kWh/sq-ft), driven by their refrigeration and indoor lighting electricity use.
- Universities and colleges have the lowest base year electric energy use intensity (8.5 kWh/sq-ft). This result is driven by MUN's fossil fuel space heating in the base year. By 2040 however, the intensity increases to 17 kWh/sq-ft, driven by MUN's conversion to electric space heating.

Exhibit 38: Base Year Commercial Energy Intensity by Segment (kWh/sq-ft)[47]

Segment	Consumption (kWh)	Floor Area (sq-ft)	Electric Energy Use Intensity (kWh/sq-ft)
Food Retail	147,836,000	2,703,691	54.7
Restaurant	94,071,000	2,031,764	46.3
Arena	46,968,000	1,510,680	31.1
Healthcare	194,726,000	6,432,780	30.3
Office	438,470,000	16,698,959	26.3
Non-Food Retail	217,644,000	9,335,288	23.3
Accommodation	103,783,000	4,563,713	22.7
Other Buildings	220,142,000	10,646,105	20.7
Schools	165,741,000	14,102,608	11.8
Warehouse	134,613,000	12,964,268	10.4
Universities and Colleges	98,450,000	11,638,208	8.5

[47] Segments with no associated floor area (i.e., EV charging segments, non-buildings, and street lighting) are omitted from this Exhibit.

Base Year Peak Demand

Exhibit 39 shows the base year peak demand by end use for the commercial sector. Observations include:

- Space heating is the largest commercial component (35%) of peak demand. As shown in the previous section, space heating represents 23% of base year electricity consumption. This consumption is concentrated in the winter when the IIS system peaks. The space heating load shape has more dramatic peaks than other end uses because demand is weather dependent.
- Indoor lighting is the second largest commercial component of peak demand (20%). Indoor lighting represents 25% of annual electricity consumption in the base year and is on during the winter peak periods. The annual lighting load shape is "flatter" than the space heating load shape. Usage patterns exhibit daily/hourly variation and some seasonal variation but are more consistent throughout the year because they are not weather dependent.
- HVAC fans and pumps are the third largest commercial component of peak demand (10%). This is expected since fan and pump operation coincide with space heating equipment operation.

Exhibit 39: Base Year Commercial Peak Demand (MW)

End Use	2023 Winter Peak Demand (MW)	2023 % of Winter Peak Demand
Space Heating	145	35%
Indoor Lighting	84	20%
HVAC Fans & Pumps	42	10%
Water Heating	32	8%
Food Service Equipment	26	7%
Plug Loads	26	6%
Miscellaneous Equipment	25	7%
Refrigeration	20	5%
Outdoor Lighting	6	1%
Street Lighting	4	1%
BEV Charging	1	0.24%
PHEV Charging	0.1	0.02%
Space Cooling	0	0%
Total	**411**	**100%**

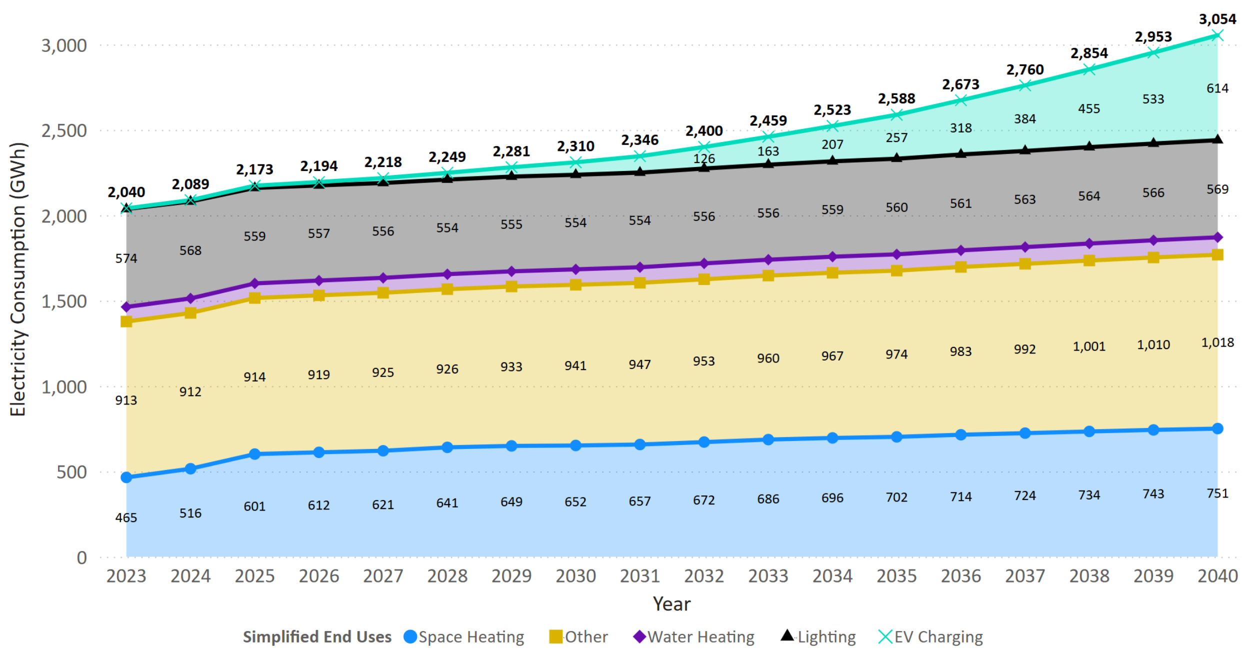
3.3.2 Reference Case Electricity Consumption and Peak Demand

This section profiles the reference case forecast electricity consumption and peak demand for the commercial sector. It begins with commentary on high-level trends, then shows how consumption is forecast to change by segment, end use, and in new versus existing buildings. It ends with a summary of peak demand results.

Commercial Reference Case Consumption Trends

Exhibit 40 shows reference case electricity consumption for the commercial sector. The contributions of space heating, water heating, lighting, and unmanaged EV charging to total consumption (represented by numerical values in bold font) are shown explicitly. The contributions of all other end uses are grouped in "Other" to enhance readability.

Exhibit 40: Reference Case Commercial Consumption Forecast (GWh)



Consumption is expected to increase by 1,014 GWh (50%) over the forecast period. 611 GWh of this increase can be attributed to the adoption of 22,221 EVs in the intermediate scenario. EV charging in the commercial sector includes public and private charging for personal vehicles (all charging that is not done at home) and depot charging for fleet vehicles. The rest of the increase (404 GWh) is explained by the following trends:

- **Space heating electrification**: The number of customer accounts with electric heating are expected to increase while those without electric heating are forecast to decrease.[48] This trend

[48] Customer accounts with electric heating use electricity as their main heating source, accounting for at least 50% of their heating, while customer accounts without electric heating use less than 50% electricity for heating.

reflects a shift towards electric space heating resulting in an overall increase in electricity consumption.[49]

- **An increase in electric energy use intensity in both new and existing buildings**: New buildings are assumed to have more efficient equipment, particularly for lighting and space heating, which leads to reductions in electricity use. However, new buildings are also assumed to have higher penetration of electric space and water heating equipment. This leads to a net increase in electricity use. Over the forecast period, existing buildings also experience a transition towards electric space and water heating, which replace fossil-fired equipment when it reaches end of life.
- **An increase in commercial customer accounts and floor space:** However, at just 6% over the forecast period (excluding street lighting customer accounts), this isn't as significant of a driver as the increased electricity use intensity.

[49] Memorial University of Newfoundland and Labrador's conversion to electric heat is one of the major factors driving the increase in space heating consumption.

Consumption by Segment

Exhibit 41 shows the forecast increase in electricity consumption by segment for the commercial sector. The largest increase in consumption is forecast in the EV charging segments (31,506% and 7,043% for fleet and personal EV charging, respectively) followed by Universities and Colleges (125%) and Restaurants (24%).

Exhibit 41: 2023 vs 2040 Commercial Consumption Forecast (GWh) by Parent Segment

Parent Segment	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption (%)
Fleet Depot Charging	0.4	435	434	31,506%
Personal EV Charging[50]	3.5	179	177	7,043%
University and Colleges	98	221	123	125%
Restaurants	94	117	23	24%
Office	438	541	103	23%
Schools	166	193	27	17%
Accommodation	104	120	16	15%
Warehouse	135	154	19	15%
Non-Food Retail	218	248	30	14%
Food Retail	148	166	18	12%
Other Buildings	220	246	26	12%
Healthcare	195	212	17	9%
Non-Building	149	157	8	5%
Arena	47	47	0	1%
Street Lighting	24	18	-7	-30%
Total	**2,040**	**3,054**	**1,014**	**50%**

[50] Commercial sector personal EV charging includes private and public charging away from home. In 2040, personal EV charging away from home represents 32% of total personal LDV electricity consumption in the intermediate scenario, or 179 GWh of 565 GWh.

Consumption by End Use

Exhibit 42 shows the expected increase in electricity consumption by end use, highlighting the space heating electrification trend discussed earlier:

- Other than EV charging, space heating is expected to undergo the largest (62%) increase in electricity consumption. The 286 GWh increase between 2023 and 2040 is driven by the switch to electric heating from fossil fuels.
- The EV charging end uses increase the most over the reference case forecast (19,500% for BEV charging and 6,400% for PHEV charging). The forecast changes in consumption in BEV charging and PHEV charging from 2023 to 2040 are 585 GWh and 26 GWh, respectively.
- Apart from street lighting, the smallest (2 GWh) change in electricity consumption occurs in the indoor and outdoor lighting end uses. Despite expected efficiency gains from conversions to LED lighting, the increase in commercial floor space causes a marginal increase in consumption for these end uses over the forecast period.

Exhibit 42: 2023 vs 2040 Commercial Consumption Forecast (GWh) by Parent End Use

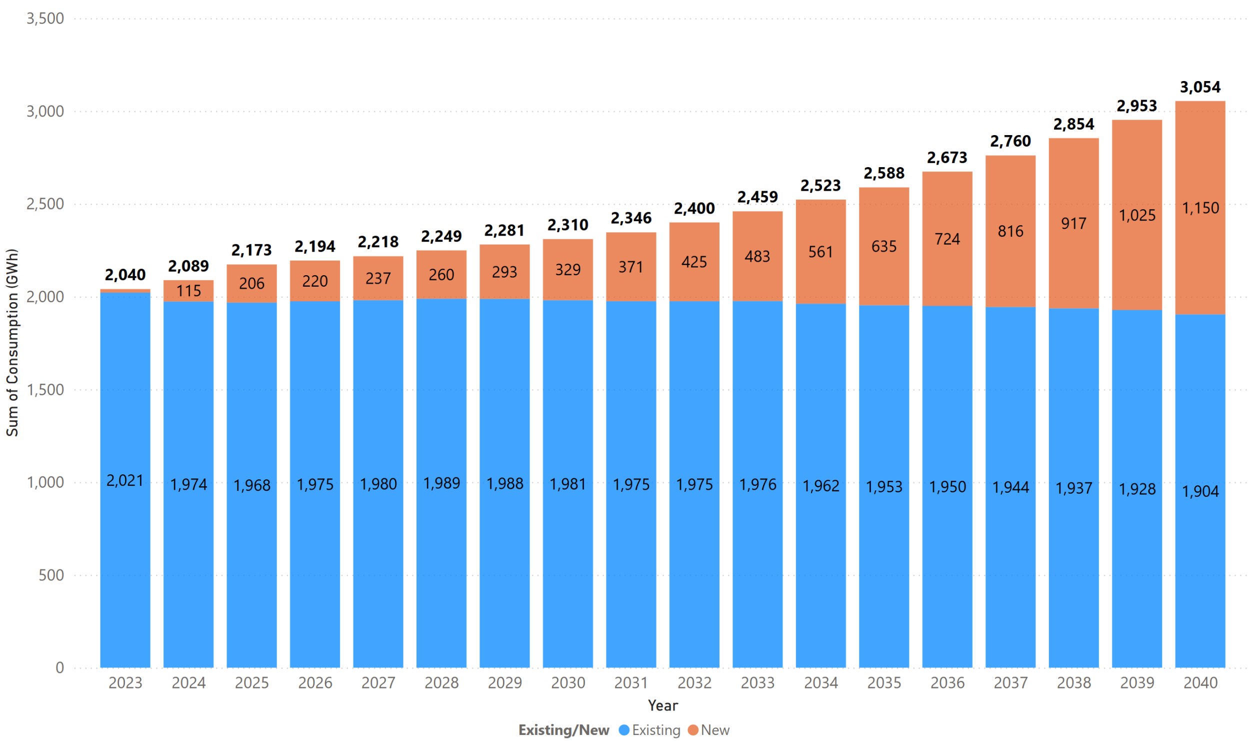
Parent End Use	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption
BEV Charging	3.5	588	585	19,500%
PHEV Charging	0.4	26	25.6	6,400%
Space Heating	465	751[51]	286	62%
Water Heating	85	102	17	20%
Food Service	70	80	10	14%
Plug Loads	172	195	23	13%
Space Cooling	40	45	5	13%
HVAC Fans & Pumps	290	328	38	13%
Refrigeration	174	194	20	11%
Miscellaneous Equipment	167	176	9	5%
Indoor Lighting	508	510	2	0.4%
Outdoor Lighting	41	41	0	0%
Street Lighting	24	18	-7	-28%
Total	**2,040**	**3,054**	**1,014**	**50%**

[51] Space heating electrification at Memorial University of Newfoundland customer accounts for 105 GWh of the increase in commercial sector space heating consumption.

Reference Case Electricity Consumption: Existing versus New Buildings

This section compares the consumption in existing versus new commercial buildings across the reference case forecast. The construction of new buildings is estimated by extrapolating customer forecasts provided by NP and drawing insights from the electricity consumption growth forecasts by rate class. Although no demolition rate is applied, a decrease in customer accounts for a given year implies the removal of existing buildings from the system. This leads to a decreasing stock of existing building over the reference case forecast period. Consequently, electricity consumption from existing buildings decreases, while consumption from new buildings, as well as the introduction and growth of EV charging, drives the 1,014 GWh overall increase in electricity consumption, as shown in Exhibit 43.

Exhibit 43: Existing vs New Building Commercial Consumption Forecast (GWh)



Reference Case Peak Demand

Exhibit 44 shows the reference case peak demand forecast for the commercial sector. Commercial sector winter peak demand is forecast to increase by 257 MW (62%) between 2023 and 2040 under unmanaged EV charging. The factors driving this increase are explained on the next page.

Exhibit 44: Commercial Sector Reference Case Peak Demand (MW)

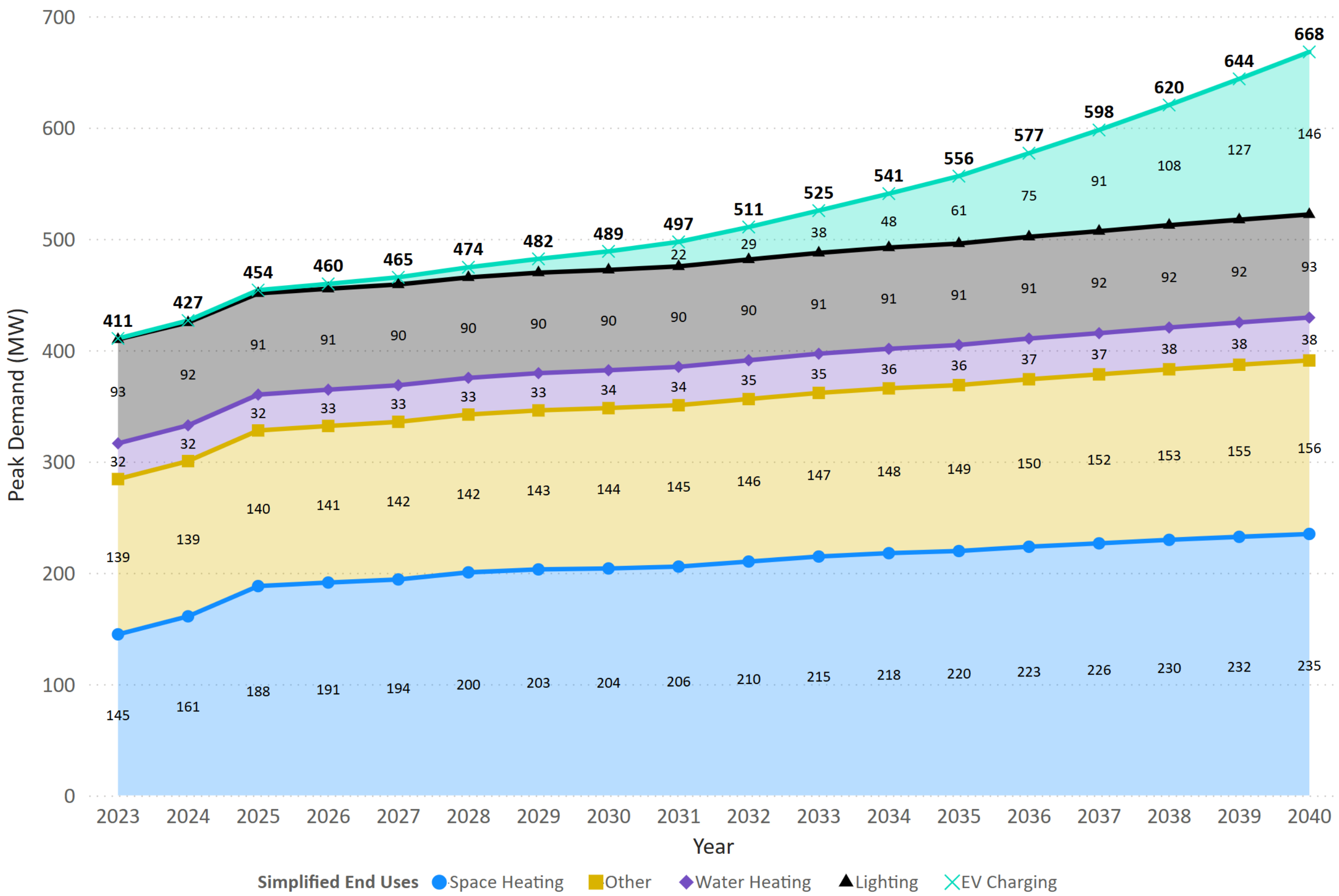


Exhibit 45 shows that commercial sector peak demand increases by 257 MW (62%) between 2023 and 2040, driven by the following factors:

- The adoption of 22,221 fleet EVs in the intermediate scenario. The peak demand from BEV charging and PHEV charging increase by 140 MW and 4.9 MW, respectively.
- The 90 MW increase in space heating peak demand MW caused by the switch to electric heating from fossil fuel heating.

Exhibit 45: Commercial Sector Reference Case Peak Demand by End Use (MW)

End Use	2023 Winter Peak Demand (MW)	2040 Winter Peak Demand (MW)	Change in Peak Demand (MW)	Change in Peak Demand (%)
BEV Charging	1	141	140	14,000%
PHEV Charging	0.1	5	4.9	4,900%
Space Heating	145	235	90	62%
Water Heating	32	38	6	19%
Food Service	26	30	4	15%
Refrigeration	20	23	3	15%
HVAC Fans & Pumps	42	47	5	12%
Plug Loads	26	29	3	12%
Miscellaneous Equipment	25	27	2	8%
Indoor Lighting	84	85	0.4	1%
Outdoor Lighting	6	6	0	0%
Street Lighting	4	2	-2	-50%
Space Cooling	0	0	0	N/A
Total	**411**	**668**	**257**	**62%**

3.4 Industrial Sector Base Year and Reference Case

This section presents industrial sector results for the base year (2023) and reference case (2024-2040), excluding any self-generation. The industrial sector includes NLH's six large industrial customers and both Utilities' large customers in the general service rate class.

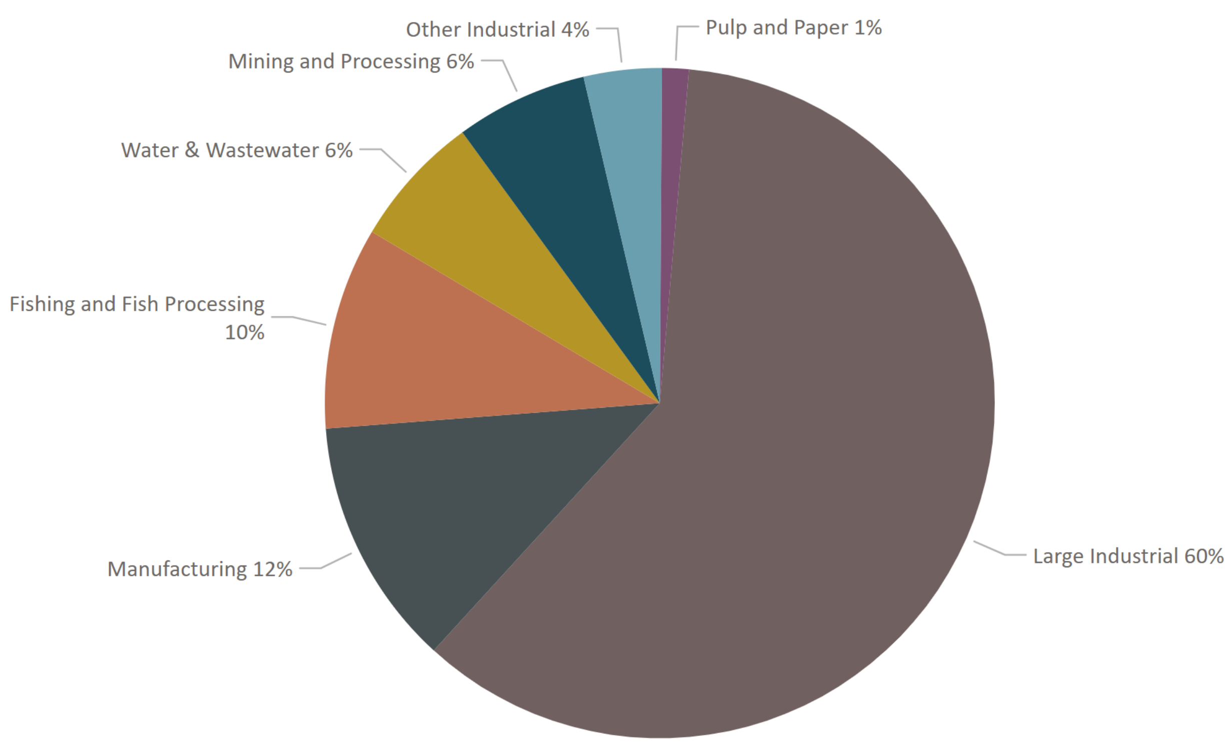
3.4.1 Base Year Electricity Consumption and Peak Demand

This section profiles the base year electricity consumption, customer accounts breakdown, and peak demand for the industrial sector.

Consumption by Segment, Customer Accounts, and End Use

Base year consumption in the industrial sector is 1,023 GWh. Exhibit 46 shows that the large industrial segment, which includes only NLH's six large industrial customers, consumes most (618 GWh, 60%) of the sector's electricity. Consumption in the industrial sector is not driven by the distribution of customer accounts. The water and wastewater segment represents 33% of industrial sector customer accounts (see Exhibit 47), for example, but only 6% of base year consumption.

Exhibit 46: Base Year Industrial Consumption by Parent Segment



There are 3,828 base year customer accounts in the industrial sector. These customer accounts are presented by segment in Exhibit 47. As shown, the largest number of customer accounts is in the water and wastewater (32.9%), manufacturing (29.0%) and other industrial (16.8%) segments.

Exhibit 47: Base Year Industrial Customer Accounts by Parent Segment

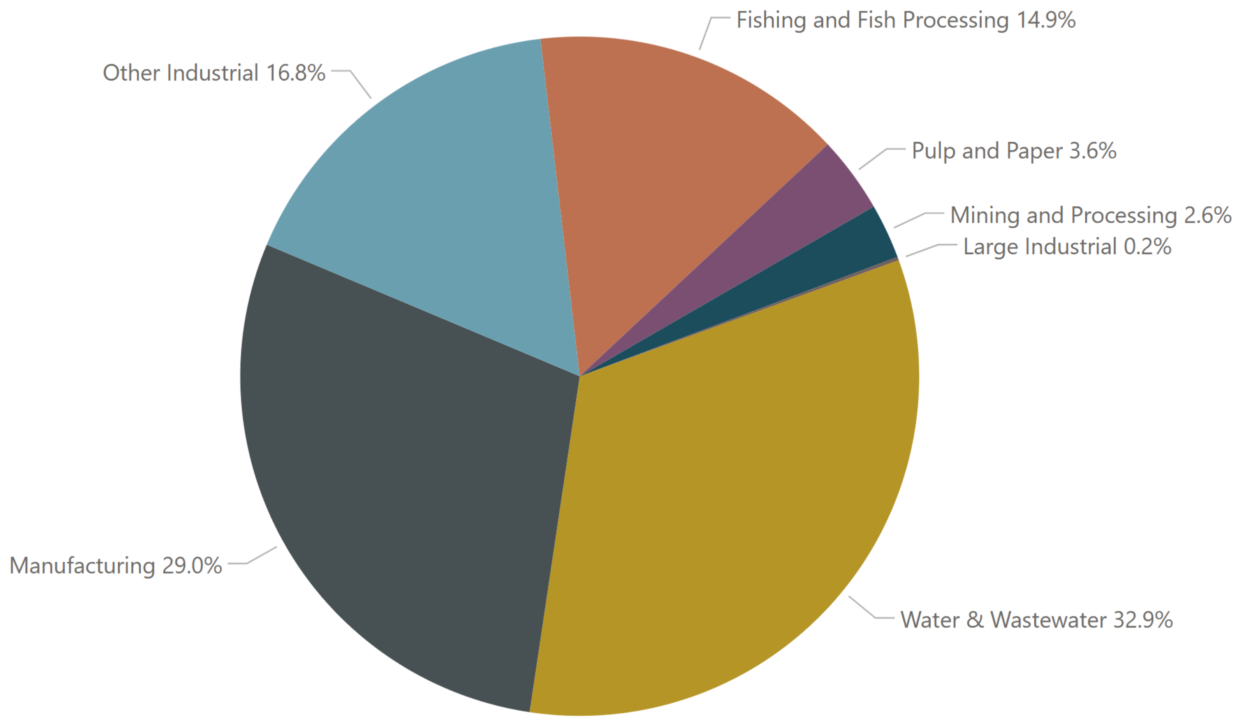
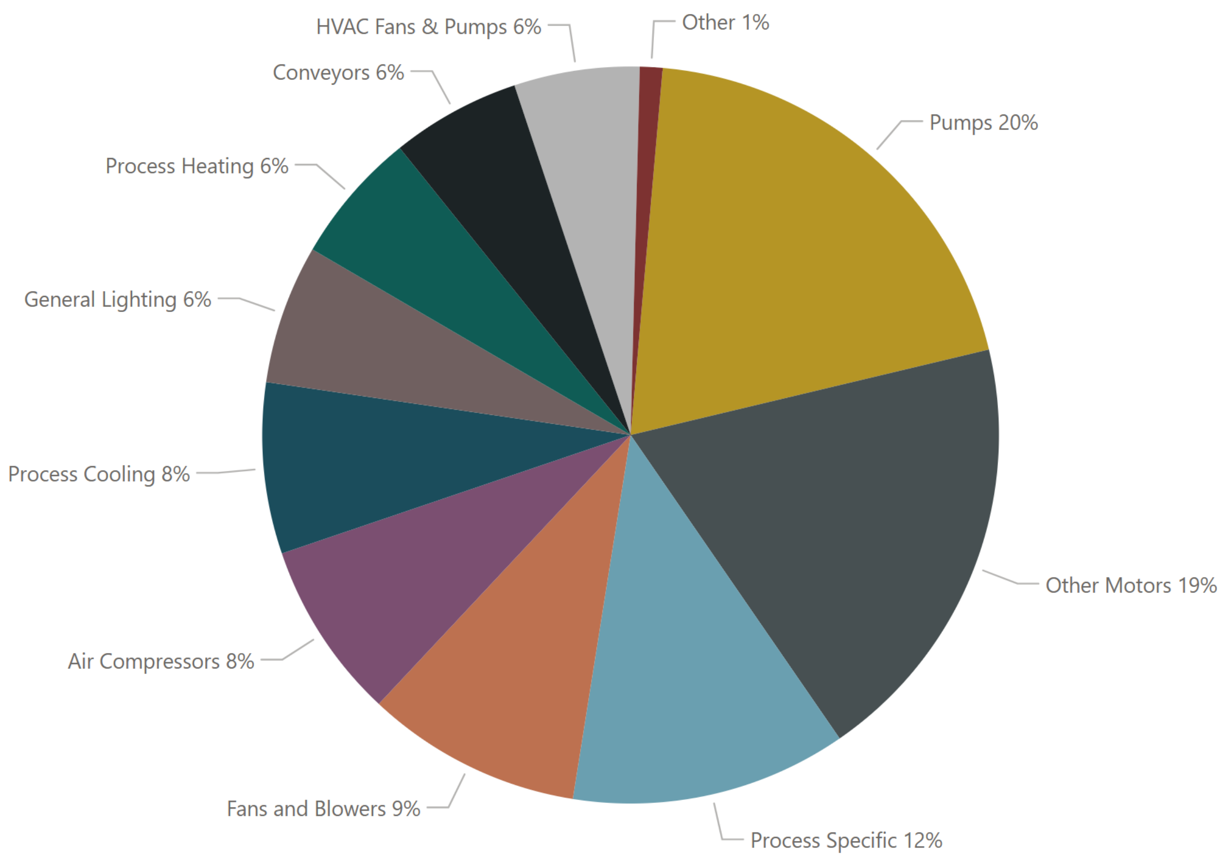


Exhibit 48 shows industrial sector base year consumption by end use. Pumps use the most electricity (203 GWh, 20%), closely followed by other motors (196 GWh, 19%) and process specific end uses (124 GWh, 12%).

Exhibit 48: Base Year Industrial Consumption by End Use



Consumption per Customer Account

Dividing consumption by the number of customer accounts gives the average electricity consumption per customer account. Exhibit 49 shows total base year consumption, customer accounts, and average electricity consumption per customer account for the industrial sector. Highlights from this exhibit include:

- The large industrial segment consumes the most electricity per customer account on average (102,968 MWh/customer account), followed by mining and processing (652 MWh/customer account) and fishing and fish processing (175 MWh/customer account).
- The water and wastewater end use consumes the least electricity per customer account on average (52 MWh/account).

Exhibit 49: Base Year Industrial Energy Intensity by Parent Segment

Segment	2023 Consumption (MWh)	2023 Customer Accounts	2023 Average Consumption per Customer Account (MWh/Customer Account)
Large Industrial	617,810	6	102,968
Mining and Processing	65,183	100	652
Fishing and Fish Processing	99,740	570	175
Manufacturing	122,727	1,109	111
Pulp and Paper	13,177	139	95
Other Industrial	38,460	644	60
Water & Wastewater	65,744	1,260	52
Total	**1,022,841**	**3,828**	**267**

Base Year Peak Demand

Exhibit 50 shows the peak demand by end use for the industrial sector in the base year. Observations include:

- Pumps is the largest industrial component of peak demand. As shown in the previous section, pumps represent 20% of base year electricity consumption.
- Process specific and other motors are the second and third largest industrial components of peak demand.

Exhibit 50: Base Year Industrial Peak Demand (MW)

End Use	2023 Winter Peak Demand (MW)	2023 % of Winter Peak Demand
Pumps	25	20%
Process Specific	20	16%
Other Motors	19	16%
HVAC Fans & Pumps	10	8%
Fans and Blowers	9	7%
Process Heating	9	7%
Air Compressors	8	7%
General Lighting	7	6%
Process Cooling	7	6%
Conveyors	6	5%
Other	2	2%
Hydrogen	0	0%
Total	**122**	**100%**

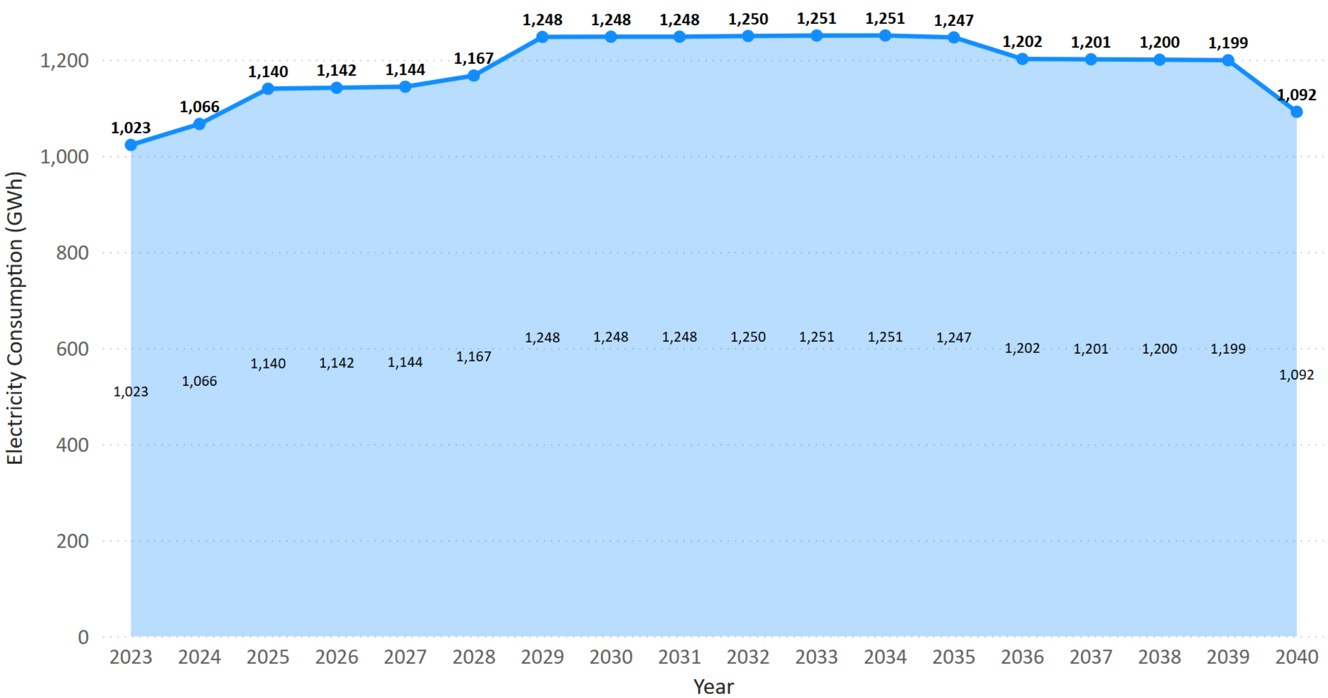
3.4.2 Reference Case Electricity Consumption and Peak Demand

This section profiles the reference case forecast (2024 – 2040) electricity consumption and peak demand for the industrial sector. It begins with commentary on high-level trends, then shows how consumption is forecast to change by segment, end use, and in new versus existing buildings or production. It ends with a summary of peak demand results.

Industrial Reference Case Consumption Trends

Exhibit 51 shows that industrial sector electricity consumption is expected to increase by 69 GWh (6%) between 2023 and 2040. Exhibit 51 also shows that industrial sector consumption is forecast to increase initially, then remain steady between 2029 and 2035 before a decline starting in 2036.

Exhibit 51: Reference Case Industrial Consumption Forecast (GWh)



The reference case trends are due to the following factors:

- **Changes in large industrial production**: The initial increase and subsequent decline of industrial electricity consumption is primarily due to forecast changes in production for the large industrial customers, consistent with NLH's forecast. As shown in section 3.4.1, large industrial customers account for 60% of industrial sector consumption.
- **An increase in industrial customer accounts**: The number of small and medium industrial customers increases by approximately 3% during the forecast period.

Consumption by Segment

Exhibit 52 shows the increase in electricity consumption by segment over the forecast period. The pulp and paper, manufacturing and other industrial segments see largest percent increases in consumption (15%, 11%, and 11%, respectively). These increases are driven by an increase in electric space heating consumption in those segments over the reference case, consistent with NLH's forecast.

Exhibit 52: 2023 vs 2040 Industrial Consumption Forecast (GWh) by Parent Segment

Parent Segment	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption (%)
Pulp and Paper	13	15	2	15%
Manufacturing	123	137	14	11%
Other Industrial	38	42	4	11%
Large Industrial	618	678	60	10%
Water & Wastewater	66	65	-1	-2%
Fishing and Fish Processing	100	96	-4	-4%
Mining and Processing	65	59	-6	-9%
Total	**1,023**	**1,092**	**69**	**7%**

Consumption by End Use

Exhibit 53 shows the increase in electricity consumption by end use over the forecast period. Excluding hydrogen production, the largest percentage increases occur in the general lighting, HVAC fans and pumps, and other motors end uses (5%, 4% and 4%, respectively). The increase in HVAC fans and pumps consumption is consistent with the increase in electric space heating consumption forecast by NLH in the pulp and paper, manufacturing, and other industrial segments, as noted previously.

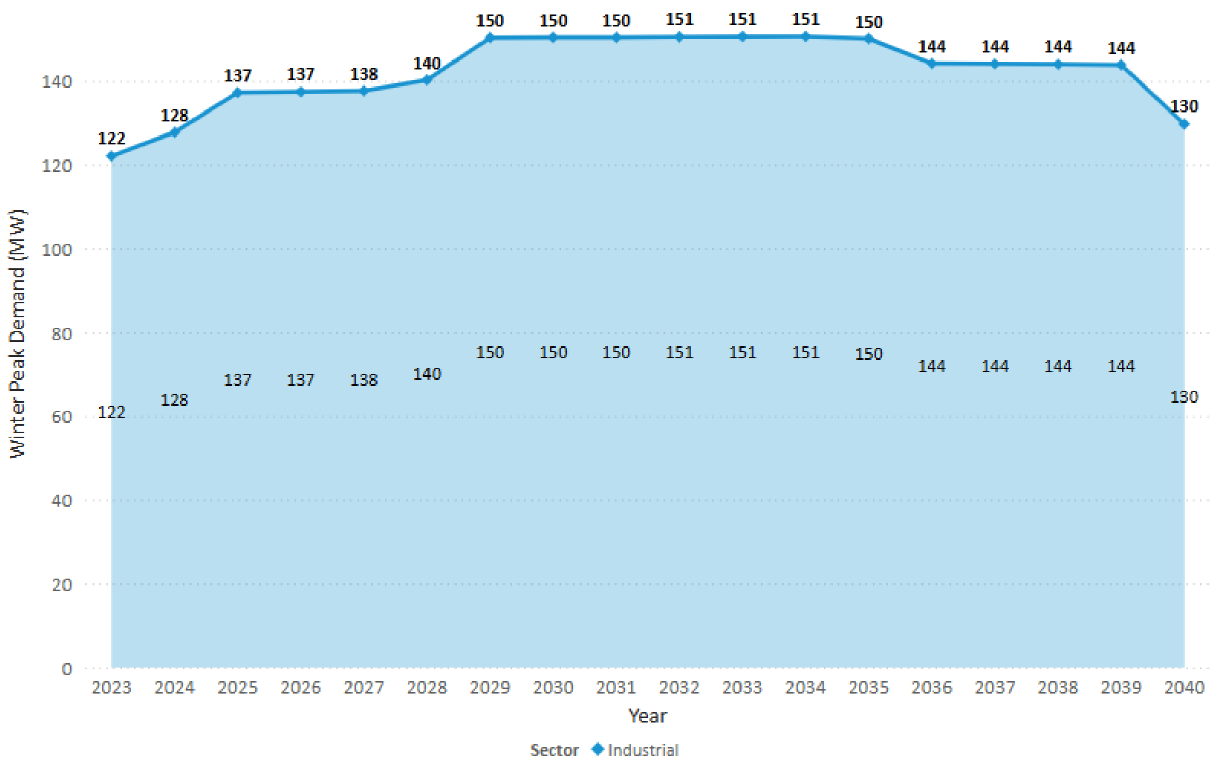
Exhibit 53: 2023 vs 2040 Industrial Consumption Forecast (GWh) by Parent End Use

Parent End Use	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption (%)
Hydrogen Production	0	49	49	--
General Lighting	62	65	3	5%
HVAC Fans & Pumps	56	58	2	4%
Other Motors	196	203	7	4%
Fans and Blowers	97	99	2	2%
Pumps	203	207	4	2%
Conveyors	58	59	1	2%
Air Compressors	80	81	1	1%
Process Specific	124	125	1	1%
Other	10	10	0	0%
Process Heating	60	60	0	0%
Process Cooling	77	76	-1	-1%
Total	**1,023**	**1,092**	**69**	**7%**

Reference Case Peak Demand

Exhibit 54 shows the reference case peak demand forecast for the industrial sector.

Exhibit 54: Industrial Sector Reference Case Peak Demand (MW)



Winter peak demand is forecast to increase by 8 MW (7%) between 2023 and 2040. Peak demand is greatest from 2032 to 2034 (151 MW), which represents an increase of 29 MW (24%) compared to 2023 (122 MW). The variations in peak demand correspond to the variations in total electricity consumption because peak demand scales proportionally with consumption. As noted in the observations on Exhibit 51, the increases and decreases in peak demand correspond to NLH's forecast for changes in industrial sector production.

3.5 Transportation Base Year and Forecast Scenarios

This section presents the transportation sector results and key findings, including:

- Base year (2023) stock, electricity consumption and peak demand,
- Forecast sales share, vehicle stock, electricity consumption, and peak demand for the intermediate scenario (2024-2040), and
- A comparison of forecast vehicle stock, electricity consumption and peak demand for the natural adoption, intermediate, and government targets scenarios (2024-2040).

The forecast EV scenarios are defined in the callout that follows.[52,53]

Forecast EV Scenarios

EVs are an emerging technology and there is uncertainty on future adoption, which is expected to be influenced by government policy among other factors. Newfoundland is still in the early stages of the transition from internal combustion engine (ICE) vehicles to EVs. As such, there is limited Newfoundland-specific data on EV registrations and historical trends. For these reasons, the Study Team modelled three forecast EV scenarios to provide a range of possible futures: natural adoption, intermediate, and government targets. The forecast scenarios are defined as follows:

*1. The **Natural Adoption Scenario** estimates EV adoption based on current incentives. MHDV and bus adoption in this scenario aligns with global forecasts for all countries, recognizing that Newfoundland will lag adoption in leading jurisdictions.*

*2. The **Intermediate Scenario** includes EV uptake beyond the natural adoption scenario, consistent with additional market interventions like vehicle rebates and accelerated build-out of charging infrastructure for LDV, and/or more favorable EV capital cost declines for MDV and HDV.*

*3. In the **Government Targets Scenario**, Federal Government targets for sales shares of LDVs and MHDVs being ZEVs by 2030, 2035, and 2040 are met. In the natural adoption and intermediate scenarios, the Federal Government targets are not met.*

The Utilities could monitor several indicators during the forecast period to determine which scenario may be unfolding. These indicators include how customer survey results on EV purchase intentions evolve over time; the extent to which vehicle manufacturers try to achieve government targets evenly in each province versus focused on specific provinces; whether the federal forward regulatory agenda retains government targets after federal elections; and whether studies expect EV price/range parity sooner or later in the analysis horizon. No shift in a single indicator determines a scenario, but collectively, trends in the indicators can reveal how the relative likelihood of each scenario changes over time.

[52] "The 2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy," Government of Canada, Available: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/sector-overview.html#sector6 (Accessed Feb. 24, 2025).

As noted in section 3.1, the Study Team integrated the intermediate EV scenario with the residential and commercial sectors because it is the middle scenario compared to the natural adoption and government targets scenarios, which bookend the EV forecast analysis. All the results presented in this section reflect unmanaged EV charging.[54]

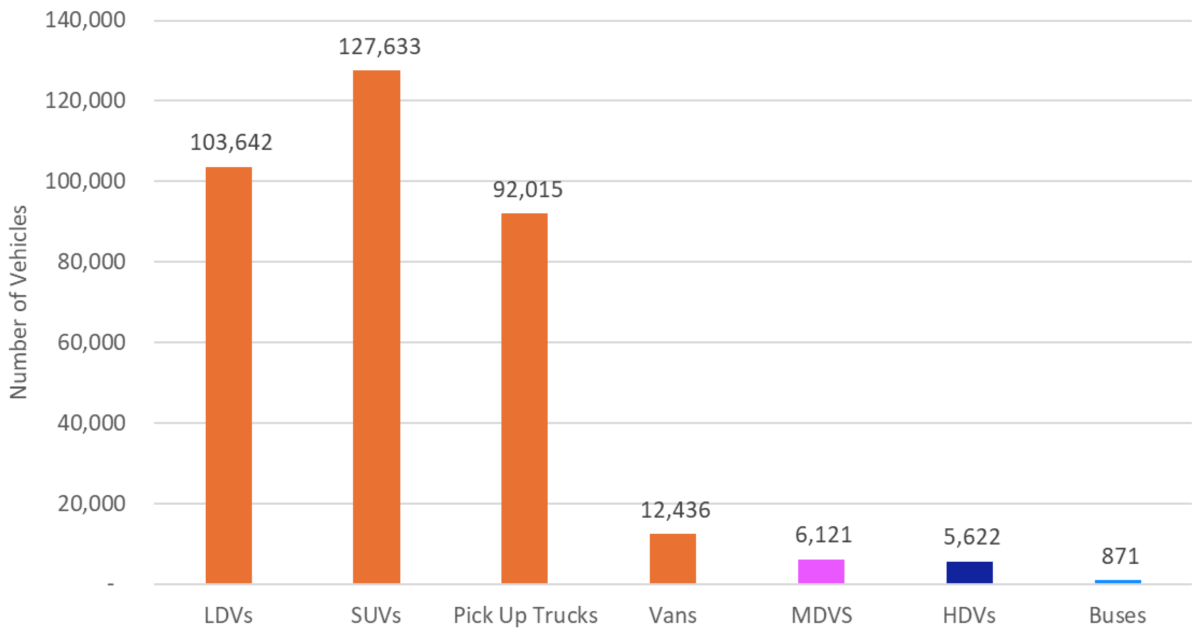
3.5.1 Base Year Stock, Electricity Consumption and Peak Demand

This section profiles the base year stock, electricity consumption, and peak demand for the transportation sector.

Base Year Vehicle Stock

The base year IIS vehicle stock includes approximately 350,000 vehicles. Exhibit 55 shows the stock by vehicle type. In the base year, LDVs make up most of the vehicle stock at 96.4%, while MHDVs and buses make up 3.4% and 0.3%, respectively.

Exhibit 55: Base Year Stock by Vehicle Type



[53] Bloomberg New Energy Finance (BNEF) via Road to zero: Research and industry perspectives on zero-emission commercial vehicles – ScienceDirect, Available: https://www.sciencedirect.com/science/article/pii/S2589004223008283 (Accessed Dec. 19, 2024).

[54] The EV forecast analysis was completed in Q1 and Q2 of 2024. Any headlines on EV manufacturer slowdowns from Q3 2024 onwards are not reflected in the forecast

Exhibit 56 shows the base year stock by vehicle powertrain. Observations include:

- In the base year, internal combustion engine (ICE) vehicles represent 99.5% of total vehicles. BEVs and PHEVs make up only 0.4% and 0.1% of total vehicles, respectively.
- Personal and fleet vehicles represent 86% and 14% of total vehicles, respectively.

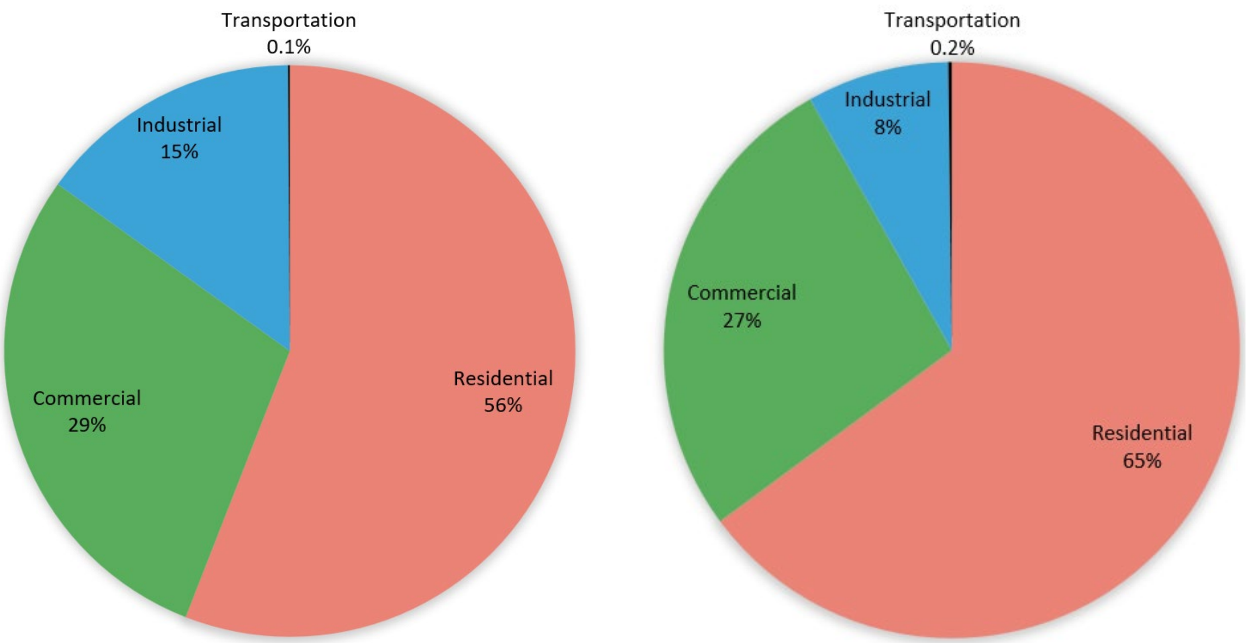
Exhibit 56: Base Year Stock by Powertrain, Ownership Type and Vehicle Type

Powertrain	Total Vehicles	% of Total	% Personal Ownership	% Fleet Ownership
BEV	1,245	0.4%	89%	11%
PHEV	462	0.1%	89%	11%
ICE	346,806	99.5%	86%	14%
Total	**348,513**	**100%**	**86%**	**14%**

Base Year Electricity Consumption and Peak Demand

Exhibit 57 shows the transportation sector contributions to base year electricity consumption and peak demand. In the base year, the transportation sector represents 0.1% (10 GWh) of total IIS consumption and 0.2% of total IIS peak demand. As shown in the previous section, there are less than 2,000 EVs in Newfoundland in the base year, the majority of which are LDVs with smaller batteries and shorter ranges compared to MHDVs and buses.

Exhibit 57: Base Year Consumption and Peak Demand by Sector



2023 Consumption: 6,984 GWh **2023 Peak Demand: 1,542 MW**

3.5.2 Intermediate Scenario Forecast Sales Share, Consumption, and Peak Demand

This section presents the forecast sales share, electricity consumption and peak demand for the intermediate scenario. As explained previously, the intermediate scenario is characterized by EV uptake beyond the natural adoption scenario, consistent with additional market interventions like vehicle rebates and accelerated build-out of charging infrastructure for LDVs.

The Study Team integrated the intermediate EV scenario with the residential and commercial sectors because it is the middle scenario compared to the natural adoption and government targets scenarios, which bookend the EV forecast analysis.

Forecast Sales Share

EV forecasts are often presented as a percentage of annual vehicles sales. This allows for comparison to adoption in other jurisdictions and measurement against targets, like the federal government's mandates for ZEV sales. The rest of this section shows the forecast sales share for LDVs, and MHDVs and buses.

The sales share forecast for BEVs and PHEVs is informed, in part, by the following results from NP's 2023 REUS:

- REUS respondents reported modest interest in adopting a BEV or PHEV in the next two years (2024 and 2025).[55] They cited high costs and lack of charging infrastructure as barriers to adoption.
- REUS respondents reported growing interest in BEVs over the forecast period. In contrast, REUS results suggest that respondents' interest in PHEVs will plateau over the forecast period.

These REUS results suggest the EV market will shift towards BEVs in Newfoundland, as ownership costs decrease and confidence in charging infrastructure increases. These findings align with trends from global studies.[56]

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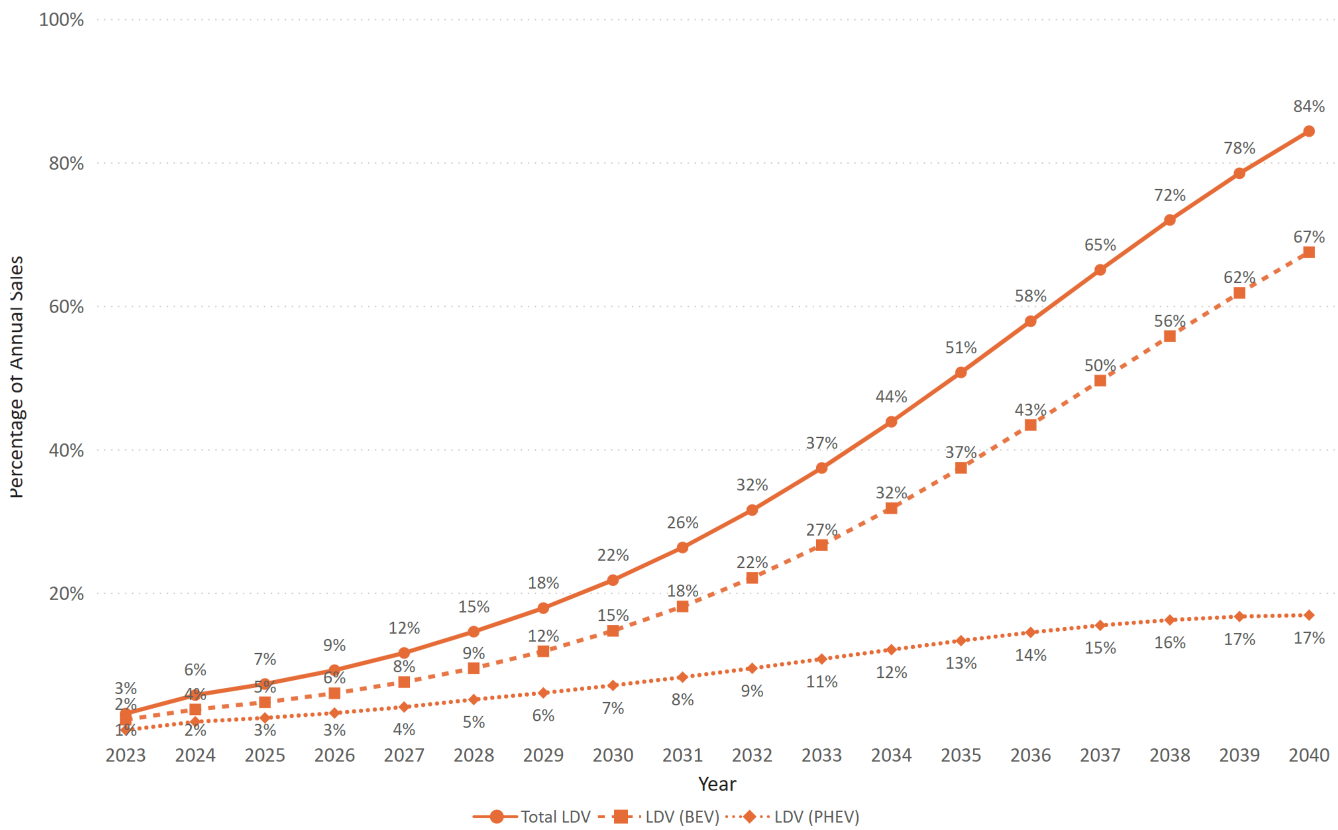
[55] The natural adoption forecast for LDV BEV falls within the range of global forecasts the Study Team compared to.
[56] "Global EV Outlook 2023," IEA, Available: https://www.iea.org/reports/global-ev-outlook-2023 (Accessed Jul. 29, 2024).

Exhibit 58 shows the sales share forecast for LDVs in the intermediate scenario, based on insights from the REUS cited previously, historical EV uptake, and comparisons to jurisdictions ahead of Newfoundland in EV adoption. Observations include:

- In the base year, BEVs and PHEVs represent 2% and 1% of sales, respectively.
- The total share of BEVs and PHEVs is forecast to reach 84% of LDV sales by 2035, which falls short of the government targets scenario goal of 100%.[57] Of the 84% sales share, BEVs are forecast to reach 67% of sales, while PHEVs are forecast to reach 17%.

Exhibit 58: Intermediate Scenario Forecast Sales Share of LDVs (%)

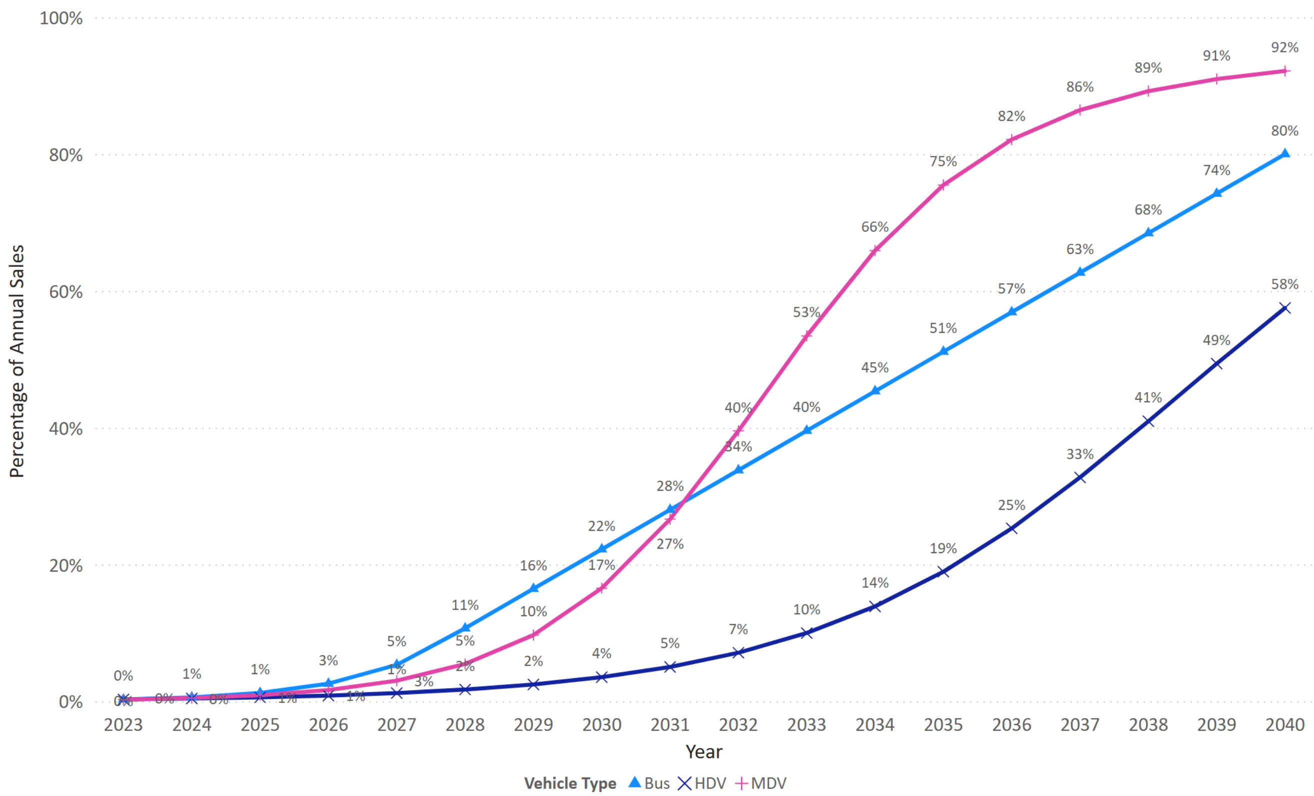


57 See the callout in section 3.5 for definitions of the forecast EV scenarios.

Exhibit 59 shows the forecast sales share of electric MHDVs and buses for the intermediate scenario. Since the maturity in electric vehicle technology for MHDVs (and buses to a lesser extent) lags behind LDVs, the expected sales share for these three vehicle types is very low (all less than 1%) in the base year and the first few years of the forecast.

However, because MHDVs and buses will typically be operated in fleets, the Total Cost of Ownership (TCO) is a good predictor of long-run market share for new technologies. Additionally, fleet vehicles will largely rely on their own depot charging rather than public infrastructure, further emphasizing that TCO will drive vehicle adoption.

Exhibit 59: Intermediate Scenario Forecast Sales Share of MHDVs and Buses (%)



The sales shares for electric MDVs and HDVs are forecast to increase substantially starting in 2030 and 2035, respectively. This timing aligns with their expected TCO break-even point with medium and heavy-duty ICE vehicles.[58] After becoming economically competitive, the sales shares of electric MDVs and HDVs are forecast to reach 92% and 58% by 2040, respectively.

[58] "Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis," National Renewable Energy Laboratory, Available: https://www.nrel.gov/docs/fy22osti/82081.pdf (Accessed Jul. 29, 2024).

Battery electric buses are a more mature technology compared to electric MHDVs, highlighted by the earliest initial increase in annual sales share. However, uptake is forecast to increase at a slower, linear rate due to:

- Long lead times for electric buses, specifically for transit agencies, and
- No immediate plans to adopt a significant number of fully electric buses in Newfoundland.

By 2040, the sales share of electric buses is forecast to reach 80%, aligning with global forecasts.[59]

[59] Bloomberg New Energy Finance (BNEF) via Road to zero: Research and industry perspectives on zero-emission commercial vehicles – ScienceDirect, Available: https://www.sciencedirect.com/science/article/pii/S2589004223008283 (Accessed Dec 19, 2024).

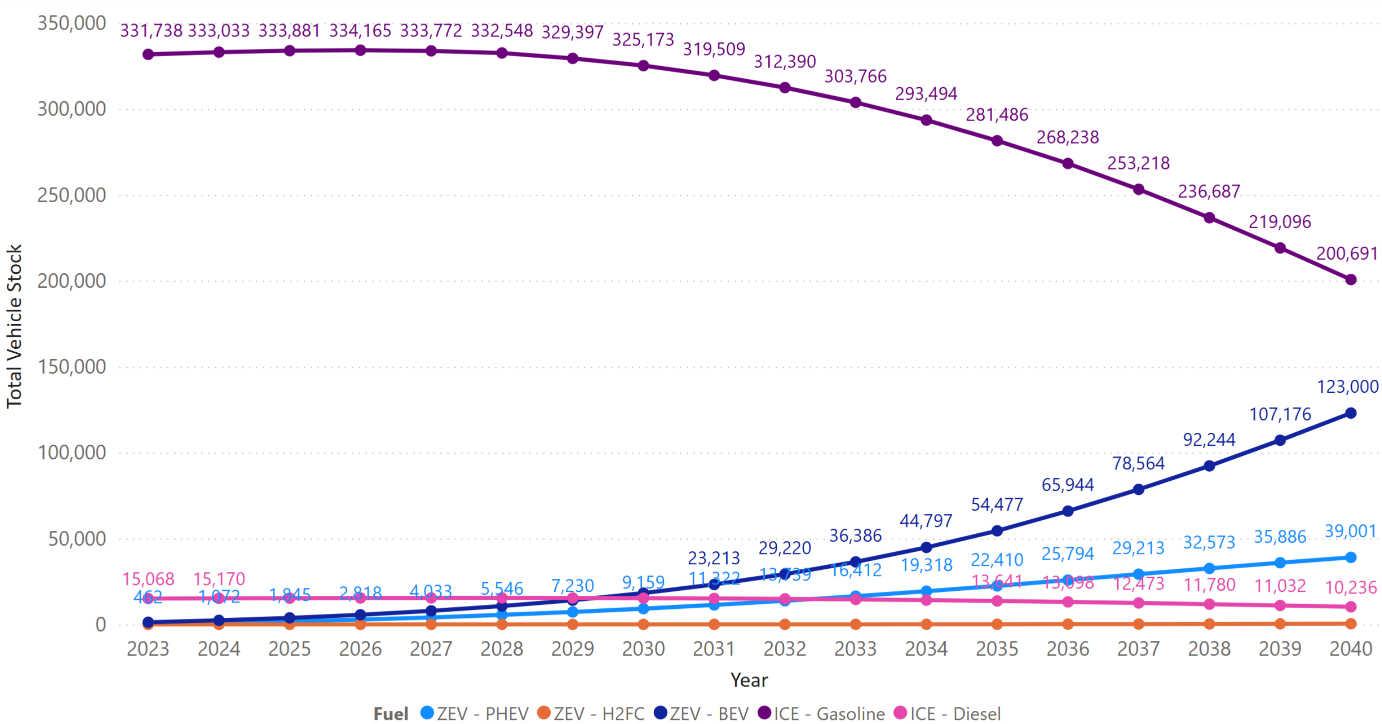
Forecast Vehicle Stock

As annual vehicle sales increase, the EV stock also increases as internal combustion engine vehicles (ICEVs) naturally reach end of life and are replaced by EVs. This results in EVs comprising an increasing percentage of the total vehicle stock in Newfoundland throughout the forecast, culminating in a 43% of the total vehicle stock share by 2040 (33% for BEVs and 10% for PHEVs).

Exhibit 60 shows the forecast vehicle stock by fuel for the intermediate scenario, including all vehicle types. Observations include:

- The total EV stock is forecast to be 123,000 BEVs and 39,001 PHEVs (162,001 total EVs) by 2040.
- The EV stock is forecast to be 18,217 BEVs and 9,159 PHEVs (27,376 total EVs) by 2030. This signifies that that majority of EV uptake occurs in the 2030s.
- ICE vehicles are forecast to decrease from almost 350,000 vehicles in 2023 to approximately 210,000 vehicles by 2040. Their share of the market is reduced from virtually 100% to 57%.

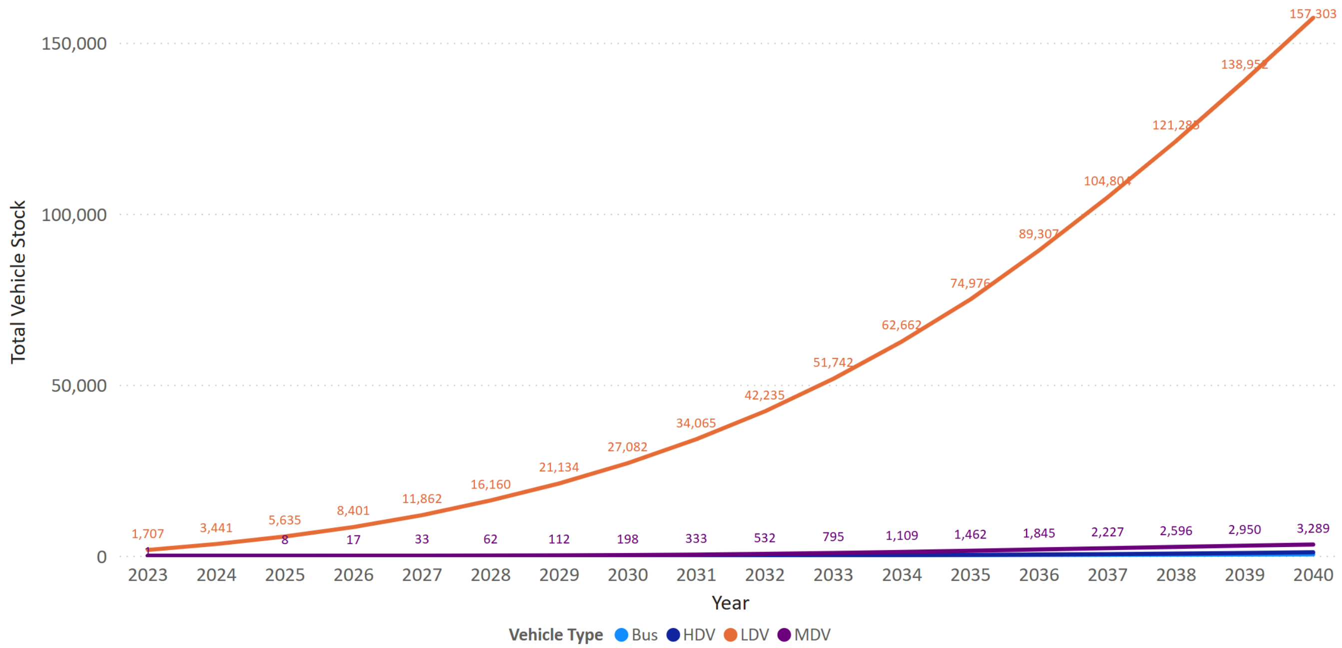
Exhibit 60: Intermediate Scenario Forecast Total Vehicle Stock by Fuel



Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ICE - Diesel	15,068	15,170	15,262	15,341	15,391	15,420	15,364	15,271	15,100	14,853	14,524	14,126	13,641	13,098	12,473	11,780	11,032	10,236
ICE - Gasoline	331,738	333,033	333,881	334,165	333,772	332,548	329,397	325,173	319,509	312,390	303,766	293,494	281,486	268,238	253,218	236,687	219,096	200,691
ZEV - BEV	1,247	2,376	3,805	5,613	7,885	10,717	14,081	18,217	23,213	29,220	36,386	44,797	54,477	65,944	78,564	92,244	107,176	123,000
ZEV - H2FC	0	0	0	1	2	4	6	10	16	27	43	62	94	136	190	253	325	407
ZEV - PHEV	462	1,072	1,845	2,818	4,033	5,546	7,230	9,159	11,322	13,739	16,412	19,318	22,410	25,794	29,213	32,573	35,886	39,001
Total	**348,515**	**351,651**	**354,793**	**357,938**	**361,083**	**364,235**	**366,078**	**367,830**	**369,160**	**370,229**	**371,131**	**371,797**	**372,108**	**373,210**	**373,658**	**373,537**	**373,515**	**373,335**

As highlighted in Exhibit 61, the vast majority of EVs in Newfoundland are expected to be LDVs. By 2040, 157,303 electric LDVs are forecast to be on the road. In contrast, MDVs, HDVs and buses are forecast to reach 3,289, 1,015 and 394 electric vehicles, respectively.

Exhibit 61: Intermediate Scenario Forecast Electric Vehicle Stock by Vehicle Type

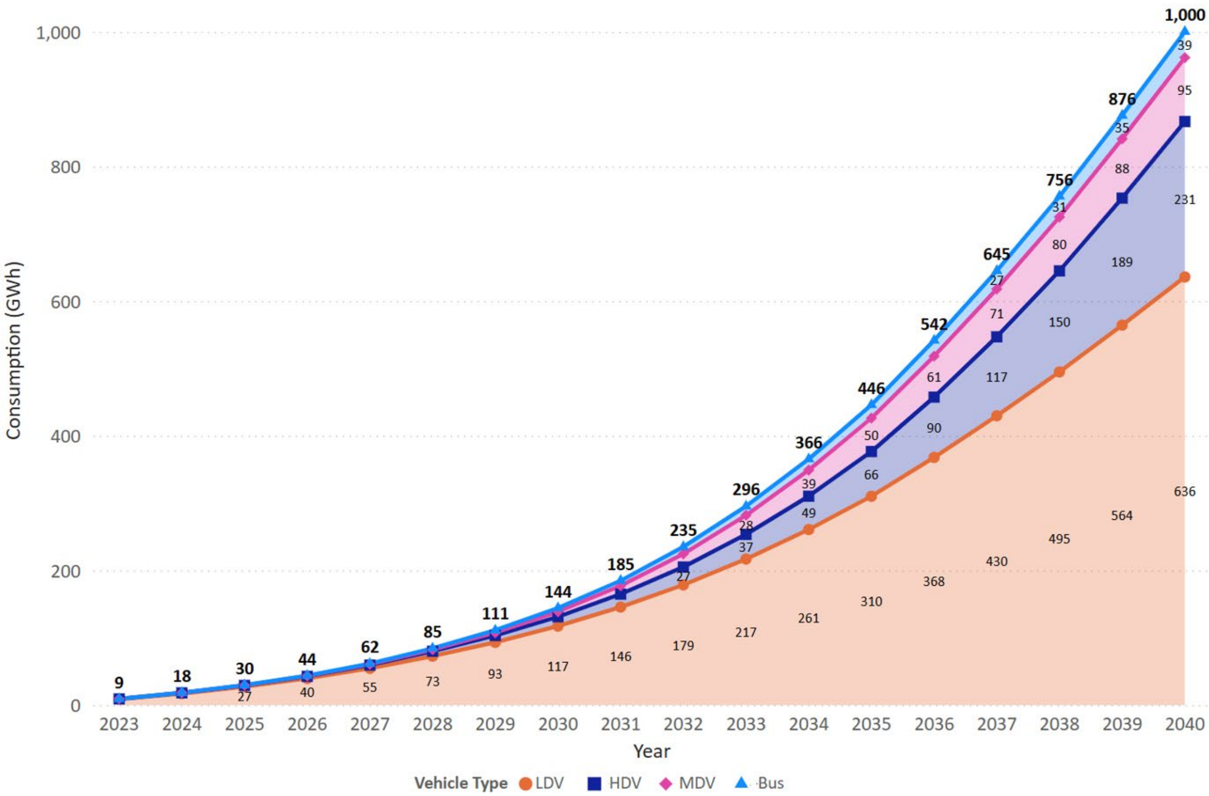


Vehicle Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Bus	0	0	1	3	7	16	29	45	65	91	119	149	183	222	261	303	348	394
HDV	1	3	6	10	16	25	36	51	72	101	142	195	266	364	485	633	812	1,015
LDV	1,707	3,441	5,635	8,401	11,862	16,160	21,134	27,082	34,065	42,235	51,742	62,662	74,976	89,307	104,804	121,285	138,952	157,303
MDV	1	4	8	17	33	62	112	198	333	532	795	1,109	1,462	1,845	2,227	2,596	2,950	3,289
Total	**1,709**	**3,448**	**5,650**	**8,431**	**11,918**	**16,263**	**21,311**	**27,376**	**34,535**	**42,959**	**52,798**	**64,115**	**76,887**	**91,738**	**107,777**	**124,817**	**143,062**	**162,001**

Forecast Electricity Consumption

Exhibit 62 shows forecast electricity consumption for the intermediate scenario by vehicle type. Total consumption is forecast to increase to approximately 1,000 GWh by 2040, which is roughly equivalent to forecast industrial sector consumption in 2040 (1,092 GWh).

Exhibit 62: Intermediate Scenario Forecast Electricity Consumption (GWh)



This growth is driven by two trends:

Trend 1: Increased Sales Share of Electric LDVs

Forecast electricity consumption is driven by consumption from electric LDVs, which are expected to reach approximately 85% sales share by 2040. LDVs also make up most of the total vehicle stock in Newfoundland (96%).

In 2030, LDV charging is forecast at 117 GWh, or 80% of total transportation sector consumption. LDV consumption is expected to increase more than five-fold over ten years, reaching 636 GWh in 2040. This growth is partly driven by BEVs, which dominate the LDV market over the forecast period because their larger batteries consume more electricity compared to PHEVs.

LDVs still make up most (64%) of transportation sector consumption in 2040. However, this represents a decrease in their contribution to the total compared to 2030, caused by the adoption of MHDVs in the last ten years of the forecast.

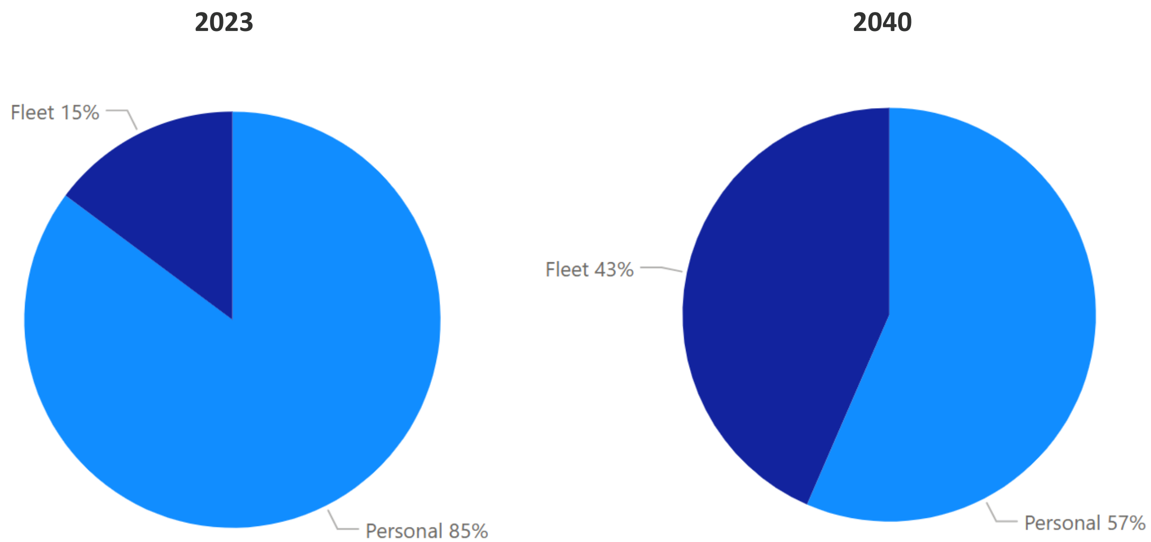
Trend 2: Growth in Fleet MHDVs and Buses

The growth of MHDVs and buses is driven by adoption from companies and fleet owners. In the base year, LDV technology maturity exceeds that of MHDVs and buses. It follows that fleet vehicles contribute modestly (1.4 GWh, 15%) to total EV consumption, as shown in Exhibit 63.[60]

Exhibit 63 shows that by 2040 however, fleet vehicles are forecast to represent 43% (435 GWh) of transportation sector consumption in the intermediate scenario. The causes of this increase include:

- **Economic feasibility**: As mentioned previously, TCO is the main driver of EV adoption in fleets. When electric MHDV and bus technologies become economically feasible in the second half of the forecast period, their contribution to total electricity consumption also increases.
- **Longer driving distances and higher energy intensities compared to personal vehicles**: Fleet vehicles are outnumbered by personal vehicles by a factor of just over six to one. Despite this, fleet vehicles travel farther annually and have higher energy intensities compared to personal vehicles.[61]

Exhibit 63: 2030 vs 2040 Transportation Consumption by Ownership Type

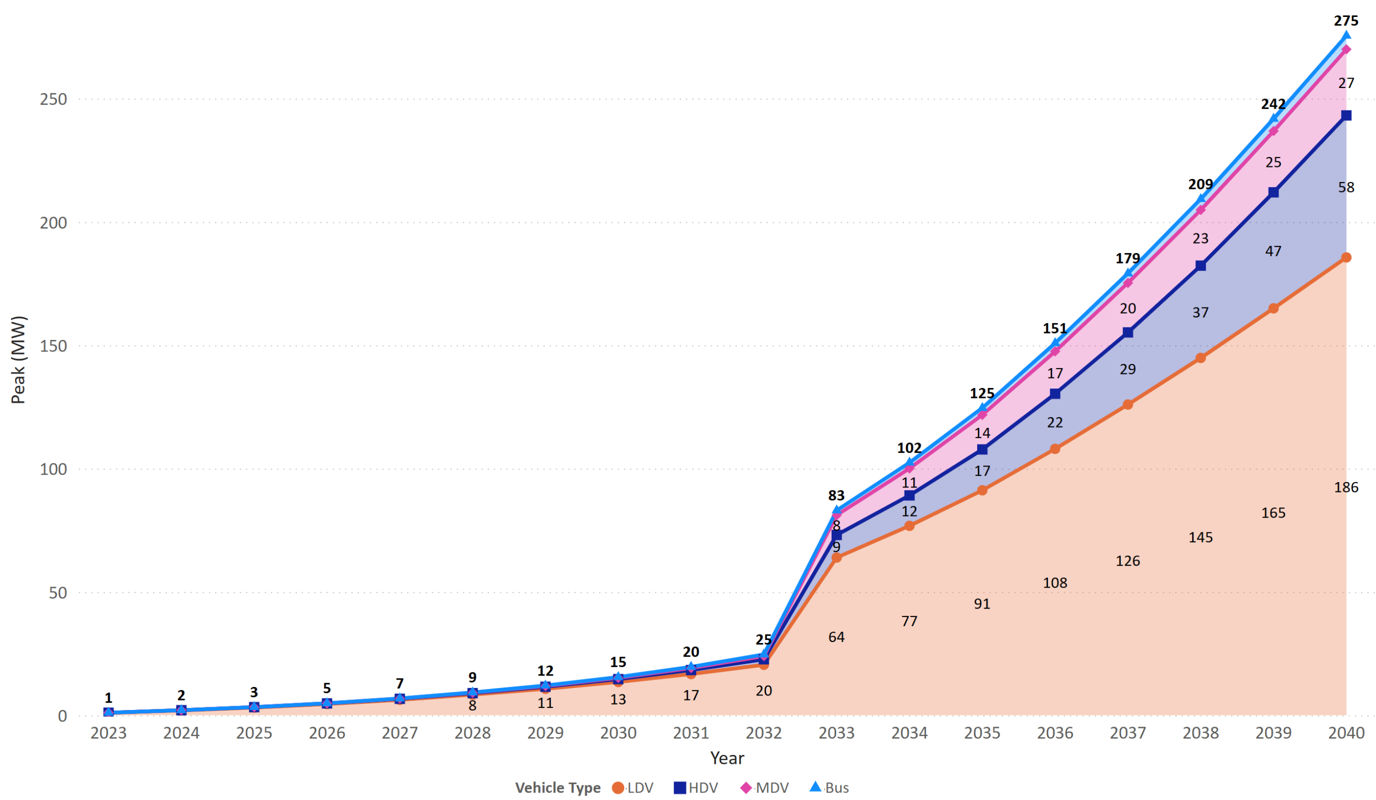


[60] Consumption from fleet vehicles in the base year is almost entirely attributed to commercial LDVs.
[61] "Comprehensive Energy Use Database, Transportation Sector – Newfoundland and Labrador," Natural Resources Canada, Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_tran_nf.cfm. (Accessed Feb. 25, 2025). See tables Table 21 and 37.

Forecast Peak Demand

Exhibit 64 shows forecast transportation sector peak demand by vehicle type for the intermediate scenario under unmanaged charging. Peak demand is forecast to increase to approximately 275 MW by 2040. This increase is driven by the same trends that drive the increase in electricity consumption. The increase in the EV peak hour seen between 2032 and 2033 is due to the system wide peak hour shifting from the morning to the evening. Prior to 2033, the peak hour is expected to occur in the morning so the EV contribution to peak is much lower since much less charging occurs then. After 2033, the EV contribution to the peak is much higher when the system peak hour occurs much closer to the EV charging peak hour.

Exhibit 64: Intermediate Scenario Forecast Peak Demand (MW) by Vehicle Type, (2040)



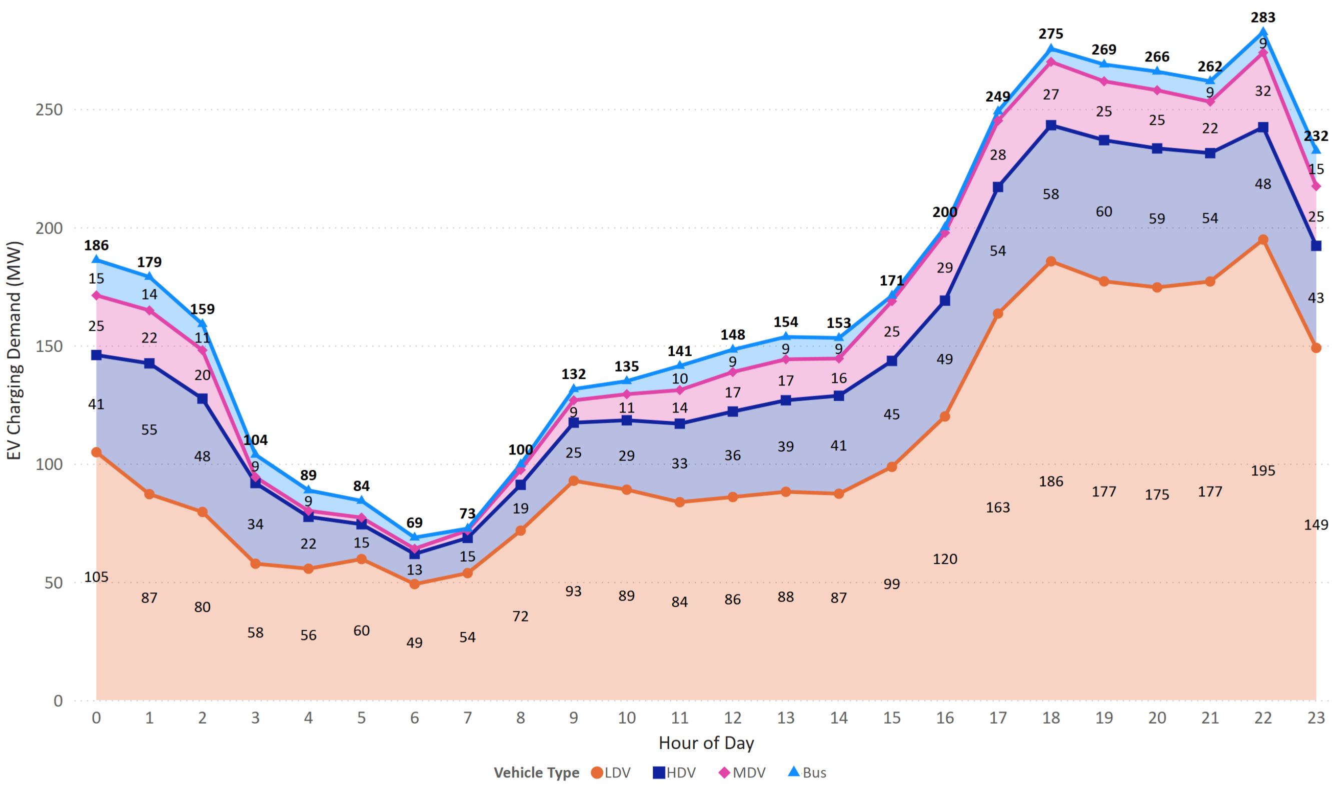
The rest of this section explains when (i.e., hour of the day) and where (i.e., at home chargers, at public chargers, etc.), peak demand is expected to occur in 2040.

Hourly Peak Demand

Exhibit 65 shows the transportation sector demand in each hour of the peak day in 2040 for the intermediate scenario under unmanaged charging. The peak day is expected to occur in the winter, when electric space heating loads peak in the residential and commercial sectors. Observations on Exhibit 65 include:

- The evening peak occurs between 6 p.m. and 10 p.m., which overlaps with the predicted IIS system evening peak at 6 p.m. The absolute transportation sector peak (283 MW) occurs at 10 p.m.
- The nighttime trough occurs between 12 a.m. and 6 a.m. This suggests that shifting EV charging load could also reduce the IIS peak. Opportunities to manage EV charging are discussed in section 4.4.
- Transportation sector demand is lowest between 6 a.m. (69 MW) and 7 a.m. (73 MW), just before the IIS morning peak occurs from 7 a.m. to 10 a.m. Given the shape of the EV charging curve, efforts should be focused on reducing the evening peak.

Exhibit 65: Peak Demand by Hour and Vehicle Type (MW), (2040)

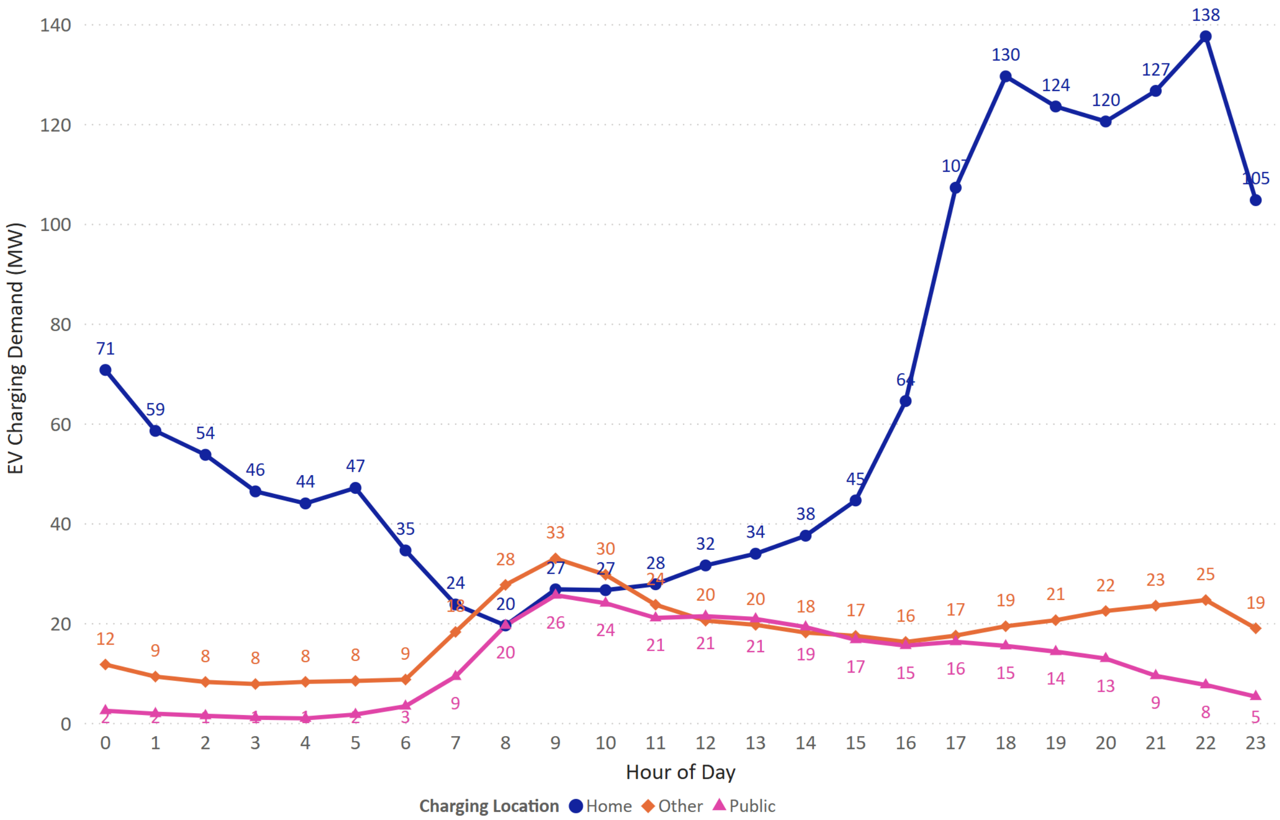


Charging Location

Charging location also influences the magnitude of EV load can be shifted off the IIS peak. Personal EVs are expected to charge at home, at public charging stations and at "other" charging locations (i.e., workplace charging stations or other private charging stations). Data from Geotab's Charge the North study for Canada shows that approximately 68% of personal EV charging occurs at home while 32% occurs away from home (19% at private locations including workplaces or other businesses and 13% at public charging stations).[62] The Study Team maintained these charging splits throughout the forecast period. Fleet vehicles are expected to charge exclusively at their private depots.

Exhibit 66 shows personal EV charging by location in each hour of the peak day in 2040 for the intermediate scenario.

Exhibit 66: Personal EV Charging by Hour and Location (MW), (2040)



[62] "Preparing for EVs: Charge the North EV Case Study," Geotab, Available: https://www.geotab.com/blog/preparing-for-evs/ (Accessed Jan. 30, 2024).

Observations on Exhibit 66 include:

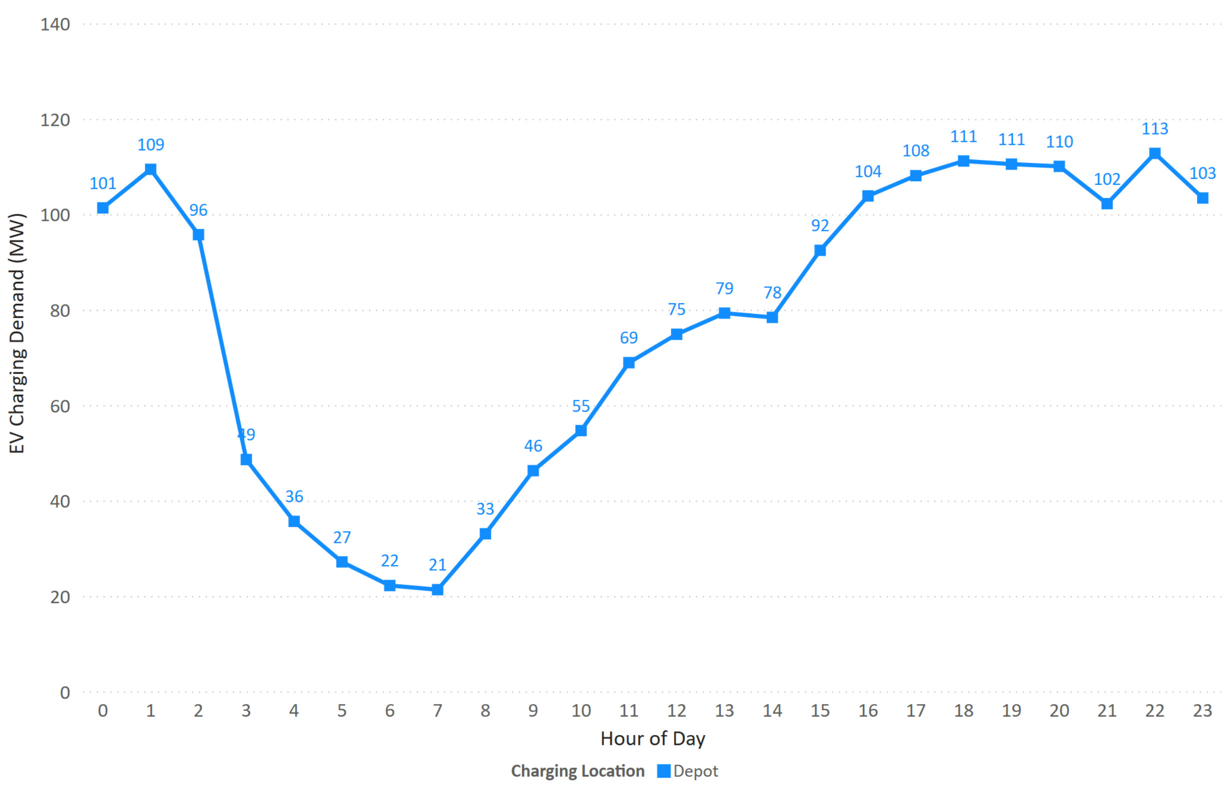
- Home charging contributes the most to the transportation sector evening peak from 6 p.m. to 10 p.m. because drivers typically plug in their vehicles after work.
- Public and other charging peaks between 8 a.m. and 11 a.m., when drivers plug in after their morning commute and are away from their homes.
- Of the three personal vehicle charging locations, home charging is the only one suited to load shifting, because public and other charging is often seen as opportunity charging.[63] Shifting home charging to the nighttime trough from 12 a.m. to 6 a.m. could reduce the IIS peak.

[63] Opportunity charging usually happens mid-route, like refueling an ICE vehicle, so there is less flexibility to shift the load.

Exhibit 67 shows fleet EV charging at depots in each hour of the peak day in 2040 in the intermediate scenario. Observations include:

- The depot charging peak contributes the most to the transportation sector peak between 3 p.m. and 2 a.m. Like the home charging peak, the depot charging peak overlaps with the IIS evening peak.
- The depot charging peak (eleven hours in duration) is seven hours longer than the home charging peak (four hours in duration). This is because fleet vehicles are charged during their downtime, which depends on their duty cycle. MHDV and bus batteries are also larger and take longer to charge compared to LDV batteries, which lengthens the peak.
- The depot charging trough does not begin until after 2 a.m. and reaches its lowest load (21 MW) at 7 a.m. Depot charging load could be shifted off peak into this trough if duty cycles allow, but load shifting potential is likely constrained by vehicle battery sizes.
- The opportunity for the Utilities to manage fleet vehicle charging load is more limited than for personal vehicles. However, certain fleet vehicles will have duty cycles that can accommodate managed charging programs to help reduce the IIS evening peak. Fleet LDVs likely present the best opportunity for utility managed charging due to their smaller batteries and shorter distances driven.

Exhibit 67: 2040 Fleet EV Charging by Hour and Location (MW)



3.5.3 Scenario Comparison

This section compares forecast vehicle stock, consumption and peak demand in the natural adoption, intermediate, and government targets scenarios. Discussion of the incentives, infrastructure (i.e., chargers, and ports) and cost requirements to move from one scenario to another are provided in Appendix A.

Vehicle Stock

Exhibit 68 and Exhibit 69 show the forecast vehicle stock for the natural adoption, intermediate and government targets scenarios for LDVs and MHDVs (including buses) respectively.

Exhibit 68: Forecast EV Stock by Scenario (LDVs)

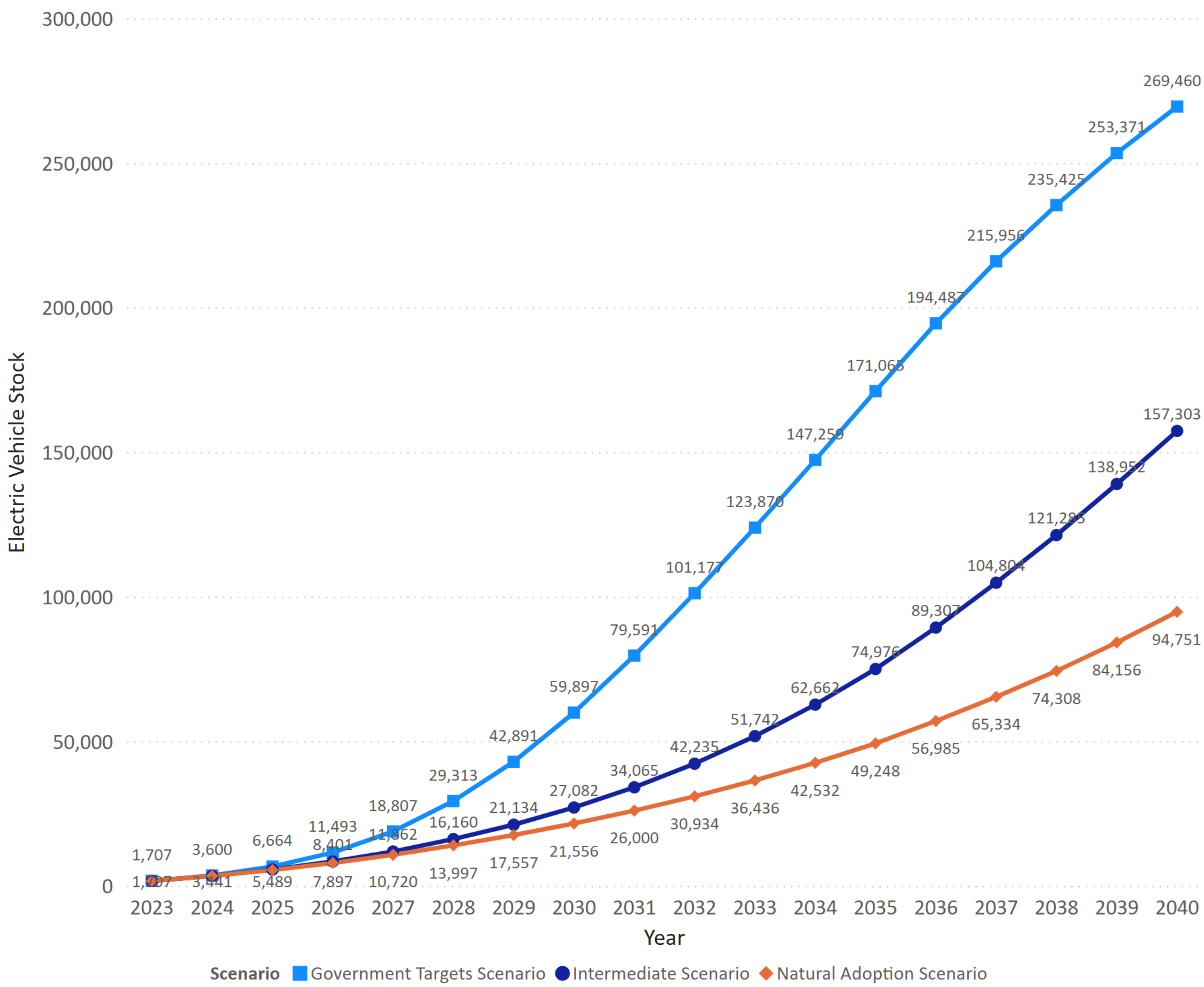
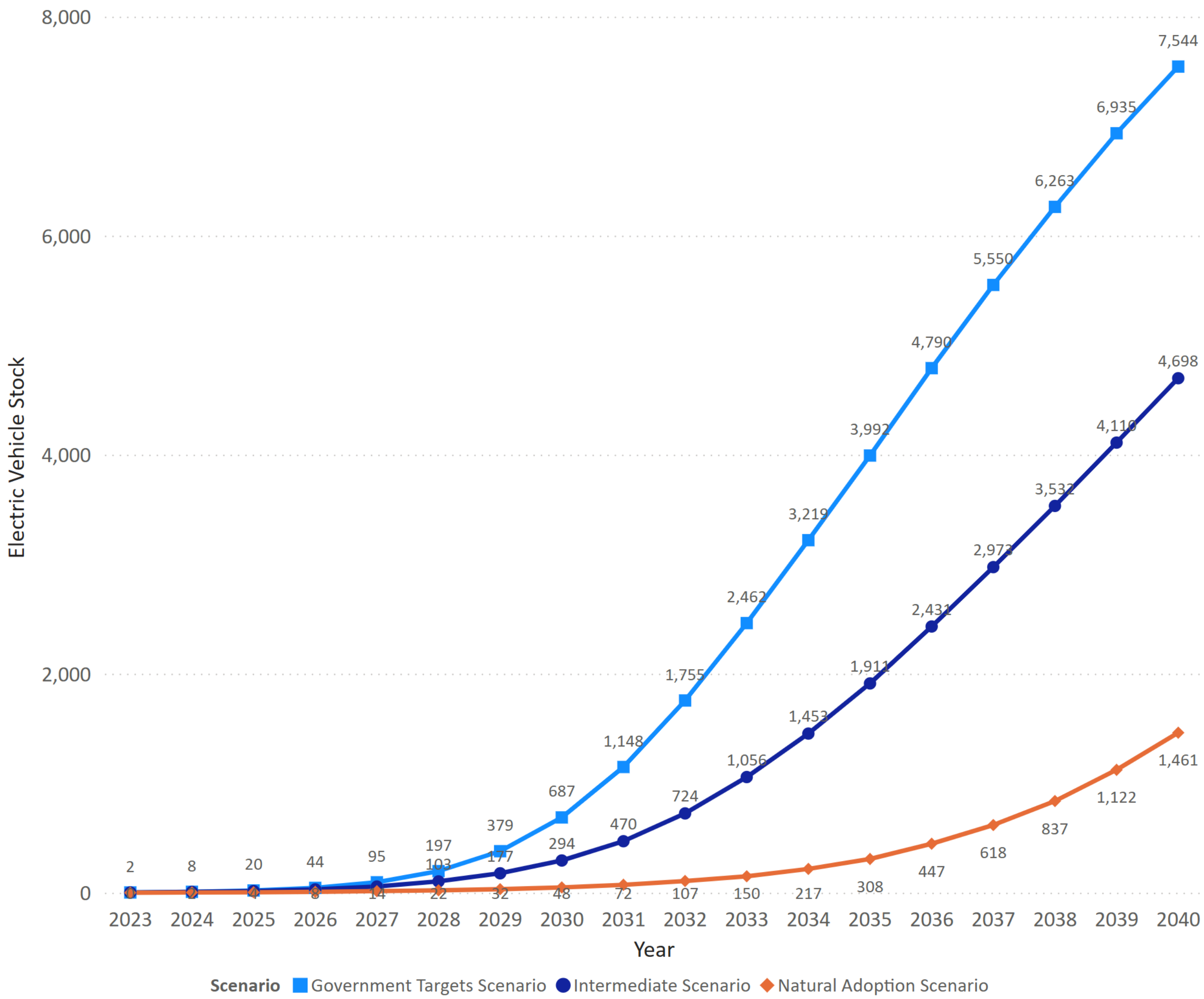


Exhibit 69: Forecast EV Stock by Scenario (MHDVs)



Observations include:

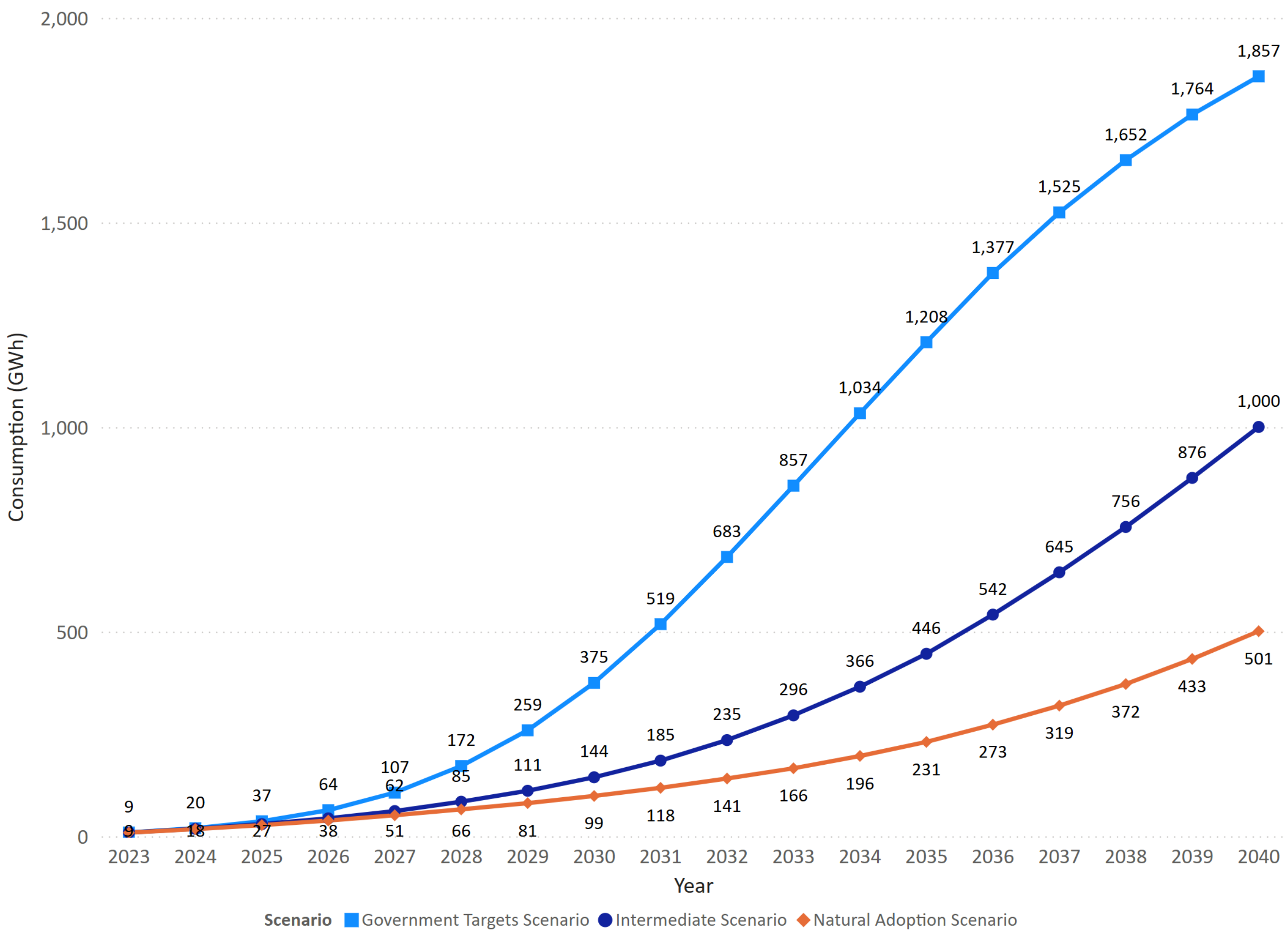
- The government targets scenario forecasts the largest EV stock by 2040, at approximately 270,000 LDVs and 7,500 MHDVs. It also has much earlier uptake in EVs, eclipsing the total 2040 LDV stock of roughly 157,000 forecast in the intermediate scenario before 2035.
- The natural adoption scenario has a much more gradual EV stock trajectory, reaching approximately 95,000 LDVs and 1,500 MHDVs by 2040. Natural adoption MHDV stock lags further behind the other scenarios as adoption only begins to increase in the mid 2030s.
- Across all scenarios, uptake for LDVs begins earlier in the forecast period than MHDVs, due to advancements in technology and lower costs. However, uptake for MHDVs rises at steeper rates as soon as MHDVs are forecast to become cost competitive with the incumbent ICEV technology. This highlights how Total Cost of Ownership (TCO) is expected to be the main driver of EV adoption for MHDVs.

Electricity Consumption

Exhibit 70 shows forecast electricity consumption by scenario. Observations include:

- By 2030, market interventions like additional vehicle rebates or accelerated build-out of charging infrastructure for LDV in the intermediate scenario results in 45 GWh more electricity consumption compared to the natural adoption scenario (144 GWh vs 99 GWh). By 2040, these market interventions are responsible for roughly 500 GWh of additional consumption (1,000 GWh vs 501 GWh).
- By 2040, the government targets scenario predicts nearly twice the electricity consumption from EV charging compared to the intermediate scenario (1,857 GWh vs 1,000 GWh) and nearly four times the electricity consumption compared to the natural adoption scenario (1,857 GWh vs 501 GWh).

Exhibit 70: Forecast EV Consumption by Scenario (GWh)

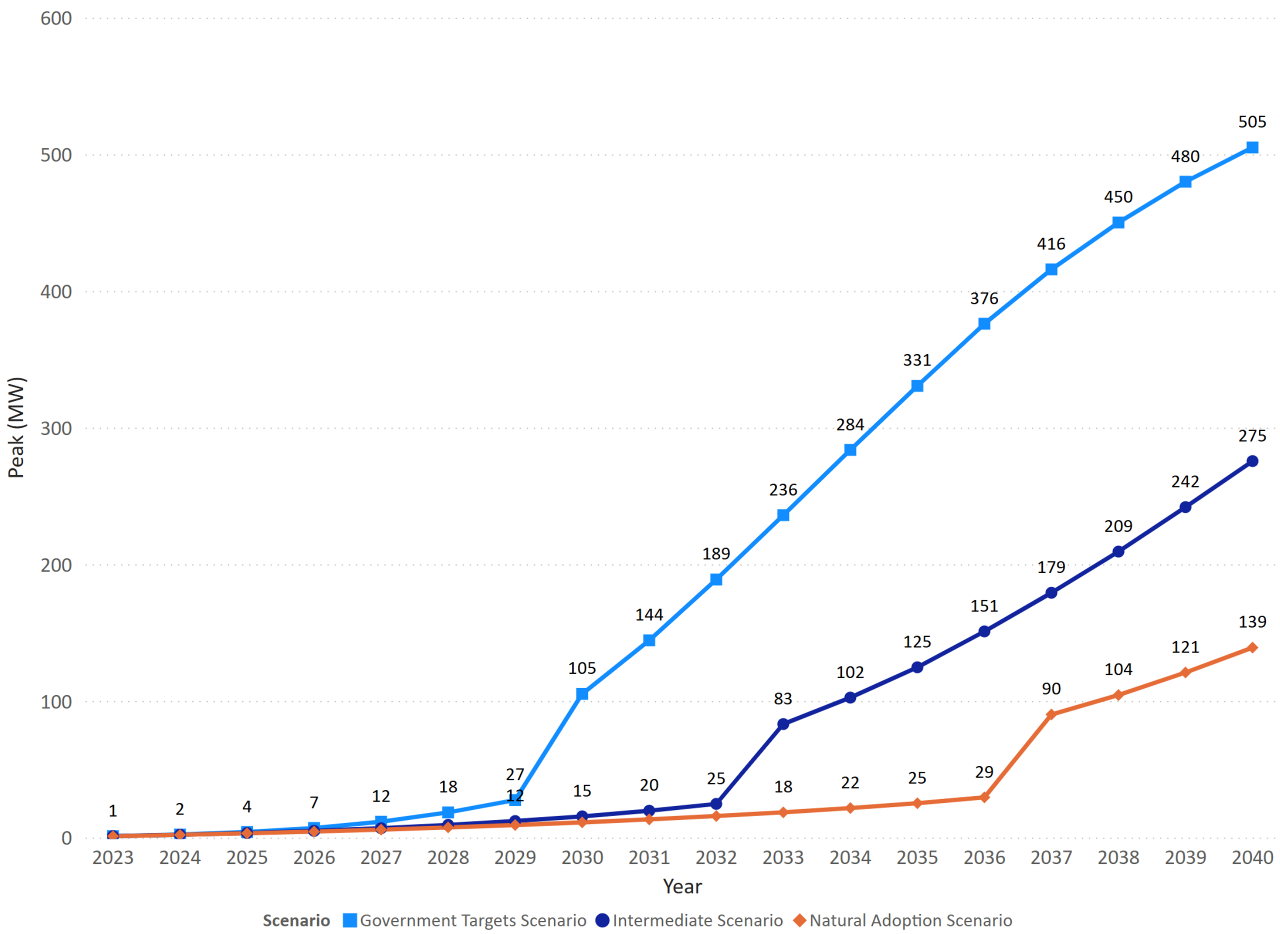


Peak Demand

Exhibit 71 shows forecast EV peak demand by scenario under unmanaged charging. Observations include:

- Like the annual consumption forecast, the government targets scenario predicts over 3.5 times the peak demand (505 MW) from EV charging compared to the natural adoption scenario (139 MW).
- The abrupt increases in EV peak in 2030 (government targets scenario), 2033 (intermediate scenario) and 2037 (natural adoption scenario) represent the switch from a morning peak to an evening peak. This shows that greater EV uptake leads to an earlier transition to an evening IIS peak.
- In the natural adoption, intermediate, and government targets scenarios, EVs contribute 7%, 13% and 22% to the IIS peak, respectively.
- EV peak demand in the government targets scenario (505 MW) falls between peak demand for the industrial (130 MW) and commercial (522 MW) sectors in 2040. This illustrates that EVs could significantly contribute to peak demand in Newfoundland over time.

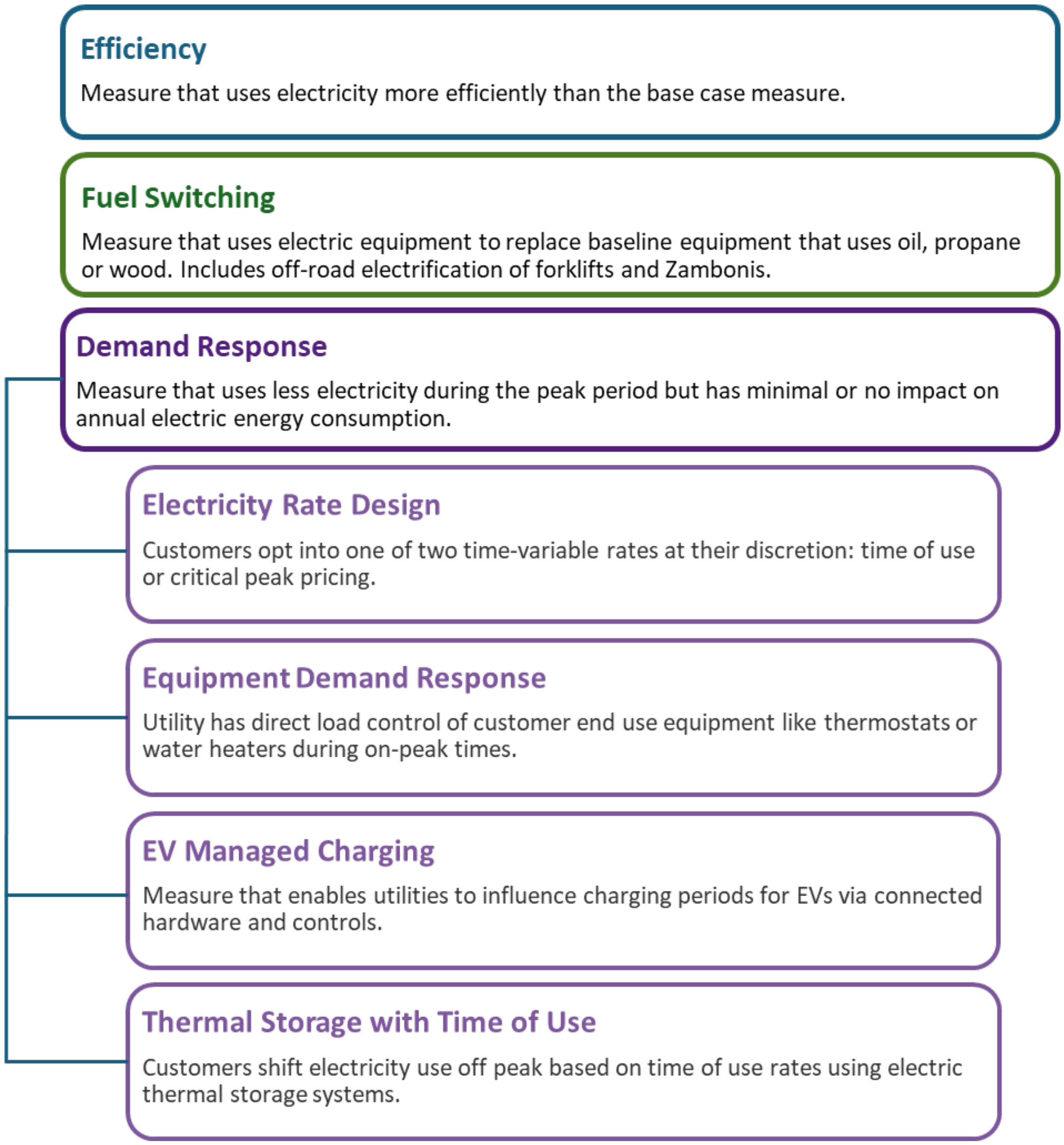
Exhibit 71: Forecast EV Peak Demand by Scenario (MW)



4 Measure Analysis

The Study Team assessed the energy savings and peak demand reduction potential for efficiency, fuel switching, and demand response measures. The demand response measures are further classified as electricity rate design, equipment demand response, and thermal storage with time-of-use. Exhibit 72 illustrates the Study measure classification and defines each measure type.

Exhibit 72: Measure Classification



Some measures are applicable across two categories. For example, dual fuel oil/electric heating systems may be applied as a fuel switching measure when replacing an oil heating system, or as a demand response measure when the oil-fired equipment is used to replace electric heating during peak periods. In these cases, the Study Team developed two individual measures, one in each category.

In addition to assessing energy savings and peak demand reduction potential for efficiency, fuel switching and DR measures, the Study Team determined what market conditions would be required to support the natural adoption, intermediate and government targets EV forecast scenarios defined in section 2.2.[64] This included an examination of the following transportation sector measures:

- **Adoption Incentives**: Payments to vehicle operators that offset the incremental cost of adopting EVs.
- **Charging Infrastructure**: Charging infrastructure costs include port costs and associated installation costs. Costs exclude distribution system upgrades to host charging loads.

Lastly, the Study Team completed a qualitative assessment of emerging measures transportation sector measures: Connected hardware and controls that enable vehicle batteries to feed energy back to specific loads, dwellings or the grid and allow the Utilities to influence the magnitude and timing of this energy flow.

Readers are encouraged to consult section 2 for additional details of the measure analysis approach. The rest of this section is structured as follows:

- Section 4.1 lists measures by sector. Within section 4.1,
    - Section 4.1.1 shows the rate structures modelled for the electricity rate design measures.
    - Section 4.1.2 shows the frequency and duration of events for the electricity rate design measures and the utility-driven equipment DR measures.
- Section 4.2 presents results for the residential, commercial and industrial sectors.
- Section 4.3 presents results for the transportation sector.

[64] In the Study, charging infrastructure refers to the ports required to support electric vehicle charging in the Transportation sector.

4.1 List of Measures

An illustrative list of the measures for the residential, commercial, and industrial sectors are listed in Exhibit 73, Exhibit 74 and Exhibit 75, respectively. Measures are presented by end use and type. Exhibit 76 shows the transportation sector measures by type. All the transportation measures affect the EV charging end use. See Appendix B for the complete list of measures by sector.

Exhibit 73: Residential Sector Measures

End Use(s) Affected	Measure Name
Water Heating	**Efficiency** • Domestic Hot Water Pipe Insulation • Low Flow Fixtures (faucet aerator, showerhead, thermostatic restrictor shower valve) • Efficient Equipment (heat pump water heater, on demand water heater) **Fuel Switching** • Oil Water Heater to Heat Pump Water Heater • Oil Water Heater to High Efficiency Electric Storage Water Heater **Demand Response** • Water Heater Smart Switch (Utility-Driven)
Lighting	**Efficiency** • Lighting Controls (various) • Efficient Lamps (various) • Efficient Integrated Fixtures (various)
Space Cooling & Space Heating	**Efficiency** • Envelope Improvement (air sealing, insulation, efficient windows and doors) • Air Source Heat Pumps (various standard and cold climate configurations) • Thermostats (digital, programable, and smart) **Fuel Switching** • Oil Boiler to Air to Water Heat Pump (various configurations) • Oil Boiler to Ductless Mini Split Heat Pump (various configurations) • Oil Furnace to Central Ducted Air Source Heat Pump (various configurations) • Oil Furnace to Ductless Mini Split Heat Pump (various configurations) • Wood Furnace to Central Ducted Air Source Heat Pump (various configurations)

End Use(s) Affected	Measure Name
	• Wood Furnace to Ductless Mini Split Heat Pump (various configurations)
Space Cooling & Space Heating & Ventilation	**Efficiency** • Energy Recovery Ventilator • Heat Recovery Ventilator
Space Heating	**Fuel Switching** • Oil Boiler to Electric Boiler • Oil Furnace to Electric Furnace **Demand Response** • Smart Thermostat or Switch (various electric heating technologies) • Thermal Storage (various configurations)
Four or More End Uses Affected	**Efficiency** • Codes and Standards • Home Energy report • LEED Certified Apartments • Efficient New Homes (ENERGY STAR, Net-Zero Ready) **Demand Response** • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Smart circuit breakers or smart panel (Utility-Driven) • Time-of-Use Rates (TOU) • Critical Peak Pricing (CPP)

Exhibit 74: Commercial Sector Measures

End Use(s) Affected	Measure Name
Water Heating	**Efficiency** • Drain Water Heat Recovery • Efficient Equipment (ENERGY STAR dishwasher, heat pump water heater) • Low-Flow Fixtures (faucet aerator, showerhead, pre-rinse spray valve, thermostatic restrictor shower valve) **Fuel Switching** • Oil Water Heater to Heat Pump Water Heater **Demand Response** • Controllable Water Heaters (Utility-Driven)
General Lighting	**Efficiency** • LED Lamps and Luminaires (various) • Interior Lighting Controls (BAS, daylighting, occupancy sensors)
High Bay Lighting	**Efficiency** • LED High Bay Luminaire
HVAC Fans & Pumps	**Efficiency** • Electrically Commutated Motor (various applications) • Variable Frequency Drive (various applications) • Premium Efficiency Motors • Recirculation Pump with Demand Controls
HVAC Fans & Pumps & Space Cooling	**Efficiency** • Advanced Building Automation Systems • Demand Control Ventilation (general, kitchen) **Demand Response** • HVAC Fans & Pumps Controls (Utility-Driven)
Miscellaneous Equipment	**Efficiency** • ENERGY STAR equipment (ice maker, uninterruptible power supply, vending machine) **Off-Road Electrification** • Electric off-road vehicles (forklift, Zamboni)
Outdoor Lighting	**Efficiency** • LED lamps (various) • LED fixtures (wall pack, parking garage, pole mounted) • Lighting Controls

End Use(s) Affected	Measure Name
Refrigeration	**Efficiency** • Arena Improvements (brine pump controls, low emissivity ceiling, schedule for ice temperature) • ENERGY STAR Refrigerators and Freezers • Refrigerated Display Case Improvements (add doors, anti-sweat door heater controls, case retrofit, LED refrigerated case lighting) • Refrigerated Walk-Ins Improvements (automatic door closers, door strip curtains, EC motor, evaporator fan control, fast acting doors) • Refrigeration System Improvements (floating heat pressure control, high efficiency compressor)
Secondary Lighting	**Efficiency** • LED lamps and luminaires (various)
Space Cooling & Space Heating	**Efficiency** • Envelope Improvement (air sealing) • Air Source Heat Pumps (various standard and cold climate configurations) • Energy Management (whole-building system, guest room) • Ground Source Heat Pumps • Thermostats (programmable, smart)
Space Cooling	**Efficiency** • Dual Enthalpy Economizer Controls • High Efficiency Equipment (chiller, rooftop unit, unitary, packaged)
Space Heating	**Efficiency** • Envelope Improvements (air curtains, efficient windows, window glazing, insulation) • Energy Recovery Ventilator • Radiant Infrared Heaters • Refrigeration Heat Recovery • Solar Wall **Fuel Switching** • Oil Boiler to Electric Heating (baseboard, boiler, furnace, various heat pump configurations) • Oil Furnace to Electric Heating (furnace, various heat pump configurations) **Demand Response** • HVAC Control (Utility-Driven)

End Use(s) Affected	Measure Name
	• Thermal Storage (various configurations)
Street Lighting	**Efficiency** • LED Street Light
Four or More End Uses Affected	**Efficiency** • Energy Management System • New Construction (25% more efficient, 40% more efficient, Net-Zero Ready) • Retro-commissioning Strategic Energy Manager **Demand Response** • Backup Generation (Utility-Driven) • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Critical Peak Pricing • Customer Curtailment • Grid Interactive Efficient Buildings (Utility-Driven) • Time-of-Use Rate

Exhibit 75: Industrial Sector Measures

End Use(s) Affected	Measure Name
Air Compressors	**Efficiency** • Cycling Refrigerated Air Dryer • Premium Efficiency ASD Compressor • System Optimization (various measures)
Conveyors	**Efficiency** • Optimized Conveyor Motor Control • Premium Efficiency Motors - Conveyor
Fans and Blowers	**Efficiency** • Correctly Sized Fans: Impeller Trimming or Fan Selection • Optimized Distribution System (Incl. Pressure Losses) - Fans and Blowers • Premium Efficiency Equipment (various) • Synchronous Belts
General Lighting	**Efficiency** • Automated Lighting Controls • High Efficiency Lighting Design • LED Luminaires (various)
HVAC Fans & Pumps	**Efficiency** • Envelope Improvements (air curtains – HVAC, building insulation, warehouse loading dock seals) • Heat Recovery (air compressor, refrigeration, ventilation) • High Efficiency Packaged HVAC • Solar Thermal Wall • Temperature Management (reduced temperature settings, smart thermostat) • Ventilation Optimization **Fuel Switching** • Comfort HVAC Electrification
HVAC Fans & Pumps, Pumps, Process Cooling, and Process Heating	**Demand Response** • Peak Shifting Through On-Site Storage (Utility-Driven)
Other	**Off-Road Electrification** • Electric Forklift
Other Motors	**Efficiency** • Adjustable or Variable Speed Drives (compressor and fan) • Motor Improvements (correct sizing, controls) • Premium Efficiency Motors - Other

End Use(s) Affected	Measure Name
Pumps	**Efficiency** • Pumping System Improvements (correct sizing, system optimization) • Premium Efficiency Equipment (motors and pumps)
Process Cooling	**Efficiency** • Air Curtains - Process Cooling • Chiller Economizer • Floating Head Pressure Controls • High Efficiency Chiller • Improve Insulation of Refrigeration System • Improved Ice Production System • Optimized Distribution System - Process Cooling • Premium Efficiency Refrigeration Control System and Compressor Sequencing
Process Heating	**Efficiency** • High Efficiency Equipment (dryer, furnace, kiln, over, water heater) • Process Heat Recovery to Preheat Makeup Water
Process Specific	**Efficiency** • Advanced ‘Predictive’ Process Control Systems • Custom Processes • Process Optimization Efforts (fishing and fish processing, mining and processing
Process Heating & Process Cooling	**Efficiency** • Heat Pumps
All End Uses Affected	**Demand Response** • Backup Generation at Peak Hours (Utility-Driven) • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Critical Peak Pricing/ Industrial Flexibility • Energy Management Information System (EMIS) • Time-of-Use (TOU)

Exhibit 76 presents transportation sector measures, all of which affect the EV charging end use.

Exhibit 76: Transportation Sector Measures

Measure Type	Measure Name
Managed Charging	**Personal Ownership** • Electric Vehicle Supply Equipment (EVSE) (BEV, PHEV) • Vehicle Telematics (VT) (BEV, PHEV) **Fleet Ownership** • VT (Bus, HDV, Light Duty BEV, Light Duty PHEV, MDV) • EVSE (Bus, HDV, Light Duty BEV, Light Duty PHEV, MDV)
Time-of-Use	**Personal Ownership** • BEV • PHEV
Adoption Incentives	• Bus • Fleet LDV • HDV • MDV • Personal LDV
Infrastructure	**Personal Ownership** • LDV Direct Current Fast Charging (DCFC) Public Charger • LDV L2 Home Charger – Multi-Unit Residential Building (MURB) • LDV L2 Public Charger • Level 1 (L1) and Level 2 (L2) LDV Home Charger **Fleet Ownership** • DCFC Depot Charger (Bus, HDV, MDV) • L2 Depot Charger (Bus, LDV) • LDV DCFC Public Charger • LDV DCFC Depot Charger • LDV L2 Public Charger **Other Ownership** • DCFC Public Charger (HDV, MDV) • L2 Public Charger (HDV, MDV)

4.1.1 TOU and CPP Rate Structures

The Study Team assessed the impact of the TOU and CPP electricity rate designs in Exhibit 77 on peak demand. Throughout the report, the TOU and CPP electricity rate design measures are referred to as time variable rates (TVR).

Exhibit 77: TOU and CPP Rates

Season	Peak	Time	Residential ($/kWh)[65]	Commercial ($/kWh)	Industrial ($/kWh)
December to March	On-peak	Morning Peak Evening Peak	$0.24	$0.17	$0.18
	Off-peak	Hours Outside of Peak Periods	$0.06	$0.04	$0.04
December to March	Critical Peak	Critical Peak Events	$0.55	$0.83	$0.85
	Off-Peak	Hours Outside of Critical Peak Periods	$0.06	$0.07	$0.07

The TOU and CPP electricity rates are based on the base year electricity retail rates from Newfoundland and TVR from other jurisdictions.[66] These rate structures are representative, and neither is currently offered or under specific consideration by the Utilities. The rate structures are designed as opt-in programs like other jurisdictions in Canada, meaning that only customers who choose to participate will see the time-varying rates in effect.

TOU

- **Mid-Peak**: Reflects the base year residential and commercial customer retail rates ($0.13/kWh for residential, and $0.096/kWh for commercial). The Study Team used the mid-peak retail rates for each sector to determine the on-peak and off-peak rates. This was done by calculating the proportion of annual demand that occurs during each peak period and estimating the corresponding off-peak rate that avoids a loss in revenue to the Utilities from reduced rates during the peak periods.
- **On-Peak**: Reflects a 4:1 rate differential between off-peak and on-peak rates and assumes revenue neutrality. Price differentials within the range of 2:1 to 4:1 are industry standard and

[65] The residential rate applies to "at home" personal EV charging.
[66] These rate structures demonstrative and not a recommendation of an actual retail rate.

are most likely to show results. A NP pilot found that a 2:1 rate differential was ineffective for Newfoundland, so the Study Team chose a 4:1 differential.[67,68,69]

- **Off-Peak**: Reflects a 4:1 rate differential between the off-peak and on-peak rates and assumes revenue neutrality.[70]

CPP

- **Off-Peak:** Reflects the off-peak rates from Hydro Quebec's Rate Flex D program for the residential sector. The commercial sector off-peak rate reflects the ratio of Hydro Quebec's summer period to winter period reduced pricing for the Rate Flex D program.[71]
- **Critical Peak:** Uses the peak demand event rates from Hydro Quebec's Rate Flex D program for the residential sector. For the commercial and industrial sectors, reflects the IIS mid-peak rates multiplied by the ratio of Hydro Quebec's peak demand event rates to off-peak rates.[71]

4.1.2 Frequency and Duration of TOU and CPP Events

The frequency and duration of peak events for which on-peak rates are used are as follows:

- **TOU:** The TOU rate is modelled as being in effect during the morning (4 hours) and evening (5 hours) peak periods on weekdays from December to March (i.e. a total of 89 days per year).
- **CPP:** The CPP rate is modelled as being in effect during critical peak events, as determined by the Utilities. For the purposes of estimating customer benefit, this analysis assumes that events are called 12 times per year during the morning and evening peak periods.

The IIS has seen weekend peaks in the past; however, the Study Team modelled a weekday-only TOU rate structure. Daily TOU has been found to lead to customer fatigue in some cases, and a weekday only structure is consistent with TOU rate implementation in Nova Scotia and Ontario.[72,73]

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[67] Personal interview, Nov 16, 2024, Joseph Lopes, Senior Principal Consultant, "Load Shape and Rate Design Programs." Conducted by: Sydney Mendoza.
[68] NP conducted a pilot with a 2:1 rate differential and concluded that it was not effective. Newfoundland Power, "Time of Day Rates Study Results" (Accessed Jan. 29, 2025).
[69] Synapse Energy Economics, Inc., "Time-of-Use Rates for Delivery and Standard Offer Response to the Maine Public Utilities Commission's Request for Comments," Available: https://www.synapse-energy.com/sites/default/files/22-086%20Comments%20on%20TOU%20Rates.pdf (Accessed Mar. 5, 2025).
[70] As requested by NP in Sept. 2024.
[71] Hydro Québec, "Rate Flex D", Available: https://www.hydroquebec.com/residential/customer-space/rates/rate-flex-d-billing.html (Accessed Oct 2, 2024).
[72] Nova Scotia Power, "Time-of-Use Rate Pilot," Available: https://www.nspower.ca/your-home/residential-rates/time-of-use (Accessed Sept 5., 2024).
[73] Ontario Energy Board, "Electricity Rates", Available: https://www.oeb.ca/consumer-information-and-protection/electricity-rates (Accessed Sept. 5, 2024).

4.2 Results – Residential, Commercial, and Industrial Sectors – Efficiency and Electrification Measures

Exhibit 78, Exhibit 79 and Exhibit 80 show measure-level cost-effectiveness test results for the top ten efficiency and electrification measures by medium TRC for the residential, commercial, and industrial sectors, respectively. In addition to the TRC, the exhibits show the measure-level program administrator cost (PAC) test results that include an incentive set to offset 50% of the incremental measure cost for ROB measures, and 50% of the full cost for RET measures. The measure-level cost-effectiveness test results are also a function of non-incentive program costs where applicable. The non-incentive program cost reflects 25% of the measure-level incentive.[74]

Exhibit 78 shows that low-cost measures like faucet aerators and LED lamps are among the top ten residential sector measures by TRC.

Exhibit 78: Residential Sector Cost-Effectiveness Test Results (2025)

Measure	Medium TRC	Medium PAC
Faucet Aerator	49.9	89.9
LED Linear Tube	16.6	10.2
Programmable Thermostat (Central)	16.1	29.0
ENERGY STAR Ceiling Fan	15.8	28.5
Domestic Hot Water Pipe Insulation	13.2	23.8
Duct Insulation	11.1	19.9
Interior ENERGY STAR LED A-Lamp	Instant Payback	19.4
External ENERGY STAR LED A-Lamp	Instant Payback	18.5
Interior ENERGY STAR LED Reflector Lamp	Instant Payback	15.2
Exterior ENERGY STAR LED Reflector Lamp	Instant Payback	14.4

[74] The non-incentive program costs do not reflect detailed program design and are assumptions for the purposes of this analysis.

Like the residential sector, low-cost measures including faucet aerators, low-flow showerheads, and thermostatic restrictor shower valves are among the top ten by TRC in the commercial sector as shown in Exhibit 79. LED lamps and fixtures are also among the top ten measures by TRC.

Exhibit 79: Commercial Sector Cost-Effectiveness Test Results (2025)

Measure	Medium TRC	Medium PAC
Faucet Aerator	103.4	186.2
Low-Flow Showerhead	52.4	94.2
Thermostatic Restrictor Shower Valve	19.5	35.1
LED High Bay Luminaire	18.3	33.0
ENERGY STAR Dishwasher	15.8	28.4
High Efficiency Compressor	14.5	26.2
ENERGY STAR Vending Machine	10.7	19.3
LED Reflector (Exterior)	Instant Payback	56.4
LED Reflector (Interior General)	Instant Payback	42.5
LED Reflector (Interior Secondary)	Instant Payback	42.1

Exhibit 80 shows the top ten industrial sector measures by TRC. A range of measures is included in the top ten, including LED high bay luminaire, refrigeration heat recovery, and insulation.

Exhibit 80: Industrial Sector Cost-Effectiveness Test Results (2025)

Measure	Medium TRC	Medium PAC
LED High Bay Luminaire	22.7	40.9
Refrigeration Heat Recovery	17.8	32.1
Insulation	15.7	28.3
Reduced Temperature Settings	Instant Payback	Instant Payback
Process Optimization Efforts - Mining and Processing	Instant Payback	Instant Payback
High Efficiency Chiller	9.3	16.8
Adjustable or Variable Speed Drive (Pump)	8.9	16.0
Use Cooler Air from Outside for Make Up Air	7.7	13.9
Correctly Sized Fans: Impeller Trimming or Fan Selection	6.6	11.8
Air Curtains - Process Cooling	6.3	11.4

4.3 Results – Residential, Commercial, and Industrial Sectors – DR Measures

This section shows program costs and measure-level cost-effectiveness test results for the residential, commercial, and industrial sector DR measures. See section 4.4 for transportation sector DR measure results.

4.3.1 Program Costs for Electricity Rate Design and Equipment DR Measures

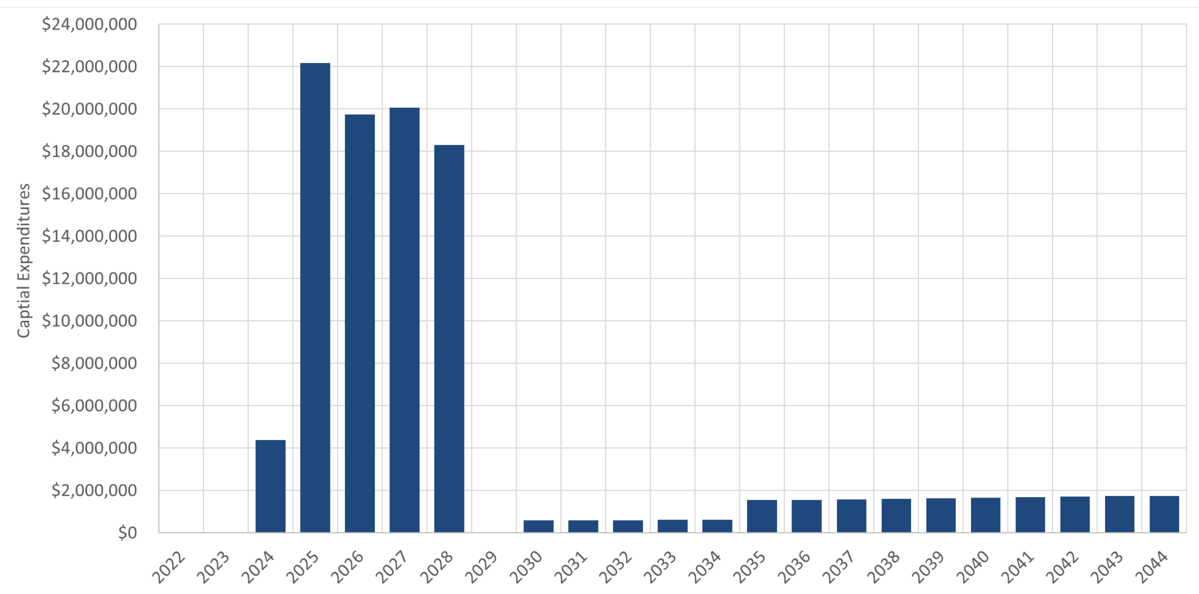
Program costs for DR measures include non-incentive program costs to develop and administer programs and incentive costs paid directly to customers. Advanced metering infrastructure (AMI) implementation costs can also form part of the non-incentive costs for DR measures (i.e., electricity rate design) if the infrastructure is not already in place.

To account for how DR programs may be administered, the Study Team developed incentive and non-incentive program costs for each DR measure in consultation with the Utilities and informed by jurisdictional research.[75] These costs are discussed under two headings that follow, advanced metering infrastructure implementation, and summary of electricity rate design and equipment DR program costs.

Advanced Metering Infrastructure Implementation

Time variable rates (TVR) are not in effect in Newfoundland but exist elsewhere in Canada, including in Ontario, Quebec and Nova Scotia. Smart meters, data management systems, and communication networks form the AMI infrastructure necessary for a utility to implement TVR like time-of-use (TOU) and critical peak pricing (CPP). Exhibit 81 shows the expected capital expenditures to install AMI in Newfoundland.[76]

Exhibit 81: Capital Expenditures for AMI in Newfoundland



[75] These costs are research-based estimates developed for the analysis.
[76] AMI costs provided by NP on November 12, 2024. Costs assume smart meters are installed starting in 2029. In the Study, costs are discounted assuming year one is 2025 to ensure consistency with the other measures.

The capital expenditures shown in Exhibit 81 include costs for smart meters in all rate classes. The following assumptions are embedded in the expenditures:

- The expected useful life of a smart meter is 20 years.
- Smart meters are installed from 2025-2029.
- Customers can opt-into TOU or CPP rates starting in 2029.
- Capital expenditures after 2029 are to replace smart meters that fail.
    - The annual smart meter failure rate is 0.5% from 2030 to 2035.
    - From 2036 to 2040, the failure rate is 2%.

In addition to capital expenditures, there are upfront and annual operational costs associated with AMI.[77,78] Annual operating expenditures of $1.5M are expected starting in 2025.

Summary of Electricity Rate Design and Equipment DR Program Costs

Exhibit 82 shows the non-incentive program cost assumptions for the residential (res), commercial (com) and industrial (ind) sector electricity rate design, utility-driven and thermal storage with TOU DR measures.

Exhibit 82: Non- Incentive Program Costs for DR Measures

Measure Type	Sector	Non-Incentive Program Costs
Electricity Rate Design (TOU and CPP)	Res	$3,132 AMI meter cost/dwelling + Other Non-Incentive Program Costs
	Com	$0.65 AMI meter cost/ft^2 + Other Non-Incentive Program Costs
	Ind	$1.6M/segment + Other Non-Incentive Program Costs
Equipment DR (Utility-Driven)	Res	20% of the total incentive
	Com	40% of the total incentive
	Ind	$15/kW of savings
Equipment DR (Thermal Storage with TOU)	Res	$3,132 AMI meter cost/dwelling[79] + Other Non-Incentive Program Costs
	Com	$0.65 meter cost/ ft^2 + Other Non-Incentive Program Costs

The electricity rate design and equipment DR measure costs include AMI infrastructure costs discussed previously. In the residential sector, the Study Team assumes there is one electricity meter per dwelling.

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[77] Nova Scotia Power, "Time-Varying Pricing Project Submission", Available: https://www.brattle.com/wp-content/uploads/2021/05/19479_nova_scotia_utility_and_review_board_-_time-varying_pricing_project_submission.pdf (Accessed Sept. 5, 2024).
[78] Hydro Québec, "Rate Flex D", Available: https://www.hydroquebec.com/residential/customer-space/rates/rate-flex-d-billing.html (Accessed Oct 2, 2024).
[79] Thermal storage with TOU equipment DR measures are modelled with TOU rates separate from the electricity rate design measures, so program costs also need to include the operational and metering infrastructure costs.

In the commercial sector, there could be several meters associated with the same building, so costs are expressed on a gross floor area basis. In the industrial sector, the number of buildings and the gross floor area is unknown, so costs are expressed on a per segment basis.

Exhibit 83 shows the annual customer enrollment and year one customer equipment incentives for the equipment DR measures. The annual enrollment incentive encourages customers to participate in DR events, and the year one incentive offsets the costs to purchase the equipment required to participate. No annual enrollment is paid to customers who participate in the thermal storage with TOU equipment DR measures because they benefit from utility bill cost savings from shifting electricity use and demand to off-peak times. There are no annual customer enrolment or year one incentives for the electricity rate design measures, so they are omitted from Exhibit 83.

Exhibit 83: Incentive Program Costs for DR Measures

<table>
<tr><th>Measure Type</th><th>Sector</th><th>Annual Customer Enrolment Incentive</th><th>Year One Customer Equipment Incentive</th></tr>
<tr><td rowspan="3">Equipment DR (Utility-Driven)</td><td>Res</td><td>$100/customer/yr.[80, 81]</td><td rowspan="3">For BTM Solar: $0.30/Watt installed DC capacity, up to $3,000.[82]
For Battery Storage: $300/kWh of installed energy storage capacity, up to $2,500.[82]
For Grid Interactive Efficient Buildings (GEB): 5% of the incremental cost.[83]
For thermal storage measures: $2,000 per central system; $540 per room unit.[84]
For all other measures: Utility pays 100% of the incremental cost of the measure.</td></tr>
<tr><td>Com</td><td>$0.04/ ft^2/yr.</td></tr>
<tr><td>Ind</td><td>$50/kW of savings[85]</td></tr>
<tr><td rowspan="2">Equipment DR (Thermal Storage with TOU)</td><td>Res</td><td>$0</td><td rowspan="2">For thermal storage measures: $2,000 per central system; $540 per room unit.</td></tr>
<tr><td>Com</td><td>$0</td></tr>
</table>

[80] Southern California Edison, "Save up to $115 with a Smart Thermostat", Available: https://www.sce.com/residential/demand-response/smart-energy-program (Accessed Sept. 5, 2024).
[81] Pacific Gas and Electric Company, "SmartAC™ program," Available: https://bit.ly/4idzkro (Accessed Sept. 5, 2024).
[82] Efficiency Nova Scotia, "SolarHomes Program," Available: https://www.efficiencyns.ca/residential/services-rebates/solar-homes/ (Accessed Sept. 5, 2024).
[83] Rocky Mountain Institute, "Value Potential for Grid-Interactive Efficient Buildings in the GSA Portfolio: A Cost-Benefit Analysis", Available: https://bit.ly/3FK2d0c / (Accessed Sept. 5, 2024).
[84] Efficiency Nova Scotia, "Electric Thermal Storage (ETS) System Rebate Guide," Available: https://www.efficiencyns.ca/tools-resources/guide/ets-system-rebate-guide/ (Accessed Sept. 5, 2024).
[85] British Columbia Hydro and Power Authority, "Demand response for business", Available: https://bit.ly/4l9TLaM (Accessed Sept. 5, 2024).

4.3.2 Cost-Effectiveness Test Results for Electricity Rate Design Measures

Exhibit 84 shows the medium achievable PAC results by sector for the electricity rate design measures, none of which pass the PAC due to high program costs associated with AMI installation and operation. The PAC is used to assess cost-effectiveness of the DR measures because utilities typically pay all incremental equipment costs in a DR program, and because incentives to participants are typically an expense to the utility over and above the incremental equipment costs. This differs from efficiency programs where the incentives usually cover a portion of the participant's incremental costs for the efficiency upgrade.[86]

The results reflect costs and benefits incurred during the four-year AMI meter installation period and the 20-year smart meter lifetime. These measures assume an opt-in rate structure where participation ramps up to a maximum of 15% in the later years of the study. Potential results and participation rates for the electricity rate design measures are presented in section 7.2.1.

Exhibit 84: Medium PAC Cost-Effectiveness Test Results – Electricity Rate Design Measures

Measure	Residential	Commercial	Industrial
CPP	0.19	0.39	0.43
TOU	0.12	0.29	0.39

[86] "Conservation Potential Study, Final Report (Volume 2 – Appendices)," Dunsky Energy Consulting (2019).

4.3.3 Cost-Effectiveness Test Results for Equipment DR Measures

In the Study, the equipment DR measures are modelled with opt-in participation and with current rates (i.e., they are not modelled with TVR). Exhibit 85 shows the measure-level cost-effectiveness test results for the top residential sector equipment demand response measures by PAC. As stated previously, the PAC is used to assess cost-effectiveness of DR measures in the Study because utilities typically pay all incremental equipment costs in a DR program, and because incentives to participants are typically an expense to the utility over and above the incremental equipment costs.[87] Exhibit 85 also shows the medium TRC for each top ten measure.

All smart thermostat or switch measures and all thermal storages measures are in the top ten by PAC for the residential sector. The utility-driven thermal storage measures show higher PAC results than the equivalent thermal storage with TOU measures, which include the AMI costs incurred during the four-year AMI meter installation period and the 20-year smart meter lifetime.

Exhibit 85: Residential Sector Cost-Effectiveness Test Results – Equipment DR Measures

Measure	Medium PAC	Medium TRC
Smart Thermostat or Switch for Baseboards or Furnaces	7.4	44.2
Thermal Storage and Electric Furnace	Utility-Driven: 6.7 Thermal storage with TOU: 4.7	Utility-Driven: 1.0 Thermal storage with TOU: 1.0
Thermal Storage and Electric Baseboard Heating	Utility-Driven: 5.5 Thermal storage with TOU: 4.0	Utility-Driven: 0.9 Thermal storage with TOU: 0.9
Behind-the-Meter Battery Storage	4.6	0.7
Smart Thermostat or Switch for Ductless Mini-Split Heat Pumps	3.1	18.7
Smart Thermostat or Switch for Central Air Source Heat Pumps	3.0	18.0
Thermal Storage and Air Source Heat Pump	Utility-Driven: 2.3 Thermal storage with TOU: 1.7	Utility-Driven: 0.4 Thermal storage with TOU: 0.3
Thermal Storage and Ductless Mini-Split Heat Pump	Utility-Driven: 2.3 Thermal storage with TOU: 1.7	Utility-Driven: 0.4 Thermal storage with TOU: 0.4
Smart Circuit Breakers or Smart Panel	0.8	1.0

[87] "Conservation Potential Study, Final Report (Volume 2 – Appendices)," Dunsky Energy Consulting (2019).

Exhibit 86 shows the top ten commercial sector equipment demand response measures by PAC. Backup generation has the highest PAC due to its relatively low incremental cost and incentive and only applies to customers with existing backup generators. Like the residential sector, all commercial sector thermal storage measures are in the top ten by PAC.

Exhibit 86: Commercial Sector Cost-Effectiveness Test Results – Equipment DR Measures

Measure	Medium PAC	Medium TRC
Backup Generation at Peak Hours	38.6	83.1
Behind-the-Meter Battery Storage	11.7	1.8
Thermal Storage and Electric Furnace Heating	Utility-Driven: 10.9 Thermal storage with TOU: 13.3	Utility-Driven: 7.0 Thermal storage with TOU: 8.3
Thermal Storage and Heat Pump Heating	Utility-Driven: 10.9 Thermal storage with TOU: 13.3	Utility-Driven: 7.0 Thermal storage with TOU: 8.3
Large Commercial Dual-Fuel Water Heater	10.9	30.9
Grid Interactive Efficient Buildings (GEB)	7.9	0.6
HVAC Control	7.1	24.8
Thermal Storage and Electric Baseboard Heating	Utility-Driven: 4.6 Thermal storage with TOU: 4.6	Utility-Driven: 1.8 Thermal storage with TOU: 2.2
HVAC Fans & Pumps Controls	4.2	14.8

Exhibit 87 shows the measure-level cost-effectiveness test results for the industrial sector equipment demand response measures that pass the PAC screen.[88] Behind-the-meter battery storage has the highest due to its longer expected useful life (20 years) compared to other measures with similar savings.

Exhibit 87: Industrial Sector Cost-Effectiveness Test Results – Equipment DR Measures

Measure	Medium PAC	Medium TRC
Behind-the-Meter Battery Storage	5.3	0.5
Backup Generation at Peak Hours	5.2	21.5

[88] The only measure that fails the screen is peak shifting through on-site storage.

4.4 Results – Transportation Sector Measures

This section presents measure-level results for the transportation sector measures, starting with managed charging.

4.4.1 Managed Charging

The Study Team used hourly load shapes to examine the peak impact of EV charging and the effectiveness of different DR measures in shifting EV charging load. Load shapes for LDV come from the Geotab Charge the North dataset which uses data logged on light-duty EVs across Canada.[89,90] The load shapes for MHDV and buses are based on fleet vehicle data from California.[91]

Exhibit 88 shows results for managed charging measures in order of decreasing PAC. Like the rest of the Study DR measures, the PAC is used to assess the cost-effectiveness of the EV managed charging measures. Managed charging can be accomplished using electric vehicle supply equipment (EVSE) or vehicle telematics (VT).[92]

Exhibit 88: Transportation Sector Managed Charging Measures (2040)

End Use(s) Affected	Ownership Type	Managed Charging Method	Measure Name	kW Savings[93]	Medium PAC	Medium TRC
EV Charging	Fleet	VT	HDV – VT	19.85	86.1	430.5
	Fleet	VT	Bus – VT	7.00	30.4	151.9
	Fleet	EVSE	HDV – EVSE	19.85	18.8	12.9
	Fleet	VT	MDV – VT	4.07	17.7	88.4
	Fleet	EVSE	Bus – EVSE	7.00	14.8	14.2
	Fleet	EVSE	MDV - EVSE	4.07	5.3	4.0
	Fleet	VT	Light Duty BEV – VT	0.76	3.3	16.5
	Personal	VT	BEV – VT	0.66	2.9	14.3
	Personal	EVSE	BEV EVSE	0.66	2.6	6.3
	Personal	VT	PHEV – VT	0.52	2.3	11.3
	Personal	EVSE	PHEV – EVSE	0.52	2.0	5.0
	Fleet	EVSE	Light Duty BEV – EVSE	0.76	1.6	1.5
	Fleet	VT	Light Duty PHEV – VT	0.26	1.1	5.3
	Fleet	EVSE	Light Duty PHEV – EVSE	0.26	0.6	0.5

[89] The dataset contains tracking and charging data from over 1,000 EV drivers across Canada. IT provides EV load profiles insights and actions to minimize charging infrastructure upgrades.
[90] A CPP rate was not considered because Geotab Charge the North dataset does not include CPP analysis.
[91] Load shape data is limited, and there is no data available for Newfoundland.
[92] EVSE and VT are defined in the Definitions section.
[93] Savings are reported on a per vehicle basis.

Key findings include:

- All measures pass the TRC except for Fleet Managed Charging – LD PHEV – EVSE, which also fails the PAC screen. The poor performance of this PHEV measures is due to the limited peak impact of individual PHEVs compared to BEVs for the same measure cost.[94]
- For Personal Managed Charging, evidence from pilot programs across North America suggests annual enrolment incentives in the range of $50 to $200. The Study Team's analysis reflects $80 per year, but the Personal Managed Charging – BEV – EVSE measure would pass the PAC with an annual enrolment incentive of up to $164. All EVSE measures also include an upfront incentive of half the incremental cost of installing a smart charger.
- VT measures are the most cost-effective because there are no incremental hardware costs to upgrade from a non-smart charging capable vehicle to a smart charging capable vehicle.

4.4.2 Time-of-Use Rates

Exhibit 89 shows the transportation sector TOU rate measures by ownership type.

Exhibit 89: Transportation Sector TOU Rate Measures

End Use(s) Affected	Ownership Type	Measure Name
EV Charging	Personal	TOU - BEV
	Personal	TOU - PHEV

The Study Team examined the potential impact of a TOU rate to incentivize personal vehicle owners to charge outside of peak periods. The analysis relies on data from the Charge the North dataset for jurisdictions that already have a residential TOU in place.[95] The jurisdictions under study had AMI and employed TOU rates with "Off-Peak" rates beginning at 7:00 p.m. at the time of data collection. Applying the resulting load shapes to the forecast EV load in Newfoundland had little overall impact: the peak time shifted to later in the evening, but the amplitude of the peak remained similar.

This issue was addressed by studying the effects of the generic residential TOU rate structure described in section 4.1.1. The impacts of the TOU rates on EV load shapes from the Charge the North dataset were applied to estimate how EV load would behave for a TOU rate structure that had "Off-Peak" rates beginning at 10 p.m.[96] The resulting load shape was used to estimate the potential for peak savings for

[94] Fleet PHEVs are estimated to have 0.50 kW less peak reduction potential than fleet BEVs. The difference in peak reduction potential between personal PHEVs and BEVs is smaller at 0.14 kW. This is largely due fleet PHEVs having a much lower utility factor (the percentage of kilometres driven that are powered by the electric motor) than personal PHEVs.

[95] "Preparing for EVs: Charge the North EV Case Study," Geotab, Available: https://www.geotab.com/blog/preparing-for-evs/ (Accessed Jan. 30, 2024).

[96] The EV TOU load shapes in the Study are informed by GeoTab Charge the North data for EV charging in Ontario, where TOU rates are in effect. Despite the potential differences in the timing of TOU price periods between Ontario and Newfoundland, the Study Team deemed this was the best available information in the absence of Newfoundland-specific data.

TOU electricity rate design measures under two EV participation scenarios: opt-in and opt-out. These scenarios are defined in the callout that follows.

Personal EV TOU Participation Scenarios

The Study Team modelled two personal EV participation scenarios to assess the potential peak reduction from EV TOU rates: opt-in participation and opt-out participation. Both scenarios represent a future where the intermediate EV forecast scenario plays out. The opt-in and opt-out scenarios form lower and upper bounds for peak reduction potential, and are defined as follows:

- ***Opt-in participation scenario:*** *Reflects a 15% participation rate, which matches the one used for the residential sector TOU measure.*

- ***Opt-out participation scenario:*** *100% of EVs are on a time-of-use rate.*

Because EV charging loads are flexible, EV owners are likely to make up a higher portion of the 15% of residential sector customers who participate in the TOU rate, compared to non-EV owners. In the early forecast years, when the number of EVs in Newfoundland is less than 15% of the number customers, the opt-out scenario represents a future where all personal EV owners participate in the EV TOU rate. For example, if there are 100,000 residential customers, and 10,000 EVs in Newfoundland, all personal EV owners participate in the EV TOU rate.

In later forecast years, when more than 15% of customers are expected to own an EV, the opt-out scenario represents a future where a separate EV rate may be offered to allow for more than 15% of all customers to be on an EV TOU rate (i.e., so that EV TOU participation could exceed whole-home TOU participation). For example, if there are 100,000 residential customers, and 20,000 EVs, 20% of residential customers would participate in the EV TOU rate.

Neither participation scenario assumes all EVs charge off-peak on a given night. The Study Team used aggregate load shapes (i.e., load shapes that reflect the charging patterns of thousands of vehicles) to assess the impact of each scenario. In addition, neither scenario assumes there is a separate meter for EVs charging. Virtual submetering or metering through EVSE could be leveraged to offer an EV TOU rate separate from the whole home TOU rate.

Fleet TOU measures were excluded from the Study because limited data exists on the impact of dedicated TOU rates for commercial fleets. In addition, commercial customers are already subject to a demand charge which acts as an incentive to limit local peak impacts at individual sites. As seen in Exhibit 67, the fleet vehicle charging peak overlaps with the IIS evening peak. This suggests that reductions in local peak impacts attributed to demand charges would also provide benefits for the IIS system.

A TOU rate can have a much larger effect on EV charging compared to any other end use in the residential, commercial and industrial sectors because EV charging is flexible (depending on the number of EVs participating). Exhibit 90 shows the medium achievable PAC results by sector for the TOU measure. Three results are shown for the residential sector: excluding EVs, including EVs with opt-in participation, and including EVs with opt-out participation. The results reflect costs and benefits incurred during the four-year AMI meter installation period, and the 20-year smart meter lifetime.

The PAC is less than 1 for all sectors, though the residential sector result including EVs with opt-out participation meets the PAC screening threshold of 0.8.

Exhibit 90: Medium Achievable PAC Cost-Effectiveness Test Results – Electricity Rate Design Measures

Measure	Residential (Excl. EVs)	Residential (Incl. EVs, Opt-In)	Residential (Incl. EVs, Opt-Out)	Commercial	Industrial
TOU	0.12	0.20	0.95	0.29	0.39

4.4.3 Adoption Incentives

Exhibit 91 shows the transportation sector adoption incentive measures. These measures represent the incremental per-vehicle incentive required to lift EV adoption from the natural adoption scenario to reach the intermediate and government targets scenarios. See Appendix E for details of the Study Team's approach to assessing the adoption incentive measures.

Exhibit 91: Transportation Sector Adoption Incentive Measures

End Use(s) Affected	Measure Name
EV Charging	• Personal LDV • Fleet LDV • MDV • HDV • Bus

Personal LDV

Exhibit 92 shows that, compared to the natural adoption scenario, a median annual per-vehicle incremental incentive of $23,833 would be required to achieve the EV adoption levels in the government targets scenario.[97] To reach the EV adoption levels in the intermediate scenario, a $4,691 incremental incentive would be required.

Exhibit 92: Results - Transportation Sector Personal Vehicle Adoption Incentives

Incremental Step	Median Annual Per-Vehicle Incremental Incentive[98]	Median Annual Incentive Program Budget (millions)
To reach the government targets scenario from the natural adoption scenario	$23,833	$303
To reach the intermediate scenario from the natural adoption scenario	$4,691	$30

[97] If government targets for EV adoption are mandated, the Utilities would not provide incentives.

[98] This is the median of the incentive values that newly purchased EVs would receive across all years of the Study forecast period.

Fleet LDV, MDV, and HDV

There is no literature to support sales market share uplift of fleet vehicles due to purchase incentives. This could be because fleet vehicles are earlier in their adoption curve compared to personal BEV, so sample sizes are limited. The Study Team offers the following thoughts:

- Fleet LDV and lighter-duty MDV may behave like personal LDV based on their incremental capital costs, vehicle kilometres travelled (VKT), and reliance on L2 chargers.[99]
- HDV probably behave differently than personal LDV based on their incremental capital costs, VKT, and reliance on DCFC chargers in many cases.[99] Directionally, the absolute per-vehicle incentive values and total annual incentive budgets may need to be much higher for HDV than for personal LDV.

[99] National Renewable Energy Laboratory, "Transportation Annual Technology Baseline (ATB) Data", Available: https://atb.nrel.gov/transportation/2022/data (Accessed: Nov. 30, 2024).

4.4.4 Infrastructure Requirements

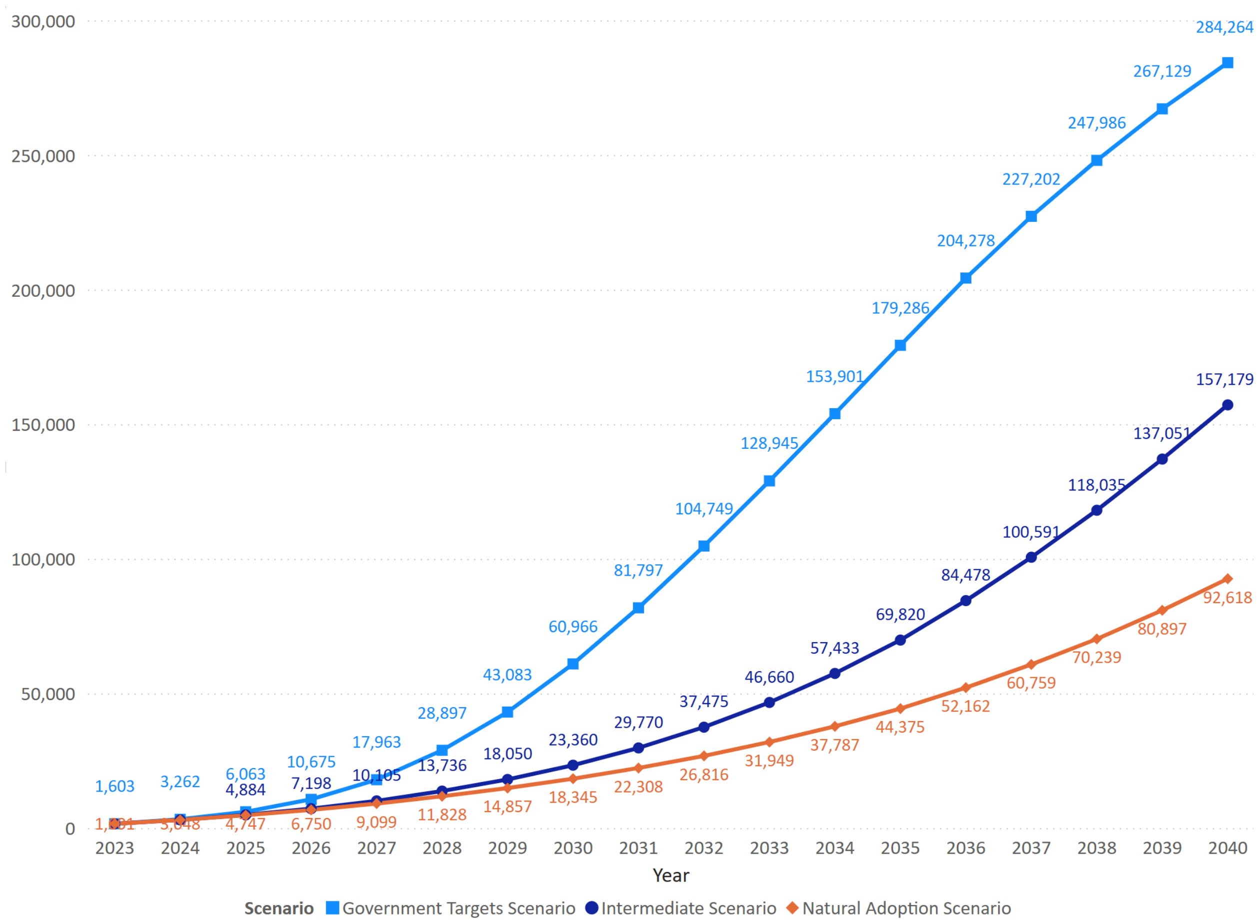
Exhibit 93 shows the transportation sector charging infrastructure measures. The Study Team calculated the number of charging ports and the investment required to support vehicle counts in the natural adoption, intermediate, and government targets scenarios. Results are shown in Exhibit 94 and Exhibit 95. See Appendix E for details of the Study Team's approach to these calculations.

Exhibit 93: Transportation Sector Charging Infrastructure Measures

End Use(s) Affected	Measure Name
EV Charging	• Personal LDV Level 1 (L1) Home Charger • Personal LDV Level 2 (L2) Home Charger • Personal LDV L2 Home Charger – Multi-Unit Residential Building (MURB) • Personal LDV L2 Public Charger • Personal LDV DCFC Public Charger • Fleet LDV L2 Depot Charger • Fleet LDV L2 Public Charger • Fleet LDV Direct Current Fast Charger (DCFC) Depot Charger • Fleet LDV DCFC Public Charger • MDV L2 Depot Charger • MDV L2 Public Charger • MDV DCFC Depot Charger • MDV DCFC Public Charger • HDV L2 Public Charger • HDV DCFC Deport Charger • HDV DCFC Public Charger • Bus L2 Depot Charger • Bus DCFC Depot Charger

Exhibit 94 shows the cumulative number of ports (including L1, L2, and DCFC) required per forecast EV scenario.[100] By 2040, 284,264 ports are required in the government targets scenario, compared to 157,179 ports in the intermediate scenario and 92,168 in the natural adoption scenario.

Exhibit 94: Results - Transportation Sector Charging Infrastructure Port Count by Scenario



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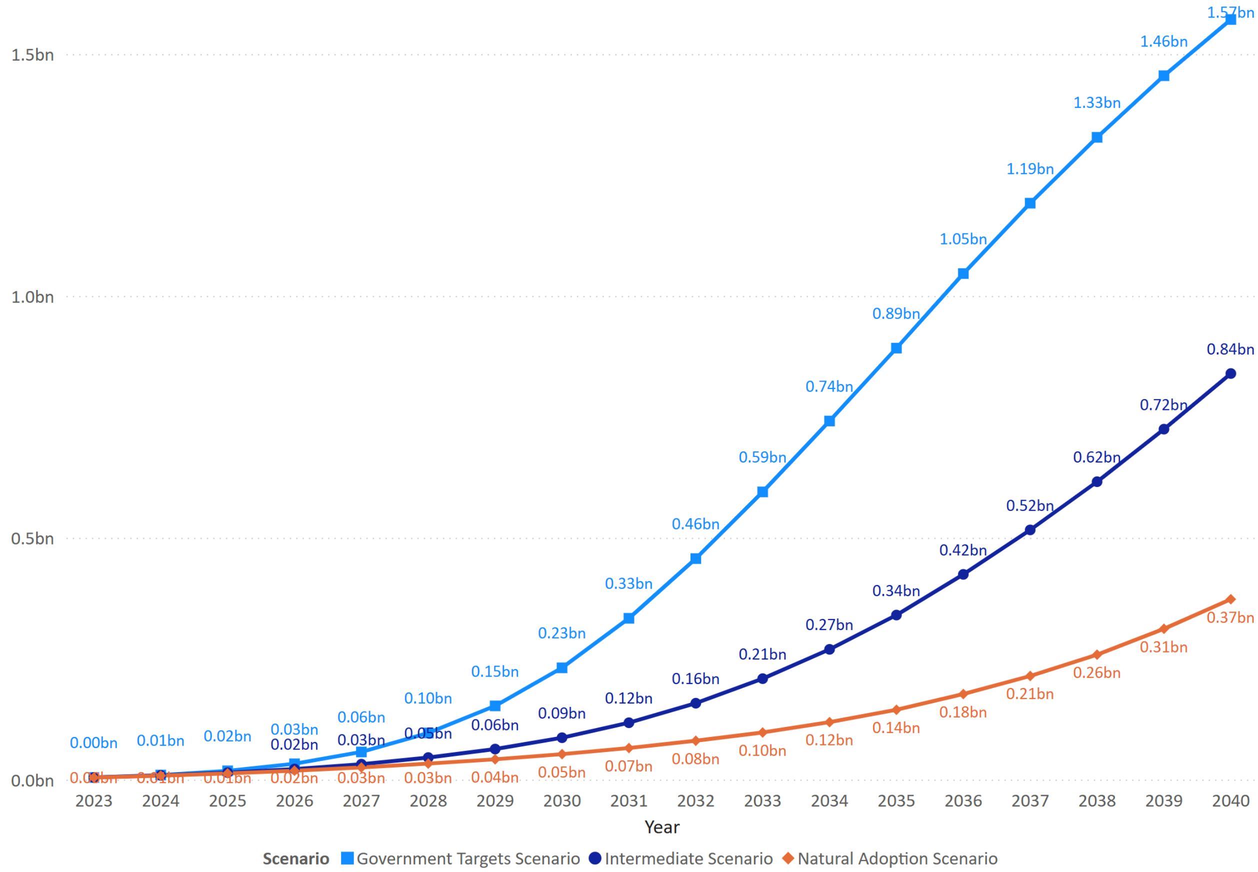
[100] The values in each year represent the sum of the infrastructure requirements for all preceding years and the year in question.

Exhibit 95 shows the cumulative investment required for each forecast EV scenario. By 2040, an estimated $1.57 billion in cumulative charging infrastructure investments is required to reach the government targets scenario, compared to $0.84 billion in the intermediate scenario and $0.37 billion in the natural adoption scenario.[101]

Exhibit 95: Transportation Sector Charging Infrastructure Investment Required by Scenario ($)



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[101] In the Study, charging infrastructure refers to the ports required to support electric vehicle charging in the Transportation sector. Charging infrastructure costs include port costs and associated installation costs. Costs exclude distribution system upgrades to host charging loads.

Exhibit 96 and Exhibit 97 show the distribution of charging infrastructure investment and the distribution of port count across charger types, respectively. By the end of the forecast period, infrastructure investment is almost evenly split between DCFC chargers and L2 chargers (L1 chargers are assumed to be provided by the vehicle manufacturer at point of vehicle sale).

Exhibit 96: Transportation Sector Charging Infrastructure Investment (Intermediate Scenario)

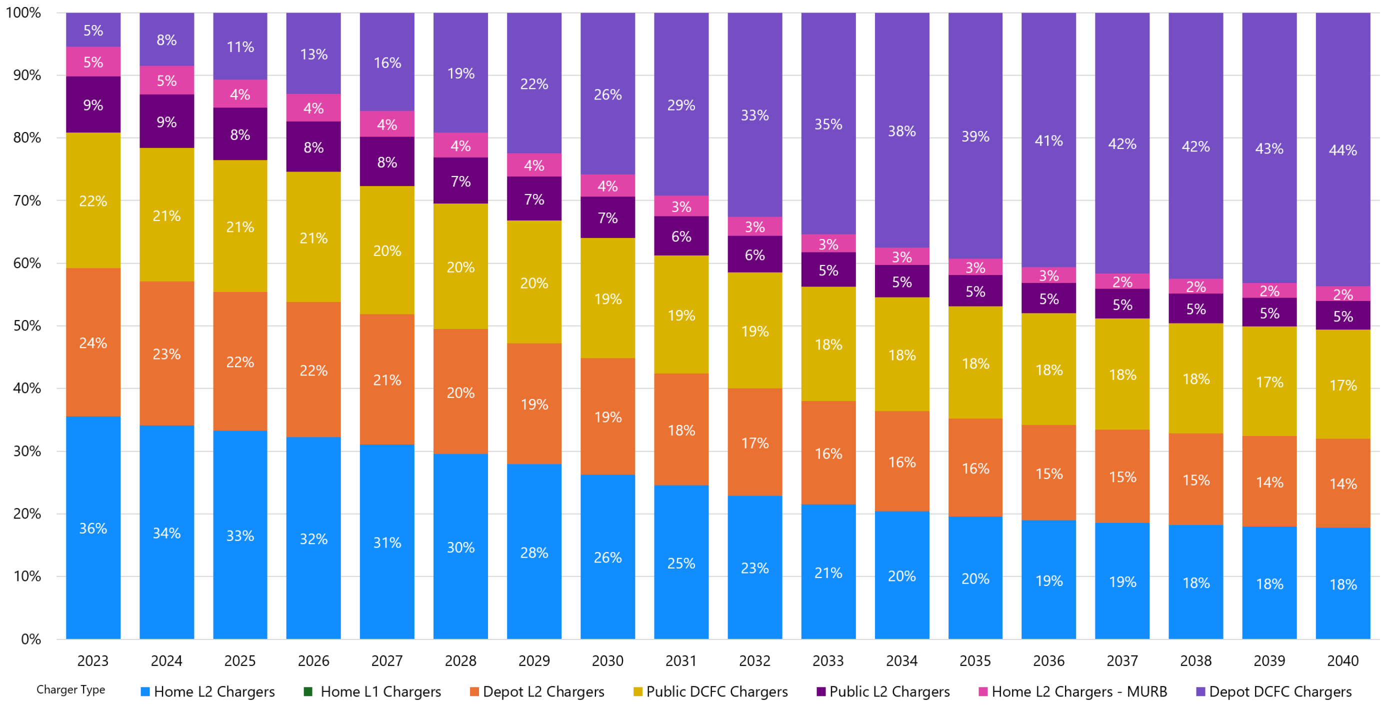
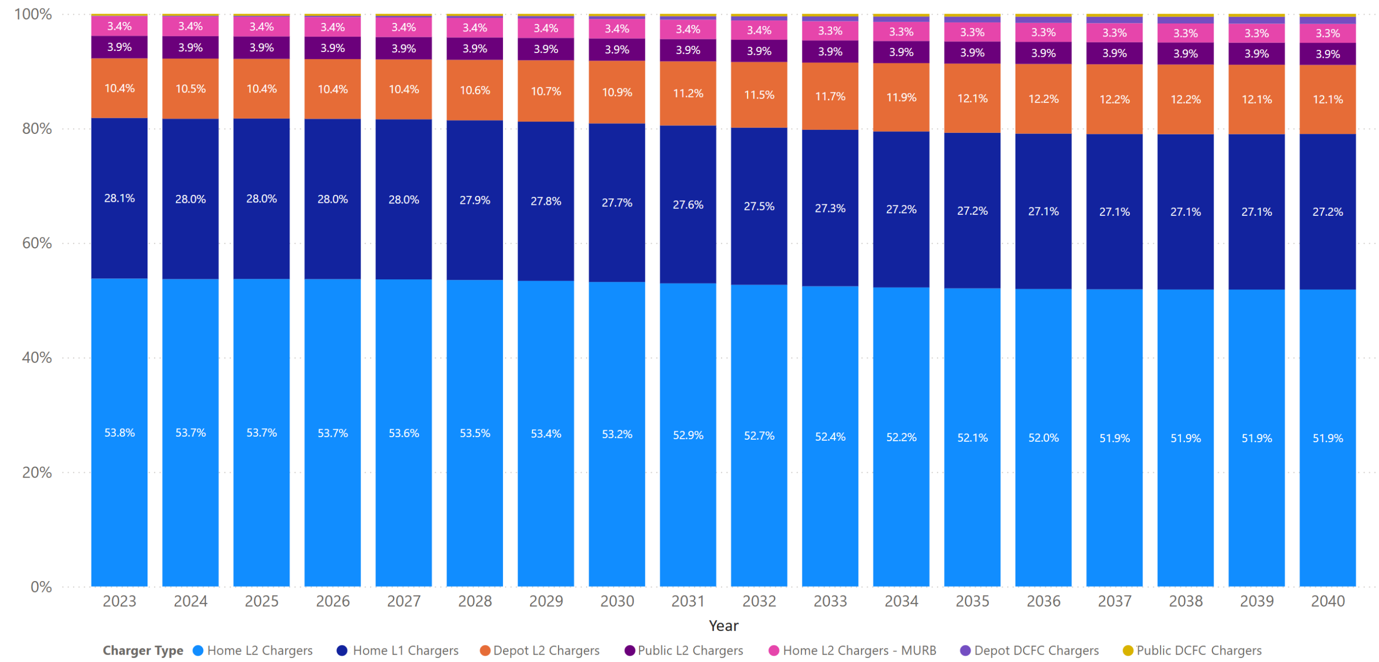


Exhibit 97 reveals the following:

- L1 and L2 home chargers dominate the port count compared to DCFC chargers, even though the investment is split more evenly for infrastructure investment due to the high cost of DCFC chargers versus L2 chargers as noted previously.
- Overall, home or depot chargers outnumber public chargers, though the per-unit cost of DCFC chargers attenuates this effect for charging infrastructure investment.[102]

Exhibit 97: Transportation Sector Port Count (Intermediate Scenario)



Charger Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Home L2 Chargers	53.8%	53.7%	53.7%	53.7%	53.6%	53.5%	53.4%	53.2%	52.9%	52.7%	52.4%	52.2%	52.1%	52.0%	51.9%	51.9%	51.9%	51.9%
Home L1 Chargers	28.1%	28.0%	28.0%	28.0%	28.0%	27.9%	27.8%	27.7%	27.6%	27.5%	27.3%	27.2%	27.2%	27.1%	27.1%	27.1%	27.1%	27.2%
Depot L2 Chargers	10.4%	10.5%	10.4%	10.4%	10.4%	10.6%	10.7%	10.9%	11.2%	11.5%	11.7%	11.9%	12.1%	12.2%	12.2%	12.2%	12.1%	12.1%
Public L2 Chargers	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%
Home L2 Chargers - MURB	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%
Depot DCFC Chargers	0.1%	0.1%	0.2%	0.2%	0.3%	0.3%	0.4%	0.5%	0.6%	0.7%	0.8%	0.9%	1.0%	1.1%	1.1%	1.2%	1.2%	1.2%
Public DCFC Chargers	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%

[102] The Public category includes, L2 chargers for personal (i.e., not fleet) use that are situated at commercial sector buildings.

4.4.5 Emerging Measures

Exhibit 98 shows emerging measures for the transportation sector. Emerging measures allow EVs to send energy back to the electricity grid, which can be useful when the grid is constrained, and additional generation is required.[103]

Exhibit 98: Transportation Sector Emerging Measures

End Use Affected	Measure Name
EV Charging	Vehicle to Load (V2L)
	Vehicle to Building (V2B)
	Vehicle to Grid (V2G)

Emerging measures can be categorized into three classes:

1. **Vehicle to load** applications use vehicle battery power as a backup source for localized loads within a site.
2. **Vehicle to building** applications enable feeding battery power from the vehicle to serve end uses in the building and are expected to primarily serve for building resilience but may also reduce building peak power demand.
3. **Vehicle to grid** applications enable feeding battery power from the vehicle back to the grid during peak periods.

These emerging measures are at the preliminary research and demonstration project stage in North America. Most research occurs in California. Generally, V2G and V2B applications are expected to be more complex and later to scale compared to V2L applications.[104] Focus segments are LDV and school buses.

A limited but growing number of LDV manufacturers include bidirectional charging capabilities in their vehicles.[105] Research suggests that the value of emerging measures to the power grid could ultimately exceed the value of managed charging.[106] Reliable data on measure costs and the relationship between

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[103] Electric Vehicle Association of Alberta, "The Current State of Bidirectional EV Charging in Canada", Available: https://albertaev.ca/bidirectional-ev-charging-in-canada/#:~:text=This%20bidirectional%20energy%20transfer%20allows,economic%20benefits%20to%20EV%20owners (Accessed: Nov. 30, 2024).
[104] Smart Electric Power Alliance, "The State of Managed Charging in 2021", Available: https://sepapower.org/resource/the-state-of-managed-charging-in-2021/ (Accessed: Nov. 30, 2024).
[105] The following manufacturers appear to currently offer or plan to offer bidirectional charging capabilities in their vehicles by 2026: Ford, Nissan, Hyundai, Kia, Volkswagen, General Motors, Tesla, and Mitsubishi.
[106] American Public Power Association, "Public power utilities, others, pursue vehicle-to-grid opportunities", Available: https://www.publicpower.org/periodical/article/public-power-utilities-others-pursue-vehicle-grid-opportunities (Accessed: Nov. 30, 2024).

participant uptake and program costs does not exist yet.[107] The Study Team recommends that the Utilities monitor pilot study results to develop this data over time.

The Utilities can consider the following activities to prepare their grids to realize the benefits of bidirectional charging, with consideration also given to the costs and barriers required to implement the activities:[108, 109, 110]

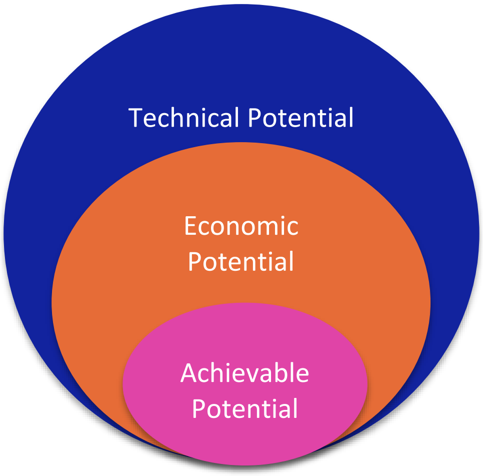
- Deploy smart meters,
- Require utility customers to register EV chargers with the utility, and,
- Develop and adopt standardized privacy-compliant communication protocols between the utility grid control system, the vehicles, and the chargers.

[107] For these reasons, the Study Team did not assess the cost-effectiveness of emerging measures.
[108] "Vehicle-to-Grid: Can This Tech Save the Planet and Make Drivers Money?" Just Energy, Available: https://justenergy.com/blog/vehicle-to-grid/ (Accessed Jul. 2024).
[109] Preparing for the Vehicle-to-Grid (V2G) Revolution | GE Digital
[110] "Vehicle to Grid Readiness Worldwide," Berylls, Available: https://www.berylls.com/vehicle-to-grid-readiness-worldwide/, (Accessed Jul. 2024).

5 Efficiency Savings Potential

This section presents energy efficiency savings potential results for the IIS. The Study Team assessed three levels of savings potential: technical, economic, and achievable, described as follows:[111]

1. **Technical Potential:** An estimate of the technically feasible energy and demand savings potential, ignoring measure cost effectiveness or market acceptance.
2. **Economic Potential:** An estimate of the energy and demand savings potential for the measures in the technical potential that also pass the cost effectiveness screening criteria established for the Study.[112] The total resource cost (TRC) test is used to screen efficiency measures. Measures are included in the economic potential if their benefit-cost ratio is 0.8 or higher.



3. **Achievable Potential**: An estimate of the energy and demand savings potential considering feasible adoption rates of cost-effective measures over the study period. Achievable potential considers market barriers, customer or end-user payback acceptance, and awareness of energy efficiency measures among other factors. The achievable scenarios are defined as follows:
    - **Lower**: Incentive is 25% of incremental cost for ROB measures and 25% of full cost for RET measures.
    - **Medium**: Incentive is 50% of incremental cost for ROB measures and 50% of full cost for RET measures.
    - **Higher**: Incentive is 100% of incremental cost for ROB measures and 100% of full cost for RET measures.

In all three achievable potential scenarios, non-incentive costs are set to 25% of the measure-level incentive. While 25% is a standard estimate used for the purposes of this Study, non-incentive costs would vary from program to program.

[111] "Foreword" Independent Electricity System Operator, Available: https://www.ieso.ca/-/media/Files/IESO/Document-Library/conservation/APS/2019-Achievable-Potential-Study-Foreword.pdf (Accessed Dec. 11, 2024).
[112] The economic potential does not consider incentive and non-incentive costs.

The rest of this section presents results and analysis for the medium achievable potential scenario, except otherwise noted. As explained in section 2, all savings are presented in at-the-meter terms, instead of at-the-generator terms. Therefore, savings results exclude line losses in the transmission and distribution network. Line losses are added to the at-the-meter savings to calculate at-the-generator savings, which are used in the TRC calculations.[113] In addition, all savings presented are cumulative.

Adoption Rates for Achievable Potential Scenarios - Efficiency

The Study Team developed measure-level adoption rates for each achievable potential scenario with consideration to:

1. Savings the Utilities have achieved historically for measures common to the Study and their historical programs.

2. Feedback from the Utilities and the EAC regarding current and 2040 expected market share for measures discussed in the achievable potential workshops.

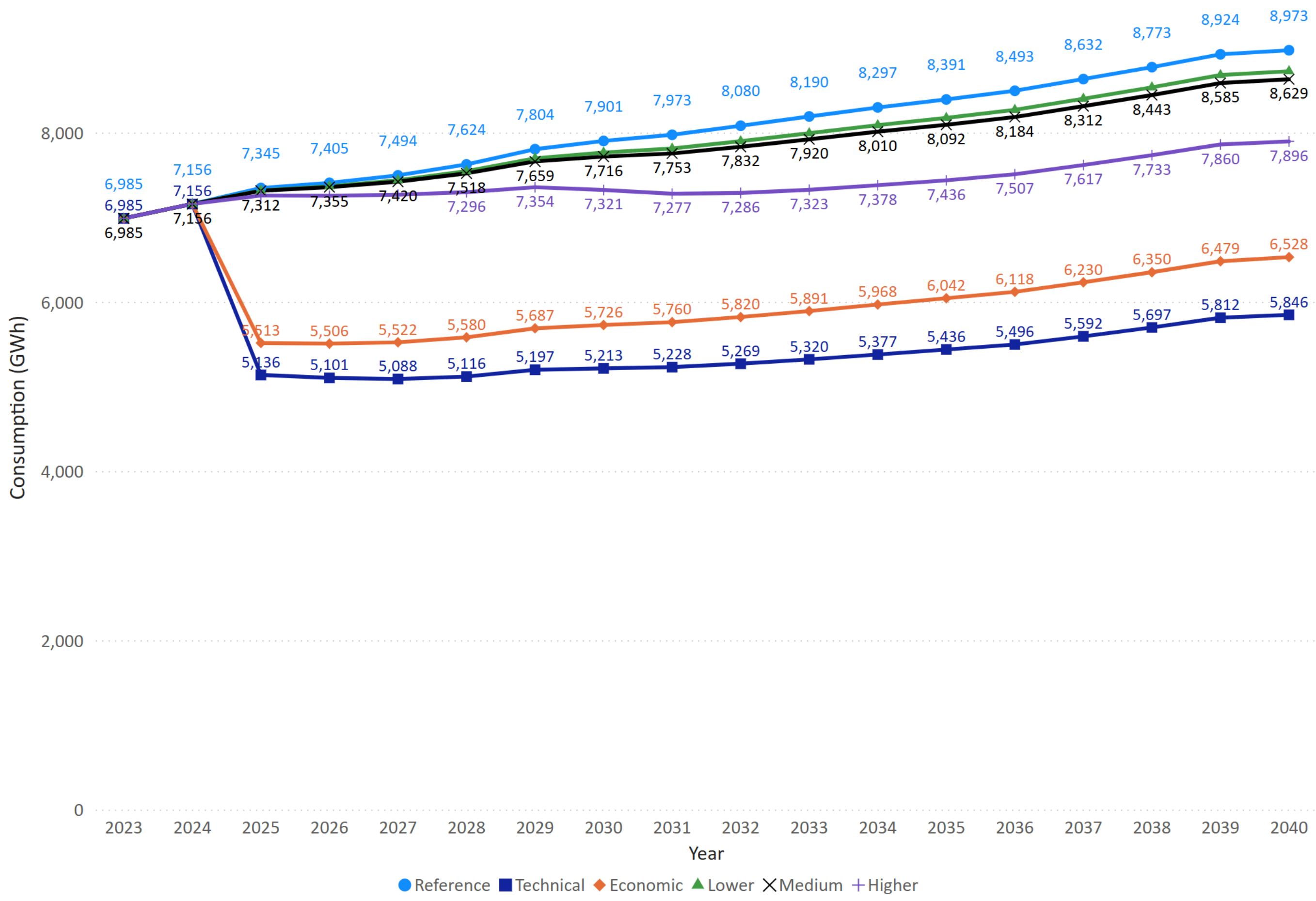
3. How results from items 1 and 2 could be extrapolated for like-measures in the Study.

[113] "Reliability and Resource Adequacy Study – 2024 Update," Newfoundland and Labrador Hydro, Available: https://nlhydro.com/wp-content/uploads/2024/07/2024-07-09_NLH_RRA-Study_2024-RAP.pdf (Accessed Nov 29, 2024).

5.1 Aggregate Efficiency Results – Annual

Exhibit 99 shows annual consumption in the reference case and by potential scenario.[114] The difference between the reference case consumption and the consumption in each of the technical, economic and achievable scenarios represents cumulative potential savings. For example, savings in 2025 represent potential for measures adopted that year, whereas savings in 2040 represent savings for measures adopted that year, plus the savings for all measures adopted between 2025 and 2039, provided they did not reach end of life in that period.

Exhibit 99: Annual Consumption by Scenario - Efficiency



The following observations can be made on Exhibit 99:

- The technical potential consumption is the lowest of all potential scenarios, since it represents the adoption of all measures if cost-effectiveness and market barriers are ignored. Technical potential savings represent 2,209 GWh (30%) and 3,127 GWh (35%) compared to the reference case in 2025 and 2040, respectively.
- The economic potential offers approximately 1,832 GWh (25%) and 2,445 GWh (27%) of savings compared to the reference case in 2025 and 2040, respectively. This means there are 377 GWh

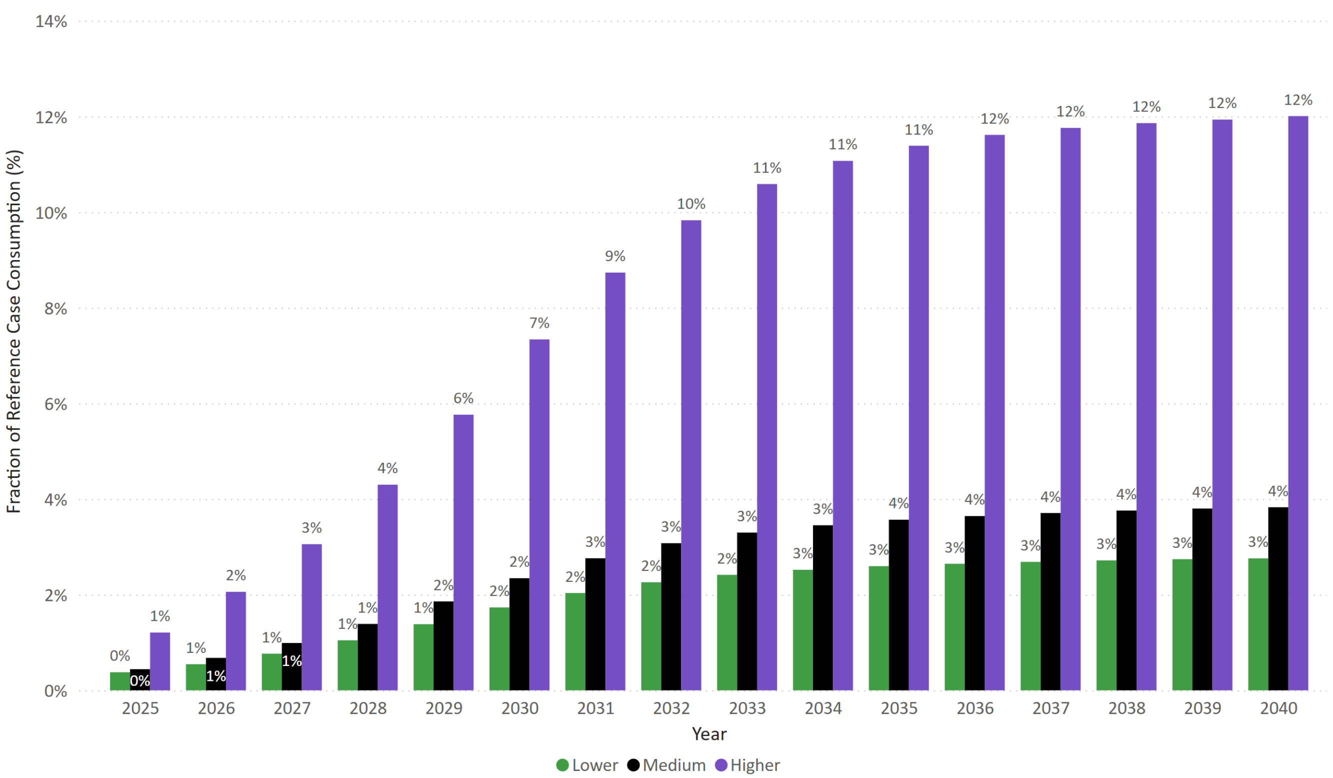
[114] The reference case in Exhibit 99 and Exhibit 100 includes intermediate scenario EV consumption.

and 682 GWh of technical potential savings that are not cost-effective in 2025 and 2040, respectively.

- The difference in consumption between the lower and medium achievable potential scenarios is approximately 100 GWh by 2040, while the difference in consumption between the medium and higher achievable potential scenarios is approximately 700 GWh by 2040. This suggests that doubling the incentive between the lower and medium achievable scenarios has a smaller impact on measure adoption than doubling the incentive between the medium and higher achievable scenarios.[115]

Exhibit 100 shows annual achievable potential savings as a fraction of reference case consumption.

Exhibit 100: Aggregate Savings Potential – Efficiency



The results in Exhibit 100 show the following:

- Potential savings increase most dramatically from 2025 to 2032, before leveling off starting in 2033. This is a result of some measures (e.g., smart and programmable thermostats and insulation in the residential sector) approaching market saturation in later study years.
- By 2040, achievable potential savings in the higher scenario (1,077 GWh) reach 12% of reference case consumption, and 3% (248 GWh) and 4% (343 GWh) in the lower and medium scenarios, respectively.[115]

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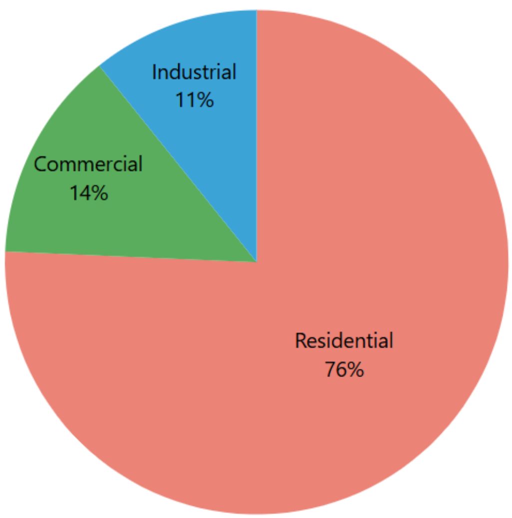
[115] As stated in the introduction to section 5, incentives in the lower, medium and higher achievable potential scenarios offset 25%, 50% and 100% of measure cost, respectively.

5.2 Efficiency Savings Potential by Sector – Annual

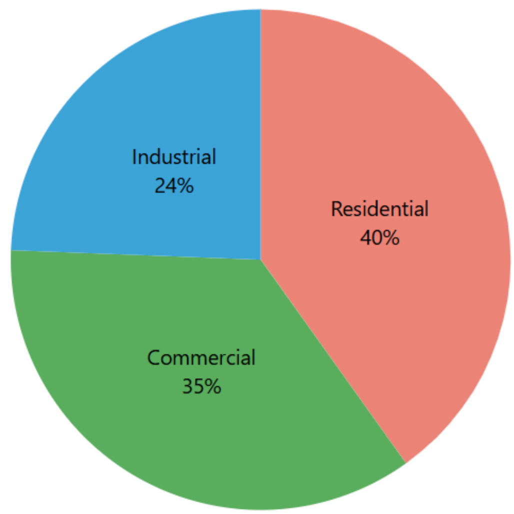
Exhibit 101 shows medium achievable potential savings by sector in 2025 and 2040. As noted previously, all savings are cumulative starting in 2025. Potential savings increase from 32 GWh in 2025 to 344 GWh by 2040. In both milestone years, the highest potential exists in the residential sector. The 2025 potential savings allocation by sector is directionally consistent with recent ECDM program results, in which residential sector programs contributed 88% of total energy savings in 2023.

By 2040, potential savings by sector are more consistent with the reference case electricity consumption forecast by sector: the residential sector is forecast to contribute 54% of reference consumption and 40% of medium achievable savings; commercial 34% of consumption, 35% of savings; and the industrial sector contributing higher relative savings levels with 12% of reference consumption and 24% of savings.

Exhibit 101: Medium Achievable Potential Savings by Sector, 2025 (left) and 2040 (right) – Efficiency



2025 Energy Savings Potential: 32 GWh



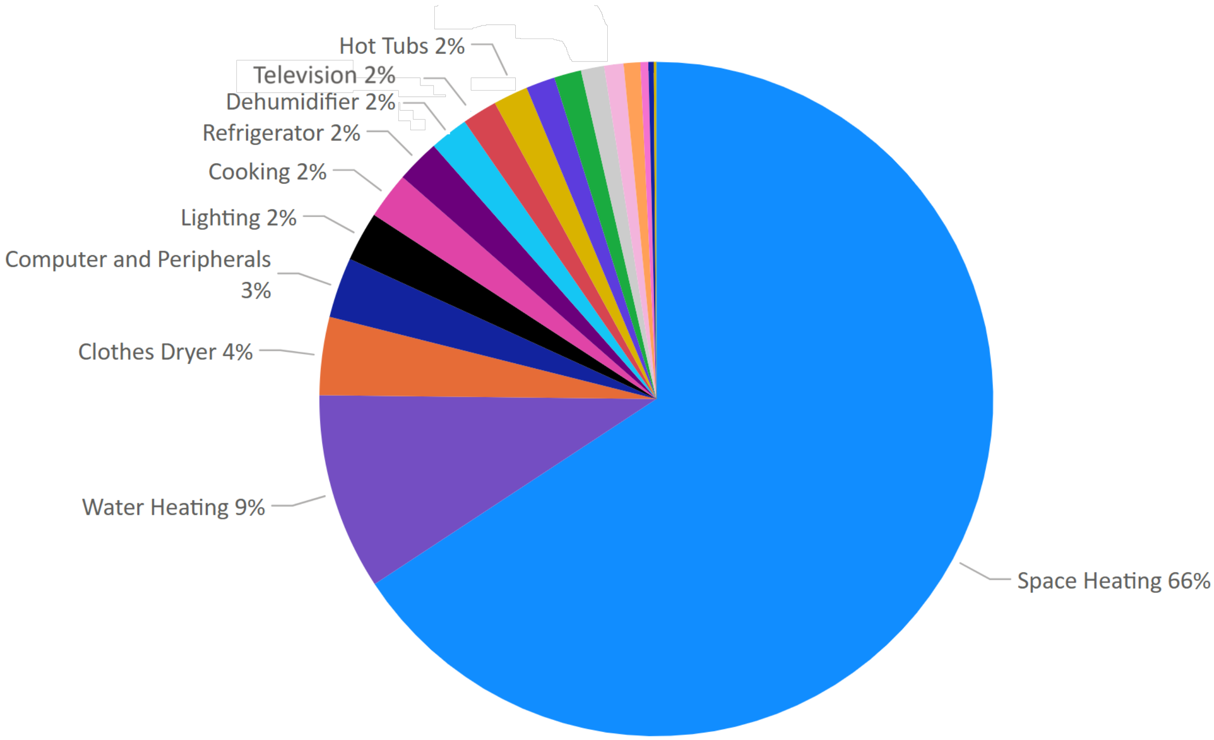
2040 Energy Savings Potential: 344 GWh

This results presented in sections 5.2.1, 5.2.2 and 5.2.3 that follow show medium achievable potential savings results by sector.

5.2.1 End Use Breakdown and Top Energy Savings Measures – Residential Sector

Exhibit 102 shows cumulative residential sector medium achievable potential energy savings by end use in 2025. Space heating offers most of the potential savings (66%), followed by water heating (9%) and clothes drying (4%).[116] Most of the residential sector efficiency measures (48%, or 31 of 64) target the space heating end use, and space heating contributes the most to total sector consumption (53% in 2023).

Exhibit 102: Residential Potential Savings by End Use – Efficiency (2025)

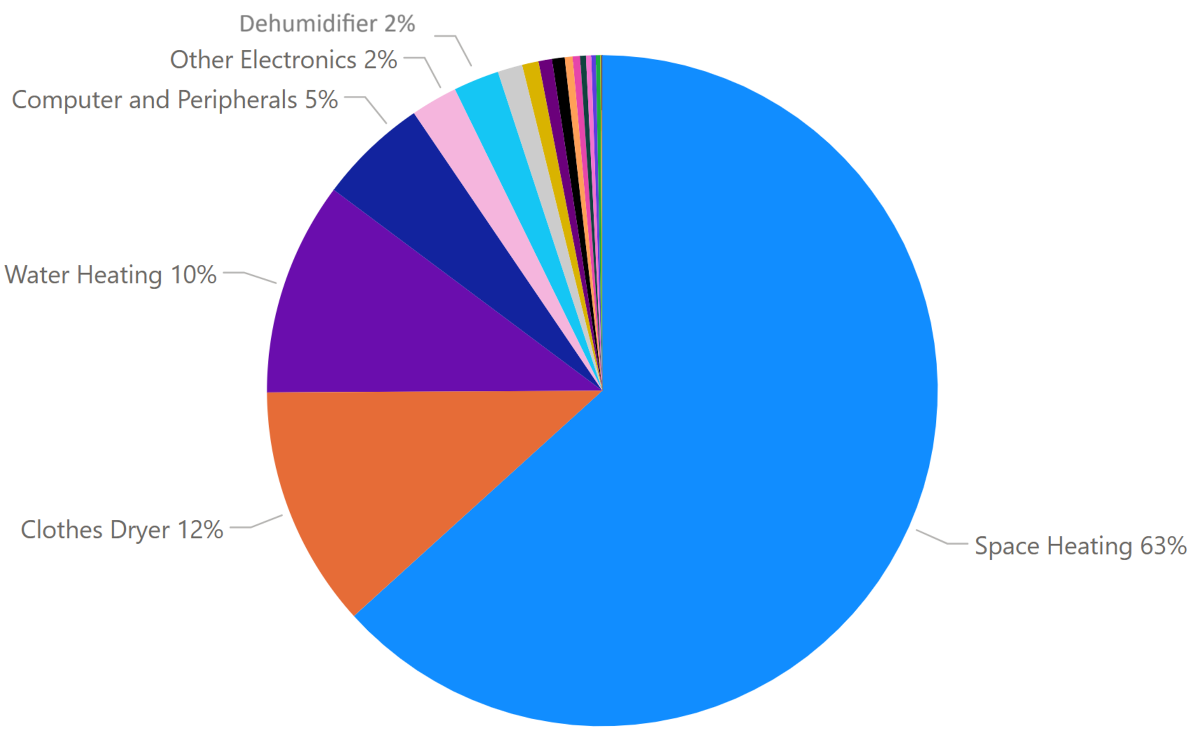


2025 Residential Energy Savings Potential: 25 GWh

[116] End uses that contribute less than 2% to the medium achievable potential savings are not labelled to improve readability: hot tubs (1%), small appliance and other (1%), television peripherals (1%), freezer (1%), other electronics (1%), ventilation (1%), space cooling (0.4%), dishwasher (0.3%), and clothes washer (0.1%).

Exhibit 103 shows cumulative residential sector medium achievable potential energy savings by end use in 2040.[117] The contributions of space heating and water heating to total potential savings change by 3% or less compared to 2025.

Exhibit 103: Residential Potential Savings by End Use – Efficiency (2040)



2040 Residential Energy Savings Potential: 138 GWh

[117] End uses that contribute less than 2% to the medium achievable potential savings are not labelled to improve readability: freezer (1%), hot tubs (1%), refrigerator (1%), lighting (1%), ventilation (0.4%), cooking (0.4%), television (0.3%), space cooling (0.3%), small appliance and other (0.2%), television peripherals (0.2%), clothes washer (0.05%), and dishwasher (0.04%).

Exhibit 104 shows savings for the top ten residential sector efficiency measures in 2025 and 2040.

Exhibit 104: Residential Top Ten Efficiency Measures by Potential Savings - Annual

Measure	2025 Savings (GWh)	Measure	2040 Savings (GWh)
Home Energy Report	16.16	Ductless Mini Split Air Source Heat Pump[118]	28.53
Air Sealing	2.43	Clothes Lines and Drying Racks	16.09
Basement Ceiling Insulation	1.64	Home Energy Report	14.12
Ductless Mini Split Air Source Heat Pump	0.94	Heat Recovery Ventilator (Ductless) – Standard to High Efficiency	11.87
Basement Wall Insulation	0.74	Advanced Smart Strips and Plugs	10.05
Attic Insulation	0.60	Heat Pump Water Heater[119]	7.63
Smart Thermostat (Multiple)	0.37	Central Ducted Air Source Heat Pump	7.11
Programmable Thermostat (Multiple)	0.35	Air Sealing	7.04
Clothes Lines and Drying Racks	0.35	Heat Recovery Ventilator (Ducted) – Standard to High Efficiency	4.44
Efficient Windows	0.26	Duct Insulation	3.98

Observations on Exhibit 104 include:

- Home energy reports offer the highest savings potential in 2025 (16.16 GWh), driven by a high adoption rate and no cost to participants. Adoption rates remain high throughout the Study period, so home energy reports are among the top ten measures in 2040.
- In 2025, one of the top ten efficiency measures is equipment-based (ductless mini split air source heat pumps). In 2040, this increases to three of the top ten efficiency measures (ductless mini split air source heat pumps, heat pump water heaters, and central ducted air source heat pumps). This result is attributed to the slower adoption ramp up for expensive measures, and an expected increase in heat pump adoption during the forecast period.[120]

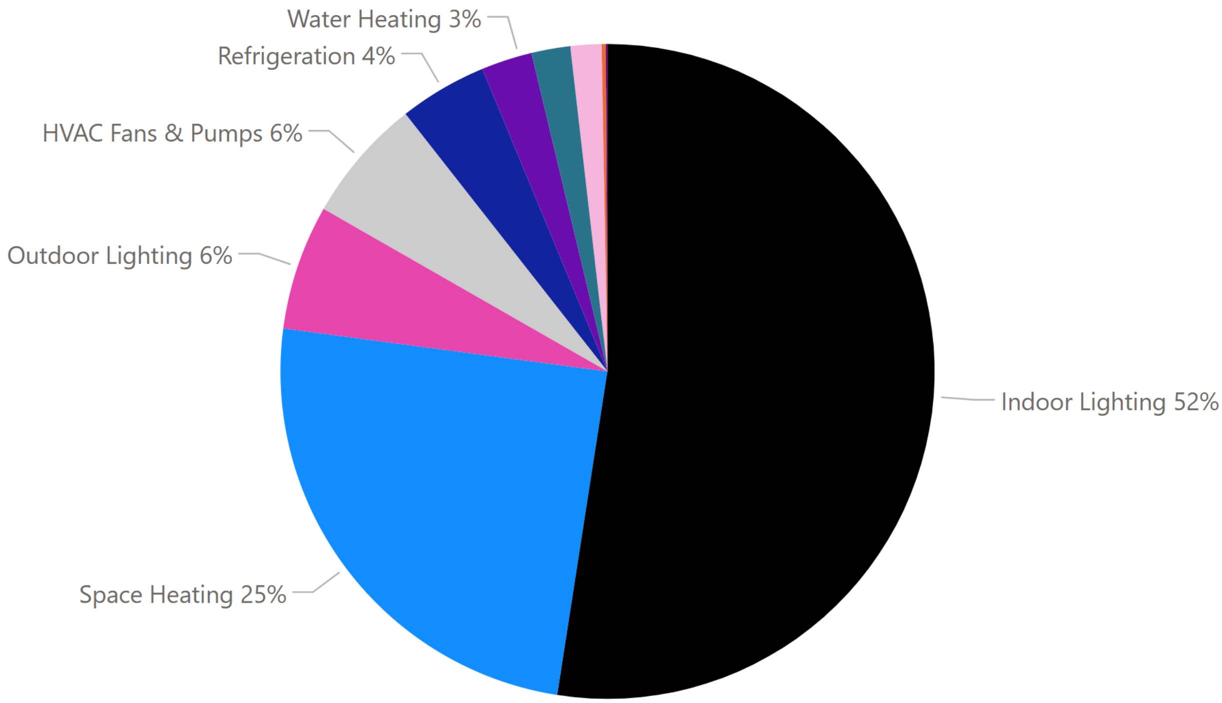
[118] This measure upgrades a baseline electric baseboard heating system to an air source ductless mini-split heat pump with an electric baseboard heat back up.
[119] The Study Team assumed the interactive effect of heat pump water heater technologies with total dwelling space heating consumption was negligible.
[120] Achievable potential workshop participants expect that ductless mini split heat pumps will become saturated in the market by 2040.

- Envelope measures (air sealing, insulation, windows, etc.) comprise five out of the top ten efficiency measures in 2025, but only one of the top ten efficiency measures in 2040. This result is driven by the relatively low-cost barrier for some of these measures and the relatively high opportunity for others, causing rapid ramp up. Most of the available opportunity is forecast to be captured by 2040.

5.2.2 End Use Breakdown and Top Energy Savings Measures – Commercial Sector

Exhibit 105 presents cumulative medium achievable potential energy savings for the commercial sector by end use in 2025. In 2025, lighting offers over half of the potential savings (52%).[121,122]

Exhibit 105: Commercial Potential Savings by End Use – Efficiency (2025)



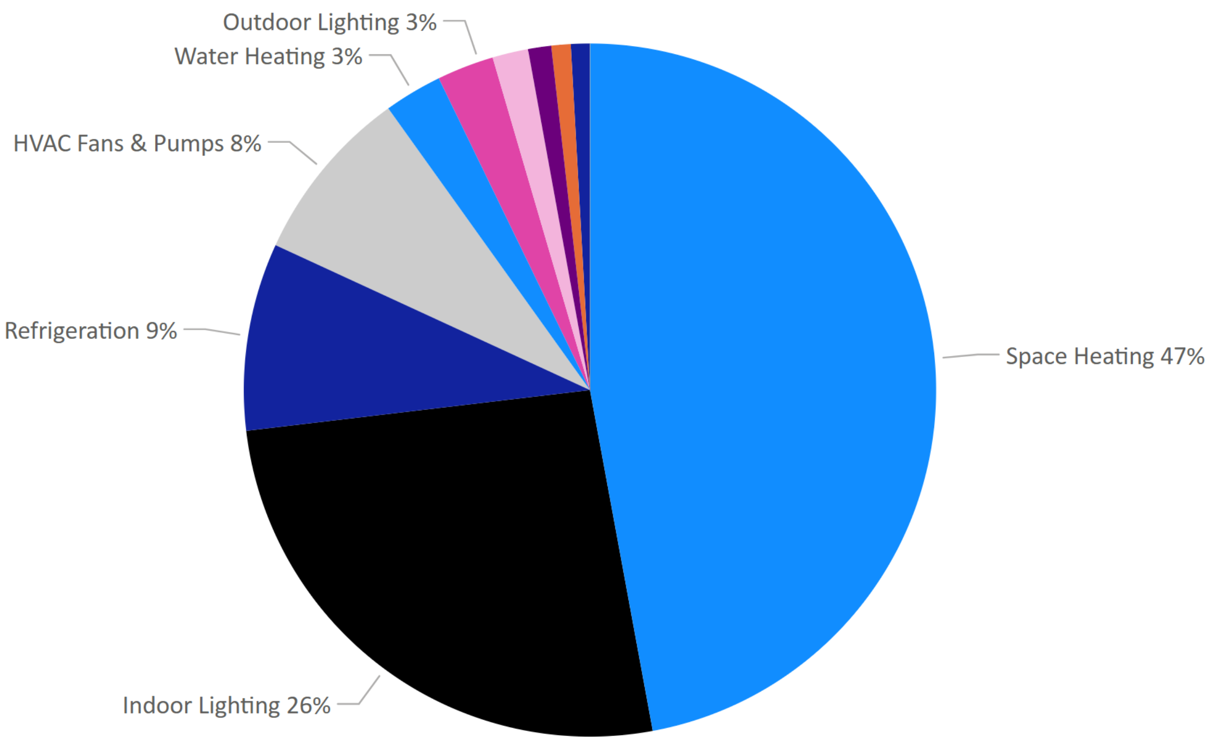
2025 Commercial Energy Savings Potential: 4 GWh

[121] Indoor lighting includes general lighting, secondary lighting and high bay lighting.
[122] End uses that contribute less than 3% to the medium achievable potential savings are not labelled to improve readability: street lighting (2%), space cooling (2%), plug loads (0.2%), food service equipment (0.08%), and miscellaneous equipment (0.003%).

Exhibit 106 shows that by 2040, indoor lighting's contribution to potential savings for the sector drops to 26%.[123] The decrease in lighting's contribution to total potential can be attributed to the following factors:

- The reference adoption of interior LED lighting in 2025 is already high at approximately 60%, meaning that only 40% of commercial floor space is lit by non-LEDs.[124,125]
- No adoption of LED lamps from 2028 onwards because of Natural Resources Canada's Amendment 18, as described in the callout that follows.[126]

Exhibit 106: Commercial Potential Savings by End Use – Efficiency (2040)



2040 Commercial Energy Savings Potential: 122 GWh

[123] End uses that contribute less than 3% to the medium achievable potential savings are not labelled to improve readability: space cooling (2%), food service (1%), plug loads (1%), street lighting (1%), and miscellaneous equipment (0.01%).
[124] "NL Power Comm Survey – Weighted Dataset Codebook," Newfoundland Power, St. John's, NL, Canada. 2024.
[125] Stakeholder input from the Commercial Sector Achievable Potential Workshop held May 24, 2024.
[126] "Amendment 18," Natural Resources Canada, Available: https://natural-resources.canada.ca/energy-efficiency/energy-efficiency-regulations/amendment-18 (Accessed: Dec. 3, 2024).

Lighting Standards: Fluorescent and General Service Lamps

*The federal minimum energy performance standard for general service **fluorescent lamps** currently requires a minimum average lamp efficacy of approximately 90 lumens/watt. Many fluorescent T8 lamps meet this requirement, so a T8 baseline is used for light fixtures in the commercial sector throughout the forecast period.*

*An amendment to the federal minimum energy performance standards, Natural Resources Canada's Amendment 18, is expected to come into force by 2026 that will require a minimum efficacy of 45 lumens/watt for **general service lamps** (i.e., A-lamps and reflector lamps). The requirement will apply to lamps manufactured after a specific date, which has not yet been set. The Study Team assumes that this requirement will be met by limiting the availability of non-LED general service lamps, and any general service lamp measures for the residential and commercial sectors are applicable only in the first three years of the forecast period (2025, 2026, and 2027), at which point Amendment 18 is expected to be in place.*

Exhibit 107 shows savings for the top ten commercial sector efficiency measures in 2025 and 2040.

Exhibit 107: Commercial Top Ten Efficiency Measures by Potential Savings - Annual

Measure	2025 Savings (GWh)	Measure	2040 Savings (GWh)
Linear LED T8 Tube (General Lighting)	1.14	Electric Furnace to Air Source Heat Pump	33.55
Linear LED T8 Tube (Secondary Lighting)	0.64	Linear LED T8 Tube (General Lighting)	17.60
Baseboard to Ductless Mini-Split Heat Pump	0.28	New Construction (25% More Efficient)	9.78
Air Sealing	0.25	Linear LED T8 Tube (Secondary Lighting)	8.88
LED High Bay Luminaire	0.22	Baseboard to Ductless Mini-Split Heat Pump	7.98
LED Reflector (Interior General)	0.18	High Efficiency Windows Glazing	5.67
LED A-Lamp (Interior General)	0.18	Air Sealing	5.27
LED Luminaire (General)	0.17	New Construction (40% More Efficient)	3.78
High Efficiency Window Glazing	0.16	Demand Control Ventilation	3.77
Retrocommissioning	0.15	New Construction (Net-Zero Ready)	3.56

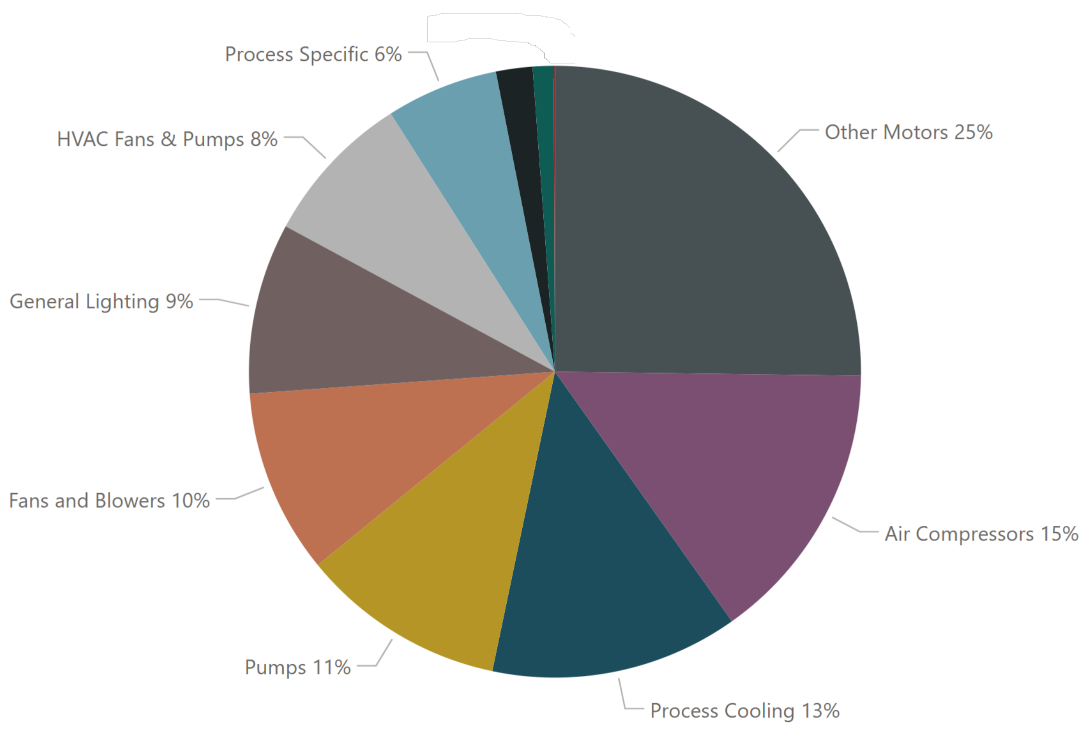
Observations on Exhibit 107 include:

- In 2025, indoor lighting measures account for 6 of the top 10 measures, but by 2040, 8 of the top 10 measures affect space heating.
- Air sealing is among the top ten measures in both milestone years, due to its broad applicability, high measure-level savings, and the fact that it is a retrofit measure, with the opportunity to undertake air sealing at any time as opposed to only when equipment is being replaced.
- By 2040, new construction measures enter the top ten, based on the increased portion of commercial sector consumption occurring in new buildings (1% of total in 2025 compared to 38% in 2040).

5.2.3 End Use Breakdown and Top Energy Savings Measures – Industrial Sector

Exhibit 108 shows cumulative medium achievable potential energy savings for the industrial sector by end use in 2025.[127] Measures affecting the other motors end use (i.e., motor controls, adjustable speed drives on motors, correctly sized motors, and EMIS) offer 25% of the total potential savings. This contribution changes to 22% of total potential for the sector in 2040 due to varying adoption rates by measure.

Exhibit 108: Industrial Potential Savings by End Use – Efficiency (2025)

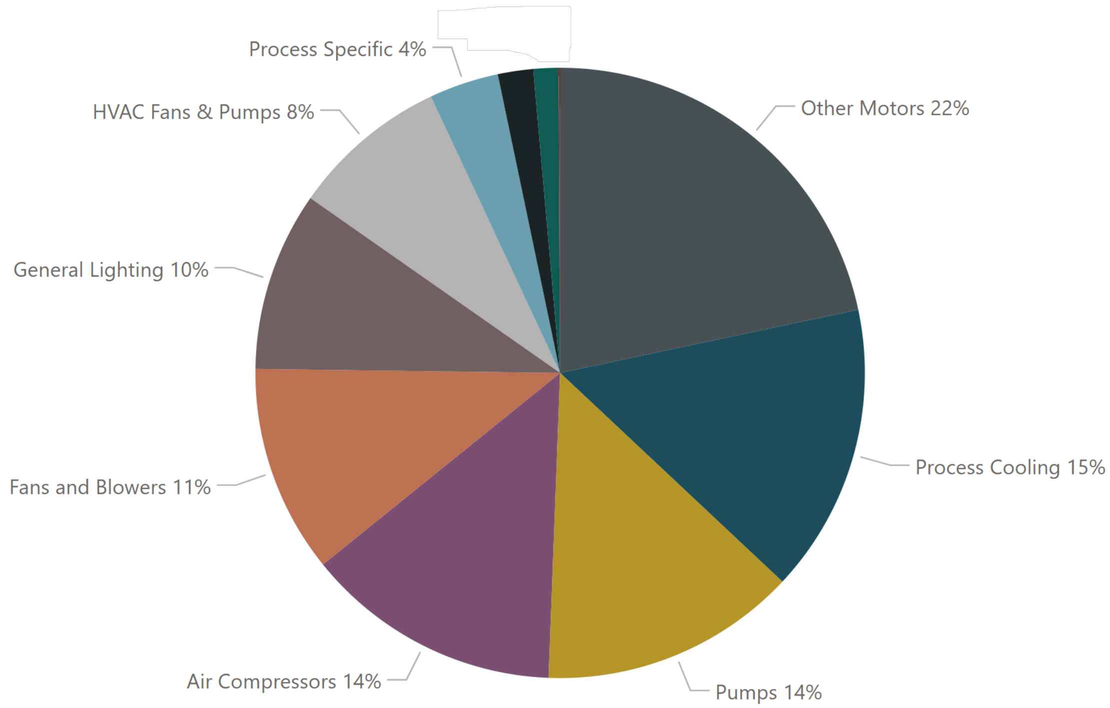


2025 Industrial Energy Savings Potential: 3 GWh

[127] End uses that contribute less than 6% to the medium achievable potential savings are not labelled to improve readability: conveyors (2%), process heating (1%), and other (0.07%).

Exhibit 109 shows cumulative medium achievable energy savings potential by end use in 2040.[128] While savings increase dramatically from 2025 to 2040, the end use breakdown of savings remains relatively consistent between 2025 and 2040. This suggests a broad-based opportunity for cost-effective conservation within the industrial sector.

Exhibit 109: Industrial Potential Savings by End Use – Efficiency (2040)



2040 Industrial Energy Savings Potential: 84 GWh

[128] End uses that contribute less than 4% to the medium achievable potential savings are not labelled to improve readability: conveyors (2%), process heating (1%), and other (0.08%).

Exhibit 110 shows savings for the top ten industrial sector efficiency measures in 2025 and 2040.

Exhibit 110: Industrial Top Ten Efficiency Measures by Potential Savings - Annual

Measure	2025 Savings (GWh)	Measure	2040 Savings (GWh)
Motor Controls – Process	0.48	Motor Controls – Process	9.76
Adjustable or Variable Speed Drive (Motors)	0.26	Optimization of Pumping Systems	7.07
Optimization of Pumping Systems	0.22	Energy Management Information System (EMIS)	5.86
Energy Management Information System (EMIS)	0.20	Adjustable or Variable Speed Drive (Motors)	5.34
Air Leak Survey and Repair	0.18	Optimized Distribution System – Fans and Blowers	5.17
LED Luminaire	0.17	Chiller Economizer	4.12
Optimized Distribution System – Fans and Blowers	0.16	Premium Efficiency Refrigeration Control System and Compressor Sequencing	3.52
Chiller Economizer	0.16	Adjustable or Variable Speed Drive (Pump)	3.31
Adjustable or Variable Speed Drive (Pump)	0.13	LED Luminaire	2.81
Premium Efficiency Refrigeration Control System and Compressor Sequencing	0.12	Adjustable or Variable Speed Drive (Compressor)	2.64

Observations on Exhibit 110 include:

- Measures targeting the other motors and pumps end use represent four of the top ten efficiency measures in both 2025 and 2040.
- EMIS is among the top ten measures in 2025 and 2040 because it is broadly applicable and targets all industrial sector end uses.

5.3 Aggregate Efficiency Results – Peak

Exhibit 111 shows the IIS winter morning and evening average peak demand, and the average annual peak demand reduction from efficiency measures in the medium achievable potential scenario relative to the reference case.[129] From 2025 to 2031, the IIS peaks in the morning based on average demand. In 2032, the IIS switches to an evening peak based on average demand due to EV adoption in the intermediate scenario.[130]

Exhibit 111: Annual Demand Reduction for Medium Achievable Potential Scenario – Efficiency

Year	Winter Morning Average Peak Demand (MW)	Winter Morning Peak Reduction, Medium Achievable (MW)	Morning Reduction (%)	Winter Evening Average Peak Demand (MW)	Winter Evening Peak Reduction, Medium Achievable (MW)	Evening Reduction (%)
2025	1,592	8	0.5%	1,556	7	0.4%
2026	1,606	11	0.7%	1,581	11	0.7%
2027	1,627	16	1.0%	1,605	15	0.9%
2028	1,656	22	1.3%	1,637	21	1.3%
2029	1,689	29	1.7%	1,673	28	1.7%
2030	1,709	37	2.2%	1,698	36	2.1%
2031	1,720	43	2.5%	1,715	43	2.5%
2032	1,739	49	2.8%	1,742	48	2.8%
2033	1,757	54	3.1%	1,769	53	3.0%
2034	1,772	57	3.2%	1,794	56	3.1%
2035	1,782	60	3.4%	1,817	59	3.2%
2036	1,798	62	3.4%	1,848	61	3.3%
2037	1,816	64	3.5%	1,881	63	3.3%
2038	1,833	67	3.7%	1,915	65	3.4%
2039	1,851	69	3.7%	1,952	67	3.4%
2040	1,855	70	3.8%	1,975	69	3.5%

[129] Results reflect unmanaged EV charging. In 2025, EVs contribute 4 MW to the winter morning peak and 8 MW to the winter evening peak in the intermediate scenario. In 2040, they contribute 110 MW and 264 MW to the morning and evening peaks, respectively.
[130] In 2033, EVs cause the absolute IIS peak to shift from the morning to the evening. See section 7 for more details.

The peak demand reductions represent cumulative average savings starting in 2025 during the four-hour morning peak starting at 7 a.m. on a weekday in February; and the five-hour evening peak starting at 5 p.m. on a weekday in February. By 2040, the efficiency measures reduce the winter morning and evening peaks by 70 MW and 69 MW, respectively.[131]

The morning peak reduction is higher than the evening peak in each year of the forecast period, though the difference is less than five megawatts annually. The reduction in each peak period depends on the mix of measures in each forecast year. Space heating contributes more to peak demand in the morning than in the evening. This means that measures that affect space heating save more in the morning than in the evening.

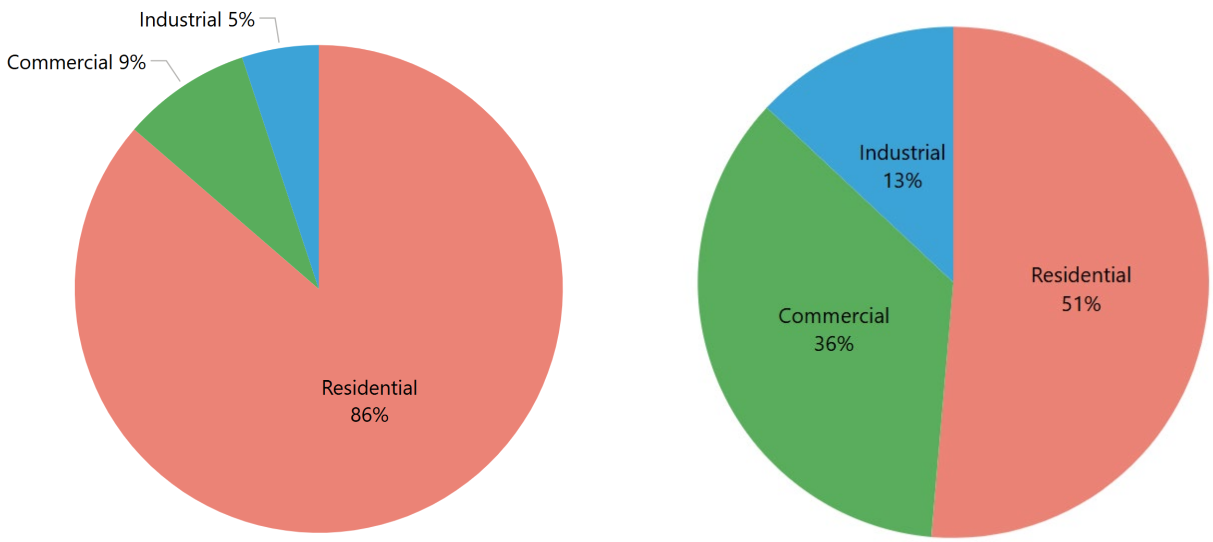
[131] Peak demand savings from efficiency measures shift the peak load vertically downwards. Some measures (e.g., heat pumps) also change the shape of the peak load depending on their energy performance on peak compared to off peak.

5.4 Efficiency Savings Potential by Sector – Peak

Exhibit 112 shows medium achievable potential savings for the peak hour by sector in 2025 and 2040. As noted previously, all savings are cumulative starting in 2025. Potential savings increase from 7,719 kW in 2025 to 71,738 kW by 2040. In both milestone years, the highest peak reduction potential exists in the residential sector. The 2025 potential savings allocation by sector is directionally consistent with recent ECDM program results, in which residential sector programs contributed 88% of total energy savings in 2023.

By 2040, potential savings by sector are more consistent with the reference case peak demand forecast by sector: the residential sector is forecast to contribute 54% of reference peak demand and 51% of medium achievable savings; commercial 34% of peak demand, 36% of savings; and industrial 12% of peak demand 13% of savings.

Exhibit 112: Medium Achievable Peak Demand Reduction Potential by Sector (kW), 2025 (left) and 2040 (right) – Efficiency



2025 Demand Reduction Potential: 7,719 kW **2040 Demand Reduction Potential: 71,738 kW**

This rest of this section presents medium achievable potential peak savings by sector.

5.4.1 Top Peak Savings Measures – Residential Sector

Exhibit 113 shows the top ten residential sector efficiency measures by peak hour demand reduction.

Exhibit 113: Residential Top Ten Efficiency Measures by Potential Reduction – Peak (kW)

Measure	2025 Peak Hour Savings (kW)	Measure	2040 Peak Hour Savings (kW)
Home Energy Report	4,180	Air Source Heat Pump – Ductless Mini Split (DMSHP)	9,161
Air Sealing	777	Heat Recovery Ventilator (Ductless) – Standard to High Efficiency	3,773
Basement Ceiling Insulation	529	Home Energy Report	3,669
Air Source Heat Pump – Ductless Mini Split (DMSHP)	301	Clothes Lines and Drying Racks	2,676
Basement Wall Insulation	237	Central Ducted Air Source Heat Pump	2,283
Attic Insulation	191	Air Sealing	2,249
Smart Thermostat (Multiple)[132]	119	Heat Pump Water Heater (HPWH)	2,196
Programmable Thermostat (Multiple)[133]	113	Heat Recovery Ventilator (Ducted) – Standard to High Efficiency	1,411
Efficient Windows	82	Advanced Smart Strips and Plugs	1,295
Heat Recovery Ventilator (Ductless) – Standard to High Efficiency	77	Duct Insulation	1,270

Observations on Exhibit 113 include:

- Home energy report, air sealing, ductless mini split air source heat pumps, and ducted heat recovery ventilators (standard to high efficiency) are among the top ten measures in both milestone years, due to their broad applicability and relatively low incremental costs. All these measures impact space heating and save more during the morning peak compared to the evening peak.
- In 2025, all top ten measures affect the space heating end use, and by 2040, measures for non-space heating end uses (clothes lines and drying racks, heat pump water heaters, and advanced smart strips and plugs) enter the top ten. This is because some of the 2025 top ten measures (e.g., smart and programmable thermostats, insulation) will approach saturation by 2040.

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[132] The 2021 Thermostat Evaluation Study from the Utilities indicates that programmable and smart thermostats have positive peak savings in the Utilities' jurisdiction. This may differ from other jurisdictions where programmable and smart thermostat adoption may drive an increase in peak.

[133] Ibid.

5.4.2 Top Peak Savings Measures – Commercial Sector

Exhibit 114 shows the top ten commercial sector efficiency measures by peak hour demand reduction.

Exhibit 114: Commercial Top Ten Efficiency Measures by Potential Reduction – Peak (kW)

Measure	2025 Peak Hour Savings (kW)	Measure	2040 Peak Hour Savings (kW)
Linear LED T8 Tube (General Lighting)	198	Electric Furnace to Air Source Heat Pump	10,635
Linear LED T8 Tube (Secondary Lighting)	94	Linear LED T8 Tube (General Lighting)	3,059
Baseboard to Ductless Mini-Split Heat Pump	89	Baseboard to Ductless Mini-Split Heat Pump	2,525
Air Sealing	71	New Construction (25% more efficient)	2,110
High Efficiency Window Glazing	49	High Efficiency Window Glazing	1,733
Electric Furnace to Air Source Heat Pump	46	Air Sealing	1,531
LED Reflector (Interior General)	31	Linear LED T8 Tube (Secondary Lighting)	1,317
LED A-Lamp (Interior)	31	Demand Control Ventilation	1,107
Demand Control Ventilation	31	New Construction (40% more efficient)	808
LED High Bay Luminaire	30	Energy Recovery Ventilator	771

Observations on Exhibit 114 include:

- In 2025, indoor lighting measures account for 5 of the top 10 measures, but by 2040 measures that affect space heating measures account for 7 of the top 10. The indoor lighting measures have the same peak reduction potential for the morning, evening and absolute peaks. In contrast, the space heating measures save more during the morning peak compared to the evening peak.
- Air sealing is among the top ten measures in both milestone years, due to its broad applicability, high measure-level savings, and the fact that it is a retrofit measure, with the opportunity to undertake air sealing at any time as opposed to only when equipment is being replaced.
- By 2040, new construction measures enter the top ten, based on the increased portion of commercial sector consumption occurring in new buildings (1% of total in 2025 compared to 38% in 2040).

5.4.3 Top Peak Savings Measures – Industrial Sector

Exhibit 115 shows the top ten industrial sector efficiency measures by peak hour demand reduction.

Exhibit 115: Industrial Top Ten Efficiency Measures by Potential Reduction – Peak (kW)

Measure	2025 Peak Hour Savings (kW)	Measure	2040 Peak Hour Savings (kW)
Motor Controls - Process	46	Motor Controls - Process	930
Optimization of Pumping System	27	Optimization of Pumping System	879
Adjustable or Variable Speed Drive (Motor)	25	Energy Management Information System (EMIS)	688
Energy Management Information System (EMIS)	24	Adjustable or Variable Speed Drive (Motor)	509
Process Optimization Efforts - Mining and Processing	21	Optimized Distribution System (Incl. Pressure Losses) - Fans and Blowers	476
LED Luminaire	20	Air Compressor Heat Recovery	452
Air Leak Survey and Repair	18	High Efficiency Packaged HVAC	442
Refrigeration Heat Recovery	18	Adjustable or Variable Speed Drive (Pump)	413
Adjustable or Variable Speed Drive (Pump)	16	Chiller Economizer	378
Air Compressor Heat Recovery	15	LED Luminaire	328

Observations on Exhibit 115 include:

- Measures targeting the other motors and pumps end use represent four of the top ten efficiency measures in both 2025 and 2040.
- EMIS is among the top ten measures in 2025 and 2040 because it is broadly applicable and targets all industrial sector end uses.

6 Fuel Switching and Off-Road Electrification Potential

This section presents space heating, water heating, and cooking fuel switching and off-road electrification potential results for the IIS. Results shown here exclude the impact of EVs.

The fuel switching and off-road electrification potential assessment mirrors the efficiency potential assessment in structure and economic screening criteria:

- Three levels of fuel switching and off-road electrification savings potential are assessed: technical, economic, and achievable.
- The total resource cost (TRC) test is used to screen fuel switching and off-road electrification measures, and measures are included in the economic potential if their benefit-cost ratio is 0.8 or higher.[134]
- The achievable potential includes lower, medium and higher scenarios, with incentive levels of 25%, 50% and 100%, respectively.

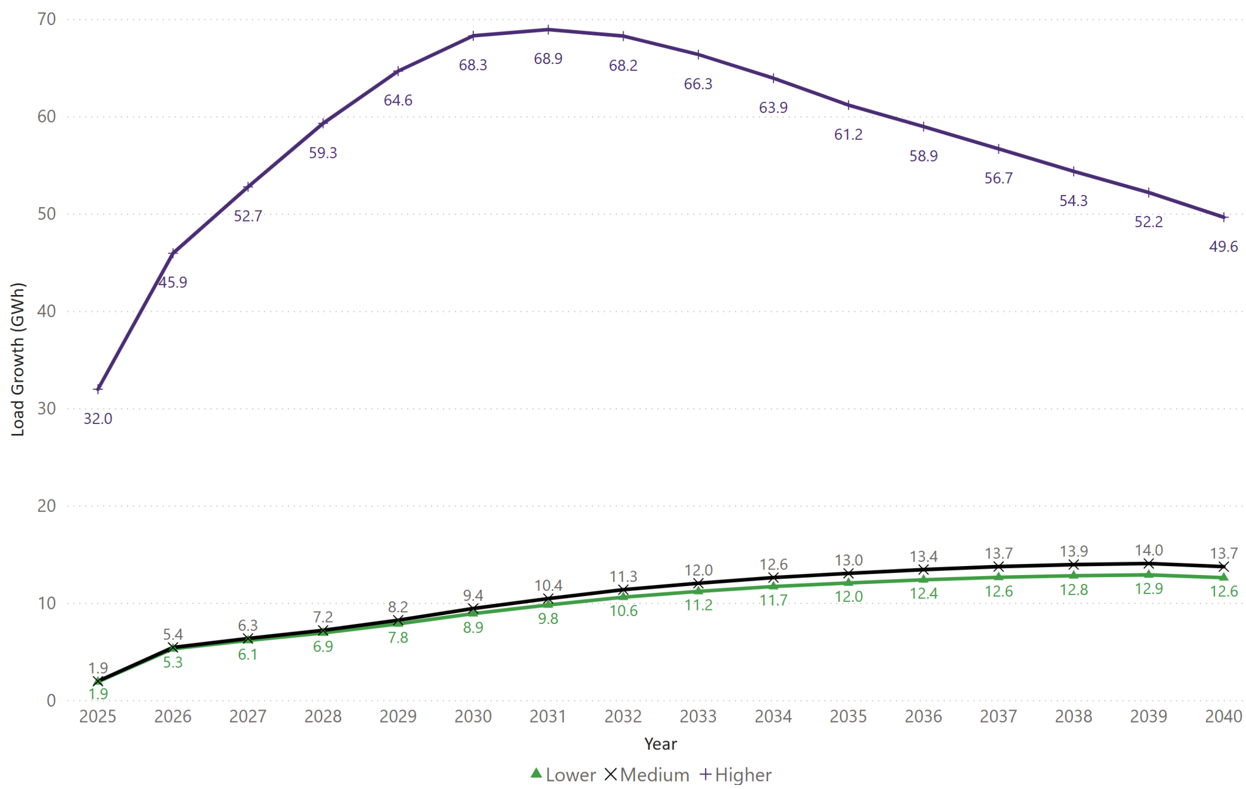
Readers are encouraged to revisit the list of fuel switching and off-road electrification measures shown in section 4.1 for context.

[134] Three residential sector fuel switching measures with TRC less than 0.8 were included in the analysis: oil furnace to cold climate air source heat pump, oil furnace to air source heat pump (partial switch), and oil furnace to electric furnace. These measures are being adopted in Newfoundland Power's Oil to Electric program.

6.1 Aggregate Fuel Switching and Off-Road Electrification Potential – Annual

The impacts of fuel switching and off-road electrification in the lower, medium and higher achievable potential scenarios are shown in Exhibit 116. By 2040, measures in the higher achievable potential scenario cause 49.6 GWh of load growth, compared to 13.7 GWh and 12.6 GWh in the medium and lower scenarios, respectively. Reference case consumption is forecast to be roughly 9,000 GWh in 2040, so this growth represents an increase of less than one percent of annual consumption for all scenarios.[135] Fuel switching potential is limited in all three sectors because of the high relative fuel share of electric space heating in the base year and because of natural fuel switching that occurs in the reference case.[136]

Exhibit 116: Fuel Switching and Off-Road Electrification Impacts by Achievable Scenario



Load growth from fuel switching increases year over year in all scenarios between 2025 and 2031 but decreases from 2031 to 2032 in the higher achievable potential scenario. This result is driven by forecast space heating conversions in the Oil to Electric program, and natural fuel switching from oil to electricity included in the reference case which erodes the impact of these space heating conversions. The callout that follows explains the higher achievable potential scenario result in more detail.

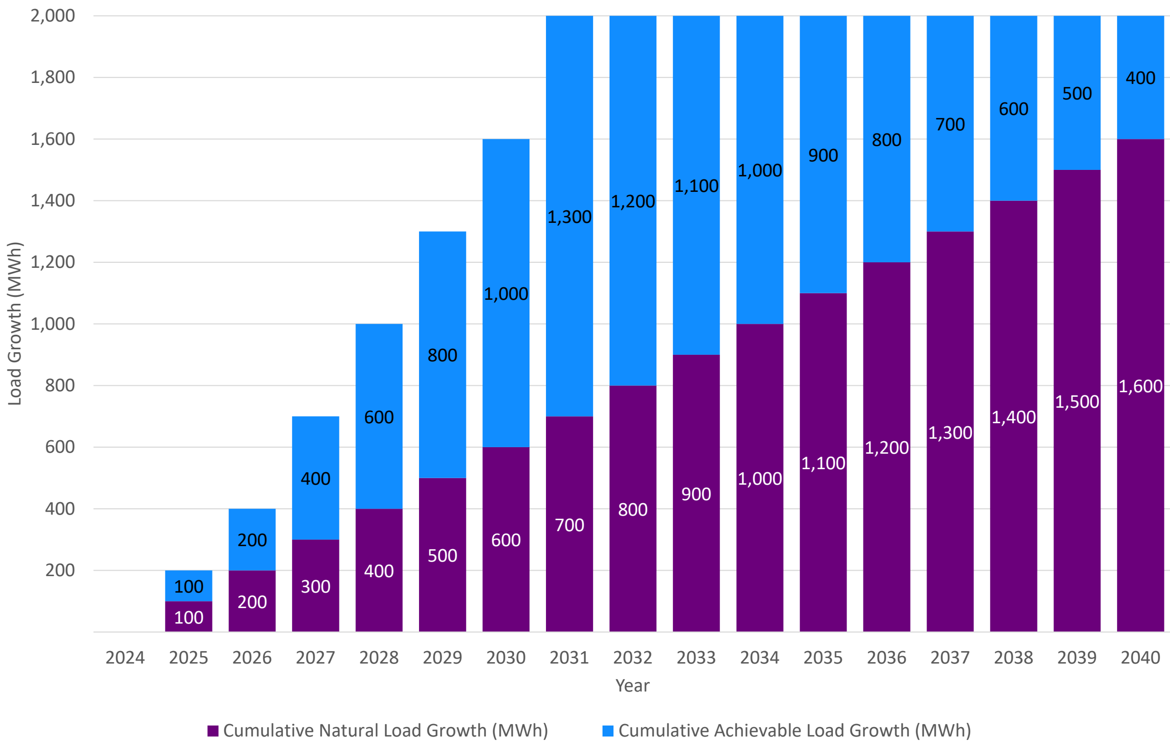
[135] 9,000 GWh is the approximate forecast consumption in 2040 including the impact of EVs in the intermediate scenario. Excluding the impact of EVs in the intermediate scenario, the approximate forecast consumption in 2040 is 1,000 GWh.

[136] MUN's conversion to electric heat is included in the reference case forecast.

Impacts of Reference Case Fuel Switching on Achievable Potential

The fuel switching measure impacts shown in sections 6.1 and 6.2 are incremental to the natural fuel switching that occurs in the reference case. Measure-level achievable fuel switching potential is limited by the number of dwellings that use fossil fuel for space or water heating, and the rate of naturally occurring fuel switching.

For example, consider a portfolio of 200 existing oil heated dwellings, where each dwelling that fuel switches either naturally or by adopting a fuel switching measure contributes 10 MWh of load growth. In the absence of demolition and new construction, the figure below shows what happens when natural fuel switching and fuel switching measure adoption occur in parallel. In the figure, the purple bars represent cumulative load growth from naturally occurring fuel switching, and the blue bars represent cumulative load growth from fuel switching measure adoption.



By 2030, 60 dwellings have fuel switched naturally for a total of 600 MWh of load growth, and 100 dwellings have adopted a fuel switching measure for a total of 1,000 MWh of load growth. In 2031, 10 more dwellings fuel switch naturally for a total of 70 and 700 MWh of load growth, and 30 more dwellings adopt a fuel switching measure for a total of 130 and 1,300 MWh of load growth.

In 2032, another 10 dwellings would have naturally fuel switch compared to 2031, for a total of 80 and 800 MWh of load growth. In 2032, only 1,200 MWh of the 1,300 MWh of load growth from dwellings that adopted a fuel switching measure by 2031 can still be considered incremental and count towards the achievable load growth. The remaining 100 MWh of load growth would have occurred naturally. Therefore, load growth from fuel switching measures in 2032 is lower than in 2031.

A similar phenomenon is responsible for the decrease in load from fuel switching measures between 2031 and 2032 in the higher achievable potential scenario shown in Exhibit 116.

6.2 Fuel Switching and Off-Road Electrification Impacts by Sector – Annual

Exhibit 117 shows fuel switching and off-road electrification impacts by sector in 2025 and 2040. The higher achievable potential scenario results are shown for the residential sector to align with current Oil to Electric program practice.[137] Medium achievable potential results are shown for the commercial and industrial sectors to align with typical ECDM program practice.

Fuel switching potential is limited in all three sectors because of the natural fuel switching that occurs in the reference case, and the high relative fuel share of electric space heating in the base year.[138] For example, in the commercial sector, 61% of floor area is associated with buildings heated primarily with electricity in the base year.[139] The 39% of floor area in buildings primarily heated with another fuel still includes substantial electric heating: the electric fuel share for these buildings is 40% in 2023 and increases to 50% by 2033 in the reference case.

Exhibit 117: IIS Achievable Fuel-Switching and Off-Road Electrification Impacts (GWh)

Sector (Scenario)	2025	2040
Residential (Higher)	31.7	42.9
Commercial (Medium)	0.2	5.1
Industrial (Medium)	0.002	0.5
Total	**31.9**	**48.5**

Electrification of Non-Road Vehicles

The Study Team assessed the electrification impacts of two non-road vehicles: forklifts and Zambonis. Electrification of these vehicles from propane offers indoor air quality benefits to warehouse and arena occupants.

Forklift electrification*: The Study Team estimates there are between 2,000 and 3,000 forklifts in Newfoundland. Approximately ten percent of CEUS respondents indicated they planned to purchase a non-road battery EV in the next five years. Using this data, the Study Team estimated an increase of 2% annually over the Study period. This leads to a total market penetration of 40% in 2040, based on a reference adoption of 6%. The impact of this additional load is approximately 200 MWh in 2040.*

Zamboni electrification*: There are 48 arenas in Newfoundland. The Study Team assumes that most of these arenas have one ice pad, and one Zamboni per ice pad, for a total of 48 Zambonis. Using the same assumptions from the CEUS as applied to forklift electrification (i.e., 2% adoption annually), this leads to a total market penetration of 40% for electric Zambonis in 2040. The impact of this additional load is approximately 65 MWh in 2040.*

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[137] Under the program, customers with low to moderate income can receive 100% of the cost of their oil to electric conversion in incentives. Approximately 65% of past program participants qualified as low to moderate income.
[138] MUN’s conversion to electric heat is included in the reference case forecast.
[139] This percentage reflects NP customers only. The main heating fuel for NLH customers was not available.

6.2.1 Residential Sector Results

In the residential sector, incentives under the higher achievable potential scenario result in the adoption of full and partial space heating fuel switching measures, including electric heat pumps, boilers, furnaces, and water heaters. Exhibit 118 shows the number of dwellings forecast to be converted from oil to electric space or water heating in the higher achievable potential scenario in 2025 and 2040.[140] By 2040, 5,618 incremental dwellings are forecast to be heated electrically or have electric water heating compared to 2025. This forecast includes the 3,000 space heating fuel switching projects forecast to be completed under the Oil to Electric program in 2025.[141]

Exhibit 118: Dwellings with Electric Space or Water Heating, Higher Achievable Potential[142]

Conversion Type	2025	2040	Difference[143]
Space heating	3,249	5,898	2,649
Water heating	27	2,996	2,969
Total	**3,276**	**8,894**	**5,618**

[140] Adoption is split between homes with sufficient electrical service capacity to accommodate electric space heating equipment and homes that require a service upgrade. The Study Team, in consultation with the Utilities, estimate that 50% of residential dwellings have enough service capacity to accommodate electric space heating equipment.
[141] Data provided from the Utilities in Nov. 2024.
[142] This exhibit combines the service upgrade and non-service upgrade versions of measures.
[143] A decrease in the number of dwellings between 2025 to 2040 indicates that the available opportunity for a measure has decreased over time because it reached saturation.

6.2.2 Commercial Sector Results

Incentives in the medium achievable potential scenario result in the uptake of full and partial space heating fuel switching measures in the commercial sector, including electric heat pumps and boilers. Adoption is limited to buildings with enough electrical service capacity to accommodate electric space heating equipment.[144] Exhibit 119 shows that an incremental 1.1 million additional square feet of commercial sector floor area are forecast to be heated electrically in 2040 compared to 2025 in the medium achievable scenario.

Exhibit 119: Electrically Heated Floor Area, Medium Achievable Potential (sq-ft)

Parameter	2025	2040	Difference
Electrically heated floor area	60,010	1,165,159	1,105,149

Impact of Dockside Electrification for Marine Vessels

Dockside electrification allows marine vessels to use electricity in port instead of diesel engines for on-board power. Thus, it has the potential to reduce ship emissions during port calls if enough electrical energy is available. Various dockside electrification opportunities exist for NL including cruise ships, cargo ships and ferries. The best candidates for dockside fuel switching are vessels that make frequent port calls with long stays and high energy consumption patterns.[145]

Data is available to estimate the dockside electrification opportunity for cruise ships in NL. The St. John's Port Authority reported 30 cruise ship visits in 2022 and 36 visits in 2023. 39 visits were expected in 2024.[146] *The size of these ships varied from less than 200 passengers to more than 3,500 passengers and time in port was 10 hours, on average. Diesel- or oil-fired generators currently power cruise ships in port. The Study Team estimates a 1,300 MWh/year electrification impact if these ships were connected to shore power in port. This estimate is based on the average energy consumption of 3 kWh per passenger-hour, 36 cruise ship visits per year, 10 hours in port per cruise ship, and 1,200 passengers per cruise ship.*[147]

There is currently limited data available on ferry and cargo ships to support an in-depth analysis of the fuel switching potential for these marine vessels. The Utilities can continue to work with the appropriate parties to see if collection of this information is possible for future analysis.

[144] The Study assumes 50% of commercial buildings have sufficient capacity.
[145] "Study and Update on Dock Electrification Technologies in Quebec," Innovation Maritime (2022).
[146] Port of St. John's, "The Port of Choice for Cruise Ships," Available: https://sjpa-apsj.com/industries/cruise/ (Accessed: Aug. 2024).
[147] "Options for Establishing Shore Power for Cruise Ships in Port of Copenhagen Nordhavn," City & Port Development, City of Copenhagen, Available: https://www.danskehavne.dk/wp-content/uploads/2015/12/GP-CMP-Shoreside-Report.pdf (Accessed: Aug. 2024).

6.3 Aggregate Fuel Switching and Off-Road Electrification Impacts – Peak

Exhibit 120 shows the annual peak impacts of fuel switching and off-road electrification in the medium achievable potential scenario for the commercial and industrial sectors, and for the higher achievable potential scenario for the residential sector.[148] The peak demand impacts represent averages during the four-hour morning peak and the five-hour evening peak. As illustrated, the electrification measures have a limited impact on the morning and winter average peak demand.

Exhibit 120: Annual Achievable Potential Demand Impacts for Residential (Higher), Commercial (Medium), and Industrial (Medium) Sectors – Fuel Switching and Off-Road Electrification

Year	Winter Morning Average Peak Demand, Reference (MW)	Winter Morning Peak Impact (MW)	Morning Impact (%)	Winter Evening Average Peak Demand, Reference (MW)	Winter Evening Peak Impact (MW)	Evening Impact (%)
2025	1,592	9.9	0.6%	1,566	9.5	0.6%
2026	1,606	14.1	0.9%	1,581	13.6	0.9%
2027	1,627	16.2	1.0%	1,605	15.6	1.0%
2028	1,656	18.2	1.1%	1,637	17.6	1.1%
2029	1,689	19.7	1.2%	1,673	19.1	1.1%
2030	1,709	20.8	1.2%	1,698	20.1	1.2%
2031	1,720	20.9	1.2%	1,715	20.2	1.2%
2032	1,739	20.7	1.2%	1,742	20.0	1.1%
2033	1,757	20.0	1.1%	1,769	19.4	1.1%
2034	1,772	19.3	1.1%	1,794	18.7	1.0%
2035	1,782	18.4	1.0%	1,817	17.8	1.0%
2036	1,798	17.7	1.0%	1,848	17.1	0.9%
2037	1,816	16.9	0.9%	1,881	16.4	0.9%
2038	1,833	16.2	0.9%	1,915	15.6	0.8%
2039	1,851	15.5	0.8%	1,952	15.0	0.8%
2040	1,855	14.8	0.8%	1,975	14.3	0.7%

[148] The winter morning and evening average peak demand values include the impact of EVs in the intermediate scenario.

7 Demand Response Potential

This section presents demand response potential results for three IIS resources:

1. **Electricity Rate Designs**: The Study Team examined the impact of two behaviour driven time-variable rates (TVR), TOU and CPP, on peak demand. The methods by which customers shift their load are not specified. These TVR are not currently offered in Newfoundland or the nearby provinces of New Brunswick and Prince Edward Island, but exist in other Canadian jurisdictions including Nova Scotia, Quebec, and Ontario. Nova Scotia currently has a time-of-day rate plan in place that is only available to customers with electric thermal storage systems, as well as pilots for TOU and CPP.[149,150]
2. **Equipment Demand Response Measures**: The Study Team assessed utility-driven, managed charging and thermal storage with TOU equipment DR measures. These measures are defined as follows:
    - **Utility-Driven**: The utility has direct load control (DLC) of customer end use equipment (e.g., water heater smart switch, smart thermostat) during on-peak times. These measures are modelled with current rates (i.e., they are not modelled with TVR).
    - **EV Managed Charging**: The utility has DLC of EV charging during the evening peak period.[151]
    - **Thermal Storage with Time-of-Use**: Customers shift electricity use off peak based on TOU rates only using electric thermal storage (ETS) systems.
3. **Customer Curtailment**: Select customers, including those in rates 2.3 and 2.4, large commercial customers, and large industrial customers curtail their energy use when NP or NLH issues a request for curtailment.

Like for efficiency and electrification, the Study Team assessed three levels of demand response savings potential for each resource: technical, economic, and achievable. However, the demand response potential assessment differs in the following ways:

- Measure-level incentives and non-incentive program costs are not varied, so there is only one achievable potential scenario. Throughout this section, this scenario is referred to as the medium achievable potential scenario.
- Participation rates are based on research and consultation with the Utilities. The only demand resource response currently in market in Newfoundland is customer curtailment, so there are no historical savings to benchmark against for the electricity rate design and equipment DR measures.

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[149] Nova Scotia Power, "Residential Rates," Available: https://www.nspower.ca/your-home/residential-rates (Accessed Mar. 7, 2025).
[150] Nova Scotia Power, "Time-Varying Pricing Rate Pilot Program,", Available: https://www.nspower.ca/time-of-day-rate-plans-business (Accessed Mar. 7, 2024).
[151] The morning peak period represents the lowest load for EV charging, resulting in much more limited peak reduction potential.

- Unless otherwise noted, results include the following:
    - Peak impacts from efficiency and fuel switching measures in the medium achievable potential scenario. This approach avoids overestimating demand response potential during the forecast period that will most likely include the adoption of efficiency and fuel switching measures.
    - EV charging demand in the intermediate scenario.

The rest of this section is structured as follows:

- Section 7.1 shows the IIS load curve in the absence of demand response activities. This curve is a reference to contextualize the shape of the curve after potential is applied.
- Section 7.2 shows demand response potential for the electricity rate design measures.
- Section 7.3 shows demand response potential for the equipment DR measures.
- Section 7.4 shows customer curtailment potential.
- Section 7.5 discusses interactive effects between demand response resources. These interactive effects occur when two resources target the same peak savings. Section 11.5 also explains the Study Team's approach to avoid double-counting savings.
- Section 7.6 shows the IIS load curve after potential is applied.

7.1 Peak Day Load Curve Analysis

To fully assess the potential impact of the demand response resources, the Study Team first established a reference load shape for the system on the IIS peak day. Exhibit 121 shows the steps completed to identify the reference load shape.

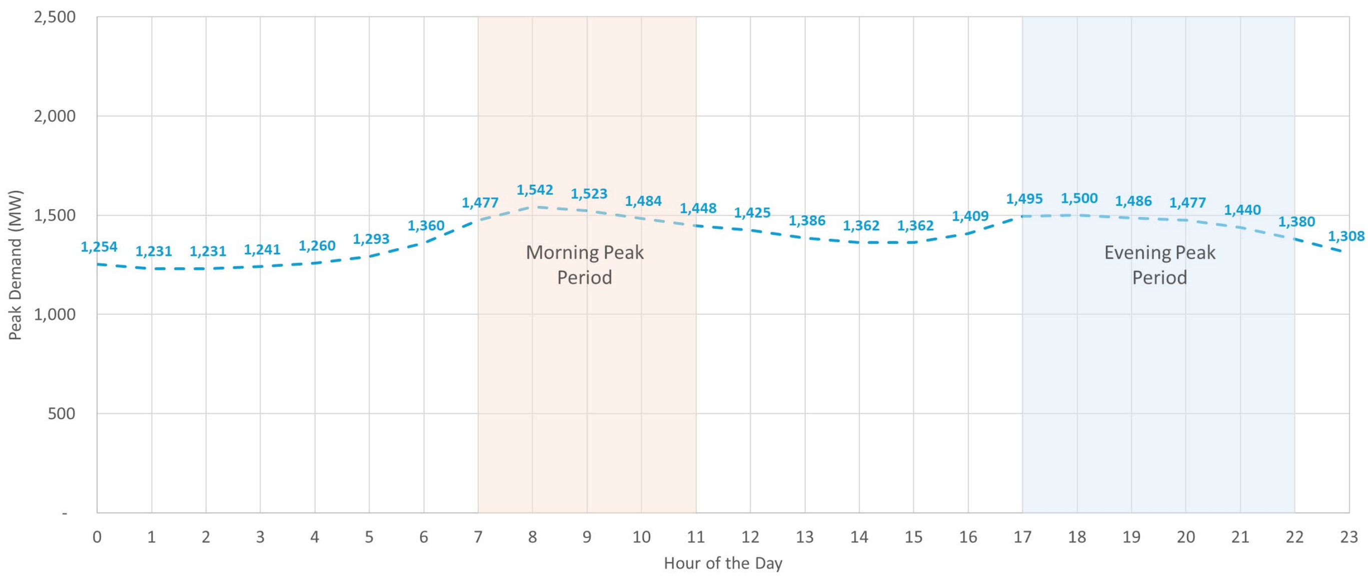
Exhibit 121: Peak Day Load Curve Analysis Approach

Step	Approach Summary
1. Analyze historical IIS hourly load data	• Analyze IIS hourly load data from 2019-2023 to determine the shape and distribution of hourly loads for the highest-demand days.
2. Determine reference load shape for the peak day	• Generate an initial load shape for the peak day using the mean hourly demand from all days in the IIS hourly load data scaled by three standard deviations. • Normalize the initial load shape to express hourly load as a fraction of daily load. • The Study Team selected this approach rather than selecting the load shape of a representative day in the 2019-2023 data because it is grounded in statistics (i.e., the representation of extremes in relation to the mean) and enables the model to be calibrated to base year peak day or hour demand.
3. Assess demand response windows	• Overlay the expected daily load shape of EV charging in the intermediate scenario (from analysis completed for this Study) on the initial load shape. • Define two peak period “demand response windows” (morning and evening) that include most of the top peak hours across the initial load shape and expected EV charging demand in the intermediate scenario. • Based on consultation with the Utilities, these demand response windows are 7 a.m. to 10:59 a.m. for the morning peak, and 5 p.m. to 9:59 p.m. for the evening peak. • Weight the initial load shape and expected EV charging load shape in the intermediate scenario according to their relative contribution to peak to create a reference load shape.
4. Identify addressable peak	• Defined the “addressable peak” as the peak hour consumption in the demand response windows that can be shifted outside each window without creating a new peak hour.

The Study Team evaluated demand response potential for the highest winter peak hour and all other peak day hours. This was important since demand response measures can create new peaks through load shifting or bounce-back effects.

Exhibit 122 and Exhibit 123 show the reference load shape and the demand response windows for the peak day in 2023 and 2040, respectively. These load shapes were created by scaling the reference load shape to match the forecast 2023 and 2040 peak hourly demand values of 1,542 MW and 2,064 MW, respectively.[152] Both load shapes include the impacts of unmanaged EV charging in the intermediate scenario.[153] As explained in the peak day analysis approach presented in Exhibit 121, the reference load shape does not reflect an actual historical peak day. Instead, the Study Team generated a calibrated reference load shape using a method grounded in statistics.

Exhibit 122: Reference Load Shape (2023)



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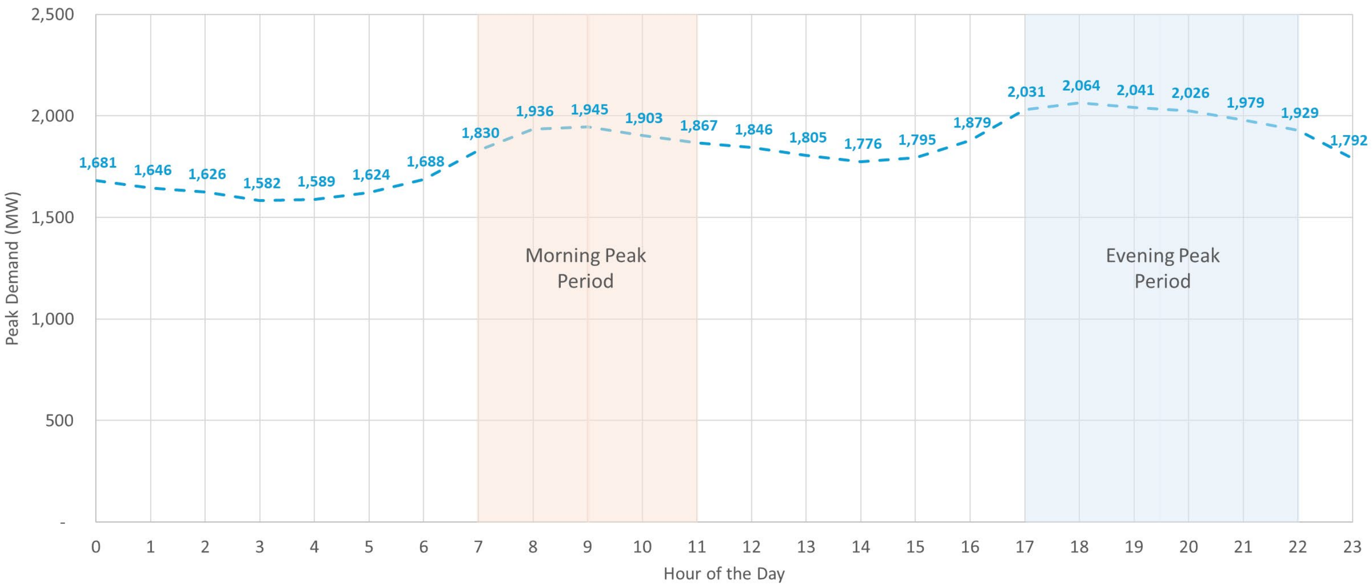
[152] The annual peak demand forecast can be found in section 3.

[153] Unless otherwise specified, any comparisons between potential results and the system peak demand in the following sections are based on the peak hourly demand including the impact of unmanaged EV charging in the intermediate scenario.

Exhibit 123: Reference Load Shape (2040)



In 2023, the IIS peaks in the morning but in 2040 it peaks in the evening. This change is partly driven by the impact of EV charging in the intermediate scenario, which causes the shift from morning (8 a.m.) to evening (6 p.m.) peak in 2033. The switch to evening peak is expected in 2037 in the natural adoption scenario and in 2030 for the government targets scenario.

7.2 Electricity Rate Design Measure Potential

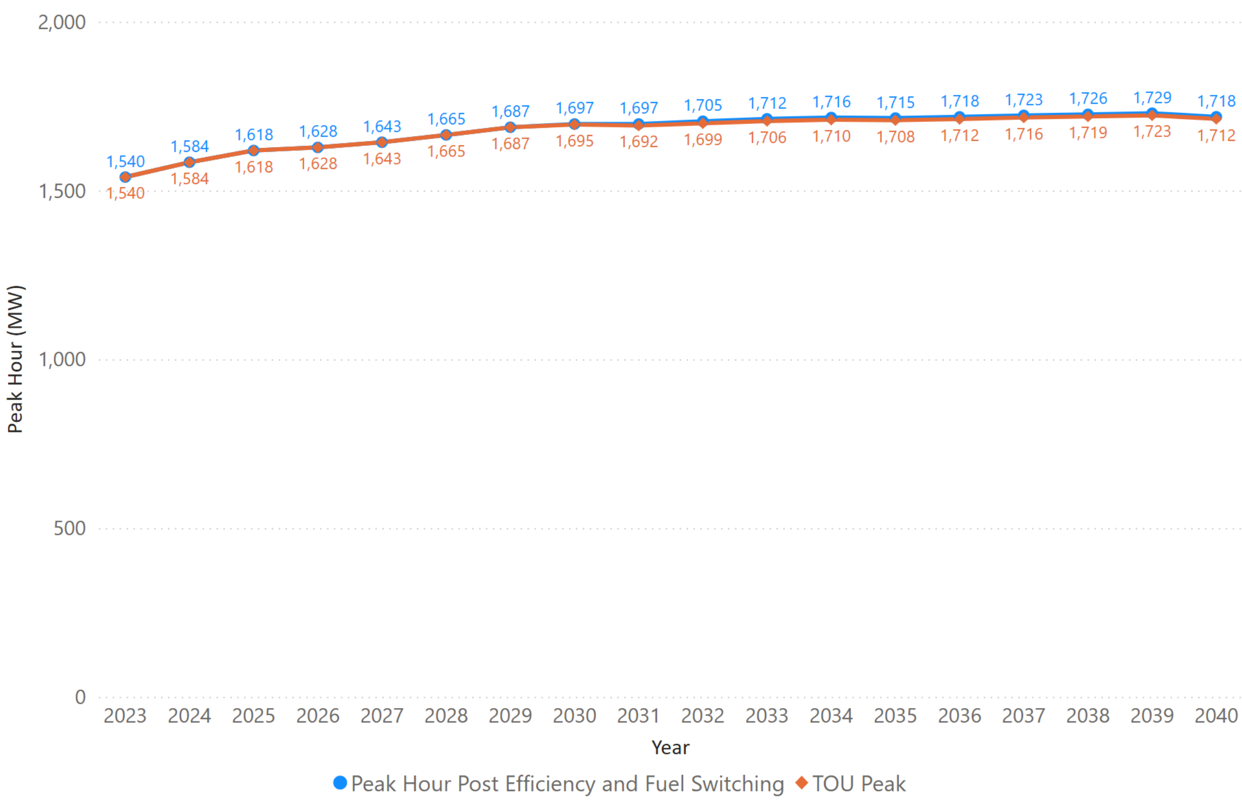
This section presents demand response peak reduction potential for the IIS from the electricity rate design measures in the medium achievable scenario. Section 7.2.1 shows results for the TOU and CPP measures for all non-EV loads. Section 7.2.2 shows results for EV TOU. Exhibit 131 and Exhibit 132 in section 7.2.2 show how EV load shifts from the rate design measures overlayed on the non-EV load shape.

7.2.1 Electricity Rate Design Measure Results

Exhibit 124 shows the medium achievable peak hour demand for the TOU electricity rate design measure (orange line) compared to the reference peak hour demand that includes impacts from efficiency and fuel switching measures (light blue line). The difference between the lines represents the potential peak demand reductions from TOU. The results exclude the impacts of TOU rates on EV charging.[154]

Savings from TOU start in 2029, once AMI infrastructure is in place.[155] Opt-in participation to the TOU rate increases from 2029 to 2033, then remains constant at 15% until 2040. In 2029, the peak demand reduction is 0.2 MW. Between 2032 and 2040, the peak demand reduction is approximately 6 MW.

Exhibit 124: Medium Achievable Peak Demand – TOU

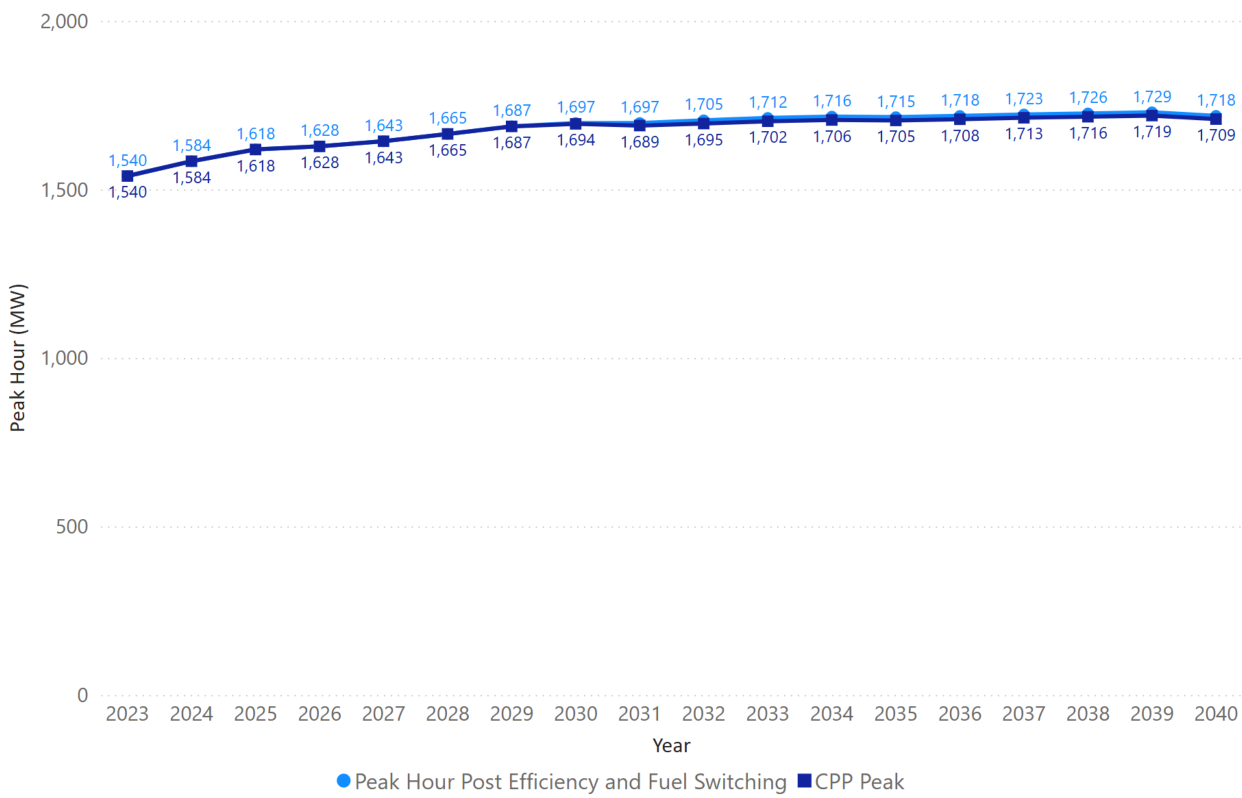


154 Section 7.2.2 shows EV TOU measure results and compares them to results shown in section 7.2.1.
155 As stated in section 4.3.1, AMI infrastructure, including smart meters, data management systems, and communication networks, is required for a utility to implement TVR like TOU and CPP.

Exhibit 125 shows the medium achievable peak hour demand for the CPP electricity rate design measure (dark blue line) compared to the reference peak hour demand that includes impacts from efficiency and fuel switching measures (light blue line). The difference between the lines represents the potential peak demand reductions from CPP.

Savings from CPP start in 2029, once AMI infrastructure is in place.[156] Opt-in participation to the CPP rate increases from 2029 to 2033, then remains constant at 15% until 2040. In 2029, the peak demand reduction is 0.4 MW. Between 2032 and 2040, the peak demand reduction is approximately 10 MW.

Exhibit 125: Medium Achievable Peak Demand – CPP



[156] As stated in section 4.3.1, AMI infrastructure, including smart meters, data management systems, and communication networks, is required for a utility to implement TVR like TOU and CPP.

As explained in section 4.1.1, the savings results for the TVR measures are informed by opt-in participation rates (15%) and per-customer savings (3% and 5% of peak hour demand for TOU and CPP, respectively) from jurisdictional research. Savings would increase with higher participation, but the Study Team's research found that a 15% participation for opt-in programs was typical.[157,158,159]

Exhibit 126 shows the medium achievable potential peak reduction for the electricity rate design measures by sector, excluding savings from EV TOU. 77% and 81% of the potential peak reductions exist in the residential sector for the TOU and CPP measures for all study years. This result is driven by the assumption that residential customers are more likely than commercial customers to alter their space heating patterns based on TVR. For reference, the residential sector accounts for 65% of the reference case peak demand in 2040. The commercial and industrial sectors contribute 27% and 8% to the total, respectively.

Exhibit 126: Medium Achievable Potential Sector Breakdown – Electricity Rate Design (2040)

Measure	Sector	Winter Peak Hour Reduction (MW)	% Contribution to Total Measure Peak Reduction
TOU	Residential	4.80	77%
	Commercial	1.11	18%
	Industrial	0.32	5%
	TOU Total	**6.23**	**100%**
CPP	Residential	7.93	81%
	Commercial	1.49	15%
	Industrial	0.35	4%
	CPP Total	**9.77**	**100%**

[157] This 15% maximum participation rate is consistent with findings from other jurisdictions in Canada where opt-in time varying rates were studied, including Nova Scotia and British Columbia.
[158] Nova Scotia Power, "Time-Varying Pricing Project Submission", Available: https://www.brattle.com/wp-content/uploads/2021/05/19479_nova_scotia_utility_and_review_board_-_time-varying_pricing_project_submission.pdf, (Accessed Sept. 5, 2024).
[159] British Columbia Hydro and Power Authority, "BC Hydro Optional Residential Time-of-Use Rate Application", Available: https://docs.bcuc.com/documents/proceedings/2023/doc_70443_b-1-bch-optional-residential-tou-rate-application.pdf (Accessed Oct. 29, 2024).

Exhibit 127 shows the demand reduction potential for both electricity rate design measures by peak period and sector for 2029 and 2040. The following observations can be made on Exhibit 127:

- TOU and CPP in the residential sector show the highest savings potential for all three peak periods because of the potential savings for space heating in the residential sector.
- CPP shows higher savings potential than TOU in all sectors and peak periods because peak events are less frequent, and the on-peak retail rate is higher.

Exhibit 127: Medium Achievable Peak Demand Reduction – Electricity Rate Design

Measure	Sector	2029 Winter Peak Hour Reduction (MW)	2029 Winter Morning Average Peak Reduction (MW)	2029 Winter Evening Peak Average Reduction (MW)	2040 Winter Peak Hour Reduction (MW)	2040 Winter Morning Average Peak Reduction (MW)	2040 Winter Evening Average Peak Reduction (MW)
TOU	Residential	0.17	0.17	0.16	4.80	4.66	4.55
	Commercial	0.04	0.04	0.04	1.11	1.11	1.11
	Industrial	0.01	0.01	0.01	0.32	0.32	0.32
	Total	**0.22**	**0.22**	**0.21**	**6.23**	**6.09**	**5.98**
CPP	Residential	0.28	0.28	0.27	7.93	7.70	7.51
	Commercial	0.05	0.05	0.05	1.49	1.49	1.49
	Industrial	0.01	0.01	0.01	0.35	0.35	0.35
	Total	**0.34**	**0.34**	**0.33**	**9.77**	**9.54**	**9.35**

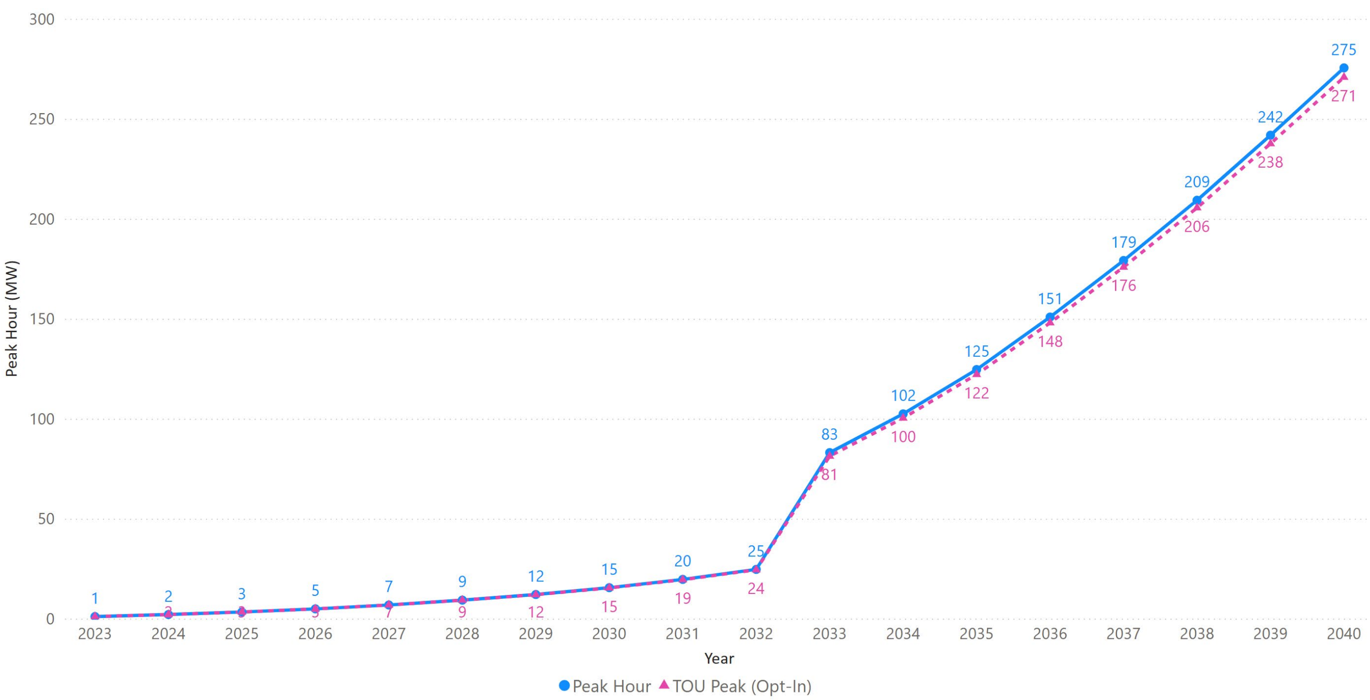
Peak impacts from the electricity rate design measures are much smaller than those from the efficiency measures. For example, for the 2040 morning peak, savings from the CPP measure are approximately 0.5% of the average winter morning peak demand, compared to 3.8% for the efficiency measures. In contrast, savings from the electricity rate design measures are higher than the impacts of electrification measures on the average winter morning peak, which is 0.2% in the same example.

7.2.2 EV Electricity Rate Design Measure Results

Exhibit 128 shows the unmanaged EV charging demand during the peak hour for each year of the forecast period (light blue line), and the charging demand with a 15% opt-in participation to the TOU rate (pink dashed line). The following observations can be made on Exhibit 128:

- Reductions to the peak hour occur each year after the introduction of the TOU rates in 2029.
- Between 2029 and 2032, the savings increase from 0.1 MW to 0.2 MW annually. The IIS peaks in the morning until 2033, when most EVs are not charging so there is limited load to shift.
- Between 2033 and 2040, the IIS peaks in the evening. Savings increase from 1.8 MW to 4.7 MW annually over this period.[160]
- The higher savings from 2033 to 2040 compared to between 2029 and 2033 occur because the TOU measure affects more EVs and because most EVs charge in the evening so there is more load to shift.
- In 2029, the peak demand reduction is 0.1 MW (0.8% of EV charging load). By 2040, the peak demand reduction is 4.7 MW (1.7% of EV charging load).

Exhibit 128: Annual EV Peak Hour Demand, Opt-In TOU[161]



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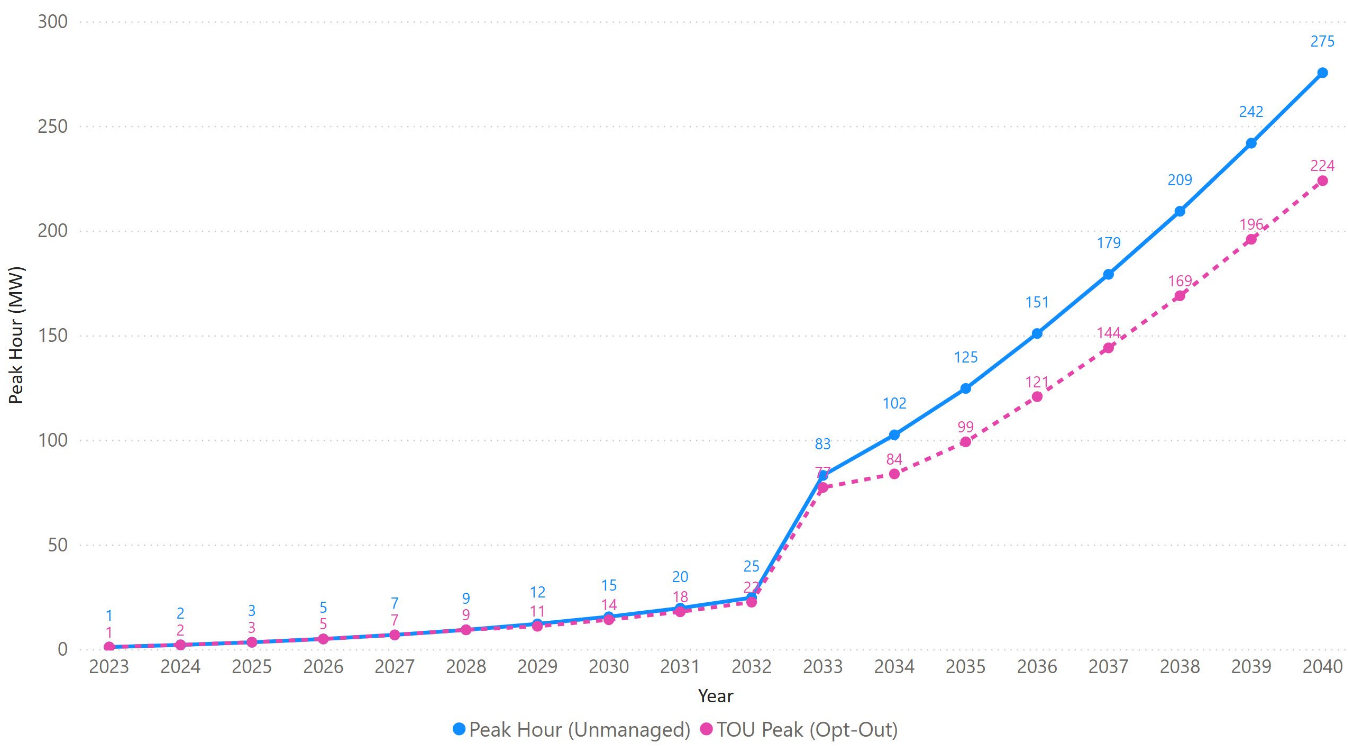
[160] Larger peak reduction potentials are realized in the evening than in the morning so when the IIS system peak is estimated to shift from the morning to the evening in 2033, peak reduction potential increases from 0.2 MW to 1.8 MW in one year.

[161] The increase in EV load during the peak hour seen between 2032 and 2033 is due to the system wide peak hour shifting from the morning to the evening. For the years before 2033, the peak hour is expected to be in the

Exhibit 129 shows unmanaged EV charging demand (light blue line) and EV charging demand with an opt-out TOU rate (pink dashed line). As explained previously, charging demand in the opt-out TOU participation scenario represents a future where the intermediate EV forecast plays out, and where 100% of EVs are on a TOU rate. The following observations can be made on Exhibit 129:

- The peak reduction potential for an opt-out TOU rate is significantly higher than the peak reduction potential for the opt-in TOU rate, especially once the IIS peak shifts to the evening. Peak reductions for the opt-out TOU rate are approximately 1 MW higher than reductions for the opt-in TOU rate in 2029 and almost 47 MW higher in 2040.
- In 2029, the peak demand reduction is 1.12 MW (9.3% of EV charging load). By 2040, the peak demand reduction is 51.60 MW (18.7% of EV charging load).

Exhibit 129: Annual EV Peak Hour Demand, Opt-Out TOU



morning and thus the EV contribution to peak is much lower as much less charging occurs then. After 2033, the EV contribution to the peak is much higher with the system peak hour now occurring much closer to the EV charging peak hour.

Exhibit 130 shows demand reductions for personal BEVs and personal PHEVs during the morning and evening peak periods, and for the peak hour. Demand reductions are shown for both the opt-in and the opt-out TOU rates. The 51.60 MW peak hour reduction from EVs based on an opt-out TOU rate in 2040 is more than eight times higher than the TOU rate reduction potential from the residential, commercial, and industrial sectors combined (6.23 MW - see Exhibit 127). This result highlights the flexibility of the EV charging load and the value to the IIS of managing the load.

Exhibit 130: Medium Achievable Peak Demand Reduction - EV TOU[162]

Measure	Vehicle Type	2029 Winter Peak Hour Reduction (MW)	2029 Winter Morning Peak Reduction (MW)	2029 Winter Evening Peak Reduction (MW)	2040 Winter Peak Hour Reduction (MW)	2040 Winter Morning Peak Reduction (MW)	2040 Winter Evening Peak Reduction (MW)
Opt-In TOU	Personal BEV	0.07	0.09	0.38	2.98	0.61	2.82
	Personal PHEV	0.03	0.03	0.34	1.71	0.16	1.54
	Total	**0.10**	**0.12**	**0.72**	**4.69**	**0.77**	**4.36**
Opt-Out TOU	Personal BEV	0.97	1.21	5.59	43.23	8.85	40.86
	Personal PHEV	0.15	0.17	1.65	8.37	0.77	7.53
	Total	**1.12**	**1.38**	**7.24**	**51.60**	**9.62**	**48.39**

[162] Reductions in load can be higher for the morning or evening periods when compared to the peak hour because the system peak hour doesn't coincide with the highest EV load. The value for the peak hour is the value that the overall system peak is reduced by.

Exhibit 131 shows the impact of an opt-in TOU rate on the IIS peak day load shape in 2040 and the resulting shift in EV charging load. The IIS peak excluding EV load (light blue line), includes the effects of energy efficiency and fuel switching measures. Limited savings from the opt-in TOU rate (pink dashed line) result in a peak reduction of approximately 4.7 MW during the IIS peak hour at 6:00 pm when compared to unmanaged EV load (black dashed line).

Exhibit 131: Impacts on Daily Load Shape – Opt-In TOU (2040)

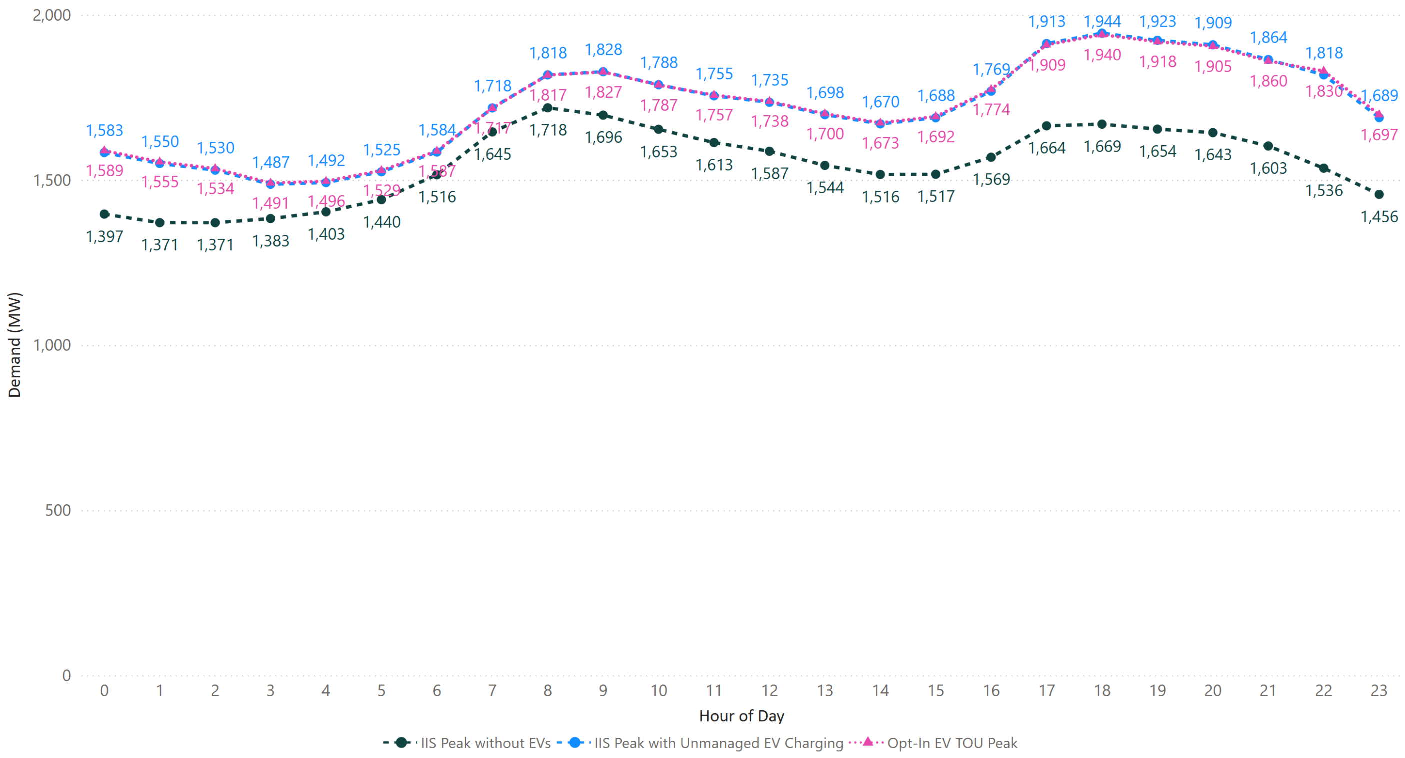
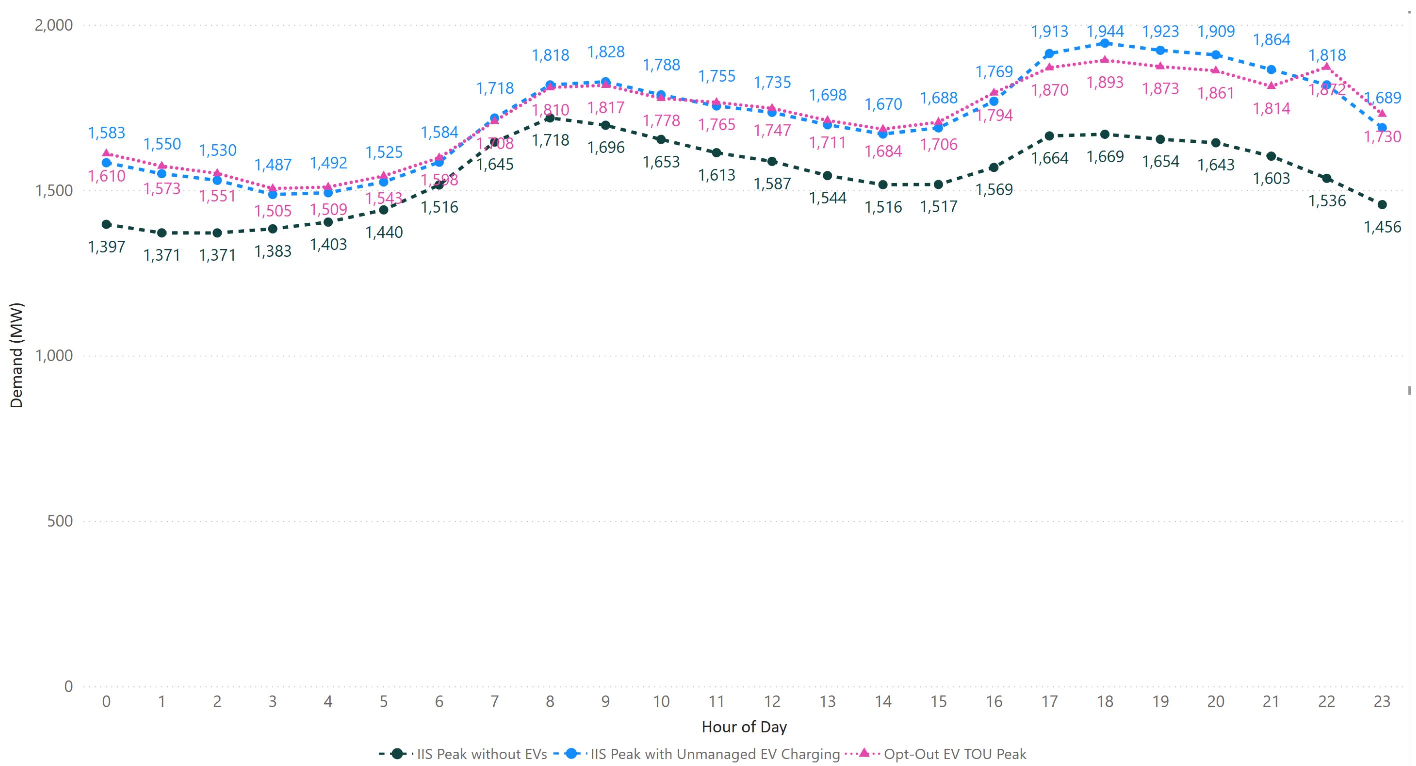


Exhibit 132 shows the impact of an opt-out TOU rate on the IIS peak day load shape in 2040 and the resulting shift in EV charging load. Observations include:

- The opt-out TOU rate is successful at encouraging personal EV owners to charge later in the evening, providing savings of 51 MW and resulting in a new peak of 1,893 MW at 6:00 p.m.
- The opt-out TOU rate also provides 11 MW of peak savings during the morning peak period.
- However, there is a large peak bounce-back at the beginning of the “Off-Peak” period at 10:00 p.m., when many of the vehicles begin to simultaneously charge again. In scenarios where the uptake of EVs is higher, or in cases where the underlying system load shape has a longer evening peak, there is a risk of creating a new, higher peak later in the evening. Implementation of a managed charging program can help mitigate this risk.[163]

Exhibit 132: Impacts on Daily Load Shape – Opt-Out TOU (2040)



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163 Managed charging programs allow utilities to have more control over the bounce back effects that may occur with widespread TOU participation.

7.3 Equipment DR Measures Potential

The Study Team also assessed the impact of equipment DR measures. The measures are split into two categories, utility-driven and thermal storage with TOU. The smart circuit breakers or smart panel measure is an example of a utility-driven measure. Each thermal storage measure has a utility-driven version and a thermal storage with TOU version.

Customer Staggering to Minimize Bounce-Back Effects

The Study Team assumed that for most measures, a reasonable number of hours for which a customer participates in demand response is four hours. This is consistent with the length of demand response events for programs from other Canadian jurisdictions including Nova Scotia and British Columbia. The evening peak period defined in section 7.1 is five hours. To avoid bounce back within the peak period, the Study Team conducted the evening peak analysis assuming the following:

- Customers are split into two groups. In-market demand response programs are assumed to stagger the onset of demand response measures in more than two groups to smooth out the response. The use of two groups is a simplification.

- Savings for group 1 start in the first hour and savings for group 2 start in the second hour.

In this way, rebound in the fifth hour for group 1 is cancelled out by the savings from group 2.

The Study Team used this method to calculate savings for the utility-driven equipment DR measures for which demand reduction over a five-hour period is unlikely. For these measures, the average demand savings for the evening peak period are reduced. Evening peak demand reduction results for these measures reflect this approach throughout the report.

7.3.1 Frequency and Duration of Equipment DR Measure Events

The Study Team modelled the equipment DR measures at the following frequency and peak event durations:

- **Equipment DR Measures (Utility-Driven):** The utility shifts customer load 12 times annually, for four hours during the morning peak period and five hours during the evening peak period.
- **Electric Vehicle Managed Charging:** The utility shifts customer EV charging for five hours during the evening peak period. Managed charging programs are not modelled at a system wide scale until 2029 (coinciding with the introduction of TOU rates).[164,165]

[164] EV managed charging measures are modelled in the absence of TOU rates as studies from other jurisdictions have indicated that if the equipment and enrolment incentives are rich enough, participation in managed charging programs are not dependent on having an underlying TOU rate structure.
[165] "PG&E Electric Vehicle Automated Demand Response Study Report," Opinion Dynamics, Available: https://opiniondynamics.com/wp-content/uploads/2022/03/PGE-EV-ADR-Study-Report-3-16.pdf (Accessed Feb. 24, 2025).

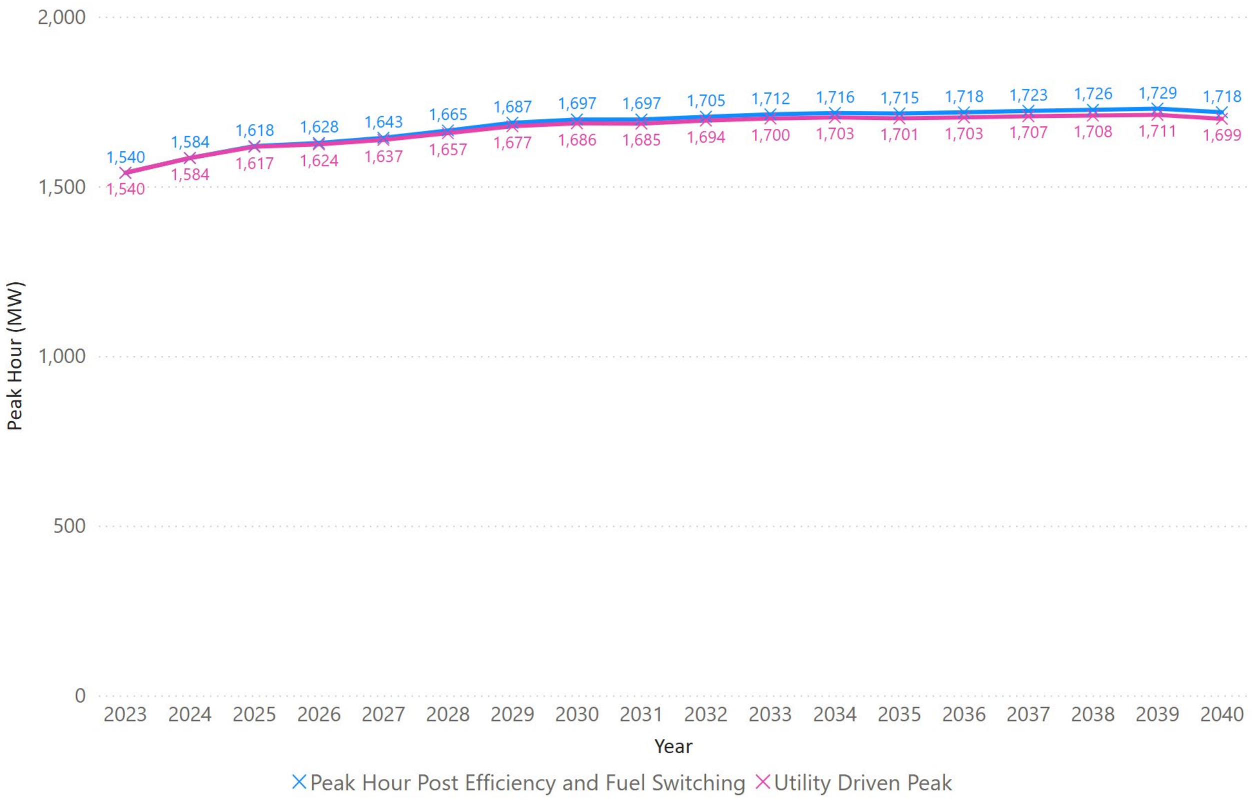
- **Equipment DR Measures (Thermal Storage with TOU):** Customers shift load off the peak periods on weekdays from December to March, for a total of 89 events per year.

7.3.2 Utility-Driven Measure Results

This section presents peak demand reduction results for the utility-driven measures, excluding EV managed charging, in the medium achievable potential scenario.[166] Participation rates for the utility-driven measures are based on rates from other jurisdictions that have been adjusted to reflect the likely participation in Newfoundland. Participation rates for the utility-driven measures are lower on average than those of the rate design measures due to customers being less likely to give the utility control of the equipment in their home or building.

Exhibit 133 shows the medium achievable peak hour demand for the utility-driven peak (pink line) compared to the reference peak hour demand that includes impacts from efficiency and fuel switching measures (light blue line). The difference between the lines represents the potential peak demand reductions from the utility-driven equipment DR measures. The demand reduction increases from 1 MW in 2025 to 19 MW by 2040.

Exhibit 133: Medium Achievable Peak Demand – Utility-Driven Equipment DR Measures



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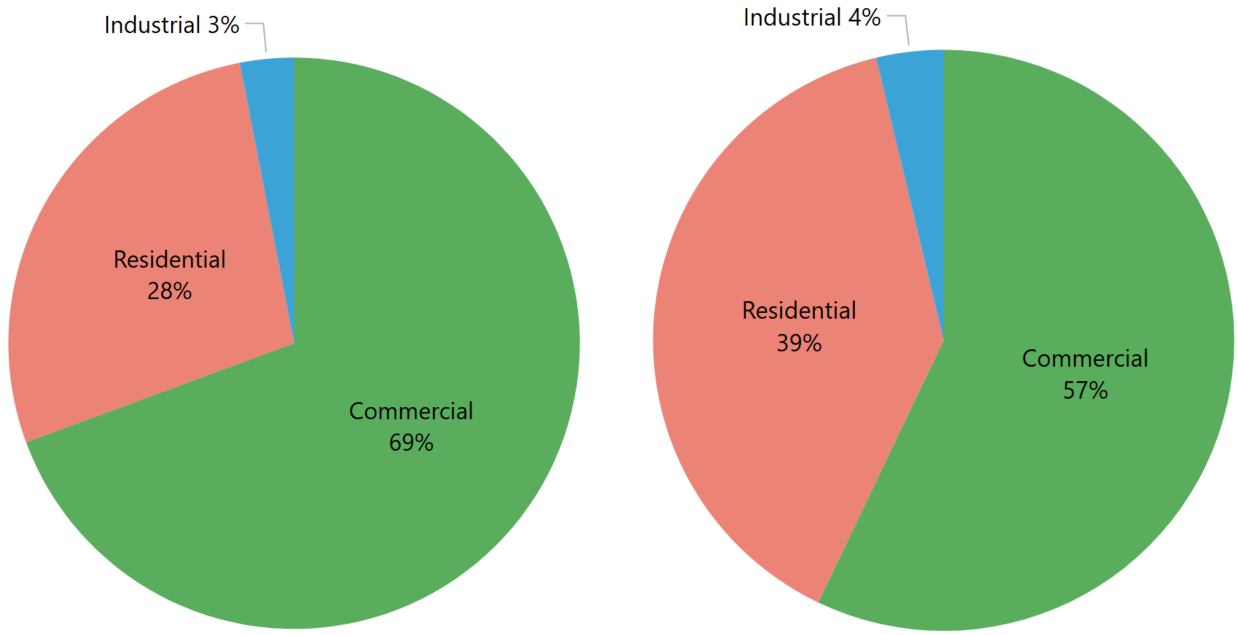
[166] The following measures are included in the medium achievable potential, even though they failed the PAC screen: electric thermal storage, battery storage, smart thermostats, substation battery, and EV managed charging. Measures that failed the PAC screen and are not cost-effective include smart thermostat or switch for ductless mini-split heat pumps and smart thermostat or switch for central air source heat pumps.

Exhibit 134 shows the medium achievable peak hour demand reduction potential for the utility-driven measures by sector. Potential peak demand reduction increases from 12.2 MW in 2031 to 19.4 MW by 2040. The commercial sector shows the most peak demand reduction in both milestone years. The proportion of peak demand reduction attributed to the residential sector increases from 28% in 2031 to 39% by 2040, as adoption of residential sector measures increases.[167]

Exhibit 134: Medium Achievable Demand Reduction Potential by Sector, 2031 (left) and 2040 (right) – Utility-Driven Equipment DR



2031 Demand Reduction Potential: 12.2 MW **2040 Demand Reduction Potential: 19.4 MW**

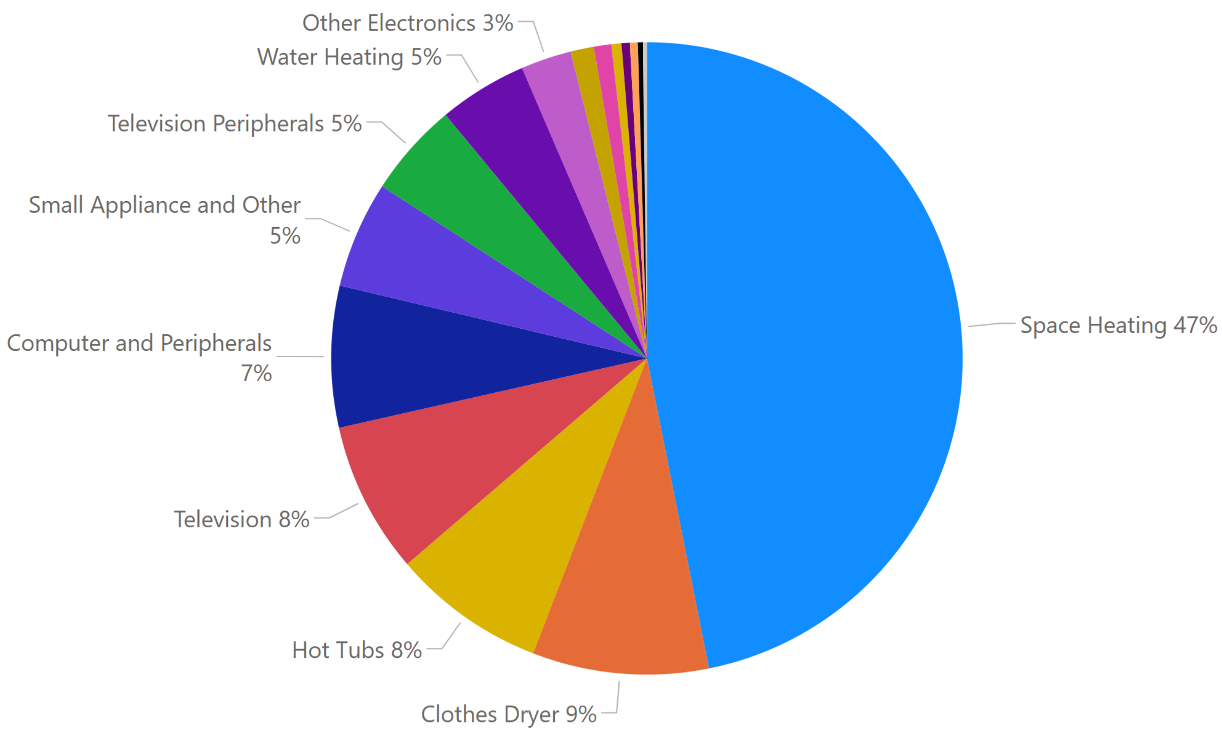
The rest of this section presents medium achievable potential peak demand reduction by sector.

[167]2031 was chosen as a milestone year for reporting purposes because it is the first year in which all utility-driven measures show peak savings.

Residential Sector

Exhibit 135 shows the 2031 peak hour demand reduction potential by end use for the residential sector.[168] Space heating offers 47% of the total potential peak demand reduction in 2031. Nine of the fourteen (64%) residential measures impact the space heating end use, which makes up 69% of the 2031 residential sector winter peak demand excluding EVs.

Exhibit 135: Residential Medium Achievable Demand Reduction Potential by End Use (2031) – Utility-Driven Equipment DR

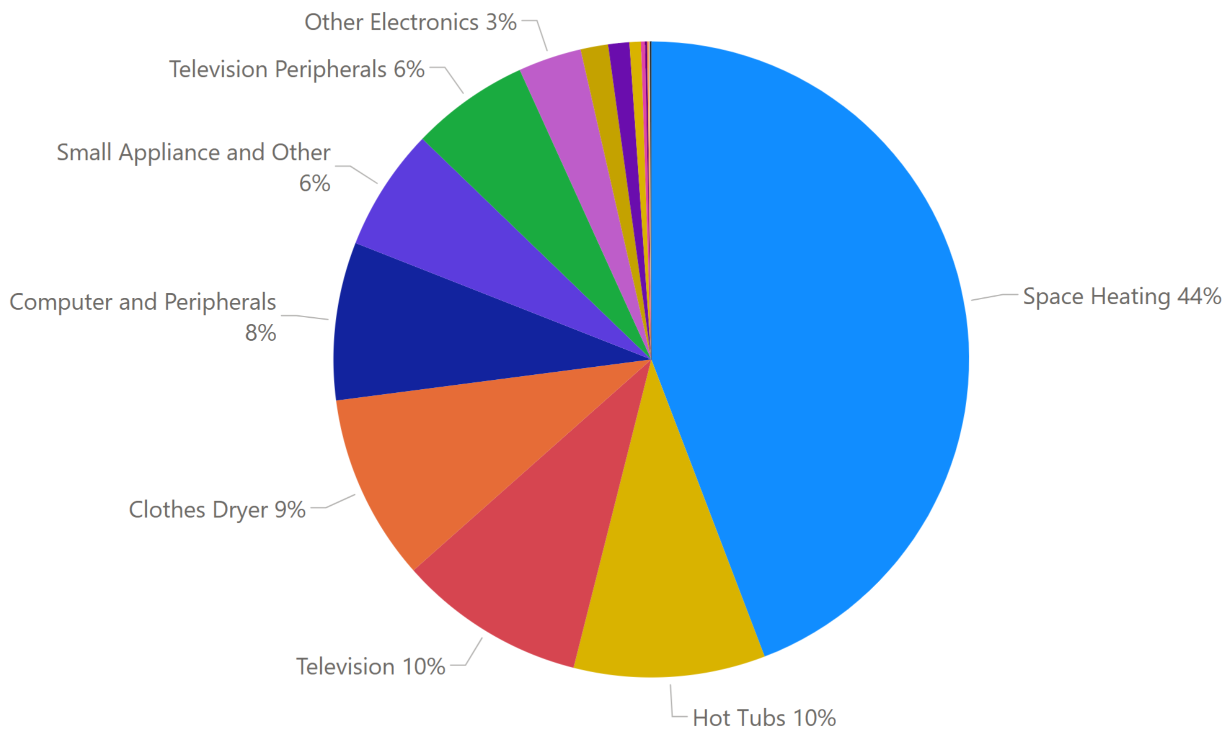


2031 Residential Demand Reduction Potential: 3.4 MW

[168] End uses that represent less than 3% of demand reduction potential are not labelled to improve readability: dishwasher (1%), cooking (1%), clothes washer (1%), refrigerator (0.4%), ventilation (0.4%), lighting (0.3%), and freezer (0.2%).

Exhibit 136 shows the 2040 peak hour demand reduction potential by end use for the residential sector.[169] Demand reduction potential by end use remains consistent because the relative measure participation rates remain consistent year over year.

Exhibit 136: Residential Medium Achievable Demand Reduction Potential by End Use (2040) – Utility-Driven Equipment DR



2040 Residential Demand Reduction Potential: 7.6 MW

[169] End uses that represent less than 3% of demand reduction potential are not labelled to improve readability: dishwasher (1%), water heating (1%), clothes washer (1%), cooking (0.2%), refrigerator (0.1%), ventilation (0.09%), lighting (0.06%), and freezer (0.06%).

Exhibit 137 shows 2031 and 2040 savings for the top residential sector utility-driven measures.

Exhibit 137: Residential Top 10 Utility-Driven Equipment DR Measures

Measure	2031 Peak Hour Demand Reduction (MW)	Measure	2040 Peak Hour Demand Reduction (MW)
Smart Circuit Breakers or Smart Panel	1.4	Smart Circuit Breakers or Smart Panel	4.0
Behind-the-Meter Solar with Smart Inverters	0.9	Smart Thermostat or Switch for Baseboards or Furnaces	0.8
Smart Thermostat or Switch for Baseboards or Furnaces	0.3	Thermal Storage and Ductless Mini-Split Heat Pump	0.7
Behind-the-Meter Battery Storage	0.2	Thermal Storage and Electric Baseboard Heating	0.6
Thermal Storage and Ductless Mini-Split Heat Pump	0.2	Behind-the-Meter Battery Storage	0.6
Smart Thermostat or Switch for Ductless Mini-Split Heat Pumps	0.2	Smart Thermostat or Switch for Ductless Mini-Split Heat Pumps	0.4
Thermal Storage and Electric Baseboard Heating	0.1	Thermal Storage and Air Source Heat Pump	0.2
Thermal Storage and Air Source Heat Pump	0.04	Smart Thermostat or Switch for Central Air Source Heat Pumps	0.1
Smart Thermostat or Switch for Central Air Source Heat Pumps	0.03	Thermal Storage and Electric Furnace	0.03
Thermal Storage and Electric Furnace	0.01	Behind-the-Meter Solar with Smart Inverters	0.0

Observations include:

- Measures that impact all or most end uses (3 of 10) and measures that target space heating (7 of 10) comprise the top ten peak reduction measures. Measures that impact specific appliance end uses like clothes drying or clothes washing do not show medium achievable potential peak demand reduction because they are not cost-effective and do not pass the PAC screen.
- Behind-the-meter solar with smart inverters shows no savings starting in 2032 when the IIS peak shifts from the morning to the evening.

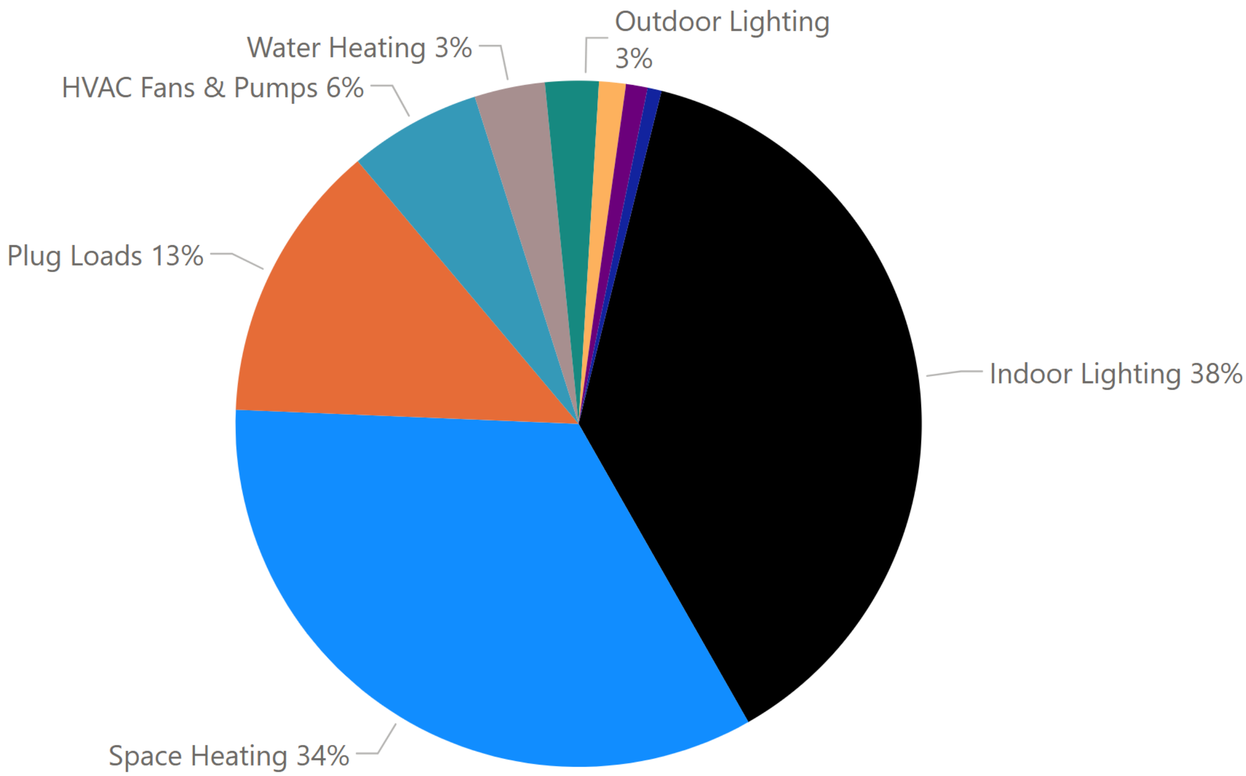
- Total savings are low relative to the peak hour demand. For example, the total space heating savings make up less than 1% of space heating demand in the residential sector by 2040. This is because of the participation rates for measures that impact the space heating end use. For example, participation rates for the thermal storage and ductless mini split heat pump measures only reach 0.5% of available units by 2040. Across all residential utility-driven measures, the average participation rate in 2040 is 3%.
- The smart circuit breakers or smart panel measure shows the highest peak demand reduction in 2031 (1.4 MW) and 2040 (4.0 MW). This is because the measure impacts most end uses and is applicable to all customers.
- Out of the measures targeting the space heating end use, the smart thermostat or switch for baseboards or furnaces measure shows the highest peak demand reduction in 2040 (0.8 MW). This measure has no incremental cost to the customer and a large opportunity comprising both homes with electric baseboard heating and electric furnaces.[170]
- Thermal storage and ductless mini split heat pumps and thermal storage and electric baseboard heating show similar potential peak demand reduction in 2040. They perform better than the thermal storage measures for central heating systems because they have a larger opportunity in Newfoundland and have a lower incremental cost.

[170] This measure assumes the customer already has a smart thermostat installed.

Commercial Sector

Exhibit 138 shows 2031 peak hour demand reduction potential by end use for the utility-driven measures in the commercial sector.[171] Indoor lighting and space heating offer 38% and 34% of the potential peak demand reduction in 2031, respectively. Ten of the eleven (91%) commercial measures impact either indoor lighting or space heating, which make up 61% of the total 2031 commercial sector winter peak demand excluding EVs.

Exhibit 138: Commercial Medium Achievable Demand Reduction Potential by End Use (2031) – Utility-Driven Equipment DR

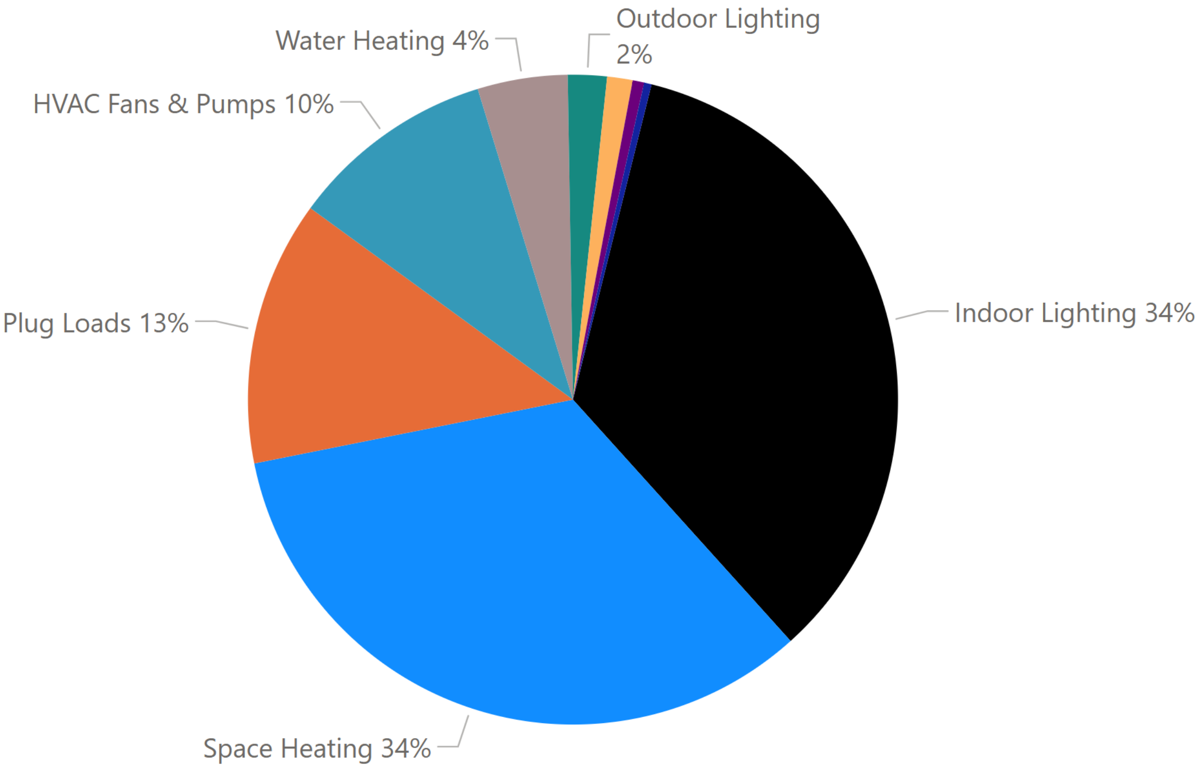


2031 Commercial Demand Reduction Potential: 8.4 MW

[171] End uses that represent less than 3% of demand reduction potential are not labelled to improve readability: miscellaneous equipment (1%), food service (1%), and refrigeration (0.7%).

Exhibit 139 shows 2040 peak hour demand reduction potential by end use for the utility-driven measures in the commercial sector.[172] Six of the eleven (55%) commercial measures impact the space heating end use, which makes up 45% of the total 2040 commercial sector winter peak demand excluding EVs. Demand reduction potential by end use remains consistent because the relative measure participation rates remain consistent year over year.

Exhibit 139: Commercial Medium Achievable Demand Reduction Potential by End Use (2040) – Utility-Driven Equipment DR



2040 Commercial Demand Reduction Potential: 11.1 MW

[172] End uses that represent less than 2% of demand reduction potential are not labelled to improve readability: miscellaneous equipment (1%), food service (0.6%), and refrigeration (0.4%).

Exhibit 140 shows 2031 and 2040 peak hour demand reduction potential for the top ten commercial sector utility-driven measures.

Exhibit 140: Commercial Top 10 Utility-Driven Equipment DR Measures

Measure	2031 Peak Demand Reduction (MW)	Measure	2040 Peak Demand Reduction (MW)
Backup Generation at Peak Hours	3.6	Backup Generation at Peak Hours	4.0
Behind-the-Meter Battery Storage	1.8	Behind-the-Meter Battery Storage	1.9
Thermal Storage and Heat Pump Heating	1.0	Grid Interactive Efficient Buildings (GEB)	1.9
Behind-the-Meter Solar with Smart Inverters	0.8	Thermal Storage and Heat Pump Heating	1.5
Grid Interactive Efficient Buildings (GEB)	0.5	HVAC Control	0.9
HVAC Control	0.3	HVAC Fans & Pumps Controls	0.5
HVAC Fans & Pumps Controls	0.2	Thermal Storage and Electric Furnace Heating	0.1
Thermal Storage and Electric Furnace Heating	0.1	Thermal Storage and Electric Baseboard Heating	0.04
Thermal Storage and Electric Baseboard Heating	0.03	Large Commercial Dual-Fuel Water Heater	0.01
Large Commercial Dual-Fuel Water Heater	0.004	Behind-the-Meter Solar with Smart Inverters	0.0

Observations include:

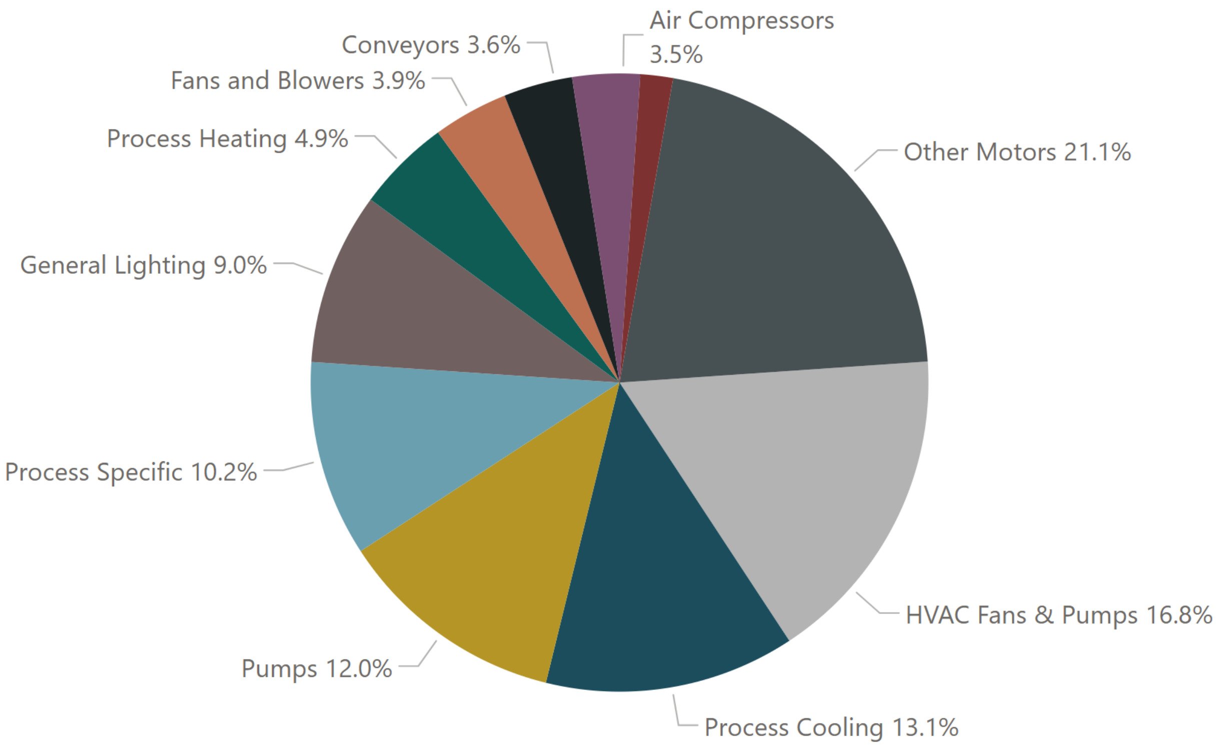
- Measures that target all or most end uses show the highest potential peak demand reduction followed by the measures that target space heating.
- Behind-the-meter solar with smart inverters shows no savings starting in 2032 when the peak shifts from the morning to the evening.
- Like the residential sector, savings for commercial utility-driven measures are low compared to the overall winter peak demand. For example, by 2040, space heating savings make up 2% of the space heating winter peak demand. Participation rates for the different utility-driven measures range from 3% to 8% by 2040.

- Backup generation at peak hours shows the highest peak demand reduction by 2040 (4.0 MW). This measure assumes customers have an existing generator and has a small incremental cost and relatively high savings (80%).
- Thermal storage and heat pump heating shows the highest peak demand reduction for measures that target space heating (1.0 MW in 2031 and 1.5 MW in 2040). This is driven by a higher technical applicability for heat pumps in the commercial sector than other space heating systems.

Industrial Sector

Exhibit 141 shows the peak hour demand reduction potential by end use for industrial sector utility-driven measures in 2031.[173] The other motors end use offers 21.1% of the potential peak demand reduction in 2031. Three of the six (50%) utility-driven measures impact the other motors end use, which makes up 15% of the total industrial winter peak demand in 2031.

Exhibit 141: Industrial Medium Achievable Demand Reduction Potential by End Use (2031) – Utility-Driven Equipment DR

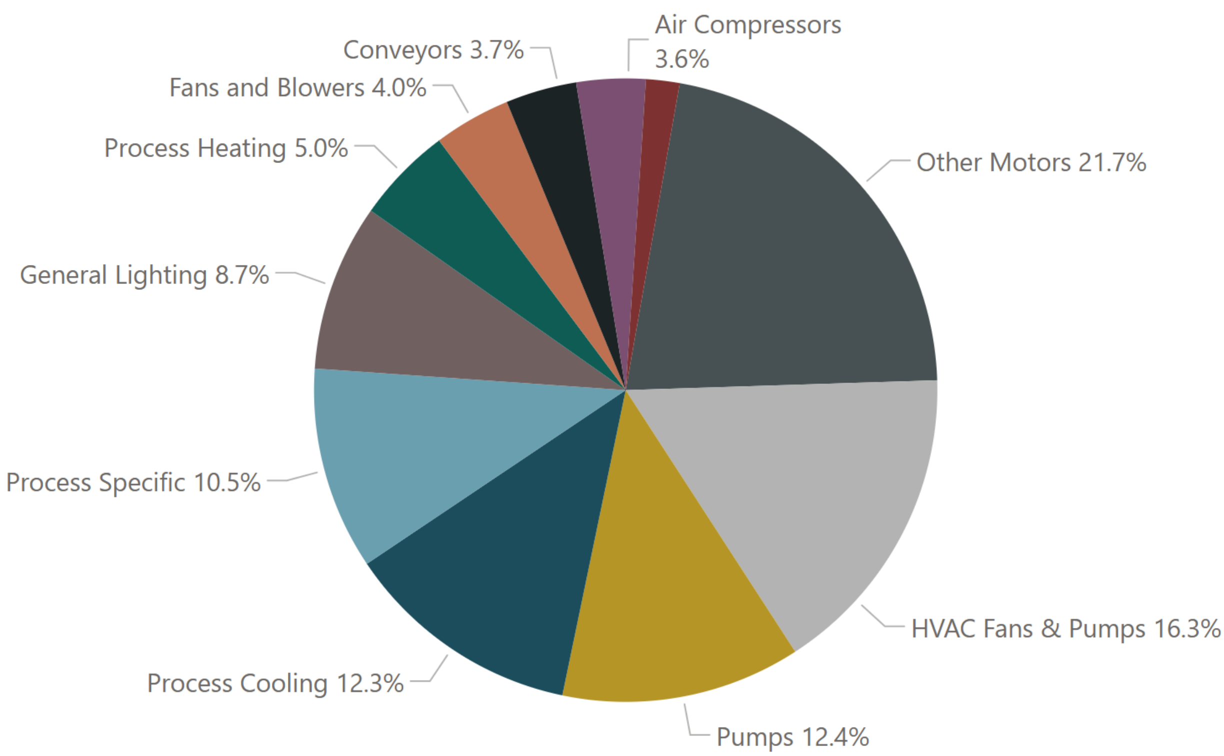


2031 Industrial Demand Reduction Potential: 0.4 MW

[173] The Other end use represents 1.7% of demand reduction potential is not labelled to improve readability.

Exhibit 142 shows the peak hour demand reduction potential by end use for industrial sector utility-driven measures in 2040.[174] Demand reduction potential by end use remains consistent because the relative measure participation rates remain consistent year over year.

Exhibit 142: Industrial Medium Achievable Demand Reduction Potential by End Use (2040) – Utility-Driven Equipment DR



2040 Industrial Demand Reduction Potential: 0.7 MW

174 The Other end use represents 1.7% of demand reduction potential is not labelled to improve readability.

Exhibit 143 shows 2031 and 2040 peak hour demand reduction potential for the industrial sector utility-driven measures.

Exhibit 143: Industrial Utility-Driven Equipment DR Measures

Measure	2031 Peak Hour Demand Reduction (MW)	Measure	2040 Peak Hour Demand Reduction (MW)
Behind-the-Meter Battery Storage	0.2	Behind-the-Meter Battery Storage	0.6
Backup Generation at Peak Hours	0.1	Backup Generation at Peak Hours	0.1
Behind-the-Meter Solar with Smart Inverters	0.0002	Behind-the-Meter Solar with Smart Inverters	0.0

Observations include:

- There is a more even distribution of peak demand reduction between the different industrial end uses compared to the residential and commercial sectors. The top three peak demand reducing end uses are other motors, HVAC fans and pumps, and process cooling. Three of the four (75%) industrial sector utility-driven measures impact all end uses, so the relatively high savings are driven by higher winter peak demand for those end uses.
- Savings for the industrial utility-driven measures make up less than 1% of the total industrial demand. As in the residential and commercial sectors, participation rates for the industrial utility-driven measures are assumed to be low even out to 2040, ranging from less than 1% to 13%, depending on the measure.
- Behind-the-meter solar with smart inverters shows no savings starting in 2032 when the peak shifts from the morning to the evening.
- Behind-the-meter battery storage shows the highest peak demand reduction in 2031 (0.2 MW) and 2040 (0.6 MW), driven by a high technical applicability and relatively high percent savings compared to other similar measures.

Substation Battery

Exhibit 144 shows the frequency, duration and savings for the substation battery measure.

Exhibit 144: Frequency, Duration, and Peak Demand Reduction for the Substation Battery Measure

Measure	Frequency of Peak Events	Duration of Peak Events	Peak Hour Demand Reduction (MW)
Substation Battery	12	Morning Peak: 4 hours Evening Peak: 5 hours	12 MW per battery

The results shown are for a single battery at one substation, however, they could be scaled to include additional batteries at multiple substations. For a single substation battery, considering only the incremental cost of the battery, the PAC result is 3.0, showing that this measure is cost-effective.

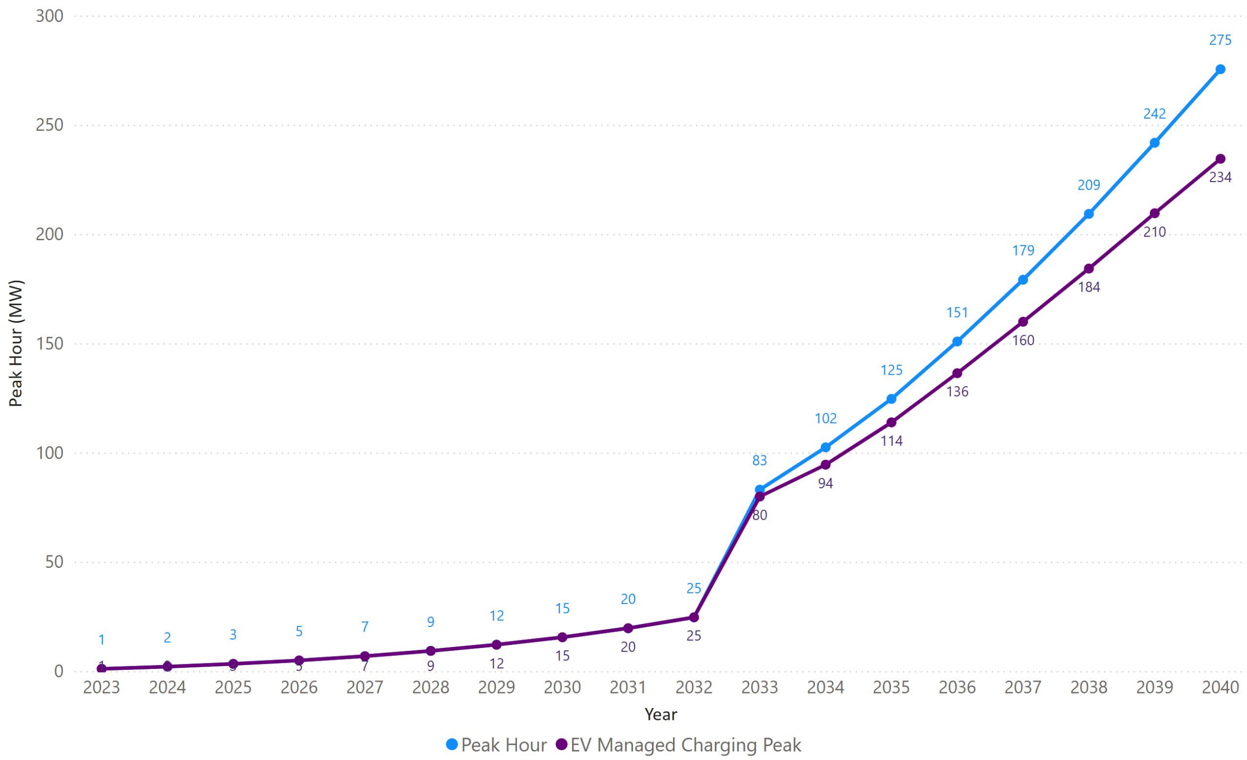
However, there are jurisdiction-specific costs to connect batteries to the grid. Further research beyond the scope of this Study is required to estimate these costs and their impact on the PAC.

7.3.3 Electric Vehicle Managed Charging Results

This section presents peak demand reduction results for the EV managed charging measures, including electric vehicle supply equipment (EVSE) and vehicle telematics (VT). Appendix F shows a sample calculation that explains how the managed charging results were calculated.

Exhibit 145 shows the unmanaged EV load during the peak hour for each year of the forecast period (light blue line), and the resulting reduction in EV load due to the achievable potential for managed charging measures (dark purple line). Because the system peak hour is estimated to occur in the morning until 2033, on-peak reductions from managed charging are not realized until 2033. After 2033, savings from the managed charging begin to gradually increase, reaching a maximum reduction potential of approximately 41 MW by 2040. This corresponds to a roughly 15% decrease in the EV load during the system peak hour in 2040.

Exhibit 145: Annual EV Peak Hour Demand – Managed Charging[175]



[175] The increase in EV load during the peak hour between 2032 and 2033 is due to the system wide peak hour shifting from the morning to the evening. See Exhibit 128 in section 7.2.2 for a detailed explanation.

Exhibit 146 displays the EV load reduction during the evening peak period from managed charging measures. Load reductions are minimal, due to low achievable potential participation rates earlier in the forecast period, but there are still some peak reductions that can be realized in the evening period, beginning in 2029. While the managed charging measures will not influence the system wide peak before 2033, they may still have effects on local distribution networks that may be experiencing evening peaks earlier in the forecast period. However, it should be noted that the managed charging measures never result in savings during the morning peak period due to the measures not being viable during that time of day.

Exhibit 146: Annual Average EV Evening Peak Demand – Managed Charging

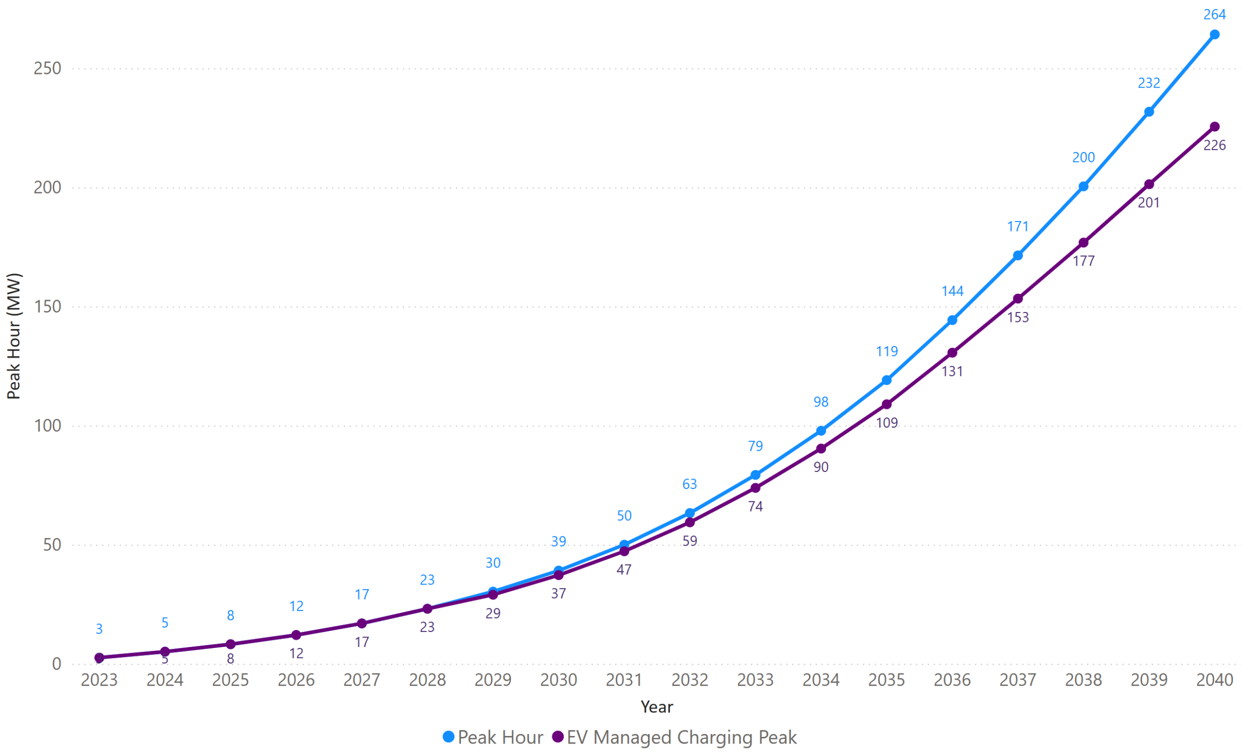


Exhibit 147 displays the breakdown of managed charging peak savings in 2040 by EVSE and VT measure.

- VT accounts for 70% (29 MW) of the total managed charging load reductions by 2040. As vehicle telematics become more standard in EVs, the lack of necessary hardware upgrade costs for EV owners who opt to participate in a managed charging program results in higher participation in the VT measure.
- However, at 30% (12 MW) of the potential demand reduction, there remains a market for the EVSE measure. Reducing hardware costs as charging technologies mature as well as privacy concerns about access to vehicle telematics systems may lead participants to join programs using their EVSEs.

Exhibit 147: EV Peak Hour Reduction by Measure Type (2040)

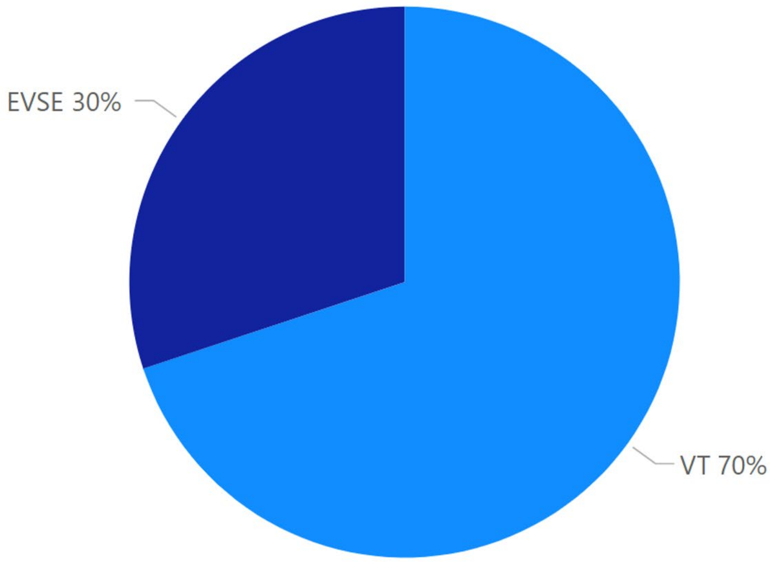
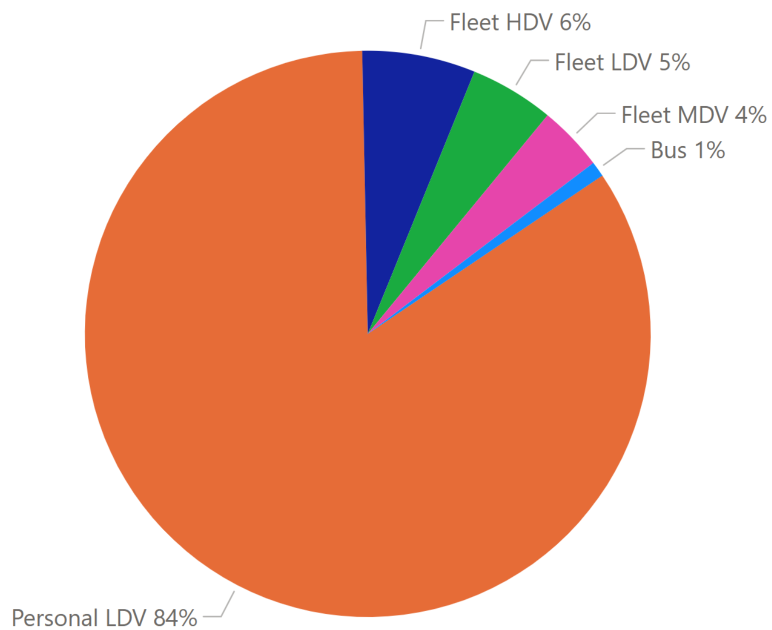


Exhibit 148 shows the peak hour demand reduction potential for managed charging in 2040 by vehicle type.

- Personal LDVs dominate the peak reductions, accounting for 84% of all EV reductions.
- The remaining 16% is distributed among the four fleet vehicle types, with 6% from HDVs, 5% from LDVs, 4% from MDVs and 1% from buses. [176]

These results are due to the number of vehicles estimated to participate in the measures from each vehicle type. Personal LDVs represent the most EVs across all categories and do not have regular duty cycles that limit when they can shift their charging load. Fleet MHDVs also have much larger batteries and longer daily routes that require high powered chargers, which also limits how much peak load they can shift.

Exhibit 148: EV Peak Hour Reduction by Vehicle Type (2040)



[176] Transit buses were not considered in the managed charging program because their operating schedules often dictate that charging already occurs overnight (i.e., outside the evening peak period). Only school buses contribute to the managed charging program for the bus category.

Exhibit 149 shows 2040 EV peak reduction by measure. The results reflect the findings highlighted in Exhibit 147 and Exhibit 148.

Exhibit 149: EV Managed Charging Measures (2040)

Measure	Peak Hour Demand Reduction (MW)
Personal BEV - Telematics	18.9
Personal BEV – EVSE	10.7
Personal PHEV – Telematics	4.9
Fleet HDV – Telematics	2.0
Fleet LDBEV – Telematics	1.3
Fleet MDV – Telematics	1.1
Fleet HDV – EVSE	0.7
Fleet LDBEV – EVSE	0.5
Fleet MDV – EVSE	0.4
Bus – Telematics	0.3
Fleet LDPHEV – Telematics	0.2
Bus - EVSE	0.1
Total	**41.1**

Because the achievable potential for load shifting through EV managed charging measures is forecast to exceed 40 MW, it is important for the Utilities to know where that load is shifted to. This helps avoid a peak bounce-back, which can occur when many vehicles begin charging simultaneously after a managed charging period has ended. This bounce-back effect has the potential to shift the peak to a new hour and potentially cause a new peak if not managed properly. Exhibit 150 shows the impact of the achievable potential managed charging measures layered onto the IIS system peak day load shape (which includes the effects of energy efficiency and fuel switching measures).

- The unmanaged 24-hour load shape (light blue line) shows hourly peak demand in the absence of any managed charging program or TOU rates. The evening peak (1,944 MW) occurs at 6:00 p.m.
- The managed 24-hour load shape (dark purple line) shows hourly peak demand with the achievable potential for the managed charging measures. The managed charging programs are successful in shifting EV load from the evening peak period into the troughs overnight and ensuring that no other large spikes in load are created. The peak hour remains at 6:00 p.m. but is reduced by 41 MW to 1,903 MW.

Exhibit 150: Achievable Potential Impacts on Daily Load Shape (2040) – Managed Charging

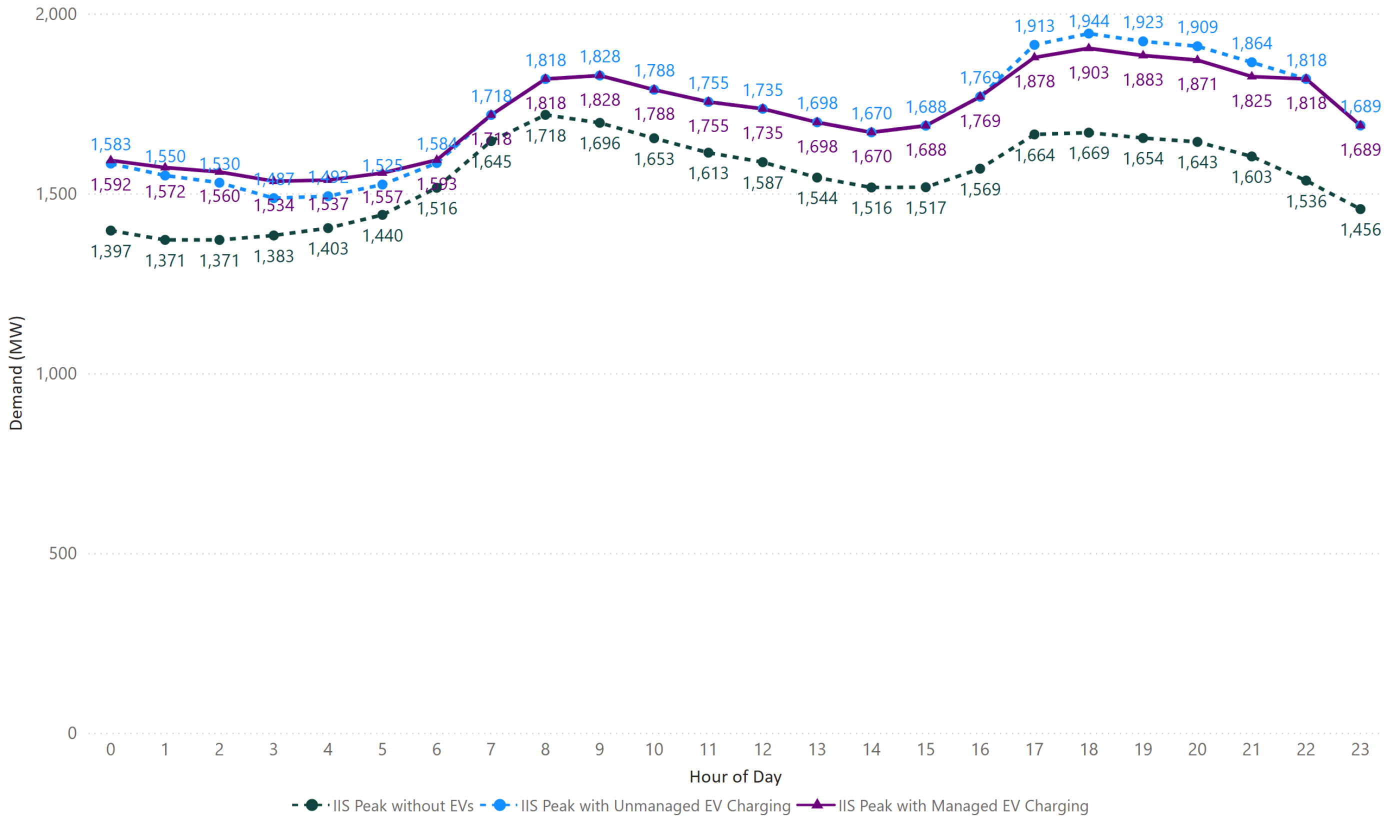
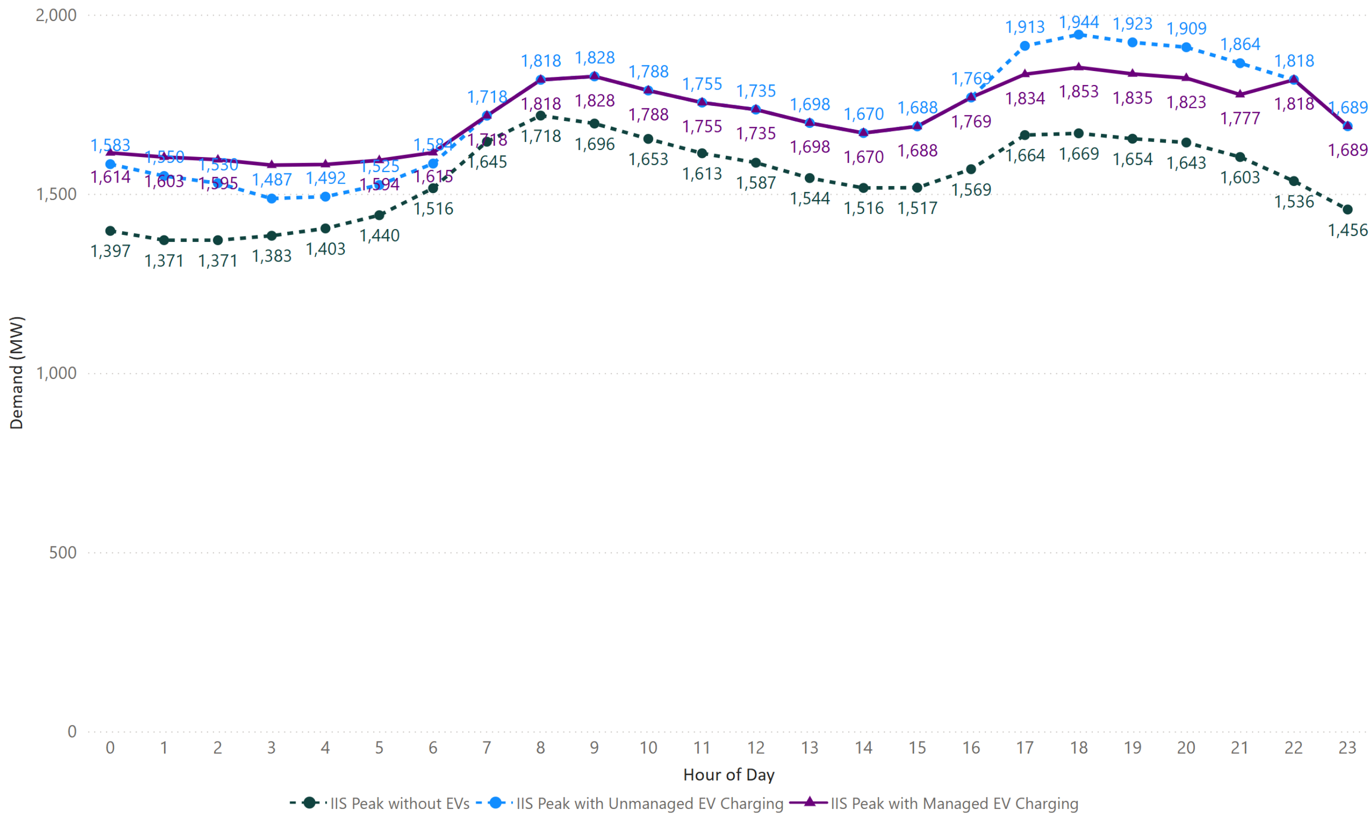


Exhibit 151 shows the impact of the technical potential managed charging measures on the system peak day load. The technical potential explores the peak reduction possible if all personal vehicles with access to at-home charging adopted the measure and all fleet vehicles with duty cycles permitting participation also adopted the measure.

- The technical potential of the managed charging measures results (dark purple line) in a system peak of 1,853 MW at 6:00 p.m., a reduction of over 90 MW compared to the unmanaged EV load (light blue line). This results in a further reduction of more than 50 MW when compared to the achievable potential.[177]
- A load reduction of this magnitude begins to raise the possibility of creating a new peak at a different time in the day. As participation rates for the measures increase, the period in which the measure occurs may need to be adjusted (highlighted by the spike in load at 10:00 p.m.) and more optimized managing of load might be required to avoid creating a new peak.

Exhibit 151: Technical Potential Impacts on Daily Load Shape (2040) – Managed Charging



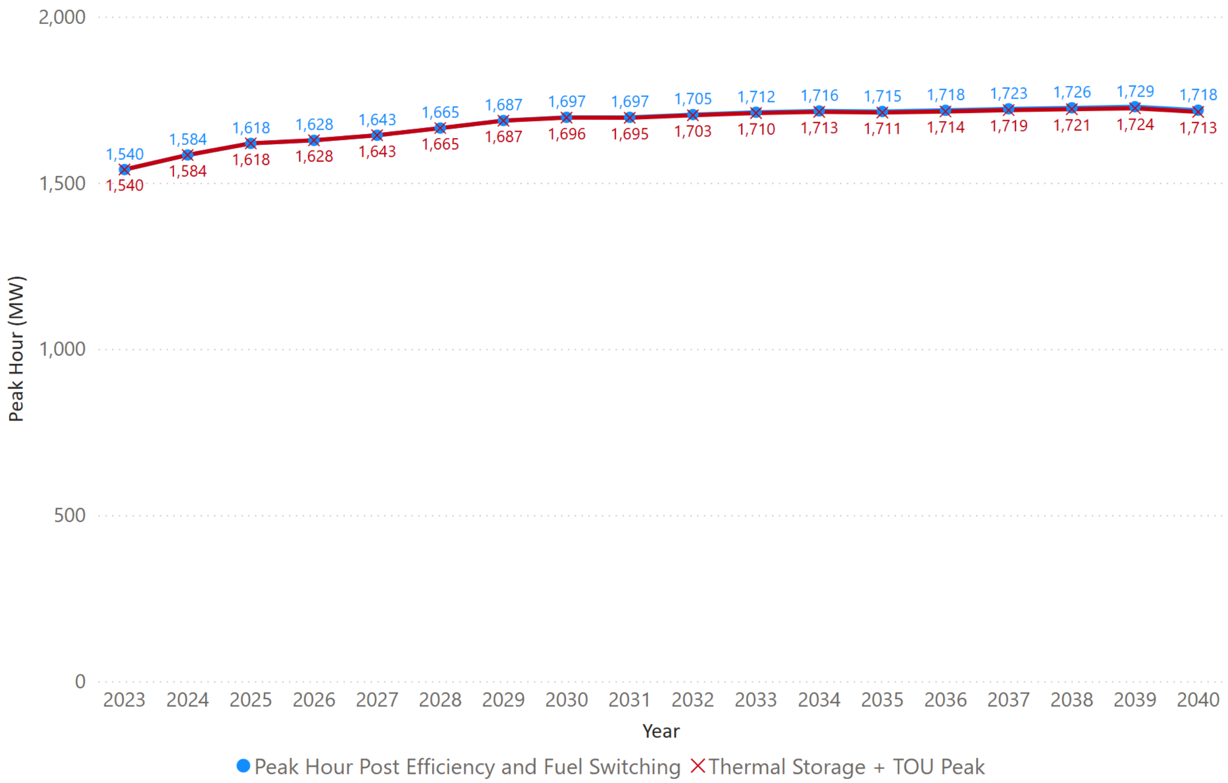
[177] Since EVs are an emerging technology, measure participation will take time to increase, even for vehicles where managed charging is feasible. This is due to access to at home charging or duty cycles that permit participation.

7.3.4 Thermal Storage with TOU Measure Results

Exhibit 152 shows the medium achievable peak hour demand for the thermal storage with TOU measures (red line) compared to the reference peak hour demand that includes impacts from efficiency and fuel switching measures (light blue line). The difference between the lines represents demand reduction potential for the thermal storage with TOU measures in the medium achievable potential scenario. By 2040, the thermal storage with TOU measures offer 5 MW of peak reduction potential.

The thermal storage with TOU measures are separate from the behaviour-based TOU design measures where customers use any method to shift peak. For the thermal storage with TOU measures, customers use an electric thermal storage system to shift their space heating load. Overlap and interactive effects between the two measure types are discussed in section 7.5.

Exhibit 152: Medium Achievable Peak Demand – Thermal Storage with TOU



When the thermal storage with TOU measures are first implemented, all (100%) of the medium achievable potential peak reduction potential comes from the commercial sector due to low participation rates in the residential sector. The peak reduction potential in the residential sector increases over the Study period as more customers participate. By 2040, the peak reduction is 1.6 MW in the residential sector and 3.5 MW in the commercial sector. The rest of this section presents medium achievable potential peak demand reduction by sector.[178]

[178] No thermal storage with TOU measures are modelled for the industrial sector.

Residential Sector

Exhibit 153 shows the peak reduction by measure for the residential sector in 2034 and 2040.[179]

Exhibit 153: Residential Thermal Storage with TOU Equipment DR Measures

Measure	2034 Peak Hour Demand Reduction (MW)	Measure	2040 Peak Hour Demand Reduction (MW)
Thermal Storage and Ductless Mini-Split Heat Pump	0.1	Thermal Storage and Ductless Mini-Split Heat Pump	0.7
Thermal Storage and Electric Baseboard Heating	0.1	Thermal Storage and Electric Baseboard Heating	0.6
Thermal Storage and Air Source Heat Pump	0.0	Thermal Storage and Air Source Heat Pump	0.2
Thermal Storage and Electric Furnace	0.01	Thermal Storage and Electric Furnace	0.03

The results in Exhibit 153 show the following:

- The thermal storage with TOU measures perform like the equivalent utility-driven measures. For example, the thermal storage with TOU measure with the highest peak demand reduction in 2040 is thermal storage and ductless mini-split heat pump (0.7 MW), which also offers the highest peak demand reduction potential of the utility-driven thermal storage measures.
- Savings for the thermal storage with time-of-use measures are higher than the equivalent utility-driven measures because participation is assumed to be higher when a TVR is involved. Customers can see bill reductions from each weekday in the winter when a TOU rate structure is in place.

[179] 2034 was chosen as a milestone year for reporting purposes because it is the first year in which all thermal storage with TOU measures show peak demand savings.

Commercial Sector

Exhibit 154 shows the peak reduction by measure for the commercial sector in 2034 and 2040.

Exhibit 154: Commercial Thermal Storage with TOU Equipment DR Measures

Measure	2034 Peak Hour Demand Reduction (MW)	Measure	2040 Peak Hour Demand Reduction (MW)
Thermal Storage and Heat Pump Heating	2.4	Thermal Storage and Heat Pump Heating	3.2
Thermal Storage and Electric Furnace Heating	0.2	Thermal Storage and Electric Furnace Heating	0.3
Thermal Storage and Electric Baseboard Heating	0.1	Thermal Storage and Electric Baseboard Heating	0.1

The results in Exhibit 154 show the following:

- As in the residential sector, the commercial sector thermal storage with TOU measures behave the same way as the utility-driven measures relative to each other. The measure with the highest peak demand reduction is thermal storage and heat pump heating, showing 3.2 MW of savings in 2040.
- The commercial sector thermal storage with TOU measures also show higher savings than the commercial utility-driven measures, because commercial customers will see daily savings that would otherwise not be realized without a time varying rate.

Exhibit 155 shows the sector level peak hour demand reduction potential for each measure type.[180] Efficiency and electrification impacts refer to the savings or increase in peak demand as a result of the efficiency and electrification measures, discussed in sections 5 and 6. Electrification impacts are shown as negative savings.

Exhibit 155: Peak Demand Reduction by Sector and Resource Type (MW), (2040)

Sector	Efficiency	Electrification	TOU	CPP	Utility-Driven Equipment	Thermal Storage with TOU Equipment
Residential	36.9	-2.6	4.8	7.9	7.6	1.6
Commercial	25.5	-1.6	1.1	1.5	11.1	3.5
Industrial	9.3	-0.08	0.3	0.3	0.7	-
EVs	-	-	4.7	-	41.0	-
Total[181]	**71.7**	**-4.3**	**10.9**	**9.7**	**60.4**	**5.1**

Of the non-EV demand response measures, the utility-driven equipment DR measures show the highest potential, followed by the CPP, TOU, and thermal storage with TOU measures. Each of these resources provide less peak demand reduction than the efficiency measures but show a higher peak impact than the electrification measures.

Note that the peak demand reduction for the demand response measures is not additive and savings for each measure type are calculated separately. For example, the savings for the TOU rate design measure only consider the savings potential for the scenario where customers use any method to shift peak, whereas the thermal storage with TOU measures assume that customers only use electric thermal storage to shift peak and do not change habits that affect other end uses. Section 7.5 further discusses the methods used to account for overlap and interactive effects between the different measure types.

[180] Exhibit 155 shows the absolute winter peak hour demand reduction potential by sector and resource type, not the average demand reduction during the evening winter peak period.
[181] Total TOU peak reductions increase to 58.9 MW when including the Opt-Out version of the TOU rate for EVs.

7.4 Customer Curtailment Potential

The Study Team developed a conservative, high-level estimate of curtailment potential for NP's rate 2.3 and 2.4 customers and both Utilities' large customers.[182] The estimate is based on current and planned NP and NLH curtailment contracts and programs, consultation with the Utilities, meetings held with NLH's large industrial customers, the 2023 CEUS, and curtailment programs in other jurisdictions.

7.4.1 Eligible Customers

The Study Team identified the following customer groups as eligible for curtailment:

- **Rate 2.4 Existing Energy Curtailment Program (ECP) Participants:** Rate 2.4 customers who are already participating in NP's ECP.[183]
- **Rate 2.4 New ECP Participants:** Rate 2.4 customers who are eligible and likely to participate in the ECP, based on the sector (public or private) and the segment to which they belong.
- **Large Customers:** The Utilities may enter short-term or long-term capacity assistance contracts with large commercial or industrial sector customers.

7.4.2 Curtailment Potential Results

Exhibit 156 shows curtailment potential by customer group. The curtailment potential from large customer contracts was developed with input from the Utilities. Of this potential, 22.5 MW is an early-call curtailment resource, while the remaining 98 MW is treated as a contingency resource. Individual customers are not identified to maintain confidentiality. Curtailment potential is not varied annually in the Study.

Exhibit 156: Curtailment Potential Results (all years)

Customer Group	Curtailable Load/Customer	Number of Customers	Total Curtailment
2.4 Existing ECP participants	500 kW/participant	24	12.0 MW
2.4 New ECP participants	300 kW/participant (30% of peak demand)	8	2.4 MW
Large Customer Contracts	Contract-Specific	3	120.6 MW
	Total	**35**	**135 MW**

Large Industrial Customer Consultation Summary

The Study team and NLH met with the large industrial customers to discuss efficiency, electrification, and curtailment potential. These meetings did not identify additional candidates for curtailment beyond those customers with curtailment contracts currently in place. This finding is consistent with NLH's understanding of curtailment potential among their large industrial customers.

[182] A more detailed estimate is beyond the scope of this Study.
[183] Newfoundland Power, "Energy Curtailment Program," Available: https://www.newfoundlandpower.com/en/Business-Services/Rates-and-Services/Curtailment-Program (Accessed Sept. 4, 2024).

Total curtailment potential (135 MW) represents 7% of the winter peak demand in 2040. Exhibit 157 shows that the curtailment potential is much higher than the medium achievable peak demand reduction potential for the other commercial and industrial sector demand response resources. However, large customers may be asked to curtail their loads only when the IIS is very constrained. Savings from existing and new ECP participants represent 11% of the total curtailment potential.

Exhibit 157: Commercial and Industrial Sector Peak Demand Reduction by Resource (2040)

Resource	Demand Reduction Potential (MW)
Total Curtailment	135
TOU	1.4
CPP	1.8
Utility-Driven Equipment	11.8
Thermal Storage Equipment with TOU	3.5

7.5 Interactive Effects

The Study Team was asked to estimate the interactive effects between the demand response resources. This estimate was required to avoid double-counting savings from resources that target the same reduction on the IIS reference load shape. For example, the residential electricity TOU rate design measure targets the same peak savings as the behind-the-meter solar with smart inverters measure.

The Study Team estimated the interactive effects between the following resources:

- **Efficiency and electrification measures and the demand response measures**: The interactive effects are accounted for in the potential reduction for the demand response measures, as explained in the introduction to section 7.
- **Electricity rate design measures and equipment demand response measures**: These resources are modelled separately, so savings for participants in both measures are double counted unless interactive effects are considered. A sample calculation to estimate the interactive effects between these measure types is provided in section 7.5.1.
- **Equipment demand response measures and ECP participant curtailment**: These resources are modelled separately, so savings for participants in both measures are double-counted unless interactive effects are considered.

The Study Team did not apply electricity rate design measures or equipment DR measures to the large industrial customers, so there was no interaction with curtailment.

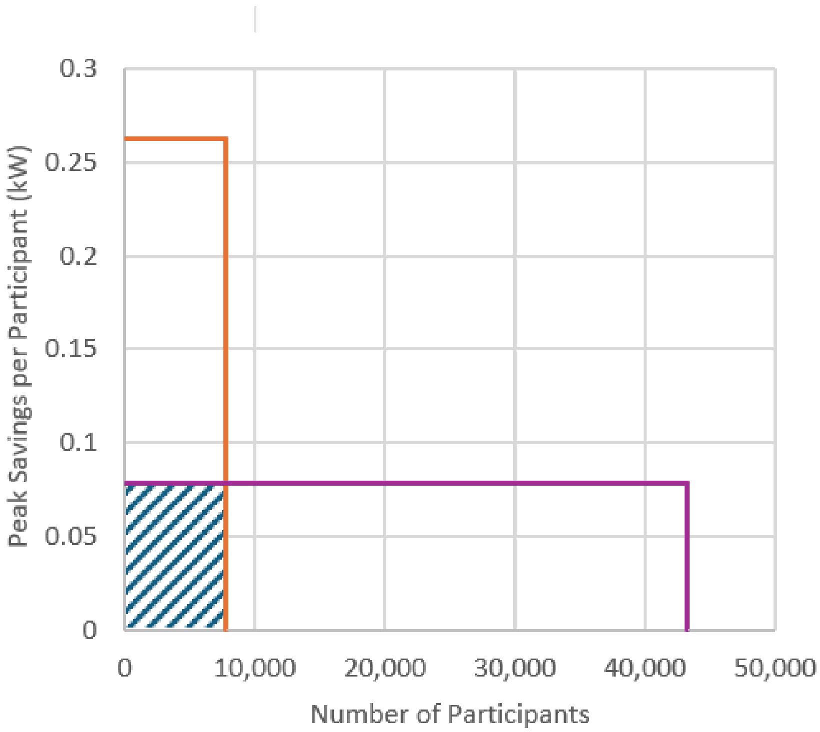
7.5.1 Interactive Effects Sample Calculation

This section includes an example to show how the Study Team estimated the interactive effects between a pair of demand response measures: residential sector TOU and behind-the-meter solar with smart inverters. To estimate the overlap in savings, the Study Team graphed the peak demand savings per participant on the y-axis and the number of participants on the x-axis for each measure. This method produces two overlapping rectangles, where the overlap area represents the magnitude of the savings that would otherwise be double counted.[184]

[184] This is a simplified approach because overlap is not always total. For example, a TOU rate itself may impact both behavior and equipment choices (e.g., like using telematics to manage EV charging time), but more active approaches like utility load control may target the same end-uses and provide additional savings.

The Study Team's approach is illustrated graphically in Exhibit 158 for the residential sector behind-the-meter solar with smart inverters and TOU measures. The overlap in savings is denoted by the rectangle with diagonal dark blue stripes. For this pair of measures, the 2040 savings of 4,828 kW is equal to the savings from the BTM with smart inverters measure (2,032 kW) plus savings from TOU measure (3,405 kW), less the area of the overlap (609 kW).

Exhibit 158: Interactive Effects Example



This Study Team repeated the method described here to estimate and subtract overlap anywhere it is expected to occur between measures. A similar approach was used to estimate the overlap between the managed charging and TOU rate design measures for EVs. [185] The overlap was calculated for every hour to estimate the resulting daily load shape that accounts for interactive effects between the two measures. Should the Utilities decide to implement electricity rate design measures and implement a program with equipment demand response measures, consideration should be given to overlap in savings. This overlap could be estimated by way of program evaluation.

[185] The opt-in TOU rates for EVs were modelled for this analysis. With an opt-in rate of 15%, there were fewer EVs participating in the TOU rates than the managed charging programs. Therefore, it was assumed that all managed charging participants would have also been opting in to the TOU rate. Because of this, only the peak reductions from the managed charging measures are included in the resulting load shape.

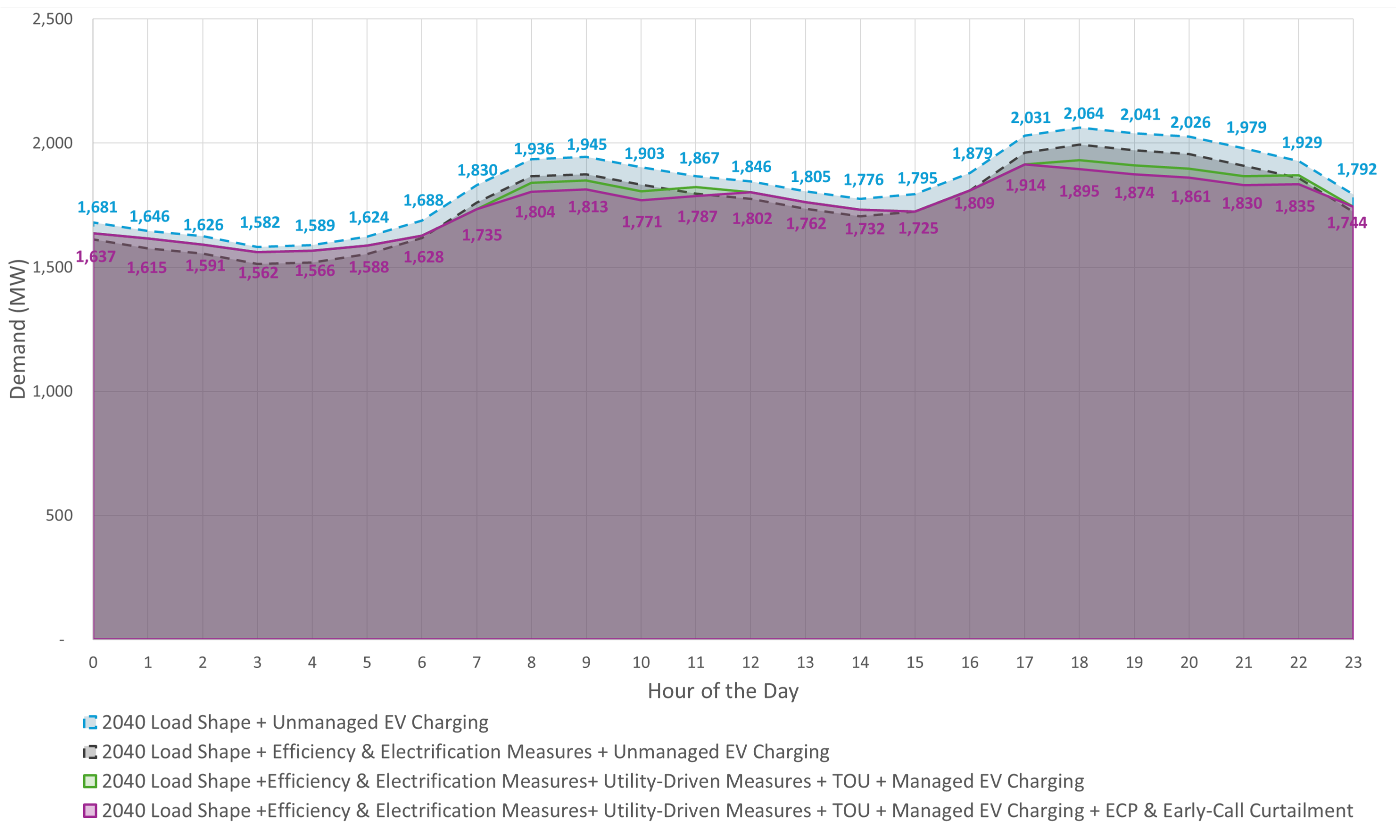
7.6 Resulting Load Shape

Exhibit 159 shows the reference and resulting peak day load shapes for combinations of the of the demand response resources discussed previously. [186] The load shapes in Exhibit 159 are defined as follows:

1. **Light blue load shape**: The 2040 reference load shape with unmanaged EV charging.
2. **Dashed black line load shape**: The 2040 reference load shape with unmanaged EV charging, including peak reductions from efficiency and electrification measures.
3. **Green load shape**: The 2040 reference load shape including peak reductions from efficiency and electrification measures, utility-driven equipment DR measures, TOU, and managed EV charging.
4. **Purple load shape**: Reflects the same reductions as the green load shape and including the curtailment potential from ECP participants and the early-call curtailment resource.

All the load shapes account for interactive effects, eliminating any double counting.

Exhibit 159: Standard and Resulting Peak Day Load Shapes (2040)



[186] A portion of the large customer curtailment is not included here because it is used as a contingency resource.

For additional readability, Exhibit 160 shows the hourly demand during the morning and evening peak periods for each load shape.

Exhibit 160: Hourly Demand for Standard and Resulting Peak Periods (MW)

Peak Period	Hour	Reference (2040 Load Shape + Unmanaged EV Charging)	2040 Load Shape + Efficiency & Electrification Measures + Unmanaged EV Charging	2040 Load Shape +Efficiency & Electrification Measures+ Utility-Driven Measures + TOU + Managed EV	2040 Load Shape +Efficiency & Electrification Measures+ Utility-Driven Measures + TOU + Managed EV + ECP & Early-Call Curtailment
Morning	8am	1,936	1,866	1,840	1,804
	9am	1,945	1,875	1,849	1,813
	10am	1,903	1,833	1,807	1,771
	11am	1,867	1,797	1,823	1,787
	12pm	1,846	1,776	1,802	1,802
Evening	5pm	2,031	1,961	1,914	**1,914**
	6pm	**2,064**	**1,994**	**1,931**	1,895
	7pm	2,041	1,971	1,910	1,874
	8pm	2,026	1,956	1,897	1,861
	9pm	1,979	1,909	1,866	1,830
	10pm	1,929	1,859	1,871	1,835

The following observations can be made on Exhibit 159 and Exhibit 160:

- After the efficiency and electrification measures, the utility-driven equipment DR measures, and managed EV charging are applied, the evening peak period starts at 5 p.m. and ends at 10:59 p.m. (illustrated by the green load shape). This represents a peak period that is one hour longer than the evening peak period for the reference load shape (illustrated by the dashed light blue load shape), which starts at 5 p.m. and ends at 9:59 p.m.
- When the ECP and early-call curtailment are applied during the evening peak period (i.e., 5 p.m. to 9:59 p.m. denoted by the purple load shape), the peak hour occurs at 5 p.m., one hour earlier than in the reference load shape (illustrated by the dashed light blue load shape).

The rightmost column in Exhibit 161 shows the reduction in peak hour demand for each load shape in Exhibit 159 compared to the reference load shape (dashed light blue line) in 2040. For each combination of demand response resources, the addressable peak is equal to the peak reduction. This is because the peak demand is reduced in all cases (i.e., the resources do not create a higher peak than the original peak). While demand response initiatives and programs can provide value to the electricity system during periods of high demand, they may not provide value during system emergencies like a prolonged supply shortfall.

Exhibit 161: Reference and Resulting Peak Demand (2040)

Load Shape	Peak Hour	Peak Demand (MW)	Addressable Peak (MW)	% Reduction
Reference (2040 Load Shape + Unmanaged EV Charging)	6 pm	2,064	-	-
2040 Load Shape + Efficiency & Electrification Measures + Utility-Driven Measures + TOU + Managed EV Charging	6 pm	1,931	132	6.4%
2040 Load Shape + Efficiency & Electrification Measures + Utility-Driven Measures + TOU + Managed EV Charging + ECP & Early-Call Curtailment	5 pm	1,914	149	7.2%

8 Conclusions

The Energy Solutions Potential Study assesses the near term and long-term potential for energy efficiency, electrification, and peak demand management activities led by the Utilities. The Study results leverage the Utilities' knowledge of their customer base, the best available data, and inputs based on extensive research and the Study Team's professional judgement. This section summarizes conclusions for the Study:

- **Energy Efficiency Potential**: The Study identifies opportunities for energy efficiency across the residential, commercial, and industrial sectors.
    - In the residential sector, measures that affect space heating offer the most potential savings. In the early years of the forecast period, these savings are dominated by envelope measures including air sealing and insulation, but by the end of the forecast period, equipment-based measures including heat pumps and HRVs offer the most potential savings. In addition, home energy reports offer residential sector savings throughout the Study period.
    - Initially, lighting measures dominate the commercial sector potential savings, but their savings potential decreases over time as LED lighting becomes saturated and federal lighting standards are introduced. By the end of the forecast period space heating measures including heat pumps and air sealing offer the most potential savings due to their broad applicability.
    - In the industrial sector, there is a broad-based opportunity for cost-effective conservation across end uses.
- **Impact of EVs**: The Study includes three forecast EV scenarios to explore a range of possible futures: natural adoption, intermediate and government targets. The results presented in the Study focus on the intermediate scenario:
    - In the intermediate scenario, EV charging is forecast to increase from 9 GWh in 2023 to 1,000 GWh by 2040. The adoption 162,001 EVs will require an estimated infrastructure investment of 0.84 billion.
    - Peak demand from EV charging is forecast to increase from 1 MW in 2023 to 275 MW in 2040. In 2033, EV charging causes the IIS peak to switch from morning peak to evening peak.
    - Consideration to EV managed charging can mitigate the impacts of EV charging on IIS peak. Shifting personal EV at-home charging could reduce the IIS peak. The opportunity to managed fleet EV charging is more limited than for personal EVs based on their duty cycles. However, certain fleet vehicles will have duty cycles that can accommodate managed charging.
- **Fuel Switching and Off-Road Electrification Potential**: Fuel switching potential is limited in the residential, commercial and industrial sectors because of the high relative fuel share of electric space heating in the base year, and natural electrification that occurs in the reference case.
    - In the higher achievable potential scenario, 49.6 GWh of load growth is forecast by 2040, compared to 13.7 GWh and 12.6 GWh in the medium and lower achievable potential scenarios, respectively.

- The electrification of forklifts and Zambonis is forecast to add 0.3 GWh of load to the IIS by 2040. These vehicles offer air quality improvements for warehouse and arena occupants.
- Dockside electrification will also cause IIS load growth and represents an area for further research.

- **Demand Response Potential**: The Study assesses demand response potential opportunities across three measure types: electricity rate design, equipment demand response, and customer curtailment.
  - The TOU and CPP electricity rate design measures are not cost-effective, due to the high program costs associated with the installation and operation of the AMI infrastructure required to administer them.
  - Several configurations of thermal storage measures are cost-effective for the residential and commercial sectors, with and without TOU rates. Market barriers to adoption could include lack of familiarity with thermal storage, aesthetic considerations for room units, and space constraints.
- **Overall Impacts on IIS Peak Day Load Curve**: In the base year, the IIS peak occurs in the morning. In 2040, the IIS peak is expected to occur at 6 p.m., driven in part by unmanaged EV charging in the intermediate scenario. The Study findings reveal the following impacts on the IIS load curve:
  - Aside from large customer curtailment, energy efficiency measures show the highest potential to reduce IIS peak. For example, in 2040, the efficiency measures reduce the winter morning and evening peaks by 70 MW and 69 MW, respectively. In contrast, the utility-driven measures reduce the winter morning and evening peaks by 23 MW and 18 MW. The TOU electricity rate design measure reduces the winter morning and evening peaks by 6 MW.
  - After the efficiency and electrification measures, the utility-driven equipment DR measures, and managed EV charging are applied, the evening peak period starts at 5 p.m. and ends at 10:59 p.m. This lengthens the evening peak period by one hour compared to the reference load shape.
  - When the ECP and the early-call curtailment are applied during the evening peak period, the peak hour occurs at 5 p.m., one hour earlier than in the reference load shape.
  - For each combination of demand response resources, the addressable peak is equal to the peak reduction. This is because the peak demand is reduced in all cases (i.e., the resources do not create a higher peak than the original peak).

Appendix A Methodological Approach

This appendix presents the Methodological Approach for the Study under the following headings:

- Base Year Energy Use Model Development
- Reference Case Energy Use Forecast Development
- Peak Demand
- Measure Assessment
- Potential Assessment
- Role of Stakeholder Groups
- Data Sources and Assumptions

Base Year Energy Use Model Development

The Study base year reflects the known characteristics of IIS customer electricity consumption in 2023. The Study Team's approach to base year development and calibration for the residential, commercial and industrial sectors is summarized in Exhibit 162.

Exhibit 162: Approach to Base Year Development and Calibration

Step	*Description*
1	Compiled and analyzed available data on NP and NLH's existing customer stock by sector, rate class, and segment.
2	Compiled utility billing data by segment and region.
3	Created sector model inputs with detailed assumptions regarding fuel shares, end use penetrations, equipment saturations and efficiency levels, and generated preliminary results.
4	Adjusted input assumptions for end uses with greater uncertainty until the results closely matched the actual utility billing data. Documented any adjustments for the Utilities' information (see sector-specific calibration steps following the exhibit).
5	Used end-use hours use factors to convert annual electric energy use to electric demand in each selected peak period.
6	Compared the total peak demand from the three sectors to the actual utility peak demand.
7	Adjusted the weather-sensitive hours use factors for all sectors to produce electric demand results that closely matched the actual utility regional peak demand.
8	Developed archetype models for Residential and Commercial segments with characteristics typical of construction and annual consumption that closely approximated the average consumption from the calibrated model for use in measure analysis.

Calibration: The calibration methods implemented to match the base year billing data for each sector are as follows:

Residential Sector:

1. Generated initial model parameters (See Exhibit 178).

2. Adjusted space heating[187] UECs by region and customer account type (domestic or seasonal) to align with the base year consumption.

Commercial Sector:

1. Generated initial model parameters (See Exhibit 179).
2. Adjusted segment UECs to align with the base year consumption by segment.
3. Adjusted the units per customer account to align with the base year consumption by segment and rate class.

Industrial Sector:

1. Generated initial model parameters, except units (See Exhibit 180).
2. Calibrated unit parameter to establish base year production values by segment and rate class.
3. Adjusted segment UECs to align with the base year consumption by segment.
4. For industrial customers, used billing data to determine the base year consumption.

The rest of this section shows the structure for the residential, commercial, and industrial sector models.

Residential Sector Model Structure

Exhibit 163 shows the residential sector model structure by segment, end use, vintage and rate class. Residential segments are divided by electric and non-electric space heating. This differentiation is important for the reference case and potential assessment, because customer account growth and measure applicability vary by space heating fuel. Exhibit 163 also shows two EV charging end uses: battery electric vehicle (BEV) charging and plug-in hybrid electric vehicle (PHEV) charging.

Exhibit 163: Residential Sector Segments, End Uses, Vintages and Rate Classes

Segments (8)	End Uses (20)	Vintages (6)	Rate Classes (1)
• Apartment, electric space heat • Apartment, non-electric space heat • Attached, electric space heat • Attached, non-electric space heat • Other and non-dwellings • Single-Family Detached (SFD), electric space heat	• BEV Charging • Clothes Dryer • Clothes Washer • Computer and Peripherals • Cooking • Dehumidifier • Dishwasher • Water Heating • Freezer • Hot Tubs • Lighting • Other Electronics	• Pre-1965 • 1965 to 1979 • 1980 to 1989 • 1990 to 1999 • 2000 to 2012 • Post-2012	• 1.1

[187] Space heating UECs are the most impactful to overall model output, and one of the most uncertain inputs. Space heating consumption accounts for over 50% of the base year total consumption.

Segments (8)	End Uses (20)	Vintages (6)	Rate Classes (1)
• SFD, non-electric space heat • Vacant and partial	• PHEV Charging • Refrigerator • Small Appliance and Other • Space Cooling • Space Heating • Television • Television Peripherals • Ventilation		

Commercial Sector Model Structure

Exhibit 164 shows the commercial sector model structure by segment, end use and rate class. Some segments are differentiated by size (e.g., offices, non-food retail). This differentiation is important for the potential assessment portion of the Study because measure applicability varies by building size. Exhibit 164 also shows six EV segments (personal EV private charging, personal EV public charging, fleet LDV depot charging, fleet MDV depot charging, fleet HDV depot charging, and fleet bus depot charging) and two EV end uses (BEV charging and PHEV charging).

Exhibit 164: Commercial Sector Segments, End Uses and Rate Classes

Segments (23)	End Uses (17)	Rate Classes (4)
• Arena • Fleet Bus Depot Charging • Fleet HDV Depot Charging • Fleet LDV Depot Charging • Fleet MDV Depot Charging • Food Retail • Healthcare • Large Accommodation • Large Non-Food Retail • Large Office • Large Other Building • Non-Building • Personal EV Private Charging • Personal EV Public Charging • Restaurant • School • Small Accommodation • Small Non-Food Retail	• BEV Charging • Computer Equipment • Computer Servers • Food Service Equipment • General Lighting • High Bay Lighting • HVAC Fans & Pumps • Misc Equipment • Other Plug Loads • Outdoor Lighting • PHEV Charging • Refrigeration • Secondary Lighting • Space Cooling • Space Heating • Street Lighting • Water Heating	• 2.1 • 2.3 • 2.4 • Street Lighting

Segments (23)	End Uses (17)	Rate Classes (4)
• Small Office • Small Other Building • Street Lighting • Universities and Colleges • Warehouse		

Industrial Sector Model Structure

Exhibit 165 shows the industrial sector model structure by segment, end use and rate class. The Large Industrial segment includes only NLH's six large industrial customers.

Exhibit 165: Industrial Sector Segments, End Uses and Rate Classes

Segments (7)	End Uses (12)	Rate Classes (10)
• Fishing and Fish Processing • Large Industrial • Manufacturing • Mining and Processing • Other Industrial • Pulp and Paper • Water and Wastewater	• Air Compressors • Conveyors • Fans and Blowers • General Lighting • HVAC Fans & Pumps • Other • Other Motors • Process Cooling • Process Heating • Process Specific • Pumps • Hydrogen	• 2.1 • 2.3 • 2.4 • Industrial

Transportation Sector

The Study Team developed the base year energy use model for the transportation sector in the following sequence:

1. **Step 1**: Determine the base year vehicle stock for the transportation sector using historical vehicle registrations and data on active EV stock.
2. **Step 2**: Determine the split between personal and fleet LDVs in the base year stock using data from the Reliability and Resource Adequacy Study 2022 Update. Maintain the split (89% personal; 11% fleet) across the forecast horizon.
3. **Step 3**: Multiply vehicle stock by vehicle efficiency and annual vehicle kilometers travelled to determine annual consumption per vehicle.
4. **Step 4**: Integrate transportation sector results with the residential and commercial sectors. In the residential sector, EV consumption is modelled as an end use. In the commercial sector, EV consumption is modelled in segments that represent public, private, and depot charging.

Exhibit 166 shows the transportation sector model structure by ownership type, vehicle type, and powertrain.[188] Two EV charging end uses are modelled for the transportation sector, BEV charging and PHEV charging.

Exhibit 166: Transportation Sector Vehicle Segmentation[189]

Ownership Type	Vehicle Type	Powertrain
Personal	LDV	BEV
	LDV	PHEV
Fleet	LDV	BEV
	LDV	PHEV
	MDV	BEV
	HDV	BEV
	Bus	BEV

[188] Electric micro-mobility was excluded from the Study because its impact is limited and due to a lack of Newfoundland-specific data.
[189] Pictograms at the following links illustrate EV segmentation types [Ready, Set, Electric: Vehicle Types and Electric Opportunities | Edison Energy], and [4 Types of Electric Vehicles—Which is Better? | Optiwatt].

Reference Case Energy Use Forecast Development

The reference case forecasts electricity consumption over a sixteen-year (2024-2040) period and represents the baseline against which new potential can be calculated. The Study Team's approach to reference case development and calibration for the residential, commercial and industrial sectors is summarized in Exhibit 167.

Exhibit 167: Approach to Reference Case Development and Calibration

Step	*Description*
1	Compile and analyze Newfoundland and Labrador Hydro's (NLH's) 2023 long-term forecasts. Use Newfoundland Power's (NP's) 5-year Customer, Energy and Demand (CED) forecast to inform rate classes and general service customer counts.
2	Developed detailed technical descriptions of the new stock at the segment, end use, and end-use equipment level.
3	Compiled data on forecast levels of construction, demolition, and natural (non-utility-influenced) efficiency within the existing and new (post 2022) building stock.
4	Created sector model inputs and generated electricity use forecasts with consideration to: • Current consumption patterns and known future changes, including expected customer growth, • Current and known future changes to codes and standards, • Natural turnover of equipment and appliances, and, • Current trends and expected changes in space heating and water heating fuel shares.
5	Exclude conservation from ongoing conservation, demand management, and electrification (CDME) program activities carried out after 2023 and exclude EV load forecast by NLH.
6	Compared generated forecast with utility load forecast data (kWh) by sector.
7	Calibrated as necessary by adjusting input assumptions for end uses with greater uncertainty. Document calibration steps for the Utilities' information (see sector-specific calibration steps following the exhibit).
8	Used end-use hours use factors to convert annual electric energy use to electric demand in each selected peak period.
9	Adjusted the weather-sensitive hours use factors for new construction in all sectors to produce electric demand (kW) results that closely match the actual utility regional peak demand forecast.
10	Developed energy end-use assumptions for typical new construction for all segments (via building energy simulation modelling and/or engineering analysis), calibrating average annual consumption to average consumption from the calibrated model.

Calibration: The calibration methods implemented to match the reference case forecast for each sector are outlined below:

Residential Sector

1. Adjusted customer accounts to model how new construction is segmented (across utilities, dwelling types, and main heating fuel) and the natural electrification of existing homes.[190] Used regional housing starts data to estimate the relative customer account growth across dwelling types. Assumed no demolition rate.
2. Increased the saturation of some end uses over the forecast period. Affected end uses are dishwasher, computer and peripherals, televisions, television peripherals, other electronics, space cooling, and hot tubs. Saturation growth rates were estimated by comparing 2014 REUS and 2022 REUS saturation data.
3. Increased the space heating efficiency input to reflect the adoption of heat pumps in this end use.
4. Modeled changes in UEC for some end uses to reflect improvements in equipment and changes in tertiary load. Affected end uses were dryer, freezer, refrigerator, space heating, and lighting.
5. Adjusted space heating UECs to align with the reference case forecast by utility and customer account type (domestic or seasonal).

Commercial Sector

1. Adjusted customer accounts to establish construction and demolition. New construction was estimated by extrapolating customer forecasts and drawing insights from the electricity consumption growth forecasts by rate class. Although no demolition rate was applied, a decrease in customer account numbers for a given year implied the removal of existing buildings from the system.
2. Increased the space heating fuel shares over the forecast period to better align with the expected increase in electricity consumption per customer account in the reference case forecast (for rate classes 2.1 and 2.3).
3. Adjusted the size parameter for the 2.4 rate class to match the reference case forecast consumption. Commercial buildings in the 2.4 rate class are assumed to be large, akin to industrial buildings, so the size parameter was used to model fluctuations in electricity consumption from production increase and decreases.
4. Slightly adjusted all UECs (within +/-1%) to align with the reference case forecast by utility.

Industrial Sector

1. Using the same approach as commercial, adjusted customer accounts to establish new construction and demolition. New construction was estimated by extrapolating customer forecasts and drawing insights from the electricity consumption growth forecasts by rate class.

[190] The space heating fuel share is not adjusted in the forecast period because the fuel share for each dwelling type and main heating fuel segment does not change. Instead, the share of electrically heated customer accounts increases over time.

2. Using the same approach as commercial, increased the space heating fuel shares over the forecast period to better align with the expected increase in electricity consumption per customer account in the reference case forecast (for rate classes 2.1 and 2.3).
3. Adjusted the size parameter by segment and rate class to match the reference case forecast consumption for general service and NLH's large industrial customers. Variations in the size parameter indicated fluctuations in production levels.
4. Slightly adjusted all UECs (within +/-1%) to align with the reference case forecast by utility.

Transportation Sector

Because future rates of EV adoption are uncertain, the Study Team modelled three forecast EV stock scenarios instead of one reference case:

1. **Natural Adoption Scenario:** This scenario estimates EV adoption based on current incentives.
2. **Intermediate Scenario:** This scenario includes EV uptake beyond the natural adoption scenario, consistent with additional market interventions like vehicle rebates or accelerated build-out of charging infrastructure for LDV.
3. **Government Targets Scenario:** In this scenario, Federal Government targets for sales shares of LDVs and MHDVs being ZEVs by 2030, 2035, and 2040 are met.[191,192]

The Study Team developed the forecast scenarios in the following sequence:

1. **Step 1:** Estimate the total number of vehicles for the forecast period.
2. **Step 2:** Determine stock decay over time using vehicle survivorship curves.
3. **Step 3:** Forecast future vehicle sales so the total stock over time matches the projection from Step 1.
4. **Step 4:** Determine the number of EV sales by applying the market share curves to the annual vehicle sales forecast for each scenario using data from sources including the 2023 NP REUS.
5. **Step 5:** Multiply vehicle stock by vehicle efficiency and annual vehicle kilometers travelled to determine annual consumption per vehicle.
6. **Step 6:** Integrate results with the residential and commercial reference case forecasts. Forecast EV consumption is apportioned to customer accounts in the same way is it is in the base year.

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[191] 20% of LDV sales as ZEVs by 2026, at least 60% by 2030, and 100% by 2035. 35% of total MHDV sales as ZEVs by 2030 and 100% by 2040.
[192] "The 2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy," Government of Canada, Available: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/sector-overview.html#sector6 (Accessed Feb. 24, 2025).

Base Year Peak Demand

Base year peak demand is calibrated to the Utilities' estimate of IIS peak hour demand for the residential, commercial, and industrial sectors in 2023. In the Study, the peak hour is defined as follows:

- **Peak Hour:** The single highest hour of IIS demand, typically occurring on the coldest day in the winter. Depending on the Study year, the single hour peak can occur in the morning or the evening.

The Utilities are also interested in demand outside the peak hour, so two additional peak periods are defined in the Study:

- **Morning Peak Period:** The four-hour period in the morning with the highest average IIS demand, defined as 7 a.m. to 10:59 a.m. for Newfoundland.
- **Evening Peak Period:** The five-hour period in the evening with the highest average IIS demand, defined as 5 p.m. to 9:59 p.m. for Newfoundland.

The rest of this section explains the approach to establish base year peak demand. It begins with the common approach for the residential, commercial, and industrial sectors, then presents the sector-specific approach for transportation.

Residential, Commercial and Industrial Sectors

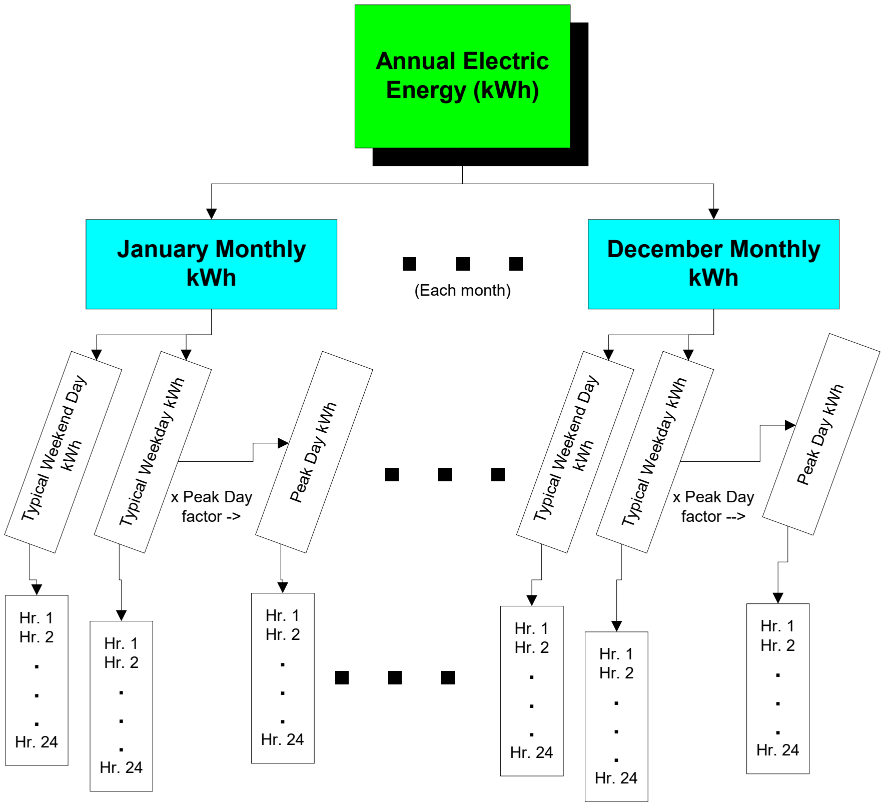
The Study Team used load profiles for each peak period to convert annual electric energy consumption to hourly demand for the residential, commercial, and industrial sectors. This section outlines the method used to develop electric peak end use profiles for the base year (2023) for the residential, commercial, and industrial sectors. The discussion is organized into the following subsections:

- Peak load profile development
- Peak Factors

Peak Load Profile Development

A peak load profile provides greater detail beyond the annual electric energy values. Annual electric energy is broken down into monthly electric energy, then average energy use per day, by day type (weekday, weekend day, peak day) and, finally, hourly demand by day type. Exhibit 168 illustrates the progression that converts annual electric energy to hourly demand. This method is used for the residential, commercial, and industrial sectors.

Exhibit 168: Overview of Peak Load Profile Methodology



Development of the peak load profile employs four specific factors as outlined below:

- **Monthly Usage Allocation Factor**: This factor represents the percent of annual electric energy usage that is allocated to each month. This set of monthly fractions (percentages) reflects the seasonality of the load shape, whether a facility, process or end use, and is dictated by weather, days in the month, or other seasonal factors. This allocation factor can be obtained from either (in decreasing order of priority): (a) monthly consumption statistics from end-use load studies; (b) monthly seasonal sales (preferably weather normalized) obtained by subtracting a "base" month from winter and summer heating and cooling months; or (c) heating or cooling degree days on an appropriate base.

- **Weekend to Weekday Factor**: This factor is a ratio that describes the relationship between weekends and weekdays, reflecting the degree of weekend activity inherent in the facility or end use. This may vary by month or season, though primarily for non-residential facilities. Based on this ratio, the average electric energy per day type can be computed from the corresponding monthly electric energy.

- **Peak Day Factor**: This factor reflects the degree of daily weather sensitivity associated with the load shape, particularly heating or cooling; it compares a peak (e.g., hottest or coldest) day to a typical weekday in that month.

- **Per Unit Hourly Factor**: The relationship of load among different hours of the day for each day type (weekday, weekend day, peak day) and for each month reflects the operating hours of the electric equipment or end use within facilities or residences by sub sector. For example, for lighting, this would be affected by time of day, season (affected by daylight), and room or business type, where applicable. For the Base Year, lighting is treated on an aggregate basis by total residence/facility.

The four factors (sets of ratios) defined above provide the basis for converting annual energy to any hourly demand specified, including Peak Period #1 defined above. The following equation shows the calculation of the ratio of peak hour demand to annual consumption[193]:

$$DemandRatio = \mathrm{Mo.Allocation}_i * \frac{1}{\mathrm{DaysInMonth}_i * (\frac{5}{7} + \frac{2}{7} * \mathrm{WkendRatio}_i)} * PeakDayFactor_i * \mathrm{PkHourFactor}_i$$

Where: DemandRatio is the ratio of peak demand to annual consumption for the peak period of interest
$\mathrm{Mo.Allocation}_i$ is the monthly usage allocation factor for month i, the month in which the peak period occurs
$\mathrm{DaysInMonth}_i$ is the number of days in month i
$\mathrm{WkendRatio}_i$ is the weekend to weekday factor for month i
$\mathrm{PeakDayFactor}_i$ is the peak day factor for month i
$\mathrm{PkHourFactor}_i$ is the per unit hourly factor for the peak hour and peak day for month i

In the case of an electric utility, if peak demand is expressed in MW and annual consumption is expressed in MWh, the above ratio would be in MW/MWh. For convenience, the demand ratio is often inverted to produce an hours-use factor, which is in units of hours. The following simple equation gives the hours-use factor:

$$HoursUseFactor = \frac{1}{DemandRatio}$$

The following examples may provide a more intuitive grasp of the hours-use factor:

- An end use with a load that is constant throughout the year would have an hours-use factor of 8760 (because there are 8760 hours in a non-leap year and the end use would therefore use 1/8760 of its annual energy in each hour)
- An end use concentrated in the winter, such as space heating, might have an hours-use factor of 2000 or even 1000. An hours-use factor of 1000 would produce a peak load over 8 times as high as a completely flat load with the same annual consumption.
- An end use that is only used during the peak hour and is never switched on for the rest of the year would have an hours-use factor of 1.
- An end use that is never used during the peak hour (such as an outdoor pool heater in a jurisdiction with a winter peak) effectively has an infinite hours-use factor. To avoid division by zero , we typically use 1×10^{15}.

For most end uses, Posterity Group used the same hours-use factors developed for the 2015 Potential Study. The non-HVAC shapes, which do not tend to vary significantly through time or geographically,

[193] The equation for a peak period with multiple hours would be slightly more complex.

were developed based on load shape research conducted in various North American jurisdictions. The space heating shapes were tailored to the Utilities' jurisdiction using St. John's weather data.

Posterity Group conducted a calibration process to adjust hours-use factors to obtain agreement between our model and the Utilities' peak load estimate for the base year. We adjusted two groups of hours-use factors:

- All the hours-use factors for industry were adjusted by a common adjustment factor to obtain agreement between the modeled peak load of the large industrial customers and the utilities' peak load value for those customers.
- The hours-use factors for HVAC-related end uses in the residential and commercial sector were adjusted by a second adjustment factor to obtain agreement between the overall modeled system peak load and the utilities' peak load value for the system.

For the morning and evening peak periods, Posterity Group determined the average demand during each period and calibrated the space heating peak factors to align the total with the average demand.[194]

Transportation Sector

Base year peak demand for the transportation sector uses 8760 load shapes for each combination of vehicle type and charging location. These load shapes are applied against base year annual energy consumption to determine demand in each hour of the year.

The Study Team identified the day that included the peak hourly EV load, then overlayed that day's 24-hour load shape onto the reference peak day load shape for the residential, commercial and industrial sectors. The overall IIS peak hour is identified based on the resulting aggregated load shape that reflects peak demand for all sectors.

[194] The Study Team adjusted peak factors for the space heating end use in the residential and commercial sectors for the morning and evening peak period calibration because overall demand is driven by space heating in those sectors. The peaks for each period in the industrial sector are the same because overall demand is not driven by space heating.

Reference Case Peak Demand

The rest of this section explains the approach to establish reference case peak demand. It begins with the common approach for the residential, commercial, and industrial sectors, then presents the sector-specific approach for transportation.

Residential, Commercial and Industrial Sector

The Study Team used calibrated peak factors from the base year in each year of the reference case forecast. Therefore, for each combination of end-use and building type, the reference case peak load scales with annual energy consumption for the residential, commercial, and industrial sectors. Aggregating the resulting end-use peak loads provides the forecast single peak hour or average peak demand for each year in the reference case.

Transportation Sector

Like the base year peak demand, reference case peak demand for the transportation sector relies on 8760 load shapes for each combination of vehicle type and charging location. The Study Team applied the load shapes against forecast annual reference case consumption to determine hourly demand in each reference case year.

Measure Assessment

The approach to the measure assessment is summarized in Exhibit 169. The Study Team consulted the following sources to add measures in Step 2 below:

- The 2015 Newfoundland and Labrador Conservation and Demand Management Potential Study and the 2019 Conservation Potential Study,
- The 2022 Ontario Distributed Energy Resource Potential Study,
- Posterity Group's internal measure libraries,
- Technical reference manuals from other North American jurisdictions, and,
- Suggestions from the Utilities and the local External Advisory Committee (EAC).

Exhibit 169: Measure Assessment Approach

Step	*Description*
1	Reviewed the measure analysis completed for the 2020-2034 Potential Study. Removed measures that have been superseded through market transformation or codes/standards, or that no longer represent significant potential.
2	Added measures that were not examined for the 2020-2034 Study, with a focus on demand management measures.
3	Solicited input from the Utilities regarding measure additions or deletions.
4	Solicited input from the local External Advisory Committee (EAC) stakeholders regarding measure additions or deletions.
5	Established a short list of measures for detailed analysis and inclusion in subsequent study steps.
6	Assessed mass-market measures, including the following parameters for each one[195,196]: **For energy efficiency measures** • Per participant energy reduction • Per participant demand reduction • Differences (if any) between the 'post measures' load shape and the end use load shape, such that associated demand reduction would be disproportionate to the energy savings (for energy efficiency measures) • Measure cost (full or incremental as appropriate) • Participant avoided bill cost • Utility lost revenue • Eligible customers • Previous program results and customer enrollment (participant) rates where appliable.

[195] Interactive effects will be estimated as part of measure savings estimates where relevant.
[196] The measure library deliverable will include all measures assessed in the Potential Study, regardless of their cost-effectiveness. A 'mature market' version of select measures may be developed to represent expected future equipment costs.

Step	Description
	For electrification measures • Per participant energy savings (fossil fuels), and annual consumption (electricity) • Differences (if any) between the ‘post measures’ load shape and the end use load shape, such that associated demand increase would be disproportionate to the electricity consumption increase • Per participant electricity peak demand increase • Participant avoided bill cost (other fuels) and additional bill cost (electricity) • Utility additional cost of new electricity supply • Utility revenue impact • Eligible customers • Measure cost (full or incremental as appropriate) • Previous program results and customer enrollment (participant) rates where appliable. **For demand response measures** • Per participant demand reduction • Differences (if any) between the ‘post measures’ load shape and the end use load shape, such that associated demand reduction would be disproportionate to the energy savings (for energy efficiency measures) • Measure cost (full or incremental as appropriate) • Participant avoided bill cost • Utility lost revenue • Eligible customers • Customer enrollment (participant) rates from other jurisdictions. **For transportation sector emerging measures, adoption incentive measures, and infrastructure measures** • Examined research on transportation sector decarbonization technologies and grid integration costs. The sections entitled EV Adoption Incentives and EV Charging Infrastructure that follow provide additional details.
7	For non-mass market measures such as special rate options, used customer data provided by the Utilities, in-depth discussions with Newfoundland and Labrador Hydro’s Key Account Manager(s) and jurisdictional research to inform customer enrollment (participant) rates.
8	Create a Newfoundland-specific electronic measure TRM workbook for each sector, containing the parameters developed under step 6 above.

EV Adoption Incentives

This section explains how the Study Team calculated the incremental per-vehicle incentive to lift EV adoption from the natural adoption scenario to the intermediate and government targets scenarios.[197]

Exhibit 170 shows the transportation sector adoption incentive measures. Literature on personal LDV uptake suggest that every $1,000 of incremental per-vehicle incentive increases the sales market share of EVs between 2% and 9% annually. The Study Team used an 8% sales market share increase for every $1,000 of incremental per-vehicle incentive because several studies supported that ratio.[198,199,200]

Exhibit 170: Transportation Sector Adoption Incentive Measures

End Use(s) Affected	Measure Name
EV Charging	• Personal LDV • Fleet LDV • MDV • HDV • Bus

The Study Team calculated the incremental per-vehicle incentive to lift EV adoption from the natural adoption scenario in two steps:

- **Step 1**: Calculated the number of incrementally added vehicles for each forecast year and scenario.
- **Step 2**: Multiplied the ratio of 8% higher sales market share of EVs for every $1,000 of incremental per-vehicle incentive by the increase in sales market share.[201] Because the sales market share difference between the scenarios changes every year, the incremental per-vehicle incentive also changes every year. For this reason, the adoption incentive results presented in section 4.4.3 reflect the median incentive over the forecast period.

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[197] If government targets for EV adoption are mandated, the Utilities would not provide incentives.
[198] MIT Center for Energy and Environmental Policy Research, "Providing the Spark: Impact of Financial Incentives on Battery Electric Vehicle Adoption", Available: https://ceepr.mit.edu/wp-content/uploads/2021/09/2019-015.pdf (Accessed Jan. 2024).
[199] Science Direct, "The Impact of state policies on electric vehicle adoption – A panel data analysis," Available: https://www.sciencedirect.com/science/article/abs/pii/S1364032123008729?via%3Dihub (Accessed Jan. 2024).
[200] University of Ottawa Department of Economics, "Assessment of Electric Vehicle Incentive Policies in Canadian Provinces," Available: https://ruor.uottawa.ca/server/api/core/bitstreams/9019befa-ab3e-4458-8473-16df13dd8354/content (Accessed Jan. 2024).
[201] Demand-side management market transformation theory suggests that regulations should supersede incentives as the market intervention used to drive adoption when the sales share of a new technology reaches 75%-80% of the eligible population. As such, the model limits rebate applicability for each EV scenario to the time horizon before this tipping point (75%-80% penetration) is reached. For the government targets and the intermediate scenarios, respectively, the Study Team calculated how much of an incremental per-vehicle incentive was required to lift EV adoption from the natural adoption scenario.

EV Charging Infrastructure

The Study Team's method to determine charging infrastructure requirements is summarized as follows:

- **Step 1**: Started with the vehicle counts from each analysis scenario (i.e., natural adoption, intermediate, and government targets).
- **Step 2**: Used external data sources to determine the number of charging ports required to support vehicle counts and the number of ports per charger type for each scenario.
- **Step 3**: Applied costs per charging port for the various charger types to estimate the magnitude of the investment required to deploy the charging infrastructure. A variety of backward-looking studies that have examined EV early adopters for LDVs suggest that the presence of charging infrastructure can help drive EV uptake. However, the extent to which this is the case (among other driving factors) is uncertain and depends on specific local conditions.[202]
- **Step 4**: For personal LDV,
    - Built bottom-up assumptions for home charging by stipulating the number of ports per home charger (one) and the number of vehicles per charging port (one EV per charging port).[203]
    - Layered these bottom-up assumptions on data about the proportion of vehicles with home charging access and about what charger levels they use. Multiple studies estimate the proportion of home charging at about 78%. For consistency, the Study Team limited input data to two of these studies that provided all the required data points:
        - The International Council on Clean Transportation estimates that 88% of vehicles will have home charging access and that 94% of home charging will occur in single family homes (leaving 6% for MURBs).[204]
        - The National Renewable Energy Laboratory estimates that 26% of home chargers will be L1.[205] The Study Team assumed that all these L1 chargers would be in single family homes, since MURBs would typically require wiring upgrades to support charging in their parking garages. Given growing LDV battery sizes, conducting such a MURB infrastructure upgrade just to install L1 outlets appears imprudent. For **public charging**, the Study Team relied on literature about how many public L2 and DCFC ports may be required to meet LDV fleet sizes. Some disagreement exists across sources, so the Study Team

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[202] MDPI, "Impact of Incentive Policies and Other Socio-Economic Factors on Electric Vehicle Market Share: A Panel Data Analysis from the 20 Countries," Available: https://www.mdpi.com/2071-1050/13/5/2928 (Accessed Jan. 2024).
[203] The average household is likely to only have one EV by the end of the study horizon based on how the scenarios assume the market will transform over time.
[204] The International Council on Clean Transportation, "Charging up America: Assessing the Growing Need for US Charging Infrastructure Through 2030," Available: https://theicct.org/sites/default/files/publications/charging-up-america-jul2021.pdf (Accessed Jan. 2024).
[205] National Renewable Energy Laboratory, "The 2030 National Charging Network: Estimating US Light-Duty Demand for Electric Vehicle Charging Infrastructure," Available: https://www.nrel.gov/docs/fy23osti/85654.pdf (Accessed Jan. 2024).

used the median values extracted across the source materials (since the data is not normally distributed).[206, 207, 208]

- Assumed that PHEVs do not use DCFC, due to their relatively smaller battery sizes compared to BEVs. The number of ports per PHEV relies on the number for BEVs and discounts the number of ports per PHEV by the ratio of the per-vehicle annual energy consumption for PHEVs versus BEVs (from the analysis scenarios). L1 chargers are exempt from this discounting, since each PHEV could theoretically be plugged into a standard 110V DC outlet. The discount factor varies minimally across analysis years. This means that, on average, PHEVs use 45% of the chargers that BEV use.

- **Step 5**: For fleet LDV,
  - For L2 depot charging, assumed one charging port per vehicle based on interviews with fleet operators.
  - For the number of vehicles per port on public DCFC, used the same assumption as for Personal LDV.
    - In the absence of more definitive bottom-up estimates, used the ratio between depot and public L2 chargers to estimate the vehicles per port for depot DCFC from public DCFC.
    - Based on study data from California, assumed that 96% of chargers will be at depots and 4% of chargers will be at public locations. Also assumed that 99% of depot chargers will be L2 and 1% of depot chargers will be DCFC.[209]
  - For fleet PHEVs, used the same method for estimating the charging infrastructure required for personal PHEVs.[210]
- **Step 6**: For MHDV (including buses),
  - Used a top-down approach that relied on study data from California on how many ports were needed in fleet depots and public locations to support MHDV EV fleets.[211,212]

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[206] National Renewable Energy Laboratory, "The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure," Available: nrel.gov/docs/fy23osti/85654.pdf (Accessed Jan. 2024).
[207] International Council on Clean Transportation, "Charging Up America: Assessing the Growing Need for U.S. Charging Infrastructure Through 2030," Available: https://theicct.org/sites/default/files/publications/charging-up-america-jul2021.pdf (Accessed Jan. 2024).
[208] Dunsky Energy + Climate Advisors, "Canada's Public Charging Infrastructure Needs", Available: https://natural-resources.canada.ca/sites/nrcan/files/energy/cpcin/2022-ev-charging-assesment-report-eng.pdf (Accessed Jan. 2024).
[209] PowerPoint Presentation (caletc.com)
[210] Based on the discount factor method, fleet PHEVs use on average 24% of the chargers that BEVs use.
[211] PowerPoint Presentation (caletc.com)
[212] California data was used because the state is a leader in fleet vehicle electrification research and programming.

Exhibit 171 summarizes the model inputs developed for the various vehicle segments.

Exhibit 171: Key Charging Infrastructure Model Inputs

Vehicle Segment	Vehicles per Port
Personal LDV	L1 Home - 1 L2 Home - 1 L2 MURB - 1 L2 Public - 12 DCFC Public - 73
Fleet LDV	L2 Depot - 1 L2 Public - 12 DCFC Depot - 6.1 DCFC Public - 73.3
MDV	L2 Depot - 1[213] L2 Public - 33.3 DCFC Depot - 3.7 DCFC Public - 16.7
HDV	L2 Depot - N/A[214] L2 Public - 33.3 DCFC Depot - 1.1 DCFC Public - 9.1
Bus[215]	L2 Depot - 1[213] L2 Public - N/A DCFC Depot - 2.4 DCFC Public - N/A

[213] The Study Team used the same assumption as for Fleet LDV based on interviews with fleet operators that indicate this choice for operational certainty and simplicity.
[214] HDV have sufficiently large batteries to rule out Level 2 depot charging.
[215] School buses, due to their duty cycles, are amenable to Level 2 depot charging. Transit buses, due to their duty cycles, are assumed to use DCFC depot charging only.

Then, the Study Team completed the following steps to calculate charger costs:

- **Step 1**: Consulted two sources (Atlas Policy and NREL) that provided full installed costs per charging port across charger types.
    - NREL includes a meta-analysis of third-party studies and aggregates information to account for uncertainty across these inputs.[216, 217] Since both studies focused on the U.S., the Study Team assumed costs were provided in U.S. dollars.
- **Step 2**: Assumed the same costs from Step 1 in Canadian dollars, since converting the values would have yielded costs that were too high compared to results from stakeholder interviews and audits of select costs in Canada.

Exhibit 172 summarizes the results of these steps.

Exhibit 172: Charger Cost Model Inputs

Charger Topology	Inputs (USD)	Description
L1 Home	$0	• Assume manufacturers include a L1 charging cable with the vehicle • Assume homeowners have a wall plug with free capacity
L2 Home	$1,834	• Average of Atlas Policy and NREL estimates • Atlas Policy represents an average across attached and detached homes
L2 MURB	$3,857	• Reflects the Atlas Policy estimate since it separates MURB costs
L2 Depot/Public	$6,291	• Average of Atlas Policy and NREL estimates
DCFC Depot/Public	$186,731	• Average of Atlas Policy and NREL estimates across charger power levels

[216] Atlas Public Policy, "U.S. Passenger Vehicle Electrification Infrastructure Assessment," Available: https://atlaspolicy.com/wp-content/uploads/2021/04/2021-04-21_US_Electrification_Infrastructure_Assessment.pdf (Accessed Jan. 2024).
[217] National Renewable Energy Laboratory, "The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure," Available: https://www.nrel.gov/docs/fy23osti/85654.pdf (Accessed Jan. 2024).

Potential Assessment

The approach to the technical and economic potential assessments is shown in Exhibit 173.

Exhibit 173: Technical and Economic Potential Assessment Approach

Step	*Description*
1	Work with the Utilities to establish measure cost-benefit analysis and screening methods that reflect the demand side choices the Utilities and their customers will be faced with over the study period. Document the inputs and equations for the cost-benefit analysis. For efficiency and electrification measures, used the TRC to screen, with a passing threshold of 0.8. Report PCT and PAC. For demand response measures, used the PAC screen, with a passing threshold of 0.8. Report TRC.
2	Develop technical potential estimates of the energy reduction, peak demand reduction, and energy addition (from electrification) that can be achieved in Newfoundland through the implementation of the measures from 2025-2040.
3	Assess cost-effectiveness on a variety of sensitivities for marginal cost, including varying marginal costs throughout different periods of the year, or compared to deferred or nullified capital investment requirements. This sensitivity analysis will require using relatively permissive economic screening criteria at the measure level.
4	Develop separate estimates of economic energy efficiency potential, demand management potential, and electrification potential.
5	Estimate economic potential for screened-in measures at the sector and segment levels to develop comprehensive economic potential estimates. Force pass a list of measures determined in collaboration with the Utilities.[218]

The approach to the achievable potential assessment is shown in Exhibit 174.

Exhibit 174: Potential Assessment Approach

Step	*Description*
1	For efficiency and electrification measures, develop traditional payback/adoption curves. For demand response measures, develop adoption rates based on participation research for similar measures across North America.
2	Use economic potential forecasts using cost-effectiveness tests as screens as input to a simplified achievable potential analysis developed using traditional payback/adoption curves.
3	Discuss the results of the simplified achievable potential analysis for five measures per sector with the Utilities and their stakeholders in workshop format to identify market barriers and opportunities. For mass market energy efficiency options, analyze four main considerations:

[218] Measures that fail the economic screen can be force passed so they will appear in the achievable potential. The electricity rate design measures were force passed, for example, because the Utilities wanted to discuss them in the Study report.

Step	Description
	1. What participation rates are feasible given market barriers, incentive levels, eligibility, and the success of existing programs? 2. What types of customers participate? 3. How do savings vary for different customer types? 4. What share of customers can be economically enrolled in a program?
4	Revise the adoption rates from Step 1 based on input from the Utilities and their stakeholders in Step 3 and based on savings achieved in the Utilities' existing programs. The Utilities provided the following data to support this Step: • "Small Technologies Savings": includes energy (kWh) savings from 2020 to 2023 for the twenty-one residential energy efficiency measures in the Small Technologies program. • "Business Efficiency Program Participation Results 2019 – 2023": includes energy (kWh) and demand (kW) savings from 2019 to 2023 for the nineteen commercial and industrial energy efficiency measures in the Business Efficiency Program. • "Savings for Forecast 2009-2025F": includes historical (2009 to 2023) and forecast (2024 to 2025) energy (kWh) savings for all energy efficiency programs offered by NP. • Historical data from NP for the residential Oil to Electric Program.
5	For efficiency and electrification measures, estimate achievable potential under three scenarios: • Lower • Medium • Higher For demand response measures, estimate the individual impacts of the following components, then estimate any interactive effects: 1. Electricity rate design measures 2. Equipment-based demand response measures 3. Customer curtailment
6	Report potential assessment savings in at-the-meter terms, instead of at-the-generator terms. Therefore, savings results exclude line losses in the transmission and distribution network. Line losses are added to the at-the-meter savings to calculate at-the-generator savings, which are used in the TRC calculations.[219]

[219] "Reliability and Resource Adequacy Study 2024," Newfoundland and Labrador Hydro, Available: https://nlhydro.com/wp-content/uploads/2024/07/2024-07-09_NLH_RRA-Study_2024-RAP.pdf (Accessed: Nov. 15, 2024).

The approach to calculating customer curtailment potential is shown in Exhibit 175.

Exhibit 175: Curtailment Potential Assessment Approach

Step	*Description*

1	Consult existing data and research to inform the curtailment potential method and inputs, including:
	• Current and planned NP and NLH curtailment contracts and programs, including:
	  ○ Data from NP's Energy Curtailment Program (ECP)
	  ○ The Winter 2023-2024 Capacity Assistance Report
	• Notes from the meetings PG staff held with NLH's large industrial customers and NLH
	• NP and NLH's 2023 Commercial End Use Study
	• Curtailment programs in other jurisdictions, including Green Mountain Power's Flexible Load Management (FLM) 2.0 Pilot and Pacific Gas & Electric Company's (PG&E) Automated Demand Response (ADR) program.

2	Identify eligible rate 2.4 customers and large industrial customers and determine the number of customers likely to participate.
3	Calculate curtailable load per customer and total curtailable load for all participants.
4	Determine program costs and incentives per customer and total program costs and incentives for all participants.

The approach to the peak day analysis is shown in Exhibit 176.

Exhibit 176: Peak Day Analysis Approach

Step	*Description*
1	Calculated the demand reduction in the single highest hour (this step was not necessary to the peak day analysis, but this value is necessary for cost-effectiveness testing).
2	Calculated the average demand reduction for each demand response resource in the 4-hour morning peak window and the 5-hour evening peak window.
3	Determined the impact after the morning and evening peaks when the average demand reduction from each peak period is added to the hours immediately following them.
4	Estimated the reduction in demand between the original peak hour and the resulting peak hour.

Role of Stakeholder Groups

The Utilities and its stakeholders played an important role in the Potential Study. An External Advisory Committee (EAC) of Stakeholders provided input at two key steps in the Study workflow: measure identification and achievable potential. This input included desktop review of the long list of measures and participation in achievable potential workshops. Four achievable potential workshops were held, one for each sector. The workshop logistics and number of participants are shown in Exhibit 177.

Exhibit 177: Achievable Potential Workshop Logistics and Participation

Workshop	Date and Time	Number of EAC Participants
Residential Sector	May 23, 2024; 9:00 AM – 12:30 PM	14
Transportation Sector	May 23, 2024; 1:00 PM – 4:30 PM	11
Commercial Sector	May 24, 2024; 9:00 AM – 12:30 PM	10
Industrial Sector	May 24, 2024; 1:00 PM – 4:30 PM	5

In addition, NLH's large industrial customers were surveyed to provide insight into their operations and likelihood of measure adoption.

Data Sources and Assumptions

This section lists data sources and assumptions for the Potential Study.

Reference Case Forecast

The reference case forecast aligns with the long-term forecasts developed by Newfoundland and Labrador Hydro for their service territory and Newfoundland Power's service territory. These forecasts were provided in the "3.0 NLH - Long Term Forecasts for NP and Island Rural" MS Excel workbook. Further insights are drawn from the "CED Forecast v10 GRA for Potential Study" and "Historical and Forecast Customer and Energy Sales" MS Excel workbooks for Newfoundland Power and Newfoundland and Labrador Hydro respectively. Lastly, 2023 billing data from both Utilities was used to align to actuals from that year. These sources were consolidated to create a "Master Reference Case Forecast" for each sector.

Residential Sector

The data sources for each key modelling parameter are provided in Exhibit 178.

Exhibit 178: Residential Sector Modelling Sources[220,221]

Parameter	Sources
Customer Accounts[222]	• Master Reference Case Forecast • Newfoundland Power: *CED Forecast v10 GRA for Potential Study* *3.0 NLH – Long Term Forecasts for NP and Island Rural* • Newfoundland and Labrador Hydro: *NLH Residential Monthly* *3.0 NLH – Long Term Forecasts for NP and Island Rural* • Newfoundland Census data (historical)[223]
Units	• Set to 1
Size Factor	• Set to 1
Saturation	• Residential End Use Survey (2022) • 2015 Potential Study • Engineering assumptions
Fuel Share	• Residential End Use Survey (2022) • 2015 Potential Study • Engineering assumptions
Unit Energy Consumption (UEC)	• NRCan – Average annual UEC of major household appliances, 2000-2021[224] • 2015 Potential Study • Engineering assumptions

[220] Italicized sources indicate Excel workbooks.
[221] Several parameters are further calibrated from initial values. See the sections on Base Year Energy Use Model Development and Reference Case Energy Use Forecast Development for details.
[222] Billing data provided by both utilities was used to split out the Master Reference Case Forecast customer accounts and consumption by segment and rate class.
[223] Used to estimate base year vintage breakdown. Vintage data is available in the 2022 REUS, but some segments have very low response rates and so census data is used to improve confidence in base year vintages.
[224] "Comprehensive Energy Use Database," Natural Resources Canada, Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CM&sector=AAA&juris=CA&rn=49&page=2. (Accessed Feb. 1, 2024).

Commercial Sector

The data sources for the key modelling parameters are provided in Exhibit 179.

Exhibit 179: Commercial Sector Modelling Sources[225,226]

Parameter	Sources
Customer Accounts[227]	• Master Reference Case Forecast • Newfoundland Power: *2022 NP Monthly SIC Code Data* *Arenas & Stadiums 2* • Newfoundland and Labrador Hydro: *NLH Island Interconnected Commercial 2022_rev2*
Units	• Initially derived from the 2015 Potential Study
Size Factor	• Set to 1
Saturation	• Commercial End Use Survey • Engineering assumptions
Fuel Share	• Commercial End Use Survey • Engineering assumptions
Unit Energy Consumption (UEC)	• 2015 Potential Study • Improving efficiency in ice hockey arenas (ASHRAE)[228] • Commercial End Use Survey

225 Italicized sources indicate Excel workbooks.
226 Several parameters are further calibrated from initial values. See the sections on Base Year Energy Use Model Development and Reference Case Energy Use Forecast Development for details.
227 Billing data provided by both utilities was used to split out the Master Reference Case Forecast customer accounts and consumption by segment and rate class.
228 "Improving efficiency in ice hockey arenas," American Society of Heating, Refrigerating, and Air-Conditioning Engineers, Inc., Available: https://bit.ly/40uIdFr (Accessed Feb. 1, 2024).

Industrial Sector

The data sources for the key modelling parameters are provided in Exhibit 180.

Exhibit 180: Industrial Sector Modelling Sources[229,230]

Parameter	Sources
Customer Accounts[231]	• Master Reference Case Forecast • Newfoundland Power: *2022 NP Monthly SIC Code Data* • Newfoundland and Labrador Hydro: *NLH Island Interconnected Commercial 2022_rev2* *4.0 NLH Island Industrial Forecast Requirements*
Units	• Master Reference Case Forecast
Size Factor	• All set to 1
Saturation	• Commercial End Use Survey • Engineering assumptions
Fuel Share	• Commercial End Use Survey • Energy Data Management Manual for the Wastewater Treatment Sector[232] • Engineering assumptions
Unit Energy Consumption (UEC)	• 2015 Potential Study • Commercial End Use Survey

229 Italicized sources indicate Excel workbooks.
230 Several parameters are further calibrated from initial values. See the sections on Base Year Energy Use Model Development and Reference Case Energy Use Forecast Development for details.
231 Billing data provided by both utilities was used to split out the Master Reference Case Forecast customer accounts and consumption by segment and rate class.
232 "Energy Data Management Manual for the Wastewater Treatment Sector," U.S. Department of Energy, Available: https://www.energy.gov/sites/prod/files/2018/01/f46/WastewaterTreatmentDataGuide_Final_0118.pdf. (Accessed Feb. 1, 2024).

Appendix B List of Measures

This appendix shows the full list of measures in the Study. It is structured as follows:

- Exhibit 181 lists residential sector measures.
- Exhibit 182 lists commercial sector measures.
- Exhibit 183 lists industrial sector measures.
- Exhibit 184 lists transportation sector measures.

Exhibit 181: Residential Sector Measures

End Use(s) Affected	Measure Name
Clothes Dryer	**Efficiency** • Clothes Lines and Drying Racks • ENERGY STAR Clothes Dryer • Heat Pump Clothes Dryer **Demand Response** • Clothes Dryer Direct Load Control (Utility-Driven)
Clothes Washer	**Efficiency** • ENERGY STAR Clothes Washer **Demand Response** • Clothes Washer Direct Load Control (Utility-Driven)
Computer and Peripherals & Other Electronics	**Efficiency** • Advanced Smart Strips and Plugs
Cooking	**Efficiency** • Convection Oven • High-Efficiency Induction Cooktops **Fuel Switching** • Induction Stove
Dehumidifier	**Efficiency** • ENERGY STAR Dehumidifier
Dishwasher	**Efficiency** • ENERGY STAR Dishwasher **Demand Response** • Dishwasher Direct Load Control
Water Heating	**Efficiency** • Domestic Hot Water Pipe Insulation • Faucet Aerator • Heat Pump Water Heater • Heat Pump Water Heater Upgrade • Low Flow Showerhead

End Use(s) Affected	Measure Name
	• On Demand Hot Water Heater • On Demand Hot Water Heater (Central) • Thermostatic Restrictor Shower Valve **Fuel Switching** • Oil Water Heater to Heat Pump Water Heater • Oil Water Heater to High Efficiency Electric Storage Water Heater **Demand Response** • Water Heater Smart Switch (Utility-Driven)
Freezer	**Efficiency** • ENERGY STAR Freezer • Freezer Recycle
Refrigerator	**Efficiency** • ENERGY STAR Refrigerator
Freezer & Refrigerator	**Efficiency** • Appliance Retirement for Extra Refrigerators
Hot Tubs	**Efficiency** • Insulated Hot Tub Cover
Lighting	**Efficiency** • Dimmer Switches • Exterior ENERGY STAR LED Reflector Lamp • Exterior Lighting Controls • Exterior ENERGY STAR LED A-Lamp • Interior ENERGY STAR LED A-Lamp • Interior ENERGY STAR LED Reflector Lamp • Interior Lighting Controls • LED Linear Tube • LED Panel
Small Appliance and Other	**Efficiency** • ENERGY STAR Room Air Purifier
Space Cooling & Space Heating	**Efficiency** • Air Sealing • Air Source Heat Pump - Ductless Mini Split • Air Source Heat Pump - Ductless Mini Split- Cold Climate • Air Source Heat Pump Tune Up • Attic Insulation • Basement Ceiling Insulation • Basement Wall Insulation

End Use(s) Affected	Measure Name
	• Central Ducted Air Source Heat Pump • Central Ducted Air Source Heat Pump - Cold Climate • Crawlspace Ceiling Insulation • Digital Non-Programmable Thermostat (Central) • Digital Non-Programmable Thermostat (Multiple) • Duct Insulation • Duct Sealing • Efficient Windows • ENERGY STAR Doors • Ground Source Heat Pump • Programmable Thermostat (Central) • Programmable Thermostat (Multiple) • Smart Thermostat (Central) • Smart Thermostat (Multiple) • Wall Insulation **Fuel Switching** • Oil Boiler to Air to Water Heat Pump - Space Heating • Oil Boiler to Air to Water Heat Pump - Space Heating – Service Upgrade • Oil Boiler to Cold Climate Ductless Mini Split Heat Pump • Oil Boiler to Cold Climate Ductless Mini Split Heat Pump – Service Upgrade • Oil Boiler to Ductless Mini Split Heat Pump • Oil Boiler to Ductless Mini Split Heat Pump - Partial Switch • Oil Boiler to Ductless Mini Split Heat Pump - Partial Switch – Service Upgrade • Oil Boiler to Ductless Mini Split Heat Pump – Service Upgrade • Oil Furnace to Central Ducted Air Source Heat Pump • Oil Furnace to Central Ducted Air Source Heat Pump – Partial Switch • Oil Furnace to Central Ducted Air Source Heat Pump – Partial Switch – Service Upgrade • Oil Furnace to Central Ducted Air Source Heat Pump – Service Upgrade • Oil Furnace to Cold Climate Central Ducted Air Source Heat Pump • Oil Furnace to Cold Climate Central Ducted Air Source Heat Pump – Service Upgrade • Oil Furnace to Ductless Mini Split Heat Pump

End Use(s) Affected	Measure Name
	• Oil Furnace to Ductless Mini Split Heat Pump – Service Upgrade • Wood Furnace to Central Ducted Air Source Heat Pump • Wood Furnace to Central Ducted Air Source Heat Pump – Service Upgrade • Wood Furnace to Cold Climate Central Ducted Air Source Heat Pump • Wood Furnace to Cold Climate Central Ducted Air Source Heat Pump – Service Upgrade • Wood Furnace to Ductless Mini Split Heat Pump - Partial Switch • Wood Furnace to Ductless Mini Split Heat Pump - Partial Switch – Service Upgrade
Space Heating & Space Cooling & Water Heating	**Fuel Switching** • Oil Boiler to Air to Water Heat Pump - Space Heating and Water Heating
Space Cooling & Space Heating & Ventilation	**Efficiency** • Energy Recovery Ventilator (Ducted) • Energy Recovery Ventilator (Ductless) • Heat Recovery Ventilator (Ducted) • Heat Recovery Ventilator (Ductless)
Space Heating	**Fuel Switching** • Oil Boiler to Electric Boiler • Oil Furnace to Electric Furnace **Demand Response** • Smart Thermostat or Switch for Baseboards or Furnaces (Utility-Driven) • Smart Thermostat or Switch for Central Air Source Heat Pumps (Utility-Driven) • Smart Thermostat or Switch for Ductless Mini-Split Heat Pumps (Utility-Driven) • Thermal Storage and Air Source Heat Pump (Utility-Driven and Thermal Storage with TOU) • Thermal Storage and Ductless Mini-Split Heat Pump (Utility-Driven and Thermal Storage with TOU) • Thermal Storage for Heating (Utility-Driven and Thermal storage with TOU)
Ventilation	**Efficiency** • ENERGY STAR Ceiling Fan

End Use(s) Affected	Measure Name
Four or More End Uses Affected	**Efficiency** • Codes and Standards • Home Energy report • LEED Certified Apartments • New Home - ENERGY STAR • New Home - Net-Zero Ready **Demand Response** • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Critical Peak Pricing (CPP) • Smart circuit breakers or smart panel (Utility-Driven) • Time-of-Use (TOU)

Exhibit 182: Commercial Sector Measures

End Use(s) Affected	Measure Name
Computer Servers	**Efficiency** • ENERGY STAR Server
Water Heating	**Efficiency** • Drain Water Heat Recovery • ENERGY STAR Dishwasher • Faucet Aerator • Heat Pump Water Heater • Low-Flow Showerhead • Pre-Rinse Spray Valve • Thermostatic Restrictor Shower Valve **Fuel Switching** • Oil Water Heater to Heat Pump Water Heater **Demand Response** • Controllable Water Heater (Utility-Driven) • Large Commercial Dual-Fuel Water Heater (Utility-Driven)
Water Heating & Refrigeration	**Efficiency** • Floodwater Deaeration (Non-thermal) - Arena
Food Service Equipment	**Efficiency** • High-Efficiency Cooking Equipment
General Lighting	**Efficiency** • LED A-Lamp (Interior) • LED Luminaire (General) • LED Reflector (Interior, General) • Lighting Controls (Interior), BAS • Lighting Controls (Interior), Daylighting • Lighting Controls (Interior), Occupancy Ceiling • Lighting Controls (Interior), Occupancy Wall • Linear LED T8 Tube (General)
High Bay Lighting	**Efficiency** • LED High Bay Luminaire
HVAC Fans & Pumps	**Efficiency** • Cooling tower fan or pump with VFD • DHW Circulator Pump with EC Motor • Heating Water Circulator Pump with EC Motor • HVAC Electronically Commutated Motor (EC motor) • HVAC Fan or Pump VFD

End Use(s) Affected	Measure Name
	• HVAC Variable Frequency Drive - Motors • Premium Efficiency Motors • Recirculation Pump with Demand Controls
HVAC Fans & Pumps & Space Cooling	**Efficiency** • Advanced Building Automation Systems • Demand Control Ventilation • Kitchen Demand Control Ventilation **Demand Response** • HVAC Fans & Pumps Controls (Utility-Driven)
Miscellaneous Equipment	**Efficiency** • ENERGY STAR Ice Maker • ENERGY STAR Uninterruptible Power Supply • ENERGY STAR Vending Machine **Off-Road Electrification** • Electric Forklift • Electric Zamboni
Other Plug Loads	**Efficiency** • Advanced Smart Strips
Outdoor Lighting	**Efficiency** • LED A-Lamp (Exterior) • LED Parking Garage Fixture (Exterior) • LED Pole Mounted Fixture (Exterior) <= 200 W • LED Pole Mounted Fixture (Exterior) > 200 W • LED Reflector (Exterior) • LED Wall Pack (Exterior) • Lighting Controls (Exterior)
Refrigeration	**Efficiency** • Automatic Door Closers • Brine Pump Controls - Arena • ENERGY STAR Refrigerators and Freezers • Fast Acting Doors (Cooler) • Fast Acting Doors (Freezer) • High Efficiency Compressor • LED Refrigerated Case Lighting • Low Emissivity Ceilings in Arenas • Refrigerated Case Anti-Sweat Door Heater Controls • Refrigerated Case Retrofit • Refrigerated Display Case with Doors

End Use(s) Affected	Measure Name
	• Refrigerated Walk-ins Door Strip Curtains • Refrigerated Walk-ins EC Motor • Refrigerated Walk-ins Evaporator Fan Control • Refrigeration Floating Head Pressure Control • Schedule for Ice Temperature - Arena
Secondary Lighting	**Efficiency** • LED Luminaire (Secondary) • LED Reflector (Interior, Secondary) • Linear LED T8 Tube (Secondary)
Space Cooling & Space Heating	**Efficiency** • Air Sealing • Air Source Heat Pump – Standard to High Efficiency • Baseboard to Ductless Mini-Split Heat Pump • Baseboard to Packaged Terminal Heat Pump • Cold Climate Air Source Heat Pump • Ductless Mini-Split Heat Pump – Standard to High Efficiency • Electric Furnace to Air Source Heat Pump • Energy Management System • Ground Source Heat Pumps – Standard to High Efficiency • Guest Room Energy Management • Packaged Terminal Heat Pump – Standard to High Efficiency • Programmable Thermostat • Smart Thermostat
Space Cooling	**Efficiency** • Dual Enthalpy Economizer Controls • High Efficiency Electric Chiller • High Efficiency Rooftop Units • High Efficiency Unitary Air Conditioners • Packaged Terminal Air Conditioner – Standard to High Efficiency • Rooftop Unit – Standard to High Efficiency • Room Air Conditioner – Standard to High Efficiency • Server Room Air Conditioner • Unitary Air Conditioner
Space Heating	**Efficiency** • Air Curtains • Efficient Windows • Energy Recovery Ventilator

End Use(s) Affected	Measure Name
	• Radiant Infrared Heaters • Refrigeration Heat Recovery • Roof Insulation • Solar Wall • Wall Insulation • Window Glazing **Fuel Switching** • Oil Boiler - Baseboard Heat • Oil Boiler to Air-to-Water Heat Pump • Oil Boiler to Ductless Mini-Split Heat Pump - Partial Switch • Oil Boiler to Ductless Mini-Split Heat Pump - Partial Switch • Oil Boiler to Electric Boiler • Oil Furnace to Air Source Heat Pump • Oil Furnace to Ductless Mini-Split Heat Pump – Partial Switch • Oil Furnace to Electric Furnace **Demand Response** • HVAC Control (Utility-Driven) • Thermal Storage and Electric Baseboard Heating with TOU • Thermal Storage and Electric Baseboard Heating (Utility-Driven) • Thermal Storage and Electric Furnace Heating with TOU • Thermal Storage and Electric Furnace Heating (Utility-Driven) • Thermal Storage and Heat Pump Heating with TOU • Thermal Storage and Heat Pump Heating (Utility-Driven)
Street Lighting	**Efficiency** • LED Street Light
Four or More End Uses Affected	**Efficiency** • Energy Management System • New Construction (25% more efficient) • New Construction (40% more efficient) • Net-Zero Ready • Retro-commissioning Strategic Energy Manager **Demand Response** • Backup Generation (Utility-Driven) • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Critical Peak Pricing • Customer curtailment

End Use(s) Affected	Measure Name
	• Grid Interactive Efficient Buildings (Utility-Driven) • Time-of-Use Rate

Exhibit 183: Industrial Sector Measures

End Use(s) Affected	Measure Name
Air Compressors	**Efficiency** • Air Leak Survey and Repair • Cycling Refrigerated Air Dryer • Low Pressure Drop Filters • Optimized Distribution System (Incl. Pressure and Air End Uses) - Air Compressor • Optimized Sizes of Air Receiver Tanks • Premium Efficiency ASD Compressor • Sequencing Control • Use Cooler Air from Outside for Make Up Air • Zero Loss Condensate Drain
Conveyors	**Efficiency** • Optimized Conveyor Motor Control • Premium Efficiency Motors - Conveyor
Fans and Blowers	**Efficiency** • Correctly Sized Fans: Impeller Trimming or Fan Selection • Optimized Distribution System (Incl. Pressure Losses) - Fans and Blowers • Premium Efficiency Fan Control with ASDs • Premium Efficiency Motors - Fan or Blower • Synchronous Belts
General Lighting	**Efficiency** • Automated Lighting Controls • Greenhouse Grow Lights • High Efficiency Lighting Design • LED High Bay • LED Luminaire
HVAC Fans & Pumps	**Efficiency** • Air Compressor Heat Recovery • Air Curtains - HVAC • High Efficiency Packaged HVAC • Improved Building Insulation • Reduced Temperature Settings • Refrigeration Heat Recovery • Smart Thermostat • Solar Thermal Wall • Ventilation Heat Recovery

End Use(s) Affected	Measure Name
	• Ventilation Optimization • Warehouse Loading Dock Seals **Fuel Switching** • Comfort HVAC Electrification
HVAC Fans & Pumps, Pumps, Process Cooling, and Process Heating	**Demand Response** • Peak shifting through On-Site Storage (Utility-Driven)
Other	**Off-Road Electrification** • Electric Forklift
Other Motors	**Efficiency** • Adjustable or Variable Speed Drives (Compressor and Fan) • Correctly Sized Motor • Motor Controls – Process • Premium Efficiency Motors - Other
Pumps	**Efficiency** • Correctly Sized Pumps: Impeller Trimming or Pump Selection • Optimization of Pumping System • Premium Efficiency Motors - Pumps • Premium Efficiency Pump Control with ASDs
Process Cooling	**Efficiency** • Air Curtains - Process Cooling • Chiller Economizer • Floating Head Pressure Controls • High Efficiency Chiller • Improve Insulation of Refrigeration System • Improved Ice Production System • Optimized Distribution System - Process Cooling • Premium Efficiency Refrigeration Control System and Compressor Sequencing
Process Heating	**Efficiency** • High Efficiency Oven/Dryer/Furnace/Kiln • High Efficiency Water Heater • Insulation • Process Heat Recovery to Preheat Makeup Water
Process Specific	**Efficiency** • Advanced 'Predictive' Process Control Systems • Custom Processes • Process Optimization Efforts - Fishing and Fish Processing

End Use(s) Affected	Measure Name
	• Process Optimization Efforts - Mining and Processing
Process Heating & Process Cooling	**Efficiency** • Heat Pumps
All End Uses Affected	**Demand Response** • Backup Generation at Peak Hours (Utility-Driven) • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Critical Peak Pricing/ Industrial Flexibility • Energy Management Information System (EMIS) • Time-of-Use (TOU)

Exhibit 184 presents transportation sector measures, all of which affect the EV charging end use.

Exhibit 184: Transportation Sector Measures

Measure Type	Measure Name
Managed Charging	**Personal Ownership** • BEV - Electric Vehicle Supply Equipment (EVSE) • BEV – Vehicle Telematics (VT) • PHEV – EVSE • PHEV – VT **Fleet Ownership** • Bus – EVSE • Bus – VT • HDV – EVSE • HDV - VT • Light Duty BEV – EVSE • Light Duty BEV – VT • Light Duty PHEV – EVSE • Light Duty PHEV – VT • MDV – EVSE • MDV – VT
Time-of-Use	**Personal Ownership** • BEV • PHEV
Adoption Incentives	• Bus • Fleet LDV • HDV • MDV • Personal LDV
Infrastructure	**Personal Ownership** • LDV DCFC Public Charger • LDV L2 Home Charger – Multi-Unit Residential Building (MURB) • LDV L2 Public Charger • LDV Level 1 (L1) Home Charger • LDV Level 2 (L2) Home Charger **Fleet Ownership** • Bus DCFC Depot Charger • Bus L2 Depot Charger • HDV DCFC Depot Charger

Measure Type	Measure Name
	• LDV DCFC Public Charger • LDV Direct Current Fast Charger (DCFC) Depot Charger • LDV L2 Depot Charger • LDV L2 Public Charger • MDV DCFC Depot Charger • MDV L2 Depot Charger **Other Ownership** • HDV DCFC Public Charger • HDV L2 Public Charger • MDV DCFC Public Charger • MDV L2 Public Charger

Appendix C Cost-Effectiveness Test Inputs and Measure-Level Results

This appendix includes inputs to the cost-effectiveness test calculations, including retail rates, inflation and discount rates, and avoided costs. It also includes measure-level cost-effectiveness test results for all measures.

Retail Rates

Exhibit 185: Retail Rates by Customer Rate Class

Rate Class	Marginal Energy Cost	Demand Charge	Source(s)
1.1 Domestic Service	$0.13256/kWh	n/a	• Newfoundland Power Schedule of Rates Rules & Regulations, Effective July 1, 2023[233] • Newfoundland and Labrador Hydro Schedule of Rates, Rules and Regulations, Updated July 1, 2023[233]
2.1 General Service	$0.1016/kWh	$9.70/kW from Dec-Mar $7.20/kW for all other months	
2.3 General Service	$0.09385/kWh	$8.15/kVA from Dec-Mar $5.65/kVA for all other months	
2.4 General Service	$0.09305/kWh	$7.82/kW from Dec-Mar $5.32/kW for all other months	
Industrial Firm	$0.0591/kWh	$10.73/kW for all months	Newfoundland and Labrador Hydro Schedule of Rates, Rules and Regulations, Updated July 1, 2023

Notes on Retail Rates

- The marginal energy cost for the commercial sector is weighted by base year consumption for the 2.1, 2.3 and 2.4 general service rate classes. Data on historical CDME participation by rate class was not available for weighting.
- The marginal energy cost for the industrial sector is weighted by base year consumption for the 2.1, 2.3 and 2.4 general service rate classes. Data on historical CDME participation by rate class was not available for weighting. NLH's large industrial customers are excluded from the

[233] The Study uses 2023 rates because the base year is also 2023.

weighting because they have not historically participated in CDME, and this trend is not expected to change during the forecast period.

- The winter demand charge is used for the peak retail rates. Multiplied the weighted average winter retail demand charge by 4 so that it is valued in each of the 4 winter months. Applied 0.75 derating factor to account that customer might not be coincident with utility peak.
- For the demand response measures, because commercial demand is driven by space heating, customers in the commercial sector will see savings 4 times per year, once per winter month. Industrial demand is not driven by space heating and therefore customers in the industrial sector will see savings 12 times per year.

Inflation and Discount Rates

Exhibit 186: Inflation and Discount Rates

Parameter	Value	Source(s)
Inflation	0%	Navigator cannot accommodate inflation.
Participant Discount Rate (Real)	0%	n/a; a 0% discount rate is used because participants do not typically apply discounting to their financial decisions.
Utility Discount Rate (Real)	4%	Newfoundland Power, comment 31 in the NL Potential Study Measure Analysis Comments Log.
Societal Discount Rate (Real)	1%	Government of Canada Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030, available online.

Avoided Marginal Costs

The source for the avoided costs data is "*2023 Marginal Costs_IIS from Hydro with NP Distribution (Oct 2023 update)*."

Exhibit 187: Capacity Costs ($/kW)

Year	Generation	Transmission	Distribution	Total
2023	$288.97	$18.17	$23.62	$330.76
2024	$286.15	$18.57	$24.08	$328.80
2025	$290.99	$18.95	$24.54	$334.48
2026	$295.92	$19.34	$25.01	$340.27
2027	$300.93	$19.73	$25.50	$346.16
2028	$306.03	$20.14	$25.99	$352.16
2029	$311.23	$20.55	$26.50	$358.28
2030	$316.52	$20.97	$27.02	$364.51
2031	$321.90	$21.40	$27.55	$370.85
2032	$327.38	$21.84	$28.10	$377.32
2033	$332.96	$22.29	$28.65	$383.90
2034	$338.63	$22.74	$29.22	$390.59
2035	$344.41	$23.21	$29.80	$397.42
2036	$350.30	$23.68	$30.40	$404.38
2037	$356.29	$24.17	$31.00	$411.46
2038	$362.38	$24.67	$31.62	$418.67
2039	$368.59	$25.17	$32.25	$426.01
2040	$374.91	$25.69	$33.14	$433.74
2041	$381.34	$26.22	$33.80	$441.36
2042	$387.89	$26.75	$34.48	$449.12

Exhibit 188: Energy Supply Costs ($/kWh)

Year	Winter Peak	Winter Off Peak	Non-Winter
2023	$172.24	$139.98	$40.46
2024	$144.89	$124.50	$34.21
2025	$122.40	$103.38	$29.95
2026	$84.71	$69.40	$27.05
2027	$62.51	$48.76	$25.44
2028	$61.38	$49.95	$28.39
2029	$58.98	$50.29	$26.72
2030	$54.00	$45.47	$24.56
2031	$50.59	$42.25	$22.02
2032	$50.15	$41.23	$24.48
2033	$54.66	$45.96	$23.64
2034	$56.49	$48.31	$25.09
2035	$51.38	$45.86	$24.66
2036	$48.29	$44.00	$24.46
2037	$48.29	$44.37	$22.08
2038	$46.48	$43.57	$23.88
2039	$49.04	$46.26	$21.40
2040	$47.51	$47.53	$21.41
2041	$56.70	$57.20	$25.62
2042	$55.23	$55.45	$26.18

Measure-Level Cost-Effectiveness Test Results

Exhibit 189 to Exhibit 195 show measure-level cost effectiveness test results for the residential, commercial, industrial and transportation sectors. Two cost-effectiveness test results are shown for the medium achievable potential scenario: the program administrator cost test (PAC), and the total resource cost test (TRC).[234] Results for the electricity rate design and thermal storage with TOU demand response measures reflect costs and benefits incurred during the four-year AMI meter installation period and the 20-year smart meter lifetime.

Exhibit 189: Measure-Level Cost-Effectiveness Test Results, Residential Sector (2025)

Measure	Type	Medium PAC	Medium TRC
Advanced Smart Strips and Plugs	EE	2.6	1.5
Air Sealing	EE	4.8	2.7
Air Source Heat Pump - Ductless Mini Split (DMSHP)	EE	4.2	1.5
Air Source Heat Pump - Ductless Mini Split (DMSHP) - Cold Climate	EE	2.1	0.9
Air Source Heat Pump Tune Up	EE	2.2	1.2
Appliance Retirement for Extra Refrigerators	EE	1.4	0.8
Attic Insulation	EE	2.7	1.5
Basement Ceiling Insulation	EE	4.1	2.3
Basement Wall Insulation	EE	2.5	1.4
Central Ducted Air Source Heat Pump	EE	4.9	2.8
Central Ducted Air Source Heat Pump - Cold Climate	EE	N/A	N/A
Clothes Lines and Drying Racks	EE	5.9	3.3
Codes and Standards	EE	N/A	N/A
Convection Oven	EE	N/A	N/A
Crawlspace Ceiling Insulation	EE	4.8	2.7
Digital Non-Programmable Thermostat (Central)	EE	10.1	5.6
Digital Non-Programmable Thermostat (Multiple)	EE	2.4	1.3
Dimmer Switches	EE	N/A	N/A
Domestic Hot Water Pipe Insulation	EE	23.8	13.2
Duct Insulation	EE	19.9	11.1
Duct Sealing	EE	2.2	1.2
Efficient Windows	EE	1.6	0.9
ENERGY STAR Ceiling Fan	EE	28.5	15.8
ENERGY STAR Clothes Dryer	EE	N/A	N/A
ENERGY STAR Clothes Washer	EE	2.9	1.6
ENERGY STAR Dehumidifier	EE	8.0	4.5
ENERGY STAR Dishwasher	EE	N/A	N/A

[234] The incentive in the medium achievable potential scenario reflects 50% of the incremental cost for replace on burnout measures and 50% of the full cost for retrofit measures.

ENERGY STAR Doors	EE	N/A	N/A
ENERGY STAR Freezer	EE	10.0	10.0
ENERGY STAR Refrigerator	EE	1.7	0.9
ENERGY STAR Room Air Purifier	EE	N/A	N/A
Exterior ENERGY STAR LED Reflector Lamp	EE	14.4	10.0
Exterior Lighting Controls	EE	2.1	1.2
External ENERGY STAR LED A-Lamp	EE	18.5	10.0
Faucet Aerator	EE	89.9	49.9
Freezer Recycle	EE	N/A	N/A
Ground Source Heat Pump (GSHP)	EE	N/A	N/A
Heat Pump Clothes Dryer	EE	N/A	N/A
Heat Pump Water Heater (HPWH)	EE	2.0	1.2
Heat Pump Water Heater (HPWH) - Standard to High Efficiency	EE	N/A	N/A
Heat Recovery Ventilator (Ducted) - Standard to High Efficiency	EE	7.4	4.1
Heat Recovery Ventilator (Ductless) - Standard to High Efficiency	EE	7.5	4.2
High-Efficiency Induction Cooktops	EE	N/A	N/A
Home Energy Report	EE	7.7	7.6
Insulated Hot Tub Cover	EE	N/A	N/A
Interior ENERGY STAR LED A-Lamp	EE	19.4	10.0
Interior ENERGY STAR LED Reflector Lamp	EE	15.2	10.0
Interior Lighting Controls	EE	1.6	0.9
LED Linear Tube	EE	10.2	16.6
LED Panel	EE	1.4	1.5
LEED Certified Apartments	EE	N/A	N/A
Low Flow Showerhead	EE	7.8	4.3
New Home - ENERGY STAR	EE	N/A	N/A
New Home - Net-Zero Ready	EE	N/A	N/A
Oil Boiler to Cold Climate Ductless Mini Split Heat Pump (DMSHP)	FS	0.0	0.4
Oil Boiler to Cold Climate Ductless Mini Split Heat Pump (DMSHP) - Service Upgrade	FS	N/A	N/A
Oil Boiler to Ductless Mini Split Heat Pump - Partial Switch	FS	N/A	N/A
Oil Boiler to Ductless Mini Split Heat Pump - Partial Switch - Service Upgrade	FS	N/A	N/A
Oil Boiler to Electric Boiler	FS	N/A	N/A
Oil Boiler to Electric Boiler - Service Upgrade	FS	N/A	N/A
Oil Furnace to Cold Climate Central Ducted Air Source Heat Pump	FS	N/A	N/A

Oil Furnace to Cold Climate Central Ducted Air Source Heat Pump - Service Upgrade	FS	N/A	N/A
Oil Furnace to Ductless Mini Split Heat Pump (DMSHP) - Partial Switch	FS	N/A	N/A
Oil Furnace to Ductless Mini Split Heat Pump (DMSHP) - Partial Switch - Service Upgrade	FS	N/A	N/A
Oil Furnace to Electric Furnace	FS	N/A	N/A
Oil Furnace to Electric Furnace - Service Upgrade	FS	N/A	N/A
Oil Water Heater to Heat Pump Water Heater	FS	N/A	N/A
Oil Water Heater to Heat Pump Water Heater - Service Upgrade	FS	N/A	N/A
Oil Water Heater to High Efficiency Electric Storage Water Heater	FS	N/A	N/A
Oil Water Heater to High Efficiency Electric Storage Water Heater - Service Upgrade	FS	N/A	N/A
On Demand Hot Water Heater (Distributed)	EE	N/A	N/A
Programmable Thermostat (Central)	EE	29.0	16.1
Programmable Thermostat (Multiple)	EE	6.8	3.8
Propane to Electric Induction Stove	FS	N/A	N/A
Propane to Electric Induction Stove - Service Upgrade	FS	N/A	N/A
Smart Thermostat (Central)	EE	15.3	8.5
Smart Thermostat (Multiple)	EE	6.8	3.8
Thermostatic Restrictor Shower Valve	EE	2.2	1.2
Wall Insulation	EE	N/A	N/A
Wood Furnace to Cold Climate Central Ducted Air Source Heat Pump	FS	N/A	N/A
Wood Furnace to Ductless Mini Split Heat Pump (DMSHP) - Partial Switch	FS	N/A	N/A
Wood Furnace to Ductless Mini Split Heat Pump (DMSHP) - Partial Switch - Service Upgrade	FS	N/A	N/A

Exhibit 190: Measure-Level Cost-Effectiveness Test Results, Residential Sector DR Measures

Measure	Medium PAC	Medium TRC
Critical Peak Pricing (CPP) - Residential	0.2	0.2
Time-of-Use (TOU) - Behaviour Driven - Residential	0.1	0.1
Smart Circuit Breakers or Smart Panel - Utility Driven	0.8	1.0
Smart Thermostat or Switch for Baseboards or Furnaces - Utility Driven	7.4	44.2
Thermal Storage and Ductless Mini-Split Heat Pump - Utility Driven - Residential	2.3	0.4
Thermal Storage and Ductless Mini-Split Heat Pump - Thermal Storage + Time-of-Use - Residential	1.7	0.4
Thermal Storage and Electric Baseboard Heating - Thermal Storage + Time-of-Use - Residential	4.0	0.9
Thermal Storage and Electric Baseboard Heating - Utility Driven - Residential	5.5	0.9
Behind-the-Meter Battery Storage - Utility Driven - Residential	4.6	0.7
Smart Thermostat or Switch for Ductless Mini-Split Heat Pumps - Utility Driven	3.1	18.7
Thermal Storage and Air Source Heat Pump - Thermal Storage + Time-of-Use - Residential	1.7	0.3
Thermal Storage and Air Source Heat Pump - Utility Driven - Residential	2.3	0.4
Smart Thermostat or Switch for Central Air Source Heat Pumps - Utility Driven	3.0	18.0
Thermal Storage and Electric Furnace - Thermal Storage + Time-of-Use - Residential	4.7	1.0
Thermal Storage and Electric Furnace - Utility Driven - Residential	6.7	1.0
Behind-the-Meter Solar with Smart Inverters - Utility Driven - Residential	N/A	N/A
Clothes Dryer Direct Load Control - Utility Driven	N/A	N/A
Clothes Washer Direct Load Control - Utility Driven	N/A	N/A
Dishwasher Direct Load Control - Utility Driven	N/A	N/A
Water Heater Smart Switch - Utility Driven	N/A	N/A

Exhibit 191: Measure-Level Cost-Effectiveness Test Results, Commercial Sector (2025)

Measure	Measure Type	Medium PAC	Medium TRC
Advanced Building Automation Systems	EE	6.9	1.4
Advanced Smart Strips	EE	7.1	3.9
Air Curtains	EE	7.1	3.9
Air Sealing	EE	11.2	6.2
Air Source Heat Pump - Standard to High Efficiency	EE	N/A	N/A
Baseboard to Ductless Mini-Split Heat Pump	EE	7.2	2.3
Baseboard to Packaged Terminal Heat Pump	EE	5.7	2.9
Brine Pump Controls - Arena	EE	9.6	5.3
Cold Climate Air Source Heat Pump	EE	N/A	N/A
Demand Control Ventilation	EE	8.9	5.0
DHW Circulator Pump with EC Motor	EE	5.0	2.8
Drain Water Heat Recovery	EE	6.8	3.8
Dual Enthalpy Economizer Controls	EE	N/A	N/A
Ductless Mini-Split Heat Pump - Standard to High Efficiency	EE	N/A	N/A
Efficient Windows	EE	N/A	N/A
Electric Furnace to Air Source Heat Pump	EE	10.4	5.8
Energy Management System	EE	1.8	1.0
Energy Recovery Ventilator (ERV)	EE	4.9	2.7
ENERGY STAR Dishwasher	EE	28.4	15.8
ENERGY STAR Ice Maker	EE	1.9	1.1
ENERGY STAR Refrigerators and Freezers	EE	3.7	2.1
ENERGY STAR Server	EE	N/A	N/A
ENERGY STAR Uninterruptible Power Supply	EE	13.2	7.3
ENERGY STAR Vending Machine	EE	19.3	10.7
Fast Acting Doors Cooler	EE	10.0	10.0
Fast Acting Doors Freezer	EE	5.9	5.1
Faucet Aerator	EE	186.2	103.4
Floodwater Deaeration (Non-thermal) - Arena	EE	4.8	2.7
Ground Source Heat Pump - Standard to High Efficiency	EE	N/A	N/A
Guest Room Energy Management	EE	1.9	1.1
Heat Pump Water Heater	EE	N/A	N/A
High Efficiency Compressor	EE	26.2	14.5
High Efficiency Electric Chiller	EE	N/A	N/A
High Efficiency Unitary Air Conditioners	EE	N/A	N/A
High Efficiency Window Glazing	EE	5.6	3.1
High-Efficiency Cooking Equipment	EE	3.3	1.8

Measure	Measure Type	Medium PAC	Medium TRC
HVAC electronically commutated motor (EC motor)	EE	5.4	3.0
HVAC Variable Frequency Drive - Motors	EE	2.4	1.3
LED A-Lamp (Exterior)	EE	14.3	9.8
LED A-Lamp (Interior)	EE	10.8	7.2
LED High Bay Luminaire	EE	33.0	18.3
LED Luminaire (General)	EE	4.2	2.3
LED Luminaire (Secondary)	EE	4.0	2.2
LED Parking Garage Fixture (Exterior)	EE	5.0	2.8
LED Pole Mounted Fixture (Exterior) <= 200 W	EE	3.4	1.9
LED Pole Mounted Fixture (Exterior) > 200 W	EE	3.2	1.8
LED Reflector (Exterior)	EE	56.4	10.0
LED Reflector (Interior General)	EE	42.5	10.0
LED Reflector (Interior Secondary)	EE	42.1	10.0
LED Refrigerated Case Lighting	EE	0.4	0.8
LED Street Light	EE	2.3	1.3
LED Wall Pack (Exterior)	EE	1.7	10.0
Lighting Controls (Exterior)	EE	N/A	N/A
Lighting Controls (Interior) BAS	EE	N/A	N/A
Lighting Controls (Interior) Daylighting	EE	2.8	1.6
Lighting Controls (Interior) Occupancy - Ceiling	EE	2.3	1.3
Linear LED T8 Tube (General Lighting)	EE	8.3	9.8
Linear LED T8 Tube (Secondary Lighting)	EE	7.9	9.3
Low Emissivity Ceilings in Arenas	EE	1.7	1.0
Low-Flow Showerhead	EE	94.2	52.4
New Construction (25% more efficient)	EE	7.2	4.0
New Construction (40% more efficient)	EE	4.0	2.2
New Construction (Net-Zero Ready)	EE	2.0	1.1
Oil Boiler to Air-to-Water Heat Pump	FS	0.0	1.8
Oil Boiler to Ductless Mini-Split Heat Pump - Partial Switch	FS	0.0	1.8
Oil Boiler to Electric Boiler	FS	0.0	0.9
Oil Furnace to Air Source Heat Pump	FS	0.0	1.7
Oil Furnace to Ductless Mini-Split Heat Pump - Partial Switch	FS	0.0	1.8
Oil Water Heater to Heat Pump Water Heater	FS	N/A	N/A
Packaged Terminal Air Conditioner	EE	N/A	N/A
Packaged Terminal Heat Pump - Standard to High Efficiency	EE	N/A	N/A
Pre-Rinse Spray Valve	EE	11.6	6.4
Programmable Thermostat	EE	7.1	4.7

Measure	Measure Type	Medium PAC	Medium TRC
Radiant Infrared Heaters	EE	1.9	1.1
Recirculation Pump with Demand Controls	EE	N/A	N/A
Refrigerated Case Anti-Sweat Door Heater Controls	EE	8.8	4.9
Refrigerated Case Retrofit	EE	6.9	3.8
Refrigerated Display Case with Doors	EE	1.4	0.8
Refrigerated Walk-ins Door Strip Curtains	EE	3.8	2.1
Refrigerated Walk-ins EC Motor	EE	6.7	3.7
Refrigerated Walk-ins Evaporator Fan Control	EE	1.5	0.9
Refrigeration Floating Head Pressure Control	EE	2.2	1.2
Refrigeration Heat Recovery	EE	7.1	3.9
Retrocommissioning (RCx)	EE	3.5	2.0
Roof Insulation	EE	2.2	1.2
Rooftop Unit - Standard to High Efficiency	EE	N/A	N/A
Room Air Conditioner - Standard to High Efficiency	EE	N/A	N/A
Schedule for Ice Temperature - Arena	EE	4.8	2.7
Server Room Air Conditioner	EE	2.1	1.1
Smart Thermostat	EE	6.6	5.6
Solar Wall	EE	4.0	2.2
Thermostatic Restrictor Shower Valve	EE	35.1	19.5
Unitary Air Conditioner	EE	5.5	3.4
Wall Insulation	EE	2.5	1.4

Exhibit 192: Measure-Level Cost-Effectiveness Test Results, Commercial Sector DR Measures

Measure	Medium PAC	Medium TRC
Commercial Curtailment	0.0	0.0
Substation Battery	0.0	0.0
Backup Generation at Peak Hours - Utility Driven - Commercial	38.6	83.1
Thermal Storage and Heat Pump Heating - Thermal Storage + Time-of-Use - Commercial	13.3	8.1
Behind-the-Meter Battery Storage - Utility Driven - Commercial	11.7	1.8
Grid Interactive Efficient Buildings (GEB) - Utility Driven	7.9	0.6
Critical Peak Pricing (CPP) - Commercial	0.4	0.4
Thermal Storage and Heat Pump Heating - Utility Driven - Commercial	10.9	7.0
Time-of-Use (TOU) - Behaviour Driven - Commercial	0.3	0.3
HVAC Control - Utility Driven	7.1	24.8
HVAC Fans & Pumps Controls - Utility Driven	4.2	14.8
Thermal Storage and Electric Furnace Heating - Thermal Storage + Time-of-Use - Commercial	13.3	8.2
Thermal Storage and Electric Furnace Heating - Utility Driven - Commercial	10.9	7.0
Thermal Storage and Electric Baseboard Heating - Thermal Storage + Time-of-Use - Commercial	4.6	2.2
Thermal Storage and Electric Baseboard Heating - Utility Driven - Commercial	4.6	1.8
Large Commercial Dual-Fuel Water Heater - Utility Driven	10.9	30.9
Behind-the-Meter Solar with Smart Inverters - Utility Driven - Commercial	N/A	N/A
Controllable Water Heater - Utility Driven	N/A	N/A

Exhibit 193: Measure-Level Cost-Effectiveness Test Results, Industrial Sector (2025)

Measure	Measure Type	Medium PAC	Medium TRC
Custom Processes	EE	N/A	N/A
High Efficiency Oven/Dryer/Furnace/Kiln	EE	N/A	N/A
High Efficiency Water Heater	EE	N/A	N/A
Improve Insulation of Refrigeration System	EE	N/A	N/A
Improved Building Insulation	EE	N/A	N/A
Low Pressure Drop Filters	EE	N/A	N/A
Premium Efficiency Motors - Conveyor	EE	N/A	N/A
Premium Efficiency Motors - Fan or Blower	EE	N/A	N/A
Premium Efficiency Motors - Other	EE	N/A	N/A
Premium Efficiency Motors - Pumps	EE	N/A	N/A
Process Optimization Efforts - Fishing and Fish Processing	EE	N/A	N/A
Ventilation Heat Recovery	EE	N/A	N/A
Ventilation Optimization	EE	N/A	N/A
Warehouse Loading Dock Seals	EE	N/A	N/A
LED High Bay Luminaire	EE	40.9	22.7
Refrigeration Heat Recovery	EE	32.1	17.8
Insulation	EE	28.3	15.7
Process Optimization Efforts - Mining and Processing	EE	10.0	10.0
Reduced Temperature Settings	EE	10.0	10.0
High Efficiency Chiller	EE	16.8	9.3
Adjustable or Variable Speed Drive (Pump)	EE	16.0	8.9
Use Cooler Air from Outside for Make Up Air	EE	13.9	7.7
Correctly Sized Fans: Impeller Trimming or Fan Selection	EE	11.8	6.6
Air Curtains - Process Cooling	EE	11.4	6.3
Floating Head Pressure Controls	EE	10.7	6.0
High Efficiency Packaged HVAC	EE	9.6	5.3
Synchronous Belts	EE	9.2	5.1
Adjustable or Variable Speed Drive (Motor)	EE	8.7	4.9
Optimized Sizes of Air Receiver Tanks	EE	8.5	4.7
Advanced Predictive Process Control Systems	EE	8.4	4.6
High Efficiency Lighting Design	EE	6.2	3.4
Adjustable or Variable Speed Drive (Compressor)	EE	5.9	3.3
Adjustable or Variable Speed Drive (Fan)	EE	5.0	2.8
Optimization of Pumping System	EE	5.0	2.8
Motor Controls - Process	EE	5.0	2.8
Air Leak Survey and Repair	EE	4.9	2.7

Measure	Measure Type	Medium PAC	Medium TRC
LED Luminaire	EE	4.5	2.5
Energy Management Information System (EMIS)	EE	4.0	2.2
Optimized Conveyor Motor Control	EE	4.0	2.2
Air Compressor Heat Recovery	EE	3.7	2.1
Air Curtains - HVAC	EE	3.6	2.0
Comfort HVAC Electrification	FS	0.0	1.6
Optimized Distribution System (Incl. Pressure and Air End-Uses) - Air Compressor	EE	2.8	1.5
Greenhouse Grow Lights	EE	2.7	1.5
Automated Lighting Controls	EE	2.6	1.4
Correctly Sized Motor	EE	2.5	1.4
Optimized Distribution System (Incl. Pressure Losses) - Fans and Blowers	EE	2.2	1.2
Chiller Economizer	EE	1.9	1.1
Process Heat Recovery to Preheat Makeup Water	EE	1.8	1.0
Cycling Refrigerated Air Dryer	EE	1.8	1.0
Improved Ice Production System	EE	1.7	0.9
Zero Loss Condensate Drain	EE	1.6	0.9
Premium Efficiency Refrigeration Control System and Compressor Sequencing	EE	1.6	0.9
Optimized Distribution System - Process Cooling	EE	1.6	0.9
Sequencing Control	EE	1.5	0.8

Exhibit 194: Measure-Level Cost-Effectiveness Test Results, Industrial Sector DR Measures

Measure	Medium PAC	Medium TRC
Behind-the-Meter Battery Storage - Utility Driven - Industrial	5.3	0.5
Critical Peak Pricing (CPP) - Industrial	0.4	0.4
Time-of-Use (TOU) - Industrial	0.4	0.4
Backup Generation at Peak Hours - Utility Driven - Industrial	5.2	21.5
Behind-the-Meter Solar with Smart Inverters - Utility Driven - Industrial	N/A	N/A
Peak shifting through On-Site Storage - Utility Driven - Industrial	N/A	N/A

Exhibit 195: Measure-Level Cost-Effectiveness Test Results, Transportation Sector Managed Charging Measures

Measure Name	Medium PAC	Medium TRC
HDV – VT	86.1	430.5
Bus – VT	30.4	151.9
HDV – EVSE	18.8	12.9
MDV – VT	17.7	88.4
Bus – EVSE	14.8	14.2
MDV - EVSE	5.3	4.0
Light Duty BEV – VT	3.3	16.5
BEV – VT	2.9	14.3
BEV EVSE	2.6	6.3
PHEV – VT	2.3	11.3
PHEV – EVSE	2.0	5.0
Light Duty BEV – EVSE	1.6	1.5
Light Duty PHEV – VT	1.1	5.3
Light Duty PHEV – EVSE	0.6	0.5

Appendix D Marginal Cost Sensitivity

The Study Team was asked to explore the impact of a 40% increase in IIS marginal costs on measure-level cost-effectiveness and achievable potential. This appendix shows the results of the analysis.

Exhibit 196 lists the measures in each sector that become cost-effective with a 40% increase in 2023 IIS marginal costs. None of the transportation sector measures become cost-effective.

Exhibit 196: Cost-Effectiveness Impacts

Measure	Sector	Technical TRC (2023 Marginal Costs)	Technical TRC (1.4*2023 Marginal Costs)
New Home – ENERGY STAR	Residential	0.69	0.95
ENERGY STAR Server	Commercial	0.78	1.1
Energy Management System	Commercial	0.77	1.1
Recirculation Pump with Demand Controls	Commercial	0.71	0.99
Warehouse Loading Dock Seals	Industrial	0.72	1.05
High Efficiency Oven/Furnace/Dryer/Kiln	Industrial	0.69	0.97
Ventilation Heat Recovery	Industrial	0.67	0.94
Improve Insulation of Refrigeration System	Industrial	0.59	0.83
Custom Process	Industrial	0.58	0.81

Exhibit 197 shows the lower, medium and higher achievable potential energy savings estimates for the measures that become cost-effective with a 40% increase in 2023 IIS marginal costs.

Exhibit 197: Achievable Potential Impacts – Energy (2040)

Measure	Sector	Lower Achievable Potential Savings (GWh)	Medium Achievable Potential Savings (GWh)	Higher Achievable Potential Savings (GWh)
New Home – ENERGY STAR	Residential	1.30	1.88	9.14
ENERGY STAR Server	Commercial	0.35	0.46	0.94
Energy Management System	Commercial	4.26	5.65	11.43
Recirculation Pump with Demand Controls	Commercial	1.40	1.85	3.75
Warehouse Loading Dock Seals	Industrial	0.20	0.28	0.53
High Efficiency Oven/Furnace/Dryer/Kiln	Industrial	0.05	0.07	0.14
Ventilation Heat Recovery	Industrial	1.57	2.17	4.17
Improve Insulation of Refrigeration System	Industrial	0.19	0.27	0.52
Custom Process	Industrial	0.50	0.69	1.33

Exhibit 198 the lower, medium and higher achievable peak reduction potential for the measures that become cost-effective with a 40% increase in 2023 IIS marginal costs.

Exhibit 198: Achievable Potential Impacts – Overall Peak (2040)

Measure	Sector	Lower Achievable Potential Savings Estimate (kW)	Medium Achievable Potential Savings Estimate (kW)	Higher Achievable Potential Savings Estimate (kW)
New Home - ENERGY STAR	Residential	307	454	2,422
ENERGY STAR Server	Commercial	14,813	19,699	40,002
Energy Management System	Commercial	352,551	468,848	952,061
Recirculation Pump	Commercial	56,530	75,178	152,659
Warehouse Loading Dock Seals	Industrial	34	48	96
High Efficiency Oven/Furnace/Dryer/Kiln	Industrial	7	10	20
Ventilation Heat Recovery	Industrial	266	373	745
Improve Insulation of Refrigeration System	Industrial	17	23	47
Custom Process	Industrial	75	105	209

Appendix E Distribution Impacts Analysis

This appendix presents the findings from the Study Team's analysis of factors that could influence the adoption of electric vehicles (EVs) and heat pumps across Newfoundland. The findings are based on the approach the Study Team and the Utilities agreed to in July 2024.

In this appendix, the Study Team identifies drivers of adoption and discusses how they may vary across regions. The appendix is structured as follows:

- Approach provides an overview of the approach and any relevant caveats,
- Findings summarizes key findings, and,
- Heat Maps presents heat maps that illustrate the geographical distribution of adoption drivers and their potential impact on EV and heat pump adoption.

Approach

Multivariate Regression Studies from Other Jurisdictions

The Study Team's approach draws on multivariate regression studies from jurisdictions outside Newfoundland that have analyzed factors influencing EV and heat pump adoption. These studies include:

- Providing the Spark: Impact of Financial Incentives on Battery Electric Vehicle Adoption link
- Investigating the factors influencing the electric vehicle market share: A comparative study of the European Union and United States link
- The Impact of state policies on electric vehicle adoption -A panel data analysis link
- Get Connected: Electric Vehicle Quarterly Report 2023 (Q3) link
- Assessment of Electric Vehicle Incentive Policies in Canadian Provinces link
- Impact of Incentive Policies and Other Socio-Economic Factors on Electric Vehicle Market Share: A Panel Data Analysis from the 20 Countries link
- Characterizing air source heat pump market segments: A Canadian case study link
- Modeling Air Source Heat Pump Adoption Propensity and Simulating the Distribution Level Effects of Large-Scale Adoption link
- Pumping up building decarbonisation: The role of policy awareness in heat pump adoption among Canadian homeowners link
- Pumping up adoption: The role of policy awareness in explaining willingness to adopt heat pumps in Canada link

These studies often face limitations, particularly concerning sample sizes for EV adoption, which are generally too small to conduct a robust study for Newfoundland. Additionally, the Study Team was unable to find Newfoundland-specific studies focused on geographically granular heat pump adoption.

Caveats

Backward Looking Data - Early Adopters

One limitation of multivariate regression analysis is that the data primarily reflects early adopters, particularly in the case of electric vehicles (EVs). This data on early adopters pertains to light-duty vehicles. Data for heavier vehicle types, such as medium-duty and heavy-duty vehicles, is not yet available. This data limitation can skew the results, as early adopters of light-duty vehicles may have different characteristics compared to the broader population that will adopt heavier vehicles in the future.

Jurisdictional Differences

Another caveat is the jurisdictional differences between Newfoundland and the other regions studied. Factors such as climate, energy prices, government incentives, and public infrastructure can vary significantly and may influence adoption rates.

Findings

The Study Team recommends that the Utilities monitor the following key drivers when considering future EV and heat pump adoption:

- EV charging infrastructure,
- Population age,
- Population income,
- Population density,
- Average number of rooms per dwelling, and,
- Construction year of houses.

Exhibit 199 shows these drivers and lists the expected influence of each one on EV and heat pump adoption, as determined by multivariate regression studies from other jurisdictions.

Exhibit 199: Key Geographically Granular Adoption Drivers

Driver	Influence on EV Adoption	Influence on Heat Pump Adoption	Comments
EV Charging Infrastructure	High	None	Critical for EV adoption; not relevant for heat pumps.
Population Age	Moderate	Moderate	Younger populations may adopt EVs more readily due to higher openness to new technology, while older populations might have more stable housing situations, making them more likely to invest in heat pumps.
Population Income	High	High	Higher income levels correlate with higher adoption rates for both technologies.
Population Density	High	Moderate	Dense urban areas may see higher EV adoption; heat pumps are increasingly adopted across various regions, particularly where energy efficiency and cost savings are prioritized.[235]
Average Rooms per Dwelling	Low	High	Larger homes are more likely to adopt heat pumps, while EV adoption is less influenced by home size.
Construction Year of Houses	Low	High	Older homes are more likely to adopt heat pumps due to the need for modernization and energy efficiency improvements.

Additional findings include:

- For EVs, infrastructure and population density are critical because proximity to charging stations and the concentration of early adopters in urban areas play significant roles.
- Income is a strong predictor for EV and heat pump adoption because both technologies are still relatively expensive.
- The house construction year is a particularly important driver for heat pump adoption. Older homes tend to be less energy-efficient and often require upgrades to their heating systems, making them prime candidates for heat pump installations. Conversely, newer homes, which are typically equipped with modern heating systems, may have a lower likelihood of adopting heat pumps.

Although the drivers in Exhibit 199 provide a useful framework for understanding regional differences in adoption rates, they only offer a partial explanation. A model built solely on these factors would capture

[235] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2018/market-snapshot-steady-growth-heat-pump-technology.html, https://climateinstitute.ca/reports/heat-pumps-canada/

some of the trends but may fall short in accurately predicting all regional variations. This limitation underscores the importance of incorporating more detailed customer persona data, such as individual preferences, behaviours, and demographic specifics, which are not publicly available for Newfoundland. Such data could significantly enhance the predictive power of the model, providing a more comprehensive understanding of the factors driving adoption in different regions. The studies we examined suggest that the variables we outlined (combined with some customer persona data that is not publicly available) may predict about 11 to 43% of near-term spatial electric heat pump and 70 to 80% of near-term spatial EV adoption differences.

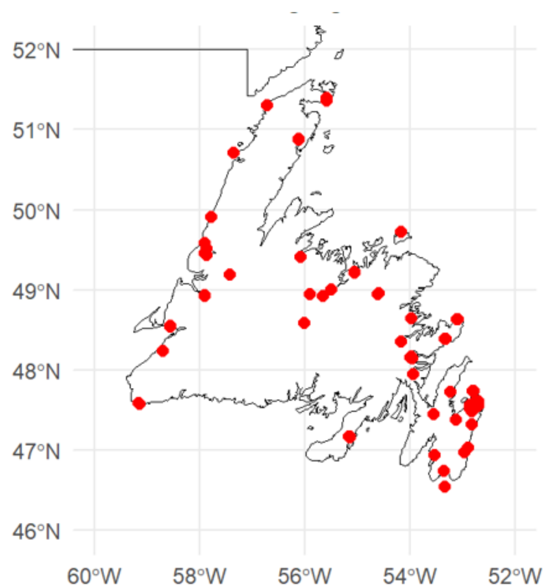
Heat Maps

This section presents six heat maps to illustrate the spatial distribution of key drivers influencing the adoption of electric vehicles (EVs) and heat pumps across Newfoundland.

Electric Vehicle Charging Infrastructure

Exhibit 200 highlights the distribution of EV charging infrastructure across Newfoundland. This driver is important for EV adoption, as the availability of charging stations influences the convenience and practicality of owning an electric vehicle. Areas with dense infrastructure are expected to show higher adoption rates.

Exhibit 200: Public Electric Vehicle Charging Stations in Newfoundland[236]

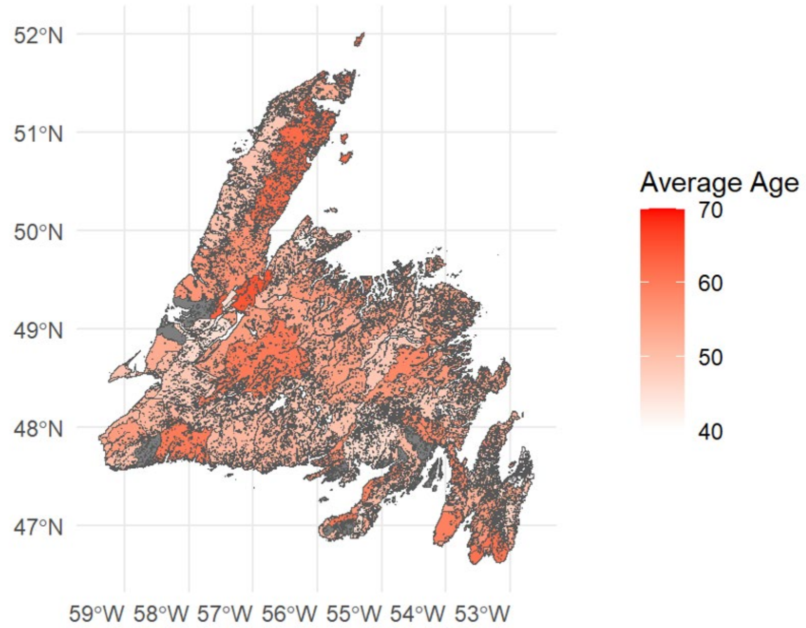


[236] The source data for this map is from the Application Programming Interface to the Alternative Fueling Stations Locator data provided by NRCan (Accessed: Dec. 10, 2024, endpoint URL: https://developer.nrel.gov/api/alt-fuel-stations/v1.json). The map includes all levels of publicly accessible charging stations.

Population Age

Exhibit 201 displays the median population age across the region. Younger populations may be more inclined to adopt new technologies, including EVs, while older populations may have different priorities, such as home heating efficiency, which could influence heat pump adoption.

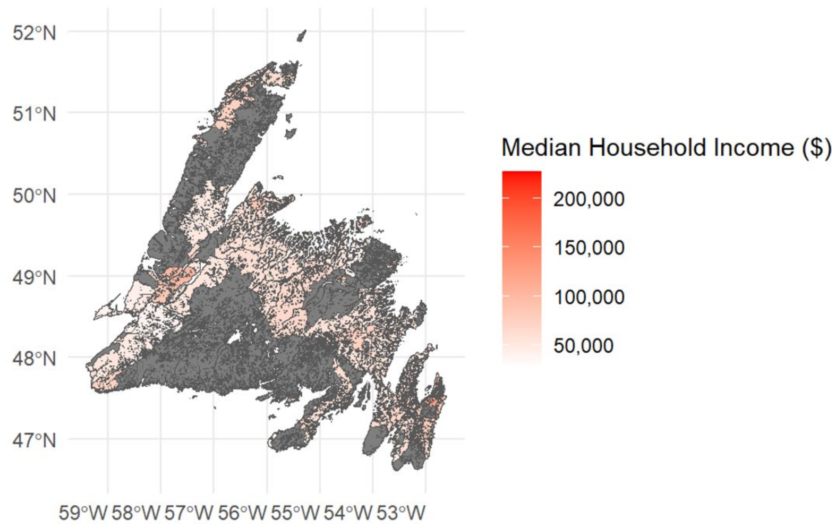
Exhibit 201: Average Age of Population



Median Household Income

Exhibit 202 illustrates the distribution of median household income. Income is a critical factor for both EV and heat pump adoption, as higher income levels correlate with a greater ability to invest in these technologies. This map helps identify regions where economic capacity might drive higher adoption rates.

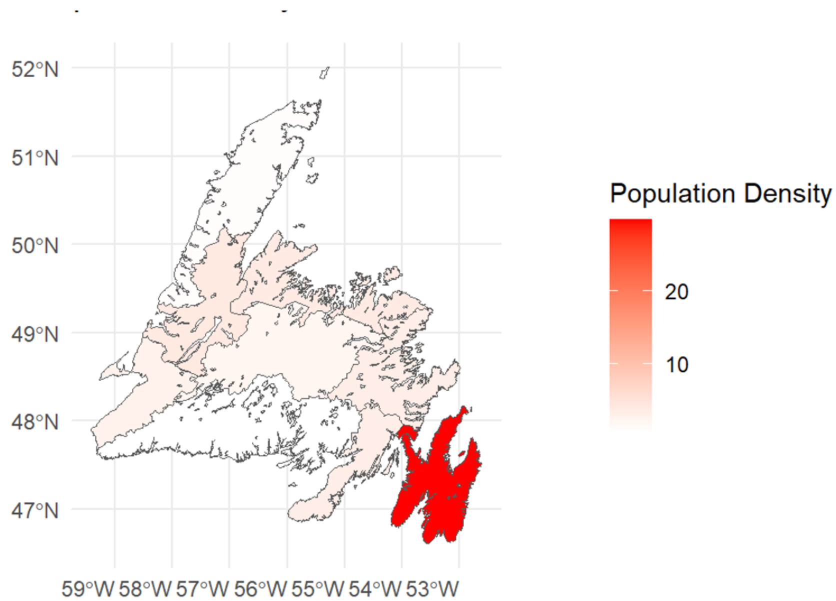
Exhibit 202: Median Household Income



Population Density

Exhibit 203 shows the population density across Newfoundland. Population density impacts the adoption of EVs and heat pumps in different ways. Higher density areas may have better access to infrastructure (e.g., EV charging stations), while lower density areas, often characterized by larger homes and reliance on individual heating systems, typically have higher heating demands. This makes them prime candidates for energy-efficient alternatives like heat pumps, especially in regions with limited access to natural gas infrastructure.

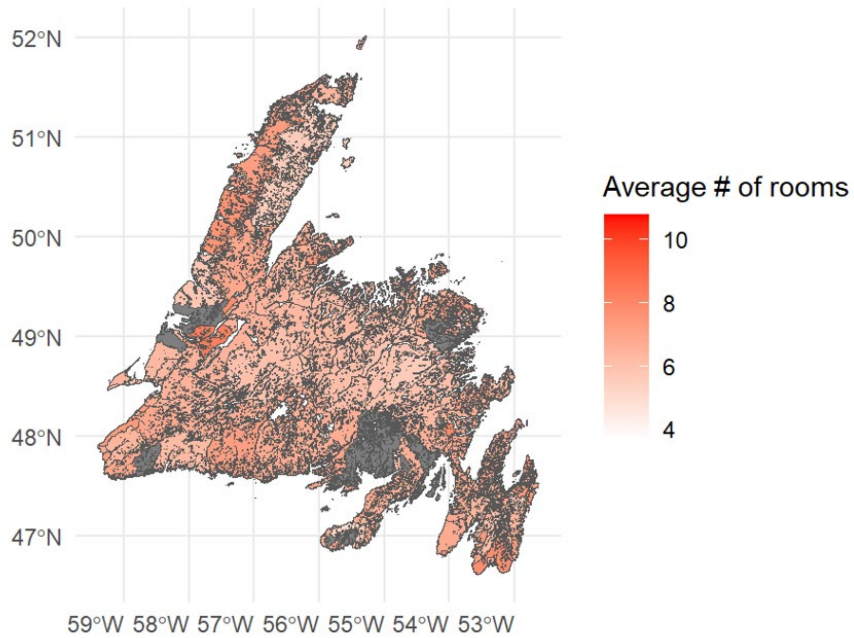
Exhibit 203: Population Density



Average Rooms per Dwelling

Exhibit 204 visualizes the average number of rooms per dwelling, which is particularly relevant for heat pump adoption. Larger homes with more rooms tend to be more likely candidates for heat pump adoption. This driver, however, is less likely to directly influence EV adoption.

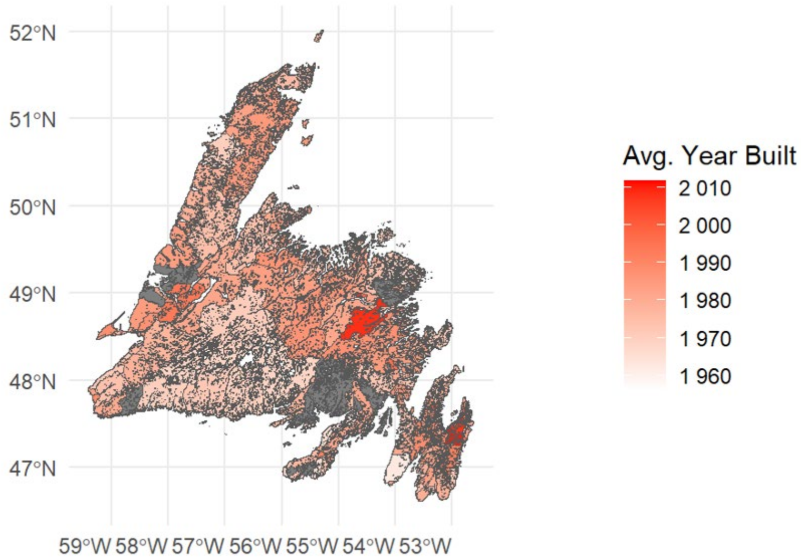
Exhibit 204: Average Rooms per Dwelling



Average Construction Year of Homes

Exhibit 205 displays the average year of construction for houses across Newfoundland. This driver is significant for heat pump adoption, as older homes can have older heating systems and poorer energy efficiency, making them more likely to benefit from heat pump installations. Regions with a higher prevalence of older homes may therefore see higher rates of heat pump adoption.

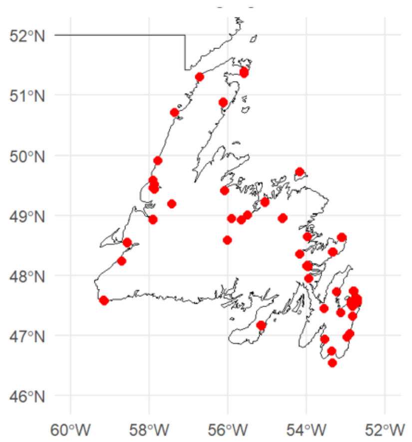
Exhibit 205: Average Construction Year of Homes



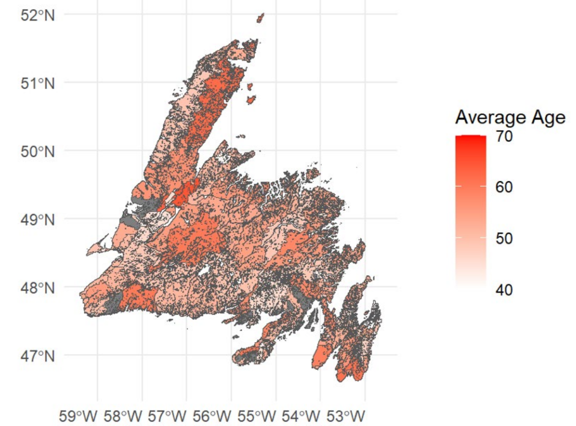
To facilitate comparison, the heat maps from Exhibit 200 to Exhibit 205 are also displayed side by side in Exhibit 206 . This layout allows for a direct comparison of how each driver varies geographically and how these variations might interact to influence adoption rates.

Exhibit 206: Heat Map Comparison

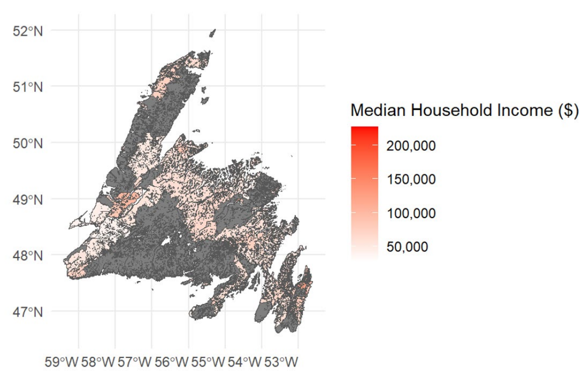
Public Charging Stations



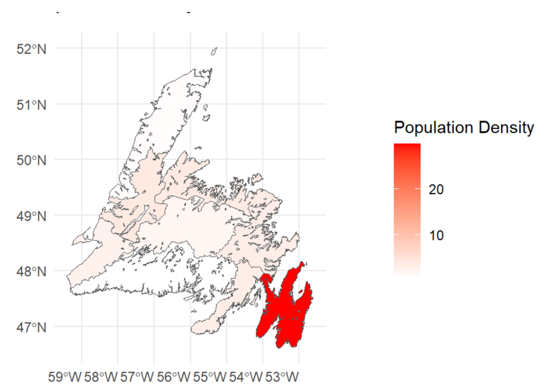
Average Age of Population



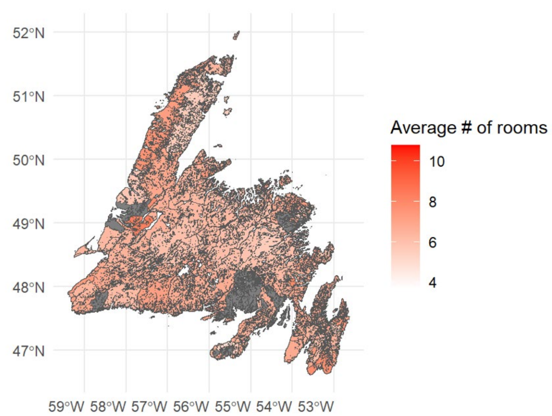
Median Household Income



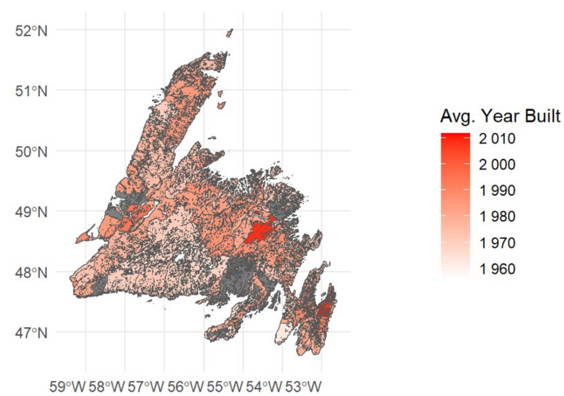
Population Density



Average Rooms per Dwelling



Average Construction Year of Homes



Appendix F Electric Vehicle Managed Charging Sample Calculations

This appendix shows how the Study Team calculated savings for the personal LDBEV (light duty battery electric vehicle) managed charging demand response measure (subsequently referred to as "the measure") in 2040.

Step 1: Calculate Total Annual Energy Use for at Home BEV Charging

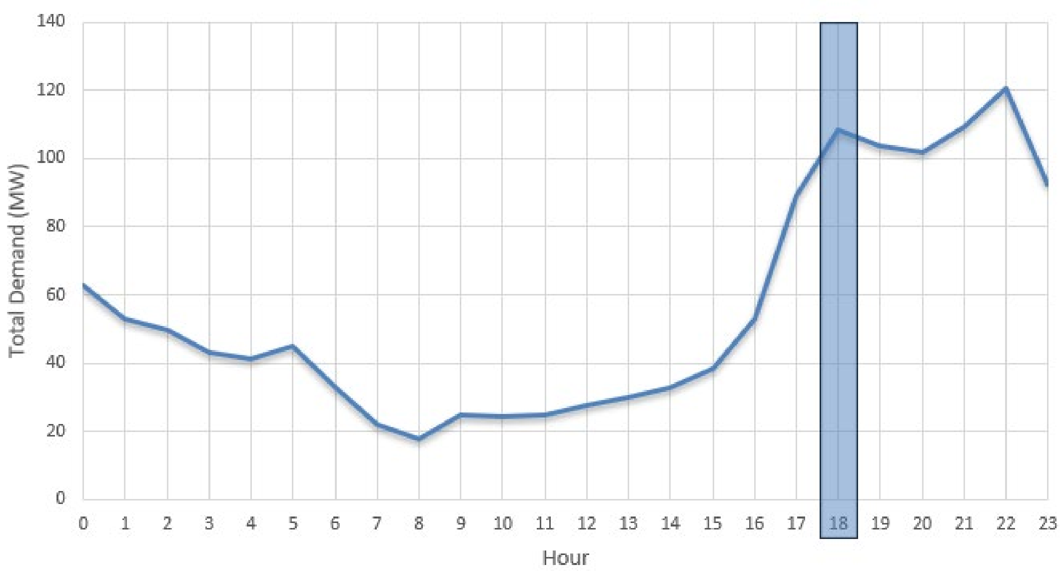
PG calculated the total annual energy use for at home BEV (battery electric vehicle) charging in 2040 using four parameters:

1. Average vehicle kilometres travelled,
2. Vehicle efficiency,
3. The total number of BEVs, and
4. The percentage of charging that occurs at home.

Step 2: Determine 24-Hour Peak Load Shape for at Home Charging

To determine the 24-hour peak load shape for at home charging, the Study Team calculated hourly demand by multiplying total annual energy use by each hour's factor from the 8760-load shape.[237] The Study Team then used the hourly demand to determine the 24-hour load shape for the "peak day", including the "peak hour", as shown in Exhibit 207. The same approach is used to determine the "peak day" and "peak hour" for all other vehicle types and charging locations.

Exhibit 207: Peak Day 24-Hour Load Shape



[237] An 8760-load shape shows the percentage of demand that occurs in each hour of the year.

When including the charging load from other vehicle types and the overall system load shape, the actual peak hour on the system occurs at 6 PM (highlighted by the blue rectangle)**.** Therefore, the contribution of the at home LDBEV charging to the system peak hour at 6 PM is **108.3 MW**.

Step 3: Calculate Measure-Level Savings

The Study Team calculated measure-level savings for LDBEVs by determining the amount of demand that can be shifted off peak. This demand is divided by the number of vehicles participating in the demand response event to calculate the savings per vehicle.

Amount of Demand that Can be Shifted

Based on studies from other jurisdictions and programs, participating vehicles can shift about **50%** of their load over the duration of a peak event as defined in the Potential Study (five hours from 5 pm to 9:59 pm).

Number of Participants

Only vehicles with access to at home charging can participate in the personal LDBEV managed charging demand response event. The International Council on Clean Transportation estimated this value at 78% in 2025.[238] So for example, if the total LDBEV stock is 200, then 156 vehicles (0.78% x 200 vehicles) have at home charging access.

The Study Team estimated participation for the measure in 2040 at **42.6%** *of all personal LDBEVs* by extrapolating from the 2022 Ontario Distributed Energy Resources Potential Study.[239] This value aligns with findings from Opinion Dynamic's PG&E Electric Vehicle Automated Demand Response Study.[240] This equates to 85 participating vehicles of the total personal LDBEV stock is 200 vehicles.

Therefore, the percentage of vehicles charging at home that participate in the measure is 54.6% (i.e., 85 vehicles/156 vehicles with access to home charging).

Using these values, the Study Team calculated the peak savings for each hour between 5 pm and 9:59 pm. The sample calculation equation below focuses on 6 pm, as this is the system peak hour.

$$Savings = \ Peak_{6pm,at\ home}(\%\ peak\ savings_{per\ vehicle} \times \%\ vehicle\ participation)$$

Where:

- The "at home" charging peak at 6 pm is 108.3 MW (from Step 2),
- The % peak savings per vehicle is 50%, and
- The % vehicle participation is 54.6% (42.6%/78%).

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[238] Table 1 on page 16, International Council on Clean Transportation, "Charging up America: Assessing the Growing Need for U.S. Charging Infrastructure Through 2030," Available: https://theicct.org/sites/default/files/publications/charging-up-america-jul2021.pdf (Accessed Jan. 2024).
[239] Dunsky Energy + Climate Advisors, "Ontario's Distributed Energy Resources (DER) Potential Study," Available: https://dunsky.com/wp-content/uploads/DER-potential-study-IESO-Dunsky-Vol1.pdf (Accessed Jan. 2024).
[240] Pages 34 – 37, Opinion Dynamics. (2022). "PG&E Electric Vehicle Automated Demand Response Study Report," Available: https://opiniondynamics.com/wp-content/uploads/2022/03/PGE-EV-ADR-Study-Report-3-16.pdf (Accessed: Jan. 2024).

$$Savings = 108.3\ MW(50\% \times \frac{42.6\%}{78\%})$$

$$Savings = 29.6\ MW$$

To calculate the savings per participant, the Study Team divided the total savings by the number of participating personal LDBEVs. With a forecast total of 105,295 personal LDBEVs in 2040 and 42.6% of them participating in the demand response program, the total number of participants equates to 44,856. The savings per vehicle (0.659 kW/vehicle) are calculated as follows:

$$Savings\ per\ vehicle = \frac{Savings}{Partcipating\ Vehicles} = \frac{28.0\ MW}{44{,}856\ vehicles} = 0.659\ kW\ per\ vehicle$$