5. Electric Grid Impacts and Managed Charging

Key Takeaways

- As the EV charging network grows, electricity demand during peak periods will increase and may stress distribution grid infrastructure (e.g., transformers, feeders, and substations).
- EV charger deployment in line with the CECP could add over 1,500 MW to peak demand in 2030 and approximately 4,000 MW to peak demand by 2035.
- In the next five years, up to 11 percent of Massachusetts feeders could overload due to transportation electrification increasing to 23 percent in 2030. Similarly, about 10 percent of substations could overload in 2030 and 28 percent in 2035.
- Managed charging can lower the impact on the grid of EV charging, reducing the percentage of feeders overloaded in 2030 to 2 percent and the percentage of substations overloaded in 2035 to 6 percent in the modeled scenarios.
- If managed effectively, EVs can lower electric bills for all customers. From 2011 to 2021, EV drivers provided net benefits of $3+ billion to utility customers nationally.
- EVICC will work with the EDCs to develop a comprehensive managed charging strategy and further evaluate the implications of EV charging for the distribution grid through the process required under Section 103 of the 2024 Climate Act.

As EV adoption accelerates in Massachusetts, growing electricity demand will challenge the state's electric transmission and distribution (T&D) grid, necessitating upgrades, careful planning, and load management strategies to ensure reliability, resilience, and cost-effective integration.

This section examines the expected impacts of EV charging on the Commonwealth's electric grid, including stress points in the existing infrastructure and the regulatory and operational processes for addressing them. It also explores the potential for EV adoption to reduce electric rates and the role of managed charging - especially through active and passive utility programs, time-of-use rates, and smart technologies - as a critical tool to mitigate grid constraints, shift load to off-peak hours, and reduce incremental system costs. This chapter highlights current utility practices, emerging best practices, and areas for improvement, while identifying both near- and long-term actions needed to ensure a reliable, cost-effective, and equitable EV charging ecosystem.

Summary of transmission and distribution impacts, challenges, alternatives

Transmission and distribution impacts

The cumulative effects of EV charging demand across the Commonwealth and in specific locations present growing challenges for the state's T&D grid. While overall system load will likely increase steadily, the more pressing concern is where and when this load occurs. Clusters of residential and commercial chargers, especially those with high power ratings can stress local transformers, feeders, and substations. These impacts vary widely depending on local grid conditions, making proactive grid planning and forecasting essential to maintaining the reliability of the electric grid and avoiding costly, reactive infrastructure upgrades.

Challenges

The growing demand for EV charging presents a range of grid-related challenges that extend beyond overall electricity consumption. One of the most complex is the localized and often unpredictable nature of new EV charging development, which can outpace traditional utility planning and investment timelines. High concentrations of charging, particularly at commercial fleet depots and highway corridor fast charging stations create high-capacity demands that can strain distribution circuits, transformers, and even upstream transmission infrastructure. These pressures are often most severe in areas

Transmission and distribution impacts refer to the physical and operational stress placed on the electric grid as new demand sources—like EVs—are added. The electric transmission system carries high-voltage electricity over long distances, while the electric distribution system delivers it to homes and businesses. EV charging, especially when uncoordinated, can lead to localized overloading of transformers or require upgrades to feeders and substations. Without timely upgrades or demand management strategies, these stressors can degrade service reliability and increase costs for ratepayers.

with aging grid assets, limited available capacity, or long upgrade lead times, all of which can slow the equitable and efficient deployment of charging infrastructure. Another key challenge for commercial charging site hosts is the impact of utility demand charges, which can lead to prohibitively high operating costs when power usage spikes during peak charging periods. These charges can discourage investment in public and fleet EV charging stations, particularly in underserved or low-utilization areas.

In addition to challenges posed by location-specific loads, other barriers include uncertainty in the timing and pace of EV adoption, changes to charging behavior, mismatches between utility upgrade schedules and charger deployment timelines, and constraints such as workforce shortages, equipment availability, or permitting delays. There also exists the potential that service and capacity upgrades meant for EV charging equipment are taken by other customer types, such as data centers. Addressing these issues will require more flexible and proactive utility planning, improved coordination among stakeholders, and policy alignment that integrates grid needs with the Commonwealth's broader transportation electrification goals.

Alternatives

Electric utilities understand the impact of increased EV adoption and charging station deployment. They incorporate EV adoption forecasts in their grid planning processes and work with EV charging infrastructure developers to plan grid infrastructure construction. Building electric grid infrastructure is expensive, however, and alternative solutions to T&D grid infrastructure development will be critical in ensuring that decarbonization of the transportation sector is done in the most cost-effective manner possible. The most notable alternative solutions are EV load management mechanisms that encourage charging to occur at off-peak times, resulting in more efficient use of existing grid infrastructure and helping to defer potentially costly grid infrastructure upgrades.

Examples of EV load management mechanisms include active managed charging programs (i.e., utility directly controls EV charging), passive managed charging programs (i.e., an incentive is provided for not charging at certain times), advanced rate designs, and demand response programs. Other alternative solutions exist such as the dynamic use of battery energy storage systems and other distributed energy resources to mitigate grid constraints caused by EV charging. Solutions also exist to leverage the energy stored in EVs to provide grid and resilience benefits, namely vehicle-to-everything programs and microgrids that rely on EVs for back-up power. When these strategies are complementary to each other, they become valuable components of a comprehensive approach to managing EV load.

Managed charging can also help mitigate the burden of demand charges by smoothing peak demand. Other solutions to help address the financial impact of demand charges include, rate design alternatives such as time-of-use rates, demand charge holidays, subscription-based pricing models, and demand charges that increase with charger station utilization.

Overview of relevant T&D infrastructure upgrade processes

High volumes of simultaneous EV charging can increase existing peaks or create new peaks on the local electric distribution system and can increase overall T&D system peaks. Increases in peak demand require transmission and distribution system planners and engineers to design and deploy new grid assets to meet this new demand and to ensure safe and reliable operation of the electric grid.

Overview of electric distribution company infrastructure upgrade processes and regulatory structures

Electric distribution company overview

To satisfy their responsibility of providing safe and reliable service, electric utilities plan ahead to ensure that the electric grid has sufficient capacity to support new loads and higher peaks. Utilities develop near-term and long-term electric demand forecasts to assess whether their existing grid infrastructure, i.e., substations, distribution lines, and transformers, is capable of hosting this growing demand. These forecasts guide decisions about when and where grid upgrades are needed. Since grid infrastructure upgrades require significant capital investment, utilities use demand forecasts to shape their capital expenditure strategies.

In addition to electric demand assumptions, revenue and return on equity (ROE) expectations play significant roles in shaping utility capital expenditure strategies. Electric utility customers pay for the costs of grid infrastructure through their electric bills. For customers of investor-owned utilities, these costs include both infrastructure costs and the cost of capital. The cost of capital consists of both the cost of any debt and the ROE for utility investors. In the Commonwealth, there are three investor-owned utilities, Eversource, National Grid, and Unitil, which are also known as the electric distribution companies (EDCs). The Massachusetts EDCs serve over 90% of the state's electric customers.[1]

Because the EDCs earn a return on capital investments, regulatory oversight is necessary to ensure utilities are not investing in unnecessary infrastructure.[2] Regulatory oversight includes ensuring that demand forecasts accurately reflect actual system needs and capacity so that equitable and least-cost outcomes to meet both grid reliability and the state's electrification needs can be achieved. The Massachusetts Department of Public Utilities (DPU) has regulatory oversight over the state's three EDCs.

New customer connection process

EV chargers, like all electric loads, must be connected to the grid to provide the electricity required for charging. To initiate this load connection process, EV charger project owners submit "load letters" to their utility detailing the project's location, basic specifications, and projected electric capacity needs. The utility then coordinates with the project owner to advance the required construction, permitting, and safety steps.

[1] Office of Energy Transformation. Financing the Transition: Background. Massachusetts Executive Office of Energy and Environmental Affairs. Accessed June 10, 2025. https://eml.berkeley.edu/~train/regulation/ch1.pdf. https://www.mass.gov/doc/background-financing-the-transition/download.

[2] Train, Kenneth E. Regulation: Chapter 1 – Introduction. University of California, Berkeley. Accessed May 22, 2025. https://eml.berkeley.edu/~train/regulation/ch1.pdf.

Load requests may not immediately receive approval from the utility if the utility lacks available hosting capacity; this is more common for larger load requests, such as fast chargers for EV fleets. In these cases, the utility will add the request to its connection queue and study the project to assess grid capacity constraints and identify necessary grid infrastructure upgrades. The costs of grid upgrades needed to accommodate a specific project are typically passed onto that project. Some DCFC projects will not be able to absorb these costs and keep EV charging rates affordable for customers. Alternative financing may need to be explored for these projects.

The load interconnection process can be lengthy. Project owners can face long wait times, sometimes leading to project delays or cancellations. Further, the opaqueness of the load connection process can cause uncertainty for EV charger developers and fleet operators hoping to electrify. The Commonwealth is working with the utilities and stakeholders to evaluate and improve the load connection process, aiming for greater transparency and efficiency. A streamlined and clearer process will aid the timely deployment of EV charging infrastructure, while advancing grid reliability and affordability goals.

Regulatory processes

As transportation and building electrification advances, multiple regulatory processes have emerged to proactively plan for increasing demand on the electric grid. Key among them are the Electric Sector Modernization Plans (ESMPs) and the 2024 Climate Act's transportation demand forecasting directive (Section 103 of the 2024 Climate Act), each playing important roles in shaping the future of the grid and ensuring that EV load can be energized. The ESMPs and processes required under Section 103 of the 2024 Climate Act are discussed in further detail in Appendix 8.[3]

Utility load forecasting and customer engagement efforts

As part of the grid planning processes outlined above, the electric utilities engage a broad range of stakeholders to inform their load forecasts and ensure that grid planning reflects state policy goals and community needs. The electric utilities also incorporate data from load letters into their load forecasts. Utilities often engage in early discussions with these customers to understand the scale and timing of their anticipated demand. Sometimes, these anticipated large loads are factored into the utilities' forecasts.

Deliberate stakeholder engagement is critical to ensuring EV adoption and charger planning reflects the needs of all Commonwealth residents, including underserved communities. The utilities should continue working with stakeholders to meaningfully incorporate community feedback into their plans for the electric grid.

[3] In addition to these regulatory processes, the Commonwealth continues to work closely with the utilities on other initiatives to plan and prepare for future grid impacts from electrification. The DOER is participating in the gas and electric utilities' stakeholder process to provide input on a long-term process for integrated energy planning among the utilities. Through integrated energy planning, the electric and gas utilities will work together to plan for a strategic, affordable, and reliable transition to electrification over time. To complement EVICC's transportation electrification projects, EEA is working to develop projections of anticipated building electrification load in the next ten years and the impact of this new load on the electric grid. These projections will help inform the state's engagement with the utilities on proactive grid planning processes.

Managed Charging Programs

Managed charging refers to strategies that incentivize a shift in or control the timing of EV charging to reduce grid impacts.

Active managed charging involves real-time utility or aggregator control of EV charging.

Passive managed charging uses time-based price signals to encourage customers to charge during off-peak periods, i.e., times of the day when the transmission or distribution system's load is low. For EV owners, off-peak charging generally means waiting to charge their vehicles until later in the evening rather than charging immediately upon coming home from work when system peaks occur.

Managed charging and load shifting programs

The EDCs - National Grid, Eversource, and Unitil - and more than one-quarter of Massachusetts' 41 MLPs currently offer or plan to offer EV managed charging programs and/or EV rates. A summary of these programs is provided in Table 5.1. National Grid is the state's only EDC that currently offers a managed charging program. While National Grid has not yet published an assessment of its fleet managed charging program, National Grid asserts that its residential managed charging program has seen significant success in both attracting customers and reducing peak load, enrolling around 6,000 customers in 2023[4] and shifting over 80% of weekday EV charging loads to off-peak periods.[5] Eversource and Unitil have recently proposed comparable residential managed charging programs.[6]

Table 5.1. Summary of National Grid, Eversource, and Unitil's Managed Charging Programs

	National Grid	Eversource	Unitil
Program Status	Existing	Proposed	Proposed
Eligible Customer Classes	• Residential • Fleet	Residential	Residential
One-Time Enrollment Incentive	$50	$50	$50
Incentive	• $0.05 per kWh for the summer months (June 1- September 30) • $0.03 per kWh for the non-summer months (October 1-May 31)	$10/month	$10/month
Peak Periods	1:00-9:00 pm	1:00-9:00 pm	1:00-9:00 pm

[4]See D.P.U. 24-196, Exh NG-MTM-1 at 23

[5]D.P.U. 23-44 Exhibit NG-MM-9, Consideration 3: Develop incentives for weekend charging, and D.P.U. 22- 63 Exhibit NG-MM-10, Finding 2: The off-peak rebate resulted in more weekday charging.

[6]These proposals are pending DPU approval in the open D.P.U. 24-195 and D.P.U. 24-197 EV Midpoint Modification dockets. See Appendix 3 for additional information on the EV Midpoint Modification dockets.

Advanced rate design

Rate design and ratemaking regulatory mechanisms serve as valuable load management tools, including for EV charging. Specifically, time-varying rates (TVR), such as time-of-use (TOU) rates and critical peak pricing (CPP), can provide price signals and encourage customers to shift their EV charging to off-peak periods.

To explore TVR implementation, the Interagency Rates Working Group (IRWG), a collaboration between DOER, the Attorney General's Office (AGO), and the Executive Office of Energy & Environmental Affairs (EEA) issued a Long-Term Rates Strategy in March 2025 that outlines recommendations for specific TVRs that advance the Commonwealth's grid modernization and affordability goals. To further investigate the implementation of these recommendations, DOER convened the Massachusetts Electric Rate Task Force, a stakeholder group which will develop a more granular set of rate design and ratemaking regulatory mechanism recommendations.

Opt-in EV time-of-use rates can be an effective mechanism to reduce load on the grid. EV TOU rates operate similar to passive managed charging programs and offer customers the opportunity to save money by charging lower rates during off-peak hours when demand on the grid is low and by charging higher rates during peak hours when demand on the grid is high. Like managed charging programs, opt-in EV TOUs can have various designs that can be limited or enhanced by the metering technology utilized by the utility. Due to the similarities between managed charging and opt-in EV TOUs, it is important to carefully consider whether and how specific managed charging programs and opt-in EV TOU rates complement each other. It is also important to consider to what extent the value of having both programs is offset by the administrative cost of maintaining two offerings and the potential customer confusion two EV-specific rate programs may create.[7]

Managing EV load enables rate reductions because it increases asset utilization without requiring new capacity and grid infrastructure. This means that utilities can spread the fixed system costs over more customers, which effectively reduces rates for all customers, even those that do not own EVs. Even with added grid costs, such as transformer replacements and distribution upgrades, EVs can still be beneficial for ratepayers. Strategic EV load management planning can mitigate peak impacts and avoid costly grid upgrades. With the right policies, transportation electrification can be a powerful tool for lowering electric bills while improving grid efficiency and reducing emissions.

As Massachusetts modernizes its grid, thoughtful rate design will be essential in aligning EV charging behavior with system needs. Ensuring the successful implementation of whole-home TVRs will help reduce peak demand, lower system costs, and achieve the state's broader clean energy goals, including those related to EV adoption and charger deployment, as well as advancing the Commonwealth's broader energy affordability goals.

[7]he 2022 Act Driving Clean Energy and Offshore Wind directed the EDCs to file residential EV TOU rate proposals with the DPU. The DPU is currently reviewing Eversource's and National Grid's TOU rate proposals in D.P.U. 23-84 and D.P.U. 23-85, respectively, and is statutorily required to issue at least one order on these proposals no later than October 31, 2025.

Vehicle-to-everything (V2X)

V2X technologies and programs enable vehicle-grid integration by allowing EVs to communicate with other infrastructure, including homes (V2H), commercial buildings (V2B), and the electric grid itself (V2G).

EVs are capable of providing services back to the grid, such as peak shaving, load shifting, and demand response. V2G uses bidirectional charging, allowing plugged-in EVs to send energy back to the grid during times of high demand on the grid to ease grid constraints. EV owners who participate in these programs are compensated for their contributions to grid capacity. V2G can also enable EVs to improve customer and system resiliency, as they can provide backup power during blackouts and emergencies.

The scalability of V2X will likely vary by vehicle class. For example, electric school bus fleets are considered strong candidates for V2X due to their predictable routes, consistent charging availability, and centralized depot charging. Highland Electric Fleets, a Massachusetts-based electric school bus service provider, partners with school districts across the country to electrify their school bus fleets and utilize buses as revenue-generating grid assets.

Scaling V2X for light-duty EV owners is more nascent. In Massachusetts, MassCEC used EVICC-awarded funds to launch its V2X Demonstration Projects Program. This program aims to expand access to V2X technology and demonstrate the viability of bidirectional charging in the Commonwealth.

V2X is an emerging concept, so its full capabilities remain to be seen, particularly for non-fleet light-duty EVs. However, when scaled, it can create significant benefits for the grid, including cost savings for all residents, even those without EVs. The Commonwealth should continue exploring it as a viable grid service opportunity.

Managed charging program conclusion - best practices and utility bill reduction potential

Active and passive managed charging and other load shifting programs have many benefits. First, they promote EV charging when generation and capacity is available on the grid by providing rebates or other incentives for charging at off-peak times. Second, they create opportunities to delay grid infrastructure upgrades, which can minimize ratepayer costs. Finally, they support emissions reduction goals by both reducing the costs associated with EV ownership, thus incentivizing EV adoption, and electricity demand during periods when fossil generation is being used most.

Effective programs and rates send clear price signals to incentivize off-peak charging, which results in the efficient use of existing grid infrastructure. Well-designed price signals are:

- Predictable;
- Capable of influencing EV charging behavior; and,
- Create opportunities for participants to reduce their electric bills.

These programs and rates should also be:

- Paired with effective customer education and straightforward enrollment processes;

- Designed to allow for participation with as many types of EVs and EV chargers as possible;
- Capable of dynamically responding to technological innovations and evolving grid conditions; and,
- Integrated with other load-management offerings, like whole home TOU rates, to meaningfully reduce grid constraints and maximize ratepayer savings.

EV adoption can provide a net reduction in utility bills for EDC ratepayers if EV charging load is managed and grid upgrades are avoided. A 2024 Synapse analysis found that between 2011 and 2021, EV drivers across the country contributed over $3 billion more in utility revenues than costs, meaning that incremental utility revenue from EV charging outweighed incremental generation, transmission, and distribution costs. At current retail rates, utility revenue from EVs in Massachusetts would be more than $1.5 billion in 2030 alone if the CECP EV adoption targets are realized.[8] This gross annual revenue could help fund grid upgrades, maintain affordability, and lower bills for all customers.

Long-term, the combination of active and passive managed charging and whole home TOUs, along with opportunities for V2X and other programs that can leverage the ability of EV to provide power back to the grid, represent a comprehensive framework for minimizing the grid impacts of EV charging and maximizing its value.

[8] Utilizing $0.33/kWh as the current average retail rate in Massachusetts and assuming that 970,000 EVs are registered in the Commonwealth by 2030, each using an average of 4,725 kWh per year.

Analysis of Impact of EV Charging on the Electric Grid

By 2035, Massachusetts is expected to host an extensive EV charging network of private residential chargers, public chargers, and chargers specifically for medium- and heavy-duty vehicles. Future EV growth in line with the state's Clean Energy and Climate Plan could add approximately 1,500 MW to peak demand by 2030 and 4,000 MW to peak demand by 2035.

EV growth will necessitate additional capacity in some areas of the grid. EVICC estimates that up to 23 percent of feeders could overload by 2035 from EV charger adoption without considering building electrification, highlighting the value of promoting managed charging policies and programs. Addressing the impact of EV charger installations will require a mix of cost-effective and comprehensive solutions, including managed charging solutions, distributed solar, energy storage, and feeder and substation upgrades, where required.

Methodological Approach

As described in Chapter 4, the EVICC technical consultant team modeled EV charging needs to determine the number and distribution of EV chargers to serve future EVs across the state. The consultant team also analyzed the impact that EVs will likely have on the electricity system and on distribution equipment across the three EDCs. This analysis can be considered a tool to help the Commonwealth and its utilities prioritize the feeders and areas that need further evaluation of potential grid impacts and may warrant targeted interventions to manage load.

The consultant team estimates that Massachusetts will need to host nearly 800,000 EV chargers in 2030 and approximately 1.55 million chargers in 2035 to support the CECP projections of EV adoption. These are displayed in Table 4.10 of Chapter 4.

The consultant team modeled four separate scenarios to represent the range of possible EV load increases in 2030 and 2035. Scenario 1 included EV loads without any managed charging programs and are shown in Figure 5.1. This scenario has the highest EV loads among all four scenarios and the most widespread grid implications.

Scenario 2 is referred to as the "flat charging" scenario and serves as a hypothetical scenario investigating how the steady, as-even-as-possible charging of vehicles would impact loads. Scenario 2 represents a hypothetical charging program that encourages low-level flat charging during overnight or workday periods.

The third scenario was built using current off-peak charging program data and participation rates from Massachusetts utilities in 2024.[7] Scenario

Feeders are low- to medium-voltage distribution lines (4-35 kV) that carry electricity from a substation to lower voltage (typically 120-480 V) distribution lines that directly serve customers. Feeders typically serve several hundred to thousands of customers. Feeders connect to substations, where high-voltage electricity (115+ kV) from the transmission system is converted to lower voltage levels for the distribution system. Several feeders often connect to a single substation.

3 assumes that these programs' charging management and participation rates will continue in the future.

The final scenario (Scenario 4) explores the outcome of fully managed, flexible load. In this scenario, almost all home, work, public Level 2, and private DCFCs serving both light-duty and medium- and heavy-duty EVs are assumed to participate in robust and advanced managed charging programs that move load off grid peaks. For public DCFCs serving light-duty and medium- and heavy-duty vehicles, an estimated 10 percent of the load during peak hours is assumed to be managed and redistributed to other hours of the day. This scenario is used to better understand which feeders host inflexible load and which areas have the greatest potential for targeted managed charging programs.

Analysis Results

Peak Load

Although not all EV chargers will be used at once, the consultants estimate that by 2035, the load from EV chargers will increase the summer peak demand by approximately 4,000 MW during afternoon/early evening peak periods, if unmanaged. This represents 30 percent of forecasted load for Massachusetts in 2035.[8] If existing load management programs continue at current participation rates, new load from EV chargers could be reduced by roughly 19 percent, representing an afternoon/early evening peak of 3,225 MW in 2035. With nearly complete management of flexible load, 2035 EV load could be reduced by nearly 88 percent relative to unmanaged load, representing an afternoon/early evening peak of 477 MW in 2035. As seen in Figure 5.2, management of almost all flexible load leads to much lower loads, particularly in the greater Boston area, Worcester, Lowell, and Springfield. In all scenarios, between 2030 and 2035, total EV load is expected to roughly double (Table 5.2).

Table 5.2. 2030 and 2035 demand from EVs during peak hours

Year	Scenario 1 – Unmanaged (MW)	Scenario 2 – Flat Charging (MW)	Scenario 3 – Status Quo (MW)	Scenario 4 – Technical Potential (MW)
2030	1,635	1,092	1,521	253
2035	4,225	2,846	3,435	501

[7]Massachusetts Phase III EV Program Year 1 Evaluation Report National Grid, DPU 24-64 Exhibit NG-MMJG-1
[8]Based on ISONE's 2024 CELT forecast, MASSACHUSETTS 50/50 2033 load escalated by 2% per year to 2035.

Figure 5.1. Scenario 1 - Unmanaged 2035 EV loads during grid peaks

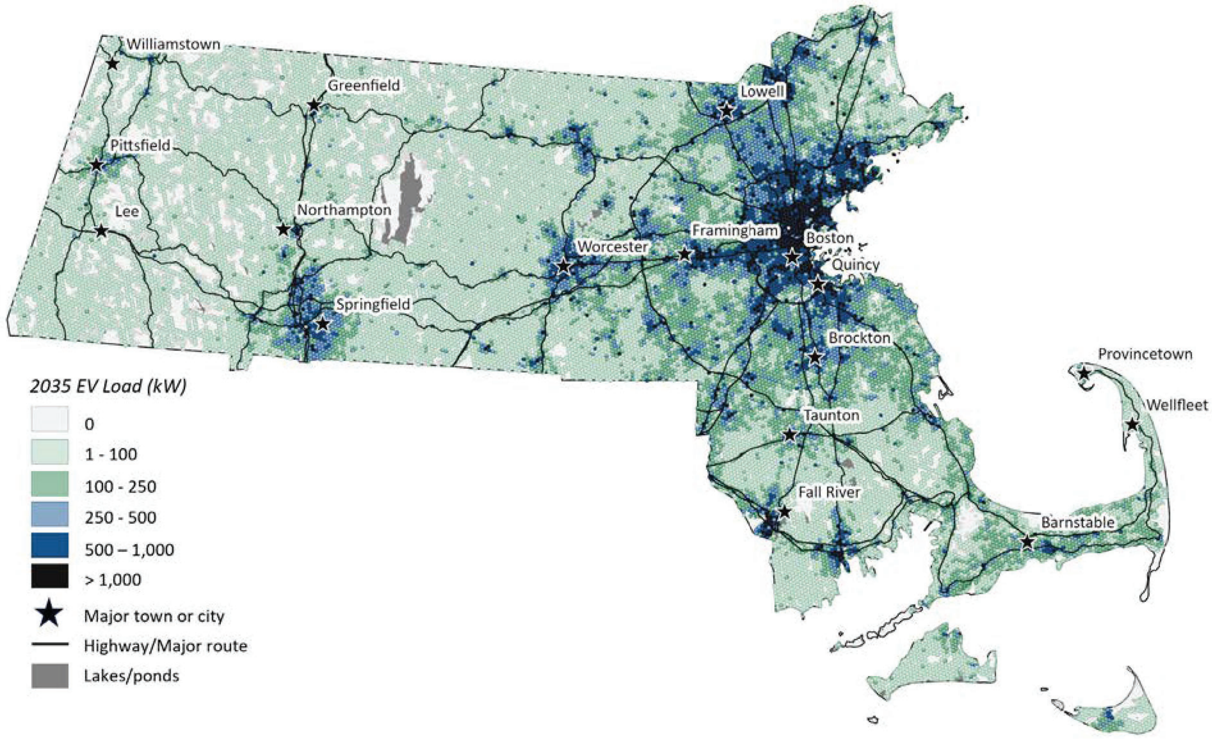


Figure 5.2. Scenario 2 – flat charging 2035 EV loads during grid peaks

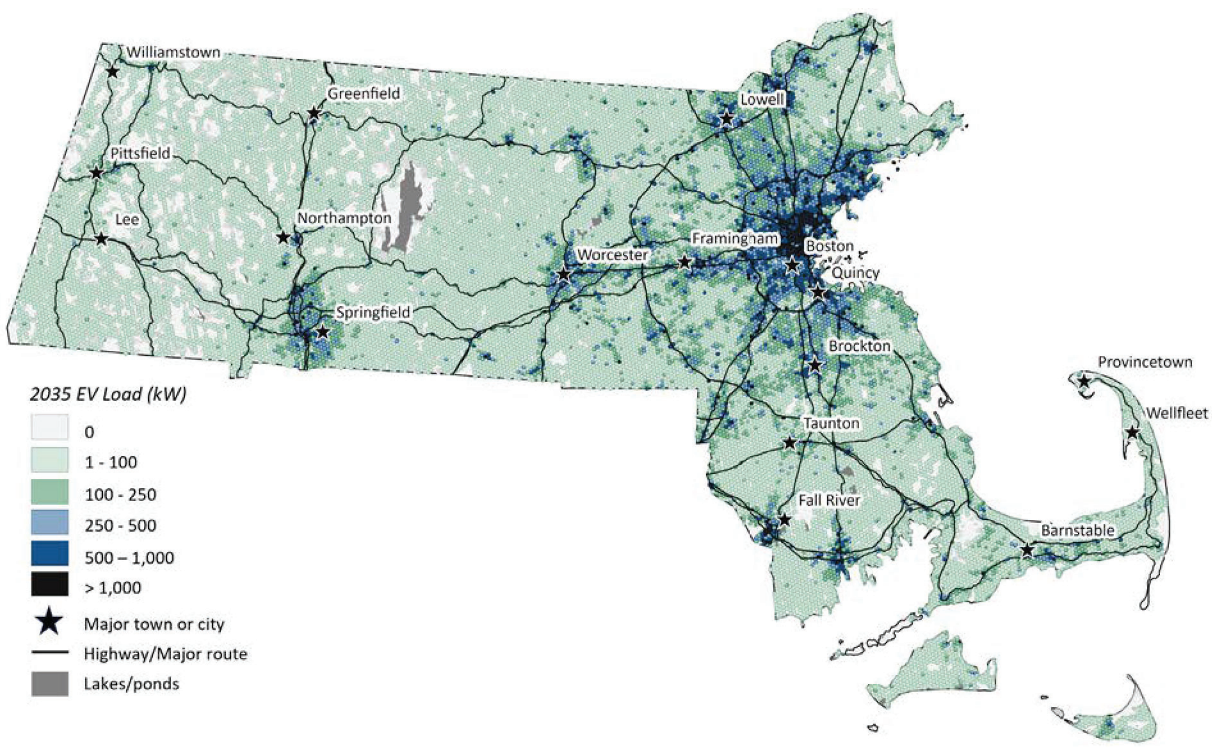


Figure 5.3. Scenario 3 – status quo 2035 EV loads during grid peaks

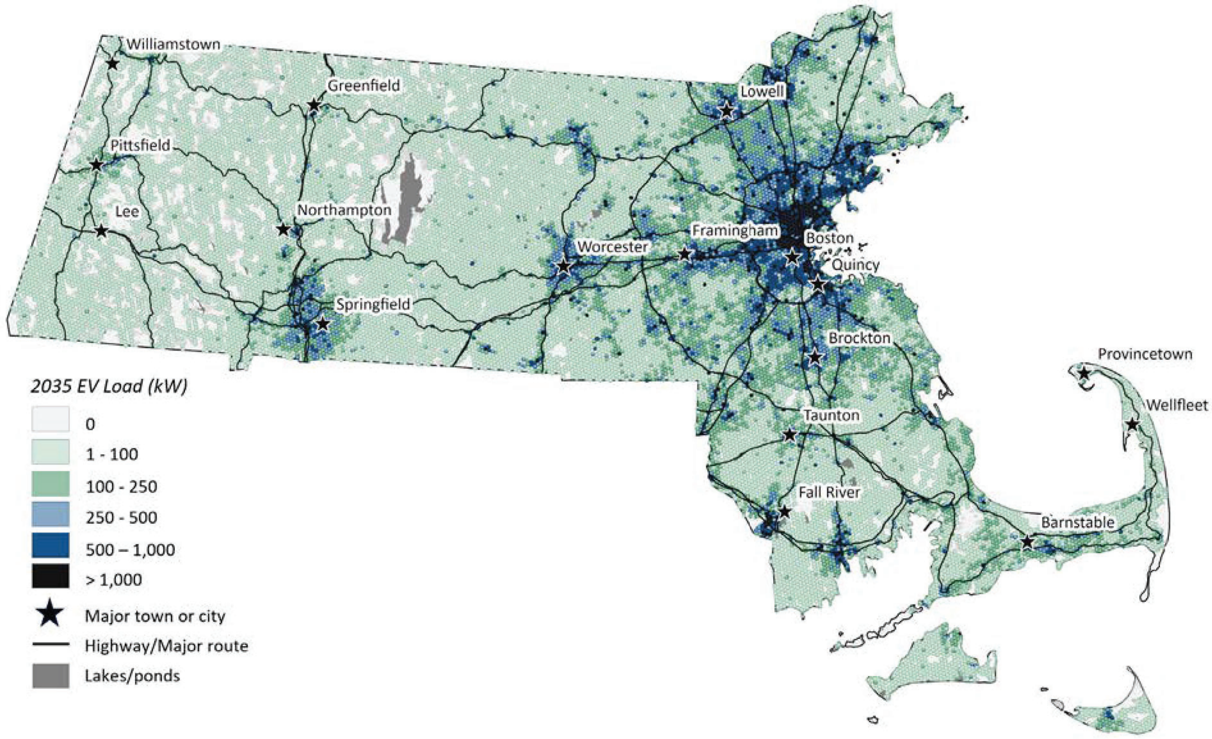
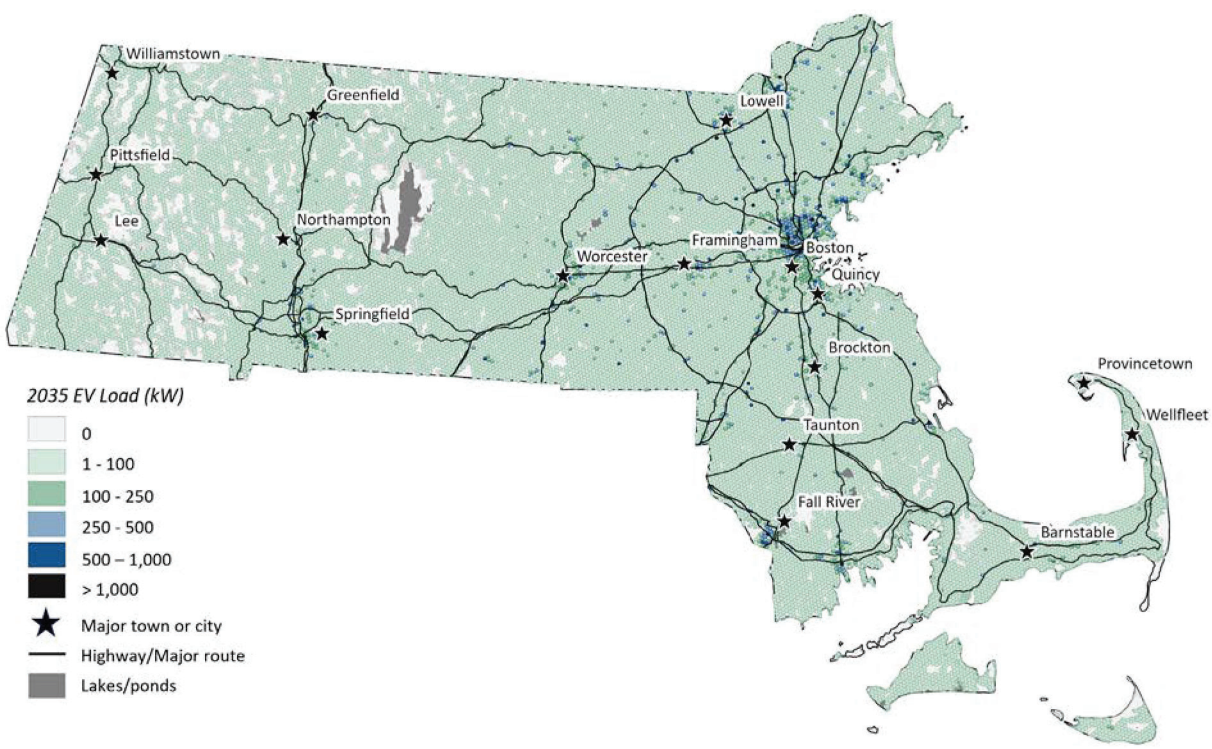


Figure 5.4. Scenario 4 – Technical potential 2035 EV loads during grid peaks



The consultant team mapped EV load onto maps of the EDC's distribution grids to identify areas that may need further study, targeted load management, and/or grid upgrades. The team assessed both feeders and substations. The need for grid upgrades depends not only on the existing and new load on each feeder and substation, but also the existing capacity of those distribution assets.

Utilizing available 2022 peak load and capacity rating data for each feeder, the consultant team identified feeders that are projected to carry peak loads equal to or greater than 80 percent of their nameplate capacity in 2030 and 2025.[9] Eighty percent of the nameplate capacity is the industry standard for planning for a grid upgrade as utilities reserve the top 20 percent margin as a safety buffer for unexpectedly high load events or emergencies, such as a nearby feeder going offline or extreme weather.[10] For simplicity, feeders with a load-to-capacity ratio equal to or greater than 80 percent are referred to as "overloaded"; feeders with a load-to-capacity ratio greater to 110 percent are referred to as "severely overloaded".

Feeders

This Assessment isolates the grid impacts associated with EV adoption and charger deployment. Other types of load growth, such as building electrification, were not analyzed and feeders already overloaded in 2022 were excluded.

Table 5.3 summarizes the feeder results of the grid impact analysis for 2030 and 2035 and Figure 5.5 shows the magnitudes of feeder overloading in 2030 and 2035.

[9]Peak load refers to the maximum 2022 demand on that feeder, which may not be coincident with the overall system peaks. The feeder rating refers to the upper limit on how much electricity can be carried on that feeder. Headroom is the difference between the capacity of the feeder and peak load. Dividing the peak load by the capacity rating gives a load-to-capacity ratio.

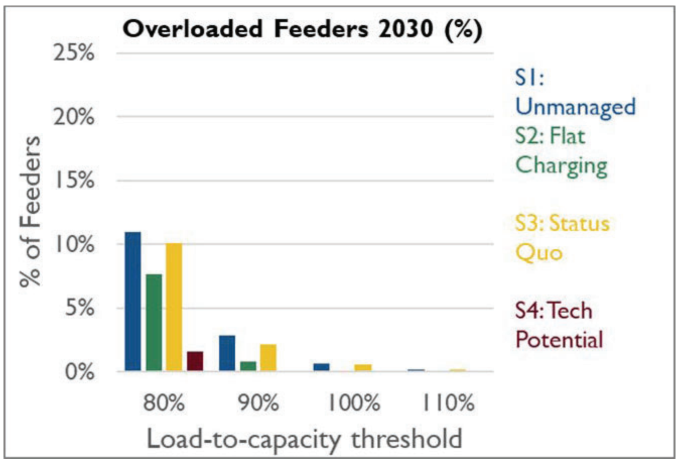
[10]EPRI. 2023. EVs2Scale2030 Grid Primer: An Initial Look at the Impacts of Electric Vehicle Deployment on the Nation's Grid. Available at: https://www.epri.com/research/products/000000003002028010. Some utilities use thresholds higher or lower than 80% to evaluate grid upgrades.

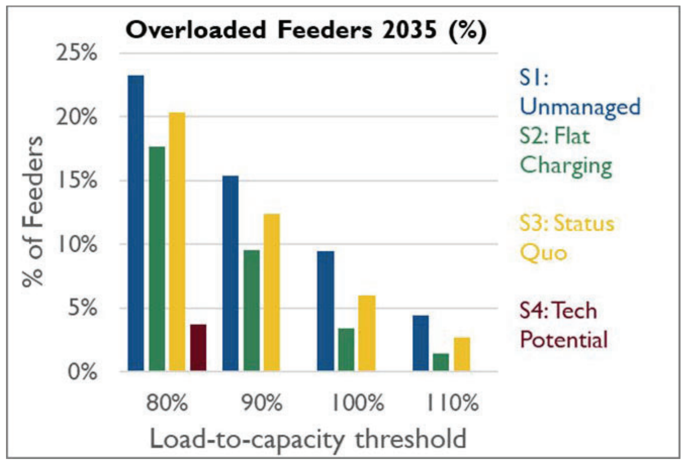
Table 5.3. Overloaded Feeders in 2030 and 2035

	Scenario 1 – Unmanaged	Scenario 2 – Flat Charging	Scenario 3 – Status Quo	Scenario 4 – Technical Potential
2030 count	288	200	265	41
% of Total Feeders*	11%	8%	10%	2%
2035 count	611	465	535	97
% of Total Feeders*	23%	18%	20%	4%

* Total feeders = 2,628

Figure 5.5. Overloading on feeders in 2030 and 2035





In the next five years, between 2 and 11 percent of Massachusetts feeders could overload. By 2035, the number of feeders overloading from unmanaged EV load could increase to nearly a quarter of all Massachusetts feeders. Overloading is seen across a variety of sizes of feeders in 2035, rather than clustered on smaller feeders. Feeders that overload with load-to-capacity fractions above 80 percent should be subject to additional monitoring and are possible candidates for targeted load management programs.

Overloading is strongly dependent on the EV charger load, existing load, and the capacity of the feeder (i.e., how much load the feeder can serve). Future overloading will depend on future loads, distributed generation, energy efficiency, demand response, and feeder capacity changes.

Figure 5.6 through Figure 5.9 show the spatial distribution of feeder overloading across Massachusetts in 2035 under each managed charging scenario. The greatest concentration of feeder upgrades is in the greater Boston area, Worcester, Lowell, and portions of Springfield and the Berkshires, where EV adoption is projected to be the largest relative to other areas in Massachusetts.

Figure 5.6. Scenario 1 – Unmanaged 2035 grid impact results

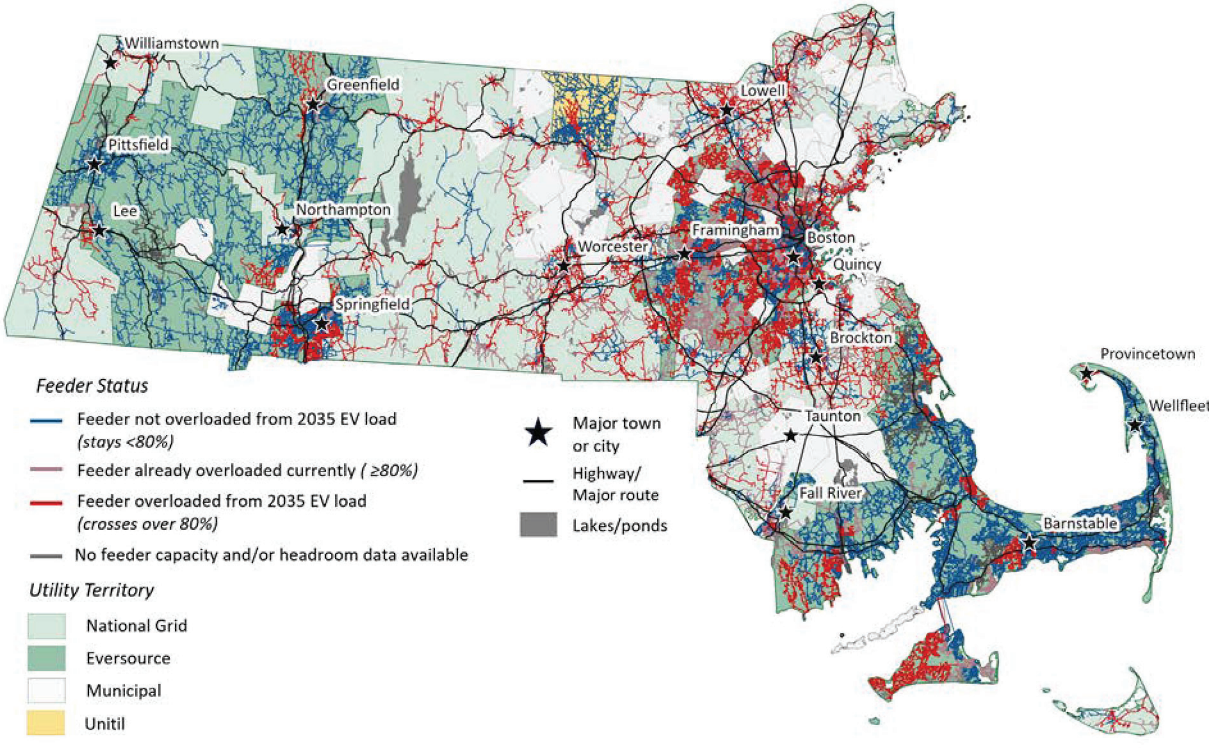


Figure 5.7. Scenario 2 – Flat charging 2035 grid impact results

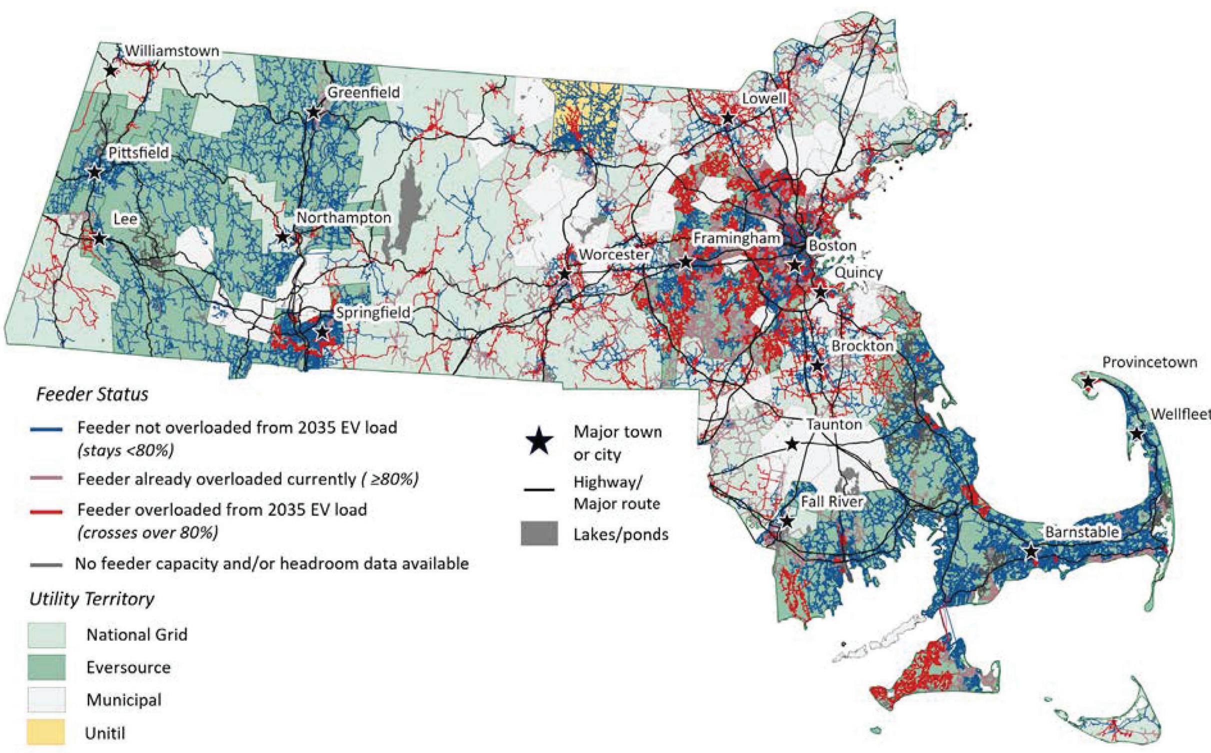


Figure 5.8. Scenario 3 – Status quo 2035 grid impact results

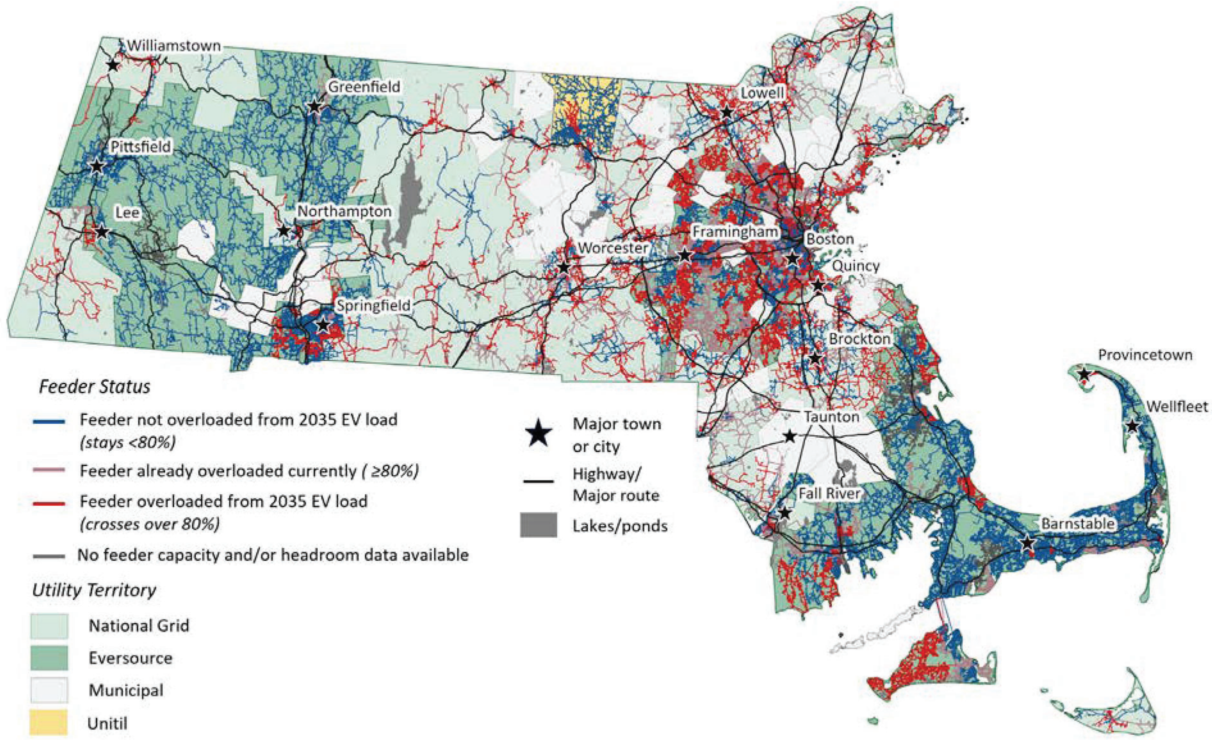
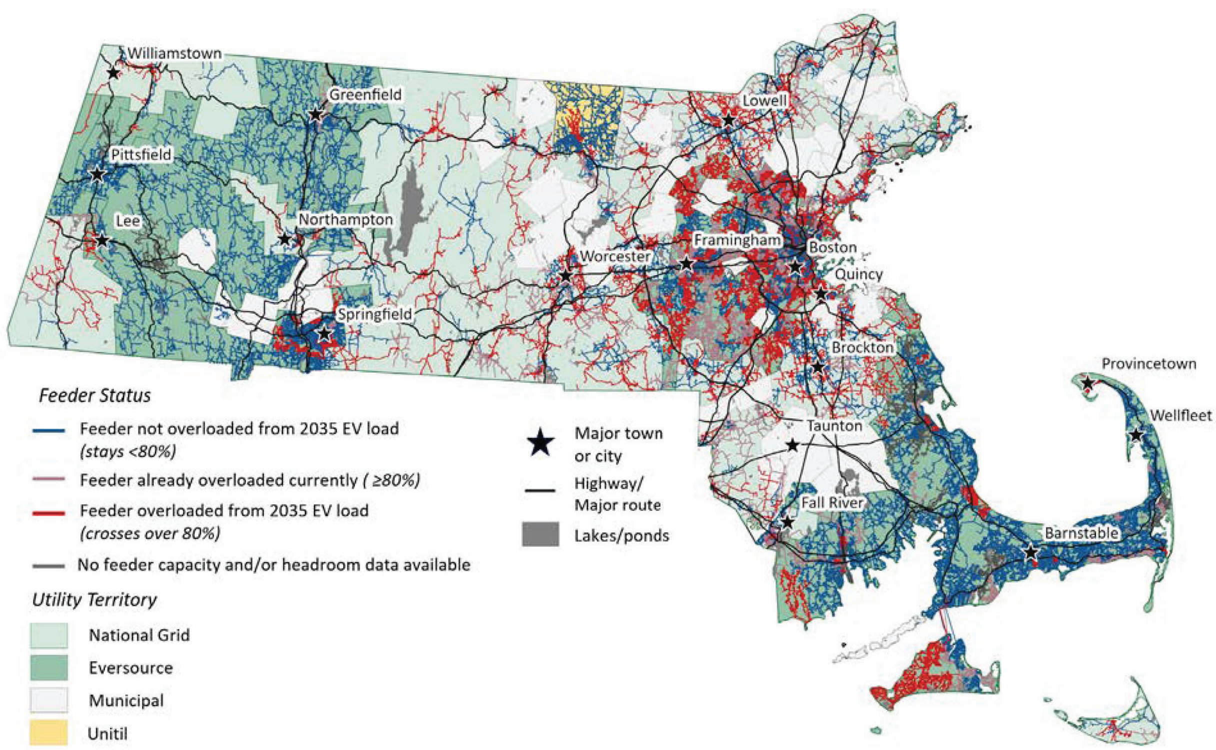


Figure 5.9. Scenario 4 – Technical potential 2035 grid impact results

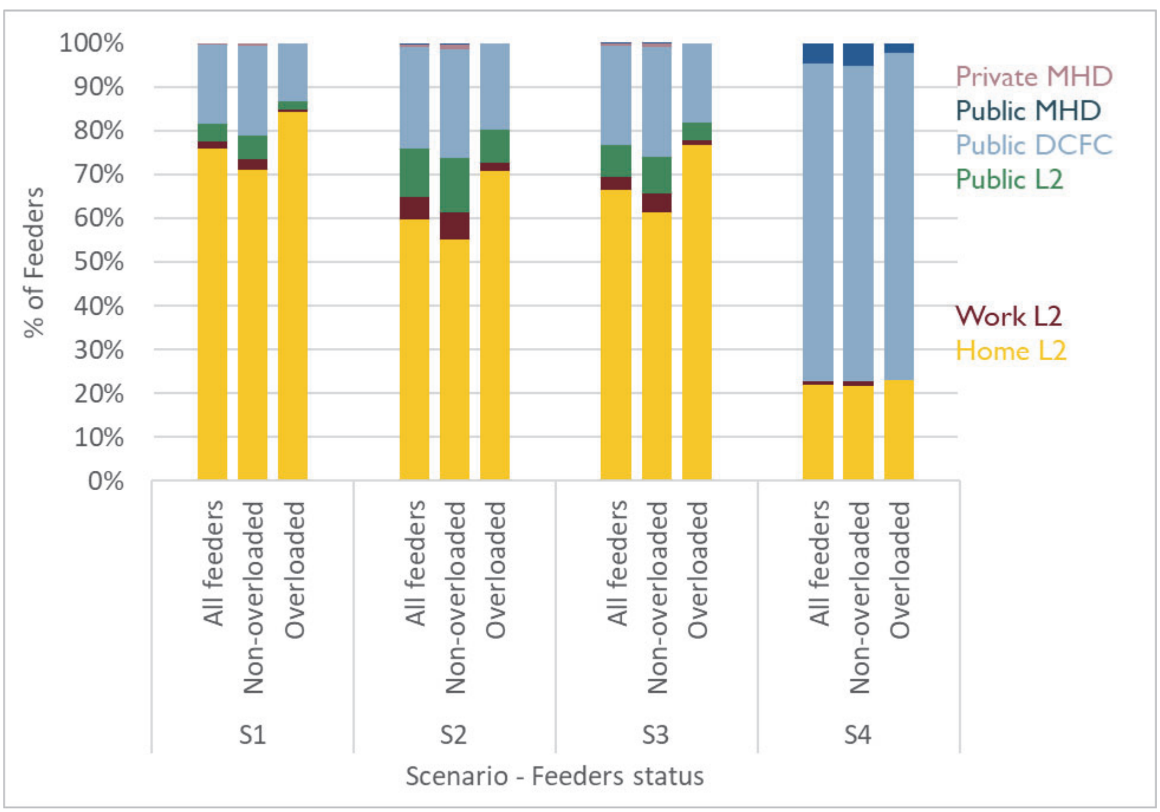


This analysis finds that public Level 2 and DCFCs cause the most feeder overloading in 2035 as other EV charger types have greater potential to be managed. Specifically, residential chargers are more easily managed than public chargers, especially compared to DCFCs along transportation corridors and chargers serving multi-unit dwellings without off-street charging. Roughly 90 percent of EV chargers installed in Massachusetts in 2035 are expected to be residential Level 1 and Level 2 chargers, typically serving single-family homes. In scenarios with no management (scenario 1) or some management (scenarios 2 and 3), the overloaded feeders are dominated by home Level 2 chargers, as depicted by the yellow bars in Figure 8. However, with high participation rates in robust and highly effective management programs (scenario 4), almost all home and public Level 2 charging is managed. This suggests that management programs targeting home chargers could help avoid the need for grid upgrades on certain feeders at risk of overloading, which is especially important in areas with large numbers of residential chargers, such as suburban areas (as seen in Figures 5.6-5.9).

Public DCFCs serving light-duty and medium- and heavy-duty vehicles are harder to manage. Vehicles using these types of chargers typically need to charge immediately and do not have as much flexibility to shift to different time periods or reduce charging speeds. Approximately 54 percent and 10 percent of the overloaded feeders in scenario 4 are dominated by public DCFCs and DCFCs for MHD EVs, respectively.

As discussed further in Appendix 8, Section 103 of the 2024 Climate Act requires the EDCs to identify distribution system upgrades necessary to meet

Figure 5.10. Dominant charger types at peak times on 2035 feeders, by status of feeder [11]



[11]Private chargers for MHD EVs are primarily Level 2, while public MHD chargers are mostly made up of DCFC.

ten-year EV charging demand in coordination with EVICC and aligned with the EVICC Assessment. As part of that process, EVICC plans to provide the EDCs with a list of electric distribution feeders and substations to evaluate for potential system upgrades to accommodate transportation electrification in 2030 and 2035.

Substations

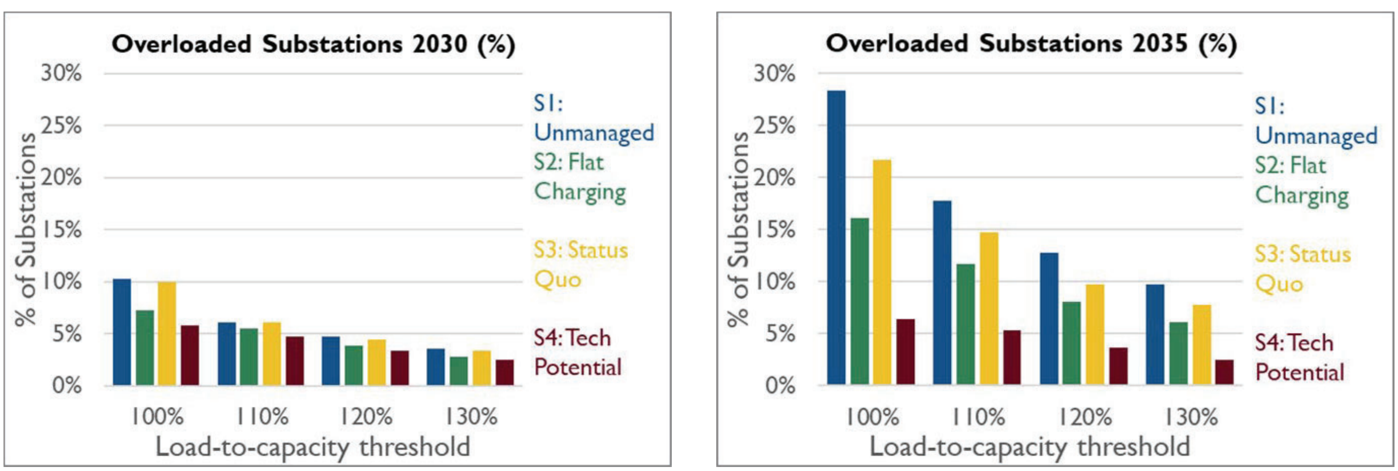
A load-to-capacity ratio of 100 percent was used to assess substation overloading.[13] About 10 percent of all substations could be overloaded from EV load by 2030 and 28 percent by 2035, as shown in Table 5.4. Substations that are projected to overload by 2030 may already be flagged for upgrades in utility ESMPs, which have a 5-year planning horizon. Figure 5.11 shows the magnitude of substation overloading in 2030 and 2035 and these results are shown geospatially in Figure 5.12 and Figure 5.15 under each managed charging scenario. Substation overloading is concentrated in eastern Massachusetts, specifically greater Boston, where most EV chargers are expected to be required.

Table 5.4. Overloaded substations in 2030 and 2035

Overloaded Substations	Scenario 1 – Unmanaged	Scenario 2 – Flat Charging	Scenario 3 – Status Quo	Scenario 4 – Technical Potential
2030 count	37	26	36	21
% of Total Substations*	10%	7%	10%	6%
2035 count	102	58	78	23
% of Total Substations*	28%	16%	22%	6%

* Total substations = 360

Figure 5.11. Overloaded substations in 2030 and 2035



[13]While an 80 percent load-to-capacity ratio is also typically utilized to plan for substation upgrades, the consultant team was unable to verify the coincidence of the feeder loads connected to each substation. Thus, the team took a more conservative approach in evaluating which substations would be "overloaded."

Figure 5.12. Scenario 1 – Unmanaged load 2035 substation grid impact result

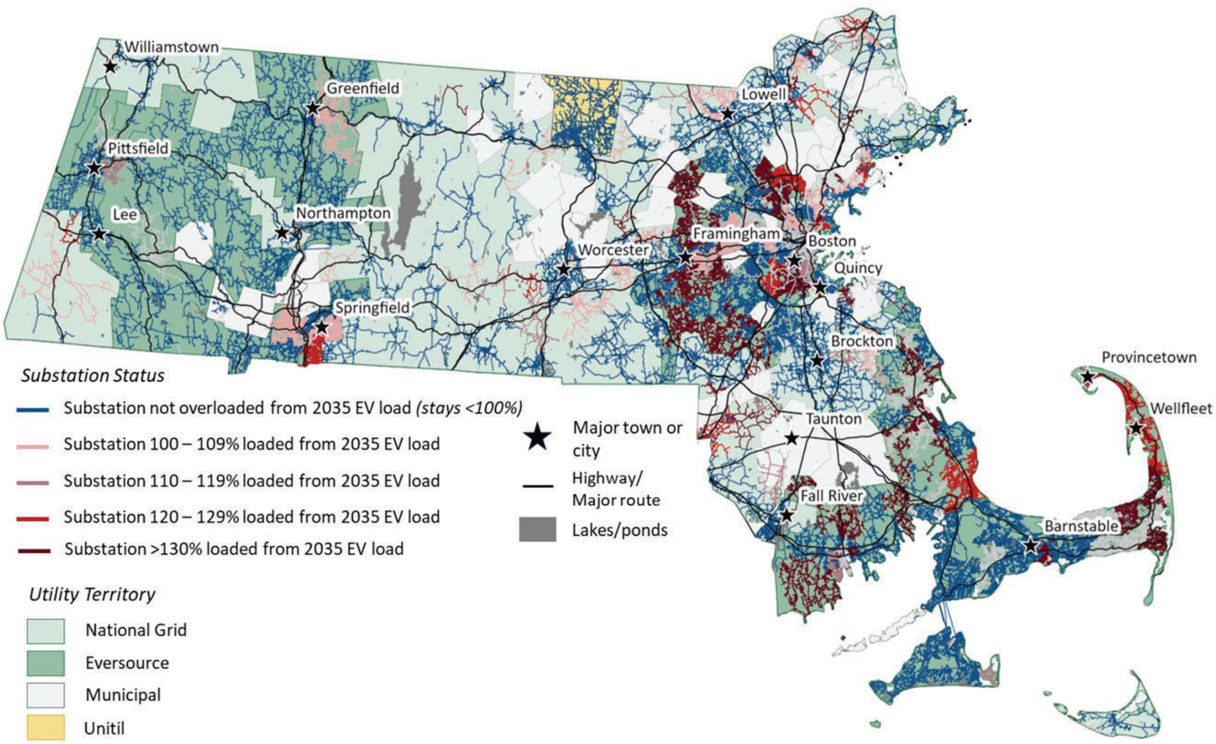


Figure 5.13. Scenario 2 - Flat charging 2035 substation grid impact results

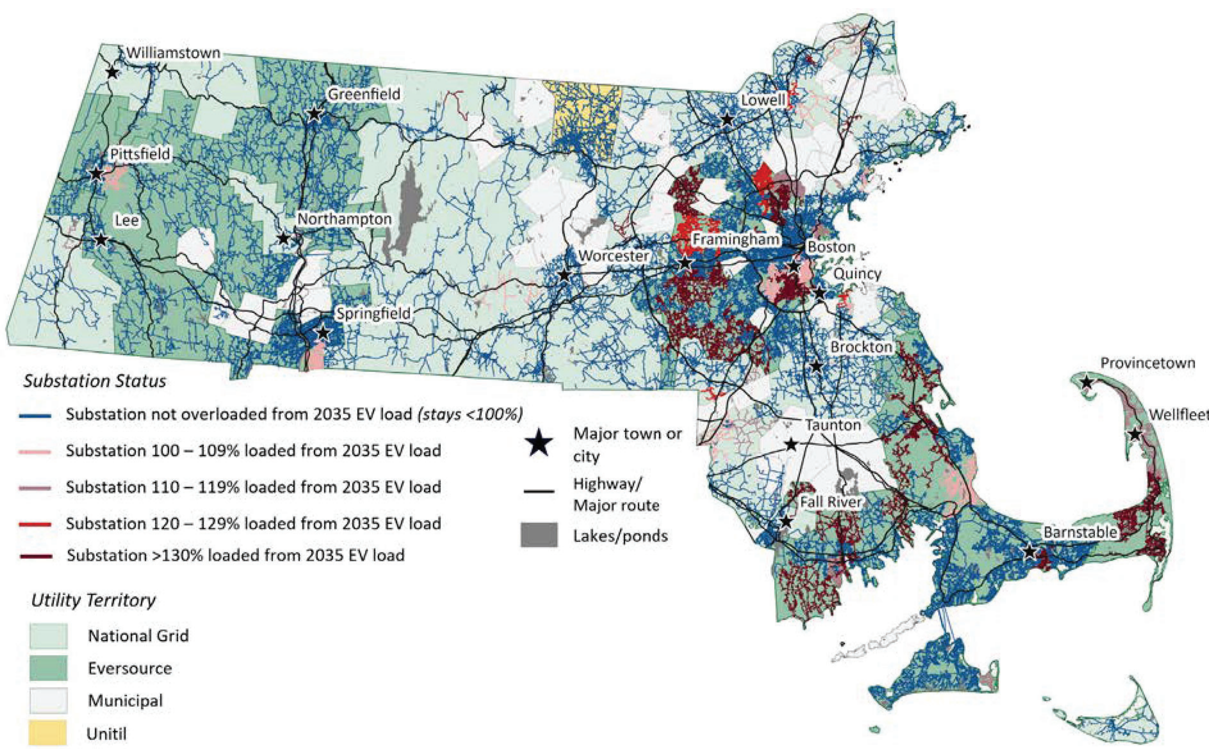


Figure 5.14. Scenario 3 - Status quo 2035 substation grid impact results

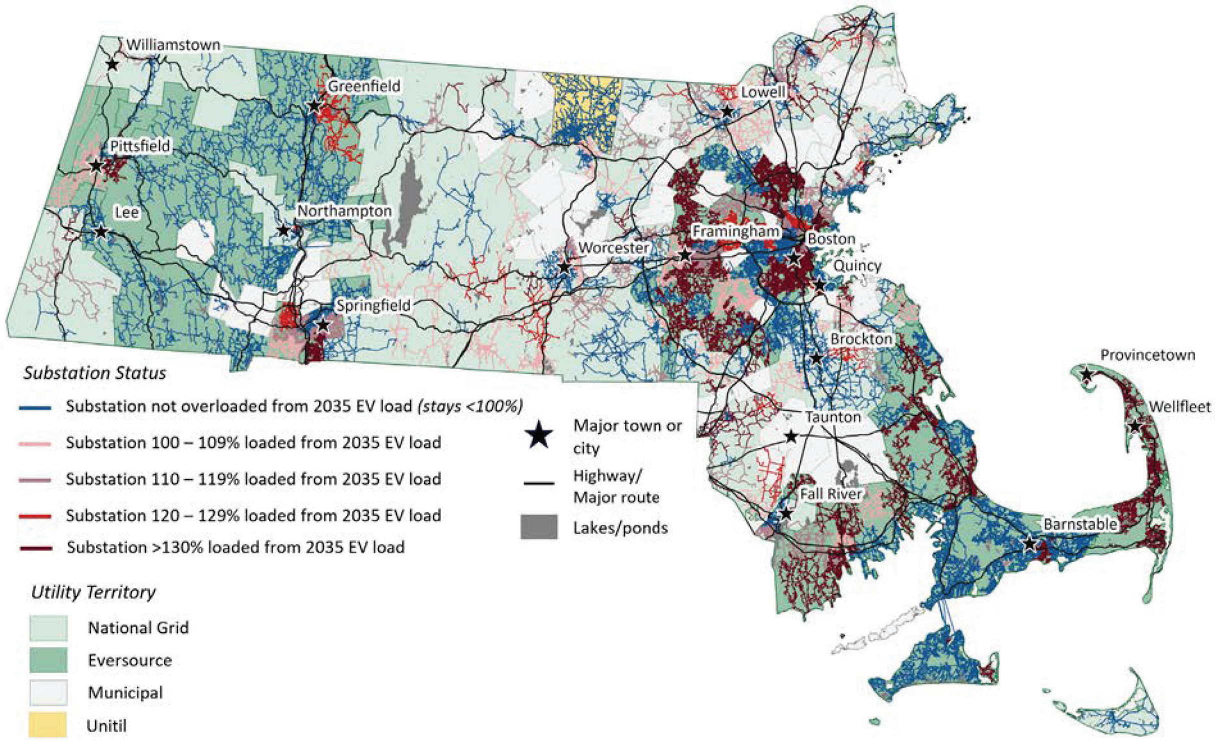
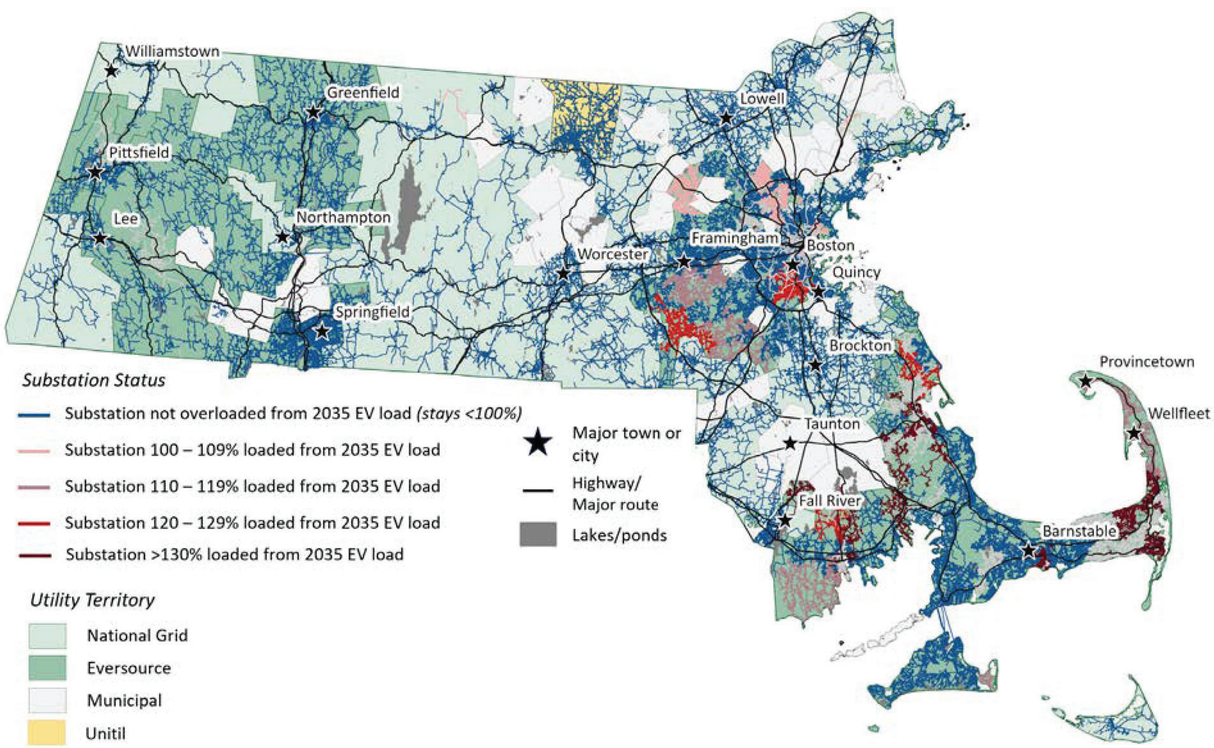


Figure 5.15. Scenario 4 – Technical potential 2035 substation grid impact results



Environmental Justice Populations Grid Impact Case Study

Environmental justice populations[14] are a focus of the Second EVICC Assessment. Due to the multiple benefits of EV ownership including bill savings and reduction in local air pollution, EJ populations can often benefit the most from switching to an EV.

Despite comprising 50 percent of Massachusetts' population, EJ populations host 70 percent of the state's distribution feeders (see Figures 5.16 and 5.17). These communities also bear a disproportionate share of system stress; over 75 percent of overloaded feeders are located within EJ areas. While managed charging programs reduce the number of overloaded feeders statewide, their benefits are less pronounced in EJ populations.

As shown in Table 5.5, the share of overloaded feeders in EJ areas increases in Scenario 4. This pattern suggests that feeders in EJ populations may be supporting a higher proportion of inflexible load types—such as public DCFCs serving both light-duty and medium- and heavy-duty EVs—limiting the effectiveness of managed charging interventions in these areas.

Table 5.5. Overloaded feeders in environmental justice populations (2035)

Overloaded Feeders	Scenario 1 – Unmanaged	Scenario 2 – Flat Charging	Scenario 3 – Status Quo	Scenario 4 – Technical Potential
Total	611	465	535	97
EJ populations	469	365	414	77
% in EJ populations	77%	78%	77%	79%

[14] Executive Office of Energy and Environmental Affairs – Office of Environmental Justice and Equity, 2025. Environmental Justice Populations in Massachusetts. Available at https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts

Figure 5.16. Scenario 1 – Unmanaged load 2035 grid impact results for EJ populations

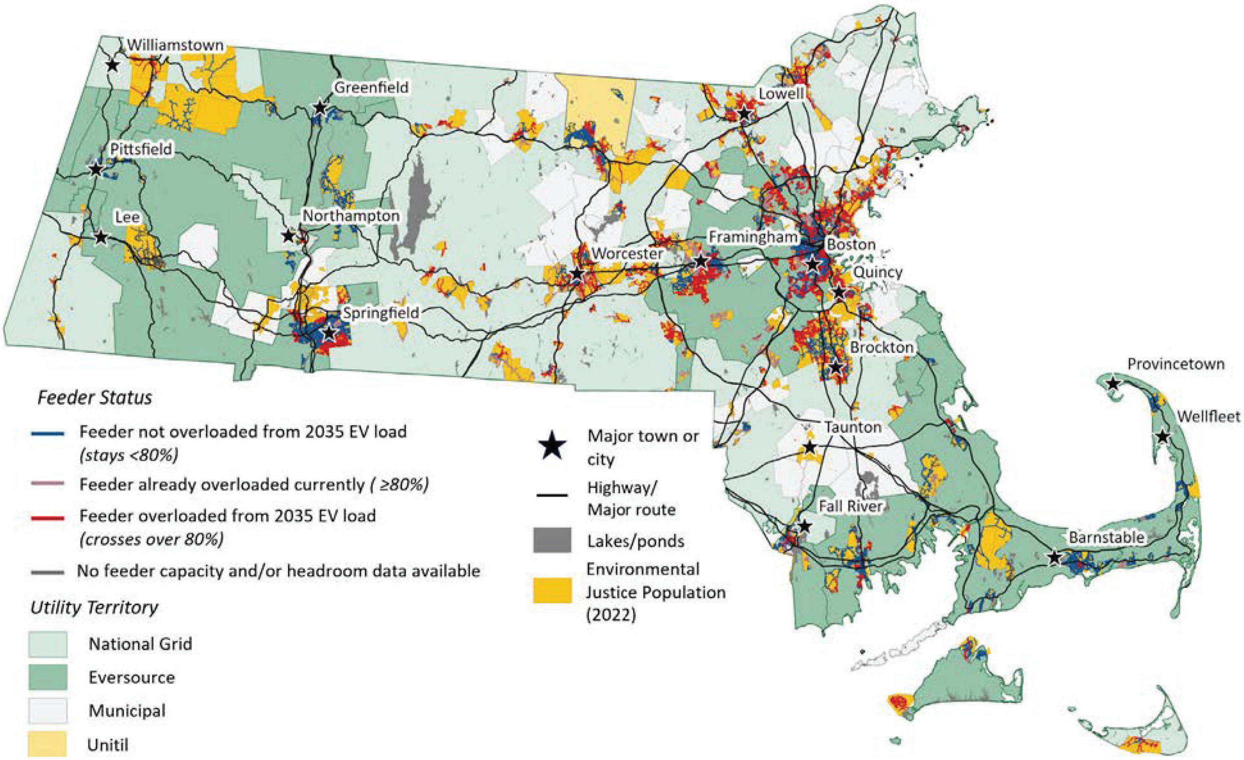
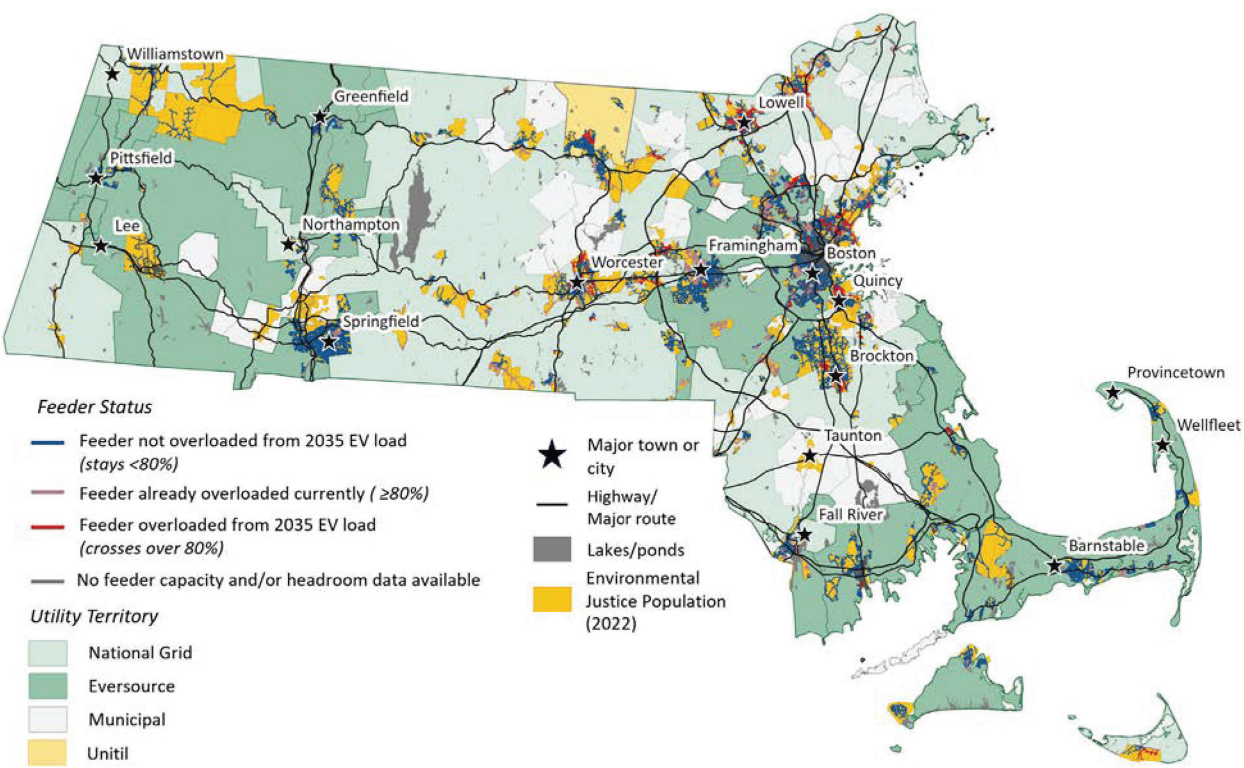


Figure 5.17. Scenario 4 – Technical potential 2035 grid impact results for EJ populations



Key Geographies Case Studies

In a separate analysis using charger counts from the Initial EVICC Assessment, Synapse quantified 2030 grid impacts at six different types of key geographies across Massachusetts.[15,16] Table 5.6 shows the results from this analysis.

Table 5.6 - EV impacts at four key geographies (2030)

key geography	Feeder or substation focus	Available headroom (MW)	Feeder/Substation capacity fraction with added EV Load - Unmanaged	Feeder/Substation capacity fraction with added EV Load - Managed
Transportation corridor - Charlton Service Plaza	Feeder	0.8 MW	27%	23%
Rural area - Harvard	Feeder	5 MW	5%	31%
Suburban area - Waltham	Substation	23.8 MW	132%	17%
Urban Area - Lowell	Substation	104 MW	19%	2%

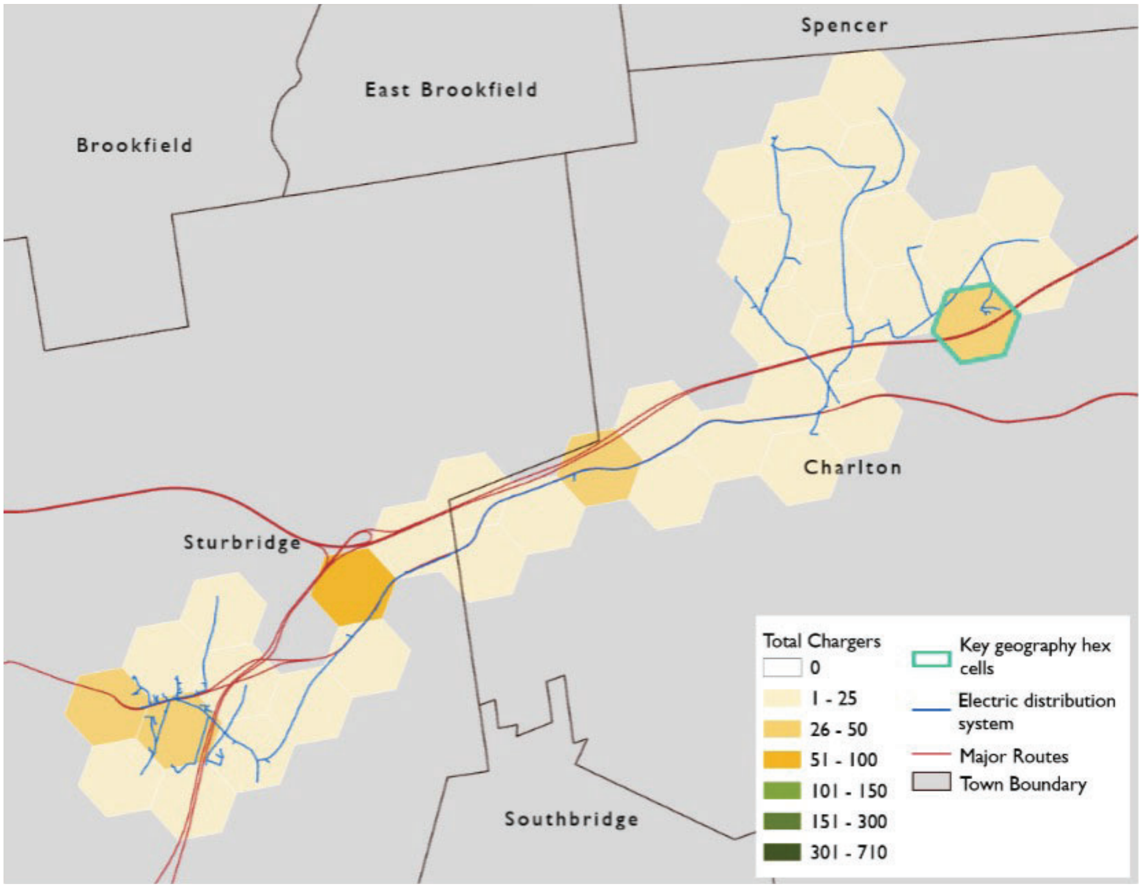
Transportation Corridors

At service plazas serving transportation corridors, future EV load tends to be high, concentrated, and inflexible. For example, the Charlton service plaza along Interstate-90 is expected to host a high number of DCFCs serving long-distance travel. At that rest stop, light-duty DCFCs alone could take up 23-27% of available feeder headroom (0.8 MW) depending on the level of managed charging. When considering all chargers in the feeder area, the new EV demand could fill 86 percent of the available feeder headroom. Managed charging programs have limited effectiveness at the Charlton service plaza, since DCFCs load is considered inflexible (these chargers are akin to gas stations, where drivers need to use them immediately upon arrival). Figure 5.18 shows the Charlton service plaza feeder and estimated future charger counts. The service plaza is in the hex cell highlighted in bold teal.

[15]Charger counts between the Initial EVICC Assessment and Second EVICC Assessment changed. The results from the case studies are from the Initial EVICC Assessment.

[16]To see the full presentation, visit https://www.mass.gov/doc/evicc-meeting-deck-april-2-2025/download.

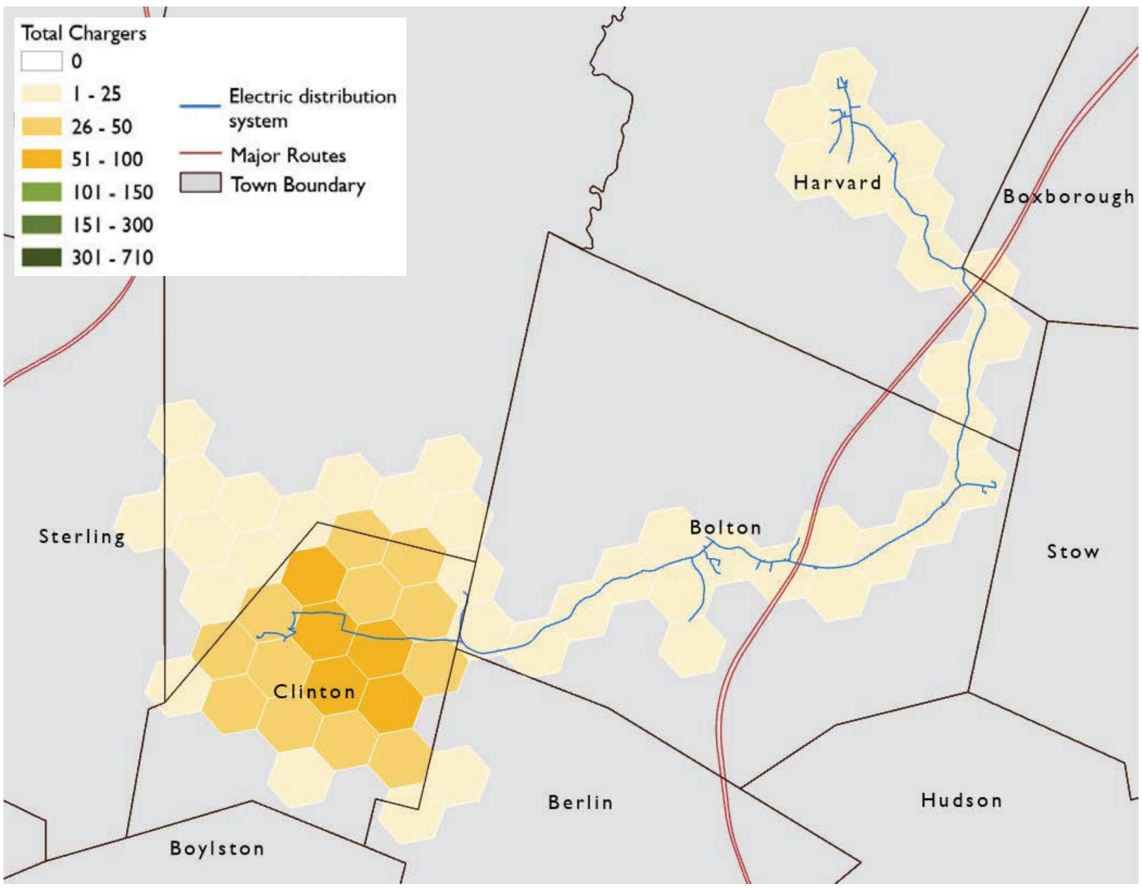
Figure 5.18. Charlton service plaza total charger count (2030)



Rural Areas

About half of Massachusetts is considered rural.[17] In rural areas, there are fewer and more dispersed EV chargers, putting less stress on the distribution grid. For example, the town of Harvard is served by a National Grid feeder that extends to nearby towns of Bolton and Clinton (see Figure 5.19). There are over 600 chargers anticipated to connect to this feeder by 2030. Over 80 percent will be residential chargers. This feeder has a relatively high amount of headroom, roughly 5 MW. EV charging could occupy between 5 to 30 percent of the available headroom, depending on the level of charging management. The trend observed in Harvard is consistent across other rural areas of Massachusetts; rural feeders generally have more available headroom to accommodate future EV load.

Figure 5.19. Harvard total charger count (2030)

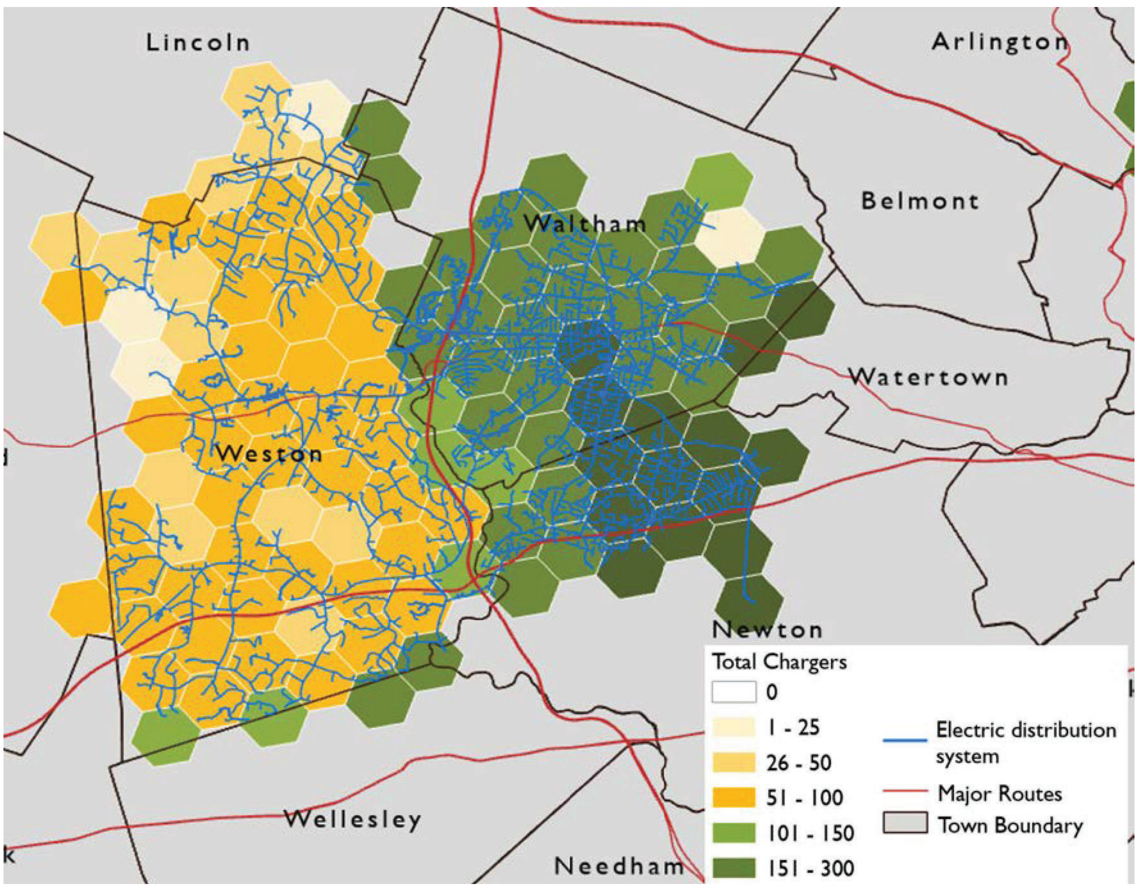


[17]Massachusetts Department of Public Health, 2017. Chapter 1 – Population Characteristics. Available at https://www.mass.gov/files/documents/2017/10/04/MDPH%202017%20SHA%20Chapter%201.pdf.

Suburban Areas

In suburban areas, a single large substation tends to serve multiple towns. For example, the Boston suburb of Waltham is served by one substation, which also serves nearby Weston (see Figure 5.20). This substation could host up to 16,000 chargers by 2030, with most chargers being residential Level 1 and Level 2. If unmanaged, these chargers would overload the substation and take up over 130 percent of the available headroom. On average, residential chargers are more flexible than other charger types. Under an advanced charging scenario, only 17 percent of available substation headroom would be used by new chargers during peak hours, demonstrating the potential for managed charging programs in these types of geographies.

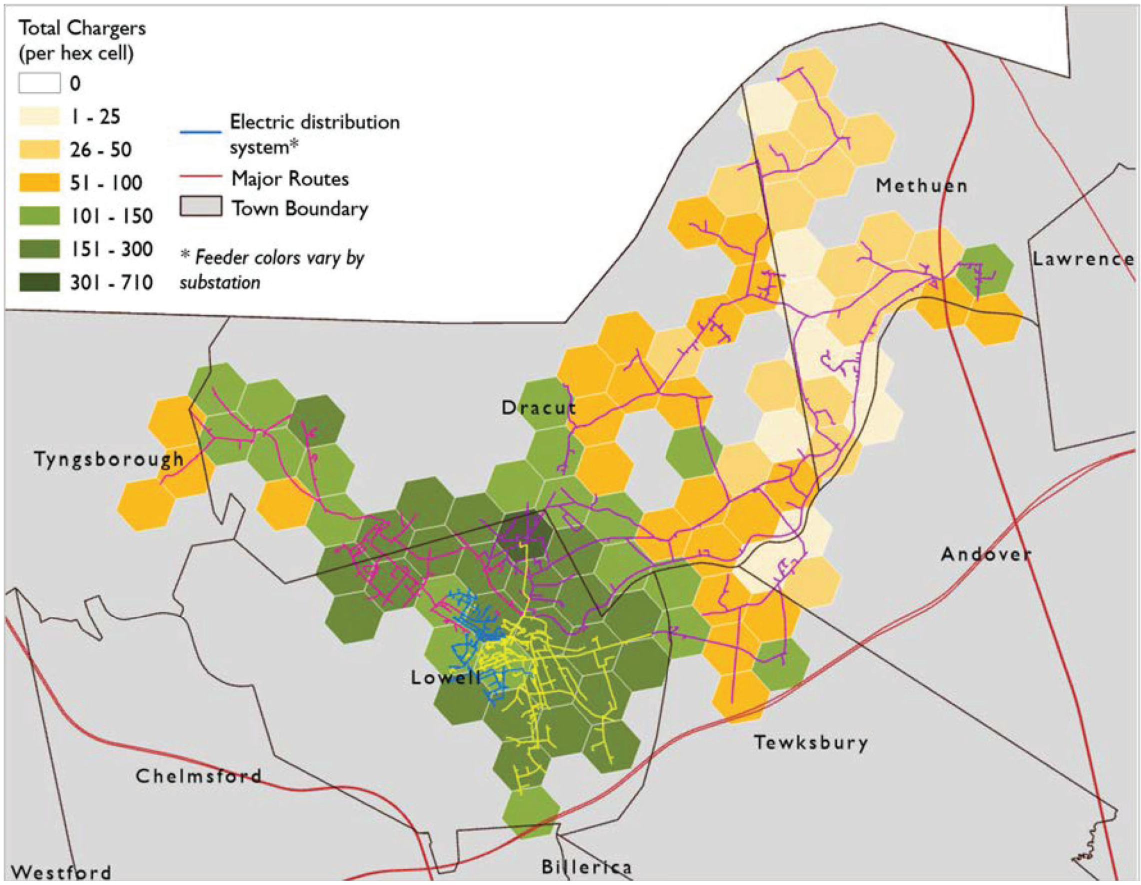
Figure 5.20. Waltham total charger count (2030)



Urban Areas

Multiple substations often serve a single urban area, as is the case with Lowell. More than four substations serve the city of Lowell and surrounding suburbs (see Figure 5.21). Together, these four substations are expected to host up to 10,600 chargers by 2030. Given the large amount of headroom on these substations in Lowell, chargers are only expected to take up 20 percent of the cumulative available substation headroom in this case study.

Figure 5.21. Lowell total charger count (2030)



These case studies at specific key geographies demonstrate the potential for managed charging programs to reduce peak demand and avoid electricity system costs . Grid impacts vary widely, depending on location. As seen in the above examples, rural areas such as Harvard tend to have lower loads and feeders tend to have excess capacity, suggesting that rural areas may be more easily able to accommodate future EV load. Higher loads in suburban and urban areas in combination with less available capacity on feeders and at substations make managed charging particularly valuable, especially in areas with high concentrations of single family homes, which are more likely to participate in and be responsive to managed charging programs. EV loads along transportation corridors, such as Charlton, have less potential for management as vehicles visiting those need to charge to make it to their destination. These areas may need quicker grid upgrades, as they cannot easily rely on load management programs.

Addressing an overloaded distribution system

Utilities should engage in comprehensive planning to meet future electric vehicle load growth. This means using non-wires alternatives in tandem with physical grid upgrades for cost-effective and time-sensitive solutions to support EV charger buildout across the state.

When feasible and cost-effective, existing loads should first be reduced through demand side management programs, such as energy efficiency, managed charging programs, time-of-use rates, demand response, and distributed energy resources (DERs). For instance, DERs like solar photovoltaics and battery storage systems placed strategically to reduce grid impacts associated with large DCFC banks can help avoid grid upgrades on those feeders or substations. These solutions can usually be implemented on a faster timeline than upgrades to feeders and substations, which take between 2 to 10 years depending on the size of the upgrade, giving the utilities time to evaluate whether load could be reconfigured, phases could be balanced to shift unmanageable load, or if a traditional infrastructure upgrade is needed. If a traditional upgrade is needed, the utility should still evaluate how best to utilize these approaches to mitigate the size, cost, and timing of the grid upgrade and to ensure that the appropriate managed charging approach is deployed for that portion of the grid.

Demand side EV load management programs are essential to controlling electric system costs and limiting electric rate increases. By shifting charging to off-peak periods or periods with high renewable generation, these programs can help “flatten” the electric system’s peak demand, reducing the need for costly grid infrastructure upgrades and improving grid efficiency. As shown in Table 5.3, 537 feeders are projected to become overloaded by 2035. This will drive substantial grid infrastructure upgrades, the costs of which will be borne by all ratepayers. However, if the full technical potential of managed charging were realized, only 7 feeders would be overloaded. While achieving the full technical potential of managed charging is not feasible, expanding managed charging significantly is a key strategy to reduce system costs for all ratepayers and advance the Commonwealth’s clean energy goals.

The first step in managing future EV load will be to take full advantage of alternative grid upgrades. However, feeder and substation grid upgrades will be inevitable and necessary in many locations, especially as EV penetration grows past the levels expected in 2035 and as electrification of other sectors puts more demands on the grid. Table 5.7 summarizes some of these distribution system upgrades. Multiple levels of grid upgrades exist, including reconfiguring existing feeder load, reconductoring existing lines, and promoting overloaded feeders to higher voltages. High EV load growth, especially paired with other non-EV electrification load, may require the construction of new feeders and substations.

Table 5.7. Solutions to Address Grid Impacts

Potential Solution	Description	Timeline	Relative cost[18]
Reduce loads (EVs and buildings) on feeders	Use demand side management (e.g., energy efficiency, demand response, active load management) to reduce building and EV loads	varies	varies
Distributed battery storage and distributed solar	Battery solutions at the substation- ,feeder-level, or site-level to manage peaks (holistically planned with considerations of distributed solar)	varies	varies
Reconfigure feeder load	Shift load to neighboring feeders, where possible/feasible	3-8 months[19]	$
Balance phases	Redistribute load across single-phase lines (within three-phase lines) on the same circuit	3-12 months[19]	$
Reconductoring	Replace existing conductors with higher amperage cables	3-12 months,[19] 10-14 months[20]	$$
Voltage conversion of feeders	Promote overloaded feeders to higher voltage (e.g. 4.16 kV to 13.2 kV feeders)	3-12 months[19]	$$
New feeder construction	Construct new distribution feeders	12-26 months[20]	$$$
Distribution substation upgrades	Upgrade substation transformers and other equipment as necessary to increase substation and feeder capacity	12-18 months,[19] >24 months[20]	$$$
New distribution substation construction	Construct new substations	24-48 months[19,20]	$$$$

[18]The relative cost range is roughly: $: <$1M; $$: $1-3M; $$$: $3-5M; $$$$: >$5M.

[19]Borlaug et al., 2021. Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems. Nature Energy. Available at https://doi.org/10.1038/s41560-021-00855-0

[20]Black & Veatch, 2022. 10 Steps to Build Sustainable Electric Fleets – Optimal Charging Networks Ensure Triple Bottom Line Benefits. Available at https://webassets.bv.com/2022-08/22CCx10StepsFleetEbook%20%281%29.pdf

Public Comments

Stakeholders have shared feedback about grid impacts and managed charging solutions at regular EVICC meetings, the Second Assessment public hearings, and through other engagement opportunities. A summary of those comments are included below.

- In general, grid constraints were considered a major barrier to charger deployment in rural areas, since infrastructure upgrades can be costly. Stakeholders expressed a need for more education and awareness for owner/operators around demand charges and either technological or programmatic innovations to reduce demand charge impacts.
- Feedback included calls for more widespread options for pairing EV charging with battery storage, particularly in EJ populations and rural areas, to potentially mitigate grid upgrades and demand charges.
- For rural communities, EV charging infrastructure supported by solar energy and battery storage was suggested as a solution for making rural charging more resilient in the face of more frequent grid outages.

A summary of comments provided during the public hearings on the Second EVICC Assessment and the minutes and presentations from prior EVICC public meetings are available on the EVICC website.

EVICC Recommendations

EVICC recommends the following actions to address the key themes highlighted in this Chapter and to minimize the electric grid impacts of EV charging in the future.

- **Agency Action:** Explore additional, innovative rate designs, novel incentive structures, and customer engagement strategies, such as active managed charging or campaigns to increase participation rates in existing managed charging programs, to maximize the practical potential of managed charging to avoid grid upgrades and minimize grid-related costs in areas that are projected to face grid constraints by 2030 or 2035. *(Lead(s): DOER and the EDCs; Support: EEA and DPU, as appropriate)*
- **Agency Action:** Develop a long-term managed charging strategy, defining program benefits, cost-effectiveness metrics, and incentive structures, and integrating lessons from pilot projects and industry best practices into broader implementation. Such strategy should include relevant metrics that provide meaningful insight into their progress in developing and implementing the comprehensive strategy. *(Lead(s): DOER and the EDCs; Support: EEA and DPU, as appropriate)*

- **Agency Action:** Incorporate anticipated load reductions resulting from managed charging programs into distribution system planning efforts and plans. *(Lead(s): The EDCs; Support: DOER, EEA, and DPU, as appropriate)*
- **Agency Action:** Continue ongoing coordination to identify and execute next steps related to EV load management planning and vehicle-to-everything (V2X) load dispatch capabilities. *(Lead(s): DOER and EEA; Support: MassCEC, DPU, as appropriate, and the EDCs)*
- **Agency Action:** Create a planning framework for integrating EV charging infrastructure projections into electric distribution system planning through the requirements outlined in Section 103 of the 2024 Climate Act, including identifying potential grid constraints that may be caused by transportation electrification in 2030 and 2035 for further investigation by the EDCs. The framework should include the process by which the EDCs will identify and file for approval with DPU necessary grid upgrades. The framework and grid upgrades should ensure that known, high-value charging locations, such as the MassDOT Service Plazas, have sufficient grid capacity to support light-, medium-, and heavy-duty EVs on the timescale needed to meet the Commonwealth's climate requirements. *(Lead(s): EEA and the EDCs; Support: DOER, MassDOT, MBTA, and DPU, as appropriate)*
- **Agency Action:** Assess grid resilience and infrastructure needs for EVs before, during, and after major weather events and other emergency events with a particular focus on emergency vehicle and public transportation fleets, identifying key reliability gaps and backup power solutions, including off-grid and solar and storage technologies, to inform future planning. (Lead(s): EEA; Support: DOER, MassDOT, MBTA, the EDCs, and emergency management agencies)
- **Agency Action:** Continue ongoing coordination to identify and execute next steps related to EV charger interconnection processes. *(Lead(s): EEA , DOER, and the EDCs; Support: MassDOT, MBTA, and DPU, as appropriate)*