Time-of-Use Rate Proposal

Prepared for DOER's Petition for an Investigation into Time-Varying Rates

Massachusetts Department of Energy Resources

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Table of Contents

I. Overview

Massachusetts Department of Energy Resources' (DOER) *Time-of-Use (TOU) Rate Proposal (TOU Rate Proposal)* provides a framework to implement well-designed, cost-reflective time-varying rates (TVRs) for Massachusetts' households and businesses. DOER developed these recommendations through a multi-year, iterative policy process, which leveraged robust stakeholder engagement and the state energy office's expertise.

Massachusetts' current volumetric rate design obscures the primary driver of electric system costs – peak demand – resulting in inefficient consumption patterns, unnecessary infrastructure investment, and upward pressure on customer bills. TVRs are rate structures in which the price of electricity changes over time to align with system costs. TVRs offer substantial public benefits including promoting energy affordability, empowering customers with greater control over their utility bills, reducing electric system infrastructure costs, and accelerating clean energy technology deployment.

All three Massachusetts' electric distribution companies (EDCs) expect to deploy advanced metering infrastructure (AMI) (also known as "smart meters") to all customers by the end of 2027. DOER recommends implementation of **default, opt-out time-of-use (TOU) rates that vary supply, transmission, and distribution service, with a four-hour peak period of 4 – 8 PM** to provide all customers with an accurate price signal, an opportunity to maximize their savings, and broader benefits. To enable a smooth rollout of this major change in how customers understand their energy use, DOER recommends comprehensive customer protections including providing an opt-out option, shadow billing, and bill stabilization.

This *TOU Rate Proposal* includes: (1) **design and implementation recommendations**, which outline specific recommendations for how to design and implement cost-reflective TOU rates; (2) **customer experience recommendations**, which describe how to effectively roll out TOU rates to customers; and (3) **program and policy integration considerations,** which explain how TOU rates can be integrated with other ongoing rate and policy initiatives in the electric sector.

DOER submits this report to support its request for the Massachusetts Department of Public Utilities (Department) to open an investigation into TVRs. To leverage the savings and other benefits of the *TOU Rate Proposal,* the DOER asks the Department to expeditiously conduct a TOU rate investigation. Further, DOER respectfully requests that the Department aims to issue a final Order in this proceeding no later than April 2027, such that ratepayers benefit from timely implementation of TOU rates.

To facilitate the prompt development of TOU rates, DOER recommends the Department structure its investigation to proceed in a timely and efficient manner, with clear actions and decision points. First, DOER recommends the Department commence its investigation with a request for information to the EDCs, invitation to interested parties to provide comments on the *TOU Rate Proposal,* and any additional Department questions within its Vote and Order opening such an inquiry. DOER recommends specific information throughout this report that is best suited for a request for information early in this proceeding. The Department may also convene technical sessions to facilitate discussion among parties on specific issues. Following the development of the record, the Department should make key decisions regarding the design and implementation of TOU rates, such that the Department and stakeholders can continue prioritizing customer experience issues ahead of implementation and the EDCs have time to prepare compliance filings in accordance with the Department's decisions. Finally, the investigation can serve as an ongoing forum for clear implementation timelines and updates.

II. Summary of Recommendations & Considerations

This *TOU Rate Proposal* contains DOER's recommendations on TOU rates, including: (1) design and implementation recommendations, which outline specific recommendations for how to design effective TOU rates; (2) customer experience recommendations, which describe how to roll out TOU rates effectively to customers; and (3) program and policy integration recommendations, which explain how launching TOU rates should be integrated with other ongoing rate and policy initiatives in the electric sector.

Design & Implementation Recommendations

DOER recommends TOU rates for all electric customers that incorporate all relevant time-varying electricity costs, including supply, transmission, and distribution costs. Specifically, DOER recommends the Department:

- require the EDCs to implement a default TOU rate that reflects time-varying electric system costs across supply, transmission, and distribution service with a single, consolidated peak period;
- adopt an initial peak period of 4-8 PM (HE 17-20) across all three Massachusetts load zones;
- require the EDCs to jointly prepare an annual report, filed no later than March 1, that reviews and amends, if necessary, the peak period to align with changes in energy prices and usage trends;
- adopt a single, consolidated peak period across supply, distribution, and transmission;
- direct the EDCs to file empirical analyses of distribution system peak demand that assesses the coincidence with ISO-NE system peaks to inform distribution rate design;
- direct the EDCs to provide default TOU to all basic service customers as soon as practicable;
- determine the appropriate approach for the EDCs to solicit supplier bids between two alternatives: (1) uniform pricing that the EDCs would use to calculate TOU pricing for basic service customers or (2) separate on-peak and off-peak pricing;
- direct the EDCs to file proposed tariff revisions and updated provision practices to implement default TOU basic service rates to all customers as soon as practicable, and no later than August 1, 2028;
- expeditiously conduct its investigation into load settlement, D.P.U. 26-44, as it is an integral part of suppliers' success with time-varying supply products;
- direct the EDCs to file proposed revenue-neutral, TOU transmission rates for any non-demand customers on or before June 18, 2027, for rates effective no later than May 1, 2028;
- direct the EDCs to allocate transmission costs through a common approach to its recommended peak period of 4-8 PM in all months, with higher transmission rates during the peak season;

- direct the EDCs to propose distribution rates informed by a marginal cost of service study and TOU analysis in their next base distribution rate case; and
- provide the EDCs guidance on marginal cost study requirements during this investigation.

Customer Experience Recommendations

DOER recommends the Department adopt a coordinated and deliberate plan in this investigation to ensure efficient and effective path toward offering all customers TOU rates. Specifically, DOER recommends the Department:

- direct the EDCs to implement default TOU rates for customers while allowing all customers to opt-out;
- investigate and adopt critical bill protections, such as opt-out capability for customers, shadow billing, and bill stabilization measures, to mitigate unanticipated or unintended consequences of transitioning customers to a TOU rate; and
- require the EDCs to submit regular (e.g., quarterly) progress reports through enrollment of all residential customers.

To support an expeditious investigation, DOER recommends the Department issue a request for information to the EDCs in the order opening this inquiry. Specifically, DOER recommends the Department direct the EDCs to:

- conduct load research based on available AMI data ahead of TOU rollout to support more granular and distributional bill impact analyses and report on the findings at a technical session;
- jointly prepare a customer transition plan for Department review and stakeholder input during the course of the investigation;
- develop a joint marketing, education, and outreach (MEO) plan for Department review and stakeholder input during the course of the investigation; and
- direct the EDCs to coordinate with stakeholders early in the investigation to develop implementation and MEO plans.

Program and Policy Integration Considerations

TOU rates do not operate independent of existing rates and programs designed to deliver policy objectives and customer benefits, and with careful planning and coordination can be complementary. DOER has contemplated the impacts of TOU rates on low-income discount rates, heat pump rates, public benefits fixed charges, load management and demand response programs, net energy metering and portfolio standards and discusses each below.

III. Introduction

Massachusetts' households and businesses face energy affordability concerns daily. To address this crisis, the Healey-Driscoll Administration launched an Energy Affordability Agenda, which included Administration actions, including several by the Department, in addition to filing *An Act Relative to Energy Affordability, Independence and Innovation,*[1] and signing Executive Order No. 654: To Secure Massachusetts' Energy Future by Establishing an Energy Supply Plan that Drives Affordability and Reliability.[2] Specifically, E.O. 654 directs the Department to expedite the review of proposals that can unlock the benefits of time-of-use electricity rates, distributed energy resources, energy efficiency, and virtual power plants and direct the EDCs to expeditiously implement all approved measures.[3] These efforts exemplify the state's short- and long-term approach to reducing energy costs and cost-effectively advancing decarbonization efforts. Electric rate design reform is an available untapped, yet significant, tool to support an affordable and reliable energy system. Well-designed rates can empower customers to reduce their electric bills and reduce long-term costs for all customers. Notably, the Department took recent steps to advance rate designs that promote affordability, including implementation of heat pump rates and adoption of a statewide low-income discount rate framework.[4] To drive further progress, DOER submits a petition requesting the Department investigate TVRs and adopt the recommendations in this report.

DOER, as the state energy office, is the Commonwealth's primary energy policy agency. DOER's mission is to create a clean, affordable, resilient, and equitable energy future for all in the Commonwealth and focuses on transitioning our energy supply to increase cost savings and lower emissions, reducing and shaping energy demand, and improving our energy system infrastructure. To meet these objectives, DOER connects and collaborates with energy stakeholders to develop effective policies, provides tools to individuals, organizations, and communities to support clean energy goals, and supports transparent and accessible education to energy information.

On April 30, 2025, DOER convened the Massachusetts Electric Rate Task Force (Rate Task Force) to facilitate informed and forward-looking dialogue on electric rate design and

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[1] *Governor Healey's Energy Affordable Agenda* (Mar. 3, 2025), available at: https://www.mass.gov/info-details/governor-healeys-energy-affordability-agenda; *House Bill No. 4144* (May 13, 2025), available at: https://www.mass.gov/doc/2025-energy-affordability-independence-and-innovation-act-filing-letter-and-bill-text/download.

[2] Executive Order 654 (E.O. 654), available at: https://www.mass.gov/executive-orders/no-654-to-secure-massachusetts-energy-future-by-establishing-an-energy-supply-plan-that-drives-affordability-and-reliability.

[3] E.O. 654, s. 3(g).

[4] Department, *All Electric Utility Customers Will Soon Be Eligible for Heat Pump Discount Rates* (Jul. 29, 2025), available at: https://www.mass.gov/news/all-electric-utility-customers-will-soon-be-eligible-for-heat-pump-discount-rates; *Notice of Inquiry by the Department of Public Utilities on its own Motion into Energy Burden with a Focus on Energy Affordability for Residential Ratepayers*, D.P.U. 24-15-B, Phase I Order on Tiered Discount Rates (Feb. 17, 2026).

regulatory mechanisms to advance the Commonwealth's affordability and decarbonization goals.[5] Over eight months, the Rate Task Force further explored the Massachusetts Interagency Rates Working Group's (IRWG) *Long-Term Ratemaking Recommendations (Long-Term Recommendations),* which identified ratemaking opportunities to improve affordability by mitigating unnecessary investment in the electric power system and to cost-effectively achieve Massachusetts' greenhouse gas (GHG) emission reduction mandates.[6]

The IRWG identified that existing electric rates inhibit near- and long-term affordability for Massachusetts' households and businesses (collectively, customers).[7] The Commonwealth's EDCs[8] are deploying AMI for customers, which creates new opportunities to implement well-designed, cost-reflective electric rates, such as TOU rates. These rates can: (1) promote greater fairness and equity by ensuring customers pay their fair share of electric system costs; (2) empower customers to consume electricity in ways that reduce the need for investments in energy infrastructure, thereby avoiding significant ratepayer costs; and (3) increase the reliability of our shared electric grid through demand-side resources.

DOER submits the *TOU Rate Proposal* to support its petition requesting the Department open an investigation into TVR and intends these recommendations to serve as a foundation for that inquiry.[9] Herein, DOER presents a path for the Commonwealth to advance cost-reflective TVR, including design, implementation, customer experience, and program and policy integration recommendations.

DOER has incorporated stakeholder feedback throughout, including from Rate Task Force stakeholder sessions and written comments submitted in response to DOER's *Ratemaking Straw Proposal* presented to the Rate Task Force on November 24, 2025.[10] Nevertheless, DOER does not represent these recommendations as settled or consensus positions of Rate

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[5] For additional detail on the Rate Task Force process, see: Exhibit B: *Stakeholder Process & Engagement Report* (Mar. 2026).

[6] IRWG, *Long-Term Ratemaking Recommendations: Accompanying Recommendations to Long-Term Ratemaking Study* (Mar. 2025), available at: https://www.mass.gov/doc/irwg-long-term-ratemaking-recommendations/download; Energy and Environmental Economics, Inc., *Long-Term Ratemaking for a Decarbonizing Commonwealth (Mar. 2025) (Long-Term Ratemaking Study)*, available at: https://www.mass.gov/doc/irwg-long-term-ratemaking-study/download.

[7] *Long-Term Recommendations* at 8-9. For the purposes of this report, customers and ratepayers are used interchangeably. Further, this report is focused on EDC customers, though its recommendations may also be relevant to MLPs.

[8] NSTAR Electric Company d/b/d Eversource Energy (Eversource), Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid (National Grid), and Fitchburg Gas and Electric Light Company d/b/d Unitil (Unitil).

[9] *Investigation by the Department of Public Utilities on Its Own Motion into Gas and Electric Delivery Charges and Bill Redesign*, D.P.U. 25-200, Vote and Order Opening Inquiry at 23 (Dec. 15, 2025).

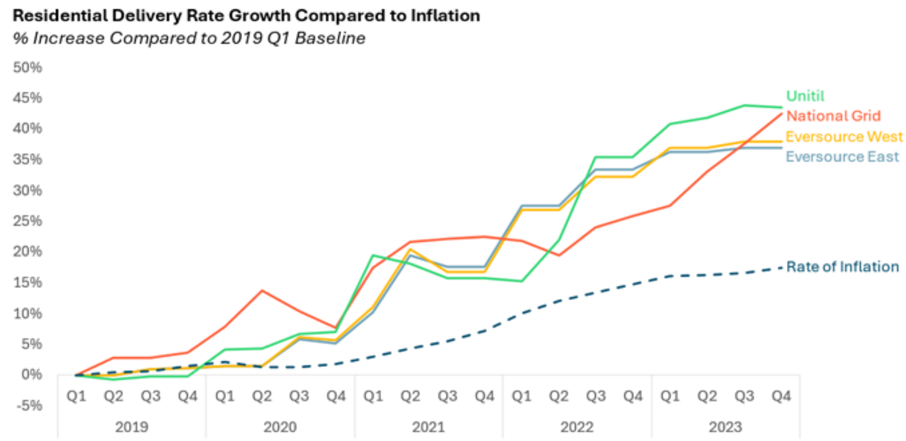
[10] DOER, *Ratemaking Straw Proposal* (Nov. 24, 2025), available at: https://www.mass.gov/doc/rate-task-force-ratemaking-straw-proposal/download. DOER also published stakeholder comments in response to the *Ratemaking Straw Proposal*, available at: https://www.mass.gov/doc/ratemaking-straw-proposal-comments/download.

Task Force participants.[11] DOER's recommendations do, however, reflect the outcome of a multi-year, iterative policy-development process, which leveraged robust stakeholder engagement as well as the state energy office's expertise. DOER, with stakeholder encouragement, requests the Department investigation focus on TVR, and specifically on implementing TOU rates in the years ahead.

IV. Modernizing Rate Design

For the past decade, electric rates have outpaced inflation, increasing energy burdens for electric customers.[12] Moderate- and low-income customers are hit the hardest, with low-income households spending nearly 25% of their income on energy bills and moderate-income households spending almost 10%.[13]

Figure 1: EDC Delivery Rate Growth for Residential Customers, 2019-2023[14]



Presently, retail electric rates do not provide the proper price signal to minimize electric system costs because they are misaligned with the cost drivers of the electric system, mainly peak demand.[15] Current rates do not reflect the time-varying cost of different services related to consuming electricity – i.e., supply, transmission, and distribution. The key consequence of

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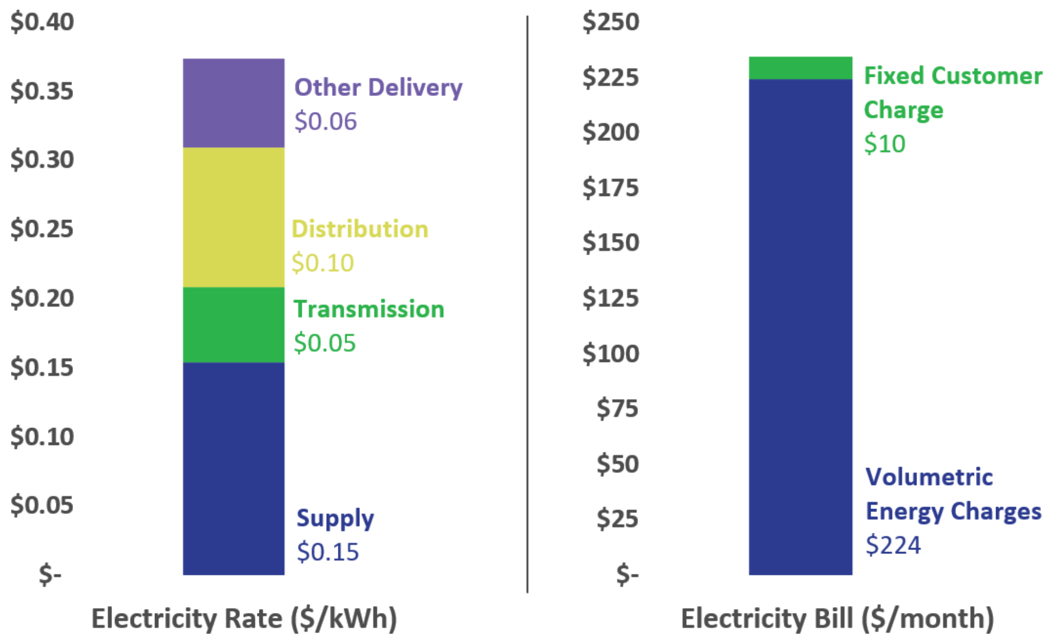
[11] *Stakeholder Process & Engagement Report*, Appendix includes a list of Rate Task Force participants, including expert presenters.
[12] DOER, *Massachusetts Electric Rate Task Force Kick-off Meeting* at 5 (Apr. 30, 2025), available at: https://www.mass.gov/doc/rate-task-force-phase-1-kick-off/download; DOER, Alternative Rate Design Expert Presentation Series at 2 (Jun. 9, 2025), available at: https://www.mass.gov/doc/topic-2-alternative-rate-designs-expert-presentations/download.
[13] DPU, *Energy Burden Inquiry*, available at: https://www.mass.gov/info-details/energy-burden-inquiry.
[14] *Long-Term Recommendations* at 10; see also, DOER, *Massachusetts Electric Rate Task Force Kick-Off Meeting* at 5 (Apr. 30, 2025), available at: https://www.mass.gov/doc/rate-task-force-phase-1-kick-off/download.
[15] While the cost drivers of different levels of the electric power system are unique (*i.e.,* generation, transmission, and distribution), additional investments are largely driven by system peak demand and localized grid constraints. See *Long-Term Recommendations* at 8-9.

this misalignment is higher peak demand, otherwise unnecessary or premature investments in new grid infrastructure, and ultimately, upward pressure on customers' rates and bills.[16]

Figure 2 shows the major components of National Grid's residential electric rate on the left, totaling $0.37384 per kilowatt-hour (kWh). On the right, the example customer bill of $234 is based on usage of 600 kWh, which demonstrates residential customers' bills are largely determined by the volume of kWh consumed in a given month.

Figure 2: Illustrative Residential Electric Rate and Customer Bill[17]



[16] *Long-Term Recommendations* at 9.
[17] Based on National Grid's delivery and Basic Service rates effective, March 1, 2026. The distribution rate reflects National Grid's net distribution rate. National Grid's base distribution charge is $0.06677/kWh. which reflects the recovery of annual revenue requirement approved in accordance with the Department's Order from National Grid's most recent base distribution rate case. The difference reflects several reconciling mechanisms incorporated into the distribution charge presented on customers' bills. Available at: https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/meco_delivery.pdf and https://www.nationalgridus.com/media/pdfs/billing-payments/electric-rates/ma/resitable.pdf.

Peak demand, or those hours when electricity demand is highest, drives incremental costs because the electric system must be built to meet demand at all times. Most Massachusetts customers' electric bills are determined by volumetric, energy charges ($/kWh) that are uniform throughout the day, failing to reflect the varying cost of electricity. Uniform, volumetric electric rates do not incentivize customers to reduce consumption during peak hours (i.e., peak shaving) or shift their consumption to lower cost, off-peak hours (i.e., load shifting). As a result, expensive new grid infrastructure is needed to maintain a reliable system.[18]

This misalignment between retail rates and cost causation has several material consequences:

- **inefficient consumption patterns:** customers lack actionable price signals to reduce or shift usage during peak periods, when the marginal cost of electricity is highest;
- **excessive infrastructure investment:** elevated and unmanaged peak demand necessitates investment in generation, transmission, and distribution infrastructure that could otherwise be avoided or deferred;
- **upward pressure on rates and bills:** these investments increase the revenue requirements of EDCs and, in turn, customer rates and bills; and
- **cross-subsidization among customers:** customers with flatter or more flexible load profiles subsidize those with more pronounced peak usage, contrary to principles of fairness and cost causation

These inefficiencies are expected to intensify as Massachusetts works towards widespread electrification to meet its GHG emissions limits.[19] Widespread electrification will require substantial buildings and transportation electrification, renewable and clean energy generation deployment, and electric grid infrastructure upgrades. Without rate design reform, unmanaged load growth driven by electrification has the potential to increase customers' electric bills, undermining the Commonwealth's affordability goals and further inhibiting adoption of efficient electrification technologies like heat pumps and electric vehicles (EVs).[20] The regional electric grid operator, ISO New England (ISO-NE), forecasts steady growth in annual energy use and higher peak electricity demand over the next decade due to electrification.[21] To ensure widespread electrification remains cost-effective and does

[18] *Long-Term Recommendations* at 8-9.
[19] G.L. c. 21N, § 3; EEA, *Massachusetts Clean Energy and Climate Plan for 2025 and 2030* (Jun. 30, 2022), available at: https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030; and EEA, the *Massachusetts Clean Energy and Climate Plan for 2050* (Dec. 2022), available at: https://www.mass.gov/infodetails/massachusetts-clean-energy-and-climate-plan-for-2050.
[20] See, e.g., ISO New England, *2050 Transmission Study* (Feb. 12, 2024), available at: https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf.
[21] Cakert, Dennis. *ISO New England Overview & Considerations for Rate Design* at 6-7 (May 19, 2025), available at: https://www.mass.gov/doc/topic-1-time-of-use-rate-design-expert-

not just benefit customers making the transition, new paradigms for customer energy consumption will be necessary.

Load management policies and technologies, with TVR as a central incentive, have the potential to reduce peak demand by 4.5 gigawatts (GW) in 2030 and 13.8 GW in 2050, saving customers nearly $1 billion per year and nearly $5 billion per year, respectively.[22] Load management, and peak demand reduction in particular, can be enabled through rate design and targeted programs to different effect.[23] Efficient rate designs can be complemented by targeted programs to address more granular challenges, such as localized grid constraints. The Commonwealth must manage loads through a combination of efficient rate design and targeted programs to mitigate incremental electric system costs associated with electrification and decarbonization.[24] The design and implementation of these strategies must enable ISO-NE and the EDCs to integrate peak demand reduction and load management expectations in their forecasting and capital planning.[25]

Conversely, electric rates that reflect the costs of generating and delivering electricity, which vary throughout the day, can promote peak shaving and load shifting to avoid or defer infrastructure investments.[26] Well-designed time-varying rates (TVRs), such as time-of-use (TOU) rates, provide customers with a price signal that encourages valuable demand flexibility, including peak load management that can improve grid reliability and help consumers reduce wholesale costs.[27] TOU rates advance the Department's statutory and policy objectives through:

- **economic efficiency:** promoting consumption decisions that reflect the marginal cost of service, reducing inefficient overconsumption during peak periods and improving utilization of existing infrastructure;
- **cost containment:** incentivizing peak load reduction and shifting, thereby mitigating the need for incremental investments in generation, transmission, and distribution infrastructure and associated long-term system costs;
- **customer empowerment and affordability:** providing meaningful opportunities to manage electricity bills by adjusting timing of their usage;

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presentations/download; Black, Jon, *2026 Draft Energy and Seasonal Peak Forecasts* (Feb. 20, 2026), available at: https://www.iso-ne.com/static-assets/documents/100032/energy_demand_fx2026_draft_final.pdf. ISO-NE presented draft results at the February 20, 2026, Load Forecast Committee meeting and expects to publish the 2026 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report) on May 1, 2026.

[22] DOER, *Peak Potential: Reducing Energy Cost and Empowering Customers with Load Management and Virtual Power Plants* (Dec. 2025)(Draft) at 1-5, available at: https://www.mass.gov/doc/doer-peak-potential-report-and-policy-recommendations/download.

[23] *Long-Term Recommendations* at 12, n. 13.

[24] EDC Comments for IRWG Long-Term Recommendations at 1. (Nov. 15, 2024)

[25] *Long-Term Recommendations* at 15.

[26] *Long-Term Recommendations* at 7.

[27] Cakert, Dennis. *ISO New England Overview & Considerations for Rate Design* at 8.

- **equity and fairness:** reflecting cost causation, which reduces cross-subsidization among customers and better aligns cost responsibility with system impacts; and
- **system reliability and decarbonization:** reducing peak demand and facilitating integration of renewable and distributed energy resources.

As the region further decarbonizes electricity supply, TVRs that promote load shifting will become more valuable.[28] Ultimately, TVR will enable customers to lower their utility bills by managing the timing and volume of their electricity usage, and balances cost-reflectivity with simplicity, providing all customers with the opportunity to participate and benefit.

Rate Design Principles

The Department has extensive ratemaking authority over the EDCs, including broad and substantial authority to design and set rates.[29] The Department is required to "prioritize safety, security, reliability of service, affordability, equity and reductions in greenhouse gas emissions."[30]

The Department defines rate structure as the level and pattern of prices charged to each customer class for its use of utility service.[31] The pattern of prices in rate structures is a function of rate design and should, to the extent possible, meet the Department's rate structure goals summarized in **Table 1**.[32]

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[28] *Id.*
[29] G.L. c. 164, §§ 76, 94; D.P.U. 25-200, Vote and Order Opening Inquiry at 8.
[30] G.L. c. 25, § 1A.
[31] *Investigation by the Department on its own motion as to the propriety of the rates and charges contained in [various] Schedules . . ., filed with the Department by Fitchburg Gas and Electric Light Company on July 16, 1984, to become effective August 1, 1984*, D.P.U. 84-145-A, Order at 59 (Jan. 31, 1985).
[32] *Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service, a Performance-Based Ratemaking Plan, and a Capital Recovery Mechanism*, D.P.U. 23-150, Order at 476-477.

Table 1. Department Rate Structure Goal

Goal	Definition
Efficiency	Rates should reflect the cost of providing service and provide an accurate basis for customers' decisions about the lowest-cost method of fulfilling consumers' needs at lowest-cost for society as a whole
Simplicity	Rates should be easily understandable, enabling customers to make appropriate decisions about use
Continuity	Rate changes should be made in predictable and gradual manner, allowing customers reasonable time to adjust consumption patterns
Equity	Rate structures should consider affordability among customers in establishing rate classes
Fairness	Rates should not require customer classes to pay more than the costs of serving that class, unless justified for clearly articulated reasons and explicit Department decision
Earnings Stability	Rates should provide stable utility earnings that will not vary significantly with normal fluctuations in demand

The IRWG and the Rate Task Force considered the Department's rate structure goals throughout their efforts.[33] Furthermore, this *TOU Rate Proposal* addresses the Department's rate structure goals as they pertain to TOU rates, especially those of efficiency, simplicity, and fairness. TOU rate structures can provide more efficient, cost-reflective signals, remain easily understood by customers, and promote a more fair and equitable recovery of system costs.

Time-Varying Rates

Time-varying rates (TVR) are pricing structures in which the price of electricity changes over time to align with system costs. The Department concluded that TVR would: (1) allow customers to respond to the actual varying costs of electricity; (2) enable individual customers to save money by altering usage; (3) benefit all customers by reducing peak energy and capacity market costs; (4) increase system efficiency and support the distribution system by reducing peak demand; and (5) provide appropriate incentives to DER and other demand resources.[34]

The purpose of TVR is to send economically efficient price signals so customers can shift usage, manage bills, and help reduce total system costs. **Table 2** includes several TVR benefits of TVR. Further, TVR supports the Department's grid modernization objective to optimize system demand by facilitating consumer price responsiveness.[35]

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[33] DOER, *Massachusetts Electric Rate Task Force Kick-off Meeting* (Apr. 30, 2025) at 7, available at: https://www.mass.gov/doc/rate-task-force-phase-1-kick-off/download; DOER, *Ratemaking Straw Proposal* (Nov. 24, 2025) at 4, 7, 11-12, available at: https://www.mass.gov/doc/rate-task-force-ratemaking-straw-proposal/download; IRWG, Long-Term Recommendations at 7, Figure 2.

[34] *Investigation by the Department of Public Utilities on its own Motion into Time-Varying Rates*, D.P.U. 14-04, Order Opening Investigation (Jan. 23, 2014) at 1.

[35] *Petition of [the EDCs] for Approval by the Department of Public Utilities of its Grid Modernization Plan*, D.P.U. 15-120/15-121/15-122, Order at 101-102.

Table 2. TVR Benefits

Benefit	Details
Customer Savings	Customers can lower bills by shifting electricity usage to off-peak periods. Consumption during off-peak periods reduces the need for infrastructure upgrades, lowering the overall cost of the electric system, which is passed onto customers.
Fair Cost	Cost-reflective TVR charges customers according to the actual costs they incur to the system, reducing the potential for customers over- or under-paying.
Grid Reliability	Reducing demand during peak periods helps prevent grid overload and reduces the need for infrastructure upgrades.
Environmental Benefits	Shifting electricity usage to off-peak periods reduces carbon emissions.

There are several types of TVRs, such as time-of-use (TOU) rates, peak-period demand charges, critical peak pricing (CPP), and real-time pricing (RTP, or "dynamic rates"). Each option presents a tradeoff between complexity and opportunity for economic load response.[36] 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 decision- making, but they also provide less opportunity for loads to respond to system conditions. On the other end of the spectrum, dynamic rates have greater complexity but provide greater opportunity for loads to respond to system conditions, more precisely aligning customer and system costs.[37]

Time-of-use (TOU) is a form of TVR in which customers pay a different price for electricity during different periods of the day and potentially by season. Managing a transition from uniform rates to the suite of TVR options is an exercise in balancing core rate design principles, including cost-reflectivity, price stability, and predictability.

DOER finds that default TOU rates, paired with customer protections and marketing, education, and outreach (MEO), balances cost-reflectivity and customer experience. TOU rates align price signals with predictable system conditions - for example, the annual peak system demand that drives transmission and capacity costs reliably occurs in the summer during late afternoon/early evening. TOU rates also provide customers with a predictable price signal that they can plan around to manage electric bills, because customers know in advance what they will pay during defined peak and off-peak periods. In addition, TOU rates support electrification by rewarding customers who charge vehicles, pre-cool or pre-heat homes, and operate flexible technologies during lower-cost hours.

TOU rates encourage shifting consumption from peak to off-peak hours by offering lower rates in predefined, off-peak 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

[36] *Long-Term Ratemaking Study,* at 22, Figure 4.
[37] *Long-Term Recommendations* at 21-22

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.[38]

Other forms of TVR can complement TOU rates. For example, real-time pricing and critical peak pricing, which can be layered on top of TOU rates, follow system conditions to maximize cost-reflectivity, delivering additional system benefits and cost savings opportunities. Such rates are well suited for customers who are comfortable with dynamic pricing and have flexible, automated technologies. But for most households and businesses, TOU rates are an incremental change to current rates that introduce the concept that costs vary with time. Implementing TOU rates will pave the way for more efficient future rate designs and opportunities for more savings.

Current Electric Rates

The EDCs provide delivery service to customers with similar electricity usage patterns and service characteristics (i.e., customer classes) and design rates for each customer, or rate class.[39] Generally, customer classes include residential, small commercial and industrial (C&I), medium and large C&I, and street lighting customers. Each customer class may include several rate classes, each with distinct terms, conditions, and pricing for service. For example, Eversource offers six residential rate classes for standard residential customers, residential heat pump customers, and residential space heating customers – each with a residential assistance rate (e.g., R-1, R-1HP, R-2, R-2HP, R-3, and R-4). The EDCs also offer alternative rates approved from time to time, including demand charge alternative rates, Unitil's residential EV charging rate, and heat pump rates - to support specific technologies or policy goals.

Massachusetts EDCs currently offer TVRs to certain ratepayers, including time-varied energy and demand charges. The Appendix summarizes existing TVRs for both the EDCs and Municipal Light Plants (MLPs), including details regarding peak period definition, seasonality, and demand charges, as applicable. In general, these TVRs are available to general service, or commercial and industrial customers, with a number of legacy rate offerings closed to future customers. The peak period definitions vary, but the peak period typically captures most day-time hours (e.g., 12-8 PM, 8 AM - 9 PM, and 10 AM - 10 PM). Eversource's optional time-of-use (T-1) rate, now closed to further enrollment, is the only TVR offered by the EDCs

[38] *Long-Term Recommendations* at 8.

[39] *Investigation by the Department on its own motion as to the propriety of the rates and charges contained in [various] Schedules . . ., filed with the Department by Fitchburg Gas and Electric Light Company on July 16, 1984, to become effective August 1, 1984*, D.P.U. 84-145-A, Order at 124 (Jan. 31, 1985). The Department considers two factors, voltage level and load pattern, in determining whether a separate class is necessary.

that accounts for seasonality, charging customers a higher energy rate during the summer peak period (i.e., June to September).[40]

Unitil offers a TOU rate applicable to a separate charging meter for EVs (EV-RES), which is limited to residential customers who require EV charging service. This rate varies supply, transmission, and distribution charges by peak, mid-peak, and off-peak.[41] The peak period is significantly shorter than the peak period of the other TVRs, defined as 3-8 PM for non-holiday weekdays. The mid-peak captures early morning and afternoon hours, defined as 6 AM - 3 PM for non-holiday weekdays while the off-peak is defined as all other days/hours.

Decades ago, the Department found that optional TOU rates, like those referenced above, would be useful in providing the EDCs with requisite experience in TOU pricing based on marginal costs.[42] Indeed, the EDCs now have significant experience with time-varied pricing to inform the wide-spread implementation of TOU as contemplated by the recommendations herein.

At least four MLPs have deployed AMI to their customers and now offer TOU rates to residential customers, further elucidating the possibilities and opportunities for TVR in Massachusetts. Peak period periods still vary, but the MLP's peak period definitions are generally narrower than the existing EDC peak periods, including peak windows of 3-7 PM, 4-8 PM, 2-7 PM, and 12-7 PM. Three of the four TOU rates also account for seasonality. Concord Municipal Light Plant is the most recent MLP to offer its residential customers a new time-of-day (TOD) electric rate.[43] Distinct from the other three TOU rate offerings included in the Appendi**,** Concord MLP's TOD rate is a default, opt-out rate for all residential (R-1) rate customers. These customers will automatically transition to the TOD rate on April 1, 2026, unless a customer completes an opt-out form. These residential TOU rates can be instructive for the EDCs in implementing TOU rates.

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[40] NSTAR Electric Company d/b/a Eversource Energy, *Eastern Massachusetts Greater Boston Service Area Optional Time of Use (Rate T-1),* M.D.P.U. No. 14H, available at: https://www.eversource.com/docs/default-source/rates-tariffs/ma-electric/14-tariff-ma.pdf?sfvrsn=a8763b5f_5. All EDCs, however, offer heat pump rates to residential customers with seasonally-differentiated delivery charges, defining summer as May to October and winter as November to April.
[41] Fitchburg Gas and Electric Light Company, *Residential Electric Vehicle Service (Rate EV-RES)*, M.D.P.U. No. 460, available at: https://unitil.com/sites/default/files/2024-07/e_MA-ev-res.pdf.
[42] D.P.U. 84-145-A, Order at 131.
[43] TOU and TOD are used interchangeably. Concord MLP concluded that TOD would improve customer understanding and acceptability. Additional information available at: https://concordma.gov/4060/Time-of-Day-Electric-Rates

AMI Investment, Deployment, and Billing System Readiness

In 2022, the Department approved the EDCs' AMI Implementation Plans and pre-authorized $1.1 billion investment.[44] It remains critical that ratepayers promptly realize the full benefits of these significant investments, including the availability of TVRs.[45] Unitil completed AMI deployment in 2025 and National Grid and Eversource expect to complete installation by the end of 2027.[46] All three EDCs will also need to upgrade billing systems to begin offering TVR.[47]

Recommendation: *To support an expedient inquiry, the Department should direct the EDCs to file a report outlining all necessary actions an EDC must take before it can enroll customers in a TOU rate.*

The report should contain, at a minimum, the following information: (1) status of AMI deployment, including AMI meters and all associated processes and functionalities (e.g., customer information systems, meter data management systems, etc.); (2) a schedule for implementation of TOU rates to customers based on DOER's recommendations; (3) identification of any additional changes to AMI functionalities or billing systems to implement TOU rates based on DOER's recommendations; and (4) a description of costs to implement TOU rates based on DOER's recommendations. This report should also delineate all associated costs and anticipated timelines to implement TOU rates, including for basic service, competitive suppliers, transmission, and distribution rates.

The EDCs have indicated that they need approximately 12 months following the Department's approval to begin offering TOU rates to customers.[48] This window underscores the importance of a prompt Department decision such that customers have TOU rates available to them. DOER understands that, during this period, the EDCs will update their customer information system (CIS), which manages customer accounts, billing, and rate

[44] The Department approved approximately $668 million for Eversource, $487 million for National Grid, and $14 million for Unitil. D.P.U. 21-80-B/81-B/82-B, Order on New Technologies and Advanced Metering Infrastructure Proposals at 238, 258, 277 (Nov. 30, 2022).
[45] *Petition of [the EDCs] for approval of its Grid Modernization Plan for calendar years 2022 to 2025*, D.P.U. 21-80-B/81-B/82-B, Order on New Technologies and Advanced Metering Infrastructure Proposals at 197 (Nov. 30, 2022).
[46] National Grid, *TVR Implementation Considerations* at 3 (Jul. 21, 2025); Eversource, *Eversource MA AMI Implementation* at 3 (Jul. 21, 2025); and Unitil, *Unitil AMI Deployment Update* at 1 (Jul. 21, 2025), available at: https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download.
[47] *Id.*
[48] National Grid, *TVR Implementation Considerations* at 9 (Jul. 21, 2025); Eversource, *Eversource MA AMI Implementation* at 3 (Jul. 21, 2025); and Unitil, *Unitil AMI Deployment Update* at 4 (Jul. 21, 2025), available at: https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download.

allocations, and meter data management systems (MDMS), which collect, validate, and process interval data from AMI meters, before conducting further testing.[49] Finally, the Department plans to resolve load settlement issues necessary to allow suppliers to offer time-varying supply products.[50]

V. Design & Implementation Recommendations

This section recommends providing customers with cost-reflective, simple, and easy-to-follow price signals through fair electric rates that will support beneficial load-management.[51]

> ***Recommendation:*** *The Department should require the EDCs to implement a default TOU rate that reflects time-varying electric system costs across supply, transmission, and distribution service with a single, consolidated peak period.*

First, DOER outlines its approach to identify a peak period that considers long- and short-run system costs, based on available Massachusetts' load and price data between 2011 and 2025.[52] A consolidated peak period that aligns across the different electric service components (i.e., supply, transmission, and distribution) exemplifies the trade-off between cost-reflectivity and simplicity inherent in rate design. Further, DOER discusses peak period length and peak to off-peak price ratio.

Next, DOER reviews cost drivers of different electric service components, including wholesale energy and capacity costs, transmission system costs, and distribution system costs. Finally, DOER explains that rate design will need to be responsive to evolving system and customer needs, requiring ongoing analysis of this nature.

Given Massachusetts' restructured retail electricity market and unbundled electric rates, DOER identifies unique considerations in evaluating how such costs may be appropriately

[49] *Id.*

[50] *Investigation by the Department of Public Utilities on Its Own Motion Into the Use of Interval Data Collected by Advanced Metering Infrastructure to Settle Load with ISO New England Inc.*, D.P.U. 26-44, Vote and Order Opening Investigation (Mar. 12, 2026).

[51] DOER's recommendations in this section are generally consistent with the IRWG's previous recommendations as further detailed in *Long-Term Recommendations* at 12-22.

[52] Exhibit C: Massachusetts Energy Load & Price Analysis. DOER aggregated ISO-NE's annual SMD hourly data files for Massachusetts load zones in the past 15 years. Available at: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info.

reflected in a TOU rate.[53] DOER further recognizes that for some customers greater cost-reflectivity and complexity in rates will be advantageous and desirable. Competitive suppliers, through municipal aggregation or individually, should be able to offer these options to customers on an opt-in basis.

Peak Period

The peak period must reflect the hours when the electric system is most stressed and energy is most expensive. The IRWG identified key principles for evaluating peak periods.[54] First, peak periods should reflect actual peak period system costs, such that TOU rates provide clear and compelling price signals to encourage customers to shift their demand and therefore reduce further grid infrastructure investments. Second, peak periods should be sufficiently narrow to capture the most critical hours for reducing demand and make it easier for customers to most effectively shift their consumption. Third, where possible, peak periods should be consistent across EDCs to minimize customer confusion.

A single, consolidated peak period across supply, transmission, and distribution can result in a significant price signal that can drive customers to adjust the volume and timing of their energy usage. As customers reduce their usage and shift it to periods of lower cost, overall system costs will decrease as well as customers' bills.[55]

A well-designed peak period will holistically consider all cost drivers and capture the hours that consistently drive **long-run marginal costs** (i.e., long-term system costs) and **short-run marginal costs** (i.e., high wholesale energy prices).[56] The hours that drive long- and short-run electric system costs are not randomly distributed. DOER identified patterns in electricity consumption by analyzing recent years.

Long-Run Marginal Costs

In the long-run, efficient price signals promote energy consumption patterns that defer or avoid electric system capacity and delivery infrastructure driven by demand growth.[57] Electricity consumption during peak load hours (i.e., peak demand) necessitates investments and system upgrades to expand generation, transmission, and distribution capacity.[58] To limit cost growth for all ratepayers, a peak period should aim to capture the hours most likely to

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[53] *Investigation by the Department of Public Utilities on its Own Motion into Electric Industry Restructuring,* D.P.U. 95-30, Order at 38-39, 129 (Aug. 15, 1995). The Department ordered electric utilities to separate, or unbundle, distinct products and services and identify unique rates for each. Consequently, ratepayers were provided with price signals that enabled the purchase and sale of electricity-related services in a more transparent and comparable manner through the transition to increased competition.
[54] *Long-Term Recommendations* at 20-21.
[55] *Long-Term Recommendations* at 15-16.
[56] *See, e.g.,* Kahn, Alfred, *The Economics of Regulation: Principles and Institutions.* The MIT Press, Cambridge, MA (Second Printing, 1989).
[57] *Long-Term Ratemaking Study* at 16.
[58] *Id.* at 18; *Long-Term Recommendations* at 15.

coincide with system peak demand, such that customers are incentivized to reduce or manage load during those hours by reducing or shifting electricity demand through behavior and technologies.

To determine when the system is consistently under the most stress, DOER conducted a peak probability analysis that estimates the likelihood that any given hour contributes to system peak in each of Massachusetts' three wholesale load zones: Northeast Massachusetts and Boston (NEMA), Southeast Massachusetts (SEMA), and West/Central Massachusetts (WCMA).[59] This provides a probabilistic assessment of which hours are likely to drive long-run system costs and avoids overemphasizing the specific hours in which peak demand has historically occurred. DOER submits Exhibit C for the Department and other interested stakeholders to better understand DOER's recommended peak period and to test alternatives in this investigation.[60] DOER considered various sensitivities with different ranges but believes that more recent years more reasonably reflect current load dynamics.

Figure 3 provides a heat map of the probability that an hour in a given month (e.g., July 4-5 PM) contributes to system peak, defined as the top 50 real-time load hours for all load zones from 2023-2025. Based on the heat map, the highest probability of hours coinciding with annual peak are concentrated in summer (i.e., June through September) and between 2-7 PM (HE 15-19) in NEMA and 3-8 PM (HE 16-20) in SEMA and WCMA.

For clarity, the heat maps presented in this report do not identify the underlying data; the percentages in Exhibit C do not reflect the frequency of the load hour as a share of total observed peaks. Instead, it approximates the expected probability of the hour coinciding with system peak. For example, in NEMA 22% of all July 4-5 PM (HE 17) hours in this period were in top 50 hours of annual load.[61]

[59] Exhibit C.

[60] Exhibit C includes 15 years of data to test different ranges and identify trends over time. DOER drew from expert methods presented on or included in comments to the Rates Task Force. We note that more sophisticated analyses, such as logistic regression models, can be used to refine peak period selection. We prepared this simpler probability analysis in an Excel workbook for greater understanding and transparency during the Department's investigation.

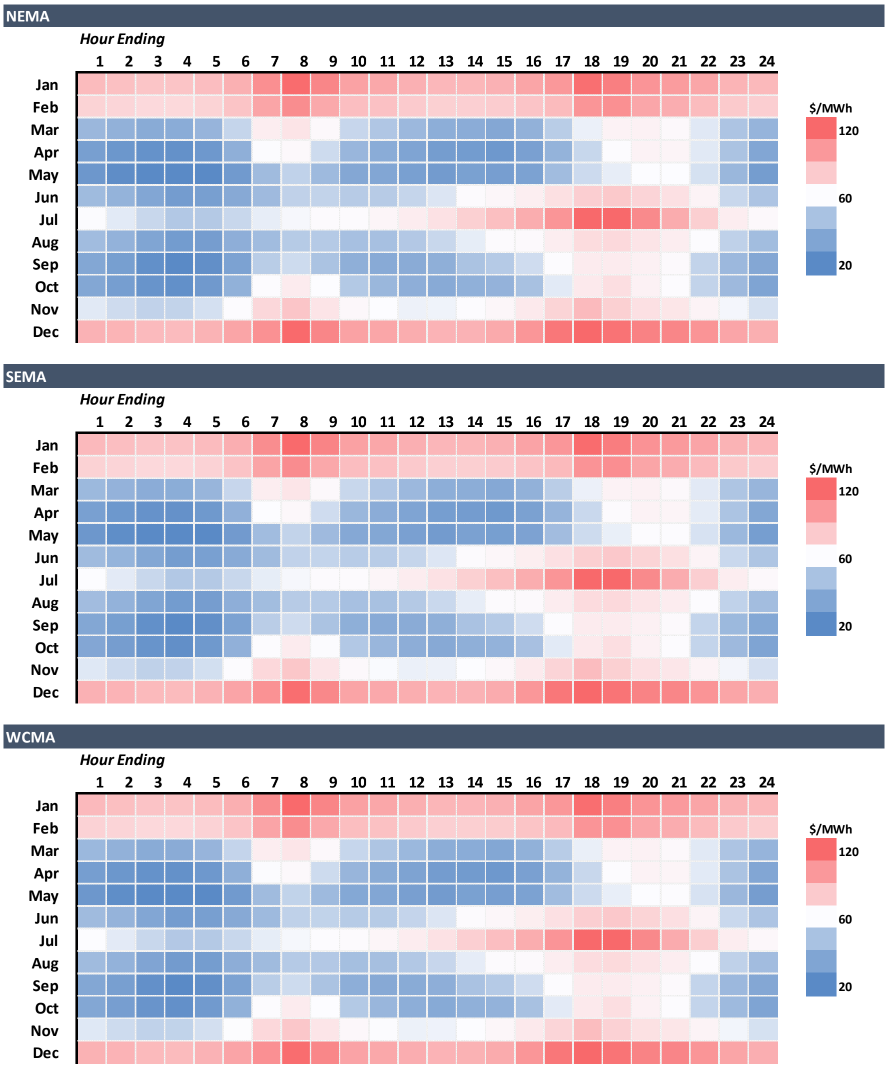
[61] There are 150 total observations real-time peak load across the three years presented in each load zone. The July 4-5 PM load hour was observed as a peak load hour on 20 occasions out of a possible 93 hours within the period (31 days in July over three years). The percentage is calculated as 20 ÷ 93 = 0.22, or 22%. Alternatively, 13% of observed peak loads occurred in the July 4-5 PM load hour (20 ÷ 150 = 0.13, or 13%).

Figure 3. Heat Map of Probability of Contributing to System Peak (2023-2025)

Short-Run Marginal Costs

In addition to peak probability analysis, which prioritizes long-run marginal costs associated with peak demand capacity expansion, DOER also considered wholesale energy prices, which reflect the short-run electric system costs of energy consumption. Efficient price signals promote energy consumption during off-peak hours to increase the utilization of existing generation capacity and delivery infrastructure. Importantly, rate designs that reflect this dynamic can translate load growth into lower energy supply costs and reduce average delivery rates. **Figure 4** visualizes average day-ahead energy prices, showing higher energy prices between 5-9 PM (HE 18-21) throughout the year across all three load zones.

Figure 4. Heat Map of Average Day-Ahead Energy Prices, 2023-2025



i. *Peak Period Selection*

A well-designed, cost-reflective peak period must balance long- and short-run marginal costs, while ensuring customers may reasonably shift their consumption.

> ***Recommendation:*** *The Department should adopt an initial peak period of 4-8 PM (HE 17-20) across all three Massachusetts load zones.*

DOER's recommended peak period accounts for most of the hours likely to contribute to system peak. DOER's recommended peak period is narrower than the windows identified in **Figure 3,** but still captures 58%, 77%, and 78% of critical load hours (top 20 real-time load hours) in NEMA, SEMA, and WCMA, respectively. Furthermore, this period would have captured 87% of the annual system peaks in each load zone that occurred in the past five years.

DOER's recommended peak period also captures the hours of the day with relatively high day-ahead energy prices throughout the year. There are other hours with relatively high energy prices; however, a four-hour peak period accounts for the hours with the highest year-round short-run supply costs.

The design of a peak period for future system conditions is an imperfect science but is nonetheless a necessary step to realize the benefits of TOU rates. Ultimately, DOER recommends a four-hour period to maximize customers' ability to shift their use, which is key to unlocking system cost reductions and customer savings. DOER initially proposed a five-hour peak period of 3-8 PM (HE 16-20).[62] Expanding the peak period beyond four hours yields diminishing returns in capturing incremental system costs while materially reducing customers' ability to respond. Several stakeholders recommended a four-hour peak period, citing concerns that customers may have more difficulty shifting consumption under the longer five-hour period and noting that four hours aligns with the current typical battery discharge duration.[63]

DOER recognizes the seasonality reflected in this analysis.[64] **Figure 3** shows that system peak demand typically occurs in the summer, which implies long-run marginal costs are highest in the summer. **Figure 4** shows elevated energy prices, or short-run marginal costs, in the summer and winter (i.e., November through February) with substantially lower costs in shoulder seasons. In New England, winter energy prices are relatively high, despite lower overall load, because natural gas prices are higher due to limited supply, making it more

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[62] *Ratemaking Straw Proposal* at 18.
[63] *Ratemaking Straw Proposal Comments* (Dec. 19, 2025) at 57, 64, 70-71.
[64] DOER recognizes that in its Ratemaking Straw Proposal at 16, as well as in the IRWG's *Long-Term Recommendations* at 13-14, it recommended designing seasonal TOU rates. Seasonal considerations are discussed for supply, transmission, and distribution in their respective subsections below.

expensive to operate gas power plants, which generally set the wholesale energy price.[65] To maintain cost-reflectivity under a consolidated peak period, varying price levels throughout the year is justified. Unique considerations for each electricity service component are discussed below.

ii. Peak Period Evolution

DOER's peak period recommendation is based on recent load patterns and system needs, likely years ahead of the implementation of TOU rates. It is critically important for peak periods to evolve with system needs.

Recommendation: *The Department should require the EDCs to jointly prepare an annual report, filed no later than March 1, that reviews and amends, if necessary, the peak period to align with changes in energy prices and usage trends.*

For rate design to encourage valuable demand flexibility to improve grid reliability and help customers manage wholesale costs, peak periods may need to adjust over time. Consequently, DOER recommends that rate design, and the peak period definition, be more responsive to evolving system and consumer needs by allowing for a greater degree of flexibility in rate design, while maintaining continuity and simplicity for customers.[66] Evaluating trends from year to year, or over a set of years, will ensure that the peak period does not become misaligned with system costs. It will also enable visibility into emergent peak periods (e.g., winter morning peaks from heating electrification).

DOER recommends the annual report include, at a minimum, a similar approach to DOER's evaluation of long- and short-run marginal electric system cost drivers based on Massachusetts' energy load and price data from the past three years. If the EDCs deem a change to the peak period is warranted, the EDCs should include a proposal to transition from their existing pricing periods for basic service pricing, transmission rates, and distribution rates accordingly.

Electrification will continue to change system conditions and needs. For example, DOER's analysis demonstrates that electrification, particularly behind-the-meter (BTM) solar, has driven changes in the hours when the system is most stressed over the past 15 years. Expectedly, the probability of summer afternoon hours contributing to peak has substantially fallen as the probability of summer evening hours contributing to peak has increased,

[65] ISO-NE, *2024 Annual Markets Report* at 91-92 and 100-102 (May 23, 2025), available at https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf.
[66] *Ratemaking Straw Proposal* at 12.

presumably due to reduced load at times coincident with high BTM solar generation.[67] A longer peak period through the afternoon and evening may have been reasonable between 2011-2013; however, DOER's analysis suggests this period is not fit for recent system conditions.

iii. Consolidated Peak Period

A single consolidated peak period will provide customers with a simple price signal that will maximize beneficial load-shifting behavior. Ensuring that the price signal is simple, easy to follow, and customer-centric will increase the likelihood of customer behavior changes, likely outweighing any granularity provided with multiple peak periods for different bill components.[68] Stakeholders also broadly identified standardized peak periods as important in designing effective TOU rates for customers.[69]

Recommendation: *The Department should adopt a single, consolidated peak period across supply, distribution, and transmission.*

The EDCs, however, raised concern that "selection of a specific single peak period for supply and distribution is premature without robust analysis of data to determine whether distribution system peaks are indeed aligned with ISO-NE peaks."[70] Here, DOER provides detailed analysis of readily available data on Massachusetts load zone peaks and energy pricing, further detailed in Exhibit C.

Recommendation: *The Department should direct the EDCs to file empirical analyses of distribution system peak demand that assesses the coincidence with ISO-NE system peaks to inform distribution rate design.*

The distribution system may have localized peaks noncoincident with broader system peaks.[71] While a consolidated peak period may not capture every local distribution peak, to the extent that the peaks are even moderately correlated, it is an improvement over current uniform, energy-based distribution rates and targeted programs are better suited for

[67] Exhibit C, Sch. 3. Based on the top one percent of real-time load, evaluating the three-year period, 2023 to 2025 as compared to three-year reference period, 2011-2013.
[68] *Long-Term Recommendations* at 15-16.
[69] *Ratemaking Straw Proposal Comments* at 9, 49, 55, and 64 (Dec. 19, 2025), available at: https://www.mass.gov/doc/ratemaking-straw-proposal-comments/download.
[70] *Joint EDC Comments on DOER's Ratemaking Straw Proposal* at 8 (Dec. 19, 2025), available at: https://www.mass.gov/doc/ratemaking-straw-proposal-comments/download.
[71] *Long-Term Recommendations* at 16-17.

localized distribution peaks as discussed in the Load Management and Demand Response Programs section below.

Further, the Department has found it appropriate to apply consistent definitions for pricing parameters across all three EDCs, noting that it would facilitate the future review of the successes, failures, and lessons learned from the initial implementation of a rate.[72] Here, DOER considers it similarly appropriate, particularly during the transition to TOU rates, to apply consistent definitions for peak periods across components and EDCs. DOER's peak probability analysis and wholesale energy price analysis, which exhibited only modest variations between load zones, reasonably justifies a common peak period across the EDCs.

iv. Peak to Off-Peak Ratio

Peak to off-peak (P/OP) ratios characterize the relationship between customer peak electric rate to the off-peak electric rate. For example, the P/OP ratio of a TOU rate with a peak electric rate of $0.45/kWh and off-peak electric rate of $0.15/kWh is 3:1. The P/OP ratio is a common metric in considering expected customer responsiveness to TOU rate design. TVR pilot and program data demonstrates that as the P/OP ratio increases, the observed peak reduction increased, though at a decreasing rate.[73] The IRWG recommended the Department further investigate the appropriate ratio, noting that an optimal ratio is high enough to incentivize customers to shift usage while also not being so high to be punitive, especially to those already facing high energy burdens.[74]

The P/OP ratio is an important measure in evaluating customer acceptance and the incentive provided for load shifting; however, the appropriate P/OP ratio should emerge from the underlying cost structure of each service component rather than from an administratively defined target ratio. A specified P/OP ratio for customers' retail rates would be challenging to achieve and sustain. The customer is exposed, and likely responds, to the total P/OP ratio, not necessarily the P/OP ratio of the supply, transmission, or distribution component independently. A higher P/OP ratio for transmission and distribution charges may be warranted due to a number of additional uniform charges diluting the total retail rate P/OP ratio. Further, customers may continue to pursue fixed price supply products in retail energy markets, which would further dilute the P/OP ratio.

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[72] See, e.g., *Petition of NSTAR Electric Company, d/b/a Eversource Energy for Approval of Residential Seasonal Heat Pump Rates*, D.P.U. 25-55, Order at 19 (Jul. 29, 2025). The Department directed common definitions of summer and winter seasons for heat pump rates across the EDCs.

[73] *Long-Term Ratemaking Study* at 39-40, Figure 15; Sergici, Sanem. *Time-of-Use Rate Design and Roll-out: Learnings from Other Jurisdictions.* Prepared for Maine PUC Docket No. 2024-00231 at 6 (Oct. 8, 2024), available at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2024-00231.

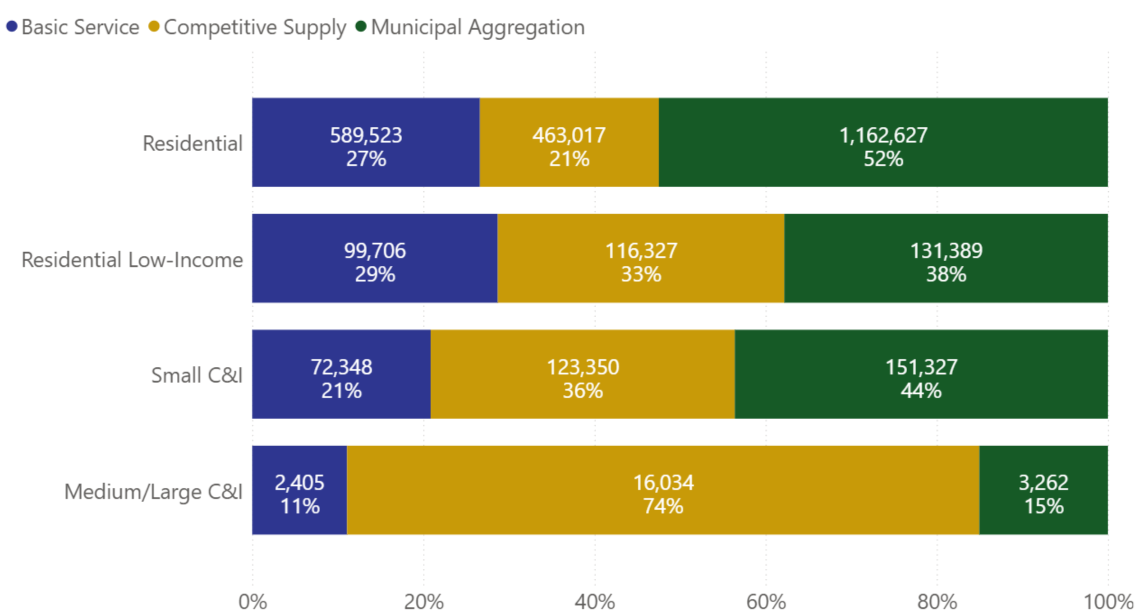
[74] *Long-Term Recommendations* at 21.

Supply Service

Massachusetts, like most New England states, restructured its electric utility industry in the late 1990s to foster competition through expanded customer choice and competitive markets.[75] Consequently, Massachusetts ratepayers can contract for electric supply service through three different contracting mechanisms: basic service, municipal aggregations, or competitive suppliers.[76] In each case, a retail energy supplier (supplier) is responsible for providing customers with electric supply service.

As of June 2025, municipal aggregations, basic service, and competitive suppliers accounted for 48%, 27%, and 25% of all electric customers, respectively.[77] As shown in **Figure 5**, medium and large commercial and industrial (C&I) customers more commonly receive electric supply service through individual competitive suppliers while all other customers more commonly receive supply through their municipal aggregation.

Figure 5: Massachusetts Electric Customers, September 2025



i. Supply Costs

Each retail supply option offers customers a retail rate - or product - that reflects the expected all-in cost of energy services required to serve them. Customers' retail supply rates are typically fixed for a period of one month to several years, and most are consistent throughout

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[75] *An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein.* St. 1997, c. 164, § 1.
[76] *Long-Term Recommendations* at 17-20.
[77] DOER, *Electric Customer Choice Data* (Jun. 2025), available at: https://www.mass.gov/info-details/electric-gas-customer-choice-data.

all hours of the day. Uniform rates diverge from underlying energy and capacity cost drivers, which vary over time. Consequently, customers do not receive a price signal to shift consumption to periods that incur lower energy or capacity costs.[78] Even modest reductions in peak demand can lower wholesale energy prices and capacity costs, producing system-wide benefits that accrue to all customers regardless of individual responsiveness.

Retail supply costs include wholesale supply costs, portfolio standard compliance, and additional supplier administrative costs and profits. ISO-NE administers the region's wholesale electricity markets, which determine wholesale supply costs associated with several distinct energy services, including energy, capacity, and ancillary services. **Energy** and **capacity** costs represent the vast majority of wholesale supply costs; for example, energy and capacity costs accounted for 78% and 17% of non-transmission wholesale electricity costs in 2024, respectively. [79]

Energy Costs

Energy costs are the costs associated with generating or consuming energy, commonly measured in megawatt-hours in wholesale markets and kilowatt-hours (kWh) in retail markets. Energy prices – or locational marginal prices (LMP) - vary by time and location and reflect the marginal cost (or value) of energy.[80] ISO-NE administers a day-ahead energy (DA) market and a real-time (RT) energy market. The former is a financial market that coordinates the production and consumption of energy for the following operating day on an hourly basis. The latter is a sub-hourly physical market that coordinates the production of energy in real-time based on power system conditions.[81] Most retail customers, however, are not exposed to the volatility of these energy markets. Instead, suppliers charge customers a uniform supply rate at a fixed rate ($/kWh) for all electricity consumption, regardless of time-of-day. Suppliers manage the resulting price risk, in addition to volume risk, associated with their load obligation through various hedging strategies and other market practices.

A more cost-reflective TOU rate would account for the expected variation in wholesale energy prices during each TOU period. For example, average DA energy prices during July 2025 in the NEMA load zone were $151.36/MWh between 4-8 PM (HE 17-20) and $66.12/MWh in all other hours (i.e., P/OP ratio of 2.3:1).

Figure 6 shows average real-time load between 2023 and 2025 across all Massachusetts wholesale load zones, which unsurprisingly correlates with **Figure 4**, despite reflecting DA

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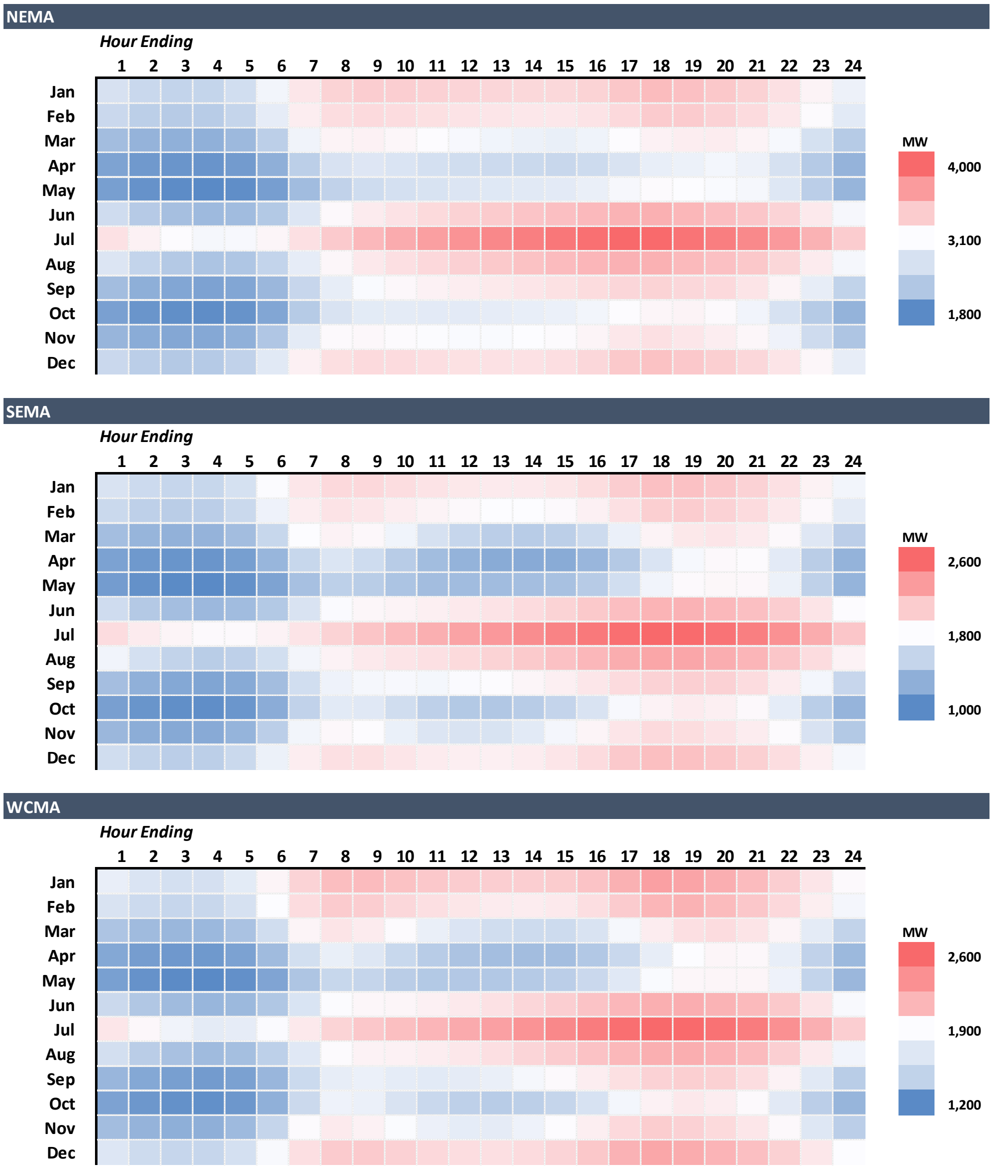
[78] ISO-NE, Inc. *An Overview of New England's Wholesale Electricity Markets: A Market Primer* (May 23, 2025), available at: https://www.iso-ne.com/static-assets/documents/100023/imm-markets-primer.pdf.
[79] ISO-NE, *2024 Annual Markets Report* at 31-33, Figure 1-1 (May 23, 2025), available at: https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf. Ancillary service, uplift and unit agreement payments accounted for the remaining 5%.
[80] *An Overview of New England's Wholesale Electricity Markets: A Market Primer* at 21. In fact, the LMP includes three components: energy, congestion, and loss.
[81] *Id.* at 17-31.

LMPs and RT load. Load is highest during late afternoon and early evening hours in the summer and lowest year-round overnight.

Figure 6: Heat Map of Average Real-Time Load, 2023-2025



Load is a primary driver of energy prices. ISO-NE dispatches generators in order of bid price until the last unit of demand is met, and the clearing price of energy is set by the next (most expensive) generator.[82] As a result, even relatively small reductions in load during peak hours, when energy prices tend to be highest, can reduce wholesale energy costs for all customers. TOU rates reward customers for shifting load away from peak energy price hours, giving them more control over the energy portion of their bills and reducing total energy costs.

Capacity Costs

ISO-NE administers a capacity market to secure sufficient capacity to meet system-wide reliability standards.[83] ISO-NE calculates an installed capacity requirement (ICR), based on forecasted peak demand and a reserve margin, and administers an auction to procure commitments from generators to be available when needed.[84]

Under the current capacity market design – the forward capacity market (FCM) – committed resources receive capacity payments for fulfilling their obligation during the commitment period. ISO-NE allocates capacity costs to load-serving entities (LSEs), or suppliers, based on their load obligation during the hour of peak system load in the previous year (known as 1CP, defined as real-time load during the annual system peak hour).[85] As such, LSEs can reduce capacity costs by lowering their load obligation during peak system loads.

Table 1 presents the coincident peaks used for ISO-NE's capacity cost allocation.[86] Peak demand has historically occurred in summer (i.e., June – September) during the late afternoon or early evening. A cost-reflective rate that accounted for the long-run marginal costs associated with capacity would include a price signal to discourage consumption during these system-wide peaks. DOER's recommended peak period would have encouraged lower usage during four of the five most recent system-wide annual peak hours. Certainly, a TOU rate will not necessarily capture all system peaks past, present, or future. Other TVRs, such as critical peak pricing (CPP), can provide interested customers with greater exposure to dynamic system conditions and costs.

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[82] *See, e.g.,* https://www.iso-ne.com/about/what-we-do/how-resources-are-selected-and-prices-are-set.
[83] *An Overview of New England's Wholesale Electricity Markets: A Market Primer* at 63-71.
[84] ISO-NE, Installed Capacity Requirement, available at: https://www.iso-ne.com/system-planning/system-plans-studies/installed-capacity-requirement
[85] *ISO-NE Overview & Considerations for Rate Design* at 5. For additional information regarding ISO-NE's Capacity Auction Reforms, see: https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project
[86] ISO-NE, FCM Annual System Peak Day, Hour, and Load, available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/ann-sys-peak-day-hr-load.

Table 1. System-Wide Annual Peak Hours Used for Allocating Capacity Costs

Year	Peak Date	Time
2022	June 29, 2021	4-5 PM (HE 17)
2023	August 8, 2022	3-4 PM (HE 16)
2024	September 9, 2023	5-6 PM (HE 18)
2025	July 16, 2024	5-6 PM (HE 18)
2026	June 24, 2025	6-7 PM (HE 19)

In the short-run, DOER recognizes that when LSEs reduce their capacity costs by incentivizing customers to lower, or shift, consumption away from the annual peak, it results in higher capacity cost allocations for other LSEs. In the long-run, however, the incentive for each LSE to lower their capacity costs by reducing load during peak hours should result in lower capacity requirements, requiring less investment and customer costs.

ISO-NE administered a forward capacity market (FCM) for nearly two decades, but is currently undertaking a substantial, multi-year effort to implement reforms, including the transition from a forward to prompt auction and from an annual to seasonal capacity commitment periods. These potential updates do not preclude Massachusetts from proceeding with supply TOU rates now, but they may change how capacity costs are allocated to peak periods and seasons to better align with cost allocation and causation under a new design.

Further, ISO-NE forecasts that New England will become winter peaking in the mid-to-late 2030s, driven by the electrification of transportation and heating, at which point winter mornings and evenings are expected to drive capacity needs.[87]

ii. Basic Service Rates

In Massachusetts, EDCs are required to provide electric supply service to customers not served by a competitive supplier, referred to as basic service.[88] The EDCs procure basic service in accordance with relevant statutes, regulations, and approved tariffs.[89] In practice, basic service functions as a price-to-compare for other supply offers by competitive suppliers, either independently or through a municipal aggregation. Accordingly, a TOU basic service

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[87] ISO-NE 2025 CELT Report, available at https://www.iso-ne.com/system-planning/system-plans-studies/celt; Black, Jon, *2026 Draft Energy and Seasonal Peak Forecasts*; E3, *Challenges and Opportunities for Electric Rate Reform in Massachusetts* at 10-11 (Jun. 30, 2025), available at: https://www.mass.gov/doc/topic-3-bill-and-distributed-energy-resources-impacts-expert-presentations/download.

[88] G.L. c. 164, § 1B(d); 220 CMR 11.02. Basic service, acting as a service of last resort, is also known in other restructured jurisdictions as default service, standard service, or standard offer service.

[89] Eversource, *Basic Service Tariff*, M.D.P.U. No. 46F (eff. Jan. 1, 2025), available at: https://www.eversource.com/docs/default-source/rates-tariffs/ma-electric/46-tariff-ma.pdf?sfvrsn=24c63938_8; National Grid, *Tariff for Basic Service,* M.D.P.U. No. 1541 (eff. May 1, 2024), available at: https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/basic_service_tariff.pdf; Unitil, Schedule BS: Basic Service, M.D.P.U. No. 440 (eff. Jul. 1, 2024), available at: https://unitil.com/sites/default/files/2024-07/e_MA_bs.pdf.

rate is a likely precondition to widespread TOU supply product offerings through municipal aggregations and independent competitive suppliers.

Recommendation: *The Department should direct the EDCs to provide default TOU to all basic service customers as soon as practicable.*

The EDCs recognize the value in investigating TVR for basic service and can accommodate TOU basic service rates.[90] The Department has authority over the EDCs' basic service procurement and pricing practices, including to direct the EDCs to procure or price basic service on a time-varying basis.[91] In fact, the Department has supported default TOU basic service rates,[92] and recently reaffirmed its intention "to improve the accuracy and price signals sent to basic service customers regarding the underling cost of electricity."[93] The Department "intends to investigate structural changes to basic service that includes [TVRs] in a future investigation."[94]

The EDCs competitively procure basic service by issuing requests for proposals (RFPs) seeking wholesale power supply bids for the supply of firm, load-following power to provide customers with all-requirements service.[95] The EDCs procure basic service by customer group

[90] Joint EDC Comments on DOER's Straw Proposal at 9; National Grid, *TVR Implementation Considerations* at 9-10 (Jul. 21, 2025); Eversource, *Eversource MA AMI Implementation* at 3-5 (Jul. 21, 2025); and Unitil, *Unitil AMI Deployment Update* at 4-5 (Jul. 21, 2025), available at: https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download.
[91] G.L. c. 164, § 1B(d), (f); see, generally, *Investigation by the Department of Public Utilities on its own Motion into the Provision of Basic Service,* D.P.U. 23-50 and D.P.U. 15-40; *Investigation by the Department of Public Utilities upon its Own Motion into Time Varying Rates,* D.P.U. 14-04; *Request for Comments on the Procurement of Default Service Power Supply for Residential and Small Commercial and Industrial Customers,* D.P.U. 04-115; *Investigation by the Department of Telecommunications and Energy on its own Motion into the Provision of Default Service,* D.T.E. 02-40; and *Investigation by the Department of Telecommunications and Energy on its own Motion into the Pricing and Procurement of Default Service pursuant to G.L. c. 164, § 1B(d),* D.P.U. 99-60.
[92] D.P.U. 14-04-C, Order (2014).
[93] D.P.U. 23-50, Vote and Order Opening Investigation at 18-19 (2023).
[94] D.P.U. 23-50-A, Order at 15.
[95] *See, e.g., NSTAR Electric Company d/b/a Eversource Energy's Basic Service supply for its Eastern Massachusetts service territory,* D.P.U. 25-BSF-C2, Appendix A (May 16, 2025), available at: https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aeciibaee?o+W7mPm+d0Sd6Ipb7QNFOMNCatjOk9WV8p1DYzg/yRiPcSxI+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6ngIfa80wd3rxFD8G4j981M2Rna9aVTXA. All-requirements service includes delivery, to the pool transmission facility (PTF) within the appropriate load zone, of the portion of the electric capacity, energy and ancillary services and all other ISO-NE market products required to meet the needs of basic service customers.

(e.g., residential, commercial, and industrial). [96] The EDCs incur wholesale and retail market costs in providing supply service to basic service customers. Accordingly, the EDCs set basic service rates as a pass-through.[97]

Currently, the EDCs require uniform bid prices on a $/MWh basis; prices may vary by month, but varying by TOU is expressly disallowed. For most residential, small C&I, and streetlighting customers, basic service pricing remains uniform, or fixed, for six months.

Figure 7: National Grid Residential Fixed and Variable Basic Service Rates, (cents/kWh)

Aug. 2025 – Jan. 2026						Feb. 2026 – Jul. 2026					
15.484						15.372					
Aug. 2025	Sep. 2025	Oct. 2025	Nov. 2025	Dec. 2025	Jan. 2026	Feb. 2026	Mar. 2026	Apr. 2026	May. 2026	Jun. 2026	Jul. 2026
14.295	14.036	13.998	14.697	16.412	18.496	17.391	15.113	14.499	14.246	14.597	15.546

Figure 7 summarizes National Grid's residential basic service rates, including the fixed price and variable price option.[98] The EDCs administratively calculate the fixed price basic service option for these periods based on the expected load-weighted average of the monthly bid prices.[99] Both basic service price options also include a basic service adder (i.e., recovering administrative, bad debt, working capital, and procurement costs) and the compliance costs associated with the Commonwealth's portfolio standards discussed below. The EDCs could implement TOU basic rates through two alternative approaches.

Recommendation: *The Department should determine the appropriate approach for the EDCs to solicit supplier bids between two alternatives: (1) uniform pricing that the EDCs would use to calculate TOU pricing for basic service customers or (2) separate on-peak and off-peak pricing.*

Under the first alternative, the EDCs could continue to procure basic service in a similar manner and administratively set pricing for customers based on the Department-approved peak period. The EDCs currently reconcile under- and over-recoveries of basic service costs

[96] D.TE. 02-40-C, Order at 22; D.T.E. 02-40-A, Order at 13. The Department also requires the EDCs procure power: (1) at fixed monthly prices; (2) on a load-zone specific basis (3) separate prices for each load zone for industrial customers, and (4) on a quarterly basis for industrial customers. In practice, the EDCs solicit bids for between one and four tranches, or blocks of supply, and suppliers may elect to bid only to specific tranches.
[97] D.P.U. 23-50-A, Order at 4, n. 4.
[98] National Grid's basic service rates, available at: https://www.nationalgridus.com/media/pdfs/billing-payments/electric-rates/ma/resitable.pdf.
[99] *See, e.g., NSTAR Electric Company d/b/a Eversource Energy's Basic Service supply for its Eastern Massachusetts service territory,* D.P.U. 25-BSF-C2, Appendix B for additional detail on this calculation.

during each pricing period from all EDC customers because basic service acts as insurance, or a safety net, for all customers and the potential for a changing number of basic service customers over time.[100] The EDCs reconcile these costs in accordance with Department-approved tariffs.[101] If the Department deems this a suitable alternative, it would be appropriate for a common approach for the EDCs to determine cost-reflective basic service TOU rates. Notably, Unitil provides TOU basic service pricing to customers taking service under its residential EV service (EV-RES) rate via this approach.[102] In each of its basic service filings, Unitil provides a worksheet that reflects the calculation of the basic service TOU rate for its EV-RES rate.[103]

Alternatively, the EDCs would issue basic service RFPs soliciting bids from suppliers based on the Department-approved peak period. Suppliers would provide peak and off-peak bid pricing based on the defined peak period, determining the appropriate price differentiation between peak and off-peak periods. Robust supplier participation under this alternative may require resolution of load settlement issues. Further, the EDCs have experienced declining participation from suppliers in basic service solicitations in the past years, and the Department has taken actions accordingly.[104] Increasing the complexity and requirements of basic service solicitations may risk further decreasing the competitiveness of procurements.

DOER recommends the Department seek comments on these two alternatives and thereafter, direct the EDCs to make all necessary changes to the procurement process, including revisions to its basic service tariff and RFP.

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[100] D.P.U. 23-50, Order Opening Inquiry at 7, citing D.T.E. 99-60-C at 10, 13.

[101] Eversource, *Basic Service Cost Reconciliation*, M.D.P.U. No. 47F (eff. Jan. 1, 2025), available at: https://www.eversource.com/docs/default-source/rates-tariffs/ma-electric/47-tariff-ma.pdf?sfvrsn=b4297cb1_4; National Grid, *Basic Service Adjustment Provision,* M.D.P.U. No. 1554 (eff. Oct. 1, 2024), available at: https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/mdpu_1554_bs_adjmt_prov_10.01.24.pdf; Unitil, Schedule BSA, Basic Service Adjustment, M.D.P.U. No. 477, available at: https://unitil.com/sites/default/files/2025-01/e_MA_BSA.pdf.

[102] *NSTAR Electric Company d/b/a Eversource Energy's Basic Service supply for its Eastern Massachusetts service territory, Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal, Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal,* D.P.U. 21-90/21-91/21-92, Order at 270.

[103] *Basic Service Filing of Fitchburg Gas and Electric Company d/b/a Unitil*, D.P.U. 25-BSF-A4, Schedule EV-RES Rate Development (Dec. 5, 2025), available at: https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aehfbedee?oKfRhlYyOo3oWoWcOSlBaMNCatjOk9WV8p1DYzg/yRiPcSxI+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA.

[104] *See, e.g.,* D.P.U. 23-50, Order Opening Inquiry at 2; D.P.U. 15-40, Order at 1.

Recommendation: *The Department should direct the EDCs to file proposed tariff revisions and updated provision practices to implement default TOU basic service rates to all customers as soon as practicable, and no later than August 1, 2028.*

A cost-reflective basic service rate would account for the capacity costs associated with load during peak hours and wholesale energy prices, which vary across season and time-of-day. **Figure 3** and **Figure 4** imply that capacity and energy costs would result in higher supply rates in the summer and winter, as compared to shoulder seasons. A fixed price option during the current basic service delivery terms of February through July and August through January, however, will dull this price signal. The Department directed all EDCs to procure basic service on this schedule to "minimize significant differences in basic service rates that customers [experienced] between rate periods and across [EDCs] due to high wholesale electricity prices in the winter months, especially January and February."[105] In its decision, the Department exercised the trade-off between cost-reflectivity and bill stability for customers that remains important. DOER, at this time, does not recommend making any further changes to the delivery term schedule and underscores the suitability of its recommended peak period of 4-8 PM throughout the year as an incremental step to more cost-reflective rates, and the potential for further development in the future.

Nonetheless, the average P/OP ratios for DA energy prices across all three load zones in 2025 was 1.5:1 with DOER's recommended peak period, 4-8 PM (HE 17-20), during each of the delivery terms.[106] A cost-reflective P/OP ratio for supply rates with this peak period would be greater to account for the long-term marginal costs associated with capacity. DOER recommends that the basic service adder and portfolio standard compliance costs continue to be recovered on a uniform basis regardless of time-of-day; however, those charges will dull the price signal to customers.[107]

The EDCs' basic service solicitations occur on a staggered schedule, procuring supply blocks ahead of the delivery term. Specifically, the EDCs procure power supply semi-annually for residential, small C&I, and street lighting customers in two 50% blocks, the first and second approximately ten and four months ahead of the delivery term, respectively. For medium and large C&I customers, the EDCs procure 100% of their power supply requirements approximately four months ahead of the delivery term on a quarterly basis. **Figure 8**

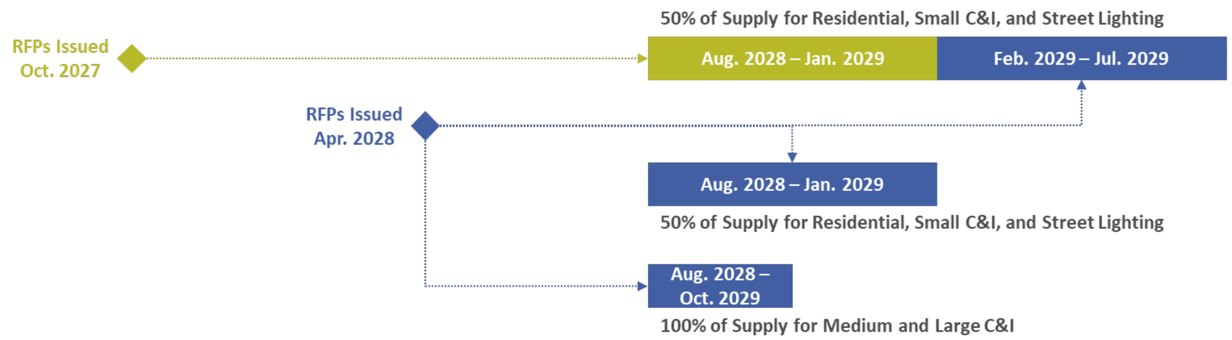
[105] D.P.U. 23-50-A, Order at 12.

[106] Exhibit C, Schedule 4.

[107] A peak and off-peak wholesale supply rate of $0.20/kWh and $0.10/kWh, respectively, would result in a P/OP ratio of 2:1. If the additional uniform charges add $0.03/kWh to all hours, the customers' retail supply rate will be $0.23/kWh on-peak and $0.13/kWh off peak, resulting in a P/OP ratio of 1.77:1.

illustrates Eversource's basic service procurement schedule for delivery commencing August 1, 2028, assuming no other changes are made to the procurement schedule.

Figure 8: Eversource's Basic Service Procurement Schedule



Implementing TOU basic service rates will require forward-planning, particularly if there are any necessary changes to the solicitation, because the EDCs procure the first 50% of supply for most customers approximately 10 months ahead of the delivery term. For example, Eversource's RFP issued in October 2027 may need to be revised to provide TOU basic service pricing to customers for delivery commencing August 1, 2028. Further, the Governor's pending energy affordability legislation, H. 4144, which amends G.L. c. 164, § 1B, will provide additional flexibility to the solicitation of basic service if enacted.[108]

iii. Municipal Aggregation and Competitive Supply Products

Municipal aggregation refers to when municipalities, individually or together, competitively procure electric supply contracts on behalf of customers within their borders.[109] Following the Department's review and approval of the municipal aggregation plan, the Department does not oversee or regulate aggregation supply product prices or attributes. Municipal aggregations are responsive to the priorities of their customers, and as a growing share of the retail supply market, are an essential part of supply TOU in Massachusetts.[110] Encouraging supply TOU products will require additional engagement to communicate the benefits among local governments, their constituents, and the consultants who support them.

Massachusetts' customers may also independently contract for electric supply service with a competitive supplier. The Department established rules to govern the Commonwealth's

[108] Section 14 of *An Act Relative to Energy Affordability, Independence and Innovation,* H. 4144.
[109] G.L. c. 164, § 134 (a); 220 CMR 11.02. In 2024, the Department adopted guidelines that granted municipalities greater discretion in forming and managing aggregations, *Investigation by the Department of Public Utilities on its own Motion into Establishing Guidelines for Municipal Aggregation Proceedings*, D.P.U. 23-67-A Order (Jul. 9, 2024). For additional information, see: https://www.mass.gov/municipal-aggregation.
[110] *Long-Term Recommendations* at 19.

restructured electric industry and has occasionally exercised its authority to increase consumer protection within retail competitive electricity markets.[111]

One critical objective of restructuring Massachusetts' energy market was to foster competition and innovation in rate design among retail suppliers. Similar to basic service, most municipal aggregation and competitive supply products are uniform, fixed price contracts.

Recommendation: *The Department should expeditiously conduct its investigation into load settlement as it is an integral part of suppliers' success with time-varying supply products.*

Currently, suppliers are unable to settle supply costs with ISO-NE based on customers' actual hourly usage (i.e., load settlement), which impedes suppliers' business cases for offering customers time-varying products. The EDCs perform load settlement using a combination of estimated customer load, based on class average load profiles developed from statistically designed samples and individual customer usage history, and individual customer actual hourly interval metered values.[112] Under current load settlement rules, suppliers are assigned energy and capacity obligations based on representative load profiles for a customer class rather than on the customers' actual interval usage. Consequently, if a supplier were to offer a more cost-reflective, time-varying product and customers responded by shifting usage away from high-cost hours, the supplier would not realize a corresponding reduction in assigned wholesale costs. Load settlement based on actual AMI interval data is therefore a prerequisite to municipal aggregations and competitive suppliers offering meaningful time-varying supply products. In addition to load settlement, the EDCs perform billing and customer service functions for customers, and the EDCs will need to implement updates to their billing systems and load settlement procedures.

With full AMI deployment, ISO-NE will be able to calculate energy, capacity tags, and related obligations using customer-specific interval data, provided that the EDCs implement necessary billing and load settlement systems. The Department recently opened an investigation to examine the necessary systems and system upgrades to allow load settlement with ISO-NE based on customer interval usage data collected by AMI to develop policies that will enable suppliers to offer TVR.[113]

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[111] 220 CMR 11.00; *see, e.g., Investigation by the Department of Public Utilities on its own Motion into Initiatives to Promote and Protect Consumer Interests in the Retail Electric Competitive Supply Market,* D.P.U. 19-07 and *Investigation by the Department of Public Utilities on its own Motion into Initiatives to Improve the Retail Electric Competitive Supply Market,* D.P.U. 14-140.
[112] D.P.U. 25-BSF-C2, Appendix C: Settlement Process.
[113] D.P.U. 26-44, Vote and Order Opening Investigation at 1.

Load settlement based on customer-specific AMI interval data will enable suppliers to offer dynamic, cost-reflective time-varying products. The IRWG recommended TVRs, such as critical peak pricing (CPP), on an opt-in basis, which can provide further opportunities to reduce peak demand and unlock additional savings for customers.[114]

Transmission Service

The transmission system is the network of high voltage infrastructure, including transmission lines, substations, and transformers, which delivers electricity from generation to local distribution systems. Transmission owners, such as National Grid and Eversource Energy, own and operate the majority of transmission facilities in the Commonwealth; however, ISO-NE, operating as the regional transmission organization (RTO), conducts transmission planning according to its open access transmission tariff (OATT).[115]

i. Transmission System Costs

Transmission system costs, referred to individually as transmission owners' revenue requirement, reflect the costs of owning and operating the transmissions system. Transmission owners are obligated to maintain or replace their existing facilities; yet load growth – particularly demand growth – requires expansion of existing infrastructure or the addition of new infrastructure. According to ISO-NE, managing new load to reduce increases in peak demand will avoid $7-9 billion in new transmission costs by 2050, thereby benefiting all ratepayers.[116] Consequently, reducing peak loads can lower long-run transmission costs.

The Federal Energy Regulatory Commission (FERC) regulates interstate transmission of electricity, which preempts state authority over public utility transmission owners filed tariffs.[117] The states, however, have authority to determine retail transmission rates for customers within their state.[118]

Current transmission system costs include costs associated with regional network service (RNS) and local network service (LNS). RNS recovers the costs of operating, maintaining and investing in the higher-voltage, regional bulk transmission system - also known as pool transmission facilities (PTF). LNS recovers the costs of lower-voltage facilities that serve a specific area rather than the entire region. RNS and LNS rates are set to fully recover the transmission revenue requirements from customers, including the EDCs. For example, Eversource estimates the total transmission costs for serving its distribution customers in

[114] *Long-Term Recommendations* at 21-22; Nelson, Ron. *High-Level Overview of Long-Term Advance Rate Design* at 5-6 (Jun. 9, 2025), available at: https://www.mass.gov/doc/topic-2-alternative-rate-designs-expert-presentations/download; E3, *Challenges and Opportunities for Electric Rate Reform in Massachusetts* at 18 (Jun. 30, 2025), available at: https://www.mass.gov/doc/topic-2-alternative-rate-designs-expert-presentations/download.
[115] Clean Energy Transmission Working Group, *Report to the Legislature* at 7-8 (Dec. 2023), available at: https://www.mass.gov/doc/clean-energy-transmission-working-group-final-report/download.
[116] *2050 Transmission Study* at 16-17.
[117] Federal Power Act, 16 U.S.C. §§ 791 et. seq.; *New York et. al. v. FERC et al.*, 535 U.S. 1, 22 (2002).
[118] Clean Energy Transmission Working Group, *Report to the Legislature* at 4.

2026 to be approximately $960 million, with RNS and LNS costs accounting for $719 million and $200 million, respectively.[119]

The RNS rate, subject to FERC approval, is determined by the Pool Transmission Owners Administrative Committee to recover PTF costs, in addition to reconciling prior year under- or over-recovery.[120] The RNS rate, effective January 1, 2026, is $183.75/kW-year and is based on the forecasted regional service annual transmission revenue requirement divided by the average 12-month coincident peak.[121] ISO-NE and transmission utility tariffs allocate FERC jurisdictional transmission costs based on each distribution utility's share of the monthly coincident peak hour (i.e., monthly coincident peak, or 12CP) for RNS and of their transmission provider's LNS peak.

Accordingly, there is a gap between long-run marginal transmission costs, driven by annual peak demand, and the allocation of current transmission costs to utilities based on monthly coincident peak. For example, a distribution utility could reduce their peak demand in April to lower their share of transmission costs, however, it would do little to lower annual peak. It also has the effect of shifting transmission costs to other utilities or states, either through the reconciliation of wholesale or retail transmission rates. DOER recognizes that in the near-term, lowering transmission costs will result in cost-shifting; however, in the long-run, efficient transmission rates will incentivize peak load reductions that will lower transmission system costs.

ii. Transmission Rates

The EDCs recover transmission costs from their customers as a pass-through by annually establishing transmission rates, subject to Department review and approval, to recover the costs of transmission service – including forecasted transmission costs and over- or under-recovery, plus interest, from previous years. [122] The EDCs establish separate transmission rates

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[119] *Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its 2025 electric reconciliation filing effective January 1, 2026, pursuant to G.L. c. 164, §§ 1A(a) through 1H and 220 CMR 11.03(4)(e),* D.P.U. 25-158, Exh. ES-BJO-3 (Oct. 31, 2025). The remaining costs account for ancillary services or uncategorized transmission services.

[120] For more information regarding determination of RNS rates, see: https://www.iso-ne.com/markets-operations/settlements/rate-development.

[121] Participating Transmission Owners Administrative Committee, *Annual Update Regarding ISO Tariff Changes in Effect as of June 1, 2025 and January 1, 2026; Docket No. ER20-2054 (Jul. 31, 2025),* available at: *Section II OATT Rates* (Jan. 2, 2026), available at: https://www.iso-ne.com/markets-operations/settlements/rate-development.

[122] Eversource, *Transmission Service Cost Adjustment*, M.D.P.U. No. 48A (eff. Jan. 1, 2025), available at: https://www.eversource.com/docs/default-source/rates-tariffs/ma-electric/48-tariff-ma.pdf?sfvrsn=53e1f48c_6; National Grid, *Transmission Service Cost Adjustment Provision,* M.D.P.U. No. 1592 (eff. Mar. 31, 2025), available at: https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/2025/mdpu_1592_transmission_service__03.31.25.pdf; Unitil, *Schedule ETC: External Transmission Charge,* M.D.P.U. No. 305 (eff. Jan. 1, 2017), available at: https://unitil.com/sites/default/files/2021-05/E_dpu305_ETC.pdf; Unitil, *Schedule* ITSCA: Internal Transmission Service Cost Adjustment, M.D.P.U. No. 304 (eff. Jan. 1, 2017), available at: https://unitil.com/sites/default/files/2021-05/E_dpu304_ITSCA.pdf.

for each rate class, which apply to all customers in their service territory as a component of their delivery rate. Most residential and small C&I customers (non-demand customers) pay for transmission via a uniform volumetric energy rate ($/kWh) that does not vary throughout the year.

Recommendation: *The Department should direct the EDCs to file proposed revenue-neutral, TOU transmission rates for any non-demand customers on or before June 18, 2027, for rates effective no later than May 1, 2028.*

Medium and large C&I customers, on the other hand, pay based on non-coincident demand ($/kW). The Department also approved expansion of coincident peak transmission billing for large C&I customers, determining that pricing transmission service based on a customer's use at system peak, rather than based on the customer's non-coincident peak, provides more equitable assignment of cost responsibility.[123]

Well-designed TOU rates would provide customers with a stable and predictable price signal to shift use away from times when the transmission system is stressed, unlocking immediate savings for customers by incentivizing consumption patterns that reduce the need for new transmission investments. For non-demand customers, transmission rates fail to reflect the time-varied nature of annual system peak, driving long-term marginal cost, and monthly system peaks, the basis for transmission cost allocation.

Recommendation: *The Department should direct the EDCs to allocate transmission costs through a common approach to its recommended peak period of 4-8 PM in all months, with higher transmission rates during the peak season.*

DOER recommends a TOU transmission rate balance long-run marginal cost price signals and the recovery of transmission costs in the near-term. DOER's recommended peak period of 4-8 PM (HE 17-20) has a high probability of capturing the annual peak as discussed above, in addition to monthly coincident peaks. Higher pricing during this period, therefore, will encourage lower consumption during the hours that are most likely to determine annual system peak and determine the EDCs allocation of transmission costs. While TOU transmission rates may not perfectly align with the monthly coincident peak allocation methodology, they provide a materially improved proxy for long-run cost causation compared to uniform volumetric rates. Unitil's EV-RES rate reflects a similar approach: currently effective transmission rates are $0.17386/kWh on-peak, $0.03447/kWh mid-peak,

[123] D.P.U. 23-150, Order at 517.

and $0.00311/kWh off-peak (i.e., P/OP ratio of 134:1).[124] This transmission rate's P/OP ratio is high (134:1), yet the total P/OP ratio of this rate is 2.28:1 due to lower differentials for supply and distribution charges and other non-time-varying components of the bill.

A uniform TOU transmission rate throughout the year fails to reflect the seasonal variation in the long-run marginal costs of the transmission system. Currently, the New England bulk power system peaks in the summer, which implies existing headroom during non-summer months. As such, high volumetric rates during winter and shoulder seasons unnecessarily disincentivize electricity consumption. ISO-NE estimates that the region's grid will transition to winter peaking, though it forecasts that transition will not occur for the next ten years.[125] Seasonal TOU transmission rates with a year-round 4-8 PM (HE 17-20) peak period can reasonably reflect efficient price signals to customers. The Department found that seasonal pricing for transmission service was reasonable and cost-based in its decision to approve Eversource's heat pump rate.[126] Consistent with this finding, DOER recommends that seasonal TOU transmission rates be designed with higher pricing from June through September compared to the rest of the year to reflect long-run marginal costs.

The EDCs' regional retail transmission costs also tend to be higher in the summer. For example, Eversource's average retail RNS costs in 2025 are $78.7 million between June and September and $53.2 million in all other months.[127] Nevertheless, the EDCs will continue to be billed for transmission service based on monthly coincident peak, which may result in additional over- or under-recovery throughout the year. The EDCs should continue to reconcile these costs, subject to the Department's review and approval, in their annual adjustment filings.

Distribution Service

The distribution system is a complex, interconnected system that includes bulk substations, sub-transmission feeders, distribution area substations, primary feeders, lower-voltage feeders, primary taps, line transformers, and secondary cables.[128] The EDCs own, maintain, and operate the distribution system in a manner to meet their obligation to provide ratepayers with safe and reliable electric delivery service.

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[124] *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its 2025 electric reconciliation filing effective January 1, 2026, pursuant to G.L. c. 164, §§ 1A(a) through 1H and 220 CMR 11.03(4)(e)*, D.P.U. 25-168, Schedule EV-RES Rate Development (Nov. 3, 2025). Unitil adjusts EV-RES transmission rates by scaling the residential external transmission rate by a factor of 4.28, 0.81, and 0.03 for the peak, mid-peak, and off-peak rates, respectively.
[125] Black, Jon, *2026 Draft Energy and Seasonal Peak Forecasts* at 32, 38 (Feb. 20, 2026).
[126] D.P.U. 25-55, Order at 21.
[127] D.P.U. 25-158, Exh. ES-BJO-3 at 1.
[128] Nieto, Amparo. *Marginal Cost of Distribution Service and Use for TOU Delivery Rate Design* at 6 (May 19, 2025).

i. *Distribution System Costs*

Distribution system costs include the costs related to existing infrastructure and unavoidable future capital investments, as well as operations and maintenance costs associated with managing the electric grid.[129] The Department must ensure that distribution rates are just and reasonable, such that "rates afford it the opportunity to meet its cost of service, including a fair and reasonable return on honestly and prudently invested capital."[130] The Department, through a base distribution rate case pursuant to G.L. c. 164, § 94, allocates the revenue requirement, or total cost of service, to each rate class using an allocated cost-of-service (ACOS) study and then determines, for each rate class, the proper level for customer and delivery charges, including based on its rate design goals.[131] In Massachusetts, the EDCs and Department rely on an ACOS study as a reference or a guide in the ratemaking process.[132] Rate design informed by an ACOS study, which focus on embedded and existing costs, will tend to prioritize: (1) sufficiency - yielding revenues sufficient to recover utility costs; (2) fairness – to the extent that costs are fairly allocated to different customer classes; and (3) earnings stability – providing the EDCs revenues that do not vary significantly over a period of one or two years.[133]

The Department-approved revenue requirement, however, does not reflect all distribution system costs. The EDCs recover additional costs from ratepayers outside of rate cases through reconciling mechanisms. The EDCs employ a number of reconciling mechanisms to recover infrastructure, operations, and maintenance costs.[134] In late 2025, the Department opened an investigation to conduct a comprehensive review of charges and reconciling mechanisms to contain costs, reduce bill volatility, promote efficiency and transparency, best reflect cost incurrence, and reduce administrative burden.[135] The Department's investigation will focus, among other things, on identifying reconciling mechanisms that can be eliminated or included in base distribution rates going forward.[136] If, in that proceeding, the Department directs the EDCs to sunset any reconciling mechanisms and include the associated costs into base distribution rates, DOER expects that the EDCs would need to implement such changes through a base distribution rate case. These proceedings are supplementary, and neither

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[129] *Long-Term Ratemaking Study* at 17.
[130] *Id.* at 6.
[131] D.P.U. 25-200, Vote and Order Opening Inquiry at 11; DOER, *Ratemaking and Massachusetts Electric Utilities* at 12-14 (Sep. 3, 2025), available at: https://www.mass.gov/doc/topic-1-ratemaking-and-utilities-targeted-conversation/download; Long-Term Recommendations at 36-39.
[132] Electric Distribution Companies, *Allocated Cost Studies and Historical Test Years in Massachusetts* at 3, available at: https://www.mass.gov/doc/topic-2-tools-of-cost-of-service-regulation-expert-presentations/download.
[133] D.P.U. 23-150, Order at 476-477; Whited, Melissa. *The Ratemaking Process* (Jul. 2017),available at: https://www.synapseenergy.com/sites/default/files/Ratemaking-Fundamentals-FactSheet.pdf.
[134] See, e.g., DOER, *Reconciling Mechanisms* (Sep. 8, 2025), available at: https://www.mass.gov/doc/topic-2-tools-of-cost-of-service-regulation-expert-presentations/download; Long-Term Recommendations at 45-47.
[135] D.P.U. 25-200, Vote and Order Opening Inquiry at 12 (Dec. 15, 2025).
[136] *Id.* at 13.

should be delayed, because DOER's recommendations on distribution rates below focus on the base distribution rates as established in a base distribution rate case, excluding treatment of reconciling mechanisms at issue in D.P.U. 25-200.

ii. Distribution Rates

In Massachusetts, base distribution costs are recovered through a combination of customer charges ($/month), base distribution energy charges ($/kWh), and base distribution demand charges ($/kW, or $/kilovolt-ampere, kVA).[137] In the near-term, distribution system costs recovered through these rates generally reflect embedded, or unavoidable costs. In other words, marginal changes in customer energy consumption will not increase or decrease costs contemporaneously. The Department and the EDCs have not relied on a marginal cost of service (MCOS) study for rate design. An MCOS study focuses on how electric system costs change with an incremental increase in service, which provides the basis for designing rates that promote efficient price signals.[138] As such, cost-reflective TOU rates should be based on and informed by a MCOS study.

Recommendation: *The Department should direct the EDCs to propose distribution rates informed by a marginal cost of service study and TOU analysis in their next base distribution rate case.*

Distribution rates should properly align with marginal cost structure, which would provide customers with efficient price signals to avoid unnecessary expansion of the distribution system.[139] In most cases, current distribution rates do not provide cost-reflective price signals to most customers. Recovering distribution costs through uniform volumetric charges obscures the role of peak demand in driving infrastructure investment and results in cross-subsidization between customers with differing load profiles.

The monthly customer charge, intended to recover customer-related costs – such as metering costs, customer service, and account expenses – is typically a nominal cost on customers' bills, as shown in **Figure 2**. For residential and most small C&I customers, the remaining distribution service costs - not recovered through the monthly customer charge - are recovered through a uniform, volumetric charge, established by calculating the difference of the estimated annual revenue from monthly customer charges and the revenue requirement allocated to each customer class divided by historical annual energy consumption. In effect,

[137] Residential and small C&I customers are charged for distribution service primarily on a $/kWh basis, while medium and large C&I customers pay demand charges ($/kW) to recover the costs of their distribution service.
[138] *Long-Term Recommendations* at 41; Whited, Melissa. *The Ratemaking Process* at 1-2 (Jul. 2017).
[139] Nieto, Amparo, *Marginal Cost of Distribution Service and Use for Time of Use Delivery Rate Design* at 4, 7 (May 19, 2025), available at: https://www.mass.gov/doc/topic-1-time-of-use-rate-design-expert-presentations/download.

customers are paying average system costs at all times despite minimal marginal system costs associated with consumption.

Ultimately, distribution rates, whether time-varied or not, should be based on an MCOS study filed in a base distribution case proceeding. DOER recognizes that the marginal cost basis for different distribution infrastructure may justify varying rate structures. For example, TOU rates may not be cost-reflective of local distribution facilities, such as service drops sized to meet customer's service requirements. Primary distribution infrastructure, serving relatively more customers, tends to have greater load diversity and may also be more strongly correlated with broader system peaks than secondary, or local distribution facilities.[140] An MCOS study and an analysis of hourly probabilities of peak on primary distribution should inform the allocation of costs to DOER's recommended peak period for the purpose of designing TOU distribution rates.[141]

The Department recognizes that "the use of a marginal cost study facilitates the development of rates that provide consumers with price signals that accurately represent the costs associated with consumption decisions."[142] The Department, however, has not required the EDCs to file MCOS studies as part of their distribution rate case filings for nearly ten years.[143] The Department's accepted methodology and guidelines in preparing an appropriate marginal cost study, therefore, may need to revisited prior to the EDCs filing MCOS studies in their next base distribution rate case filing to reduce administrative burden.[144] Nonetheless, the Department's precedent is instructive for developing MCOS studies and rate design.[145]

Recommendation: *The Department should provide the EDCs guidance on MCOS requirements during this investigation.*

[140] E3, *DER-iving Local Value: Distribution Grid Services in the Commonwealth of Massachusetts* at 15 *(Sep. 2025),* available at: https://www.masscec.com/sites/default/files/documents/masscec_grid_services_roadmap.pdf. Primary and secondary distribution facilities must both be sized to meet peak demand to ensure reliable service to customers. Primary distribution infrastructure refers to the higher voltage wires and transformers that connect the transmission system to local infrastructure. Secondary distribution infrastructure refers to the lower voltage wires and transformers that deliver electricity to customers.
[141] *Id.* at 10 (May 19, 2025); see, e.g., Central Maine Power Company 2022 Distribution Rate Case Filing, Maine Public Utilities Commission, Docket No. 2022-00152, Testimony and Exhibits of Amparo Nieto at MCOS-9 (Aug. 11, 2022).
[142] *Petition of Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of General Increases in Base Distribution Rates for Electric Service,* D.P.U. 18-150, Order at 516.
[143] *Id.* at 517.
[144] *See, e.g.,* D.T.E. 05-27, Order at 317-322; D.T.E. 03-40, Order at 377, D.T.E. 02-24/25, Order at 243-245
[145] *See, e.g.,* D.P.U. 84-145-A, Order at 65-68.

Several jurisdictions utilize MCOS during proceedings, which can serve as example for Massachusetts. New York, for example, adopted a consistent method for jurisdictional utilities performing MCOS studies to inform rates and other pricing and compensation decisions.[146] Beyond ratemaking, a marginal cost study may provide essential information to ensure load management program offerings and grid services compensation are similarly cost-based.

VI. Customer Experience Recommendations

Transitioning customers to a default TOU rate in a way that maximizes customers' experience and benefits will require a coordinated and measured approach. This section provides recommendations related to enrollment, customer protection, as well as marketing, education, and outreach (MEO) for implementing default TOU, emphasizing evidence and lessons learned from other jurisdictions.[147]

Default TOU Rates with Opt-Out

Default TOU means that all customers are automatically enrolled into the TOU rate. Opt-out means that customers have the ability to proactively choose to a uniform rate.

> ***Recommendation:*** *The Department should direct the EDCs to implement default TOU rates for customers while allowing all customers to opt-out.*

The Department has previously supported default TOU rates for basic service, citing extensive evidence of the benefits of default enrollment.[148] Specifically, the Department found that opt-out TOU rates with a CPP component will, among other benefits, result in more efficient customer electricity usage that will lower the overall cost of the system for all customers in the long-term and strike a balance between clear and accurate price signals and a simple, predictable, and easy to understand pricing regime.[149]

DOER agrees that default, opt-out enrollment in TOU rates has the potential to deliver significantly greater benefits than opt-in rates. Evidence from other jurisdictions shows that

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[146] *Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies*, CASE 19-E-0283 and *In the Matter of the Value of Distributed Energy Resources*, CASE 15-E-0751, Order Addressing Marginal Cost of Service Studies at 12 (Aug. 19, 2024).
[147] *See, e.g., Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations,* Decision 15-07-001 (Jul. 13, 2015), available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF; see also, Phillps, Paul. *Reflections on California's TOU Transition* (Jul. 21, 2025), available at: https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download.
[148] D.P.U. 14-04-C, Order at 13, 21.
[149] D.P.U. 14-04-B, Order at 9-11.

default, opt-out enrollment tends to be more successful because it maximizes customer participation.[150] Opt-out rates when compared to opt-in rates tend to result in higher rate enrollment (e.g., 92% for opt-out versus 15% for opt-in) and similar retention rates (e.g., 88.5% versus 91% in the second year).[151] Maximizing customer participation maximizes the total load exposed to price signals for demand management, increasing the likelihood of reduced system costs.[152] Additionally, greater customer participation under an opt-out approach increases the cost-effectiveness of fixed costs related to implementation and MEO.[153]

Opt-in enrollment to TOU rates can yield a stronger response from participants on a per-customer basis compared to opt-out enrollment; however, due to lower participation, opt-in enrollment will have lower overall load responsiveness and therefore, will have reduced system benefits.[154] For example, Rhode Island Energy expected an opt-out approach to result in nearly 1.7 times the benefits of an opt-in approach.[155]

Default, opt-out TVR has become more common among utilities in the past several years, including in California, Michigan, New York, and Colorado. California implemented default, opt-out TOU rates for all of investor-owned utilities, recognizing that higher load reductions would be provided by default TOU rates as compared to opt-in rates.[156] Further, prior to their current investigation into TOU rates, the Maine Public Utilities Commission found that "the

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[150] United States Department of Energy, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (Nov. 2016) at 27, available at: https://www.energy.gov/sites/prod/files/2016/12/f34/CBS_Final_Program_Impact_Report_Draft_20161101_0.pdf.
[151] *Id* at viii.
[152] *Long-Term Ratemaking Study* at 41-42.
[153] D.P.U. 84-145-A, Order at 65. The Department noted that a "deciding factor in the extent to which the design for a particular rate class should reflect differences in marginal costs as a function of time is the benefit gained by the utility system as a whole compared to the costs of administering the TOU rate. The benefits are a function of the absolute size of the variation in costs between time periods. The costs are any extra metering, meter reading, and billing costs associated with the TOU rate."
[154] *Long-Term Ratemaking Study* at 41-42; further citing, U.S. DOE 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 (Nov. 2016), https://www.energy.gov/sites/prod/files/2016/12/f34/CBS_Final_Program_Impact_Report_Draft_20161101_0.pdf.
[155] The Narragansett Electric Company, d/b/a Rhode Island Energy, RI PUC Docket No. 22-49-EL, *Schedule PJW/WR-1, Book 2 of 3* at 134 (Nov. 18, 2022), available at: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-11/2249-RIE-AMFPlan-Book2%2011-18-22.pdf.
[156] Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor-Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations, Decision 15-07-001 at 95 (Jul. 13, 2015). Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF.

success of a TOU . . . likely requires it to be opt-out," because higher participation rates are necessary to achieve greater system benefits. [157]

Based on a set of consumer behavior studies, the U.S. Department of Energy (U.S. DOE) found that, compared to opt-in TOU, default TOU with opt-out results in greater peak demand reductions (12% versus 6%) and similar retention rates (90% versus 87%).[158] The U.S. DOE also concluded that an opt-out approach can be approximately twice as cost-effective because, in part, enrolling volunteers can require more effort and resources than defaulting customers to TOU rates.[159] This finding reflects, in part, the higher aggregate impact of having a large number of participants reduce load by a lesser degree as compared to a small number of participants reducing load by a greater degree. The Marketing, Education, and Outreach Plan section discusses how widespread MEO efforts, coupled with meaningful bill reductions for responsive customers, are essential to a successful (i.e., high retention, high load response) opt-out program.

The EDCs can implement default TOU for delivery service for all customers in their service territories, and for basic service customers; however, the majority of residential customers currently receive supply service from municipal aggregations or competitive suppliers. Suppliers will have the opportunity to offer time-varying supply products, and municipal aggregations will need to decide whether to offer their customers a TOU rate as the standard default rate option. As a result, if the Department approves default, opt-out transmission and distribution rates for all customers, as DOER recommends, most customers will still only have a limited share of their rate time-varied.

In addition, customers that decline to have an AMI meter installed at their residence will need to be provided with an opt-out rate.[160] Analog meters do not have the ability to measure when electricity is being consumed and therefore cannot support TOU or other TVR measures. DOER recommends the Department evaluate the appropriate pricing for customers who have declined installation of an AMI meter.

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[157] Maine Public Utilities Commission, Report Regarding the Implementation of Time-of-Use Rates Pursuant to Resolves 2023, chapter 79 at 3 (Nov. 20, 2023) at 3, available at: https://www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/TOU%20Report%20-%20Resolves%202023%20ch.%2079.pdf; Philip L. Bartlett II, *Maine Public Utilities Commission: Massachusetts Electric Rate Task Force* at 6 (May 25, 2025), available at: https://www.mass.gov/doc/topic-1-time-of-use-rate-design-expert-presentations/download.

[158] U.S. DOE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* at vi. (Nov. 2016).

[159] *Id.* at vi-vii.

[160] D.P.U. 21-80-B/81-B/82-B, Order on New Technologies and Advanced Metering Infrastructure Proposals at 312-15 (Nov. 30, 2022).

Bill Impacts and Customer Protections

To ensure that default TOU rates promote affordability, it is imperative that the Department considers bill impacts and implements necessary customer protections.[161] Default TOU rates across all three EDCs cannot be implemented until AMI deployment is complete in 2028. This provides ample time for the EDCs to review data, conduct analysis, and engage with stakeholders on how to identify vulnerable populations, beyond customers enrolled on low-income discount rates, and mitigate adverse impacts.

i. Bill Impact Analysis

When EDCs file changes to electric rates, they provide an illustrative bill impact analysis showing how the new rate will impact monthly bills for different example customer types.

Several commenters to DOER's *Ratemaking Straw Proposal* noted that conventional bill impact analyses are not detailed enough to assess the distributional impacts of TVR to various segments of residential customers (e.g., low-income customers, heat pump customers, etc.).[162] The EDCs called for "robust analysis, including an assessment of peak periods and whether system peaks are (and will always be) aligned with distribution system peaks" and called for bill impacts analysis to be conducted on a utility-specific basis prior to implementing any alternative rate.[163]

The Massachusetts Clean Energy Center, on behalf of the IRWG, commissioned E3 to create the Household Energy Expenditure Model (HEEM), which explores bill impacts across diverse customer usage profiles to identify challenges faced by different customer segments beyond the average customer impact.[164] HEEM can be a starting point for the EDCs to conduct more granular bill impact analyses to assess the impacts of TVR.

Dr. Destenie Nock also supported the IRWG by assessing potential impacts of TVR on diverse households and provided recommendations to address energy affordability, protect

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[161] Whited, Melissa, *Lessons and Strategies for Implementing Time-Varying Rates* at 7-8 (Jul. 21, 2025), available at: https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download.

[162] *Acadia Center Comments on DOER's Ratemaking Straw Proposal* at 2 (Dec. 19, 2025); Joint Advocacy Groups *Comments on the Ratemaking Straw Proposal* at 2 (Dec. 19, 2025); *Comment of the Low-Income Weatherization and Fuel Assistance Program Network, the Low-Income Energy Affordability Network (LEAN) and the Massachusetts Energy Directors Association (MEDA)* at 4 (Dec. 18, 2025), available at: https://www.mass.gov/doc/ratemaking-straw-proposal-comments/download.

[163] Electric Distribution Companies Comments on Department of Energy Resources ("DOER") Ratemaking Straw Proposal, at 7-8, available at: https://www.mass.gov/doc/ratemaking-straw-proposal-comments/download.

[164] Cullinan, Sarah, *Interagency Rates Working Group (IRWG) Bill Impact Recommendations* at 2-4 (Jun. 30, 2025), available at: https://www.mass.gov/doc/topic-3-bill-and-distributed-energy-resources-impacts-expert-presentations/download; E3, *Challenges and Opportunities for Electric Rate Reform in Massachusetts* at 6-7 (Jun. 30, 2025), available at: https://www.mass.gov/doc/topic-3-bill-and-distributed-energy-resources-impacts-expert-presentations/download; *Long-Term Ratemaking Study* at 31-34.

vulnerable groups, and incorporate a more data-driven and holistic approach. Dr. Nock's recommendations include:

- enhancing data-driven methods to assess rate impacts and target at-risk customers, such as by monitoring energy-limiting behavior in the summer and winter;
- increasing demographic designations via utility surveys or census tracts; and
- identifying non-shiftable loads (e.g., medical devices) and offer alternative rate structures that do not increase energy burden.[165]

AMI data can be used to assess energy-limiting behavior, energy affordability, and bill impacts of TVR at the customer level. To date, the EDCs have installed AMI for hundreds of thousands of Massachusetts customers, which provide access to granular data to conduct more sophisticated bill impact analyses.[166]

Recommendation: *The Department should direct the EDCs to conduct load research based on available AMI data ahead of TOU rollout to support more granular and distributional bill impact analyses and report on the findings at a technical session.*

Developing the next generation of bill impacts analyses will require further engagement and collaboration with stakeholders, many of whom stated that further analysis is essential to their support of default TOU. As a first step, EDCs and stakeholders can collaborate in developing approaches for identifying vulnerable customers (e.g., customers with medical devices) and analyzing their ability to shift load. The Department could direct EDC to provide data and analysis to characterize the diversity of technology access and load profiles of their customers. The Department, EDCs, and stakeholders -including DOER, AGO, and consumer advocates - could then determine a set of customer profile types that would be representative for TVR bill impact analysis. The Department could then direct the EDCs to file detailed bill impact analyses for those customer profile types when each EDC proposes transmission and distribution TOU rates.

The above approach will allow the Department and stakeholders to understand in greater detail the bill impacts that different customer types will experience under TVR and can inform the design of additional customer protection measures to mitigate negative impacts.

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[165] Dr. Nock, Destinie, *Nock IRWG Recommendations based on the Near- and Long-Term Report* at 8-23, 28-30 (Jul. 21, 2025), available at: https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download.

[166] National Grid, *TVR Implementation Considerations* at 2 (Jul. 21, 2025), available at: https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download. Unitil, *Unitil AMI Deployment Update – 7/10/25* at 1 (Jul. 21, 2025), available at: https://www.mass.gov/doc/topic-4-implementation-and-protections-expert-presentations/download.

ii. Opt-Out, Shadow Billing, and Bill Stabilization

In addition to bill impact analysis, the Department should consider customer protection measures as part of the rollout of default TOU.

Recommendation: *The Department should investigate and adopt critical bill protections, such as opt-out capability for customers, shadow billing, and bill stabilization measures, to mitigate unanticipated or unintended consequences of transitioning customers to a TOU rate.*

Evidence from other jurisdictions' TOU implementation demonstrates that default TOU rates can create affordability benefits for all residential customers, including low-income customers.[167] DOER recommends, however, that all customers be permitted to opt-out of TOU rates, to mitigate severe impacts on specific customers and provide customers with a full suite of options to reduce their energy burden. We note that existing law stipulates how net metering (NEM) credits should be applied under TOU rates, which may incentivize NEM customers to opt out of TOU rates. DOER addresses this concern in the Net Energy Metering section.

DOER also recommends that shadow billing, which is the practice of calculating a customer's bill under both non-TOU and TOU rates and presenting both on a bill, be provided to all customers for a one-year period following enrollment. This allows customers to determine whether opting out would reduce their energy burden, empowering them to decide which rate is more beneficial.

DOER further recommends that the EDCs analyze the impacts of bill stabilization for all qualified low-income customers for a one-year period following enrollment on TOU rates. Bill stabilization is a method by which customers are held harmless: they pay the lower of their bill under either TVR or a uniform, volumetric rate. While bill stabilization can be a valuable tool to minimize harm to low-income customers, it requires that customers in other rate classes subsidize those that receive bill stabilization. Before the EDCs implement bill stabilization, therefore, the Department should weigh the benefits and costs of such a measure.

[167] Opinion Dynamics, *Assessing Equity in TOU: How Low-Income Customers Fare on Time of Use Rates*, Table 4 at 7 (2020), available at: https://opiniondynamics.com/wp-content/uploads/2021/06/2020_ACEEE-Summer-Study_Assessing-Equity-How-Low-Income-Customers-Fare-on-TOU_Rates_Folks.pdf.

Finally, DOER recognizes that the statewide low-income discount rate framework, which the Department recently adopted, will substantially reduce energy burden for qualified customers under both TOU and a uniform volumetric rate.[168]

Customer Transition Plan

Customers should be transitioned to TOU rates in a strategic manner that minimizes adverse customer experience.

> ***Recommendation:*** *The Department should direct the EDCs to jointly prepare a customer transition plan for Department review and stakeholder input during the course of the investigation.*

Specifically, DOER recommends the Department direct the EDCs to prepare a customer transition plan that addresses: (1) implementation timeline; (2) sequencing of TOU roll-out; (3) customer opt-out process; (4) incremental implementation costs, including costs for MEO, customer contact center, web application and app portal, billing system upgrades, and back-office customer account maintenance; and (5) associated tracking and reporting.[169]

DOER expects that EDCs will prepare company-specific transition plans each time they file a proposal to time-vary electricity charges (e.g., basic service, transmission, and distribution); however, a model, joint implementation plan will promote administrative efficiency and facilitate greater input from stakeholders.

The customer transition plan should draw upon lessons from other jurisdictions to expeditiously enroll all customers, and consider:

- customer bill impacts and relevant geography when sequencing the transition from uniform rates to TVR to minimize harm and better target marketing, education, and outreach;
- the appropriate timing to provide shadow billing ahead of implementation to allow customers time to prepare for new rates;
- operational feasibility and quality control to transition the maximum number of customers each month;
- the appropriate timing of implementation to avoid transitioning customers during periods when customer bills are highest, such as summer and winter;
- coordination with municipal aggregations and suppliers; and

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[168] D.P.U. 24-15-B, Order at 20-21, 28; D.P.U. 23-150 Order at 577-580. The Department approved National Grid's proposal to implement a tiered discount rate framework for qualifying electric income-eligible customers during its most recent base distribution rate case in 2024.

[169] *See, e.g.,* D.P.U. 25-55, Exh. ES-HP-5 (Compliance)(Rev.) (Aug. 7, 2025), available at: https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aeeiecdhj?YjtY432CpRexDZ3mFyyo9vQhs/2b91Ji2Ak1vuq3aS6PcSxI+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6ngIfa80wd3rxFD8G4j981M2Rna9aVTXA

- flexibility to adjust to new circumstances and implement lessons learned during roll-out.

Marketing, Education, and Outreach Plan

Transitioning from uniform rates to TOU will require coordinated communications efforts by the EDCs to inform and educate customers about the change. The EDCs have ample experience in creating robust MEO plans for their Three-Year Energy Efficiency Plans.[170] The IRWG[171] and Rate Task Force[172] provide resources and recommendations for developing MEO plans for default TOU, including lessons learned from other jurisdictions.[173]

Recommendation: *The Department should direct the EDCs to develop a joint MEO plan for Department review and stakeholder input during the course of the investigation.*

Stakeholders should include MEO professionals, low-income advocates, community groups, aggregators, suppliers, and others. Stakeholders should work with the EDCs to identify MEO strategies and data-analytic tools, including the usage of AMI data,[174] to create a comprehensive, targeted plan that communicates the benefits of TVR.

Many aspects of implementation and MEO plans do not require a Department decision on rate design details and are relevant to other TVRs in the Commonwealth. A delay in the development of such plans, therefore, risks a timely implementation of TOU rates.

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[170] Mass Save, *Massachusetts 2025-2027 Three-Year Energy Efficiency and Decarbonization Plan* at 298 (Oct. 31, 2024), available at: https://ma-eeac.org/wp-content/uploads/Exhibit-1-2025-2027-Three-Year-Plan.pdf.
[171] *Long-Term Recommendations* at 24.
[172] Dr. Henderson, Courtney, *Marketing, Education, & Outreach* (Aug. 4, 2025), available at: https://www.mass.gov/doc/topic-5-marketing-education-and-outreach-expert-presentations/download. GridX, *Marketing, Education & Outreach (ME&O) for Time-Varying Rate Programs – Best Practices Across the U.S.* at 12-18 (Aug. 4, 2025), available at: https://www.mass.gov/doc/topic-5-marketing-education-and-outreach-expert-presentations/download.
[173] Marke, Geoff, *Peaks and Valleys: Missouri's Time of Use Experience* (Aug. 4, 2025), available at: https://www.mass.gov/doc/topic-5-marketing-education-and-outreach-expert-presentations/download. GridX, *Marketing, Education & Outreach (ME&O) for Time-Varying Rate Programs – Best Practices Across the U.S.* at 19-24 (Aug. 4, 2025), available at: https://www.mass.gov/doc/topic-5-marketing-education-and-outreach-expert-presentations/download. Caputo, Samantha, *Dynamic Rates Engagement* at 24-27 (Aug, 4, 2025), available at: https://www.mass.gov/doc/topic-5-marketing-education-and-outreach-expert-presentations/download.
[174] Caputo, Samantha, *Dynamic Rates Engagement* at 5-8 (Aug, 4, 2025), available at: https://www.mass.gov/doc/topic-5-marketing-education-and-outreach-expert-presentations/download.

Recommendation: *The Department should direct the EDCs to coordinate with stakeholders early in the investigation to develop implementation and MEO plans.*

Early coordination and development of implementation and MEO plans allows for iteration and testing in a manner that will enhance rollout of default TOU while not delaying customer enrollment.[175] To ensure that stakeholders have ample opportunity for input, DOER recommends the Department direct the EDCs to begin coordinating with interested stakeholders as soon as practicable to develop its MEO plan for review.

Monitoring and Evaluation

Ongoing monitoring and evaluation are necessary to verify that TOU rates achieve their intended goals, including reducing peak and rewarding customers for shifting load, while identifying and addressing any unintended bill impacts, particularly for vulnerable or hard-to-shift customers.

Recommendation: *The Department should require the EDCs submit regular (e.g., quarterly) progress reports through enrollment of all residential customers.*

The EDCs' progress reports should contain information including, but not limited to:

- enrollment metrics, updates to rollout plan, and timeline to completion;
- MEO plan adherence, cost, and issues encountered;
- opt-out rates and trends;
- bill impact metrics after enrollment, segmented by demographics and usage patterns; and
- changes in load shape and peak demand.

Additionally, the deployment of AMI will result in large quantities of granular data on customer electricity usage. AMI data can be analyzed in a manner that protects customer privacy while still providing important policy insights.

[175] DOER, *Marketing, Education, and Outreach* at 15-19 (Aug. 13, 2025), available at: https://www.mass.gov/doc/topic-5-marketing-education-and-outreach-targeted-conversation/download.

VII. Program & Policy Integration Considerations

The rollout of TVR will have implications for a variety of existing electric rates and policy programs that are designed around current volumetric rate structures. With careful planning and coordination, TVR can integrate well with these existing rates and programs to deliver policy objectives and customer benefits. This section outlines DOER's recommendations to plan and implement that coordination, in addition to outlining considerations based on the Rate Task Force's discussions.

Low-Income and Tiered Income Discounts

The Department requires all distribution companies, including the EDCs, to provide a discount on utility bills for eligible low-income customers.[176] Currently, Eversource's and Unitil's low-income residential rate class customers receive a 42% and 40% discount on their total electric bills, respectively.[177] National Grid implemented an income-based, five-tiered discount rate for its low-income residential rate class customers in 2025, who receive a 32% to 71% discount on their total electric bills based on qualifying income.[178]

In January 2024, the Department opened an inquiry to examine energy burden with a focus on energy affordability for residential ratepayers.[179] The Department adopted a statewide low-income discount rate framework and directed the EDCs, in addition to gas distribution companies, to implement a tiered discount rate with six tiers on or before November 1, 2026.[180] The Department directed the EDCs to develop discounts for each income-tier based on a target energy burden, which may result in discount rates that vary by EDC.[181]

Bill discounts are applied to a customer's total monthly bill amount, rather than their rate, such that TOU rates need not change how bill discounts are applied. In other words, existing and any future low-income residential rate class customers should continue to be provided the discount rate whether the customer remains on the default TOU rate or opts out.

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[176] G.L. c. 164, s. 1F (4); 220 CMR 11.04 (5)

[177] Eversource offers three low-income residential rate classes: Residential Assistance (R-2), Residential Space Heating Assistance (R-4), and Residential Assistance Heat Pump (R-2HP). Additional tariff information available at: https://www.eversource.com/residential/account-billing/manage-bill/about-your-bill/rates-tariffs/electric-tariffs-rules; Unitil offers two low-income residential rate classes: Residential Assistance (RD-2) and Residential Assistance Heat Pump (HP-RES LI). Additional tariff information available at: https://unitil.com/electric-gas-service/pricing-rates/tariffs.

[178] National Grid offers two low-income residential rate classes: Residential Low-Income (R-2) and Residential Low-Income Heat Pump Rate. Additional tariff information available at: https://www.nationalgridus.com/MA-Home/Rates/Tariff-Provisions. For additional information on the tiered discount rate offering, see: https://www.nationalgridus.com/MA-Home/Payment-Assistance-Programs/Discount-Rates.

[179] D.P.U. 24-15, Vote and Order Opening Inquiry (January 5, 2024).

[180] D.P.U. 24-15-B, Order at 20-21, 28 (February 17, 2026). The Department previously approved National Grid's proposal to implement a tiered discount rate framework for qualifying electric income-eligible customers in 2024. D.P.U. 23-150 Order at 577-580 (September 30, 2024).

[181] D.P.U. 24-15-B, Order at 23-24.

The Department intends to review each EDC's tiered discount rate program approximately 12 months following implementation (i.e., November 1, 2027), as well as in each EDC's base distribution rate case.[182] These reviews present the Department with an opportunity to direct any adjustments to the low-income discount rate framework necessitated by TVR implementation to ensure that the discount rates are achieving the target energy burdens and remain aligned with changes in energy prices or usage trends.

Further, the Department convened a stakeholder working group, co-chaired by representatives from the Attorney General's Office, the distribution companies, and the National Consumer Law Center, to address Phase II issues for low-income discount rates (e.g., enrollment, verification, outreach).[183] The working group continues to explore these issues to inform Phase II of its energy burden investigation and its findings may be relevant to broader MEO strategies.

Heat Pump Rates

The Department approved heat pump rates for qualified residential electric customers of all three EDCs.[184] Heat pump rates differentiate the distribution charge (and, only in the case of Eversource, the transmission charge) between November and April (i.e., heating season) and are available to customers that partially or entirely heat their home with heat pumps. Heat pump rates are designed to be revenue-neutral and offer crucial savings for customers using heat pumps during the heating season.

Unitil began offering its heat pump rate to customers in March 2025, while National Grid and Eversource implemented their heat pump rates on November 1, 2025. The Department continues to investigate heat pump rate design and associated implementation topics, including recommendations from the IRWG.[185] The IRWG recommended that heat pump rates seasonally adjust all reconciling charges, not just the distribution charge, in order to better reflect system costs and to increase savings for ratepayers.

The Department approved the heat pump rates as an interim offering.[186] DOER agrees with the Department that heat pump rates are an interim measure that should be reassessed in the broader context of TVR.[187] TOU rates offer a more holistic approach to delivering similar

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182 D.P.U. 24-15-B, Order at 30.
183 D.P.U. 24-15-B, Order at 7, n. 8.
184 D.P.U. 25-55, Order at 17-27; D.P.U. 23-150, Order at 509-513; D.P.U. 23-80, Order at 406-409.
185 D.P.U. 25-08, Vote and Order Opening Inquiry.
186 D.P.U. 25-55, Order at 22, 27. See also, D.P.U. 23-150, Order at 512-513 ("The [heat pump] rate shall be an interim offering . . . available until [National Grid's] next base distribution rate case, or until an alternative is approved by the Department."); *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Electric Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan*, D.P.U. 23-80, Order at 409 ("In its next base distribution rate case filing, [Unitil] shall propose necessary changes to the heat-pump rate offerings or propose alternative rate offerings designed to address electric home heating solutions.").
187 D.P.U. 25-08, Vote and Order Opening Inquiry at 6-10.

customer benefits that heat pump rates are providing in the near-term; in a future with fully-implemented TOU as DOER proposes here, heat pump rates will be unnecessary.

The EDCs' MCOS studies should inform the transition from heat pump rates to TOU rates. Stakeholders requested analysis of interactions between TOU rates and heat pump rates, as well as bill impacts.[188] The EDCs are also uniquely positioned to evaluate bill impacts and propose mitigation strategies, if necessary, to address the effect of moving those customers to TOU default rates.

Because heat pump rates are differentiated distribution rates (except Eversource, which also adjusts its transmission rate), heat pump customers will not be significantly affected in the near-term by time-varied supply and transmission rates if they are time-varied first, as DOER recommends. The Department found Eversource's proposal to implement lower transmission rates in the heating season to be reasonable and cost-based.[189] Eversource's heat pump rate customers, therefore, would experience similar transmission service pricing based on DOER's recommendation to seasonally vary transmission rates.

Public Benefits Fixed Charges

The Commonwealth recovers the cost of critical climate and affordability policies, including MassSave, the low-income discount rate, and SMART, through volumetric charges. The Department is investigating whether to recover such costs via fixed charges instead of volumetric charges.[190] DOER finds that policy fixed charges (1) promote fairness and cost reflectivity, (2) support electrification, and (3) reduce inter-seasonal bill volatility.[191] Several stakeholders noted general support for DOER's policy fixed charge proposal.[192]

Under the current volumetric approach, a customer's contribution to these critical policies and programs is based on their total electricity consumption, which is unrelated to the total costs of such programs, undermining the fairness and cost-reflectivity of the volumetric electric rate. The volumetric recovery of policy costs also exacerbates seasonal bill volatility, because customers contribute more to policy costs in months when their use, and therefore electric bill, is highest. Public benefits fixed charges smooth cost recovery evenly across months and seasons.

Public benefits fixed charges are an important complement to TOU rates. TOU rates can reflect the time-varied costs associated with electric service – supply, transmission, and distribution – while public benefits fixed charges can similarly promote cost-reflectivity in electric rates. The former provides customers with lower volumetric rates during off-peak periods and the latter results in lower volumetric rates at all hours of the day. Together, they

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[188] *Ratemaking Straw Proposal Comments* (Dec. 19, 2025) at 11, 14.
[189] D.P.U. 25-55, Order at 21.
[190] D.P.U. 25-200, Vote and Order Opening Inquiry.
[191] *Ratemaking Straw Proposal* at 28.
[192] *Ratemaking Straw Proposal Comments* (Dec. 19, 2025) at 30-31, 66, 73-74.

can deliver significantly lower prices during off-peak hours, unlocking savings opportunities essential for load management and electrification to be cost competitive.

Load Management and Demand Response Programs

Load management and demand response programs and policies can complement AMI-enabled TOU rates by providing targeted incentives that support customers in shifting energy use from grid-constrained and high-cost periods. DOER's Peak Potential: Load Management for an Affordable Net-Zero Grid explores the potential for load management in Massachusetts and identifies policy strategies for future load management programs.[193] This report demonstrates that TVR is required to achieve the tremendous potential cost savings from load management. TVR is fundamental to enabling the next generation of effective load management programming like managed EV charging and whole home demand response. TVR may also change the value proposition for some existing programs that target load management.

Several Massachusetts programs incentivize customer behavior aligned with grid conditions and needs, even without AMI yet widely available, including: (1) the *ConnectedSolutions* program, offered through Mass Save, which provides event-based incentives for reducing load based on system peaks; and (2) the EDC's *EV managed charging programs,* which incentivize off-peak EV charging. These programs have been highly effective at addressing system peaks by providing dispatch peak reductions. Once TOU rates are launched to address system-wide peak grid conditions, these programs should evolve to include more technologies and address localized peaks and constraints.

DOER's proposed TOU rates would create a reliable, territory-wide load management resource during the peak window. With TOU rates in place, existing load management programs such as ConnectedSolutions and EV managed charging will need to evolve to become *locational* peak load management. These programs can evolve to address grid events that do not align with the TOU peak window, such as location-specific transmission and distribution constraints, sudden generation stoppages, and extreme weather, when dispatchable flexibility from EVs and other DERs provides value beyond what TOU rates already capture. This will require changes in enrollment and compensation structures to reward marginal, event-driven flexibility and enable significant participation from DER aggregators. Pilots funded by the 2025-2027 Three-Year Energy Efficiency and

[193] DOER, *Peak Potential: Reducing energy costs and empowering consumers with load management and virtual power plants*, (Dec. 2025)(Draft) available at: https://www.mass.gov/doc/doer-peak-potential-report-and-policy-recommendations/download.

Decarbonization Plan[194] and the Grid Services Compensation Fund[195] will demonstrate the provision of additional delivery methods and geotargeted grid services using a combination of AMI- and device-based strategies.

EV managed charging programs must also evolve as TOU rates are implemented. The Department recognized that EV managed charging, including National Grid and Eversource's current managed charging programs, paired with whole-home TOU rates, can effectively reflect the cost of providing electricity to EV charging stations at different times of the day.[196] Managed charging programs, absent changes however, will compensate customers for behavior already incentivized through TOU rates. To remain additive, managed charging must evolve beyond time-based structures towards locational dispatch and must respond to localized grid constraints. Active managed charging, which involves utilities or third-party aggregators directly controlling charging speed and timing, can efficiently detect and respond to these localized constraints. When paired with TOU rates, active managed charging can also better integrate renewable generation by automatically increasing charging during periods of high solar output and reducing charging when generation declines.

Future load management programs should also be designed to mitigate "rebound peaks" resulting from a transition to TOU rates.[197] A rebound peak refers to the unintended consequence of shifting peak demand to the beginning of the off-peak period. For example, if EV customers all schedule their EV to charge as soon as the lower off-peak rate begins at 8 PM, this could create an unintentional "rebound peak" at 8 PM as EV charging load surges. The EDCs have significant operational insight through their current EV managed charging programs that can inform program changes that can mitigate rebound peaks.

Net Energy Metering

Net energy metering (NEM) is a policy that allows customers with qualifying renewable energy systems to receive credit on their electric bill for net excess electricity they send back

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[194] Mass Save, *Massachusetts 2025-2027 Three-Year Energy Efficiency and Decarbonization Plan* at 144-145, 322 (Oct. 31, 2024), available at: https://ma-eeac.org/wp-content/uploads/Exhibit-1-2025-2027-Three-Year-Plan.pdf. In 2026, National Grid plans to launch a behavioral demand response program following the scaled deployment of AMI to ensure significant metering saturation.

[195] *Petition of [the EDCs], pursuant to G.L. c. 164, § 92B, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan,* D.P.U. 24-10/24-11/24-12, Order Approving Electric Sector Modernization Plans (ESMPs) at 176-177, 198, 217-218, 250 (Aug. 29, 2024).

[196] *Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval to Offer Optional Electric Vehicle Time-of-Use Rates,* D.P.U. 23-84 and *Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval to offer Optional Electric Vehicle Time-of-Use Rates,* D.P.U. 23-85, Order at 20-21.

[197] *Long-Term Ratemaking Study* at 42; E3, *The Economics of Electrification in Nova Scotia* (Oct. 2023), available at: https://www.ethree.com/wp-content/uploads/2023/12/E3_NS-Power_Electrification-Report-1.pdf.

to the grid.[198] NEM is available to qualifying residential, commercial, and industrial customers in Massachusetts and provides a bill credit based on the customer's rate class.[199]

The EDCs calculate the NEM credit based on a formula set in statute utilizing inputs from the customer's total retail rate as determined by the customer's rate class.[200] As a result, the net metering status quo is that the only consistent variable is the basic service change in price twice a year, because the rest of the components are stable until the Department approves a rate change. Basic service, transmission, and distribution TOU rates will, therefore, impact NEM customers by changing customers avoided costs and NEM credits based on the relationship between NEM facility generation and time-of-use periods.

TOU rates provide more cost-reflective signals to NEM customers, yet the transition will change these customers' overall compensation. Current law and practice establish how energy is "netted out" and how net metering credits should be calculated during a billing cycle for a customer account on a TOU rate. NEM credits are calculated separately for each defined TOU period (*e.g.*, peak, off-peak), across the duration of the billing cycle. This incentivizes net metering resources to discharge their output to the grid during peak periods, when compensation rates are higher, and shift consumption to off-peak periods. This incentive structure is cost-reflective, because it compensates for NEM generation when it is most valuable to the grid, encouraging customers to manage or shift energy consistent with these signals.[201]

The Commonwealth's solar incentive program, the Solar Massachusetts Renewable Target (SMART) program sets incentives based on total compensation levels.[202] The transition to TOU rates should not hinder Massachusetts solar deployment because the SMART program's solar incentive payments will complement any changes to the value of energy, such that total compensation rate will continue to support projects.

Non-solar or NEM customers not participating in the SMART program, may see a reduction in overall expected savings as a result of the transition to TOU rates because their generation and usage will be netted within the peak and off-peak periods for each billing cycle. This may

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[198] Meserve, Samantha. Impacts on Existing Policies and Incentive Programs (Jun. 30, 2025), available at: https://www.mass.gov/doc/topic-3-bill-and-distributed-energy-resources-impacts-expert-presentations/download.

[199] For more information regarding net metering, see: https://www.mass.gov/net-metering.

[200] NEM credits for renewable energy are calculated as the sum of (1) default or basic service, (2) distribution charge, (3) transmission charge, and (4) transition charge. For most solar NEM facilities, this sum is then multiplied by 60 percent to arrive at the final value to apply to the excess generation. For NEM facilities of municipalities or other governmental entities the value remains 100 percent of the calculated sum. G.L. c. 164 §§ 138, 139.

[201] E3, *Challenges and Opportunities for Electric Rate Reform in Massachusetts* at 17 (Jun. 30, 2025), available at: https://www.mass.gov/doc/topic-3-bill-and-distributed-energy-resources-impacts-expert-presentations/download

[202] Under the SMART program, the base compensation rate is equal to the value of energy plus the solar incentive payment.

incentivize some NEM customers to opt-out of TOU rates (when they become available) in order to preserve the greater savings and compensation available to them under current rate design. NEM customers opting-out of TOU rates, however, also prevents the benefits associated with reducing peak demand and saving system costs to benefit all ratepayers.

DOER recommends that all customers, including NEM customers, have the option to opt-out of TOU rates. NEM customers, however, should be disincentivized from bypassing the cost-reflective price signals that TOU rates provide. To mitigate this disincentive, the EDCs may propose a monthly minimum reliability contribution (MMRC) for NEM customers that opt-out of a TOU rate.[203]

The essential purpose of an MMRC is for all EDC customers to contribute to the fixed costs that ensure the reliability, proper maintenance, and safety of the electric distribution system. Well-designed MMRCs would serve to ensure NEM customers are not unduly avoiding contributing to the costs of reliably operating the distribution system.[204] An MMRC proposal should be supported by newly available AMI data and cost of service data across all rate classes – including the EDC's ACOS and MCOS studies.[205]

Portfolio Standards

Massachusetts has several portfolio standards that promote renewable or other low-carbon generation, including the Renewable Energy Portfolio Standard (RPS), Alternative Energy Portfolio Standard (APS), Clean Peak Energy Standard (CPS), and Clean Energy Standard (CES) (together, portfolio standards). DOER administers the RPS, APS, and CPS, while the Massachusetts Department of Environmental Protection (DEP) administers the CES.

Under these portfolio standards, suppliers are obligated to purchase and retire compliance certificates from qualifying resources on behalf of their customers, or make an alternative compliance payment (ACP), based on total energy delivered in a given compliance year.[206] As such, a uniform volumetric charge ($/kWh) is cost-reflective. Suppliers include an estimate of the projected market price of compliance, reflected in customers' competitive retail supply product offerings. The EDCs separately manage the portfolio standard requirements associated with basic service customers, as opposed to the selected suppliers; DOER does not recommend the EDCs time-varying the compliance costs in basic service pricing.

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[203] Pursuant to G.L. c. 164, §139 (j), the EDCs may file an MMRC proposal for Department review and approval.
[204] *Investigation of the Department of Public Utilities, on its own Motion, Instituting an Emergency Rulemaking pursuant to G.L. c. 164, §§ 138 and 139; G.L. c. 30A, § 2; 220 C.M.R. §§ 2.00 et seq.; and Executive Order 562, to Amend 220 C.M.R. § 18.00 et seq,* D.P.U. 16-64, Hearing Officer Memorandum at 3-5 (Aug. 19, 2016). The Department's straw proposal should be instructive in establishing an MMRC.
[205] Pursuant to G.L. c. 164, §139 (j), the EDCs may file an MMRC proposal for Department review and approval.
[206] 225 CMR 14.00, 15.00, 16.00, 21.00 and 310 CMR 7.75.

The CPS incentivizes qualified clean peak resources to supply electricity or reduce demand during seasonal peak periods that historically coincide with Massachusetts' peak electricity demand.[207] DOER defines clean peak seasons and seasonal peak periods in regulation, which establish the time of day in which a resource generates Clean Peak Energy Certificates (CPECs).[208] DOER's recommended peak period of 4-8 PM aligns with CPS' seasonal peak period between May 15 and February 28 (i.e., Summer, Fall, and Winter). DOER is not concerned with the difference in its recommended peak period and the CPS. TOU rates and the CPS are distinct, but complementary policies, that will require further evaluation as peak periods evolve in the future.

[207] G.L. c. 25A, § 17; 220 CMR 21.00.

[208] 220 CMR 21.05 (3) and (4). Currently, the four clean peak seasons are defined as: (1) spring – March 1 through May 14; (2) summer – May 15 through September 14; (3) fall – September 15 through November 30; and (4) winter – December 1 through February 28. The seasonal peak periods are defined as 5:00 – 9:00 PM in spring, and 4:00 – 8:00 PM in the other three clean peak seasons. DOER determines the seasonal peak periods, though G.L. c. 25A, § 3 limits the period to one to four hours.

Appendix

MA EDC Time-Varying Rates

Rate	Time Periods	Demand Charge Component
Eversource		
T-1 Optional Time of Use (Greater Boston) (Closed)	Peak: 9 AM - 6 PM (summer weekdays); 8 AM – 9 PM (winter weekdays) Off-peak: all other hours Summer: Jun-Sep/ Winter: Oct-May	No demand charge
T-4 Optional Medium General Service Time of Use (Western MA)	Peak: 12-8 PM Off-peak: all other hours	Non-TVR demand charge
T-5 Extra Large General Service (Wester MA)	Peak: 12-8 PM Off-peak: all other hours	Peak or coincident peak demand charge
G-7 Optional General Time of Use (South Shore/Cape & Vineyard) (Closed)	Peak: 9 AM – 6 PM (weekdays, eastern daylight savings time); 4-9 PM (weekdays, eastern standard time) Off-peak: all other hours	Non-TVR demand charge
G-6 Optional Time of Use (Cambridge) (Closed)	Peak: 9 AM - 6 PM (weekdays, eastern daylight savings time); 4-9 PM (weekdays, eastern standard time) Off-peak: all other hours	No demand charge
G-3 Large General Service (Western MA)	Peak: 12-8 PM Off-peak: all other hours	Peak or coincident peak demand charge
National Grid		
G-3 General Service Time-of-Use	Peak: 8AM – 9 PM (weekdays, non-holidays) Off-peak: all other hours	Peak or coincident peak demand charge
Unitil		
GD-3 Large General Delivery Service	Peak: 10 AM – 10 PM (non-holiday weekdays) Off-peak: all other hours	Non-TVR, on-peak demand charge
GD-4 Optional General Delivery Time of Use	Peak: 10 AM – 10 PM (non-holiday weekdays) Off-peak: all other hours	Non-coincident peak demand charge
EV-RES	Peak: 3-8 PM (non-holiday weekdays) Mid-peak: 6 AM – 3 PM (weekdays, non-holidays) Off-peak: 8 PM – 6 AM (all other days)	No demand charge

MLP Time-Varying Rates

Customer and Enrollment Type	Time Periods	Seasonality
Concord Municipal Light Plant[209]		
Residential default, opt-out	Peak: 3-7 PM (weekdays) Super off-peak: 1-5 AM (all days) Off-peak: All other hours	Standard: Dec-Feb, May-Sep Shoulder: All other months
Groton Electric Light[210]		
Residential, opt-in	Peak: 4-8 PM Off-peak: All other hours	Standard: All other months Winter: Dec-Mar
Belmont Light[211]		
Residential, opt-in (pilot, enrollment closed)	Peak: 2-7 PM (summer); 4-8 PM (non-summer) Off-peak: all other hours	Summer: Jun-Sep Non-summer: Oct-May
Reading Municipal Light Department[212]		
Residential, opt-in	Peak: 12-7 PM (weekdays, non-holidays) Off-peak: all other hours	No seasonality

[209] https://concordma.gov/4060/Time-of-Day-Electric-Rates
[210] https://www.grotonelectric.org/rates/tou-rates/
[211] https://www.belmontlight.com/customer-services/residential-rates/
[212] https://www.rmld.com/160/Rate-Information

Massachusetts Load & Price Analysis

This appendix provides a brief overview of each schedule within Exhibit C: Massachusetts Load & Price Analysis.

Schedule 1 aggregates Massachusetts wholesale load zone demand and pricing information between 2011 and 2025.[213] DOER amended this data with several helper columns to inform analysis. The 'Rank_DA_Demand' and 'Rank_RT_Demand' columns rank order each hour of day-ahead demand and real-time demand within each year and load zone. The 'Peak_Indicator' column dynamically indicates which hours are defined as peak based on user inputs (e.g., top count/top %, real-time/day-ahead). The 'Monthly_RT_Demand_Peak_Indicator' column reflects the monthly real-time peak demand hour. Finally, the 'Non-Holiday Weekday' column identifies non-holiday, weekdays.

Schedule 2 shows the likelihood that each hour is among the system's most stressed hours based on a user-defined range of years.

Schedule 3 shows the change in likelihood of months and years being peak between a user-defined reference period and the period defined in Schedule 2.

Schedule 4 presents average day-ahead LMP by month and hour of non-holiday weekdays during a user-defined range of years. It also shows average non-weighted peak and off-peak pricing based on a user-defined peak period definition. The P/OP ratio indicates the relationship between the former and latter.

Schedule 5 presents average real-time LMP by month and hour of non-holiday weekdays during a user-defined range of years. It also shows average non-weighted peak and off-peak pricing based on a user-defined peak period definition. The P/OP ratio indicates the relationship between the former and latter.

Schedule 6 shows average real-time demand by month and hour of non-holiday weekdays during a user-defined range of years.

Schedule 7 shows average day-ahead demand by month and hour of non-holiday weekdays during a user-defined range of years.

Scheduled 8 identifies the frequency of monthly peaks occurring in each hour during a user-defined range of years.

[213] ISO-NE, SMD Hourly Data, available at: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info.