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The Road to Transportation Decarbonization:

Understanding Grid Impacts of Electric Fleets

Prepared Jointly by National Grid and Hitachi Energy

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Acknowledgment and Disclaimer

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Table of Contents

1. The Concept in Short: Executive Summary

- **Context:** Policy and business considerations are expected to drive the electrification of commercial and public fleet vehicles (delivery and maintenance vehicles, buses, etc.) in the coming years. These vehicles are major contributors to greenhouse gas emissions and local pollution.
  - ► National Grid and Hitachi Energy have shown corporate-level commitment and leadership when it comes to the electrification of transportation. To that end, and in order to support the progressive vehicle electrification policies and goals of the states in which National Grid operates, National Grid and Hitachi Energy partnered on this study to facilitate a better understanding of the longer-term impacts of fleet electrification on the power grid, and to lay the foundation for future collaboration with the public and private sectors to address these needs.
- **Opportunity:** Quantifying the impact of large-scale, long-term full fleet electrification will allow utilities, policymakers, and fleet operators to better plan for investments in infrastructure to accelerate the electric fleet transition at the lowest possible cost.
  - ► To make informed decisions, stakeholders need a more tangible understanding of how loads associated with fleet electrification will manifest on the electric grid.
  - ► That is, how will differences in fleet locations, usage patterns, fleet sizes, vehicle types, and/or charging patterns impact specific portions of the distribution or transmission systems?
- **Overview of Analysis:** This case study provides a valuable “bottom-up” analysis of what long-term fleet electrification might look like on a specific part of the electric distribution system. The analysis estimates future electric loads associated with the electrification of fleets in an area of National Grid’s service territory. It evaluates:
  - ► The electric load that would result from full electrification of a given fleet.
  - ► The electric load that would result from the electrification of multiple fleets in a given area.
  - ► Existing capacity on distribution feeders to accommodate those loads.
  - ► Impacts aggregated to the substation level, accounting for additional load from residential and public charging.
- **Major Findings:** Because fleets have very different usage patterns and often are “clustered” in specific areas, the impacts can vary substantially on different parts of the distribution system.
  - ► Of the 19 distribution feeders studied, over 68% of them (13) could eventually need to be upgraded when nearby fleets fully electrify.
  - ► On several feeders where large fleets are clustered, the demands imposed by fully electric fleets would eventually exceed feeder capacity and require upgrades. One feeder (which currently has over 6 MW of headroom) sees an increase to over three times its rated load from serving fully electric heavy-duty fleets.
  - ► Impacts would be felt at the substation level, with one substation seeing a 60% increase in peak load from full fleet electrification and additional 20% load increase from full residential and public fueling electrification.
  - ► It is important to note that this analysis considers long-term impacts of fully electric fleets, and further study is needed to evaluate the timing of these impacts. Given the magnitude of these load increases at certain portions of the system, impacts could be felt well before “full” fleet electrification, especially as other load impacts (e.g., light-duty vehicles and heating electrification) are considered.

  - The analysis also demonstrates that differences in charging strategy can reduce the magnitude and duration of peak loads associated with fleet charging, suggesting that managed charging will play a role in supporting EV adoption and reducing systemwide costs.

- **Implications:** The results of this “bottom-up” case study offer several takeaways that should be examined and tested with further analysis:
  - Utilities, system operators, and policymakers are working to accelerate electric vehicle deployment. To ensure continued success, they should act now and begin forecasting and planning for the medium- and long-term impacts of fleet electrification.
  - Solutions should consider an end-to-end analytical approach: transmission, distribution, and distributed energy resources (DERs), in addition to charging programs.
  - Fleet electrification needs should be considered in tandem with other needs (e.g., asset condition) to increase efficiency and reduce costs.
  - Addressing fleet needs will require collaboration across multiple stakeholders, including but not limited to: utilities, regulators and policymakers, fleet operators, suppliers, and communities. National Grid and Hitachi Energy are committed to partnering with these stakeholders to advance policy and planning to meet fleet electrification goals.

- **Next Steps:** This study considers eventual impacts in one area of National Grid’s distribution service territory, and does not identify specific solutions, upgrades, or costs. The insights from this study provide a foundation for future analysis, which should consider:
  - Collaboration with fleet operators to further quantify electrification needs and timelines.
  - Detailed analysis of system needs and solutions (including transmission, distribution, DERs, and charging programs).
  - Policy considerations and recommendations to facilitate and expedite interconnection of electrified fleets.

2. Introduction: The Importance of Fleet Electrification

The transportation sector has overtaken electric generation as the United States’ largest source of greenhouse gas emissions. To meet decarbonization goals, more focus must be put on mitigating emissions from this sector. Movement away from fossil fuels to more sustainable fuel sources, such as electricity, is one path forward. While news and media coverage of vehicle electrification often focuses on passenger vehicles, the electrification of fleets presents a major opportunity: medium- and heavy-duty vehicles (MHDVs) accounted for almost a quarter of U.S. transportation emissions in 2019 (U.S. EPA, 2021).

In Massachusetts, for example, MHDVs account for approximately 3% of the Commonwealth’s on-road vehicles but are approximately 29% of the on-road CO_2 emissions (Edington, et al. 2020). Similarly, in New York, trucks and buses are 4% of vehicles on the road but 25% of total transportation sector emissions. On a per vehicle basis, MHDVs can emit up to 8-30 times the amount of CO2 emissions as typical personal vehicles (U.S. DOT 2021).[1] Fleet MHDVs can also emit up to 30-150 times the amount of Particulate Matter (PM) 2.5 emissions per vehicle; PM2.5 emissions are responsible for over 60% of all U.S. deaths from environmental causes (Union of Concerned Scientists 2019).

[1]See Table 4-43

Addressing transportation emissions – currently driven by internal combustion engine (ICE) vehicles – will be critical to meeting climate, environmental, and equitable transportation goals. Electrifying transport, and fueling vehicles with clean electricity, has emerged as a consensus strategy to address light-duty vehicle emissions. There is some debate that other fuel sources – such as hydrogen – may be used with certain MHDVs; however, several factors – public policy, fleet suitability for electrification, and a strong business case for fleet electrification – suggest that fleets will soon begin electrifying at scale.[2]

Figure 1: Cargo Trucks and Buses as a Proportion of All Vehicles and Emissions

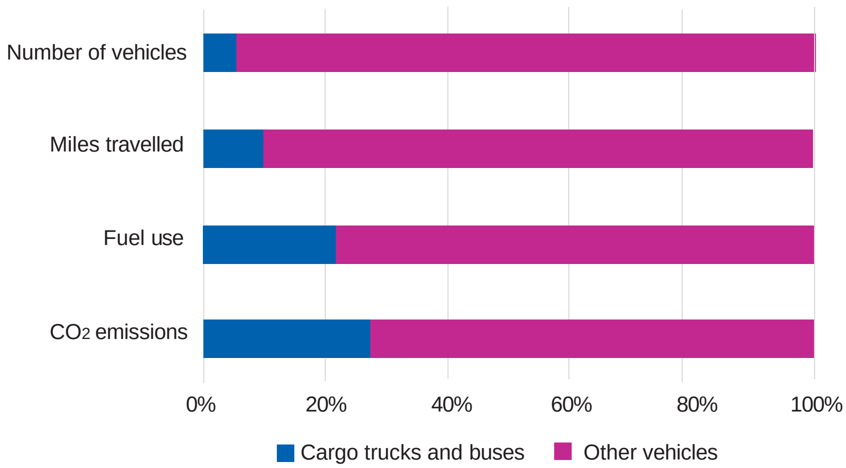


Chart Source: Nadel and Huether 2021

Policies Dictate that Electric Fleets Become More Prevalent

Fifteen states and the District of Columbia have pledged for 100% zero-emission MHDV sales by 2050 (30% by 2030) with 37 businesses issuing letters of support (Fuller 2020). Support has also emerged from the federal government, as President Biden has promised to replace the 650,000 vehicles in the federal fleet with EVs (Shepardson 2021).

Policymakers are turning their focus to fleet electrification for good reason: fleets offer a substantial return on investment when it comes to decarbonization. While cargo trucks and buses account for a small proportion of total vehicles or miles traveled, they represent a far greater share of fuel use and emissions, as shown in Figure 1 (Nadel and Huether 2021). Helping fleets convert will take heavier polluters off the road – and when fleets make bulk purchases of electric vehicles, this conversion can have large, immediate benefits for pollution and health.

Fleet electrification will also be an important component of a just transition to a greener economy. Electrifying fleets in both urban and rural settings provides equitable access to clean public transportation, particularly in disadvantaged and Environmental Justice Communities (EJCs). It also reduces CO_2, air pollution, and noise pollution associated with the movement of goods and services within communities, including communities that have disproportionately borne the impact of pollution associated with commercial vehicles (e.g., communities near fleet depots, distribution centers, or major highways).

Activity has also accelerated at the corporate level. National Grid is one of over 100 members of the EV100. Companies involved in the initiative have already deployed 170,000 EVs and have committed to electrifying 5 million vehicles by 2030 (National Grid 2021, Press Release).

[2] Other supportive factors not reviewed here could include energy conversion efficiency, fuel creation and distribution challenges, and technology maturity.

Fleet Activity is Well-Suited for Electrification

Even without further policy action, electric fleet sales are expected to rapidly ramp up. Bloomberg New Energy Finance (BNEF 2021) projects that, rising from a baseline of effectively zero, electric vehicles will grow to make up more than 10% of commercial MHDV sales by 2030, and almost 30% by 2040 – even in a scenario that assumes no additional policies or regulations supporting MHDV electrification.[3] Bloomberg's analysis suggests that reaching the more ambitious pathway of net zero emissions by 2050 will likely require policies to drive much faster rates of electrification, with 95% of all commercial MHDV sales needing to come from Zero-Emission Vehicles (ZEV) by 2040, and practically all commercial MHDVs converted to ZEV by 2050.[4]

Figure 2: Truck Freight (by Weight) by Distance Traveled

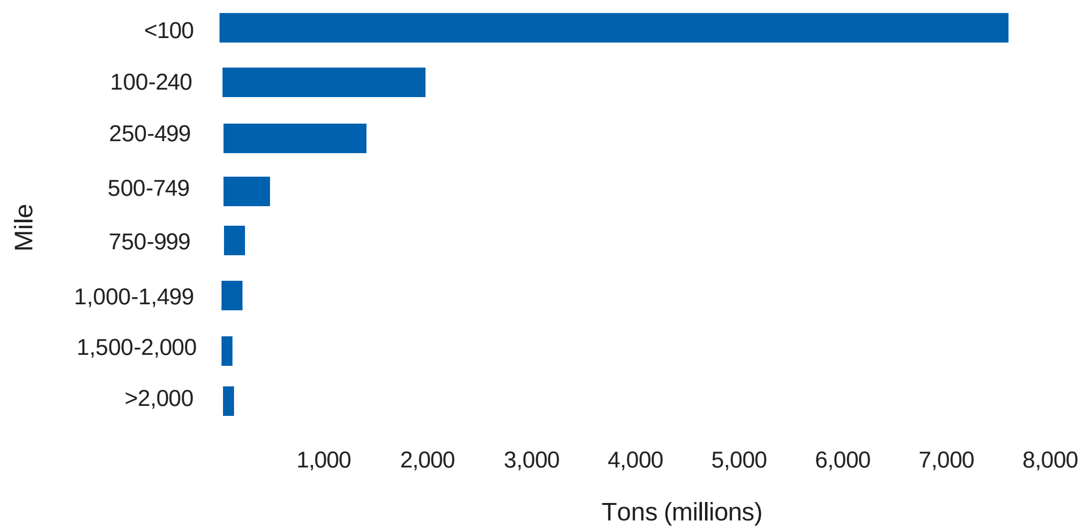


Chart source: U.S. DOT 2019

The pace of electrification will vary by vehicle type. Local delivery or last mile and public transit fleet operators are already poised to electrify. As one industry expert notes about local package delivery, "Because of three factors – the short length of operation, the ability to return to a central base, and frequent stops and starts that work well with regenerative braking – the duty cycle works well with electric" (Motavalli 2020). Public transit vehicles have similar characteristics, and substantial policy support: for instance, public transit agencies in New York have announced plans to electrify their bus fleets by 2035, with an interim goal of 25% by 2025 (New York State Office of the Governor 2020). Globally, BNEF's 2021 EV Outlook projects that ~60% of all bus sales will be electric by 2030.

While transit and last-mile delivery may be the first fleet segments to electrify, other applications such as freight trucking are also ideal for electrification. Distances traveled are often relatively short: 63% of trucking freight (by weight) travels under 100 miles and 80% under 240 miles (see Figure 2), which reduces concerns related to electric vehicle range (U.S. DOT 2019). Furthermore, vehicles are often on a set route and can return to a depot to charge. These heavy-duty vehicles will require larger batteries and infrastructure to support more significant charging needs, and therefore could take longer to electrify than smaller delivery vehicles without the necessary grid infrastructure in place to support their refueling/charging needs.

[3] "Economic Transition Scenario" is primarily driven by "techno-economic trends and market forces, and assumes no new policies or regulations are enacted that impact the market." Reference figure = Figure 9 (EV Share of Global New Vehicle Sales by Segment).

[4] "Net Zero Scenario" considers a global vehicle fleet capable of zero CO2 emissions. Zero Emission Vehicles include battery-electric and fuel cell vehicles. Reference figure = Figure 12 (Zero Emission Vehicle Sales Share Outlooks). Hydrogen fuel-cells would represent 10% of all commercial MDV/HDVs on the road in 2050, with remainder being fully electric vehicles.

Fleets – as this study demonstrates – tend to be located near each other, or along other transportation infrastructure (e.g., highways). Where this is the case, this could also support electrification efforts, as infrastructure investments can be targeted to these areas.

Total Cost of Ownership Will Increasingly Favor Electric Fleets

Electric vehicles usually have higher upfront costs than comparable ICE vehicles, a barrier to vehicle adoption of EVs. However, commercial fleet operators tend to consider full lifetime costs and make their purchasing decisions accordingly; electric vehicles tend to have lower operating costs (fuel and maintenance) than gas or diesel vehicles, supporting the case for EVs on a total cost of ownership (TCO) basis.

Total cost of ownership is approaching parity (or has already reached parity) in many EV models, including fleet vehicles. The North American Council for Freight Efficiency (NACFE 2018) has studied medium-duty (Class 3-6) and heavy-duty (Class 7-8) electric vehicles against their ICE counterparts and found that many medium-duty vehicles have already reached cost parity, with heavy-duty soon to follow. Similarly, BNEF (2021) finds the TCO of all-electric vehicles is already below ICEs in some cases, with regional and long-haul operations quickly becoming competitive.

Battery cost declines contribute to this trend toward EV cost parity and, eventually, advantage. Battery pack prices have declined almost 90% since 2010 (from $1,191/kWh to $137/kWh) and are projected to fall another 58% to $58/kWh in the next decade (BNEF 2021). Manufacturers are developing new vehicle models and scaling up production; more than 50 MHDV models are currently available, and more than 125 models are expected to be available by 2023 (CALSTART 2020).

Fleet Electrification is Coming – and Will Impact the Electric Grid

The shift to electric fleets may appear slow compared to the current adoption levels of passenger vehicles. However, commercial EV adoption is expected to accelerate quickly – BNEF (2021) projects a >150x increase in the number of electric buses and commercial fleet vehicles from 2020 to 2025, compared to a 4x increase in electric passenger vehicles. When this acceleration happens, it could have major impacts on fleets, communities, and supporting electric distribution and transmission infrastructure. Even if policy and corporate goals set targets 10, 20, or even 30 years away, the impacts may materialize earlier as EV adoption scales up.

Fleet operators might procure many vehicles at once, driven by needs to standardize fleet operation and maintenance, economies of scale in procurement, or the expiration of lease agreements. In comparison to the passenger vehicle segment, which is more sensitive to upfront prices, once the TCO of electric vehicles is lower than ICE vehicles, operators might transition as quickly as possible, based solely on economics. This could result in step-changes in electric load at operators' sites, compared to a steadier growth in residential and other commercial areas such as public and workplace charging.

Fleet operators may also use larger electric vehicle supply equipment (EVSE) than in public, work, or residential charging applications. This means that, even if overall charging times were shorter, the amount of electricity demand at any given point in time could be higher. These individual fleet sites could quickly become megawatt-scale loads. MHDVs will also likely require more energy (kWh) per charging session, due to larger battery sizes and greater VMT.

The scale of MHDV charging needs means that MHDVs will represent a significant portion of the overall electricity demand from electric vehicles. BNEF recently estimated that electric buses and trucks will require only 1.3% of all charging ports but will account for ~25% of the total electricity used for electric transportation (BNEF 2021).[5]

Through make-ready infrastructure support, fleet advisory solutions, and customer support functions, utilities are already playing an important role in helping fleet operators electrify their fleets.[6] However, the scale and scope of full fleet electrification pose new challenges for utilities and system operators. Quantifying how – and identifying where – fully electric fleets might impact the electric grid will be critical to enable fleet electrifi- cation at scale, while minimizing costs for fleets and other electric customers. Utilities need to start planning now for transmission and distribution investments that will be needed over the next decade to ensure a reliable electricity grid.

What Are the Impacts of Long-Term, Large-Scale Fleet Electrification?

To better understand the long-term impacts of fleet electrification on existing electricity networks, National Grid and Hitachi Energy undertook a case study of actual fleets in an area of National Grid's U.S. service territory.

This study considers two key questions:

- What are the impacts of fully electrifying a given fleet?
  - ► While action is being taken to electrify portions of fleets in the near-term – for instance, transitioning 25% of certain public transit fleets to electric by 2025 – the impact of large-scale electrification of MHDV fleets has not, as of yet, been completely demonstrated.
  - ► This study considers specific fleets in an area of National Grid's service territory. It attempts to project the size of load associated with fully electrifying a given fleet (that is, converting 100% of fleet vehicles to electric),[7] while also considering differences in how vehicles might be operated or used based on fleet type.
  - ► Some fleets may not fully electrify until the 2030s or 2040s. However, by understanding the magnitude of large-scale fleet electrification, utilities and system operators can better plan for and support those needs, especially where fleet electrification is accelerated by policy mandates or corporate goals, or where additional load is driven by passenger vehicle or heating electrification.

[5] See Figure 318 (BNEF 2021).

[6] For example, see National Grid's program pages for New York (https://www.nationalgridus.com/Upstate-NY-Business/Energy-Saving-Programs/ Electric-Vehicle-Charging-Station-Program) and Massachusetts (https://www.nationalgridus.com/MA-Business/Energy-Saving-Programs/ Electric-Vehicle-Charging-Station-Program).

[7] Fleets may not convert fully to battery-powered vehicles; for instance, hydrogen fuel cells or natural gas-powered vehicles may be used, and adoption could differ on weight class or vehicle type. This study considers 100% electrification to better understand the magnitude of potential impacts on the electric system. Further analysis could incorporate different scenarios on adoption of EVs, though BNEF's 2021 EV Outlook suggests that ~90% of all medium- and heavy-duty commercial vehicles and ~86% of municipal buses would be battery-powered under a global "Net Zero" scenario.

- What are the impacts of multiple fleets in an area fully electrifying at once?
  - This study also considers the implications of electrifying multiple fleets in a given area. That is, if multiple fleets in close proximity electrify over the same timeframe, what is the total impact on electric demand?
  - The analysis maps these long-term load impacts to specific distribution feeders. It then evaluates whether those impacts might exceed the capacity available of those feeders. Where the system is constrained, upgrades might eventually be needed to enable fleet electrification, especially where there are “clusters” of fleets (i.e., a commercial area with multiple fleet depots served by the same distribution feeder). Solutions could address the needs of multiple fleets at once, rather than a potentially inefficient piecemeal approach to address one fleet at a time.
  - This analysis does not fully incorporate additional load associated with light-duty vehicle electrification (home and public). However, the analysis does assess – at a high level – how these additional EV impacts might further constrain available capacity at the substation level by layering potential additional loads on top of the fleet profiles developed.

This analysis provides a “bottom-up” case study as to how large-scale fleet electrification might impact a specific portion of the electric grid. It provides a foundation for future analysis, which would:

- **Refine Assumptions on Fleet Usage and Timelines** – More detailed data on fleet sizes, locations, adoption schedules, and operational behaviors (ideally provided by fleets themselves) will be necessary to fully understand impacts at specific points on the electric grid. This study considers an endpoint: full electrification of all commercial and public fleet vehicles. Further analysis to understand how impacts scale with total fleet adoption, and the likely timing of fleet adoption, will enable a better understanding of how investments could be scheduled to meet these needs.
- **Analyze Broader System Needs and Solutions** – System-level analysis across multiple areas, and incorporating other impacts (e.g., light-duty vehicle electrification or heat electrification), will allow stakeholders to understand how these impacts might manifest more broadly and what solutions are needed to address them. Evaluation should compare multiple options to determine optimal solutions.
- **Identify Policy Considerations** – There may be opportunities to suggest new processes, programs, and frameworks to better meet customer and system needs.

This analysis provides valuable insight not only for utilities (both at distribution and transmission-level), but fleet operators, regulators and policymakers, communities, suppliers, and other stakeholders committed to the decarbonization of commercial transportation. While several implications are identified at the end of this document, this study is intended to open the door for further collaboration across the public and private sectors to accelerate the electrification of MHDVs.

3. Case Study: Large-Scale Fleet Electrification's Impact to the Electric Grid

Context, Assumptions, and Data Collection

Current fleet planning efforts respond to applications for fleet make-ready needs as those applications are submitted by fleet owners/operators. This is an important step in collecting relevant information on the fleet, which helps inform both the fleet owner and the utility of the expected electrical demand and required infrastructure. These early-stage fleet conversions – particularly for initial EV pilot projects consisting of a small number of light duty vehicles – can result in minor grid impacts and require minimal upgrades. As EV fleets scale up however, their collective and long-term impacts will necessitate larger upgrades in response to customer needs.

To understand these impacts, this study offers a framework to evaluate the large-scale electrification loads of multiple fleets in a specific area of National Grid's distribution network. Results can inform utilities, customers, and regulators of the barriers and opportunities related to fleet electrification. The framework was implemented to identify the impact of 100% fleet electrification in a top-100 metro area in National Grid's U.S. service territory.

The analysis considers six factors to generate charging scenarios for the fleets in the study area:

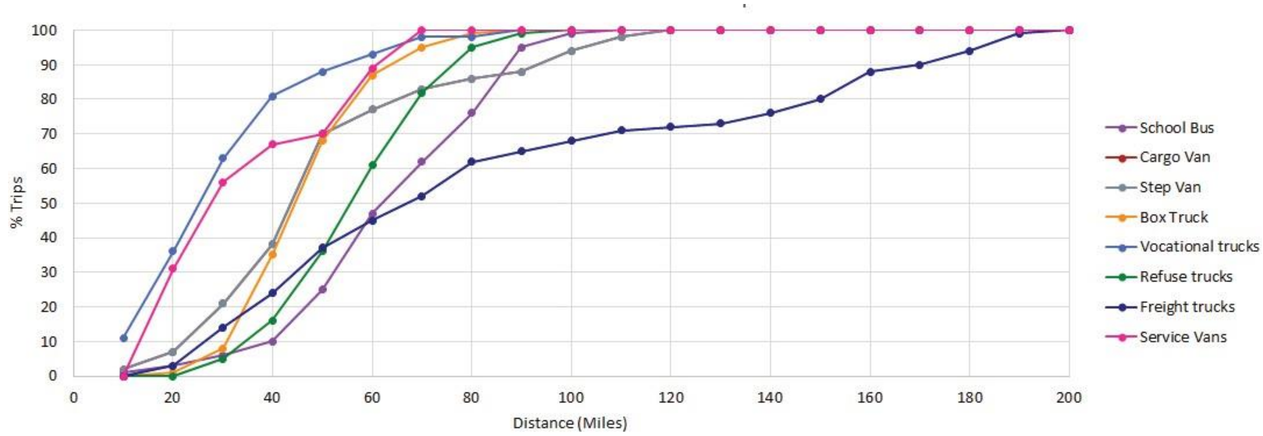
1. Fleet locations: 51 major fleet operators were manually identified in the study area through online map services and satellite imagery.
   a. The analysis assumes that fleet vehicles would only be charging at the depot, irrespective of any temporary stops during trips.
   b. The analysis focuses on large companies with easily identifiable fleets. As such, small commercial sites and geographically dispersed fleets which would also be expected to electrify are not included in this study.
2. Fleet vehicle count: The number of vehicles in individual fleets was estimated based on facility and parking lot sizes, the number of parking spots available, and visible vehicles at fleet locations.
3. Fleet vehicle class: Eight categories of fleet vehicles were identified based on 1) the type of service provided by the fleet operators (e.g., transit or freight) and 2) satellite images of the parked vehicles. The vehicles at each site were assigned to one or two vehicle classes, depending on available data. The overall fleet composition for the study area is summarized in Table 1.

Table 1: Study area fleet summary

Fleet Vehicle Type	Total Vehicles
Medium-Duty (Box Trucks, Step Vans, Bucket Trucks, etc.)	1,577
Heavy-Duty (Regional Freight Trucks)	781
School Buses	311
Total	**2,669**

4. Electric vehicle characteristics: Extensive literature review was performed based on the projected EV models available for each EV fleet vehicle category.
   a. The area of the study experiences cold winters, with low temperatures in January averaging 15 degrees Fahrenheit. Extremely cold ambient temperatures can significantly affect battery capacity, so the impact of temperature on battery efficiency (that is, total miles/kWh) was separately considered for winter and summer scenarios for each vehicle type (Yuksel and Michalek 2015).
   b. The total charging requirement of the battery is determined from the trip mileage and the battery efficiency of each vehicle category.
5. Driving pattern: The National Renewable Energy Laboratory's (NREL) Fleet DNA dataset informed assumptions for the driving pattern of the fleet operators. The Fleet DNA dataset is an open-source real-world dataset of MHDVs and provides comprehensive information on fleet vehicles' driving patterns.
   a. Figure 3 shows distance traveled by fleets, expressed as the cumulative proportion of all trips that traveled less than a certain distance in miles.[8] Regardless of the category of the fleet vehicle, more than 50% of all trips are <70 miles, and more than 90% of trips are <100 miles for all categories but freight trucks.

Figure 3: Cumulative distribution of trips based on the distance travelled for different categories of the fleet vehicles[9]



6. Charging infrastructure. Charger ratings are determined by: 1) the average dwell time of the vehicles (time at the depot between trips) and 2) the vehicle's total energy demand for its operating profile. Charger ratings were determined such that a vehicle's battery would be able to fully charge during its dwell time. All charging is assumed to be done at the depot, with no opportunistic or on-route charging. This analysis also assumes that the average fleet owner has two vehicles per charger, which in practice could vary by fleet and use case.
   a. Estimates of the vehicles per charger ratio vary. A recent report by Rocky Mountain Institute estimates 1 to 2.5 vehicles per charger (Daniels and Nedler 2021). The International Energy Agency's (IEA 2020) EV outlook assumes 3.8 trucks per dedicated charger and 7.7 buses per charger, though at higher charger capacities.[10]

[8] A trip = from when a fleet vehicle leaves the depot to when the vehicle returns to the depot.

[9] Graph considers total trips under a certain distance, as compared to earlier figure which shows total freight (weight).

b. The charger rating estimates and 2:1 vehicle-to-EVSE ratio assumptions used in this analysis are meant to provide a "right-sized" estimate of EVSE needs for customers by balancing the upfront costs of additional charging infrastructure with operational constraints. Currently, fleet operators have considered installing or have installed a few higher-capacity chargers for on-demand fast charging, while right-sizing most chargers for the most common vehicle use case. For modeling efficiency, each group of vehicles is assumed to have a constant 2:1 ratio. The implications of this assumption are addressed in later sections.

Modeling Methodology & Analysis

Once these data were collected and assumptions were determined, the analysis involved the following process (at a high level):

1. Because fleet operational data is highly variable and uncertain, the analysis uses a Monte Carlo simulation to evaluate probabilistic distributions of fleet schedules in order to develop reasonable boundaries of potential charging profiles.

2. The analysis then uses that simulation to develop fleet charging profiles in winter and summer conditions. Charging profiles were further developed for two different charging strategies:

   a. "Full Charging with Right-Sized Infrastructure" – This strategy assumes that the fleet vehicles charge at the full charger nameplate rating immediately upon returning to the facility (or upon a charger becoming available). That is, if a vehicle is using a 150 kW-rated charger, it will charge at 150 kW until the battery is fully charged.

   b. "Minimum Charging with Right-Sized Infrastructure" – This strategy assumes that total facility charging needs are met at the lowest rate possible to fully charge vehicles before they are scheduled to leave the next day. That is, even if a vehicle is using a 150 kW-rated charger, it may charge at less than 150 kW as long as that lower rate allows it to fully charge before it departs the depot.[11] The optimization routine manages the charging schedule of the parked vehicles and adjusts the rate of charging of the fleet to meet vehicles' overall charging requirement during their dwell time at the lowest charging peak at the facility. Vehicles could charge at their full nameplate rating for a period of time and then a lower rating as more vehicles return to the depot.

3. The analysis then considers where fleets are located on the distribution system. It assigns fleets to the nearest distribution feeder, which is the electric circuit from the substation to residential and commercial neighborhoods. The analysis then aggregates the load across multiple fleets to understand total impacts of multiple fleets electrifying.

   a. Understanding impacts at the feeder level is critical because utilities plan distribution infrastructure upgrades based on available capacity at the feeder level – that is, feeders that are approaching their capacity limits prompt system infrastructure upgrades.

   b. The analysis adds this aggregated load over a "baseline" load (current forecasted winter or summer peak load) to determine if the feeder can accommodate the new load attributable to fleet electrification.

   c. The analysis further aggregates the load up to the substation level and considers how residential and public charging load in a "100% electrification" scenario might further constrain available capacity.

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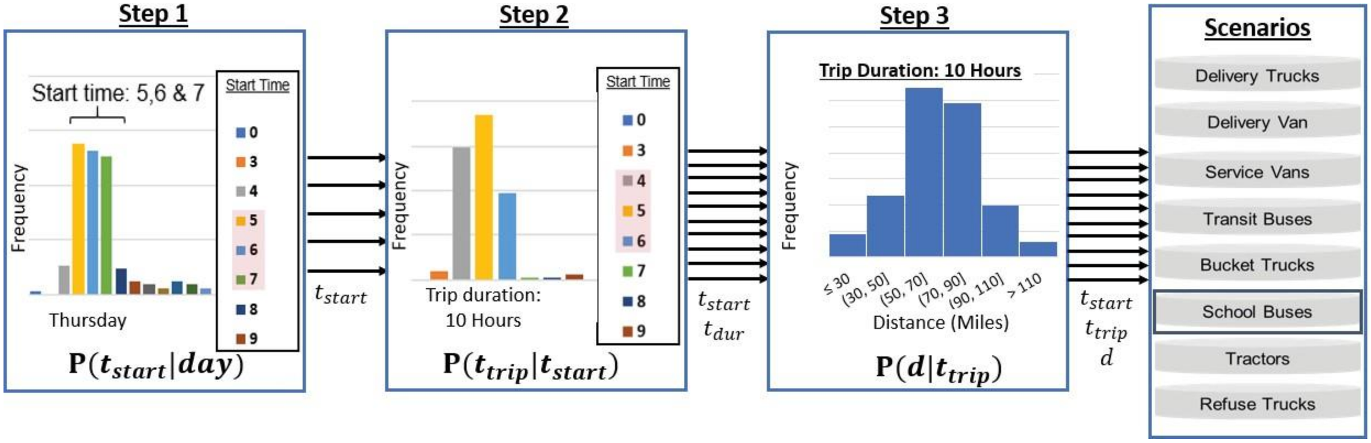
[10] The IEA outlook assumes 3.8 trucks per charger with an average of 480 kW, or ~125 kW per vehicle, and 7.7 buses per charger with an average of 190 kW, or ~25 kW per vehicle. When adjusted for the total kW available per vehicle, this study is in line with those ranges of power levels.

[11] "Minimum Charging" charging strategy does not consider any reduction in charger efficiency vs "Full Charging" charging strategy, i.e. whether the vehicle charges less efficiently. Each strategy in this analysis assumes 85% charger efficiency.

Monte Carlo Based Fleet Schedule Generation:
Monte Carlo is a scenario generation technique, often used to model scenarios based on the probability of their occurrence. The approach has been widely used to identify the risks due to events that cannot be accurately forecasted due to unknown variables' intervention and contribution. The Monte Carlo-based framework for fleet schedule generation is shown in Figure 4 in which three steps are performed to generate scenarios for fleet schedules, using school buses as the example vehicle category:[12]

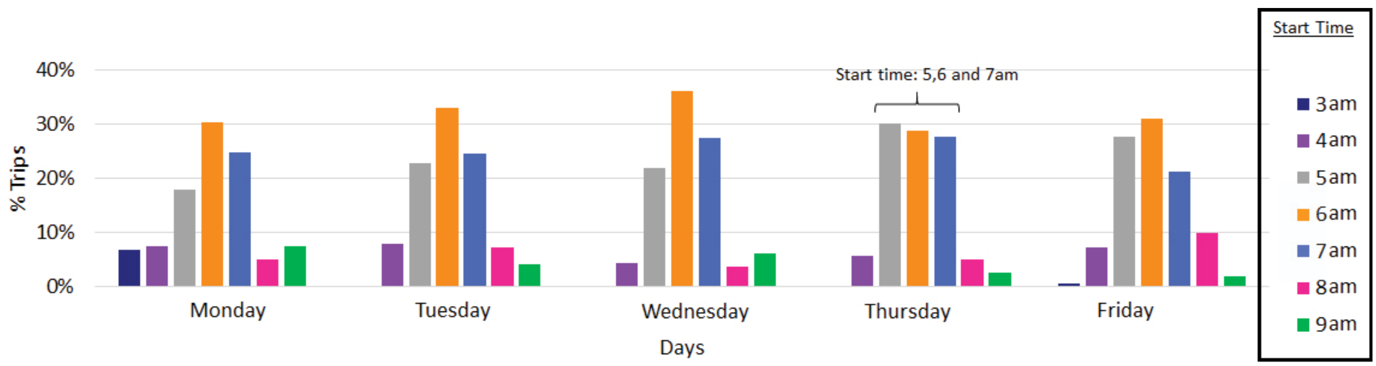
Figure 4: Monte-Carlo based framework for fleet schedule generation



Step 1: Generating start time for a given fleet type on a given day.

Figure 5 shows the probability of school buses starting their trips at a specific hour of the day.[13] Unsurprisingly, the majority of school bus trips start between 5:00 am to 7:00 am, though some can start as late as 8:00 am or 9:00 am, with more variation on Friday.

Figure 5: Probability of a trip starting at a specific hour of the day. (Fleet Type: School Bus)



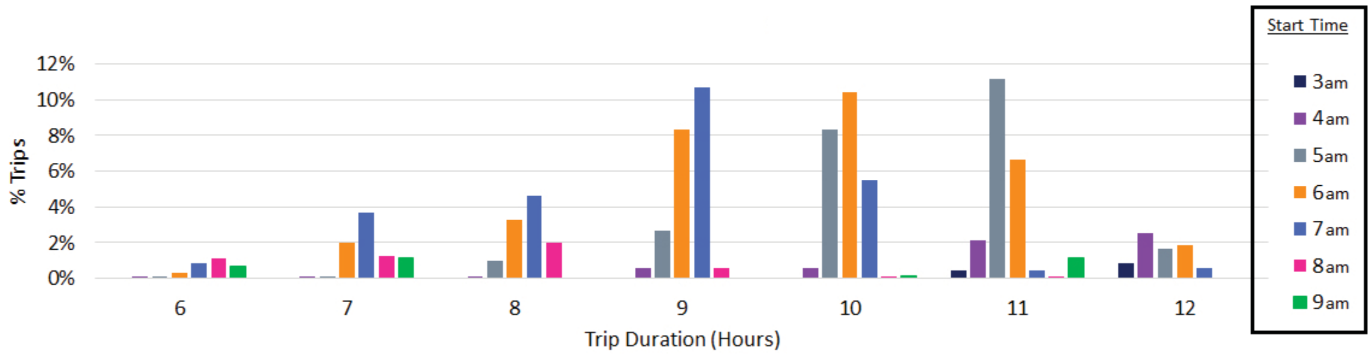
[12] The Monte Carlo method produced probability distribution functions for every category of fleet vehicle at each step. Three steps are performed to generate scenarios for fleet schedules, with each step generating scenarios for probable values of a new variable from the probability distribution function and input variables from prior steps.

[13] The probability of a journey starting at hour (t^k_{start}) for a given day (day) can be represented as $P(t^k_{start}|day)$.

Step 2: Generating trip length information for a given start time and day.

Most school bus trips in the Fleet DNA database tend to last from 8 to 11 hours. Trip duration varies by start time, as demonstrated in Figure 6 with scenarios generated from the Fleet DNA dataset.[14]

Figure 6: Distribution of the trip duration based on the start time of the trip



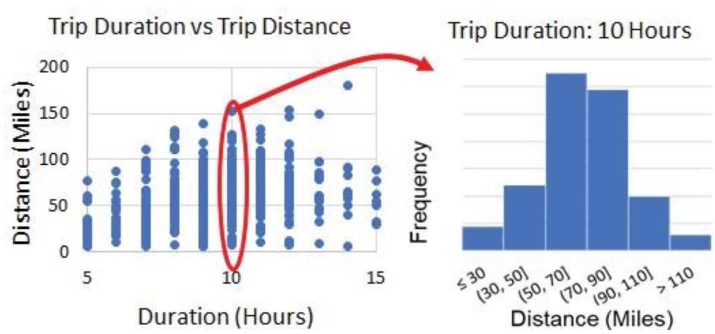
Step 3: Generating distance covered during the trip for a given trip duration.

The miles covered by fleet vehicles vary based on the trip duration. Figure 7 shows the distribution of the distance traveled by school buses for trip durations ranging up to 12 hours.[15]

At the end of Step 3, scenarios were generated (based on probability of occurrence with sample data from the Fleet DNA database) with the following variables:

- Day of week
- Hour of trip start
- Total duration of trip in hours
- Distance traveled during the trip

Figure 7: Distribution of the distance traveled by the school bus during a 10-hour long trip



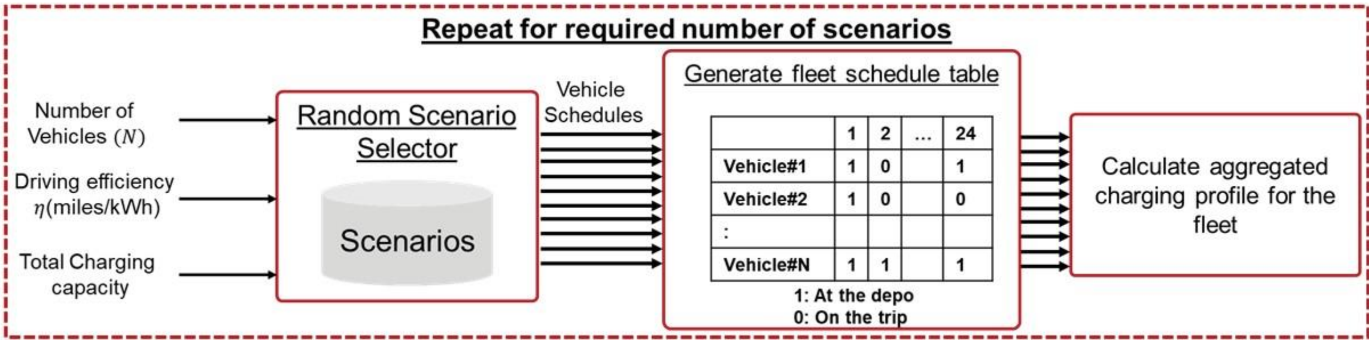
A database is created for every class and category of fleet vehicle, with 1,000 different scenarios developed for every working day. These scenarios are used to determine the potential charging load for each of the 51 fleets.

[14] The sample distribution for the fleet start time and trip duration for a given day is input to the Monte Carlo framework to generate random scenarios. The intersection between duration of the trip (t_{trip}) and start time (t^k_{start}) for a given day (day) would follow the probability distribution. $P(t^k_{start} \cap t_{trip} | day)$.

[15] Every trip duration consists of a unique probability distribution for the distance traveled during the trip. These probability distributions also add distance information to the set of scenarios generated in Step 2.

Estimation of Fleet Load Profiles

Figure 8: Aggregated fleet charging profile generation



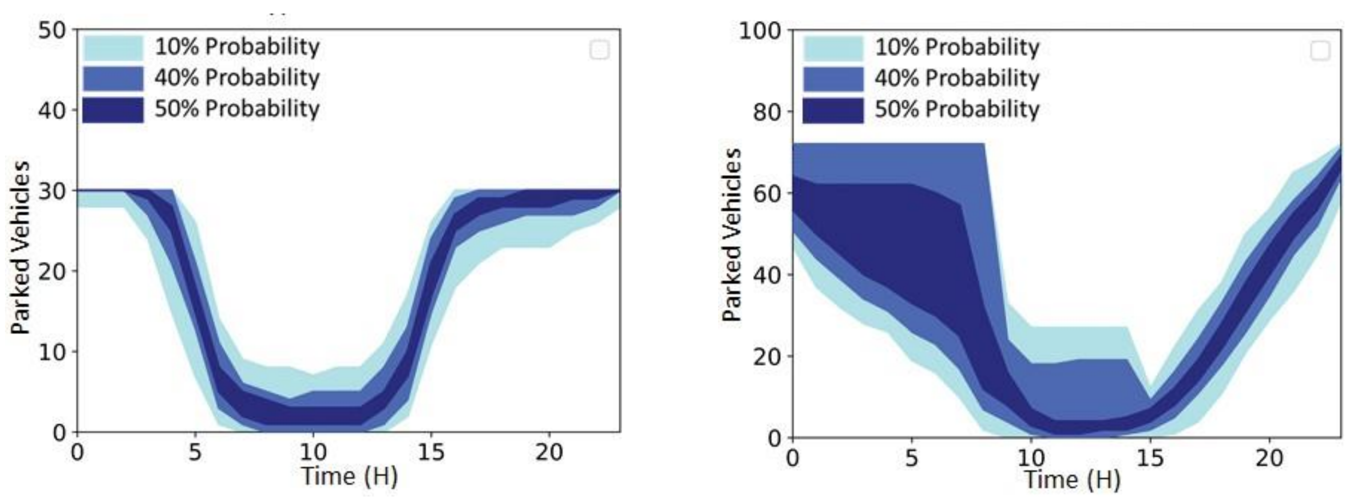
For a given day and the type of fleet vehicles, these scenarios are then used to generate schedules for the fleet in question;[16] that is, when is a fleet vehicle out on a trip, and when is it parked at the depot?

Figure 9 shows how many vehicles are likely to be parked at the fleet depot throughout the day for two types of fleet vehicles: school buses and freight trucks. Note that the shape of each distribution is different: freight vehicles tend to start later than school buses and return over a longer period of time as they complete their trips. Also note that while a school bus may be expected to return to a depot in the middle of the day, the Fleet DNA data do not show that, and it has not been manually adjusted in the analysis.

Figure 9: Parking scenarios for the fleets

(a) Fleet Case study 1: School Buses Parked

(b) Fleet Case study 2: Freight Trucks Parked



[16] A number of scenarios, equal to the number of vehicles in the fleet, are randomly selected from those generated. These sets of scenarios indicate typical workday schedules for fleet operators. For any workday, a unique C(*1000*,N_v) combinations/workday schedule can be extracted from the scenario database for a fleet with N_v vehicles.

This analysis provides a probabilistic view of how many vehicles are likely to be parked at a fleet depot at any given hour of the day – and thus, how many vehicles might be able to charge at any given hour of the day.

The next step, then, is to understand how much those vehicles need to charge. Charging requirements are aggregated across all vehicles in a given fleet to calculate the total charging requirement for the fleet as a whole.[17] Charging requirements are estimated at every hour for each fleet.[18]

The charging profiles for the two case studies referenced above – school buses and freight trucks – are presented in Figures 10 and 11, illustrating the variations in the charging load profiles for different types of fleets, as well as the impact of weather on the charging load profiles. This analysis considers a “Full Charging” strategy: buses charge at the maximum rating of a given charger when they return to the depot or when the charger becomes available. A lower-impact “Minimum Charging” strategy scenario was also developed and is presented in Figures 14, 15, and 17. Even with more managed charging loads, however, significant load increases still materialize on distribution feeders (and, as the analysis will later show, substations).

Fleet Case Study 1: School Buses

Figure 10: Charging scenarios for a fleet of 30 school buses

(a) Winter- Full Charging Strategy (b) Summer- Full Charging Strategy

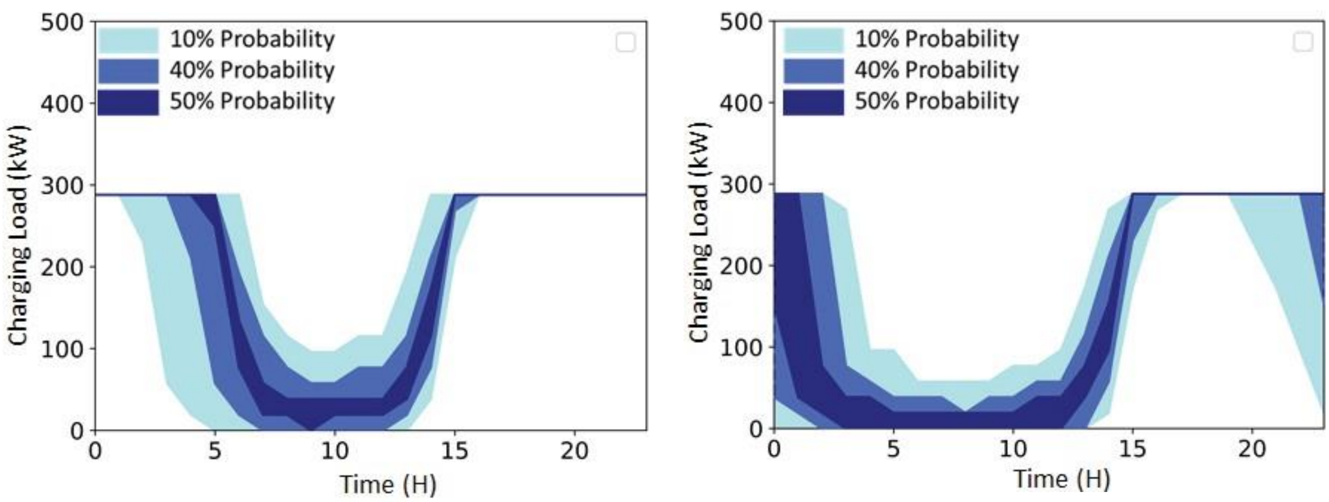


Figure 10(a) shows 1,000 charging scenarios for a fleet of 30 school buses in the winter. The charging requirement for the fleet is facilitated by 15 chargers rated at 19.2 kW each. In most scenarios, the school buses start trips in the morning between 5:00-7:00 am, and return to the depot between 3:00-6:00 pm, with an average dwell time between 13-16 hours.

[17] Fleet charging is limited by the number of vehicles available for charging at each hour, the aggregated charging requirement for all vehicles based on vehicle usage, charging efficiency, vehicle battery efficiency, individual charger rating or limit (defined in kW), and the number of chargers available for a given fleet (the analysis assumes 1 charger for every 2 vehicles).

[18] $\min_{(i = 1, 24)} \Sigma\, w^i(i) * kW^i_{charge}(i)$ represents the ideal charging requirement at each hour. GEKKO, a python-based machine learning, and optimization suite, was used to estimate the charging requirements are estimated at every hour for each individual fleet. The priority coefficient (w) can be used to further prioritize the charging during the specific hours of the day.

Figure 10(b) shows the same analysis for the same fleet of school buses during the summer. Buses have higher efficiency in warmer temperatures and need to charge 35-40% less than they would during colder conditions, which leads to differences in the charging load profile.[19] In the winter, each bus needs about 8-9 hours to charge; in the summer, each bus needs about 5-6 hours. In either season, the bus fleet will need to maximize its available charging capacity overnight; in the summer, the fleet might only need to maximize charger capacity from 3:00 pm to 2:00 am, while in winter, charger capacity might be maxed out from 3:00 pm to 6:00 am.

Fleet Case Study 2: Freight Trucks

Figures 11(a) and (b) show the aggregate charging load profiles for a fleet of 72 freight trucks in winter and summer, respectively. The fleet depot is assumed to have 36 chargers rated at 150 kW each. For freight trucks, trip duration varies for each vehicle depending on the type of service it provides and the area it serves. While school buses arrive back to their depot in a relatively defined time range, freight trucks might arrive back at their depot anytime from 4:00 pm to midnight.

Figure 11: Charging scenarios for a fleet of 72 freight trucks

(a) Winter-Full Charging Strategy (b) Summer-Full Charging Strategy

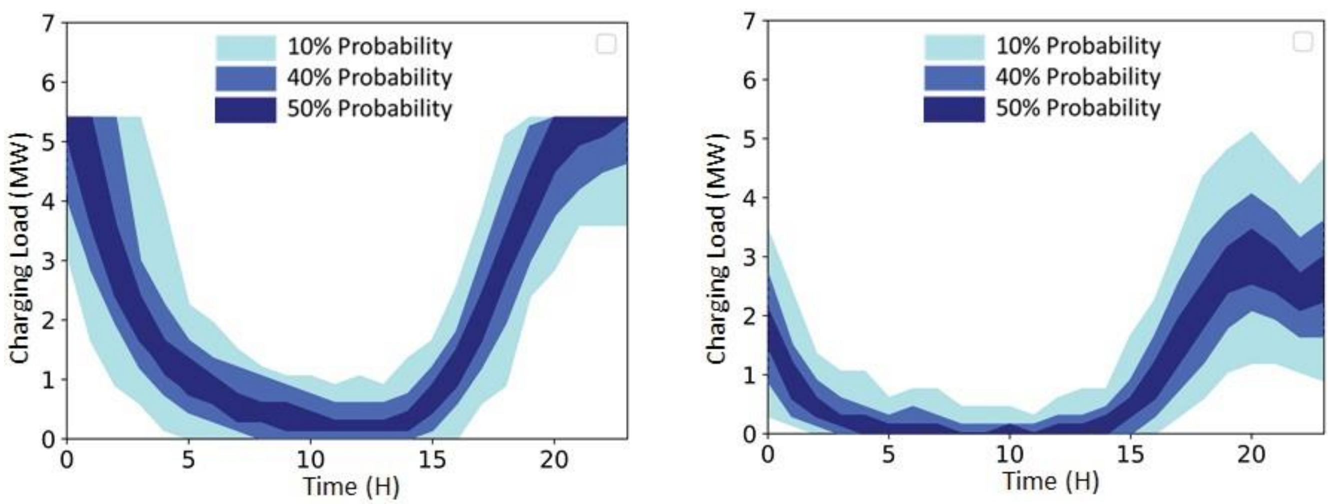


Figure 11 shows the freight fleet's aggregate charging load profile during winter and summer weather conditions. Charging efficiency is similarly lower during winter months.[20] Since 50% of the trucks arrive at the depot by 8:00 pm, the charging limit of 5,400 kW is reached by 8:00 pm in most scenarios. In the summer, lower overall charging requirements – driven by higher battery efficiencies at higher temperatures – mean that the fleet might not max out its charging capacity, as the high capacity 150 kW chargers take less time to fully charge the trucks.

[19] The miles per kWh for school buses is assumed to be 0.44 during winter and 0.70 during summer. Efficiency figures for each vehicle category are defined from manufacturer specifications, compiled from the Zero-Emission Technology Inventory (ZETI) tool by CALSTART (2020).

[20] The miles per kWh for freight trucks is assumed to be 0.17 during winter and 0.45 during summer. Efficiency figures for each vehicle category are defined from manufacturer specifications, compiled from the Zero-Emission Technology Inventory (ZETI) tool by CALSTART (2020).

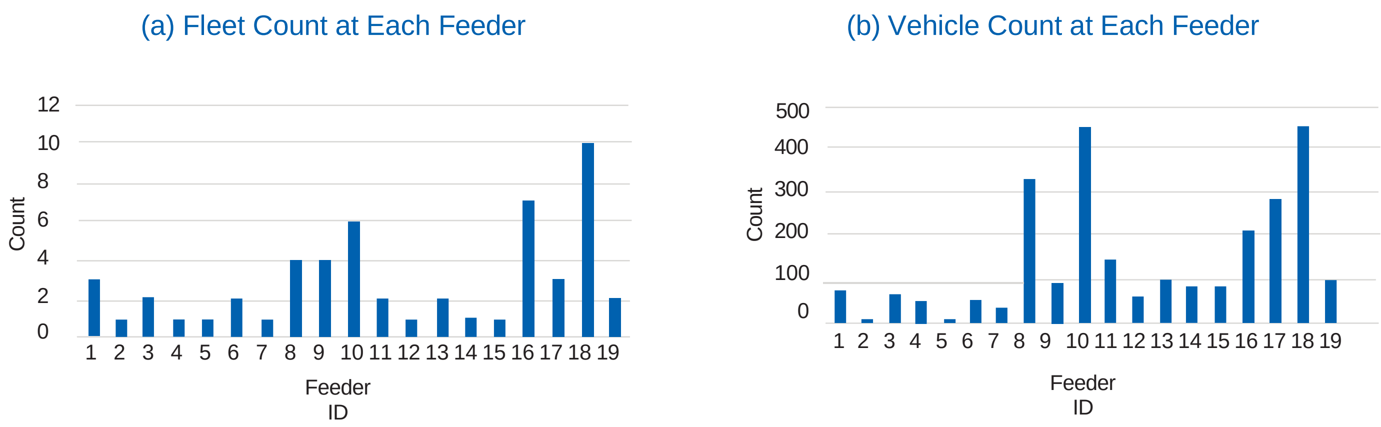
System Impacts of Fleet Electrification

So far, the analysis has demonstrated the charging impacts of two specific fleets. To understand overall impacts on the grid – for instance, to understand whether specific feeders or substations will be able to meet new load from electrified fleets – utilities need to understand the impacts of electrifying all of the fleets in a given area. Thus, after developing charging profiles for each fleet in the study area, the analysis then assigns those fleets to a specific feeder on National Grid's electric distribution system in the study area and aggregates the total hourly load associated with full electrification of those fleets.

Impact of fleet electrification on feeder loading

51 major fleets were identified in the study area. These fleets were mapped to 19 distribution feeders. Out of those 19 feeders, 5 feeders hosted "clusters" of 4 or more fleets as seen in Figure 12(a).

Figure 12: Total Fleets (a) and Vehicles (b) supported by the feeders



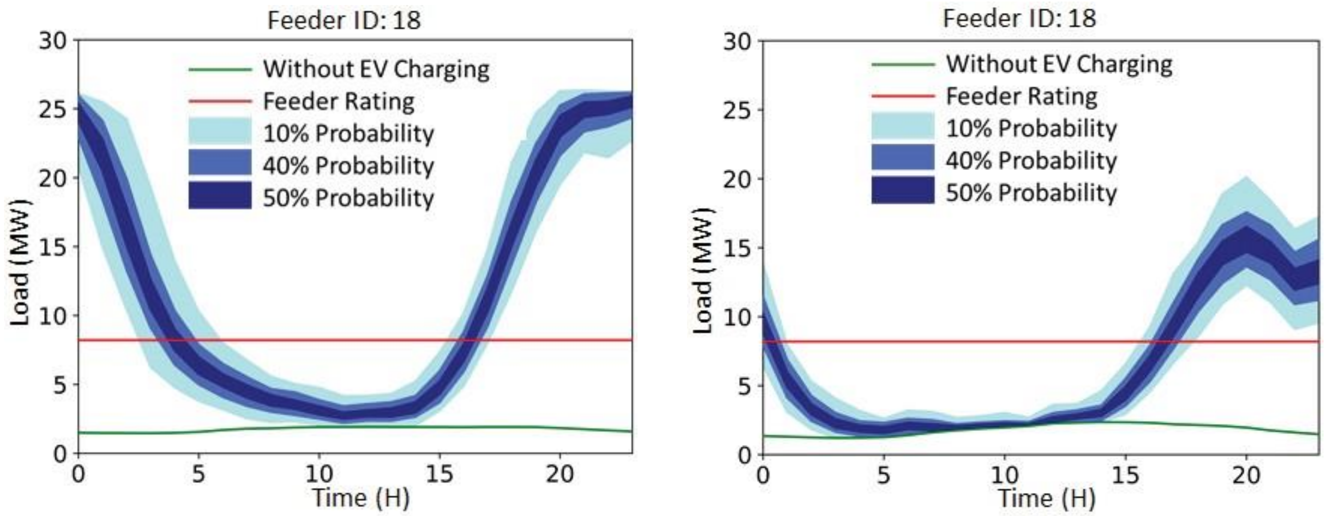
Several feeders not only host multiple fleets, but host large fleets: more than 400 fleet vehicles were mapped to Feeder 10 and Feeder 18. The geographical concentration of these large fleets means that more load would be seen on these feeders as a result of fleet electrification. The aggregate charging load for every fleet operator was added to the corresponding feeder's summer and winter peak profiles to get the overall impact of fleet electrification on the feeder.

Figure 13(a) shows the daily peak load profile for Feeder 18 in winter. Currently, 2 MW of load is expected in peak winter conditions, based on forecasts through 2024. Feeder 18 is rated to support 8.2 MW, which is more than enough capacity to meet the existing load. However, as mentioned, more than 400 fleet vehicles were identified in the area of Feeder 18; if these fleets were to fully electrify under this set of assumptions, the peak load would exceed the feeder rating by over 3 times the rated load during the overnight charging period. This is a remarkable increase in load – almost 25 MW – though the logic is straightforward:

- 400+ fleet vehicles associated with Feeder 18, 67% of which come from freight vehicles
- 200+ vehicles charging at peak hours overnight (assuming a 2:1 vehicle to EVSE ratio)
- Vehicles charging at an average rate of ~120 kW (due to the high proportion of freight fleets "clustered" at this feeder)

Figure 13: Load profiles for Feeder 18 with fleet charging

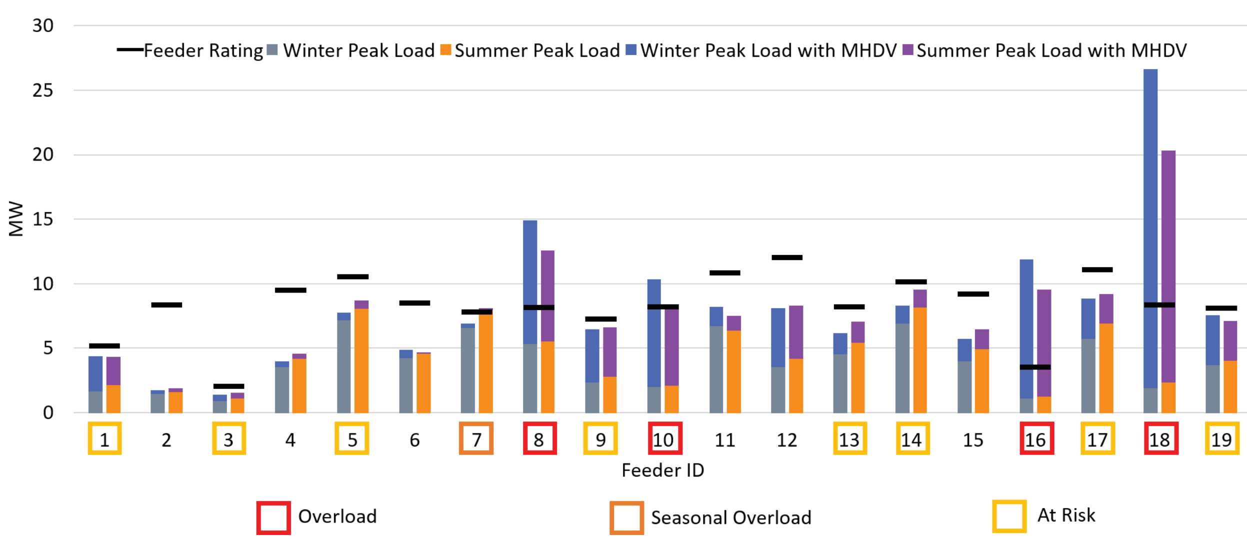
(a) Winter-Full Charging Strategy (b) Summer-Full Charging Strategy



As Figure 13(b) shows, the effects would be moderated in summer conditions, though night-time load would still exceed the feeder rating. (Charging strategies could possibly be implemented to help mitigate these overload scenarios, given the capacity available for much of a peak summer day, though the ability for a fleet operator to charge during the day varies by vehicle category and use case.)

Figure 14(a) summarizes the impact of fleet electrification on the 19 feeders supporting fleets in the study area under a “Full Charging” strategy. Impacts of fleet electrification are magnified in winter conditions, when battery efficiency is lower and charging requirements are therefore higher. Hence, for the feeders experiencing higher electrification, the peak load is observed during winter.

Figure 14(a): Impact of fleet electrification on the feeders during winter and summer peak load with Full Charging Strategy[21]



[21] “At Risk” = over 80% of rated load in one season.

Of the 19 distribution feeders studied, over 68% of them (13 feeders) would eventually be overloaded or at risk of overloading when nearby fleets fully electrify. For four feeders – Feeders 8, 10, 16, and 18 – the peak load imposed by fleet electrification would exceed the feeder rating capacity in both summer and winter conditions. As previously discussed, Feeder 18 faces substantial impacts from the electrification of over 400 fleet vehicles (many of which are regional freight vehicles with chargers rated at 150 kW); Feeder 16 supports just over 200 vehicles, though has a lower feeder voltage (4.8kV).

Impacts are not limited to these four feeders with high fleet penetration. For another 9 feeders, full fleet electrification would either cause the feeder to exceed available capacity in one season, or to exceed 80% of the current feeder capacity. A detailed summary of the impacts with the Full Charging strategy is shown in Table 2, with scenarios approaching feeder capacity highlighted in yellow and scenarios exceeding Feeder capacity highlighted in red. These impacts only reflect electrification of fleet load (not further light-duty passenger load beyond the baseline forecast, or load from smaller fleets not captured in the analysis). The potential load from full electrification, and the system needs resulting from that load, should be kept in mind as decarbonization efforts progress.

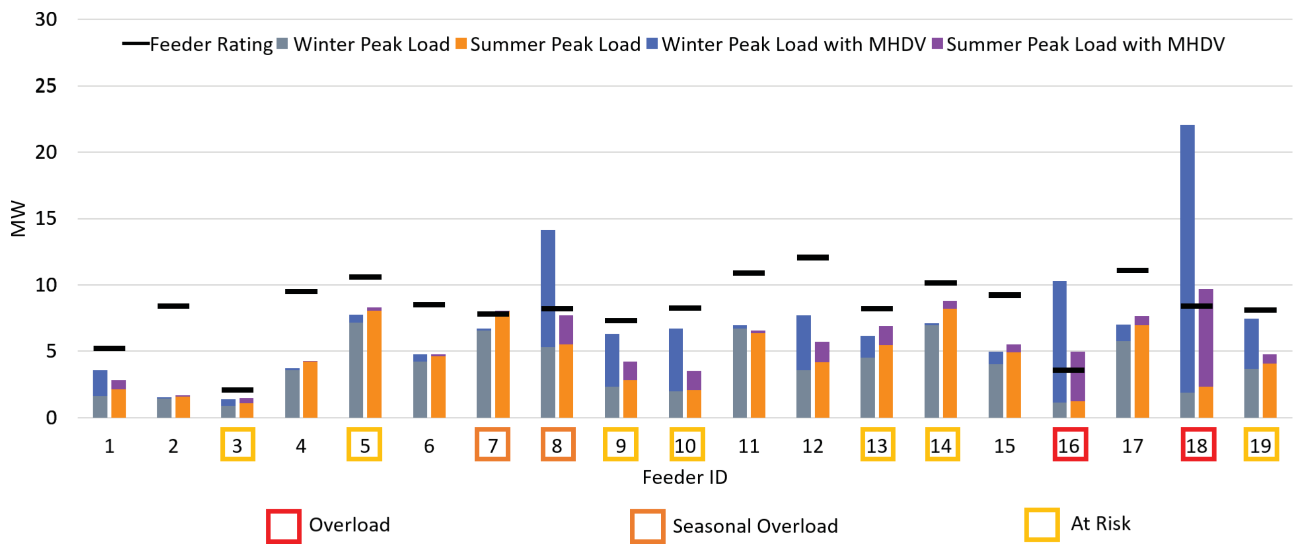
Table 2: Summary: Impact of studied fleet electrification on feeder loading (Full Charging Strategy)

Feeder ID	Feeder Rating (MW)	Summer Peak Load (MW)	Summer Peak with Fleet EV (MW)	Summer Feeder Loading with EV	Winter Peak Load (MW)	Winter Peak with Fleet EV (MW)	Winter Feeder Loading with EV
1	5.0	2.2	4.3	86%	1.7	4.4	87%
2	8.2	1.6	1.9	23%	1.5	1.7	21%
3	1.9	1.1	1.6	83%	0.9	1.4	74%
4	9.3	4.2	4.6	49%	3.6	4.0	43%
5	10.4	8.1	8.7	84%	7.2	7.8	75%
6	8.3	4.6	4.7	56%	4.2	4.9	59%
7	7.6	8.0	8.1	106%	6.6	6.9	90%
8	8.0	5.5	12.6	157%	5.3	14.9	186%
9	7.1	2.8	6.6	93%	2.3	6.5	91%
10	8.0	2.1	8.2	102%	2.0	10.3	128%
11	10.7	6.4	7.5	70%	6.7	8.2	77%
12	11.9	4.2	8.3	70%	3.6	8.1	68%
13	8.0	5.5	7.1	88%	4.5	6.2	77%
14	10.0	8.2	9.5	96%	7.0	8.3	83%
15	9.0	4.9	6.5	72%	4.0	5.7	64%
16	3.4	1.3	9.5	282%	1.1	11.9	351%
17	10.9	7.0	9.2	84%	5.8	8.9	81%
18	8.2	2.4	20.3	248%	1.9	26.7	325%
19	7.9	4.1	7.1	90%	3.7	7.1	95%

Note: Feeder 7 load is already estimated to exceed its rating. A load transfer project is planned to bring this below rating.

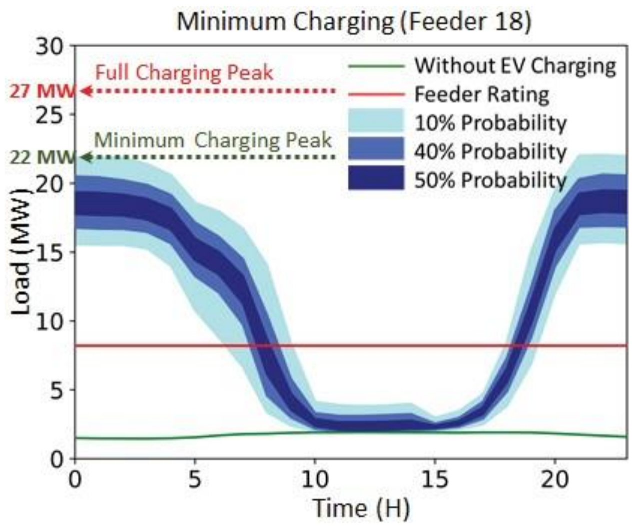
Could impacts be mitigated by differences in charging strategy? To understand this, feeder impacts were also evaluated for the Minimum Charging strategy described earlier, with results presented in Figure 14(b) below. This strategy assumes that fleet vehicles charge at the minimum rate possible to fully charge before the vehicles are scheduled to leave the next day. This differs from typical managed charging programs in that charging is not guided to avoid system impacts. However, the Minimum Charging scenario does represent a smoothing of charging load, and does offer learnings about how charging strategies can minimize peak needs.

Figure 14(b): Impact of fleet electrification on the feeders during winter and summer peak load with Minimum Charging Strategy



Under the Minimum Charging strategy, Feeder 10 can support fully electric fleets without exceeding its rating, and Feeder 1 and Feeder 17 would move out of the at-risk category. However, 11 of the 19 feeders (58%) would still be overloaded or at risk of being overloaded with full fleet electrification. Most feeders see <20% reduction from this strategy during winter, when lower battery efficiency require charging at high levels for full dwell times in both scenarios. For a detailed summary of the Minimum Charging strategy's impacts on the Feeders, see Table A in Appendix A. Figure 15 shows the feeder profiles during winter with the Minimum Charging strategy and can be compared to the Full Charging load profile in Figure 13(a). The peak load due to fleet charging reduces from 27 MW to 22 MW with this strategy.

Figure 15: Reduction in the peak load duration through minimum charging strategy



Regardless of the two charging strategies used, the analysis demonstrates that the loads associated with long-term, large-scale fleet electrification would require eventual upgrades, especially where "clusters" of fleets with many vehicles, or with large vehicles (e.g., freight), electrify on similar timeframes.

Broader Electrification and Substation Impacts

Just as fleets are electrifying, so too will light-duty passenger vehicles (cars, SUVs, minivans, etc.). The simultaneous electrification of MHDVs and light-duty vehicles has the potential to magnify the impacts of vehicle electrification.[22] Investments or upgrades to address fleet electrification should also consider the impacts of light-duty electrification, and vice versa.

The next step of this analysis aggregates fleet load at the substation level, and additionally considers the load associated with "100% electrification" scenarios for two categories of light-duty EV charging:

1) **Residential Charging**

   a. Residential charging is defined in this paper as the charging performed "at home" by EVs privately owned by individuals and driven for personal use.

   b. Among current EV owners in National Grid's New England territory, 80-85% of EV charging energy was dispensed at home (Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid 2021).[23]

2) **Public Charging**

   a. Public charging typically includes the on-street charging facilities located at commercial locations, workplace, or parking lots.

   b. The study does not include highway charging loads, though the study area is adjacent to several inter states. Highway service plazas and off-highway charging sites are likely to gravitate to faster charging DCFC over time, potentially even ultra-fast charging at several hundred kW for LDVs and potentially MW levels per port for heavy-duty vehicles).[24] Highway charging sites are therefore likely to be significant additional points of load beyond those studied here.

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[22] National Grid and other utilities have begun incorporating LDV loads into load forecasts.

[23] See pages 20 and 59.

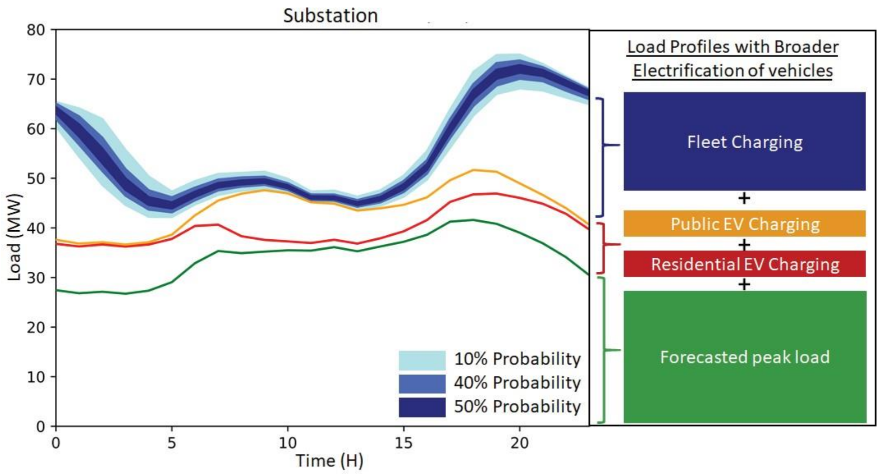
[24] See for example the CharIN Megawatt Charging System (MCS) task force: https://www.charin.global/technology/mcs/

Figure 16 evaluates potential substation impacts for a specific substation, which serves 7 feeders including Feeder 17 and Feeder 18 (the freight-heavy feeder with the largest absolute impacts from fleet electrification).

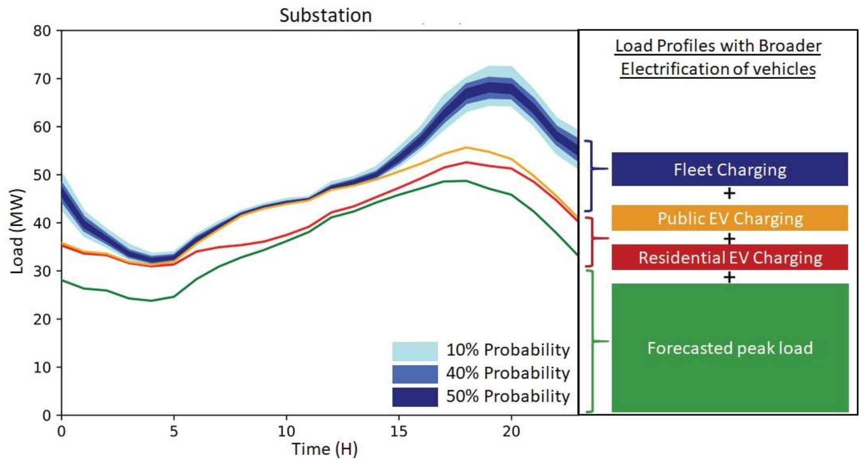
- The substation's forecasted peak load, including existing near-term forecasts of residential and public charging, was first assessed for each hour of a winter or summer day.[25]
- The analysis then layered on load associated with a "100% electrification" scenario for residential and public charging, for light-duty vehicles. This was done by extracting the per vehicle load profile used by the National Renewable Energy Laboratory's Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite, and applying it to EV adoption forecasts made using Bayesian analysis of each census block group's demographics.[26]
- The analysis finally adds in the load associated with fully electrified MHDV fleets served by the substation, as previously described.
- The analysis considers these fleet loads on a peak summer and a peak winter day.

Figure 16: Impact of 100% fleet, residential and public charging at the substation

(a) Winter-Full Charging Strategy



(b) Summer-Full Charging Strategy



[25] National Grid's base feeder forecasts used in this analysis currently include a small amount of residential and public EV load that was accounted for in the analysis.

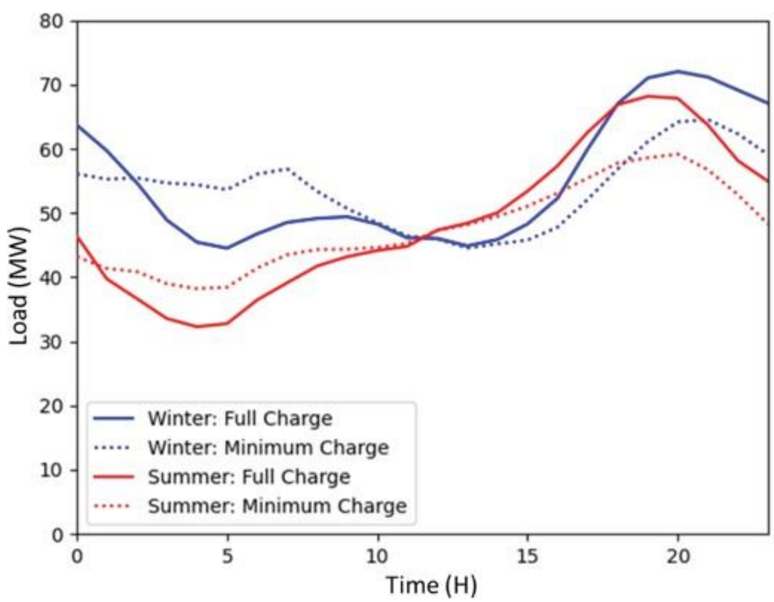
[26] EV adoption forecasts were made for a range of EV penetration percentages. The 100% penetration case is used for the analysis in this paper.

- Finally, the analysis considers the same Full Charging strategy used for prior analysis of fleet impacts. It also assesses the Minimum Charging strategy, in which fleets would charge their vehicles at the lowest possible rate to reach full charge, which could reduce and smooth impacts associated with fleet load.

As can be seen in Figure 16, residential and fleet charging are more common during the nighttime whereas public charging loads are relatively higher in the daytime, though both share a peak period in the evening hours with fleet charging. As a result, the contribution from residential and public charging increases the substation demand by 20%, while the charging requirement from electrified fleets increases the peak substation demand by over 60% more.

The substation has two transformers serving three and four feeders each; as a result, the load is not shared equally between the two. One of the substation transformers – for instance, the transformer that serves both of Feeders 17 and 18 – may become overloaded, even if the combined station capacity appears suitable. There is no tie between the transformers to share load. Additionally, other substation equipment and devices could have specific constraints that would lower the actual available capacity and should be considered while evaluating the impacts of charging load at the substation level.

Figure 17: Impact of Fleet Charging Strategy (Full Charging vs Minimum Charging) on substation loading; load includes residential, public, and fleet estimates



The Minimum Charging Strategy previously mentioned could reduce charging load from fleets, but the peak reduction achieved from this minimum charging strategy depends on the overall charging demand, dwell time of fleet vehicles, and the charging capacity of the chargers.

Figure 17 compares the effect of a Minimum Charging strategy versus a Full Charging strategy for fleet vehicles on the overall demand experienced by the substation during summer and winter (no change is implemented to residential or public charging profiles). As above, due to lower battery efficiency in cold temperatures, winter charging requirements are higher, irrespective of the charging strategy. However, a Minimum Charging strategy for fleets reduces peak load of the studied substation by approximately 10 MW. The Minimum Charging strategy is more effective in reducing the charging peak during the summer (reduction of >10MW) because the overall charging requirement is lower (particularly in the morning, since vehicles take less time overall to charge; this suggests the studied load is more effectively shifted to these morning hours in summer conditions). Although the Minimum Charging strategy helps reduce charging peaks, additional alternatives like energy storage should also be considered to address peaks through shifting or smoothing applications.

This analysis suggests that not only will specific distribution feeders feel the impact of fleet electrification, but those impacts could travel up the distribution system and into the transmission system. Detailed study of individual substations is required to further analyze what upgrades would be necessary to accommodate the future charging requirement. This type of analysis could reveal efficiencies in interconnection options and network upgrades.

Conclusions of Analysis and Further Considerations

This analysis demonstrates that:

- Full fleet electrification could have substantial impacts at the feeder and substation levels, especially where large, heavy-duty fleets are clustered. The results of the analysis indicate 4 distribution feeders that exceed their ratings in both winter and summer seasons as fleets electrify, with 9 additional feeders exceeding or reaching 80%+ of feeder rating in either winter or summer conditions.
    - ► To take one specific example, the load from fully electric fleets increases winter load on Feeder 18 to more than 300% of the feeder rating, which suggests that even intermediate stages of fleet electrification (particularly among heavier-duty fleets with higher charging requirements) would begin to have substantial impacts on specific portions of the electric grid.
    - ► Broadly, the results show that many feeders associated with large fleets (13 of 19 identified) face future overloads or are at risk of future overloading. This finding is especially noteworthy considering that only the fleet loads are compared to the feeder ratings. Residential and public charging would create additional loads, as would heat electrification.
    - ► The Full Charging scenario presented should be viewed as a reasonable case for fleet operations, not a worst-case where vehicles are all charged at their fastest rating. It assumes right-sizing of chargers that mitigates worst-case outcomes. For example, school bus fleets are assumed to use 19 kW Level 2 chargers; in practice, buses are capable of charging faster, and the chargers could be rated several times above that to allow faster charging if needed.
    - ► The Minimum Charging scenario illustrates potential benefits from managed charging, which should be encouraged to mitigate impacts where possible.
    - ► Many fleets were, by design, not included in this analysis. The results here are for the largest (and therefore most impactful) fleets that could be identified, but there are many smaller fleet operators that would add additional load when they adopt electric vehicles. As such, the fleet loads here could grow even higher as smaller businesses or geographically dispersed fleets electrify.
    - ► Fleets could also have major impacts at the substation level. At the substation considered in this analysis (which serves Feeder 18), full fleet electrification could increase winter peak load by approximately 60%.
- Additionally, as residential and public premises install their own electric charging, the aggregate loads could have further impacts at the substation level.
    - ► High levels of residential and public charging could increase peak load by approximately 20% at the substation considered in this analysis.
    - ► Further analysis is planned to review residential and public charging impacts on electric networks in detail.

- Charging patterns and load profiles will vary by fleet. With full transparency of the operating profiles of fleets, potential impacts on the electric system could be more accurately estimated using methods similar to those employed in this case study. These impacts cannot be fully analyzed without more granular data.

While this study reviews the impacts of full-scale electrification, which will take years to achieve, early movers could soon begin causing electric grid impacts. As discussed in Section 2, many corporate and public fleets are already moving to decarbonize. Section 4 discusses recommendations to better prepare for this future and support these "early adopter" fleet operators. Preemptively addressing system issues and customer needs will allow for faster uptake of EVs and earlier achievement of decarbonization and environmental goals. There are a number of sensitivities that could affect the results and lead to higher or lower levels of EV load and system impact. Below is a discussion of some of the larger drivers that could affect results and should be monitored over time. It is impossible to perfectly forecast the levels of EV load that will materialize, but the analysis and recommendations in this study are intended to provide guidance for fleet operators, utilities, and other stakeholders as they push forward with decarbonization efforts.

Table 3: Summary of Impact Analysis Sensitivities

	Higher Grid Impact	Lower Grid Impact
Fleet Operations	• Faster, immediate charging at higher charging rates is preferred for operations, or perhaps required for peak periods (e.g. between Black Friday and Christmas for delivery companies, or for local emergency management) • Charging is not able to be optimized due to vehicle schedules	• Vehicles travel fewer miles per day • Vehicles utilize on-route charging and less depot charging, reducing the concentrated loads on specific feeders • Vehicle dwell times are longer than estimated, even up to days/weeks of idle time • Battery efficiency increases substantially more than expected
Fleet Location	• Additional fleets that were not identified in the study electrify, e.g. small and local companies • New fleets move to constrained areas (e.g., due to favorable access to transportation infrastructure) or existing fleets expand	• Fleets relocate over time to more accessible parts of the electric network ("headroom hunting")

	Higher Grid Impact	Lower Grid Impact
Fleet Vehicle Types and Numbers	• Fleets have more vehicles than estimated • Fleets have a higher proportion of heavy- duty vehicles than estimated • Fleets relocate vehicles to serve seasonal needs, e.g. holiday delivery	• Fleets have fewer vehicles than estimated • Fleets have a higher proportion of light-duty vehicles than estimated
Charging Infrastructure	• Fleets install more fast-charging ports than anticipated or higher power chargers, regardless of additional cost[27] • Fleets install more charging ports to allow more vehicles to be charged at the same time (decreasing EV:EVSE ratio)	• Fleets install fewer fast-charging ports than anticipated • Fleets have fewer charging ports for simultaneous charging (increasing EV:EVSE ratio)[28]
Temperature Impact	• Fleets install more charging ports to compensate for lower battery efficiencies at lower temperatures	• Fleets require less charging time to fully charge the fleet due to higher battery efficiencies at higher temperatures • Advances in battery technology improve performance in cold weather
Other Technologies	• Electrification of heating, such as with electric heat pumps, accelerates and adds additional electric load	• Hydrogen (or natural gas or diesel) takes larger share of MHDV market[29] • Energy storage and other DERs improve in performance and cost competitiveness • Managed charging is able to meaningfully reduce peaks across many different fleet types and use cases

[27] A fast charging port in this study is defined as DCFC with maximum charging rate at 150 kW while a Level 2 charging port is at 19 kW. It is expected that DCFC charging power may increase to 400 kW (Howell, et al. 2017).

[28] Charging port is an individual charger with a defined maximum charging capacity. A charger may have multiple dispensers to connect to multiple vehicles to allow partial charging or scheduled charging without moving these vehicles. These dispensers can only charge at the maximum of their connected charging port.

[29] Hydrogen could have separate grid impacts, e.g. to support electrolysis.

4. Implications: Preparing the Electric Grid for Large-Scale Fleet Electrification

This analysis demonstrates the potential scale of full fleet electrification and its impact on portions of the electric distribution network. It is intended to support more comprehensive planning for long-term, large-scale electrification needs. National Grid and Hitachi Energyintend to build from these insights and further study potential system impacts and interconnection options, which could reach beyond the distribution to the transmission network as well. We welcome and encourage feedback and collaboration from customers, policymakers, and other stakeholders who are studying this topic.

Decarbonizing fleet transportation is a long-term effort. Utilities and policymakers can act now to understand the implications of fleet electrification and what can be done to prepare the grid for this impact – and to remove barriers to the electric vehicle transition for fleet operators.

We Must Plan for Long-Term Fleet Impacts in Order to Support Electrification

As this study demonstrates, significant impacts from fleet electrification should be anticipated – especially where several large fleets are fully electrifying in the same area. These impacts could manifest abruptly where fleet operators have ambitious electrification mandates and switch over large portions of their vehicles at once, such as a transit agency making a bulk procurement of electric buses.

The traditional approach to upgrading electric infrastructure for single-customer use could be ill-suited for this potential "step-change" in electric demand. Traditionally, utilities only invest in these types of upgrades when a specific customer has made a request for service, such as when a business is installing vehicle chargers. This approach is cost-effective when only one customer needs service. However, the electrification of multiple, neighboring fleets could impose large loads that stress this reactive service to load process and delay interconnection timelines. Further, this process could lead to a "who pays" dilemma in that the cost of an upgrade that services multiple customers might be borne by the first fleet to request service.

While electric load growth forecasting has traditionally been the mechanism for proactive system investment to support shared load growth of an area, electric fleet loads are a challenge to incorporate into traditional utility processes because of the sheer variation in where fleets are located. As this study demonstrates, fleets might be concentrated in certain areas of the distribution or transmission systems. Only considering fleets on a case-by-case basis misses the "clustering" effect illustrated by this analysis and makes it impossible to plan for the most cost-effective solutions. Instead, utilities will need to consider the needs of multiple fleets in a given area.

Collaborative and proactive planning is needed to accelerate and support fleet electrification. By planning for high electrification scenarios, utilities could direct investments to ensure fleet operators do not need to wait for large and potentially lengthy infrastructure upgrades to install chargers and put their new vehicles to work. Without this proactive planning, fleet electrification could also come at higher cost, as multiple, piecemeal upgrades are made to enable one fleet at a time – for instance, a distribution project which might require an upgrade several years later – when one, larger upgrade would have provided for multiple fleets at once – as the figure below illustrates. Streamlining and updating supportive interconnection processes could reduce costs, address fleet pain points, and accelerate progress toward decarbonization goals.

Figure 18: Illustrative Implications of Fleet Electrification

Using actual operational data will be necessary when conducting long-term system planning studies. Individual fleets will have drastically different routes, use profiles, and vehicle mixes. This study shows the potential impacts and system constraints for one specific area, but a similarly sized group of fleets in another area (e.g. more urban, longer routes, heavier payloads) may have different energy requirements and therefore different impacts on the grid. Strong partnerships must be formed to accomplish this – both between the planning groups of fleet operators and utilities, but also among fleet operators. Sharing detailed operating data among these groups is a significant challenge that must be overcome.

We Need an End-to-End Analytical Approach: Solutions Should Include Transmission, Distribution, Distributed Energy Resources, and Charging Infrastructure Programs

A long-term, comprehensive approach to planning should enable utilities to direct least-cost, least-regrets investments that enable and accelerate fleet electrification. Planning studies and options analyses should consider transmission, distribution, and distributed energy solutions simultaneously.

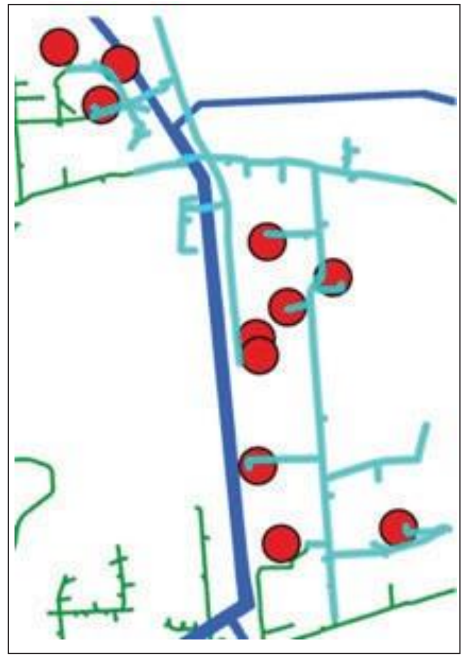
The scale of charging loads indicates that distribution upgrades (and/or DERs) may not always be sufficient to meet electrification needs. Substantial spot loads could require a connection to higher-voltage portions of the electric system: for instance, in National Grid's service territory, at a common distribution voltage (13.2 kV), the maximum individual customer load would typically be limited to 2,500 kVA (which at most would equal 2.5 MW) for delivery of secondary voltage (e.g. 277/480V) (National Grid 2021, Electric Specifications).Where customer load exceeds this threshold, those fleets may either need DERs (for instance, on-site solar or storage) to reduce their peak demand, or, alternatively, to connect directly to the transmission or sub-transmission networks, which offer higher capacity than distribution networks.

Even where distribution upgrades are sufficient to meet near-term needs, future analysis will evaluate whether one right-sized, upfront investment could reduce long-term costs and quicken the pace of fleet electrification. Rather than upgrading distribution facilities multiple times as fleets expand and new companies adopt electric vehicles, a single transmission upgrade – such as a new tap and substation – might be able to meet those needs more efficiently and at lower lifetime cost. A new substation could serve a significant amount of load off the transmission network and last for decades, allowing multiple neighboring fleets to easily electrify their vehicles without needing to revisit their service requirements repeatedly. By contrast, making incremental minimum upgrades might be less expensive upfront, but more expensive in the long-term. Pursuing an incremental approach could also lead to unfavorable outcomes in which fleets must delay their electrification plans to wait for the required infrastructure upgrades or are forced to "headroom hunt" to find adequate distribution infrastructure in other locations.

New transmission connections could be an especially attractive solution where fleet depots are near existing transmission lines. Consider Figure 19 at right, which shows several fleet customers identified in this study (red circles), the distribution feeder that serves them (light blue line), and nearby transmission lines (dark blue lines). The green lines are other distribution feeders, and the base map was removed. Where full electrification of multiple fleets may be difficult to deliver through the distribution system, solutions could take advantage of nearby transmission lines. This presents an opportunity to leverage transmission for high capacity charging for multiple fleets.

In addition to traditional infrastructure investment, managed charging will have a role to play in supporting EV adoption. This analysis demonstrates that differences in charging strategy can reduce the magnitude and duration of peak loads associated with fleet charging. Today, most fleet operators and service providers have focused on limiting their own demand (and therefore bill impact). Utilities should seek to work with customers to manage charging impacts across all fleets in a given area to reduce impact on specific feeders, which will help reduce systemwide costs and address system needs as electric fleets scale up. Implications or benefits of "vehicle-to-grid" (V2G) capabilities for clustered fleets also merit study.

Figure 19: Depiction of Fleet Locations (Red Circles), Distribution Feeder (Light Blue Line), and Nearby Transmission (Dark Blue Lines)



Fleet Electrification Needs Can Be Addressed in Conjunction with Other Investments

National Grid and other utilities continuously invest in maintaining and upgrading electric networks. Today, those investments largely address asset condition issues associated with aging infrastructure, especially as relates to the transmission system. As utilities plan for mandatory asset condition or aging infrastructure investments, they should consider the impacts of transportation electrification and how investments could be accelerated, targeted, or right-sized to address multiple needs at once.

For example, if there are fleets near a line or substation that is slated to be replaced for asset condition issues, those utility facilities could be upgraded to serve the expected fleet charging needs as well. National Grid's Multi-Value Transmission framework, as well as the New York Joint Utilities' "Phase 1" investment plans for 2030 state climate goals,[30] could serve as a valuable case study. These offer examples of projects proposed for reliability, safety, and compliance purposes that also address bottlenecks or constraints that inhibit renewable energy delivery.

Addressing electric transportation needs simultaneously with other investments will minimize costs and accelerate the pace of adoption by proactively addressing network constraints. These investment plans should also consider how grid-enhancing technologies, such as dynamic line-rating, can allow for better utilization of existing systems, further reducing costs (and increasing reliability) of serving fleets' and other vehicles' electric load. Understanding how system needs will evolve over time will be critical.

Taking a more holistic approach will also be necessary to plan for generation capacity as the electrification of transport drives substantial increases in electric load, potentially at the same time as other applications (e.g., electric heating or hydrogen production). New planning processes will be needed to support this. As mentioned previously, instead of studying the system impacts of each customer service request on its own, through collaboration with fleet operators, utilities could instead study the anticipated needs for all fleets in a given area, which could be more easily incorporated into system forecasting and planning processes.

[30] See NY Public Service Commission 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

5. The Road from Here: Actions to Accelerate Fleet Electrification

This study begins to answer a pressing question: what impacts could large-scale MHDV fleet electrification have on the electric grid? This is the first step to developing strategies and policies in support of electrifying these fleets. Further analysis will provide additional insight on system impacts, interconnection options, and actions needed to enable and accelerate full electrification.

Electrifying MHDVs presents a major opportunity, which will require a broad coalition to be fully realized. In addition to utilities, that coalition must include:

Fleet Owners and Operators: Provide comprehensive data on fleet sizes, locations, implementation schedules, and operational requirements (dwell time, energy requirements) to enable utilities and charging providers to better meet their needs.	Fleet operators can partner with companies like Hitachi EnergyGrids and National Grid to refine and expand the analysis presented in this study. High-quality data as to where fleets are located, how many vehicles are in a fleet, and how those vehicles might be used is limited. Sharing this data would support long-term planning by utilities. Each fleet location is unique and may require its own detailed analysis. This study has leveraged available data to estimate charging profiles and system needs, but more granular data will improve the results and allow coordination among sites. By working with their utility or charging providers, system integration challenges can be addressed proactively. This would help fleets meet their ambitious electrification goals at pace and at lowest cost.
Policymakers: Utilize studies such as this one to inform policies needed to accelerate fleet electrification at lowest cost.	Legislators, regulators, and other policymakers are already taking action to support near-term MHDV electrification. This study provides a view of what will be needed to meet medium- and long-term MHDV electrification goals. The results and subsequent analysis can support proactive plans to enable large-scale fleet electrification over time and at lowest cost to customers, helping meet important policy goals in the most efficient manner possible. Future policy attention could focus on: 1) How to plan for the needs of multiple fleets in an area, versus one fleet at a time (holistic vs. “piecemeal” approach). 2) How to support the needs of individual fleets with large needs, e.g. utility programs to support heavy-duty fleet operators with necessary electric infrastructure and electrification planning. 3) How to proactively and efficiently invest to accelerate fleet electrification.

Communities: Identify additional community needs, goals, and constraints with regard to fleet electrification.	As discussed above, particulate and other emissions from trucks significantly impact local air quality. Fleet electrification can particularly benefit Environmental Justice Communities (EJCs), which have been disproportionately impacted by pollution over time. Many fleet depots and vehicle routes go through these communities and would be priority candidates to convert to electric power. Eliminating tailpipe emissions from fleet vehicles will be critical to addressing environmental justice concerns. Further analysis can identify fleet depots in EJCs and the infrastructure needed to help those facilities electrify.
Suppliers: Use insights from this study to develop services, systems, and products to support the implementation and operation of fleet electrification.	Suppliers of electric fleet services and products can support full electrification requirements by understanding the operational constraints for solutions to meet various market needs. These suppliers include the vehicle original equipment manufacturers (OEMs), providers of charging infrastructure, energy optimization and systems integration service providers, and IT service companies. Integrated solutions with standard interoperability will be needed to foster the technology adaptations. Accelerating the market adoption of MHDV electrification requires additional collaborations among suppliers and market participants to provide end-to-end solutions with seamless integration.

Collaboration will lead to a faster, better coordinated, and lower cost transition to electric vehicles. National Grid and Hitachi Energy look forward to partnering with all interested stakeholders to support the decarbonization of medium- and heavy-duty transportation. The insights offered by this case study, as well as the implications and next steps identified above, provide an early vision of what that partnership should seek to accomplish.

Proper system and investment planning can identify and alleviate roadblocks for fleet operators and pull forward fleet EV adoption, so that the environmental and public health benefits are realized years or decades sooner than currently forecasted. Proactively addressing the impacts of new load associated with fleet electrification is key to ensuring the transition to zero-emission medium- and heavy-duty vehicles is as fast, efficient, and equitable as possible.

About Us:

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, Massachusetts, and Rhode Island. 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. As part of our commitment to a clean energy future, National Grid is a Principal Partner for COP26, the UN global climate summit, which will be located in the UK in November 2021.

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Appendix A:

Table A: Summary: Impact of studied fleet electrification on feeder loading (Minimum Charging Strategy)

Feeder ID	Feeder Rating (MW)	Summer Peak Load (MW)	Summer Peak with Fleet EV (MW)	Summer Feeder Loading with EV	Winter Peak Load (MW)	Winter Peak with Fleet EV (MW)	Winter Feeder Loading with EV
1	5.0	2.2	2.8	56%	1.7	3.6	71%
2	8.2	1.6	1.7	20%	1.5	1.5	19%
3	1.9	1.1	1.5	80%	0.9	1.4	74%
4	9.3	4.2	4.3	46%	3.6	3.7	40%
5	10.4	8.1	8.3	80%	7.2	7.8	75%
6	8.3	4.6	4.8	57%	4.2	4.8	57%
7	7.6	8.0	8.0	106%	6.6	6.7	88%
8	8.0	5.5	7.7	96%	5.3	14.1	177%
9	7.1	2.8	4.2	59%	2.3	6.3	89%
10	8.0	2.1	3.6	44%	2.0	6.7	84%
11	10.7	6.4	6.6	61%	6.7	7.0	65%
12	11.9	4.2	5.7	48%	3.6	7.7	65%
13	8.0	5.5	6.9	86%	4.5	6.2	77%
14	10.0	8.2	8.8	88%	7.0	7.1	71%
15	9.0	4.9	5.5	61%	4.0	5.0	55%
16	3.4	1.3	5.0	147%	1.1	10.3	304%
17	10.9	7.0	7.7	70%	5.8	7.0	64%
18	8.2	2.4	9.7	118%	1.9	22.1	269%
19	7.9	4.1	4.8	60%	3.7	7.5	94%

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