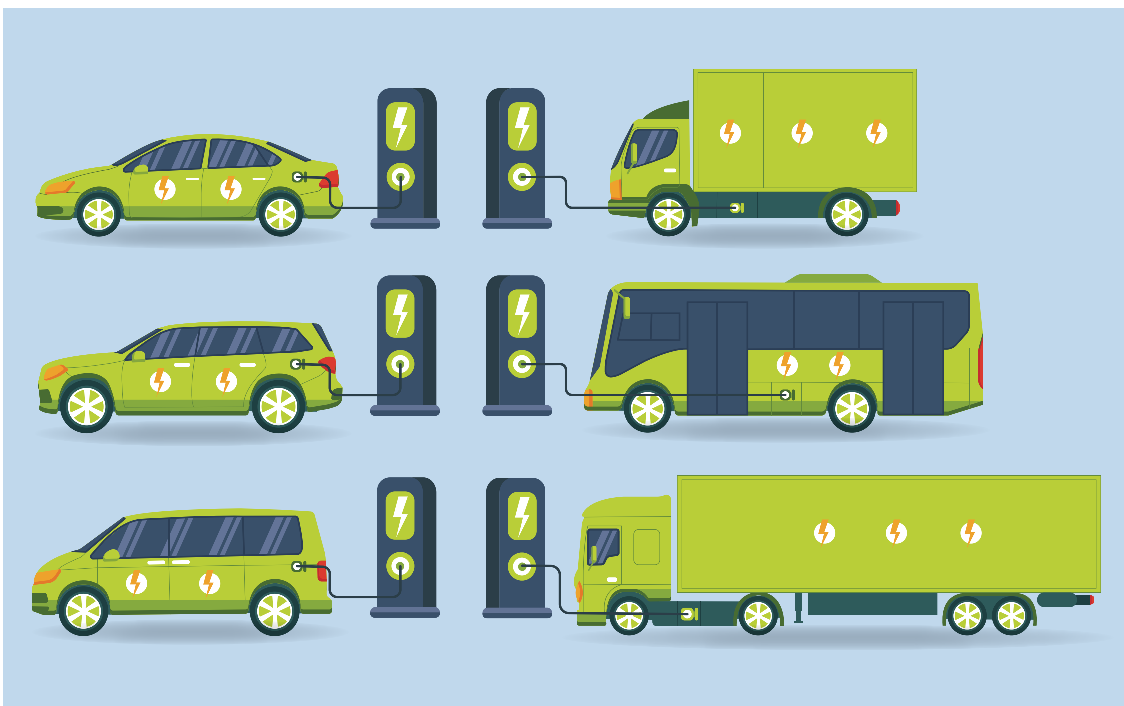
NARUC

National Association of Regulatory Utility Commissioners

Proactive Distribution System Investment Strategies that Support Transportation Electrification



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Executive Summary

The era of flat electricity demand is over. In recent years, electric vehicles (EVs), particularly light-duty vehicles but also a growing number of medium- and heavy-duty applications, have been a significant source of new load growth across the country— particularly in jurisdictions with more ambitious policies that encourage EV adoption. Whereas EV charging stations can be built in months, larger EV charging station installations can be challenging for a utility to energize unless the local distribution system has significant headroom. When a utility has only short notice to address a significant increase in load, it may be presented with difficult options, leading to either significant delays before a new charging installation can be energized or hastily planned reactive investments to serve that new load.

While increasing distribution system capacity generally, to respond to load growth forecasts may be part of the answer, there are key uncertainties to manage related to the size of new charging station load, where that load will be located, and when it will materialize. These uncertainties lead to several different kinds of risks to manage. Notably, investing too much leads to excess costs and hurts ratepayer affordability, but building too little or in the wrong place would worsen problems we are seeing today: major energization delays, potentially suboptimal investments, and reliability risks.

This report looks at efforts that five states (CA, CO, MA, MN and NY) have undertaken to manage this uncertainty and risk in a manner that avoids or reduces unnecessary delays for energization of EV charging installations while providing a cost-effective long-term buildout of the distribution system. These forward-looking efforts to deal with the challenges of transportation electrification have been described as proactive investment strategies resulting from proactive planning approaches, which can include:

- **Forecasting improvements:** Additional data sources and methodologies for forecasting energy demand are incorporated in determinations of grid needs to account for emerging and evolving loads, including transportation electrification.
- **Changes to criteria for investments:** Determinations of when investments in the grid are made are evolving in the face of novel sources of demand to continue to ensure lowest overall cost and beneficial outcomes for energy customers.
- **Prioritization and investment:** Managing the risk and uncertainty in forecasting demand is focused on a balanced approach to ensure adequate capacity to serve demand reliably while containing costs.

In assessing the potential for incorporating proactive planning approaches in regulatory processes, leading commissions are considering:

- Exploring and developing additional data sets and methodologies that account for EV adoption trends in response to market conditions, customer usage trends, and other factors to narrow the variance in uncertainty between forecasting traditional sources of customer demand and EV charging – revisiting these adjustments periodically and as necessary.
- Identifying and coordinating areas of continual improvement in proactive planning forecasts and approaches across other planning processes to ensure consistency and responsive action using the best available data.
- Mitigating the risk of stranded or underutilized assets not only through better forecasts, but also through operational adjustments in the grid such as transferring loads through new electrical connections from congested areas in the grid to areas with excess capacity, particularly in dense and urban areas where connections to loads can more readily be moved around.

- Considering diversity in customer project type and charging application when assessing risks. Risk may not be uniform across all EV demand served, classes of vehicles, or desired configurations. Thus, a mitigation strategy tailored to the particular dynamics of specific charging facilities may be more appropriate than a blanket approach.

Ultimately, planning processes can be considered an implementation of the prudence standard, answering the question "How can we make reasonable decisions given the information we have at the present time?" Working to manage the uncertainty around likely new EV charging loads should improve forecasts and allow for more informed decisions around the short-term need for new infrastructure investments. Ultimately, the changes contemplated to assess cost-effective proactive investments that support transportation electrification may ultimately be subsumed into broader planning processes. These innovations can also inform those broader planning efforts and may also be helpful when examining challenges due to other sources of load growth.

1 Introduction

Electric vehicle (EV) adoption, spanning light-, medium- and heavy-duty applications, is increasing nationwide and is creating significant new electricity demand from its associated charging. As a result, state public utility commissions are assessing utility requests for investment in distribution infrastructure to serve this new load. However, due to a variety of novel factors associated with EV demand, there is uncertainty as to where, when, and how much investment will be necessary. Several jurisdictions in turn have begun to investigate tailored approaches for addressing this dynamic through emerging efforts in proactive planning.

Proactive planning approaches recognize the nature of emerging and evolving sources of demand, including EV charging, and the challenge associated with accurately anticipating their impact on the grid. These approaches identify responsive actions to mitigate risks associated with uncertainty in projecting demand, which may include refinements to forecasting inputs and methods, initiating additional traditional capital investments, and pursuing alternative solutions for providing load relief, such as expanding operational flexibility.

This paper documents the state of proactive investment in the distribution system[1] supporting transportation electrification, largely as of January 2025.[2] First, it describes background on EV adoption and distribution system planning, and then it focuses on three key aspects of proactive planning proceedings:

- An explanation of **how proactive planning and investment is different** from other recent efforts to improve distribution system planning;
- The **benefits of making proactive investments** in the distribution system, and the use cases that are driving the proactive approach; and
- A discussion of the **key planning, regulatory and decision-making considerations** that have surfaced from proceedings in five leading states.

These efforts are being explored in parallel with related approaches in modernizing distribution system planning and illustrate how load growth may need to be assessed more comprehensively across planning efforts.

1 Investment in the distribution system represented 44 percent of all capital expenditures in 2023 and has been growing at above-inflationary rates since 2019. Forrester, et. al, Retail Electricity Price and Cost Trends: 2024 Update, Lawrence Berkley National Lab (2024).

2 Research for this paper was completed in 2024; circumstances beyond the control of the authors delayed publication to late 2025. The scope of this paper includes the distribution system; it excludes examination of investments in generation, transmission and in behind-the-meter electric vehicle supply equipment (EVSE).

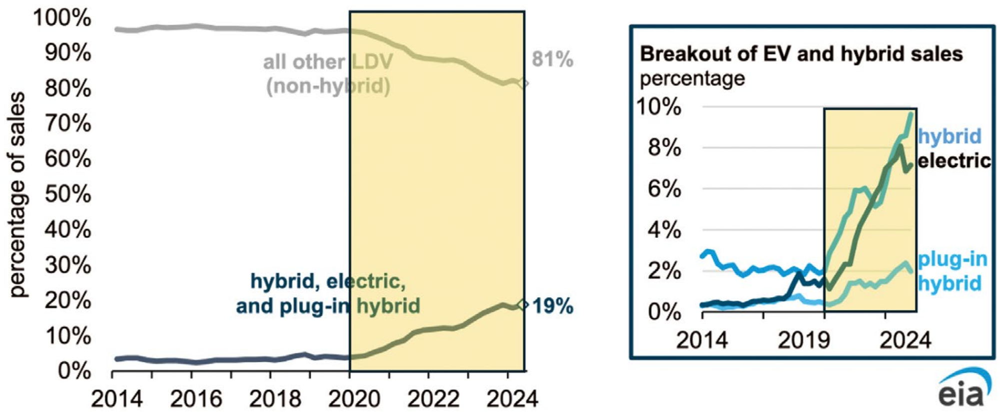
2 Background on EV Adoption and Distribution System Planning

Electric vehicle (EV) adoption levels have reached new heights over the past few years. The incremental electricity consumption from EV charging accompanying this adoption is projected to make it a significant contributor to load growth moving forward. Understanding key aspects of electric distribution system planning and the different types of EV charging applications are important when contemplating reforms.

2.1 Forecasts for EV Adoption and Electricity Consumption

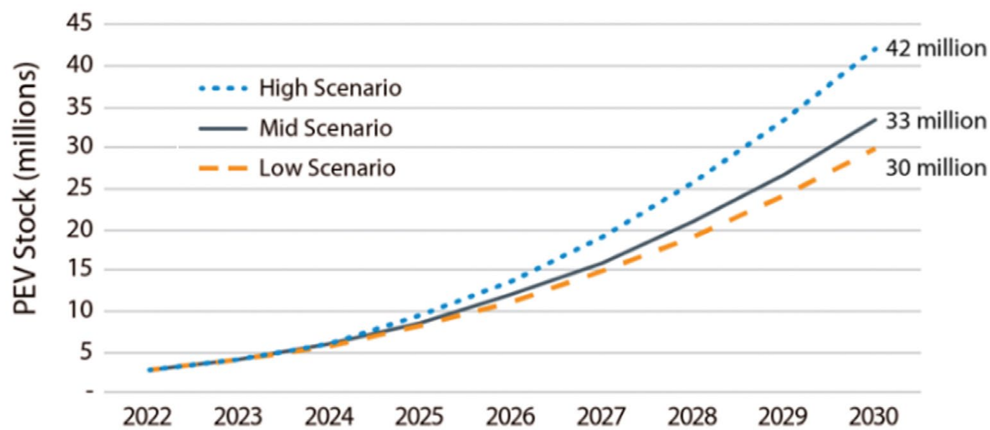
The adoption rate of electric vehicles , including full battery electric vehicles and plug-in hybrids, has increased significantly over the last decade. Over the past five years, light-duty EV adoption has grown from about 2 percent of total sales in 2019 to about 10 percent in 2024 as illustrated in **Figure 1**.

Figure 1: Quarterly US Light Duty Vehicle Sales by Powertrain[3]



In 2023, 4.9 million light-duty electric vehicles (LD EVs) were registered in the U.S.,[4] and 2024 sales were reported at 1.3 million.[5] As a result, LD EVs totaled approximately 6.2 million at the end of 2024. This is consistent with NREL's 2021 adoption forecast as illustrated in **Figure 2**.

Figure 2: NREL's US Light Duty EV Adoption Scenarios[6]



3 "U.S. Share of Electric and Hybrid Vehicle Sales Increased in the Second Quarter of 2024 - U.S. Energy Information Administration (EIA)," August 24, 2024, https://www.eia.gov/todayinenergy/detail.php?id=62924.

4 "Vehicle Registration Counts by State," Alternative Fuels Data Center: Vehicle Registration Counts by State, 2024, https://afdc.energy.gov/vehicle-registration.

5 "U.S. EV Sales Get A Trump Bump In Q4 2024," InsideEVs January 2025., https://insideevs.com/news/746165/us-ev-sales-trump-bump-2024/

6 The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure , NREL, Figure 7, page 16, https://www.nrel.gov/docs/fy23osti/85654.pdf.

NREL's adoption forecast recognizes that "efforts to see [EVs] represent the majority of light-duty vehicle sales by 2030 could lead to 30 million – 42 million light-duty EVs on the road by 2030."[7] However, more recent forecasts have reduced this outlook significantly. For example, Bloomberg New Energy Finance recently reduced its cumulative EV sales estimate by 14 million vehicles in 2030. Instead of 36 million EVs on the road by 2030, it expects about 22 million.[8] This represents an almost 40 percent decrease from last year's forecast, but it is still almost three times higher than the present stock of registered vehicles. In any case, the projected future stock of light-duty EVs remains substantial compared to today's levels.

Electric medium- and heavy-duty vehicles (MHDVs) are not yet being adopted at the same rate as light-duty vehicles. "Out of 978,748 total new truck registrations in 2024, Zero Emissions Trucks (ZETs) accounted for 2.3 percent of all registrations, down from 3 percent in 2023."[9] However, according to a 2024 NREL study, zero emission medium- and heavy-duty vehicles (MHDVs) may become cost competitive with diesel MHDVs on a Total Cost of Driving (TCD) basis by 2035.[10] For heavy-duty vehicles (Classes 7-8) in short-haul market segments, TCD parity is expected to occur in 2034.[11] As TCD parity comes closer to reality in the coming years, MHDV adoption can be expected to accelerate.

The average American drives about 13,500 miles annually,[12] and EVs average about 3.6 miles per kWh.[13] As a result, a typical LD EV may consume approximately 3,750 kWh per year, which means that the 2024 stock of EVs (6.2 million) consumed an estimated 23 TWh. Using BNEF's estimate of 22 million EVs by 2030, this translates into a demand of 83 TWh. Since electricity consumption in the United States in 2024 was 4,110 TWh[14], 60 additional TWh of EV consumption by 2030 represents a 1.5 percent increase from the 2024 total for all sectors. Electrified MHDV adoption would further increase this estimate. Furthermore, electricity consumption from EVs may reach over 1,500 TWh by 2050 according to the National Renewable Energy Laboratory's (NREL) Electrification Futures Study.[15] These trends for transportation electrification should be accounted for in load forecasts used for electric system planning, along with other sources of load growth.

2.2 Evolution of Distribution System Planning

The purposes of electric system planning, at the broadest level, follow many of the broader purposes of utility regulation, namely the provision of safe and reliable service at just and reasonable rates. In this context, investments can reasonably be made to accommodate load growth, replace aging infrastructure, or achieve reductions in other costs. A good planning process will also lead to increased confidence for regulators and stakeholders in utility decision-making, while recognizing that administrative costs and timelines for the planning

7 National Renewable Energy Laboratory. (n.d.). EVi-Pro: Electric vehicle infrastructure —Projection tool. https://www.nrel.gov/transportation/evi-pro.htm.

8 BNEF 2025 Electric Vehicle Outlook, https://about.bnef.com/insights/clean-transport/electric-vehicle-outlook/, Number of electric vehicles on the road in the US in 2030 from EVO 2024 and the updated EVO 2025.

9 Zeroing in on Zero Emissions Trucks," CALSTART, June 9, 2025, https://calstart.org/zio-zets/.

10 "Assessing Total Cost of Driving Competitiveness of Zero-Emission Trucks," 2024, Catherine Ledna, Matteo Muratori, Arthur Yip, Paige Jadun, and Christopher Hoehne from NREL and Kara Podkaminer from the U.S. Department of Energy. https://doi.org/10.1016/j.isci.2024.109385. The study recognizes that this transition is supported by various federal environmental and tax policies.

11 "Study Examines Cost Competitiveness of Zero-Emission Trucks – Tech Progress, Supportive Policies, and Infrastructure Investments Drive Down Costs and Spur Technology Adoption," NREL, April 2024, Julia Thomas. https://www.nrel.gov/news/program/2024/study-examines-cost-competitiveness-of-zero-emission-trucks.html.

12 US Dept. of Transportation, Federal Highway Administration, https://www.fhwa.dot.gov/ohim/onh00/bar8.htm?source=post_page.

13 Data Sources and Assumptions for the Electricity Sources and Fuel-Cycle Emissions Tool, https://afdc.energy.gov/vehicles/electric-emissions-sources.

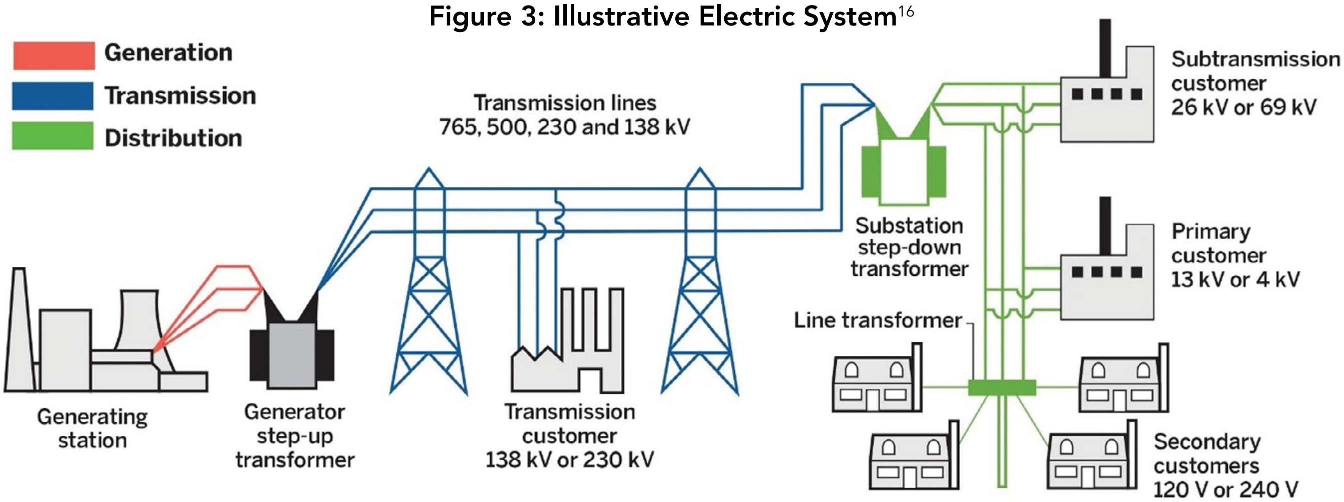
14 U.S. Energy Information Administration, Monthly Energy Review, November 2025, Table 7.1 Electricity Overview, https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_3.pdf.

15 Zhou, Ella, and Trieu Mai. 2021. Electrification Futures Study: Operational Analysis of U.S. Power Systems with Increased Electrification and Demand-Side Flexibility. Golden, CO: National Renewable Energy Laboratory. Pg. 3, Figure 2, "2050 High" for Transportation. https://www.nrel.gov/docs/fy21osti/79094.pdf.

process must be reasonable for utilities, utility commissions, and stakeholders. Decision-making by utilities, as well as the planning processes set up to guide that decision-making, must balance different types of risks and account for key uncertainties.

Each element of the electric system must be designed to support customer load reliably. Figure 3 illustrates a simplified version of the electric system, from large central generation facilities to small secondary voltage customers connected to the distribution system. The bulk generation and transmission system must meet resource adequacy needs for an entire region. The subject matter of this brief focuses on state-level distribution planning, which is shown in green in **Figure 3**.

Figure 3: Illustrative Electric System[16]



Source: Adapted from U.S.-Canada Power System Outage Task Force. (2004). *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*

Note that some large customers connect directly to the distribution system at primary voltage and a few very large customers connect directly to the transmission or sub-transmission system at even higher voltages. At the distribution level, substations must be sized sufficiently for all customer load in a smaller area. Line transformers must be sized for a small group of secondary voltage customers and in some cases a single secondary voltage customer. The service line, also known as a service drop, that connects an individual customer or building to the shared grid must have sufficient capacity as well, whether that one customer is a manufacturing facility connected to the transmission system or a home connected to a secondary voltage distribution conductor. Last but not least, the system must be kept within the allowed ranges for both frequency and voltage at all times.

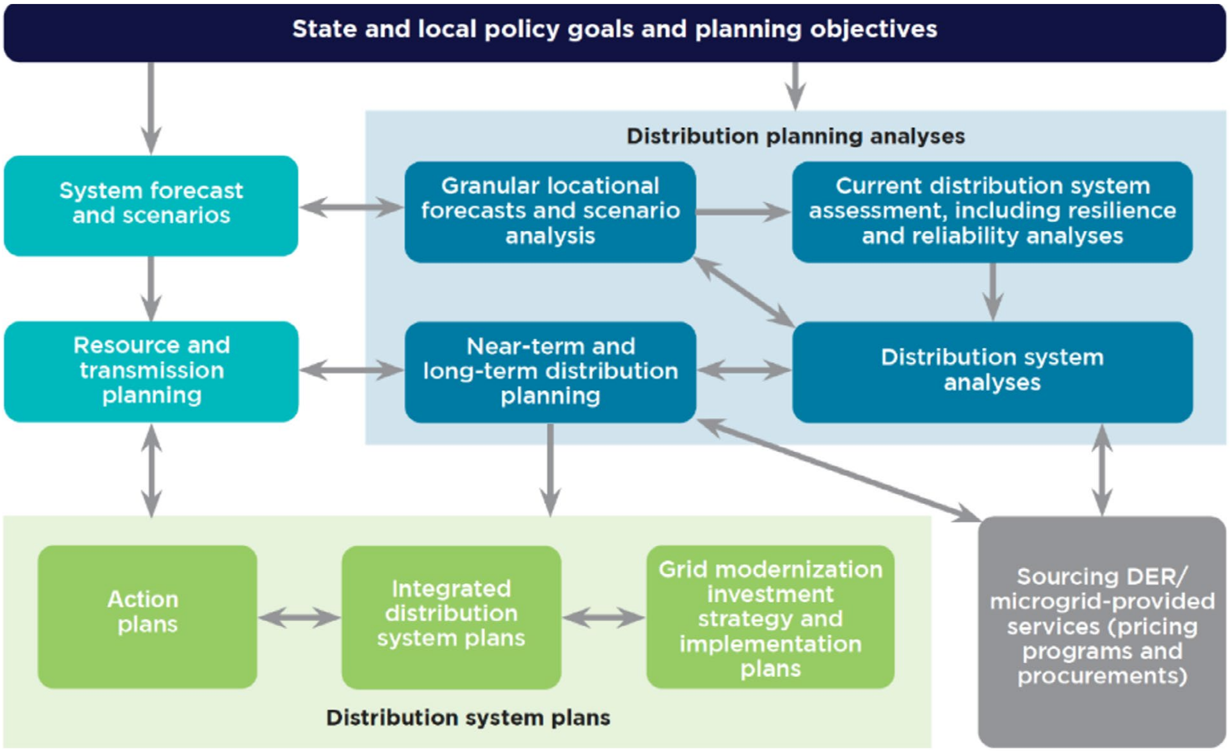
Electric distribution system planning received limited attention in the 1990s and 2000s, but, in the last 15 years, many state utility commissions have issued new requirements and implemented new processes.[17] **Figure 4** illustrates electric distribution system planning as a whole, which begins with state and local policy goals and planning objectives and moves through an interconnected set of steps that includes forecasting, distribution system analysis, and consideration of alternative approaches to provide reliable service.

The end result of this process is an investment plan or, more broadly, an action plan that guides a broad range of activities, as shown in the green shaded box in Figure 4. This can include investments, retirements,

16 Jim Lazar, Paul Chernick, William Marcus, Mark LeBel (Electric Cost Allocation for a New Era : A Manual (Regulatory Assistance Project, 2020), Pg. 32, Figure 7. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

17 Lawrence Berkeley Lab et al., State Requirements for Electric Distribution System Planning, December 2024, https://emp.lbl.gov/publications/state-requirements-electric.

Figure 4: Flow Chart for Electric Distribution System Planning[18]



procurements, programmatic changes, and new rate designs. While each jurisdiction has handled its relevant issues in different ways and at different paces, five important features for modern electric distribution system planning are described below in **Table 1**.

Table 1: Key Shared Features for Modern Electric Distribution System Planning[19]

Feature	Description
Advanced Forecasting and System Modeling	Improved locational detail for load forecasting, customer technology adoption, and up-to-date system modeling using granular data to identify system needs correctly.
Disclosure of System Needs and Value	Well-defined needs and values to scope alternative solutions.
Improved Solution Acquisition Practices	Traditional utility investments should be compared to programs, competitive procurements and improved customer pricing options.
Support for Innovation	New system technologies and customer programs should be fully considered, including testing and scalable pilots.
Meaningful and Equitable Stakeholder Participation	Establishing processes for open dialogue, transparent information sharing, collaboration, and consensus building among utilities and stakeholders.

18 LeBel et. al., Opportunities for Integrating Electric and Gas Planning, Ernest Orlando Lawrence Berkeley National Laboratory, January 2025. Pg. 5, Figure 2. https://eta.lbl.gov/publications/opportunities-integrating-electric

19 Adapted from Gridlab, Integrated Distribution Planning – A Path Forward, 2019, Pg. 6. https://gridlab.org/wp-content/uploads/2019/04/IDPWhitepaper_GridLab-1.pdf

Many advances in distribution system planning have only become possible in the recent past because of the new functionalities and data collection enabled by advanced metering infrastructure as well as new sensors, communications, and controls. It is in this broader context that the challenges of increased EV load are emerging. Specific dockets that tackle proactive planning are often taking place in parallel with one or more other proceedings addressing electric distribution system planning issues. As an example of an expanded solution acquisition practice, procurement of non-wires alternatives has emerged in several states as a way to avoid or reduce distribution system investment costs when cost-effective demand-side resources are available.

One key theme of planning improvements is how to account for uncertainty and balance different kinds of risks. In forecasting, this can be done through scenario analysis or using more sophisticated probabilistic methods. The final investment plan or action plan can be determined, at least in part, by choosing investments and other strategies that may not be wholly necessary under a single deterministic central forecast but rather reduce certain kinds of risks and accommodate key uncertainties across a range of possible future scenarios.

2.3 Interaction of EV Charging Applications and Electric Distribution System Planning

While electric distribution companies rely on the investment or action plan to guide decision-making, events in the real world rarely perfectly match what was foreseen in the plan. As an example, load growth from EVs and other sources can occur faster or slower and those loads could be located in different places. Utilities have processes in place to ensure that new customers or significant incremental load (e.g., adding numerous fast charging stations) from existing customers can be served without significant risks to reliability. Any new customer must seek permission to connect to the grid and existing tariffs and other rules dictate when a customer must seek permission from the utility to significantly increase its consumption. This starts with a load service request from the relevant customer. In many cases, it is straightforward for the utility to see that there are no issues adding a single new customer. If a new home is built in a residential neighborhood, it may be the case that there is sufficient capacity on a local line transformer for that new customer and no risk of that customer adversely impacting the broader distribution system in any way. While it may take some time for administrative formalities and to schedule a crew to do the work, these are routine tasks that do not take an unusual amount of time or an inordinate amount of money. The same can be true for larger loads that are located on circuits with a significant amount of headroom.

However, if there are any reasonable questions about the distribution system's capability to accommodate a new customer or incremental load, a utility process will take more time. Such a load service request may require an energization study, assessing whether the existing electrical system can safely and reliably deliver power to the new load without overloading equipment, violating voltage limits, or otherwise compromising reliability.[20] An energization study typically involves power flow analyses, transformer capacity examination, and voltage drop analyses, along with coordination among the customer, landowner, utility and other authorities that have jurisdiction. If the study reveals that the existing system cannot safely and reliably accommodate the new load, then it must be determined what investments or other system changes are needed. These analyses can take a significant amount of time and may reveal that expensive upgrades are needed to accommodate that new load.

2.3.1 EV Charging Applications

Addressing these specific challenges for the distribution system requires a more detailed understanding of EV charging applications. EV charging equipment is categorized by the voltage and size of the power draw in kW. The three major use cases most relevant to locational distribution planning, light-duty Level 2 charging, DCFC, and MHDV fleets, are summarized in **Table 2** then described in more detail.

20 EV Charging Infrastructure Energization: An Overview of Approaches for Simplifying and Accelerating Timelines to Processing EV Charging Load Service Requests, Section 4.2, page 16, Pacific Northwest National Laboratory (2025) https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_151131.pdf

Table 2: Summary of Charging Use Case Characteristics

Characteristic	LD L2	L3 DCFC	MHDV Fleets
Energization Time	• Short (weeks or months) • Significant study only required for larger banks of L2 installations.	• Longer (months or years) • Typically requires an energization study.	• Longer (months or years) • Typically requires an energization study.
Size of Load	• Small - Medium (kW)	• Medium - Large (kW–MW)	• Medium - Large (100s of kW to MW)
Location of Load	• Widely distributed	• Along highway corridors and urban areas.	• Clustered around commercial and industrial areas.
Flexibility of Load	• High	• Low	• Low - Medium

2.3.1.1 Level 1 Charging

The smallest charging applications are known as Level 1, which is equivalent to plugging an EV into a standard residential wall outlet. This is a 120V application, with a typical power draw around 1-2 kW.[21] This is equivalent to many other household appliances, would almost never be limited by the capacity of a customer's electric panel, and requires no special attention in distribution planning.

2.3.1.2 Light Duty Level 2 Charging

Level 2 EV charging equipment uses either 208V or 240V depending on the customer type. Power draw for this type of equipment can range from 3 to 20 kW[22]. Towards the lower end of this range, this is similar to other major household appliances such as an electric tank water heater. At the higher end, this would be the biggest single power draw at a residential customer location, but to date this may be limited to customers who are buying certain kinds of electric light-duty trucks.

In many cases, Level 2 charging installations requires no load service request or energization study but should be considered broadly in load forecasting for distribution system planning. In some cases, particularly if bundled with the installation of other new electric end uses, installation of a single Level 2 charging appliance could trigger the need for a new customer electric panel with a higher capacity, particularly in older houses with 100A panels. Such a panel replacement would often call for involvement of the local utility, because it may require replacement of that customer's service line or potentially impact the line transformer serving that customer. Alternatively, a customer could avoid the need for any service line upgrades by installation of a smart panel with energy management technologies instead of a larger capacity panel.[23]

Larger installations of multiple Level 2 charging stations, in a commercial parking lot, an employee parking lot, multi-family housing or a public location, will more frequently require an energization study by the utility. In cases where utility upgrades are required, it may take a substantial amount of time to approve and energize those Level 2 charging stations, often measured in weeks or months. Level 2 charging applications are also

21 "Fact #995, September 18, 2017: Electric Vehicle Charging at Home Typically Draws Less than Half the Power of an Electric Furnace," Energy.gov, September 18, 2017, https://www.energy.gov/eere/vehicles/articles/fact-995-september-18-2017-electric-vehicle-charging-home-typically-draws.

22 "Electric Vehicle Charging Stations," Alternative Fuels Data Center: Electric Vehicle Charging Stations, https://afdc.energy.gov/fuels/electricity-stations.

23 Smart Electric Panels in Homes Could Prevent Overtaxing the Grid, Canary Media, July 18, 2022, https://www.canarymedia.com/articles/grid-edge/smart-electric-panels-in-homes-could-prevent-overtaxing-the-grid.

relatively flexible.[24] Vehicles are often charging at these stations for many hours, so a modest interruption or slowdown in charging may be acceptable. The start and end of charging sessions are also controllable in many cases, particularly if a vehicle is being charged overnight at home.

2.3.1.3 Level 3 Charging and DC Fast Charging

Level 3 charging, also known as direct current fast charging (DCFC), is another distinct category of charging applications. DCFC typically requires 480V service, meaning that it is not possible to install these types of stations at secondary voltage residential and commercial customers. Each charging port at a DCFC may draw up to 500 kW instantaneously, so a bank of DCFC stations can easily have a maximum power draw measured in MW. This means that DCFC stations have load profiles more in common with large commercial and industrial customers than everyday residential uses. In many cases, DCFCs are sited on travel corridors for maximum convenience during longer distance trips. In such a case, load is relatively inflexible because drivers expect to charge quickly and return to the highway. DCFC may also be a valuable service for EV drivers in urban areas who do not have dedicated charging available.

Connection to the distribution system for DCFC is a significant undertaking unless they are co-located with a major large commercial or industrial electricity use. This means they will nearly always require an energization study. The investments necessary to enable DCFC to connect to the distribution system can be quite significant; the study itself may take months, and the investment required can take months or years after the study. In many cases, DCFC may benefit from transmission level service instead of a connection to the distribution grid. Importantly, some charging station operators have also developed DCFC stations that utilize battery storage to enable a lower cost connection at secondary voltage, which makes the process more similar to a large Level 2 charging station as described above.

2.3.1.4 MHDV Charging – A mixed application.

Charging applications for medium- and heavy-duty fleets blends a mix of issues relevant to both Level 2 charging and DCFC.[25] Some types of medium-duty electric trucks share much in common with larger light-duty trucks, which requires larger capacity Level 2 charging applications to recharge their battery in a reasonable timeframe. In some cases, medium-duty trucks may require or benefit from DCFC for certain applications. This means that most medium-duty fleets will have a maximum simultaneous power draw measured in the hundreds of kW and likely need to be served at primary distribution voltage. In many cases, this will require an energization study which takes months and any subsequent distribution system investments would add to the timeline.

Heavy-duty fleets will always require higher voltage charging more similar to DCFC, or could even be considered in a category even higher than DCFC. The EV charging industry is developing standards for a Megawatt Charging System for heavy-duty vehicles.[26] As a result, nearly all heavy-duty applications will require an energization study, and many will require significant distribution system investments to enable their connection. Once again, these applications may benefit from a direct connection to the transmission system.

Fleet vehicles typically operate on schedules that are dictated by the needs of the business and are thus less flexible than many Level 2 charging applications. However, because many businesses have some discretion over a fleet operating schedule, this may represent a middle case, including the potential for external battery storage to smooth power draw and shift grid usage in some cases. Furthermore, school bus fleets are a heavy-duty application with significant downtime, which enables more flexible charging schedules and the usage of the bus battery as a resource. Lastly, MDHV applications, outside of highway corridor travel needs, will likely require charging in or near their base of operations, which will be in commercial and industrial areas.

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24 Unlocking System Savings With Flexible EV Charging: Lessons From Colorado, RAP (2024), https://www.raponline.org/wp-content/uploads/2024/06/RAP-ICCT-farnsworth-enterline-basma-kadoch-unlocking-system-savings-flex-ev-colorado-2024-june.pdf

25 Light-duty fleets would typically be served by a large bank of Level 2 charging stations discussed above.

26 Argonne National Laboratory, Charging for Heavy Duty Electric Trucks, March 2023, https://www.anl.gov/sites/www/files/2023-03/MCS_FAQs_Final_3-13-23.pdf.

3 Proactive Planning Benefits, Challenges, and Strategies

Several states have begun to experience a growing volume of requests from customers seeking electricity service for EV charging installations. These requests differ from those of more traditional sources of organic demand growth that tend to increase more gradually over time or, in the case of large traditional load additions, with sufficient advanced notice through forward-looking construction timelines and new service requests. As a result, some new emerging sources of demand, including EV charging facilities, are more challenging to anticipate and forecast using traditional methods alone.

When there is insufficient distribution capacity to serve demand at the time new energization requests are made, investments in distribution capacity or other form of capacity relief are pursued. Capacity investments, however, often require considerably more lead time to deploy than is required to energize charging facilities in a distribution system with sufficient capacity to serve this demand. Insufficient grid capacity thus often results in energization delays for charging facilities seeking grid connection.

While one possible approach to solve this constraint could involve investing in increasing distribution capacity broadly, any state public utility commission (PUC) will be conscious of ratepayer costs and want to balance adequate utilization of these investments and customer costs. As a result, several jurisdictions have been investigating tailored approaches for addressing this dynamic through emerging efforts in proactive planning.

Proactive planning recognizes the nature of emerging and evolving sources of demand, including EV charging, and the challenges associated with accurately anticipating their impact on the grid. These planning approaches are designed to mitigate risks associated with uncertainty in projecting demand, recognizing that actions and investments will be needed despite the uncertainty. Proactive planning strategies include: refining forecasting inputs and methods (e.g., more temporally and spatially granular load forecasts), reconsidering criteria for when additional capital investments will be warranted, and considering a wider range of solutions for providing load relief, such as expanding operational flexibility.

Proactive investments resulting from planning are designed to ensure that the electric system can accommodate future demand (including from EV charging and other large loads) efficiently, reliably, and at lower long-term costs.

By incorporating trends in EV adoption, regional development, policy-driven electrification goals and other refinements in forecasting, utilities can identify where capacity constraints are likely to emerge and invest strategically in substations, feeders, and other distribution assets before they become bottlenecks. Although such investments require upfront expenditures and carry some uncertainty regarding timing, location, and scale, they can enable faster project energization and minimize more costly unplanned and reactive upgrades.

The following sections compare the differences between traditional and proactive planning and discuss the rationale for further refinement in planning processes and approaches along with examples being put into practice today.

3.1 Benefits of Proactive Planning

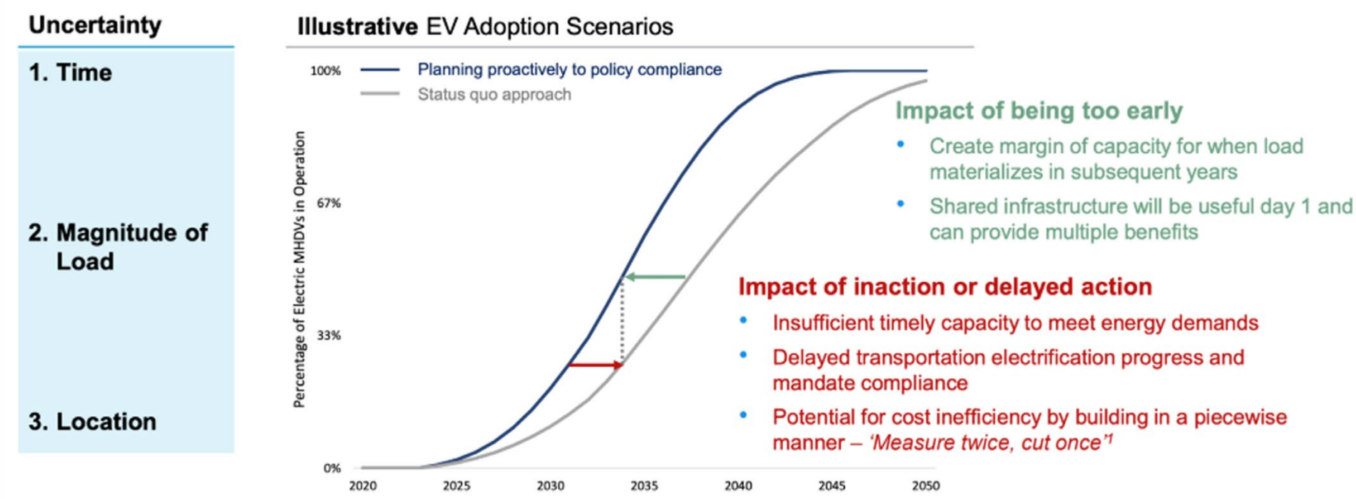
Utilities and their regulators consider proactive investments on the distribution system for transportation electrification for various reasons, including reducing energization times and promoting cost efficiency, which are explored below.

3.1.1 Reduced Energization Times

In the context of the investigations underway, utilities propose proactive investments to address a time lag challenge. MHDV charging equipment can typically be purchased and installed within 6-12 months.[27] However, development timelines for upgrading distribution grid infrastructure will take longer.28 Feeder upgrades typically take 1-2 years to build and substation upgrades can take 2-4 years or more.29 This time lag can lead to prolonged energization timelines for charging equipment and ultimately slow EV adoption.

The grey "status quo" adoption curve in **Figure 5** illustrates how EV adoption is hindered by energization delays. The blue line illustrates how EV adoption can be accelerated by planning proactively.

Figure 5: Illustrative Impacts of Proactive Investment on EV Adoption[30]



When proactive investments are made, hosting capacity becomes available before the EV charging load materializes. This mitigates the time lag, and EV adoption can proceed along the left-hand curve in Figure 5. In the absence of proactive investment, a lack of hosting capacity can lead to delayed energization, and the resulting pace of EV adoption is likely to proceed along the slower, right-hand curve.[31]

It is worth noting two additional aspects of Figure 5. First, in the left column, the figure lists three uncertainties that affect investment decisions. These are the primary uncertainties that utilities must address to justify proactive investments to regulators: (i) the gap between the time that investments in system capacity are made and the time that the EV load materializes; (ii) the size of the load(s); and (iii) the locations where infrastructure will be needed. Note also that the "impact of inaction or delayed action" implicates "cost inefficiency by building in a

27 This timing challenge is discussed in Proactive Grid Investment Assessment Medium-and Heavy-Duty Vehicle Transportation Electrification," ("Proactive Grid Investment") EDF (2024) page 12. https://library.edf.org/AssetLink/atal4338qv8ucl8226qok35dmm170r4e.pdf.

28 Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resoure Planning Data Portals, and Integration Capacity Analysis Maps, Planning and Project Execution. Table 6, page 27. (Planning and Project Execution). https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M539/K999/539999224.PDF.
Order Establishing Proactive Planning Proceeding, (Aug 2024), California Public Utilities Commission, 9/13/24 Figure 1, page 13.

29 Some delays have been reported at up to 8 years. "Proactive Grid Investment Assessment Medium-and Heavy-Duty Vehicle Transportation Electrification," 2024, page 12. https://library.edf.org/AssetLink/atal4338qv8ucl8226qok35dmm170r4e.pdf.

30 EV Proactive Planning Studies Technical Conference Presentation, ConEdison and National Grid, NY Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure, Slide 7, November 2, 2023. ("EV Proactive Planning Studies").

31 It should be noted that stop-gap fleet management efforts can help mitigate the lack of behind-the-meter hosting capacity. Generally speaking, limited hosting capacity results in delayed energization, which is the case for EV charging equipment and any other new loads (e.g., new housing development, industry). Absent proactive planning, customers will be unable to charge their fleets if no interim solutions or non-wires alternatives are used.

piecewise manner." This points to the importance of promoting cost efficiency by "right sizing" the proactive infrastructure investment.

3.1.2 Cost-Effective Investment Patterns

The right sizing of infrastructure investment is a component of a utility planner's set of considerations. According to EPRI, "[r]ight-sizing strategies seek to ensure deployment of distribution capacity and capabilities of the right scope, at the right time, and in the right place."[32] The idea is that right sizing is likely to be less costly than trying to meet the same load by building piecewise over an extended period (i.e., "dig once"). Another consideration in planning for a capacity-related upgrade involves investigating cost-effective options such as retrofitting component(s) so that another capacity upgrade is not needed before the end of useful life of anything recently installed.

The rationale behind right-sizing infrastructure investments is supported. For example, decreased costs can result from labor efficiencies of mobilizing crews once for a single large project vs. multiple smaller projects; lower administrative and regulatory costs come from seeking permits and approvals once vs. many times.[33] Economies of scale can also decrease costs, at least on a unit basis, and have been documented for distribution system circuits and substations in PG&E's territory.[34] A study by Black and Veatch also found that "proactive planning approaches generally yield lower cost outcomes than a sequential approach."[35] However, it is possible for such savings to be offset by the cost of building infrastructure too far in advance of the load. While our research uncovered several studies in support of building once, there is not an extensive record of implemented proactive approaches and their cost-effectiveness at this time.

3.2 Challenges and Risk Mitigation

Several characteristics unique to electric transportation make anticipating the level of customer demand to be served differently from forecasting traditional customer loads, which can influence whether the benefits of proactive investments will be realized.

Nature of the Demand

- **Size:** The magnitude of customer EV demand can significantly exceed that of other end-uses, requiring higher draws of existing grid capacity to serve this demand.
- **Time:** Uncertain rates of customer adoption of EVs, due to market conditions, policies, or other factors make it difficult to project the timing of when this source of demand will materialize over a long-term planning horizon.
- **Location:** The location of where on the electric system this demand will materialize is an additional challenging dimension to account for in anticipating system needs and capacity to serve this demand.
- **Other:** Once charging infrastructure is installed, the effective demand on the grid can vary based on the class of vehicle, customer driving and charging behavior, presence of time-varying rates, and other factors.

Risks and Risk Mitigation Approaches

A misalignment in the magnitude of the projected and realized demand could result in delayed energization of charging infrastructure if there isn't sufficient grid capacity to serve the required levels of demand at that

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32 Designing Distribution Systems to Enable Deep Decarbonization, An Introduction to Right-sizing the Distribution System to Meet Future Needs, EPRI, August 2024, page 3.

33 Proactive planning will also help with factors that have nothing to do with transportation electrification. The U.S. is currently entering a period of load growth generally, so building electrification and data center growth could be relevant factors.

34 "What Will Electrification Cost (the Distribution System)?" June 2022. Table 3 https://energyathaas.wordpress.com/2022/06/27/what-will-electrification-cost-the-distribution-system/

35 "Proactive Grid Investment, page 16. https://library.edf.org/AssetLink/atal4338qv8ucl8226qok35dmm170r4e.pdf.

location or higher costs to customers for investments that were not ultimately required if demand did not materialize where and when projected.

Though the risk of taking the wrong action in response to more uncertain forecasts of EV demand is clearly present and top of mind, there are also risks associated with inaction in pursuing solutions to this growing segment of energy demand. Not acting on grid investments or solutions that can provide grid relief because the EV forecasts are more uncertain relative to traditional loads could result in delays in interconnecting demand, a narrower set of sub-optimal solutions to choose from once the nature of the demand is more certain, and reliability issues when effective capacity to serve demand is in short supply.

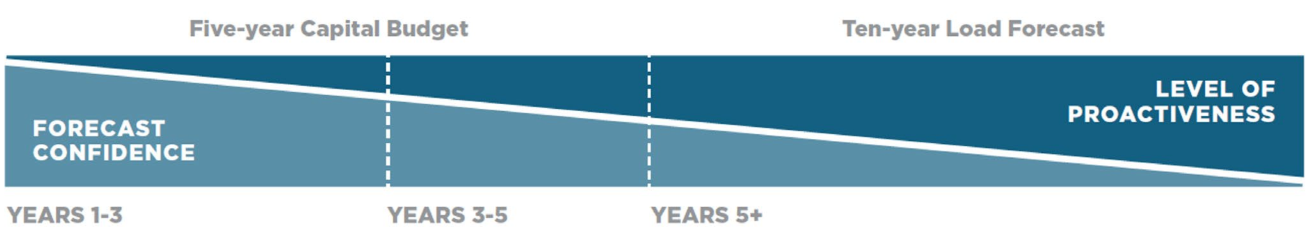
Given the tradeoffs between action and inaction on investments in the face of uncertainty in forecasting EVs, it becomes important to explore ways in which these risks could be better understood and mitigated. Options for mitigating risks can include:

- Exploring and developing additional data sets and methodologies that account for EV adoption trends in response to market conditions, customer usage trends, and other factors to narrow the variance in uncertainty between forecasting traditional sources of customer demand and EV charging – revisiting these adjustments periodically and as necessary.
- Identifying and coordinating areas of continual improvement in EV planning forecasts and approaches across other planning processes to ensure consistency and appropriate responsive action using the best available data.
- Mitigating the risk of stranded or underutilized assets not only through better forecasts, but also through operational adjustments in the grid such as transferring loads through new electrical connections from congested areas in the grid to areas with excess capacity, particularly in dense and urban areas where connections to loads can more readily be moved around.
- Considering diversity in customer project type and charging application when assessing risks. Risk may not be uniform across all EV demand served, classes of vehicles, or desired configurations. Thus, a mitigation strategy tailored to the particular dynamics of specific charging facilities may be more appropriate than a blanket approach.

3.3 Proactive Planning Strategies

Proactive planning falls on a continuum that seeks to balance forecasting confidence and investment timeframes, as illustrated in **Figure 6**.

Figure 6. Proactive Planning Continuum[36]



Though forecasting EV charging needs can be challenging, its potential impact on grid capacity and the benefits of well-supported planning reinforce the idea that it is very important. Many states have attempted to improve forecasting data, assumptions, and methodologies in order to better manage the uncertainty that accompanies the development of projections of EV demand.

36 Zach Pollock, Xcel Energy, Proactive Investment Framework (CHARGED, 2025), 14, Figure 3, https://chargedinitiative.org/wp-content/uploads/2025/12/CHARGED_Proactive-Investment-Framework_Report_updated_12_15.pdf.

3.3.1 Load Forecasting Methods

Under traditional planning processes to meet future demand, the timing, size, and location of new load to be served is either known (i.e., based on a new service request) or is well understood through observations of long-term customer usage (e.g., lighting and cooling product turnover) and other historical trends. Using these forecasts of demand, planners evaluate and identify investments that can reliably, and cost effectively serve demand when it arrives on the system.

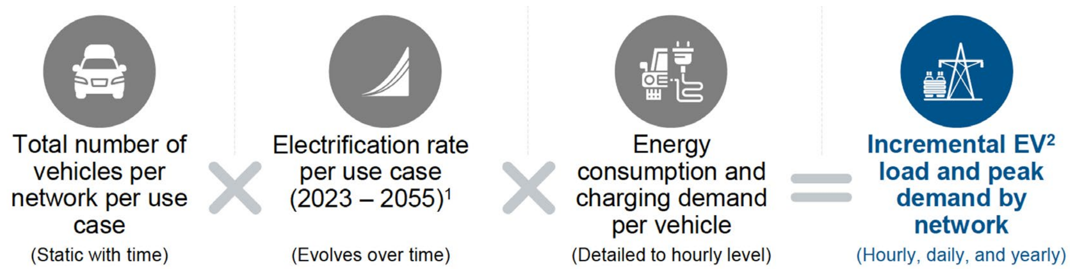
In contrast, proactive planning approaches apply to emerging sources of demand whose timing, size, and location are more difficult to predict than the traditional sources of demand, but for which waiting until closer to the date of energization could mean a more costly set of system investments are required as the only viable options that can be pursued in time to reliably meet demand. At a high level, public policy requirements for EVs can be built into load projections, which should be developed consistently across proceedings. Additional scenarios can be developed, as well as other forms of sensitivity analysis, to help address broad uncertainty about the level and pace of load growth due to EV charging.

To address these uncertainties, utilities are working to increase the quality of their load forecasts in a more granular and location-specific way. Because long term trends for EV charging are not yet discernable in historical load data, traditional forecast methods alone are not likely to accurately estimate the timing, size, and location of the load at the same level as other traditional sources of demand. In the context of proactive planning, traditional load forecasting methods are supplemented by methods that use more granular data. These data may include the electrification rate of different vehicle classes, the load profiles of different vehicles, the efficiency of various charging levels, and other assumptions. The combination of more granular data and probabilistic forecast methods provides a more detailed estimate of the timing, location, and size of future EV loads. This is essentially the incorporation of bottom-up estimates for EV charging into the load forecast.

These forecast methods are a distinguishing feature of proactive investment planning. Two examples highlighted here, one from New York and one from Colorado, illustrate how more temporally and spatially granular load forecasts are being used to address the uncertainty of making a proactive investment.

As shown in **Figure 7**, Con Edison and National Grid's approach in New York involves estimating 1) the number of vehicles on each network 2) the electrification rate, and 3) the energy and charging demand. When these three estimates are combined, the result is a forecast of "incremental EV load and peak demand by network." The data that feeds this process can come from depot databases, vehicle telematics, or adoption modeling.

Figure 7: Consolidated Edison and National Grid's EV Load Forecast Approach[37]



Source Con Edison and National Grid

In contrast, **Table 3** illustrates Xcel Colorado's forecasting evolution across six different categories from prior to 2021 through 2024. Its "Forecasting Methodology" has changed from being reactive and deterministic to being proactive and probabilistic. In other words, rather than assuming all variables and parameters are known with some amount of certainty, Xcel Colorado's probabilistic modeling reflects uncertainty by assigning probabilities to certain outcomes, thereby allowing for a wider range of possible results.

37 EV Proactive Planning Studies Slide 10, November 2, 2023

Table 3: The Evolution of Xcel Colorado's Distribution System Forecasting[38]

	Prior to 2021	2021 to 2022	2023 to 2024
Forecasting Methodology	Reactive & Deterministic	Reactive, Deterministic & Probabilistic	Proactive & Probabilistic
Temporal Considerations	Peak Hour per Asset & Growth Coincident with Peak	Time-Series TLY Curves (8760) & Load Curves	Time-Series TLY Curves (8760) & Load Curves
Forecasting Adoption	Applied Fixed Growth Rate	Spatial Allocation & Propensity Modeling	Spatial Allocation & Propensity Modeling
Growth Vectors	Service Applications	Service Applications & Corporate Energy Sales	Service Applications, Corporate Energy Sales, Clean Heat Plus BE, EV Growth, BTM PV
Planning Scenarios	Single Scenario	Single Scenario	Two Scenarios
Forecasting Tools	Itron's Distribution Asset Analytics (DAA)	Integral Analytics' LoadSEER	Integral Analytics' LoadSEER

"Temporal Considerations" in Xcel Colorado's analysis have also evolved by becoming much more granular over this time period. Prior to 2021, the peak hour per asset and growth in the coincident peak load were the primary temporal considerations. Since then, hourly loads across all hours of the year have become the norm. Similarly, "Forecasting Adoption" has become more spatially specific and is now based on "propensity modeling," a statistical technique that endeavors to predict the chances of something happening, instead of making assumptions about fixed growth rates.[39] Xcel Colorado's number of "Growth Vectors" has increased to encompass multiple electrification and DER trends, including clean heat (heat pumps), beneficial electrification (BE), EV growth, and behind-the-meter solar (BTM PV) adoption trends. Xcel Colorado is also quantifying a second planning scenario, and its forecasting tools (i.e., the software they use to do these analyses) have been modified to enable many of the changes described.

3.3.2 Investment Approval Pathways and Analysis Approaches

Once the timing, size and location of the load has been forecast, distribution system planning can begin to identify networks where investment is likely to be needed. The capacity of the electrical network varies as illustrated in New York by National Grid's case study feeder (see **Figure 8**). The case study approach can encompass an "area of need" where the infrastructure cannot accommodate much additional load or an "area of capacity" that can accommodate additional load.

These categorizations are made with the improved forecast with more granular information on transportation electrification, including the locations of first-mover fleets, municipal and transit fleets, high concentrations of commercial fleets, commercial and industrial zones, airports and seaports, interstate corridors and service locations, and other areas of high-density truck traffic.[40]

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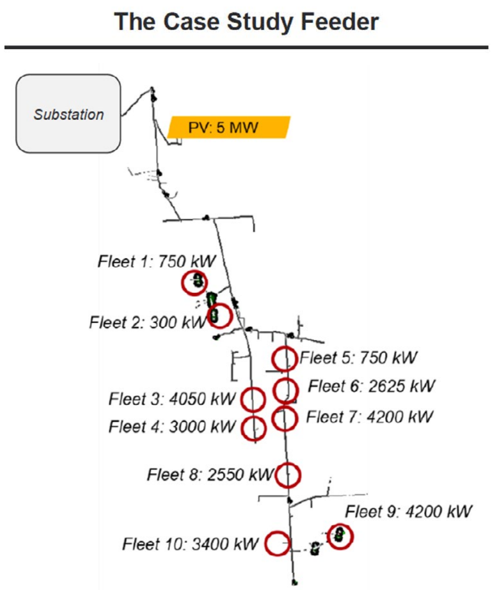
38 Public Utilities Commission of the State of Colorado, December 2024, Direct Testimony and Attachments of Jack W. Ihle, PSCo 2025-2029 Distribution System Plan and Grid Modernization Adjustment Clause, Figure JWI-D-3. ("Ihle Direct"), https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1032788.

39 Probablistic modeling selects randomly from a sample distribution (e.g., monte carlo modeling) while propensity modeling builds a data-driven profile of a customer(s) who is likely to adopt or invest in EVs and EVSE.

40 Id. Slide 18.

Figure 8: National Grid's Case Study Feeder[41]



About the Case Study Feeder

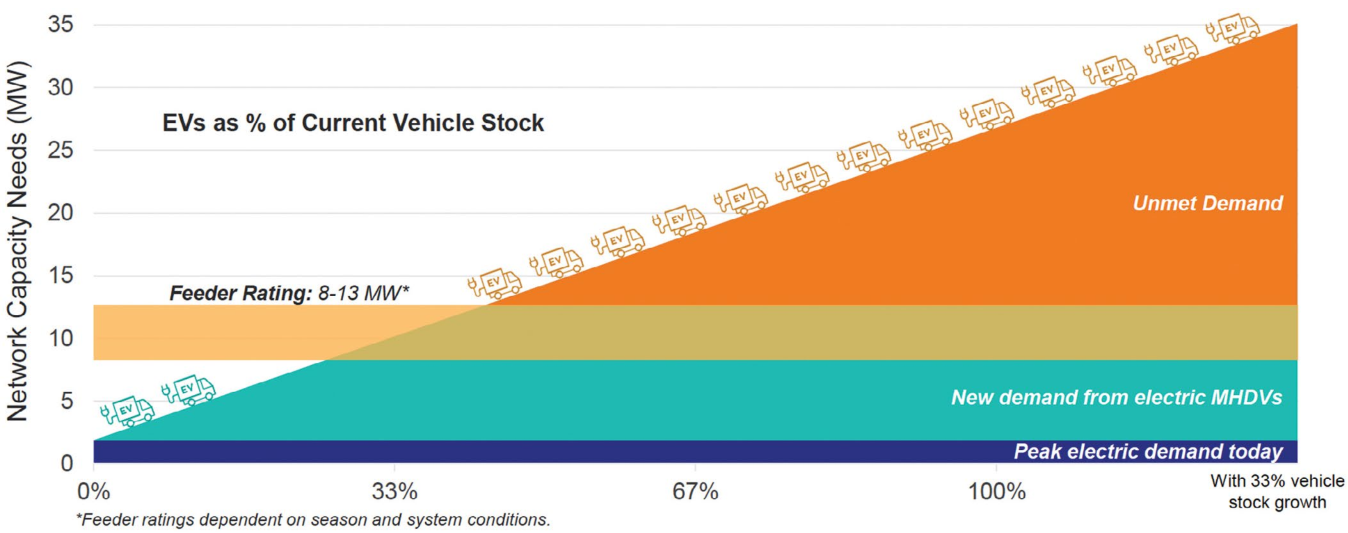
There's currently plenty of room on this distribution feeder for EV charging…	• Current peak load is only 2 megawatts. • Depending on season, the line is rated for 8-13 MW of load – which can support plenty of EV charging.
…but the **electrification of 400+ trucks** will eventually exhaust that capacity.	• Electrifying <u>all</u> trucks in the area will up to 25 MW of load ***– up to a 12x increase***
Luckily, **we may be able to "tap" neighboring lines** or substations for capacity.	• Currently, there's room on neighboring distribution lines / substation – so the utility can switch some depots over to accommodate further electrification.

This feeder is what we call an "Area of Capacity" – it can accommodate many electric trucks, but will still need careful planning and investment in the long-term.

The case study feeder shown in Figure 8 has surplus capacity. It can serve an additional 6-11 MW of EV charging at peak. However, there are ten different fleet operators on the feeder, and they may seek to electrify over 400 trucks at unknown times in the future. This could result in a load that could reach 25 MW, about twice the present capacity of the feeder. One potential way to serve this load is to tap a neighboring line or substation to make use of its surplus capacity, which is referred to as a load transfer.

The point in time when the feeder's capacity is exceeded will be affected by the adoption rate of EVs on the feeder, which is estimated as part of the bottom-up load forecast. As shown in Figure 9, the surplus capacity on the case study feeder is likely to be exhausted when the MHD EV adoption rate reaches about 33 percent. This is the point at which additional investment will be required. Some level of proactive investment might

Figure 9: Capacity Limitations on National Grid's Case Study Feeder as MHDVs Electrify[42]



41 Id. slide 18.

42 Id.

be economic at some point in the future prior to full realization. Whatever the eventual solution is, the case study feeder illustrates that careful planning is required to accommodate a potentially large and uncertain load energization timeline.

In a September 2025 decision, the New York Department of Public Service approved a new proactive planning framework along with a new pathway for approval of urgent upgrades that must take place before the implementation of the reform planning process.[43] This new framework will allow each utility to file an annual report specifically requesting authorization for proactive distribution system upgrades that were not anticipated in longer term capital plans. Specific justifications will need to be presented for these investments and detailed reporting requirements will be implemented for approved investments as well.[44]

In Colorado, Xcel's Distribution System Plan uses a base forecast as the foundation for conducting location-specific distribution engineering analyses. The results of these analyses are summed into a capital budget that is intended to support investments to meet the base forecast. As shown in **Table 4**, the budget includes eight investment categories, three of which include proactive investments: capacity, new business, and the transportation electrification plan.

Table 4: Xcel Colorado's 2025 – 2029 Distribution Capital Budget ($Millions)[45]

Category	2025	2026	2027	2028	2029	Total
Asset Health & Reliability	$286	$320	$342	$364	$400	$1,713
Capacity	$289	$413	$478	$472	$427	$2,078
Tools & Communications	$13	$13	$16	$17	$17	$75
Mandates	$53	$54	$55	$56	$57	$275
New Business	$132	$137	$145	$159	$162	$736
Transportation Electrification Plan	$53	$86	$90	$106	$107	$442
Wildfire	$324	$412	$505	$455	$468	$2,164
AGIS	$27	$2	$10	$0	$0	$39
Total:	**$1,177**	**$1,436**	**$1,641**	**$1,628**	**$1,639**	**$7,522**

While the use of benefit-cost analysis (BCA) is a relatively new best practice in the context of distribution system planning, providing quantitative evidence that proactive investments are cost-effective or pass a relevant BCA test is an important criteria in many states. In Minnesota, grid modernization projects must include a BCA based on the best information that it has at the time, including a discussion of non-quantifiable benefits. Massachusetts requires Electric System Modernization Plans (ESMP) to show portfolio-level net benefits, and Colorado specifies that the Total Resource Cost and Utility Cost Tests explicitly incorporate clean-energy and equity goals. Proactive projects in New York must demonstrate project need, value, and alignment with policy goals through cost benefit analysis. Finally, California's cost-benefit methodology consists of a detailed process that ensures that every proactive investment decision is justifiable against state policies, alternatives, and long-term risks.

In addition, all five states investigated for this paper incorporate equity into proactive planning through mechanisms ranging from quantitative scoring to formal procedural requirements. For example, Colorado requires that capital investments prioritize and directly benefit Disproportionately Impacted Communities

43 Order Adopting Modified Proactive Planning Framework, New York Department of Public Service, Case 24-E-0364, issued September 18 2025.

44 Id. at p. 30-33.

45 Ihle Direct page 11.

(DICs) and requires the use of the Colorado EnviroScreen tool to integrate DIC status into the climate resiliency risk scoring and reliability performance incentives. California evaluates equity in its proactive planning reports by tracking customer enrollment data in low-income assistance programs and by using CalEnviroScreen data. It also requires utilities to submit annual Community Engagement Plans that address the needs of Tribal, disadvantaged, and Environmental and Social Justice (ESJ) communities. Massachusetts requires its utilities to implement a comprehensive equity framework that is focused on procedural and distributional equity. Specifically, Massachusetts requires coordination with the Community Engagement Stakeholder Advisory Group (CESAG) to develop policies concerning language access, environmental justice (EJ), and the equitable siting of distribution infrastructure. Finally, New York requires that project prioritization criteria incorporate impacts to Disadvantaged Communities (DACs).

4 Proactive Planning Proceedings & Processes

In researching this paper in 2024, the authors identified states where proactive planning was being considered in regulatory proceedings. Section 4 details key proceedings and orders in five states before synthesizing key process issues, including cost recovery.

4.1 State Proactive Planning Proceedings

Although the five states featured (CA, CO, MA, MN, NY) were not the only states that have started to address questions of proactive investment, their proceedings and related filings represented the most-current activity on the topic at the time, as shown in **Table 5**.

The proceedings in which proactive investments are a topic are unique to each state. For example, the California Public Utility Commission (CPUC) has been advancing the topic through three proceedings that are focused on (i) accelerating energization timelines for charging stations, (ii) planning for high DER futures, and (iii) Transportation Electrification Planning (TEP). In Colorado, the topic has been advanced through two proceedings, one that is focused on barriers to electrification and DERs and one that is focused on distribution system planning. Minnesota is also advancing proactive planning approaches in its distribution system planning proceeding.

A slightly different approach is being taken in Massachusetts where the topic is being advanced through a grid modernization proceeding. New York advanced the topic by focusing specifically on MHDV charging barriers, which is considered the most challenging of the three TE use cases.[46] However, the MHDV proceeding was recently broken out into a wider, more comprehensive proceeding that deals with proactive planning broadly, and where TE is just one of several issues being advanced.

Table 5: Regulatory Proceedings Where Proactive Planning is a Topic

State	Proceeding	Latest Decision or Filing[47]
CA	Energization	24-09-020, Order Instituting Rulemaking to Establish Energization Timelines; Rulemaking 24-01-018 Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays Decision (Sept. 2024)
	High DER	Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps (Oct 2024)Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resource Future. Rulemaking 21-06-017, Decision Adopting Improvements to Distribution Planning and Project Execution Process (Sept. 2024)
	Transportation Electrification Proactive Planning and Infrastructure (TEPI)	Scoping Memo & Ruling (Apr 2024)

46 As discussed in Section 2.3.1.

47 This column represents the latest information as of December 31, 2024. Please note that significant procedural milestones are upcoming, and readers are encouraged to monitor the development of these proceedings using the hyperlinks in the table.

State	Proceeding	Latest Decision or Filing
CO	Barriers to Electrification and DERs[48] PSCo DSP Proceeding	Interim Decision Of Hearing Commissioner Megan M. Gilman Addressing Commission Study Of Potential Barriers To Beneficial Electrification And The Deployment Of Distributed Energy (Apr 2024) ("Colorado Interim Decision") PSCo Distribution System Plan Application, Procedding No. 24A-E (Dec 2024) PSCo Distribution System Plan (Dec 2024)
MA	Elec. Sector Modernization Plan (Required Scope)	Order (Feb 2024)
MN	Integrated Distribution Planning	Notice Establishing Workgroup (Sep 2024) In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy, Notice Soliciting Stakeholder Members (9/2024)
NY	Barriers to MHDV Charging	CASE 23-E-0070 - Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure, Order Instituting Proceeding and Soliciting Comments (April, 2023)
	Proactive Planning	CASE 24-E-0364 - In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure, Order Establishing Proactive Planning Proceeding (August, 2024)

4.2 Commission Process Approaches for Considering Proactive Investments

One of the core roles of a utility regulator is to weigh the relative merits of utility company requests for approval of certain investment costs. As EV adoption increases, resulting in significant new and anticipated electricity load from EV charging alongside many other distribution-level loads, it is important to understand the options available to commissions as they review larger distribution system investment proposals on faster timelines than in the past.

4.2.1 Convening Workgroups or Workshops

Several commissions have found that a non-adjudicative approach, prior to opening a potentially formal adjudicative docket, is especially informative and useful in this somewhat novel context of proactive investment where there are few readily available models for action.[49] NARUC has noted that "some states have implemented nonjudicial approaches in preparing for EV grid impacts and other related issues, holding stakeholder engagement sessions and technical conferences to bring together representatives from the utility sector, auto

48 Please note that this proceeding is entitled "Implementation of Senate Bill 23-291" in the PUC's e-filing system.

49 "Oversight," Colorado Department of Regulatory Agencies, https://puc.colorado.gov/pucoversight. See also, "The Legal Process," Washington Utilities and Transportation Commission, https://www.utc.wa.gov/about-us/about-commission/open-public-agency/legal-process.

companies, charging software and equipment suppliers, transportation planners, vendors, technical experts, and intervenors to meet with Commission staff."[50]

In response to Xcel's 2023 Integrated Distribution Plan filing, the Minnesota Commission indicated that:

> [A]dditional record development is needed surrounding proactive grid upgrades and cost allocation. The Commission will therefore delegate authority to the Executive Secretary to establish a stakeholder process to develop a framework on cost allocation and proactive upgrades for Xcel.[51]

The Commission further noted that "the workgroup should clearly identify areas of agreement and disagreement to help facilitate a Commission decision on these issues."[52] Upon completion, the commission adds that the workshop process will be "followed by a notice and comment period on any framework followed by a Commission decision."[53]

In the Colorado Interim Decision," Commissioner Gilman determined that it would be beneficial to convene informal workshops to better understand issues related to proactive planning and investment in her state.[54] She determined that "the local utility's inability to add load—warranted further study as part of the examination already underway in this Proceeding of potential barriers to beneficial electrification in this state." Commissioner Gilman, consequently, convened a series of workshops "to solicit input from the diverse range of stakeholders including, among others, existing and prospective utility customers, builders and housing developers, local government officials, and utility representatives."[55]

These examples illustrate how a commission, through its convening authority, can use broader stakeholder engagement to explore specific topics like load forecasting or service-quality to better understand different aspects of proactive planning and investment. Open processes such as these involve many of the same stakeholders that will participate later in formal processes. Workshops can help familiarize both stakeholders and regulators with the many facets of a new subject and may assist in narrowing down the number of topics that are eventually litigated in a formal proceeding. Furthermore, this approach is especially useful where commissions find themselves resource-constrained. Commissions can request that the utilities and stakeholders develop and bring forward needed information to improve the general understanding of how proactive planning and investment would work in that jurisdiction.[56]

4.2.2 Scoping Orders

Typically, when a utility receives a formal request for service from a customer, the utility uses that request as part of its demonstration to the regulator that there is a need for investment. This customer request, sometimes referred to as a "load letter" might actually be an exhibit that gets attached to the filing containing a utility's investment proposal.

Today, public utility commissions operating in their formal adjudicative capacity routinely face questions about proactive investment and the need for distribution infrastructure investments within the expectation of growing electric transportation demand. While they may not be provided with evidence as tangible as a load letter to

50 "Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators," Charles Harper, Gregory McAndrews, & Danielle Sass Byrnett
October 2019, pg. 14, https://pubs.naruc.org/pub/32857459-0005-B8C5-95C6-1920829CABFE.

51 In the Matter of Xcel Energy's 2023 Integrated Distribution Plan, Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements, September 16, 2024, pg. 12. https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b90BDFB91-0000-C212-9EBA-FEC602C284D2%7d&documentTitle=20249-210223-01.

52 Id.

53 Id.

54 "Colorado Interim Order, pg. 3, April 18, 2024.

55 Id.

56 For more information, examples, and considerations, see NARUC, 2021, Stakeholder Engagement: A Decision Making Framework, https://pubs.naruc.org/pub/7A519871-155D-0A36-3117-96A8D0ECB5DA.

substantiate such a request, regulators can expect to review evidence that will provide a view into likely load growth and system capacity to accommodate this growth. Regulators will also use this evidence to assess the reasonableness of proposed proactive investment costs, and what incentives are best put into place to ensure that the company controls costs so customer rates and energy bills over time stay as low as possible.

Commissions have the best sense of their administrative capacity. Taking what they have gathered in informal workshops, commissions will be better prepared to articulate precisely the topics and issues that they want to review in a formal, adjudicated setting. Commissions issue scoping orders, as the name suggests, to notify parties of the extent of a formal investigation. Scoping orders also serve to focus parties' attention on the topics and issues that a commission wants to consider and those that it does not.[57] For example, in the Massachusetts Electric Sector Modernization Plan (ESMP) proceeding, the Department of Public Utilities (Department) indicated that it:

> "will investigate the forecast methods and net benefits proposals relied on by the Companies, the appropriate cost recovery framework for proposed ESMP investments (i.e., through base distribution rates and/or through annual reconciling mechanism(s)), as well as the relevant standards of review to be utilized.[58]

In the same order, the Department expressly indicated that it would not adjudicate: (1) the Companies' budget pre-approval requests, including for newly proposed [capital investment projects]; (2) cost allocation proposals; or (3) rate design or rate redesign proposals.[59]

Scoping can also work to break a larger filing into discrete pieces. This enables a more stepwise and manageable commission inquiry. For example, in New York, in response to the Public Service Commission's August 2024 order, the Joint Utilities[60] filed their "Long-term Proactive Planning Framework."[61] The Joint Utilities propose a scope to the investigation that is divided into four stages: "(1) load assessment; (2) planning and solution design; (3) project eligibility and prioritization criteria; and (4) proposal and authorization of eligible projects."[62] Taken together, these four stages comprise what the utilities refer to as a "cycle." The utilities indicate that "Cycle 1" will result in proposals in the fourth quarter of 2025.

Furthermore, they propose that this will be the first of three cycles expected to run into 2028.[63] This four-stage framework is still subject to approval, and it remains to be seen if it can serve as a structure in which proactive plans can be reviewed in a way that supports subsequent investment proposals. It is clear, however, that scoping is a useful docket management tool available to commissions to manage the breadth and many topics that come with proposals for proactive planning.

4.2.3 Cost Recovery for Proactive Investments

Proactive planning efforts have changed more traditional planning approaches by explicitly reflecting and addressing the uncertainty introduced by emerging and evolving demands for energy, including transportation

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57 Before issuing a scoping order, a commission takes comments from the parties to get their opinions on the appropriate scope of the investigation.

58 Massachusetts Department of Public Utilities, Interlocutory Order on Scope of Proceedings, D.P.U. 24-10/24-11/24-12 at 23 (February 20, 2024).

59 Id.

60 The Joint Utilities are Central Hudson Gas & Electric Corp. (Central Hudson); Consolidated Edison Company of New York, Inc. (Con Edison); Niagara Mohawk Power Corporation d/b/a National Grid (National Grid); New York State Electric & Gas Corporation (NYSEG); Orange & Rockland Utilities, Inc. (O&R); and Rochester Gas and Electric Corporation (RG&E).

61 Case 24-E-0364, In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure (Proactive Planning Proceeding), Order Establishing Proactive Planning Proceeding (issued August 15, 2024)

62 Joint Utilities Long-Term Proactive Planning Framework December 13, 2024, pg. 5.

63 Id. Figure 1 pg. 7.

electrification. However, approaches to utility cost recovery for proactive investments do not appear to have changed appreciably from more established regulatory practices.

Based on research for this paper, cost recovery for proactive investments appears to make use of existing rider and rate case mechanisms as summarized in Table 6.[64]

As noted in Table 6, cost recovery for PG&E's proactive investments will come though base rates. The CPUC, for example, writes, "SB 410 requires the Commission to grant interim rate recovery for energization related costs prior to determining whether they are just and reasonable as a part of PG&E's next GRC [i.e., general rate case] while clarifying that any costs not found just and reasonable are subject to refund."[65] Taking a slightly different approach in Colorado, Xcel proposes to use its proposed Grid Modernization Adjustment Clause ("GMAC") rider to recover costs associated with its 2025-2029 Distribution System Plan. Xcel Colorado states that this is consistent with Colorado Senate Bill 24-218 which directs that a "qualifying retail utility shall recover, on an annual basis, projected distribution activities" through the GMAC, to be established as part of this DSP.[66] Ultimately, however, Xcel Colorado proposes to incorporate GMAC costs into base rates.[67]

Table 6: Cost Recovery for Proactive Investments

State	Cost Recovery Mechanism	Citation
CA	Base rates or SB 410 mechanism	Decision Authorizing a Ratemaking Mechanism…pursuant to SB 410 (July 2024)
CO	Rider (Grid Modernization Adjustment Clause [GMAC])	Direct Testimony of Jason J. Peuquet (Dec 2024)
MA	Rider rolled into base rates. (e.g., annual reconciling mechanism or Grid Modernization Factor)	ESMP Order (Aug 2024), page 435-447
MN	Base rates (subject of the Phase 2 Workgroup recommendations)	Staff Compiled Decision Options and Draft Framework, (July 2025), page 14
NY	Rider (surcharge) rolled into base rates	Joint Utilities Long Term Proactive Planning Framework, (Dec 2024), Sr.No. 55, page 32

These more traditional approaches to cost recovery may change as regulators, for example, in Massachusetts and Minnesota, follow up on plans to open dockets specifically on the issue of cost recovery. In its August 2024 Electric Sector Modernization Plan decision, the Massachusetts DPU indicated that it will determine the parameters of cost recovery in a second phase of the ESMP proceedings.[68] Similarly, Minnesota PUC Staff recommend that "Xcel Energy must pursue cost recovery through a separate proceeding."[69]

64 This observation is shared by the authors of "Unlocking load growth at the grid edge: Practices for managing, recovering, and allocating distribution system investments", Guillermo Pereira, Jeff Deason and Anthony Sandonato, ("Unlocking Load Growth") LBNL January 2025. In section 2.3 of their paper, the authors point out that this is the case generally for electrification programs.

65 Decision Authorizing a Ratemaking Mechanisms for Energization Projects Pursuant to Senate Bill 410." at pg. 40. ("Decision Authorizing a Ratemaking").

66 Hearing Exhibit 107, Direct Testimony of Jason J. Peuquet

67 Id.

68 ESMP Order (Aug 2024), pg 444, https://www.mass.gov/doc/final-esmp-order-82924/download

69 Compiled Decision Options and Draft Framework (July 2025), page 14, https://minnesotapuc.legistar.com/LegislationDetail.aspx?ID=7451501&GUID=7C5A47A7-7F87-40CF-A3E3-2E448547A7C0&Options=&Search=

The alignment with existing cost recovery approaches and merger with other proceedings demonstrates two points. First, that planning processes are fundamentally linked with the prudence standard. If an investment passes muster with established planning principles, it almost certainly passes the prudence standard as well. Planning guidelines can be considered a method for demonstrating that a decision is reasonable given the information available at the present time. Second, the innovations implemented in specific proactive planning proceedings can and likely should be integrated more broadly into distribution system planning. Furthermore, these concepts may be helpful in other related contexts, such as bulk electric system planning and other sources of load growth.

5 Conclusions and Next Steps

Customer adoption of electric vehicles is creating a new source of growth for the electric system along with other segments of the overall economy. This innovation also brings along new sources of uncertainty for distribution system planning. Research for this paper generated key insights in managing this growth and uncertainty, and explored methods for managing associated risks and assessing the efficacy of solutions that ensure adequate grid capacity and maintain reliability.

Fundamentally, proactive planning reforms have been pursued in order to better understand the nature of this growing EV demand and ensure that existing planning processes continue to yield reliable, low-cost electric service. To further incorporate proactive planning approaches in regulatory processes, utilities and commissions can:

- Explore and develop additional data sets and methodologies that account for EV adoption trends in response to market conditions, customer usage trends, and other factors to narrow the variance in uncertainty between forecasting traditional sources of customer demand and EV charging – revisiting these adjustments periodically and as necessary.
- Identify and coordinate opportunities for ongoing improvements in EV forecasts and planning approaches across other planning processes to ensure consistency and appropriate responsive action using the best available data.
- Mitigate the risk of stranded or underutilized assets not only through better forecasts, but also through operational adjustments in the grid such as transferring loads through new electrical connections from congested areas in the grid to areas with excess capacity, particularly in dense and urban areas where connections to loads can more readily be moved around.
- Consider diversity in customer project type and charging application when assessing risks. Risk may not be uniform across all EV demand served, classes of vehicles, or desired configurations. Thus, a mitigation strategy tailored to the particular dynamics of specific charging facilities may be more appropriate than a blanket approach.

Additionally, these innovations may apply directly or indirectly to other sources of incremental load growth, including new manufacturing capacity or data centers.

6 Annotated Resource List

Below are additional resources that public utility commissions and other state agencies may find helpful for understanding proactive investment in electric distribution system infrastructure as it relates to transportation electrification.

6 .1 Non-Governmental Organizations

Alliance for Transportation Electrification (ATE) maintains an online listing of numerous TE resources ATE has produced a three-part "Issue Brief" series on proactive investment (Brief I, Brief II).

- Energizing EV Charging Stations, Issue Brief III – The Pre Planning Process (2024) lists the half dozen parties most often involved during the period before a new service application is submitted to the utility.[70] Effective coordination between these parties is necessary to optimize the development process and shorten the time to energization. The paper discusses the steps that should occur before formal application.[71] These steps, as well as the role and responsibilities of each party, are discussed in depth. The paper also explores eight best practices, recommendations that suggest how the utility, the customer, and the host site can engage early in the development process.
- Fleet Advisory Services (FAS) for Fleet Electrification: Meet Customer Needs and Provide Grid Benefits (2023) illustrates five utility-specific case studies where FAS services have been offered. It concludes with a three-part set of recommendations and a series of regulatory issues to address. Recommendations include utilities electrifying their own fleets first; conducting granular distribution system planning such as publishing hosting capacity maps; and supplementing their planning with one-to-one consultations with advisory services customers. The regulatory issues to which they draw attention include load forecasting, planning, grid integration, building ahead of need, stranded asset risk, technology risk and location risk.

Electric Power Research Institute (EPRI) published a pair of reports in 2024 framing issues that arise in the context of making proactive TE investments. These publications also list a series of best practices and recommendations.

- Designing Distribution Systems to Enable Deep Decarbonization, An Introduction to Right-sizing the Distribution System to Meet Future Needs (2024) begins with a call to action, and poses the question, "What can we do now to prepare the distribution grid?" While not specifically targeted to TE, its three-part framework is directly applicable and addresses three high-level requirements to right-size the distribution grid that focus on scope, timing and location. The paper summarizes five near-term actions that can be taken to support grid readiness including development of an industry-wide strategic planning framework, investment strategies and planning criteria, modernizing and standardizing grid designs, identifying gaps and opportunities to enable decarbonization, and stakeholder engagement and workforce development.
- Interim Service Solutions and Timely Grid Connections for Large Transportation Electrification Projects (2024) begins by defining three key attributes of TE projects: (1) timeline for TE projects, (2) the energy density of the TE load addition, and (3) the uncertainty and variability of TE load characteristics. EPRI recommends certain approaches and solutions to accommodate each of these aspects of TE projects.

70 Parties include i. the utility, ii. the electric vehicle service provider (EVSE), iii. the site host who may not be the owner/operator of the charging station, iv. local governments who have permitting authority, v. state government agencies such as the public utilities commission, department of transportation, etc., and vi. the federal government that is often a source of funding and technical assistance.

71 The steps include i. developer site selection with utility assistance, ii. utility grid planning for increased loads and utility commission approval of those plans, iii. the study process, iv. the administrative process within utilities and local governments, v. permitting and easements, and vi. supply chain management.

Energy Systems Integration Group (ESIG) convened the "Grid Planning for Vehicle Electrification Task Force" to discuss challenges in the grid planning process. In Charging Ahead – Grid Planning for Vehicle Electrification (2024), the authors identify gaps in distribution system planning for vehicle electrification and ways to address these gaps. The paper examines TE challenges that directly affect integrated distribution planning, and it outlines how coordinated planning can help instill regulator confidence in long-term plans. Such planning needs to include improved forecasting, reflect smart charging, incorporate "future-ready" equipment, and promote proactive upgrades based on multi-stakeholder input.

In Building the Grid to Need - Best Practices for Proactively Developing Distribution Grids to Support Truck and Bus Electrification (2024), **Environmental Defense Fund** focuses its study on Medium and Heavy Duty Vehicles (MHDVs) and seeks to improve the responsiveness of what authors characterize as a "reactive" regulatory process. The paper provides useful recommendations across four topic areas: regulatory reforms, mitigating risk, accountability and incentives, and cost recovery.

GridLAB, RMI & Advanced Energy United have convened the "CHARGED initiative" with a goal to "identify tools and methods that utilities across the United States can adopt to enable electrification in ways that minimize infrastructure costs and maintain system reliability." In Charged – Inaugural Convening Report (2024), the authors discuss 40 "Least Regrets Solutions" over five workstreams.[72] Although all five workstreams are applicable to proactive investment in TE, the least regret solutions for the first workstream – distribution system planning – are the most relevant: exploring opportunities to improve forecasting and power flow modeling, proactive upgrades with routine investments, and planning for operational flexibility. The Charged Initiative is developing additional solutions for publication in 2025, including a public scenario planning explorer, a framework for proactive investment, and development of performance incentive mechanisms for proactive investment.

In Paving the Way: Emerging Best Practices for Electric Vehicle Charger Interconnection (2022), the **Interstate Renewable Energy Council** (IREC) surveyed EV charging station developers across the US to determine the primary factors that contribute to long development timelines. The main factors identified are (1) interconnection process delays, (2) difficulties obtaining easements (establishing the right for a utility to install, access, and service electrical equipment on a property), and (3) slow permitting processes. The paper pairs best practices with reported challenges and serves as a useful list of actions that can be taken to reduce interconnection timelines.

Rocky Mountain Institute's (RMI) concept note, Transportation Electrification Building Blocks - Practical Guidance for Regulators and Utilities to Strategically Plan for Rapid Electric Vehicle Load Growth (2024), is intended to "help regulators and utilities make effective decisions…", and frames a series of improvements to traditional grid planning and investment approaches. The authors identify three basic challenges in need of attention: (1) uncertainty, (2)the existing regulatory paradigm, and (3) utility and regulator risk aversion. In response, the authors identify building blocks as guidance to improved planning for EV load growth.[73] RMI suggests the use of its publicly accessible GridUp Tool which they describe as capable of helping utilities forecast when and where energy and power demands will materialize from vehicle electrification.

ACEEE Electrifying Truck Fleets: Utility Infrastructure Is Crucial (2024) provides analysis and case studies of several leading utilities and states that are promoting and preparing for electric fleets, offering useful models for others to follow. Depending on the number and size of chargers, fleet charging can require several megawatts of power, with loads up to 40 MW (similar to the power needs of many large factories). To supply this power, utilities need to assess customer charging needs and incorporate their findings into the planning of local distribution

72 The five workstreams are i. distribution system planning, ii. rates and incentives, iii. targeted and integrated deployment, iv. grid connection, and v. distribution operations.

73 Building blocks include i. planning against long-term EV market expectations; ii. Improving load forecasting; iii. prioritizing efficient and cost-effective use of distribution infrastructure; iv. Aligning grid connection with customer needs; v. improving risk sharing and mitigation; and vi. Enabling accountable, longer-term utility capital investments.

grids. Utility Planning for Electric Truck and Bus Fleets: An Overview (2024) is a roadmap intended for utilities and utility regulators. It outlines suggested steps for utilities to take immediately to start planning for new electric truck and bus fleet loads. It proposes a seven-step planning process for addressing new electric truck and bus fleet loads.

6.2 Governmental Organizations

US Department of Energy's, **Joint Office of Energy & Transportation** published Grid-Constrained Electric Vehicle Fast Charging Sites: Battery-Buffered Options (2024), a case study designed to help inform developers interested in "battery-buffered options to support direct-current fast charging (DCFC) stations in grid-constrained areas." The authors recognize that in cases where energy storage alone is insufficient to serve vehicle charging, i.e., where the existing grid infrastructure cannot support an average design day vehicle demand, there are strategies to ensure that the battery can be recharged either by increasing battery charging capacity or decreasing design day average demand.

Pacific Northwest National Laboratory (PNNL) convened a workshop in July 2024 to discuss proactive regulatory approaches to electrification and load growth and published a preparatory white paper on the topic, Proactive Regulatory Approaches to Electrification and Load Growth (2024). The whitepaper outlines a series of regulatory topics to be covered at the workshop including issues related to customer protections such as planning, procurement, ratemaking, cost allocation, and cost recovery. It also describes a series of risks including stranded assets, acting too early or too late, investing in the wrong location, and technological obsolescence. Finally, it summarizes the issues and challenges that have been experienced by six different states and several different utilities.

Lawrence Berkley National Laboratory (LBNL) maintains a listing of IDSP-related publications, many of which address issues and themes that are directly applicable to proactive investment in TE. This past year, it also released its decision framework for IDSP which includes summary information on seventeen different topics ranging from analytical to economic to stakeholder engagement. Each of the topic areas includes best practices, state and utility practices and annotated resources. LBNL's Interactive Decision Framework for Integrated Distribution System Planning (2024) is intended to help provide utilities, states, and stakeholders with a shared understanding of distribution planning requirements as they are adopted. LBNL has also been researching the cost recovery and rate making issues related to proactive investment and expects to publish its findings in the coming months.

6.3 Selected State-Specific Studies & Plans

National Grid (NY/MA) published a pair of studies about the future of highway fast charging and fleet electrification. One notable finding in Electric Highways: Accelerating and Optimizing Fast-Charging Deployment for Carbon-Free Transportation (2022) is that "Future-proofing" grid interconnections at high-traffic sites will limit the need for duplicative upgrades—and accelerate fast-charger deployment. This finding leads to the recommendation to build grid infrastructure once and avoid having to revisit the effort.

In The Road to Transportation Decarbonization: Readying the Grid for Electric Fleets (2023), **National Grid** draws conclusions about (1) the speed at which grid impacts from electrification will be experienced,(2) the import of identifying "high potential" areas, (3) the need for planning and regulatory structures to evolve, (4) grid infrastructure strategy for MHDV electrification will vary by location, and (5) new forms of partnership and cooperation will be needed to enable the electric MHDV transition.

Synapse Energy Economics produced Distribution System Investments to Enable Medium- and Heavy-Duty Vehicle Electrification: A Case Study of New York (2023) on behalf of Environmental Defense Fund. The analysis examined "the impact on rates of a MHDV make-ready program in two areas of New York: Con Edison's service area in New York City and the western part of National Grid's service territory in upstate New York." Synapse calculated "distribution system upgrade costs required to support 100 percent electric MHDV sales by 2045, consistent with state targets, and make-ready program costs." They compared these with expected revenues from MHDV electrification under current utility tariffs. Synapse determined that "a make-ready program would have a neutral-to-beneficial impact on rates in both utility service areas for the period 2023–2045." Furthermore, it determined that:

> these positive net revenue results imply that socializing the costs of make-ready and distribution system upgrades necessary to meet New York State's MDHV electrification targets are unlikely to cause ratepayer bills to increase in either of the utility service areas studied, due to being offset by the revenues contributed by MHDVs over the same period.

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