MEDIUM AND HEAVY-DUTY VEHICLE (MHDV) GRID-INTEGRATION STUDY

Final Report - August 28, 2024

Transport Canada Transports Canada

Canada

Medium and Heavy-Duty Vehicle (MHDV) Grid Integration Study

Final Report

Date: August 28, 2024

This publication showcases grid-integration costs in Canada.

Aussi disponible en français sous le titre : « Étude sur l'intégration des véhicules moyens et lourds (VML) au réseau»

For more information, contact:

Transport Canada
330 Sparks Street Ottawa ON Canada K1A 0N5
Zero-emission vehicles (canada.ca)

Cat. No. T42-35/2024E-PDF (Electronic PDF, English) ISBN 978-0-660-74870-2 Cat. No. T42-35/2024F-PDF (Electronic PDF, French) 978-0-660-74871-9.

Posterity Group
135 Laurier Ave W, Suite 408
Ottawa, ON K1P 5J2

Contents

TP 15620E
(12/2024)

1. Executive Summary

1.1 Introduction

As a signatory to the Memorandum of Understanding on Zero-Emission Medium- and Heavy-Duty Vehicles (MHDV), Canada has committed to enabling 100% zero-emission new truck and bus sales, where feasible, by 2040. Additionally, the 2030 Emissions Reduction Plan sets an aspiration for 35% of total MHDV sales to be Zero Emission Vehicles (ZEV) by 2030. Multiple technologies meet these ZEV goals, but Medium and Heavy-Duty Electric Vehicles (MHDEV) are anticipated to play a pivotal role in the transport sector transition. To achieve these goals, MHDEV charging infrastructure must be developed and integrated into Canadian electricity distribution systems, necessitating grids ready to handle the substantial loads from electric vehicles.

Posterity Group (PG) was commissioned by Transport Canada (TC), alongside Environment and Climate Change Canada (ECCC) and Natural Resources Canada (NRCan), to conduct the MHDV Grid Integration Study. This study aims to inform Transport Canada's TCSim model and aid program and policy development for MHDV fleet electrification. The study examines the following research question: what are the costs and qualitative considerations for integrating MHDEV into the power grid?

1.2 Research & Analysis Methods

The study utilizes multiple data sources and analysis methods to answer the research question:

- Review of existing literature and data from reputable research organizations such as the National Renewable Energy Laboratory (NREL), Canadian Urban Transit Research & Innovation Consortium (CUTRIC), Rocky Mountain Institute (RMI), and the Pembina Institute.
- Development of charging archetypes that categorize charging behavior patterns into clusters for analytical clarity.
- Collection and analysis of data specific to the Canadian context via a stakeholder engagement process.
- Creation of an editable Microsoft (MS) Excel model that provides a cost assessment tool and enables sensitivity analysis across selected model assumptions.

The study identifies and evaluates costs associated with integrating MHDEVs into the distribution grid, distinguishing between:

- *Distribution Grid Costs:* Costs incurred by utilities to connect MHDEV charging locations to the grid. These costs are less examined than generation and transmission grid costs and are highly case-dependent.
- *Charging Infrastructure Costs:* Costs borne by charging infrastructure providers and/or fleet operators to install charging infrastructure behind the utility meter.

In total, the study identifies 15 charging archetypes. Eleven archetypes are specific to individual vehicle types. Four additional archetypes capture charging scenarios where multiple vehicle types might share an archetype. These archetypes consist of customer site and public on-route chargers, which cater to fleet types that rely on opportunity charging rather than return to base depot charging. **Exhibit 1** shows all 15 MHDV charging archetypes and lists the vehicle type, charging strategy, charging location, and charger type. Delivery vans, medium and heavy duty (MHD) regional delivery and heavy duty (HD) trucks are highlighted in blue to signify that they are the client team's primary archetypes of interest and will be analyzed in more detail.

Exhibit 1: MHDV Charging Archetypes

ID	Vehicle Type	Charging Strategy	Charging Location[1]	Charger Type
1	Transit Bus	Return to Base Depot	Depot	DCFC
2	Transit Bus	Opportunity	On-Route	DCFC
3	School Bus	Return to Base Depot	Depot	Level 2
4	**Delivery Van**	**Return to Base Depot**	**Depot**	**Level 2**
5	**MHD Regional Delivery**	**Return to Base Depot**	**Depot**	**Level 2**
6	Vocational Trucks[2]	Return to Base Depot	Depot	DCFC
7	Drayage Truck	Return to Base Depot	Depot	DCFC
8	Drayage Truck	Opportunity	Depot	DCFC
9	**HD Truck**	**Return to Base Depot**	**Depot**	**DCFC**
10	**HD Truck**	**Opportunity**	**Depot**	**MW+**
11	Yard Tractors	Return to Base Depot	Depot	DCFC
12	All	Opportunity	Customer Site	DCFC
13	All	Opportunity	Customer Site	MW+
14	HDV	Opportunity	On-Route	MW+
15	MDV	Opportunity	On-Route	DCFC

[1] Return to base depot charging always occurs at the depot while opportunity charging can occur at various locations including on-route, at the depot, or at the customer sites.
[2] This archetype will focus on refuse trucks but can be applied for several different vocational vehicles.

1.3 Key Findings

1.3.1 Quantitative Findings

Per-vehicle charging power requirements and average archetype fleet sizes are the key drivers of MHDEV grid integration costs. **Exhibit 2** illustrates this finding by outlining the costliest charging archetypes and their respective cost drivers. The overall costs are dominated by distribution grid costs. This is due to each of these archetypes requiring more than 3 MW of distribution grid capacity, triggering the need for costly substation upgrades. The costliest archetype, transit bus depot charging, requires more than 10 MW capacity, necessitating the construction of a new substation.

Exhibit 2: Insights on the Costliest Charging Archetypes

Archetype	Total Costs (millions of $CAD)	Key Cost Drivers
Transit Bus – Depot – DCFC	$61.6	The very large fleet size of 200 buses is the main cost driver.[3] Comparatively high powered DCFC (around 80 kW) factors into charging infrastructure costs as well.
On Route – MW	$24.2	High powered MW+ charging leads to high charging infrastructure costs. Assumed coincidence factor of 1 (resulting in all chargers being utilized during the charging peak) causes significant load on the distribution grid.
HD Truck (Long Haul) – Depot – MW	$17.0	Highest powered charger (at 2 MW) to accommodate HD long haul trucks using opportunity charging windows. Creates a large load on the distribution grid, even with minimal vehicles charging at once.
Vocational – Depot – DCFC	$3.6m	The cost for this archetype is largely dictated by its large fleet size of 60 vehicles.
HD Truck (Long Haul) – Depot – DCFC	$3.2m	Highest powered charger of the non opportunity charging archetypes at around 130 kW. Assumed that all HD trucks charge simultaneously overnight resulting in large load on the distribution grid.

Overall, distribution grid costs are typically higher for higher powered chargers (MW+ and higher powered DCFC) while charging infrastructure costs are typically higher for lower powered chargers. **Exhibit 3** plots the ratio between the distribution grid and charging infrastructure costs versus the rated power of the chargers, along the x axis.[4]

Negative ratios represent archetypes where the charging infrastructure costs exceed the distribution grid costs and are indicated by blue circles. Positive ratios represent archetypes where the distribution grid costs exceed the charging infrastructure costs and are indicated by green triangles. A ratio of zero

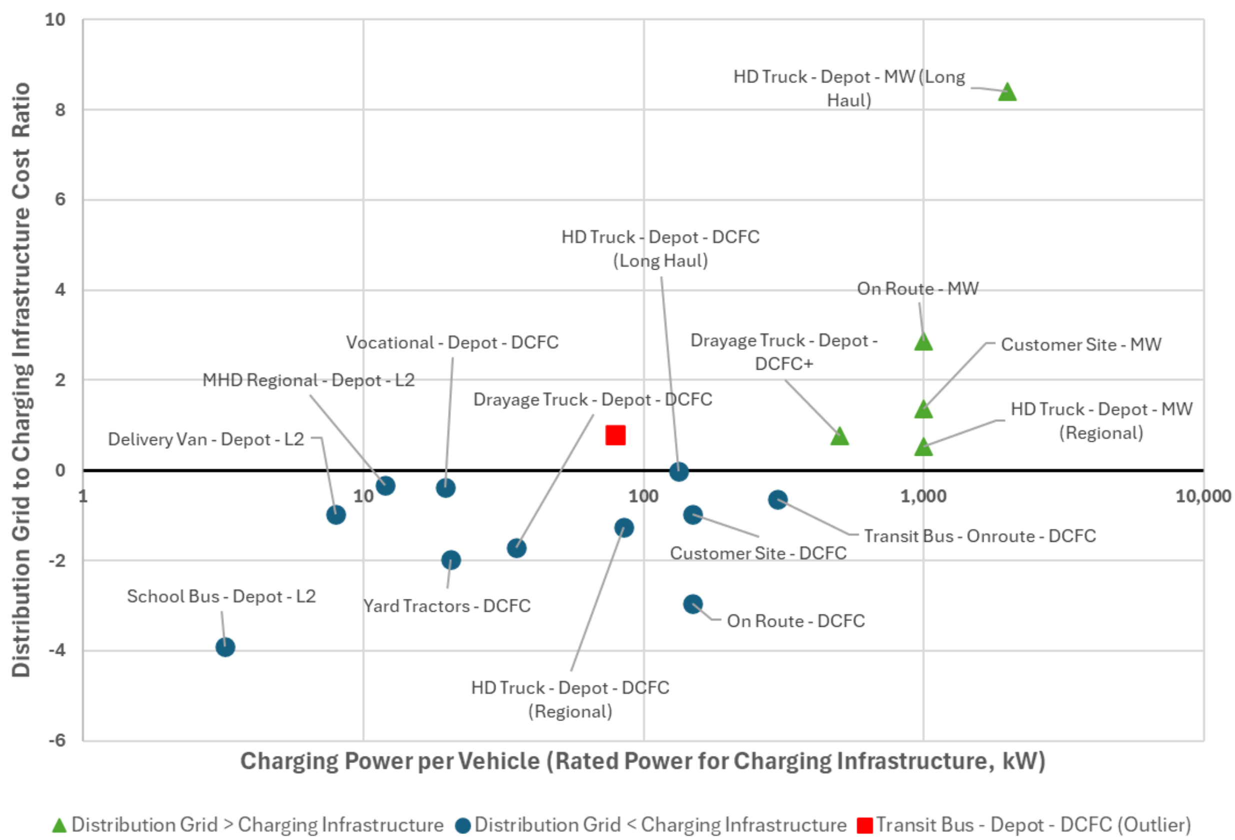
[3] Based on TTC bus depots: from https://www.ttc.ca/transparency-and-accountability/Operating-Statistics/Operating-Statistics---2022/Conventional-System and https://transittoronto.ca/bus/8300.shtml.
[4] A logarithmic scale is used for the x-axis to provide more clarity in the exhibit.

would represent an archetype where the two costs are equal, signifying that archetypes further away from the x-axis have greater cost imbalances.

The general trend shows that lower powered chargers have higher charging infrastructure costs (negative ratios) while higher power chargers have higher distribution grid costs (positive ratios). This is largely due to the archetypes with lower powered charging not requiring as much total capacity and thus not triggering the costlier substation upgrades. The charging infrastructure costs decrease per kW with increasing power, whereas the distribution grid costs increase.

The only outlier in the analysis is the transit bus depot charging archetype, indicated via the red square. It is the only archetype that uses a charger less than 500 kW that has a positive ratio and larger distribution grid costs than charging infrastructure costs. This is due to the large fleet size that leads to the requirement of constructing a new substation. This greatly increases distribution grid costs. However, the lower charging power means that this archetype is still closer to the x-axis (meaning that the costs are more balanced), despite having almost $40 million in distribution grid costs.

Exhibit 3: Distribution Grid vs. Charging Infrastructure Costs



1.3.2 Qualitative Findings

The utility regulatory frameworks for most jurisdictions require utilities to wait until they receive added service or new customer requests for their commercial and industrial rate customers before they can expand the distribution system to meet the requested additional demand. In most jurisdictions, the utility customer who makes the service request also pays for most distribution grid costs associated with the request (typically based on cost-sharing formulas that depend on the jurisdiction and specific case).[5] This not only poses a cost hurdle but also impacts fleet transition timelines. Larger distribution grid updates (especially upgraded or new substations) can have delivery timelines of up to ten years.

Buildings and even building mechanical systems tend to last longer than MHDV lifetimes. This means the regulatory requirements and grid infrastructure delivery timelines pose less of a hurdle for energy transition in the built environment than for MHDV. Fleet operators must typically also coordinate with multiple parties, not just utilities, to advance their fleet transitions (e.g., with municipalities to receive electric and construction permits for depot upgrades). This exacerbates timeline hurdles.

Most jurisdictions carve out exceptions in their regulatory frameworks that enable utilities to proactively invest in their power systems to meet policy objectives (e.g., energy efficiency, demand management, decarbonization). Such carve out instruments could be explored to advance proactive planning for MHDEV grid integration. Massachusetts, New York State, and Michigan have opened special dockets with their public utility commissions to examine this issue.[6] To address stakeholder coordination challenges, some jurisdictions (e.g., California, various states in the European Union) are conducting studies that overlay transport demand models with models of forecast distribution system capacity to identify corridors and hubs that should be prioritized for such proactive system upgrades.[7]

The study raises two key implications for future work:

1. While the study clusters fleet charging behaviors into archetypes, considerable heterogeneity exists within each archetype. The study addresses some of this heterogeneity via the sensitivity features built into the cost assessment tool. However, further stakeholder engagement should be conducted with fleet operators, utilities, and charging infrastructure providers to reduce uncertainty about charging behaviors and the associated distribution grid and charging infrastructure costs.
2. Deploying the distribution grid and charging infrastructure upgrades to meet MHDEV power demand appears to represent a collective action challenge. Each of the key stakeholders (fleet operators, utility regulators, distribution utilities, and municipalities) face uncertainty about where and how quickly MHDEV demand may materialize and how quickly distribution grids will grow to support this demand. Two items may help alleviate this uncertainty. First, developing stakeholder coordination frameworks that map the planning steps that each stakeholder category must take and identify how these steps ideally interconnect to form an efficient process flow. And second, examining how transport demand overlays with distribution grid capacity to identify optimal charging corridors and hubs and indicate areas for proactive distribution grid upgrades.

[5] Cost sharing formulas and specifications are complex (the utility guidance documents average between 50 and 100 pages), but typically determine the degree of investment the utility is authorized to bear on behalf of the customer (e.g., 1,277 kW/$), which leaves a remaining amount for the customer to bear.

[6] ACEEE Report

[7] Please see the following study for one such example: Impact of electric vehicle charging demand on power distribution grid congestion | PNAS.

2. Introduction

As a signatory to the Memorandum of Understanding on Zero-Emission Medium- and Heavy-Duty Vehicles (MHDV), Canada has committed to working to enable 100% zero-emission new truck and bus sales, where feasible, by 2040.[8] Canada has further stated its aspirational aim to achieve 35% of total MHDV sales being Zero Emission Vehicles (ZEV) by 2030 under the 2030 Emissions Reduction Plan.[9] While multiple propulsion technologies meet these ZEV goals, Medium and Heavy-Duty Electric Vehicles (MHDEV) are expected to play a key role in the transport sector transition. If these goals are to be achieved, MHDEV charging infrastructure will need to be developed and integrated into Canadian electricity distribution systems at a rapid pace. This means that electricity distribution grids also need to be ready to handle the loads associated with electric vehicles.

Posterity Group (PG) was commissioned by Transport Canada (TC) to conduct the MHDV Grid Integration Study. Environment and Climate Change Canada (ECCC) and Natural Resources Canada (NRCan) are additional members of the client team. The study aims to provide input data for Transport Canada's TCSim model and to help inform program and policy development for MHDV fleet electrification. The study examines the following research question: what are the costs and qualitative considerations for integrating MHDEV into the power grid? These include costs borne by the utility to connect MHDEV charging locations to the distribution grid (i.e., *distribution grid costs*) and costs borne by charging infrastructure providers and/or fleet operators to install charging infrastructure behind the utility meter (i.e., *charging infrastructure costs*). The study focuses on distribution grid costs because these are less examined than generation and transmission grid costs and are more case-dependent. While well-examined, the costs that utilities bear for expanding generation and transmission assets to meet incremental peak demand (such as the peak demand created by adding electric vehicle charging to the grid) are sizable investments. Utilities typically reflect these investments in their rate structures and associated rate increases across their customer base. Utilities typically plan their electrical grid to forecast peak demand under system design conditions. Forecast peak demand is constructed by considering seasonal weather patterns (when heating and cooling demand might peak in relation to weather, with a magnitude that is typically extrapolated to extreme weather conditions) and non-weather energy use behavior (when energy users turn on specific energy end uses, such as lighting and commercial or industrial process loads). For each of their asset scales (e.g., transmission vs. distribution assets), utilities determine when these patterns overlap to form a peak at the scale of the asset (e.g., for a specific distribution system). When new demand materializes that overlaps with this peak (e.g., from EV charging), utilities plan to expand their assets to meet the new peak demand.

PG provides the study results in an editable Microsoft (MS) Excel model, the cost assessment tool, that enables sensitivity analysis across select model assumptions. This report accompanies the cost assessment tool.

This study focuses on medium and heavy-duty battery electric vehicles and excludes emerging technologies that are not prevalent in North America, such as overhead catenary power lines and battery swapping. Our definition of MHDEV only includes battery electric vehicles that are powered exclusively with grid electricity and does not include plug-in hybrid electric vehicles. However, we acknowledge the uncertainty inherent in predictions of future technology adoption, and future studies may address the costs and practical considerations for integrating these other ZEV variations into the

[8] https://globaldrivetozero.org/mou-nations/

[9] https://www.canada.ca/en/environment-climate-change/news/2022/03/2030-emissions-reduction-plan--canadas-next-steps-for-clean-air-and-a-strong-economy.html

Canadian vehicle fleet (such as fuel cell electric vehicles). To reduce the complexity prevalent across real-world charging patterns into analytical concepts that can provide insights across individual situations, the client team requested PG to develop charging archetypes that group charging behavior into clusters.

The remainder of this report is organized into the following sections:

- Section 3 describes the analytical steps and data sources that PG used to answer the research objectives.
- Section 0 details the results from the research and analysis activities and outlines potential implications for future work.

3. Research & Analysis Methods

This section describes the four-step approach used to answer the research questions and build out the cost assessment tool, as highlighted in **Exhibit 4**. Each step draws from some mixture of the following resources:

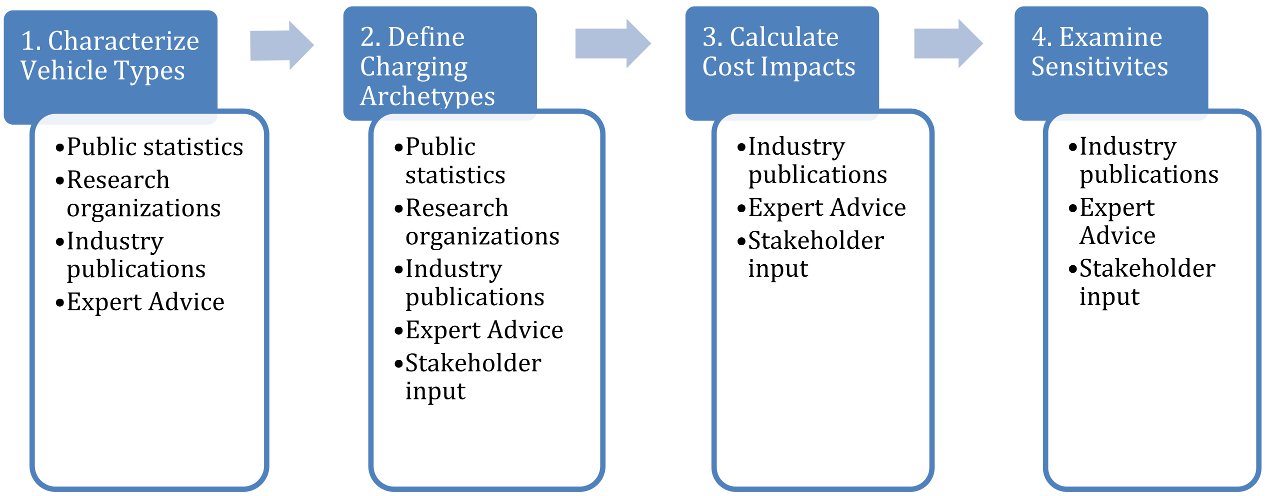
- Research Organizations: includes the National Renewable Energy Laboratory (NREL), Canadian Urban Transit Research & Innovation Consortium (CUTRIC), Rocky Mountain institute (RMI) and the Pembina Institute.
- Industry Publications: includes key reports from the North American Council for Freight Efficiency (NACFE), the International Council on Clean Transportation (ICCT), the U.S. Department of Energy, CALSTART, California utilities (SDG&E and PG&E) and others.
- Expert advice: consultation with Jonn Axsen, professor at Simon Fraser University and director at the Sustainable Transportation Action Research Team
- Stakeholder input: interviews with various organizations and stakeholders that are closely connected to the matter (more on this below).

We began by characterizing vehicle types (Section 0), relying on expert advice and public statistics from research organizations and industry publications. The information gathered from this step was crucial in defining the charging archetypes that serve as the foundation of the study (Section 0). From there, we calculated the cost impacts for each of the archetypes (Section 0) and examined sensitivities that apply to them (Section 0).

In addition to the resources used in the first step, the final three steps also incorporate insights from stakeholder engagement. This stakeholder engagement encompasses more than a dozen structured interviews (each lasting about 45 minutes with questions based on an interview guide but providing some leeway for the interviewer to follow the interviewee's course of conversation) with the following types of entities and the heaviest focus on utilities, due to the limited public data available on grid-side costs:

- Utilities (about 27% of interviewees): including crown corporations and investor-owned utilities across multiple provinces, spanning both pure distribution utilities as well as entities that are vertically integrated across generation, transmission, and distribution.
- Charging providers (about 7% of interviewees): our interviewees focused on selling and installing hardware as well as supporting fleet transition planning.
- Fleet operators (about 20% of interviewees): primarily from the freight segment.
- Municipalities/special purpose districts (about 13% of interviewees): these are both in the role of providing charging infrastructure and operating their own fleets.
- Industry organizations (about 20% of interviewees): these aggregate numerous stakeholders that include research organizations and fleet operators.
- Transit operators (about 7% of interviewees): Canadian agencies with large bus fleets.

Exhibit 4: Research and Analysis Approach



3.1 Analyzing Vehicle Types

PG started at the more granular end of the transportation sector to develop MHDV grid integration archetypes by identifying and outlining the various MHDV vehicle classes and types. This involves identifying the vehicle and duty cycle characteristics, including vehicle class and weight, typical routes, and driving distances. **Exhibit 5** outlines the key findings from this activity and provides additional information on the battery characteristics for the electric version of each vehicle.

Exhibit 5: Vehicle Types and Duty Cycle Characteristics[10]

Vehicle	Transit Bus	School Bus	Delivery Van	MHD Regional Delivery	Refuse Truck	Drayage Truck	HD Regional Truck	HD Long-Haul Truck	HD - Terminal/Yard Tractors
Description	Plubic transport vehicle for urban and suburban passenger travel	Transports students on fixed routes between home and schools	Cargo vehicle for last mile deliveries, including local parcel and goods distribution, in predominantly urban and suburban regions	Medium-heavy duty trucks for regional freight delivery, including retail goods	Specialized for waste collection with frequent stopping in urban settings	Heavy-duty vehicle to tranpsort goods between ports and warehouses	Heavy-duty trucks for cargo transport within one region	Heavy duty cargo vehicle to move goods long distances	Heavy duty trucks commonly used at warehouses,distribution centers, ports, rail yards, and other commercial and industrial locations.
Operation	Passenger	Passenger	Cargo	Cargo	Cargo	Cargo	Cargo	Cargo	Cargo
Class	Class 4-8	Types A, B, C, D	Class 2b-5	Class 4-7	Class 7-8	Class 7-8	Class 7-8	Class 7-8	Class 7-8
GVWR (kg)	7,255-28,000	4,500-14,400	3,855-8,845	4,536-14,969	11,793-44,000	11,793-44,000	11,793-44,000	11,793-44,000	11,793-44,000
Duty cycle characteristics	Predictable, fixed routes	Predictable routes	Variable routes	Variable routes	Predictable routes	Predictable routes, multiple shifts and reduced dwell time	Unpredictable routes	Long variable routes	Average shifts of 8 hours, typically 2 per day. All within yard.
Average daily distance (range of kms)	150-300	16-128	50-250	50-250	50-120	120-383	250-500	250-1000	35-220
Average daily distance (km)	200	58	100	100	69	211	409	1086	54
Efficiency (kWh/km)	1.2	0.6	0.5	0.7	2.1	1.6	1.6	1.6	1.6
Battery size (kWh)	250-660	100-150	75-170	120-280	336	250-1000	250-1000	250-1000	220-250
Vehicle range (km)	165-250	130-160	170-400	200-320	275	240-800	240-800	240-800	22 hours (typically measured in hours of use)

10 Data was extracted from the following sources:

- CALSTART (2020), "The Beachhead Model – Catalyzing Mass-Market Opportunities for Zero-Emission Commercial Vehicles". The_Beachhead_Model.pdf (globaldrivetozero.org)
- Shell (2021), "Decarbonising Road Freight: Getting into Gear". Decarbonising road freight | Shell Global
- U.S. Department of Energy (2019), "Medium- and Heavy-Duty Vehicle Electrification, An Assessment of Technology and Knowledge Gaps". Pub136575.pdf (ornl.gov)
- SDGE, "Electric Vehicle Charging Guidebook for Medium- And Heavy-Duty Fleets". SDGE - EV Guidebook - Final - Web.pdf
- CALSTART, ZETI (Zero-Emission Technology Inventory). Global Commercial Drive To Zero Program — ZETI (Zero-Emission Technology Inventory) (globaldrivetozero.org)
- U.S. Department of Transportation. (2023). Electric Bus Basics. https://www.transportation.gov/urban-e-mobility-toolkit/e-mobility-basics/bus.
- Lion Electric. (2023). Lion8 All Applications. https://thelionelectric.com/documents/en/Lion8_all_applications.pdf.
- California Energy Commission. (2019). 2019 Building Energy Efficiency Standards for Residential and Nonresidential Buildings (CEC-600-2019-064). https://www.energy.ca.gov/sites/default/files/2021-05/CEC-600-2019-064.pdf.
- NREL & PANYNJ. (2019). Yard Tractor Electrification Study. https://aapa.files.cms-plus.com/PDFs/Nov%202019%20NREL_PANYNJ_Yard%20Tractor%20Electrification%20Study_AAPA_110519.pdf.
- NREL (2022), "Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis" Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis (nrel.gov)
- CUTRIC. (2024). Zero-Emission Bus (ZEB) New Database Report. https://cutric-critic.org/wp-content/uploads/2024/05/CUTRIC_ZEB-New-Database-report-2024-FINAL.pdf.
- North American Council for Freight Efficiency (NACFE). (2022). Terminal Tractors RoL-E Fact Sheet. https://nacfe.org/wp-content/uploads/2022/01/Terminal-Tractors-RoL-E-Fact-Sheet.pdf.
- National Renewable Energy Laboratory. (2024). The 2023 Annual Technology Baseline: Methodology and Results. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy24osti/87322.pdf
- Public-Private Infrastructure Advisory Facility. Urban Bus Toolkit. https://www.ppiaf.org/sites/ppiaf.org/files/documents/toolkits/UrbanBusToolkit/assets/1/1c/1c11.html

3.2 Defining Charging Archetypes

At their most granular level, vehicle types are based on having similar characteristics, duty cycles or operations. These groupings form the basis of the charging archetypes, with additional archetypes emerging from specific vehicle types that may undertake multiple duty cycles.

The two main factors in defining the archetypes are charging power level requirements and charging strategies:

Charging Power Requirements:

- Level 2: 3 – 19.2 kW
- Direct Current Fast Charging (DCFC): > 19.2 kW
- Megawatt Plus (MW+):[11] > 1000 kW

Charging Strategies:

- Return to Base Depot Charging: vehicles return to their base (depot) and can be charged overnight. Due to longer recharging times, lower capacity chargers can be used.
- Opportunity Charging: vehicles do not regularly return to base or do not have a duty cycle that can accommodate overnight charging. These vehicles charge for shorter periods of time using higher capacity chargers (up to MW+) when they have the opportunity to do so. This charging strategy is also referred to as on-route charging.

This results in eleven archetypes that are specific to individual vehicle types. We created four additional archetypes to capture charging scenarios where multiple vehicle types might share an archetype. These archetypes consist of customer site and public on-route chargers, which cater to fleet types that rely on opportunity charging rather than return to base depot charging. **Exhibit 6** shows all 15 MHDV charging archetypes and lists the vehicle type, charging strategy, charging location, and charger type. Delivery vans, MHD regional delivery and HD trucks are highlighted in blue to signify that they are the client team's primary archetypes of interest and are analyzed in more detail.

Exhibit 6: MHDV Charging Archetypes

ID	Vehicle Type	Charging Strategy	Charging Location[12]	Charger Type
1	Transit Bus	Return to Base Depot	Depot	DCFC
2	Transit Bus	Opportunity	On-Route	DCFC
3	School Bus	Return to Base Depot	Depot	Level 2
4	**Delivery Van**	**Return to Base Depot**	**Depot**	**Level 2**

[11] Megawatt plus charging is a form of DCFC but provides power upwards of 1 MW.
[12] Return to base depot charging always occurs at the depot while opportunity charging can occur at various locations including on-route, at the depot, or at the customer sites.

ID	Vehicle Type	Charging Strategy	Charging Location[12]	Charger Type
5	**MHD Regional Delivery**	**Return to Base Depot**	**Depot**	**Level 2**
6	Vocational Trucks[13]	Return to Base Depot	Depot	DCFC
7	Drayage Truck	Return to Base Depot	Depot	DCFC
8	Drayage Truck	Opportunity	Depot	DCFC
9	**HD Truck**	**Return to Base Depot**	**Depot**	**DCFC**
10	**HD Truck**	**Opportunity**	**Depot**	**MW+**
11	Yard Tractors	Return to Base Depot	Depot	DCFC
12	All	Opportunity	Customer Site	DCFC
13	All	Opportunity	Customer Site	MW+
14	HDV	Opportunity	On-Route	MW+
15	MDV	Opportunity	On-Route	DCFC

3.3 Calculating Grid Impact Costs

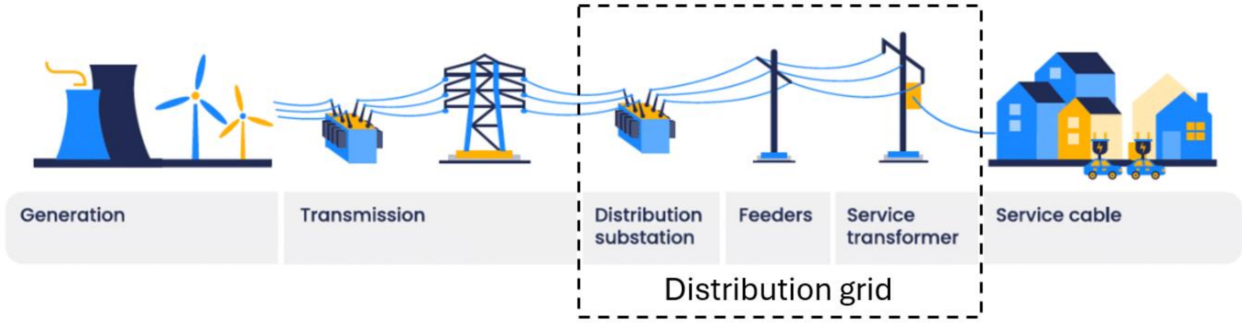
The main objective of this study is to examine the grid integration costs associated with MHDEV charging and how they differ between charging archetypes. Grid integration costs can be split into two different components, *distribution grid costs* and *charging infrastructure costs*, and are dictated by both the individual charger power and the overall power capacity required by a given archetype. This section explains the two cost components and how they are shaped by characteristics of the charging archetypes.

3.3.1 Distribution Grid Costs

Distribution grid costs refer to the costs that are incurred when upgrades to the distribution grid are required. The distribution grid refers to the final stage of the electrical grid that delivers power to individual customers and end users. This part of the grid is comprised of three main components, distribution substations, feeders and service transformers. **Exhibit 7** illustrates the components of the distribution grid in the context of the overall electricity grid.

[13] This archetype will focus on refuse trucks but can be applied for several different vocational vehicles.

Exhibit 7: Distribution Grid as a part of the Electric Grid[14]



As fleets begin to electrify, they will cause a certain level of power demand as they charge. If that demand exceeds the capacity that is available on the distribution grid, upgrades to the system are needed. There are two main distribution grid upgrades that vary in cost based on the capacity required and the type of upgrade needed:

Circuit Upgrades

Circuit upgrades are the first type of distribution grid upgrades. They consist of upgrades to the distribution feeders and transformers that carry power from substations to customers. Circuit upgrades are generally required to meet all types of increased demand, so they will always be necessary if the grid capacity needs to be expanded. For lower-level upgrades (less than 1 MW), upgrades to the feeder may not be required, so in many cases, just the distribution transformers need to be upgraded. As the capacity needs increase, feeder upgrades are more likely to be required. Because of this, the cost assumptions in this study reflect a higher likelihood of upgrades under 1 MW only requiring distribution transformer upgrades.

Exhibit 8 displays the costs for circuit upgrades in $CAD/kW for varying capacity requirements. The exhibit also includes any fixed costs that may be associated with the upgrades, which are represented by the y-intercept in the cost function. The costs follow economies of scale, with decreasing $CAD/kW as larger upgrades are implemented. Cost values are informed by stakeholder consultation, expert advice, and publications from industry and research organizations.[15]

[14] Image from: https://www.energyhub.com/blog/avoiding-gridlock-the-distribution-impacts-of-ev-charging/

[15] Publications include:

- *Gao, Y., et al. (2022). Can distribution grid infrastructure accommodate residential electrification and electric vehicle adoption in Northern California?* https://iopscience.iop.org/article/10.1088/2634-4505/ac949c
- National Renewable Energy Laboratory. (2021). *Perspectives on Charging Medium- and Heavy-Duty Electric Vehicles*. https://www.nrel.gov/docs/fy22osti/81656.pdf
- Rocky Mountain Institute. (2019). *Reducing Ev Charging Infrastructure Costs*. https://rmi.org/wp-content/uploads/2020/01/RMI-EV-Charging-Infrastructure-Costs.pdf

Exhibit 8: Distribution Grid Circuit Costs

Capacity Need (MW)	Capital Costs	
	Cost per kW ($CAD)	Fixed Costs ($CAD)[16]
0 ≤ MW < 1	$601.71	-
MW ≥ 1	$427.40	$1,041,488.88

Substation Upgrades

Upgrades to distribution substations are the second type of distribution grid upgrades. Distribution substations transform voltages from high to low levels, typically when power is delivered between the transmission and distribution grids. Unlike the circuit upgrades, substation upgrades are not always required and often only become necessary for higher incremental capacity needs. Based on information from research organizations and stakeholder input, we assume that substation upgrades are only required once capacity needs exceed 3 MW. These upgrades generally involve upgrading or replacing transformers that step down the voltages and circuit breakers within the distribution substation. For large projects that require an expansion of the grid by more than 10 MW, the construction of an entirely new substation is assumed to be required, further increasing costs. The costs for substation upgrades scale with increasing capacity requirements (up to 10 MW) while the cost for a new substation is assumed to be a fixed value, that seeks to cover a wide range of substation sizes and builds.

Exhibit 9 below provides substation costs, split between per-capacity costs in $CAD/kW and fixed costs. We developed these values from the same sources that we used for the circuit costs.

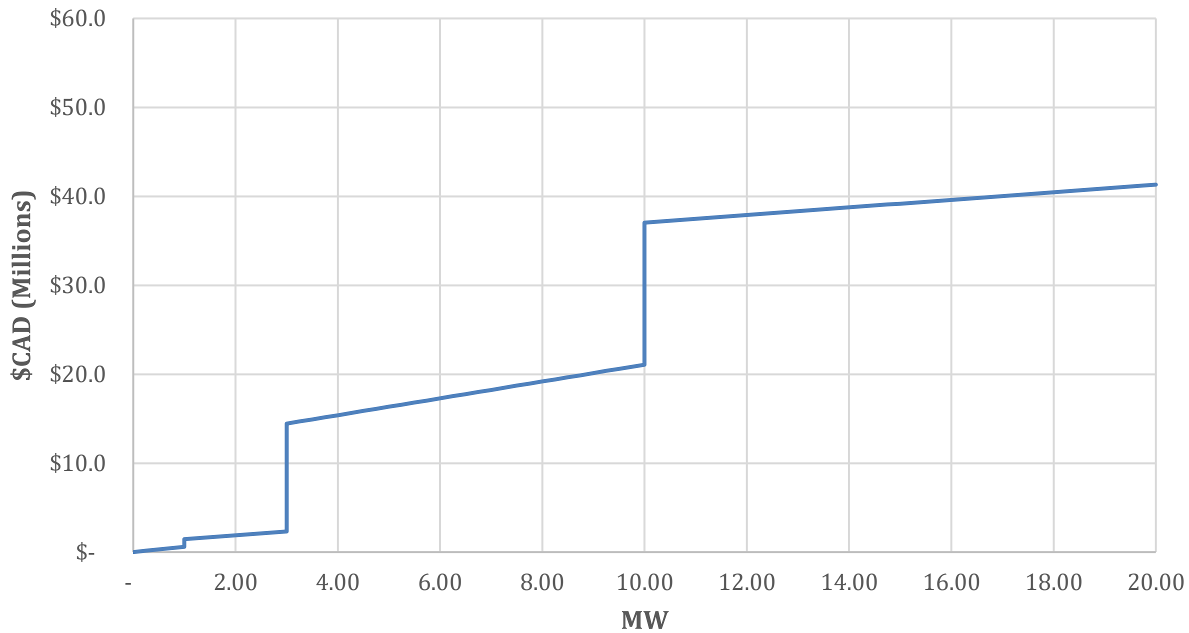
Exhibit 9: Distribution Grid Substation Costs

Capacity Need (MW)	Capital Costs	
	Cost per kW ($CAD)	Fixed Costs ($CAD)
0 ≤ MW < 3	-	-
3 ≤ MW < 10	$518.99	$10,568,887.68
MW ≥ 10	-	$31,725,000.00

Combining the costs from the two upgrade types creates a stepwise cost function that can be used to estimate overall distribution grid costs for a given capacity need. **Exhibit 10** displays this cost function and clearly highlights the large cost increments that are incurred when requiring substation upgrades or the construction of new substations (at 3 MW and 10 MW, respectively). Additional details on how we constructed the cost function can be found in 0. In reality, distribution grid upgrade costs are very case-dependent and are only fully estimated during detailed project design.

[16] Fixed costs in this case are due to the assumption that greater capacity needs necessitate feeder upgrades.

Exhibit 10: Distribution Grid Cost Function



3.3.2 Charging Infrastructure Costs

Charging infrastructure costs refer to the cost of installing the chargers that are required for fleet MHDEVs to operate. The costs vary greatly depending on the charging power needed and they consider both hardware and installation costs.[17] PG split the charging infrastructure cost analysis into the two main charging technologies:

Level 2 Charging

Level 2 charging refers to charging using alternating current (AC), typically at power levels between 3 and 19.2 kW. Level 2 charging is commonly used in applications where longer charging time is available and vehicle battery sizes are not too large. Level 2 chargers can replenish such batteries fast enough to meet the vehicles' necessary duty cycles. The costs assumed for Level 2 charging are averaged across the range of charging power and can be viewed in **Exhibit 11**.

Exhibit 11: Level 2 Charging Costs[18]

Charger Type	Power (kW)	Hardware Cost ($CAD)	Installation Cost ($CAD)	Average Cost ($CAD)
Level 2	3 - 19.2	$1,350 - $6,750	$2,700 - $8,100	$9,450

[17] Hardware costs refer to the cost of the charger itself while installation costs refer to any costs needed at the depot to accommodate the installation of the charger.

[18] Level 2 charging costs determined from stakeholder consultation and the following sources:

- Rocky Mountain Institute. (2019). *Reducing EV Charging Infrastructure Costs*. https://rmi.org/wp-content/uploads/2020/01/RMI-EV-Charging-Infrastructure-Costs.pdf

Direct Current Fast Charging (DCFC)

DCFC refers to fast charging using direct current (DC). DCFC has charging power that is greater than 19.2 kW but is typically rated between 50 and 350 kW. While still DCFC, chargers with greater than 1 MW of power are an emerging technology and referred to as MW+ chargers in this study. DCFC is typically more suitable for vehicles with larger batteries that would not be able to fully charge overnight with Level 2 charging or for applications where per-instance charging time is limited.

Exhibit 12 displays the hardware and installation cost ranges, the averaged costs and the average cost per kW for various levels of DCFC and MW+ chargers. DCFC comes in multiple different power ratings and not just the levels listed. Chargers can often be customized to specific charging needs. To estimate the costs for DCFC power levels between those listed, we analyzed the relationship between costs and kW of power. The cost per kW decreases with increasing charging power so we fit a logarithmic equation to the data to allow for the calculation of costs for any DCFC charging level. **Exhibit 13** displays the resulting cost curve.

Exhibit 12: DCFC (and MW+) Charging Costs[19]

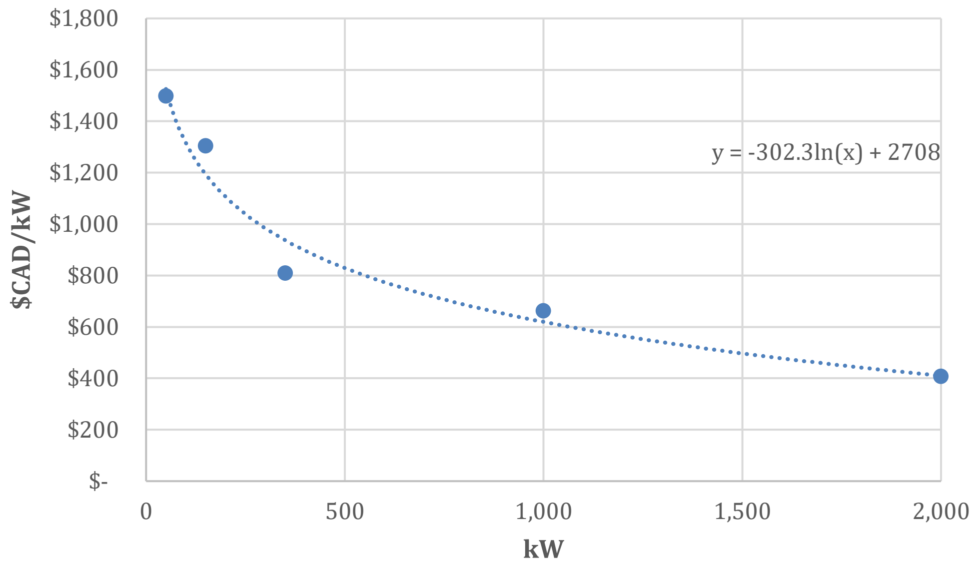
Charger Type	Power (kW)	Hardware Cost ($CAD)	Installation Cost ($CAD)	Average Cost ($CAD)	$CAD/kW
DCFC	50	$27,000 - $47,250	$13,500 - $62,100	$74,925	$1,499
DCFC	150	$94,500 - $135,000	$27,000 - $135,000	$195,750	$1,305
DCFC	350	$162,000 - $216,000	$33,750 - $155,250	$283,500	$810
MW+	1,000	$453,600	$202,500-$216,000	$662,850	$663
MW+	2,000	$607,500	$202,500-$216,000	$816,750	$408

- Atlas Public Policy. (2021). *U.S. Electrification Infrastructure Assessment: Medium- and Heavy-Duty Truck Charging*. https://atlaspolicy.com/wp-content/uploads/2021/11/2021-11-12_Atlas_US_Electrification_Infrastructure_Assessment_MD-HD-trucks.pdf
- National Renewable Energy Laboratory. (2023). *The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure*. https://www.nrel.gov/docs/fy23osti/85654.pdf

[19] DCFC (and MW+) charging costs determined from stakeholder consultation and the following sources:

- National Renewable Energy Laboratory**.** (2021). *Perspectives on Charging Medium- and Heavy-Duty Electric Vehicles*. https://www.nrel.gov/docs/fy22osti/81656.pdf
- Rocky Mountain Institute. (2019). *Reducing Ev Charging Infrastructure Costs*. https://rmi.org/wp-content/uploads/2020/01/RMI-EV-Charging-Infrastructure-Costs.pdf
- *International Council on Clean Transportation. (2021). Infrastructure to support a 100% zero-emission tractor-trailer fleet in the United States by 2040.* https://theicct.org/wp-content/uploads/2021/12/ze-tractor-trailer-fleet-us-hdvs-sept21.pdf
- Atlas Public Policy. (2021). *U.S. Electrification Infrastructure Assessment: Medium- and Heavy-Duty Truck Charging*. https://atlaspolicy.com/wp-content/uploads/2021/11/2021-11-12_Atlas_US_Electrification_Infrastructure_Assessment_MD-HD-trucks.pdf
- National Renewable Energy Laboratory. (2023). *The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure*. https://www.nrel.gov/docs/fy23osti/85654.pdf

Exhibit 13: Cost per Charging Level Function for DCFC[20]



3.3.3 Calculating Archetype Costs

Using the methods described for calculating distribution grid and charging infrastructure costs, we calculate the costs for each archetype. We use characteristics such as daily distance driven, vehicle efficiency and typical downtime to estimate the charging power required to sufficiently charge the vehicle in each archetype. This determines the required type of charger (Level 2 or DCFC) and charging power. Typical fleet sizes and the charger to vehicle ratios determine the total amount of capacity that is required for a given archetype. These values are then used to calculate the total grid integration costs via the following steps:

1. The cost function shown in **Exhibit 10** is used to calculate *distribution grid costs* based on the total amount of capacity that is required.

The type of charger required, and the number of chargers, determine the *grid integration costs*. If a Level 2 charger is needed, costs are taken from the average cost column in **Exhibit 11**. If a DCFC is needed, the logarithmic cost function from **Exhibit 13** is used to calculate the cost of the charger based on the power required. These costs are then multiplied by the total number of chargers that are needed for the archetype (determined from the fleet sizes and typical charger to vehicle ratios).

3.4 Investigating Sensitivities

As previously noted, the patterns of fleet electrification and the distribution grid's available capacity vary greatly on a case-by-case basis. To address this, PG allows for various sensitivities to be explored in the cost assessment tool. This section explores these sensitivities and their effects on final costs for each archetype.

[20] Charger costs are calculated by multiplying charging power by the $CAD/kW determined using the logarithmic function.

3.4.1 Input Sensitivities

The input sensitivities explore the differences that may occur within the same archetype based on changes to several vehicle or charging logistics characteristics. There are many cases where fleets may operate slightly differently within the same charging archetype which changes the type of charging and grid solutions that are required. These sensitivities are listed below:

1. Vehicle characteristics:
    a. *Vehicle downtime:* Similar vehicles may have different downtimes (the timing and duration when the vehicle is not in operation each day). This impacts the power of the charger required to fully charge the vehicle in the allotted charging time.
    b. *Daily distance driven:* Similar vehicles may drive different daily distances. This affects how much of the vehicle's battery needs to be recharged and can necessitate a higher or lower powered charger.

Fleet operation:

c. *Average fleet size:* Fleet sizes change from operator to operator. The number of vehicles within the fleet dictates the overall demand and number of chargers required.

d. *Charger to vehicle ratio:* Charger to vehicle ratios also differ between fleets. The ratio dictates the overall number of vehicles that can charge at once (and thus the overall demand) and the number of chargers required.

Charger usage:

e. *Coincidence factor:* Coincidence factors refer to the number of vehicles that are charging simultaneously and are a sensitivity for the opportunity charging archetypes. This dictates the number of vehicles that charge at once (and thus the overall demand).

3.4.2 Output Sensitivities

The sensitivities applied to the outputs largely explore how costs change based on different peak mitigation strategies and how costs change by regions. The five output sensitivities are explored below:[21]

1. *Peak curtailment due to managed charging:*

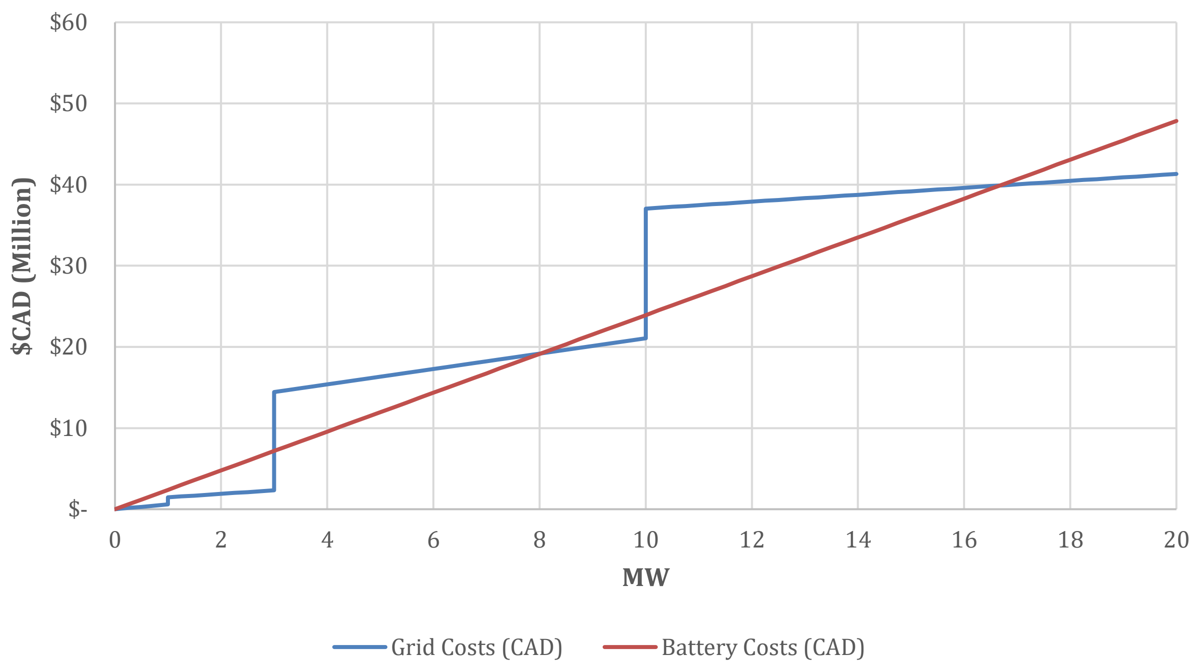
Managed charging programs can be an effective way to reduce a fleet's EV load that coincides with the system peak and shift charging to another part of the day during which there is more capacity available on the distribution system. Managed charging often has an additional cost (for the software or charging technology) but can provide significant EV load savings during peak time, reducing the grid upgrades that are required. This sensitivity enables reducing the peak demand of the archetype which in turn reduces distribution grid costs while slightly increasing charging infrastructure costs.[22]

[21] Only the final three sensitivities apply to opportunity charging archetypes.
[22] Managed charging was found to reduce peak by up to 50% for fleets using lower powered chargers (based on https://sepapower.org/resource/the-state-of-managed-charging-in-2021/) and 30-40% for fleets using higher powered chargers (based on stakeholder engagement).

2. Peak curtailment due to battery storage:

Another strategy to reduce EV demand that coincides with the system peak is to use behind the meter battery storage (i.e., a stationary non-vehicle battery). By recharging the battery during non-peak hours of the day, the battery can be used to charge vehicles during the peak time, reducing the peak load required by the fleet. This sensitivity results in a reduction in distribution grid costs while adding an additional battery storage cost. Stakeholder input suggests that fleets are just starting to consider peak curtailment via stationary batteries and battery costs are still comparatively high, so there are only select scenarios where adding battery storage is economically beneficial. The most beneficial scenarios are when the introduction of battery storage can eliminate the need for costlier upgrades such as substation upgrades or the construction of a new substation. **Exhibit 14** highlights this insight, overlaying the function for distribution grid costs and the cost of battery storage.[23]

Exhibit 14: Distribution Grid vs. Battery Storage Costs



3. Available capacity on the grid:

Based on available grid capacity in the area where the electrification of the fleet is occurring, there may be no need for distribution grid upgrades. Generalizing the available capacity on the distribution grid by region or area is difficult, so the assumed baseline is that all EV load is excess capacity required on the grid. However, if prior knowledge of the distribution system is available, this sensitivity enables examining distribution grid costs based on how much free capacity is available on the grid. The distribution grid costs are thus calculated based on the amount of load required that surpasses the free capacity.

[23] https://www.nrel.gov/docs/fy23osti/85332.pdf - battery costs have continued to decline, so the Battery Cost curve may shift downwards in the future.

4. Cost variances by provinces:

Specific project costs by region or province are also difficult to estimate. In the absence of more specific information, we use benchmark provincial labour rates as a proxy for cost differences between provinces.[24] This allows for some sensitivity on how project costs would scale in different regions across Canada.

5. Cost allocations between fleet owners and utilities:

Lastly, the allocation of costs between the fleet owners and utilities is examined as a sensitivity. Based on stakeholder input, the utility customer typically incurs 100% of the required distribution grid upgrade costs, either by financing the upgrades directly or paying for them through their electricity rates. Traditionally, utilities have charged customers who require an upgrade up-front, even if other customers benefit from it. For projects like fleet electrification, this approach may differ, as utilities – particularly those that are crown corporations – might aim to support policy changes by reducing the up-front costs for the customer. Lastly, in cases where infrastructure is proactively built out, costs could be distributed to the rate base (while ensuring that residential customers are not subsidizing upgrades driven by commercial loads). This sensitivity allows for the percentage of the distribution grid costs to be changed to examine how the costs might behave in scenarios where the utility pays for a certain portion of the upgrades.

4. Results

This study focuses on providing quantitative results via the cost assessment tool. Section 0 summarises the key quantitative findings from the study. However, the study also identified several qualitative upshots from its quantitative analysis and further qualitative considerations from its desktop research and stakeholder engagement activities. Section 0 outlines the key qualitative upshots. Finally, Section 0 identifies potential implications of this study for future work.

4.1 Quantitative Findings

4.1.1 Cost Assessment Excel Tool

Results for the study are presented in their entirety in the supplementary cost assessment Excel tool, calculated using the methods described in Section 3. The tool presents the total grid integration costs for each of the 15 defined archetypes, and two sub-archetypes that differentiate between regional and long haul HD trucking. The tool also allows for sensitivity analysis based on the parameters discussed in Section 0. **Exhibit 15** and **Exhibit 16** illustrate how the tool works via the example of the delivery van Level 2 depot charging archetype.

Exhibit 15 displays the archetype characteristics and the input parameters that are used to calculate the charging power requirements. Values that are listed in red font represent the input sensitivities discussed in Section 0.[25] The tool uses the Total peak draw (kW) value to calculate the distribution grid and charging infrastructure costs.

Exhibit 16 displays the functionality of the output sensitivities that are discussed in Section 0. The user can adjust each sensitivity as they wish and view the updated costs that are calculated. As with the input

[24] https://www150.statcan.gc.ca/n1/daily-quotidien/230519/cg-b002-eng.htm
[25] The "Notes" column provides typical values for these input parameters and may suggest some additional values for sensitivities.

sensitivities, the notes column provides guidance on the sensitivities and some typical values that may be associated with each of them.

Exhibit 15: Cost Assessment Tool Results for the "Delivery Van Level 2 Depot Charging" Archetype

Archetype	Delivery Van - Depot - Level 2	Notes
Archetype description	This archetype serves return-to-base class 2b-5 vehicles that have the opportunity to charge overnight when they are parked in the depot during their downtime. At typical daily distances driven and downtimes, Level 2 charging is sufficient to keep vehicles charged for their routes. Typical vehicle to charger ratio is 1:1.	
Vehicle description	Cargo vehicle for last mile deliveries, including local parcel and goods distribution, in predominantly urban and suburban regions	
Operation	Cargo	
Class	Class 2b-5	
GVWR (kg)	3,855-8,845	
Duty cycle characteristics	Variable routes	
Downtime	10	Typical downtime is 10 hours overnight (from "Duty Cycles" tab)
Peak time	Overnight	
Charging location	Depot	
Daily distance range (km)	50-250	
Average daily distance (km)	100	Average daily distance driven is 100 km
Efficiency (kWh/mile)	0.8	Class 2B vans have efficiencies of 0.6, larger step vans have efficiencies of 1.0 [4]
Battery sizes (kWh)	75-170	
Typical fleet size	10	Typical fleet size is 10, large fleet size is 44 (from "Fleet Sizes" tab)
Charger to vehicle ratio	1	Typical charger to vehicle ratios range between 1 and 0.8 (ratios often decrease with increasing fleet size) [stakeholder]
Estimated Peak based on average milage (kW)	7.94	
Charging type	Level 2	
Total peak draw (kW)	79.36	
Distribution Grid Costs	$ 47,752	
Charging Infrastructure Costs	$ 94,500	

Exhibit 16: Output Sensitivity Functionality in the Cost Assessment Tool

Sensitivities:		
Peak curtailment due to managed charging	50%	Managed charging source says fleet peak can be reduced by 50% in simulations [29]
Updated total peak draw (in kW)	39.68	
Distribution Grid Costs	$ 23,876	
Charging Infrastructure Costs	$ 109,500	Extra $1500 per charger for L2, $5000 for DCFC to go from "dumb" to "smart" charger [stakeholder]
Peak curtailment due to battery storage	10.00	Choose the peak curtailment due to battery storage in kW
Battery cost scenario (low, mid, high)	Mid	Choose the battery storage cost scenario (mid represents the reference case)
Year in which battery is	2024	Choose the year in which the battery has been purchased (prices are projected to decrease in the future)
Updated total peak draw (in kW)	29.68	
Distribution Grid Costs	$ 17,859	
Charging Infrastructure Costs	$ 109,500	
Battery Storage Costs	$ 23,922	
Available capacity on the system (in kW)	20.00	
Updated total peak draw (in kW)	9.68	
Distribution Grid Costs	$ 5,825	
Charging Infrastructure Costs	$ 109,500	
Battery Storage Costs	$ 23,922	
Cost variances by provinces	Ontario	Labour costs used to estimate differences in costs across provinces [26]
Distribution Grid Costs	$ 6,052	
Charging Infrastructure Costs	$ 111,640	Uses assumption that half of charging infrastructure cost is installation costs
Battery Storage Costs	$ 24,389	
Costs for fleet owners (customers) and utility based on percentage of grid upgrade cost incurred by the customer	100%	Customer typically incurs 100% of required upgrade costs [stakeholder consultation]
Cost to Utility	$ -	
Cost to Fleet Owner	$ 142,081	

These results are displayed for each of the 15 charging archetypes (and the two sub-archetypes) within the cost assessment Excel tool, along with summary sheets and supporting information on the input parameters and cost functions used. Sections 0, 0, and 0 present highlights from the results that are calculated in the tool and discuss key trends and patterns.

4.1.2 Key Trends and Patterns

The results indicate a wide range of costs for archetypes, spanning from more than $60 million to slightly less than $150,000. This section examines the costliest archetypes and evaluates trends observed among all archetypes.

Exhibit 17 displays the five highest cost archetypes. **Exhibit 18** explains the cost data and provides insights into why these archetypes are comparatively costly.

Exhibit 17: Grid Integration Costs per Charging Archetype (Top 5)

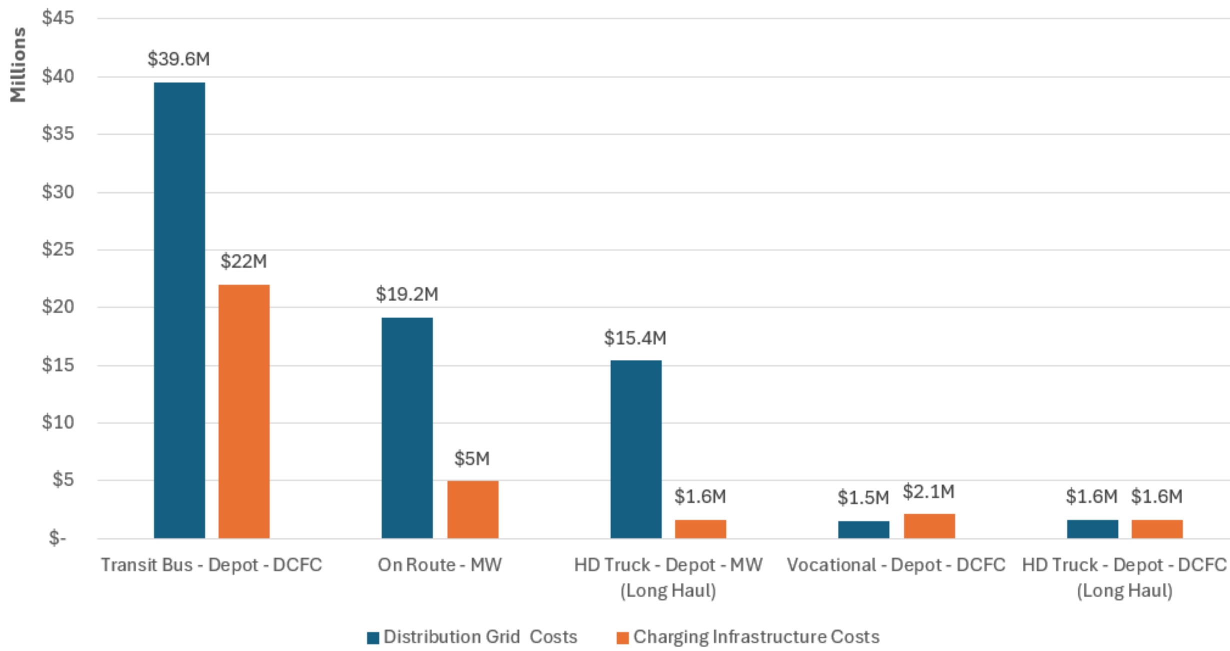


Exhibit 18: Insights on the Costliest Charging Archetypes

Archetype	Total Costs (millions of $CAD)	Key Cost Drivers
Transit Bus – Depot – DCFC	$61.6	The very large fleet size of 200 buses is the main cost driver.[26] Comparatively high powered DCFC (around 80 kW) factors into charging infrastructure costs as well.
On Route – MW	$24.2	High powered MW+ charging leads to high charging infrastructure costs. Assumed coincidence factor of 1 (resulting in all chargers being utilized during the charging peak) causes significant load on the distribution grid.

[26] Based on TTC bus depots: from https://www.ttc.ca/transparency-and-accountability/Operating-Statistics/Operating-Statistics---2022/Conventional-System and https://transittoronto.ca/bus/8300.shtml.

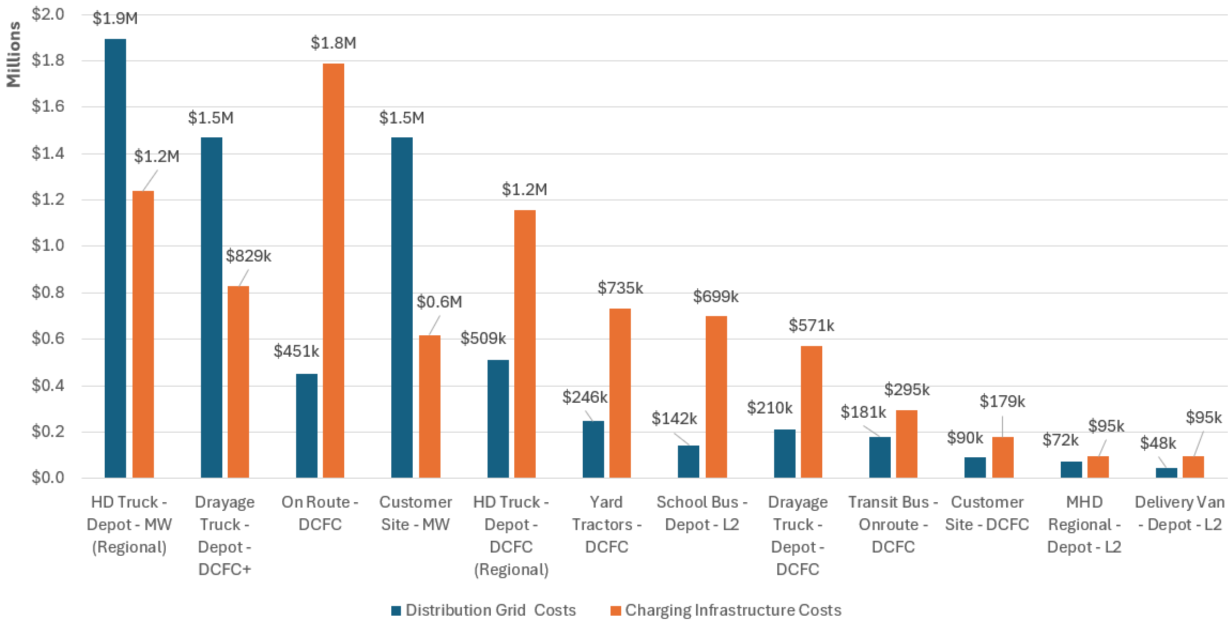
Archetype	Total Costs (millions of $CAD)	Key Cost Drivers
HD Truck (Long Haul) – Depot – MW	$17.0	Highest powered charger (at 2 MW) to accommodate HD long haul trucks using opportunity charging windows. Creates a large load on the distribution grid, even with minimal vehicles charging at once.
Vocational – Depot – DCFC	$3.6m	The cost for this archetype is largely dictated by its large fleet size of 60 vehicles.
HD Truck (Long Haul) – Depot – DCFC	$3.2m	Highest powered charger of the non opportunity charging archetypes at around 130 kW. Assumed that all HD trucks charge simultaneously overnight resulting in large load on the distribution grid.

As illustrated by the three most expensive archetypes, the overall costs are dominated by distribution grid costs. This is due to each of these archetypes requiring more than 3 MW of distribution grid capacity, triggering the need for costly substation upgrades. The costliest archetype, transit bus depot charging, requires more than 10 MW capacity, necessitating the construction of a new substation.

Exhibit 19 displays the grid integration costs for the remaining archetypes. In general, archetypes employing higher powered chargers are more expensive. This is highlighted in the exhibit with the costlier archetypes (on the left) largely using MW+ and DCFC and less costly archetypes (on the right) largely using Level 2 chargers.

Fleet size has a large influence on the grid integration costs. This is evident as the transit bus depot charging and vocational vehicle depot charging archetypes rank among the top five costliest archetypes. By the same logic, the school bus archetype, that relies on Level 2 charging, is positioned closer to the middle of the remaining archetypes.

Exhibit 19: Grid Integration Costs per Charging Archetype (Remaining)



4.1.3 Distribution Grid versus Charging Infrastructure Costs

One of the major trends in the results is the ratio between the distribution grid costs and charging infrastructure costs and how this ratio scales with charging power requirements. The exhibits in the previous section highlight that distribution grid costs are typically higher for higher powered chargers (MW+ and higher powered DCFC) while charging infrastructure costs are typically higher for lower powered chargers. **Exhibit 20** displays this trend in more detail by plotting the ratio between the distribution grid and charging infrastructure costs versus the rated power of the chargers, along the x axis.[27]

In this exhibit, negative ratios represent archetypes where the charging infrastructure costs exceed the distribution grid costs and are indicated by blue circles. Positive ratios represent archetypes where the distribution grid costs exceed the charging infrastructure costs and are indicated by green triangles. A ratio of zero would represent an archetype where the two costs are equal, signifying that archetypes further away from the x-axis have greater cost imbalances.

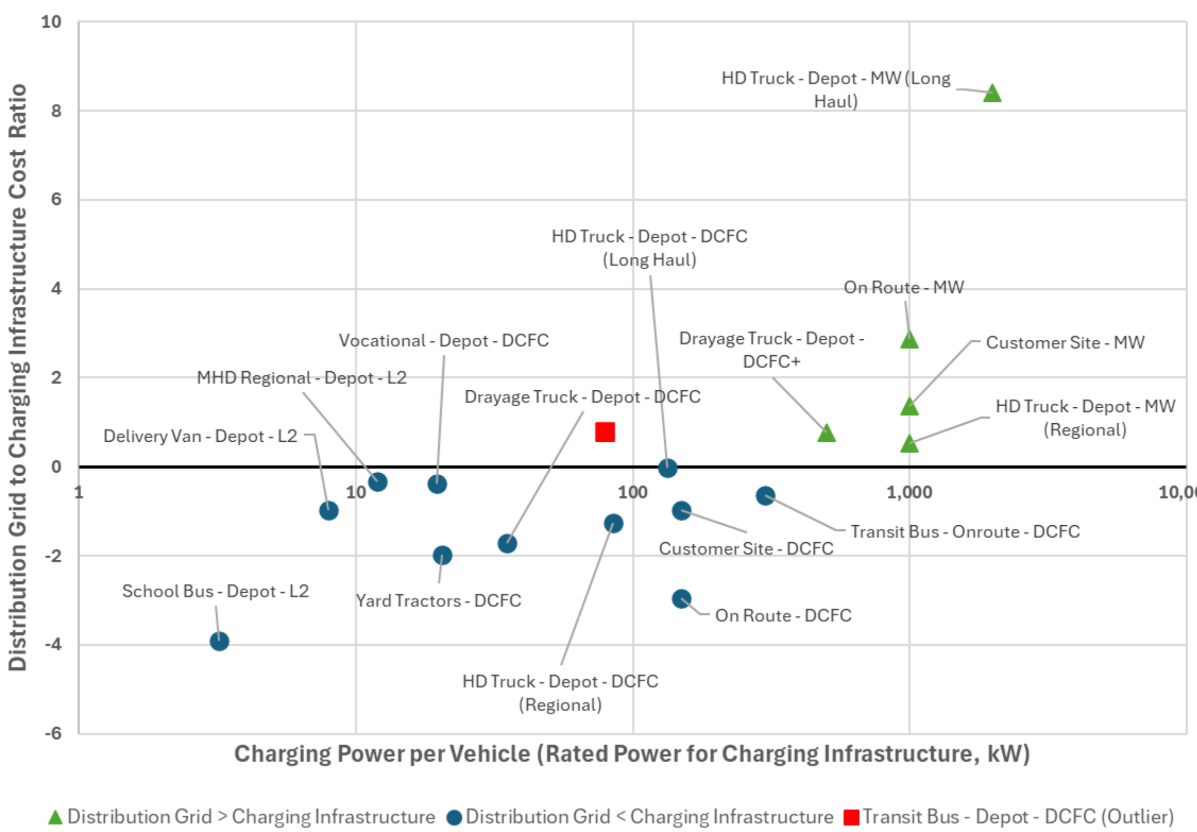
The general trend shows that lower powered chargers will have higher charging infrastructure costs (negative ratios) while higher power chargers have higher distribution grid costs (positive ratios). This is largely due to the archetypes with lower powered charging not requiring as much total capacity and thus not triggering the costlier substation upgrades. Charging infrastructure costs were also generally found to be more expensive on a per-kW basis than circuit upgrades, which are the only distribution grid costs before reaching 3 MW in capacity needs. Lastly, the charging infrastructure costs decrease per kW with increasing power, whereas the distribution grid costs increase along their stepwise cost function due to triggering the costlier upgrades.

The only outlier in the analysis is the transit bus depot charging archetype, indicated via the red square. It is the only archetype that uses a charger less than 500 kW that has a positive ratio and larger

[27] A logarithmic scale is used for the x-axis to provide more clarity in the exhibit.

distribution grid costs than charging infrastructure costs. As discussed in the previous section, this is due to the large fleet size that leads to the requirement of constructing a new substation. This greatly increases distribution grid costs. However, the lower charging power means that this archetype is still closer to the x-axis (meaning that the costs are more balanced), despite having almost $40 million in distribution grid costs.

Exhibit 20: Distribution Grid vs. Charging Infrastructure Costs



4.1.4 Highlighted Archetypes

After examining the overall results and analyzing prevalent trends, we examine the archetypes listed as the primary focus in Section 0.

Delivery Vans and MHD Regional Delivery

These two archetypes have been grouped together because they are very similar in many aspects. One significant insight from the stakeholder engagement interviews regarding these archetypes is that Level 2 charging stations generally satisfy the requirements of these vehicles. Daily distances driven by these vehicles are often overestimated and the downtime is long enough that Level 2 chargers can be utilized to fully recharge the batteries overnight.

This finding is consistent with results calculated in the cost assessment Excel tool. For a typical downtime of 10 hours and an average daily distance driven of 100 km, the calculated charging power required for delivery vans and MHD regional delivery vehicles is approximately 8 kW and 12 kW, respectively. With Level 2 chargers reaching a maximum of 19.2 kW, this shows that Level 2 charging is adequate for the average fleet duty cycle within these two archetypes.

HD Trucks – Depot Charging

The HD trucking archetypes comprise two sub-archetypes that differentiate regional versus long haul HD trucks. On average, regional HD trucks are estimated to cover a daily distance of approximately 400 kilometers. At this distance, regional trucks can rely exclusively on overnight charging for their operations. Long haul HD trucks however were found to average over 1,000 km per day. This distance outranges all the electric HD trucks currently on the market, meaning that some form of on-route charging is required to allow the trucks to complete their daily distances. This on-route charging is supplementary to the overnight charging that is expected to occur at the depot.

Provided that on-route charging opportunities are available for long haul HD trucks, the estimated charging power required for overnight charging is approximately 85 kW for regional HD trucks and 130 kW for long haul HD trucks. While the power required for overnight charging is not particularly high when compared to the power required for opportunity and on-route charging, the difficulties for this archetype lie in operating the long haul routes so that the trucks have opportunities to charge intermittently.

HD Trucks – Opportunity Charging

This second sub-archetype addresses the concern of having to charge on-route for long haul HD trucks. The sub-archetype also studies the need for opportunity or on-route charging for regional HD trucking that may have duty cycles that do not allow for overnight charging. Downtime for opportunity charging is assumed to be one hour to simulate trucking operations that run 24/7 by switching drivers.

To accommodate the very short charging times, charging power levels need to be high. We deem 1 MW to be sufficient for regional HD trucking duty cycles but long haul HD trucking is assumed to require 2 MW. While all vehicles charge simultaneously overnight, the MW+ chargers used for opportunity charging allow for staggered charging of vehicles. This greatly reduces the capacity requirements on the distribution grid. The number of high-speed chargers compared to overnight chargers is estimated to be between 20% and 50%, which provides information on how many MW+ chargers are required for a given fleet size.[28]

Based on the inability of current trucking technology to reach the average daily distances, a combination of the two sub-archetypes is likely required for long haul truck operation. This would consist of combining overnight chargers for the entire fleet with MW chargers that would be used for opportunity charging. Additional emphasis will need to be placed on duty cycles and routing logistics to avoid having several trucks requiring fast charging at once, which leads to higher capacity requirements and large distribution grid costs.

4.2 Qualitative Findings

4.2.1 Current Utility Regulation May Hamper the Pace of Fleet Electrification

The utility regulatory frameworks for most jurisdictions require utilities to wait until they receive added service or new customer requests for their commercial and industrial rate customers before they can expand the distribution system to meet the requested additional demand. In most jurisdictions, the utility customer who makes the service request also pays for most distribution grid costs associated with the request (typically based on cost-sharing formulas that depend on the jurisdiction and specific

[28] Estimates provided by https://www.sciencedirect.com/science/article/pii/S1361920923002225?via%3Dihub and https://www.sciencedirect.com/science/article/pii/S2667095X22000228?via%3Dihub.

case).[29] This not only poses a cost hurdle but also impacts fleet transition timelines. Larger distribution grid updates (especially upgraded or new substations) can have delivery timelines of up to ten years. Additionally, some jurisdictions (e.g., Ontario) have not updated their utility system design guidelines to reflect EV charging voltage needs, so customer requests for MHDEV service inherently trigger distribution system equipment upgrades (e.g., requiring transformer upgrades at a minimum) even if the distribution grid has sufficient free capacity to accommodate the charging demand.

Buildings and even building mechanical systems tend to last longer than MHDV lifetimes. This means the regulatory requirements and grid infrastructure delivery timelines pose less of a hurdle for energy transition in the built environment than for MHDV. Fleet operators must typically also coordinate with multiple parties, not just utilities, to advance their fleet transitions (e.g., with municipalities to receive electric and construction permits for depot upgrades). This exacerbates timeline hurdles.

Most jurisdictions carve out exceptions in their regulatory frameworks that enable utilities to proactively invest in their power systems to meet policy objectives (e.g., energy efficiency, demand management, decarbonization). Such carve out instruments could be explored to advance proactive planning for MHDEV grid integration. Massachusetts, New York State, and Michigan have opened special dockets with their public utility commissions to examine this issue.[30] To address stakeholder coordination challenges, some jurisdictions (e.g., California, various states in the European Union) are conducting studies that overlay transport demand models with models of forecast distribution system capacity to identify corridors and hubs that should be prioritized for such proactive system upgrades.[31]

4.2.2 Capacity Constraints and Costs for Distribution Grids and Charging Infrastructure Vary by Site Context

Some stakeholders suggest that urbanized areas with older power distribution infrastructure tend to be closer to their distribution grid capacity limit than newer and more rural areas. This makes these areas more likely to require distribution grid upgrades to meet MHDEV demand. However, the exact unused capacity on the distribution grid depends on the specific site context.

In addition to the factors examined in the cost assessment tool, land acquisition and stakeholder engagement can be a significant cost driver for distribution grid upgrades. According to some stakeholders, these components can account for approximately 30% of the total upgrade cost.[32] Design standards can further increase such cost variability. For example, some jurisdictions require utility distribution upgrades to be underground which can be about one order of magnitude more costly than above-grade upgrades. Finally, upgrade site choice can impact both distribution grid and charging infrastructure costs. Greenfield sites (e.g., a new location for a substation or a previously undeveloped site for a fleet charging depot) may be more expensive to develop than upgrading existing brownfield sites.

---

[29] Cost sharing formulas and specifications are complex (the utility guidance documents average between 50 and 100 pages), but typically determine the degree of investment the utility is authorized to bear on behalf of the customer (e.g., 1,277 kW/$), which leaves a remaining amount for the customer to bear.

[30] ACEEE Report

[31] Please see the following study for one such example: Impact of electric vehicle charging demand on power distribution grid congestion | PNAS.

[32] These costs should be added to the cost results from the cost assessment tool.

4.2.3 Case-Specific Context Impacts Fleet Characteristics and Considerations

Some stakeholders report that DCFC chargers may face more stringent supply chain limitations (at least in the short term) than the more mass-market Level 2 chargers, so fleets that rely predominantly on Level 2 chargers may be able to access charging infrastructure more easily. Fleet operators who predominantly rely on Level 2 charging archetypes report a preference for one charging port per vehicle to ensure that their fleets can meet their duty cycle requirements even under unforeseen circumstances. Some fleet operators also indicate a preference for a DCFC charger as a backup in predominantly Level 2 archetypes. Additionally, certain fleets calculate a safety margin for sizing their charging infrastructure (e.g., 20% more charging capacity than they expect they will need) to provide redundancy for unexpected circumstances.

Transit bus fleets express concern about air conditioning power demand in the summer. Refrigeration truck fleets highlight similar concerns about refrigeration power and express a preference for running refrigeration units on diesel generators rather than from the vehicle battery.

Finally, smaller fleet operators are concerned about their ability to upgrade their depots for MHDEV charging because they tend to lease depots and may thus not have full control over them.

4.2.4 Preference for Hardware and Software Standardization

The fleet operators we interviewed express a desire for greater standardization in the charging infrastructure hardware and in the software interfaces that enable communication between fleet energy management, route management, and yard management systems. Stakeholders highlight that this might present an opportunity for intervention by federal regulators.

4.2.5 Stakeholder Feedback Density

Semantic analysis offers a measure of how often stakeholders discussed different topics during the study, serving as an indirect gauge of the significance attributed to the qualitative themes discovered through stakeholder engagement. **Exhibit 21** summarizes the semantic analysis outcomes and highlights that issues like fleet diversity and delays to fleet transition timelines were more frequently mentioned by stakeholders compared to matters involving permitting processes and observable trends about the availability of free distribution system capacity in urban versus rural areas.

Exhibit 21: Density of Stakeholder Feedback across Key Themes

Theme	Description	Frequency
Heterogeneity in Fleet Size and Behavior	Influence on charging infrastructure and distribution grid costs.	High
Utility Challenges	Challenges faced by utilities in adapting to transport sector power demand.	High
Regulatory Frameworks	The impact of proactive versus reactive planning in the utility planning process.	Medium
Transition Speed and Coordination	The pace of fleet electrification and associated coordination challenges across fleet operators, utilities, and municipalities.	Medium
Substation Upgrade Duration	The timeline for substation upgrades and its impact on infrastructure deployment.	Medium
Grid Design Requirements	Considerations for underground versus above-grade infrastructure.	Low
Stakeholder Engagement and Permitting	Timeline impacts from stakeholder engagement and permitting processes.	Low
Distribution System Capacity	Differences in free distribution grid capacity across urban versus rural sites.	Low

4.3 Implications for Future Work

The study raises two key implications for future work:

1. While the study clusters fleet charging behaviors into archetypes, considerable heterogeneity exists within each archetype. The study addresses some of this heterogeneity via the sensitivity features built into the cost assessment tool. However, further stakeholder engagement should be conducted with fleet operators, utilities, and charging infrastructure providers to reduce uncertainty about charging behaviors and the associated distribution grid and charging infrastructure costs.

Deploying the distribution grid and charging infrastructure upgrades to meet MHDEV power demand appears to represent a collective action challenge. Each of the key stakeholders (fleet operators, utility regulators, distribution utilities, and municipalities) face uncertainty about where and how quickly MHDEV demand may materialize and how quickly distribution grids will grow to support this demand. Two items may help alleviate this uncertainty. First, developing stakeholder coordination frameworks that map the planning steps that each stakeholder category must take and identify how these steps ideally interconnect to form an efficient process flow. And second, examining how transport demand overlays with distribution grid capacity to identify optimal charging corridors and hubs and indicate areas for proactive distribution grid upgrades.

Appendix A Distribution Grid Cost Breakdown

This appendix describes the process of how we construct the cost function used to determine distribution grid costs for the different charging archetypes. We initially studied costs on a per upgrade type/equipment basis informed by reports from the National Renewable Energy Lab (NREL) and the Rocky Mountain Institute (RMI) and validated through stakeholder interviews. These costs are listed in **Exhibit 22** below.

Exhibit 22: Distribution Grid Costs by Type/Equipment

Upgrade Category	Upgrade Type/Equipment	Capacity	Cost ($CAD)
Circuit	Distribution Transformer	150-300 kVA	$20,250 - $67,500
Circuit	Distribution Transformer	500-750 kVA	$60,750 - $94,500
Circuit	Distribution Transformer	1000+ kVA	$87,750 - $236,250
Circuit	Install/Upgrade Feeder Circuit	To handle 5+ MW	$2.7 - $16.2 million
Substation	Add Feeder Breaker	To handle 5+ MW	$540,000
Substation	Substation Upgrade	To handle 3-10+ MW	$4.1 - $6.8 million
Substation	New Substation Installation	To handle 3-10+ MW	$16.2 - $47.3 million

While this information is very useful, it does not factor in the interactions and combinations between different upgrade types. A research article from the *Environmental Research: Infrastructure and Sustainability* journal studied the cost per kW for circuit and substation upgrades from Pacific Gas and Electric Company's (PG&E) service territory, eliminating the delineation by equipment type. These cost assumptions are shown in **Exhibit 23**.

Exhibit 23: Costs per kW for Circuit and Substation Upgrades (PG&E's Service Territory)

Capacity Requirements (MW)	Circuit Upgrade Costs ($CAD/kW)			Substation Upgrade Costs ($CAD/kW)		
	25th pctl	Median	75th pctl	25th pctl	Median	75th pctl
MW < 1	$601.71	$2,531.25	$7,818.75	$13,412.25	$25,465.63	$39,126.77
1 ≤ MW < 2	$339.98	$1,848.00	$2,825.40	$4,853.24	$6,399.04	$9,423.12

2 ≤ MW < 4	$265.63	$909.02	$1,954.19	$3,952.71	$5,370.81	$6,032.81
4 ≤ MW < 8	$362.68	$591.49	$1,060.16	$1,535.17	$2,706.35	$3,470.67
MW ≥ 8	$320.26	$496.60	$791.53	$855.91	$1,198.29	$1,605.34

When comparing the costs per kW from **Exhibit 23** to the individual costs of the equipment upgrades in **Exhibit 22**, they are reasonably consistent. While these costs sometimes are higher than the equipment costs, this highlights that multiple different types of upgrades are often required, adding to the complexity of modelling total costs. To draw insights from both exhibits, we make the following assumptions to develop the cost function:

1. Median circuit costs for upgrades less than 1 MW are high compared to the upgrade costs for distribution transformers. To adjust for this, the 25th percentile costs per kW are used, reflecting that feeder upgrades are less likely to be required.
2. For circuit upgrades larger than 1 MW, the median costs are used to reflect a higher likelihood of feeder upgrades. A line of best fit from the median costs is used to address the discontinuities when transitioning across the different capacity requirement bins.
3. Substation upgrade costs per kW are very high, particularly for lower capacity upgrades. Insights from NREL and RMI suggest that substation upgrades are typically required for capacity needs greater than 3 MW. To align with this, the line of best fit from the median substation costs per kW is used for upgrades between 3 and 10 MW.
4. For capacity upgrades greater than 10 MW, new substation installations are assumed to be required. The average cost from the range provided in **Exhibit 22** is used as a constant cost for all new substation builds ($31.75 million).
5. Total distribution grid costs are calculated by combining circuit and substation costs to account for the requirements of multiple different upgrade types.