Long-Term Ratemaking for a Decarbonizing Commonwealth

Prepared for the Massachusetts Interagency Rates Working Group

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Executive Summary

Study Background

The Commonwealth of Massachusetts faces a critical juncture in aligning electricity rate structures with its ambitious decarbonization goals. Rapid deployment of renewable generation and grid infrastructure upgrades, transformational grid participation from consumers, and electrification of buildings, transportation, and industry are all crucial components of the state's clean energy plans. These factors will change the way electricity is produced, transported, and used – which will in turn necessitate a reimagination of how consumers interact with and pay for electricity. This report, prepared for the Massachusetts Interagency Rates Working Group (IRWG), explores strategies for long-term ratemaking and regulatory reform to support electrification, affordability, and load flexibility in a changing electric system in the 2030s and beyond. The analysis presented here, along with the findings from the companion Near-Term Study released in December 2024,[1] informs the IRWG's Near-Term Rate Strategy and Long-Term Ratemaking Study Recommendations, which can be found on the IRWG website.[2]

The widespread deployment of advanced metering infrastructure (AMI) throughout the state, expected to be complete by 2029, will allow electric utilities to offer customers time-varying rates (TVRs). This will reflect the achievement of a longstanding goal for the Department of Public Utilities (DPU), dating back to a 2014 docket on TVR.[3] The DPU wrote in a recent utility rate case that "providing customers with the opportunity to respond to the actual varying costs of electricity will allow them to reduce their electric bills by reducing their usage during hours in which electricity prices are highest."[4] TVR will enable customers to see price signals that vary throughout the day and across the year in a way that reflects electric system costs, including marginal costs of energy as well as the costs of longer-term investments in generation and transmission infrastructure. Cost differentials between time periods will provide signals for customers to shift and/or reduce load. Concurrently, enabling technologies such as electric vehicle chargers, smart water heaters, and customer batteries will increasingly allow customers to respond to these price signals automatically and without behavioral changes. The combination of TVR and enabling technologies is expected to benefit both customers and the electric grid, helping customers reduce the costs of powering flexible technologies, and limiting the load growth during peak hours, thereby avoiding or deferring

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[1] Near-Term Rate Design to Align with the Commonwealth's Decarbonization Goals. Prepared for the Massachusetts Interagency Rates Working Group (December 2024), https://www.mass.gov/doc/irwg-near-term-rate-strategy-report-e3/download.

[2] Interagency Rates Working Group (August 2024), https://www.mass.gov/info-details/interagency-rates-working-group.

[3] D.P.U. 14-04, Orders 14-04-B (June 2014) and 14-04-C (November 2014).

[4] D.P.U. 23-50 Order Opening Investigation at 19 (January 2023).

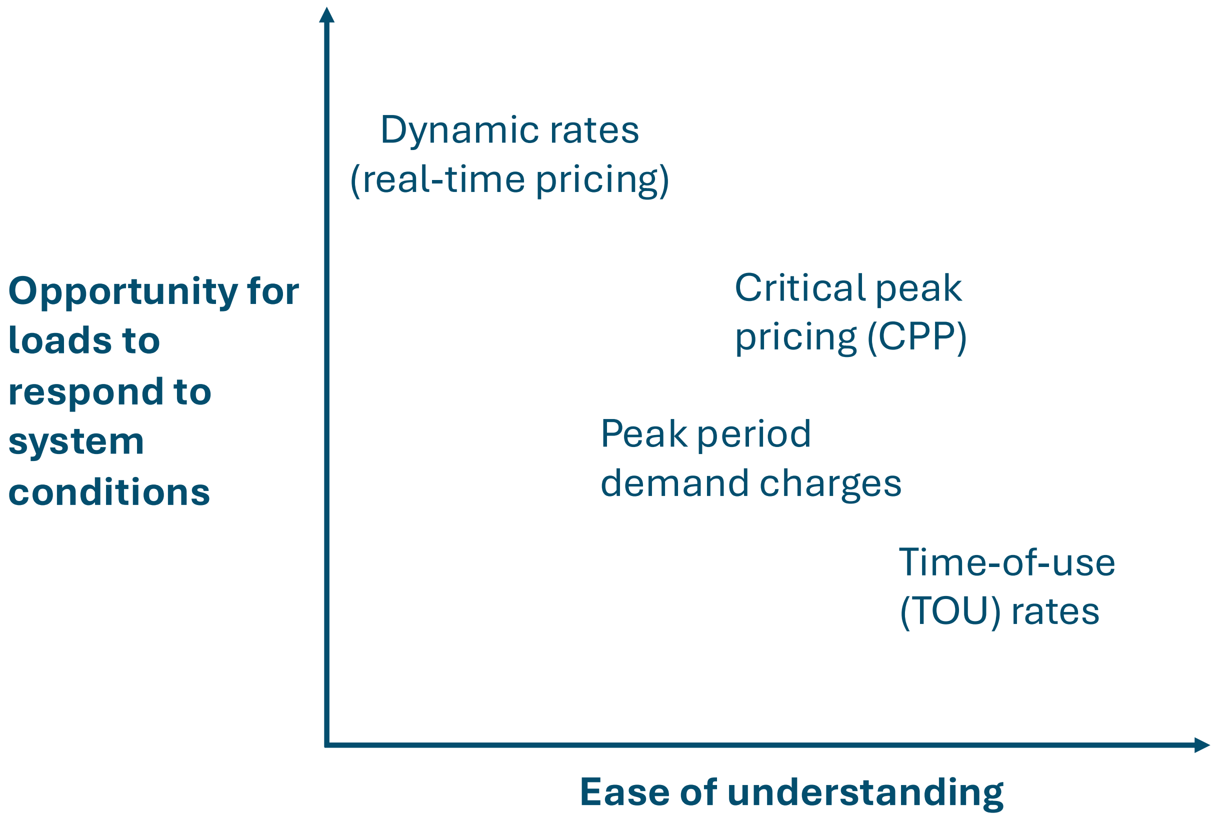
electric system costs. Controlling the growth in electric system costs will help maintain affordable bills for ratepayers and is a core priority for ensuring an affordable energy transition.

By the mid-2030s, peak electricity demand in the Commonwealth is expected to shift from summer to winter as more buildings adopt electric space heating. This transition, occurring alongside the rollout of TVR in Massachusetts, may create challenges for building electrification. Under cost-reflective rates, electricity prices will be highest during winter mornings and evenings—when heating demand is at its peak. While these price signals will encourage customers to improve efficiency and shift usage to lower-cost periods, they will also lead to higher winter heating costs for those using electric heat pumps compared to seasonal heat pump rates that offer winter discounts, such as those explored in the Near-Term Rate Strategy Report. Regulators and policymakers can pursue different options to help reduce winter bills for heat pump customers while retaining price signals that reflect system costs, including reducing volumetric rates through higher fixed charges, moving some costs out of electric rates altogether, and offering a policy credit for heat pump customers on their winter bills.

Key Findings: Time-Varying Rate Design

Time-varying rates will need to strike a balance between ease of understanding, which is important for customer acceptance, and reflection of system costs, which will enable peak load reduction to reduce system costs. Figure ES 1 illustrates a range of potential TVR rate designs with varying levels of price granularity, reflecting a balance between ease of understanding and ability to reflect system conditions. Each option the Commonwealth might consider comes with opportunities and challenges.

Figure ES 1: Trade-Offs between Rate Complexity and Load Response in TVR



The TVR options considered in this report include:

- **Time-of-use (TOU)**: This design encourages shifting consumption from peak to off-peak hours by using different rates in predefined periods. TOU rates are already widespread across the country and reflect a natural starting point for TVR. TOU rates may be designed in different ways that reflect a range of complexity, from fewer periods with smaller price differentials to more periods with larger price differentials. TOU designs with more granular price signals would provide a greater opportunity to reduce system costs through load flexibility but may be more complex for customers to understand.
- **Peak-period demand charges:** This design introduces a bill component tied to the maximum customer demand (kW) during a specified period, rather than total consumption during that period (kWh). Although this approach could help reflect the high costs of serving load during peak hours, demand charges are relatively uncommon in residential electric rates today and customers would likely need significant education to effectively reduce peak demand and avoid unintended bill increases.
- **Critical peak pricing (CPP):** This design imposes significantly higher volumetric charges during a limited set of peak demand "events" or "calls" during the year, incentivizing load flexibility and demand reduction during the specific periods that drive electric system costs. These calls provide greater opportunity for customer response and system cost savings but may create bill

volatility for customers with limited flexibility. CPP is generally offered on top of TOU rates. In contrast to TOU rates and peak-period demand charges, CPP targets the small set of system peak hours that drive capacity needs, rather than a large number of hours that are categorized as "peak," such as all summer evenings.

- **Real-time pricing (RTP):** This design offers the most granular signals, reflecting the actual (rather than predicted) variation in hourly avoidable system costs across the year. While RTP could yield significant bill volatility if applied to a household's primary meter, certain highly flexible and automated end uses could be exposed to RTP to maximize grid benefits. As with demand charges, RTP would also entail significant customer education.

A cost-based approach would tie differentials in TVR pricing to differences in avoidable system costs between time periods. TVR will provide new opportunities to communicate price signals that can enable load reduction and load shifting, reducing the costs of building and operating the electric system. If shifting load from one hour to another could avoid a certain amount of costs to the grid, a rate that reflects system costs would communicate and deliver that same amount of savings to the customer. This design maximizes customer response while ensuring that customers are not compensated beyond the benefits they provide to the electric system. This connection between TVR and avoidable system costs also provides a mechanism for evolving TVR designs as major changes occur on the electric system and to its cost drivers, including the forecast transition to a winter peak, anticipated greater transmission and distribution system buildout, and increased reliance on renewable generation.

Load flexibility will be essential for maximizing the benefits of TVR, both for customers and for the grid. End uses such as electric vehicle (EV) charging offer substantial potential for shifting load, while space heating and cooling are likely to be less flexible during peak demand hours, given the importance of timely delivery of heating and cooling and their dependence on weather conditions. Technologies that enhance flexibility such as smart water heaters, smart thermostats, thermal storage, building weatherization (to increase thermal inertia), and distributed energy resources will be important to help customers reduce energy bills and support greater grid benefits. By offering time-varying price signals and enabling widespread load flexibility, Massachusetts can work to limit growth in system peaks, defer or avoid infrastructure upgrades, and limit growth in overall costs.

TVR will have synergies with EV charging, delivering significant savings for EV charging while helping to limit costs to the electric grid. EV charging is expected to be one of the main drivers of electric load growth over the coming decades. Fortunately, it is also anticipated to be a highly flexible load. Under today's rates, a customer who charges their EV at home would spend $70-110/month across the year.[5] Under the example TOU rate we develop in this study, the customer could manage their charging to reduce the cost of charging to $50-90/month, while simultaneously helping to avoid costly investments on the electric grid. Notably, these savings will not be accessible to customers

[5] Assuming EV electric energy usage ranging from 220 to 320 kWh per month, varying over the course of the year, and 2024 National Grid R-1 volumetric rate of roughly 34 ¢/kWh. National Grid, Summary of Rates (2024), https://www.nationalgridus.com/media/pdfs/billing-payments/bill-inserts/mae/cm4394_mae_ratesummary.pdf.

who do not have access to home EV charging. Although it will also be important to develop a robust public charging network, public charging rates will generally be higher as they must also recover upfront and maintenance costs for charging infrastructure. Ensuring access to widespread and affordable EV charging will be a broader challenge that extends beyond the scope of residential electric rate design.

The advent of TVR will require a reassessment of how rates and distributed energy resource compensation programs interact to ensure that customers see consistent price signals that align bill savings with benefits to the grid. The interaction of TVR, net energy metering, and distributed generation and distributed energy resource (DG/DER) programs will need to be clearly specified and coordinated to ensure that customers dispatch resources in a way that maximizes grid benefits. In the future, programs may also play a role in providing customers with load management signals that align with localized distribution system needs.

Key Findings: Time-Varying Rates on a Winter-Peaking Grid

Once a winter peak develops, seasonal rates with a winter discount will no longer be cost-reflective and will need to be retired or will risk adverse consequences. The companion Near-Term Study described seasonal rates with a winter discount as a promising rate option to reduce costs for electric heat pumps and better align electric rates with the cost structure of today's summer-peaking grid. However, in the mid-2030s, increased electrification of space heating is forecast to drive the emergence of a winter peak on the electric grid.[6] Once this occurs, seasonal rates with a winter discount will have two important adverse impacts. First, customers would not see appropriate price signals to encourage reduction of winter peak loads through more efficient heating equipment, building shell improvements, or other measures. Second, winter discount rates would collect less than the utility's cost of service for electric heating customers, requiring utilities to raise rates for all customers. To avoid these outcomes, seasonal rates with a winter discount would need to be sunset once a winter peak emerges on the electric grid.

Cost-reflective rates will present challenges to winter electric bills for electric heating customers. Increasing winter heating demand is forecast to drive growth in a winter system peak, with associated high marginal electric system costs during winter peak hours. To the extent that TVR will reflect these costs in rates, this will lead to high pricing during winter morning and evening hours with the greatest demand for space heating and will thus lead to increased bills for electrified households. Heating loads are relatively inflexible compared to other electric loads such as electric vehicle charging, exacerbating this issue. Innovative and proactive strategies will be needed to support the goals of (1) maintaining cost-reflective rates to encourage peak demand reduction

[6] According to the 2050 Transmission Study from ISO New England, the region's electric peak demand may increase to upward of 57 GW winter peak compared to 22 GW in 2024, incurring transmission system upgrades costs of up to $26 billion cumulatively by 2050, with significant additional distribution system and generation capacity costs as well. ISO New England, 2050 Transmission Study (February 2024), https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf.

during costly hours for the grid and reduce overall system costs, and (2) supporting energy affordability for households with electric heating. Two different approaches will help to address this concern:

1) **Conservation and load shifting during winter peak hours.** The price signals from TVR will support a wide range of different strategies to reduce customer loads during winter peak hours. This may include high-efficiency heating equipment, such as ground-source heat pumps and cold-climate heat pumps, building efficiency measures that reduce space heating demand, technologies to reduce peak heating demands from the grid such as batteries and thermal storage, load flexibility for non-heating end uses to shift these loads out of winter peak hours, and others. By providing price signals that communicate the high value for load reduction in these hours, TVR will encourage these strategies and help to limit the growth in overall electric system costs, helping to manage energy bills for all customers.
2) **Rate design approaches.** Rate design offers several tools to help mitigate high winter bills for electric heating customers while maintaining price signals that illustrate the value of reducing loads during winter peak hours. One straightforward approach would be to reduce overall volumetric rate levels by increasing the share of costs recovered through a fixed charge. Even on a winter-peaking grid, a relatively small share of the bill for a fully electrified customer would reflect costs that are avoidable through load shifting or load reduction, and cost-based rates could recover some or all of the costs that are *not* avoidable through a fixed charge. A second approach would be to identify certain costs in electric rates, such as costs tied to programs and public policy goals and instead recover these costs from taxpayers. A third approach would be a monthly "policy credit" provided to electric heating customers on their winter bills to support bill reductions while maintaining pricing that encourages winter peak load reduction.

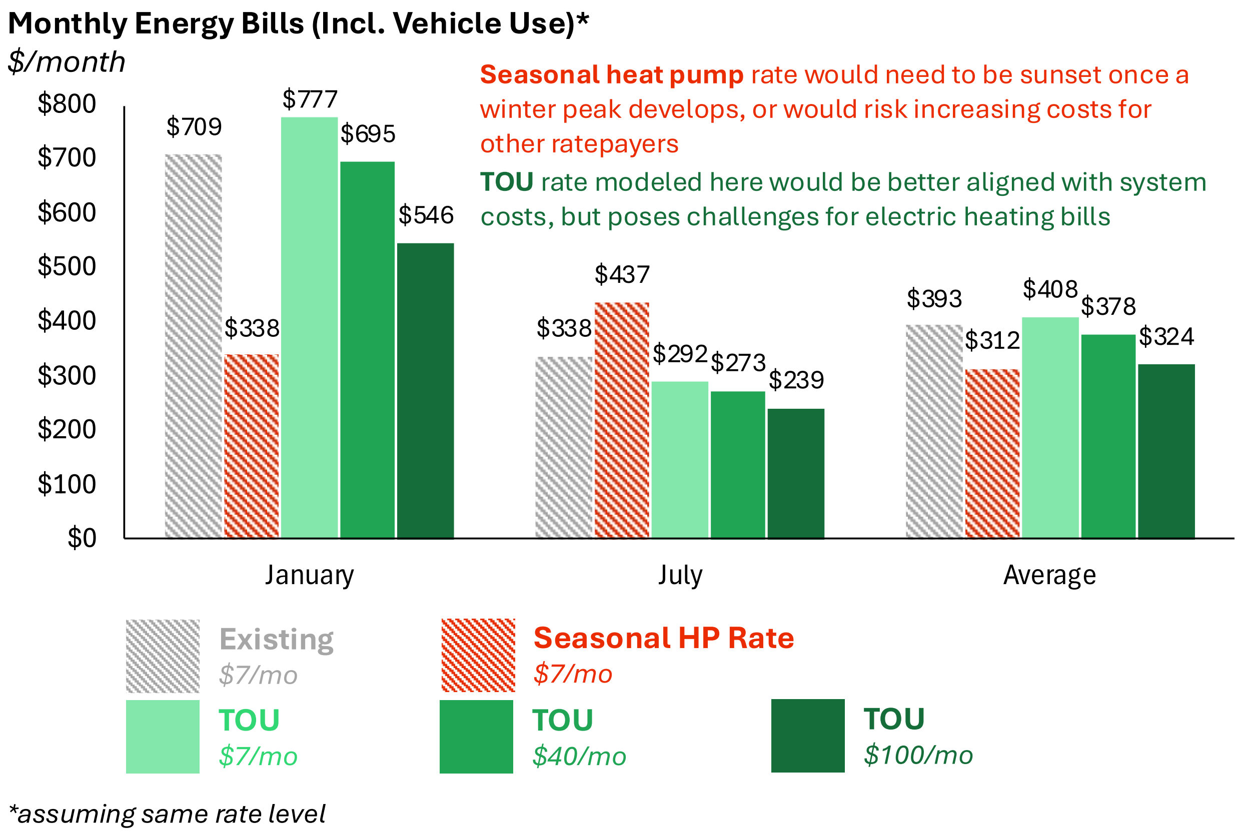
We present a snapshot of winter and summer electricity bills for a fully electrified customer under different rates, highlighting the challenges outlined above for electrified heating customers in transitioning to winter-peaking TVR rates and emphasizing the need for a managed transition from seasonal heat pump rates to TVR. The different TVR options included also illustrate how increasing fixed charges to recover policy and embedded system costs can support a reduction in volumetric rates and corresponding reductions in winter and annual bills for electrified customers. The rates presented include:

- National Grid 2024 electric rate,[7]
- Near-term seasonal heat pump rates developed in the Near-Term Study,[8]
- TOU rates developed in this study with varying levels of fixed charges:

[7] National Grid rates from 2024 used, prior to those approved in D.P.U. 23-150 Final Order (September 2024).
[8] Near-Term Rate Design to Align with the Commonwealth's Decarbonization Goals. Prepared for the Massachusetts Interagency Rates Working Group (December 2024), https://www.mass.gov/doc/irwg-near-term-rate-strategy-report-e3/download.

- $7/ month, corresponding to National Grid 2024 rate,
- $40/month, corresponding to the costs of programs collected through rates in 2024,[9]
- $100/month, corresponding to the collection of program costs as well as a large share of embedded delivery costs.

Figure ES 2: Monthly Electric Bills for a Fully Electric Residential Customer in 2030, under Varying Rate Structures (Monthly Fixed Costs Shown below in Legend)[10]



Key Findings: Ratemaking Frameworks

Shifting costs related to public policy and utility programs (e.g., energy efficiency incentives) from volumetric rates to funding mechanisms outside of rates, such as the state budget, would support a significant reduction in energy costs. Ratepayer-funded programs have been instrumental in supporting energy efficiency and other public policy objectives in the Commonwealth. However, the cost of these programs now represents a sizable share of the electric

[9] The average cost of programs and policies per customer varies by utility; the $40 estimate presented reflects a National Grid customer's cost.

[10] Multifamily home in Central Massachusetts, 1200 square feet, adopting a heat pump, electric vehicle, and weatherizing building, including light touch envelope improvements such as attic floor insulation and air sealing.

rate and accounts for about 11% of average household electricity bills. While the goals and achievements of these programs are laudable, cost recovery through rates increasingly poses a challenge for energy affordability and building and vehicle electrification. Funding these policy objectives through other means, such as the state's income tax system, would help to reduce energy burden, make electrification more cost-effective, and be a more progressive way to fund these policy goals.

Introduction

This report explores the future for electric ratemaking for residential customers in Massachusetts in the context of our changing electric system. The previously published Near-Term Report examined residential rate design strategies available to the Commonwealth today to better align electric rates with state climate policy and energy affordability mandates.[11] Looking out to the 2030s and 2040s, the need to ensure affordability for electrified and non-electrified customers is unchanged, but advanced metering infrastructure (AMI) will enable new rate offerings and increasing flexible customer technologies will enable greater customer response to price signals. Accordingly, the task of designing rates fit for the modern electric grid does not stop with near-term solutions. While the focus of this study is limited to the residential customer class, the benefits of cost-reflective rate design and load flexibility described apply to non-residential customer classes as well.

In the section **Embedded and Avoidable Electric Costs**, we provide an overview of the significant transformation that the electricity system is poised to undergo through 2050. Electrification of transportation, buildings, and industry is expected to increase electricity demand, reshaping the months and hours of highest grid utilization. This will necessitate the procurement of clean generation and capacity resources to reliably meet demand while shifting away from fossil generation, as well as investments in the transmission and distribution systems. These transformations will present challenges and opportunities for providing customers with price signals to align electricity consumption with system needs while keeping energy affordable for all households and supporting the Commonwealth's decarbonization goals. Today, the electric grid in New England is summer-peaking, meaning that electric system infrastructure is built out to reliably meet summer peak demands driven by air conditioning. As more homes and businesses adopt heat pumps, the electric system is expected to become winter-peaking by the mid-2030s.[12] Once this occurs, and peak heating demand emerges as a key driver of electric system costs, adding space heating load will no longer be possible without increasing system expenses. Rates will need to evolve to continue reflecting system costs and to ensure that customers receive price signals to reduce demands when system costs are highest and thus limit further growth in electric system costs. This change will present a cost challenge for customers with electric heating, due to the coincidence of heating demand and high prices, setting up the need for cost mitigation strategies across technology, policy, and ratemaking.

[11] Near-Term Rate Design to Align with the Commonwealth's Decarbonization Goals. Prepared for the Massachusetts Interagency Rates Working Group (December 2024), https://www.mass.gov/doc/irwg-near-term-rate-strategy-report-e3/download.

[12] 2035 identified as transition year in Eversource Electric Sector Modernization Plan (January 2024) at 2, https://www.eversource.com/content/residential/about/sustainability/renewable-generation/electric-sector-modernization-plan; 2033 identified as transition year in Unitil Electric Sector Modernization Plan (January 2024) at 101, https://unitil.com/sites/default/files/2024-01/Unitil-ESMP-2025-2050-DPU-FINAL.pdf ; late 2030s identified in National Grid Future Grid Plan (January 2024) at 67, https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-executive-summary.pdf.

In the section **Time-Varying Rates**, we describe the opportunities presented by time-varying rates (TVRs) in providing signals to customers to shift and reduce peak demand and avoid forward-looking utility costs. The advent of AMI will enable greater insights into energy consumption for households and will enable utilities to develop rates and billing systems that can communicate to customers when it is cheaper or more expensive to use electricity. TVR will play a key role in rate design as well as managing overall cost levels, as TVR can encourage load flexibility and peak reduction to avoid electric system costs and manage cost levels for all. TVR will be enabled in the next five years, but planning should begin now to explore how rates must strike the careful balance of providing price signals for load flexibility while limiting bill volatility for customers with limited flexibility, to prepare ratepayers for changing electric rate structures and grid participation, and to promote the adoption of flexible technologies.

Lastly, in the section **Ratemaking Reform**, we briefly discuss other tools to manage overall cost levels and draw attention to the ratemaking framework and scope of costs included in electric rates today, exploring ways to reduce electricity cost levels in the future. This includes shifting costs outside of electric rates, especially the costs of programs and policies that are not tied to electric system costs.

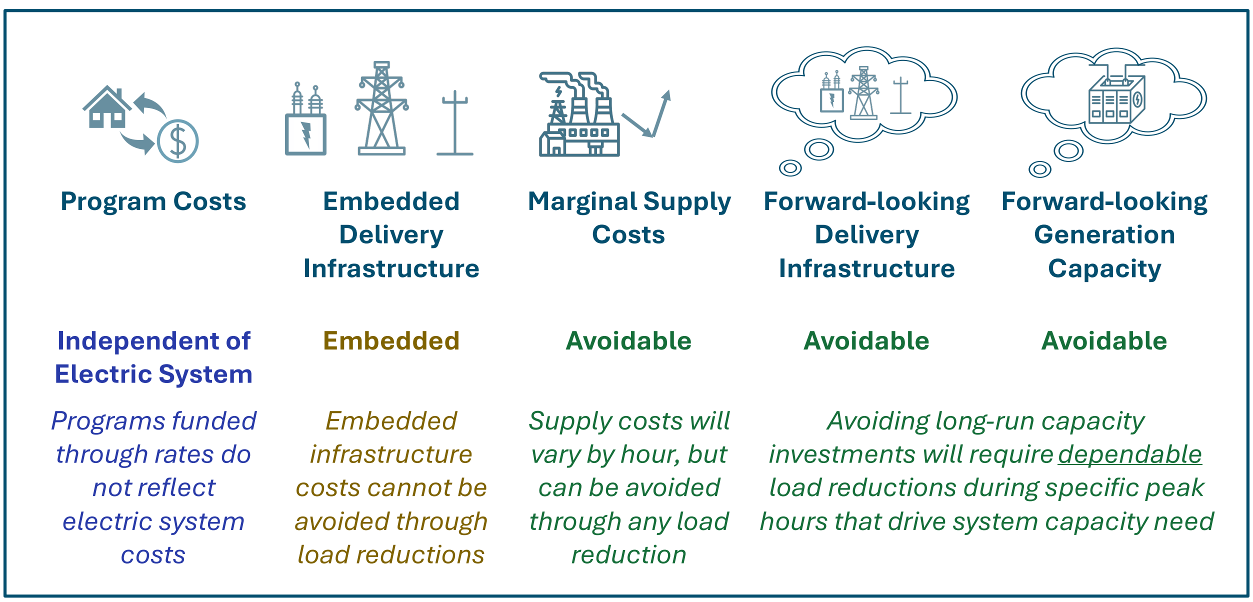
This study aims to expand on these topics and provide a longer-term view of what electric ratemaking in the Commonwealth could look like to best position the state to achieve its decarbonization and affordability policy goals.

Embedded and Avoidable Electric Costs

As the energy system in Massachusetts continues evolving to meet the Commonwealth's ambitious economy-wide decarbonization goals, many drivers of increasing costs to the energy system have materialized or will materialize in the coming years. Examining these cost drivers—the topic of this section—is important for designing retail rates of the future. In the past, ratemaking approaches have often focused on the drivers of historical costs. However, the combination of TVR and new flexible technologies will dramatically increase the ability of customers to manage their loads to avoid or defer *future* or *forward-looking* utility costs. This represents a dramatic change in the purpose of electric rate design: rather than simply a mechanism to fairly recover historical costs, electric rates can take on a new role as price signals that can communicate to customers when and how much they can help reduce costs on the electric system.

Figure 3 presents a high-level illustration of different electric system costs and the potential for load flexibility to provide savings for each component. "Embedded" costs refer to the historical expenditures that a utility has already incurred, or future costs that are locked in and cannot be deferred or avoided. In the context of designing price signals for customer response, these can be treated as sunk costs that cannot be reduced through marginal changes in customer energy consumption. Conversely, "avoidable" costs describe the ongoing costs that utilities incur for the actual generation of electricity, as well as the costs of forward-looking grid investments that could be avoided or deferred if growth in peak loads is slowed. The following subsections explore these categories in further detail.

Figure 3: Embedded and Avoidable Costs by Component



Program Costs

The first cost category in Figure 3 is the cost of utility programs, which are not tied to electric system costs. Today, volumetric rate adders are used to fund state policies and utility programs (e.g., energy efficiency and clean energy technology programs such as solar and electric vehicle incentives). Although these programs have supported important policy outcomes such as developing energy efficiency programs that reduce customer bills, the growing cost of these programs and their recovery through volumetric rates increasingly pose challenges for energy affordability and building and vehicle electrification. These programs now account for about 11% of average household electricity bills.

Funding these programs and policy objectives through other means, such as the state budget, would help to reduce energy burden, make electrification more cost-effective, and be a more progressive way to fund these policy goals, *i.e.*, would recover a larger share of these costs from higher-income households and a smaller share from lower-income households. This approach is explored in greater detail in the section **Ratemaking Reform**.

Embedded Costs

As shown in Figure 3, a significant share of utility costs are embedded costs, meaning that short- or long-term changes in customer energy consumption cannot avoid or defer these costs. Embedded costs include the recovery of costs related to existing infrastructure and unavoidable future capital investments, as well as a large share of operations and maintenance costs that cover the day-to-day upkeep and management of the electric grid.

Because embedded costs do not reflect any opportunity for utilities to avoid or defer forward-looking costs, they would not factor into time-varying price signals for customers in a rate design that is intended to reflect system costs. Instead, they could be recovered through different rate components including a flat volumetric charge, a fixed charge, and/or a non-coincident peak demand charge. Using volumetric charges to recover these costs will price electricity above the utility's avoidable costs and will have an adverse impact on bills for customers who adopt electric vehicles and heat pump technologies. These considerations are explored in more detail in the section **Time-Varying Rates**.

In addition, beyond shifting program costs away from electric rates, policymakers and regulators could consider the more radical approach of reassessing cost recovery for embedded electric system costs. For example, certain utility costs could be securitized through state debt with costs recovered over time from taxpayers. This idea may be especially relevant for large-scale distribution system investments such as grid hardening and modernization. Funding transformational grid investments through tax dollars instead of electric rates could have a large impact on reducing electric rate levels. However, this would be a significant departure from traditional cost recovery approaches. In addition, when applied to capital investments, this approach would have risks to the utility business model including important impacts on utility returns, and these risks would warrant careful consideration.

Avoidable Costs

As Massachusetts continues to decarbonize and electrify, future electric system costs are set to emerge, with opportunities to avoid and defer costs and thus limit cost growth for all ratepayers. These cost drivers include expanded clean electricity generation, as well as peak-driven investments in generation, transmission, and distribution capacity additions and system upgrades. The costs of generation will take on more temporal variation in a high renewables system: they will be lower when the sun is shining or the wind is blowing (providing energy at nearly no variable cost), but high in hours when renewable generation is low and load is served by expensive fuels. Load-driven investments in the transmission and distribution systems will be driven by consumption during the hours when these systems are most stressed and thus will largely align with hours when generating electricity is most expensive due to high supply costs.

Avoidable costs are the utility costs that can be deferred or avoided through load reduction and load management, *i.e.*, shifting the level and timing of electricity demand through behavior and enabling technologies. To the extent that flexible technologies such as electric vehicle (EV) chargers can shift load out of peak hours, there will be important savings through deferring or avoiding grid investments. The changing paradigm of avoidable costs for both energy supply and delivery will concentrate the highest avoidable costs in a relatively small number of hours over the year, as well as create greater intraday volatility in avoidable costs throughout the year. These changes will form the basis of cost-based TVR design, explored later in this report.

Generation

Meeting the Commonwealth's clean electricity generation goals of a 93% reduction in gross greenhouse gas emissions compared to 1990 levels by 2050[13] will require expanded investment in renewable energy resources such as wind and solar, as well as clean firm capacity resources that are able to provide clean energy when renewable generation is unable to meet the needs of demand. Examples of clean firm resources include nuclear energy, hydropower, hydrogen combustion turbines, long-duration energy storage, and natural gas generation with carbon capture and sequestration. Many of these technologies are still in developmental stages and are expensive compared to existing firm capacity resources such as natural gas-fired combustion turbines. Short-term marginal changes in customer electricity consumption can help avoid electricity generation when wholesale energy prices are highest, while sustained, longer-term reductions in system peak demand can help avoid long-term investments in generation capacity.

Transmission

Transmission infrastructure will require extensive upgrades to accommodate the influx of renewable energy, much of which will be sited in locations far from urban load centers, as well as extensive load

[13] Clean Energy and Climate Plan for 2050 (December 2022), https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download.

growth driven by electrification. Peak loads in the territory served by ISO New England (ISO-NE) could reach upwards of 57 GW as a winter peaking system by 2050, compared to a roughly 22 GW summer peak in ISO-NE today.[14] Peak-driven transmission upgrades will be necessary to enhance capacity and reliability, particularly during periods of high demand. Safely and reliably operating the transmission system under these periods of higher peak load will require upgrades to existing transmission infrastructure, the application of grid-enhancing technologies such as dynamic line ratings and advanced conductors to increase the efficiency and capacity of existing lines and rights-of-way, and investments in new transmission capacity. According to the 2050 Transmission Study from ISO-NE, needed transmission system upgrades are expected to incur cumulative costs of up to $16 billion by 2050 under a 51 GW peak scenario and up to $26 billion under a 57 GW peak scenario.[15] Sustained, predictable reductions in system peak can thus yield significant savings in avoided transmission system investments.

Distribution

Load growth, system modernization, and the need to replace aging infrastructure will drive future distribution system investment. Load management can help reduce or defer some of these costs. As electric infrastructure ages, the need for equipment replacement becomes a significant cost driver because assets such as substations, poles, and wires require ongoing maintenance and eventual replacement. This replacement cycle is essential for ensuring reliability and efficiency but can impose substantial financial burdens on utilities and, therefore, consumers. In recent years, utilities have made significant investments to upgrade and modernize their electric distribution systems. The 2022 Climate Law required electric distribution companies (EDCs) to publish periodic Electric Sector Modernization Plans (ESMPs) to proactively upgrade electric distribution systems to align with policy goals including improving grid reliability and resilience, integration of renewable and energy storage technologies, and preparing for electrification-driven load growth.[16] In their ESMPs, the EDCs proposed substantial investments that will result in a significant growth in costs. Eversource, for instance, planned a $4.5 billion investment in electric operations and $1 billion clean energy enablement from 2025-2030.[17] National Grid plans to spend $2.5 billion over five years on the investments needed to meet the state's goals.[18] Unitil proposed roughly $50 million in new capital

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[14] ISO New England, 2050 Transmission Study (February 2024), https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf.

[15] Ibid. The costs quoted here reference transmission upgrades that will be needed to avoid thermal overloads in an electrified future, but further investments in upgrades and/or advanced technologies may be needed to ensure voltage and transient stability.

[16] Background and procedural requirements on electric sector modernization plans (December 2024), https://www.mass.gov/info-details/electric-sector-modernization-plan-resources.

[17] Eversource Electric Sector Modernization Plan (January 2024), https://www.eversource.com/content/residential/about/sustainability/renewable-generation/electric-sector-modernization-plan.

[18] National Grid Future Grid Plan (January 2024), https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-executive-summary.pdf.

expenditure.[19] The rate impacts of these ESMP investments alone vary from 3% to 5.5% as cumulative bill increases from 2025 through 2030; total bill increases will likely be greater since non-ESMP investments still comprise the majority of expected utility investments in the next five years.[20] Going forward, customers and utilities can work together to defer or reduce the required size of future distribution system upgrades by reducing peak demands on the distribution system through energy efficiency and load management.

[19] Unitil Electric Sector Modernization Plan (January 2024), https://unitil.com/sites/default/files/2024-01/Unitil-ESMP-2025-2050-DPU-FINAL.pdf.

[20] Synapse Energy Economics, Inc., Consultant Comments on the 2024 Massachusetts Electric Sector Modernization Plans (February 2024), https://www.mass.gov/doc/consultant-comments-on-the-2024-esmps.

Time-Varying Rates

The widespread rollout of AMI will enable price signals at timescales that better match the future intra-day variation of electricity system costs. Additionally, customer-facing technologies that simplify and even automate price responsiveness are expected to facilitate widespread customer engagement with TVR. TVR will provide price signals that encourage customers to shift loads from constrained hours into hours with more abundant supply and help reduce electric system costs for all customers.

To provide customers with actionable financial signals, utilities and customers will need to consider *daily* variation in system costs, in addition to *seasonal* variation that was leveraged in proposed near-term rate designs. On a diurnal timescale, EV charging can be shifted to take advantage of low-cost hours during each day, supporting load growth without adding commensurate cost. Similarly, home energy storage systems can charge during low-cost hours and discharge to the grid or serve household loads during high-cost hours. On a seasonal timescale, heat pumps installed today will add load in the winter when there is "headroom" for this load relative to the summer peak for which the system is designed, thus increasing utilization of existing infrastructure. However, as the Commonwealth's building stock electrifies to meet state decarbonization goals, a winter peak will emerge, creating high-cost time periods that coincide with heating demand.

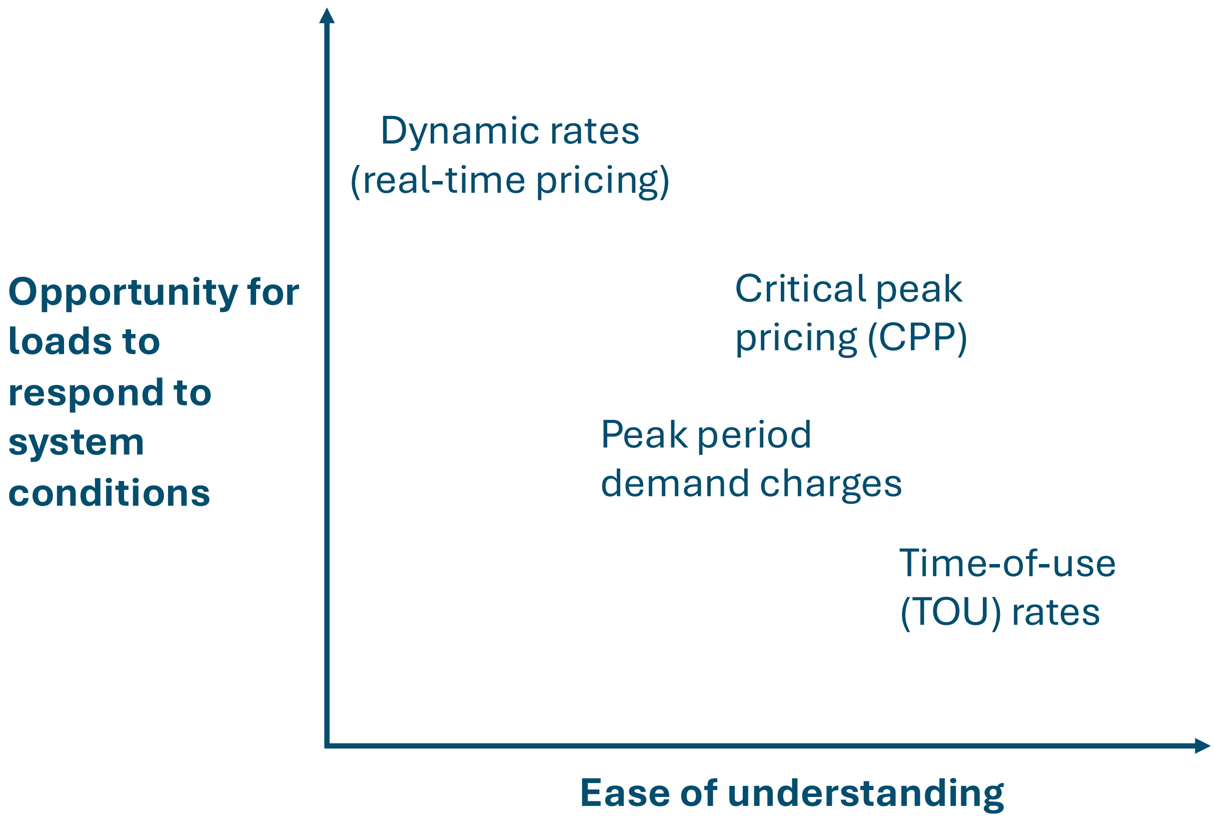
This section provides discussion and analysis of best practices for TVR designs that can leverage load flexibility to reduce system costs, while ensuring that customers with limited load flexibility do not see untenable bill increases. Key topics include a characterization of load flexibility for key end uses, guidelines for developing cost-based TVRs, and the merits and drawbacks of different TVR rate options. A brief synopsis of the regulatory history of TVR in the Commonwealth is also included in the section **Regulatory Background of TVR in Massachusetts**. We present high-level analysis to illustrate bill impacts of example TVR designs on different customer types, with the important caveat that this study does not attempt to forecast future growth in overall cost levels. **The example TVR options shown later in this section are designed to reflect system conditions in 2035 but also to be revenue-neutral with today's rates and thus do not include the impacts of expected changes in sales, customers, and system costs.**

TVR Design Options

TVRs are rate designs that charge different prices based on the time of day and the season and can incentivize customers to shift consumption into off-peak periods that are less expensive for the grid. There are several types of TVRs, with commonly used structures presented here: time-of use (TOU) rates, peak-period demand charges, critical peak pricing (CPP), and real-time pricing (RTP, or "dynamic rates"). Peak time rebates (PTR) are also discussed.

As shown in Figure 4, different time-varying rate options will have tradeoffs between complexity and opportunity for economic load response. On one end, designs such as TOU rates are less complex, in that there are fewer elements for consumers to understand and incorporate into their decisionmaking but may also provide less opportunity for loads to respond to system conditions. On the other end, dynamic rates have greater complexity but provide greater opportunity for loads to respond to system conditions, more precisely aligning customer and system costs. Designs such as CPP and peak-period demand charges can help find a middle ground between complexity and system response.

Figure 4: Trade-Offs between Rate Complexity and Load Response in TVR



Time-of-Use Rates

TOU rates are the most common implementation of TVRs. These rates have two primary objectives: (1) encourage customers to reduce consumption during peak hours by shifting usage to off-peak periods; and (2) ensure electric rates better reflect underlying system costs so that customers who use the grid during constrained hours help to pay the associated costs. In a “cost-based” TOU rate, the differences between peak and off-peak pricing would reflect differences in avoidable system costs. In practice, peak and off-peak pricing may be designed to target ratios that aim to find a balance between customer responsiveness and customer acceptance, as explored in the **TVR Implementation Considerations** section.

Critical Peak Pricing

CPP can provide further opportunities to reduce peak demand during key hours of the year when electric system costs are highest for the grid. CPP provides customers with a trade: customers receive a small discount over many hours of the year in exchange for dramatically higher pricing during a limited set of hours. The Sacramento Municipal Utility District (SMUD) has an instructive pilot, offering 2c/kWh savings during all summer off-peak and mid-peak hours, and a 50c/kWh additional charge during CPP calls, which are 1-4 hours long, limited to 50 hours total per year, and announced to customers on the prior day. If designed well, flexible customers would see savings, with inflexible customers seeing similar or slightly higher bills. Due to the potential for bill increases, CPP is often offered as an opt-in program today. However, as flexible loads become more common, it could potentially be part of a default rate in the future.

PTRs are an alternative to CPP, modeled after utility demand response programs, that also provide price signals during a few key hours of the year. Under PTR, customers receive rebates if they reduce consumption relative to a pre-established baseline during times when system costs are highest. In the D.P.U. 14-04 proceeding on TVR, several stakeholders, including ISO-NE and National Grid, flagged concerns with the challenges of establishing a baseline to use in calculating peak-period demand reductions due to the diversity of energy consumption patterns across customers as well as the potential for gamification of this calculation by more sophisticated customers.[21] In addition, this approach offers limited opportunity for introducing time-varying pricing relative to TOU rates.

Peak-Period Demand Charges

Demand charges use $/kW pricing to reflect a customer's maximum monthly usage, either during a complete monthly billing period or during a specified time window. "Non-coincident peak" (NCP) demand charges, which are assessed based on a customer's highest usage over the month, are designed to create a bill component that roughly scales with customer "size." These charges are generally used to recover embedded distribution system costs in a way that is reflective of historical cost causation but may not be designed with the goal of avoiding forward-looking costs. In contrast, "peak-period" demand charges measure a customer's maximum usage during pre-specified peak hours. Alongside TOU rates, these charges are meant to provide an additional signal to reduce peak loads during hours that are anticipated to be costly or difficult for the electric system.

Comparing Coincident Peak Pricing with Peak-Period Demand Charges

Demand charges are commonly used in rate design for commercial and industrial customers due to greater customer sophistication, including in Massachusetts. However, for residential customers, there are two reasons why CPP may be a simpler and more effective solution to provide granular price signals to customers and achieve load reductions during hours of system need. First, although

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[21] D.P.U. 14-04, Comments of ISO New England Inc. on the Anticipated Policy Framework for Time Varying Rates in Re: D.P.U. 14-04-B at 4 (July 2014).

CPP would require customers to respond to utility "calls," it may be easier for customers to understand compared to peak-period demand charges due to greater familiarity with $/kWh pricing rather than $/kW pricing. Second, CPP targets specific days when the system costs are expected to be highest (e.g., up to 20 days) and can respond to demand forecasts as they develop, rather than peak-period demand charges, which would apply to all peak hours across a pre-determined set of days (e.g., all weekdays from June through September).

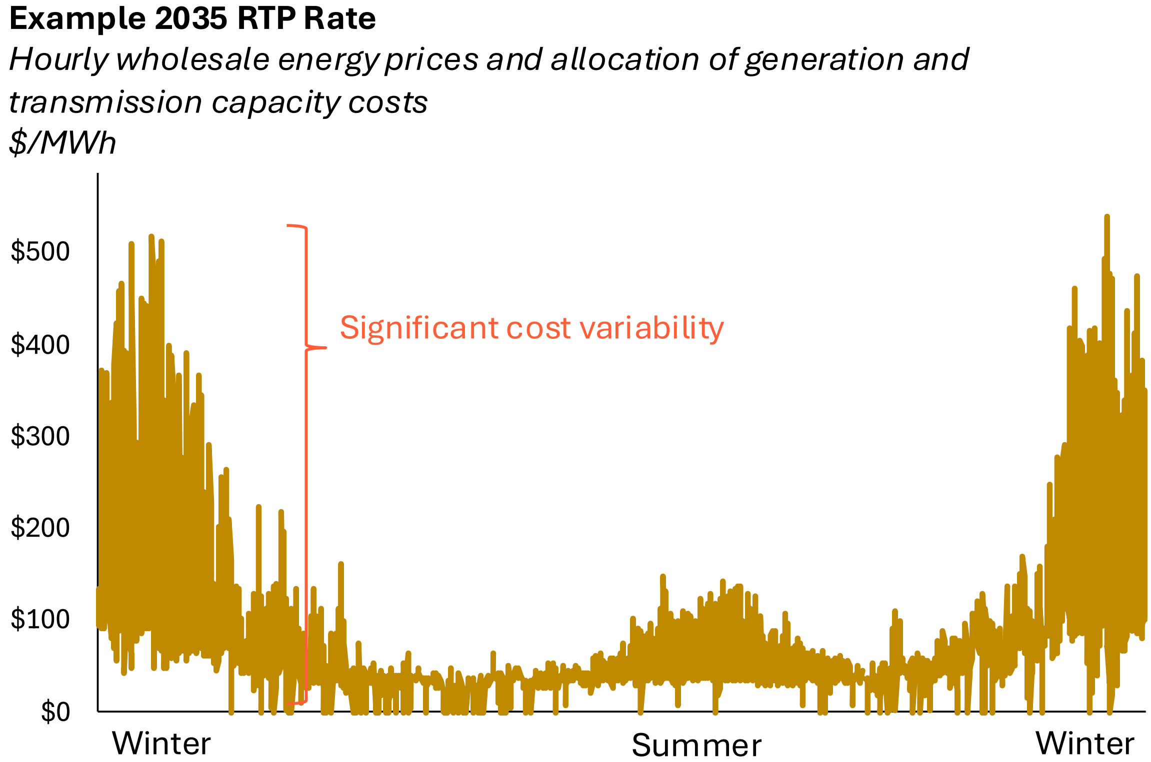
Real-Time Pricing / Dynamic Rates

"Real-time pricing" provides the most granular price signals, for example, providing customers with rates that are tied to hourly energy prices in the day-ahead wholesale market. Although this design could lead to highly dynamic customer response aligning customer usage with low- and high-cost periods for the grid, it would also lead to increased bill volatility for customers due to the significant hourly variation in avoidable costs. Figure 5 uses the latest available New England Avoided Energy Supply Costs (AESC) avoided wholesale energy, generation capacity, and transmission forecast costs for 2035 as an illustrative RTP rate, highlighting the higher costs in the peak hours of the winter months.[22]

It may be premature to expose residential customers to RTP at their primary meter, and it would be prudent to implement RTP pilots and consider options to reduce bill volatility in advance of any whole-home RTP offering. However, as technologies that facilitate grid responsiveness become more accessible, such as electric vehicle charging and smart water heaters, and distributed energy resource management (DERM) hardware and software develop, RTP pilots could be applied specifically for highly flexible end uses, such as EV charging, to maximize system benefits. Such pilots may require additional metering to measure consumption for specific end uses or could measure usage via the devices themselves.

[22] Avoided Energy Supply Costs in New England, Case CF5 (2024), https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc. Avoidable distribution system costs are not included but would present additional cost reduction opportunities throughout the course of the year.

Figure 5: Example 2035 RTP Rate Including Supply and Delivery Costs



Customer Load Flexibility

The ability of customers to respond to intra-day price signals via load shifting and demand reduction will affect their ability to see bill savings and provide system benefits under a time-varying rate. More responsive customer loads like EVs and programmable thermostats can take advantage of lower cost price periods to reap the benefits of TVR and reduce loads during higher priced periods. Customer responsiveness will also include the deployment of dispatchable DERs such as battery storage. In addition, more responsive customers can tolerate more volatility in their energy prices, to the point that a highly flexible customer may see the lowest average bills under RTP, which allows for the greatest ability to tailor usage to prices.

Table 1 presents the assumed load-shifting fractions used in this study, sourced from a Lawrence Berkeley National Laboratory (LBNL) study from 2024,[23] while Figure 6 presents a snapshot of resulting energy consumption by end use on the coldest day of 2035 for an example electrified multifamily home in Central Massachusetts.[24] The following findings are highlighted below:

[23] The California Demand Response Potential Study, Phase 4: Appendices to Report on Shed and Shift Resources Through 2050, LBNL (May 2024), https://energyanalysis.lbl.gov/publications/california-demand-response-0.

[24] An extreme weather day was chosen to show a lower bound of potential flexibility to illustrate the utility system planning perspective of expected load management.

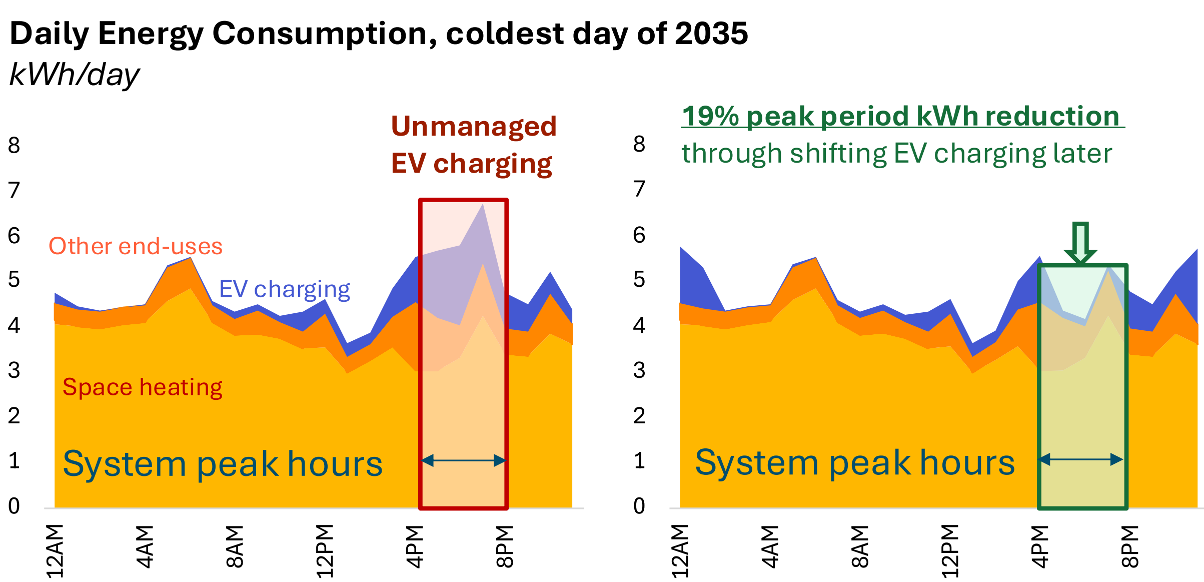
- EV load flexibility presents the clearest opportunity for system peak load reduction because (1) vehicles spend large amounts of time not in use and may be available to charge during a wide range of hours, (2) controls to schedule charging are widespread today, and (3) EV load will represent a significant fraction of annual household consumption. In the case shown below, EV flexibility helps drive the 19% reduction in peak-period energy consumption, by shifting charging to later in the evening. These savings will not be accessible to customers who do not have access to home EV charging, underscoring the importance of ensuring the public charging options are also time-varying and increasing access to home charging for renters and customers in multi-family homes. Vehicle-to-grid enablement will further expand the grid and customer benefits of managed charging, by allowing vehicle batteries to discharge energy to the grid or directly to households.
- Space heating and cooling are expected to be less flexible loads, especially for heating demand during cold winter spells and cooling demand during hot summer periods, as residents require space conditioning during these times to ensure a comfortable and healthy living environment. Building energy efficiency improvements and thermal storage technologies could enable lower heating demand during peak hours. A conservative approach of zero flexibility was assumed in this study to present a conservative estimate of heating-driven winter electricity bills.
- Heat pump water heaters can shift water heating demand by preheating water during low-cost periods, reducing peak demand for the grid and unlocking bill savings for customers with TVR. Advanced water heaters may be able to achieve higher levels of peak demand reduction, with a field study conducted by the Pacific Northwest National Laboratory from 2016 through 2020 observing up to a 90% peak demand reduction in water heating demand from heat pump water heaters compared to an electric resistance baseline.[25]
- Some households, especially those without home EV charging, may have less flexibility compared to households with more flexible loads. For these homes, TVRs that increase the costs of on-peak electricity usage may yield increases in electricity bills. For households in this category that are also low-income, energy affordability measures such as discount rates will need to protect these customers from exacerbating their energy burden. Developing a robust set of protections for low-income customers will help ensure that the system-wide cost-reduction benefits of TVR are achieved equitably.

[25] Pacific Northwest National Laboratory, Technology Integration: Heat Pump Water Heaters (HPWH), https://www.energy.gov/eere/buildings/articles/technology-integration-heat-pump-water-heaters.

Table 1: Annual Load Shifted by End Use

	Space Conditioning	Water Heating	Other	EV
Share of On-Peak Load Shift (%)	0%	40%	75%	90%
Notes	*Could increase with programmable thermostats, improved building envelope, and thermal storage. However, peak reduction in extreme weather is uncertain.*	*More advanced heat pump water heaters could shift greater share of annual load.*	*Smart dishwashers, clothes dryers, and other devices could increase the share of shiftable household load.*	*90% of EV charging load assumed to be shiftable, further benefits possible from charging strictly off-peak.*

Figure 6: Household Peak Reduction Potential by End Use[26]



[26] Multifamily home in Central Massachusetts, 1200 square feet, adopting a heat pump, electric vehicle, and weatherizing building. Space heating is assumed to have zero flexibility here.

Developing Cost-Based TVR

TVR can help ensure that customers are provided with clear price signals that reflect avoidable system costs. These avoidable costs serve as the basis for TVR design, as they reflect the hourly ability to reduce system costs through load shifting and load reduction. A cost-based approach to TVR design ties the differentials in TVR pricing to differences in avoidable system costs between time periods. If shifting load from one hour to another could avoid a certain amount of costs to the grid, a rate designed to be cost-reflective would communicate and deliver that same amount of savings to the customer. This design maximizes customer response while ensuring that customers are not compensated above the benefits they provide to the electric system.

For the design of TOU rates, these costs can be distilled into load-weighted month-hour averages, or season-hour averages, which can serve as the basis for identifying appropriate on- and off-peak windows, as well as economically efficient price differentials between on- and off-peak periods. In a cost-based rate, to continue ensuring that customer price signals remain aligned with electric system costs, these differentials would change over time to reflect evolving electric system costs, and TOU period definitions may also be updated periodically. Customers will need to be prepared for regular adjustments to electric rates as system costs evolve.

The illustrative rates developed in this section reflect three components of avoidable costs: energy, generation capacity, and transmission capacity. Other avoidable cost components could also be included in TVR design. As one example, forward-looking distribution capacity costs are driven by peak loads on constrained sections of the distribution system. While distribution capacity costs could be included in TVR design, the geographic variation in these costs will pose challenges for rate design. An additional example is the cost of externalities, such as the share of greenhouse gas emissions costs that are not reflected in existing energy prices. While the time-dependence of these costs could also be reflected in TVR design, a reduction in emissions does not reflect direct financial savings to utility ratepayers, and thus stakeholders and regulators might choose to treat these costs differently from avoidable electric system costs.

Constructing cost-based time varying rates requires a robust set of avoidable electricity system costs for each hour of the year. To develop illustrative rates, this study used the 2024 vintage of AESC costs for the year 2035 to develop hourly avoidable costs, treating avoided energy, generation capacity, and transmission system costs as “avoidable.”

Figure 7 shows season-hour averages using 2035 AESC avoidable electric system costs. For this figure and the rates developed in this report, “Winter” rates cover the 6-month period from November through April and “Summer” rates cover the six-month period from May through October. In the winter-peaking grid of 2035, generation capacity and transmission capacity costs are considerably higher in the winter, as these peak load hours are the hours that would drive the need for new system investments.

An important note is that the wholesale energy costs derived from 2035 AESC are considerably lower than 2024 utility supply rates, which can be explained by recent supply cost increases driven by higher gas prices, as well as future energy price decreases expected from greater penetration of low-cost renewables.

Figure 7: Modeled Avoidable Electric System Costs in 2035

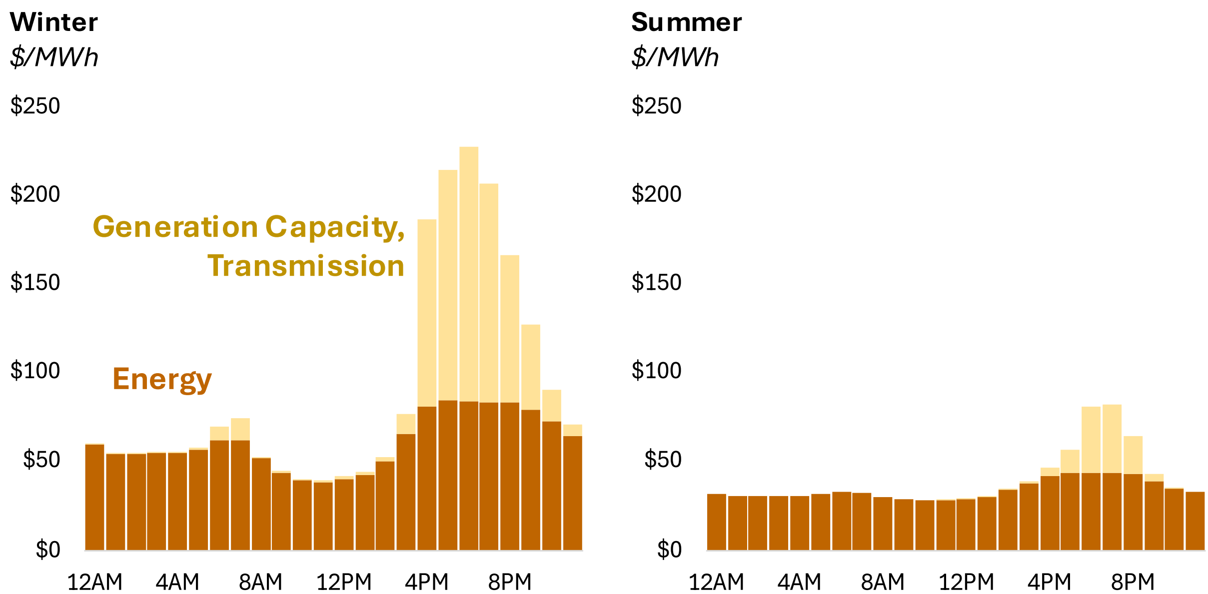


Figure 8 shows two example seasonal TOU rates developed using these costs. To develop these illustrative TOU rates, this study used a three-hour on-peak period from 5pm to 8pm and one-hour mid-peak periods from 4-5pm and 8-9pm, which are informed by the hourly pricing shown above in Figure 7.

In the rate design shown on the left of Figure 8, a $40/month fixed charge was included to recover program costs, corresponding to the average policy and program costs recovered on customer bills today. Embedded costs are recovered through an equal cent-per-kWh charge in all hours and represent the remaining revenue requirement costs outside of avoidable costs, mainly existing distribution system costs. In the rate design shown on the right of Figure 8, a $100/month fixed charge is included, covered program costs plus a large share of embedded costs, resulting in considerably lower volumetric rates and a larger peak-to-off-peak ratio. In both designs, winter rates are higher than summer rates, in keeping with the AESC costs presented above.

Note that the 2035 avoidable cost estimates used from AESC are lower than 2024 utility supply costs. Since this study developed revenue neutral rates with 2024 utility revenue requirement, this leads to a modeled outcome that may understate the share of avoidable costs relative to the mix of supply and delivery costs in today's rates but reflects the forecast 2035 avoidable costs as a share of 2024 cost levels (supply, delivery, and program costs).

Figure 8: Example 2035 Seasonal TOU Rate with Different Monthly Fixed Charge Options

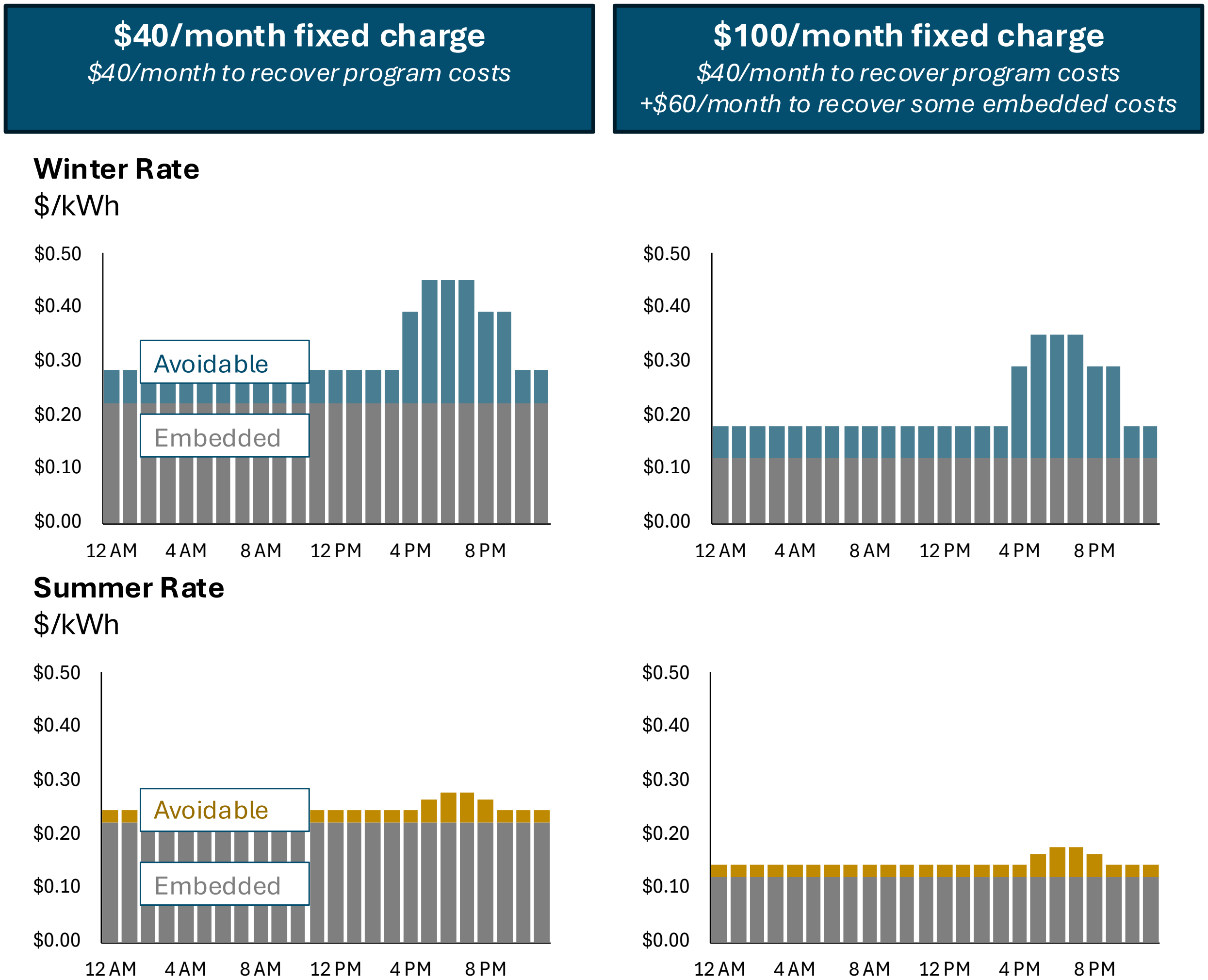
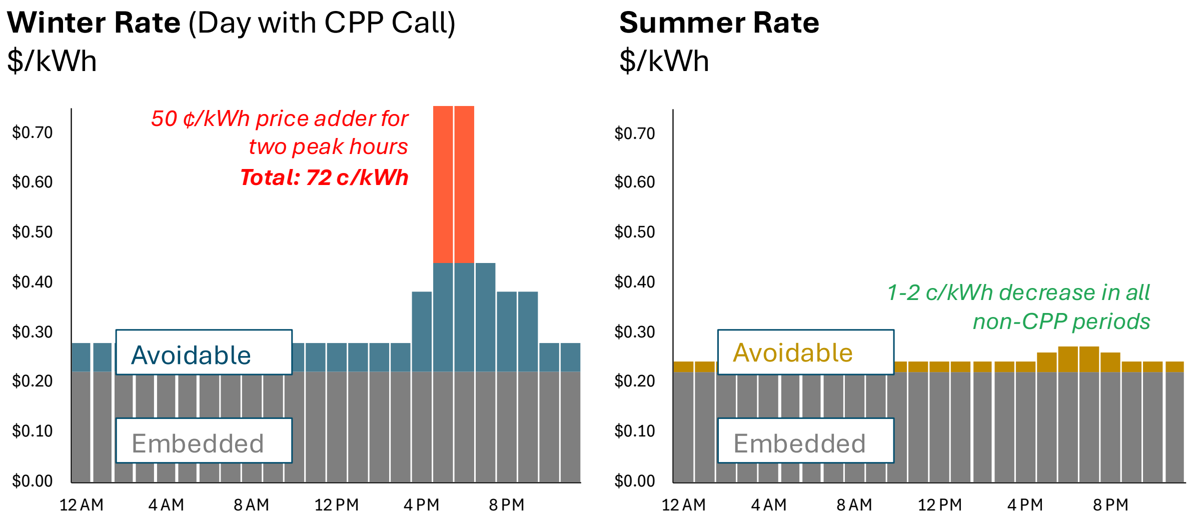


Figure 9 shows the impact of a CPP design on top of the TOU rate with a $40/month fixed charge, where the top 50 net load hours of the year are assumed to be subject to CPP "call" events, with a 50 ¢/kWh price adder stacked on top of the on-peak price.[27] Concentrating cost recovery for capacity costs in these hours can accommodate the reduction of on- and off-peak prices by 1-2 ¢/kWh over the rest of the year.

[27] This assumption mirrors an existing Sacramento Municipal Utility District CPP pilot rate offering. https://www.smud.org/Rate-Information/Residential-rates/Critical-Peak-Pricing.

Figure 9: Example 2035 Seasonal TOU + CPP Rate (with $40/Month Fixed Charge)



Bill Impacts of TVR

To illustrate the impacts of potential TVR designs on household energy bills, this study developed TOU rate designs using 2024 customer billing determinants and EDC revenue requirements but aligned with forecast system conditions in 2035. While comparisons are presented between these TVR options and existing and modeled near-term seasonal heat pump rates, these rates should not be interpreted as projections of *future* rates, as the same cost levels (or underlying utility revenue requirements) are assumed across the modeled options. Instead, these comparisons reflect the expected changes to bills driven by rate *design* and the shift to a winter peak, comparing bills under a near-term seasonal rate in a summer peaking system to TOU bills in a winter peaking system. Future cost levels are uncertain and will be driven by infrastructure deployment. This will increase rates, load, and customer growth, which will put downward pressure on rates by spreading out costs over greater demand.

CPP bill impacts are not directly modeled in this analysis. CPP aims to go beyond the levels of load shifting achieved by TOU and incentivize greater customer response including behavioral changes and even load curtailment, achieving a greater level of peak demand reduction than TOU rates alone.[28] Due to limited available data reflecting the diversity of customer response during CPP call events, and the challenge of considering the customer costs of this response, CPP bills are not modeled in this study. Overall, households with greater flexibility during peak-periods, as well as households with consumption during off-peak hours, would likely see larger savings from CPP. Conversely, households with more limited flexibility would face a greater risk of bill volatility under

[28] Brattle Group, A Meta Analysis of Time-Varying Rates(June 2019), https://www.brattle.com/wp-content/uploads/2021/05/16560_a_meta_analysis_of_time-varying_rates.pdf.

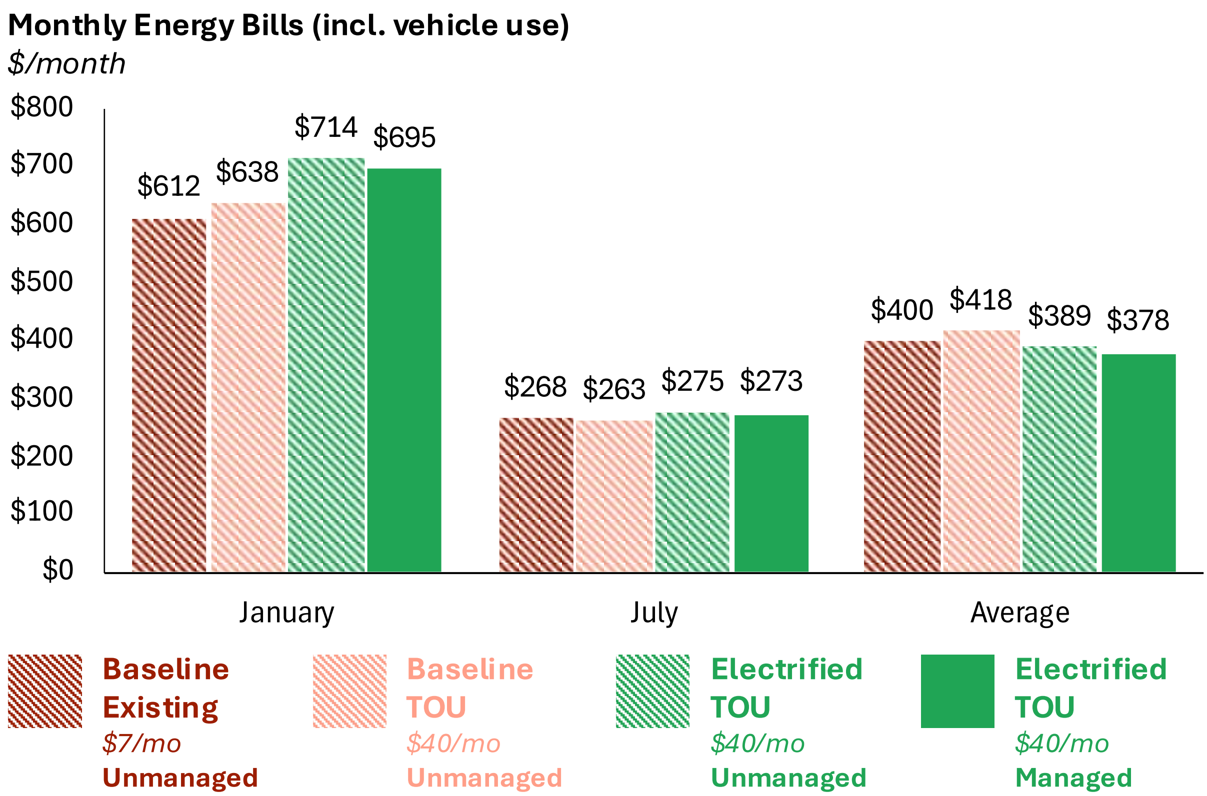
CPP, emphasizing the need for adequate protections of such households, especially if CPP is introduced as an opt-out (default) rate.

Different levels of load management are also presented to highlight the potential bill savings from EV load flexibility, as well as limited flexibility from other end uses. The load management levels presented are a conservative estimate, with enabling technologies such as programmable thermostats and building efficiency improvements playing a crucial role in unlocking further load flexibility. The impacts of load management on future utility cost levels were not included in this study.

Figure 10 separates out the impacts of the rate change (to TOU) from the impacts of electrification, broken into four stages. This figure illustrates 1) a baseline natural-gas heated home[29] under 2024 electric rates, 2) the same home after transitioning to a TOU rate (with a $40/month fixed charge), 3) the same home after subsequent electrification, and 4) the same home after subsequently beginning to manage EV charging.

[29] Multifamily home in Central Massachusetts, 1200 square feet, adopting a heat pump, electric vehicle, and weatherizing building.

Figure 10: Monthly Bills, Considering Impacts of Rate Change and Electrification (Monthly Fixed Costs Shown below in Legend)[30]



First, this analysis highlights that shifting from today's rates to a TOU rate may yield small bill increases for customers with low usage and limited load flexibility. This highlights the importance of including adequate energy affordability protections for low-income households with these characteristics that already face high energy burden, such as developing fixed charges that are progressive.

Next, this figure illustrates that, once on the TOU rate, annual energy costs would decrease after electrification[31] and decrease even further with managed EV charging, even considering the addition of air conditioning for this household which did not have air conditioning before. Finally, this figure illustrates that electrification under a cost-based TOU rate with a $40/month fixed charge will lead to increased winter heating costs.

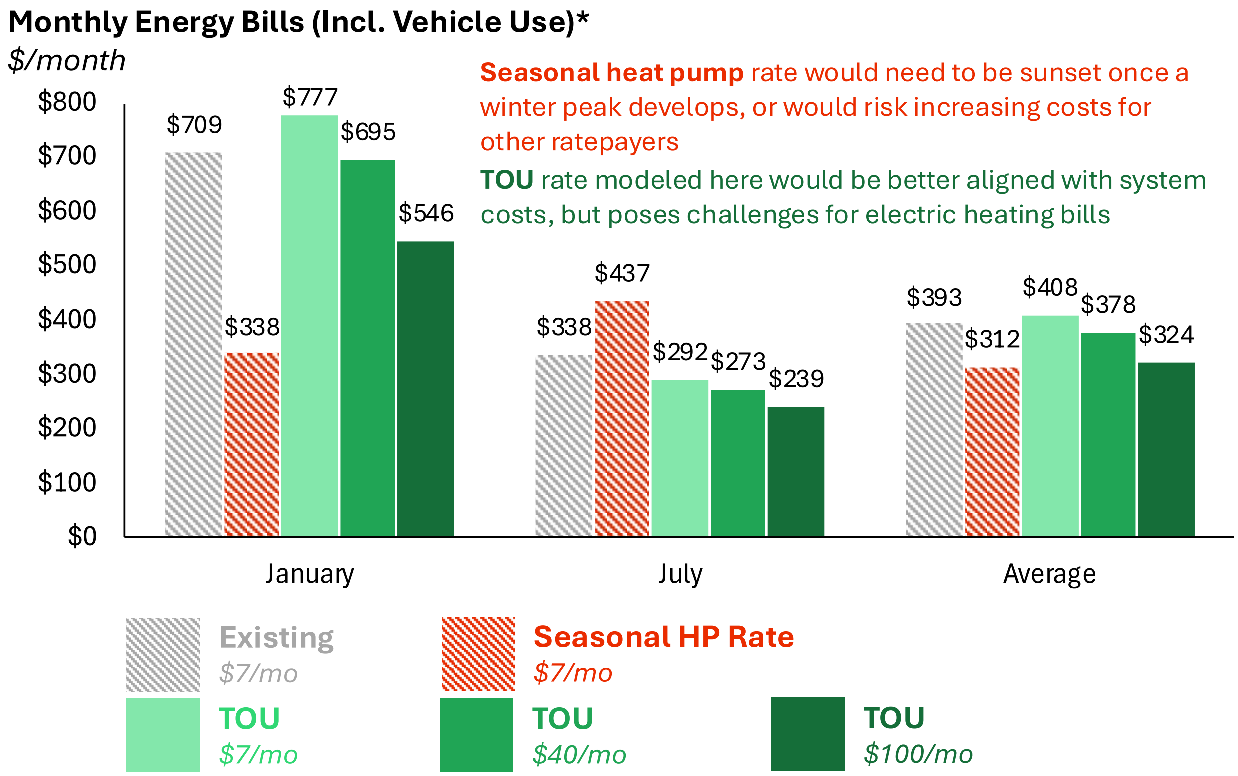
Figure 11 presents a comparison of summer and winter energy bills (including the operational costs of personal vehicle use) for an all-electric home under existing rates, the seasonal rate developed in

[30] Multifamily home in Central Massachusetts, 1200 square feet, with natural gas heating and no air conditioning today, adopting all-electric devices and building efficiency improvements as described above.

[31] While the two example monthly bills for January and July show increases in heating and cooling expenses compared to the natural gas baseline respectively, the relative bill savings in the other months of the year drive the annual bill reduction shown in the average monthly bill column.

the Near-Term report, which will need to be sunset, and novel TOU rates with different levels of monthly fixed charges.

Figure 11: Monthly Electric Bills for a Fully Electric Residential Customer in 2030, under Varying Rate Structures (Monthly Fixed Costs Shown below in Legend) [32]



**assuming same rate level*

This figure illustrates how the shift to a winter-peaking grid implies that cost-based TOU rates will have high pricing during peak winter hours, leading to high winter bills for electric heating customers. Summer bills are lower for these customers, reflecting lower summer energy prices and demand. However, the average bill over the year may be relatively high, especially relative to near-term seasonal rates, posing an affordability challenge for electric heating customers.

This figure also highlights the importance of fixed charges as a key tool to reduce bills for electric heating customers. With a $7/month fixed charge, the illustrative TOU rate would lead to higher average bills than under today's flat rates. Adopting a $40/month fixed charge, corresponding to the program costs in today's rates, would significantly reduce bills for electric heating customers, though average bills would still be higher than under the near-term seasonal rate. Finally, adopting a $100/month fixed charge, which would also include a large share of embedded costs, would lead to average bills close to the level of the near-term seasonal rate.

[32] Multifamily home in Central Massachusetts, 1200 square feet, adopting a heat pump, electric vehicle, and weatherizing building, including light touch envelope improvements such as attic floor insulation and air sealing.

Winter Peaking Cost Challenge

The analysis in the prior section underscores that cost-reflective rates on a winter-peaking electric system are poised to present a challenge for customer costs for electric heating. Meeting the Commonwealth's decarbonization goals while prioritizing energy affordability will entail an all-of-the-above approach across technology deployment, policy, and rate design.

High winter electric rates will provide an important price signal to encourage measures that can reduce load during peak winter hours. Efficient electric heating technologies that can limit electric peak impacts can play a major role in deferring and avoiding electric system costs. Ground-source heat pumps, cold-climate heat pumps, and networked geothermal systems may all help to reduce loads during peak winter hours. In addition, building envelope improvements will be key to limiting electric loads during peak winter hours. New technologies such as thermal energy storage will also help shift heating demand away from peak hours.

Reducing volumetric rates will continue to be an essential tool to improve affordability for electric heating customers. Shifting program and embedded infrastructure cost recovery out of volumetric rates and into fixed charges would dramatically reduce energy bills for winter heating customers. Shifting these costs out of electric rates altogether would have an even greater benefit in improving energy affordability for all customers, not just winter heating customers.

Policy solutions may also play a role in supporting the Commonwealth's decarbonization goals while maintaining price signals to support conservation and load shifting during peak winter hours. For example, winter bill credits for heat pump customers could help to reduce winter bills while maintaining price signals to support conservation and load management. Proposals for providing low-income bill credits to support energy affordability for customers facing high summer air conditioning costs using non-ratepayer climate policy funding have been suggested in other jurisdictions.[33] Similar funding mechanisms would help reduce ratepayer burden while supporting the Commonwealth's affordability and decarbonization goals.

We emphasize that many of these solutions require continued investment in programs to complement rate design. The future role of load management programs presents an especially valuable opportunity for programs to capture highly localized distribution value. Rate designs typically apply uniformly over the utility service territory or large zones within the service territory. This allows for alignment of time-varying rate signals that reflect system-level investments such as on transmission and generation investment. However, distribution investment will be based on more localized needs, which may or may not align with the timing of bulk system needs. Programs may be better suited to target avoiding or deferring distribution system investments, as limits on geographic granularity for programs are imposed only by availability of data and communication mechanisms. With the state and EDCs pursuing methods to enable spatially granular load/distributed energy

[33] Smith et al., Reallocating the Residential California Climate Credit to Low-Income Customers (December 2024), https://woods.stanford.edu/sites/woods/files/media/file/cepp_policy_brief_climate_credit_reallocation.pdf.

resources (DER) management,[34] the Commonwealth is on track to address the possible gap of signaling load flexibility to avoid future distribution investment.

TVR and DER Customers

Under today's flat rate structure, dispatchable DERs do not receive price signals in rates to guide their operations. In the absence of TVR, Massachusetts has developed programs to guide DER dispatch, including:

1. **Solar Massachusetts Renewable Target (SMART):** state incentive program to promote cost-effective solar development, with energy storage adder.
2. **ConnectedSolutions**: utility incentive program to support demand response through utility load management of smart thermostats and batteries during periods of peak system stress.
3. **Clean Peak Standard (CPS):** state incentive program to encourage dispatch and demand response from renewable generation and storage during specified windows.

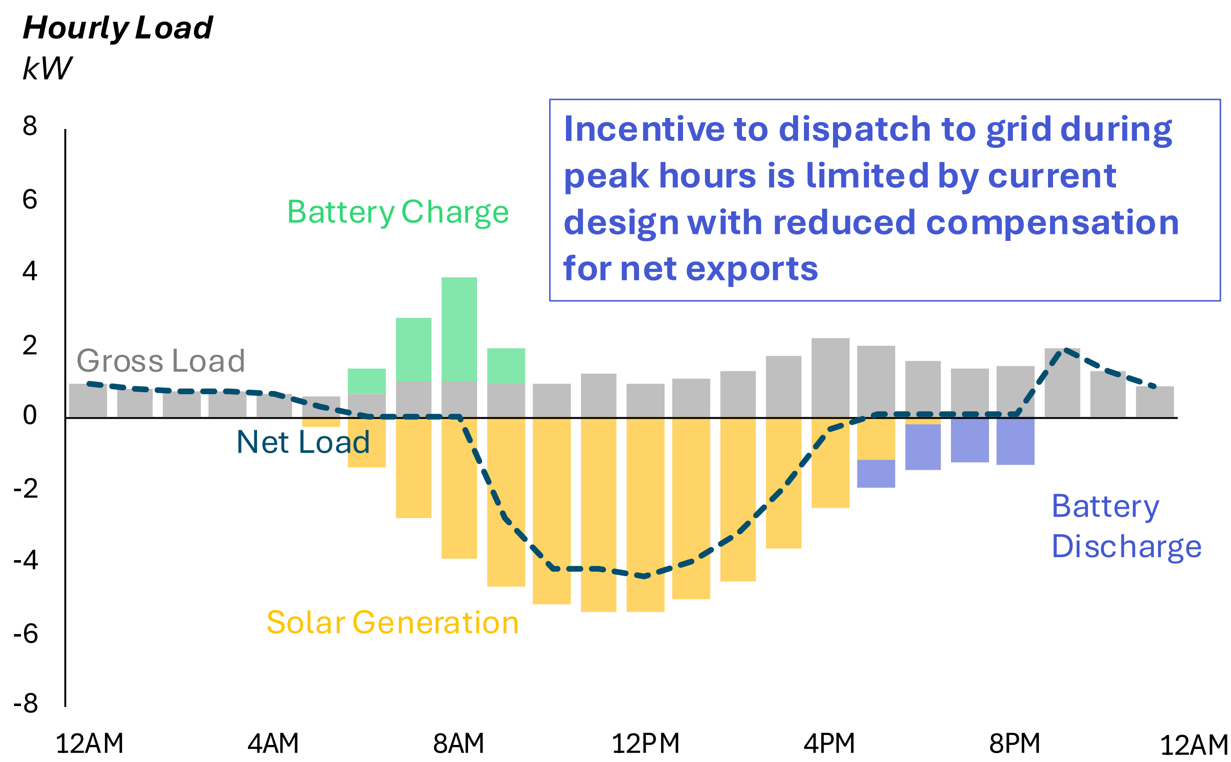
As utilities begin to introduce additional price signals through TVR, the interactions between TVR and these programs will need to be well-defined and carefully considered to achieve the goal of incentivizing dispatch that benefits the grid.

After the introduction of TVR, the existing Net Energy Metering (NEM) program may have unintended consequences for DER dispatch. The NEM program has a "net billing" design where monthly net exports, calculated by TOU period, would be compensated at a lower rate than the customer's import rate. This design is meant to reflect that some share of the utility rate should not be bypassable through customer solar, or at least through solar exports. However, under TVR, the current net billing design would lead to customers seeing a diminished price signal to export energy during peak hours and may instead encourage dispatching a battery to offset household energy use during all hours of the day. This battery dispatch approach would be misaligned with grid-optimal dispatch. The next two figures illustrate this outcome, contrasting existing and alternative DER rate structures.

Figure 12 shows a modeled solar plus storage dispatch profile under summer TOU rates and the existing NEM program design. For simplicity, compensation through ConnectedSolutions, SMART, and CPS are not included for this example. Under this structure, the customer may not fully cycle their battery because they aim to limit grid exports during any TOU period, even though it would benefit the grid to shift additional solar energy into peak hours.

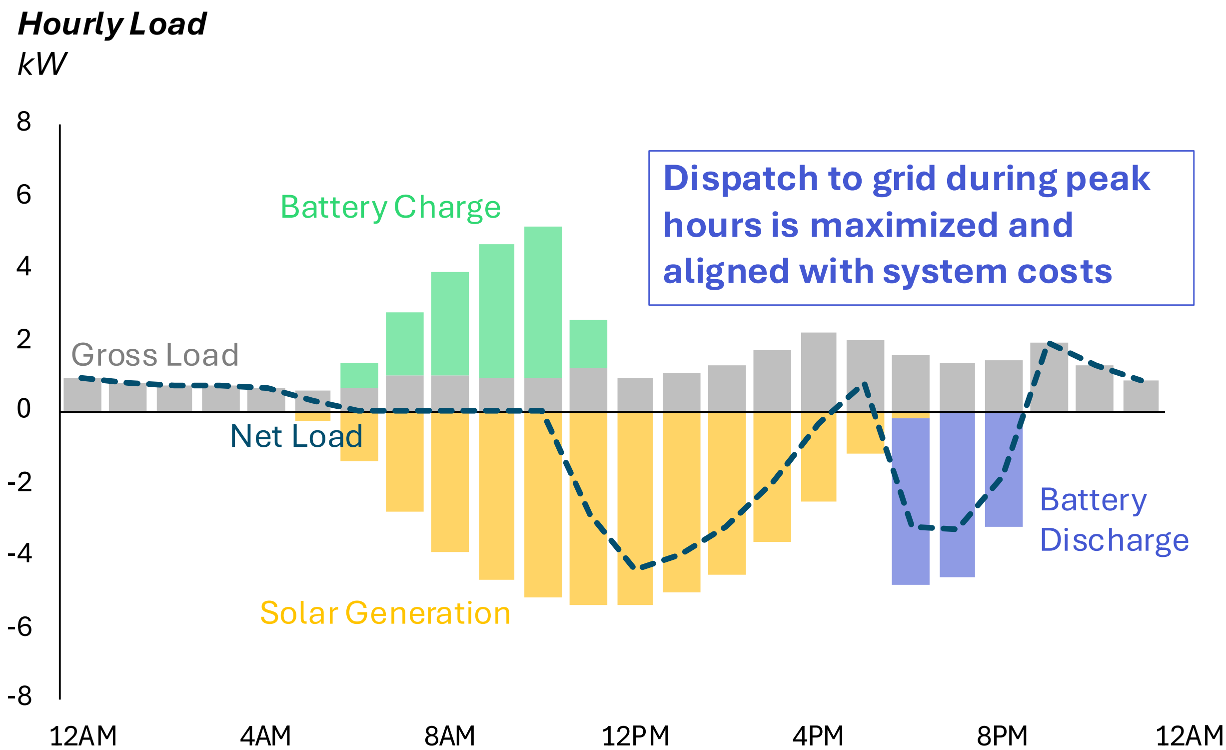
[34] Massachusetts Clean Energy Center, Grid Services Study, https://www.masscec.com/grid-modernization-and-infrastructure-planning/grid-services-study.

Figure 12: Solar + Storage with Non-Optimal Dispatch, Summer Day



In Figure 13, the same solar plus storage customer is shown under an alternative structure that encourages DER dispatch during peak hours, even if it leads to grid exports. This dispatch schedule would be more beneficial to the grid because it provides additional energy during peak hours, helping to reduce avoidable costs during these high-priced hours.

Figure 13: Solar + Storage Dispatch that Prioritizes Peak Hour Grid Exports, Summer Day



Economically efficient rates for DERs would have symmetric import and export rates, with TVR differentials that reflect differences in avoidable system costs. Rather than assessing non-bypassable charges as a reduction in export compensation, as done under the current NEM program, symmetric import and export rates would require recovering costs deemed non-bypassable through monthly fixed charges or some other design that does not distort price differentials among hours.

TVR Implementation Considerations

Decades of research into the implementation of TVRs across some of the largest utilities in the nation provide important lessons to inform TVR implementation in Massachusetts. Key lessons from these examples shed insight on design considerations such as how many hours should be in a peak-period, how large price differentials and ratios between peak and off-peak periods should be, and how to best encourage customer response while also protecting customers from bill increases.

Figure 14 illustrates a meta-analysis of over 350 TVR "pricing treatments" or rate options since 1997, showing the peak load reductions across each treatment with and without enabling technologies like smart thermostats.[35] The rate options modeled include TOU, CPP, PTR, and variable peak pricing (VPP), which entails a hybrid approach between TOU and RTP, providing customers with advance notice of time-varying peak prices (e.g., Eversource offers a VPP rate in Connecticut, allowing customers to purchase supply from Eversource on a daily basis, with information about daily on-peak prices available from the previous day).[36] The figure shows that per-customer peak load reduction can vary widely across rates, but CPP rates achieved the highest range of reductions (up to 60%) compared to TOU, PTR, and VPP. TOU and PTR reached 25% reductions in peak, increasing to 35-40% with enabling technologies. This analysis provides a benchmark for the possible range of customer peak demand reductions and emphasizes the promise of enabling technologies and CPP.

Figure 14: Relationship between TVR Designs and Peak Reduction (Faruqui 2019)[37]

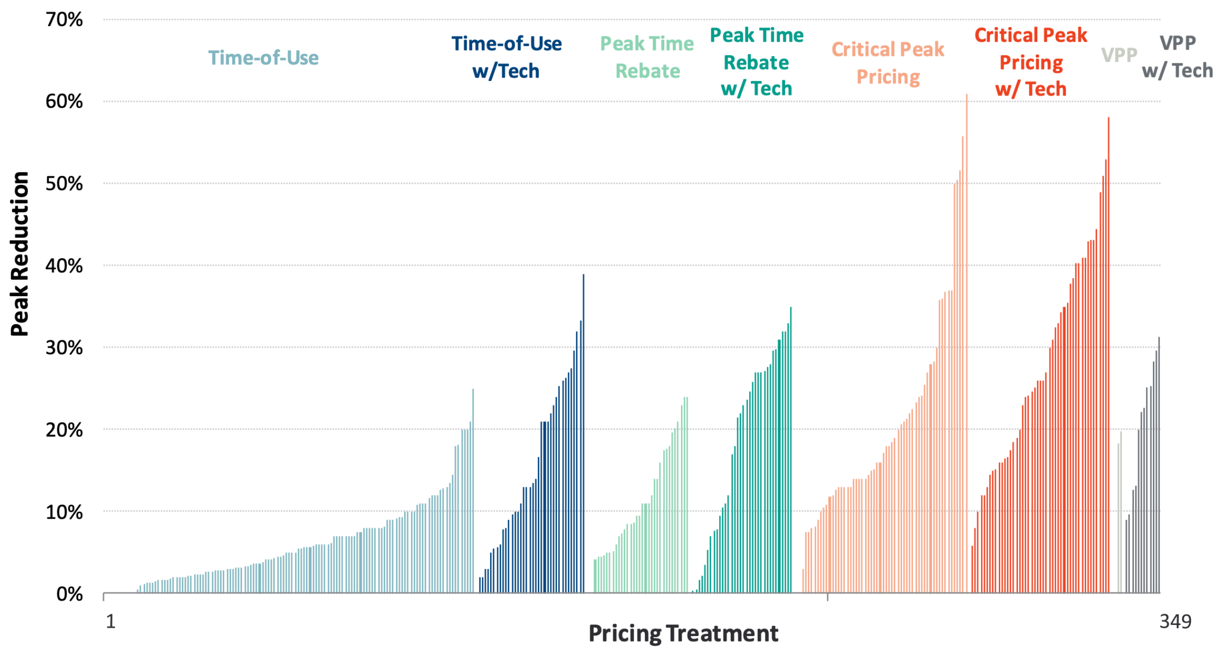


Figure 15, from the same meta-analysis, further explores the relationship between peak-to-off-peak ratios, peak load reductions, and enabling technologies. As observed in the prior figure, customers with enabling technologies can reduce peak more than customers without such technologies due to the increased ability to automate response to price signals. For example, at a peak-to-off-peak ratio of 4:1, customers with enabling technologies see more than 50% higher peak reduction relative to those without. The figure also highlights that, as the ratio between peak and off-peak pricing increases, the observed peak reduction increased, but at a diminishing rate. This provides additional context to the distribution of rate impacts in the prior figure, emphasizing the peak reduction potential of higher peak-to-off-peak ratios. Importantly, these findings may not be fully reflective of

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[35] Brattle Group, A Meta Analysis of Time-Varying Rates(June 2019), https://www.brattle.com/wp-content/uploads/2021/05/16560_a_meta_analysis_of_time-varying_rates.pdf.
[36] Eversource, Variable Peak Pricing (VPP), https://www.eversource.com/clp/vpp/vpp.aspx.
[37] Ahmad Farqui, The Transformative Power of Time-Varying Rates (March 2019), https://energycentral.com/c/em/transformative-power-time-varying-rates.

the automated technology options, such as managed EV charging, that are expected to become widespread in the future.

Figure 15: Relationship between Peak-to-Off-Peak Price Ratio and Peak Impact (Brattle 2019)[38]

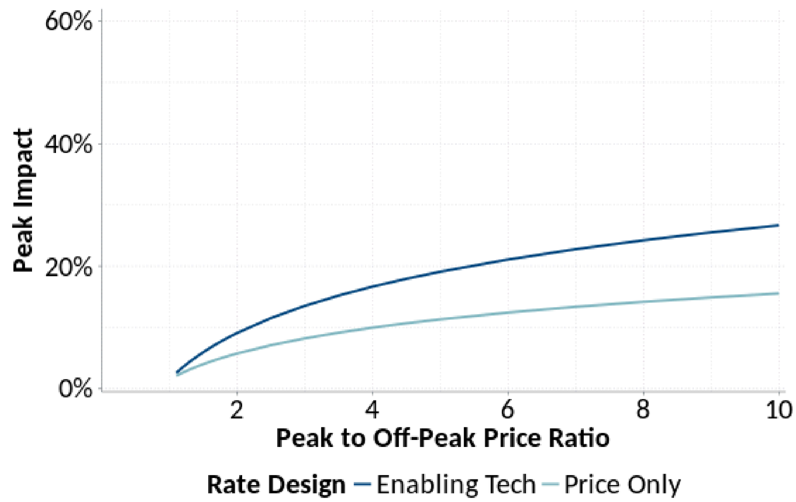

Figure 16, from a Maryland TVR pilot across three utilities (Baltimore Gas and Electric Company (BGE), Pepco, and Delmarva Power and Light (DPL)) from 2019-2021, differentiates impacts on peak consumption by low- and moderate-income (LMI) customers and non-LMI customers. The results of the study suggest that LMI customers are similarly price responsive to TOU rates as non-LMI customers.[39] This outcome highlights the importance of continuing to explore and understand the bill impacts of TVR on low-income households, as well as the importance of balancing the goals of protecting homes with low, inflexible usage that covers only basic energy needs, no enabling technologies, and less ability to actively adjust energy usage, with offering low-income customers the opportunity to reduce bills and energy burden with TVR.

[38] Brattle Group, A Meta Analysis of Time-Varying Rates (June 2019), https://www.brattle.com/wp-content/uploads/2021/05/16560_a_meta_analysis_of_time-varying_rates.pdf.

[39] Brattle Group, PC44 Time of Use Pilots: End-of-Pilot Evaluation, Prepared for Maryland Public Service Commission (October 2021), https://www.brattle.com/wp-content/uploads/2021/12/PC44-Time-of-Use-Pilots-End-of-Pilot-Evaluation.pdf.

Figure 16: Peak Impacts from LMI and Non-LMI customers (Sergici et al. 2021)[40]

Another important consideration is deciding whether a new TVR option should be opt-in or opt-out (default). While an opt-in rate option can yield a stronger response (more engagement) from participants on a per-customer basis compared to opt-out rates, the total population-wide response is significantly stronger for an opt-out rate because opt-out rates have a much higher share of

[40] Brattle Group, PC44 Time of Use Pilots: End-of-Pilot Evaluation, Prepared for Maryland Public Service Commission (October 2021), https://www.brattle.com/wp-content/uploads/2021/12/PC44-Time-of-Use-Pilots-End-of-Pilot-Evaluation.pdf.

participants.[41] Due to lower overall participation, and therefore less overall load responsiveness across the customer base, opt-in rates will have reduced system benefits because they are more limited in their ability to reduce system peak load and load during other high cost periods. For example, an assessment of opt-in vs. opt-out approaches for TVR for Rhode Island Energy saw over a doubling of societal benefits with opt-out rates.[42] For similar reasons, the California Public Utilities Commission (CPUC) automatically transitioned most customers to default (opt-out) TOU,[43] with bill protections as well as exclusions for certain customers such as low-income customers in hot climates, to protect vulnerable customers with limited load flexibility.[44]

Since TVR provides an incentive to reduce consumption during high-cost hours, "rebound peaks" can form at the end of a high-priced TOU period, which has been cited as an important concern in TVR design in recent modeling studies. The concept of a rebound peak is illustrated by Figure 17 from E3 analysis in Nova Scotia. Each panel of the figure shows total load for the same example weekday, with layers of light-duty EV loads showing the expected growth in that load over time. The second panel represents a modeled response of this load to a TOU rate. In this example, a rebound peak forms as customers who would have started charging during the on-peak period in the absence of TOU rates instead begin charging all at once as the peak-period ends. The third panel shows the smoothing effects of vehicle-grid integration (VGI), a technology and policy solution that enables vehicles to charge and discharge electricity from and to the grid, depending on electric system needs. The case shown reflects utility-controlled load management, although this could also take the form of localized demand response programs. Other solutions proposed to address rebound peaks include staggered or diversified off-peak period offerings, as has been implemented by a French utility, Enedis.[45]

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[41] U.S. Department of Energy, Lawrence Berkeley National Laboratory, *American Recovery and Reinvestment Act of 2009: Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from Consumer Behavior Studies* (November 2016), https://www.energy.gov/sites/prod/files/2016/12/f34/CBS_Final_Program_Impact_Report_Draft_20161101_0.pdf.

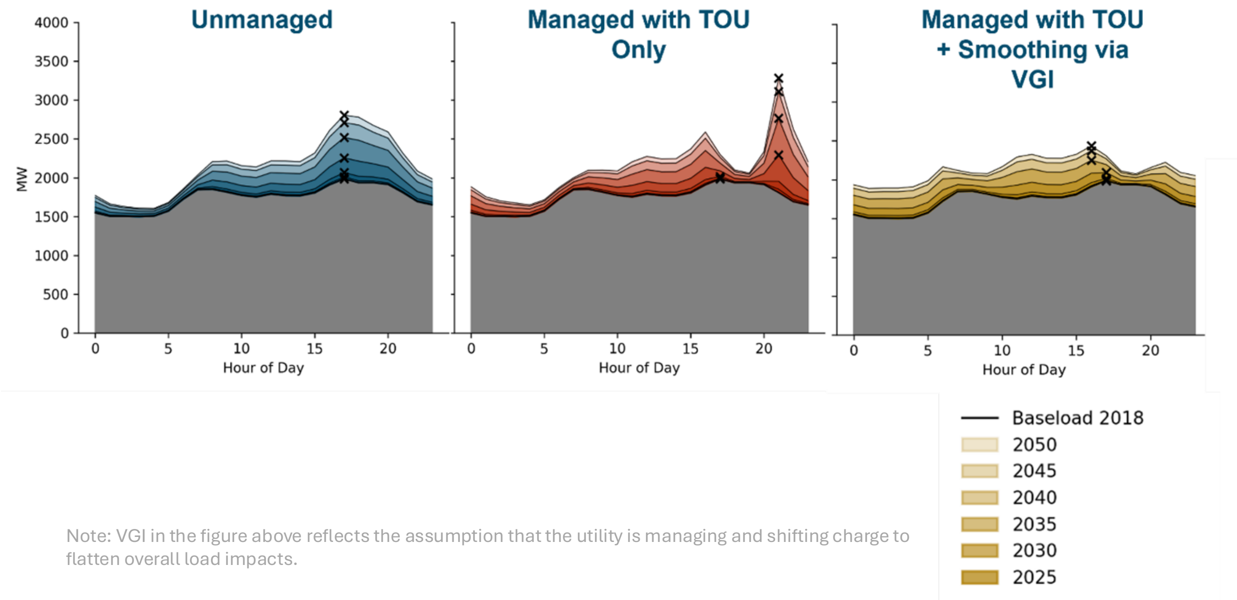
[42] Rhode Island Public Utilities Commission Docket No. 22-49-EL, Advanced Metering Functionality Business Case and Attachments, Schedule PJW/WR-1, Book 2 of 3 (November 2022), https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-11/2249-RIE-AMFPlan-Book2%2011-18-22.pdf.

[43] CPUC 15-07-001 Decision (July 2015).

[44] CPUC 15-07-001 Decision (July 2015). Additional context available at CPUC R.12-06-013: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates/residential-rate-reform-r-12-06-013.

[45] Selectra, Heures Pleines/Heures Creuses in France: Prices, Schedules and Tips (December 2024), https://en.selectra.info/energy-france/guides/electricity/heures-pleines-creuses.

Figure 17: Example Peak Winter Weekday Loads with Increasing Light-Duty Vehicle Loads in Nova Scotia (E3 2023)[46]



As noted earlier, the focus of this study is limited to the residential customer class, but the benefits of cost-reflective rate design and load flexibility is applicable to non-residential customers classes, such as commercial and industrial customers, as well. To the extent that peak demand drives total system costs, TVR and load flexibility can be leveraged to reduce total system costs for all customers. Utilities rely on various demand allocators, including coincident and noncoincident demand, to distribute, or allocate, demand-related costs during rate cases. Table 2 presents a sample of three distinct demand allocators utilized by Massachusetts electric utilities to allocate categories of demand-related costs by customer class in their most recent rate cases.

Table 2: Recently Used Demand Allocators for Massachusetts EDCs

EDC	Demand Allocator	Description	Residential	Commercial & Industrial
National Grid[47]	Class Coincident Peak at 115kV	Based on class coincident peak demand at transmission-rated voltage level; used to allocate cost categories such as transmission plant	50.62%	49.37%
Eversource[48]	Class Non-Coincident Peak	Based on class non-coincident peak demand; used to allocate cost categories such as substations and conductors	44.25%	55.73%

[46] E3, The Economics of Electrification in Nova Scotia (October 2023), https://www.ethree.com/wp-content/uploads/2023/12/E3_NS-Power_Electrification-Report-1.pdf.
[47] D.P.U. 23-150, Exhibit NG-PP-3A (REV2).
[48] D.P.U. 22-22, Exhibit ES-ACOS-5 (Compliance Dec. 2022).

Unitil[49]	Coincident Peak Demand Substation	Based on class coincident peaks at the transmission level; used to allocate cost categories such as substation and load dispatching costs	58.4%	41.6%

The implementation considerations outlined above highlight the importance of utilities and regulators in the Commonwealth learning from the lessons of other jurisdictions. TVR will be a powerful tool to align customer price signals with system costs and presents a valuable opportunity to reimagine the goals and principles of rate design. To see the greatest benefits from TVR, the Commonwealth must balance the system cost avoidance benefits of higher peak-to-off-peak price ratios and opt-out rates with challenges posed by bill impacts to customers with inflexible loads and consider the role of programs and rate design in mitigating the emergence of secondary rebound peaks.

[49] D.P.U. 23-80, Exhibit Unitil-JDT-3 (Compliance Dec. 2024).

Ratemaking Reform

As outlined in the Near-Term Study, electricity costs have increased steadily over the last five years, leading to high energy burdens for the Commonwealth's low-income households.[50] Limiting the growth of electric rates will be essential to protecting energy affordability and supporting the Commonwealth's decarbonization goals for electrification. The majority of this study has focused on TVR as a tool to leverage customer load management to reduce the growth in electric system costs. This section describes broader cost recovery, financing, and ratemaking strategies to manage overall electric system costs. These approaches were not modeled directly in this study but remain important areas of future analysis.

As the Commonwealth considers changes to cost recovery, financing mechanisms, and electric ratemaking frameworks, it will be important to carefully evaluate both the potential benefits and risks of these changes and to ensure that they support policy goals, better align utility incentives with policy goals, and minimize cost impacts for utility ratepayers.

Shifting Costs Out of Rates

As detailed in the section **Program Costs,** volumetric rate adders that fund policies and utility programs account for nearly 11% of average household electricity bills today. These do not reflect costs associated with building and maintaining the electricity system and it is a policy decision to recover these costs through electric rates. Funding these programs through other means, such as the state's income tax system, would help reduce electric rates and energy burden and would provide improved price signals for customers to electrify household and transportation end uses. In addition, funding these programs through income taxes would be a less regressive approach than funding them through rates, *i.e.*, a smaller share of the costs would be recovered from low-income customers.

As a more radical approach, some of the embedded costs of the electric system could be recovered outside of electric rates. For example, as explored in the section **Embedded Costs**, certain utility costs could be securitized through state debt with costs recovered over time from taxpayers. When applied to capital investments, this approach would have important impacts on utility returns and would need careful consideration. However, funding transformational grid upgrades through tax dollars instead of electric rates could have a large impact on reducing electric rate levels.

The Office of Energy Transformation (OET), established in 2024, has highlighted the establishment of alternative mechanisms to finance the energy transition as one of its three core priorities:

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[50] E3, "Energy Burden in Low- and Moderate-Income Households Today", Near-Term Rate Design to Align with the Commonwealth's Decarbonization Goals. Prepared for the Massachusetts Interagency Rates Working Group (December 2024), https://www.mass.gov/doc/irwg-near-term-rate-strategy-report-e3/download.

"[This OET working group will] identify alternative mechanisms for financing electricity distribution system infrastructure upgrades necessary to achieve Massachusetts' clean energy and climate mandates that reduce the cost of the energy transition for ratepayers and minimize bill impacts, while providing the revenue necessary to make the infrastructure investments required to support the energy transition and meet our climate and clean energy mandates."[51]

Alternative Financing Strategies

As described above, the OET plans to explore alternative financing mechanisms to reduce the costs of the energy transition for electric ratepayers. Regulators and policymakers in other jurisdictions have also expressed interest in financing electric system costs through alternative means. Although this approach holds the promise of leveraging low public borrowing costs to reduce the cost of investments, it entails important risks, including risks associated with public debt and default as well as risks to the utility. In addition, it may be important to distinguish among financing the costs of electricity procurement, electricity transmission investments, and electric distribution investments, as these may have differing potential benefits as well as distinct impacts on utility business models.

Alternative Ratemaking Mechanisms

Traditionally, the DPU has relied on "cost of service" (COS) regulation, also called "rate of return" regulation, to establish electric rates that provide utilities a reasonable rate of return on prudent investments that serve ratepayers. Under this approach, the DPU periodically approves a "revenue requirement" for each EDC, which is a calculation of a total annual sum of revenue the EDC would need to recover from ratepayers to cover the costs it has or will expend associated with operating the electric system and investing in capital to maintain and expand the system, and enabling the utility to earn a reasonable return on capital investments.

However, this model has been criticized for incentivizing utilities to act inconsistent with the best interest of ratepayers, including pursuing capital investment and working to increase customer sales. To better align utility and public goals, the Commonwealth has deployed a host of different strategies for all three EDCs, including revenue decoupling and capital trackers, as well as performance-based ratemaking features such as formula rates and performance incentive mechanisms. These ratemaking frameworks aim to better align utility financial interests with public goals and limit incentives for overinvestment, ideally balancing utility revenue certainty with ratepayer protection against overspending.

[51] Healey-Driscoll Office of Energy Transformation Announces Advisory Board and Focus on Peaker Plants, Everett LNG Terminal, and Affordability (July 2024), https://www.mass.gov/news/healey-driscoll-office-of-energy-transformation-announces-advisory-board-and-focus-on-peaker-plants-everett-lng-terminal-and-affordability.

Assessing the effectiveness of the Commonwealth's ratemaking framework in limiting electric service cost increases is a challenging endeavor, since there is no basis for comparison to determine what rates would look like absent these strategies. Each of the ratemaking reforms implemented by the DPU attempts to strike a balance, providing incentives to utilities through revenue certainty and financial rewards, while better protecting ratepayers from unnecessary utility expense and rate shocks, and better aligning utility actions with state policy priorities. Going forward, these measures should be reassessed through the lens of customer energy affordability and policy alignment, with a focus on ensuring that electric rate growth does not derail the Commonwealth's electrification and affordability goals.

Conclusion

This research effort sought to shed light on several important questions pertinent to the future of electric ratemaking in Massachusetts and to inform the IRWG's recommendations, helping to develop options for electric ratemaking in the Commonwealth in the future. First, we considered different kinds of costs currently recovered through electric rates. Next, we identified and compared the opportunities and challenges of different TVR options available for the state to explore as AMI is deployed through the end of the decade, including TOU, CPP, and RTP rate designs. This included an illustrative design of a TOU rate with cost-based differentials among TOU periods, aiming to align customer response with differences in avoidable system costs. Next, we compared customer bills on illustrative TOU rates to 2024 rates for customers with and without electric heating, and for those with dispatchable DERs. We also explored implementation considerations for TVR in the Commonwealth based on lessons learned from other jurisdictions, including opportunities and challenges of opt-in versus opt-out rates, the expected heterogeneity of price response to TVR for LMI and non-LMI households, and the challenges of secondary "rebound" peaks. Finally, we outlined approaches to managing system costs outside of rate design, including expanding non-ratepayer funding and reexamining existing ratemaking frameworks.

Key Takeaways

- Electric system costs are expected to increase to reliably meet existing and new electric loads.
- Electric utilities will increasingly be able to offer TVRs to residential customers with the anticipated statewide deployment of AMI by 2029.
- TVR can help align customer and system costs, providing incentives for load flexibility that can reduce peak demand and limit the increase in electric system costs for all ratepayers.
- TVR covers a range of different rate designs with an inherent tradeoff between complexity and ability to reflect system conditions.
- Many jurisdictions have implemented simpler TOU rates as default, with more complex TOU designs and/or CPP as opt-in rate options.
- For RTP, near- to mid-term potential is for highly flexible customers and end uses, rather than whole-home RTP.
- For TVR design to reflect system costs, it is valuable to identify the subset of electric system costs that can be deferred or avoided through customer load reduction or load shifting.
- Customers must be prepared with the expectation that TVR rates will evolve year-to-year as system costs change.
- EV charging presents the clearest opportunity for system peak load reduction due to high load flexibility, existing technology for managing charging loads, and the large share of total household electricity usage for customers with EVs.

- A winter-peaking grid will have high costs during the coldest hours of the year. Although this will provide important price signals to support load reduction and load shifting during these hours, a key challenge will be maintaining affordability of building electrification.
- There will be key roles for programs and technologies that reduce winter peak impacts such as efficient heating technologies, building shell measures, and nascent technologies like thermal storage.
- TVR will likely lead to changes in bills for distributed generation and DER customers, necessitating review and coordination of programs and rate design to ensure that participant compensation is aligned with system benefits and with clean energy technology adoption goals.
- TVR design will need to balance the goals of protecting low-income homes with low, inflexible usage that covers only basic energy needs, no enabling technologies, and less ability to actively adjust energy usage, with providing customers with opportunities to reduce their bills and energy burden.
- TVR may yield secondary "rebound" peaks, which will require technology and policy strategies such as VGI and diversified off-peak rate designs to mitigate peak-driven cost increases.
- Reducing the scope of costs currently recovered through electric rates would contribute to reducing electric ratepayer burden.
- Leveraging state financing for electric system costs, as well as updating ratemaking mechanisms in Massachusetts, may both support reducing ratepayer costs and achieve other policy goals, but may also include altered risks for ratepayers and utilities that require careful consideration.

Appendix

Methodology and Data Sources

HEEM Overview

To explore a diversity of bills with and without electrification under current and alternative rate designs, E3 developed the Household Energy Expenditure Model (HEEM). HEEM enables the calculation of household energy costs for pre- and post-electrification households in Massachusetts under different rate options. HEEM models a diverse set of representative households and captures energy expenditures for both home energy demands and vehicle usage. Key output metrics such as monthly bills and energy burden illustrate the impact of different rate designs on electrification cost-effectiveness and on energy affordability. HEEM enables the comparison of pre- and post-electrification customers on a given rate, as well as the comparison of one customer between different rate options.

HEEM Representative Customers

To capture a diverse set of households across Massachusetts, HEEM models representative customers based on combinations of key building, technology, and other characteristics, as shown in Figure 18. Building characteristics include housing type (single-family vs. multifamily homes), size (<1,600 square foot vs. >1,600 square foot), vintage (pre-1970 vs. post-1970), region, baseline heating source, and air conditioning. Technology characteristics include home and vehicle electrification status. Lastly, other customer characteristics include occupant status (renter vs. owner) and eligibility for bill discount programs. For each combination of customer characteristics, representative households were selected from the National Renewable Energy Laboratory (NREL)'s public ResStock database version 2024.2.[52] The ResStock baseline package was used for pre-electrification households while ResStock measure package 12 was used to represent fully electrified households.[53]

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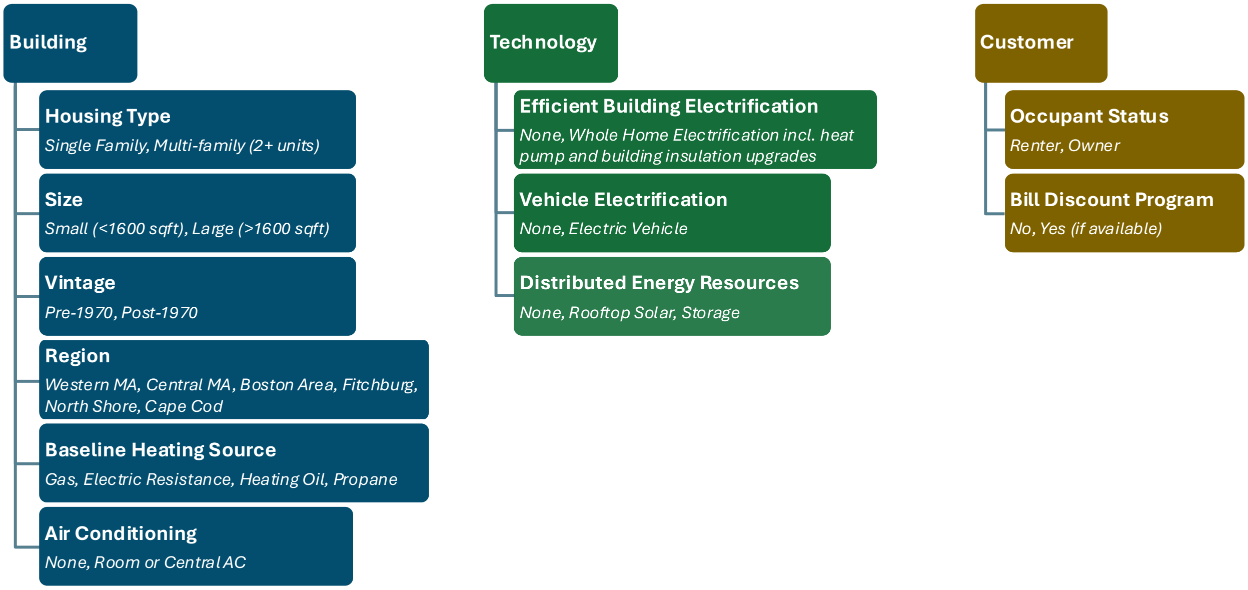
[52] ResStock includes electricity and gas usage data and hourly profiles for thousands of representative residential customers in Massachusetts. More information available at https://www.nrel.gov/buildings/resstock.html.

[53] Measure package 12: "High efficiency cold-climate air-to-air heat pump with electric backup + light touch envelope improvements + HPWH + appliance electrification".

Figure 18: HEEM Customer Prototypes



For each home selected, HEEM aggregates detailed hourly home energy usage profiles from ResStock into hourly load shapes by fuel (electric, natural gas, fuel oil, propane) and end use (space cooling, space heating, water heating, cooking, clothes drying, and other). On top of that, gasoline usage and home electric vehicle charging consumption are estimated assuming one personal vehicle, approximately 10,000 vehicle miles per year, [54] an internal combustion engine (ICE) efficiency of 21.5 miles per gallon (looking at the average on-road fuel efficiency for vehicles in Massachusetts today),[55] and an EV efficiency of 0.3008 kWh per mile, taking the average efficiency of new vehicles sold.[56] While there is significant variation in vehicle efficiency, the majority of EVs sold in Massachusetts to date have tended to be higher efficiency Tesla vehicles, as tracked by the Massachusetts Offers Rebates for Electric Vehicles (MOR-EV) program,[57] with efficiencies of up to 0.21-0.26 kWh per mile; this study opted for a more conservative average to account for potential future growth in sales of other vehicle manufacturers as more models at lower price points are made available.

HEEM Rate Design

The core functionality of HEEM is the evaluation of electric bills, heating fuel bills, and gasoline expenditure based on customer energy usage and rate and pricing information.[58] HEEM is designed to calculate electric bills under various rate designs. Rate designs are *input*s to the model, including

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[54] Appendices to the Clean Energy and Climate Plan for 2025 and 2030 (2022), https://www.mass.gov/doc/appendices-to-the-clean-energy-and-climate-plan-for-2025-and-2030/download.
[55] Zhou et al., Affordability of Household Transportation Fuel Costs by Region and Socioeconomic Factors (December 2020), https://publications.anl.gov/anlpubs/2021/01/165141.pdf.
[56] Electric Vehicle Database, https://ev-database.org/cheatsheet/energy-consumption-electric-car.
[57] MOR-EV, Statistics, https://mor-ev.org/statistics.
[58] In additional to electric rate inputs, historical 2023 gasoline, fuel oil and propane prices are used to calculate associated fuel expenses.

both existing rates and proposed future rate designs. The section **Developing Cost-Based TVR** details how this study used the 2024 AESC estimates of 2035 wholesale energy, generation capacity, and transmission prices to develop a set of "avoidable" costs to inform TVR peak-to-off-peak ratios, with rates designed to be revenue-neutral with 2024 utility revenues for ease of comparison with existing and near-term seasonal heat pump rates. Relative to today's share of delivery vs. supply costs, the embedded costs shown in the illustrative TVR designs reflects a larger share of total utility costs, as 2024 supply costs are a larger share of 2024 utility revenues compared to the estimated share of 2035 wholesale energy costs as a share of 2024 utility revenues.

Regulatory Background of TVR in Massachusetts

The Commonwealth has had a lengthy regulatory history considering TVR for residential customers. In October 2012, a DPU investigation into the modernization of the electric grid, D.P.U. 12-76 identified TVR as an important issue and concluded that it would allow customers to respond to cost-reflective dynamic electricity prices, enable customers to save money, reduce peak energy and capacity market costs, increase system efficiency and reduce peak demand, and provide appropriate incentives to DERs, demand response, and targeted energy efficiency. The DPU later recommended a dedicated investigation into TVR, leading to docket D.P.U. 14-04. After soliciting and consolidating feedback from stakeholders, the DPU stated in the D.P.U. 14-04-B Interim Order that, once AMI is deployed, basic service should transition to an opt-out TOU and CPP structure with an optional opt-in flat rate with a PTR. It also recommended that TVR should not be implemented for delivery charges because of a lack of time-varying cost causality. In support of TOU and CPP rates, the DPU stated that "in aligning retail electricity prices more closely with the hourly varying price of wholesale energy supply, TOU/CPP pricing will reduce the degree of cross subsidization that currently favors those consumers who use more energy at peak times at the expense of those who use energy more uniformly. Moreover, even if consumers do not respond to TOU/CPP pricing by shifting load from peak to off-peak hours, the majority of consumers would likely still benefit from TOU/CPP due to a reduction in the cross subsidization inherent in the current flat pricing model."[59] Following further comments, the DPU issued a Final Order, D.P.U. 14-04-C, adopting the Interim Order without any changes.[60]

Since the adoption of the 2014 TVR framework, the DPU and EDCs have made little progress on developing residential TVR options, primarily due to slow deployment of supporting customer metering and billing infrastructure required to enable TVR participation. AMI deployment in the Commonwealth was initially deprioritized in favor of grid modernization investments that could provide more certain and immediate benefits,[61] but the DPU recommitted to consideration of full-scale AMI in a 2021 order (D.P.U. 20-69) before approving EDC plans for meter rollout in 2022.[62] Outside of DPU proceedings, the 2022 Act Driving Clean Energy And Offshore Wind directed EDCs

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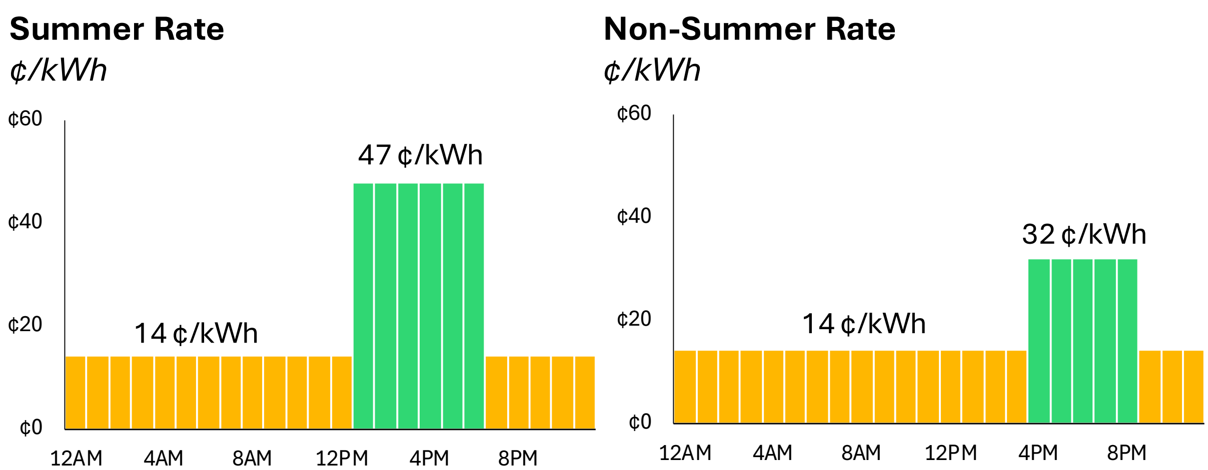
[59] D.P.U. 14-04-B Order at 9 (June 2014).
[60] D.P.U. 14-04-C Order at 3 (November 2014).
[61] D.P.U. 15-120/121/122 Interlocutory Order at 1 (May 2016).
[62] D.P.U. 21-80-B; D.P.U. 21-81-B; D.P.U. 21-82-B at 238 (November 2022).

to propose EV TOU rates to the DPU.[63] To date, only Unitil has had a residential EV TOU rate approved, with National Grid offering a managed charging program rebate instead.[64] In December 2022, the DPU approved Unitil's proposed three-part time-of-use rate (off-peak, mid-peak, and on-peak pricing), stating that "[the proposed rate] will assist in incentivizing off-peak charging and support the Commonwealth's public policy goals and the Department's grid modernization objective to optimize system demand by facilitating consumer price responsiveness".[65] However, there has been no enrollment in this rate as of May 2024, driven in part by the upfront cost barrier of installing the requisite additional AMI socket.[66] Notably, Unitil offers a whole-home TOU rate to residential customers in New Hampshire.

While the EDCs have been slow to roll out TVR options for residential customers, several Massachusetts municipal lighting plants (MLPs) that have deployed AMI now offer residential TOU rates.[67] For example, Belmont Light offers a pilot residential TOU rate as shown in Figure 19, with an off-peak rate of 14¢/kWh, a non-summer on-peak rate of 32¢/kWh from 4pm to 8pm, and a summer on-peak rate of 47¢/kWh from 1pm to 7pm. While some TOU designs target specific on- to off-peak ratios, this rate from Belmont is an example of a rate developed to be reflective of hourly avoided system costs, rather than anchoring to a target price ratio.

Figure 19: Belmont MLP Residential TOU Pilot Rate



[63] Session Laws Acts of 2022, Ch 179 Sec. 90.
[64] National Grid Off-Peak Charging Program: https://www.nationalgridus.com/electric-vehicle-hub/Programs/Massachusetts/Off-Peak-Charging-Program. As of January 2025, Eversource and Unitil are developing similar managed charging programs:
Eversource: https://www.eversource.com/content/residential/save-money-energy/clean-energy-options/electric-vehicles/ev-charger-managed-charging.
Unitil: https://unitil.com/electric-vehicles/electric-vehicle-programs-in-development.
[65] D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92 Order at 269 (December 2022).
[66] Unitil Massachusetts Electric Vehicle Program, 2023 Annual Report (May 2024).
[67] Belmont Light, Time of Use Rates, https://www.belmontlight.com/timeofuse/.