The Road to Transportation Decarbonization:

Readying the Grid for Electric Fleets

Prepared Jointly by National Grid and Hitachi Energy

September 2023

Acknowledgment and Disclaimer

Acknowledgment of individuals who contributed to this study: (in alphabetic order)

National Grid:

Gideon Katsh
John McDaniel
Matilda Olsen
Kelly Stropp
Ryan Wheeler
Jeff Wilke
Brian Yung

Hitachi Energy:

Jonathan Hou
Shyamal Patel
Gary Rackliffe
Tashi Wischmeyer
Michael Ziemann

The authors would like to thank the following people for their reviews and contributions to this paper:

Marcus Alexander (EPRI)
Karsten Barde (National Grid)
Jeremiah Deboever (EPRI)
Mark Domino (National Grid)
Jamie Dunckley (EPRI)
Charlotte Fagan (National Grid)
Britta Gross (EPRI)
Brian Johnson (National Grid)
Ari Kahn (RMI)
Colette Lamontagne (National Grid)
John Lamontagne (National Grid)

Dave Mullaney (RMI)
Nadia Panossian (NREL)
Elton Prifti (National Grid)
Sejal Shah (National Grid)
Jeff Shih (National Grid)
Emily Slack (National Grid)
Kurt Steinert (Hitachi Energy)
Brian Wilkie (National Grid)
Eric Wood (NREL)
Daniel Yung (National Grid)

Legal Notice:

Table of Contents

1. Executive Summary

For over 100 years, our electric grid has delivered safe and reliable power to customers for lighting, comfort, manufacturing, and industry. It has accommodated economic growth and the introduction of new, advanced technologies. Today, we are on the cusp of asking even more from it.

Surface transportation will soon be powered by the grid. We have already begun plugging in our personal cars; now the vehicles that underpin our economy, medium and heavy-duty vehicles (MHDVs) – trucks, buses, and vans – are starting to rely on the electric grid too. State and federal policies, economics, and market developments are supporting this transition to electric vehicle models.

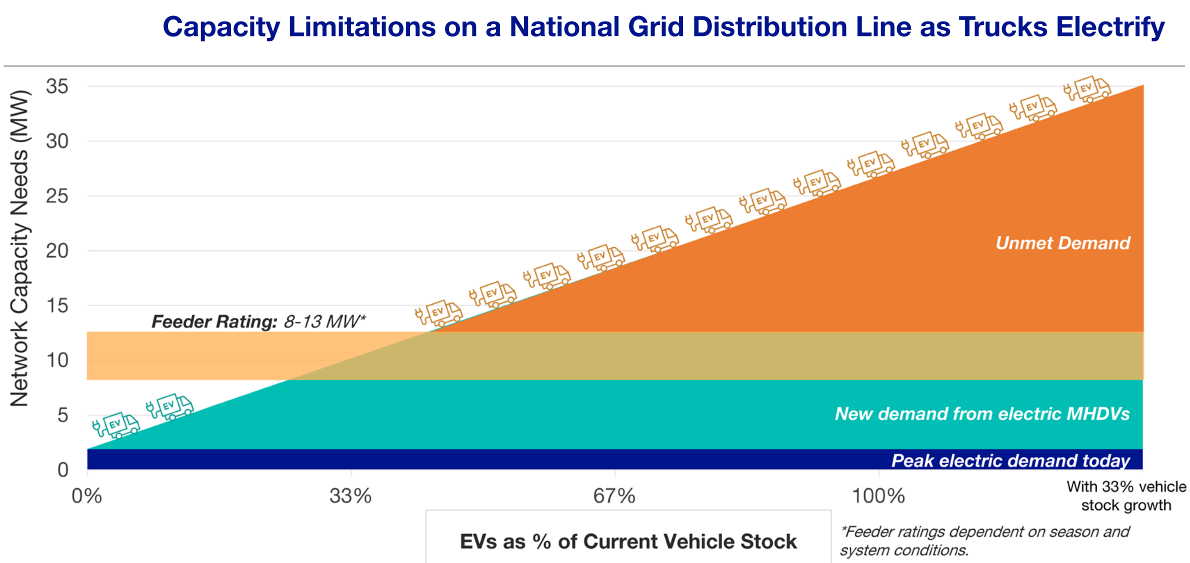
Even in the current, very initial stage of fleet electrification, some customers are experiencing delays and unforeseen costs to add charging capacity at fleet depots. Without changes to utility planning processes, regulatory structures, and fleet-utility collaboration, these early setbacks will significantly slow the deployment of cleaner, more efficient vehicles, and undermine transportation decarbonization. Without proactive planning by utilities, the pace of electric MHDV adoption is primed to outstrip the electric infrastructure it will depend upon.

Summary of this Case Study

To understand what will be needed from utilities to support the electrification of MHDVs, National Grid and Hitachi Energy partnered on this analysis of one power line (the "study feeder") in National Grid's U.S. electric service territory, estimating electric demand and system impacts as larger percentages of the vehicles electrify. The case study feeder currently serves relatively little electric demand but would eventually need to support the charging needs of over 400 electric trucks at 10 depots.

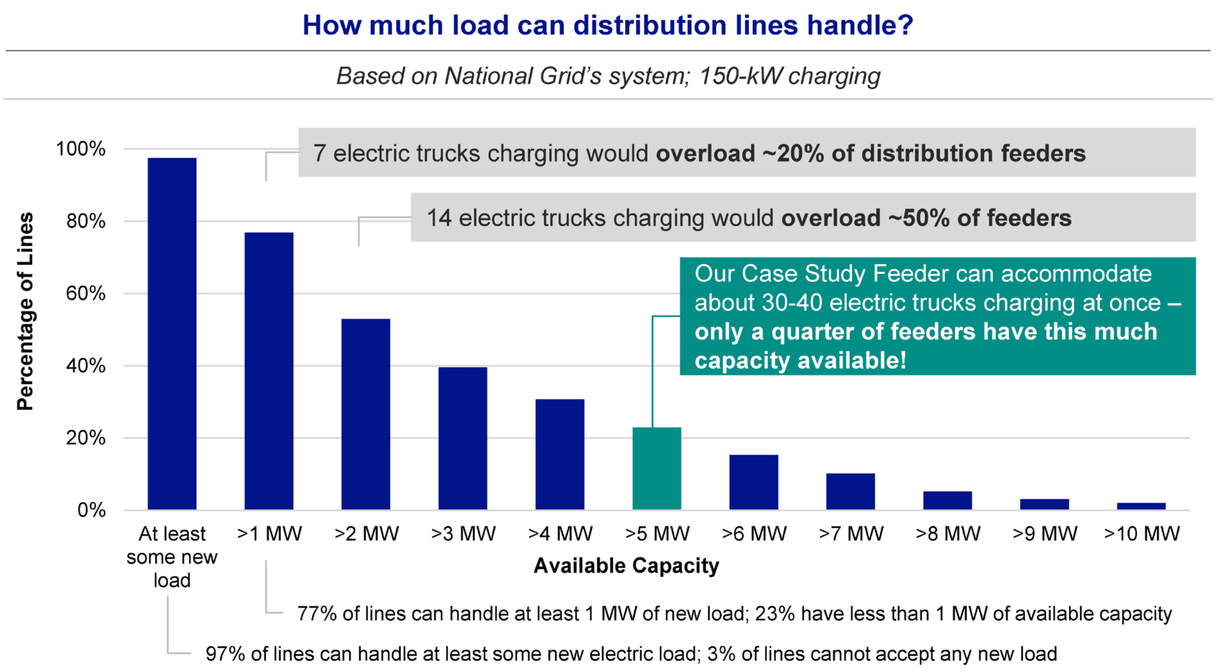
When 10 percent of those trucks electrify, peak demand on the case study feeder will almost double. When 33 percent of those trucks electrify, capacity on the line will be exhausted, and impacts will even be seen at the substation and on the transmission network. As more fleets electrify, additional elements of the area grid will be strained without action from the utility. Figure ES-1 summarizes load growth on the study feeder as MHDV electrification increases.

Figure ES- 1: Effects of Vehicle Electrification Load on the Study Feeder



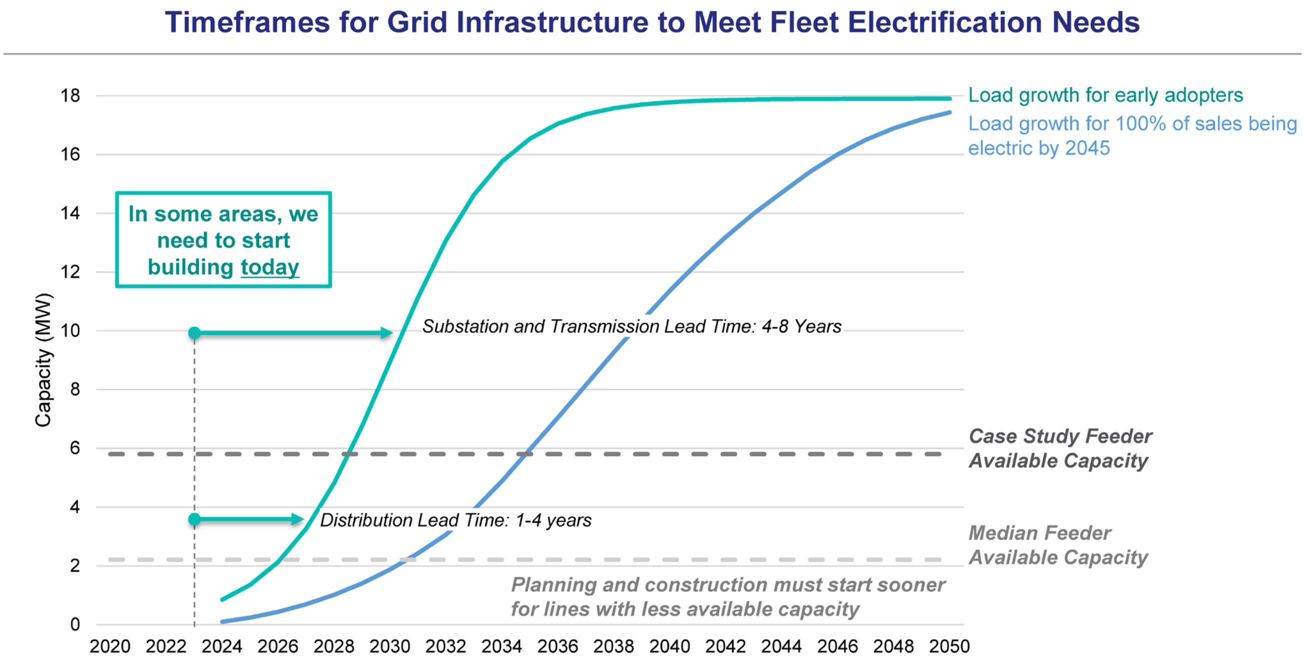
Impacts and solutions will differ from one utility area to another, but the study feeder provides a useful case study in how to support electric MHDVs over time. Most electric distribution lines have less available capacity than the study feeder, meaning that fewer fleets can electrify without triggering upgrades. These areas will require urgent action by utilities and policymakers to ensure the electric grid can support electric MHDVs at the pace that fleets and policymakers wish to transition to them. Planning and building must start now to meet those goals.

Figure ES-2: Available Capacity for MHDV Charging on Grid Infrastructure



Grid investments and fleet plans can be guided by which areas have sufficient available capacity for near-term electrification – as the case study feeder does – and which are more constrained. In the area supported by the study feeder, there are low-cost solutions National Grid can employ to serve electric vehicle charging without major upgrades. Not every community or fleet will be so lucky. In areas with high vehicle density and limited available system capacity, anticipatory grid investment will be critical to ensuring fleets have the grid capacity to electrify their vehicles.

Figure ES-3: Timing Needs for Fleet Electrification



Findings and Recommendations

Planning and preparing our grid infrastructure to support electric trucks and buses will unlock significant benefits for our communities, the climate, and the economy.

This paper identifies clear conclusions for utilities, policymakers, and fleet operators:

Conclusion #1: Some areas will see grid impacts from MHDV electrification soon.

- **Finding:** Multi-megawatt charging loads from fleet "clusters" – or even a single depot – will quickly exhaust grid capacity in some areas.
- **Recommendation:** Utilities and policymakers must anticipate near-term loads and grid impacts from early adopters of electric MHDVs, particularly where large fleets or states have clear electrification targets or mandates.

Conclusion #2: Investments in high-potential areas should be coordinated to reduce long-term costs and accelerate MHDV electrification.

- **Finding:** Utilities can identify priority investment areas (Areas of Need) as well as locations where fleet electrification can be accelerated with minimal or deferred infrastructure upgrades (Areas of Capacity, like the one considered in this study).
- **Recommendation:** Coordinate investment to high-priority areas, using new data, tools, and forecast methodologies. Identify Areas of Capacity and Areas of Need that can be aligned with fleet electrification and utility investment plans.

Conclusion #3: Regulatory and planning structures must evolve to accommodate MHDV electrification.

- **Finding:** Almost none of the loads identified in this case study would be captured in typical utility planning or regulatory processes. Without changing those planning and investment frameworks, it will be impossible to coordinate infrastructure buildout and accommodate MHDV charging demand in high-density areas.
- **Recommendation:** Develop anticipatory planning and investment processes and regulatory mechanisms to ensure the grid is ready to meet the fast-growing needs of electric MHDVs.

Conclusion #4: The right grid infrastructure strategy for MHDV electrification will vary by location.

- **Finding:** This study demonstrates that utilities can employ multiple infrastructure strategies to support electric MHDVs. The right strategy will depend not only on current needs and conditions, but also on ensuring that solutions accommodate long-term charging growth.
- **Recommendation:** Consider each location's particular needs when developing a strategy and enable utilities to make investments in enduring and right-sized solutions that solve immediate and future needs. Near- and long-term views will help align on the preferred solution over time.

Conclusion #5: New forms of partnership and cooperation will be needed to enable the electric MHDV transition.

- **Finding:** National Grid and Hitachi Energy partnered on this study to demonstrate what is needed from utilities to support electrification of trucks and buses. Making widespread fleet electrification a reality will require new collaboration among fleet operators, MHDV manufacturers, and utilities to coordinate investments, provide visibility to charging needs, and eliminate barriers to charging deployment.
- **Recommendation:** Collaborate across stakeholders to best support each other's needs around fleet electrification. Utilities need to partner with large and small fleets, vehicle manufacturers, state departments of transportation, and municipalities to understand and support their fleet electrification journeys.

2. Introduction and Context

In September 2021, National Grid and Hitachi Energy published a study entitled, "*The Road to Transportation Decarbonization: Understanding Grid Impacts of Electric Fleets,*" which investigated how electrification of medium- and heavy-duty vehicles (MHDVs) could impact specific portions of the electric distribution or transmission system.[1] It accomplished this by estimating the power needs of more than 50 fleets (over 2,000 vehicles) in one area of National Grid's service territory if they were to fully electrify their trucks, vans, and buses.

Since that study was published, the expected pace of MHDV electrification has accelerated due to new policies, cost declines, market developments, and investment from manufacturers and fleets.

Fleet Electrification is Accelerating

We noted in the 2021 paper that "fleet electrification is coming." Developments in the past two years have accelerated that process, as demonstrated by reviewing several drivers we identified then.

Driver #1 from 2021: "Policies dictate that electric fleets become more prevalent."

This is even more true today, as National Grid's home states of New York and Massachusetts have since passed legislation or adopted regulations that target up to 100 percent of MHDV sales being zero-emission by 2045 (New York State Senate, 2022). The California Air Resources Board (CARB) recently approved its Advanced Clean Fleets rule, which is even more aggressive. It requires fleets begin adopting zero-emission vehicles starting in 2024 and some fleets must be entirely zero-emission by 2035.

Federal policies are playing a significant role as well. Since the passages of the Bipartisan Infrastructure Law in 2021 and the Inflation Reduction Act (IRA) in 2022, $88 billion of corporate commitments have been announced in EV and battery manufacturing, which are expected to quickly ramp up vehicle and battery manufacturing capacities to better meet demand (Environmental Defense Fund, 2023). In April 2023, the U.S. Environmental Protection Agency (EPA) proposed new vehicle emissions regulations that could lead to nearly 70 percent of light-duty vehicle (LDV) and 40 percent of medium-duty vehicle (MDV) sales being electric by market year 2032, and 25-50 percent of heavy-duty vehicle (HDV) sales by then (HDVs could be a combination of battery-electric and hydrogen fuel cell vehicles). The U.S. also announced it would join the Global Memorandum of Understanding (MOU) on Zero-Emission Medium- and Heavy-Duty Vehicles, which targets 100 percent new zero emission vehicle (ZEV) MHDV sales by 2040 (CALSTART, 2022).

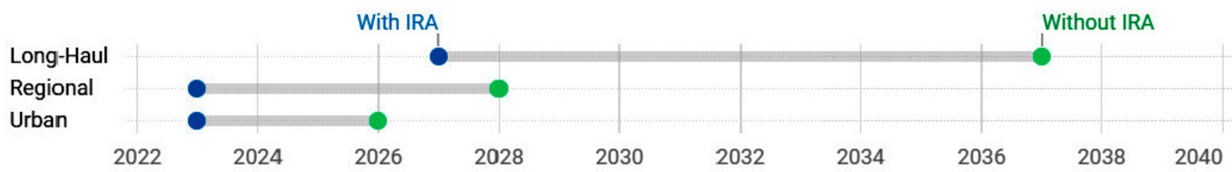
Driver #2: "Total cost of ownership will increasingly favor electric fleets."

The economics of electric MHDVs received a significant boost from the incentives and programs included in the IRA. These policy incentives are anticipated to make the costs of electric MHDVs equal to diesel vehicles years earlier than they otherwise would have been. As shown in Figure 1 below, a study from RMI anticipates that regional and urban trucks will reach parity with combustion engine equivalents very soon, with long-haul trucks to do so in 2027, ten years sooner than without the IRA (Khan, 2022).

---

[1] Available at ngrid.com/fleet-electrification-study.

Figure 1: Electric truck parity dates with diesel by duty cycle



Another study conducted in 2022 by automotive services firm Roush, in cooperation with the Environmental Defense Fund, found that every type of vehicle studied will have a lower total cost of ownership (TCO) for an electric model than diesel engine counterparts by 2027 (Nair, 2022). By then, most electric models are also expected to have lower upfront purchase prices, as a result of battery cost declines and increased efficiencies in manufacturing.

Despite these favorable TCO trends, grid and on-site electric infrastructure will still pose a meaningful barrier to MHDV adoption if not addressed by utilities. These study results do not include costs for grid infrastructure, which would add to EVs' total costs. Minimizing those infrastructure costs, as discussed in later parts of this paper, will be important to ensure that TCOs favor EVs and that fleets are able to economically and timely convert to electric models.

Driver #3: "Fleet activity is well-suited for electrification."

Increasingly, these new vehicles can replace combustion engine models. A report by RMI, "Charting the Course for Early Truck Electrification," finds, "based on how vehicles are driven today, approximately 65 percent of medium-duty trucks (MDTs) and 49 percent of heavy-duty trucks (HDTs) stationed in California and New York are electrifiable, meaning they could be replaced with EVs based on current technology. These vehicles are responsible for about 30 percent of the vehicle miles traveled by trucks based in the two states" (Lund, 2022). While there are segments that could not be electrified today, future developments in batteries, vehicles, and public charging infrastructure could open additional use cases to electrification over time.

Not only are companies realizing the opportunities for electrification, but manufacturing is catching up to demand, leading to increased availability of competitive models. With the support from policies and business commitments, MHDV manufacturers have released new models of electric MHDVs. In 2023, there are currently 205 battery-electric models of MHDV available, up from 161 in 2021 (CALSTART, 2023). Tesla delivered its first electric semi-truck in late 2022, and completed a 500-mile test trip, loaded at just under 82,000 pounds, on a single charge (Ali, 2022).

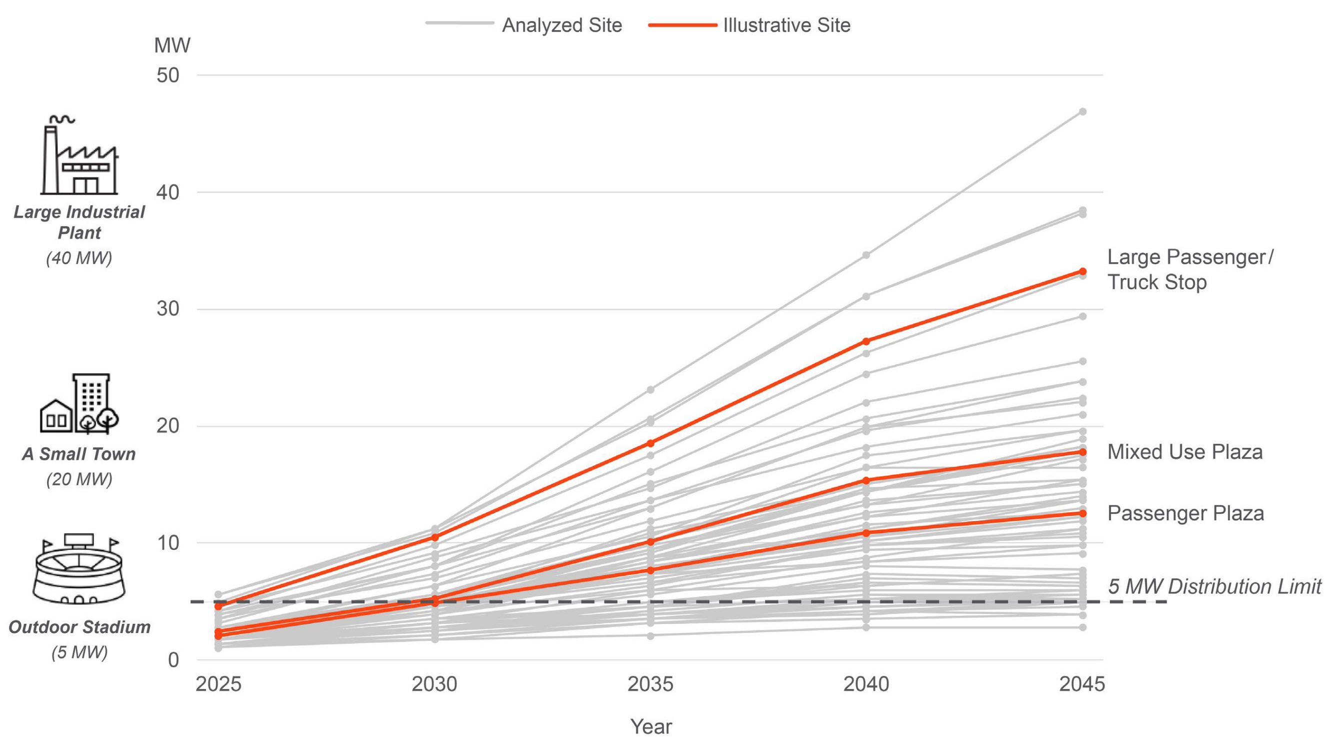
The acceleration of MHDV electrification makes it even more urgent to understand *what* the charging demands and specific impacts will be, *where* they will occur, *when* grid impacts will manifest, and *how* utilities can ready their systems for this major change.

We Must Now Provide the Power to Fleets

National Grid and Hitachi Energy partnered on this second phase of study because of these developments. Where our initial paper considered load growth associated with 100% fleet electrification, this paper zooms in to consider grid impacts of those charging loads (the 'what') on different parts of utility networks (the 'where') associated with varying electric MHDV adoption levels (the 'when'). It then presents options for increasing grid capacity for fleet charging and mitigating their anticipated impacts (the 'how').

As more chargers are installed and larger sites are proposed, the interconnection requirements will be more involved and time consuming. The Electric Power Research Institute (EPRI) finds that some sites for MHDV charging – including "post-workday" charging – could require as much as 50 megawatts (MW) (Tuyuri, 2023).[2] A site of that size would draw the same amount of power as a large industrial or manufacturing facility (see Figure 2) and, under current planning paradigms, could take 4 to 8 years for grid interconnection (Katsh, Fagan, Wilke, et al., 2022). Those historic ways of planning and accommodating loads are insufficient for fleets moving quickly to electrify and trying to comply with regulations that require them to rapidly increase the proportion of EVs in their fleet.

Figure 2: Capacity Required to Meet Demand of Sites in National Grid's Electric Highways Study



Electric service and utility interconnections are already proving to be a challenge to electric fleets, even in this nascent stage of MHDV electrification. Some utility customers are facing typical wait times of one to two years, but expectations are that some sites could take much longer to receive sufficient electric service (Khatib and Strauss, 2022; Walton, 2023a; Legatos, 2023; Hedreen, 2023). For years now, renewable power generators have faced significant delays and increased costs to interconnect, and interconnection issues are considered by some to be the greatest challenge to the buildout of clean generation (Clifford, 2023; Lawrence Berkeley National Laboratory, 2023). Addressing grid interconnection hurdles and getting ahead of these challenges for EVs will be critical to ensuring fleets can electrify at pace and that the grid is an enabler, not a bottleneck, for electrification.

[2] Coincidentally, EPRI analyzes a site that size that would support 400 trucks, about the same number of vehicles studied on the distribution line in this phase of work.

3. Approach

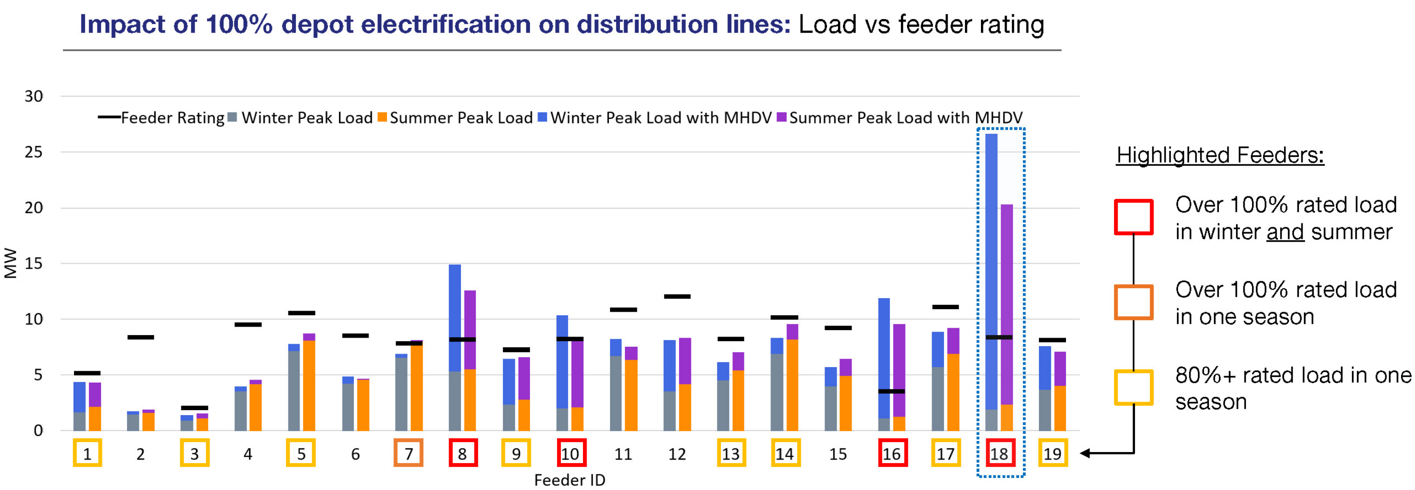
Many studies and forecasts have estimated load growth at the county, zip code, or regional level. This is important to understand and forecast, but utility planning and solution engineering happen at specific locations. To gain useful insights and determine the viability of different solutions, we needed to study an actual part of National Grid's system. Therefore, in our 2021 study, National Grid and Hitachi Energy evaluated load impacts of full fleet electrification (converting 100 percent of MHDVs to electric vehicles and charging those vehicles at fleet depots overnight) in one metro area in National Grid's service territory. The analytical process is summarized in Appendix A.

Results from 2021 Study – Impacts of 51 Fleets Electrifying 100% of Their Vehicles

The 2021 study found significant load growth on many of the distribution lines (also called distribution feeders) in the study area, shown in Figure 3.

Of the 19 distribution lines studied, five overload in at least one season when all estimated fleet vehicles electrify and charge overnight at depots. Another eight exceed 80 percent of their line rating under these same conditions. The impacts from EVs are more noticeable in winter, when, due to efficiency losses and greater cabin and battery heating requirements, EVs require more electricity to travel the same distance.

Figure 3: Feeder Loading Due to Full Fleet Electrification[3]



Proactive Planning

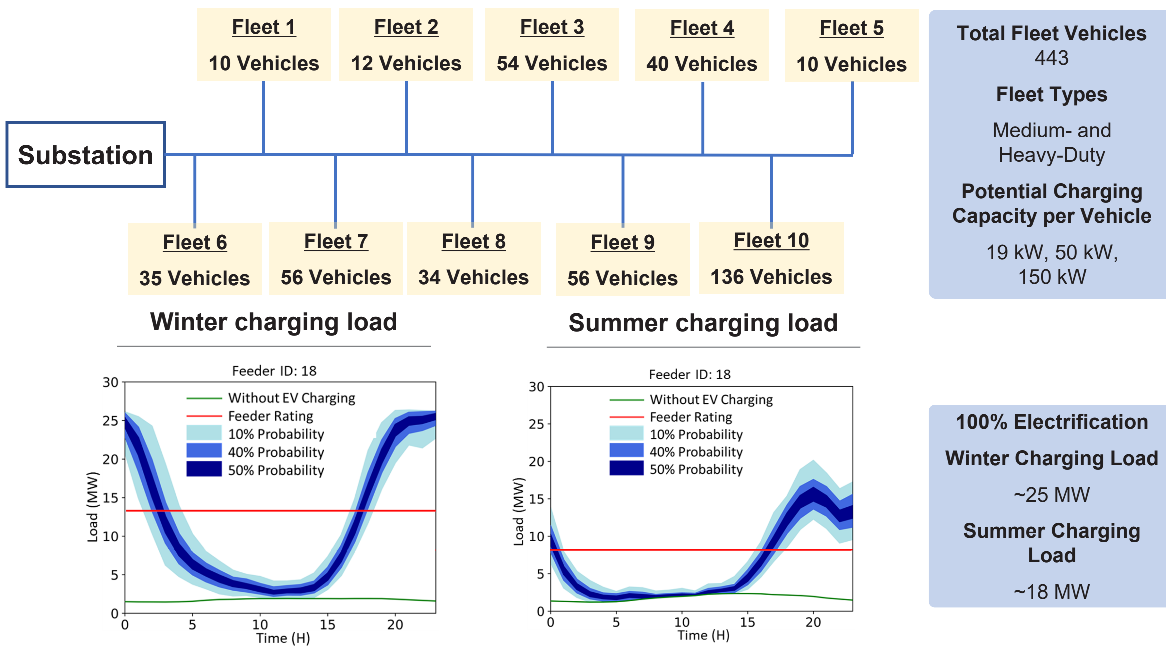
These findings illustrate that advanced planning for fleet electrification is critical. Significant electric demand is expected, especially in commercial areas with clusters of fleets. However, the impacts and new infrastructure needed can be challenging to pinpoint, as they are site-specific and dependent on factors such as the types of vehicles that are charging, growth in other electric loads, the timing of EV adoption, and seasonal and daily conditions on the electric network. To better understand these issues and develop broad strategies to

[3] Note: The feeder ratings here are shown for summer. In winter, the rating would be higher due to colder temperatures. Additionally, it is important to note that the load increases highlighted on the distribution lines above do not include additional electric demand growth, for instance from electric heating or from LDV charging.

serve electric fleet vehicles, National Grid and Hitachi Energy used the detailed load forecasting analysis from the first study to develop a second, more comprehensive analysis of the implications of MHDV charging. We focused on the distribution line with the largest number of fleets, vehicles, and charging load. This is Feeder #18 in Figure 3 above, hereafter referred to as the “case study feeder.”

We identified 10 fleets and estimated over 400 MHDVs served by the case study feeder, primarily assumed to be regional freight and box trucks. When those vehicles fully electrify, they could increase peak electric demand on the line by more than 20 MW – about the same amount of power required by a small town.

Figure 4: 100 percent Fleet Electrification Impacts on the Study Feeder



Types of Impacts (the ‘What’)

Multiple iterations of distribution planning models were run to demonstrate how growing electric demand from MHDV charging will impact the study feeder. The analysis includes consideration of infrastructure scenarios discussed below.

Specifically, this analysis demonstrates two types of impacts for the study feeder:

- **Thermal overloading:** Segments of the study feeder exceed the rated limits and overheat.
- **Voltage drops:** The operating voltage dips below the minimum allowable level, which could cause parts of the grid to collapse.

Grid Infrastructure Scenarios (the 'Where')
This analysis applies several **grid infrastructure scenarios** to understand what these impacts might look like in different neighborhoods, answering questions such as:

- What if there were already capacity constraints in the area?
- What if the utility had to plan for additional contingency situations?
- What are the solutions for the fleets served by the study feeder?

Three grid infrastructure scenarios are reviewed. First, the actual infrastructure in the study area is used in an ***available capacity*** case. There are other distribution lines and substations close to the study feeder, creating opportunities to leverage those for EV charging capacity. This is fortunate for the study area but is not representative of National Grid's whole service territory. Many parts of National Grid's service territory have older equipment, lower voltage lines, are located further from other infrastructure, and/or are more heavily loaded than the current study feeder.

As such, we review a ***constrained area*** case, in which we assume there is not additional grid capacity nearby. This allows us to evaluate solutions in other areas where grid capacity is constrained, as well as reach conclusions accounting for electric demand growth in other sectors (LDV charging and electric heating).[5] The constrained case provides important insights to make the study broadly applicable across utility service territories. In some areas, small increases in electric demand will have material distribution system impacts, though this also creates an opportunity to align investments in readying the grid for EV charging with other planned investments.

Technical Specifications of the Study Feeder (Feeder #18)

- The study feeder is a 13.2 kV feeder with a rated capacity of 8.2 MVA during summer and 12.8 MVA during winter.[4]
- It is currently loaded at 30 percent of its summer rating and 15 percent of its winter rating. Lines are usually loaded at roughly 60-70 percent of their ratings, making this a particularly favorable location for near-term electrification.
- The current peak loading of 2.4 MW is measured during the summer.
- 88 percent of total load on the study feeder is from commercial and industrial customers; only 12 percent is residential.
- The study feeder is supported by a 115/13.2kV substation transformer rated at 37.4 MW.
- The busbar supports an additional 2 feeders with peak loads of 6.6 MW and 7.3 MW.

Table 1: Summary of Case Study Feeder Data

	Summer	Winter
Line Rating	8.2 MW	12.8 MW
Current Peak Load	2.4 MW	1.9 MW
Available Capacity	5.8 MW	10.9 MW
100% MHDV Load	17.9 MW	24.8 MW
Total 100% Load	20.3 MW	26.7 MW

4 For purposes of this study, we assume that MVA (megavolt-amperes) equal MW (megawatts) – a power factor of one. In practice, the available MW (and available EV charging capacity) would be lower than MVA, though how much lower varies by line and location.

5 Estimates for residential and public charging were developed as part of the 2021 analysis. These total only ~200 kW maximum peak addition to the study feeder, which primarily serves commercial customers.

We also consider a ***contingency*** scenario. Transportation, and electric MHDV charging specifically, will sometimes require higher levels of electric reliability and resilience than most customers today. That requires configuring the network (and reserving capacity on nearby distribution lines) to allow switching to a second distribution line if the primary line goes offline. Reserving capacity on nearby lines would also add to system costs by requiring additional capacity be built, even if only used in emergencies. This need is particularly acute for fleets used in emergency operations, such as fire trucks, school buses, and utility fleets required to restore power during and after a storm. This scenario gives insight to the required infrastructure necessary to meet reliability imperatives, even during the most challenging conditions.

Table 2: Summary of Grid Infrastructure Scenarios

<table>
<tr><th colspan="2">Grid Infrastructure Scenarios</th></tr>
<tr><td colspan="2">Available Capacity (Base Case)</td></tr>
<tr><td>Available capacity on study feeder / substation</td><td rowspan="3">Review of solutions using existing infrastructure in the study area, which has nearby lines and substations that can support growing load.</td></tr>
<tr><td>Available capacity on neighboring distribution lines / substation</td></tr>
<tr><td>No contingency needs</td></tr>
<tr><td colspan="2">Constrained Area</td></tr>
<tr><td>Available capacity on study feeder / substation</td><td rowspan="3">Reviews of solutions in an area with limited ability to switch load to other distribution lines.</td></tr>
<tr><td>No available capacity on neighboring distribution lines / substation</td></tr>
<tr><td>No contingency needs</td></tr>
<tr><td colspan="2">Contingency Needs</td></tr>
<tr><td>Available capacity on study feeder / substation</td><td rowspan="3">An analysis with a view to ensuring continued operations for fleet operators in case of system outages.</td></tr>
<tr><td>Available capacity on neighboring distribution lines / substation</td></tr>
<tr><td>With contingency needs</td></tr>
</table>

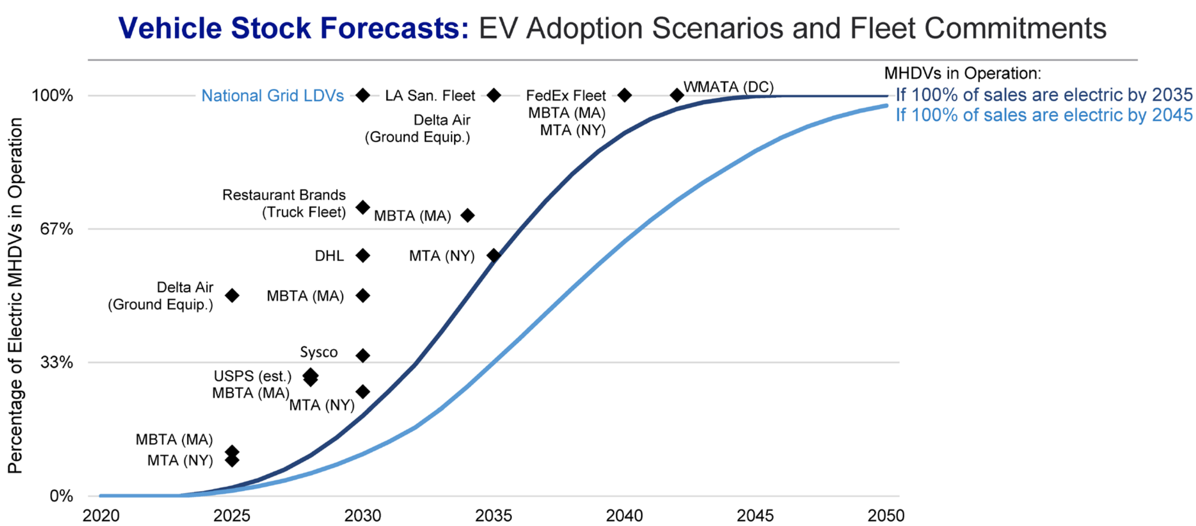
Adoption Scenarios (the 'When')

The initial study estimated the electric loads that fleet depots would introduce at full electrification. This study reviews electric MHDV adoption in stages to understand how phased introduction of fleet electrification can impact grid infrastructure as more electric MHDVs enter operations.

The analysis considers adoption in increments of 33 percent. If the analysis shows an issue at 67 percent adoption, that should be read to indicate that the problem arises by the time of 67 percent adoption; it could materialize anywhere between 33 to 67 percent. A 133 percent scenario is used to understand impacts if the overall electric demand is larger than forecasted, including if the population of vehicles grows over time, as discussed later.

These adoption levels do not imply a strict timeline for grid impacts, though illustrative adoption forecasts are shown in Figure 5. The two lines are scenarios for MHDVs in operation based on policy targets, 100 percent of vehicle sales being electric by 2035 (dark blue) or by 2045 (light blue). However, some districts or geographic areas will electrify faster than others, creating significant spot loads on individual lines. Jurisdictions with strong policy targets will see faster adoption, but even areas with no policy targets will likely see impacts due to the improving economics of electric MHDVs. Many fleet operators have also announced commitments to convert their vehicles to electric models at a pace that exceeds those policy targets, shown in Figure 5. Areas with these fleets are already seeing impacts.

Figure 5: EV Stock Forecasts with Early Adopter Targets[6]



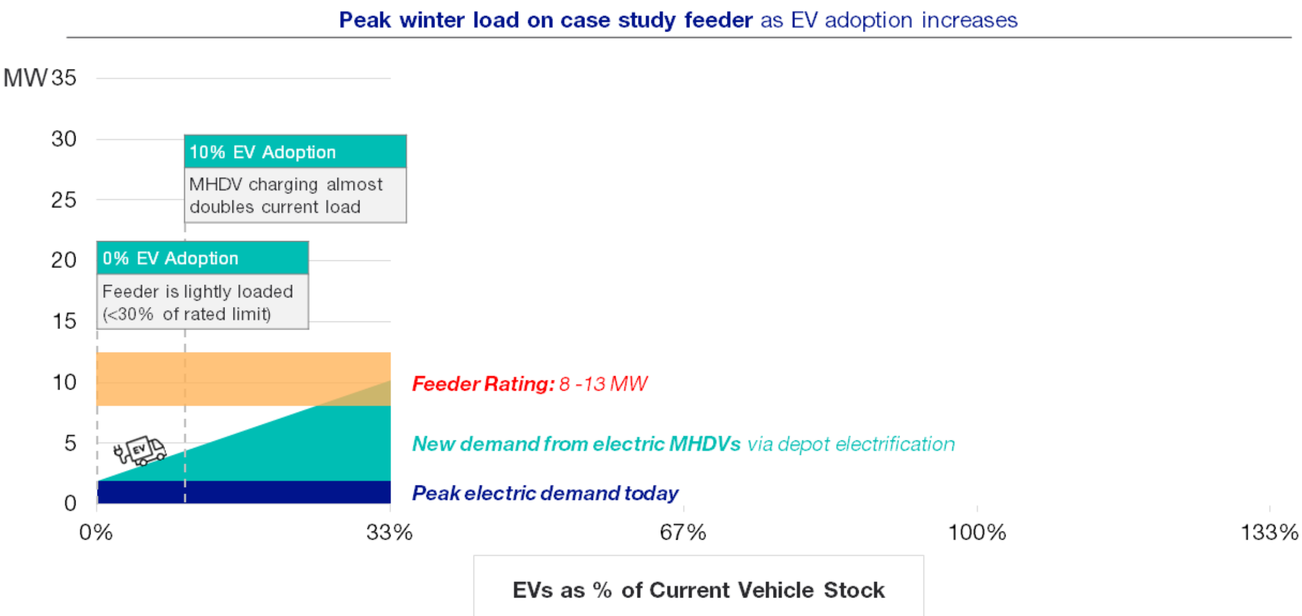
6 The vehicle stock forecasts were developed as part of National Grid's Electric Highways Study to inform the percentage of vehicles that may be electric over time, based on policy targets for sales. Lines represent vehicle stock, not sales. (https://www.nationalgrid.com/us/EVhighway; see page 13 for details of MHDV forecast). The 100% sales by 2045 scenario aligns with New York's goal of 30% zero-emission MHDV sales by 2030, and it uses sales projections to turn over the MHDV stock. The 100% by 2035 sales scenario is a more aggressive scenario with faster resulting stock turnover. The methodology results in nearly identical population percentage curves for medium-duty and heavy-duty vehicles. Sources for fleet-specific goals are public announcements, news articles, and published plans (Crunden, 2020; Delta Airlines, 2023; Deutsche Post DHL Group, 2023; Garland, 2021; MBTA, 2022; MTA, 2022; Restaurant Brands International, 2021; USPS, 2022; WMATA, 2023).

4. Results

Early Adoption: Electrifying 33 Percent of Current Vehicles in Operation

When just 10 percent of current MHDVs electrify, peak load nearly doubles on the study feeder. This is a significant increase – however, the study feeder happens to have significant excess capacity. Few feeders in National Grid's service territory are similarly capable of accommodating a doubling of load.

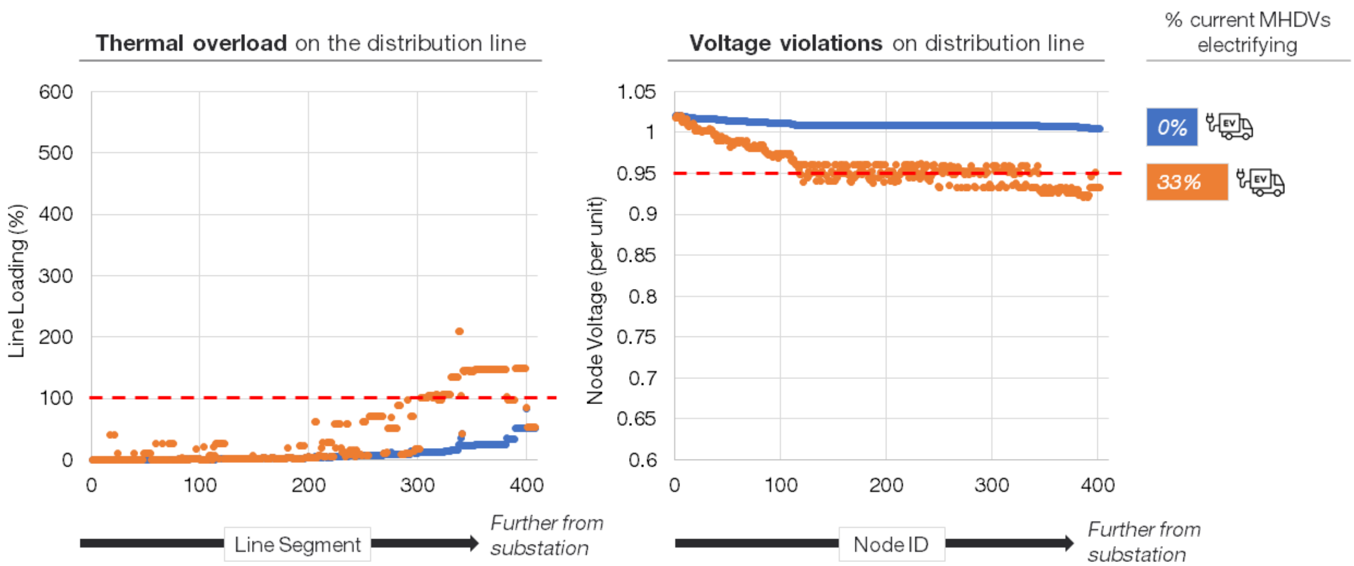
Figure 6: Effects of 33 Percent Vehicle Electrification Effects on Feeder[7]



Electric trucks will quickly consume this capacity, though. As shown in Figure 7 below, when 33 percent of current MHDVs electrify, segments of the study feeder exceed their thermal rating (above 100 percent of their rating) and drop below minimum allowable voltage levels (between 0.95 and 1.05 pu, or 95-105 percent of the nominal voltage rating). Furthermore, though not shown below, the area sees additional power losses: 5 percent of total electricity is lost to the internal resistance of the line (lost as heat). This implies that it is better to locate large fleet loads closer to substations to reduce impacts from line losses and voltage drops and could be a consideration for fleets in their planning.

[7] Range of feeder line rating reflects summer and winter ratings.

Figure 7: Impacts on Distribution Line Segments at 33 Percent Fleet Electrification

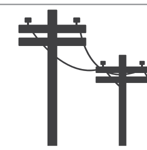
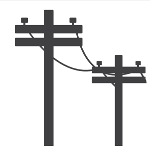


This means that we need to strategically plan to ensure that the study feeder does not overload as more fleets electrify. Luckily, in this portion of National Grid's service territory, there are other distribution lines nearby that happen to be fed from a different nearby substation, so the distribution system in this area can be reconfigured and some fleets switched to other distribution lines. This resolves the issues shown in Figure 7.

In the ***constrained area case***, however, switching load to other distribution lines is not feasible – here, we assume that other infrastructure is not nearby or does not have excess capacity. Therefore, new grid infrastructure is needed to serve the EV charging demand. A new distribution line from the substation would be needed to provide capacity (assuming there is space at the substation to accommodate it). Energy storage could also be a solution, and perhaps suitable for this early stage of electric load growth. This is discussed in detail in a later section.

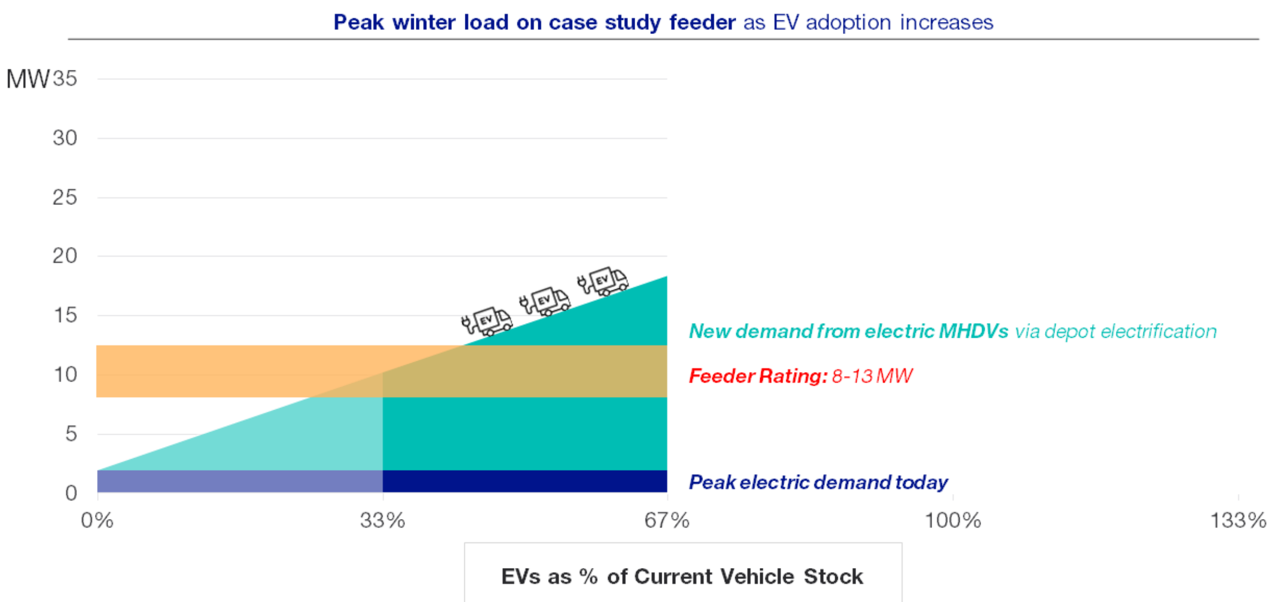
Similarly, in the ***contingency case***, a new distribution line is needed to provide service and resilience to the fleets in the area. This is more complex than the other cases because the line must come from a different transformer or substation than the current line, in case of an outage affecting the original line or substation (such as a storm knocking a tree into a line or causing flooding at a substation). In the base case, the utility switches a portion of fleets over to an adjacent distribution line; in this contingency scenario, the utility must be able to switch all fleet loads to that neighboring line.

Table 3: Summary of Infrastructure Needs in 33 Percent Adoption Scenario

By the time 33 percent MHDVs electrify…		
Scenario	**Infrastructure Needed**	
Available Capacity (Base)	MHDV charging requires **reconfiguring a neighboring distribution line and switching some load onto it**.	
Constrained Area	A **new distribution line** is needed.	
Contingency Needs	A **new distribution line** is needed from a different transformer (or substation) than the existing line.	

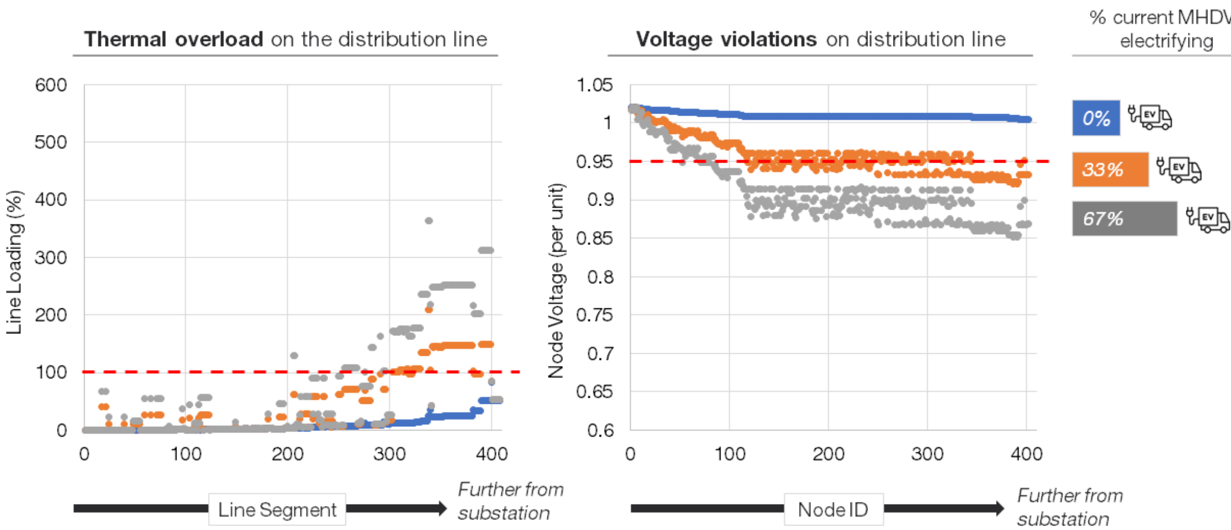
Broad Adoption: Electrifying 67 Percent of Current Vehicles in Operation

Figure 8: Effects of 67 Percent Vehicle Electrification Load on the Study Feeder



When two-thirds of current vehicles electrify, increased needs and impacts on the electric grid begin to emerge. At 67 percent adoption, the thermal and voltage impacts are greater and there is not enough spare capacity on the neighboring distribution line to serve the electric load, so **a new distribution line** is required to serve fleets in the area. In the base case, this capacity can be provided from a nearby substation and avoid impacts on the substation currently serving the area.

Figure 9: Impacts on Distribution Line Segments at 67 Percent Fleet Electrification

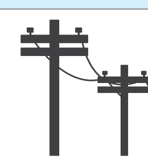
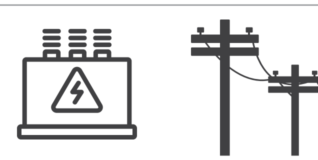
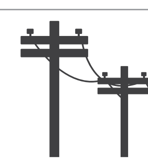


If not for that load-switching, the substation currently serving the study feeder would also start to see equipment overloads between 33 percent and 67 percent adoption (see more detailed description of substation impacts in Figure 14 on page 24). This would require a major upgrade to the existing substation or a new substation if it were not possible to switch load onto a nearby substation with available capacity.

Because of this, a more constrained area without capacity available on adjacent electrical infrastructure would require an expanded or new substation to bring in more capacity and serve new distribution lines. This is a significant effort that could take upwards of eight years to place in service. Space constraints, particularly in urban areas, can introduce further complexity and cost and may even make this solution infeasible.

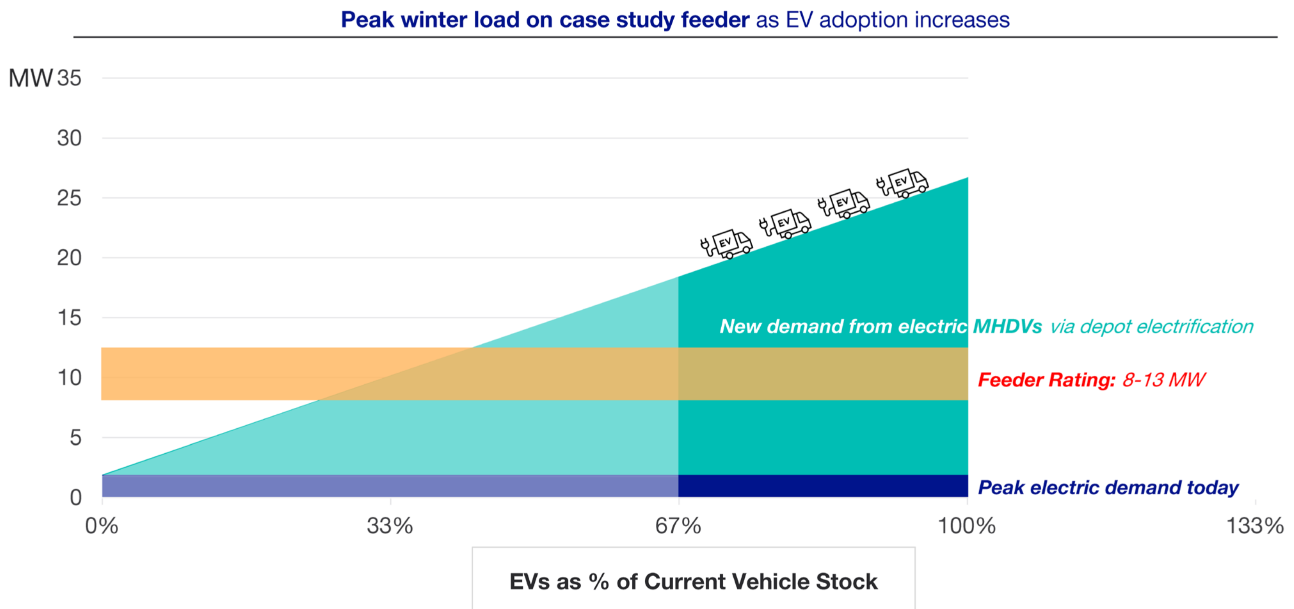
In the contingency case, the new line from the 33 percent case continues to serve fleets adequately.

Table 4: Summary of Infrastructure Needs in 67 Percent Adoption Scenario

By 67 percent adoption…		
Scenario	**Infrastructure Needed**	
Available Capacity (Base)	**New distribution line** to nearby substation (which currently has excess capacity) is needed.	
Constrained Area	**New or expanded substation** needed along with new distribution line extending to fleets.	
Contingency Needs	**New distribution line from 33 percent case continues to serve fleets.**	

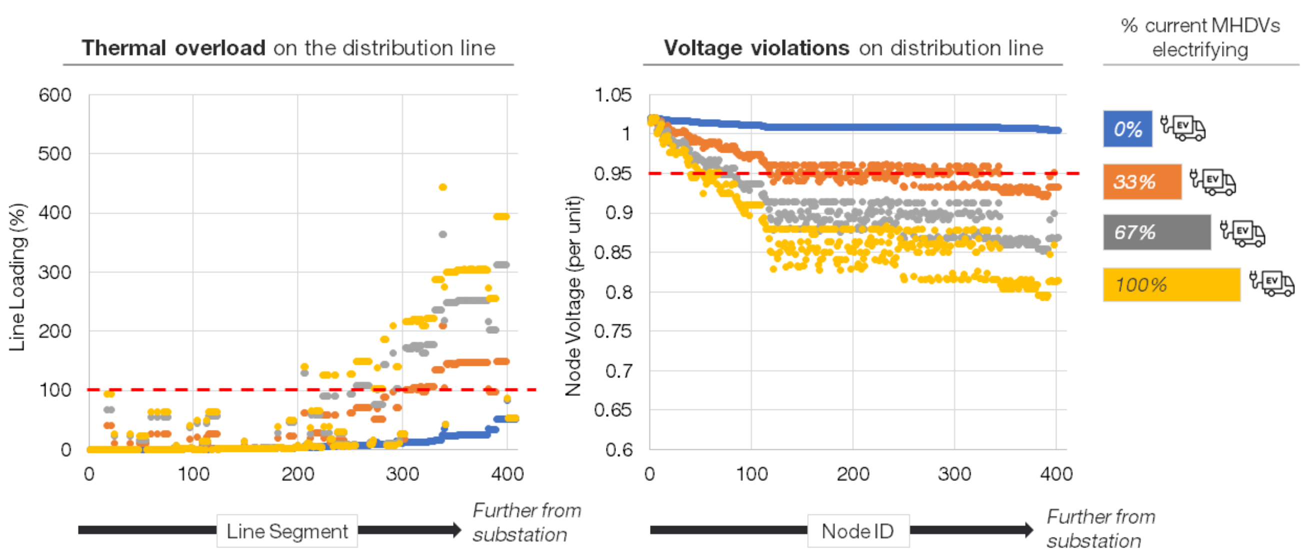
Full Adoption: Electrifying 100 Percent of Current Vehicles in Operation

Figure 10: Effects of 100 Percent Vehicle Electrification Load on the Study Feeder



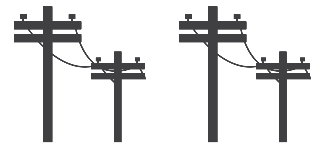
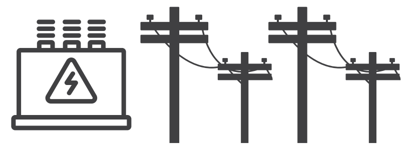
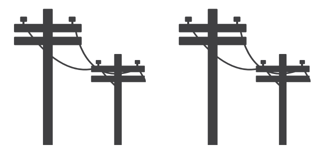
When every existing MHDV on the line is replaced with an electric vehicle, the loading on the line increases further, violating the thermal rating of the study feeder by over 300 percent in some areas and causing more severe voltage drops on even more segments of the study feeder. Several fleet depots are estimated to each introduce about 4 MW of peak electric load, whereas all ten fleet depots could introduce around 25 MW of load in winter.

Figure 11: Impacts on Distribution Line Segments at 100 Percent Fleet Electrification



To address these issues, a second distribution line from the nearby substation is needed to serve the study area. In the constrained case, the new or expanded substation from the 67 percent adoption level can continue serving this load growth but would need additional distribution lines to distribute power.

Table 5: Summary of Infrastructure Needs in 100 Percent Adoption Scenario

By 100 percent adoption…		
Scenario	**Infrastructure Needed**	
Available Capacity (Base)	**Second new distribution line** to nearby substation is needed.	
Constrained Area	**New or expanded substation continues to serve load** along with **new distribution lines** extending to fleets.	
Contingency Needs	**Second new distribution line** to different transformer or nearby substation is needed.	

This study has the benefit of looking at the ideal solutions for pre-determined adoption levels. In practice, impacts could materialize at multiple, smaller increments of adoption, which would each require a new solution to provide sufficient capacity. Understanding the needs of a long-term solution would provide important context to system planners and lead to a more efficient and lower cost investment plan for electric fleets.

We can see an example of this concept in the Constrained Area case. If a new substation is necessary to serve fleet depots in the long-term, it may not make sense to build a new distribution line – tapping a different substation – to serve early adopters, when that line could instead be built along with the new, presumably closer substation. That distribution line would support early adoption but is left "stranded" by the later solution – perhaps an inefficient use of investment dollars.

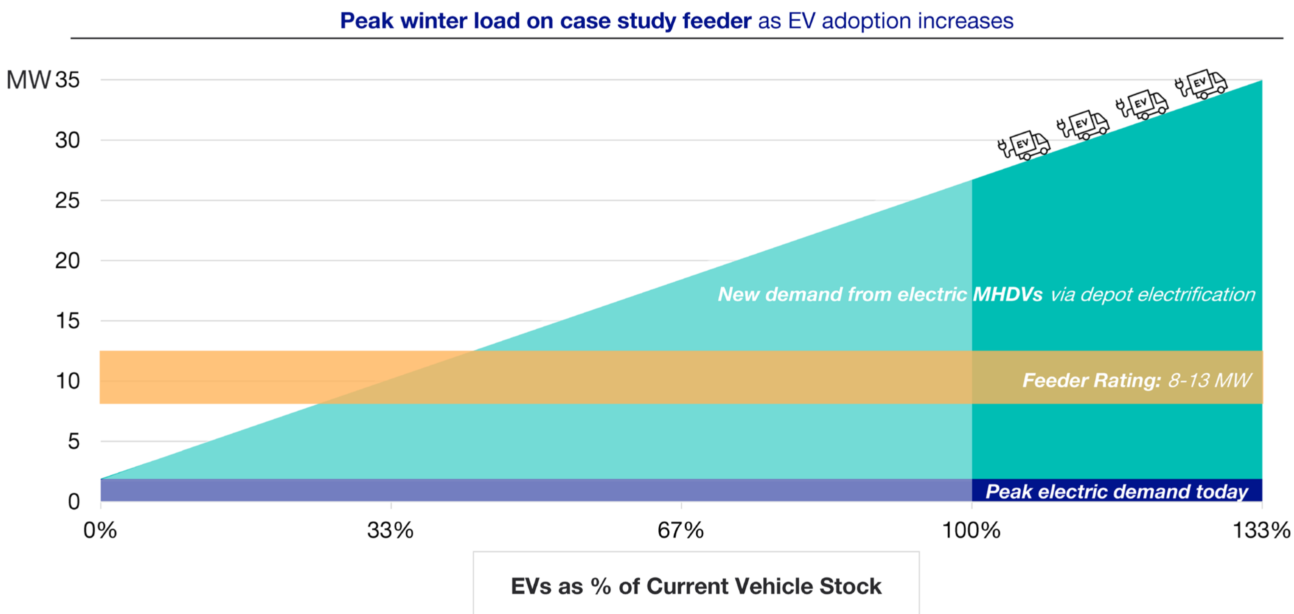
The ideal solution in each fleet area may differ and depend on variables that will not always be clear, but utilities should seek to plan for "no-regrets" investments where possible. If large investments, such as a new substation, will be needed to accommodate large-scale adoption, it may be most cost-effective to design early solutions with those future projects in mind (and, as discussed in National Grid's Electric Highways study, even accelerate future investments and "build it once and build it right").

Because of the variable and site-specific nature of cost estimates, none are given in this study, but the transition to a mostly decarbonized transportation sector will require a step change in investment.[8]

[8] Recent study results (including draft results) from California estimate that utilities there will need to spend $15 billion to $50 billion by 2035 to upgrade their distribution grids for EVs (California Public Advocates Office, 2023; Kevala, 2023).

Full Adoption with Fleet Growth: Electrifying 133 Percent of Current Vehicles in Operation

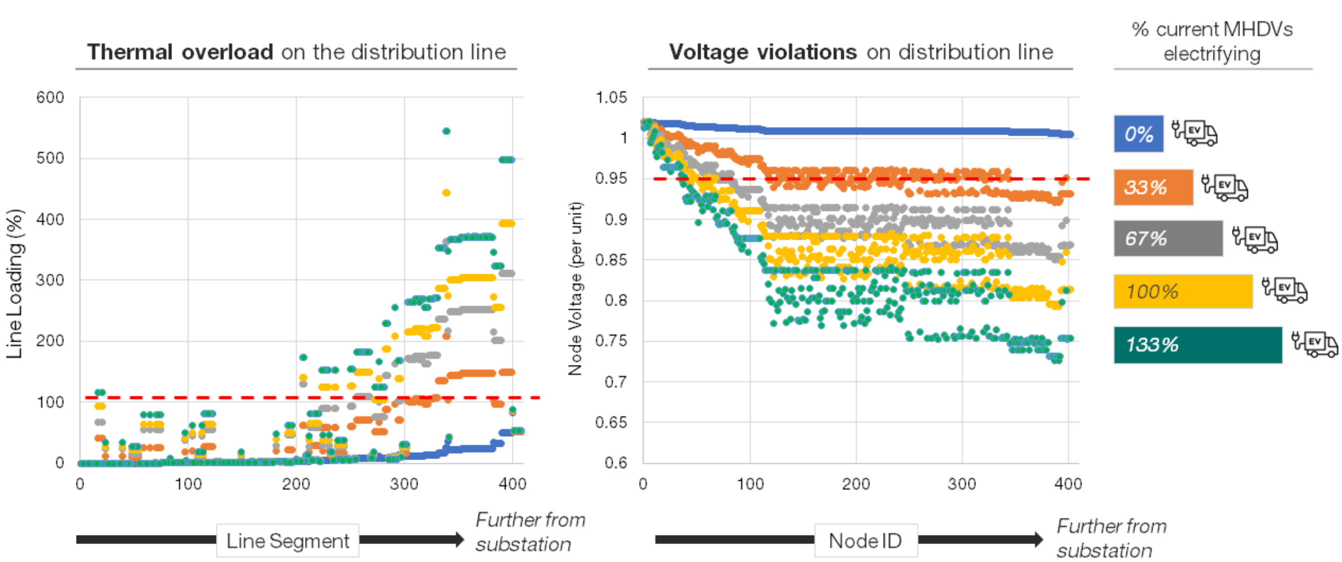
Figure 12: Effects of 133 Percent Vehicle Electrification Load on the Study Feeder



This study uses estimates of current vehicle stock, but the U.S. Energy Information Administration (EIA) forecasts over 50 percent growth in the number of MHDVs by 2050 in its 2023 Annual Energy Outlook.

More vehicles will lead to more charging demand and faster load growth, which will increase electric demand on the grid. To understand potential growth in the number of fleet vehicles on the road as compared to today, or potential undercounting of smaller fleet vehicles in the original survey, we include a 133 percent case. In addition, this 133 percent scenario provides insight into areas that will experience substantial load growth from other sectors, such as passenger vehicle charging and electric heating (which is not considered in this analysis).

Figure 13: Impacts on Distribution Line Segments at 133 Percent Fleet Electrification



There are other factors that could result in higher charging loads than estimated under our initial study's load forecasting methodology:

- The 2021 study was based on "right-sized" charger requirements to minimize the number of chargers and the resulting peak load, with chargers sized to meet each fleet's needs while splitting each charger between two vehicles and charging during overnight hours. However, some fleets have been oversizing charging capacity in favor of flexibility in their operations.
- Megawatt charging standards released in summer 2022 indicate that the trucking industry is looking for faster charging that can better support dynamic operations (CharIN, 2022). These high-power chargers will increase the need for grid infrastructure and require further support from utilities. If the industry is trending toward faster charging, even in only some applications, planning now will be critical to ensure that the electric grid can quickly integrate these large loads and support the transportation industry.
    - For comparison, the highest rated charger considered in this analysis had a capacity of 150 kilowatts – 15 percent the rate of a megawatt charger – and was sized to provide power to the vehicles based on their overnight charging requirements. This is discussed in the Modeling Methodology & Analysis section of the 2021 study.
- Load estimates were calculated based on assumptions of vehicle numbers, types, routes, schedules, and other factors. Discussions with fleet operators, as well as service requests from fleets in these areas, suggest that our forecasts may be too conservative. Our 2021 analysis estimated one site would require 1 MW for full electrification, only for the customer to then request 1 MW for depot charging for its first vehicles in 2022. At another site, we estimated 300 kW for the customer, who then indicated it estimates needing 2.5 MW of EV charging capacity in the future. In addition to these higher-than-expected numbers, a new operations center with about 4 MW of peak load for EV charging is being built near the study area and is expected to consume all available capacity on its distribution line (not the study feeder).

There are also factors that could result in lower charging loads and fewer system impacts. Improvements in cabin heating, for example, would lower the energy requirements in cold weather and reduce the winter peaks that we see. Better data on cold weather performance may also soon become available as electric MHDVs are rolled out across the country.

We offer these not to undercut the results of our own study, but to emphasize the uncertainties in predicting future EV load growth and its effects and the substantial risk of underestimating fleet charging load.[9] This context is important in that it shows how quickly our estimates and forecasts are being outpaced by technology adoption and innovation, increasing the pace at which we will see system impacts. In an electric future, available capacity will not remain available for very long – which could mean that even our ability to switch load onto other distribution lines or substations will quickly become limited.

[9] "Prediction is very difficult, especially about the future."

Upstream Grid Impacts

This study focuses on the distribution system, which delivers power from substations to end users. Impacts on the substation are also important to consider and could lead to additional issues that must be addressed.

At the substation serving the study feeder, the existing equipment can handle early electrification, but Figure 14 below shows how load growth eventually exceeds the limits of that equipment. Between 33 percent and 67 percent adoption, the transformer powering the study feeder will reach 100 percent of its rated loading, and the new EV load may also reduce the transformer's rating by limiting the amount of time it has to cool overnight. This is a critical limitation since transformers are costly items with long lead-times; it can take years to replace a transformer like this, and they will have very long order times for the foreseeable future (Walton, 2023b). If not planned for adequately, this could lead to significant delays in providing service to new fleets.

The analysis base case anticipates serving the fleets from a different, nearby substation in order to alleviate the loading that would be seen. Without this nearby infrastructure, the existing substation would have to be upgraded or expanded or a new substation would need to be built before 67 percent adoption – as demonstrated in the constrained area case.

Figure 14: Impacts of Fleet Electrification on Study Feeder's Substation Equipment[10]

Overloads (%) on selected substation devices by EV adoption level

		0%	33%	67%	100%	133%
Transformers	*CT1*	56	93	129	167	204
	CT2	34	56	78	100	122
	CT3	34	56	78	100	122
	CT4	45	74	103	134	163
	CT5	45	74	103	134	163
	CT6	34	56	78	100	122
	CT7	14	75	135	197	258
	CT8	14	75	135	197	258
	T1	43	72	100	130	158
Breakers & Bus Bar	*B1*	34	56	78	100	122
	B2	7	37	68	99	129
	BB1	34	56	78	100	122

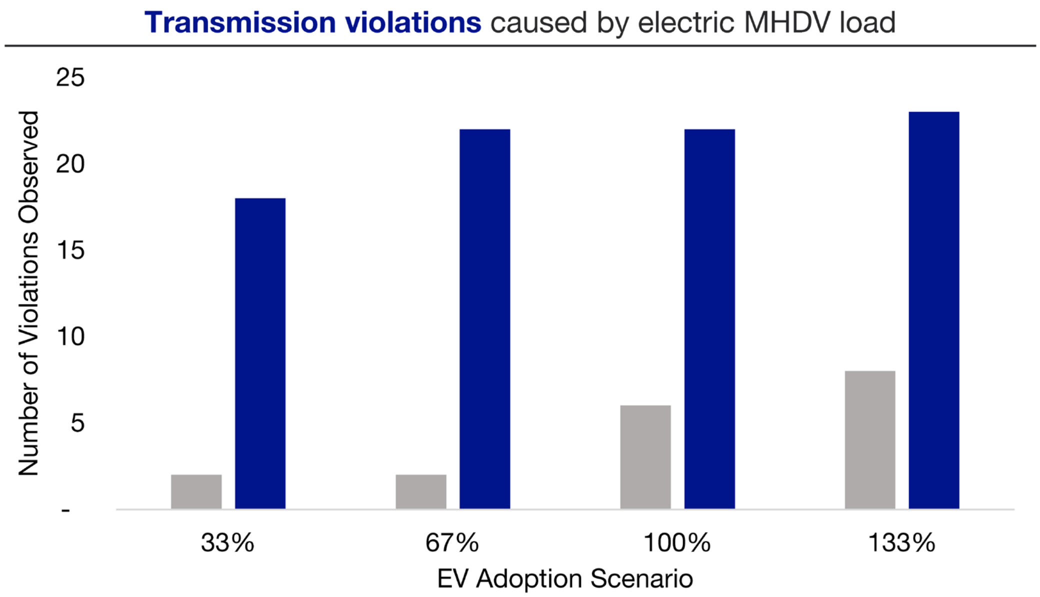
In addition, load impacts will begin to materialize on the transmission network. Substations can feed multiple distribution lines and a single transmission line can serve multiple substations, meaning that transmission lines can feel the impacts of not only fleet electrification on the study feeder but also from surrounding commercial districts as well.

[10] The substation currently serves residential and commercial customers. In addition to fleet charging load, the substation would be expected to serve any additional loads in the future, such as LDV charging loads for residential and public charging.

To quantify this, we modeled fleet loads from all 51 fleets and all 19 distribution lines in the 2021 study – not just the study feeder (feeder #18) – in simple transmission planning studies reviewing N-1 and N-1-1 criteria, which transmission operators consider to ensure a robust and reliable transmission network.[11] Estimates of light-duty residential and local public charging on those 19 distribution lines were also included. No other load growth, such as EV highway charging or electric heating, was included.

Even at 33 percent adoption levels, there are violations when planning to serve load under N-1 and N-1-1 scenarios. This is summarized in Figure 15.

Figure 15: Thermal Violations Observed in Transmission Contingency Scenarios as EV Adoption Increases



The solutions required for these violations include the replacement of current transformers, reconductoring multiple miles of both overhead and underground transmission lines as well as station connections, and operational changes to prevent further upgrades. These solutions can be costly and involve long timelines to study, design, and construct. These impacts represent a longer-term risk to the pace of EV adoption, and therefore must start being addressed now. Utilities must plan not only to enable "spot" load on the distribution system, but to ensure that load can be accommodated by the transmission lines delivering power to area substations.

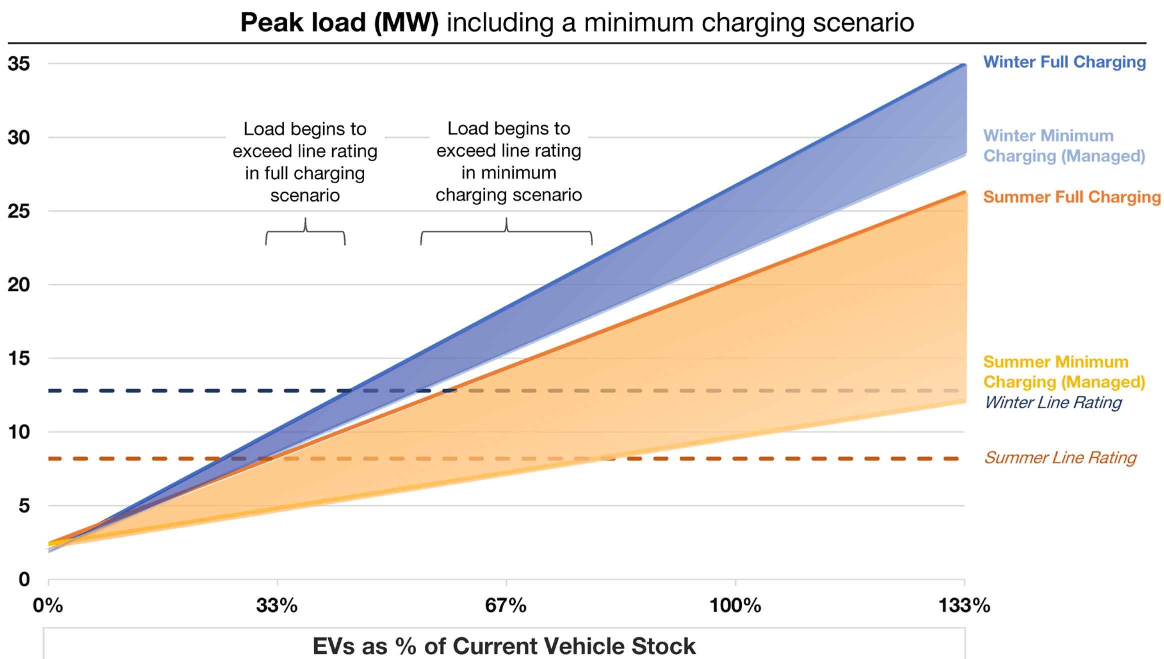
While identifying specific areas of available capacity on transmission networks may not be practical, due to the networked nature of such systems, incorporating MHDV loads into planning forecasts can give transmission operators visibility to where broader network reinforcements will be required and allow them to address these needs simultaneously with other investments.

[11] See, for example, https://www.iso-ne.com/static-assets/documents/2017/11/transmission_planning_technical_guide_rev2.pdf, pages 48-50. N-1 refers to one contingency failure, or one line going out or one piece of equipment failing. Another required planning study is for N-1-1, which refers to two such contingencies happening simultaneously.

Mitigating Distribution System Impacts: Managed Charging

Our first study analyzed a 'constant minimum charging' case, where vehicles were assumed to charge at the slowest rate possible overnight to have full batteries at the start of operations the next morning. While not exactly the same as a managed charging program (which would target specific system peak hours), it is informative to the benefits of managed charging. The study found that slowing charging reduced the peak load, though not enough to eliminate the grid impacts. In winter, at 100 percent adoption, the peak went from 27 MW in the full charging cases to 22 MW in the minimum charging case – certainly beneficial, but still far exceeding the existing infrastructure's capabilities. In the summer, there was a much larger benefit; this is because the vehicles need less electricity in the summer and so need to recharge less overnight. However, since winter charging still drives needs, that would still need to be considered by any system planning.

Figure 16: Load Growth from Fleet Electrification Under Full Charging and Managed Charging Cases



Rates or tariffs can be designed to incentivize charging at optimal times. These programs are often designed to address system peaks and constraints. Active demand management could also be used to manage charging loads among fleets and minimize peak demand in a specific area of the grid, such as on the study feeder. Some fleet operators, though, may not be receptive to reducing charging loads at certain times of day or the year. Companies that deliver packages before the December holidays, for instance, may be willing to pay more to charge their vehicles and ensure continued operations. Other fleets may operate vehicles on multiple shifts per day and not have down-time for long charging sessions. As such, a view of fleet needs across a commercial district – not just at each premise – may be beneficial to balance competing interests.
It is worth reiterating that this study solely considers overnight depot charging. Where public fast-charging is available to fleets, it could have similar effects to managed charging in this area by shifting load from overnight at the depot – when the grid is constrained – to daytime at specific fast-charging locations. As National Grid's 2022 Electric Highways Study demonstrates, however, these fast-charging sites will also require anticipatory planning on the utility's part (Katsh, Fagan, Wilke, et al., 2022).

Implications for the Electric Grid as Trucking Districts Electrify

Electrifying a quarter or a third of MHDVs could sound like it is far in the future, but it may not be. Many large fleets have ambitious electrification or zero-emission goals for the next five or ten years.[12] This study reveals that certain areas of the electric grid would be better suited to serve rapid electrification than other areas, such as where there is limited available capacity.

The study feeder could be considered an Area of Capacity, with the ability to accommodate near-term growth of electric fleet vehicles. In summer, it has 5.8 MW of available capacity, and even more in winter (though, today, the summer line rating will be the limiting one in planning studies). This will not be the case across the electric grid. In Areas of Need, commercial districts with more heavily loaded or limited grid infrastructure, we should expect to see grid impacts (and require upgrades) sooner.[13]

Figure 17: Description of Electric Distribution Characteristics

Areas of Capacity	Areas of Need
‣ Sufficient capacity for near-term EV needs. ‣ Fleets can electrify with minimal grid upgrades. ‣ Upgrades may be needed over longer term, but could proceed in parallel with early adopters.	‣ Limited available capacity. ‣ Constraints on near-term electrification. ‣ Large upgrades needed to support scale of EV fleets. ‣ Grid upgrades can enable many fleets to electrify.

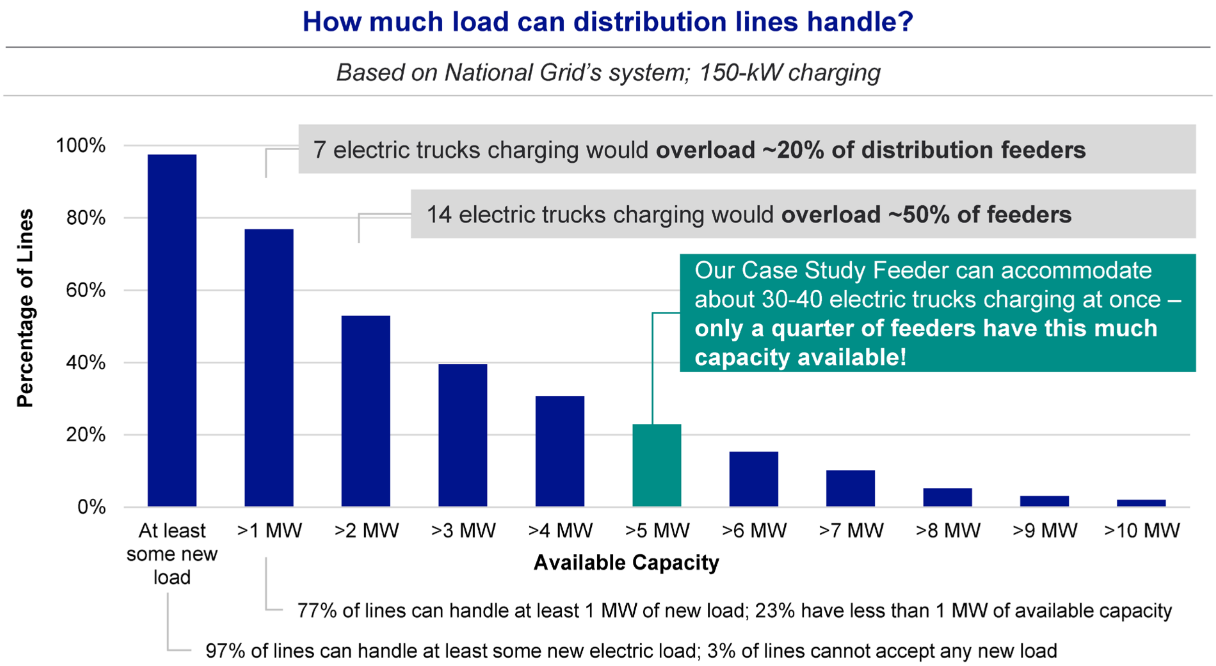
Categorizing areas into this framework will require detailed studies and there will not necessarily be clear dividing lines between areas. Areas of Capacity with ample spare capacity could still face constraints in the future – as happens with the study feeder. It has significant available capacity and can support 33 percent vehicle adoption before seeing impacts, and can support further adoption with minimal upgrades. At some point, though, even Areas of Capacity will face constraints and require more significant upgrades for EV charging needs.

[12] For example, see the Environmental Defense Fund's Electric Fleet Deployment Commitment List. Additionally, a number of fleet operators are participating in the North American Council for Freight Efficiency's (NACFE) Run on Less – Electric Depot program, which will inform needs for fleets to scale BEVs at their sites. See https://runonless.com/electric-depot/.

[13] For further discussion, see Joint Utilities' comments to New York PSC's Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure (case number 23-E-0070), filed June 5, 2023. Available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={20FE8C88-0000-CF1D-B046-563200EBE36C}.

Only around 25% of National Grid's lines have 5 MW or more of available capacity. Many could not handle even one large EV fleet customer. Considering this context is important for expanding this analysis from a case study area to a utility service territory. Load growth and potential solutions need to be reviewed more granularly where fleets are anticipated to electrify.

Figure 18: Available Capacity on National Grid Distribution Lines[14]



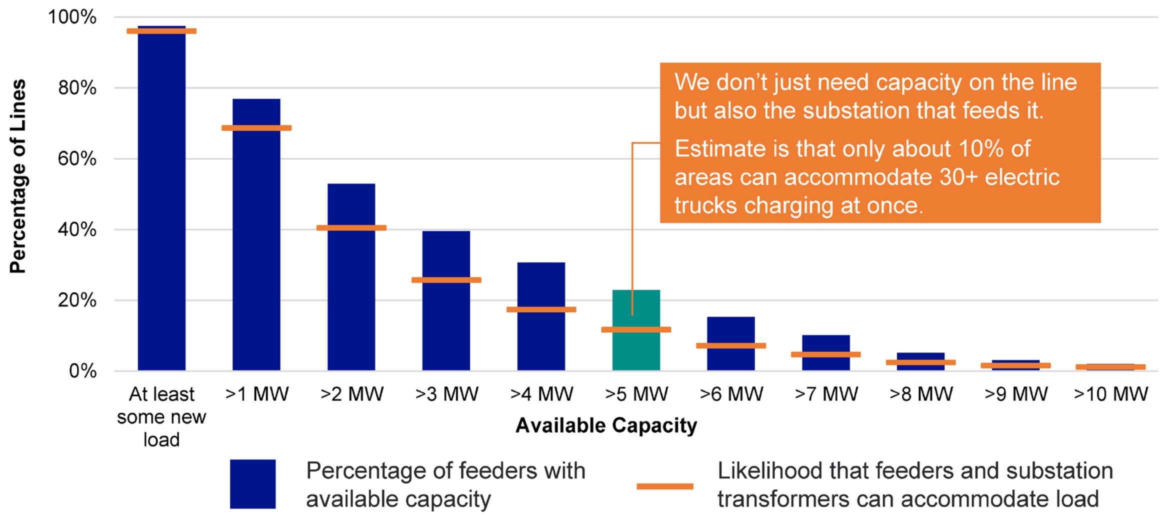
Considering grid infrastructure beyond the distribution lines will be important. As shown earlier, fleet electrification will have implications for substations and transmission lines. Figure 19 adds consideration of substation capacity by reviewing the likelihood of available capacity on both the distribution line and the substation transformer. Transformers also have some capacity limitations and, combined, around just ten percent of areas are likely to have both line and transformer capacity for 5 MW of capacity.

[14] Available capacity is against summer ratings.

Figure 19: Available Capacity on National Grid Distribution Lines and Substation Transformers[15]

How much load can distribution lines and transformers handle?

Based on National Grid's system; 150-kW charging



Planning those long-term infrastructure upgrades now can facilitate smooth EV adoption and help ensure efficient spending. For example, as discussed earlier, making a large investment for 33 percent adoption without considering if it could also suffice for 67 percent or greater adoption could result in duplicative investment and stranded costs. Related, encouraging fleet charging in an Area of Capacity would be cost-effective early on and could allow time for longer-term upgrades to be put in place while fleets use up the available capacity. Supporting fleets that wish to electrify now while planning upgrades for the future could lead to a holistic, coordinated strategy that enables electric MHDVs at least cost.

[15] Likelihood lines are probabilities calculated by multiplying the percentage of distribution lines with available capacity by the percentage of transformers with available capacity. For the 5+ MW column, approximately 23% of lines and 49% of transformers have that much capacity, resulting in a likelihood of 11% that both pieces of infrastructure would have capacity.

5. Infrastructure Options to Meet Electric Fleet Needs

The analysis emphasizes the importance of considering multiple scenarios to understand how we can ready the electric grid for fleet depot charging. In the first phase of our partnership, National Grid and Hitachi Energy identified the need for an end-to-end analytical approach to infrastructure for depot charging, incorporating solutions across distribution infrastructure, transmission infrastructure, and 'non-wires' alternatives such as energy storage and charging programs.

We consider three holistic solution strategies below – electric network reconfiguration, multi-value grid infrastructure, and non-wires solutions – the options for "how" utilities can address EV charging needs. Additional detail can be found in Appendix B.

Electric Network Reconfiguration

Electric network reconfiguration allows a utility to switch fleet charging load onto adjacent distribution lines or even build new distribution lines to neighboring substations to avoid constraints on the original distribution line or substation. The costs of reconfiguration are relatively small and can allow near-term progress on electric MHDV adoption, but may not always be a viable solution, depending on local grid conditions, and will not serve electric fleets at scale. Over time, other parts of the electric distribution system will run out of spare capacity, especially as new demands from LDV charging and electric heating take capacity across the system.

This strategy is ideal for an area like the case study feeder, which might be viewed as a "best place for a worst case" of charging load. If charging demands outpace expectations (as initial service requests in this area suggest it very well might), this area has capacity on the initial feeder and spare capacity on adjacent infrastructure to flexibly adapt. However, upstream (transmission) impacts must additionally be evaluated to ensure long-term sustainability of this approach.

Multi-Value Grid Infrastructure

Traditional utility investments, specifically new distribution lines and new/expanded substations, can serve multiple fleets in a commercial district. These are core utility investments that can meet long-term growth in an area once they are installed.

Making **multi-value grid upgrades** will be especially valuable in areas with existing grid constraints, where rapid fleet electrification is expected, and where other grid upgrades are scheduled (such as to address aging infrastructure). This can also be helpful where that same grid infrastructure can be used to meet other needs such as electric heating, public charging, and new renewable energy interconnections, among other uses.

This strategy creates the most capacity of any option (circuit switching does not technically increase capacity in an area), allowing for rapid ramping of fleet electrification once in place. These investments can be targeted to high-potential heavy trucking districts to incentivize not only transportation electrification but other economic development, and to benefit communities that host large numbers of fleet depots.

This strategy is not risk-free. It could require a significant amount of investment and, if investments are made in anticipation of future load growth, there is a risk of them being underutilized for a period of time before load materializes, especially if it does not materialize as planned. However, policies are clear, and economics are continually favoring electric vehicles. There is a corresponding risk that companies will try to convert to electric vehicles but are unable to because of grid constraints and the long lead-time of grid infrastructure upgrades. Mitigating this risk should also be a priority of utilities and policymakers.

Energy Storage

With this solution, utilities can deploy non-wires solutions such as storage to match demand for charging to system capacity.

A stationary battery energy storage system (BESS) can be placed on different parts of the network:

1. At the substation – sited to prevent substation overloads and increase deliverability from the transmission network.
2. On the distribution network – sited to prevent feeder overloads, voltage dips, power losses, to increase capacity on the line, and to provide backup power in case of an outage.
3. At the customer site / behind the meter – sited to address both of above issues, as well as allow the fleet to charge at optimal times (e.g., when rates are lower) and manage demand charges.

Storage could be implemented more quickly than some traditional infrastructure solutions. It can help maximize utilization of existing infrastructure and support EV charging demand while larger, longer-term projects are developed. It could also be paired with renewable energy to increase the amount of available kWh to charge during the day. However, current storage technologies do not serve multi-day charging needs; there must be time for the storage to charge during the day. This introduces challenges in finding time and grid capacity to charge a battery to meet fleet needs. At high levels of adoption, there is not enough available capacity to charge the battery during the day to meet fleet needs overnight. These issues will become more challenging as electric heating and residential charging increase.

Appendix C contains detailed analysis of energy storage as a solution to the grid impacts observed in this study. There is potential for storage to meet EV charging needs, but there are limitations based on how storage is allowed to charge and discharge and how to ensure that it does not cause adverse impacts on the electric grid.

Another opportunity for storage is for utilities to develop energy storage as a grid asset and provide capacity to fleet customers (and for other needs when not needed by fleets). There are limitations to what utilities are currently allowed to do with storage, though. Some jurisdictions do not allow utility ownership of storage. System operators and planners are concerned that storage will cause adverse impacts on the electric grid without better capabilities to manage and control it, even if it is intended to minimize grid needs. Several entities are already looking at allowing energy storage as a transmission asset to solve some reliability and system needs; using storage for EV charging grid capacity would similarly make sense.[16],[17] National Grid, in fact, has developed storage to serve capacity needs in other areas, with significant cost savings for customers (Gheorghiu, 2019; National Grid, 2019).

Much of the storage developed to date has been for other use cases, such as providing generation capacity or backup power. Storage here would serve a different purpose – transmission and distribution capacity – that utilities are obligated to provide through their core operations.

What about energy storage and managed charging together?
Managed charging can reduce peak demand but will not reduce the total amount of energy needed by electric fleets – it will just shift the time of charging. Where managed charging can be planned for with certainty, it could reduce the size of the battery needed.

---

[16] The Midcontinent Independent System Operator (MISO) allows Storage as a Transmission-Only Asset (https://www.misoenergy.org/stakeholder-engagement/MISO-Dashboard/storage-as-transmission-only-asset/) and the Independent System Operator New England (ISO-NE) has filed with FERC for approval of this (https://isonewswire.com/2023/01/10/energy-storage-would-aid-transmission-system-under-iso-ne-proposal/).

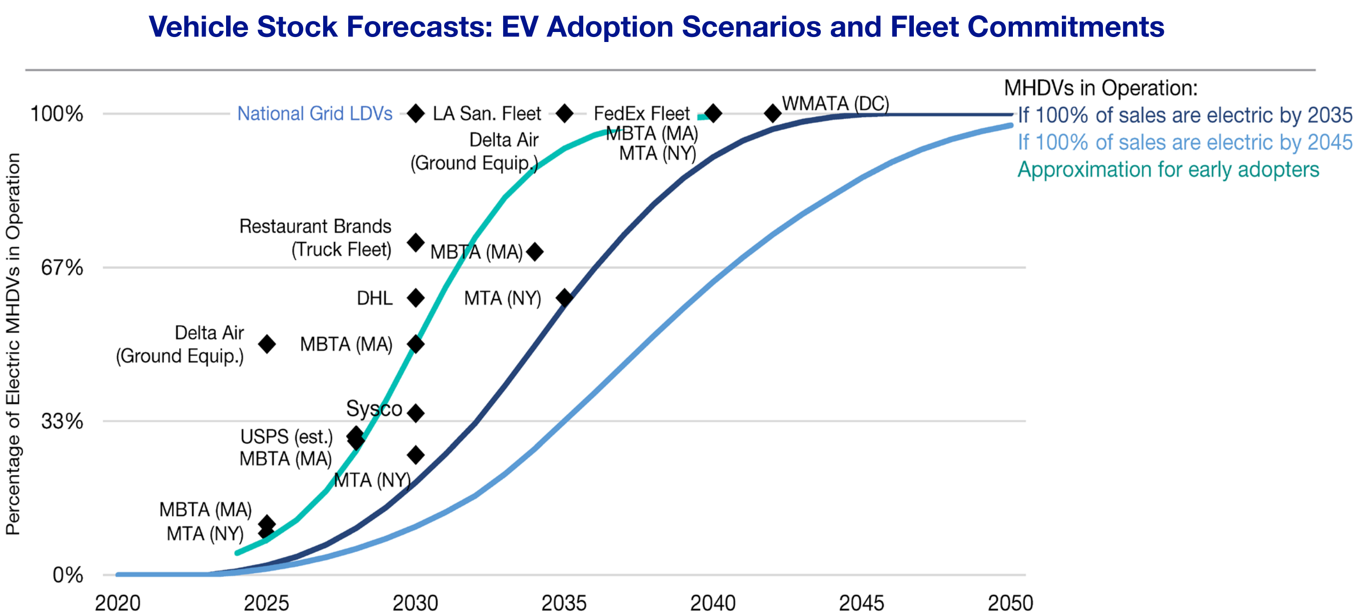
[17] The Energy Storage Association, now under the American Clean Power Association, developed a policy position on using storage as a transmission asset: https://energystorage.org/wp/wp-content/uploads/2019/12/2019-Policy-Position-Storage-as-Transmission.pdf.

6. Findings and Recommendations

Some Areas Will See Grid Impacts from MHDV Electrification Soon

Under current regulations in New York and Massachusetts, which dictate up to 100 percent ZEV sales for MHDVs by 2045, 33 percent of all MHDV vehicles in operation may be electric by the early 2030s. However, as previously shown in Figure 5 and repeated in Figure 20, some companies are already converting growing percentages of vehicles in their fleet to electric. It will take longer for MHDVs to decarbonize at scale, but areas with these first-moving fleets will see electric demand spike in the next few years. Some locations are already encountering capacity constraints. Utilities can support these early adopter fleets while also accelerating much broader MHDV electrification by reducing the cost and timeline for all fleets to connect to the electric grid. If the grid is not ready to accommodate these early adopters, companies may need to delay MHDV adoption.

Figure 20: EV Stock Forecasts with Early Adopter Targets[18]



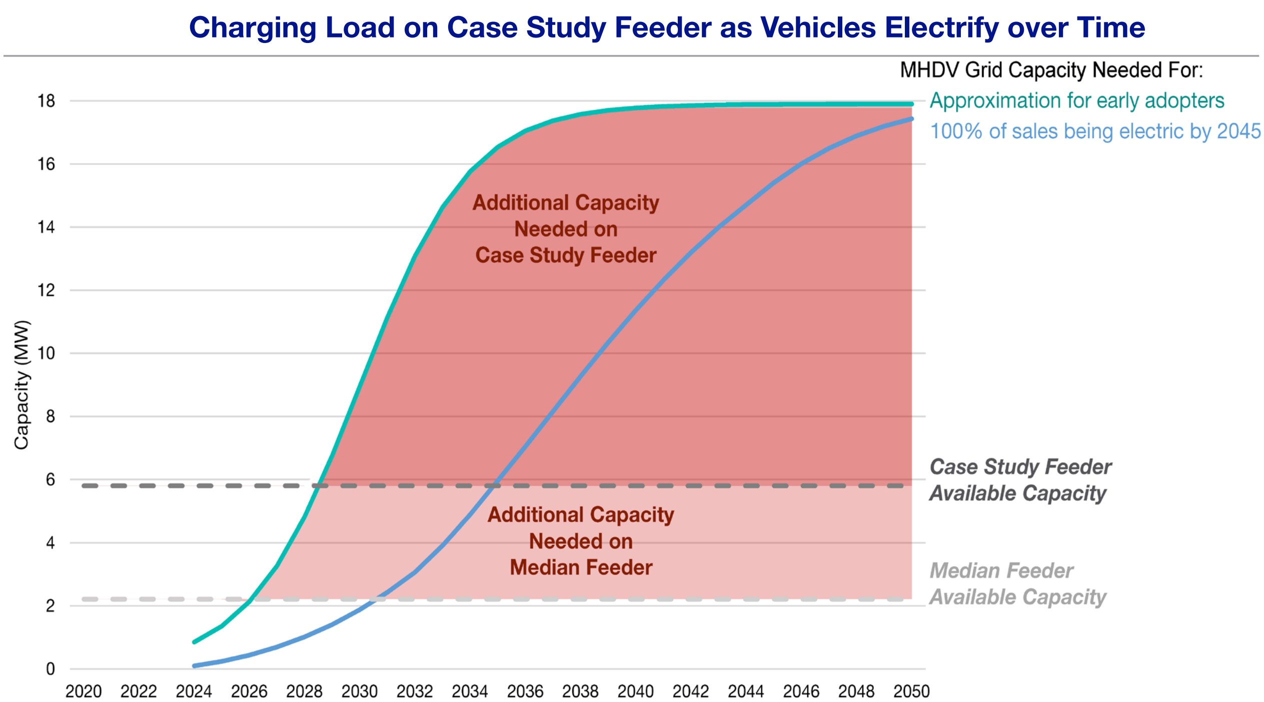
Our analysis of the study feeder emphasizes the importance of proactively identifying these early-adoption and high-vehicle-density areas. Even the study feeder, which is lightly loaded at around 30 percent of its summer rating and 15 percent of its winter rating, would be overloaded once 33 percent of existing fleet vehicles are electrified.

Figure 20 does not provide guidance on how well utility networks can accommodate electric fleet vehicles. The study feeder has more available capacity (5.8 MW in summer and 10.9 MW in winter) than about 80% of other lines (~2.2 MW of available summer capacity in National Grid's service territory). More constrained areas will still see fleets requesting capacity, and utilities must be able to serve them and ensure EV adoption can scale quickly.

[18] Sources for fleet-specific goals are public announcements, news articles, and published plans (Crunden, 2020; Delta Airlines, 2023; Deutsche Post DHL Group, 2023; Garland, 2021; MBTA, 2022; MTA, 2022; Restaurant Brands International, 2021; USPS, 2022; WMATA, 2023).

Figure 21 uses the previous vehicle adoption curves and aligns them with the load estimates of this study to provide indicative timelines of when new grid capacity will be needed to serve fleets. On the case study feeder, which has 5.8 MW of available summer capacity, new capacity would be needed around 2035 under policy goals but 2028 in for early-moving fleets. On a distribution line with a median amount of available capacity – again, about 2.2 MW – and the loads estimated here, new capacity would be needed by around 2030 under policy targets and 2026 for early-moving fleets. Other lines will have different amounts of available capacity and charging demand (illustrated by the results in Figure 3) that would lead to different, specific impacts. This area currently has more capacity than a typical line but could have much more charging demand due to the types of fleets and larger vehicles located there.

Figure 21: Timeframe for Grid Impacts on Study Feeder and Median-Capacity Feeder[19]

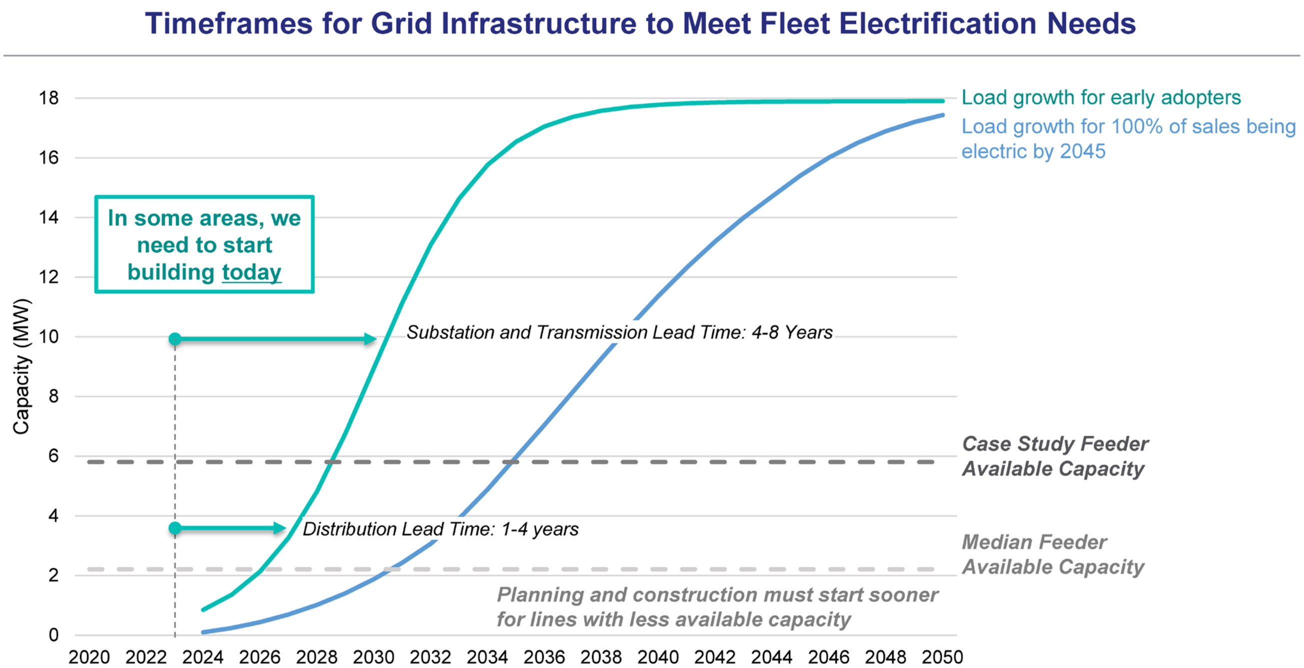


Delivering this new capacity in time requires planning to start now. A typical electric distribution project could take 1-4 years to design, construct, and place in service. If there needs to be substation or transmission-level work, that timeline could be up to 8 years. This is shown in Figure 22 below. Even if broad impacts do not materialize until the early 2030s, we must start planning the needed infrastructure now. In some areas, we may already be behind schedule.

Using these adoption scenarios to understand short-term and long-term needs can also lead to near-term investments that are designed to scale and support future growth. Importantly, those investments enable faster and potentially lower total system cost solutions than the current reactive approach to planning. Meeting market expectations and regulatory mandates requires immediate, integrated planning on the part of utilities to make sure their systems are ready to serve rapidly growing charging demand.

[19] Note that this chart uses summer charging capacity (17.9 MW at 100% adoption) and line ratings on the study feeder, to provide an accurate comparison to the median available capacity, which is based on summer ratings. Prior charts in the study use winter charging (24.8 MW at 100% adoption) and include existing peak capacity. See Table 1 for a comparison of summer and winter data. Currently, equipment is typically limited in summer, though that may change over time as systems are forecasted to become winter peaking. See Appendix D for additional data on summer vs. winter charging loads and line ratings for the study feeder.

Figure 22: Grid Infrastructure Schedules to Meet Electric MHDV Needs



Note: This chart uses summer data to align with median feeder available capacity data.

Recommendation: Utilities and policymakers must anticipate near-term loads and grid impacts from early adopters of electric MHDVs, particularly where large fleets or states have clear electrification targets or mandates.

Investments In High-Potential Areas Should Be Coordinated to Reduce Long-Term Costs and Accelerate MHDV Electrification

This paper provides a framework to target and prioritize grid upgrades and investments. By encouraging early electrification through customer engagement and programs (such as make-ready infrastructure funding and fleet advisory services) in Areas of Capacity, utilities and policymakers can help MHDV electrification scale as quickly as possible, taking advantage of currently available grid capacity in these areas. Long-term investment plans can be developed for Areas of Need, enabling many fleets at once in each area, getting more "bang for the buck."

There will be an evolution in how to categorize areas over time. Right now, the study feeder appears to be an Area of Capacity. It has significant available capacity and can support 33 percent vehicle adoption before seeing impacts. At some point, though, even it will face constraints and require more significant upgrades for EV charging needs. Planning those long-term infrastructure upgrades now can facilitate smooth EV adoption in the area and may be critical to ensure efficient spending. For example, making a large investment for initial stages of adoption without considering if it could also suffice for greater levels of adoption could result in duplicative investment and stranded costs if the first investment does not remain useful.

By identifying needs early on, utilities can also coordinate these system reinforcements with other investments. For instance, New York is implementing a proactive transmission planning framework for clean generation which has resulted in acceleration of multi-value transmission investments that both address reliability needs and increase renewable deliverability. The program will also address major “areas of concern” where local transmission constraints could limit renewable generation deployment (State of New York Public Service Commission, 2023).

Applying such an integrated, anticipatory framework to accommodate load growth, especially large spot loads caused by electric fleet vehicles, would be beneficial. It could help utilities ensure that the grid is ready for transportation electrification and could integrate solutions with other needs, such as addressing electric heating or making necessary reliability upgrades. Forecasting increasing capacity needs for EVs (and other loads) would let utilities bundle solutions with other projects, saving time and money on efforts to support the clean energy transition.

New data and analytic techniques can help utilities identify fleet “clusters” in their service territories, estimate potential charging load from depot or public charging, and define Areas of Need and Areas of Capacity for MHDV electrification on their systems. For example, companies could use vehicle telematics or land parcel data to identify likely fleet depots or public charging hubs. In doing so, utilities must take care not to undercount potential impacts, which National Grid’s own experience with initial service requests in the study area has demonstrated is a real risk. Estimating load impacts from smaller fleets, which are not considered in this study, could be particularly challenging.

Recommendation: Coordinate investment to high-priority areas, using new data, tools, and forecast methodologies. Identify Areas of Capacity and Areas of Need that can be aligned with fleet electrification and utility investment plans.

Regulatory and Planning Structures Must Evolve to Accommodate MHDV Electrification

Deploying appropriate grid infrastructure to enable MHDV electrification will require proactive investment from utilities, particularly in Areas of Need where constraints already exist. However, a key challenge is that, with few exceptions, utilities are discouraged from planning and building projects in anticipation of new electric demand not captured in traditional forecasting. Utilities make upgrades based on customer service requests and system forecasts. A customer request might be submitted only a few weeks or months before a fleet hopes to charge its vehicles. Across the wider distribution or transmission system, utilities plan and build projects based on traditional load-forecasting methodologies, which are becoming increasingly complex and based on assumptions around energy efficiency, behind-the-meter generation, energy storage, electric vehicles, and electric heating.

Fleet electrification is a particular challenge to forecast because there is no historical load growth on which to base future estimates. There is therefore no way for a utility to proactively plan for fleet electrification under current processes. Finding a way to overcome this is crucial and will allow faster adoption of electric vehicles. Looking out to when many MHDVs will be electric and estimating grid needs at that point will allow system upgrades that can serve those vehicles in the timeframe needed.

An integrated, actionable approach such as this can also bring down costs by prioritizing upgrades where they are needed most, eliminating duplicative investments by considering future charging load growth, and leveraging managed charging programs or interim storage solutions to create instant headroom. Utilities need to not only react to customer requests but anticipate them. New approaches, such as the novel data and analytical techniques referenced above, will be needed to identify fleet clusters and estimate the timing and magnitude of load growth from depot charging.

New regulatory and planning approaches are needed to address this. For instance, regulators could provide utilities with common criteria to identify Areas of Need and Areas of Capacity in their territories, and direct utilities to plan for spot loads introduced by fleet clusters on their distribution and transmission systems. To minimize the risk of underutilized investment, which has been a key concern about proactive investment, regulators could direct utilities to prioritize “no regrets” areas that have a high probability of seeing large EV charging demand and needing new grid infrastructure.

Traditionally, loads of a size equivalent to a large charging depot have been part of large commercial or industrial projects, such as a stadium or factory, for which utilities have years of lead time to prepare. Charging depots are a radical paradigm shift where customers could have vehicles and chargers on-site within just a few months. This provides for a suboptimal customer experience as utilities may need years to provide the power required. Utilities (and regulators) must also address a substantial risk of underbuilding an upgrade where the initial interconnection or load request dramatically understates the growth to come; instead, utilities should consider “future-proofing” upgrades wherever possible.

Proactive and coordinated investment is being pursued in other areas of the electric sector and can inform transportation electrification. As previously mentioned, New York recently approved significant investments for multi-value transmission to unbottle renewable generation while addressing other system needs. Policymakers in Massachusetts and New Jersey have recently announced major initiatives to coordinate transmission for offshore wind.[20] Over a decade ago, Texas coordinated its Competitive Renewable Energy Zone (CREZ) transmission projects, built in support of future wind energy development, that led to 18 GW of new wind capacity and a range of other economic benefits (ACEG, 2017). These approaches to grid infrastructure investment in support of renewable energy can translate to fleet electrification. There are areas we can identify now with a high degree of certainty that will see large numbers of electric MHDVs and resulting significant load growth. Planning and developing the infrastructure to support them now will prove beneficial.

In the long-term, processes could evolve to include an even larger role for state energy offices, state and city departments of transportation, public transit authorities, school districts, fleet operators, and affected communities. State energy offices and departments of transportation may be best situated to lead this, provide guidance to utilities, and coordinate with regulatory agencies that will need to approve investment plans. It will take time and experience to comprehensively integrate electric and transportation network planning. However, increasing collaboration between utilities, policymakers, and fleets to ensure that the electric grid meets the needs of electrifying MHDVs will deliver substantial benefits and help accelerate the transition to zero emission vehicles.

Recommendation: Develop anticipatory planning and investment processes and regulatory mechanisms to ensure the grid is ready to meet the fast-growing needs of electric MHDVs.

[20] In September 2022, five New England states put out a request for information (RFI) on modular offshore wind transmission infrastructure, and in January 2023, four states submitted a concept paper to the U.S. Department of Energy on a Joint State Innovation Partnership for Offshore Wind (New England Energy Vision, 2023). New Jersey recently awarded a “transmission-first” project designed to interconnect multiple future offshore wind farms – a project that is estimated to save $900 million as compared to each wind developer building its own transmission connection (NJ BPU, 2022).

The Right Grid Infrastructure Strategy for MHDV Electrification Will Vary by Location

This study examines three different grid infrastructure strategies to enable MHDV electrification. It also demonstrates that the appropriate infrastructure strategy will depend on local context, such as the amount of fleet depot charging expected and the capacity available on the local electric grid.

Strategy	Applicable Context
Electric Network Optimization	A “no regrets” first step for any utility. Likely to be especially useful in areas with existing grid capacity, and in the early years of the MHDV transition before this and/or other load growth begin to strain the distribution network.
Multi-Value Infrastructure Upgrades	Can eliminate constraints and create substantial capacity to enable not only depot charging, but public charging and other load growth. Targeting investments and bundling with other projects, such as scheduled reliability or asset condition upgrades, can maximize the efficiency of this approach.
Energy Storage	Charging programs and behind-the-meter distributed energy resources (DERs) can be used to smooth load impacts, while grid-side storage can be used to enhance deliverability or provide needed resilience. Can be considered during grid planning to defer or complement infrastructure upgrades.

Recommendation: Consider each location’s particular needs when developing a strategy and enable utilities to make investments in enduring and right-sized solutions that solve immediate and future needs. Near- and long-term views will help align on the preferred solution over time.

New Forms of Partnership and Cooperation Will Be Needed to Enable the Electric MHDV Transition

Fleets and utilities have not needed to coordinate to this level before. New relationships and working arrangements will be needed between them to understand each group’s needs and timelines. Sharing data will also be critical to support grid planning and let utilities aggregate needs among many fleet operators, and to allow fleets to begin electrifying in areas where they face the fewest constraints. Utilities can be an afterthought to fleets, but it is critically important for them to engage early on their electrification plans so that we can align on timelines and be ready when they will be.

To achieve fleet charging needs, utilities and policymakers will need to discuss changes to system planning and investment to ensure electric infrastructure projects can be planned, built, and placed in service according to fleet customer timelines. There are examples of anticipatory grid planning that have benefitted renewable energy development, discussed above, and EV charging is on the cusp of similarly rapid growth. Electric fleet charging needs are, admittedly, uncertain – there is no guarantee they will electrify, nor are there guarantees that their charging loads will be as large as we forecast. However, there are strong indicators that this will be a critical need soon. There are already signposts to this from early adopters requesting large amounts of capacity and facing interconnection challenges.

Utilities need to meet customer demands faster, by using all analytical tools available and creating solutions across the system that drive down costs and speed up time to completion. Failure to properly plan for the large amount of fleet charging (and other electrification load growth) will result in an uncoordinated network buildout that is less reliable, less customer-friendly, and higher cost.

By taking action now, utilities, policymakers, and fleet operators can work together to ensure the grid can meet the needs of electric fleets:

Group	Recommended Activities
Utilities	Identify areas where grid infrastructure can and cannot accommodate expected MHDV electrification and develop a portfolio of solutions to address immediate needs cost-effectively. *How: Leverage vehicle telematics data and propensity modeling to identify fleet "clusters" and model expected depot charging growth.*
Policymakers	Create planning mechanisms which provide utilities clear criteria for identifying high-priority areas for grid infrastructure deployment, as well as appropriate investment criteria. To the extent possible, bring the transportation sector and communities into the process to ensure the right areas are addressed. *How: Create venues, whether regulatory or administrative, to develop these criteria and create stakeholder consensus on where investment is needed.*
Fleets	Engage with utilities as soon as electrification timelines are considered or adopted and provide data to utilities on size of fleet and expected charging demand growth. *How: Participate in utility fleet advisory programs, emerging regulatory or planning proceedings, and share operational data (including where possible, vehicle telematics data).*

Recommendation: Collaborate across stakeholders to best support each other's needs around fleet electrification. Utilities need to partner with large and small fleets, vehicle manufacturers, state departments of transportation, and municipalities to understand and support their fleet electrification journeys.

7. Conclusion

In summary, the results of the study recommend that we:

1. Anticipate near-term loads and grid impacts from early adopters of electric MHDVs, particularly where large fleets or states have clear electrification targets or mandates.
2. Coordinate investment to high-priority areas, using new data, tools, and forecast methodologies. Identify Areas of Capacity and Areas of Need that can be aligned with fleet electrification and utility investment plans.
3. Develop anticipatory planning and investment processes and regulatory mechanisms to ensure the grid is ready to meet the fast-growing needs of electric MHDVs.
4. Consider each location's particular needs when developing a strategy and enable utilities to make investments in enduring and right-sized solutions that solve immediate and future needs. Near- and long-term views will help align on the preferred solution over time.
5. Collaborate across stakeholders to best support each other's needs around fleet electrification. Utilities need to partner with large and small fleets, vehicle manufacturers, state departments of transportation, and municipalities to understand and support their fleet electrification journeys.

Supporting an efficient and effective transition to electric trucks and buses would deliver substantial benefits to communities that bear the brunt of local air and noise pollution, fleet operators and municipalities with ambitious decarbonization goals, and fleet operators looking to reduce operating costs and exposure to fossil fuel price volatility.

Environmental justice and disadvantaged/overburdened communities could particularly benefit from MHDV electrification, and the strategies in this paper can be targeted to benefit those locations.[21] Every long-haul truck emits as much nitrous oxide (NOx) as 85 passenger vehicles (Tuyuri, 2023). Residents in those areas may not convert to an electric vehicle themselves right away – perhaps due to upfront vehicle costs and limited public charging infrastructure – but fleet operators already operating in those areas will have more resources and capability to transition their vehicles. Supporting those fleets will benefit the local communities immensely by cleaning up the vehicles that park and travel there, and careful planning can also consider how benefits may be delivered to those areas even if new infrastructure is developed elsewhere.

The approaches discussed in this report can provide broad benefits and help:

- Achieve electrification and decarbonization policy targets.
- Serve environmental justice and disadvantaged/overburdened communities currently impacted by MHDV pollution.
- Serve fleet operators seeking to reduce emissions and/or save on operating costs.
- Electrify the "easy wins" as soon as possible. That is, support fleet operators that have clear state goals with fast-charging development where grid infrastructure has capacity to deliver the power needed ("Areas of Capacity").
- Set ourselves up for long-term success in fleet electrification. Increasing grid capacity in high fleet density and currently constrained areas (and/or "Areas of Need") will enable more fleet operators to transition to EV operations in the future by minimizing interconnection issues and lowering costs.
- Ensure grid infrastructure will be "used and useful" – the standard necessary for utilities to make investments. Support from state energy and transportation offices and partnerships with fleet operators and the broader transportation industry will particularly support this and lead to an electric grid that can enable the rapid electrification of fleet vehicles.

---

[21] For example, "diesel death zones" where trucking pollution has large impacts on public health (Treebumrung, 2021).

8. References

Ali, Iqtidar. "Watch: Tesla Semi's 500-Mile Drive on One Charge." CleanTechnica, December 11, 2022. https://cleantechnica.com/2022/12/11/watch-tesla-semis-500-mile-drive-on-one-charge/, accessed April 2023.

Americans for a Clean Energy Grid (ACEG). "Texas as a National Model for Bringing Clean Energy to the Grid." Blog post, October 13, 2017. https://cleanenergygrid.org/texas-national-model-bringing-clean-energy-grid/

California Air Resources Board (CARB). "California approves groundbreaking regulation that accelerates the deployment of heavy-duty ZEVs to protect public health." Press Release, April 28, 2023. https://ww2.arb.ca.gov/news/california-approves-groundbreaking-regulation-accelerates-deployment-heavy-duty-zevs-protect

California Air Resources Board (CARB). "Advanced Clean Fleets Regulation Summary." May 17, 2023. https://ww2.arb.ca.gov/resources/fact-sheets/advanced-clean-fleets-regulation-summary, accessed June 2023.

California Public Advocates Office. "Public Advocates Office study on the costs of upgrading the distribution grid for electrification." Fact sheet. June 5, 2023. https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/reports/230614-cal-advocates-distribution-grid-impacts-study-fact-sheet.pdf

CALSTART, "COP27: USA, Ukraine, Ireland, Aruba, Belgium, Croatia, Curaçao, Dominican Republic, Liechtenstein, Lithuania Sign Global MOU, Support Path To 100% New Truck and Bus Sales By 2040." Global Commercial Vehicle Drive to Zero, November 17, 2022. https://globaldrivetozero.org/2022/11/16/cop27-usa-growing-number-nations-sign-global-mou/, accessed May 2023.

CALSTART, "Drive to Zero's Zero-Emission Technology Inventory (ZETI) Tool Version 8.0." https://globaldrivetozero.org/tools/zero-emission-technology-inventory/, accessed April 2023.

Clifford, Catherine. "Wind and solar power generators wait in yearslong lines to put clean electricity on the grid, then face huge interconnection fees they can't afford." CNBC, April 6, 2023. https://www.cnbc.com/2023/04/06/outdated-us-energy-grid-tons-of-clean-energy-stuck-waiting-in-line.html

CharIN. "CharIN e. V. officially launches the Megawatt Charging System (MCS) at EVS35 in Oslo, Norway." Press Release, June 14, 2022. https://www.charin.global/news/charin-e-v-officially-launches-the-megawatt-charging-system-mcs-at-evs35-in-oslo-norway/

Crunden, E.A. "Los Angeles commits to 100% electric sanitation fleet by 2035. Other cities aren't ready to follow." WasteDive, January 29, 2020. https://www.wastedive.com/news/los-angeles-sanitation-truck-fleet-100-percent-electric/571166/

Delta Airlines. "A 'business imperative': Delta outlines roadmap to more sustainable travel." Delta News Hub, March 7, 2023. https://news.delta.com/business-imperative-delta-outlines-roadmap-more-sustainable-travel

Deutsche Post DHL Group. "Green last mile & line haul." https://www.dpdhl.com/en/sustainability/environment/green-last-mile-line-haul.html, accessed May 2023.

Environmental Defense Fund (EDF). "U.S. Electric Vehicle Manufacturing Investments and Jobs. Characterizing the Impacts of the Inflation Reduction Act after 6 Months." March 2023. https://blogs.edf.org/climate411/files/2023/03/State-Electric-Vehicle-Policy-Landscape.pdf

Garland, Max. "Sysco targets transportation and production emissions in sustainability goals." SupplyChainDive, November 29, 2021. https://www.supplychaindive.com/news/sysco-supplier-scope-3-emissions-sustainability/610582/

Gheorghiu, Iulia. "There once was a 48 MWh Tesla battery on Nantucket, which saved National Grid $120M in its budget." UtilityDive, October 10, 2019. https://www.utilitydive.com/news/Tesla-national-grid-battery-energy-storage-8hour-long-duration-diesel-generation-system-nantucket/564428/

Hedreen, Siri. "EV charging developers face 'ludicrous' wait times for grid interconnection." S&P Capital IQ, March 30, 2023. https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?id=74980701&KeyProductLinkType=6, accessed April 2023

Katsh, Gideon, Charlotte Fagan, Jeff Wilke, et al. "Electric Highways: Accelerating and Optimizing Fast-Charging Deployment for Carbon-Free Transportation." National Grid, November 2022. https://www.nationalgrid.com/us/EVhighway

Kevala. "Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates." California Public Utilities Commission proceeding R.21-06-017. May 9, 2023. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF

Khan, Ari, Gerard Westhoff, and Dave Mullaney. "The Inflation Reduction Act Will Help Electrify Heavy-Duty Trucking." RMI, August 25, 2022. https://rmi.org/inflation-reduction-act-will-help-electrify-heavy-duty-trucking/

Khatib, Moe, and Zachary Strauss. "New York and New Jersey MHDV Fleet Workshop: Summary Report for Online Workshop Hosted by Atlas Public Policy and the Environmental Defense Fund Held on October 17, 2022." Atlas Public Policy, December 2022. https://www.edf.org/sites/default/files/documents/2022-12-21-Final%20NY%20and%20NJ%20Fleet%20Workshop%20Report.pdf

Lawrence Berkeley National Laboratory. "Grid connection requests grow by 40% in 2022 as clean energy surges, despite backlogs and uncertainty." News Release, April 6, 2023. https://emp.lbl.gov/news/grid-connection-requests-grow-40-2022-clean

Legatos, Jasmin. "Wait Times for Electrical Upgrades, Not EVs, Should Be a Fleet Buyer's First Priority." Electric Autonomy Canada, January 11, 2023. https://electricautonomy.ca/2023/01/11/electrical-upgrades-fleet-wait-times/, accessed January 2023.

Lund, Jessie, John Schroeder, Emily Porter, and Dave Mullaney, "Charting the Course for Early Truck Electrification." RMI, 2022.
https://rmi.org/insight/electrify-trucking/

Massachusetts Bay Transportation Authority (MBTA). "Bus Electrification Plan." May 2022.
https://cdn.mbta.com/sites/default/files/2022-5-Bus-Electrification-Plan.pdf

Metropolitan Transportation Authority (MTA). "MTA Zero-Emission Bus Transition Plan." MTA Zero-Emissions Fleet Transformation Working Group. May 2022.
https://new.mta.info/document/91336

Nair, Vishnu, Sawyer Stone, Gary Rogers, Sajit Pillai. "Technical Review of: Medium and Heavy-Duty Electrification Costs for MY 2027- 2030." Roush Industries, Inc., February 2, 2022.
http://blogs.edf.org/climate411/files/2022/02/EDF-MDHD-Electrification-v1.6_20220209.pdf

National Grid. "National Grid Launches First-of-Its-Kind Battery Storage System." Press Release, June 3, 2019.
https://www.nationalgridus.com/news/2019/06/national-grid-launches-first-of-its-kind-battery-storage-system/

National Grid and Hitachi Energy. "The Road to Transportation Decarbonization: Understanding Grid Impacts of Electric Fleets." September 2021.
https://www.nationalgridus.com/media/pdfs/microsites/ev-fleet-program/understandinggridimpactsofelectricfleets.pdf

New England Energy Vision. "New England States Transmission Initiative."
https://newenglandenergyvision.com/new-england-states-transmission-initiative/, accessed April 2023.

New York State Senate. Assembly Bill A4302. 2022. Retrieved from:
https://www.nysenate.gov/legislation/bills/2021/a4302

Restaurant Brands International. "Our Objectives and Our Progress 2021."
https://www.rbi.com/English/sustainability/planet/default.aspx, accessed July 2023.

State of New Jersey Board of Public Utilities (NJ BPU). "Order On the State Agreement Approach SAA Proposals." Docket No. QO20100630 – In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey. October 26, 2022. Available at:
https://www.nj.gov/bpu/pdf/boardorders/2022/20221026/8A%20ORDER%20State%20Agreement%20Approach.pdf

State of New York Public Service Commission (NY PSC). "Order Approving Phase 2 Areas of Concern Transmission Upgrades." Case 20-E-0197 – Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act. February 16, 2023.
https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={0C1FE2AF-2922-4BF5-809C-5C93F4F73121}

Treebumrung, Pete and Stephanie Lee. "The 'Diesel Death Zone' of Los Angeles." ArcGIS StoryMaps. July 29, 2021. https://storymaps.arcgis.com/stories/18f4ea90caf74b279cfbc2f74075d17e, accessed May 2023.

Tuyuri, Shaun. "Charging Loads and Infrastructure Requirements for Electrification of Long-Haul Heavy-Duty Trucking." EPRI, February 2023. https://restservice.epri.com/publicdownload/000000003002026104/0/Product

U.S. Energy Information Administration (EIA). "Annual Energy Outlook 2023." March 16, 2023. https://www.eia.gov/outlooks/aeo/

U.S. Environmental Protection Agency (EPA), "Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles." Office of Transportation and Air Quality, EPA-420-F-23-009, April 2023. https://www.epa.gov/system/files/documents/2023-04/420f23009.pdf

U.S. Environmental Protection Agency (EPA), "Proposed Standards to Reduce Greenhouse Gas Emissions from Heavy-Duty Vehicles for Model Year 2027 and Beyond." Office of Transportation and Air Quality, EPA-420-F-23-011, April 2023. https://www.epa.gov/system/files/documents/2023-04/420f23011.pdf

United States Postal Service (USPS). "USPS Intends To Deploy Over 66,000 Electric Vehicles by 2028, Making One of the Largest Electric Vehicle Fleets in the Nation." News Release, December 20, 2022. https://about.usps.com/newsroom/national-releases/2022/1220-usps-intends-to-deploy-over-66000-electric-vehicles-by-2028.htm

Walton, Robert. "Electric Vehicles Near 'Tipping Point' in 2023, but Tax Credit Questions, Utility Interconnection Challenges Lie Ahead." UtilityDive, January 18, 2023. https://www.utilitydive.com/news/electric-vehicles-ev-2023-tax-credit-incentive-charging-network/640016/, accessed January 2023.

Walton, Robert. "Utilities sound alarm over distribution transformer shortage as procurement times surpass 1 year and costs triple." UtilityDive, December 19, 2022. https://www.utilitydive.com/news/distribution-transformer-shortage-appa-casten/639059/, accessed April 2023.

Washington Metropolitan Area Transit Authority (WMATA). "Metro's Better Bus initiative looks to accelerate transition to zero-emission bus fleet." News Release, March 23, 2023. https://www.wmata.com/about/news/Zero-Emission-Bus-Plan-Announcement.cfm

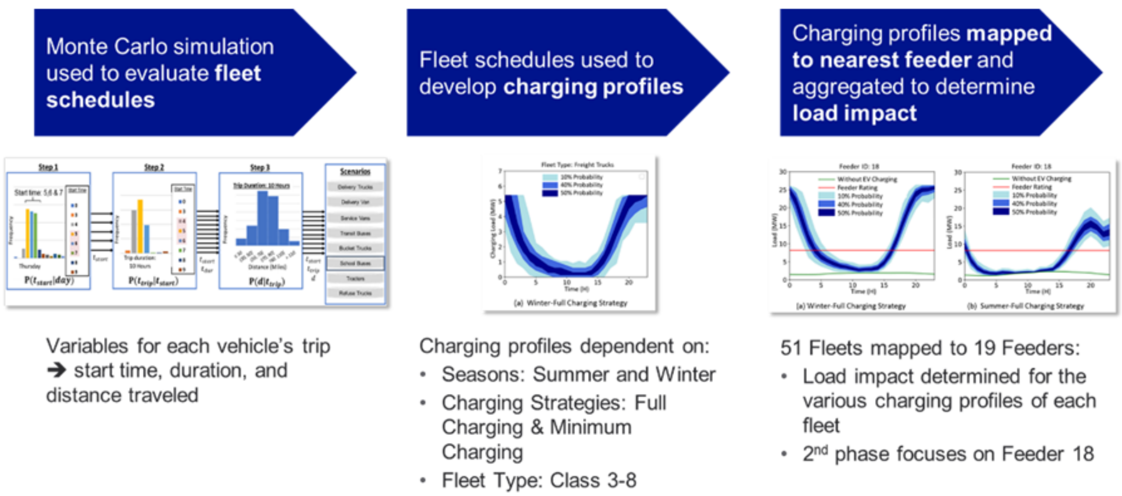
Appendix A: Methodology for Estimating Electric Load Impacts from 2021 Study

We identified 51 large fleet operators in a case study area of National Grid's service territory (a commercial area near an urban center, near multiple interstates and an airport), estimated the types and number of vehicles at each location, and then estimated the daily charging needs for each site based on publicly available datasets (NREL's Fleet DNA database[22]) for vehicle start times, trip distances, and other factors. The load profiles replicated below assume that all vehicles convert to electric.

We generated a load curve for each site in summer and winter, then mapped these to the distribution line serving the site to determine the aggregate load impacts on the distribution system.[23]

Nineteen feeders were studied in total. The study approach is illustrated in Figure A-1 below.

Figure A-1: Study Approach to Determine Load Impacts from Vehicle Electrification



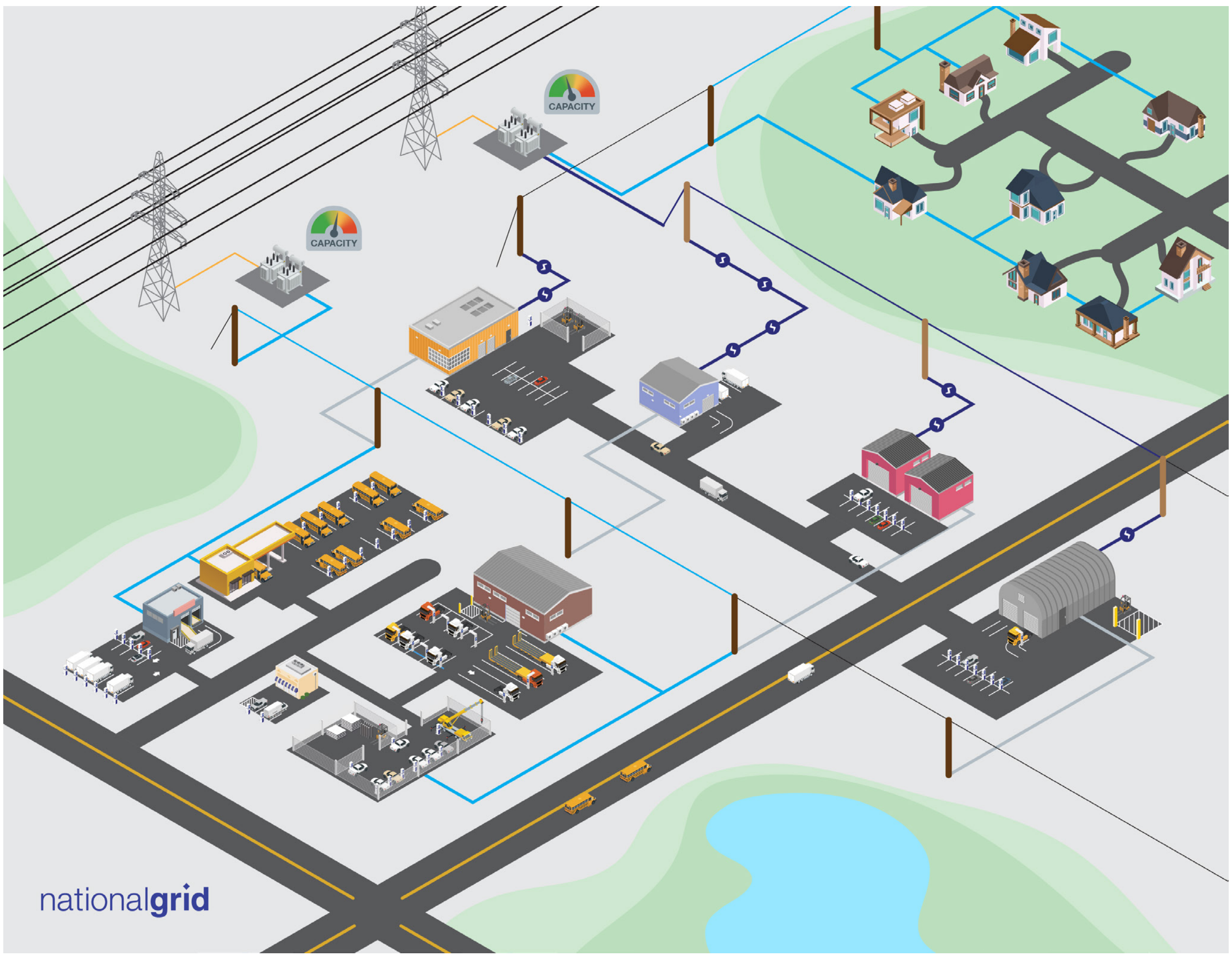
The analysis only considers the impacts of large depot sites that were easily identifiable using satellite imagery and mapping. Many other fleet vehicles exist in the study area and, when electrified, will add additional load to the electric grid. As such, actual load in the area is likely to be higher when including smaller fleet operators.

[22] https://www.nrel.gov/transportation/fleettest-fleet-dna.html
[23] These forecasts assume that all charging happens at the depot.

Appendix B: Infrastructure Solutions

Electric Network Reconfiguration

Benefits	• Low-cost, flexible way of providing power to electrifying fleets. • Maintains original infrastructure for contingencies.
Considerations	• Requires having capacity available on neighboring electric distribution lines and positions (open connection points) available at neighboring substations. • Does not create long-term capacity. • Could increase complexity of operating the electric grid.

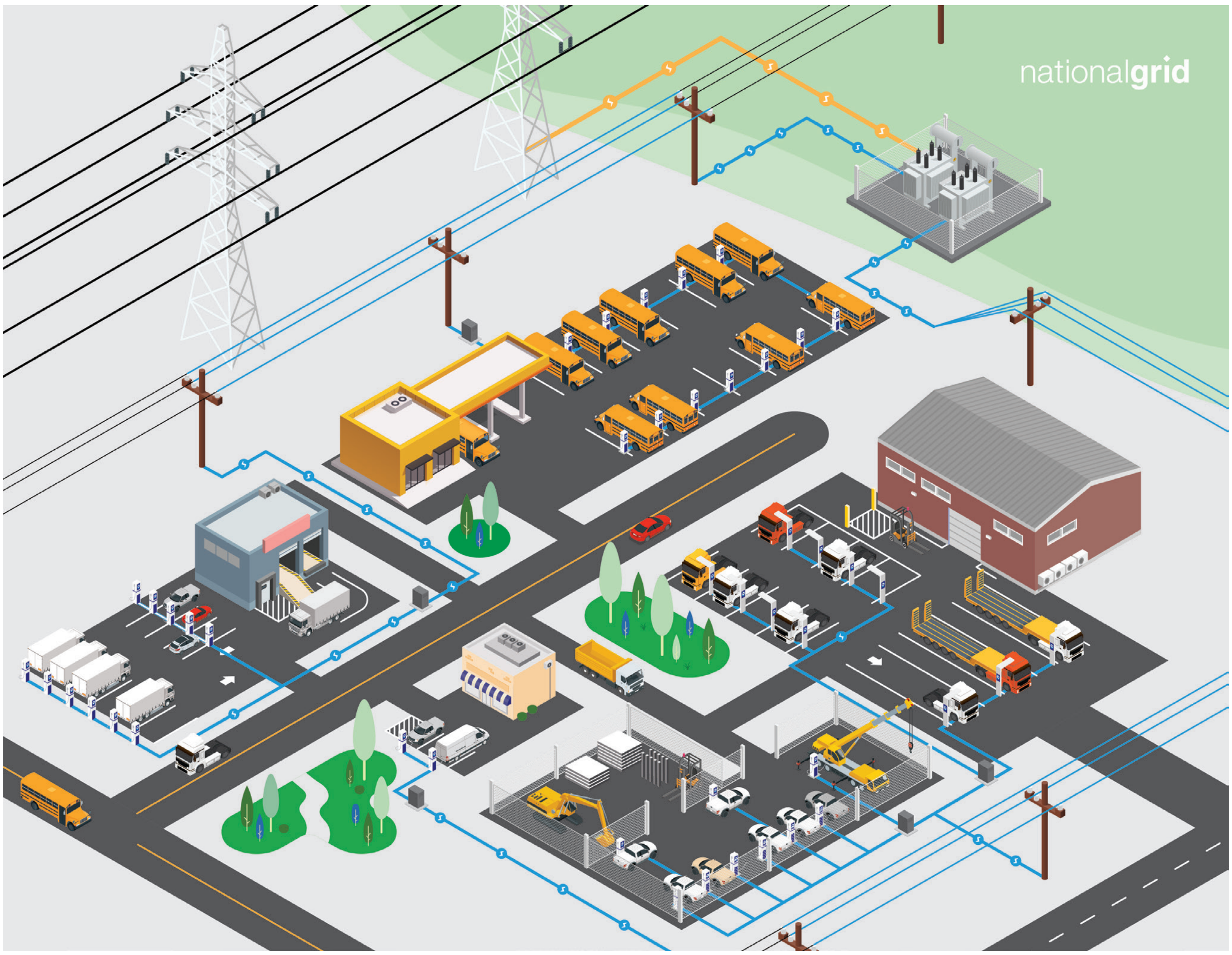


How it works:

1. Utility switches some fleet depots which are currently served from a constrained distribution line to a separate, neighboring line that has available capacity.
2. When the substation becomes constrained, the utility may be able to build a new distribution line to a neighboring substation with existing capacity, though this could be costly.

Multi-Value Grid Infrastructure

Benefits	• Can proactively invest to meet expected future load and address other electrification needs (e.g., passenger vehicle charging or electric heating).
Considerations	• Requires additional investment, space, and time to implement. • Costs would be higher. • At just a few MW of load, fleet depots may need to connect directly to higher voltage lines. This could alleviate the distribution system but add complexity to the process for fleets as well as transmission owners/operators.

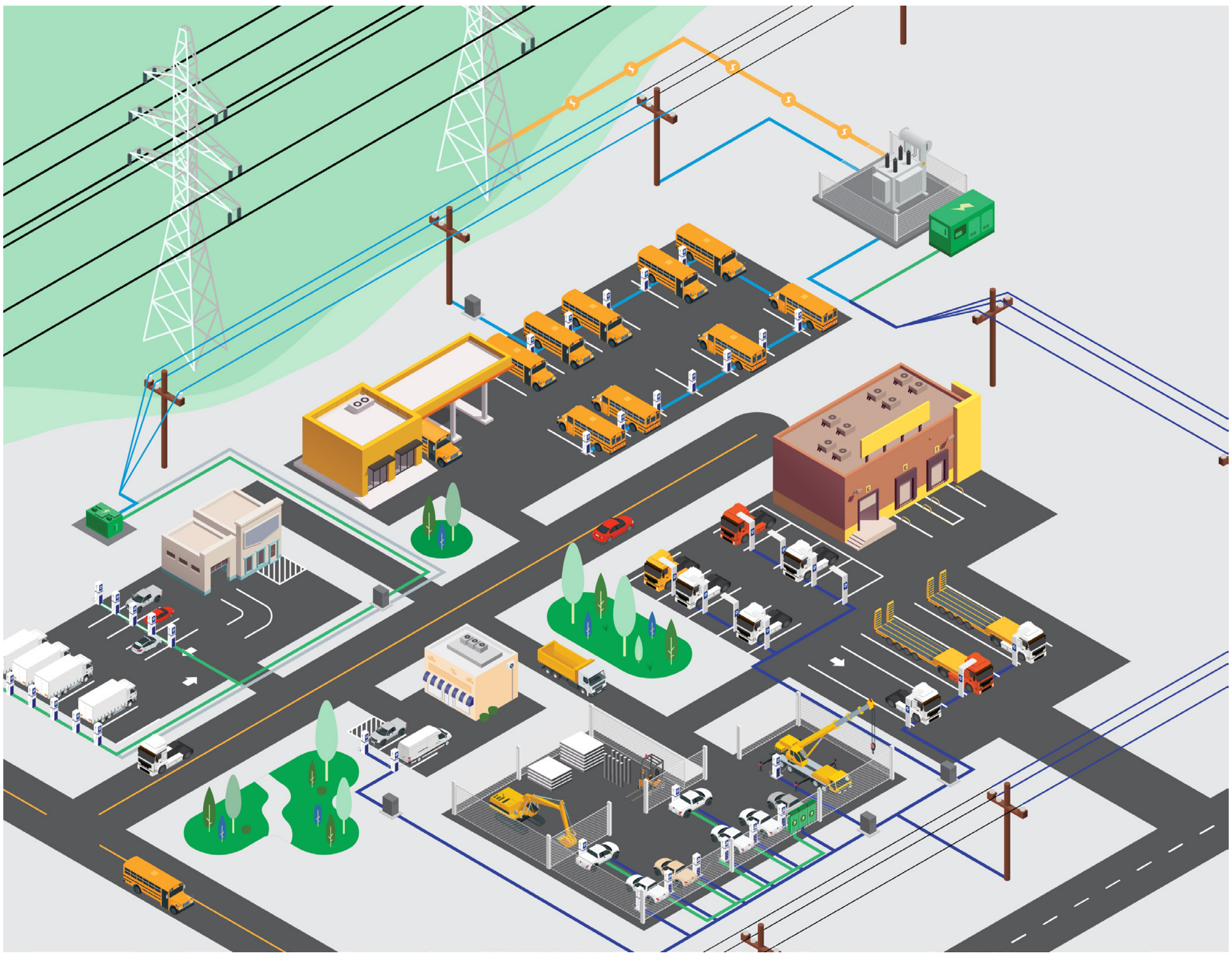


How it works:

1. Utility builds or upgrades a substation to access power from the transmission network sufficient to electrify all fleets in a trucking district while also providing room for future growth.
2. New distribution lines deliver power from the substation to each fleet depot or charging site.

Energy Storage and Non-Wires Alternatives

Benefits	• Can scale to meet emerging charging needs, mitigate total power demands, and provide interim solutions. • May be faster to deploy depending on grid solution timeframe.
Considerations	• Grid infrastructure upgrades may still be needed to provide power to a battery, to serve nameplate charging capacities, or address higher utilization of the network from charge / discharge cycles. • Costs of larger systems could be as high or higher than grid upgrades.



How it works:

1. Energy storage is installed either by a utility (at the substation or on the distribution line) or by end-use customers (at the depot or charging site) to provide power when there is not enough capacity on the grid to meet charging needs.
2. Managed charging programs or rates incentivize fleets to charge their vehicles to limit demands placed on the electric grid.

Appendix C: Energy Storage

We analyzed the feasibility of energy storage to mitigate grid impacts at different EV adoption levels using simplified charging and discharging profiles to address load above the line rating. The profiles do not take economics into account (i.e., even if it is costly to charge in the afternoon peak times, the storage would still charge to have enough energy in later hours), and there are no losses included for round-trip efficiency. Storage is assumed to charge as soon as there is available capacity during the day and discharge as soon as load exceeds the line rating at night.

Planning and operating the grid require a more cautious approach to integrating new technologies in order to ensure safe and reliable operation. Utilities cannot rely on electricity prices or market signals to inform when storage will charge or discharge. Even if these are clearly logical, there must be a technical means of ensuring it does not charge at peak demand times.

Customer-owned storage in some areas of National Grid's service territory is directed to follow a schedule, where it must charge and discharge between specific hours of the day.[24] Those schedules currently require storage to charge overnight through early afternoon – overlapping with fleet charging – and discharge in the evening. As such, today, storage would not be able to resolve the MHDV charging overloads observed in this study. There are other limitations to storage as well, including physical space and real estate needed for a large installation, or local regulations and fire department concerns.

To overcome scheduling limitations and allow more flexibility for storage to operate, new grid management tools, such as distributed energy resource management systems (DERMS), will need to be implemented. Utilities can use DERMS for aggregation and dispatch of distributed energy resources (DERs) on their networks and control DER to ensure there are no adverse impacts from their operation. DERMS could let utilities allow more dynamic operation of energy storage based on real-time conditions, rather than a pre-set schedule. Utilities are already pursuing these new systems, but they might not be rolled out for several more years.

To understand feasibility for energy storage to mitigate grid impacts, two scenarios are presented under 67 percent EV adoption. Both assume that DERMS technologies are in place to allow flexible operation of storage.

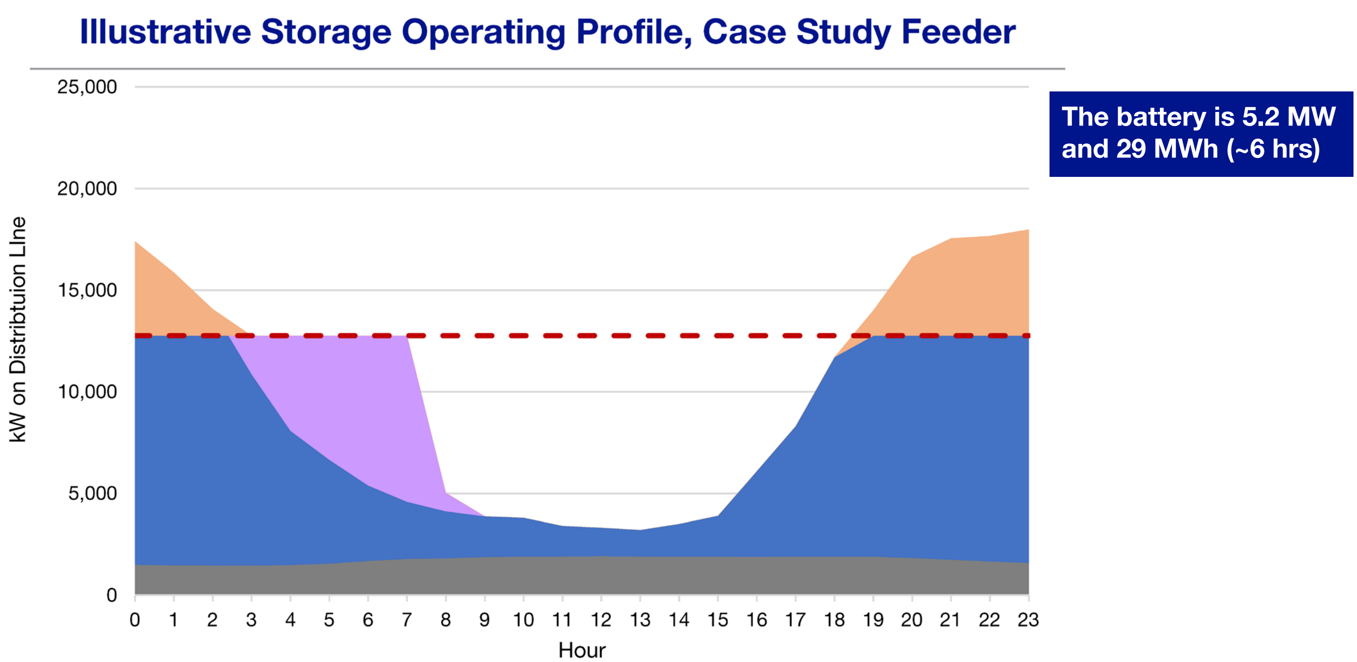
1. Study Feeder — The actual loads and available capacity on the study feeder.
2. Typical Feeder — Storage performance if the study feeder were currently at 65 percent of its rating, which is more typical for distribution lines in our system.

[24] See https://dps.ny.gov/system/files/documents/2022/11/ju-national-grid-new-england-ess-schedule.pdf. This schedule is on slide 7

Study Feeder

- Uses a high kWh winter day to test the ability of energy storage to mitigate the impact of EV charging load. Note that this is not the highest MW day observed.
- Assumes 67 percent EV adoption level.
- At this point, storage can be used to avoid overnight overloads if DERMS capability allows it to charge and discharge in real time versus on a pre-set schedule.

Figure C-1: Energy Storage Charging Profile in Available Capacity Case



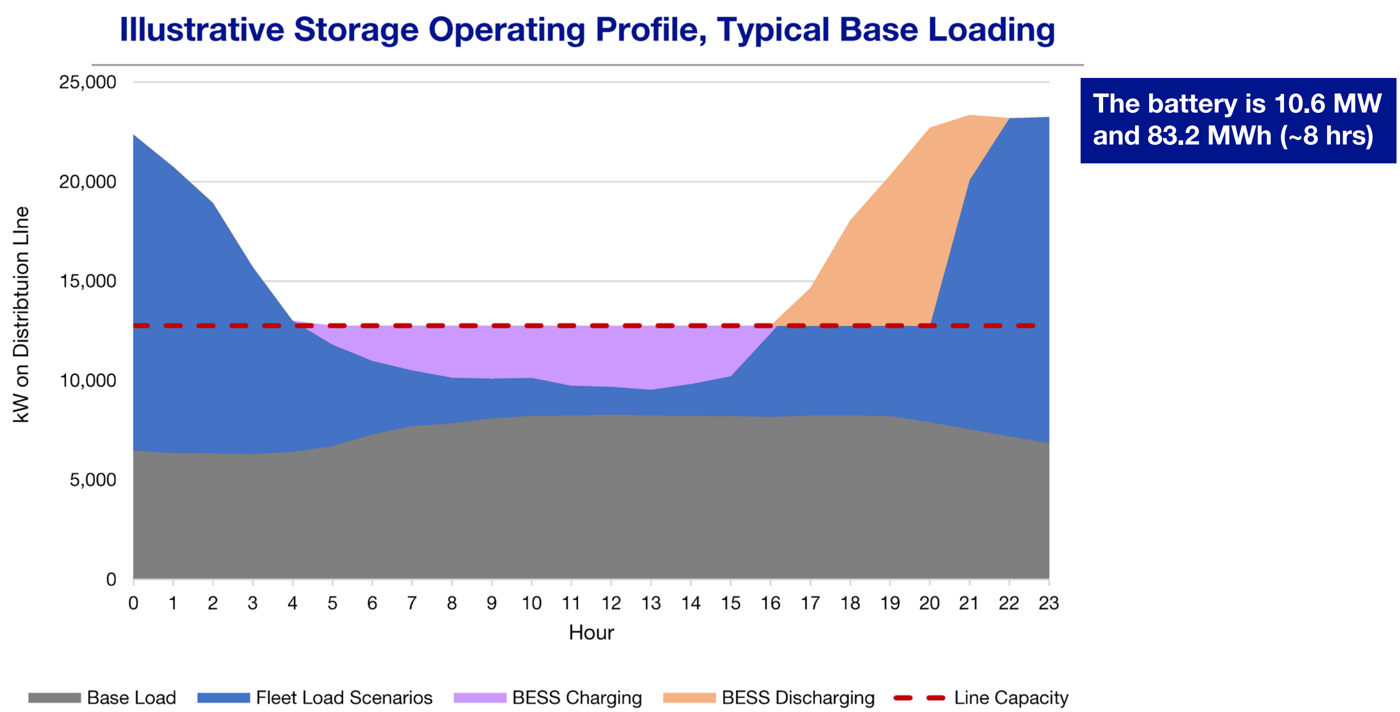
On the study feeder, storage appears to be a potential solution until close to 100 percent adoption. A key reason for this is that there is currently minimal load, only 15 percent of the winter rating. This provides ample time for the battery to charge during the day in order to discharge at night.

However, distribution lines are typically loaded around 60-70 percent of their maximum rating, meaning energy storage is less likely to be able to mitigate the load impact. This is the next scenario presented, using a larger amount of base load to assess feasibility in other locations.

Typical Feeder

- Uses the same data but scales the Base Load to reach 65 percent of the line rating.

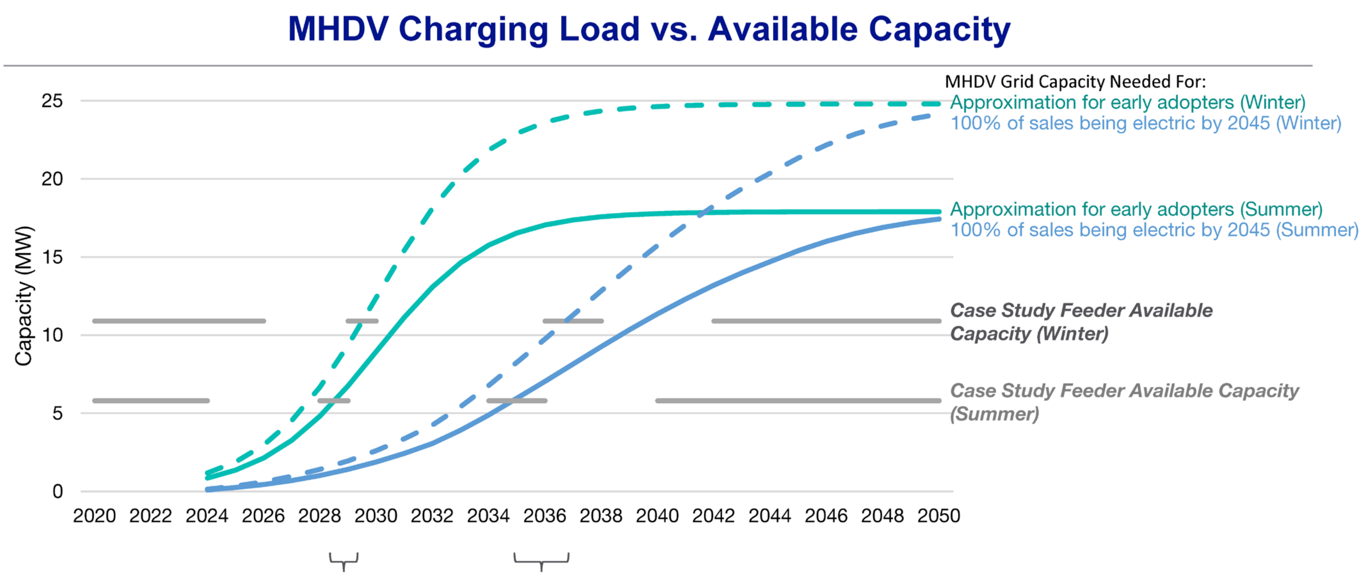
Figure C-2: Energy Storage Charging Profile with Base Load at 65 Percent of Line Rating



In other parts of the distribution network, storage has more limited time and capacity to charge, and so more limited opportunities to support electric fleets. In Figure C-2, the battery no longer has enough energy to serve fleets after hour 20, based on the energy it could charge during the day.

Appendix D: Comparison of Summer and Winter Available Capacity

Figure D-1: MHDV Charging Load vs. Available Capacity in Summer and Winter Scenarios



Comparing winter to summer scenarios leads to ~1 year later for early adopters and ~2 years later for policy targets.

These do not include any assumptions on stock vehicle growth. That would hasten the need for additional grid capacity.

About Us:

nationalgrid

National Grid (NYSE: NGG) is an electricity, natural gas, and clean energy delivery company serving more than 20 million people through our networks in New York and Massachusetts. National Grid is transforming our electricity and natural gas networks with smarter, cleaner, and more resilient energy solutions to meet the goal of reducing greenhouse gas emissions.

For more information, please visit **ngrid.com**, follow us on Twitter, watch us on YouTube, like us on Facebook and find our photos on Instagram.
Contact: **EVGridStudy@nationalgrid.com**

Hitachi Energy

Hitachi Energy is a global technology leader that is advancing a sustainable energy future for all. We serve customers in the utility, industry and infrastructure sectors with innovative solutions and services across the value chain. Together with customers and partners, we pioneer technologies and enable the digital transformation required to accelerate the energy transition towards a carbon-neutral future. We are advancing the world's energy system to become more sustainable, flexible and secure whilst balancing social, environmental and economic value. Hitachi Energy has a proven track record and unparalleled installed base in more than 140 countries. Headquartered in Switzerland, we employ around 40,000 people in 90 countries and generate business volumes of approximately $10 billion USD.

https://www.hitachienergy.com
https://www.linkedin.com/company/hitachienergyhttps://twitter.com/HitachiEnergy
Contact: **Us-Power.Consulting-NAM@hitachienergy.com**

CM9489 (8/23)