ANALYSIS GROUP

Heavy Duty Vehicle Electrification

Planning for and Development of Needed Power System Infrastructure

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About Analysis Group

Analysis Group is one of the largest international economics consulting firms, with over 1,000 professionals across 14 offices in North America, Europe, and Asia. Since 1981, Analysis Group has provided expertise in economics, finance, analytics, and strategy to top law firms, Fortune Global 500 companies, government agencies, and other clients. The firm's energy and climate practice area is distinguished by its expertise in economics, finance, market modeling and analysis, regulatory and policy analysis, and infrastructure development. Analysis Group's consultants have worked for a wide variety of clients, including energy suppliers, energy consumers, utilities, regulatory commissions, other federal and state agencies, tribal governments, power system operators, foundations, financial institutions, start-up companies, and others.

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I. Summary

In April 2023, the Environmental Protection Agency (EPA) proposed new regulations to implement greenhouse gas emissions standards for heavy-duty vehicles (HDV) to reduce greenhouse gas (GHG) emissions from the transportation sector. EPA's proposed rule would achieve major reductions in greenhouse gas emissions and other harmful air pollutants from the transportation sector over a period spanning a couple decades.

It is widely expected that as the standards are implemented and require growing reductions in the GHG emission intensity of HDVs, compliance will be met in part through an increase in the number of electric trucks in the HDV sector. This will over time increase the demand for electricity and the power system infrastructure needed to reliably meet the growing demand.

In some sense, this is not new: Electric companies are obligated through laws and regulations to plan for and reliably meet any and all growth in electricity demand within their service territories. For many decades public utility commissions (PUCs) and the Boards of Directors of municipal electric light companies (Munis) and electric cooperatives (Coops) have required that electric companies carefully plan for demand growth and ensure timely development of the generation, transmission and distribution infrastructure needed to meet growth. And the electric industry has capably met the challenge of rapid growth in demand at the regional, state, and individual utility levels.

The overall level and pace of the expected growth in electricity demand due to EPA's proposed rule – and the generation and transmission infrastructure that could be needed to meet the demand – is quite small relative to historic periods of growth in demand for electricity. Yet the nature of the demand growth – a proliferation of electric vehicle charging stations, including local on-site fleet-based charging and widely-dispersed "side of the road" public charging locations – is different in some ways than the types of growth utilities have experienced historically. It is thus important to review what impacts this HDV electrification could have on the distribution systems of local electric companies, and whether the planning, financing, and development processes in place at utilities, and regulatory processes in place at states, are sufficient to manage this type of growth.

In this report we explore the potential impacts of an expanded zero-emissions vehicle fleet on electric distribution systems, and evaluate pathways for states and utilities to efficiently manage any associated growth in infrastructure needs. To do this we (1) review the expected nature, size, and pace of increased distribution system infrastructure needs, (2) review relevant utility statutory and regulatory obligations to meet the growth in demand, (3) evaluate the regulatory frameworks and processes in place to support planning for and development of distribution system infrastructure where and when needed, and (4) consider ways in which states and electric companies can proactively address any potential challenges associated with meeting this demand growth.

Specifically, our analysis seeks to answer several questions related to the potential impact of HDV electrification on electric company distribution system planning and operations, and the framework in place to meet the associated growth:

- What is the nature of the capacity and location of charging stations likely needed to support the potential level of electrification implied by the EPA proposed rule?

- What factors related to the existing infrastructure and operation of electric company distribution systems need to be considered in assessing how the needed charging station growth will affect distribution system needs and operations?
- Where incremental distribution system upgrades are needed, how do they compare with upgrades needed to meet demand growth in other contexts (e.g., economic growth, major housing or commercial developments, data centers, etc.)?
- What are the legal and regulatory obligations of electric companies to meet growth in electric demand?
- What do regulators require of utilities to ensure that demand growth is met?
- What planning processes do electric companies use to forecast and plan for system growth?
- What might the development timeline for new infrastructure look like considering past infrastructure development efforts?
- What proactive planning and regulatory tools are being used to help meet and manage growth (and change) in distribution systems associated with both electrification and the proliferation of distributed energy resources?
- What new technologies, policies, and strategies are emerging to help fleets, charging station developers, and utilities successfully and economically manage the changes that will emerge over time due to HDV electrification?

Based on our review, we come to the following observations:

The overall magnitude of growth in demand that would result from EPA's proposed rule is very small relative to historic periods of growth in the electric industry, and will not pose a challenge from the perspectives of power system generation or transmission infrastructure needs. The U.S. and individual regions and states have seen significant periods of growth in electricity demand in the past. The level of growth in demand over the next ten years associated with the need for charging facilities is very small relative to past periods of growth. Specifically, the impact of EPA's rule is to increase U.S. demand for electricity by 0.15% percent on an annual average basis over the next eight years, which is 13.8% percent of the annual average growth in electricity demand over the last 30 years. Utility planning and wholesale markets have demonstrated the ability to add generation and transmission resources as needed to meet levels of electricity demand growth far greater than that expected due to EPA's proposed rule.[1]

Charging station needs that may result from EPA's proposed rule range greatly in size and location; most counties and utilities in the U.S. analyzed in ICCT's report will likely not face new distribution system infrastructure needs due to charging load different from past experience. Recent ICCT analysis shows the geographic and technological diversity in the types of new charging stations that may be prompted by a level of electric HDV market development roughly equivalent to EPA's expected impacts over the next decade associated with its proposed Phase 3 rule. The majority of utilities and counties in the country will not face the need to increase distribution system capacity at a level that is qualitatively different from past system infrastructure needs driven by traditional growth in electricity demand within their service territories.

[1] There are many ways in which significant changes to generation fleets and interstate transmission development are very important in the decarbonization of energy supply and use and achievement of climate policies, particularly with respect to development and interconnection of large renewable resources. However, relative to the context for the EPA proposed rule, generation and transmission are far less important when considering what is needed to make HDV electrification happen.

Some utilities will need to plan for the development of new distribution system infrastructure to accommodate fairly large point sources of new charging station demand. In most cases the types of charging station energy and peak demand requirements are not out of line with what utilities have had to accommodate when interconnecting other sources of significant load growth, such as large housing developments, business parks, malls, data centers, and the like. Nevertheless, many charging stations will be significant sources of new electricity demand and, like utility past experience with large system additions, will require careful planning and interconnection analysis on behalf of the utilities. In addition, a small number of electric companies may experience significant levels of charging station growth depending, e.g., on the location of large fleets and/or significant truck transport infrastructure within their service territories.

Adding significant new distribution system infrastructure is not a new experience for states, public utility commissions, or electric companies, and there are long-standing policies and practices in place to process development of infrastructure needed to ensure system reliability. In every state, public utility commissions are empowered by statute to enforce the obligation of electric companies to provide reliable service to all customers in their service territory. Commissions administer this oversight through various filing, planning and ratemaking policies and precedent that establish obligations on and provide the financial means for utilities to ensure they reliably meet all current and future electricity requirements, of all existing and new customers within their franchised service territories. Policies and practices include – but are not limited to – distribution system performance standards; comprehensive distribution system forecasting, planning and development requirements; and financial incentives for development including rate of return considerations, potential performance penalties, cost recovery preapproval, and capital investment trackers.

The need for a high level of certainty around the timely integration of charging stations and associated distribution system infrastructure at the scale and speed needed for HDV electrification warrants – and has already prompted – proactive action on behalf of some states and utilities to engage and expand planning and regulatory practices at the scale necessary to ensure timely readiness of the power system. Commissions can (and do) institute rulemakings and/or investigations to provide guidance and impose obligations when specific circumstances warrant commission action outside of standard planning, performance, and ratemaking contexts. And vehicle electrification represents something of a chicken-and-egg problem: utilities are averse to investment in system assets that may be underutilized for some period of time; and truck fleet owners are averse to investing in electric vehicles until sufficient charging is available. Putting EPA's proposed rule in place will provide additional and important regulatory certainty for states, industry, and PUCs to take action, as has been demonstrated in states that have adopted the California Advanced Clean Trucks (ACT) rule. Given ACT requirements and more generally the importance of vehicle electrification to state climate agendas, many states have required, and many utilities have implemented, proactive and forward-looking comprehensive assessment of the potential growth in demand associated with electrification, and identification of (and planning for) specific distribution system needs to accommodate growth. Continued proliferation of proactive regulatory policies, utility planning and development, and ratemaking incentives for financing system upgrades across all states can ensure timely distribution system improvements.

There are many emerging technologies, ratemaking practices, and distributed resource solutions that have the potential to significantly and efficiently reduce the expected impacts on distribution systems associated with vehicle electrification. Utilities have reliably met demand growth for decades through planning for and developing new distribution system infrastructure as needed, including for major new developments of a similar size as the largest charging stations, such as office parks and data centers. Yet demand growth via vehicle electrification – particularly HDV electrification involving in part large, centralized fleets (such as school buses) – presents a different set of circumstances for integrating and managing new demand. In particular vehicle electrification offers opportunities for (1) efficient management of load factors through time of use pricing, (2) the participation of fleets as grid stabilization and demand response resources to improve cost factors and help address increasing net load variability through "vehicle-to-grid" constructs, and (3) the opportunity to mitigate the potential impacts on distribution system demand levels and operations through colocation of charging centers with advanced distributed resource technologies such as solar PV and battery energy storage.

Evolution of distribution systems to meet the potential increase in charging station demand associated with EPA's proposed Phase 3 rule for HDVs is eminently achievable. We come to this conclusion based on our review of (1) the regulatory framework for distribution system planning, development, and operations, (2) industry experience with accommodating even greater levels of demand growth than expected, (3) the existence of both reliability obligations and financial incentives for investment in distribution system infrastructure, and (4) the current and future opportunities to efficiently manage growth and mitigate distribution system impacts.

II. Background

A. Summary of EPA rule

On April 27, 2023, the EPA proposed a rule entitled Greenhouse Gas Emission Standards for Heavy-Duty Vehicles – Phase 3 (hereafter "Phase 3").[2] The Phase 3 rule is part of the EPA's Clean Trucks Plan, which aims to reduce harmful emissions from heavy-duty trucks. It builds on two earlier phases, the first of which was enacted in 2011.[3] The Phase 3 proposed rule establishes more stringent standards for vehicles beginning with model year 2027, which were previously regulated under Phase 2, and revises certain GHG standards for 2027 and proposes additional standards for model years 2028-2032.

The proposed Phase 3 standards affect newly manufactured heavy-duty vehicles; that is, vehicles with a gross vehicle weight rating of more than 14,000 pounds. Affected vehicles are divided into two categories, vocational vehicles and tractors, each of which is further divided into subclasses with their own progression of CO_2 standards. These subclasses mirror those outlined in the Phase 2 standards.

In line with earlier versions of this rule, Phase 3 standards can be meet using an averaging, banking, and trading (ABT) program, which allows manufacturers to comply with standards at the average fleet level rather than the individual vehicle level. The credit averaging sets for the ABT program are based on weight-class, namely: light-heavy-duty, medium-heavy-duty, and heavy-heavy duty vehicles, excluding any vehicles that are certified under optional custom chassis standards. Within a given weight-class manufacturers can average CO_2 emissions across compression-ignition, spark-ignition, battery electric, and fuel cell electric vehicles in order to meet the standards.[4] They can also bank credits they earn from decreasing emissions beyond EPA standards to be used in the future, or they can trade these credits to other manufacturers.[5] In model year 2022, the majority of manufacturers leveraged the ABT system, and 93 percent of all vehicles families were certified with ABT.[6]

While the EPA expects that zero emissions vehicle technologies will be used to meet the Phase 3 standards, the rule does not mandate the adoption of any specific technologies. EPA expects that manufactures will take advantage of technologies like battery electric and fuel cell electric vehicles, as well as improvements to internal combustion engine vehicles including powertrains, vehicle aerodynamics and transmission efficiencies. EPA anticipates that technological improvements to internal combustion engines and other vehicle technologies that help to reduce greenhouse gas emissions will continue to progress as they have in recent years.[7] The rule also takes into account economic incentives for the development of zero-emission vehicles (ZEVs), charging infrastructure, and hydrogen technologies included in the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA).[8]

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[2] Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles—Phase 3, 88 Fed. Reg. 25,926 (April 27, 2023) (hereafter "Phase 3 standards"), available at: https://www.govinfo.gov/content/pkg/FR-2023-04-27/pdf/2023-07955.pdf.
[3] Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles, 76 Fed. Reg. 57,106 (September 15, 2011), available at: https://www.govinfo.gov/content/pkg/FR-2011-09-15/pdf/2011-20740.pdf.
[4] Phase 3 Standards, p. 25957.
[5] *Ibid*., p.73492.
[6] *Ibid*., p. 25957.
[7] *Ibid*., p. 25932.
[8] *Ibid*., p. 25930, see also p. 25936.

If enacted, the EPA projects the proposed standards would reduce CO_2 emissions by 1.8 billion metric tons between 2027 and 2055,[9] equivalent to the CO_2 emissions for the entire U.S. transportation sector in 2019; or to removing the CO_2 emissions of 20 million passenger vehicles for 20 years.[10]

B. Current state of ZEV industry, trucks

Electric vehicles have become increasingly common in the US. After electric vehicles were first introduced to the mass market in 2010, it took eight years to sell the first 1 million vehicles, but it only took three additional years to sell the next million.[11] An additional 800,000 EVs were sold in 2022 alone.[12] In the last month of 2022, EVs accounted for 6.3 perfect of light-duty sales, up from only 1.7 percent at the same time in 2017.[13] This rapid growth has continued into 2023, with over 258,000 EVs sold in the first quarter, a nearly 45 percent increase over last year.[14] The Edison Electric Institute estimates that there were 2.4 million EVs on the road at the end of 2021 and they expect that number to grow to 26.4 million by 2030.[15] Additionally, since the passage of the IIJA and the IRA, EV manufacturers have announced over $87 billion in investments for facilities to produce EVs and batteries to power them. By 2026, these new facilities are expected to produce 4.3 million passenger vehicles and batteries to support 11 million passenger vehicles, annually.[16]

To date, the commercial deployment of EVs has been limited within the heavy-duty vehicle sector. In 2021, 0.1 percent of all heavy-duty vehicles sold in the US were electric.[17] The existing heavy-duty vehicle fleet consists primarily of diesel-fueled, compression-ignition engines.[18] Yet recent technology developments and manufacturer commitments are likely to enable the market for heavy-duty EVs to expand. The U.S. Department of Energy's National Renewable Energy Laboratory (NREL) has found that demand for MDHD ZEVs could rise rapidly once cost parity with diesel vehicles is reached.[19] This total-cost-of-driving parity could be reached within a decade or so due to projected advances in technology, even in the absence of economic incentives.[20] The EPA certified 380 heavy-duty battery electric vehicles in model year 2020, and the number of certified models more than tripled in

[9] *Ibid.,* p. 25935.
[10] "Emissions of Carbon Dioxide in the Transportation Sector," Congressional Budget Office, December 2022, available at: https://www.cbo.gov/system/files/2022-12/58566-co2-emissions-transportation.pdf.
[11] "Electric Vehicle Sales and the Charging Infrastructure Required Through 2030," Edison Electric Institute, June 2022, (hereafter "EV Infrastructure Report") p. 1, available at: https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Electric-Transportation/EV-Forecast--Infrastructure-Report.pdf.
[12] "Electric Vehicle Market Update: Manufacturer & Commercial Fleet Electrification Commitments Supporting Electric Mobility in the United States," EDF, April 2023 (hereafter "EV Market Update 2023"), p. 6, available at: https://www.edf.org/sites/default/files/2023-05/Electric%20Vehicle%20Market%20Update%20April%202023.pdf.
[13] Fact of the Week #1275 Dataset, Department of Energy, January 2023, available at: https://www.energy.gov/eere/vehicles/articles/fotw-1275-january-30-2023-monthly-plug-electric-vehicle-sales-united-states.
[14] EV Market Update 2023, p. 5.
[15] EV Infrastructure Report, p. 1.
[16] "U.S. Electric Vehicle Manufacturing Investments and Jobs: Characterizing the Impacts of the Inflation Reduction Act after 6 Months," Environmental Defense Fund and WSP, March 2023, p. 7, available at: https://blogs.edf.org/climate411/files/2023/03/State-Electric-Vehicle-Policy-Landscape.pdf.
[17] "Global Electric Vehicle Outlook 2022," International Energy Agency, May 2022, available at: https://www.iea.org/reports/global-ev-outlook-2022.
[18] Phase 3 Standards, p. 25938.
[19] "Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis," NREL, March 2022, available at: https://www.nrel.gov/docs/fy22osti/82081.pdf.
[20] Estimates for when cost parity will be achieved vary substantially. NREL's analysis suggests parity can be reached by 2035 even in the absence of economic incentives, while a study by Roush industries found that parity could be reached by 2030, or even as early as 2027 when factoring in IRA incentives. *Ibid*., p. 2. See also, "Technical Review of: Medium and Heavy-Duty Electrification Costs for MY 2027- 2030," Roush Industries, Inc, February 2, 2022, available at: https://blogs.edf.org/climate411/files/2022/02/EDF-MDHD-Electrification-v1.6_20220209.pdf.
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the following year.[21] Although zero-emission HD trucks comprise only a small percentage of the HD trucks overall, the number of EV HDVs on the road increased 70-fold between January 2020 and December 2022.[22]

This technological growth, in combination with EPA's proposed rule and the array of incentives in the IRA and IIJA, is expected to significantly accelerate the growth in heavy duty electric vehicles over the next ten years. Critical to this growth will be assurance that there will be sufficient vehicle charging capacity and locations to ensure seamless operation of HDV fleets. Most LDV charging infrastructure is located in residential areas and widely dispersed across individual households and smaller charging stations. HDV charging infrastructure differs in some important respects; in particular, much HDV charging infrastructure will require centralized depots that can accommodate multi-vehicle fleets, and involve higher levels of demand per station. It is possible to approximate the magnitude and nature of the charging capacity need by combining assumptions about the degree to which EPA's proposed requirements will be met through vehicle electrification with analyses of how this level of growth in HDV electrification affects the overall need and location of specific types of vehicle charging infrastructure.

C. Analytic Method

Given the expected expansion of HDV electrification, the purpose of this study is to consider the potential need for expansion of the electric system. Specifically, how are the EPA standards likely to translate into charging capacity development over time, and what are the processes in place to ensure that this level of growth in infrastructure can be managed? Are there additional steps that may be taken by states and electric companies to anticipate and ensure timely development of any needed new infrastructure?

Our focus is on local utility systems, primarily at the distribution level. As discussed in more detail below, there is very little reason to expect that HDV growth in electricity demand on its own presents any challenges to vertically integrated utilities or wholesale markets from the perspectives of generation capacity and/or transmission system development and operations.[23]

Moreover, at the distribution system level it is not sufficient to simply compare potential charging station demand growth to system capacities. Instead, it is helpful to recognize that for many decades utilities have had an obligation to reliably meet all existing demand and new growth in demand, and that there is a wide array of familiar regulations, planning processes, and ratemaking incentives in practice to ensure that growth is met and reliability maintained. In addition, many states and electric companies are already far ahead in the development of new planning tools and tailored rate designs to address and manage ongoing changes in distribution system needs.[24]

[21] Phase 3 Standards, p. 25938.
[22] "Zeroing in on Zero-Emission Trucks," CALSTART, May 2023, p. 2, available at: https://calstart.org/wp-content/uploads/2023/05/Zeroing-in-on-ZETs-May-2023-Market-Update.pdf.
[23] There are many ways in which significant changes to generation fleets and interstate transmission development are very important in the decarbonization of energy supply and use and achievement of climate policies, particularly with respect to development and interconnection of large renewable resources. However, as discussed in Section III below, generation and transmission are far less important when considering what is needed to make HDV electrification happen. For this reason, our primary focus in this report is on the distribution level.
[24] Many of these regulatory requirements and tools are focused explicitly on growth in demand due to electrification of the building and transportation sectors; yet others were at least originally focused on managing the growth in distributed energy systems (solar, battery storage) at the distribution level. All of these examples, however, have the feature that they enable electric companies to reliably anticipate and address changes in distribution system needs and operations.

In short, the potential growth in demand on distribution systems associated with EPA's proposed HDV rule is neither a new challenge nor an eventuality that states and electric companies are unprepared for.

Considering these factors, our analysis seeks to answer a sequence of questions in evaluating the potential impact of HDV electrification on electric company distribution system planning and operations:

- What is the nature of the capacity and location of charging stations likely needed to support the potential level of electrification implied by the EPA proposed rule?
- What factors related to the existing infrastructure and operation of electric company distribution systems need to be considered in assessing how the needed charging station growth will affect distribution system needs and operations?
- Where incremental distribution system upgrades are needed, how do they compare with upgrades needed to meet demand growth in other contexts (e.g., economic growth, major housing or commercial developments, data centers, etc.)?
- What are the legal and regulatory obligations of electric companies to meet growth in electric demand?
- What do regulators require of utilities to ensure that demand growth is met?
- What planning processes do electric companies use to forecast and plan for system growth?
- What might the development timeline for new infrastructure look like considering state zoning and permitting requirements?
- What proactive planning and regulatory tools are being used to help meet and manage growth (and change) in distribution systems associated with both electrification and the proliferation of distributed energy resources?
- What new technologies, policies, and strategies are emerging to help fleets, charging station developers, and utilities successfully and economically manage the changes that will emerge over time due to HDV electrification?

We gauge the potential size and location of new electric company distribution system demand on a report recently completed by the International Council on Clean Transportation (ICCT White Paper).[25] The ICCT White Paper combines trucking operational data and route information with locational factors to estimate the types, quantity and approximate location of new charging capacity that may be needed due to electrification policies and growth in electric HDVs. A comparison of this study with EPA's proposed rule timelines shows that the ICCT data is sufficient to judge at a high level the likely timing and nature of charging station demand under the proposed EPA rule as well as more protective alternatives EPA is considering.

With this in hand, we consider how potential new demand compares with other projects that utilities routinely plan for, and provide an overview (and examples) of the regulatory framework in place that guides utilities' approach to meet demand growth through utility planning and infrastructure development. We also provide examples of the

[25] "Near-term infrastructure deployment to support zero-emission medium- and heavy-duty vehicles in the United States," International Council on Clean Transportation, May 11, 2023, available at: https://theicct.org/wp-content/uploads/2023/05/infrastructure-deployment-mhdv-may23.pdf. Hereafter, "ICCT" or "ICCT White Paper." The ICCT White Paper uses the term medium- and heavy-duty vehicles (MHDV) to refer to Class 4-8 vehicles, while EPA refers to these classes of vehicles collectively as "heavy-duty vehicles." Throughout this report, we use the term heavy duty vehicles (HDV) to refer to these vehicles collectively, following the terminology in the proposed Phase 3 standards.

planning procedures and project approval processes in place at distribution utilities to ensure they can reliably meet forecasted growth in demand.

There is nothing new about this combination of utility obligations, the associated regulatory framework, and the planning and development processes in place at all utilities to meet forecasted load growth. However, it is helpful to review how states and utilities are proactively developing policies, analyses and processes to tailor the well-worn practices of utility planning and project development to the changing nature of growth in both supply (through solar/storage installations) and demand (through electrification). For this we provide summaries of forward-looking utility planning tools and practices, and the regulatory and ratemaking policies being developed to ensure timely response to changing demand.

In Section III we provide information on the context for demand growth due to HDV electrification. In Section IV we summarize the existing and emerging policies and practices of states and electric companies to manage demand growth over time. Finally, in Section V we provide observations and recommendations based on our research and analysis.

III. The Power System Context for HDV Electrification

A. An estimate of the potential magnitude of HDV electrification and charging station demand under the EPA rules

EPA's proposed rule requires that HDVs meet increasingly stringent GHG emission standards on a fleet-wide average basis as the standards phase in from 2027 to 2032. The proposed standards do not mandate the use of a specific technologies, and EPA expects compliance to be achieved through a mix of both internal combustion engine and vehicle improvements and growth in the use of ZEV technologies – such as electric HDVs (battery and fuel cell). It is widely expected that significant electrification of the HDV fleet may occur to achieve the proposed EPA standards.

While EPA provides estimates of how its proposed rule may increase electric HDVs over time, it does not translate this estimate into an approximation of the increase in demand associated with chargers needed to support this growth in electric HDVs. In order to get a rough sense of the potential nature and location of increased electricity demand associated with the EPA rule, we compared it to a recent study completed by ICCT that translates expected growth in electric trucks to the need for charging stations across the country.

Specifically, the ICCT White Paper evaluates the potential demand for vehicle charging assuming a "market growth" scenario based in part on the implementation of advanced vehicle emission standards across a number of states. The ICCT White Paper pairs traffic data from the Federal Highway Administration's Highway Performance Monitoring System with fleet load profile data from LBNL to estimate the total daily electricity demand, peak load, and number of chargers required to fuel local trucking activities in each county, assuming a certain portion of these trucks are EVs.

The ZEV market share used in the ICCT analysis is based on a "market growth" scenario for 2030, described in a prior ICCT report.[26] As shown in Table 1, ICCT's projected ZEV shares in 2030 are higher than the Phase 3 MY 2030 shares for all vehicle categories, and instead align more closely with the MY 2032 shares. This means the ICCT White Paper overstates the amount of charging that will be needed by 2032 relative to EPA's primary proposal Phase 3 standards. However, the ICCT projections can be viewed as a good approximation of some of the more protective options EPA is considering, including options that would result in additional battery electric vehicle (BEV) tractor deployment.

[26] Pierre-Louis Ragon, Claire Buysse, Arijit Sen, Michelle Meyer, Jonathan Benoit, Josh Miller, and Felipe Rodríguez. "Potential benefits of the U.S. Phase 3 Greenhouse Gas Emissions Regulation for Heavy-Duty Vehicles," ICCT, April 14, 2023 (hereafter, Ragon et. al., 2023), available at: https://theicct.org/publication/hdv-phase3-ghg-standards-benefits-apr23/.

Thus, while there are differences between the ICCT and EPA estimates of electrification of the HDV sector, the ICCT estimates are comparable to the expected EPA values for projected ZEV shares within a few years of each other, and if anything represent a conservative estimate of expected vehicle electrification relative to EPA. That is, the ICCT expected ZEV penetration is higher and/or sooner than the levels expected due to the primary proposal in EPA's rule and is a relatively good approximation of the more protective alternatives EPA is considering. Thus, for the purpose of our review, we find the ICCT results are a useful basis for benchmarking the likely degree and nature of the charging demand under the range of options EPA is considering in its proposed rule by sometime in the early- to mid- 2030s.

Table 1: Comparison of ICCT and EPA EV estimates

	Vocational Class 4-8		Short-Haul Tractors		Long-Haul Tractors	
Model Year	**Phase 3**	**ICCT**	**Phase 3**	**ICCT**	**Phase 3**	**ICCT**
2027	20%		10%		0%	
2028	25%		12%		0%	
2029	30%		15%		0%	
2030	35%	51%	20%	44%	10%	16%
2031	40%		30%		20%	
2032	50%		35%		25%	

Notes: Table 1 compares the ZEV market share outlined in the Phase 3 proposed standards by truck type and model year with the 2030 projected share used in the ICCT analysis. The EPA assumed that ZEVs will be a mix of BEVs and FCEVs, whereas the ICCT White Paper assumes the ZEV fleet is entirely BEVs.

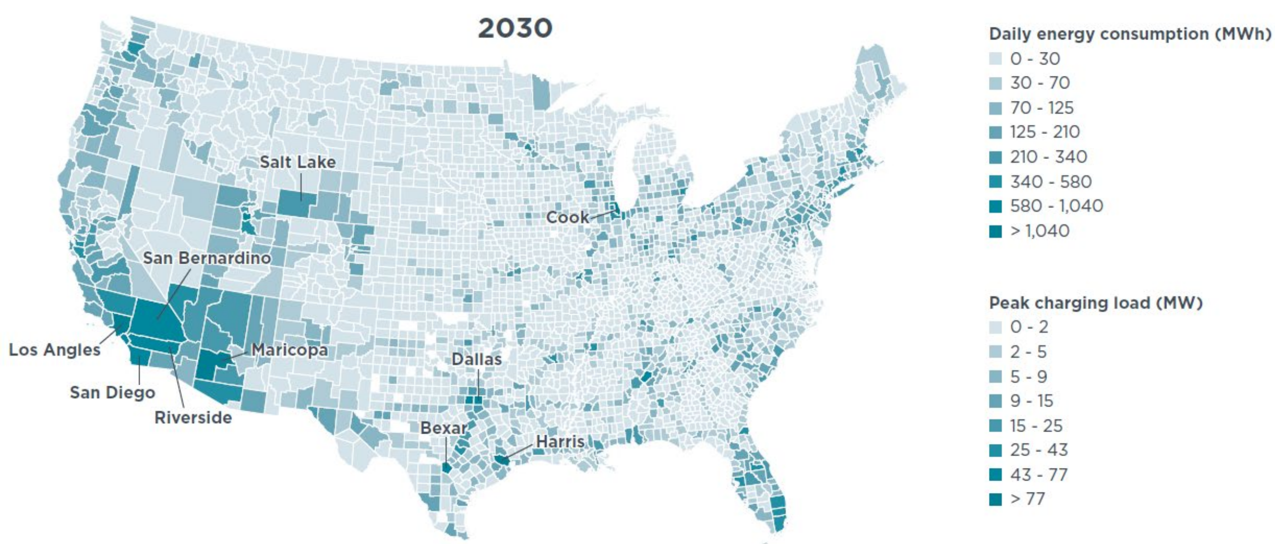
Sources: Phase 3 standards, Ragon et. al. (2023).

With this comparison in mind, we reviewed how the ICCT electrification estimate translates into expectations of vehicle charging station demand across the U.S. Specifically, the Report breaks down expected charging station needs by county, and finds substantial variation in HDV charging needs across counties. The median county is projected to see approximately 19 megaWatt hours (MWh) of daily energy use from HDVs, and a peak demand from charging of only 1.4 megaWatts (MW). While this means that most counties – and their associated utilities – in the U.S. will not experience a significant level of increase in infrastructure needs, that is not the case uniformly across all counties. For example, the report identifies ten counties with peak loads from vehicle charging exceeding 50 MW, with the highest peak load in Los Angeles County, with 132 MW of peak demand from HDV charging.

Figure 1 (from the ICCT White Paper) shows the wide variability in the expected distribution of daily energy consumption (in MWh) and peak charging load (in MW) across counties in the U.S. The figure is for 2030 in the ICCT analysis. In effect, the ICCT numbers reflect the level of demand impacts not likely to be realized until 2032 or later under EPA's primary proposed Phase 3 standards, but do reflect the overall range of options EPA is considering, including more protective alternatives.

From the perspective of the impact on power system operations, a couple features of this map stand out. First, the vast majority of electric company service territories in the U.S. will see relatively minor impacts from charging stations. The average daily peak demand is 5 MW or less for 83 percent of all counties.[27] Second, areas with higher levels of daily energy and average peak charging load impacts tend to be concentrated in urban areas with already very high system demand and capacities, or along major U.S. interstate corridors. As noted in the ICCT White Paper, this suggests that an assessment of a modest number of priority counties can identify states and utility service territories where proactive evaluation and mitigation of potential distribution system impacts may be warranted.

Figure 1: Daily HDV electricity consumption (MWh) and peak load (MW) by county



Note: Data labels indicate the ten counties with the highest energy consumption from electric HDVs.
Source: ICCT White Paper, Figure ES1.

B. How will this affect the electric industry?

The impact of increased electricity demand from HDV electrification will depend on many factors, and on what part of the electric system is being considered. Broadly speaking, we can review the potential impacts on the power system by the need for an increase in *generation* capacity based on the increased demand; necessary additions to *transmission* system infrastructure; and upgrades and enhancements that may be required at the more local *distribution* system level.

It is very unlikely that the potential increase in demand for power and energy associated with EPA's proposed Phase 3 rule would introduce any challenges from the perspectives of power generation and transmission. This is because, based on the demand impacts identified in ICCT's analysis, the potential magnitude of energy and demand growth is small relative to the quantity of generation and transmission capacity available, and relative to the level of generation and transmission routinely added to power systems across the country.

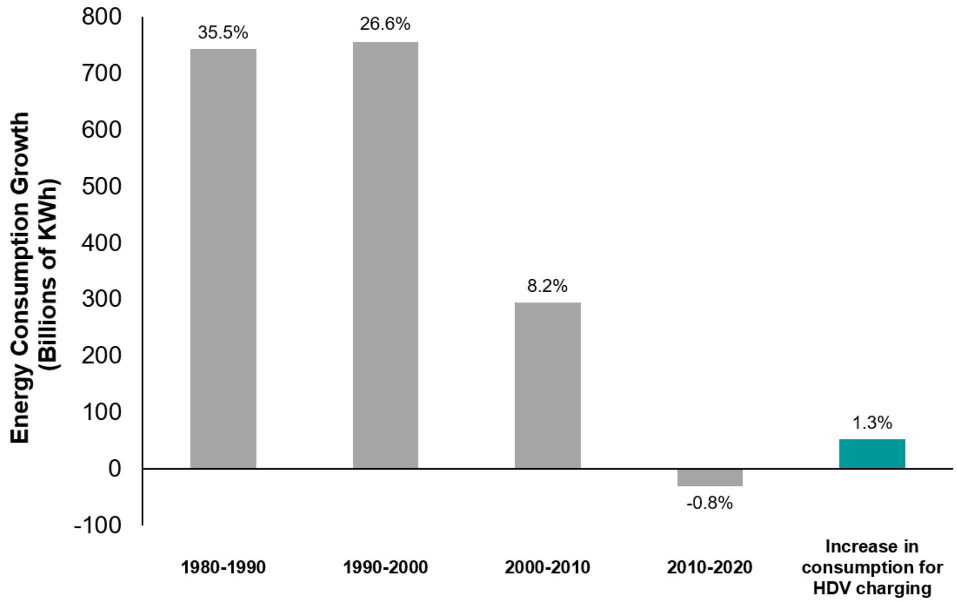
In the ICCT growth scenario that in effect represents the level of charging station growth under the EPA proposed rule, annual energy requirements would increase by approximately 51 terawatt hours (TWh), with an increase in

[27] The ICCT White Paper includes projections for 3,078 counties, of which 2,542 have average peak loads of 5 MW or less.

estimated peak load of roughly 10 gigawatts (GW).[28] Importantly, this level of growth will occur gradually over ten years, and represents an annual average growth in energy consumption of roughly 5 TWh, and an annual average increase in demand of roughly 1 GW.

These annual average growth factors represent tiny fractions of the level of electricity demand in the US, and a small fraction of the expected annual growth rates of both generation capacity and transmission. Specifically, 5 TWh of annual growth is roughly 0.1 percent of the U.S. total electricity consumption in 2022 of 4,048 TWh, and 1 GW of demand is roughly 0.09 percent of the 1,160 GW (nameplate) of generating capacity in the U.S.[29] Historically, the US has seen substantial growth in energy consumption, see figure 2 below. This shows that increasing consumption by the 51 TWh required to account for HDV charging over the next 10 years, is entirely plausible given the scope of previous consumption increases. While consumption in the last decade has fallen slightly, the driving force behind this trend is not lack of generating or distribution capacity, but rather increased energy efficiency which has driven aggregate consumption down.[30]

Figure 2: Historic growth in annual energy consumption and projected growth required for HDV charging



Notes:

[1] Grey bars represent the change in national annual energy consumption from the beginning to the end of the period. The blue bar represents the increase in national annual energy consumption that would be required for HDV charging based on ICCT projections for 2030, relative to 2020 national consumption (thus also representing a ten-year period).

[2] Data labels are the percent change in consumption over the stated time period, or relative to 2020 for the increase in consumption for HDV charging.

Sources: ICCT White Paper, EIA Electricity Overview.

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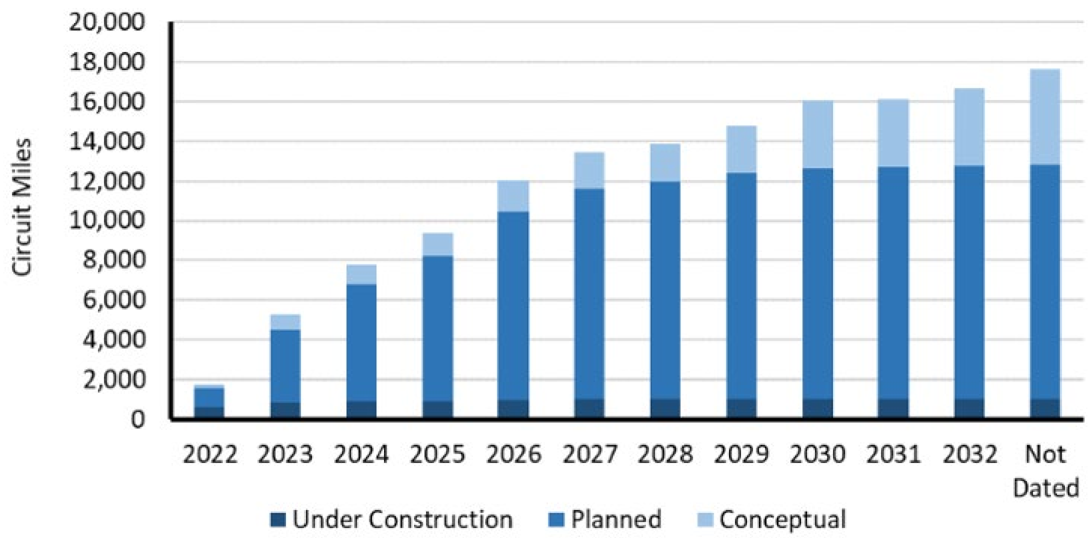
[28] ICCT White Paper Table 3, p. 14. We calculate the annual energy consumption as daily energy consumption of 139,893 MWh * 365 = 51 x 10^6 MWh, or 51 TWh. Estimated peak charging load is 10,317 MW, or 10 GW.

[29] EIA Total Energy Annual Data, Table 7.1 Electricity Overview and Table 7.7a Electric Net Summer Capacity Total (All Sectors), available at: https://www.eia.gov/totalenergy/data/browser/?tbl=T07.01#/?f=A&start=1949&end=2022&charted=1-2-3. Hereafter, "EIA Total Energy Annual Electricity Data Tables."

[30] Stéphanie Bouckaert and Timothy Goodson, "The mysterious case of disappearing electricity demand," IEA Commentary, February 14, 2019, available at: https://www.iea.org/commentaries/the-mysterious-case-of-disappearing-electricity-demand.

The expected impact on electricity demand is also dwarfed by the expected growth in new power plant and transmission system investments over the next decade. The US is expected to add over 54 MW new generating capacity in 2023 alone, over fifty times the average annual HDV charging growth estimate.[31] Similar growth in the transmission sector is expected in the coming years, adding approximately 8,000 miles and 42 GW of transfer capacity in shovel-ready high-voltage transmission projects focused on moving renewable resources to load, increasing the U.S. transmission system transfer capacity by roughly 11 – 12 percent.[32] And this represents only a portion of the total number and capacity of all of the transmission projects that are in construction, planned, or in development over the next ten years.[33] See Figure 3.[34]

Figure 3: Transmission Projects Under Construction, Planned, and in Concept



Source: NERC 2022 Long-Term Reliability Assessment, Figure 21, p. 22.

These results do not only hold on a national basis – they are similar for nearly every specific state and utility in the country. Using the ICCT breakdown of charger growth by county, we compared the projected growth in energy consumption and peak load to the existing electricity demand and generating capacity of states and of individual electric companies. Figure 4 shows how the annual average growth in electricity demand associated with HDV charging compares to the existing generation capacity for states across the U.S. Even for the twenty utilities with

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[31] "More than half of new U.S. electric-generating capacity in 2023 will be solar," EIA, February 6, 2023, available at: https://www.eia.gov/todayinenergy/detail.php?id=55419#:~:text=In%202023%2C%20developers%20plan%20to,in%202023%2C%20at%202.0%20GW.

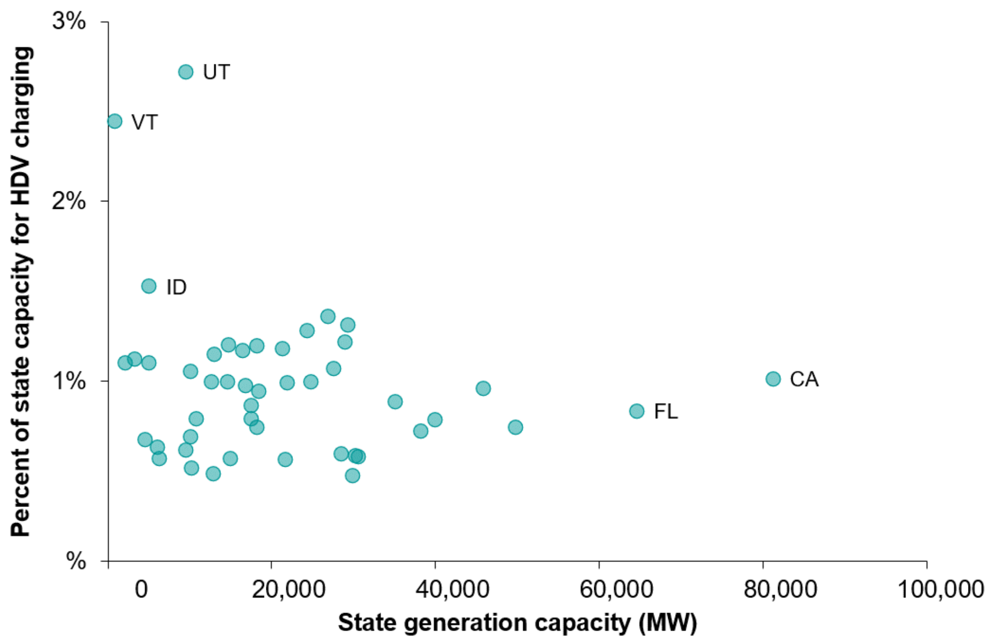
[32] Michael Goggin, Rob Gramlich, and Michael Skelly, "Transmission Projects Ready to Go: Plugging Into America's Untapped Renewable Resources," Americans for a Clean Energy Grid, April 2021, p. 4, available at: https://cleanenergygrid.org/wp-content/uploads/2019/04/Transmission-Projects-Ready-to-Go-Final.pdf.

[33] There are many ways in which significant changes to generation fleets and interstate transmission development above and beyond what is needed for HDV electrification are very important in the decarbonization of energy supply and use and achievement of climate policies, particularly with respect to development and interconnection of large renewable resources. The focus here, however, is solely on the incremental impact of HDV electrification associated with the EPA proposed Phase 3 rule.

[34] 2022 Long-Term Reliability Assessment, NERC, December 2022, p. 22, available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

the highest level of HDV charging demand, the total demand impact is small relative to existing system capabilities, as can be seen in Figure 5.

Figure 4: Projected HDV peak load as a percent of state's 2021 generation capability



Notes:

[1] Projected HDV peak load is calculated by summing the ICCT White Paper's projected county-level peak load for HDV charging across all counties in a given state. The percentage of state generating capacity is then calculated by dividing the state's peak load for HDV charging by the generating capacity in that state in 2021.

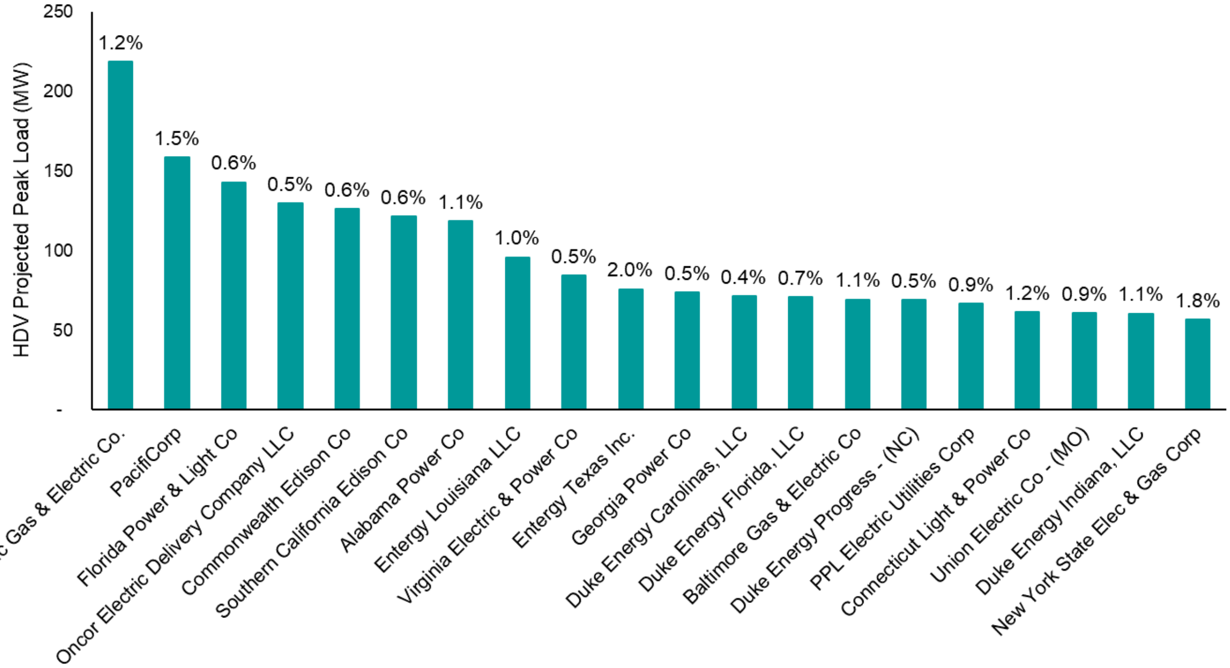
[2] Graphic omits Texas, which exceeds 100,000 MW of state generating capacity. Texas's 2021 generating capacity was 139,751 MW and the projected HDV peak load is 0.82% of state peak load.

Sources:

[1] ICCT White Paper county-level data, available at: https://theicct.org/wp-content/uploads/2023/05/ICCT_US_infrastrucure_data_county.xlsx.

[2] EIA State electricity profiles for 2021, available at: https://www.eia.gov/electricity/state/.

Figure 5: Projected HDV peak load and HDV percent of utility's 2021 actual peak load, for 20 utilities with highest projected HDV demand



Notes:

[1] Projected peak loads are calculated by allocating the ICCT's county-level projected peak load equally across all utilities in the county, and summing the utility's portion of peak load across all counties in the utility's service territory.

[2] Chart excludes CenterPoint Energy because its 2021 peak load data is missing from the EIA Form 861 Operational Data. CenterPoint Energy has the 17th highest estimated HDV peak load.

Sources:

[1] ICCT White Paper county-level data, available at: https://theicct.org/wp-content/uploads/2023/05/ICCT_US_infrastrucure_data_county.xlsx.

[2] Annual Electric Power Industry Report, Form EIA-861 detailed data files for 2021, available at: https://www.eia.gov/electricity/data/eia861/.

It is reasonable to conclude that for electric companies and states in the U.S., the level and pace of growth in annual energy requirements and peak electric demand associated with the proposed EPA Phase 3 rule – and thus the nature and process for building out generation and transmission infrastructure to support this level of growth – are small relative to existing system capacities and historical levels of growth, and manageable within existing market and regulatory frameworks to ensure timely development of needed generation and transmission infrastructure. In fact, demand growth in the electric sector has been relatively flat in recent years, and even declining in some years and some states. This introduces the possibility that in locations with flat or declining load growth a greater portion of HDV charging load could be absorbed by infrastructure in place.

While this is likely to also be true at the distribution level for the majority of electric companies in the U.S., there are also likely specific locations where the addition of charging capacity could represent a meaningful increment over existing distribution system capacities, and where the additional demand associated with major charging stations could require significant distribution system enhancements or upgrades. This is because in some counties the

ICCT estimates the need for charging capacity to support increases in peak charging loads over the next ten years on the order of tens to hundreds of MW, using station equipment with nameplate charging capacity on the order of several hundreds of MW or more.[35]

While these levels of demand may be small relative to the demands and capacities of utility, state, and regional generation and transmission infrastructure, they are not necessarily small relative to the infrastructure and capacities of individual distribution system feeders and circuits. This is because unlike much LDV charging infrastructure, which is generally dispersed and mostly in residential areas, HDV charging infrastructure differs in some important respects. In particular, much HDV charging infrastructure will require centralized depots that can accommodate multi-vehicle fleets, and involve higher levels of demand per station. In some respects, HDV charging infrastructure needs more closely resemble those of data centers, which demand even greater power at a concentrated location. As discussed in section IV.A below, utilities have successfully connected 290 MW of load related to data centers between 2016 and 2021, and an additional 1.6 GW of load is under construction today.[36]

The ways in which new charging station demand will affect distribution system needs and operations depends on many factors that will need to be evaluated on a case by case basis, including (a) the location on the feeder or circuit, (b) the available room on the feeder or circuit to absorb additional demand; (c) the changing nature of demand on the circuit associated with other factors (e.g., economic growth, conservation and demand response, installation of distributed resources such as solar PV and battery storage); (d) the size of the charging station and its likely timing and level of peak charging; (e) the timing of need for installation of the new charging load; and (f) any additional features of the charging facility that can moderate or place a ceiling on distribution system impact (e.g., colocation of solar or battery resources, restrictions on charging timing or levels, etc.).

While all of these factors will play out over time in determining the ease or difficulty in ensuring timely development of needed distribution system infrastructure, they will not play out in a vacuum. The process of planning for, developing, permitting, and financing distribution system investments is far from new. Electric companies have an obligation to reliably meet load growth, and there is an array of state laws, regulations, PUC precedent, utility planning processes and analyses, and infrastructure development procedures that are familiar to all parties, and that have successfully been used to guide large and small investments in distribution systems to meet load growth and maintain power system reliability. Moreover, many states and utilities are proactively adapting these policies and procedures to anticipate the impacts on reliable system operations of building and vehicle electrification and other decarbonization policies.

In short, state and utility precedent, practices and planning tools are either already well suited to adequately manage the timely processing and development of needed infrastructure, or can be adapted to ensure power systems can evolve as needed to meet the growth levels implied by the proposed EPA Phase 3 requirements. The next section discusses where heightened attention to key features of utility planning and regulation can help anticipate and eliminate any obstacles to timely development of distribution system infrastructure where the degree of required development significantly exceeds past experience.

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[35] ICCT White Paper Table 3, p. 14.
[36] "North America Data Center Trends H1 2022," CBRE, September 9, 2022, available at: https://www.cbre.com/insights/reports/north-america-data-center-trends-h1-2022. Hereafter, "CBRE Data Center Trends Report."

IV. Key Features Supporting Reliable System Growth with Electrification

A. Key Features of Industry and Utility Regulation that will Support Success in Implementation of EPA Rules

Although the higher power requirements associated with HDV charging stations could in some cases require distribution system upgrades, utilities have an obligation to serve new load, and the state regulatory practices and utility planning processes in place for decades are designed to ensure that new load is forecasted and planned for, to ensure continued reliable service to all. In addition, many states have specifically promulgated proactive policies that will support the energization of newly built HDV charging stations. The combination of these existing policies, plus innovative new policies being pursued by early adopter states, can be engaged across all states to expedite the deployment of HDV charging stations in a timely manner. This in turn will ensure federal and state transportation policies can be met while maintaining core distribution system reliability standards.

Fundamentally, electric utilities meet the incremental load requirements because of common law, statutory, and regulatory requirements to provide service to all customers unless the utility is not allowed or otherwise unable to recover its costs to connect the new customer.[37] [38] That is, as long as there is a mechanism for the electric company to recover its costs through rates charged to all customers and/or fees charged to the interconnecting charging station entity, electric companies will be obligated to extend service to a new charging station. (See Portland's Electric Island below, for example.)[39] What has been demonstrated in early-mover states (discussed below), and should be encouraged in all states, are proactive actions by regulators and electric companies to ensure that system upgrades are not only completed, but are completed in a timely manner.

Just as local distribution utilities work closely with commercial developers of any Level 2 charging station, behind-the-meter photovoltaic system with battery storage, new oil well, apartment building, industrial complex, or mall to ensure the new facility can receive service, so too will local distribution utilities work closely with the developers of HDV charging stations to ensure timely and cost-effective energization. Moreover, as discussed below, utilities will adjust their overall capital investment planning to ensure the bulk transmission system and local substations and

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[37] Rossi, Jim, "The Common Law 'Duty to Serve' and Protection of Consumers in an Age of Competitive Retail Public Utility Restructuring," 51 Vanderbilt Law Review 1233 (1998), available at: https://scholarship.law.vanderbilt.edu/vlr/vol51/iss5/2. "Utilities are expected to offer (and in the United States, provide) service to anyone who requests it and can pay for it at the regulator's (or government's) approved prices. In this sense, service is "universal." A connection charge may be imposed if providing service involves a significant expenditure by the utility, but even that is subject to regulation and, in many cases, is subsidized in some manner by other customers or taxpayers." See, "Electricity Regulation in the US: A Guide," The Regulatory Assistance Project, June 2016, p. 36, available at: https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.

[38] The ability of electric distribution companies to meet new load can be observed historically as United States' electric load grew from 255 billion kWh in 1949 to 4,048 billion kWh in 2022 (a 1,487% increase). Source: EIA Total Energy Annual Electricity Data, Table 7.1.

[39] "Daimler Trucks North America, Portland General Electric open first-of-its-kind heavy-duty electric truck charging site," Portland General Electric Newsroom, April 21, 2021, available at: https://portlandgeneral.com/news/2021-04-21-daimler-portland-general-electric-open-electric-charging-site. See also "Re: Advice No. 22-10, Schedule 53 Heavy-Duty Electric Vehicle Charging Program Update," PGE letter to Public Utility Commission of Oregon, May 12, 2022, available at: https://edocs.puc.state.or.us/efdocs/UAA/uaa161655.pdf; "Transportation Electrification Plan," PGE, September 2019, available at: https://evtransportationalliance.org/wp-content/uploads/2021/11/2019-OR-PGE-Transportation-Electrification-Plan-1.pdf; "Re: Second Supplemental Filing of Advice No. 22-10, Schedule 53 Heavy-Duty Electric Vehicle Charging Program Update," PGE letter to Public Utility Commission of Oregon, June 15, 2022, available at: https://edocs.puc.state.or.us/efdocs/UAC/adv1395uac114513.pdf.

transformers are appropriately upgraded to handle the increase in load and power requirements associated with HDV charging stations.

The scale of the distribution system upgrades necessary to integrate HDV charging into the grid over the next ten years is neither unprecedented nor unusual. Since 2012, Florida has experienced a 19 percent increase in residential electricity load, driving a 10 percent increase in overall electricity consumption across all sectors.[40] This load growth has been fueled by a 13 percent increase in population, with eight counties experiencing greater than 20 percent population growth.[41] Despite this dramatic increase in load growth, Florida' utilities have met the challenge of expanding the distribution system, including building new substation transformers, feeder breakers, feeders, distribution transformers, and additional meters. For example, between 2013 and 2021, Florida utilities built and energized 708 new distribution circuits, leading to 9 percent growth in the number of feeders capable of stepping down transmission voltage to the distribution level.[42] Moreover, the largest power utility in Florida, Florida Power & Light (FPL) has increased its annual distribution spending from $484 million in 2010 to $1,858 million in 2020 in response to this demand growth, along with other factors including transportation electrification and storm hardening investments.[43] These distribution investments enabled FPL to increase the total amount of energy delivered from 114 TWh in 2011 to 131 TWh in 2021, and the

PGE's Electric Island

Portland General Electric (PGE) and Daimler Trucks North America (DTNA) have developed "Electric Island," a large public charging site specifically designed for medium- and heavy-duty commercial electric vehicles. In Phase I of the project, Electric Island consisted of 8 DC fast chargers, with total connected capacity of 1,064 kW. In Phase 2 of the project, PGE and DTNA are developing new megawatt-scale chargers with peak loads ranging from 500-1,500 kW and total connected load as high as 4,800 kW. All project costs are equally split between PGE and DTNA, including necessary distribution system upgrades. The site was also designed to allow for the development of battery energy storage and solar generation to help mitigate potential grid impacts associated with high-powered charging.

The Electric Island pilot project is intended to provide valuable information to PGE about prospective load patterns and grid impacts associated with heavy-duty vehicle electrification. For example, in its 2019 Transportation Electrification Plan, PGE projected 3,800 HDVs in its service territory by 2030 and 51,000 HDVs by 2050. PGE projects that the relevant substation serving Electric Island is anticipated to receive up to 40 MW of additional peak load by 2030 due to transportation electrification, of which up to 5 MW will be contributed by Electric Island. Using metering data and charging data, PGE's system planners will study load patterns at Electric Island, which will inform modeling inputs to distribution system planning and the level of any required distribution system upgrades.

[40] In 2012, Florida's residential consumption of electricity was 112,127 million kWh and total end-use consumption (i.e., all retail sales) was 220,674 million kWh. In 2020, Florida's residential consumption of electricity was 133,299 million kWh and total end-use consumption (i.e., all retail sales) was 242,440 million kWh. Source: EIA State Energy Data System, 2021, available at: https://www.eia.gov/state/seds/sep_update/use_all_phy_update.csv (Mnemonic Series Names (MSNs) "ESRCP" and "ESTCP" corresponding to "Electricity consumed by (i.e., sold to) the residential sector (million kWh)" and "Electricity total consumption (i.e., retail sales) (million kWh)."

[41] Population growth from 2012-2020. Source: US Census, Revised Estimates of Florida Population by County, 2010-2020, available at: https://www.bebr.ufl.edu/wp-content/uploads/2021/11/spr_11.xlsx.

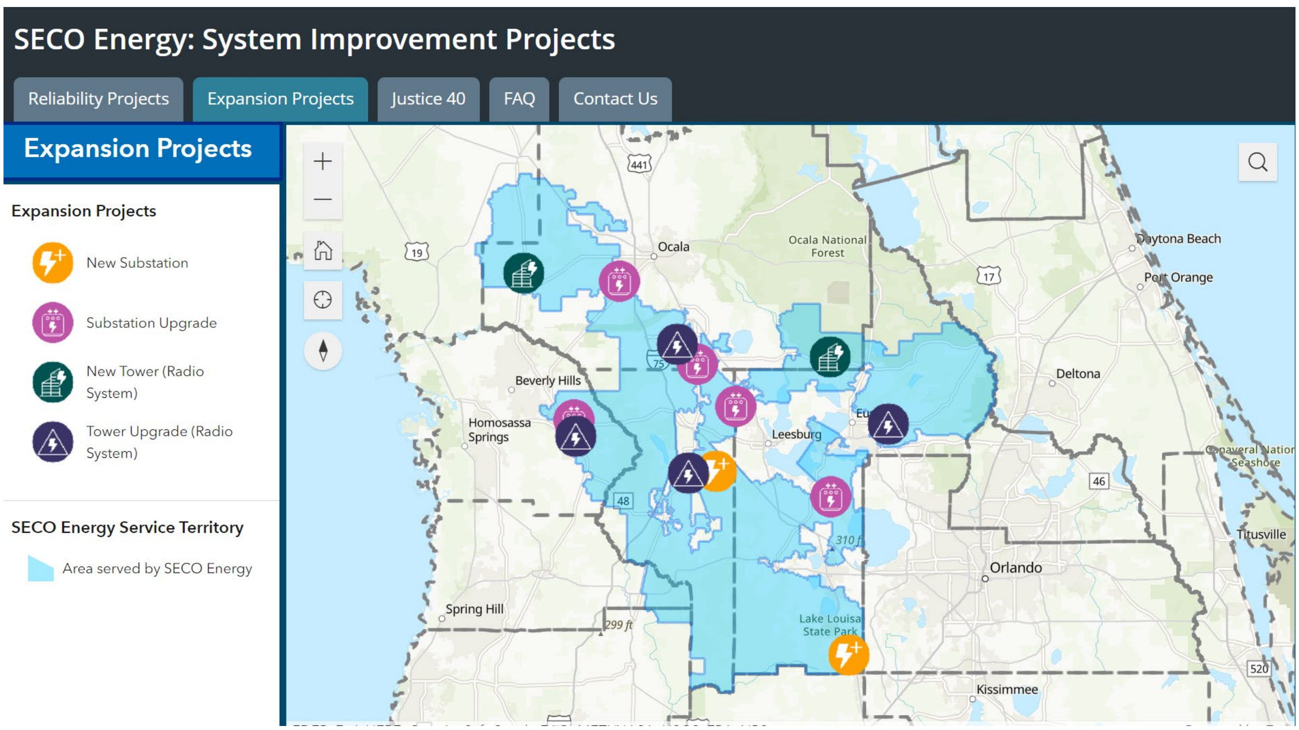
[42] Annual Electric Power Industry Report, Form EIA-861 detailed data files, 2013 and 2017, available at: https://www.eia.gov/electricity/data/eia861/.

[43] 2021 Summary Statistics Florida, Energy Information Administration, available at: https://www.eia.gov/electricity/state/florida/xls/fl.xlsx. See also "Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report," Florida Power & Light Company, 2020, available at: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=020CDC65-66E2-5005-8110-C31FAFC91712.

peak load increased by 2.4 GW during that same period. By comparison, the projected peak load from HDV charging in FPL's service territory is 143 MW, or around 6 percent of the additional load added in the prior ten years.

The ability to plan for current and projected load, and manage such growth through rapid development of distribution system upgrades, extends down to the utility level. For example, SECO Energy has many projects planned and underway to expand and upgrade the distribution system in their service area, recently completing a large substation (Sawgrass), "to handle the growing load in the southern portion of Lake County", which is growing "extraordinarily fast."[44] Figure 6 displays the active development of distribution expansion and upgrade projects under way in SECO's service area.

Figure 6: SECO Energy's Current Distribution Expansion and Upgrade Projects



Source: SECO Energy System Improvement Projects Maps, available at: https://seco.maps.arcgis.com/apps/MapSeries/index.html?appid=f7f4d0440e0f4eaab0ee8e49ca0638d1&folderid=cd6b0e1fa2bc4787bd24b0719bd6714a.

Electric utilities have also demonstrated the ability to serve customers even with very high power requirements. Colocation data centers provide physical facilities to host business' computing hardware and servers.[45] These data centers can have very high power demands – for example, STACK Infrastructure is currently adding 100 MW of load to an existing 150 MW data center campus in Northern Virginia with some individual data centers requiring

[44] SECO News June 2022, available at: https://secoenergy.com/seco-news-june-2022-2/.
[45] Data Center Colocation Benefits and Services, CoreSite, available at: https://www.coresite.com/colocation.

up to 48 MW of power. Delivery of the first building on the campus is targeted for Q1 2024.[46] This facility is supported by a 300 MW substation with electricity supplied by Northern Virginia Electric Cooperative (NOVEC).[47]

NOVEC supplies electricity to 28 data centers, with 19 more under construction in the cooperative's service area.[48] Five of the Cooperative's 62 substations primarily serve data centers, including two substations completed in 2019.[49] For every single one of these data centers, "the electric service was designed, constructed, and energized prior to the agreed-upon in-service date" even as the Northern Virginia region experienced a 353% increase in demand related to data centers.[50]

Northern Virginia is not unique, as 290 MW of load related to data centers came online across the United States between 2016 and 2021 with an additional 1,601.5 MW of load under construction today.[51] Data centers provide a clear example of the capacity of electric utilities to serve customers with localized power requirements much higher than the estimated power needs associated with HDVs.[52]

B. Legal/Regulatory Framework

Investor-owned utilities are subject to common law, statutory, and regulatory requirements to provide service for all customers in a designated service area so long as the incremental revenues associated with a customer cover any incremental costs. These requirements are typically described as an *obligation to serve* – i.e., electric utilities are obligated to "plan to serve its customers' demands for services by providing safe, reliable, and adequate supplies under normal business conditions."[53] In exchange for accepting this obligation to serve, investor-owned utilities are granted an exclusive service franchise/territory with the right to recover its prudently incurred costs of service and the opportunity to earn a fair rate of return.[54]

For example, the ICCT analysis suggests that California and Texas will account for a combined 19% of HDV energy needs by 2030. In California, investor-owned utilities "shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities […] as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."[55] Similarly, in Texas, all retail electric utilities must "serve every consumer in the utility's certificated area; and provide continuous and adequate service in that area" except for the "nonpayment of charges; nonuse; or another similar reason that occurs in the

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[46] McDuffie, Lisa, "STACK Infrastructure Breaks Ground on 100MW Data Center Campus in NoVa," ConnectCRE, January 6, 2023, available at, https://www.connectcre.com/stories/stack-infrastructure-breaks-ground-on-100mw-data-center-campus-in-nova/. See also CBRE Data Center Trends Report.
[47] "Stack Infrastructure expands Northern Virginia campus to 250MW," Stack Infrastructure Press Release, December 13, 2022, available at: https://www.stackinfra.com/about/news-events/press-releases/stack-infrastructure-expands-northern-virginia-campus-to-250mw/.
[48] 2020 Annual Report, NOVEC, available at: https://www.novec.com/About_NOVEC/upload/AR-2020_final_spreads-compressed.pdf.
[49] *Ibid.*
[50] *Ibid.*
[51] CBRE Data Center Trends Report.
[52] The ICCT White Paper projects the largest charging stations will need to provide at least 22 MW power to support long-haul trucks, although it notes "the peak charging load at each charging station is expected to be much lower than the specified station size, which represents the nominal power of all installed chargers." See ICCT White Paper, Table 4, p. 16.
[53] McDermott, Karl, "Cost of Service Regulation in the Investor-Owned Electric Utility Industry," Edison Electric Institute, 2012, available at: https://www.ourenergypolicy.org/wp-content/uploads/2012/09/COSR_history_final.pdf.
[54] This principle is often referred to as the "regulatory compact" or "regulatory bargain." See *Ibid*. Note that some electric companies, like electric cooperatives, may limit service to certain types of customers such as cooperative members only.
[55] California Public Utilities Code Sec. 451, available at: https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=3.&article=1.

usual course of business."[56] Moreover, the Public Utility Commission of Texas "may revoke or amend an electric utility's certificate of convenience and necessity (or other certificate) for such failures to serve, or grant the certificate to another electric utility to serve the applicant, and the electric utility may be subject to administrative penalties."[57]

In every state, public utility commissions are empowered by statute to enforce the obligation of franchised electric companies to provide service to all customers in their service territory. Commissions administer this oversight through various filing, planning and ratemaking policies and precedent that establish obligations on and provide the financial means for utilities to ensure they reliably meet all current and future electricity requirements of all existing and new customers within their franchised service territories. Relevant commission policies include:

1. Periodic distribution system reliability performance reviews with financial penalties for poor performance;

    For example, Hawaii and Illinois track distribution reliability metrics, set performance targets based on historical outage rates, and define financial penalties through the allowed utility rate of return if the performance target is not met.[58]

2. Requirements that the utility carry out comprehensive distribution system planning processes to forecast demands on their system well in advance of need, and take steps to ensure development of any needed infrastructure;

    For example, public utilities in California, Colorado, Delaware, Indiana, Hawaii, Maine, Maryland, Michigan, Minnesota, Nevada, New York, Oregon, Rhode Island, and Virginia are subject to integrated distribution system planning (IDP) requirements.[59] Additionally, most state commissions require Integrated Resource Planning (IRP) or similar planning processes, which generally include forecasts of demand and associated transmission and distribution requirements.[60]

3. Preapproval of utility investment in distribution system infrastructure and/or the allowance of "capital trackers" to enable utilities to roll distribution infrastructure investments into rates in-between rate cases;

[56] Texas Utilities Code Sec. 37.151, available at: https://texas.public.law/statutes/tex._util._code_section_37.151. See also Texas Utilities Code Sec. 37.152, available at: https://texas.public.law/statutes/tex._util._code_section_37.152.
[57] Texas Administrative Code, Title 16.2.25.B §25.22, available at: https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=2&ch=25&rl=22.
[58] "Performance-Based Regulation for Reliability and Resilience," Michigan Public Service Commission, November 2021, available at: https://www.raponline.org/wp-content/uploads/2021/11/rap_prause_mpsc_pbr_reliability_2021_nov_5.pdf. Hereafter, "Michigan PSC Performance-Based Regulation for Reliability and Resilience."
[59] "Integrated distribution planning overview," Department of Energy, March 2022, available at: https://eta-publications.lbl.gov/sites/default/files/schwartz-integrated-distribution-planning-overview-20220303-fin.pptx.pdf. See also, "Integrated Distribution Planning for Electric Utilities: Guidance for Public Utility Commissions," Mid-Atlantic Distributed Resources Initiative, October 2019, available at: https://www.madrionline.org/wp-content/uploads/2019/10/MADRI_IDP_Final.pdf.
[60] "Best Practices in Electric Utility Integrated Resource Planning," Synapse Energy Economics, June 2013, available at: https://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf.

For example, capital cost trackers for electric companies, including emissions controls, generation capacity, advanced metering infrastructure, and general system modernization, were utilized in 35 states as of 2015.[61]

4. Considerations (in part) of utility performance in setting the allowed shareholder rates of return in rate cases;

   As discussed above, Hawaii and Illinois track distribution reliability metrics, set performance targets based on historical outage rates, and define financial penalties through the allowed utility rate of return if the performance target is not met.[62] Additionally, performance incentives, including rate-of-return adders, were employed in 18 states (as of 2007) to encourage electric utilities to spend on energy efficiency programs.[63] More generally, many performance incentive mechanisms utilize percentage adders on an electric utility's rate of return to encourage utilities to meet pre-defined performance standards.[64]

5. Company-wide management audits in the event that utility reliability performance is deemed unacceptable.

   For example, California, Connecticut, New Jersey, and New York provide public lists of active and recent management audits of electric utilities.[65] More generally, "[r]egulatory commissions in most states and federal agencies have extensively employed audits as a regulatory tool in support of their traditional authority to set rates and assure the quality of utility service."[66]

While these practices and processes are in place, this does not guarantee that the required deployments of grid infrastructure will necessarily happen everywhere in a timely manner; that is, there are examples across states and utilities of distribution system upgrade delays. Thus, it is important in this context is to ensure that the practices and processes that exist are engaged and accelerated to ensure timely deployment across all states. Commissions can (and do) institute rulemakings and/or investigations to provide guidance and impose supplemental obligations when specific circumstances warrant commission action outside of standard planning, performance, and ratemaking cases. And in this context, states have already taken this step – recognizing that despite the ongoing obligation of utilities and the policies and procedures in place, the potential impact of accelerated electrification of the building and transportation sectors – in combination with the rapid proliferation of

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[61] For a catalog of capital cost tracker precedent as of 2015, see Table 2 in Lowry, Makos, and Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update," November 2015, pp. 7, 13-20, available at: https://www.puc.pa.gov/pcdocs/1418301.pdf.
[62] Michigan PSC Performance-Based Regulation for Reliability and Resilience.
[63] "Aligning Utility Incentives with Investment in Energy Efficiency," EPA National Action Plan for Energy Efficiency, November 2007, available at: https://www.epa.gov/sites/default/files/2015-08/documents/incentives.pdf.
[64] See, *e.g.*, performance incentive mechanisms (PIMs), which are ratemaking mechanisms that tie a portion of a utility's earnings to pre-defined performance metrics. Many PIMs utilize percentage adders on their rates of return if pre-defined performance standards are met. *See* "Performance Based Regulation Study Group Work Products," North Carolina Energy Regulatory Process, December 2020, available at: https://www.deq.nc.gov/environmental-assistance-and-customer-service/climate-change/clean-energy-plan/pbr-study-group-work-products-final/download.
[65] California: "Electric and CIP Audits," California Public Utilities Commission, 2021, available at: https://www.cpuc.ca.gov/regulatory-services/safety/electric-safety-and-reliability-branch/electric-and-cip-audits-introduction;
Connecticut: https://portal.ct.gov/PURA/Docket/Management-Audit-Reports;
New Jersey: Final Audit Reports, State of New Jersey Board of Public Utilities, available at: https://www.nj.gov/bpu/about/divisions/audits/auditreports.html;
New York: Electric Utility Management Audits, New York State Department of Public Service, available at: https://dps.ny.gov/electric-utility-management-audits.
[66] Wirick, David, et. al., "Information Risk in Emerging Utility Markets: The Role of Commission-Sponsored Audits," The National Regulatory Research Institute, available at: https://pubs.naruc.org/pub/FA85E455-E9A7-D104-D6A5-D99F0CFA4D38.

distributed energy resources – warrants proactive, advanced review and planning. The same proactive steps that have been taken in early-mover states provide a model for all other states to ensure timely nationwide deployment of system infrastructure needed for HDV electrification.

C. Distribution System Planning and Performance

Adding significant new distribution system infrastructure is not a new experience for states, public utility commissions, or electric companies, and there are long-standing policies and practices in place to ensure timely planning for and development of the infrastructure needed to ensure system reliability. And for most states and electric companies in the country, the magnitude and pace of system demand growth associated with the rollout of EPA's proposed Phase 3 rule is neither different from past periods of economically-driven demand growth, nor unusual with respect to the processes of forecasting, planning and development required.

For many decades regulators have required, and electric companies have administered, comprehensive practices and procedures to maintain system reliability in the face of uncertain demand futures. Various policies and practices include the following:

- Commission-reviewed company forecasts filed every one or two years of the demand for electricity within their service territories including expected growth in the level and changes in the shape of demand at the distribution system feeder and circuit level. These forecasts are developed for periods of ten years or more, and typically probabilistically evaluate potential variations and uncertainties in demand associated with uncertain future economic, weather, and policy circumstances.
- Commission-reviewed company plans for the development of distribution system upgrades and new installations to meet demand growth and increase the reliability and resilience of distribution system performance.
- Utility circuit-by-circuit assessment of availability to absorb additional growth in demand and/or additional installation of variable distributed solar PV resources while maintaining expected levels of reliability.
- Utility review of requests for major interconnections of new sources of electricity demand (such as major housing projects, business centers, malls, data centers, etc.), the processing of those requests through system interconnection analyses and cost assessment, commission review and approval of the utility's involvement and any associated cost recovery issues, and utility coordination with developers to ensure timely installation of any needed system upgrades and interconnection of the new load.
- Continuous utility measurement, evaluation, and filing with the PUC of metrics that measure the reliability of the distribution system and individual feeders and circuits, and PUC review of filings including the assessment of performance penalties and any orders for utility mitigation of poor-performing circuits.
- Utility and commission review of distribution system emergency operational plans and response and recovery operations and procedures to ensure that the system can withstand severe weather events and that the utility has in place a plan for rapid recovery in the event of system outages.

Finally, while the interconnection of charging stations at the levels and pace expected in response to EPA's proposed rule may for the most part be manageable with broader deployment of current policies and procedures and additional proactive policies and planning procedures, it nonetheless represents a unique circumstance relative to past examples of load growth, in the sense that there is potentially something of a chicken-or-egg problem. Utilities are averse to making investments that may in retrospect appear unneeded on a temporary basis, or underutilized for some period of time. And this is potentially the case with respect to system investments needed to support the operation of charging stations that could be underutilized as the pace of HDV electrification grows over time. Conversely, the HDV industry will be reluctant to invest in electric vehicles until there is confidence that sufficient charging capacity is in place to support normal operations.

A number of factors, described above, including state action, private investment, and fleet commitments are all providing greater certainty for utilities. Issuance of Nationwide EPA standards as proposed will provide additional levels of regulatory certainty – it will necessarily help to drive substantial and continuous growth in electric HDVs uptake, providing certainty in the future value of charging station investments and an associated increase in electricity demand. This certainty will in turn provide regulators, state permitting authorities, and utilities certainty in the ultimate need for and value of utility investments in sufficient distribution system infrastructure to support this level of demand growth, driving the development of appropriate utility planning processes and prompting regulatory action by states to support this level of investment.

Thus, in this respect, proactive policymaking and planning are very important. Fortunately, many states and utilities are already developing and implementing the proactive policymaking and planning processes that are necessary to meet this demand. Some have policies and planning practices that are explicitly evaluating the magnitude and timing of demand increases. ERCOT has a project to develop a method and process to forecast EV loads at the substation level, and will use these estimates as part of near-term transmission planning studies starting this year.[67] Many utilities have robust systems in place which evaluate the availability or lack thereof of “room” on circuits and feeders to accommodate specific or projected vehicle charging station needs. Several of utilities post capacity mapping tools publicly, to aid developers and other planners considering EV siting. (See distribution capacity mapping tools example.[68]) There are also holistic assessments of the development activities that will be needed to ensure timely

Eversource Integrated Distribution System Planning Approach

Eversource, New England’s largest energy delivery company, published an Integrated Distribution System Planning Approach earlier this year. They note that while the adoption of new technologies like electric vehicles does not alter the utility’s aim of providing reliable service – as mandated by the Massachusetts Department of Public Utilities– it does require them to develop a more comprehensive approach to long-term system planning. Specifically, Eversource has expanded its long-term plans to include the integrated impacts of load growth and distributed energy resource (DER) adoption, both of which are influenced by EV adoption. The planning document outlines a Scenario Planning approach in which they start with a “base need” scenario and subsequently build on that scenario by projecting EV growth, among other factors. The EV component is modeled using adoption probability to determine EV growth by geographic region and the time of maximum and minimum demand. Eversource uses these forecasts to identify potential violations in distribution substations and backbone feeder stations. These predicted violations can then be mitigated by reconfiguring the system or applying non-wires alternative solutions, or they can be addressed with larger scale upgrades or new constructions, both of which have established project procedures.

[67] “Report on Existing and Potential Electric System Constraints and Needs,” ERCOT, December 2022, available at: https://www.ercot.com/files/docs/2022/12/22/2022_Report_on_Existing_and_Potential_Electric_System_Constraints_and_Needs.pdf.
[68] Eversource: Massachusetts Hosting Capacity Map, available at: https://www.eversource.com/content/residential/about/doing-business-with-us/interconnections/massachusetts/hosting-capacity-map;
Dominion Energy: Electric Vehicle (EV) Capacity Map Tool, available at: https://www.dominionenergy.com/projects-and-facilities/electric-projects/ev-capacity-map;

co-development of EVs and EV charging infrastructure. (See Eversource Integrated System Planning example.[69]) Similar activities, policies, and planning and development practices can be adopted by any utility or state that identifies an expectation of excessive or challenging level of growth in charging station demand associated with EPA's proposed rule.

Some of the most robust planning actions have been taken by utilities and regulators in ACT states, showing how the certainty of HDV emission standards has prompted utility and regulatory action to meet the associated growth in demand and need for infrastructure.

For example, California Public Utility Commission (CPUC) staff are developing a Zero-Emission Freight Infrastructure Planning (FIP) framework to faciliate the adoption of ACT and related regulations like the Advanced Clean Fleets (ACF) rule.[70] This framework is developing investment-grade inputs and assumptions to identify distribution, substation, and transmission needs under high transportation electrification scenarios. Having proactively identified the electric infrastructure needed to support HDV targets, long-lead time infrastructure can be deployed in advance of charging stations. Critically, the proposed FIP Framework requires the proactive development of potential HDV charging station locations across multiple state agencies and regulatory bodies including CPUC, the California Independent System Operator, the California Transportation Commission, the California Energy Commission, and the California Air Resources Board, along with regulated IOUs undertaking Integrated Resource Planning and Distribution Planning Processes.[71]

Pacific Gas and Electric: Distributed Resource Planning (DRP) data and maps, available at: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page;
San Diego Gas and Electric: Accessing Mapping, available at https://www.sdge.com/more-information/customer-generation/enhanced-integration-capacity-analysis-ica;
Con Edison: Hosting Capacity Web Application, available at: https://coned.maps.arcgis.com/apps/MapSeries/index.html?appid=edce09020bba4f999c06c462e5458ac7;
Public Service Enterprise Group: EV Hosting Capacity Map, available at: https://nj.myaccount.pseg.com/myservicepublic/ev_hosting_capacity_map;
First Energy: EV Load Capacity Map, available at: https://www.firstenergycorp.com/help/electric-vehicles/nj-ev/new-jersey-ev/load-capacity-map.html;
Pepco: EV Load Capacity Map, available at: https://www.pepco.com/SmartEnergy/InnovationTechnology/Pages/EVLoadCapacityMap.aspx.

[69] "About Eversource," Eversource, 2023, available at: https://www.eversource.com/content/residential/about; Rules Governing the Restructuring of the Electric Industry, Massachusetts Department of Public Utilities, pp.11-12, available at: https://www.mass.gov/files/220_cmr_11.00_6_17_16_0.pdf ; Integrated Distribution System Planning Approach, Eversource System Planning, May 2023, pp.3-5, 14-15, available at: https://www.mass.gov/doc/eversource-integrated-distribution-system-planning-approach/download ; Forecasting and Electric Demand Assessment Methodology, Eversource Energy, April 2023, p. 13, available at: https://www.mass.gov/doc/eversource-forecasting-and-electric-demand-assessment-methodology/download.

[70] "Draft Staff Proposal: Zero-Emissions Freight Infrastructure Planning," California Public Utilities Commission, May 2023, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/fip-draft-staff-proposal_5_22_23-webinar-final_ver2.pdf.

[71] *Ibid.,* p. 18.

Distribution Capacity Mapping Tools

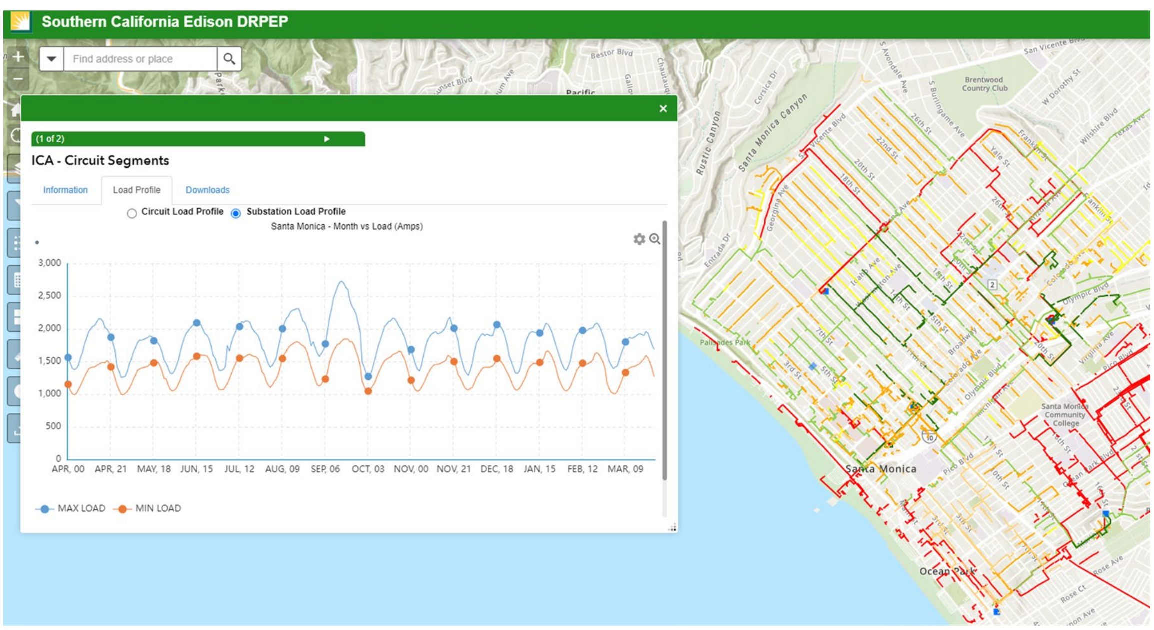
Many utilities provide publicly available mapping tools showing the capacity of their distribution systems, including hosting capacity tools geared toward integrating PV solar (e.g., Eversource), tools specifically tailored toward identifying locations amenable to EV charging infrastructure, or a combination of both.

For example, Dominion Energy's Electric Vehicle Hosting Capacity map shows the current grid capacity of the high voltage three phase distribution lines in their service territory in VA and NC, with color coding indicating capacities from 1 MW to greater than 5 MW capacity. The tool also includes the location of existing DC fast charging stations.

Southern California Edison's Distribution Resources Plan External Portal includes substation-specific load profile which shows the maximum and minimum load over time in addition to the capacity by feeder, shown below in Figure 7.

Other utilities with publicly available tools include: PG&E (CA), SDG&E (CA), ConEdison (NY), PSEG (NJ), Pepco (MD, DC, DE, NJ), and First Energy (NJ).

Figure 7: Southern California Edison's Distribution Resources Plan External Portal



Source: Southern California Edison's Distribution Resources Plan External Portal, available at: https://drpep.sce.com/drpep/.

Similarly, in New York, seven utilities have submitted a proposal for a Coordinated Grid Planning Process (CGPP) in response to an order from the Department of Public Service to "undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emissions-free resources while maintaining the State's electric grid reliability."[72] As part of the CGPP, the utilities are obligated to proactively identify potential barriers to incremental new load, including from HDV charging stations: "Utilities will apply DERs (primarily PV) and load (electrification) assumptions […] to utility distribution network models according to the location, level, and timing of the additions […] and […] perform analyses at an appropriate level of detail on the local distribution systems to identify where system constraints may limit the ability to add DERs and electrification load."[73] Furthermore, utilities are obligated to address any identified barriers through distribution upgrades: "[f]or near-term distribution system needs (within the next five years), utilities will develop a solution to mitigate the criteria violation or constraint [and] for longer-term distribution system needs (beyond five years), […] utilities will develop specific distribution system plans for upgrades as the need approaches the near(er) term to increase certainty and confidence in the proposed solution."[74]

D. Financial and Ratemaking Incentives

There are several ways that timely growth in the distribution system infrastructure needed to accommodate HDV electrification is assured through the financial incentives of rate regulation. First and foremost, distribution system upgrades represent incremental capital investments that strongly benefit utility shareholders by increasing the rate base on which shareholders earn a return on investment. The strength of this incentive on utility investment is difficult to overstate – while not unique to distribution system upgrades to accommodate vehicle electrification, the opportunity to invest in support of charging centers will help engage and motivate electric companies to pursue this opportunity without delay. A complementary piece of the ratemaking equation is the existence in most states of potentially significant penalties for poor distribution system reliability performance. Thus, greater and sooner investment in distribution system infrastructure both opens the door for increased returns and helps close the door on performance penalties.

Commissions have also recognized the disincentives tied to infrastructure investments made "between rate cases." Historically, and still in some states, investments made without tacit or explicit commission approval create cost recovery risks. Ratemaking principles allow utilities to only recover costs that are prudently incurred and that are associated with assets that are used-and-useful in the provision of electricity service. Thus, there is a risk of non-recovery of investments that were not preapproved as prudent, and/or that were not used – or underutilized – in electric service. As a result, utilities are subject to risk associated with new capital projects.

To mitigate this risk, in many states electric utilities have the option to utilize *adjustment mechanisms* when undertaking transmission and distribution upgrades to meet increases in projected load, or otherwise as deemed necessary by the commission.[75] These adjustment mechanisms are regulator-approved plans to recover certain

[72] Coordinated Grid Planning Process Proposal, State of New York Public Service Commission, December 2022, p. 3, available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={45BD5A1F-9FDA-473F-8FCF-E5CE7A11A880}.
[73] *Ibid.,* p. 26.
[74] *Ibid*., p. 26.
[75] More recently and with greater frequency, commissions have approved mechanisms that permit the costs associated with the construction of new generation capacity or delivery infrastructure to be reflected in rates through an adjustment clause; effectively including these items in rate base without a full rate case. In some instances, these mechanisms may even provide the utilities a cash return on construction work in progress. *See* "Adjustment Clauses: A state-by-state overview," S&P Global, September 2017, available at: https://www.spglobal.com/marketintelligence/en/documents/adjustment-clauses-state-by-state-overview.pdf.

costs incurred by the electric company to serve its customers. In 40 states, public utility commissions have approved the recovery of costs associated with the construction of new demand infrastructure for at least one utility.[76] In Texas, the Public Utility Commission can approve the use of distribution cost recovery factors, which allow utilities to recover incremental distribution costs via an additional tariff rider.[77]

Effectively, these adjustment mechanisms could provide utilities certainty in cost recovery prior to undertaking substation or distribution system upgrades necessary for the energization of new HDV charging stations. Such guaranteed cost recovery may be necessary because investments in HDV charging stations are in effect needed *before* the investments will be fully utilized, in order (for example) to provide certainty for the transportation industry to invest in electric trucks. Overall, the presence of performance penalties, rate of return incentives, and proactive PUC policies to "de-risk" forward-looking distribution system investments to encourage early development of charging station infrastructure can ensure that system reliability investments will be make in a timely way.

E. Enabling Strategies and Technologies

As noted, utilities have reliably met demand growth for decades through planning for and developing (in part) new distribution system infrastructure as needed, including for major new developments such as office parks and data centers. These sources of large incremental demand typically have simply increased demand on the system, with few or no features that could mitigate their impacts, or even potentially provide benefits to reliable distribution system operations.

Demand growth via vehicle electrification – particularly HDV electrification involving to a significant extent large, centralized fleets (such as school buses) – presents a different set of circumstances for integrating and managing new demand. In particular vehicle electrification offers opportunities for efficient management of load factors through time of use pricing, the potential for fleet batteries to become a grid stabilization and demand response resource,, and opportunities to mitigate the potential impacts on distribution system demand levels and operations through colocation of charging centers with advanced distributed resource technologies such as solar PV and battery energy storage.

With respect to pricing, electric utilities are increasingly allowing their customers to opt into time-varying, rather than fixed electric rates.[78] Under the simplest time-of-use (TOU) tariffs, customers are subject to a set schedule of rates that vary during specific times of the day, with the lowest rates occurring during overnight off-peak hours and the highest rates occurring during afternoon or early evening peak periods. Under a TOU tariff, electric vehicle owners would be provided a financial incentive to shift their charging to off-peak periods with lower average rates. Such a shift from peak to off-peak periods not only reduces electricity costs, but also lowers the emission impacts of the associated electricity because peak periods are also the periods when the most emissions-intensive fossil

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[76] Ernst, Russell, and Monica Hlinka, "Adjustment clauses are key aspect of utility cost recovery strategies," S&P Global, July 2022, available at: https://www.capitaliq.spglobal.com/apisv3/docviewer/documents/document_amr_186260073?searchWithinDoc=cost+recovery&amrSearch=1.

[77] Electric Substantive Rules Chapter 25.243, Public Utility Commission of Texas, 2011, available at: https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.243/25.243.pdf; Distribution Cost Recovery Factor Rider, Entergy Texas, available at: https://cdn.entergy-texas.com/userfiles/content/price/tariffs/eti_dcrf.pdf.

[78] The Department of Energy offers a tracker of demand and time-variable pricing programs, and every state has at least one utility offering a time-of-use tariff. *See* Demand Response and Time-Variable Pricing Programs, Federal Energy Management Program, available at: https://www.energy.gov/femp/demand-response-and-time-variable-pricing-programs.

fuel generators tend to come online. TOU pricing is particularly important for fleet depots, because HDVs will be financially compensated for charging overnight during periods of relatively low demand rather than paying a fixed electricity charge.

The three largest IOUs in California already offer EV-specific rates for residential and commercial customers,[79] while NYSEG has the OptimizEV pilot program underway.[80] Time-varying rate proposals have been approved in several other states, including Texas, Arizona and Colorado.[81]

Beyond the simplest TOU tariffs, electric utilities are also offering more sophisticated pricing options to better match the prices charged to customers to the underlying costs of generation, including real-time pricing, day-ahead hourly pricing, and block-and-index pricing tariffs, often as separately metered electric vehicle tariffs.[82] These options will increase the value of managed charging strategies for HDV depots. Recent research suggests that HDVs with low daily mileage charging at depots have relatively long and predictable dwell times– for example, based on a real-world operating schedules, HDVs housed at depots averaged 14 hours of downtime per day.[83] These long dwell times allow for potential managed charging strategies, including asynchronous charging of vehicles to minimize charging during peak hours, lower peak demand and associated demand charges, and lower required distribution system upgrades.[84]

Given their demand-side flexibility and the capability of storage to serve as load or generator, HDVs have the potential to provide important grid services as distributed energy resources (DERs).[85] [86] Some utilities have already deployed EVs as demand response grid resources – for example, the ChargeForward 2.0 program enrolled 300 households in the San Francisco Bay Area with BMW plug-in EVs into a load-shifting program that optimized home charging according to time-of-use rates and the availability of renewable energy generation. The pilot project was able to shift up to 20 percent of changing in any given hour to other times and the ability to add up to 30 percent of charging to any given hour.[87] Similar managed charging incentive programs are underway across the country.[88] Thus, fleet operations open the door to the collective capacity of the installed fleet batteries to act

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79 "Electricity Vehicles Rates and Cost of Fueling," California Public Utilities Commission, available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/transportation-electrification/electricity-rates-and-cost-of-fueling.

80 OptimizEV, Avangrid, 2023, available at" https://www.nyseg.com/w/optimizev?p_l_back_url=%2Fsearch%3Fq%3DoptimizEV.

81 Trabish, Hannah, "With looming EV load spikes, PG&E, Duke, other utilities adopt new rate design and cost recovery strategies," Utility Dive, April 2023, available at: https://www.utilitydive.com/news/electric-vehicle-load-spikes-pge-duke-sce-entergy-aps-dynamic-rate-design-reduced-demand-charges/646603/.

82 Demand Response and Time-Variable Pricing Programs, Federal Energy Management Program, available at: https://www.energy.gov/femp/demand-response-and-time-variable-pricing-programs.

83 Borlaug, Brennan, *et. al.,* "Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems," Nature Energy 6, 673-682, June 2021, available at: https://www.nature.com/articles/s41560-021-00855-0. Hereafter, Borlaug et. al. (2021). See also Muratori, Matteo, and Brennan Borlaug, "Perspectives on Charging Medium- and Heavy-Duty Electric Vehicles," National Renewable Energy Laboratory, December 2021, available at: https://www.nrel.gov/docs/fy22osti/81656.pdf.

84 Borlaug et. al. (2021).

85 "DERs" are typically defined as resources connected to the distribution system close to load, including distributed photovoltaic systems, wind turbines, combined heat and power, microgrids, energy storage, and diesel generators (NREL, 2019). *See*, "An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions," National Renewable Energy Laboratory, April 2019, available at: https://www.nrel.gov/docs/fy19osti/72102.pdf.

86 "Procuring Electric Vehicle Infrastructure, Federal Energy Management Program, available at: https://www.energy.gov/femp/procuring-electric-vehicle-infrastructure.

87 "Total Charge Management of Electric Vehicles," California Energy Commission, December 2021, p. iii, available at: https://www.energy.ca.gov/sites/default/files/2021-12/CEC-500-2021-055.pdf.

88 *See*, for example, Managed charging Incentive Design, Smart Electric Power Alliance, October 2021, available at: https://go.sepapower.org/l/124671/2021-10-22/lmkxyj/124671/1634926457NkzFzpt8/Managed_Charging_Incentive_Design_Guide_to_Utility_Program_Development.pdf.

as a demand response resource, one that can be used (when economic) to arbitrage energy market prices, and one that can help balance the increasing net variability of demand on power systems due to increases in weather-dependent renewable generation. It can also help lower the maximum total charging level on the system at any point in time, making better use of existing distribution system capacity and minimizing the degree (or extending the timing) of needed system upgrades. This could also be useful as a storage resource on feeders or circuits that have a high level of distributed solar PV resource penetration.

Finally, the emergence of battery energy storage and hybrid solar PV-battery storage projects opens the door to significantly mitigating the potential impact on the grid of large charging station developments. Pairing charging locations with PV, battery storage, or hybrid systems allows the charging station to reduce system demand and actively spread out charging demand and reduce required growth in distribution system feeder/circuit capacities. (See Duke Energy Fleet Depot with Integrated Microgrid example.)[89]

Duke Energy Fleet Depot with Integrated Microgrid

Duke Energy is building an electric fleet depot with a first-of-its-kind integrated microgrid charging option. The project was announced in Feb 2023 and should be online later this year. The goal is to provide commercial-grade charging for light-, medium-, and heavy-duty vehicles, which can serve as a model for other commercial customers interested in building fleet charging. It will be located at Duke's technology hub in Mount Holly, NC, and integrate the center's existing microgrid controls software, solar equipment, and energy storage.

[89] Walton, Robert, "Duke Energy to build 'first-of-its-kind' facility to accelerate fleet electrification with Daimler, Electrada," Utility Dive, February 2023, available at: https://www.utilitydive.com/news/duke-facility-accelerate-fleet-electrification-charging-depot-daimler-electrada/643253/; "Duke Energy Announces Microgrid-Integrated Fleet Electrification Depot," The Electric Generation, 2023, available at: https://theelectricgeneration.org/2023/04/13/duke-energy-announces-microgrid-integrated-fleet-electrification-depot.

V. Observations and Conclusions

In this report we explore the potential impacts of an expanded heavy-duty zero-emissions vehicle fleet on electric distribution systems, and evaluate pathways for states and utilities to efficiently manage any associated growth in infrastructure needs. To do this we (1) review the expected nature, size, and pace of increased distribution system infrastructure needs, (2) review relevant utility statutory and regulatory obligations to meet the growth in demand, (3) evaluate the regulatory frameworks and processes in place to support planning for and development of distribution system infrastructure where and when needed, and (4) consider ways in which states and electric companies can proactively address any potential challenges associated with meeting this demand growth.

Specifically, our analysis seeks to answer several questions related to the potential impact of HDV electrification on electric company distribution system planning and operations, and the framework in place to meet the associated growth:

- What is the nature of the capacity and location of charging stations likely needed to support the potential level of electrification implied by the EPA proposed rule?
- What factors related to the existing infrastructure and operation of electric company distribution systems need to be considered in assessing how the needed charging station growth will affect distribution system needs and operations?
- Where incremental distribution system upgrades are needed, how do they compare with upgrades needed to meet demand growth in other contexts (e.g., economic growth, major housing or commercial developments, data centers, etc.)?
- What are the legal and regulatory obligations of electric companies to meet growth in electric demand?
- What do regulators require of utilities to ensure that demand growth is met?
- What planning processes do electric companies use to forecast and plan for system growth?
- What might the development timeline for new infrastructure look like considering past infrastructure development efforts?
- What proactive planning and regulatory tools are being used to help meet and manage growth (and change) in distribution systems associated with both electrification and the proliferation of distributed energy resources?
- What new technologies, policies, and strategies are emerging to help fleets, charging station developers, and utilities successfully and economically manage the changes that will emerge over time due to HDV electrification?

Based on our review, we come to the following observations:

- The overall magnitude of growth in demand that would result from EPA's proposed rule is very small relative to historic periods of growth in the electric industry, and will not pose a challenge from the perspectives of power system generation or transmission infrastructure needs.
- Charging station needs that may result from EPA's proposed rule range greatly in size and location; most counties and utilities in the U.S. analyzed in ICCT's report will likely not face new distribution system infrastructure needs due to charging load different from past experience.
- Some utilities will need to plan for the development of new distribution system infrastructure to accommodate fairly large point sources of new charging station demand.

- Adding significant new distribution system infrastructure is not a new experience for states, public utility commissions, or electric companies, and there are long-standing policies and practices in place to process development of infrastructure needed to ensure system reliability.
- The need for a high level of certainty around the timely integration of charging stations and associated distribution system infrastructure at the scale and speed needed for HDV electrification warrants – and has already prompted – proactive action on behalf of some states and utilities to engage and expand planning and regulatory practices at the scale necessary to ensure timely readiness of the power system.
- There are many emerging technologies, ratemaking practices, and distributed resource solutions that have the potential to significantly and efficiently reduce the expected impacts on distribution systems associated with vehicle electrification.
- Evolution of distribution systems to meet the potential increase in charging station demand associated with EPA's proposed Phase 3 rule for HDVs is eminently achievable.