Massachusetts' Energy Transition: Innovation for Electric Utility Regulation

Authors:

Paul Hibbard

Susan Tierney

Grace Howland

Daniel Stuart

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About the Authors

Paul Hibbard, a Principal at Analysis Group, is a former Chairman of the Massachusetts Department of Public Utilities and has held positions in both energy and environmental agencies in Massachusetts. During his tenure on the Commission, Mr. Hibbard served as a member of the Massachusetts Energy Facilities Siting Board, and testified before Congress, state legislatures, and federal and state regulatory agencies. Mr. Hibbard is now a Principal in Analysis Group's Boston office and has public and private sector experience in energy and environmental technologies, economics, market structures, and policy.

Grace Howland is an Associate at Analysis Group, where she focuses on research and analysis associated with energy and environment issues, and the ongoing shift toward decarbonization. Ms. Howland has worked on projects related to electric retail rate disputes, battery storage and recycling, and the maintenance of reliable electric service as dependence on renewable resources for electric generation increases. She received her MBA from the University of Cambridge, Judge Business School.

Daniel Stuart is an Associate in Analysis Group's Boston office who specializes in applying economic and statistical analysis to litigation, regulatory, and policy matters related to energy and environmental issues. He has supported experts in Federal Energy Regulatory Commission (FERC) proceedings and in litigation related to the provision of electric utility service. Dr. Stuart has also co-authored white papers on alternative pathways for power sector decarbonization in New England, the economic impacts of the Regional Greenhouse Gas Initiative (RGGI) on Northeast states, and the potential impacts of heavy-duty vehicle electrification on the electric distribution system. Dr. Stuart received a Ph.D. from Harvard University.

Sue Tierney is a Senior Advisor at Analysis Group, where she has advised a wide variety of organizations. Previously, she served as the Assistant Secretary for Policy at the U.S. Department of Energy, and in Massachusetts she was Secretary of Environmental Affairs, Commissioner at the Department of Public Utilities, and Executive Director of the Energy Facilities Siting Council. She chairs the Board of Resources for the Future. She is a trustee of the Barr Foundation and the Alfred P. Sloan Foundation, a board member at World Resources Institute, and chairs the National Academies' Board on Environmental and Energy Systems. She has served on several National Academies' committees: The Future of the Electric Grid; Net Metering in the Evolving Electricity System; and Accelerating Decarbonization in the U.S. She chaired the Department of Energy's Electricity Advisory Committee, and now chairs the External Advisory Council of the National Renewable Energy Lab. She received her Ph.D. in regional planning from Cornell University

About Analysis Group

Analysis Group is one of the largest economics consulting firms, with over 1,200 professionals across 14 offices in North America, Europe, and Asia. Since 1981, Analysis Group has provided expertise in economics, finance, analytics, strategy, and policy analysis to top law firms, Fortune Global 500 companies, government agencies, and other clients. The firm's energy and climate practice area is distinguished by its expertise in economics, finance, market modeling and analysis, economic and environmental regulation, analysis and policy, and infrastructure development. Analysis Group's consultants have worked for a wide variety of clients, including energy suppliers, energy consumers, utilities, regulatory commissions, other federal and state agencies, tribal governments, power system operators, foundations, financial institutions, start-up companies, and others.

Table of Contents

Figures

Table

I. Executive Summary

Over the past two decades, the Commonwealth of Massachusetts has enacted an aggressive set of goals and policies to greatly reduce – and effectively eliminate – greenhouse gas ("GHG") emissions from the state's economy. Starting with the passage of the *Global Warming Solutions Act* over 15 years ago, the state's leaders have embraced a transition to an economy with continuously declining levels of GHG emissions through successive legislative and regulatory changes. The 2021 *Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy* ("2021 Act") creates a roadmap for the state's energy and climate transitions. The 2021 Act codifies an economy-wide requirement of net-zero GHG emissions by 2050, with interim emission-reduction targets of at least 50 percent by 2030 and 75 percent by 2040 (relative to emissions in 1990).[1]

Given the significant contribution of fossil fuels to the state's GHG emissions profile, Massachusetts has also, in effect, directed major changes in the state's energy mix, including most recently in the 2022 *Act Driving Clean Energy and Offshore Wind* ("2022 Act").[2] After making climate action one of the pillars of her gubernatorial campaign,[3] Governor Healey appointed the first executive-branch Climate Chief and assembled leaders in key state agencies to implement an "all-hands-on-deck" approach to carry out and strengthen the state's progress on climate action.[4]

Massachusetts law requires that the state must cut its 1990-level greenhouse gas emissions by one half in the next seven years.

The pace and breadth of change needed in energy supply and demand technologies is unmatched in any period in our history.

An "all-hands-on-deck" approach to governmental action is needed to ensure success.

These actions acknowledge the reality that climate-related events are already showing up in the daily news with shocking ferocity: unusual heat waves, cold snaps, extreme ice and windstorms, river flooding, sea level rise, wildfires and deadly levels of smoke. Massachusetts residents may not experience every type of climate impact, but no place is untouched. Massachusetts policy makers have determined the Commonwealth must reduce GHG emissions as part of global efforts to avoid the worst impacts of climate change.

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[1] Commonwealth of Massachusetts, Session Laws, Acts 2021, Chapter 8, "An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy," approved March 26, 2021, available at: https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8.

[2] Commonwealth of Massachusetts, Session Laws, Acts 2022, Chapter 179, "An Act Driving Clean Energy and Offshore Wind," approved August 11, 2022, available at: https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179.

[3] Gavin, Christopher, "Here are Gov. Maura Healey's policy priorities — and what she's done so far," *Boston.com*, January 6, 2023, available at: https://www.boston.com/news/politics/2023/01/06/maura-healey-policy-priorities-massachusetts/.

[4] Lannan, Katie, "Gov. Healey describes 'all hands on deck' approach to climate policy," *WGBH*, May 26, 2023, available at: https://www.wgbh.org/news/politics/2023/05/26/gov-healey-describes-all-hands-on-deck-approach-to-climate-policy.

The deadlines set forth in Massachusetts law make it clear that action is needed – and fast. The year 2030 is seven years away. And in only 17 years from now, Massachusetts' economy will need to have 75 percent lower GHG emissions. There is much to do in a short period of time.

Future investments and actions required to transform and decarbonize the goods and services everyone relies upon in their daily lives will create benefits in the form of lower emissions, jobs, and increased economic growth. But meeting the Commonwealth's GHG reduction timelines will be challenging. It will require rapid changes in the ways that Massachusetts businesses and consumers produce, deliver, and use energy, and the changes will need to happen more quickly than ever experienced in the past. Most of the energy infrastructure the state relies upon today is the same as it was decades ago. The building stock in the state is aged and largely built to rely on yesterday's heating, cooling, and electricity technologies. Most vehicles run on gasoline.

The pace of change needed in energy supply and demand technologies is unmatched in any period of our history. Reliance on the same old technologies and the same ways that we do things will not work against the backdrop of the Commonwealth's statutory deadlines for continuous and progressive reductions in GHG emissions.

This transformation will involve risk-taking in countless ways. It will require aggressive action by many state energy and environmental agencies in the face of significant technological and economic uncertainties. The Commonwealth's legislature, executive branch, and energy regulatory agencies have already been leading the way, but the job is far from done. It will require state agencies to do their jobs in new ways, including by adopting innovative approaches to foster rapid action across the economy.

Nowhere is this more relevant or more important than in the electric sector.

Clean electricity is key to the low-carbon transition.

First, the power sector must continue to decarbonize by adding onshore and offshore wind, solar, hydropower, and storage, especially in the near term, and by building out local and long-distance power lines.

Second, the power sector must do this while experiencing unprecedented growth and change in total demand, since the expected lowest-cost economy-wide decarbonization strategies depend upon the electrification of energy-using technologies and equipment, particularly buildings and vehicles.

The power system will play a critical role in enabling the energy transition in the state. All net-zero approaches ("pathways") identified in Massachusetts' 2050 Decarbonization Roadmap Study (December 2020) rely on two fundamental strategies that enable the energy transition at lower cost than the alternatives: First, the power sector continuously decarbonizes by adding zero-carbon electric resources, especially in the near term. This involves not just large generating resources (like onshore and offshore wind farms and hydropower) but also grid-edge technologies (like rooftop solar and battery storage, energy efficiency, and demand-management equipment and systems). This also requires reinforcing and building out the local distribution system and interstate transmission network to support the efficient movement of power to and from buildings, and from both local and distant zero-carbon generating assets. Second, the expected lowest-cost economy-wide decarbonization strategies depend strongly upon the electrification of energy-using technologies and equipment, particularly in buildings and the transportation sector.

As power-sector GHG emissions continue to decline towards net zero through those means, electricity will increasingly serve as the primary source of energy for the entire economy. This transition will necessarily increase the level of electricity consumption. It is also likely to fundamentally change the shape of electricity demand and its distribution across different parts of electric utility service territories. This in turn will require significant, and largely private, capital investments to expand the capabilities and resilience of today's electric grid.

The grid needs investment to enable it to provide for more power resources drawing from and feeding into local distribution circuits that were never planned for two-way power flows or for so many large and small injections of power (e.g., from many solar systems on individual circuits and feeders). Local grid operators will also need far better visibility into what is happening on the local grid to assure reliable and resilient delivery of power around the clock and during periods of stress on the electric system.

Enabling new clean power supplies and the deployment of electric vehicles and efficient electric building heating/cooling systems depends upon new investment in power delivery functions.

Making sure that the grid is ready to handle new patterns of electricity demand and the addition of new electric technologies will give investors in these actions the confidence to proceed.

Making sure *in advance* that local distribution systems and the broader transmission grid are ready to handle new patterns of electricity demand and new installations of electric technologies – from new electric vehicle ("EV") charging stations, to heat pumps in buildings, to rooftop solar and storage, to large grid-connected renewable resources – will give potential investors in these installations the confidence to proceed. The promise of reliable operation of an advanced electric system is a precursor to the necessary transition; it will be needed so that consumers may confidently rely on the electric system for so much of their minute-to-minute and day-to-day energy needs. The importance of achieving the highest possible level of power system reliability will be amplified by our dependence on it not just for lighting and appliances, but also for transportation, heating, and cooling.

Typically, discussions on electric-system transitions focus on power production technologies: how much pollution they are emitting; how costly and reliable are different types of facilities; how much power can be generated on rooftops. Too little attention ends up focusing on the electric wires and the operations of the local grid. Yet the full achievement of the Commonwealth's aspirations for new power supplies and the deployment of EVs and efficient electric heating/cooling systems depend perhaps most importantly upon enabling timely investments in the power delivery functions to facilitate investments in transportation and building electrification.

Capital spending on the distribution grid itself introduces both novel financial opportunities and risks to regulated electric utilities in Massachusetts. The state's investor-owned utilities and municipal light companies are responsible for anticipating the rapidly evolving needs of both consumers and power suppliers and helping enable others' investments in grid-edge technologies, while continuing to operate the system reliably every minute of every day. In this sense, the utilities' responsibilities will increasingly evolve as agents to accomplish the Commonwealth's policy goals, through at least (a) procurements of power and related transmission to facilitate the development and financing of offshore wind, (b) forward-looking interconnection processes to enable commercial and residential solar and storage installations, and (c) fortification of the distribution system to support EV charging and building heating loads. Utility planning and investment thus must be well ahead of the curve given Massachusetts' aggressive schedule for transforming its energy economy, and in order to enable millions of private decision makers in businesses, homes, and other settings to do their part as quickly and as confidently as possible.

Planning for and investing in grid modernization today needs to be much more anticipatory than it has been in the past.

The 2022 Act wisely recognized this fact and requires each Massachusetts electric distribution company to develop an "electric-sector modernization plan" to "proactively upgrade" the power delivery system so it can:

- **provide improved grid reliability and resiliency**
- **assist in the "timely adoption of renewable energy and distributed energy resources"**
- **promote electrification**
- **"prepare for future climate-driven impacts"**
- **minimize or mitigate impacts on consumers as Massachusetts realizes its GHG emission limits.**

Planning for and investing in grid modernization today needs to be much more anticipatory than it has been in the past. The 2022 Act wisely recognized this fact and requires each electric distribution company in the state to develop an "electric-sector modernization plan" to address the Commonwealth's many goals for the clean-energy, low-carbon transition. The 2022 Act calls upon these utility plans to "proactively upgrade" the power delivery system so it can provide improved grid reliability, communications and resilience, assist in the "timely adoption of renewable energy and distributed energy resources," promote electrification, "prepare for future climate-driven impacts," while also minimizing or mitigating impacts on consumers as Massachusetts realizes its GHG emission limits. The state's Department of Energy Resources ("DOER") is leading discussions with the electric utilities and an advisory council including other stakeholders in anticipation of the Department of Public Utilities ("DPU")' review of the plans that were submitted to the Grid Modernization Advisory Council (chaired by DOER) in September 2023.

The anticipatory grid planning called for in the 2022 Act raises interesting and challenging conditions in the regulated utility environment. Under traditional asset planning, for example, utilities are discouraged from overbuilding infrastructure given the risk of investment disallowances to the extent the infrastructure is not viewed as fully "used and useful" in meeting customer electricity needs. Yet grid readiness is a *precursor* to timely decarbonization of the electric sector and electrification of the building and transportation sectors. There are now situations where it is likely necessary for the utility to build ahead of and/or in amounts more than what may be strictly needed today, in order to prepare for future growth from electrification and to signal to others that the grid will be ready to handle their own investments, such as EVs, efficient electric heating systems, or community solar projects. Strict application of historical precedent could deter near-term distribution-system investments that are needed for a grid that "proactively" helps to enable larger energy-system transformations in Massachusetts.

The anticipatory grid planning called for in the 2022 Act raises interesting challenges in the regulated utility environment. Strict application of historical precedent could chill near-term distribution-system investments that are needed for a grid that proactively helps to enable larger energy-system transformations in Massachusetts.

Long-held ratemaking traditions and precedents need to be considered in the context of the state's statutory climate directives. This does not mean walking away from sensible ratemaking policies, but it does require a different framing of the issues.

In Massachusetts, the statutory framework for electric utility regulation has shifted to recognize the broader role of electric utilities and the expanded responsibility of the DPU. Long-held ratemaking traditions and precedents need to be considered in the context of the state's statutory climate directives and expectations about the role of the electric system in serving as a platform for the transition toward a low-carbon economy. This does not mean walking away from sensible ratemaking policies, but it does require a different framing of the issues and recognition of unique scope and timing issues raised by the Commonwealth's climate-related mandates.

Regulators in Massachusetts will play a central role in either enabling or slowing the pace of capital investment in the distribution utility system that will be required for the Commonwealth to meet its statutory decarbonization targets. Like other state agencies needing to step up in this "all-hands-on-deck" moment, the DPU has the opportunity and the responsibility to carry out its mission while meeting the exigencies of these times.

The DPU determines what investments and expenses are allowed to be recovered in customers' rates, in part by determining how financial risks should be shared among the utility's investors and its customers. This happens through rate cases in which such issues are adjudicated, and in other proceedings that set the ground rules for ratemaking policy and charges to consumers. While such DPU proceedings have long evaluated evidence on the costs associated with the provision of safe, reliable, and affordable utility service to consumers, the 2021 Act calls upon the DPU to administer its responsibilities by prioritizing ("with respect to itself and the entities it regulates") "safety, security, reliability of service, affordability, equity and ***reductions in [GHG] emissions to meet statewide [GHG] emission limits and sublimits***."[5] Although legal precedent in rate cases provides important guidance, regulators in Massachusetts must now exercise leadership by ensuring that evidentiary records allow them to develop new and compelling bases for decisions that fit today's conditions, rather than those that existed when prior precedent was established.

For example, any evaluation of the total cost impact of Massachusetts's decarbonization goals must account for both the increase in costs associated with electricity-sector investments and the decrease in costs associated with natural gas and petroleum. Consumers in MA spent $15.5 billion (2020$) on natural gas and petroleum for heating, transportation, and electricity generation in 2021. These fossil fuel expenditures would be greatly or entirely eliminated by 2050 under decarbonization scenarios. As a result, although the Massachusetts Roadmap Studies generally document small increases in total household energy spending across different decarbonization scenarios, the net impacts on consumer's overall energy budgets are far smaller than the gross impacts focusing solely on changes in power system costs.

[5] Emphasis added. Commonwealth of Massachusetts, Session Laws, Acts 2021, Chapter 8, "An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy," approved March 26, 2021, Section 1A, available at: https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8.

In this "all-hands-on-deck" moment, utility regulators have the opportunity and the responsibility to carry out its mission while meeting the exigencies of the moment.

The 2021 Act calls upon the DPU to administer its regulatory responsibilities by prioritizing "safety, security, reliability of service, affordability, equity and reductions in [GHG] emissions."

This will inevitably require creativity in reviewing the cost implications of electric sector modernization plans in a context in which decarbonization efforts will eventually produce net cost impacts on consumers' overall energy budgets that are far smaller than if the focus is on power system costs alone.

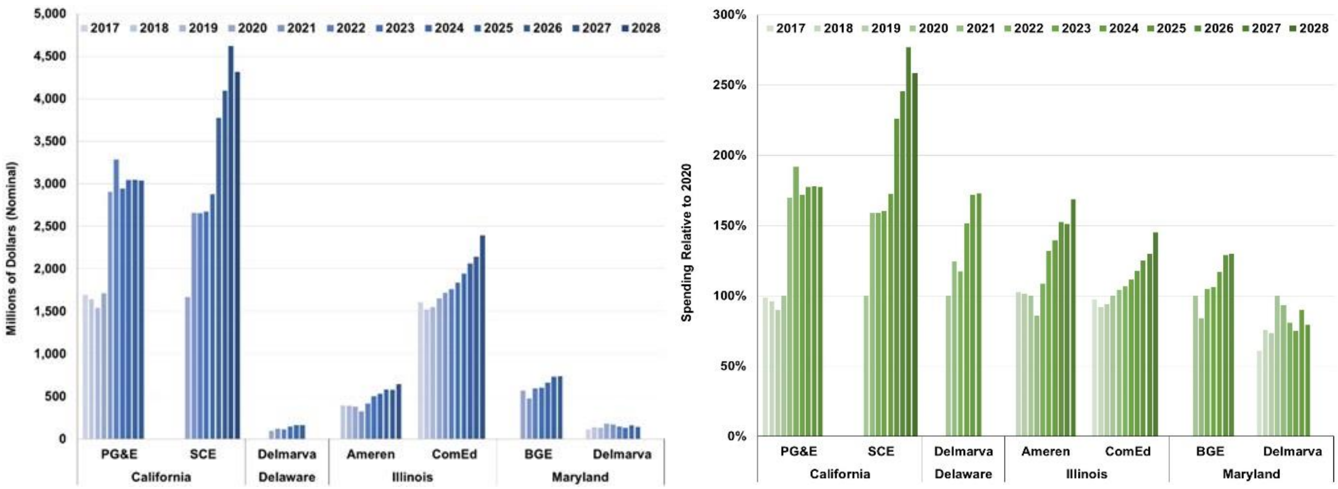
A core challenge for ratemaking in this new era of investment stems from these fundamental changes in the drivers of consumers' *total* energy costs, with (1) increases in electricity costs replacing payments for gasoline for transportation and oil, natural gas, and/or wood for heating; and (2) consumers' energy purchases shifting from paying for fuel (gasoline, oil, natural gas) on an as-used basis, to paying over time for depreciation and financing of up-front capital investments (e.g., renewable resources and grid resilience and expansion). It simply will no longer make sense to consider electricity rate changes in isolation; rather the state will need to consider how increasing electricity costs offset other components of consumers' energy budgets and evaluate how to design rates as utility costs shift towards higher fixed and lower variable costs over time.

This is important for several reasons tied to the energy transition:

1. Electric rates will reflect a shift from electric generation commodity charges (which are incurred on an as-needed basis and have a history of being volatile in Massachusetts) to recovery of up-front capital investment;
2. A household's or business' overall energy expenditures will decline in some ways (e.g., lower out-of-pocket costs for transportation and building heating fuels), partially offset by an increase in electricity payments;
3. The transition will require substantial near-term investments that will show up in the utility's cost to provide electricity service as incurred but that are long-term investments to support reliably meeting both today's and tomorrow's energy needs; and
4. This new investment in readying the grid to enable the energy transition will come at a cost, some of which is designed to support societal goals in addition to the goal of providing reliable electricity service to individual users.

Massachusetts is not alone in supporting grid investments to achieve decarbonization. **Figure ES-1** shows the grid investment trends in other jurisdictions that are hoping to spur rapid decarbonization transitions, with absolute dollar amounts on the left and percentage change in investment relative to 2020 spending on the right. In effect, electric utility ratemaking must spread some portion of the financial support for the Commonwealth's decarbonization investments across electricity customers.

Figure ES-1. Historic and Planned Distribution System Capital Expenditures, 2017-2028



Sources: [1] Individual utility filings with distribution capital spending plans and grid rate plans, see **Figure 10**. **Note:** [1] To ensure comparability across utilities, capital spending related to wildfire mitigation is not included for PG&E.

Overcoming the traditional and historically appropriate way of thinking about what are reasonable levels of investment will require new regulatory and ratemaking paradigms that take these complexities into account. It will also require effort to ensure that rate-case dockets include evidence about the broader societal and total energy budget contexts for utility investments.

Overcoming the traditional thinking about what are reasonable levels of investment will require new regulatory paradigms that take these complexities into account, as well as efforts to ensure that rate-case dockets include evidence about the larger context for utility investments.

Massachusetts regulators have already demonstrated a willingness to review and preauthorize capital spending plans associated with grid modernization and EV charging stations.

Continued regulatory innovation is needed to ensure sufficient distribution capacity is built out proactively to meet statutory decarbonization targets.

Regulators in Massachusetts have already demonstrated a willingness to review and preauthorize capital spending plans associated with grid modernization and EV charging stations (as well as in matters tied to other public policy objectives, such as natural gas utility investments to replace aging distribution pipeline infrastructure in the interest of safety). Similar approaches may be appropriate for their review of upcoming utility capital spending plans, including location-specific and system-wide investments that are key to tomorrow's distribution system.

More generally, continued regulatory innovation is needed to ensure sufficient distribution capacity is built out proactively to meet statutory decarbonization targets. Several examples of regulatory innovation might include:

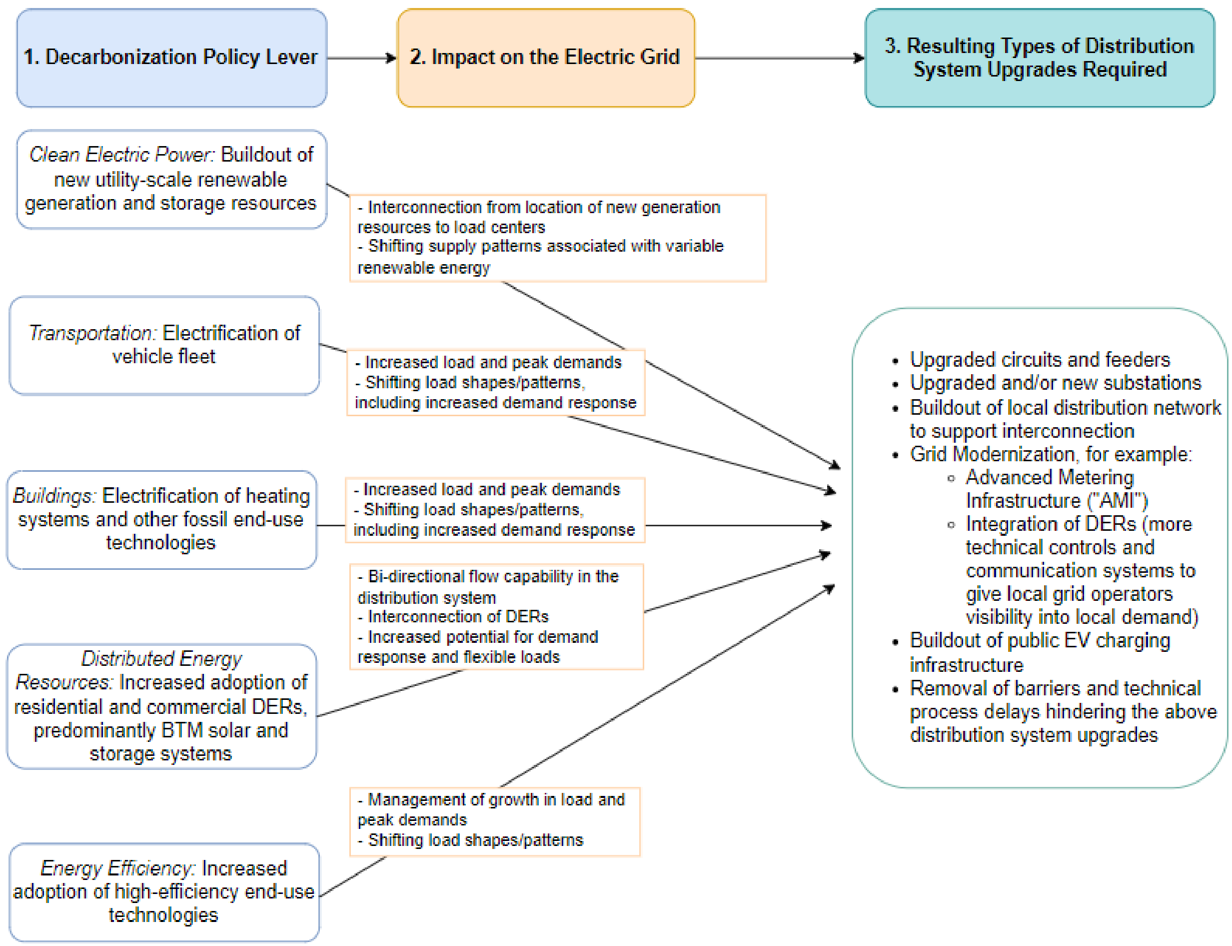
- Requirements that the utility carry out comprehensive distribution system planning processes.

- Pre-authorization of capital investments through DPU adjudication of the Electric Sector Modernization Plans developed by the utilities with input and guidance from DOER, and including budget caps and performance incentives as appropriate.
- Capital trackers to allow timely recovery of on-going capital investments.
- Other ratemaking mechanisms to allow approval and recovery of anticipatory grid investments with the ability to amortize or phase-in recovery over multiple years.
- Use of future rather than historical test years.
- Multi-year rate cases to review and allow for and establish changes in rates over multiple years.
- Highly differentiated rate designs (e.g., fixed and variable charges; income-based differentials in rate-plan offerings; modifications to conventional net metering rates).

Capital investment in the distribution system is only one of many areas ripe for regulatory innovation. State regulators are also grappling with unprecedented pace of change in resource procurement, transmission development, management of distribution system reliability and resilience, the level and shape of end-use demands and the design of rates to send reasonable pricing signals to consumers, patterns of cost causation across and within rate classes, and potentially increasingly complicated rate designs. However, regulatory innovation to enable increased levels of capital investment in the distribution system is a critical step towards meeting Massachusetts's statutory decarbonization goals.

Figure ES-2 summarizes the collective impact of all of these effects on resulting distribution system upgrades.

Figure ES-2. Summary of the Illustrative Impacts of Massachusetts Decarbonization Policy on the Electric Distribution System



II. Massachusetts’ Statutory Commitments for Economy-Wide Decarbonization

The Commonwealth of Massachusetts has long been a leader in creating a thriving place to live and work through a combination of economic, environmental and social programs. In the energy domain, Massachusetts has committed to dramatically reduce economy-wide GHG emissions in the state over the next three decades. The 2021 *Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy* (“2021 Act”) establishes mandatory emissions reductions relative to 1990 of at least 50 percent by 2030, 75 percent by 2040, and net zero by 2050.[6] Massachusetts, although an early actor in climate policy and legislation, is not the only state to have established such commitments; thirteen states have similar emissions-reduction policies.[7]

As depicted in **Figure 1**, Massachusetts’ net zero commitment is the culmination of over fifteen years of government action intended to increase renewable energy, lower air pollution and decarbonize the state’s economy. Future investments and actions required to transform and decarbonize the goods and services everyone relies upon in their daily lives will also create benefits in the form of lower jobs and increased economic growth.[8]

[6] “The interim 2030 statewide greenhouse gas emissions limit shall be at least 50 per cent below the 1990 level, and the interim 2040 statewide greenhouse gas emissions limit shall be at least 75 per cent below the 1990 level...[and] a 2050 statewide emissions limit that achieves at least net zero statewide greenhouse gas emissions; provided, however, that in no event shall the level of emissions in 2050 be higher than a level 85 per cent below the 1990 level. Each limit shall be accompanied by publication of a comprehensive, clear and specific roadmap plan to realize said limit.” *See,* Commonwealth of Massachusetts, General Laws, Part I, Title II, Chapter 21N, Section 3, “Projected 2020 business as usual level; adoption of statewide greenhouse gas emissions limits; levels and limits for electric sector; establishment of declining annual aggregate limit,” available at: https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter21N/Section3; Commonwealth of Massachusetts, Session Laws, Acts 2021, Chapter 8, “An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy,” approved March 26, 2021, Section 4 (h) and Section 8 (b), available at: https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8. *See also*, Wasser, Miriam, “What You Need to Know About the New MA. Climate Law,” *WBUR*, March 26, 2021, https://www.wbur.org/news/2021/03/26/new-mass-climate-law-faq.

[7] Four other states (Hawaii, Maryland, Nevada, and New York) have established net zero requirements by 2050 via state law. Nine states (California, Louisiana, Maine, Michigan, Montana, North Carolina, Rhode Island, Virginia, and Washington) have established net zero requirements by 2050 by executive action. *See* Cohen, Rona, “States with net-zero carbon emissions targets,” CSG East, March 24, 2023, available at: https://csg-erc.org/states-with-net-zero-carbon-emissions-targets/.

[8] *See*, for example, many studies produced by one or more of the authors of this report: four studies on the economic impacts of the RGGI program (Stuart, Daniel and Paul Hibbard, “The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States,” May 2023, available at https://www.analysisgroup.com/globalassets/insights/publishing/2023-ag-rggi-report.pdf; Hibbard, Paul, Susan Tierney, Pavel Darling, and Sarah Cullinan, “The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States,” April 17, 2018, available at https://www.analysisgroup.com/globalassets/uploadedfiles/content/insights/publishing/analysis_group_rggi_report_april_2018.pdf; Hibbard, Paul, Andrea Okie, Susan Tierney, and Pavel Darling, “The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States,” July 14, 2015, available at https://www.analysisgroup.com/globalassets/uploadedfiles/content/insights/publishing/analysis_group_rggi_report_july_2015.pdf; Hibbard, Paul, Susan Tierney, Andrea Okie, and Pavel Darling, “The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States,” November 15, 2011, available at https://www.analysisgroup.com/globalassets/uploadedfiles/content/insights/publishing/economic_impact_rggi_report.pdf); Hibbard, Paul, Pavel Darling and Jeffrey Monson, “Economic Impact of Stimulus Investment in Advanced Energy for America,” June 2021, available at

Massachusetts' signature climate law, the Global Warming Solutions Act, was enacted in 2008 and required the Secretary of Energy and Environmental Affairs ("EEA") to establish emissions limits.[9] The Secretary's original target was to reduce GHG emissions by 25 percent from all sectors of the economy below the 1990 baseline emission level in 2020, and by at least 80 percent as of 2050.[10] The 2021 Act set more aggressive emissions-reduction requirements and directed the Secretary of EEA to establish interim emissions limits for five-year milestones from 2025 to 2050, along with a comprehensive plan to achieve these emissions reductions.[11]

Over this 15-year period, Massachusetts' policies have evolved from early ones that focused primarily on increasing reliance on sources of electricity with low GHG emissions. These policies have included: the state's participation in the Regional Greenhouse Gas Initiative ("RGGI"), the multi-state cap-and-invest program that has reduced overall carbon dioxide ("CO_2") emissions from power plants in the RGGI region; the state's Renewable Portfolio Standard ("RPS") policy that required retail sellers of electricity to source an increasing percentage of supply from wind, solar and other renewable energy projects; the state's early efforts, which have been amplified in the 2022 *Act Driving Clean Energy and Offshore Wind* ("2022 Act"), to promote the development of offshore wind (e.g., through electric utility procurements of power and transmission service from such projects) and rooftop solar (e.g., through net metering ratemaking policies that compensated consumers for the injection of power into the local distribution system from on-premises solar systems). Other Massachusetts policies also promoted deeper investment in energy efficiency and other distributed energy resources to reduce demand for grid-supplied power (e.g., through utility investments and the use of proceeds from the sales of RGGI CO_2 emission allowances to invest in energy efficiency measures, or to encourage self-supply through net metering). Many of those programs were launched by the Green Communities Act and implemented in the years since it was enacted in 2008.[12]

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https://www.analysisgroup.com/globalassets/insights/publishing/2021-aee-natl-econ-impact-report.pdf; Tierney, Susan as a member of the National Academies Committee, *Accelerating Decarbonization of the U.S. Energy System*, February 2021, available at https://nap.nationalacademies.org/download/25932#; Hibbard, Paul, Susan Tierney and Pavel Darling, "The Impacts of the Green Communities Act on the Massachusetts Economy," March 4, 2014, available at https://www.analysisgroup.com/globalassets/content/insights/publishing/analysis_group_gca_study.pdf.

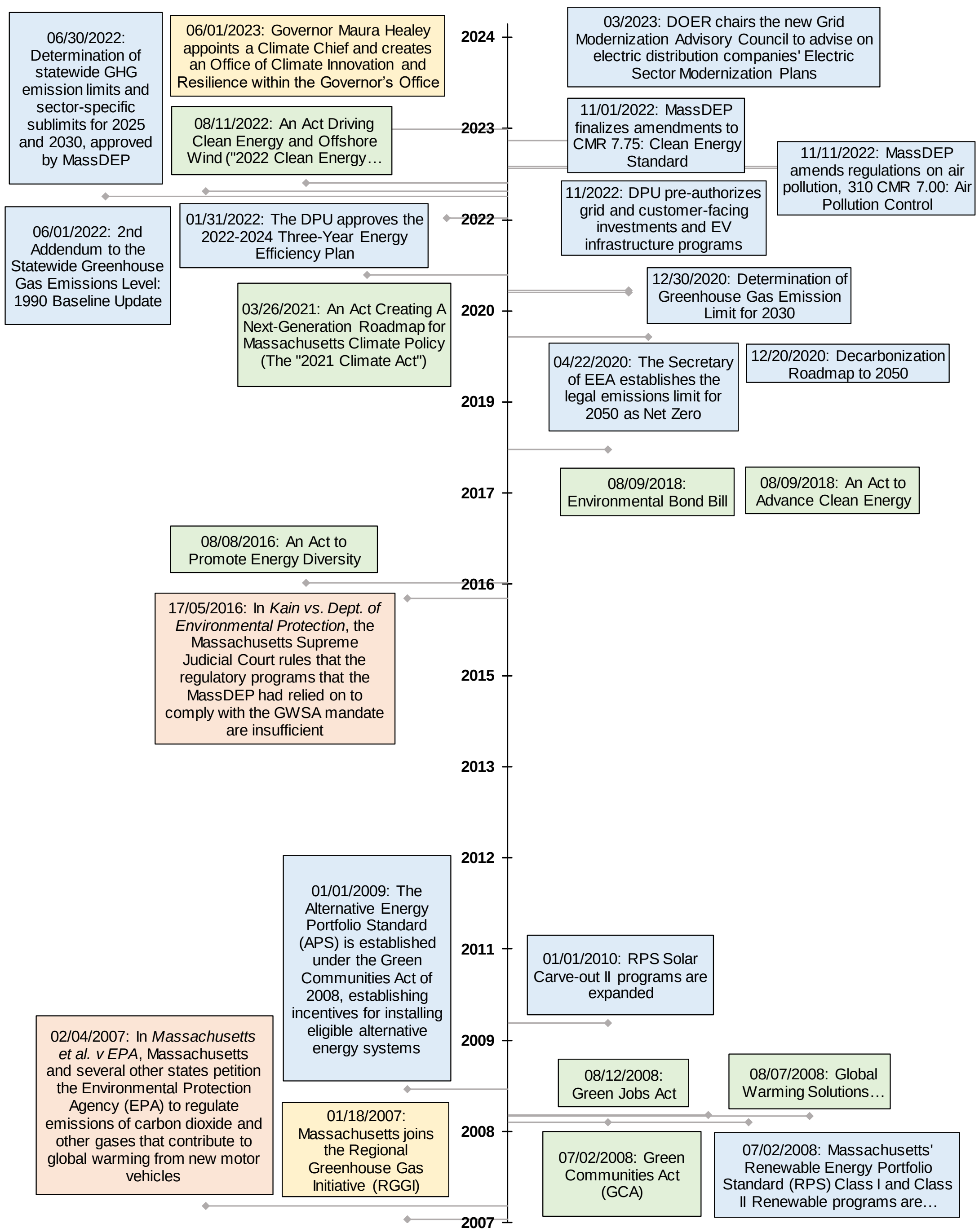
[9] Commonwealth of Massachusetts, Session Laws, Acts 2008, Chapter 298, "An Act Establishing the Global Warming Solutions Act," approved August 7, 2008, available at: https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter298.

[10] Executive Office of Energy and Environmental Affairs, "GWSA Implementation Progress," available at: https://www.mass.gov/service-details/gwsa-implementation-progress.

[11] Commonwealth of Massachusetts, Session Laws, Acts 2021, Chapter 8, "An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy," approved March 26, 2021, Section 8 (b), available at: https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8.

[12] *See* Hibbard, Paul J., Susan F. Tierney, and Pavel G. Darling, "The Impacts of the Green Communities Act on the Massachusetts Economy: A Review of the First Six Years of the Act's Implementation," Analysis Group, Inc. March 4, 2014, available at: https://www.analysisgroup.com/globalassets/content/insights/publishing/analysis_group_gca_study.pdf.

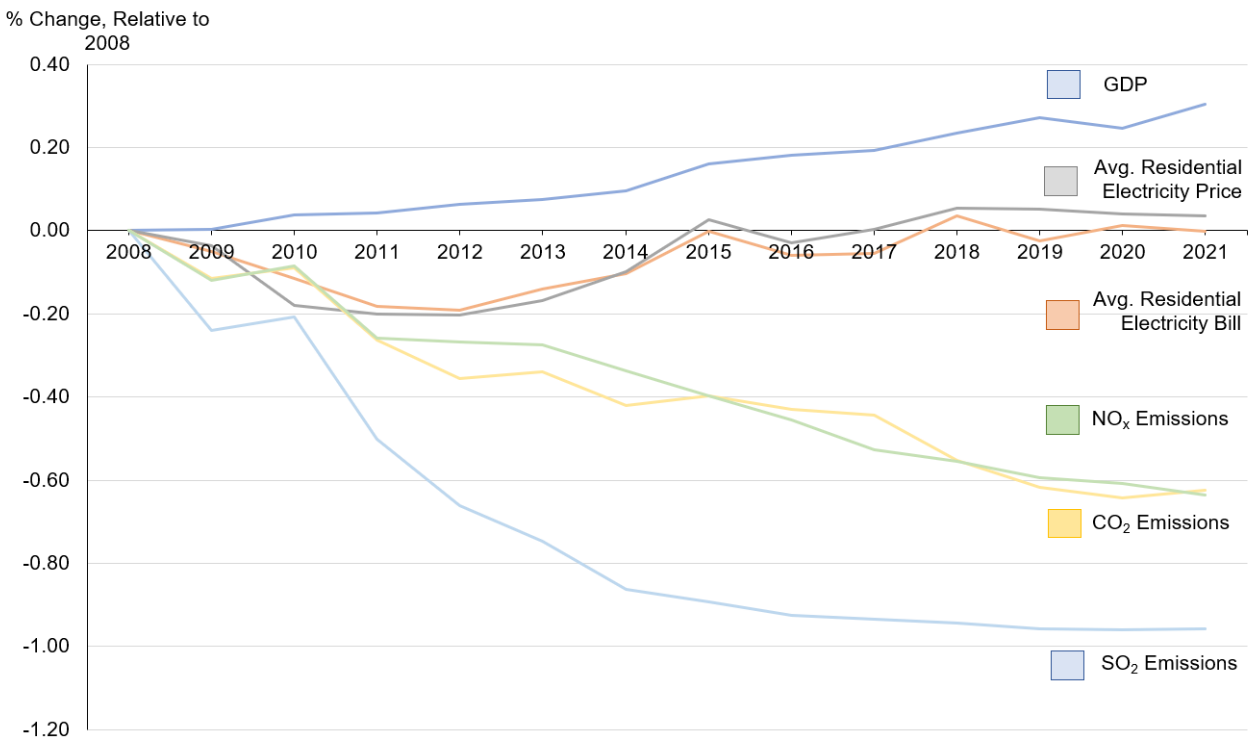
Figure 1. Decarbonization and Clean Energy Milestones in Massachusetts: 2007-2023



Note: [1] The color codes highlight the categories of milestones identified: green for statutes, blue for executive branch actions from the Department of Public Utilities ("DPU"), Department of Energy Resources ("DOER") and the Massachusetts Department of Environmental Protection ("MassDEP"), orange for court decisions and yellow for other types of initiatives.

In the years since 2008, while Massachusetts' overall economy has grown by 30 percent (in inflation-adjusted dollar value), the average residential electricity customers' annual electricity bill and electricity prices have remained relatively flat (in real terms) and the state's power-sector GHG and other air emissions have dropped dramatically, as shown in **Figure 2**.

Figure 2. Evolution of Changes in Electricity Bills, GDP and Emissions in Massachusetts: 2008-2021



Notes: [1] The percentage change of the monetary values (GDP, residential electricity bills and prices) is the real (inflation-adjusted) percentage change since 2008. [2] The emissions values refer to the total emissions by greenhouse gas or other air pollutants from electric power in Massachusetts.

Sources:

[1] GDP: U.S. Bureau of Economic Analysis, "Gross Domestic Product: All Industry Total in Massachusetts (annual, not seasonally adjusted)", available at: https://fred.stlouisfed.org/series/MANGSP.

[2] Average residential electricity bill and price: EIA, "EIA-861 Annual Electric Power Industry Report", available at: https://www.eia.gov/electricity/data/state/.

[3] Emissions: EIA, "U.S. Electric Power Industry Estimated Emissions by State", Final 2021 data released on January 10, 2023, available at: https://www.eia.gov/electricity/data/state/.

[4] Inflation adjustment: Bureau of Labor Statistics, "CPI for All Urban Consumers (CPI-U)", available at: https://data.bls.gov/timeseries/CUUR0000SA0?years_option=all_years.

Figure 3 shows actual trends in GHG emissions from different sectors of the state's economy with a focus on emissions from buildings' energy use, vehicles' combustion-related emissions, and power plants' output. As noted above, power-sector emissions have declined substantially (by 27 percent) over the 15-year period, in part driven by the policy changes in the state (as well as other factors that have driven changes in power-sector resource mixes).[13] While total state-wide emissions have declined over this period, most of the absolute emissions reductions have come from the power sector and current emissions profiles point to the need to address emissions in the building and transportation sectors, which will require electrification of many end uses that currently use fossil fuels as their direct energy source.

The mandatory emission-reduction milestones in the 2021 Act push for more rapid changes in these sectors (and the economy as a whole) than accomplished in recent years (no matter how positive they have been since 2008). GHG emissions in 2020 had dropped 31 percent relative to 1990, but emissions in 2020 (shown in **Figure 3** to have dropped over 10 percent in the single year from 2019) reflected the economic slowdown associated with the pandemic, and it is possible (if not likely) that the MassDEP‘s GHG-inventory data for 2021 and 2022 will show an uptick in emissions relative to 2020 (as indicated in **Figure 2**). To keep on track toward the mandatory 50-percent emissions reductions established for 2030 by the 2021 Act, reductions will have to occur at a faster pace (2.6 percent per year) than they did between 2008-2020 (when it was 2.2 percent per year).[14]

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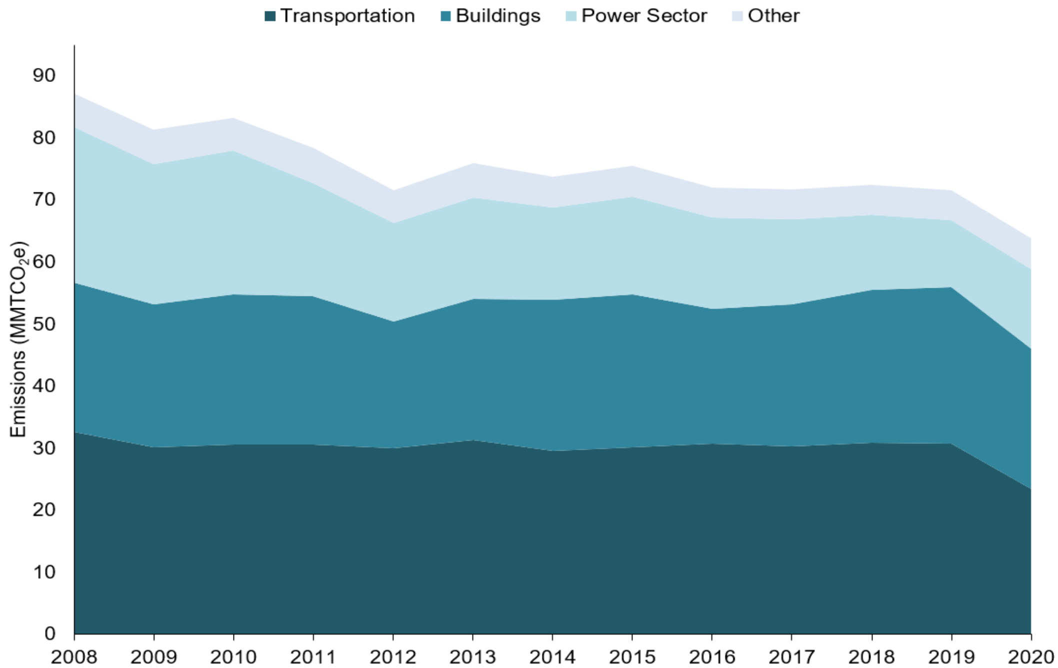
[13] These factors have included, for example, the changing mix of fossil fuels used in electricity generation towards natural gas and away from coal and oil due to reduced natural gas prices, sharp reductions in the cost of renewable technologies, and increased consumer demand. *See* Gelles, David, Brad Plumer, Jim Tankersley, and Jack Ewing, “The Clean Energy Future Is Arriving Faster Than You Think,” *The New York Times*, August 17, 2023, available at: https://www.nytimes.com/interactive/2023/08/12/climate/clean-energy-us-fossil-fuels.html.
[14] MassDEP, “Appendix C: Massachusetts Annual GHG Inventory: 1990-2020, with partial 2021 and 2022 Data”, available at: https://www.mass.gov/lists/massdep-emissions-inventories.

Figure 3. Evolution of Total GHG Emissions, by Source: 2008-2020



Notes: [1] The data for 2021 are incomplete and therefore not reported. [2] The "Other" category includes emissions from natural gas systems, industrial processes, agriculture and land use, and waste.
Source: [1] MassDEP, "Appendix C: Massachusetts Annual GHG Inventory: 1990-2020, with partial 2021 and 2022 Data", available at: https://www.mass.gov/lists/massdep-emissions-inventories.

In recent years and at the direction of more recent statutes, the Commonwealth's energy and environmental agencies have focused more specifically on policies to accelerate and broaden the set of policy tools to accomplish the state's decarbonization plans.

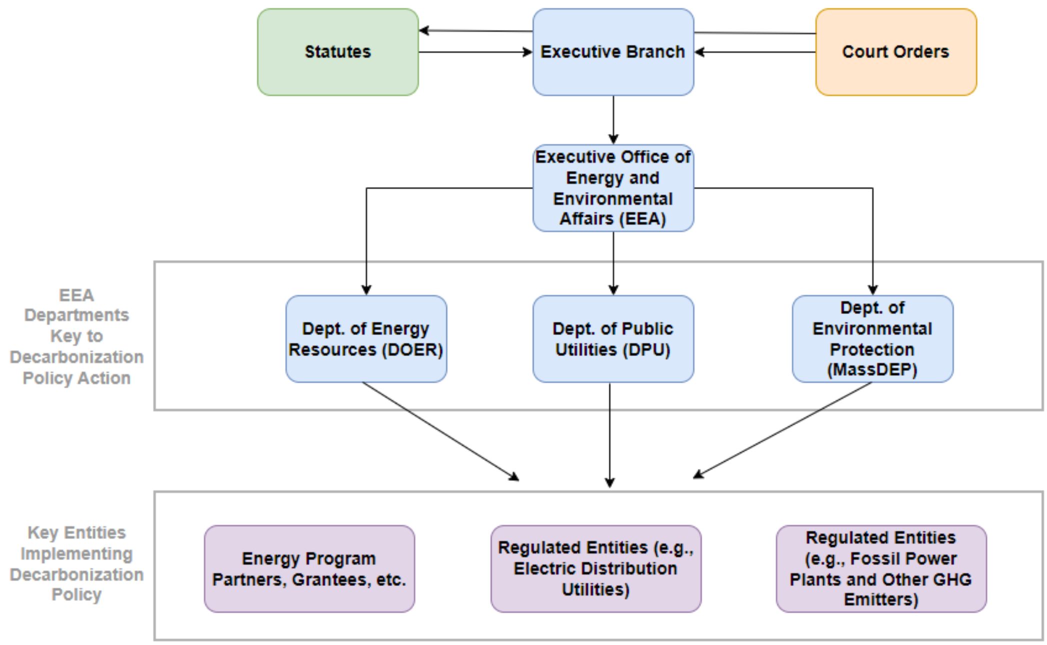
Unlike most other states, the Massachusetts' Executive Office of EEA is a Cabinet-level office that oversees both environmental and energy agencies, including the Department of Energy Resources ("DOER"), Department of Environmental Protection ("MassDEP") and Department of Public Utilities ("DPU").[15] As depicted in **Figure 4**, in this role, EEA oversees three key state agencies that have been and will continue to play significant roles in implementing the state's decarbonization policies and programs,[16] including the analysis of reasonable pathways,

[15] Executive Office of Energy and Environmental Affairs ("EEA"), "Brief History of EEA," available at: https://www.mass.gov/service-details/brief-history-of-eea.

[16] Many other state agencies and offices also play important roles, including the Office of Climate Innovation and Resilience within the Governor's office, the Massachusetts Clean Energy Center, and the Massachusetts Community Climate Bank (within MassHousing). *See,* Governor Maura Healey and Lt. Governor Kim Driscoll, "Governor Healey Announces Creation of Massachusetts Community Climate Bank, Nation's First Green Bank Dedicated to Affordable Housing," Office of Climate Innovation and Resilience, June 13, 2023, available at: https://www.mass.gov/news/governor-healey-announces-creation-of-massachusetts-community-climate-bank-nations-first-green-bank-dedicated-to-affordable-housing.

design, implementation and enforcement of regulations and programs, provision for recovery of costs associated with decarbonization pathway initiatives, and administration of other programs and actions to comply with economy-wide emissions targets.

Figure 4. Key Entities Responsible for Overseeing and Implementing Decarbonization Policy in Massachusetts



On June 30, 2022, the Secretary of EEA published the state's Clean Energy & Climate Plan for 2025 & 2030 ("CECP"),[17] which articulates sector-specific standards to facilitate emissions reductions to meet the statutory economy-wide emissions limits. Examples of key GHG-emissions and clean-energy policies adopted by or under consideration by MassDEP and that directly or indirectly affect electricity supply, sales and use include:

- *Electric Power*: The MassDEP has established the Clean Energy Standard ("CES") which requires that a minimum percentage of retail electricity sales from utilities and competitive retail suppliers be sourced from certain clean energy sources,[18] with the share of clean energy resources beginning at 16 percent in

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[17] EEA, "Massachusetts Clean Energy and Climate Plan for 2025 and 2030," June 30, 2022 (hereafter "Clean Energy and Climate Plan for 2025 and 2030"), available at: https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download.

[18] The CES was finalized in August 2017, and amended again in both December 2017 and July 2020. *See,* MassDEP, "Clean Energy Standard (310 CMR 7.75)," available at: https://www.mass.gov/guides/clean-energy-standard-310-cmr-775. The CES is met through the procurement of electricity from clean sources, or by making an Alternative Compliance Payment (ACP). *See,* MassDEP, "310 CMR 7.75: Clean Energy Standard (CES), Frequently Asked Questions (FAQ)," Version 2.2, December 2022, available at: https://www.mass.gov/doc/frequently-asked-questions-massdep-clean-energy-standard/download.

2018 and increasing 2 percent annually until it reaches 80 percent in 2050.[19] To qualify as a clean energy source, a generating unit must produce power from an eligible renewable energy resource or have "net lifecycle GHG emissions of at least 50 percent below those from the most efficient natural gas generator" (which presumably includes hydro, nuclear, and other zero- or low-carbon generation sources not otherwise considered a renewable energy resource). An eligible resource must also be located within New England's electric system or delivered into it via new transmission capacity.[20]

- *Transportation*: On December 30, 2022, MassDEP mandated that 100 percent of new vehicle sales in model year 2035 be zero emission vehicles ("ZEV") and/or plug-in hybrid electric vehicles ("PHEV").[21] In doing so, MassDEP adopted California's Advanced Clean Cars II (ACC II) program,[22] which requires (among other things) sales of "increasing numbers of battery electric vehicles (BEVs), hydrogen fuel cell electric vehicles (FCEVs), and the cleanest possible plug-in hybrid-electric vehicles (PHEVs) starting in model year (MY) 2026 for passenger cars and light-duty trucks."[23] "MassDEP's adoption of the ACC II regulations is required by the Massachusetts Clean Air Act, supports implementation of the Global Warming Solutions Act, and complies with the federal Clean Air Act…The regulations also will lead to reduced fuel consumption and fuel costs due to more fuel-efficient vehicles and next generation zero-emission vehicles, which will positively affect consumers, businesses, and fleet owners."[24]
- *Buildings*: MassDEP is considering adoption of a "clean heat standard" ("CHS").[25] The idea for a CHS was initially introduced in the CECP as a tool to create "a new market for clean heating solutions"[26] and encourage the development, sales and use of cleaner heating technologies, fuel switching of fossil-based heating systems to electric ones, and energy efficiency. Such an approach would affect demand for electricity as heating systems shift away from fossil fuels.

The Commonwealth's CECP, developed by state agencies under the Baker Administration, aligns quite directly with the goals articulated by the incoming Governor as part of the priorities she established during her campaign.[27]

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[19] MassDEP, "310 CMR 7.75 Public Hearing Draft to Final Redline, 7.75: Clean Energy Standard," September 30, 2022, p. 6, available at: https://www.mass.gov/doc/310-cmr-774-final-amendments-october-2022/download.
[20] MassDEP, "Fact Sheet, Electricity Sector Regulations, 310 CMR 7.75: Clean Energy Standard and 310 CMR 7.74: Reducing CO2 Emissions from Electricity Generating Facilities," December 2022, available at: https://www.mass.gov/doc/fact-sheet-massdep-electricity-sector-regulations/download.
[21] MassDEP filed emergency regulations amending 310 CMR 7.40. *See,* MassDEP, "310 CMR 7.00: Air Pollution Control, Recently Promulgated Amendments," available at: https://www.mass.gov/regulations/310-CMR-700-air-pollution-control#recently-promulgated-amendments; MassDEP, "Background Document on Emergency Regulation Amendments to 310 CMR 7.40 Low Emission Vehicle Program," December 30, 2022, p. 3 (hereafter "MassDEP Background Document on Emergency Regulation Amendments to 310 CMR 7.40"), available at: https://www.mass.gov/doc/310-cmr-740-background/download.
[22] MassDEP Background Document on Emergency Regulation Amendments to 310 CMR 7.40, p. 3.
[23] MassDEP Background Document on Emergency Regulation Amendments to 310 CMR 7.40, p. 3.
[24] MassDEP Background Document on Emergency Regulation Amendments to 310 CMR 7.40, p. 4.
[25] MassDEP, "Massachusetts Clean Heat Standard," available at: https://www.mass.gov/info-details/massachusetts-clean-heat-standard.
[26] MassDEP, "Stakeholder Discussion Document, Clean Heat Standard Program Design," March 2023, available at: https://www.mass.gov/doc/clean-heat-standard-discussion-document/download.
[27] Maura Healy for Massachusetts, "Climate," available at: https://maurahealey.com/issues/climate/.

Governor Healey's climate-related campaign promises included: putting one million EVs on the road by 2030, achieving 100 percent clean electricity supply by 2030, pushing utilities to upgrade the distribution system for equitable integration of behind-the-meter solar, creating a new division of the DPU focused on grid modernization, and removing barriers and technical process delays in distribution and transmission system upgrades that hinder the interconnection of new renewable electric generation. The Governor has acknowledged the unknown pace of change to the climate, and corresponding decarbonization efforts, and has stressed the importance of making anticipatory investment in infrastructure now to enable decarbonization and to mitigate negative impacts on Massachusetts communities: "The expected extremes and gradual changes will combine in unexpected ways to cause ecological, agricultural, infrastructure, human, and economic impacts sooner and larger than expected. Making the needed investments now will strengthen our communities and protect our vital resources, while addressing community priorities."[28]

Since taking office, Governor Healy has described her team of state-agency leaders as key to implementing her "all-hands-on-deck" approach to strengthening the state's climate action.[29] Meeting the GHG emissions-reduction targets on the timelines established by statute and other policies require rapid and comprehensive investment, planning, and change to the electric sector with that "all-hands-on-deck" mindset.

III. The Critical Role of the Electric Power Sector in Enabling Economy-Wide Decarbonization

The Commonwealth's approach to reducing GHG emissions depends upon transformation of the energy systems that serve Massachusetts consumers, with a particularly important role for the electric sector. That sector is key to a decarbonized future, as the economy switches to electricity from its long-standing reliance on direct use of fossil fuels for transportation and in buildings – not to mention for power production itself.

As directed by the GWSA, the Secretary of the EEA conducted analyses to develop a "comprehensive, clear, and specific roadmap plan" to realize the statutory emissions targets.[30] Like many other studies that have evaluated

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[28] Maura Healy for Massachusetts, "Climate," available at: https://maurahealey.com/issues/climate/.

[29] Lannan, Katie, "Gov. Healey describes 'all hands on deck' approach to climate policy," *WGBH*, May 26, 2023, available at: https://www.wgbh.org/news/politics/2023/05/26/gov-healey-describes-all-hands-on-deck-approach-to-climate-policy. On her first day in office, Governor Healy signed Executive Order No. 604 establishing the Office of Climate Innovation and Resilience within the office of the Governor and named Melissa Hoffer its first Climate Chief. *See,* Governor Maura Healey and Lt. Governor Kim Driscoll, "Office of Climate Innovation and Resilience," available at: https://www.mass.gov/orgs/office-of-climate-innovation-and-resilience.

[30] EEA, "Determination of Statewide Greenhouse Gas Emissions Limits and Sector Specific Sublimits for 2025 and 2030," June 30, 2022, available at: https://www.mass.gov/doc/2025-and-2030-ghg-emissions-limit-letter-of-determination/download. *See also,* the Massachusetts Interim Clean Energy and Climate Plan for 2030 (EEA, "Request for Comment on Clean Energy and Climate Plan for 2030," December 30, 2020, available at: https://www.mass.gov/doc/interim-clean-energy-and-climate-plan-for-2030-december-30-2020/download). These regional and Massachusetts-specific quantitative analysis were conducted as part of EOEEA's 2050 Decarbonization Roadmap Study effort, and the analysis was conducted in connection with the development of the 2025 and 2030 Clean Energy and Climate Plans.

alternative pathways to economy-wide net zero targets,[31] the state's roadmap relies on the following four "pillars of decarbonization" (as depicted in **Figure 5**):[32]

1. *Electrification*: adopting or switching to electric appliances, equipment and other energy-using technologies, particularly the increased adoption of electric vehicles and electric heat pumps for building heating and cooling systems.

2. *Electricity Decarbonization*: relying increasingly on investments in offshore wind, solar PV, energy storage, hydroelectric power (particularly imported from Quebec), and additions to the high-voltage transmission system and local distribution systems.

3. *Energy efficiency*: relying on more efficient equipment and behaviors for energy use in buildings, industry, and aviation.

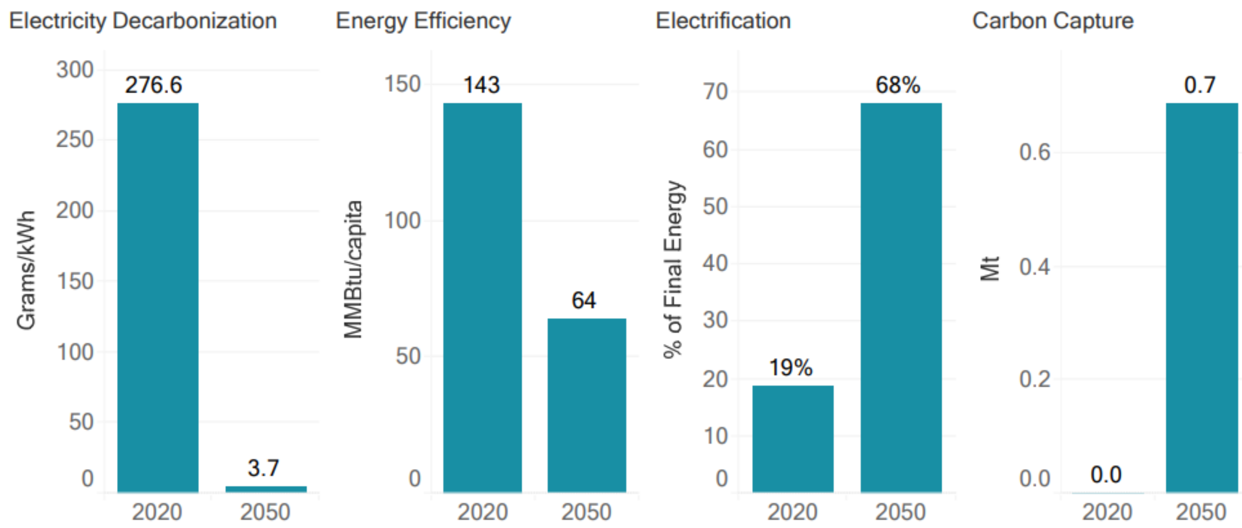
4. *Carbon capture*: removing emissions associated with fuel combustion from certain end uses that cannot be electrified.

The first three pillars have profound implications for the evolution of the electricity sector over the next thirty years, and position electricity production and use as key to decarbonizing the economy.

[31] *See, e.g.,* National Academies of Sciences, Engineering and Medicine, *Accelerating Decarbonization in the U.S. Energy System,* The National Academies Press, 2021, available at: https://doi.org/10.17226/25932; Larson, Eric, Chris Greig, Jesse Jenkins, Erin Mayfield, Andrew Pascale, Chuan Zhang, Joshua Drossman, Robert Williams, Steve Pacala, Robert Socolow, Ejeong Baik, Rich Birdsey, Rick Duke, Ryan Jones, Ben Haley, Emily Leslie, Keith Paustian, and Amy Swan, "Net Zero America: Potential Pathways, Infrastructure, and Impacts," Princeton University, October 29, 2021, available at: https://netzeroamerica.princeton.edu/.

[32] EEA, "Energy Pathways to Deep Decarbonization, A Technical Report of the Massachusetts, 2050 Decarbonization Roadmap Study," December 2020 (hereafter, "MA Energy Pathways Technical Report"), p. 2, available at: https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download.

Figure 5. Four "Pillars of Decarbonization" from the MA 2050 Decarbonization Roadmap Study



Source : MA Energy Pathways Technical Report, p. 2.

A. Decarbonization of the Electric System Will Require Substantial New Investment in Transmission and Distribution Along with Investments in Zero-Carbon Electric Resources

Eliminating GHG emissions from the power sector is the backbone of economy-wide decarbonization because zero-emissions electricity offers a relatively low-cost source of carbon-free energy. As depicted in **Figure 6**, decarbonizing electricity supply will require a major expansion in the total installed capacity of renewable technologies and storage within the state and in neighboring areas, which in turn will require major investments in transmission and distribution capacity.

In Massachusetts, solar photovoltaics and offshore wind turbines are currently expected to generate most of the electricity consumed in 2050 across all CECP net-zero scenarios, with solar providing approximately a third of total load and offshore wind supplying approximately two thirds of total load.[33] Onshore wind, hydro, nuclear, and imports of Canadian hydroelectric power are the other sources of low-carbon electricity generation. Additionally, 5.9 GW to 9.0 GW of energy storage capacity (9-12 percent of total installed capacity) would be added in Massachusetts by 2050 across all modeled net-zero scenarios.[34] To move these strategies forward, the Massachusetts CES requires 5,600 MW of procurements for offshore wind (and related transmission expenditures)

[33] EEA, "Clean Energy and Climate Plan for 2050, Massachusetts Workbook of Energy Modeling Results," January 2023 (hereafter, "MA Workbook of Energy Modeling Results"), available at: https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050. Solar PV is anticipated to supply 35 percent and offshore wind is projected to supply 61 percent of load.
[34] MA Workbook of Energy Modeling Results.

among other things. And the 2022 Act authorizes substantial state-supported investment in the expansion of an offshore wind industry and workforce to help enable such outcomes.

Massachusetts also supports further deployment of distributed generation as an integral piece of reducing power-sector GHG emissions. The cost of rooftop and utility-scale solar projects has declined dramatically in recent years,[35] and such projects remain popular in part due to supportive financial incentives existing in current net metering policy and in tax credits available through the new Inflation Reduction Act ("IRA").[36] The 2022 Act adds further incentives to support distributed generation.[37] These installations have implications for enhancements to the local grid needed to maintain distribution system reliability (as described in the next section).

While considerable attention has focused historically on the policies and steps that needed to transform the sources of power generation that serve Massachusetts consumers, much-greater reliance on these clean-power strategies depends on a much more robust electric grid, both in terms of local distribution systems and the high-voltage interstate grid. An expanded, more modern, more technically sophisticated, and more resilient grid will be essential for consumers and suppliers to have the confidence they need to make their own investment in distributed generation (not to mention electric end-using equipment for transportation and building energy use). As the Massachusetts 2050 Decarbonization Roadmap Study concluded: "Substantial expansion of transmission and distribution within Massachusetts was necessary [across all scenarios evaluated, in order] to meet the approximately doubled final electricity demand resulting from electrification."[38]

The interstate grid will also require expansion and modernization to support new pathways for the transmission of grid-connected renewable resources (e.g., to offshore wind resources and to northern hydroelectric resources) because sources of such supply are distant from load centers in Massachusetts and to the rest of the New England, New York and Canadian regions to which Massachusetts' electric system is interconnected. The interstate grid needs to be able to provide access to high quality zero-carbon electricity supply, and must be able

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[35] National Academies of Sciences, Engineering and Medicine, *The Role of Net Metering in the Evolving Electricity System*, The National Academies Press, 2023, pp. 42-53 (hereafter, "National Academies Net Metering Study"), available at: https://doi.org/10.17226/26704. Note: Footnotes in the original text have been omitted. Susan Tierney is one of the authors of this National Academies' report.

[36] The Inflation Reduction Act ("IRA") includes numerous provisions that directly or indirectly support the adoption of rooftop and other solar projects: (a) a 30 percent investment tax credit for residential, commercial and utility-scale solar investments and installations; (b) a 2.6¢/kWh production tax credit (PTC) tied to output of power from solar projects (including bonus payments for equipment with high domestic content and for facilities located in communities impacted by energy transitions; (c) the Greenhouse Gas Reduction Fund, with billions available for loans and grants for projects that include rooftop and community solar. *See, for example,* Jones-Albertus, Dr. Becca, Dr. Paul Basore, and Dr. Krysta Dummit, "Reaching for the Solar Future: How the Inflation Reduction Act Impacts Solar Deployment and Expands Manufacturing," U.S. Department of Energy, September 2022, available at: https://www.energy.gov/sites/default/files/2022-10/SETO_IRA_Webinar_Presentation_Sept_2022.pdf; Environmental Protection Agency, "Summary of Inflation Reduction Act Provisions Related to Renewable Energy," last updated on June 1, 2023, available at: https://www.epa.gov/green-power-markets/summary-inflation-reduction-act-provisions-related-renewable-energy; Environmental Protection Agency, "Greenhouse Gas Reduction Fund: Solar for All," last updated on August 31, 2023, available at: https://www.epa.gov/greenhouse-gas-reduction-fund/solar-all.

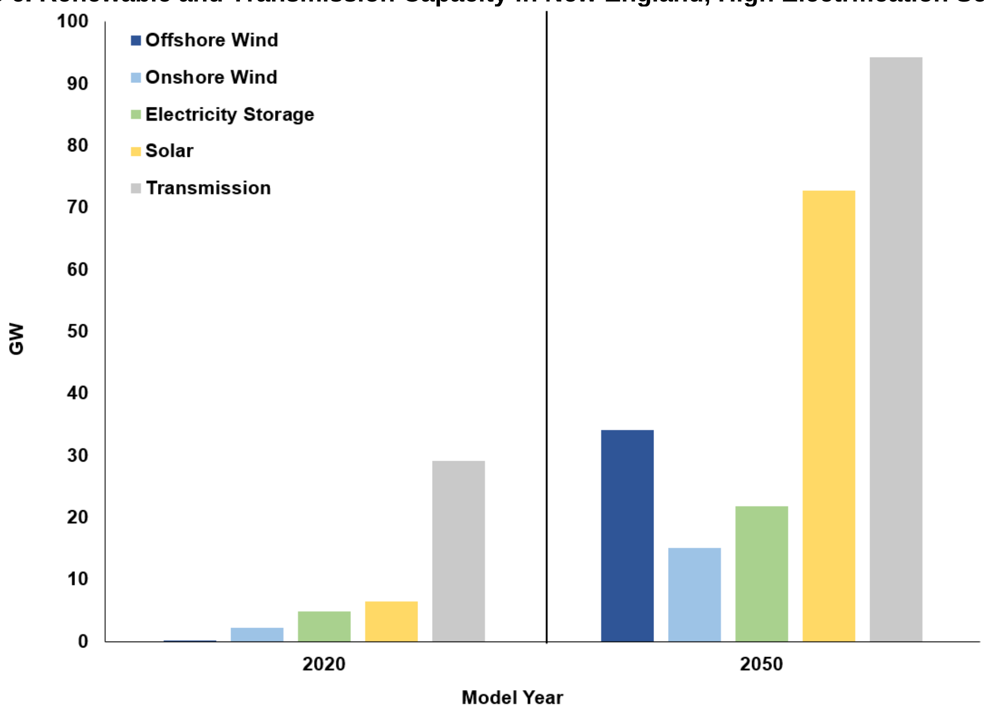
[37] Commonwealth of Massachusetts, Session Laws, Acts 2022, Chapter 179, "An Act Driving Clean Energy and Offshore Wind," approved August 11, 2022, Section 54, available at: https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179.

[38] MA Energy Pathways Technical Report, p. 7.

to manage greater variability in power flow as energy-producing conditions (e.g., windiness, sunshine) and energy-consuming conditions (e.g., across hours of the day) shift over time, and as the system encounters new forms of constraints on flows (e.g., if a transmission line is out due to storm conditions). According to the state's analyses of alternative decarbonization pathways, "[e]xpanded transmission capacity between Quebec and Massachusetts was important in all pathways, with a minimum of 2.7 GW and a maximum of 4.8 GW required above today's level. In the near term, these lines were used to import carbon-free electricity from Quebec, largely from new onshore wind projects. In the long term, the lines [would be] used to allow bi-directional power flow for balancing a high renewables power system throughout the Northeast region."[39]

Consistent with this goal, the state's decarbonization policy and related analyses strongly acknowledge these needs for more transmission investment (along with investment in renewable generating capacity), as shown in **Figure 6** showing results from the Massachusetts 2050 Roadmap Study analysis.

Figure 6. Renewable and Transmission Capacity in New England, High Electrification Scenario



Source: [1] MA Workbook of Energy Modeling Results.

The need for new transmission capacity to interconnect distant renewables and to manage new power flows is only one driver of the need for advanced planning for and investment in the electric delivery systems serving Massachusetts consumers and suppliers. The expected magnitude of changes at the distribution system level – through expanding DER installations and fundamental changes in the magnitude and shape of electricity demand

39 MA Energy Pathways Technical Report, p. 7.

through electrification – will also change power flows with implications for investment. Both the distribution and the transmission systems will require anticipatory planning to add large amounts of DERs as part of general grid modernization programs.

B. Actions on the Customer Side of the Meter – Including Energy Efficiency, Distributed Energy Resources, and Electrification of End-Use Technologies – Have Major Implications for Planning for and Investment in the Grid

Planning for the distribution system has always involved forecasting demand and ensuring timely investments to meet growth and changes in usage patterns. Yet now the obligation to modernize the state's delivery systems must take into consideration not just increased demand due to customer growth and economic factors, but also system and circuit/feeder-specific stresses from managing a growing list of emerging technologies and activities that happen on the customers' side of the meter.

Massachusetts has long been a leader in relying on deployment of energy efficiency measures to reduce the energy use in buildings and other locations and the need for associated investments in electric system infrastructure. For most of the past 15 years, Massachusetts ranked either 1st or 2nd among the states in terms of its performance on energy efficiency metrics.[40] These rankings have included funding support for utility-sponsored energy efficiency programs, tax incentives, use of RGGI revenues to invest in energy efficiency measures, among other things, including encouragement of combining weatherization investments with switching to efficient heat pumps for heating systems in buildings.

In the near term, the state-approved 2022-2024 Three-Year Energy Efficiency Plans[41] of electric and gas Program Administrators focus on actions to help achieve the Commonwealth's aggressive GHG emissions reduction targets. These plans incorporate demand-reduction technologies and programs to ensure continued reductions as well as emphasize strategic electrification and efforts to reduce barriers to participation for customers that historically have not participated in energy efficiency programs. Financial incentives in the IRA will also help to support even deeper and faster deployment of energy efficiency measures and other distributed technologies.

[40] From 2011-2019, Massachusetts ranked 1st among the states in the annual Energy Efficiency Scorecard published by the American Council for an Energy Efficient Economy ("ACEEE"), ACEEE, "Massachusetts ranked number one in energy efficiency for ninth consecutive year," October 1, 2019, available at: https://www.masssave.com/about/news-and-events/news/massachusetts-ranked-number-one-in-energy-efficiency-for-ninth-consecutive-year. In 2009 and 2010, and 2020 through 2022, Massachusetts ranked 2nd. ACEEE, "The 2009 State Energy Efficiency Scorecard," October 1, 2009, available at: https://www.aceee.org/research-report/e097; ACEEE, "The 2010 State Energy Efficiency Scorecard," October 2010, available at: https://www.aceee.org/files/pdf/ACEEE-2010-Scorecard-Executive-Summary.pdf; Berg, Weston, "Energy Efficiency Stands at Crossroads in Arizona, Massachusetts, and New Hampshire," ACEEE, January 24, 2022, available at: https://www.aceee.org/blog-post/2022/01/energy-efficiency-stands-crossroads-arizona-massachusetts-and-new-hampshire; Subramanian, Sagarika, Weston Berg, Emma Cooper, Michael Waite, Ben Jennings, Andrew Hoffmeister, and Brian Fadie, "2022 State Energy Efficiency Scorecard," ACEEE, December 2022, available at: https://www.aceee.org/sites/default/files/pdfs/u2206.pdf.

[41] *See*, dockets D.P.U. 21-120 through D.P.U. 21-129. Massachusetts Department of Public Utilities, "Energy efficiency dockets and filings," available at: https://www.mass.gov/info-details/energy-efficiency-dockets-and-filings.

Despite the potential for continued investment in energy efficiency, as well as potentially greater reliance on demand response and storage technologies to better manage customer demand and moderate growth in the overall size of the electric system, these programs and investments will likely be overwhelmed by increased electrification of end-use building technologies and vehicles. Indeed, under all net-zero pathways analyzed by the Massachusetts 2050 Decarbonization Roadmap Study – which almost exclusively feature aggressive assumptions about energy efficiency investments[42] – building and vehicle electrification results in a dramatic increase in total electricity load, changes in the shape of demand on distribution system circuits, and an overall expansion of the electric power sector in Massachusetts and New England.[43]

Figure 7 shows the results of state-agency modeling indicating that in net-zero emissions scenarios, annual total electricity consumption is projected to increase by between 3 percent to 12 percent as of 2030, 28 percent to 59 percent by 2040, and 43 percent to 93 percent by 2050 relative to a reference scenario that does not meet the overall emission-reduction outcomes. (Note that some studies prepared around the same time as the state-agency modeling indicate that total electricity demand more than doubles by 2050.[44])

This load growth is large relative to the *level* of historical electric load – electric demand under the net-zero scenarios is 82 percent to 145 percent greater in 2050 than 2021. Moreover, this anticipated growth in demand exceeds the historical *rate* of change in electric loads, which increased by a total of only 13 percent over the past thirty years.[45]

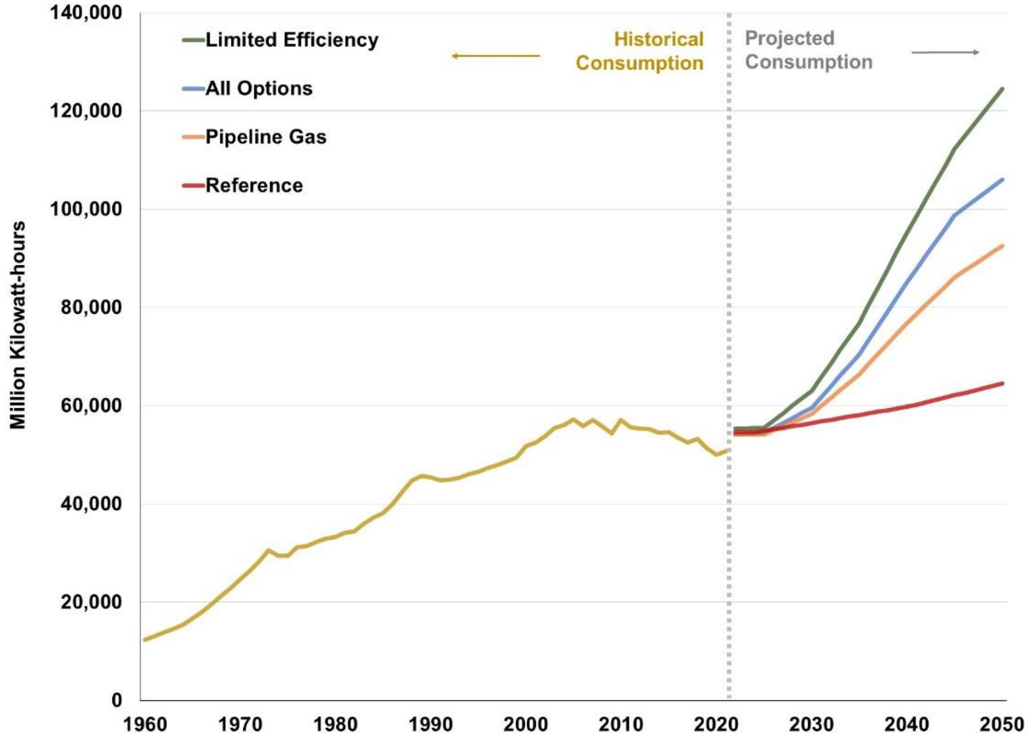
[42] Seven out of eight scenarios analyzed by the Massachusetts 2050 Decarbonization Roadmap Study include high deployment of energy efficiency technologies across the economy. The "Limited Efficiency" scenario assumes reference energy efficiency across buildings, industry and transport, based on the 2019 Annual Energy Outlook. *See,* MA Energy Pathways Technical Report, pp. 30, 41.

[43] Fast charging equipment is typically used for public charging of EVs -- and of fleets of large electric vehicles (such as electric buses or trucks). Fast chargers require higher voltages and subsequently higher levels of distribution infrastructure investment… The power demands – and battery sizes – of medium-duty and heavy-duty vehicles, trains, and aircraft require substantially more charging infrastructure than the relatively easy-to-deploy light-duty vehicle household and public chargers. Further, many of these vehicles are operated as parts of fleets which may require additional distribution system upgrades and potential power supply challenges. *See,* EEA and The Cadmus Group, "Massachusetts 2050 Decarbonization Roadmap," December 2020, pp. 38, 40, available at: https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download.

[44] *See*, for example, the results of the Princeton Net Zero America study, which estimated that total electricity demand would more than double by 2050 across all scenarios analyzed, with the largest increase in total demand (+300 percent) observed in the "E+RE+" scenario, which is described aggressive end-use electrification, with the supply side constrained to be 100 renewable by 2050, with no new nuclear plants built by 2050. Larson, Eric et al., "Net-Zero America: Potential Pathways, Infrastructure, and Impacts, interim report," Princeton University, Princeton, NJ, December 15, 2020, available at: https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.

[45] Both EIA and the MA Energy Pathways Technical Report provide estimates of *gross load* (i.e., total load served by both utility-scale and on-site/BTM energy resources). *See,* MA Energy Pathways Technical Report, p. 43 and EIA, "State Energy Data System 2021: Consumption, Technical notes & documentation - complete 2021 – Section 5: Renewable Energy," available at: https://www.eia.gov/state/seds/sep_use/notes/use_renew.pdf.

Figure 7. Historic and Projected Electricity Consumption in Massachusetts, 1960-2050 (With Projected Levels from MA Energy Pathways Modeling)



Notes on Scenarios: *Reference* assumes no limit on carbon emissions and minor increases in electrification. *All Options* incudes baseline cost assumptions and the most economic resources utilized to meet carbon emissions requirements. *Limited Efficiency* includes buildings, industry, and transportation at reference level efficiency. *Pipeline Gas* includes low electrification of gas components in industry and building sectors.

Sources: [1] EIA, "State Energy Data System, 1960-2021," available at: https://www.eia.gov/state/seds/seds-data-complete.php?sid=MA. [2] MA Energy Pathways Technical Report.

C. Facilitating Economy-Wide Decarbonization Will Require Increased Grid Modernization and Capital Investment Today

To meet this increase in annual load while simultaneously decarbonizing the power sector, substantial planning and new investment will be required – in the overall electric system, and in the infrastructure needed to support deliveries between sources and consumers of power. For example, to accommodate the reliable integration of and reliance on DERs, including those installed by consumers and those installed to help manage system operations, the local grid needs more sophisticated technical controls and communications systems to allow the local distribution-system operator to have better visibility into local demand and operational controls for reliable and resilient service, especially as the local grid steps up to provide energy around the clock for more of consumers' energy needs.

The 2022 Act calls upon state regulators to direct each electric company in the state "to develop an electric-sector modernization plan to proactively upgrade the distribution, and where applicable, transmission systems."[46] As explained more fully in the textbox below, such Electric-Sector Modernization Plans must provide information about how each electric company's plans will ensure that the electric delivery systems in the state are fit for purpose for the transitioning energy system. The DPU will have 7 months to consider each company's plan (an initial version of which was submitted to the state's Grid Modernization Advisory Council on September 1, 2023, which will review it and provide recommendations to the electric company and to the DPU. The DPU will eventually need to determine whether to approve it (including with modifications) upon a finding that it will provide net benefits for customers and meet the criteria enumerated in the statute (as listed in the textbox below).

[46] Commonwealth of Massachusetts, Session Laws, Acts 2022, Chapter 179, "An Act Driving Clean Energy and Offshore Wind," approved August 11, 2022, Section 53, available at: https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179.

Massachusetts' 2022 Act Driving Clean Energy and Offshore Wind:

Electric Sector Modernization Plans (M.G.L. Ch. 164, Sec. 92B)

(a) The department shall direct each electric company to develop an electric-sector modernization plan to proactively upgrade the distribution and, where applicable, transmission systems to:

i. improve grid reliability, communications and resiliency;
ii. enable increased, timely adoption of renewable energy and distributed energy resources;
iii. promote energy storage and electrification technologies necessary to decarbonize the environment and economy;
iv. prepare for future climate-driven impacts on the transmission and distribution systems;
v. accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and
vi. minimize or mitigate impacts on the ratepayers of the commonwealth, thereby helping the commonwealth realize its statewide greenhouse gas emissions limits and sublimits …

(b) An electric-sector modernization plan developed pursuant to subsection (a) shall describe in detail each of the following elements:

i. improvements to the electric distribution system to increase reliability and strengthen system resiliency to address potential weather-related and disaster-related risks;
ii. the availability and suitability of new technologies including, but not limited to, smart inverters, advanced metering and telemetry and energy storage technology for meeting forecasted reliability and resiliency needs, as applicable;
iii. patterns and forecasts of distributed energy resource adoption in the company's territory and upgrades that might facilitate or inhibit increased adoption of such technologies;
iv. improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources;
v. improvements to the distribution system that will facilitate transportation or building electrification;
vi. improvements to the transmission or distribution system to facilitate achievement of the statewide greenhouse gas emissions limits under chapter 21N;
vii. opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment;
viii. alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand and supporting dispatchable demand response; and
ix. alternative approaches to financing proposed investments, including, but not limited to, cost allocation arrangements between developers and ratepayers and, with respect to any proposed investments in transmission systems, cost allocation arrangements and methods that allow for the equitable allocation of costs to, and the equitable sharing of costs with, other states and populations and interests within other states that are likely to benefit from said investments.

For all proposed investments and alternative approaches, each electric company shall identify customer benefits associated with the investments and alternatives including, but not limited to, safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of distributed energy resources, avoided renewable energy curtailment, reduced greenhouse gas emissions and air pollutants, avoided land use impacts and minimization or mitigation of impacts on the ratepayers of the commonwealth.

Under almost any circumstance, this pace of electric-system change and expansion of electrification implicit in Massachusetts' statutory GHG-reduction requirements needs new thinking about what it means in terms of planning for the electric delivery system itself. The drivers of newly projected load growth fundamentally differ from the drivers of historic load growth.[47] In the past, load growth was driven primarily by increases in population and economic activity, such as changes in the number and type of commercial and industrial establishments. Looking ahead, load growth due to the electrification of transportation and in building energy use will be driven by a combination of consumer preferences, technological progress, market prices, financial incentives (e.g., from the IRA) and complementary state policies.

For example, as discussed in **Section II**, transportation electrification will be driven by Massachusetts' recent standards mandating 100 percent sales of zero-emission vehicle and plug-in hybrid-EVs by 2035.[48] Similarly, the MassDEP is currently developing a regulatory standard (the CHS noted above) for reducing GHG emissions from fossil fuels used for heating.[49] As a result, although growth in load occurs in all net decarbonization scenarios, the *level* and *rate* of load growth and associated system costs is highly uncertain.

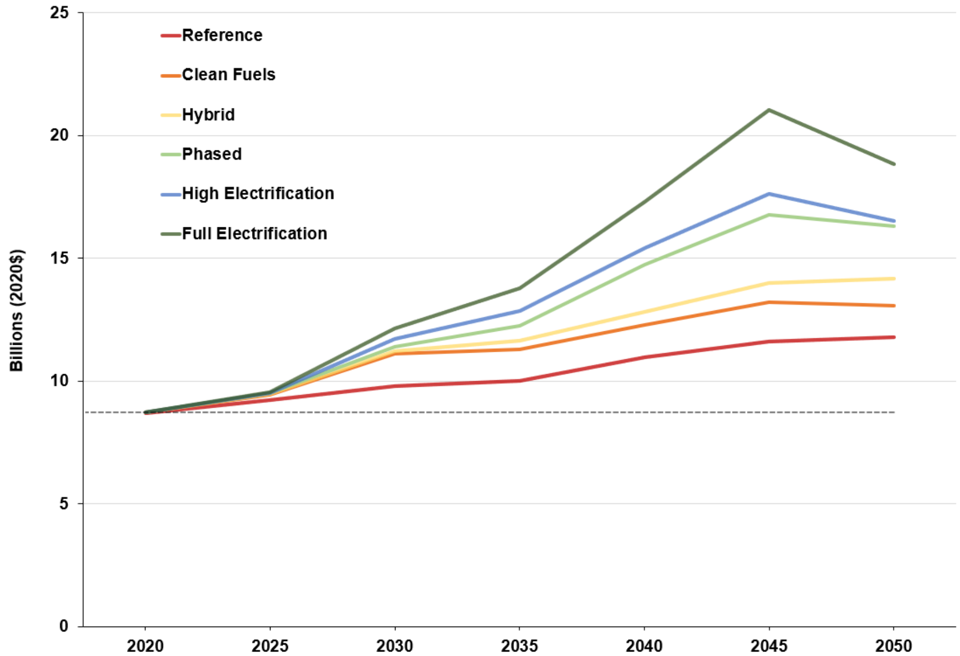
This uncertainty can be observed directly from the MA 2050 Decarbonization Roadmap Studies. The combination of fundamental changes in the level and nature of demand growth, and the various ways in which electric companies will have to manage rapid change in the face of uncertainty, will require a concerted effort to address all regulatory, cost recovery, and investment activities in a timely way. The uncertainties about the pace of change on both the supply-and-delivery infrastructure side of customers' meters and on the electricity demand side have implications for the overall costs of different paths to decarbonization. The state's analyses of pathways to decarbonization illustrate the degree of uncertainty that underpins planning for the modernization of the electric sector.

Figure 8 demonstrates that, depending upon different decarbonization paths, supply-side power system costs (including generation, bulk transmission, and distribution) could be expected to increase 11 percent to 60 percent by 2050 relative to the baseline reference scenario without net-zero GHG emissions as its goal.

The "High Electrification" scenario depicted in **Figure 8** is most similar to the "All Options" scenario which served as the baseline net-zero scenario in the MA 2050 Decarbonization Roadmap Study (as depicted in **Figure 7**). Supply-side power system costs in 2050 are $2.29 billion (14 percent) higher under a Full Electrification scenario where fuels are no longer used in buildings in 2050 and $3.48 billion (negative 21 percent) lower under a Clean Fuels scenario where carbon neutral gas and liquids are an economic option to heat buildings.

[47] After a period of system growth from 1960 to 2005, total electricity load in Massachusetts declined by -13 percent between 2005 and 2021. *See,* EIA, "State Energy Data System, 1960-2021," available at: https://www.eia.gov/state/seds/seds-data-complete.php?sid=MA.
[48] MassDEP Background Document on Emergency Regulation Amendments to 310 CMR 7.40.
[49] MassDEP, "Massachusetts Clean Heat Standard," available at: https://www.mass.gov/info-details/massachusetts-clean-heat-standard.

Figure 8. Supply-Side Power System Costs in Massachusetts, 2020-2050



Note: "Supply-side power system costs" includes generation, bulk transmission, and distribution system costs, but does not include demand-side costs like DERs or BTM PV.

Notes on Scenarios: *Reference* includes current trend of residential heating users switching from oil and liquid propane to gas, and does not result in Massachusetts meeting the carbon emissions cap. *Clean Fuels* includes reliance on carbon neutral liquids and gas to meet the carbon emissions cap. The *Hybrid* scenario includes the use of both fossil-fuel and electric heat pumps by 2030, with combustion backups remaining common. The *Phased* scenario includes the adoption of partial and whole-home heat pumps with the combination of fossil-fuel and electric heat pumps from the hybrid scenario allowed only through the 2020s, and maintains some clean fuel use in 2050. The *High Electrification* scenario includes adoption of whole-home heat pumps and some clean fuel use in 2050. *Full Electrification* is the maximum utilization of whole-home air-source and ground-source heat pumps with no fuel use in buildings in 2050.

Sources: [1] MA Workbook of Energy Modeling Results. [2] MA Clean Energy and Climate Plan for 2050 and 2030.

Importantly, any evaluation of the total cost impact of Massachusetts's decarbonization goals must account for both the increase in costs associated with electricity-sector investments and the decrease in costs associated with natural gas and petroleum. For example, consumers in MA spent $15.0 billion (2020$) on natural gas and petroleum for heating, transportation, and electricity generation in 2021.[50] These fossil fuel expenditures would be greatly or entirely eliminated by 2050 under all decarbonization scenarios. As a result, although the MA Pathways studies generally document small increases in total household energy spending across different decarbonization

[50] EIA, "Primary Energy, Electricity, and Total Energy Expenditure Estimates, 2021," Tables E.8, available at: https://www.eia.gov/state/seds/sep_sum/html/pdf/sum_ex_tot.pdf. To calculate total fossil fuel expenditures, natural gas and petroleum expenditures are totaled across the residential, commercial, industrial, and transportation sectors. Estimates include expenditures for fuels purchased for electric power generation. Reported in 2020 dollars.

scenarios, the net impacts on consumer's overall energy budgets are far smaller than the gross impacts focusing solely on changes in power system costs.[51]

The context for these changes in electricity cost is complicated, though: From the electric system's point of view, there will be increased expenditure on the capital costs of new infrastructure and less expenditure on the operating costs including purchases of fossil fuels (e.g., to produce power). Some observers[52] have labeled these shifts in costs as "steel for fuel" transitions, as the energy system transitions from being one in which a significant share of total expenditures is for fuel purchases – either direct out-of-pocket expenditures on heating and transportation fuels by consumers, or indirect expenditures on fossil fuels that are used for power generation and are passed along in the prices for electric energy. As more of the electric system shifts from facilities that combust fossil fuels (like natural gas and oil power plants, which made 52 percent of total power supply in New England in 2022[53]) to one where power is generated at facilities with more capital than fuel-related costs, consumers will pay energy bills that are less susceptible to price volatility and with higher fixed as compared to variable costs. This is a substitution of capital costs at generating facilities and transmission and distribution facilities, for fuel costs to produce power.

Consumers' increased costs to pay for electricity service will be accompanied over time by lower expenditures gasoline for transportation and oil, natural gas, and/or wood for heating. Further, consumers' energy purchases will shift from paying for fuel (gasoline, oil, natural gas) on an as-used basis, to paying over time for depreciation of up-front capital investments (e.g., for investments in renewable resources and grid resilience and expansion). It simply will no longer make sense to consider electricity rate changes in isolation; rather we will need to consider how increasing electricity costs offset other components of consumers' energy budgets and evaluate how to design rates as over time utility costs shift towards higher fixed and lower variable costs.

This is important for several reasons tied to the energy transition: First, new electric infrastructure investments to be recovered in rates will be designed to enable a shift from electric generation commodity charges (which are incurred on an as-needed basis and have a history of being volatile in Massachusetts). Second, a household's or business' overall energy expenditures will shift from a combination of out-of-pocket costs for electricity, gasoline, purchases of natural gas or oil or propane for heating, to having electricity make up more of the overall energy budget. Third, the transition will require substantial near-term investments that will show up in the utility's cost to provide electricity service as incurred, but that are long-term investments to support reliably meeting both today's and tomorrow's energy needs. Fourth, this new investment in readying the grid to enable the energy transition will come at a cost, some of which is designed to support societal goals in addition to the goal of providing electricity service to individual users. This will involve spreading some portion of the financial support for decarbonization infrastructure investment across those who can afford to pay for it.

[51] MA Energy Pathways Technical Report, pp. 69, 71.

[52] Xcel Energy, "Corporate Sustainability Report," 2020, p.3, available at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Sustainability%20Report/2020%20SR/2020-Renewable-Energy-SR.pdf; Lehr, Ron, and Mike O'Boyle, "Steel for Fuel: Opportunities for Investors and Consumers," Energy Innovation, December 2018, available at: https://energyinnovation.org/wp-content/uploads/2018/11/Steel-for-Fuel-Brief_12.3.18.pdf.

[53] ISO-NE, "Resource Mix," available at: https://www.iso-ne.com/about/key-stats/resource-mix.

Thus, focusing only on the change (including increases) in capital costs misses the point that there are reductions in fuel costs as well. And the investment in the grid needs to anticipate and get ready to support future electrification and zero-carbon resources entering the system.

IV. Electric Distribution Utilities are Embarking on a Significant Investment Program to Meet Decarbonization Goals

The necessary increase in capital spending on the grid introduces both novel financial opportunities and challenges to the state's regulated distribution utilities.

On the one hand, the state requires utility planning and accelerated investment to enable the pillars of decarbonization in Massachusetts – (1) decarbonization of the power grid through the financing of major increases in renewable resources and investments to support the reliable and efficient transmission of new renewable power around the state and region; (2) reliable management of a rapidly-changing level and shape of demand on the electric utility's distribution system given end-user uptake of electric heating and vehicle charging and installation of distributed solar and storage technologies; and (3) system investments to support reliable integration of private and public EV charging infrastructure on a forward-looking basis, scaled and paced to enable the Commonwealth's vehicle electrification mandates. All of this amounts to an opportunity to actively support the State's decarbonization efforts, and to do so while experiencing rapid growth in the utility's investment amounts, sales, revenues, and potential earnings.

On the other hand, the pace and nature of the planning and investment responsibilities do not fit neatly within the traditional utility ratemaking framework, and potentially present an unprecedented level of risk for utilities. As such, the current regulatory framework could represent an immediate and complicated barrier to the Commonwealth achieving its decarbonization targets.

Utilities' responsibilities have always included prudently planning to meet the current and future electricity needs of existing and new customers, and reliably operating the system every minute of every day. These obligations are now evolving to also include become literally an agent for change – by conducting planning to enable customers and others to make their own investments in distributed technologies and EV charging and to ensure that growth from consumers' electrification choices and the state's electrification policies can be met with the same level of system reliability.

In effect, the utility's role increasingly entails being a partner in supporting the Commonwealth's ability to achieve its own policy goals. Massachusetts statutes require utilities to procure power from offshore wind projects to help enable the financing of such facilities and the transmission projects that support them. There are statutory provisions requiring utilities to make the grid ready for decarbonization of the building and transportation sectors.

Utility planning and system reinforcement investments – and the regulatory structures that guide these – need to be ahead of the curve, given Massachusetts's aggressive schedule for transforming its energy production and use, and for helping millions of private decision makers in businesses, households and other settings determine whether to invest in EVs, electric heating systems and other equipment to meet the needs of their every day lives.

Distribution utilities will need not only to plan for modernizing their electric systems, but also to do so in conjunction with embarking on a large capital spending program. Both are required to reliably support the changing – and growing – demands on distribution system circuits and feeders due to growth from building and transportation electrification, the need for distributed resource integration and support, the new operational requirements of a system with new and continuously changing flows on the local grid, and the resilience requirements introduced by climate change, cyberattacks and other impacts.

Although there are many aspects of preparing the distribution system to better accommodate and manage the system in a world of increasing complexity[54] (including, for example, advanced communications and control technologies, data processing and analytic capabilities to monitor and predict changes in grid operating conditions),[55] there are other aspects of modernizing the grid that are highly local (e.g., capabilities of individual circuits and feeders, or other portions of distribution system networks).

Many stakeholder discussions about the changing nature of the grid focus rightly on such topics as the value of distributed generation in avoiding GHG emissions and other air pollution, in avoiding expansion of generation and transmission capacity, and in providing grid services. Too often, though, such grid modernization discussions tend to focus too little attention on the planning, operational and investment demands imposed on electric distribution systems by increased penetration of distributed generation (such as rooftop solar and battery storage). Many of the latter considerations are highly technical, but nonetheless require serious attention so that the system can provide the high degree of reliability and resilience that consumers and suppliers expect. As explained in a recent National Academies' study:

> While customers with BTM DG [behind-the-meter distributed generation] have the technological capability to provide valuable energy and flexibility services to the distribution grid, this DG needs to be integrated into the grid, not just interconnected to it. Successful BTM DG integration at high penetration rates and in ways that enable these resources to provide grid services will depend on addressing the operations challenges of the local distribution grid. In the absence of appropriate communications, control and other technologies, and a regulatory framework that supports investment in them, DG has the potential to disrupt distribution grid operation through reverse power flows, voltage violations, harmonics, phase unbalance power quality concerns, the mal/mis-

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[54] "The shift to cleaner and more distributed resources may reduce overall societal and system costs, taking into account the full costs of externalities, including greenhouse gas (GHG) emissions, pollution, and health impacts. However, addressing the challenge of decentralization and variability increases the cost of adding renewable electricity to the power grid due to investments in advanced communication, control, protection, and resilience needed to ensure an uninterrupted supply of generation to meet customer demand and for the grid to function reliably." *See,* National Academies Net Metering Study, p. 132.

[55] The National Academies' report's technology chapter on grid readiness for DERs identified the "need for the utility to maintain reliable and resilient service to all of its customer base, [and] to invest in communications and control technologies on the distribution system so that the utility has visibility into conditions on its system. Regulators, in turn, will need to view these investments as critical elements of the transitions occurring at the grid edge and in many cases enabled by net metering policy, and approve recovery of their costs." National Academies Net Metering Study, pp. 162-163.

> operation of protection devices, as well as presenting grid bottlenecks and congestion. Avoiding these problematic outcomes is essential...[56]

Thus, even as there are opportunities for non-wires solutions that can address distribution system needs in the future – some of which can be and indeed are likely to be provided by non-utility entities – there are also core capabilities that distribution utilities will need to make in their own system, for the benefit of all customers.[57]

Investment in modernizing electric distribution systems to perform the critical functions anticipated by the energy transition is likely to grow in the near term. This has been the case in jurisdictions where grid modernization is underway to support the energy transition and was indicated in the analyses prepared for the MA Pathways study. The distribution-system investment anticipated for different decarbonization scenarios in the latter study is shown in **Figure 9**, and is consistent with the trend in increased utility spending across California, Illinois, Delaware, and Maryland as depicted in **Figure 10** as these states also pursue decarbonization policy.

Utilities have long planned their system to provide "head room" for growth beyond the specific events that triggered the need for facility upgrades. But even with such approaches, the current pace and uncertainty of elements of the energy transition and the risk of potential delay in meeting the Commonwealth's GHG emissions limits if the grid is not ready to support rapid change mean that local incremental additions of headroom will not be enough to position the grid to serve as the broad platform on which changes needed to achieve societal GHG emission reduction can occur.

Readying infrastructure in anticipation of needs has proven to be useful for electric companies' investment in transmission to open up access to development of renewable resources in remote geographic locations and in enabling the integration of customer-sited DERs. Economists and policymakers have recognized the importance of such anticipatory, enabling-infrastructure investment strategies for overcoming chicken-and-egg problems that otherwise stymy development of renewables.[58] EV and charging station adoption is a similar chicken-and-egg

[56] National Academies Net Metering Study, p. 133.

[57] Note that system benefits provide by distributed generation differ from the private benefits afforded by such technologies to the occupants of the building on which DG is located. "Under net metering arrangements in most jurisdictions to date, a customer with a BTM DG resource has the option to rely on that resource when it is available and to call on power from the grid when it is not. Depending on the terms of the tariff through which the electricity customer buys electricity service from the utility, the customer (or the owner of the BTM equipment) has ultimate control when it injects power produced or stored into the local grid unless they cede it to the utility. A project where the customer prefers (and has the technical means) to maintain full control over when to draw power from the grid and when to inject it into the grid may have different operational and cost implications for the utility's operations than a project where the customer has an agreement with the utility for the latter to control when to inject energy into the grid. The former maintains the customer's private option value to use the grid at will; the latter may limit some of the customer's own private value proposition in owning or hosting DG equipment but increases the value proposition to the utility and its other customers (thus meriting greater compensation to the customer or equipment owner, which can offset any loss of private value)." *See,* National Academies Net Metering Study, p. 162.

[58] "[A] chicken-and-egg problem currently exists with respect to the development of high-quality renewable projects in remote areas (e.g., offshore wind, wind in the Prairie states) and access to transmission to ensure that that renewable power can be delivered to distant load centers." *See,* National Academies of Sciences, Engineering and Medicine, *Accelerating Decarbonization of the U.S.*

problem, with economists documenting a very high correlation between the availability of charging infrastructure and the adoption rate of EVs.[59] Indeed, academic research has demonstrated that, due to strong indirect network effects, investment in charging stations is *more* effective at spurring adoption of electric vehicles than electric vehicle subsidies for any given level of government expenditures.[60] In this sense, early deployment of charging infrastructure is a critical first step to enable timely electrification of the transportation sector.

Anticipatory investment and intentional infrastructure build-out strategies help to overcome barriers to entry and adoption of new technologies, particularly where the first set of adopters might either have to bear the full cost of infrastructure needed to use those new technologies or choose to not adopt them until there is certainty about the readiness of the supporting infrastructure. Continuing with the EV example, in California, heavy truck fleet owners are faced with upcoming regulatory requirements to decarbonize their fleets, and will require sufficient buildout of physical charging infrastructure to support decarbonizing all fleets in California.[61] [62] [63]

Massachusetts' 2022 Act confirms the importance of ensuring that the electric-sector modernization plans filed by the state's electric distribution companies are ones that "proactively upgrade the distribution system, and where

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Energy System, The National Academies Press, 2021, pp. 209-210, available at: https://doi.org/10.17226/25932; "… [N]o transmission, no PPA [power purchase agreement] …This is known as the chicken and egg problem." *See,* "Solar Energy in the Central Valley and the Chicken and Egg Challenge," *Renewable Energy World*, September 4, 2012, available at: https://www.renewableenergyworld.com/2012/09/04/solar-energy-in-the-central-valley-and-the-chicken-and-egg-challenge/#gref; "Consumers may be less willing to buy [EVs] because of a lack of public charging stations… This is the chicken in a chicken and egg scenario that sees investors, who are less willing to build charging stations, as the egg when there are so few electric vehicles on the road." *See,* National Science Foundation, "Improving electric vehicle sales may require solving unique chicken and egg problem: Subsidizing construction of charging stations possibly a cheaper way to reach US sales goals than tax incentives," January 29, 2015, available at: https://new.nsf.gov/news/improving-electric-vehicle-sales-may-require.

[59] Sierzchula, William, Sjoerd Bakker, Kees Maat, and Bert van Wee, "The influence of financial incentives and other socio-economic factors on electric vehicle adoption," *Energy Policy*, Volume 68, May 2014, available at: https://www.sciencedirect.com/science/article/abs/pii/S0301421514000822; Schulz, Felix and Johannes Rode, "Public charging infrastructure and electric vehicles in Norway," *Energy Policy*, Volume 160 (1), January 2022, available at: https://www.sciencedirect.com/science/article/abs/pii/S0301421521005255.

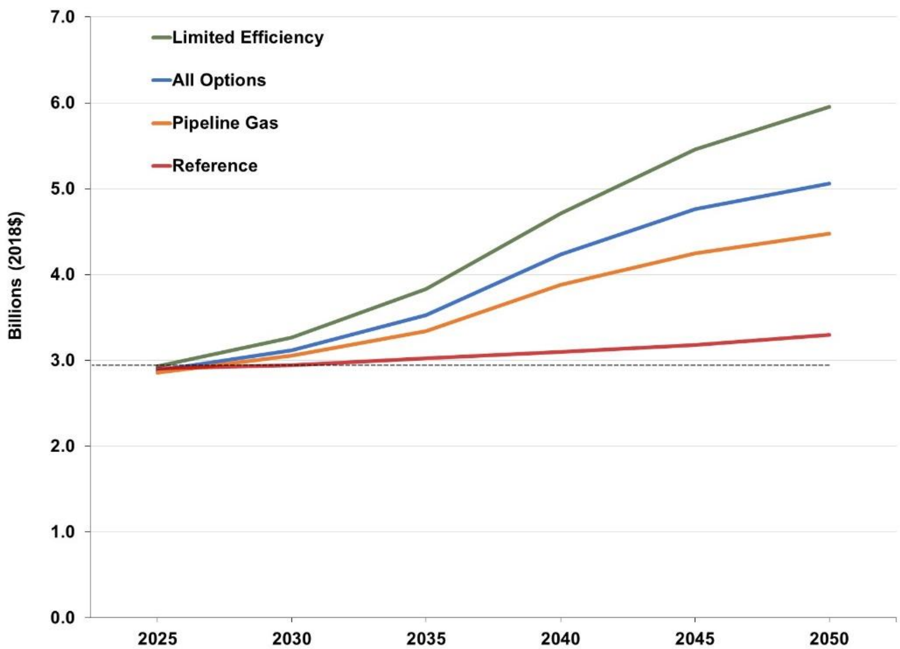
[60] Li, Shanjun, Lang Tong, Jianwei Xing, and Yiyi Zhou, "The Market for Electric Vehicles: Indirect Network Effects and Policy Design," *Journal of the Association of Environmental and Resource Economists*, Volume 4, March 2017, available at: https://www.journals.uchicago.edu/doi/full/10.1086/689702; Springel, Katalin, "Network Externality and Subsidy Structure in Two-Sided Markets: Evidence from Electric Vehicle Incentives," *American Economic Journal: Economic Policy*, Volume 13 (4), November 2021, available at: https://www.aeaweb.org/articles?id=10.1257/pol.20190131; Cole, Cassandra, Michael Droste, Christopher R. Knittel, Shanjun Li, and James H. Stock, "Policies for Electrifying the Light-Duty Vehicle Fleet in the United States," MIT CEEPR Working Paper Series, September 2021, available at: https://ceepr.mit.edu/workingpaper/policies-for-electrifying-the-light-duty-vehicle-fleet-in-the-united-states/.

[61] Commercial trucks in California are required to be emissions-free by 2042. *See,* California Air Resources Board, "Advanced Clean Fleets Regulation Summary Accelerating Zero-Emission Truck Markets," May 17, 2023, available at: https://ww2.arb.ca.gov/resources/fact-sheets/advanced-clean-fleets-regulation-summary.

[63] "The National Renewable Energy Laboratory identified 166 total charging stations for heavy-duty fleets nationwide in the third quarter of 2022, 101 of which were Level 2 chargers powerful enough to provide 25 miles of range after an hour of charging and 65 of which were DC chargers powerful enough to 100-plus miles of range after 30 minutes of charging." *See,* Wallace, Jacob, "Waste industry braces for 'bumps and bruises' in EV rollout as California sets the pace," *Waste Dive,* May 10, 2023, available at: https://www.wastedive.com/news/waste-industry-electric-refuse-california-republic-charging/649852/.

applicable, transmission systems"[64] for the many public purposes and electric services enumerated in that statute. (See the Textbox above on the relevant provisions of the 2022 Act, which include: improving grid reliability, communications and resiliency; enabling increased, timely adoption of renewable energy and distributed energy resources; promoting and accommodating energy efficiency and building and transportation electrification technologies needed for decarbonization; preparing for future climate-related impacts; and minimizing or mitigating impacts on the Commonwealth's ratepayers and "thereby helping the commonwealth realize its GHG limits and sublimits.)

Figure 9. Annual Electric Distribution Spending in Massachusetts, 2025-2050

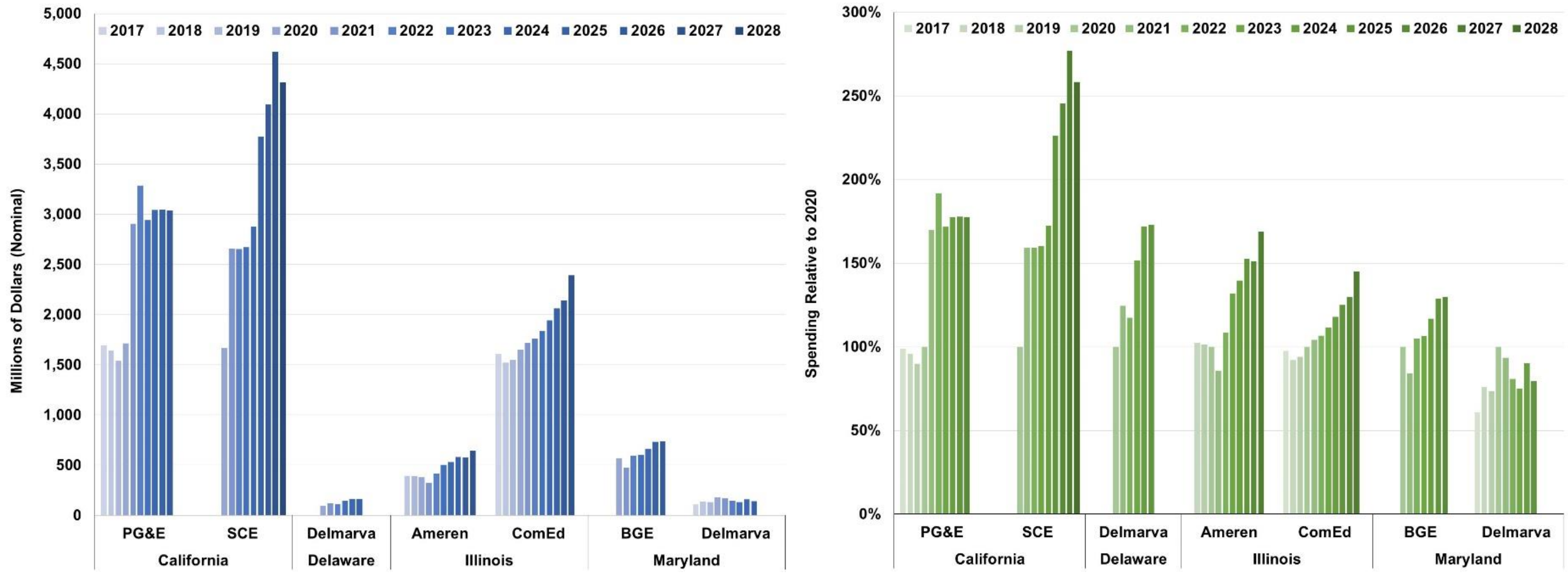


Notes on Scenarios: *Reference* assumes no limit on carbon emissions and minor increases in electrification. *All Options* incudes baseline cost assumptions and the most economic resources utilized to meet carbon emissions requirements. *Limited Efficiency* includes buildings, industry, and transportation at reference level efficiency. *Pipeline Gas* includes low electrification of gas components in industry and building sectors.

Source: [1] MA Energy Pathways Technical Report.

[64] Commonwealth of Massachusetts, Session Laws, Acts 2022, Chapter 179, "An Act Driving Clean Energy and Offshore Wind," approved August 11, 2022, Section 53, available at: https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179.

Figure 10. Historic and Planned Distribution System Capital Expenditures, 2017-2028



Note: [1] To ensure comparability across utilities, capital spending related to wildfire mitigation is not included for PG&E.

Sources for analysis:

[1] PG&E Historic Costs: 2017 and 2020 Rate Cases, filed with California Public Utility Commission; 2022 Risk Spending Accountability Report, filed with the California Public Utilities Commission.
[2] PG&E Projected Costs: 2023 Rate Case, filed with the California Public Utilities Commission.
[3] Southern California Edison Historic Costs: 2020 and 2022 Risk Spending Accountability Reports, filed with the California Public Utilities Commission.
[4] Southern California Edison Projected Costs: 2025 General Rate Case, filed with the California Public Utilities Commission.
[5] Delmarva Delaware Historic Costs: 2020, 2021, and 2022 Annual Infrastructure, Safety, and Reliability Plan, filed with the Delaware Public Service Commission.
[6] Delmarva Delaware Projected Costs: Proposed 2023-2025 Infrastructure, Safety, and Reliability Plan, filed with the Delaware Public Service Commission.
[7] Ameren Historic and Projected Costs: 2023 Multi-Year Integrated Grid Plan, filed with the Illinois Commerce Commission.
[8] ComEd Historic and Projected Costs: 2023 Multi-Year Integrated Grid Plan, filed with the Illinois Commerce Commission.
[9] Baltimore Gas and Electric Historic and Projected Costs: 2023 Minimum Filing Requirements, filed with the Public Service Commission of Maryland.
[10] Delmarva Maryland Historic and Projected Costs: 2022 Application for a Multi-Year Plan, filed with the Public Service Commission of Maryland.

V. Continued Ratemaking and Other Regulatory Innovation Will be Required to Enable Needed Investment in the Distribution System

As explained above, planning for and investing in smart grid modernization today needs to be much more anticipatory than it has been in the past. This raises interesting and challenging conditions in the regulated utility environment that will need to be addressed if the Commonwealth's utilities are to play an important supporting role in achieving the state's GHG emission reduction standards.

Under traditional asset planning, for example, utilities are discouraged from overbuilding infrastructure by virtue of regulatory tools such as an investment disallowance when an investment is viewed as imprudent or not used and useful in meeting the electricity demand of its customers. And yet, there may be situations today where it is sensible for the utility to build ahead of need in order to signal to others that the grid will be ready to handle their own investments, such as for EVs or to switch over to efficient electric heating systems or community solar projects. Such near-term utility distribution-system investments ahead of need may be chilled by the specter of disallowances, even if they are vital for enabling vehicle and heating market transformations in Massachusetts.

Although long-standing regulatory standards for system planning and investment recovery have been important tools of electric ratemaking, they may be counter-productive in the current context. Such long-held ratemaking traditions and precedents need to be reconsidered in the context of the state's statutory climate directives and the expectations about the role of the grid in enabling the transition toward a low-carbon economy. This does not mean walking away from sensible planning and ratemaking policies, but it does require a different framing of the issues and recognition of the unprecedented level and nature of system investments required.

Regulators and other public officials in Massachusetts energy agencies[65] will have a significant role in either enabling or slowing the capital investment in the distribution utility system that will required to facilitate the state's ability to meet statutory decarbonization goals. Like other state agencies needing to step up to tasks necessary in this "all-hands-on-deck" moment, the Massachusetts DPU has the opportunity, even the mandate, to figure out ways to do its job that are true to its mission while also fit for the exigencies of the moment.

As part of its normal responsibilities to approve rates that may be charged to consumers of utility service, the DPU determines what investments and expenses are allowed to be included in customers' rates, in part by determining how financial risks should be shared among the utility's investors and the utility's customers. This happens through

[65] Note too that the DOER has the important role, due to its responsibility to track the Commonwealth's progress against the state's clean energy goals, to intervene in DPU dockets, and to lead discussions among members of the Grid Modernization Advisory Council ("GMAC") and other stakeholders with respect to the Massachusetts electric utilities' Electric-Sector Modernization Plans. Grid Modernization Advisory Council, "Meeting Minutes," March 31, 2023, available at: https://www.mass.gov/files/documents/2023/04/18/20230331_GMAC%20Meeting%20Minutes_FinalApproved.pdf. *See also*, Massachusetts Department of Energy Resources, "Grid Modernization Advisory Council (GMAC)," available at: https://www.mass.gov/info-details/grid-modernization-advisory-council-gmac.

rate cases in which such issues are adjudicated, and through other fora which set the ground rules for ratemaking policy.

Ratemaking considerations in DPU rate cases and other types of regulatory proceedings have long considered costs associated with the provision of safe, reliable and affordable utility service to consumers. The 2021 Act directs the DPU to administer its responsibilities by prioritizing ("with respect to itself and the entities it regulates") "safety, security, reliability of service, affordability, equity and reductions in [GHG] emissions to meet statewide [GHG] emission limits and sublimits."[66] As such, the 2021 Act expands the DPU's statutory mandate to prioritize reductions in GHG emissions consistent with statewide emission limits and sublimits, along with traditional priorities like safety, reliability, and affordability. Although legal precedent in historical rate cases will continue to provide important guidance, Massachusetts regulators must now demonstrate leadership to establish new and compelling bases for decisions consistent with the statutory mandate to prioritize GHG reductions.

A core challenge in ratemaking for this new era of investment stems from fundamental changes in the drivers of consumers' *total* energy costs, with (1) increases in electricity costs offset by lower payments for gasoline for transportation and oil, natural gas, and/or wood for heating, and (2) consumers' energy purchases shifting from paying for fuel (gasoline, oil, natural gas) on an as-used basis, to paying over time for depreciation of up-front capital investments (e.g., for investments in renewable resources and grid resilience and expansion). It simply will no longer make sense to consider electricity rate changes in isolation; rather we will need to consider how increasing electricity costs offset other components of consumers' energy budgets and evaluate how to design rates over time as utility costs shift towards higher fixed and lower variable costs.

This is important for several reasons tied to the energy transition: First, new electric infrastructure investments to be recovered in rates will be designed to enable a shift from electric generation commodity charges (which are incurred on an as-needed basis and have a history of being volatile in Massachusetts). Second, a household's or business' overall energy expenditures will shift from a combination of out-of-pocket costs for electricity, gasoline, purchases of natural gas or oil or propane for heating, to having electricity make up more of the overall energy budget.

Third, the transition will require substantial near-term investments that will show up in the utility's cost to provide electricity service as-incurred, but which will yield long-term benefits by enabling utilities to reliably meet today's and tomorrow's energy needs, and societal goals like economy-wide decarbonization. Fourth, financial costs for decarbonization infrastructure investment should be appropriately spread among those individuals and entities who can afford to pay for it, requiring equitable rate design and the careful allocation of financial risks between utilities and ratepayers. Overcoming the traditional and historically appropriate way of thinking about reasonable levels of investment will require new regulatory paradigms that take these complexities into account. Regulators in Massachusetts have already demonstrated a willingness to review and preauthorize capital spending plans associated with grid modernization and EV charging stations. Similar approaches may be appropriate for their

[66] Commonwealth of Massachusetts, Session Laws, Acts 2021, Chapter 8, "An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy," approved March 26, 2021, Section 1A, available at: https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8.

review of upcoming distribution utility capital spending plans, including increased spending on location-specific and system-wide distribution-system investments that are key to tomorrow's delivery system.

From a ratemaking point of view, a utility's planned investments to support local distribution system needs as part of the energy transition could give rise to regulatory risk, especially given the potential for regulated utilities to face an increased possibility of under-recovery or delayed recovery of invested capital. Any such under-recovery of invested capital would lead to lower returns for the utility's investors, downward pressure on key credit metrics, and potentially increased utility costs in the raising of required capital, which would affect customers' rates. Although traditional rate-making principles are generally effective at ensuring electric rates strike a reasonable balance between consumer and investor interests for the provision of reliable electric service at least-cost, these same principles may *slow* or even *prevent* the level of capital investment required to develop a distribution system that can accommodate societal changes needed for Massachusetts to meet statutory decarbonization targets.

The possibility of significant under-recovery or delayed recovery of invested capital could form an insurmountable barrier for the investment of capital in the distribution system. For example, the DPU found that utilities "may hesitate before making investments beyond what they deem necessary to ensure safe and reliable service," and that this reluctance may even exist "when the investments are cost-beneficial for a company but involve high capital costs, combined with regulatory lag and the potential for disallowed costs."[67]

As such, continued regulatory innovation is needed to ensure sufficient distribution capacity is built out to meet statutory decarbonization targets. Examples of regulatory innovation include:

1. Requirements that the utility carry out comprehensive distribution system planning processes to forecast demands on their system well in advance of need, and take steps to plan for the provision of any needed infrastructure

    Integrated distribution system planning ("IDP") can complement grid modernization strategies or Integrated Resource Planning processes by requiring electric distribution utilities to provide granular, locational forecasts to assess distribution planning and distribution asset management. Outcomes studied in IDP processes include reliability, service quality improvements, resilience hardening, infrastructure replacement, preventative maintenance, and capacity upgrades for load and DERs.[68] Highly granular distribution analyses like those employed by IDP processes are particularly important in the face of load changes (including EV adoption, energy efficiency, demand response, sector conversion, economic growth, etc.), as well as DER adoption. IDP processes provide value by taking these various considerations into account rather than treating them in a reactionary way. Assessing

[67] Massachusetts DPU, Order D.P.U. 12-76-A, "Investigation by the Department of Public Utilities on its Own Motion into Modernization of the Electric Grid," December 23, 2013, p. 25, available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9241637.

[68] Schwartz, Lisa, "Integrated Distribution Planning Overview," U.S. Department of Energy, March 2022, available at: https://eta-publications.lbl.gov/sites/default/files/schwartz-integrated-distribution-planning-overview-20220303-fin.pptx.pdf.

load growth and changes along with anticipated (or even potential) changes in DER penetration can ensure that distribution system upgrades are appropriately sized, timed and located.

Massachusetts' statutorily mandated electric-sector modernization plans encompass this type of integrated distribution planning by synthesizing forecasting, planning and investment strategies that reflect the multiple influences of the DPU's prior grid modernization efforts, electric vehicle charging infrastructure, utility-owned storage, long-term system planning, energy-efficiency, and distribution system reliability and safety dockets.[69]

Notably, electric distribution utilities in California, Colorado, Delaware, Indiana, Hawaii, Maine, Maryland, Michigan, Minnesota, Nevada, New York, Oregon, Rhode Island, and Virginia are also subject to IDP requirements.[70]

2. Pre-authorization of capital investments, with budget caps and performance incentives as appropriate

To avoid excess uncertainty about potential cost recovery of utility investments, utility regulators in many jurisdictions have offered pre-approval of certain capital investments ("pre-authorization"). Pre-authorized ratemaking entails a formal commitment by regulators to permit the electric company to recover costs associated with certain capital investments prior to the company incurring project costs or prior to the project entering commercial operation.[71] Pre-authorization is commonly combined with

[69] Mahony, Elizabeth, "Initial Recommendations on the Electric Distribution Companies' Electric-Sector Modernization Plans," Massachusetts DOER, May 8, 2023, available at: https://www.mass.gov/doc/letter-from-doer-to-edcs-on-initial-recommendations-for-esmps/download; For relevant dockets related to each component of the electric sector modernization plan, *see*, grid modernization (D.P.U. 21-80/81/82-A, D.P.U. 21-80/81/82-B, and dockets D.P.U. 22- 40, 41, 42); electric vehicle charging infrastructure programs (D.P.U. 21-90/91/92-A); utility-owned storage investment plans (D.P.U. 20-69-A); long-term system planning (D.P.U. 20-75-C); Provisional System Program capital investment projects (CIPs) (dockets D.P.U. 22-47, 22-51, 22-52, 22-53, 22-54, 22-55, 22-61, 22-170, 23-06, 23-09, 23-12); energy efficiency three-year plans (D.P.U. 21-120-21-129); rate cases (D.P.U. 18-150, D.P.U. 19-130, D.P.U. 22-22); performance-based ratemaking schemes as approved in D.P.U. 18-150 and D.P.U 22-22; and distribution system reliability and safety dockets (such as the Annual Planning and Reliability Report, reporting of outage events, Service Quality Performance Reports, and vegetation management programs). *See also,* presentations from Eversource and National Grid on their distribution system planning. Eversource, "Integrated Distribution System Planning Approach," May 8, 2023, available at: https://www.mass.gov/doc/eversource-integrated-distribution-system-planning-approach/download; National Grid, "Distribution Planning Overview," May 11, 2023, available at: https://www.mass.gov/doc/national-grid-distribution-planning-overview/download.

[70] Schwartz, Lisa, "Integrated Distribution Planning Overview," U.S. Department of Energy, March 2022, available at: https://eta-publications.lbl.gov/sites/default/files/schwartz-integrated-distribution-planning-overview-20220303-fin.pptx.pdf; "Integrated Distribution Planning for Electric Utilities: Guidance for Public Utility Commissions," Mid-Atlantic Distributed Resources Initiative, October 2019, available at: https://www.madrionline.org/wp-content/uploads/2019/10/MADRI_IDP_Final.pdf.

[71] S. Hempling and S. Strauss, "Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?" National Regulatory Research Institute, November 2008, available at: https://pubs.naruc.org/pub/5F3D50FA-1866-DAAC-99FB-55C8EF422EC8.

processes and orders in which the regulators approve investment plans, cost caps, performance incentives, and mechanisms for regulatory oversight.[72]

The Massachusetts DPU has previously utilized pre-authorization of capital investments in the context of grid modernization capital trackers: “[p]re-authorization involves a review of the company’s cost estimates for a project, such that the Department will not revisit in later filings whether the company should have proceeded with these investments. The Department will, however, review the prudency of the company’s implementation of those investments.”[73] The DPU’s pre-authorization was combined with budget caps associated with specific investments and annual reconciliation filings.[74]

3. Capital trackers to allow for recovery of on-going investment capital cost changes outside the context of full rate cases

Cost trackers are mechanisms for the recovery of specific utility costs outside of a traditional rate case, often implemented through specific tariff riders.[75]

Historically, cost trackers were employed to account for certain types of costs that arise and warrant ratemaking treatment outside the context of a comprehensive review of the utility’s overall revenue requirement in general rate cases. Regulators have used trackers to allow for timely recovery of costs that arise, for example, from significant fluctuations in fuel commodity prices (e.g., through fuel adjustment clauses) or as a result of the introduction of a new public policy (e.g., for changes in

[72] S. Hempling and S. Strauss, “Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?” National Regulatory Research Institute, November 2008, available at: https://pubs.naruc.org/pub/5F3D50FA-1866-DAAC-99FB-55C8EF422EC8.
[73] Massachusetts DPU, Order D.P.U. 12-76-B, “Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid,” June 12, 2014, p. 3-4, available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9235208.
[74] D.P.U. 21-80-A/D.P.U. 21-81-A/D.P.U. 21-82-A. Whited, Melissa and Cheryl Roberto, “Multi-Year Rate Plans: Core Elements and Case Studies,” September 30, 2019, pp. 3,13, available at: https://www.synapse-energy.com/sites/default/files/Synapse-Whitepaper-on-MRPs-and-FRPs.pdf.
[75] See, e.g., Massachusetts DPU approval of a targeted infrastructure recovery factors to replace aging natural gas infrastructure. Lowry, Mark Newton, Matthew Makos, and Gretchen Waschbusch, “Alternative Regulation for Emerging Utility Challenges: 2015 Update,” November 11, 2015, pp. 11-12, available at: https://www.puc.pa.gov/pcdocs/1418301.pdf; Massachusetts DPU, Order D.P.U. 09-30, “Petition of Bay State Gas Company, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates Proposed in Tariffs M.D.P.U. Nos. 70 through 105, and for Approval of a Revenue Decoupling Mechanism,” October 30, 2009, available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9287355; Massachusetts DPU, Order D.P.U. 10-55, “Petition of Boston Gas Company, Essex Gas Company and Colonial Gas Company, each d/b/a National Grid, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates, a Targeted Infrastructure Recovery Factor, and a Revenue Decoupling Mechanism,” November 2, 2010, available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9275544; Massachusetts DPU, Order D.P.U. 10-114-B, “Petition of New England Gas Company, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates, a Targeted Infrastructure Recovery Factor, and a Revenue Decoupling Mechanism, set forth in the following tariffs: M.D.P.U. Nos. 1002B and 1003A through 1024A,” September 7, 2012, available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9254599.

corporate tax rates).[76] More recently, cost trackers have been expanded to include capital investments for electric companies, including related to emissions controls, advanced metering infrastructure, and general system modernization. Recovery of such costs often occurs through a "rider" or a rate element that tracks the change in cost and applies it to customer rates. As of 2015, capital cost trackers were utilized in 35 states, including Massachusetts.[77]

4. Other ratemaking mechanisms to allow approval and recovery of anticipatory grid investments with the ability to phase-in and/or amortize recovery over multiple years.

   Regulators sometimes decide to allow the gradual recovery of very large costs through ratemaking mechanisms (e.g., amortization of an expense; phase-in of an investment into utility rate base) so as to smooth out the effect on consumers' utility rates and bills while also ensuring that prudently incurred costs (including financing and/or carrying charges) are recovered.

   Amortizing expenses over a multi-year period is where a portion of total costs is recovered in each part of the period, and where all costs are eventually recoverable. A common example of amortization of an extraordinary expenditure item is ratemaking treatment of much-higher-than normal storm-related costs; after review of these costs, regulators sometimes allow the total amount to be passed through in rates (e.g., in a surcharge or other rate adder which includes expenditures adjusted for interest charges).[78]

   A phase-in of investment over a multi-year period is where a portion of total investments is put into rate base, with subsequent entries of the remaining amount in subsequent periods. Examples of the phase-in of utility investments into utility rate base occurred decades ago when state regulators decided to introduce total prudently incurred investment in new, multi-billion-dollar nuclear units over the course of several years.[79] The utility's cost to finance the investment prior to its introduction into rate base were eventually included in recoverable costs. Regulators phased total investment costs into rates when they determined that doing so would smooth rate increases.

[76] Christensen Associates Energy Consulting LLC, "Alternative Electricity Ratemaking Mechanisms Adopted by Other States," prepared for Public Utility Commission of Texas, May 25, 2016, available at: https://www.caenergy.com/wp-content/uploads/2016/02/Kirsch_Morey_Alternative_Ratemaking_Mechanisms.pdf.
[77] For a catalog of capital cost tracker precedent as of 2015, *see* Lowry, Mark Newton, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update," November 11, 2015, pp. 4, 9-16, available at: https://www.puc.pa.gov/pcdocs/1418301.pdf.
[78] *See, e.g.,* the rate treatment for natural gas costs associated with Winter Storm Uri in Colorado. Colorado Public Utilities Commission, "Impacts of Winter Storm Uri," available at: https://puc.colorado.gov/uri.
[79] See, e.g., the rate treatment for the Millstone nuclear power plant. Matthew L. Wald, "MILLSTONE IS FOCUS OF RATE PLAN," The New York Times, July 3, 1983, Section 11, Page 1, available at: https://www.nytimes.com/1983/07/03/nyregion/millstone-is-focus-of-rate-plan.html

5. Use of future rather than historical test years

Future test years allow the electric company to set their test-year revenue requirement based on forecast costs rather than actual costs incurred over a recent historic period (typically over the previous twelve months).[80] Use of a future test year also involves projected of future sales.

Future test years have been allowed by regulators (and in some cases, legislators) when large changes in system costs are expected due to changes in consumer behavior or the increased adoption of new technologies that have not been commonly used in the past. Use of future test years has been adopted in part because of the lag that can arise between the use of a past-year's revenue requirements does not produce rates that provides the utility with sufficient costs to provide service when those large changes in demand and/or cost (or cost structure) are occurring between the past period reflected in a historical test year and future conditions. Within the context of distribution system investments intended to enable economy-wide decarbonization, the use of historic test years will tend to prevent electric companies from collecting sufficient revenues to cover their increased costs.

To safeguard customers from potentially overstated future revenue requirements, electric companies using future test years are typically required to demonstrate that their projections for system costs and other billing determinants are a reasonable proxy for expected levels of actual costs.[81] As of 2019, 29 states have employed partially or fully forecast future test years for electric utilities (as of 2019).[82]

6. Multi-year rate plans to review and allow for changes in rates over multiple years

Unlike states with annual or biannual rate review cycles, multi-year rate plans ("MRPs") set electric company revenue requirements multiple years in advance, typically 3-8 years.[83] Often, rather than holding the *level* of a utility's revenue requirement fixed, attrition relief mechanisms ("ARMs") are employed with MRPs to allow revenues to be adjusted according to pre-defined, external cost factors.[84] By setting revenue requirements in advance and instituting an associated moratorium on new rate cases, MRPs break the tight link between costs and revenues typically found in annual rate reviews or incremental capital cost recovery approvals, and encourage cost reductions by allowing

[80] Guidehouse, "Electricity Regulation for a Customer-Centric Future: Survey of Alternative Regulatory Mechanisms," 2020, available at: https://guidehouse.com/-/media/www/site/downloads/energy/2020/ghelectricityregulationforacustomercentricfuture.pdf.
[81] Guidehouse, "Electricity Regulation for a Customer-Centric Future: Survey of Alternative Regulatory Mechanisms," 2020, available at: https://guidehouse.com/-/media/www/site/downloads/energy/2020/ghelectricityregulationforacustomercentricfuture.pdf.
[82] Guidehouse, "Electricity Regulation for a Customer-Centric Future: Survey of Alternative Regulatory Mechanisms," 2020, p. 5, available at: https://guidehouse.com/-/media/www/site/downloads/energy/2020/ghelectricityregulationforacustomercentricfuture.pdf
[83] Whited, Melissa and Cheryl Roberto, "Multi-Year Rate Plans: Core Elements and Case Studies," September 30, 2019, available at: https://www.synapse-energy.com/sites/default/files/Synapse-Whitepaper-on-MRPs-and-FRPs.pdf.
[84] Whited, Melissa and Cheryl Roberto, "Multi-Year Rate Plans: Core Elements and Case Studies," September 30, 2019, available at: https://www.synapse-energy.com/sites/default/files/Synapse-Whitepaper-on-MRPs-and-FRPs.pdf.

the utility’s investors to retain some or all of realized cost savings accomplished by the utility relative to the assumptions used in setting the rates.

Massachusetts has permitted electric utilities to employ MRPs to provide incentives for cost reductions, increased flexibility to address a changing operating environment (including the effects of emerging technologies) and mitigate a loss of revenue growth due to increased energy efficiency and distributed energy resources despite an increase in distribution system costs.[85] As of 2022, MRPs are being employed in 12 states to regulate electric utilities, and ten other states have recently expired MRPs.[86]

However, relative to traditional cost-of-service regulation, certain types of MRPs may be ill-suited for encouraging the distribution system investment needed to enable decarbonization. For example, ARMs based upon a historic test year and scaled by exogenous inflation or productivity factors might not capture the increased near-term distribution utility spending required to meet Massachusetts’ clean energy and economy-wide decarbonization goals.[87] As such, MRPs are appropriately coupled with cost trackers for specific areas of capital investment needed to satisfy public policy goals or statutory requirements.[88]

7. Highly differentiated rate designs

Rate design determines how an electric company’s revenue requirements are collected from customers and send pricing signals related to different aspects of electricity service. Rate design components (which vary by customer class) typically include a customer charge (related to having access to the grid, regardless of electricity usage levels), an energy charge (related to total use of electricity during a billing period), demand charges (related to the large draw of power during a billing period), and various potential “riders” or “surcharges” to cover particular ratemaking costs.

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[85] Massachusetts DPU, “Petition of Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of General Increases in Base Distribution Rates for Electric Service,” Order D.P.U. 18-150, September 30, 2019, pp. 49-54, available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11262053.

[86] Lowry, Mark Newton, “Performance-Based Ratemaking: Multiyear Rate Plans and Performance-Based Incentives,” National Association of State Utility Consumer Advocates, June 14, 2022, p. 13, available at: https://www.nasuca.org/wp-content/uploads/2021/10/Lowry-Presentation-for-NASUCA-Final.pdf.

[87] For example, National Grid (“Massachusetts Electric”) has an indexed ARM in which base revenue in a historic test period was escalated by the inflation rate, a negative factor reflecting expected productivity improvements, and a consumer dividend. *See* Lowry, Mark Newton, “Performance-Based Ratemaking: Multiyear Rate Plans and Performance-Based Incentives,” National Association of State Utility Consumer Advocates, June 14, 2022, p. 19, available at: https://www.nasuca.org/wp-content/uploads/2021/10/Lowry-Presentation-for-NASUCA-Final.pdf.

[88] Lowry, Mark Newton, “Performance-Based Ratemaking: Multiyear Rate Plans and Performance-Based Incentives,” National Association of State Utility Consumer Advocates, June 14, 2022, available at: https://www.nasuca.org/wp-content/uploads/2021/10/Lowry-Presentation-for-NASUCA-Final.pdf.

Long-standing rate design principles[89] include economic efficiency (to signal to customers the costs of providing electricity service), ensuring financial health of the utility (to enable revenues collected from customers through rates to cover the cost to provide utility service and to allow the utility to attract capital at reasonable cost), "equity and fairness,"[90] simplicity and stability (to provide rates that change gradually and that are understandable to consumers), and supportive of electricity system goals (e.g., reliability).

Thus, traditional rate design principles emphasize setting volumetric prices (e.g., energy and demand charges) where possible at marginal cost while simultaneously having the combination of charges recovering full system costs and fairly allocating burdens in an administratively and politically feasible manner.[91]

In the future, as more and more of the costs associated with the provision of electricity service become tied to capital investment relative to variable costs (such as fuel-related commodity costs), it will be important to consider differentiated rate designs. Economically efficient electric-energy charges are often dominated by the cost of purchasing, delivery and combusting fossil fuel (including emissions-related costs). With more of total electricity costs grounded in technologies (like wind, solar, storage, transmission, distribution investments) with primary fixed capital costs rather than commodity and/or other variable costs, the calculation of energy changes based on marginal cost will need to evolve. And rates designed exclusively around marginal costs would be very much based on the costs of connecting to and accessing the grid, having the option to decide to draw power from the grid, and the instantaneous demand served by the grid at various times of day and seasons of the year.

But economy efficiency is only one of many rate principles on which regulators determine just and reasonable rates. Rates times usage quantities needs to produce sufficient revenues to ensure a financially healthy utility with the ability to attract capital at reasonable cost. And rates need to be fair and understandable to customers.

Many jurisdictions, including Massachusetts, have special discounts and/or rate designs for low-income residential customers, as part of assuring that all customers have access to basic electricity service. These rate or customer-bill discounts are in addition to whatever subsidies (such as federally supported weatherization programs) and consumer-protection provisions (e.g., prohibitions on shutting off service to customers with large outstanding unpaid bills during certain cold- and/or hot-

[89] National Academies Net Metering Study, pp. 155-157.

[90] "The equity and fairness principle incorporates several elements. On the one hand, similarly situated customers (e.g., residential customers with basic usage patterns) should face nondiscriminatory rate structures, such that they have the same opportunities to purchase electricity service under common rates, terms, and conditions, as compared to other sets of customers with different usage patterns (e.g., residential customers with large seasonal electrical demands, or industrial customers with flat usage patterns). But, on the other hand, due discrimination in ratemaking may be needed to ensure that all consumers—even those with low incomes—can access basic electricity service." National Academies Net Metering Study, p. 156 (footnote 22).

[91] Bonbright, James C., *Principles of Public Utility Rates*, Columbia University Press, 1961, available at: https://www.degruyter.com/document/doi/10.7312/bonb92418/html.

weather periods) may be available to eligible customers. To ensure an equitable and efficient energy transition as electricity service provides an increasing share of a household's total energy needs and/or where increasing percentages of the cost of producing and delivering electricity is tied to capital investment (rather than fuel-related commodity costs), consumers could benefit from rate designs and rate-plan options that are much more highly differentiated to appropriately reflect variation in ability to pay by ratepayer and the utility's avoidable cost associated with a marginal customer.[92]

For example, equitable rate design could include fixed charges that are highly differentiated by income status to reflect the fact that a single low-income threshold will not account for additional variation in need across the population. Equity considerations will also have to be incorporated into the design of DER tariffs, with equitable net metering policies appropriately valuing DERs for the value they bring to the grid while simultaneously ensuring that DER owners pay their fair share costs associated with the supporting the distribution grid on which they rely for injections and withdrawals of electricity.[93] Equitable DER tariffs could also recognize that DER adoption tends to be much higher among wealthier households, creating the potential for unequitable cost-shifting if net metering policies are not appropriately designed.[94]

Regulatory innovation will be a critical success factor in enabling the Commonwealth to achieve the pace and breadth of change that will be required to meet the needs of the state's equitable energy transition.

Nowhere is this more important than in the rate regulation of electric utilities in the state.

[92] *See* Borenstein, Severin, Meredith Fowlie, and James Sallee, "Designing Electricity Rates for An Equitable Energy Transition," February 2021, available at: https://haas.berkeley.edu/wp-content/uploads/WP314.pdf. This paper provides a discussion of how an income-based fixed charge schedule, coupled with time- and location-specific volumetric charge set at the utility's avoidable cost associated with a marginal customer, can be employed to target equity concerns while preserving an economically efficient price signal to consumers.
[93] *See,* National Academies Net Metering Study.
[94] Borenstein, Severin, "Op-Ed: Sorry, rooftop solar supporters, California incentives really do punish the poor," *The Los Angeles Times*, March 28, 2022, available at: https://www.latimes.com/opinion/story/2022-03-28/solar-rooftop-net-energy-metering-incentives-california-public-utilities-commission-cpuc-gavin-newsom.

Table 1. Ratemaking and Other Utility Regulatory Innovation to Support Electric Distribution System Transitions

Policy Innovation	Description
Integrated Distribution System Planning	Regulators require the utility to carry out comprehensive distribution system planning processes to forecast demands on their system well in advance of need, and take steps to plan for and ensure development of any needed changes in infrastructure.
Pre-authorization of capital investments with budget caps and/or performance incentives	Regulators review and pre-authorize investments with a formal commitment to not revisit the prudence of the electric companies' decision to proceed with such investments, but with regulators maintaining the ability to review the prudence of the electric companies' implementation of these investments. Each electric company recovers costs for eligible investments through rate factors incorporated into its customers' monthly bills.
Capital and cost trackers to allow for recovery of on-going investment capital cost changes	Capital and cost trackers allow the utility to recover expenditures on an on-going basis by adjusting rates on a quarterly or biannual basis for certain categories of costs. Such an approach allows for the reduction of regulatory lag, because utilities do not have to wait for the next general rate case to recover such costs.
Other ratemaking mechanisms to allow for phasing-in or amortizing large costs over time significant changes in cost	In instances where very large increases have occurred in utilities' expenses or investments, regulators sometimes require that such cost increases be amortized or phased-in over a multi-year period. With provisions that the utility can ultimately recover its carrying charges (e.g., interest or financing costs), such approaches can allow for more gradual changes in rates and electricity bills for consumers.
Future test years	Forward test years, in which rates are based on projected investments, expenses, and sales rather than actual investments, expenses, and sales in a recent historic year, are employed in nearly half of all states (but not Massachusetts to date).
Multi-year rate plans	Electric company revenue requirements are set for multiple years in advance and electric company compensation is based on forecasted efficient levels of expenditures rather than the historic cost of service. Multi-year rate plans reduce the frequency of rate reviews, typically to once every 3-5 years. Multi-year rate plans are often coupled with an attrition relief mechanism to escalate the revenue requirement or target revenues between rate plan periods to address cost pressures such as inflation, economic productivity, and/or growth in number of customers independently of the electric company's own cost.
Highly differentiated rate designs	Rate designs reflect a range of purposes and principles, including economic efficiency, revenue sufficiency, equity and fairness, simplicity and stability, and support for public policies. considerations, including sufficient recovery of costs. Rate elements (e.g., customer charges, variable charges, and other fixed charges) can be used to send efficient price signals while collecting sufficient revenues from the overall customer based. Fixed charges can be highly differentiated by income and/or usage levels. Time-of-use rates are used to better match customer volumetric charges with the short-run marginal costs, with critical peak pricing designed to charge higher prices during the few days or hours of the year when demand is the highest.