SOUTHERN ALLIANCE FOR CLEAN ENERGY

ASSESSMENT OF MEDIUM- AND HEAVY-DUTY VEHICLE ELECTRIFICATION

FOCUS ON NORTH CAROLINA

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ABOUT SOUTHERN ALLIANCE FOR CLEAN ENERGY

The Southern Alliance for Clean Energy is a nonprofit organization that promotes responsible and equitable energy choices to ensure clean, safe and healthy communities throughout the Southeast. As a leading voice for energy policy in our region, SACE is focused on transforming the way we produce and consume energy in the Southeast.

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CONTENTS

EXECUTIVE SUMMARY

Electrification of transportation is underway, but utility and regulator focus has typically been limited to personal or light-duty vehicles. The electrification of medium- and heavy-duty vehicles has the potential for positive grid impacts if electric utilities and their regulators take proactive actions now to prepare for these classes of vehicles to electrify in the coming years. In an assessment of the state of North Carolina, below were our primary findings.

IMPORTANCE OF DISTRIBUTION SYSTEM PLANNING

The ability of electric utilities to provide enough power to charge vehicles is constrained by the distribution system, and not a lack of generating capacity. While existing and planned electricity generating resources are enough to meet this increased electricity demand without the addition of new fossil fuel generation investments, we foresee potentially major constraints without improvements to the way the electric distribution system is upgraded to deliver electricity to where it is needed to charge these vehicles. The historical and current method for upgrading electric grids tends to be on an as-needed basis that reacts to the addition of resources to the grid, usually by performing studies to determine the impact that increased load in that particular location before scheduling any necessary grid upgrades. This process could delay electrification plans *by years* as customers wait for the utility to complete grid upgrades. Therefore, to minimize these delays, it is important for electric utilities and their regulators to begin now to proactively plan for a grid that can benefit from full electrification of medium- and heavy-duty vehicles across North Carolina.

MANAGED CHARGING IS AN OPPORTUNITY FOR DEMAND-SIDE MANAGEMENT

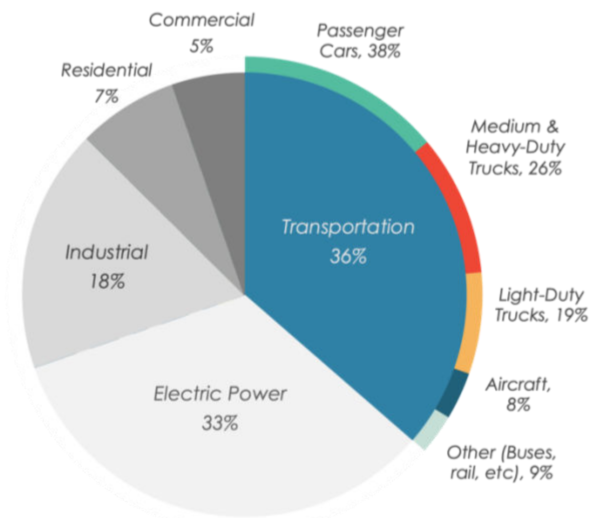
Both passive and active managed charging programs provide benefits to the electric utility and electric fleet customers. By directing charging away from times of potential grid constraints, and even using vehicle batteries as electric grid storage resources, utilities have tools to use during times of grid constraints. These constraints could take the form of a lack of generation resources during a peak load or extreme weather event, or outages on the distribution or transmission system that block the flow of electricity to certain parts of the grid. Managed charging could even help limit the individual peak load at a given charging location to allow charging to occur prior to all required utility system upgrades being online if the utility has determined that a certain level of load is tolerable without the required utility system upgrades.

SOME VEHICLES CAN AVOID OR EVEN REDUCE PEAK IMPACTS

How a vehicle is being used is a major factor in determining its mileage and driving schedule, which in turn defines the type of EVSE needed, and the opportunities for managed charging. To get an idea of near-term impacts, we examine these factors to highlight several medium & heavy-duty vehicle use-cases that are within current EV technological capabilities. These use-cases include two types of passenger buses, municipal transit buses and school buses, drayage truck, and delivery trucks. Generally, these vehicles have less time-sensitive charging needs and are not expected to have a significant impact on a utility's peak due also to their predictable schedules and relatively low operating ranges. In fact, school buses in particular, which are not expected to be in operation during summer afternoons when electric utilities in North Carolina tend to experience peak loads. This means that they could be used as grid storage resources to help actually *reduce* electric utility peaks at these times.

INTRODUCTION

Figure 1. Emissions by End-Use Sector (CO_2, EQ)



Sources: U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks. 1990 -2020. Tables 2-5 and 3-13 (MMT CO2 Eq.)

The transportation sector is the largest national source of carbon-dioxide emissions, closely followed by utilities in the electric power sector (as pictured to the left). These two industries are increasingly linked to one another, with electric utilities being an essential part of the electric vehicle (EV) market's success. For more than a decade, EV markets have seen a series of breakthroughs in the form of improved battery chemistries, falling vehicle prices, and rising model availability, leading to an upsurge in adoption of battery-electric passenger cars and light-duty trucks.

But the transportation sector's interest in electrification is no longer limited to passenger vehicles. **Instead, the focus is now on how the electric power sector can help realize the next step of the transition: electrifying fleets of medium and heavy-duty (M/HD) vehicles.**

Electrification of medium and heavy-duty vehicles is expanding as vehicle ability, charging innovation, and public policies have advanced rapidly. In fact, due to these advancements, a large number of fleets may be ready to seriously evaluate electrification for the very first time.

What do electric utilities and regulators need to do to prepare for M/HD EVs? As a first step, this paper will examine the state of North Carolina, where supportive public policies and action by the governor's office have added critical momentum to both this emerging market and the electric utilities that will meet their charging needs. We will assess a scenario that represents 100% electrification of all types of trucks, vans, and buses based on the electric utility that is likely to serve the associated load.

Since transportation electrification is occurring in tandem with a very dynamic electric power sector, it is important to understand how electricity and fleet operations impact each other. Utility operations are a major factor in the deployment of electric vehicle supply equipment (EVSE) at the level needed for all types of M/HD electrification, since widespread megawatt-charging is likely to require distribution system expansion. At the same time, the fleet operations present utilities with opportunities for managed charging.

Ultimately, we hope that these multiple perspectives will come together to broadly inform policies and strategies that make electrification beneficial for both fleet operators and electric utilities in the state of North Carolina, all while reducing carbon emissions.

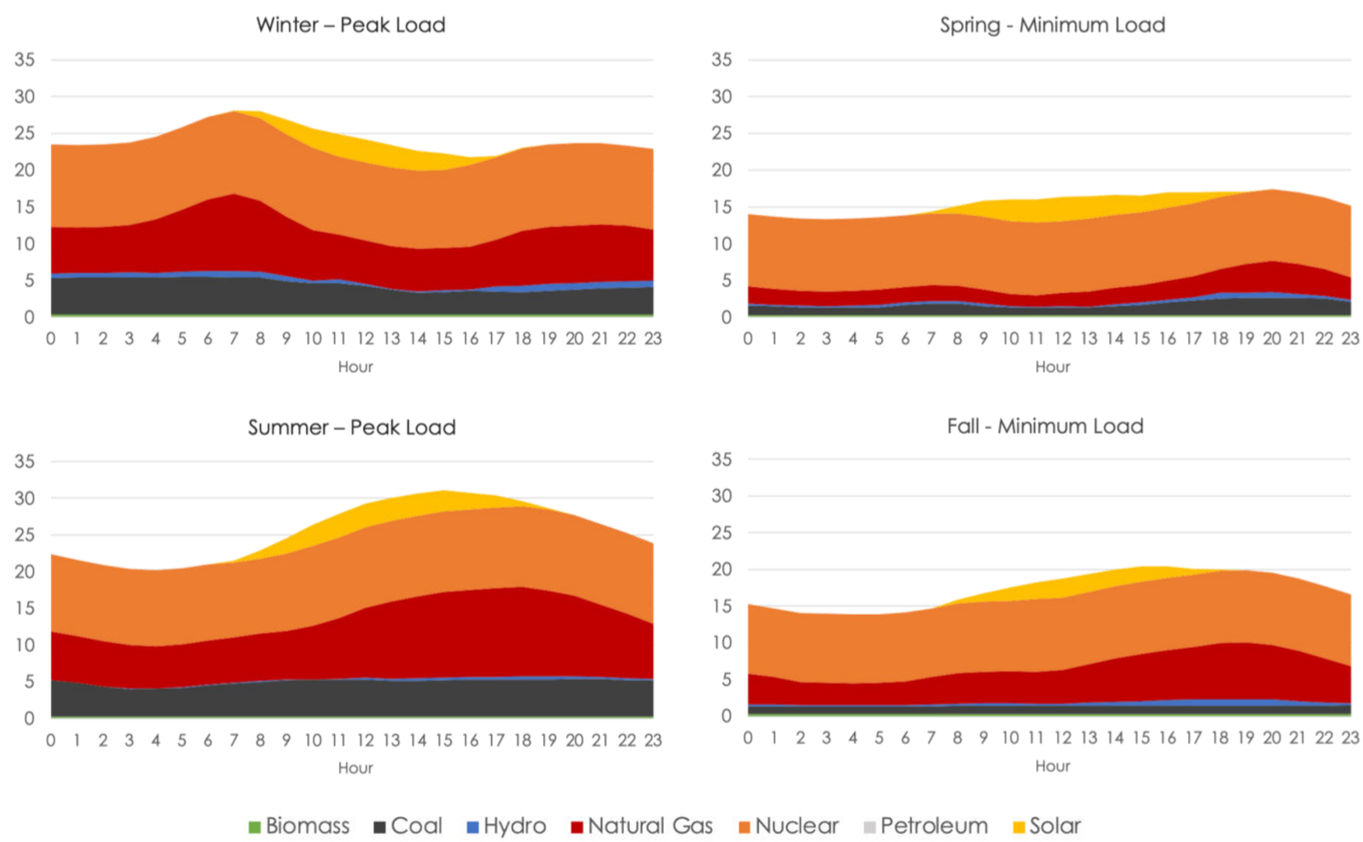
POWER AND TRANSPORTATION IN NC

ELECTRIC POWER CHARACTERISTICS

Electric utilities are a key tool for electrifying and decarbonizing the transportation sector. Nearly every utility in the state has made steep reductions in carbon emissions during the past 15-20 years, and many have set goals to decarbonize the power supply altogether. This shift away from fossil fuels and towards zero-carbon electricity generation means that the **electrification of transportation is not occurring in a vacuum, but rather in tandem with the very dynamic electricity sector.**

In North Carolina, electricity is provided to charge vehicles by a number of different types of utilities that all utilize different types of generating resources. In fact, the generating resources used can vary by location across the state, on an hourly basis over the course of the day, and by season throughout the year. Peak electricity demand in North Carolina tends to occur during the summer and winter, with lower load days being more common in the spring and fall. Thus, it is helpful to characterize the resources used in each hour of a peak winter or summer day, or a minimum load day in the spring and fall, as we have done for the state in Figure 1.

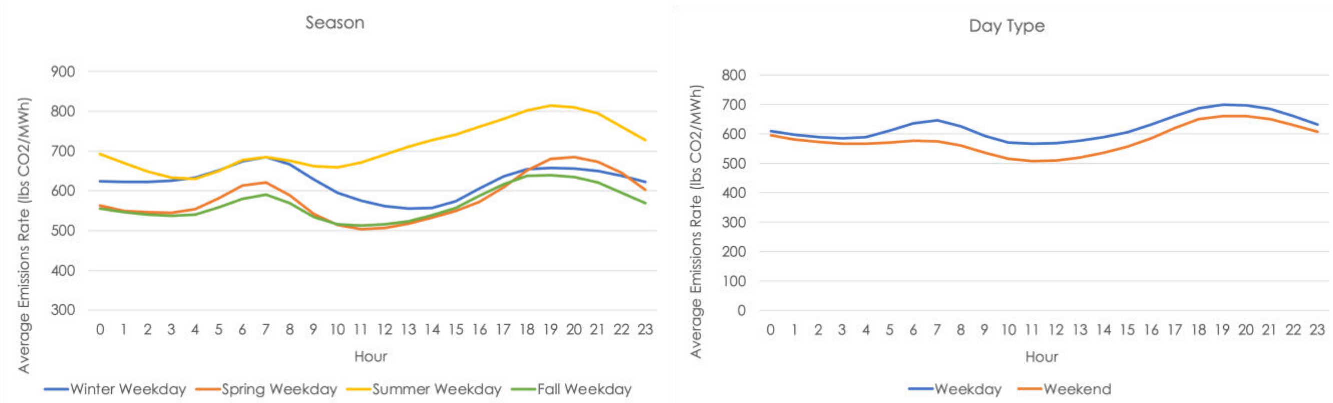
Figure 1. Average Hourly Electricity Generation (GWh) in NC by Source and by Season/Load Type



Source: SACE, Data from U.S. Energy Information Administration's Hourly Electric Grid Monitor, Real-time Operating Grid - U.S. Energy Information Administration (EIA).

The resources used to generate electricity in a given time period determines the emissions associated with that electricity, and thus the net emissions reductions achieved through electrification. Since summer and winter tend to have higher load, average hourly emissions rates are higher in those seasons as well. Similarly, since electricity demand tends to be higher during the week than on weekends, emissions rates tend higher on weekdays. In all seasons there is a dip in emissions rates during the middle of the day as solar generation reduces emissions. There also tends to be a second smaller dip in emissions rates overnight as electricity demand decreases for a prolonged period of time and fossil fuel generation is turned down. **In fact, these dips in emissions rates are an opportunity for EVs to benefit the grid while also reducing emissions.**

Figure 2. Average Hourly Emissions Rate of Electricity by Season and Day Type



Source: SACE, Data from U.S. Energy Information Administration's Hourly Electric Grid Monitor, Real-time Operating Grid - U.S. Energy Information Administration (EIA).

Electric utilities have the difficult task of balancing supply to meet demand on a minute-by-minute basis. Shaping electric load so that demand is kept more even during certain periods, like overnight, can help make this job more manageable. Another grid benefit of EVs is avoiding renewable curtailment or peak load times. Programs that direct EV charging load to match the timeframe when the resources that are available rather than the other way around are a form of demand-side management (DSM), which will be discussed later in the paper.

Historical emissions rates for different times throughout the year illustrate how charging behaviors can influence the net fossil fuel reduction and maximize the emissions impact of electrification. The emissions reductions from electrification are still considerable even when charging during times of relatively high carbon intensity of the power supply since EVs are very efficient. It is also worth noting that the other part of the net impact comes from the *type* of direct fossil fuel use that is displaced. Medium and heavy-duty vehicles (M/HD) are a prime target for emissions reductions because they normally run on diesel fuel. A gallon of diesel emits roughly 15% more carbon dioxide than a gallon of gasoline, and due to the size and weight of these vehicles, they are consuming a lot more gallons per mile than other vehicles.

Thus, electrification of M/HD fleets, even if charging occurs during times when electric emissions rates are higher, has the potential for steeper emissions reductions than electrification of light-duty vehicles. And it remains important to work toward both continued decarbonization of electricity generation overall as well as coordination of vehicle charging during lower emission hours and days to maximize electric transportation's climate benefits.

STATE TRANSPORTATION CHARACTERISTICS

Electrification of M/HD fleets assumes similar fleets will retain similar characteristics to existing fleets. Vehicles can be grouped together by gross vehicle weight rating (GVWR), an industry standard that identifies which vehicles are considered medium or heavy-duty (M/HD). M/HD vehicles are those that have been rated to have a safe operating capacity of 10,000 lbs or more including the weight of cargo, passenger, equipment, and fuel. Table 1 lists the different vehicle classes that constitute medium and heavy-duty.

Table 1. Medium- and Heavy-Duty Vehicle Classes

Gross Vehicle Weight Rating (lbs)	Federal Highway Administration		US Census Bureau
	Vehicle Class	GVWR Catagory	VIUS Classes
<6,000	Class 1: <6,000 lbs	Light Duty <10,000 lbs	Light Duty <10,000 lbs
10,000	Class 2: 6,001–10,000lbs		
14,000	Class 3: 10,001–14,000 lbs	Medium Duty 10,001–26,000 lbs	Medium Duty 10,001–19,500 lbs
16,000	Class 4: 14,001–16,000 lbs		
19,500	Class 5: 16,001–19,500 lbs		
26,000	Class 6: 19,501–26,000 lbs		Light Heavy Duty: 19,001–26,000 lbs
33,000	Class 7: 26,001–33,000 lbs	Heavy Duty >26,001 lbs	Heavy Duty >26,001 lbs
>33,000	Class 8: >33,001 lbs		

Source: Alternative Fuel Data Center (AFDC), Vehicle Weight Classes and Categories.

Vehicles this large are typically owned by commercial enterprises, local governments, or independent/for-hire truckers and are built and specialized for work purposes. They are commonly used for freight and parcel delivery, or providing municipal services like sanitation or emergency response. **A vehicle's function is a major factor in determining its daily mileage and operating schedule, which in turn define its charging requirements and opportunities for managed charging.** Therefore, it is a key consideration for those examining the impacts of electrification, since it defines when a vehicle will be able to charge from the grid and how much capacity it will need to drive its daily route.

For the purpose of this analysis, we accept more simplified vehicle use case categorization in exchange for more granular geographic data that allows us to aggregate to utility service areas. We do not distinguish whether a vehicle might charge with one utility provider and then the vehicle travel will occur elsewhere. This will allow us to **illustrate a hypothetical scenario where all trucks, vans, and buses are able to charge in roughly the same area where they travel.**

Determining the electric service provider can be a challenge since service areas are nonstandard geographies and are rarely coterminous with administrative boundaries like counties or cities that may have their own reporting statistics. Therefore, the aggregate impacts and characteristics in this section of the paper rely on data reported by the Federal Highway Administration's (FHWA) functional classification of roads. Granular road data on the distribution of vehicle distance traveled by vehicle type (cars, light trucks, single-unit trucks, and combination trucks) by roadway type can be overlaid with utility service areas as a jumping off point to determine charging load. We can also use U.S. Energy Information Administration (EIA) customer account information as a backstop to determine the reasonability of this approach. For example, the allocation for personal vehicles (passenger cars and light-duty trucks) is roughly proportional to the number of residential customers served by an electric utility. While there may be some smaller differences attributable to commuting flows, adjustments are generally not necessary in the aggregate.

STATE AND UTILITY ELECTRIFICATION IMPACTS

With these assumptions, we have estimated the vehicle miles traveled (VMT) and electricity demand needed for charging vehicle classes in three utility service territory types in North Carolina: Duke Energy, cooperative utilities, and municipal utilities.[1] These results are presented in Table 2.

Table 2. Aggregate Impacts of Vehicle Electrification by Likely Utility Service Provider

Impact	Vehicle Type		Duke Energy	Cooperatives	Municipals	Total
Million Vehicle Miles Traveled (VMT)[2]	Light-Duty		74,402	20,608	12,926	107,936
	Medium-Heavy-Duty	Buses	527	162	91	780
		Single-Unit Trucks	2,763	869	489	4,120
		Combination Trucks	3,289	1,140	468	4,898
	Total		80,981	22,780	13,974	117,734
Estimated Charging Load (GWh)[3]	Light-Duty		19,979	5,614	3,479	29,072
	Medium-Heavy-Duty	Buses	713	219	124	1,056
		Single-Unit Trucks	4,991	1,569	883	7,443
		Combination Trucks	7,427	2,575	1,058	11,060
	Total		33,111	9,978	5,543	48,631

Sources: Southern Alliance for Clean Energy Analysis of Federal Highway Administration (FHWA) Data, Utility Service Territory

It is notable that while over 90% of VMTs in the state come from light-duty vehicles, only 60% of the estimated load comes from that same grouping. The reasons for this disproportionate load are relatively clear: larger vehicles that travel more miles and carry heavier payloads require more energy. The electrification of vehicle miles traveled could add roughly 49 TWh of electricity load in North Carolina annually, depending on how the vehicles perform.

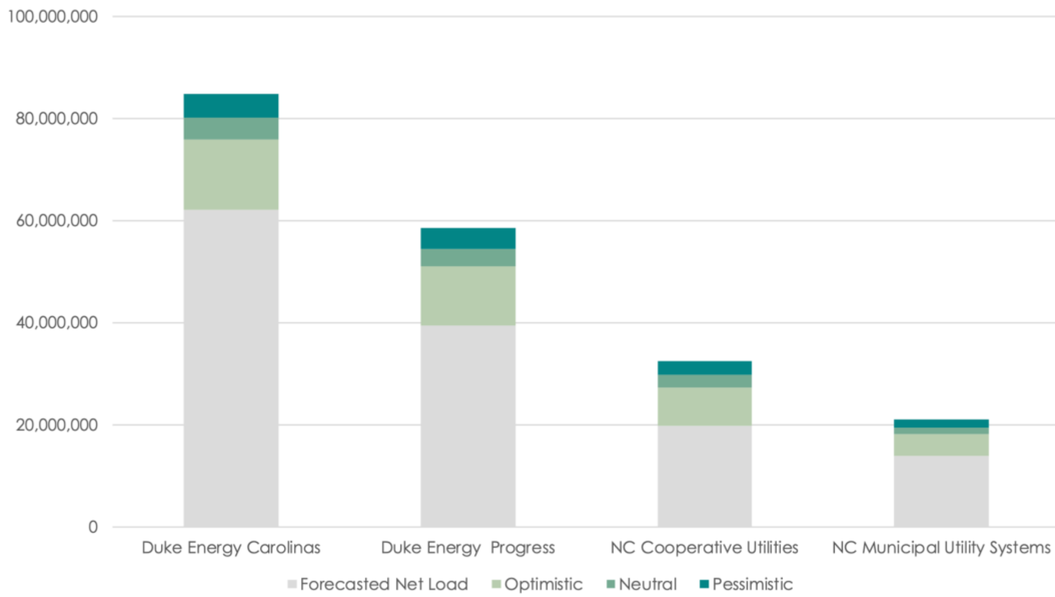
More optimistic and pessimistic assumptions regarding vehicle performance might require 34 or 75 TWh respectively. As a point of comparison, the aggregate net demand in the state was approximately 136 TWh. Most (nearly 70%) of the demand for charging is estimated to be in the service territories of Duke Energy's two electric utilities: Duke Energy Carolinas and Duke Energy Progress, as evidenced below:

[1] Note that these groupings are aggregations of multiple utilities for the purposes of summarizing.

[2] FHWA Highway Performance Monitoring System (HPMS) functional route classifications and Highway Statistics Series - Tables VM-2 and HM-44

[3] A variety of miles per kWh conversion factors were used to estimate the amount of electricity under different scenarios. For a full description of the different scenarios based on vehicle performance evaluations, please see the technical appendix.

Figure 3. Utility System Net Load with Plausible EV Charging Scenarios (MWh)



Source: Southern Alliance for Clean Energy Analysis of Federal Highway Administration (FHWA) Data and Utility Service Territory.

To put this potential load growth in context, Southeast utilities were able to ramp up generation at a similar level over a 12-year period in the late 1990's and early 2000's. But since then, utilities have forecast flat to declining demand, leading to the unused potential to ramp electric generation up to meet new load. Utilities run power plants with relatively low-capacity factors, meaning that the power plant is underutilized or not run very often, in order to keep fuel and other variable costs low when less demand is needed. There are also plans to expand renewable generating resources on the grid, in North Carolina and across the Southeast. **The additional load from M/HD charging is large, but can be met with existing and planned generating capacity in North Carolina without the need to build new fossil fuel generating resources.** However, generation is not the biggest obstacle faced by utilities when it comes to M/HD vehicles. Instead, distribution grid impacts are expected to be large, especially when it comes to long-haul trucking. The specifics of distribution system upgrades and impacts will be discussed later in the paper.

The net emissions reductions from electrification of transportation depends on the fuel displaced, usually gasoline or diesel, as well as the time and vehicle charging. Using our estimation of the resource mix in North Carolina in 2030, which is based on current utility plans, we calculated the potential for carbon emission reductions from full electrification of different vehicle classes based on the estimated number of those vehicles in each type of electric utility service territory in North Carolina. These results are presented in Table 3. As discussed earlier, there is a greater potential for emissions reductions from electrification of M/HD vehicles, which represent only 8% of total VMT in North Carolina but 26% of total emissions reductions through electrification.

Table 3. Aggregate Fossil Fuel and CO_2 Reductions by Likely Utility Service Provider and Vehicle Type[4]

Impact	Vehicle Type		Duke	Cooperatives	Municipals	Total
Thousand Gallons of Fuel Displaced	Light-Duty		3,178,753	885,914	552,606	4,616,273
	Medium-Heavy-Duty	Buses	72,158	22,199	12,505	106,861
		Single-Unit Trucks	368,399	115,825	65,152	549,376
		Combination Trucks	548,154	190,067	78,066	816,287
	Total		4,166,463	1,214,005	708,328	6,088,796
Net Short Tons CO_2 Reduced	Light-Duty		24,088,518	7,031,984	4,269,960	35,390,463
	Medium-Heavy-Duty	Buses	657,296	214,812	116,740	988,848
		Single-Unit Trucks	3,070,742	1,054,379	562,631	4,687,751
		Combination Trucks	4,552,410	1,730,212	674,151	6,956,773
	Total		32,368,966	10,031,387	5,623,482	48,023,835

Source: Southern Alliance for Clean Energy Analysis of Federal Highway Administration (FHWA) Data, Utility Service Territory.

For reference, the latest greenhouse gas inventory by the North Carolina Department of Environmental Quality (DEQ), released in 2022, estimated total emissions from transportation in 2018 in the state was approximately 63.2 million short tons of CO_2.[5] So full electrification of light, medium, and heavy-duty vehicles in the state alone could account for a net emission reduction of about three quarters of transportation emissions assuming current plans for electricity generating resources in 2030. If electric utilities deploy carbon-free electricity generation faster than projected in current plans, the carbon reductions from full electrification of these vehicle classes would be higher than these current estimates.

There are also localized pollution impacts that are more meaningful when considered outside the paradigm of where new electricity load will occur. Electrification of M/HD will result in significant public health and environmental justice benefits by reducing diesel particulate matter (PM) and other types of harmful air pollutants. Exposure to diesel particulate is highly localized, and is linked to higher rates of asthma, bronchitis, and pneumonia in neighborhoods and communities. Research by the Environmental Defense Fund correctly points out that the proliferation of same-day parcel delivery has greatly increased the number of distribution centers and warehouses in many areas, and that those in the state of North Carolina are disproportionately located in communities of color[6]. Additionally, legacy housing practices like redlining mean these communities are more likely to be near highways, warehouses, truck terminals, and ports.[7]

[4] Miles per gallon for vehicle types derived from FHWA Highway Statistics VM-1. Emissions from fuel displaced calculated with EIA's Carbon Dioxide Coefficients. Net emissions reductions represent emissions from avoided fossil fuel use, minus the tons of CO_2 from the grid mix of electricity used to charge, based on utility resource plans as of May 2023)

[5] North Carolina Greenhouse Gas Inventory, NC Department of Environmental Quality (2022).

6 Making the Invisible Visible, Environmental Defense Fund (April 2023).

7 Electrification of Medium- and Heavy-Duty Ground Transportation: Status Report, Fleming, K et al. in Current Sustainable Renewable Energy (2021)

VEHICLE CHARGING CHARACTERISTICS

VEHICLE CHARGING REQUIREMENTS

Electric vehicle service equipment (EVSE) provides a range of power output levels across alternating (AC) and direct current (DC) applications to charge vehicles at vastly different speeds. Additionally, the speed at which each an EV's battery system accepts a charge varies across makes and models, and depends on the vehicle's state of charge when it's plugged in; EVs charge fastest and consume the most electricity when between 0-60% full, at which point charging tapers to slower speeds to protect the longevity of the battery.

In general, heavier vehicles will have higher power output charging requirements than light-duty vehicles, with some heavy-duty vehicles anticipated to accept megawatt charging. Furthermore, the type of EVSE needed to meet a specific M/HD application will vary depending on a range of scenarios such as slower overnight depot charging vs. enroute ultra-fast charging.

Determining the peak demand of each M/HD charging location, be it a depot or en-route application, is not straightforward. While the system may need to be prepared to meet a peak demand equal to all chargers at maximum capacity at the same time, it is unlikely that the location will actually peak at that level. The peak will depend on how many vehicles are charging simultaneously, what power output level those vehicles are charging, and how much instantaneous power a particular vehicle's battery system can accept. For more discussion of how peak demand relates to charging locations and the number of vehicles per location, see the section on Site-level load diversity in the Synapse New York case study.[8]

VEHICLE DEPOT CHARGING

Nearly all the charging needs for certain types of M/HD vehicles can be met by installing less power-intense EVSE at vehicle depots. Depots vary by vehicle function, but are generally buildings or structures where trucks, buses, and other types of vehicles are stored when they are not on the road or in-service. These are practical locations for charging stations to be installed because they are private facilities where routine maintenance, repairs, cleaning, inspections, and equipment installations are performed on vehicles. From a utility planning perspective, the locations of vehicle depots may be easily identifiable and useful for forecasting distribution load at a much more granular feeder or circuit level.

Depots are a good opportunity to add charging capacity in the near-term since some vehicle depots will have high utilization rates right away, making cost recovery easier in the event that utilities provide some of the upgrades or equipment. According to researchers at the National Renewable Energy Laboratory, approximately 87% of M/HD vehicles have a primary operating range of 200 miles or less, which could be a fit for moderately-sized batteries depending on the type of vehicle. This means that a large portion of M/HD miles driven could be met with lower-level on-site charging in vehicle depots. While some of the more challenging aspects of meeting distribution system and peak impacts will come from charging long-haul trucking applications, the pace of electrification is much quicker for other types of vehicles, prompting the need to identify near-term potential depot charging clusters and opportunities for managed charging.

Passenger buses, such as school and transit buses, are one use-case that is expected to electrify quickly, rely primarily on depot charging, and have minimal impact to utility system peaks. Broadly, the daily milage

8 "Distribution System Investments to Enable Medium- and Heavy-Duty Vehicle Electrification: A Case Study for New York," Prepared for the Environmental Defense Fund by Metz, L., et al at Synapse Energy Economics, Inc. (April 2023)

and typical operations of passenger buses require low to moderate battery sizes relative to other Class 8 vehicles. This means that currently available battery technology is a good fit to meet this vehicle type's need in the near-term. Buses are also potential candidates for managed charging because they run on well-defined operating schedules that generally do not require time-sensitive charging, thus creating some level of flexibility when the vehicle is not in operation.

School buses generally travel around 12,000 miles a year[9] on average and have relatively low operating ranges of less than 100 miles[10] since they are on a fixed route within school districts. Coupled with relatively high model availability at 17 all-electric buses in model year 2023, school buses are among the quickest and easiest to electrify from a technological standpoint. The operating requirements of school buses can generally be met with battery sizes of 84-226 kW with low or no impacts on peak, since manufacturers reporting charging durations of 10-11 hours at Level 2 chargers ranging from 11-19 kW[11].

Further, **evaluations reveal that school buses do not tend to operate more than eight hours a day, leaving ample time for overnight charging, or during other timeframes when charging can be spread evenly so as to avoid or minimize contributions to peak events.** Even in the event that time-sensitive charging is needed, most current school bus offerings only need approximately 60 kW of DCFC. Additionally, there may be an opportunity for school buses to earn revenue from providing vehicle to grid (V2G) services. Given that many school buses do not operate on their traditional routes during the summer months, the batteries in school buses can instead be made available for dispatch. This presents a good opportunity to help alleviate summer peak events in North Carolina, while possibly earning incentives from the utility for doing so.

Transit buses travel approximately 44,000 miles a year on average, but still have relatively modest daily mileage needs since they are in operation for a larger number of days overall. With operating ranges of 100-250 miles[12], there are larger battery packs available among the electric bus model offerings that range from 215-738 kWh in size. Similarly, daily operating times are highly variable, though the majority of them operate for less than 15 hours a day. This is still generally a long enough window of time to keep time-sensitive, en-route charging to a minimum while continuously operate during the day before returning to a transit fleet facility at night. An evaluation of a peer transit agency, Knoxville Area Transit (KAT), revealed that they were able to electrify twelve buses within their fleet, all while getting the majority of their charge from 6pm-2am, thus avoiding midday peaks. Considering the significant number of vehicles stored in a municipal vehicle depot (that is likely located in proximity to other large loads in the urbanized areas where transit agencies operate), managed charging may also be a strategy to avoid or defer localized grid upgrades.

[9] Average Annual Miles Traveled by Major Vehicle Categories, via Alternative Fuel Data Center (U.S. Department of Energy)
[10] Fleet DNA Project Data Summary Report for School Buses via National Renewable Energy Laboratory (NREL)
[11] Alternative Fuels Data Center: Vehicle Search via Alternative Fuels Data Center (U.S. Department of Energy)
[12] Fleet DNA Project Data Summary Report for City Transit Buses via National Renewable Energy Laboratory (NREL)

EN-ROUTE AND OPPORTUNITY CHARGING

Operators of M/HD vehicles will likely require access to extensive fast charging networks. Since delays or downtime can cost fleet operators money due to the value of cargo that needs to be shipped and ultimately delivered, it is necessary for EVs to maintain the same level of service these vehicles currently provide. This can be done by ensuring that vehicles are able to charge throughout the day, away from a vehicle's primary charging location. All en-route and opportunity charging for M/HD is expected to be DCFC, with progressively higher requirements as the size of the vehicle and the time urgency of charging increases.

Opportunity charging is a type of charging where vehicles can be plugged in while temporarily stationary, such as loading or unloading or during longer operator breaks. En-route charging is typically when vehicles are traveling along distances on highway corridors that exceed vehicle range, and is usually more time-sensitive. Assessing the full demand for en-route and opportunity charging requires a fairly rigorous analysis including the M/HD vehicles' duty cycles, cargo weight, travel terrain, and ambient temperature, all of which impact vehicle battery range and, hence, charging needs.

However, it is relatively certain that charging networks of >1 MW DCFC between major cities and regions will be key for enabling electrification of long-haul trucking applications. Argonne National Laboratory writes: "For reference, a long-haul trucker driving a Class 8 tractor would require a 1.6-MW charge to recover 400 miles of charge within a 30-minute break." [13] **It is therefore expected that the most significant peak impacts will come from charging combination truck-tractor/semi-trailers that have mainly time-sensitive charging needs.** There vehicles will have limited, if any, ability to participate in managed or coordinated charging. Overall, more research may be needed by local agencies in order to determine the level of demand and/or flexibility that these vehicles will have in a given state or region.

But some time-sensitive charging needs may be less cumbersome to the grid. Intermodal travel is an important trucking application that helps transport and deliver commodities actually requires a series of different types of vehicles to get to its final destination. One type of intermodal travel is facilitated by **drayage trucks** that load and unload shipping containers at ports. They are specialized for moving bulk freight & containers only a short distance, usually moving goods from a port dock to another form of transportation (truck or rail), usually at a nearby distribution center or warehouse.

While it is difficult to distinguish the mileage and schedule of drayage from most forms of publicly available data, we do know from that these vehicles are very large and limited evaluations[14] reveal that most trips are near-dock operations, and even regionally operating vehicles average less than 200 miles of travel a

[13] FAQ: Charging for Heavy-Duty Electric Trucks | Argonne National Laboratory

[14] Key Performance Parameters for Drayage Trucks Operating at the Ports of Los Angeles and Long Beach via CALSTART

day. And because many of these vehicles are operated by for-hire truckers, managed charging and V2G constitutes a potential revenue stream for when these trucks are not in service. Owner-operators may face constraints in using the vehicle for additional shifts, or they may have irregular work schedules throughout the year. This suggests that further research might be needed to confirm that drayage trucks are good candidates for providing V2G services during times when load response would be valuable.

Another more common type of vehicle used for transporting goods is **delivery trucks,** which are generally the last-mile in the logistics needed to make parcel and courier delivery services available to consumers. These can come in a variety of sizes, including single-unit trucks and large step vans. Nearly all delivery trucks operate for less than 8-10 hours a day, and most travel less than 100 miles in a day[15].

While these vehicles will also have access to depot charging, drivers will likely expect access to fast charging while on the road or at job sites (perhaps charging while unloading), or during atypical days or one-time events. They are generally a good candidate for managed charging due to their charging window, but it may be difficult to avoid peak charging altogether since these vehicles typically depart for the day at a very early timeframe and delayed charging could result in undesirable scheduling delays.

UTILITY PLANNING CONSIDERATIONS

In addition to the aggregate impacts discussed previously, there are a number of issues specific to M/HD vehicle electrification that have implications for planning and regulating utilities. The prospect of fully-scaled M/HD electrification prompts a number of observations regarding how charging loads will impact peak demand, how EVs will fit into existing demand-side utility planning, and how megawatt-level charging loads can be integrated into the distribution grid.

ELECTRIC VEHICLE MANAGED CHARGING

Managed charging is a form of demand-side management (DSM), which is a practice that utilities use to align consumer demand with periods of lower resource constraints. Utility approaches to charging management encompass a variety of tools, including many existing regulatory practices, that can be used to address system constraint while also compensating EVs for valuable flexibility. This can be done by pricing electricity to induce a shift towards charging during specified windows of time, or towards charging vehicles at an intentionally minimal rate. Utilities can also offer incentives to EV operators in exchange for allowing utilities to take limited, but direct control of EV charging in response to peak events. In some circumstances, utilities may also want to make the stored battery power of EVs available for dispatch.

The utility benefit of EV managed charging of M/HD vehicles in particular is significant due to the ubiquity of fleets, and the large battery sizes of these vehicle types. This makes them a potentially significant grid resource: a large, variable load that can ideally be incentivized to also be flexible. However, the design and implementation of managed charging must be done with care. The impacts should be documented in a process of evaluation, measurement and verification (EM&V) to assess whether the desired results have been achieved or not. Utilities must seek to maximize participation by utilizing multiple forms of charging management since there will be no one-size-fits-all approach for M/HD vehicles.

One of the most commonly-used forms of managed charging is time-of-use (TOU) rate structures. This is a passive form of charging management that uses electricity pricing to align charging demand with the desired timeframe. TOU rates typically vary prices based on the time of day relative to peak demand, e.g., on-peak,

[15] Fleet DNA Project Data Summary Report for Delivery Trucks via National Renewable Energy Laboratory (NREL)

off-peak or super-off peak, or they may utilize real-time hourly pricing. In a study of EV TOU offerings[16] to commercial customers, every single rate required a dedicated second meter to measure EV charging, which is a less costly type of distribution grid upgrade. There are also rates for utility-owned charging stations because in some jurisdictions there is a standalone rate class DC fast chargers have standalone rate classes.

While some North Carolina utilities offer TOU rates, they do not have features specific to EV charging such as demand charge holidays/alternatives or dedicated meters. However, below is a table of neighboring jurisdictions that offer commercial, industrial, or fleet rates.

Table 4. EV-Specific Time of Use (TOU) Utility Rates in the Southeast

Utility Name	EV Rate	Class	Status
Alabama Power	BEVT - Business Electric Vehicle Rate	Commercial	Active
Florida Power & Light	GSD-1EV - General Service Demand EV Charging Infrastructure Rider	Commercial	Pilot
Florida Power & Light	GSLD-1EV - General Service Large Demand EV Charging Infrastructure Rider	Commercial	Pilot
Duke Energy Florida	UEV - Utility-Owned Public Charging for EVs	Utility	Pilot
Florida Power & Light	FCF-1 - Fast Charge Fee Public Charging for EVs	Utility	Active
Georgia Power	CIEV-1 - Charge It EV Charger Rider Schedule	Commercial	Proposed

Source: Southern Alliance for Clean Energy selection of rates from Lawrence Berkeley National Lab's Snapshot of EV-Specific Rate Designs Among U.S. Investor-Owned Electric Utilities

Another approach is for utilities to use active managed charging. This is similar to the objectives of demand response (DR) programs that are common in most utility demand side management (DSM) portfolios. Overall, this has much greater potential for valuable grid services than TOU rates since utilities will have direct control of EVs in order to respond to times of peak demand or other events impacting the grid. In exchange for some form of compensation, drivers or fleet operators will allow a utility service provider to take control of the speed and timing of vehicle charging.

While there are costs associated with implementation (installation of dedicated control equipment that helps it communicate with grid operators), there are also numerous benefits. The primary benefit is to avoid or reduce the impact of peak events. As discussed earlier, under certain conditions managed charging can be used to support the integration of further renewable energy on the grid by taking advantage of excess solar and avoiding curtailment during the day. There may also be a grid benefit in the form of deferring or even avoiding distribution system upgrades, which is discussed in further detail in the next section.

Bidirectional charging, sometimes known as vehicle to grid (V2G), is a more advanced implementation of managed charging that allows for energy to flow from an EV to the grid when prompted. Essentially, the goal of V2G is to use a fully-charged EV battery as a form of distributed storage available for dispatch. This utilizes very specialized equipment and is generally still only being studied as pilot programs in most number

[16] Snapshot of EV-Specific Rate Designs Among U.S. Investor-Owned Electric Utilities via Lawrence Berkeley National Laboratory

of jurisdictions, including North Carolina. State regulators recently approved a pilot program[17] for Duke Energy customers with light-duty trucks as a test of V2G technology, potential grid value, and the impact that small incentives have on customer participation.

Despite the immense potential for managed charging being a benefit to the grid, there are some issues that utilities and regulators might consider. The ability of M/HD fleets to participate in and benefit from managed charging depends on how utilities model demand. Even if there are prolonged periods of time where a vehicle is not in operation but is available to charge, these should not be considered infinitely flexible charging resources. And the performance of individual vehicles in managed charging pilots may not be indicative of the aggregate scale of the resources that will actually be available under a full electrification scenario. The operational needs of both the vehicle and the fleet are a constraint that utilities must be prepared to take into account when designing programs to reach their desired impact. For instance, delaying the charging of a vehicle that is plugged in without taking into consideration the time of departure can result in costly downtime for fleet operators.

Low enrollment and high opt-out rates are potential barriers to utilizing EV managed charging as a DSM resource at a meaningful scale. The structure of offerings and incentives will be key for utilities hoping to maximize managed charging. Many charging locations, especially vehicle depots, are likely to be associated with commercial and industrial (C&I) customer accounts. Competition between customers in this rate class are typically cited as a reason for opting out of DSM programs, meaning the customers don't participate and also don't contribute to cost recovery. The majority of the C&I customer class in both of Duke's operating companies in North Carolina have opted out of Duke's DSM portfolio, but it is difficult to say whether the same will apply to EV demand-side applications. Utilities should still seek to test a variety of approaches to mitigating these barriers, such as providing both an upfront incentive *and* a recurring incentive for each day with no-opt outs.

While much harder to address, utilities must do their best to determine which charging loads may be inflexible. There is going to be some level of charging that cannot be managed since the vehicle's operations, long-haul trucking for example, depend on timely charging. While some smaller single-unit trucks may have flexibility in terms of call events for direct control managed charging, there are going to be many Class 8 trucks that will rarely, if ever, have any flexibility in timing. That makes it even more important to maximize participation in managed charging programs from other types of vehicles since we know that not will be able to do so.

DISTRIBUTION GRID IMPACTS

Deploying EVSE with greater charging capabilities (primarily DCFC) at a large number of sites is a challenge that will require cooperation from multiple entities, but especially electric utility service providers. As discussed earlier, electric utilities are projected to be able to meet the additional electricity demand from electrification of M/HD vehicles in North Carolina, however the main concern with electrification is whether the electric grid will be able to deliver the electricity to where it is needed to charge vehicles. There will be enough electricity, but there is no guarantee that the electricity will be available where it is needed to charge M/HD fleets without proactive planning by electric utilities.

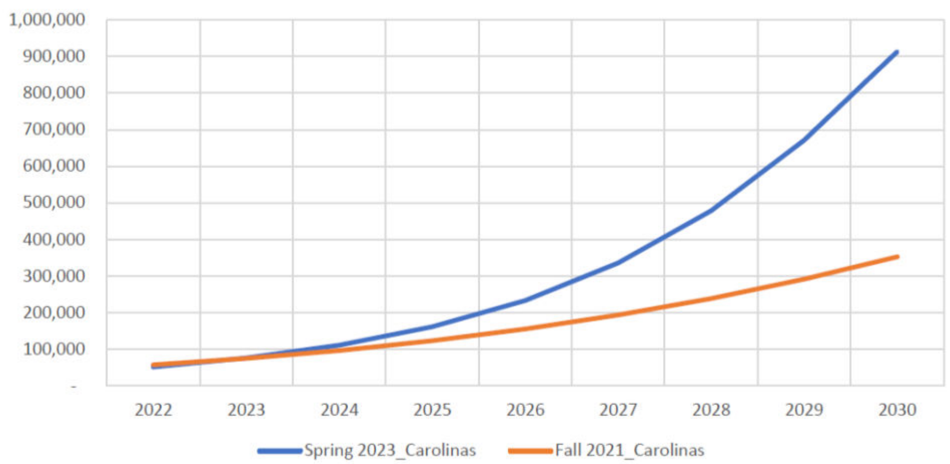
A review of Duke Energy's Integrated System Operations Planning (ISOP), which was announced as a solution to the ongoing challenges presented by electric utilities planning transmission, generation, and

[17] North Carolina Utilities Commission (NCUC) Order Approving Pilot Program Subject To Conditions in Docket No. E-7, Sub 1275

distribution in silos, was published recently. That review reveals that Duke Energy forecasts hourly load at the circuit level for 10 years, *including assumptions on EV adoption and other distributed energy resources.*

But that forecast, which Duke calls "Morecast", informs but does not directly tie into the load forecast Duke uses for its system-wide transmission and generation planning.[18] Also revealed from this review report is that Duke does not currently perform scenario analysis in its "Morecast" process, but is looking to implement that in the future. Duke's "Morecast" is not publicly available, but Duke did present the preliminary EV assumptions for the Integrated Resource Plan (IRP) it will file in North and South Carolina in the fall of 2023 at a recent IRP stakeholder meeting. While Duke is assuming a steeper adoption of EVs overall than in its previous IRP (the "Fall 2021_Carolinas" line), without the ability to break out vehicle types and by state, it is hard to tell how much of this is driven by the expected electrification of M/HD fleets specifically. Also note that this chart includes Duke's service territories in both North and South Carolina.

Figure 4. Vehicles in Operation – All Duties



Source: Duke Energy Carolinas Resource Plans Stakeholder Meeting 4 presentation, Virtual Meeting - May 31, 2023.

There are two types of grid infrastructure needed to install charging equipment for M/HD fleets, and the separation point is generally considered the customer's electric meter. The customer site may require a new meter or meters and a new panel or panels as well as additional lines, transformers, and conductors to serve the site. These are on-site upgrades. But in addition to on-site upgrades, the electric utility may require additional upgrades to distribution infrastructure elsewhere on its grid to be able to serve the increased load at the customer site. A summary[19] of these with estimated costs is presented in the table below.

[18] Duke Energy's Integrated System and Operations Planning: A comparative analysis of integrated planning practices, Lawrence Berkeley National Laboratory & National Renewable Energy Laboratory (June 2023).

[19] National Renewable Energy Laboratory (NREL), Perspectives on Charging Medium & Heavy-Duty Electric Vehicles webinar (December 2021)

Table 5. Summary of Electricity Distribution System Upgrades for Depot Charging

Component category	Upgrade	Typical cause for upgrade	Typical cost[a]	Typical timeline (month)[a]
Customer on-site	50 kW DCFC EVSE	EVSE addition	Procurement, U$20,000–36,000 per plug; installation, U$10,000–46,000 per plug[b]	3–10
	150 kW DCFC EVSE		Procurement, US$75,000–100,000 per plug; installation, US$19,000–48,000 per plug[b]	
	350 kW DCFC EVSE		Procurement, US$128,000–150,000 per plug; installation, US$26,000–66,000 per plug[b]	
	Install separate meter	Decision to separately meter	US$1,200–5,000	
Utility on-site	Install distribution transformer	200+ kW load	Procurement, US$12,000–175,000	3–8
Distribution feeder	Install/upgrade feeder circuit	5+ MW load[c]	US$2–12 million[d]	3–12[e]
Distribution substation	Add feeder breaker	5+ MW load[c]	~US$400,000	6–12[f]
	Substation upgrade	3–10+ MW load[g]	US$3–5 million	12–18
	New substation installation	3–10+ MW load[g]	US$4–35 million	24–48[h]

[a]Cost and timeline ranges include procurement, engineering, design, scheduling, permitting and construction and installation; estimates are project-specific and vary greatly. [b]Costs reflective of 2019 and expected to continue to fall in future years; EVSE installation includes upgrading or installing service conductors and load centres; per-unit installation costs are reduced as the number of installed units increase. [c]Feeder extensions or upgrades (including new feeder breakers) are typically required for new loads >5 MW, especially for voltages <20 kV; new loads >12 MW may require a dedicated feeder. [d]Feeder extensions or upgrades tend to be more expensive in urban areas than in rural areas. [e]Timeline for feeder extensions includes jurisdictional permitting for construction, obtaining easements and right-of-way, and procurement lead times. [f]Timeline for adding a new feeder breaker depends on substation layout and the time required to receive clearance for construction. [g]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. [h]Additional time may be required for regulatory approval for the transmission line construction. DCFC, direct current fast charging.

Source: National Renewable Energy Laboratory, Perspectives on Charging Medium & Heavy-Duty EVs

Traditionally, the cost of these upgrades has also been borne by the customer. Policies, such as those that socialize utility distribution system upgrades and those that help pay for on-site upgrades (typically called "make-ready" programs) can reduce one major economic barrier fleet owners face. A case study in two different areas of New York, one urban and one rural, found that increased revenues from electricity sales to charge M/HD fleets would offset or more than offset the costs of distribution system upgrades associated with integrating the charging infrastructure for these fleets.[20] The data to do a similar analysis for North Carolina is not currently publicly available.[21] Duke Energy's utilities in North Carolina have recently begun a pilot "make-ready" program that includes residential and non-residential customers.[22]

A related, but distinct, challenge from cost concerns is the lead time that is necessary to make adjustments and upgrades to the distribution system. Without routine planning to proactively determine when and where distribution system expansions are needed, such upgrades will likely be made on an as-needed basis. However, this is a major challenge given that the lead time for such upgrades can sometimes be over a year as utilities deal with supply chain issues, workforce shortages, and the time to remove certain circuits from service to do the work. **We see this as potentially the biggest challenge to electrification of M/HD fleets in North Carolina and beyond: more than the economics of electrification or whether utilities will be able to provide enough generation, is whether electric grids will be ready to supply that electricity where it is needed to charge the vehicles.**

[20] "Distribution System Investments to Enable Medium- and Heavy-Duty Vehicle Electrification: A Case Study for New York," Prepared for the Environmental Defense Fund by Metz, L., et al at Synapse Energy Economics, Inc. (April 2023)

[21] The main data requirements that are not available include circuit-level load forecasts and incremental system upgrade costs.

[22] For more about Duke's "make-ready" pilot programs, see "North Carolina's EV Charging Infrastructure Ambitions Just Got a Boost," by SACE's Stan Cross. (February 2022)

RECOMMENDATIONS

To avoid utility system constraining or harming the progress electrification of medium- and heavy-duty vehicles in North Carolina, we have the following recommendations for electric utilities, electric utility regulators, and policymakers. These recommendations are likely applicable beyond North Carolina as well.

- **Institute proactive distribution planning and implement upgrades to stay ahead of electrification needs.** Forecasts of distribution load at the feeder or circuit level should include multiple full electrification scenarios on different time scales so that utilities can identify pain points across their systems and begin to make upgrades. In other jurisdictions it is cost-effective for all customers for the utility to spread the costs of these upgrades across its entire customer base. We recommend that similar analysis be performed for North Carolina, and that the Utilities Commission open a proceeding to determine the best way to address these costs in the state.

- **Include both passive and active managed charging programs for fleet customers.** While not all customers will want to or be able to participate in active managed charging programs, passive programs like targeted time-of-use rates can help ease some potential negative impacts on the grid while also allowing fleet customers the opportunity to lower costs if their charging schedules are flexible.

- **Accelerate the deployment of carbon-free generation resources to increase the emission reduction potential of transportation electrification.** Full electrification of medium- and heavy-duty electric vehicles in North Carolina will already result in a substantial emission reduction. But until electricity generation is fully decarbonized, there will still be emissions associated with electric vehicle charging. Duke Energy is embarking on its next Carbon Plan later this year. By the time that is finalized in 2024, the mix of resources planned to meet future electricity for North Carolina may be cleaner than the resource mix we used to estimate emission reductions.

- **Continue to focus research into the impacts of specific medium- and heavy-duty electric vehicle types in North Carolina and beyond.** This analysis is just the beginning. While we were able to estimate some impacts, considerations, and benefits, there is a need for more data transparency and deeper analysis on this issue both in North Carolina and across the country.

ADDITIONAL RESOURCES FROM SACE

The Southern Alliance for Clean Energy (SACE) releases annual reports covering clean energy and transportation topics in the Southeast. We invite you to view all of our reports, white papers, and other technical resources and select reports below.

Energy Efficiency in the Southeast, *Fifth Annual Report. (2023)*

Tracking Decarbonization in the Southeast, *Fourth Annual Report. (2022)*

Transportation Electrification in the Southeast, *Third Annual Report. (2022)*

Solar in the Southeast, *Sixth Annual Report. (2023)*