On the Road to Fleet Electrification

A Framework for Estimating Distribution System Impacts of Medium- and Heavy-Duty Vehicle Electrification

Prepared for Advanced Energy United by Synapse Energy Economics

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Summary

This study offers a framework for evaluating the impact of the Advanced Clean Truck (ACT) rule and other medium- and heavy-duty vehicle (MHDV) electrification policies, and a path to begin preparing the electricity grid for widespread fleet electrification in a given state. We offer an approach to estimating the impact of fleet electrification under ACT adoption scenarios, focusing specifically on feeders and substations on the electric distribution grid. To guide future investments and electric vehicle (EV) adoption plans, the results of this analysis can reveal where the distribution system is likely able to absorb added MHDV load and where additional system upgrades might be needed to accommodate that load. We outline six key steps, which determine:

- Pace of electric MHDV adoption expected under ACT
- Where on the distribution grid MHDVs are expected to charge
- How much peak demand MHDVs will add to each substation and feeder
- How much more load each substation and feeder can accommodate without additional upgrades (i.e., the "headroom")
- What upgrades will be required to enable MHDV electrification
- What solutions are available to minimize costs

This analysis shows that on a system-wide basis the incremental MHDV charging load is relatively small relative to the existing load; each utility's total system peak only increases by a small proportion. Yet impacts at the substation and feeder levels will be much more varied. This is especially true when considering the diverse load curves of individual fleets and the specifics of the feeder taking on that load. Since MHDVs tend to cluster in certain commercial zones, MHDV demand could be substantial at the feeder level. Investigating electric MHDV adoption at a local level is therefore critical for estimating the impact of ACT on the distribution grid and for preparing for future MHDV electrification. However, as this report will also show, data limitations often make this type of analysis difficult, especially for those who do not have access to granular utility distribution system data. Each step of the framework includes case studies for Pennsylvania and Illinois, where we implement the framework, showcase data limitations, and discuss simplifying assumptions and alternative methods.

Electric utilities, regulators, state agencies, and other stakeholders should collaborate and proactively plan for ACT and other MHDV electrification, aiming to minimize costs, manage grid upgrade investments, and enable steady MHDV electrification. We recommend the following:

1. Require utilities to share data about capacity of the distribution grid.
2. Improve utility planning and regulatory processes to address barriers to electrification.
3. Implement programs to manage peak loads and minimize costs.
4. Target certain areas for grid investment and/or MHVD adoption.

Grid and Infrastructure Considerations for MHDV Electrification

MHDV Standards and Policies

The U.S. Environmental Protection Agency (EPA) sets greenhouse gas emissions (GHGs) emission standards for heavy-duty vehicles starting in model year 2027 through the Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles – Phase 3.[1] Vehicles covered under the standards include delivery trucks, refuse haulers, public utility trucks, transit and school buses, and tractor trailers. The standards are technology-neutral, allowing each manufacturer to choose how to comply—such as with electric trucks and buses, hybrid vehicles, or advanced internal combustion engine vehicles.

Taking a different approach, the Advanced Clean Truck (ACT) rule,[2] first developed and adopted by California in 2020, aims to mitigate GHGs and air pollutants from medium- and heavy-duty vehicles (MHDV) by requiring truck manufacturers to produce and sell an increasing percentage of zero-emission trucks each year.[3] While the ACT rule does not specify a technology type, zero-emission vehicles include battery-electric vehicles and hydrogen fuel cell electric vehicles. In most cases, battery electric MHDVs are the most practical vehicle type given their cost-effectiveness, technological maturity, and scalability. This report focuses primarily on battery electric MHDVs.

[1] U.S. Environmental Protection Agency. Final Rule: Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles – Phase 3. 42 U.S.C. §7401 - 7671q. Available at: https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-greenhouse-gas-emissions-standards-heavy-duty.

[2] Final Regulation Order: Advanced Clean Trucks Regulation. 13 CCR 1963. Available at: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2019/act2019/fro2.pdf.

[3] Zero-emission vehicles (ZEVs) are defined as vehicles that produce zero exhaust emissions of any criteria pollutants, precursor pollutants, or greenhouse gas pollutants. Examples of such pollutants include nitrogen oxides, particulate matter (PM), and carbon dioxide (CO_2). MHDV are defined as on-road vehicles that are greater than 8,500 pounds and categorized into three groups based on their weight and/or purpose (i.e., Class 2b-3 pickup trucks and vans, Class 4-8 rigid trucks and Class 7-8 tractor trucks).

MHDV Electrification Costs and Barriers

The transition to an electric trucking and bus industry does not come without costs and barriers. MHDV electrification, on top of light-duty vehicle (LDV) and building electrification, will require grid infrastructure upgrades to accommodate the increased load. As discussed in this report, these upgrades are dependent on where and when MHDVs charge and the available capacity of distribution feeders, substations, and other shared grid infrastructure. Proactive and location-specific planning is essential to enable this transition and unlock the numerous benefits associated with MHDV electrification.

In a study conducted for the California Public Utilities Commission, Kevala Inc. estimated that it would cost California $50 billion to prepare the distribution grid for the future electrification of LDV, MHDV, and buildings by 2035. [4] Kevala's study was a bottom-up analysis of all the investor-owned utilities' substations, transformer banks, feeders, and service transformer upgrades. In a later study conducted by the California Office of Public Advocates (Cal Advocates), the cost of distribution grid infrastructure upgrades in California was estimated to be $26 billion by 2035,[5] roughly half the cost of Kevala's estimate. The Cal Advocates' estimate assumes greater participation in EV time-of-use rates compared to Kevala. Time-of-use rates encourage charging during non-peak times, which helps manage demand and thus mitigates some of the costs associated with electrification-driven grid upgrades.[6] In fact, the Cal Advocates study found that $35 billion in costs can be avoided in California from charging in alignment with time-of-use rates.[7]

Time-of-use rates are only one means of reducing vehicle electrification system costs. Efficient electric utility rate design may be further used to curtail or encourage EV charging in response to changes in generation supply, system reliability, and system costs, while also facilitating EV adoption and maximizing fuel cost savings.[8] Other technologies and programs, such as vehicle-

[4] Kevala, Inc. 2023. Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates. Prepared for California Public Utilities Commission, Energy Division Proceeding R.21-06-017 Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF.

[5] California Public Advocates Office, 2023. Distribution Grid Electrification Model – Study and Report. Available at: https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf.

[6] The remaining difference between the Kevala Study and the Cal Advocates Study is due to different cost assumptions. Cal Advocates estimates that due to the range in upgrade costs, the total cost could range from $18 billion to $31 billion.

[7] California Public Advocates Office, 2023. Distribution Grid Electrification Model – Study and Report. Available at: https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf.

[8] Whited, M., S. Shenstone-Harris, A. Lawton, O. Griot, and J. Frost. 2023. *Maximizing the Benefits of Transportation Electrification in Pennsylvania: The Role of Rate Design*. Synapse Energy Economics for the Pennsylvania Department of Environmental Protection. Available at https://www.synapse-energy.com/sites/default/files/EV-RATE-STUDY-FINAL_3-9-22%20%2822-038%29.pdf.

to-grid (V2G) programs, can also support the more efficient use of the grid, thereby minimizing costs and improving overall reliability.[9]

Improved charging efficiency notwithstanding, grid infrastructure investments are a major factor in the pace of MHDV electrification. One of the key challenges to optimizing those investments is the limited access to utility distribution system capacity and cost data for transportation planners, state agencies, and other critical stakeholders. Sharing of utility and transportation data will further enable widespread adoption of electric MHDVs across the country. In addition, utility planning is crucial to support the rapid adoption of electric MHDVs. Certain areas of the distribution grid will be able to easily accommodate new MHDV load, while other feeders and substations will require upgrades. This report provides a framework for estimating the scale and magnitude of these upgrades and then provides recommendations for preparing the grid and managing future costs.

MHDV Electrification Benefits

Done well, MHDV electrification can put downward pressure on electric utility rates (benefiting everyone), provide valuable grid services, save money for fleet owners, and reduce pollution and greenhouse gas (GHG) emissions. Each of these benefits are discussed below.

Electrification can put downward pressure on electric rates

Greater MHDV electrification will result in greater electricity sales, increasing utility revenues. As long as the increased utility revenue from EV charging exceeds increases in utility system costs, transportation electrification will benefit all electric utility ratepayers by putting downward pressure on rates.

Multiple studies have demonstrated that the electrification of passenger vehicles and light-duty trucks have historically put downward pressure on rates,[10] and that they have the potential to continue doing so in the future.[11] For instance, a study by Lawrence Berkeley National Laboratory found that LDV electrification could reduce rates by roughly 1 percent cumulatively over the next 20 years if EV charging is shifted away from utility system peaks.[12]

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[9] Steward, D. September 2017. *Critical Elements of Vehicle-to-Grid (V2G) Economics*. National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy17osti/69017.pdf.

[10] Shenstone-Harris, S., P. Rhodes, J. Frost, E. Carlson, E. Borden, C. Lane, M. Whited. 2024. *Electric Vehicles are Driving Rates Down for All Customers.* Synapse Energy Economics for National Research Defense Council. Available at: https://www.synapse-energy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Customer%20Update%20Jan%202024%2021-032.pdf.

[11] Satchwell, A., J.P. Carvallo, P. Cappers, J. Milford, H. Eshraghi. February 2023. *Quantifying the Financial Impacts of Electric Vehicles on Utility Ratepayers and Shareholders*. National Lawrence Berkeley Laboratory. Available at: https://emp.lbl.gov/publications/quantifying-financial-impacts.

[12] Satchwell et al., 2023.

Similarly, when considering the electrification of LDVs, MHDVs, and buildings together, a study in California found that rates could decrease by 1.4 to 2.1 cents/kWh under a high electrification scenario relative a scenario with minimal electrification.[13]

Charging of electric trucks and buses, especially larger fleets, can require grid upgrades and have the potential to impose higher costs than charging of LDVs. However, if charging is managed and occurs primarily during off-peak hours, costs would be mitigated. By leveraging off-peak charging, electric MHDVs can help utilities better utilize their existing infrastructure, thereby reducing the need for costly upgrades and additional capacity during peak periods. A study in New York found that utility MHDV make-ready programs (which cover the costs of distribution system and site upgrades to support higher loads from electric trucks) have a neutral to beneficial impact on rates for the period of 2023 to 2045.[14] The net positive rate impact is greater under scenarios with managed charging, which shifts electricity consumption away from peak periods.[15]

Electrified MHDVs can act as batteries and provide grid services

Electric MHDVs have the potential to serve as mobile energy storage units, contributing to grid stability and supporting the integration of renewable energy sources. This concept is known as vehicle-to-grid (V2G) technology, whereby electric vehicles, including trucks and buses, can discharge their batteries and feed electricity back into the grid when needed.

One of the key advantages of using electric MHDVs for grid support is their large battery capacities compared to LDVs. During periods of low electricity demand or when the grid has surplus renewable energy, these MHDVs can be plugged into the grid to charge their batteries. But during periods of high demand, MHDVs can discharge energy into the grid, effectively acting as a mobile energy reservoir (e.g., during summer evening peak periods when school buses are not in use). This V2G capability can improve grid reliability and increase demand flexibility, which can provide a range of grid services from relieving local grid constraints to helping integrate higher levels of variable renewable energy such as wind and solar power. Implementing V2G technology with electric MHDVs can also offer economic benefits for fleet operators. When trucks and buses are not in use, such as when trucks are parked at

[13] Sieren-Smith, B., A. Jain, A. Eshraghi, S. Hurd, J. Ende, J. Huneycutt. February 2021. Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates And Equity Issues Pursuant to P.U. Code Section 913.1. California Public Utilities Commission. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-banc-whitepaper_final_04302021.pdf.

[14] Metz, L., M. Whited, P. Rhodes, E. Carlson. April 2023. *Distribution System Investments to Enable Medium- and Heavy-Duty Vehicle Electrification*. Synapse Energy Economics for Environmental Defense Fund.

[15] Metz et al., 2023.

distribution centers, their batteries can be leveraged to earn revenue by providing grid services.[16,17]

Although utilities across the country are implementing pilot programs, V2G technology is still in the early stages of development and requires supportive infrastructure and regulatory frameworks.[18] Still, the potential for electric MHDVs to function as flexible grid resources holds promise in creating a more resilient, efficient, and sustainable energy ecosystem.

Other economic and societal benefits of MHDV electrification

Although electric trucks and buses are typically more expensive upfront than their fossil-fuel-powered counterparts, they benefit from major fuel and maintenance savings over the course of their lifetime. According to a study by Roush Industries, an electric delivery truck can cost 34 percent less than a comparable diesel truck over its lifetime,[19] while an electric school bus could generate savings of 24 percent over its lifetime.[20] With widespread MHDV electrification, savings could be substantial. In Illinois, a recent study found that the electrification of MHDVs, through ACT, could save fleet owners $1.2 billion annually by 2050.[21] Specifically, electric vehicles have fewer moving parts and simpler drivetrains compared to internal combustion engines, leading to substantially lower maintenance needs.[22] Plus, with EVs' regenerative braking technology, certain pieces of breaking equipment need to be replaced less frequently.[23] Electric trucks and buses are three to seven times more efficient than conventional diesel vehicles,[24] which translates into reduced energy consumption per mile and lower fuel costs. Furthermore, with electricity being more cost-stable than diesel, businesses with electric fleets can better predict and manage their fuel expenses.[25] Lastly, cost savings

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[16] For example, San Diego Gas & Electric Company has a Vehicle-to-Grid program for school buses. See https://www.sdge.com/business/electric-vehicles/power-your-drive-for-fleets/current-V2G-projects.

[17] For example, PGE's "Vehicle to Everything" pilot program, for commercial customers "V2X Commercial." See https://www.pge.com/en/clean-energy/electric-vehicles/getting-started-with-electric-vehicles/vehicle-to-everything-v2x-pilot-programs.html.

[18] Steward, D. September 2017. *Critical Elements of Vehicle-to-Grid (V2G) Economics*. National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy17osti/69017.pdf.

[19] Nair, V., S. Stone, G. Rogers, S. Pillai. February 2022. *Medium and Heavy-Duty Electrification Costs for MY 2027-2030*. Roush Industries, Inc. Prepared for Environmental Defense Fund. Available at: https://blogs.edf.org/climate411/wp-content/blogs.dir/7/files/2022/02/EDF-MDHD-Electrification-v1.6_20220209.pdf.

[20] Nair et al., 2022.

[21] Robo, E., D. Seamonds, M. Freeman, A. Saha, A., D. MacNair. 2022. Illinois Clean Trucks Program: An Analysis of the Impacts of Zero-Emission Medium- and Heavy-Duty Trucks on the Environment, Public Health, Industry, and the Economy. ERM for the Natural Resources Defense Council and the Union of Concerned Scientists. Available at https://www.nrdc.org/sites/default/files/media-uploads/il_clean_trucks_report_06.pdf.

[22] Nair et al., 2022.

[23] Nair et al., 2022.

[24] California Air Resources Board. May 2018. Battery Electric Truck and Bus Energy Efficiency Compared to Conventional Diesel Vehicles. Available at: https://ww2.arb.ca.gov/sites/default/files/2018-11/180124hdbevefficiency.pdf.

[25] U.S. Department of Energy. September 2022. Saving Money with Electric Vehicles. Available at: https://www.energy.gov/energysaver/articles/saving-money-electric-vehicles.

from MHDV electrification are expected to increase in the future as advancements in battery technology will continue to reduce battery costs and make electric trucks more affordable.[26] This trend, coupled with ongoing innovations in battery longevity and performance, will continue to enhance the overall financial attractiveness of electric trucks and buses.[27] Although MHDVs make up less than 5 percent of the vehicles on the road, they produce over 20 percent of transportation GHG emissions[28] and were responsible for over one-third of U.S. GHG emissions in 2022.[29] Electrification of MHDV has the potential to significantly reduce GHG emissions. Furthermore, as the electricity generation mix continues to shift towards an increasing share of renewable energy sources in the coming decades,[30] the GHG emissions associated with electric MHDVs will continue to decrease.

Nearly all MHDVs on the road today are powered by diesel internal combustion engines, which directly emit toxic air pollutants like nitrogen oxides and particulate matter. These pollutants from MHDVs disproportionally burden low-income communities and communities of color; they affect the respiratory system, leading to asthma, lung disease and other health impacts.[31] Electrification of MHDV can reduce harmful pollution and dramatically improve air quality, since electric MHDVs produce zero tailpipe emissions.

[26] Nair et al., 2022.

[27] Goldman Sachs. November 2023. *Electric vehicle battery prices are falling faster than expected*. Available at: https://www.goldmansachs.com/intelligence/pages/electric-vehicle-battery-prices-falling.html#:~:text=Goldman%20Sachs%20Research%20now%20expects,for%20a%2033%25%20decline).

[28] U.S. Department of Energy. March 2022. "DOE Projects Zero Emissions Medium- and Heavy-Duty Electric Trucks Will Be Cheaper than Diesel-Powered Trucks by 2035." Available at: https://www.energy.gov/articles/doe-projects-zero-emissions-medium-and-heavy-duty-electric-trucks-will-be-cheaper-diesel#:~:text=Medium%2D%20and%20heavy%2Dduty%20vehicles,U.S.%20green%2Dhouse%20gas%20emissions.

[29] U.S. Department of Energy, 2022.

[30] U.S. Energy Information Administration. March 2022. "EIA projects that renewable generation will supply 44% of U.S. electricity by 2050." *Today in Energy*. Available at: https://www.eia.gov/todayinenergy/detail.php?id=51698.

[31] Fleming, K., A. Brown, L. Fulton, M. Miller M. 2021. "Electrification of Medium- and Heavy-Duty Ground Transportation: Status Report." Current Sustainable/Renewable Energy Reports 8, 180-188. https://doi.org/10.1007/s40518-021-00187-3.

Recommended Framework and Methodology for Estimating ACT Rule's Impact on the Distribution Grid

Overview and Framework Roadmap

This section describes a framework for evaluating the impact of ACT and other MHDV policies, and a path to begin preparing for widespread fleet electrification in a given state.[32] We offer a high-level, top-down approach to estimating the impact of ACT, focusing specifically on feeders and substations on the electric distribution grid. The results of this type of impact analysis can inform utilities, decision-makers, policy experts, and regulators on the barriers and opportunities related to fleet electrification and how they interact with the state of the electrical grid.

To estimate the impacts of MHDV electrification on feeders and substations of a utility's or state's distribution system, analysts need to determine the following:

Step 1: What levels of electric MHDV adoption are expected under baseline and ACT adoption scenarios

Step 2: Where on the distribution grid MHDVs are expected to charge

Step 3: How much peak demand MHDVs will add to each substation and feeder

Step 4: How much more load each substation and feeder can accommodate without additional upgrades (i.e., the "headroom")

Step 5: What upgrades will be required to enable MHDV electrification

Step 6: What solutions are available to minimize costs

The results of this analysis can guide future investments and EV adoption plans by revealing where the distribution system is likely able to absorb added MHDV load and where additional system upgrades are more likely to be needed. Proactively planning for future upgrades can help to encourage MHDV electrification at lowest cost, thereby unlocking benefits to the economy, human health, and climate change mitigation efforts.

The purpose of this framework is to provide guidance for state regulators, utilities, and other stakeholders by describing the data and modeling approaches to estimate ACT's impacts.

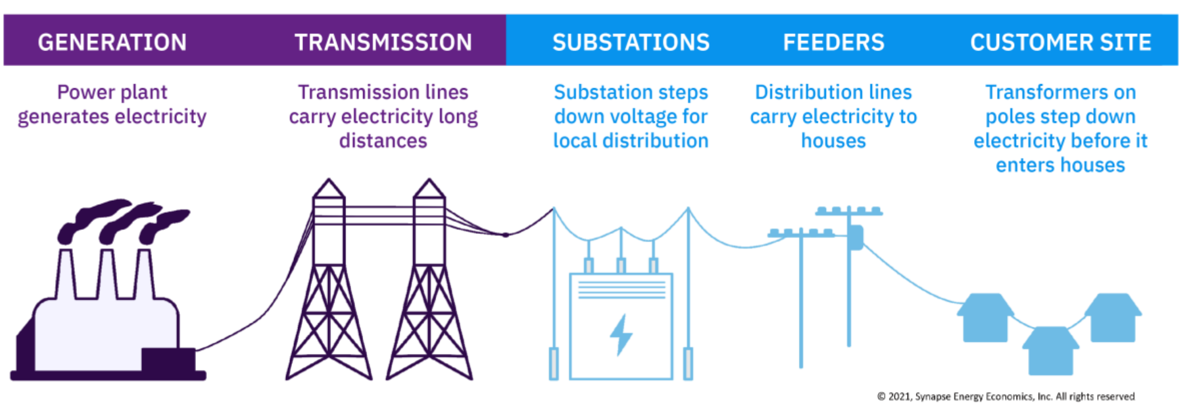
[32] Analysts may wish to focus on an individual utility rather than a state as a whole. This framework can be applied to sub-state regions or utility service territories.

However, as this report will also show, data limitations often make this type of analysis difficult, especially for those who do not have access to granular utility distribution system data. For this reason, each step of the framework will also include actual analysis Synapse performed in Pennsylvania and Illinois, showcasing and discussing simplifying assumptions that can be used in the absence of utility data. These assumptions highlight additional studies utilities ought to perform to understand electric MHDV impacts and create an opportunity for further data transparency. They also highlight how sensitive distribution-level costs are to key factors such as the number of electric MHDVs and the quantity of distribution substations and feeders assumed to experience charging load. Going forward, utility-specific data and studies are needed to develop more accurate estimates of the scale and magnitude of distribution-level upgrades in each service territory.

Overview of the Distribution System

The electricity system begins with electricity generation, where power plants, including renewable energy facilities, produce electricity. This electricity is then transmitted over long distances through high-voltage transmission lines to substations. Subtransmission substations act as intermediaries between the high-voltage transmission network and the lower-voltage distribution system. Distribution substations use transformers to further step down voltage to levels that can be safely and efficiently distributed to customers. Each distribution substation serves one or more distribution feeders, which branch out from substations and deliver electricity to individual consumers through distribution transformers and sometimes secondary distribution lines[33] (Figure 1). Together, distribution substations and feeders form the backbone of the distribution system and are the focus of this report.

Figure 1. Diagram of the electrical system

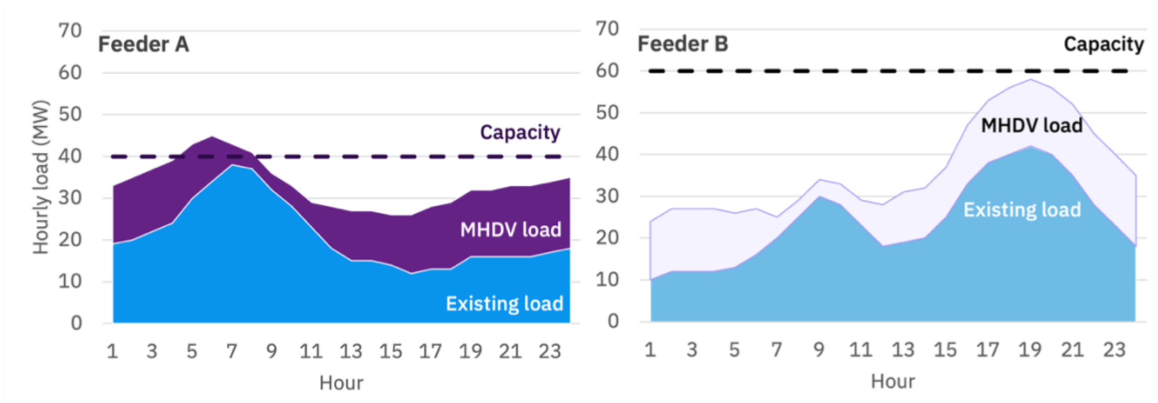


[33] Secondary distribution lines are not pictured in Figure 2.

Total electricity system costs from EV charging are driven by two key factors: energy consumption and demand. EV charging requires the generation of more electricity (measured in kilowatt-hours (kWh)) and can also increase the peak demand on the electricity system (measured in kilowatts (kW) or megawatts (MW)). Utilities must size the components of the distribution system (as well as the transmission system) to meet the maximum demand of customers using that equipment, so increases in demand may require the utility to upgrade or expand the distribution system. Specifically, each individual piece of distribution system equipment, such as substations, feeders, and transformers, is built to meet the maximum combined demand of the customers it serves. If the maximum demand on any individual component of the system approaches the maximum capacity of that component, it will need upgrading or, absent the ability to reduce or manage load, the utility will have to transfer some load to another feeder line or substation.

Figure 2 shows two example feeders, Feeder A and Feeder B. The two feeders have different load profiles and feeder capacity, but they experience the same quantity of new MHDV load. Feeder A cannot accommodate the MHDV load without exceeding the feeder's capacity. On the other hand, Feeder B's existing load has a higher peak demand than Feeder A, but the capacity of Feeder B is also greater. As a result, the added MHDV load on Feeder B does not exceed the feeder capacity and an upgrade is not required, while the utility would need to upgrade the equipment on Feeder A before the MHDV load could be added. The same thinking can be applied to substations, which typically serve multiple feeders. If the total combined load of many feeders radiating from a single substation exceeds the substation's existing capacity, the substation may need to be upgraded or a new one may need to be built. As can be seen, the impact of future MHDV electrification is highly location-dependent, driven by equipment capacity, existing, and expected new EV load. The ability to manage existing load or manage the additional MHDV load can also impact the need for and extent of upgrades.

Figure 2. Example of adding the same MHDV load to two illustrative feeders with different load profiles and feeder capacity

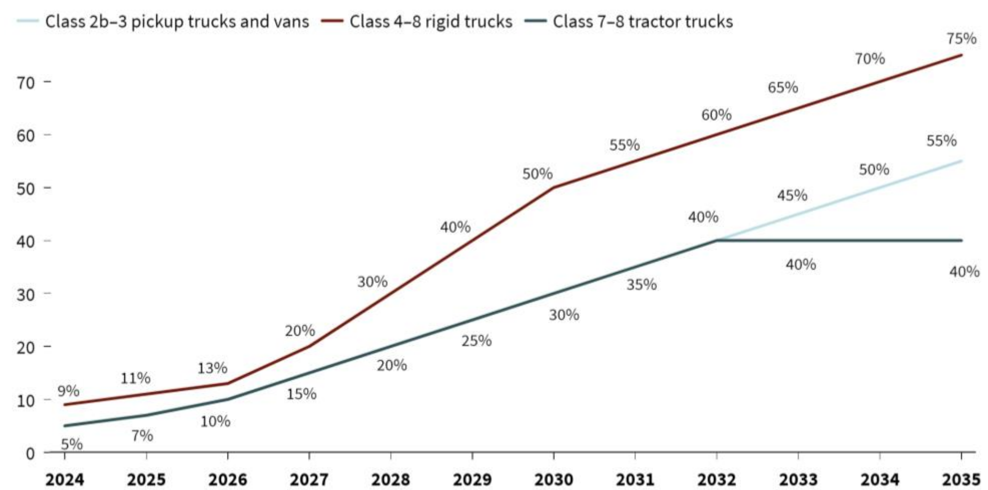


Step 1: Forecast electric MHDV adoption

To estimate the impact that MHDVs will have on the distribution grid, one must estimate future EV adoption, both annually and for a target year. Often, the analysis will seek to determine the impact of a specific regulatory goal, such as for the vehicle stock (i.e., achieving a certain number of EVs on the road by a certain date) or an annual sales target.[34] We discuss one such model in the case study below, but other EV stock turnover models and/or EV market forecasts are available to analysts.

ACT is based on an annual sales target through 2035 for different vehicle types, determined by gross weight (Figure 3). However, the total number of EVs (or vehicle stock) is a much more useful and valuable metric for estimating distribution grid impacts. Analysts should seek to collect or estimate total vehicle stock values for the target year (e.g., 2035) or annually from the present to the target year, using an EV adoption model (sometimes called a stock turnover model). Forecasting EV penetration by vehicle type is important, as different vehicle types have different charging patterns, different energy requirements and demand, and may even have different use cases or degrees of flexibility to adjust charging patterns.

Figure 3. ACT annual sale percentage requirements by weight class



Note: Class 2b—3 vehicles include large pickups as well as utility vans, mini-buses, and step vans. Class 4—8 rigid trucks include all vehicles larger than 14,000 pounds with a rigid frame without a detachable trailer, while tractor trucks in Class 7 and 8 do include a detachable trailer. Figure source: McNamara, Marie. "Understanding California's Advanced Clean Truck Regulation." Rocky Mountain Institute, July 27, 2023. Available at: https://rmi.org/understanding-californias-advanced-clean-truck-regulation/.

[34] In many cases, regulatory goals may not specify EV targets, but will specify zero-emissions-vehicle (ZEV) targets. In these cases, analysts should carefully consider the proportion of non-electric ZEVs, such as hydrogen vehicles, expected in each year and subtract these vehicles from the ZEV target to yield electric-only targets.

It is helpful to also estimate EV adoption and penetration levels under a business-as-usual (BAU) scenario, where there is some level of MHDV electrification but without full ACT rule implementation. A BAU scenario provides a baseline against which to assess the impacts of ACT and other policies. This helps decision-makers and analysts understand the magnitude and scale of grid impacts associated with ACT. For example, EPA's Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles – Phase 3 could serve as a BAU scenario. Analysts may also wish to develop multiple ACT scenarios, such as an additional scenario with greater managed charging or load control.

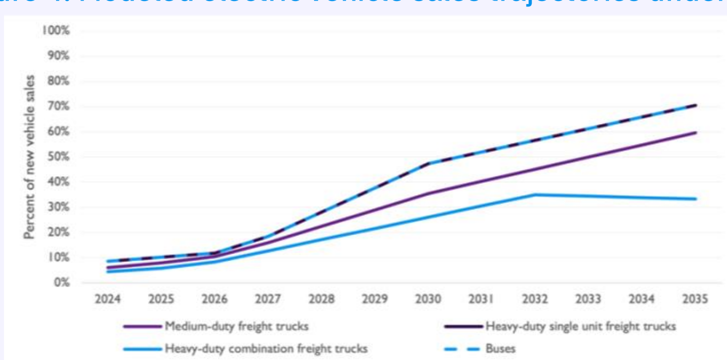
Case Study: Forecasting Electric MHDV Adoption in Pennsylvania and Illinois

We estimate electric MHDV penetration for our two case study states, Pennsylvania and Illinois, through 2035. To estimate vehicle adoption, we used EV-REDI ("Electric Vehicle Regional Emissions and Demand Impacts"),[35] an EV stock turnover model developed by Synapse Energy Economics to forecast EV adoption trajectories at the state level under a BAU scenario and under a scenario meeting ACT sales targets. EV-REDI relies on publicly available data sources to assemble state-specific information on the historical adoption of EVs and develop trajectories of future EV deployment. EV-REDI then quantifies both conventional and EV sales and stock, and the resultant impacts on electricity sales, tailpipe emissions, gasoline consumption, and other metrics. For every state, EV-REDI accounts for state trends in stocks, sales, and driving patterns, vehicle ownership lifetime, vehicle-miles traveled (VMT), changing efficiencies of both EVs and conventional vehicles, and changing trends in vehicle preferences.

EV-REDI estimates how many vehicles are on the road in any given year, based on the number of new vehicles sold and a decay curve that describes replacements of vehicles over time. Then, using information on energy efficiencies and VMT (specific to each vehicle class, e.g. buses or medium trucks), EV-REDI estimates total annual energy consumption by vehicle type.

The ACT rule is based on a sales target of zero-emission vehicles, rather than exclusively EVs. By 2035, we assumed a small portion of the zero-emission MHDVs would be hydrogen fuel cell vehicles. We used Bloomberg New Energy Finance forecasts of hydrogen vehicle adoption and subtracted that from ACT's ZEV sales requirements to produce an EV sales trajectory for use in EV-REDI. To represent ACT targets in EV-REDI, we modeled the trajectories shown in the figure below for both Pennsylvania and Illinois.

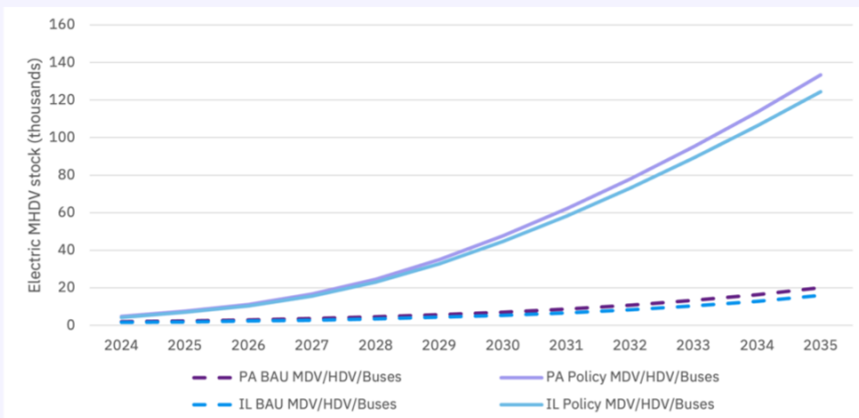
Figure 4. Modeled electric vehicle sales trajectories under ACT



35 For more information on EV-REDI, see: https://www.synapse-energy.com/tools/electric-vehicle-regional-emissions-demand-impacts-tool-ev-redi.

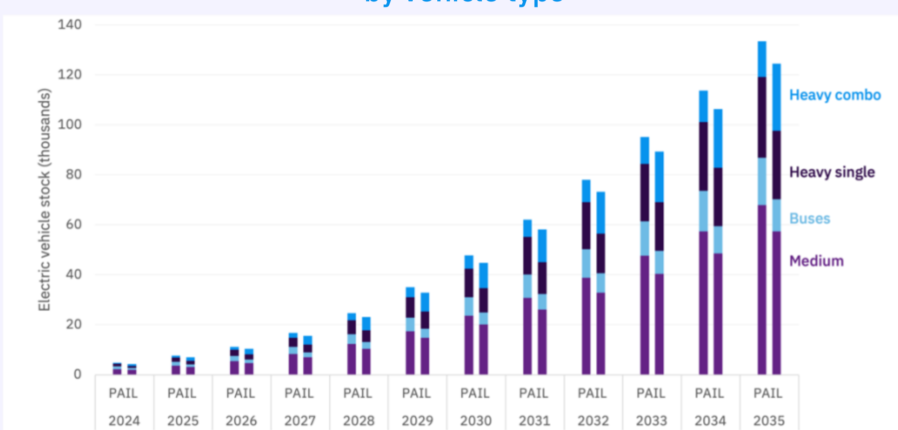
We also ran a BAU scenario, informed by Bloomberg New Energy Finance's 2023 electric vehicle modeling, which assumes that 9 percent of MHDVs sold by 2035 will be electric.[36] Ideally, analysts should incorporate existing state policies into their analyses, such as Illinois' *Climate and Equitable Jobs Act* (CEJA). We did not include CEJA in our BAU forecast for Illinois as there was not enough detailed information on adoption forecasts for electric MHDVs. Figure 5 shows the electric MHDV stock projects for Pennsylvania and Illinois under ACT (the "policy" scenarios) relative to the BAU scenario, representing a 6- and 7-fold increase over the expected BAU levels in 2035 for Pennsylvania and Illinois, respectively (Figure 5).

Figure 5. Total electric MHDV stock for the BAU and ACT policy scenarios in Pennsylvania and Illinois



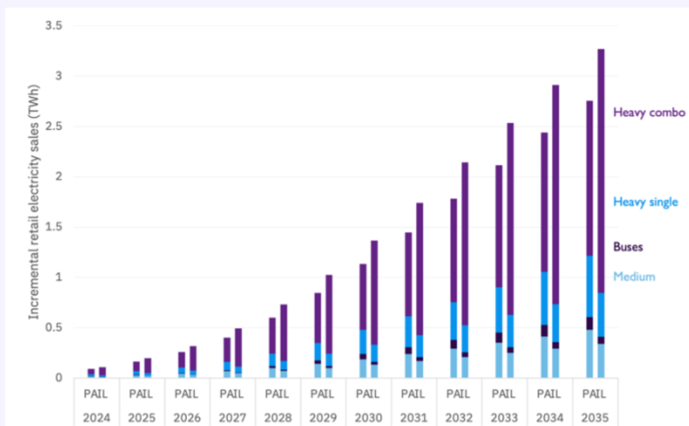
Overall, Pennsylvania will likely see over 130,000 electric MHDVs, while Illinois could see roughly 124,000 electric MHDVs by 2035 if ACT is implemented (Figure 6).

Figure 6. Electric MHDV adoption expected under ACT for Illinois and Pennsylvania, by vehicle type



Energy consumption will also increase with the adoption of ACT. By 2035, the incremental energy consumption from MHDVs will be 2.8 TWh in Pennsylvania and 3.3 TWh in Illinois, relative to the BAU (Figure 7). This increase is equivalent to 2 percent of 2022 retail sales in both states.[37] Heavy combination trucks use substantially more energy compared to a medium-duty truck, or even a bus. Although Illinois has a smaller share of total vehicles relative to Pennsylvania (Figure 6), it has a higher share of heavy-duty combination trucks,[38] which use a disproportionally large amount of energy relative to other MHDV types (Figure 7). As a result, the total energy consumption is expected to be somewhat higher in Illinois than in Pennsylvania. Analysts should carefully consider the vehicle types in their own jurisdiction, as well as potential future changes to the makeup of the MHDV fleet.

Figure 7. Incremental energy consumption of medium-duty vehicles, buses, heavy single trucks, and heavy combination trucks annually in Pennsylvania (PA) and Illinois (IL) as a result of ACT relative to the BAU scenario



Even though implementation of ACT would only increase total electricity consumption in these states by less than 3 percent by 2035, the greatest driver of costs is additional peak demand on the distribution system. As discussed above, the distribution system is built to meet expected peak demand; when demand exceeds the capacity and available headroom of the existing equipment, utilities often must make upgrades to accommodate that new load. As we explore in the next sections, peak load impacts may be lumpy across the distribution system, making it potentially difficult and expensive to manage in certain areas.

[36] BloombergNEF. Electric Vehicle Outlook 2023. Available at: https://assets.bbhub.io/professional/sites/24/2431510_BNEFElectricVehicleOutlook2023_ExecSummary.pdf, converted to sales values in EV-REDI.

[37] 2022 retail electricity sales from U.S. Energy Information Administration (EIA) form 861.

[38] Using 2021 data from the Federal Highway Administration. We assume no change to the proportion of each MHDV type beyond 2021.

Step 2: Determine where on the distribution grid MHDVs are expected to charge

Forecast the locations where MHDVs will charge

As discussed above, the impact of electric MHDVs on the distribution grid is highly location-dependent. Analysts must first seek to understand where MHDVs will charge, which in turn will provide insight into how much demand MHDVs are expected to add to each affected feeder and/or substation.

There are numerous ongoing efforts to estimate where charging might occur, where public MHDV chargers should be installed, and where fleets might first be converted to electric trucks. These efforts involve complex modeling of travel patterns, VMT, stopping locations, stopping time and duration, vehicle efficiencies, and other factors. Examples of this type of analysis include EPRI's eRoadMAP[39] and Lawrence Berkeley National Laboratory's (LBNL) HEVI-LOAD.[40] EPRI's eRoadMAP is an interactive, online tool to help electric utilities, regulators, and planners understand where, when, and how much LDV and MHDV charging load can be expected across each state. Figure 8 below shows a screenshot of EPRI's eRoadMAP for Chicago in 2030.[41] LBNL's HEVI-LOAD is a modeling tool to forecast California-wide charging infrastructure for MHDVs, including the number, type, and location of chargers, along with the related electric grid supply requirements to support the new charging stations for MHDVs. LBNL plans to expand the tool to states beyond California.[42]

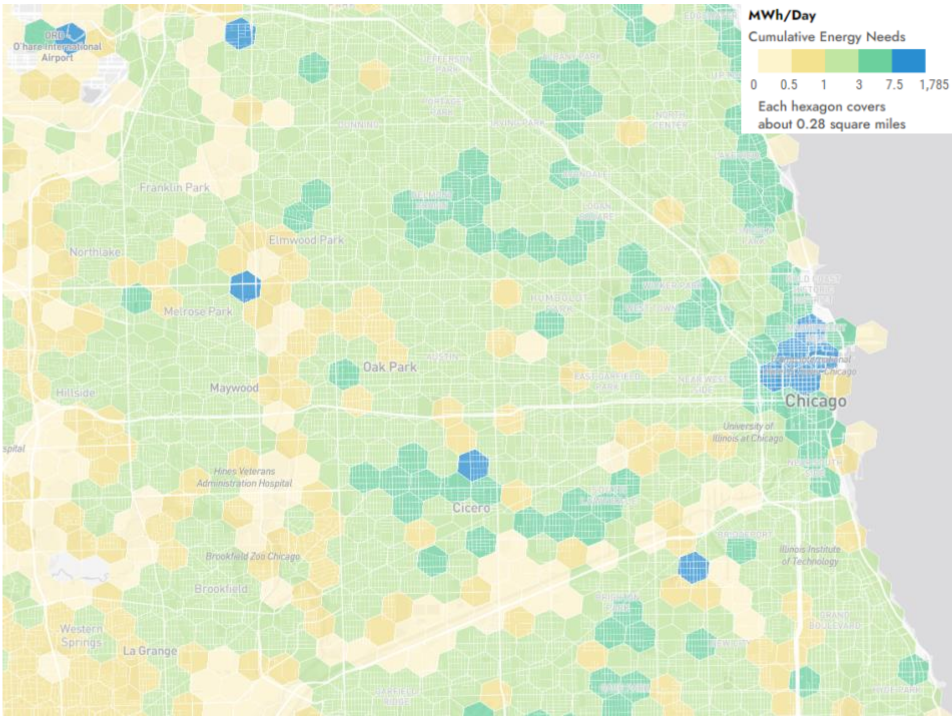
[39] EPRI's eRoadMAP, available at: https://eroadmap.epri.com/.

[40] Lawrence Berkeley National Laboratory. HEVI-LOAD: Medium and Heavy-Duty Electric Vehicle Infrastructure – Load Operations and Deployment Modeling Tool. Available at: https://transportation.lbl.gov/vehicles-and-grid.

[41] Note EPRI's projections for Illinois do not assume ACT adoption.

[42] Lawrence Berkeley National Laboratory. HEVI-LOAD: Medium and Heavy-Duty Electric Vehicle Infrastructure – Load Operations and Deployment Modeling Tool. Available at: https://transportation.lbl.gov/vehicles-and-grid.

Figure 8. EPRI’s eRoadMAP projections of annual electric energy requirements from LDVs and MHDVs in 2030 in Chicago



Note: EPRI’s 2030 projections for Illinois do not incorporate the ACT; it is presented for illustrative purposes here. Source: EPRI’s eRoadMAP, available at: https://eroadmap.epri.com/.

If datasets are unavailable on where EVs are likely to charge, analysts can still estimate where MHDVs are likely to be charging in the future. State transportation departments and other planners may be able to provide useful data such as geographic information system (GIS) files identifying where large fleets exist that could soon electrify. These locations could include storage warehouses, distribution centers, departments of public works, school bus parking areas, municipal bus parking areas, and long-haul transportation corridors, to name a few. There may also be certain types of vehicles that are not part of a fleet and do not charge regularly at the same location each day; these vehicles may need to be distributed more evenly across the region of study, rather than clustered in a few locations.

Map projected load to the distribution grid (feeder and/or substation level)

The next step is to map the charging load to the distribution grid to determine whether EV load will exceed the available capacity at the feeder or substation level. Mapping where MHDV charging is expected to occur on the distribution grid could involve GIS analysis or other visual mapping tools, but it may simply involve spreadsheet analysis. Many utilities also use fleet advisory services to map fleets in their service territories. Whatever the method, it is important to determine the total load that each feeder (and substation) is likely to see in the future with ACT adoption.

Mapping locational charging data to the distribution grid may be the most challenging piece of an analysis of ACT's impact or grid preparedness. Distribution grid information is not often publicly available, so analysts may need to work with utilities to access that information.[43] Generally, analysis at the feeder level will lay the foundation for the richest analysis, but data may only be available at the substation level. Analysts should try to estimate impacts at both the feeder and substation levels, when possible.

Step 3: Determine how much peak demand MHDVs will add to each feeder/substation

The process described above will help analysts determine the additional load on different parts of the distribution grid. The next step is to estimate the impact on each feeder's and substation's peak demand. If the analyst is converting vehicle counts or number of chargers to load profiles, special consideration should be given to how many vehicles may share a charger and how many chargers may be used simultaneously. One way to estimate increases in peak demand is to use daily load curves, such as those from LBNL's HEVI-Load.[44] If possible, demand estimates at the feeder (and substation) level should consider different vehicle types and charging behavior. For instance, a feeder with 100 buses will have very different energy requirements than a feeder with 500 medium-duty delivery trucks. Several reports have categorized and estimated the demand of various fleets or highway charging stops that could be helpful.[45,46]

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[43] Utilities may be able to provide more detailed studies on where on their system(s) MHDV are likely to charge and the expected demand they are likely to impose.

[44] Lawrence Berkely National Laboratory. HEVI-LOAD: Medium and Heavy-Duty Electric Vehicle Infrastructure – Load Operations and Deployment Modeling Tool. Available at: https://transportation.lbl.gov/vehicles-and-grid

[45] Site specific load curves available at: https://data.nrel.gov/submissions/162. Borlaug, B., Muratori, M., Gilleran, M., Woody, D., Muston, W., Canada, T., Ingram, A., Gresham, H., McQueen C. 2021. Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems. Nature Energy, Volume 6: 673-682.

[46] Katsh, G., Fagan, C., Wilke, J., Wilkie, B., Lamontagne, C., Coyne, R.G., Mandel, B., Schroeder, J., Mullaney, D., Marchini, D., Argue, C., Maida, P., Veeh, N. 2022. Electric Highways: Accelerating and Optimizing Fast-Charging Deployment for Carbon-Free Transportation. National Grid, Calstart, RMI, Stable, Geotab. Available at: https://www.nationalgrid.com/document/148616/download.

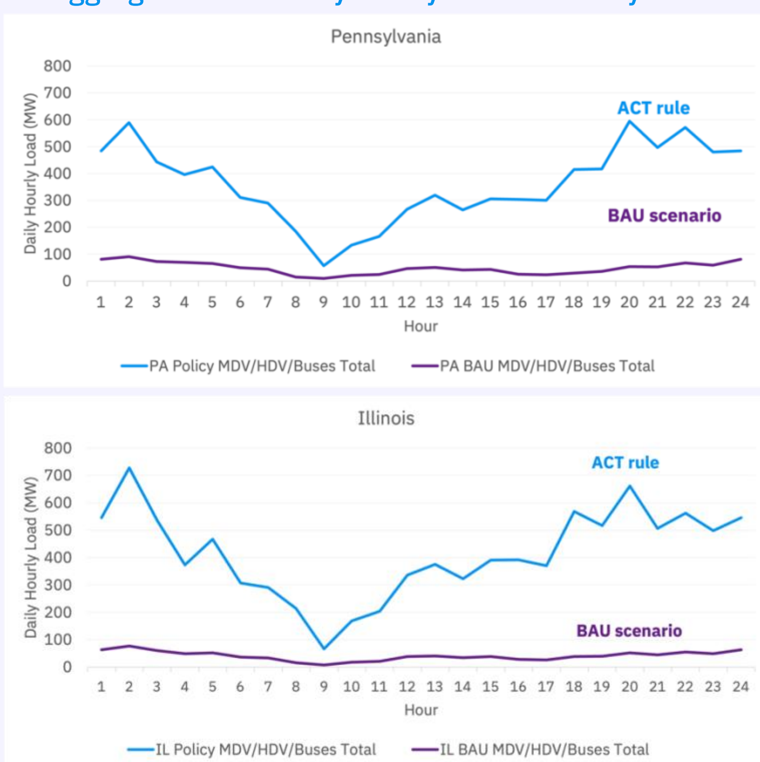
Case Study: Estimating MHDV demand on the distribution grid in Pennsylvania and Illinois

Estimating total systemwide MHDV electricity demand

Each fleet or individual vehicle will have its own charging pattern and profile, based on driving patterns, battery sizes, miles traveled, use cases, etc. We used 24-hour load curves for California MHDVs developed by LNBL for this analysis, and then for each state we scaled those load curves to match the MHDV electricity consumption derived from EV-REDI.[47] Ideally, analysts would use load curves based on state-specific data, but these can be difficult and costly to develop.

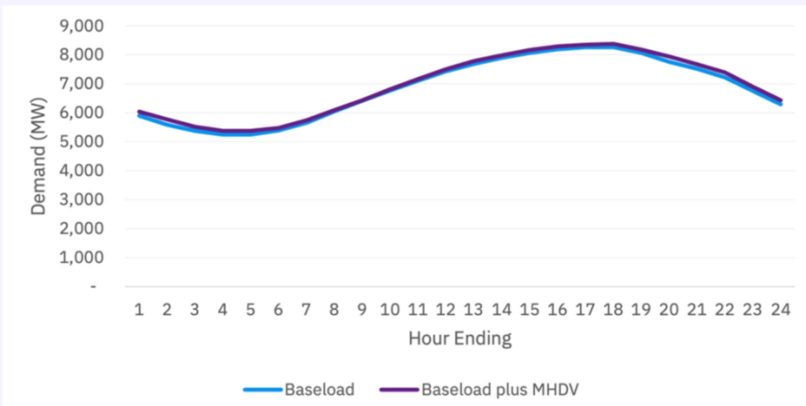
We first calculated average daily energy consumption by dividing annual energy consumption (estimated in EV-REDI) by 365 days. We then calculated the hourly demand by multiplying the load curves from LBNL (with every hour as a percentage of average daily consumption) by average daily energy consumption.[48] We did this separately for each vehicle type (medium truck, bus, heavy single truck, and heavy combo truck), as each vehicle type has a different charging and use pattern, and therefore different peak demand impacts on the electricity system. Figure 9 displays the aggregated daily load curves of all MHDVs and shows demand under both ACT rule and BAU scenarios.

Figure 9. Estimated aggregate MHDV daily hourly load in Pennsylvania and Illinois in 2035



Next, we assessed the largest utilities[49] in Pennsylvania and compared the increase in MHDV electric demand relative to forecasted peak demand (systemwide).[50] In Pennsylvania, peak demand under ACT is projected to increase by roughly 600 MW by 2035 (Figure 9, above). However, when compared to the existing load in 2035, utilities will see a peak load increase from MHDVs of between 0.7 percent and 1.3 percent (MHDV charging in the BAU scenario will increase utility peak loads by just 0.1 percent). Take for example Figure 10, which shows the average summer[51] hourly load curve for PECO, one of Pennsylvania's largest utilities by electricity sales, alongside the added load from MHDVs. MHDVs increase the load during peak hours (from 3 pm to 6 pm) between 1.1 and 1.5 percent in 2035 relative to the non-MHDV load.[52]

Figure 10. PECO's average summer daily load shape with and without electric MHDVs in 2035



Similarly in Illinois, electric MHDVs are expected to add over 700 MW of peak demand to the system. Relative to the two largest utilities, this equates to a peak increase of 1.4 and 1.6 percent, compared to 0.1 percent under the BAU scenario in 2035.[53]

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[47] Lawrence Berkeley National Laboratory. HEVI-Pro load profiles. Provided to Synapse in August 2022.

[48] LBNL load curves are average load curves for the whole year, they incorporate both weekdays and weekend days, and as a result, we divided annual energy consumption by 365 to estimate daily energy consumption. If the data is available, analysts may wish to estimate consumption for days when the vehicle is idle, and days when the vehicle is in use/charging (such as weekdays and weekend days).

[49] Investor-owned utilities that provide more than 3.5 percent of electricity sales in 2022, according to EIA form 861.

[50] Using PJM's 2023 zonal peak demand from PJM's Network Service Peak Loads, from 2016 to 2023 (available at: https://www.pjm.com/markets-and-operations/billing-settlements-and-credit). We forecasted peak load using growth factors from Electric Power Outlook for Pennsylvania 2021-2026, August 2022 (available at: https://www.puc.pa.gov/media/2013/epo_report_2022.pdf). Estimates to changes in peak demand extend to 2026, we assumed those annual changes would continue through to 2035.

[51] June, July, August, and September.

[52] Our forecast of PECO's summer average daily load curve does not account for building electrification, behind-the-meter solar and batteries, or other distributed energy resources.

[53] For ComEd, we used PJM's 2023 zonal peak demand from PJM's Network Service Peak Loads, from 2016 to 2023 (available at: https://www.pjm.com/markets-and-operations/billing-settlements-and-credit). For Ameren Illinois, we used hourly generation

This analysis shows that on a systemwide basis, the incremental MHDV charging load is small relative to the existing load; each utility's total system peak only increases by a small proportion. Yet impacts at the substation and feeder levels will be much more varied. This is especially true when considering the diverse load curves of individual fleets and the specifics of the feeder taking on that load. Since MHDVs tend to cluster in certain commercial zones, MHDV demand could be substantial at the feeder level. Investigating electric MHDV adoption at a more localized level is therefore critical for estimating the impact of ACT on the distribution grid and to prepare for future MHDV electrification, as will be discussed in the following steps.

Estimating MHDV demand at each feeder/substation

We used EPRI's eRoadMap data[54] to estimate where MHDVs would be charging throughout Illinois and Pennsylvania. Unfortunately, there was no locational information about the main investor-owned utilities' distribution system in these two states. As a result, we were not able to allocate EPRI's data to specific substations or feeders in either state.[55] Instead, we examined the impact at the county level. To estimate the number of feeders per county, we allocated the total number of feeders[56] to each county based on population density.[57] According to EPRI data, Cook, DuPage, Will, Lake and Kane counties in Illinois will experience the greatest MHDV load in 2030. This translates into a total of 449 MW of added load in the five counties by 2035 (Table 1).[58] In Pennsylvania, Allegheny, Dauphin, York, Philadelphia, and Lancaster counties will experience the greatest MHDV peak load growth by 2035, totaling 167 MW of added peak load (Table 2). As can be seen in Table 1 and Table 2, MHDV load at the county level differs noticeably in each state; in Chicago (Cook County) we expect 275 MW of new load whereas in Philadelphia (Philadelphia County), we expect only 28 MW of new load. This suggests major differences in the geographic characteristics of each city and its county, as well as differences in the cities' bus and trucking industries.

in 2023 (available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#t=10&p=0&s=MarketReportPublished&sd=desc). We forecasted peak load using Illinois's 2024 Electricity Procurement Plan Appendices E and F (Load Forecasts and Supply Portfolio), available at: https://ipa.illinois.gov/energy-procurement/2024-appendices.html. We calculated average growth factors from 2024 through 2028 and assumed the average rate of change would continue through to 2035.

[54] Provided to Synapse in January 2024.

[55] As of March 2024.

[56] From U.S. Energy Information Administration form 861. Pennsylvania has 7,614 feeders and Illinois has 9,965 as of 2022.

[57] This estimate of the number of feeders using population density is a rough approximation and may not accurately reflect the true distribution grid in each area.

[58] We scaled our peak demand estimates in 2035 to EPRI's county-level energy consumption values in 2030.

Table 1. Counties in Illinois with the greatest peak load impact in 2035

County	Cook	DuPage	Will	Lake	Kane
Estimated number of feeders	1,952	1,679	499	314	596
Estimated peak load impact in 2035 (MW)	275	73	56	24	22

Table 2. Counties in Pennsylvania with the greatest peak load impact in 2035

County	Allegheny	Dauphin	York	Philadelphia	Lancaster
Estimated number of feeders	136	56	34	4,816	35
Estimated peak load impact in 2035 (MW)	53	30	29	28	27

We then examined different scenarios in which each county's peak load is allocated to a certain share of feeders, such as 75 percent of all feeders in that county, or 2 percent of feeders in that county (Table 3 and Table 4). Understandably, the load impact on each feeder will increase if there is more clustering on a smaller number of feeders. This case study is a rough example and we provide it for illustrative purposes; in reality the expected load could be substantially different in each county and in each state. Nevertheless, the analysis provides insights that could be refined with improved information at the feeder level. For example, in Illinois, it is only when MHDV loads are clustered on 2 percent or fewer feeders does the average incremental demand from MHDVs exceed 5 MW, in only Cook and Will counties (Table 3). As discussed in Step 5, new loads of 5 MW or more often require distribution system upgrades.[59] The impact in Illinois differs noticeably from Pennsylvania, where when load is clustered on 10 percent of feeders (a major jump from 2 percent), three counties (Dauphin, York, and Lancaster) experience loads of greater than 5 MW (Table 4). This is likely because the greatest electric MHDV adoption in Pennsylvania is occurring in relatively low-density areas (e.g. Allegheny County) versus in Illinois where much higher-density areas are expected to receive the greatest MHDV load (e.g. Cook County, which includes Chicago). As a result, load is spread out over a larger number of feeders in Illinois relative to Pennsylvania. As stated above, assigning feeders to counties by population density serves as a rough proxy and may not reflect the realities of the grid. Analysts should work with their local utilities to collect data on the specifics of the distribution grids in their jurisdictions.

[59] Borlaug, B., M. Muratori, M. Gilleran, D. Woody, W. Muston, T. Canada, A. Ingram, H. Gresham, C. McQueen. 2021. "Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems." *Nature Energy*, Volume 6: 673-682. https://doi.org/10.1038/s41560-021-00855-0.

Table 3. Illustrative impact of MHDV electrification in 2035 on the Illinois counties with the largest load, as a function of the percent of feeders that will experience any MHDV load

MW load impact on each feeder					
Percent of feeders impacted	Cook County	DuPage County	Will County	Lake County	Kane County
75%	0.2	0.1	0.1	0.1	0.05
50%	0.3	0.1	0.2	0.2	0.1
25%	0.6	0.2	0.4	0.3	0.1
10%	1.4	0.4	1.1	0.8	0.4
5%	2.8	0.9	2.2	1.5	0.7
2%	7.0	2.2	5.6	4.0	1.8

Table 4. Illustrative impact of MHDV electrification in 2035 on the Pennsylvania counties with the largest load, as a function of the percent of feeders that will experience any MHDV load

MW load impact on each feeder					
Percent of feeders impacted	Allegheny County	Dauphin County	York County	Philadelphia County	Lancaster County
75%	0.5	0.7	1.2	0.01	1.0
50%	0.8	1.1	1.7	0.01	1.6
25%	1.6	2.2	3.7	0.02	3.0
10%	3.8	5.1	9.8	0.06	8.9
5%	7.5	10.1	14.7	0.1	13.3
2%	17.6	30.4	29.4	0.3	26.6

Putting MHDV feeder load in the context of fleets

In a study conducted by NREL,[60] the peak contribution delivery fleets of 100 vehicles ranged from 4.3 to 5.3 MW, without managed charging. Table 5 presents the peak loads for three types of delivery fleets: beverage, warehouse, and food delivery, and two types of charging strategies: "100 kW intermediate" and "constant minimum power." In the 100 kW intermediate charging strategy, a vehicle charges after its shift ends and will continue to do so until its battery is fully recharged or its next driving shift begins. In the "constant minimum power" charging strategy, a vehicle charges during times in its off-shift period that minimizes its contribution to peak load. Fleets with fewer trucks have lower peak load contributions, which are further minimized with managed charging.

Table 5. Peak load of 100 electric vehicles in various fleet types and under different charging strategies

	100 kW intermediate	Constant minimum power
Beverage delivery	5.3 MW	1.0 MW
Warehouse delivery	5.1 MW	1.1 MW
Food delivery	4.3 MW	2.3 MW

Source: Borlaug et al., 2021.

It is not possible for us to fully implement our recommended methodology in Pennsylvania and Illinois because the publicly available data on the electricity grid in each state is insufficient. However, we can still conclude that MHDV charging demand will not be evenly distributed within each state. Instead, it will be concentrated in a small number of locations, such as fleet depots at distribution warehouses or public fast-chargers along transportation corridors. When MHDV charging occurs in clusters, this incremental load can be substantial in those localized regions on the grid. Depending on their location, these large loads can quickly exhaust the grid capacity, as we discuss below.

[60] Borlaug, B., M. Muratori, M. Gilleran, D. Woody, W. Muston, T. Canada, A. Ingram, H. Gresham, C. McQueen. 2021. "Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems." *Nature Energy*, Volume 6: 673-682. https://doi.org/10.1038/s41560-021-00855-0.

Step 4: Determine how much additional load each affected substation and feeder can accommodate

To determine how much additional load each feeder (and substation) can accommodate, one must ascertain the capacity of the feeder (and substation) as well as determine the current load profile attributable to non-MHDV sources (including peak load, hourly load, and expected load growth from non-MHDV sources for the study period). In other words, one must determine the available headroom of each feeder (and substation).

Within a given utility's territory, or even a neighborhood or subregion, each feeder (and substation) may have a different capacity (recall our illustrative example of Feeder A and Feeder B in Figure 2). Also, the existing load on each feeder (and substation) may vary substantially. Analysts should seek to estimate the existing peak load at each affected feeder (and substation). This involves taking current-day data on each feeder (and substation) and modeling peak load growth from residential, commercial, and industrial sources, plus peak load reductions from distributed energy resources (such as energy efficiency, demand response, and behind-the-meter batteries and solar PV).

Additionally, electric LDV adoption should be considered. Generally, LDVs are smaller than MHDVs and impose less demand on a per-vehicle basis. They are also more dispersed throughout a utility's distribution grid, rather than clustered in fewer commercial areas. Nonetheless, they are a key piece of the analysis; adding a bank of DC fast-chargers for LDVs to a feeder could mean it no longer has the capacity to incorporate MHDV load.

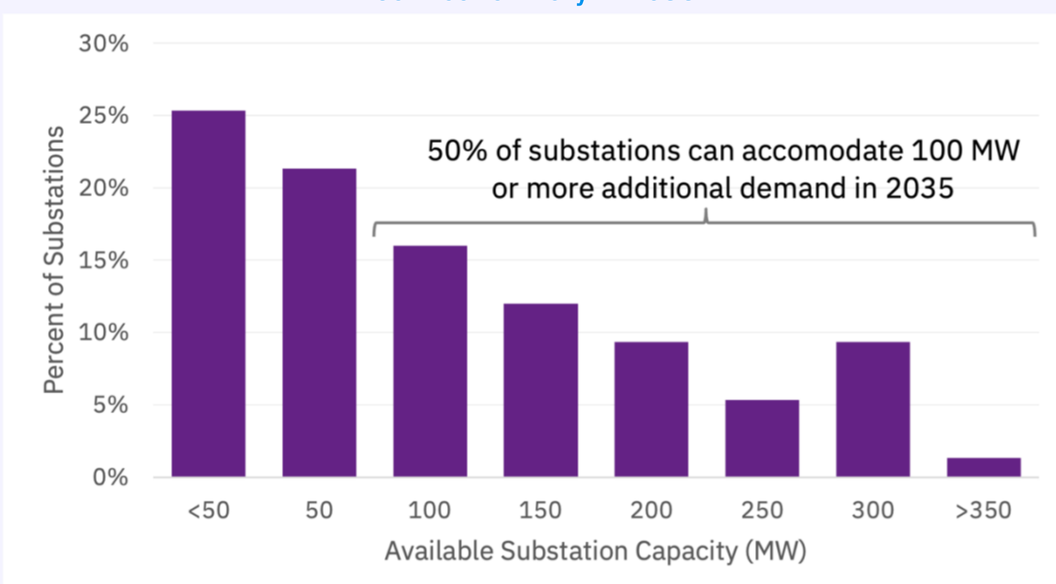
Analysts may also wish to consider differences in summer and winter capacities of distribution equipment, along with seasonal changes in load due to building electrification and the adoption of more distributed energy resources. Generally, buildings have the greatest demand in the summer when air conditioners are in use. With electrification however, buildings' electricity demand will grow in the winter, potentially surpassing the summer peak load. Similarly, we are likely to see a significant increase in behind-the-meter solar and batteries, potentially reducing summer load (as well as winter load). Thus, analysts should consider all seasons, and all hours of the year, when estimating available headroom on each feeder. Lastly, analysts should calibrate these studies with load assumptions in their jurisdiction's long-term planning documents, such as state transportation department planning documents and utility integrated resource plans.

Case Study: Estimating available capacity on shared distribution equipment in Pennsylvania and Illinois

Pennsylvania and Illinois did not have publicly available data on their distribution grids, such as the nameplate capacity of each feeder (and substation) and the existing loads. Unfortunately, this type of data is rarely publicly available. As of March 2024, New York is one of the few states that provides this data to the public. To illustrate this step, we summarize this data from Consolidated Edison's (Con Edison) and National Grid's distribution grids in New York State.

Con Edison serves most of New York City; because of the very high density of its grid, it uses a mesh secondary distribution network rather than a radial system, which makes assessing impacts at the feeder level very difficult. Instead, we assessed the capacity and available headroom at the substation level. Con Edison publishes annual hourly load estimates at each substation for 2020–2023.[61] We then used the 10-year compound annual growth factors (CAGR) for each substation from Con Edison's Distribution System Implementation Plan (DSIP) to project load in future years.[62] These projections include some level of LDV electrification. As can be seen in Figure 11, roughly half of all substations can accommodate additional demand of 100 MW or more in 2035.

Figure 11. Estimate of available substation capacity in Con Edison's service territory in 2035



[61] Con Edison Hosting Capacity Web Application. Available at: https://www.coned.com/en/business-partners/hosting-capacity.

National Grid serves most of the rest of New York State, with analysis possible at the feeder level due to the radial configuration of its distribution circuits.[63] We obtained annual hourly load projections for each feeder for 2022–2026 from the utility's public data portal.[64] National Grid does not publish 10-year CAGRs in its DSIP, so we calculated summer and winter load-growth rates using coincident peak demand projections from the NYISO Gold Book for Zones A and B,[65] adjusted to remove the vehicle load included in those forecasts. Roughly 30 percent of feeders can accommodate 2 MW of demand without additional upgrades, and over 40 percent of feeders are expected to be able to provide reliable power for MHDV demand of 1.5 MW in 2035 (Figure 12). The median available capacity in National Grid's service territory in 2035 is 1.3 MW.

Figure 12. Estimate of available feeder capacity in National Grid's service territory in 2035

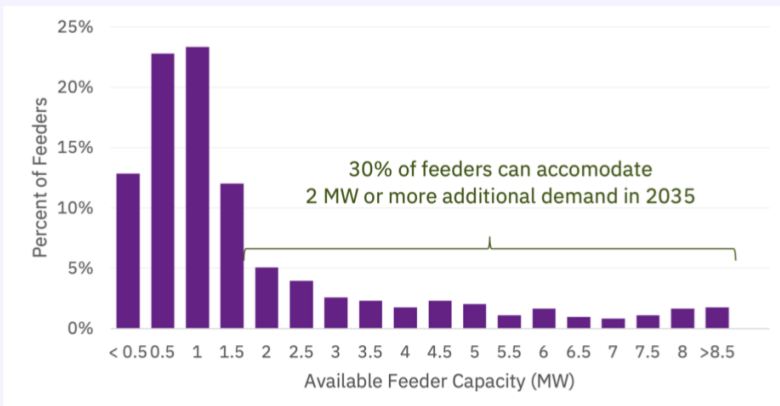


Figure 11 and Figure 12 provide context on the available headroom in two utility territories in New York. Other utility distribution networks may look very different in terms of capacity and available headroom on distribution equipment, and local analysis is crucial to preparing for transportation electrification.

[62] We adjusted negative growth rates to be zero (i.e. no decline in load at any substation), and we assumed that the growth rates would remain constant through 2035. Consolidated Edison. 2020. Distributed System Implementation Plan. Available at: https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/distributed-system-implementation-plan.pdf.

[63] We excluded substation-level analysis for National Grid for simplicity.

[64] National Grid New York System Data Portal. Available at: https://ngrid.portal.esri.com/SystemDataPortal/NY/index.html.

[65] New York Independent System Operator (NYISO). 2022. *2022 Load & Capacity Data: Gold Book*. Available at: https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf/cd2fb218-fd1e-8428-7f19-df3e0cf4df3e.

Step 5: Determine required upgrades and associated costs

After estimating incremental MHDV load, as well as growth of other load on the feeder/substation and collected information on the rated capacity of the distribution equipment, the most accurate way to determine the scale and magnitude of grid upgrades is to run a power flow analysis. Electricity distribution feeders can handle some level of overload, but exceeding their capacity frequently or for extended periods of time can lead to various issues ranging from voltage drops and reliability concerns to equipment damage and safety hazards. A power flow analysis helps determine if/when/where the system is overloaded, as load in one location may necessitate an upgrade someplace else. Specifically, power flow analyses assess the distribution network as a whole, considering key parameters such as voltage profiles, power flows, line loading, system losses, voltage stability margins, and contingency analysis (assessing the impact of equipment failures or changes in operating conditions). The analysis helps identify potential operational issues and can assess the effectiveness of proposed system upgrades or modifications. This type of analysis is typically conducted by the utility or consultants using highly specialized software.

However, power flow analysis can be complex and costly. If power flow analysis is not feasible, one can overlay the incremental EV load on top of forecasted non-MHDV load (as described above) and compare it against the rated capacity of each feeder (and substation). Generally, however, loading on a piece of distribution equipment is limited to a certain percentage of that equipment's nameplate capacity to allow unplanned outages, customer load additions, and other events that could affect reliability. Analysts may want to calculate overloading against "raw" headroom (i.e., against the rated capacity of each feeder) as well as calculate headroom against a percentage of nameplate capacity. For instance, if the feeder is rated for 10 MW, to measure against 80 percent of the rated capacity, an analyst would also look at headroom for that feeder of 8 MW. The loading threshold varies across utilities and jurisdictions, but a value between 80 to 100 percent is generally seen as a reasonable proxy for when loads start to interfere with how feeders and substations are used as backup for each other.[66]

Likelihood of upgrades and associated costs

The likelihood of an upgrade, and the type and scale of that upgrade, can vary greatly depending on the specifics of the project, the location, and the existing infrastructure. Necessary upgrades could include upgrading a feeder to a higher rated capacity, constructing new feeder lines, installing additional equipment such as a substation breaker, and/or even building a new substation. However, utilities can address some overloading conditions through

[66] EPRI. 2023. *EVs2Scale2030 Grid Primer: An Initial Look at the Impacts of Electric Vehicle Deployment on the Nation's Grid*. Available at: https://www.epri.com/research/products/000000003002028010.

low-cost load transfers to other feeders and lines. Based on our analysis of the two New York utilities, additional demand greater than 1 MW may require feeder upgrades, while loads greater than 5 MW are more likely than not to require some type of upgrade to distribution equipment. However, the specifics of each utility's distribution system can vary greatly, and different utilities may have available headroom that is much larger, or much smaller, than 1 MW (or 5 MW).

Using public cost data, project reports, and existing research, Borlaug et al. (2021)[67] summarized the types of upgrades associated with MHDVs (Table 6) and typical associated cost. The authors also conducted their own analysis of MHDV load requiring upgrades to substations and found that 78 to 86 percent of substations studied[68] can accommodate fleets of 100 trucks with 100 kW per vehicle (roughly 10 MW of demand) without additional substation upgrades, and 90 percent of substations can supply those same trucks if charged at their slowest possible rates (minimum power over the longest possible period).[69]

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[67] Borlaug, B., Muratori, M., Gilleran, M., Woody, D., Muston, W., Canada, T., Ingram, A., Gresham, H., McQueen C. 2021. Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems. Nature Energy, Volume 6: 673-682. https://doi.org/10.1038/s41560-021-00855-0.

[68] Borlaug et al. (2021) preformed a load integration study for 36 substations in the service territory of Texas' Oncor Electric Delivery Company. Ibid.

[69] Ibid.

Table 6. Distribution upgrades typically needed as a function of new load, and associated timeline and costs, according to Borlaug et al. (2021).

Component Category	Upgrade	Typical Cause for Upgrade	Typical Cost (2023 dollars)	Typical Timeline (months)
Utility on-site	Install distribution transformer	200+ kW new load	$13,000–195,000	3 – 8 months
Distribution feeder	Install/upgrade feeder circuit	5+ MW new load, >12 MW new loads may require a dedicated feeder	$2–13 million (usually more costly in urban areas vs. rural areas)	3 – 12 months
Distribution substation	Add feeder breaker	5+ MW new load, >12 MW new loads may require a dedicated feeder	~$400,000	6 – 12 months
	Substation upgrade	3-10+ MW new load	$3–6 million	12 – 18 months
	New substation installation	3-10+ MW new load	$4–39 million	24 – 48 months

Source: Borlaug, B., M. Muratori, M. Gilleran, D. Woody, W. Muston, T. Canada, A. Ingram, H. Gresham, C. McQueen. 2021. "Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems." Nature Energy, Volume 6: *673-682. Timeline for feeder extensions includes jurisdictional permitting for construction, obtaining easements and right-of-way, and procurement lead times. Timeline for adding a new feeder breaker depends on substation layout and the time required to receive clearance for construction. The decision to upgrade an existing substation versus to build a new one is largely dependent on the layout of the existing substation and whether there is sufficient room for expansion.*

Black and Veatch (2019, 2022)[70] also estimated grid upgrades required for new incremental MHDV load (Table 7). They observed that MHDV loads up to 1MW would typically require a feeder upgrade and loads up to 5 MW would require the construction of a new feeder entirely. Substation upgrades and new construction are likely with loads over 10 MW and 20 MW, respectively. These upgrades can take months to years.

Table 7. Distribution upgrades typically needed as a function of new load, and associated timeline, according to Black & Veatch (2022)

Component Category	Grid Upgrade	Charging Site Capacity	Possible Timeline
Utility on-site	New distribution transformer	Up to 1 MW	2 – 4 months
Distribution feeder	Feeder upgrade (upsizing capacity, by reconductoring or adding new line equipment)	1 MW	10 – 14 months
	New feeder circuit	5 MW	12 – 26 months
Distribution substation	Substation upgrade, new transformer bank	10 MW	24 months or more
	New substation	20 MW	24 – 48 months

Source: Black & Veatch. 2022. 10 Steps to Build Sustainable Electric Fleets. Available at: www.bv.com/resources/10-steps-sustainable-electric-fleet., and Black & Veatch. 2019. Electric Fleets: 8 Steps to Medium and Heavy-Duty Fleet Electrification. Available at: https://webassets.bv.com/2019-11/Electric_Fleets_Ebook_2019.pdf.

A 2020 California Electric Transportation Coalition (CalETC) study found that loads over 100 kW were likely to require upgrades to the secondary distribution system (e.g. feeders and distribution transformers) and loads over 5 MW were likely to require substation upgrades (Table 8).

[70] Black & Veatch. 2022. 10 Steps to Build Sustainable Electric Fleets. Available at: www.bv.com/resources/10-steps-sustainable-electric-fleet, *and* Black & Veatch. 2019. Electric Fleets: 8 Steps to Medium and Heavy-Duty Fleet Electrification. Available at: https://webassets.bv.com/2019-11/Electric_Fleets_Ebook_2019.pdf.

Table 8. Distribution upgrades typically needed as a function of new load, and associated costs, according to CalETC (2020, California only)

Power Level	Probability of needing an upgrade and associated costs		
	Substation	Primary Distribution	Secondary Distribution
15 kW – 50 kW	0%	0%	70%
50 kW – 100 kW	0%	0%	96%
100 kW – 5 MW	0% - 50%	5% – 90%	100%
> 5 MW	100%	100%	100%
Upgrade Cost (2023 dollars)	$1 million to $10 million	$170,000 to $7 million	$6,000 to $120,000

Source: CalETC (California Electric Transportation Coalition). 2020. The Infrastructure Needs and Costs for 5 Million Light-Duty Electric Vehicles in California by 2030. Available at: www.caletc.com/assets/files/EV-infrastructure-study-white-paper-FINAL.pdf.

CalETC's probability of upgrades for a substation are in line with Borlaug et al. (2021), where a substation upgrade is likely required with loads greater than 5 MW. On the other hand, Black & Veatch (2019, 2022) estimated that a new substation is required with loads greater than 10 MW. Our analysis of Con Edison substations in New York found that roughly half could accommodate loads over 100 MW, which suggests that Con Edison's substations are substantially larger than the average and highlights how capacity and headroom can vary considerably from utility to utility. Borlaug et al. (2021) and Black & Veatch (2019, 2022) differ substantially in terms of the likelihood of feeder upgrades, with the former estimating that 5 MW of new load would require feeder upgrades, and the latter assuming 1 MW of new load would require some level of feeder upgrade. According to our analysis in New York State (Section 0) loads greater than 1.3 MW are more likely than not to require upgrades to the feeder, be it upgrading the capacity or building out new lines. This again demonstrates the wide variability among utility's individual grid characteristics. As summarized in Table 5 above, fleets with 100 vehicles that do not employ managed charging can increase peak loads by roughly 5 MW; fleets with only 10 vehicles might only contribute 0.5 MW of new demand, suggesting that just a few fleets, or one very large fleet, could trigger upgrades to shared distribution system equipment.

Lastly, upgrade cost estimates cited by CalETC (2020) and Borlaug et al. (2021) demonstrate the uncertainty and wide range for the expected costs for feeder and substation upgrades and construction. For instance, CalETC (2020) cites feeder upgrade costs to be from $6,000 to $7 million, while Borlaug et al. finds that feeder upgrade costs could be between $2 million and $13 million. It is challenging to compare upgrade costs between jurisdictions and between individual utilities, as there are many factors to consider such as the cost of labor in different states. Electric utilities incur these upgrade costs but ultimately pass them on to ratepayers. Generally, capital expenditures (such as those for reconductoring feeder lines or building a new substation) are added to a utility's rate base and depreciated over the life of the asset. These expenditures incur "carrying costs" (in general return on equity, debt, and tax impacts) which, in addition to the upfront capital expenditure, are charged and collected from utility ratepayers.[71]

All in all, these three studies demonstrate the variability among capacity and costs for distribution systems across the country, and the challenges of estimating upgrades required to serve new MHDV load. Analysts should seek specific information for their own jurisdiction or from their local utilities.

[71] Costs, depreciation schedules, carrying costs, and rates must be approved by Public Utility Commissions.

Case Study: Estimating total ACT rule costs in Pennsylvania and Illinois

To estimate the total cost of ACT in Pennsylvania and Illinois, we took a high-level approach. We multiplied marginal distribution cost estimates by the incremental peak demand associated with MHDV load in each state. To capture the uncertainty and variability of distribution costs, we collected avoided distribution cost values from New England (Connecticut, Massachusetts, New Hampshire, Rhode Island, and Maine),[72] Pennsylvania,[73] Iowa, Minnesota, Missouri,[74] and California,[75] that are used by utilities and regulators in those states to estimate the avoided costs from the use of distributed energy resources. We estimated the total incremental distribution system cost associated with ACT using the highest and lowest marginal distribution cost estimates from those 10 states. Table 9 presents the range of ACT costs relative to the BAU distribution costs, representing the incremental costs associated with the ACT Rule. Also presented in Table 9avoided cost ranges we used. The total incremental costs associated with ACT are costs incurred by the utility, but that are ultimately collected from utility customers. As discussed extensively throughout the report, however, analysts should seek to undertake a much more localized analysis of the costs and potential solutions at the feeder and substation levels.

Table 9. Potential cost range of ACT rule, relative to the BAU scenario, for Illinois and Pennsylvania using avoided distribution cost values

State	Cost Range (2023 dollars)	Avoided Cost Range ($/kW-year)
Illinois	$7 million to $127 million	$17 – $286 per kW-year
Pennsylvania	$6 million to $95 million	

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[72] Vermont had an avoided cost value of $0/kW-year. New England avoided costs from: Synapse Energy Economics. 2024. *Avoided Energy Supply Components in New England: 2024 Report*. Available at: https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024.pdf.

[73] Pennsylvania avoided costs from the Pennsylvania Public Utility Commission's 2021 Act 129 Approved Marginal T&D Costs.

[74] Iowa, Minnesota, Missouri avoided costs from: Takahashi, K., T. Woolf, B. Havumaki, D. White, D. Goldberg, S. Kowk. 2021. Missed Opportunities: The Impacts of Recent Policies on Energy Efficiency Programs in Midwestern States, Prepared for Midwest Energy Efficiency Alliance. Available at: https://www.synapse-energy.com/missed-opportunities-impacts-recent-policies-energy-efficiency-programs-midwestern-states.

[75] California avoided costs from "2022 acc Electric Model v1b," E3's Avoided Cost Calculator for Distributed Energy Resources (DER). Available at: https://www.ethree.com/public_proceedings/energy-efficiency-calculator/.

Step 6: Develop an implementation plan to accommodate MHDV load

Impacts and solutions will differ from one utility, substation, or feeder to another. In some cases, the grid will be able to accommodate electric MHDV fleets and chargers, while other areas will be much more constrained and require substantial investments. For certain areas, low-cost solutions may be possible. Such solutions include non-wires alternatives and various programs and rates to manage load and charger interconnection. Numerous options are available, such as:

- demand response programs targeted specifically at owners of electric fleets and/or public charging stations, to reduce charging load during peak periods
- time-of-use rates or incentive structures that encourage off-peak charging
- behind-the-meter batteries and solar PV systems paired with chargers, which can help manage load
- V2G programs, which encourage a more efficient use of the grid, minimizing costs and improving overall reliability
- automated load management (ALM), a software solution that can help avoid costly upgrades; ALM manages load by coordinating and prioritizing the use of multiple chargers, ensuring fleet operational requirements are met while not exceeding the site's maximum charging capacity
- flexible interconnection agreements, where fleet owners agree not to exceed a certain charging capacity limit; these restrictions can be dynamic, reflecting grid constraints at different times of the day or over the course of a year

Utilities, planners, and regulators should work together to create a plan that incorporates proactive planning processes, identifies target areas for investment and/or electric MHDV adoption, and manages costs. Preparing for such investments can unlock major benefits to the health, well-being and economies of our communities, and the climate.

Recommendations for Decision-Makers and Planners

Electric utilities should proactively plan for ACT and other MHDV electrification, aiming to minimize costs, manage grid upgrade investments, and enable timely MHDV electrification. Preparing for and enabling the grid for electric MHDV adoption will benefit our economies and the health of our communities and environment.

Recommendation 1: Require utilities to share data about distribution grid capacity

Accessing distribution grid data is challenging, which can hinder efforts to develop robust and proactive MHDV electrification plans for states and other actors supporting the energy transition.

- Require utilities to make grid data more accessible so transportation planners, state agency staff, and advocates are able to efficiently work together to enable MHDV electrification. New York has demonstrated that it is possible for utilities to share detailed information about load and equipment capacity at the feeder and substation levels.
- Continue to investigate the impact of the ACT rule on the distribution grid as more data becomes available, as electric MHDV adoption grows, and as EV technology improves. The evaluation and planning processes should be iterative and collaborative and continue to evolve with the industry.

Recommendation 2: Improve utility planning and regulatory processes to address barriers to electrification

Barriers exist in the utility planning and approval process that can slow adoption and delay necessary grid upgrades.

- Explicitly incorporate electric MHDV adoption forecasts (ideally at the feeder-level) into standard utility planning documents and processes, such as Distribution Grid Plans, with a focus on the near-term upgrades and areas where electric MHDV deployment is most likely.
- Improve utility timelines for connection/energization of chargers and EV equipment, through deployment of more resources and utility staff, metrics and tracking, and potentially utility incentives.

- Enable and encourage collaboration among utilities, regulators, and state agencies to reduce barriers and improve timelines for permitting and zoning of MHDV charging equipment.

Recommendation 3: Target certain areas for grid investment and/or electric MHVD adoption

Certain locations will have a high likelihood of concentrated electric MHDV deployment, whereas other areas will have excess feeder and substation capacity that could serve as low-cost areas for fleet electrification and charging. These types of areas should be identified early and prioritized for grid investment and/or fleet adoption plans.

- Focus analysis and grid upgrade investments in areas with a high likelihood of electric MHDV deployment, such as public transit bus depots, public charging stations along highways, or certain feeders with very limited capacity that serve commercial customers with fleets.
- Identify feeders and substations with excess headroom on distribution equipment in areas that could support MHDV electric fleets and develop mechanisms and plans to encourage deployment in those areas.
- In areas with high likelihood of grid constraint, authorize prudent but proactive investment in grid infrastructure.

Recommendation 4: Implement programs to manage peak loads and minimize costs

Peak demand growth is the primary driver of increased cost and grid upgrades. Since electric MHDVs are expected to cluster in commercial zones and along transportation corridors, the peak demand on certain feeders and substations could be substantial, but also relatively predictable. There are low-cost solutions to manage demand.

- Evaluate and establish rates options, such as time-varying rates, and other customer incentive programs to encourage off-peak charging.
- Develop programs to enable and encourage MHDV chargers to be co-located with behind-the-meter batteries and solar PV systems, as well as programs that enable automated load management.
- Explore rate structures and other vehicle-grid integration programs such as automated load management, flexible interconnection agreements, and other grid-informed charging technologies.