Commonwealth of Massachusetts
Department of Public Utilities

Inquiry by the Department of Public Utilities on its own Motion into the Design and Implementation of Time-Varying Rates.	))	D.P.U. 26-62

Initial Comments
The Energy Consortium & PowerOptions, Inc.

I. Introduction and Executive Summary

The Energy Consortium (TEC) and PowerOptions appreciate the opportunity to jointly submit comments to the Massachusetts Department of Public Utilities (the "Department") on the design and implementation of time-varying rates (TVR). We submit these comments in response to the Department's Vote and Order Opening Inquiry[1] and its Notice of Inquiry and Request for Comments.[2]

TEC is a nonprofit association representing commercial, industrial, institutional, and governmental large energy users in Massachusetts. For roughly 40 years, TEC has participated actively in state and regional energy regulatory proceedings, advocating for fair cost-based energy rates, diversified supplies, retail market competition, and reliable service for its Member organizations, their employees and all Massachusetts ratepayers.

PowerOptions is a nonprofit energy consortium serving more than 800 public and nonprofit entities in Massachusetts and across New England, including, but not limited to, municipalities, public schools, higher education institutions, hospitals, senior living facilities, and public and private affordable housing providers. Our Members are mission-driven and budget-constrained, and they depend on stable, understandable energy costs to deliver essential services to communities across the Commonwealth. For more than two decades, PowerOptions has participated in Massachusetts' energy regulatory proceedings, often in coordination with TEC, advocating for rate designs and market structures that serve its public and nonprofit Members.

Together, our organizations represent a sizeable share of the Commonwealth's commercial, industrial, institutional, municipal, and nonprofit load. Our collective Members span every segment of the commercial spectrum: single-meter community organizations that take service similar to residential customers; municipalities and school districts operating hundreds of small accounts; hospitals that require 24/7 electric service; universities whose annual load patterns are unique to their academic schedule; and industrial facilities, taking demand-metered service at

[1]Inquiry by the Department of Public Utilities on its own Motion into the Design and Implementation of Time-Varying Rates, D.P.U. 26-62, Vote and Order Opening Inquiry (June 30, 2026) (Vote and Order).

[2]D.P.U. 26-62, Notice of Inquiry and Request for Comments (July 21, 2026) (Notice).

scale. The comments below are informed by that full range rather than by any one segment of the commercial and industrial sector.

PowerOptions and TEC each participated in the Massachusetts Electric Rate Task Force, and each submitted written comments on DOER's Ratemaking Straw Proposal in December 2025.[3] PowerOptions addressed the treatment of commercial and industrial customers, cost causation, peak period length, customer protections, and competitive supply. TEC addressed interval data settlement with ISO-NE, cost causation in commercial ratemaking, consolidated statewide time-of-use periods, seasonal rate phase-in, opt-in rates for highly flexible customers, and the treatment of reconciling mechanisms. The positions set out below build on both of those filings.

We commend the Department of Energy Resources (DOER) for the stakeholder process that produced its Time-of-Use Rate Proposal,[4] as well as the Department for opening this inquiry promptly. DOER's proposal is thorough, and it moved in response to stakeholder input on several points that matter to our Members. Because we support the direction it sets, the comments that follow are directed at where the proposal still needs development before the Department settles on an implementation framework.

Our principal positions, each developed in the sections that follow, are summarized below:

- TVR reform should be holistic, because a framework that addresses only non-demand accounts leaves the majority of commercial load, and with it a substantial share of the Commonwealth's near-term load flexibility potential, outside the reform. The demand-metered rate classes warrant the same attention as the non-demand classes.
- The analysis described in DOER's proposal is largely constructed around residential customer profiles, but cost and bill impact analysis should cover all customer segments. The Department should require that commercial, institutional, municipal, and nonprofit customer types be examined with the same rigor.
- The peak period should be four hours, consolidated across supply, transmission, and distribution, and subject to periodic review, which is the correct trade-off even though a single window will not be a perfect price signal for every cost component.
- ISO-NE load settlement and third-party data visibility should be treated as prerequisites rather than parallel workstreams for TVR implementation. Most of our Members do not take basic service, and without settlement-quality interval data flowing to competitive

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[3]PowerOptions, Comments on Ratemaking Straw Proposal (Dec. 18, 2025); The Energy Consortium, Comments on the Ratemaking Straw Proposal Released on November 24th, 2025 (Dec. 2025). Both are available at: https://www.mass.gov/doc/ratemaking-straw-proposal-comments/download, and are included in the record of this proceeding at Exhibit E to DOER's Petition.

[4]Petition of the Massachusetts Department of Energy Resources Requesting the Department of Public Utilities Open an Investigation into Time-Varying Rates, Exhibit A, Time-of-Use Rate Proposal (Apr. 8, 2026) (Exh. A).

suppliers and authorized third parties, a default basic service TVR will deliver exposure to those Members without any corresponding opportunity.

- Customer protections and marketing, education, and outreach (MEO) should reach commercial accounts, and particularly the smaller nonprofit and community-serving organizations that take service on the same non-demand rates as residential customers.
- Price signals should be durable, because durable price signals are the only way to effectively promote adoption of distributed energy resources (DER). The Department should coordinate TVR with existing DER programs and long-term contracts and should avoid disrupting the compensation basis for assets already committed under agreements of ten to twenty years.

II. General Comments on DOER's Time-of-Use Rate Proposal

A. TVR Reform Should Be Holistic and Should Reach Demand-Metered Rate Classes

DOER's proposal advances TOU rates furthest for non-demand customers, recommending that the Department direct the EDCs to file revenue-neutral TOU transmission rates for those customers on or before June 18, 2027, for rates effective no later than May 1, 2028.[5] For distribution, DOER recommends that the EDCs propose rates informed by a marginal cost of service study and TOU analysis in their next base distribution rate cases.[6] Medium and large commercial and industrial customers therefore sit largely outside the near-term scope of the reform proposed.

We understand the reasoning behind that sequencing, which rests on the fact that demand-metered customers already face non-coincident demand charges and, in some classes, coincident peak transmission billing, and that customers not served on uniform volumetric rates present a less apparent case for immediate change than the non-demand classes do. We nonetheless ask the Department to look past this framing.

Existing TOU delivery structures for large commercial and industrial customers are time-varying in name more than in effect. National Grid's Rate G-3, the general TOU class for customers with billing demand above 200 kW, sets a thirteen-hour peak period of 8:00 a.m. to 9:00 p.m. on non-holiday weekdays, nearly 39 percent of the hours in a month and the entirety of business hours. Eversource's Rate G-3, available to Greater Boston customers metered at 14,000 volts or greater, uses the same thirteen-hour window from October through May and a nine-hour window from June through September.

Similarly, Unitil's large general service rate places on-peak hours between 10:00 a.m. and 10:00 p.m. on non-holiday weekdays.

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[5]Exh. A at 38-39.

[6]Exh. A at 42-43.

Furthermore, these rates lack a meaningful differentiation of the volumetric energy charge as the proposed framework contemplates for non-demand customers. Eversource's currently effective Greater Boston rate summary lists peak and off-peak distribution energy charges for the G-3 Rate as separate line items, but both are set at $0.00964 per kWh representing an On-Peak to Off-Peak ratio of 1:1.

The disconnect this creates is the point we ask the Department to carry forward into this proceeding. Against DOER's proposed four-hour peak period of 4:00 p.m. to 8:00 p.m., the peak periods embedded in the delivery tariffs that serve our larger Members run more than twice that length, and in the October through May period more than three times that length, beginning as much as eight hours earlier in the day. The divergence is not one of duration alone, because in the June through September period Rate G-3's peak ends at 6:00 p.m. while the proposed window runs to 8:00 p.m., so that two of the four hours the proposal treats as the system peak are currently priced as off-peak for these customers. A framework that defines the Commonwealth's peak as 4:00 p.m. to 8:00 p.m. for one set of customers, while leaving 8:00 a.m. to 9:00 p.m. in place for another, tells two groups of customers two different things about when the system is under stress, and our Members operate on both sides of that line, in many cases within a single organization.

The practical result is that our Members cannot plan against a consistent understanding of when the Commonwealth's peak occurs, and a thirteen-hour window is in any event too wide to shift load out of in the way a four-hour window invites. PowerOptions made this point to the DOER in December 2025, and the currently effective tariffs bear it out.[7]

TEC and PowerOptions have both advocated for narrower and more actionable commercial peak periods, working together most recently in D.P.U. 23-150.[8] That testimony focused on the changing load dynamics in New England and that daily minimum loads were increasingly projected to occur during the daytime hours in shoulder months due to excess solar and that the dispersion of peak hours by month and annually does not reflect the distribution tariff peak period.[9] It also showed that daily summer peak demand values are becoming increasingly concentrated in the late afternoon, largely due to the impact of BTM solar reducing loads earlier in the day.[10] This testimony clearly laid out the problem statement that DERs have fundamentally changed system load patterns, resulting in excess solar in the morning and early afternoon hours, but distribution TOU periods have not changed. Presently, a customer would be penalized with demand charges for ramping up their load to consume excess solar. The currently legacy C&I TOU periods are now in direct conflict with Massachusetts state policy to encourage full utilization of renewable energy.

[7] PowerOptions, Comments on Ratemaking Straw Proposal at 2 (Dec. 18, 2025) (observing that existing G-3 time-of-use structures offer on-peak and off-peak delivery rates with very broad peak windows and minimal or no price differential between periods).

[8] D.P.U. 23-150, Direct Testimony of A. Nutter at 23-29 (Mar. 29, 2025) and Sur-Rebuttal Testimony of A. Nutter at 5-10 (May 3, 2025).

[9] DPU 23-150 Exhibit TEC/PO-JDB/AN-1, pp. 24-26

[10] DPU 23-150 Exhibit TEC/PO-JDB/AN-Surrebuttal-1, p. 8

A related point follows from our straw proposal comments, which caution against treating a harmonized peak period as a one-size-fits-all outcome. Some of our Members with highly flexible load or storage currently utilize the opt-in coincident peak transmission billing option available to large customers and are able to provide demand response that benefits the system as a whole. Rate options of this kind should be preserved notwithstanding their low customer counts. The customers who select them are self-selecting based on their load flexibility, which is the characteristic the Commonwealth is seeking to cultivate. Moving toward a consolidated peak period for most customers should not come at the cost of eliminating the more granular options that the most responsive customers already use.[11] The Rate G-3 tariff provides for this election, and conditions it on the customer remaining on the elected option for a minimum of twelve consecutive months.[12]

We are not asking the Department to redesign demand and delivery charges in this docket, but rather to state expressly that all commercial and industrial rate classes, including those with demand meters, will be brought into the TVR framework, and to ensure that the analysis developed here supports that work rather than excluding it. We ask first that the empirical analyses the Department has ordered from the EDCs support peak period evaluation for all rate classes, not only non-demand classes, and second that when the EDCs file distribution rate proposals informed by marginal cost of service studies, the Department require those filings to address the alignment, or misalignment, between the consolidated TVR peak period and the peak periods embedded in existing demand-metered tariffs. A Commonwealth-wide peak period of 4:00 p.m. to 8:00 p.m. and a Rate G-3 peak period of 8:00 a.m. to 9:00 p.m. cannot both be cost-reflective.

This is not solely a question of fairness between customer classes, as Executive Order No. 654 directs the Department to expedite review of proposals that unlock the benefits of time-of-use rates, distributed energy resources, and virtual power plants.[13] A substantial share of the load flexibility contemplated by that order sits behind demand meters, in the chillers, thermal systems, batteries, and building controls that our Members operate, and a TVR framework that does not reach those meters will not reach that flexibility.

B. Cost and Bill Impact Analysis Should Cover All Customer Segments

DOER recommends that the EDCs conduct load research using available AMI data, characterize the diversity of technology access and load profiles across their customers, and develop representative customer profile types for bill impact analysis. We support that recommendation, while noting that the analytical tools DOER cites in support of it were built to assess residential

[11] The Energy Consortium, Comments on the Ratemaking Straw Proposal at 2 (Dec. 2025).

[12] M.D.P.U. No. 13I at 2 (Transmission Billing Adjustment).

[13] Executive Order No. 654, To Secure Massachusetts' Energy Future by Establishing an Energy Supply Plan that Drives Affordability and Reliability, sec. 3(5) (Mar. 16, 2026), 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.

outcomes.[14] The customer segments named throughout that discussion are low-income customers, heat pump customers, and customers with medical devices.

Those are important segments, and they deserve the attention DOER gives them, but they do not describe the whole customer population that a default rate will reach. The Department should direct the EDCs to develop representative commercial profile types with the same care, and those profiles should include at minimum:

- small nonprofit and community-serving organizations on non-demand service, including houses of worship, food pantries, human service providers, and small cultural institutions;
- municipalities and school districts operating diverse portfolios that combine large facilities with many small, low-usage accounts such as pump stations, signals, streetlights, and small municipal buildings;
- 24/7 operations with limited curtailment flexibility, including hospitals, emergency services, congregate care, and water and wastewater facilities;
- affordable housing properties, including master-metered and sub-metered configurations; and
- demand-metered institutional and industrial customers across load factor ranges.

C. Peak Period Design

We appreciate DOER's move to a four-hour peak period of 4:00 p.m. to 8:00 p.m.[15] PowerOptions raised concerns about the initial five-hour proposal in December 2025, on the basis that short-duration storage is often designed around roughly four hours of discharge and that sustaining load reductions across a five-hour window would be difficult for many facilities without significant additional investment. The four-hour window is materially better aligned with the physical capability of the assets that our Members have installed or are evaluating.

We also support a single consolidated peak period across supply, transmission, and distribution.[16] We recognize that a consolidated window will not be a perfect price signal for each cost component, and that distribution peaks in particular may be local and may not coincide with the ISO-NE system peak. We accept that trade-off, because a single window that customers can understand, communicate internally, program into building automation systems, and hold constant across a budget cycle is more likely to produce load shifting in practice than a technically superior set of component-specific windows that proves difficult to operationalize at the facility level. Simplicity carries independent value across the full range of customers we represent, and it carries

[14] Exh. A at 47-48. DOER cites the Household Energy Expenditure Model and Dr. Nock's recommendations, each developed to assess impacts across residential customer segments.

[15] Exh. A at 21-22. DOER states that the 4:00 p.m. to 8:00 p.m. window would have captured 87 percent of the annual system peaks in each load zone over the past five years.

[16] Exh. A at 23.

the most value for the smaller commercial accounts that take service on rates analogous to residential ones.

We support DOER's recommendation that the EDCs jointly prepare an annual report reviewing the peak period and amending it as system needs change.[17] We ask the Department to pair that flexibility with predictability, and to define what a reasonable amendment cadence is before adopting one.

We are not persuaded that an annual review should carry an expectation of annual change, and we ask the Department to consider whether a yearly amendment cycle is too frequent to be workable. A facility that installs storage, reprograms its building automation system, or restructures its operating schedule around a 4:00 p.m. to 8:00 p.m. window needs that window to remain in place long enough for the change to return value, and a peak period that moves every year is difficult to plan against. We therefore suggest that the Department distinguish between an annual review, which we support, and an annual adjustment, which warrants considerably more caution. A reasonable construct would establish a multi-year default term for the peak period, permit amendment within that term only where the EDCs demonstrate a material divergence between the window and observed system conditions, and require that any amendment be announced well in advance of its effective date, phased where the change is significant, and accompanied by an assessment of the effect on customers that acted on the basis of the prior window.

A similar caution applies to seasonal differentiation, and we note that Eversource moved from seasonal pricing to flat pricing in its rate design, reportedly in response to customer feedback.[18] We therefore recommend that any move toward seasonal pricing be phased in. Season definitions should be stable, announced well in advance, and introduced in a manner that lets customers adjust operations and budgets across at least one full cycle before the financial consequence attaches.

Finally, we ask the Department to resolve day-type treatment expressly. DOER recommends a 4:00 p.m. to 8:00 p.m. peak period applicable in all months, but the proposal does not state whether that period is intended to apply on weekends and holidays, and the supporting load and price analysis is presented for non-holiday weekdays. The Department, by contrast, has directed the EDCs to analyze the appropriateness of the window for each day type, and nearly every existing Massachusetts time-varying tariff limits the peak period to non-holiday weekdays.[19] Unless the EDCs are able to produce evidence to the contrary, peak periods for C&I customers should be

[17]Exh. A at 23-24; Vote and Order at 6 n.7.

[18]The Energy Consortium, Comments on the Ratemaking Straw Proposal at 2 (Dec. 2025) (noting that Eversource moved from seasonal pricing to flat pricing in its rate design, reportedly driven by customer feedback, and recommending that any move toward seasonal pricing be phased in), citing D.P.U. 22-22.

[19]Compare Exh. A at 21-24 and Exhibit C, Schedules 4 through 7 (presenting day-ahead and real-time prices and demand by month and hour for non-holiday weekdays), with Vote and Order at 10 (directing the EDCs to analyze the appropriateness of a single four-hour peak window from 4:00 p.m. to 8:00 p.m. for each day, meaning weekday, weekend, and holiday, during summer, shoulder, and winter seasons). See also Exh. A at 61.

limited to non-holiday weekdays. Weekends are important times for maintenance of DER systems and rarely associated with peak distribution infrastructure loads.

D. Implementation Sequencing

Two broad approaches to sequencing are available to the Department, and each carries genuine advantages and corresponding risks. A phased approach would draw on the AMI already installed for a substantial number of Massachusetts customers to begin load research, bill impact analysis, and limited implementation ahead of complete deployment.[20] That approach delivers benefits to customers sooner, allows design questions to be tested against real billing experience while they can still be corrected, and spreads the operational burden of the transition across a longer period. It also risks drawing conclusions from an installed base that may not yet reflect the full diversity of the customer population, and it may require customers to absorb more than one change in structure as the framework is refined. A full deployment approach would complete AMI installation, evaluate impacts against a complete dataset, and implement once. That approach produces a more reliable analytical foundation and a single, cleaner transition for customers, but it defers the benefits of TVR and concentrates implementation risk into a narrower window.

We do not take a position on which of these the Department should adopt, but rather ask that it evaluate both approaches on the record and explain the basis for the sequence it selects. Our substantive request concerns what either sequence must produce, because under either approach the analytical record supporting a default TVR framework should reflect commercial, industrial, institutional, municipal, and nonprofit customer types before the framework is set rather than after. If the Department proceeds on the basis of installed AMI, it should first confirm that the installed base is sufficiently representative of the commercial, industrial and institutional segments to support conclusions about them, and it should be explicit about the limits of any sample that is not. If the Department instead waits for full deployment, it should use the intervening period to develop the commercial profile types, the data access framework, and the settlement capability described below, so that implementation is not delayed further once deployment concludes.

E. Distributed Energy Resources, Net Metering, and Long-Term Contract Stability

Many of our Members access distributed energy resources through third-party ownership structures, including power purchase agreements and energy services agreements with terms of ten to twenty years, rather than by capitalizing projects directly. The durability of a retail price signal therefore reaches our Members indirectly, since it is first assessed by the developers and financing parties that price those agreements, and arrives afterward in the pricing, the terms, and in some cases the availability of the offers they receive. To the extent the Department intends TVR to encourage DER adoption rather than simply to redistribute charges across hours, a reasonably

[20] Exh. A at 47. DOER notes that the EDCs have installed AMI for hundreds of thousands of Massachusetts customers to date.

stable and predictable framework will support that objective, and frequent or unanticipated change will work against it.

It follows, first, that the Department should coordinate TVR design with existing DER program offerings aimed at grid services, including ConnectedSolutions and successor demand response and virtual power plant constructs, so that a customer evaluating an investment can assess the combined value of the retail price signal and the program revenue rather than facing two independently variable streams. It follows, second, that the Department should be deliberate about the effect of TVR on assets already contracted under the current rate structure.

Net metering warrants specific attention for the same reason, and DOER acknowledges that the transition to TOU rates will change net metering customers' avoided costs and credits, and that some net metering customers may see a reduction in expected savings because generation and consumption will be netted within each defined TOU period.[21] Many of our Members host net metering facilities, and a number of those facilities were developed and priced under the current credit structure.

We do not ask the Department to insulate net metering from rate design reform, and we recognize that a credit which varies by TOU period is defensible on cost reflectivity grounds for projects developed going forward. We do ask the Department to distinguish between prospective projects and facilities already operating under long-term agreements, and to develop a record on the effect of the proposed TOU periods on the existing fleet before adopting a framework that changes it. For facilities that were sited, contracted, and priced under the rules in effect at the time, we ask the Department to establish a safe harbor preserving the existing basis of compensation for the remaining term of the agreement. A change applied to the installed fleet operates as a retroactive revision to the economics of transactions that the parties can no longer reopen, and the confidence of the customers and counterparties that will finance the next generation of projects will depend on how the Department treats the current one.

We also note DOER's suggestion that the EDCs may propose a monthly minimum reliability contribution for net metering customers that opt out of a TOU rate.[22] We do not oppose the principle that all customers should contribute to the fixed costs of a safe and reliable distribution system. We do caution that a charge conditioned on the exercise of an opt-out right is functionally a penalty for using a customer protection, and that the interaction between such a charge and the customer protections discussed in Section III below should be examined carefully before any such proposal advances.

[21] Exh. A at 57-58.

[22] Exh. A at 59.

F. Fixed Charges, Cost Causation, and Coordination with D.P.U. 25-200

We support the cost causation and fairness principles reflected in DOER's proposal, including the principle that each customer class should pay no more than the cost to serve that class, and the effort to avoid systematic cross-subsidization within and between classes wherever reasonably achievable. We emphasize that this principle protects residential customers as much as commercial ones. Where costs bear no meaningful causal relationship to an individual customer's consumption, recovering them through a fixed charge rather than a volumetric charge can improve cost reflectivity, reduce seasonal bill volatility, and avoid penalizing customers who electrify or invest in efficiency.

Two cautions apply to that direction, the first being that a per-meter fixed charge falls disproportionately on entities that operate many small, low-usage accounts, since a municipality with streetlights, traffic signals, pump stations, and small buildings, or an affordable housing provider with common-area meters, absorbs the charge many times over against a small consumption base. Any migration of costs from volumetric to fixed recovery should be evaluated for intra-class equity on that basis, not only for average class impact.

Second, the broader question of what belongs in fixed charges, what belongs in base distribution rates, and what belongs in reconciling mechanisms is squarely before the Department in D.P.U. 25-200.[23] We do not ask the Department to resolve that question here, but rather to sequence the two proceedings so that TVR design does not presuppose a fixed charge outcome that D.P.U. 25-200 has not yet reached, and so that our Members are not asked to evaluate bill impacts against a rate architecture that is simultaneously under revision in a separate docket.

G. Complex Metering Arrangements

Master-metered and sub-metered configurations are common across our Membership, particularly in affordable housing, senior living, higher education residential facilities, and mixed-use municipal properties. These arrangements do not fit cleanly into a residential or commercial framing, and they raise issues that a default TVR rollout will not resolve on its own.

Two features of these arrangements warrant the Department's attention: the first being that the party receiving the price signal and the party controlling the underlying consumption are frequently not the same, so that the response TVR is designed to produce may not be available to the account holder that bears the cost. The second is that the terms governing these arrangements are often established in leases, occupancy agreements, or regulatory agreements of long duration, which limits how quickly the parties can adjust to a change in rate structure. We also note that customer protections designed around the residential rate class may not extend to residents served through

[23] 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 (Dec. 15, 2025).

a commercial master meter, and we ask the Department to consider whether that gap requires attention.

We ask the Department to require the EDCs to identify master-metered and sub-metered accounts in their implementation reports, to include those configurations among the representative customer profile types used for bill impact analysis, and to address them explicitly in transition planning.

III. Response to Selected Questions in the Notice

We respond below to the questions posed in Section VI of the Vote and Order and repeated in the Notice. Our responses reflect the perspective of commercial, institutional, municipal, and nonprofit customers. We do not address every question with equal depth, and we confine our responses to the matters on which our Members' experience bears directly.

1. Consumer protections necessary for successful design and implementation of TVR

We ask the Department to require that shadow billing be made available to customers before default enrollment rather than only after it, because a counterfactual delivered once a customer has already been moved onto a new rate can inform a complaint, while the same counterfactual delivered beforehand can inform a decision. Our December 2025 comments described the approach Pacific Gas and Electric Company used when it converted commercial customers to new time-of-use periods and seasons, under which the new rates were opened on an opt-in basis for roughly eighteen months, with shadow bills available, before the mandatory transfer.[24] We recommend the Department adopt an analogous structure here, providing for a defined pre-implementation period during which shadow billing is available and enrollment is voluntary, followed by default enrollment for customers that have not acted.

Beyond the transition, we support treating shadow billing as a continuing consumer protection rather than a one-time transitional measure, a recommendation that other parties have also made in this record.[25] Our recommendation is that shadow billing be provided on an ongoing basis, subject to a reasonableness test on administrative cost, and that it be available to customers on both sides of the default, so that a customer defaulted onto TVR can see what it would have paid on the prior structure and a customer that opts out can see what it would have paid on TVR. Both counterfactuals serve the same purpose, which is to let an organization evaluate its own decision against its own data rather than against an illustrative example. For institutions that must justify

[24]The Energy Consortium, Comments on the Ratemaking Straw Proposal at 2 (Dec. 2025) (describing Pacific Gas and Electric Company's conversion of commercial customers to Rates B-10, B-19, and B-20, which were opened on an opt-in basis for approximately eighteen months, with shadow bills available, before the mandatory transfer from legacy Rates A-10, E-19, and E-20).

[25]See, e.g., Rewiring America, Written Comments in Response to the Ratemaking Straw Proposal at 2-3 (Dec. 19, 2025) (recommending that shadow billing be treated as an ongoing consumer protection tool rather than a one-time transitional measure, and that personalized rate comparison reports be delivered at least annually).

an energy decision to a board, a finance committee, or an elected body, the counterfactual is often the difference between a decision that can be defended and one that cannot.

We recognize that ongoing shadow billing carries administrative cost, and we ask the Department to require the EDCs to quantify that cost rather than assume it is prohibitive, so that it can be weighed against the value of sustained customer confidence in a default rate structure. If continuing shadow billing for all customers indefinitely proves unreasonable, we ask that it be maintained at minimum for twelve months before default enrollment and twenty-four months after, and that it remains available on request thereafter.

Separately, opt-out capabilities should be available without penalty, and it should be available on a year-round basis rather than only at implementation or during defined windows thereafter, so that a customer can act when it identifies a problem rather than waiting for the next opportunity to do so. It should also be available in advance of default implementation, since a customer that can evaluate a shadow bill during the pre-implementation period and elect its rate on that basis is making an informed choice, whereas a customer that must first be defaulted, then billed, and only then permitted to act is responding after the fact. In neither case should the election be conditioned on a charge that offsets its value.

Customers should be able to move between the default rate and the alternative as their circumstances warrant, and we ask the Department to confirm that a customer may switch without penalty or exit charge. We also ask that the Department establish what constitutes a reasonable interval between elections, rather than leaving the question to be worked out through EDC practice, because a customer able to switch at will could elect whichever structure suited the coming day or season, shifting cost onto customers that do not switch and imposing administrative cost on the EDCs that all ratepayers ultimately fund. A minimum dwell period of roughly twelve months on an elected rate would be long enough to discourage daily or seasonal arbitrage and short enough that a customer is not held on an unsuitable rate for an unreasonable duration, though any such rule should permit an exception where the customer's circumstances change materially.

One point requires specific attention, and we do not see it addressed in the proposal.[26] A large share of our Members take supply under fixed-term contracts through competitive suppliers or municipal aggregation. The default TVR rollout should not disturb the terms of a contract already in effect.

We ask the Department to assess bill stabilization for all customers rather than only for low-income residential customers during the initial transition. A defined stabilization period of roughly twelve months following default enrollment, limiting a customer's exposure to an increase attributable solely to the change in rate structure, would reduce the risk that an organization encounters an unanticipated variance in its first year on the rate. We recognize that a stabilization mechanism carries a cost and that the cost is borne by ratepayers, so we ask that it be scoped and priced rather than dismissed, and that the Department consider whether a shorter or capped mechanism achieves

[26]Exh. A at 49-50.

most of the protective value at a fraction of that cost. Relatedly, we ask that notice of enrollment timing and of expected bill effects be delivered far enough ahead that a customer can reflect the change in the budget it is preparing rather than the one it is already executing.

Monthly billing is a limited feedback mechanism for a rate structure that prices four hours of each day differently. Now that AMI makes a shorter feedback loop possible, we ask the Department to require the EDCs to provide in-cycle usage and cost alerts at intervals of roughly ten days rather than once per billing period, and to pair each alert with actionable guidance on what the customer can change for the remainder of the cycle, since an alert that reports a figure without indicating what to do with it is unlikely to change behavior. This functionality should be available to all customers, including commercial and institutional accounts.

The proposal's discussion of customers with limited ability to shift load is framed largely around residential circumstances, such as households with in-home medical devices, but the same constraint operates at institutional scale and should be recognized as a commercial category as well. Hospitals and health systems, senior living and congregate care facilities, emergency services, water and wastewater treatment, and laboratory and research buildings have limited ability to curtail during peak hours regardless of price, because the load in question supports life safety, patient care, resident comfort, regulatory compliance, or continuous process requirements. We ask the Department to define a difficult-to-curtail category spanning residential and commercial customers, and to require the EDCs to identify such accounts during implementation planning.

2. Strategies for avoiding a new peak following the end of a peak rate period

Rebound peak mitigation is not a subject on which our organizations hold particular technical expertise, and we defer to the parties that do. We offer two observations from the perspective of the customers who will be operating the assets involved.

First, we believe mitigation of rebound peaks requires substantial coordination amongst customers, utilities and DER aggregators, and coordination requires visibility. If DER aggregators and third-party control providers can see near-real-time AMI load shape for the accounts they manage, they can stagger discharge, recharge, and restart across a portfolio rather than moving every asset at the same boundary hour. If they cannot, every controlled asset responds to the same published schedule at the same moment. Third-party data access, discussed in response to question 3 below, is therefore a rebound mitigation measure as well as a market enablement measure.

Second, rate design can avoid creating the problem that it then has to solve, since a sharp price discontinuity at the end of the peak window operates as an instruction to activate load at that instant. A graduated step between peak and off-peak pricing, or a defined intermediate period, would reduce the incentive to concentrate deferred load at a single hour. We recognize this involves a trade-off against the simplicity we advocate in Section II.C above, and we do not recommend a specific design. We ask only that the Department evaluate the boundary condition explicitly rather than treating rebound solely as a customer behavior problem to be addressed through outreach.

3. Changes required to enable TVR supply rates for non-demand customers served by competitive suppliers or municipal aggregation

This question is central to our Members' interest in this proceeding, and we ask the Department to treat it as critical rather than a downstream implementation detail.

The great majority of our Members do not take basic service, but instead take competitive supply, in many cases through aggregated procurement, or take service through municipal aggregation. A default basic service TOU rate that competitive supply and municipal aggregation cannot mirror does not merely leave those customers unserved; it places them at a structural disadvantage, because the customer sees peak period exposure in its delivery charges without a corresponding supply-side product that lets it convert a load shift into a saving, and must choose between the procurement arrangement that serves and protects it well and access to the benefits of TVR. That is not a choice the Department should require.

The precondition for any of this is ISO-NE load settlement, an issue that TEC and PowerOptions addressed jointly in D.P.U. 26-44 and restate here.[27] Under profile-based settlement, a time-differentiated retail product reduces to a redistribution of charges across hours with no corresponding reduction in wholesale cost, because supply and capacity costs continue to be allocated from a class-average profile. The supplier or aggregator has no mechanism to translate a customer's peak-hour load reduction into lower wholesale cost recovery, and therefore no basis on which to share savings with the customer, so that TVR without AMI-based settlement produces exposure without opportunity.

We therefore ask the Department to coordinate this proceeding with D.P.U. 26-44[28] and to treat resolution of load settlement as a condition precedent to default TVR implementation, not a parallel track that may or may not converge. Specifically, we ask the Department to require the EDCs to specify, and then to build:

- settlement-quality interval data for each account, delivered to the customer's supplier or aggregator on a defined and enforceable schedule;
- standardized, documented delivery of that data through electronic data interchange or an application programming interface, consistent in format across all three EDCs, so that a supplier serving customers in multiple territories is not required to build three separate integrations;

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[27] D.P.U. 26-44, Initial Comments of The Energy Consortium and PowerOptions (Apr. 20, 2026).

[28] 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).

- a functioning authorization framework under which a customer can grant a competitive supplier, an aggregator, a consortium, a DER aggregator, or another third-party access to its own interval data, at portfolio scale, through a process that does not require a separate manual authorization for every account;
- rate-ready billing capable of supporting supplier-defined time periods that may differ from the default peak period, so that competitive products are not constrained to replicate basic service; and
- near-real-time or day-after data availability at a granularity sufficient to support DER dispatch and virtual power plant participation, not only after-the-fact billing determinants.

On sequencing, we ask that the capability to offer time-varying products through competitive supply and municipal aggregation be enabled no later than the date default basic service TOU rates take effect. Enabling the default first and the competitive market later would penalize customers for the procurement choice they have already made and would do so during precisely the period in which customer confidence in the new structure is being established.

Finally, we ask that suppliers, municipal aggregators, consortia, and DER aggregators be included in the design and testing of these systems rather than only in the rollout. These parties can identify integration failures before customers do, and the cost of discovering them during a default enrollment is considerably higher than the cost of discovering them in testing.

4. Key elements for inclusion in the EDCs' implementation and MEO plans

We appreciate the Department's direction that the EDCs develop a joint MEO plan consistent across companies and building on prior Department directives and the work of the Energy Burden Working Group.[29] Consistency matters to our Members, many of which operate facilities in more than one service territory and cannot administer three different sets of guidance.

We also appreciate DOER's recommendation that the EDCs jointly develop a customer transition plan addressing implementation timeline, sequencing of rollout, the opt-out process, incremental implementation costs, and associated tracking and reporting.[30] A single joint plan that describes the complete customer experience end to end, from first notice through enrollment, education, opt-out election, and post-enrollment support, is the right instrument. We ask that stakeholders be given a meaningful opportunity to comment on that plan before it is approved rather than after implementation begins, and that the plan be treated as a living document that is updated as the EDCs learn from early enrollment waves.

[29]Vote and Order at 12-13.

[30]Exh. A at 50-52; Vote and Order at 9.

Our principal request is that MEO be designed for commercial customers as a distinct audience, rather than as a residential program with a commercial addendum, since the organizations we represent reach decisions differently than households do.

We ask that the joint MEO plan include the following elements.

- Sector-specific materials and technical assistance, including practical examples drawn from schools, municipal buildings, hospitals, houses of worship, human service providers, and affordable housing that show what load shifting actually looks like in those settings.
- Particular attention to small nonprofit and community-serving organizations, which take service on the same non-demand rates as residential customers and will be defaulted onto TVR on the same schedule. Their facilities and consumption patterns differ substantially from a household's, and guidance directed at residential customers will not map onto their circumstances.
- Delivery through trusted intermediaries, since consortia, competitive suppliers, aggregators, municipal aggregation administrators, and technical assistance providers are often the parties our Members turn to first on an energy question, and including these channels in MEO planning is a low-cost way to reach customers that the EDCs' own channels do not reach as effectively.
- Data access as an MEO deliverable, because education without usable data does not produce load shifting in a multi-site organization, so bulk interval data export, portfolio-level views, and a workable third-party authorization process should be treated as part of the MEO obligation rather than as separate IT work.
- Timing aligned to institutional calendars, so that outreach touches public entities during budget preparation and procurement cycles rather than only in the weeks before an enrollment date.
- Outcome-based metrics, under which success is measured by comprehension, retention, measured change in load shape by segment, and documented reasons for opt-out, rather than by materials distributed.
- An ongoing stakeholder forum, since a working group including municipal, school, hospital, housing, and nonprofit representatives would allow the Department and the EDCs to identify implementation problems in these segments as they arise rather than after enrollment concludes.

Reporting should also cover all customers, and as DOER recommends, the EDCs should submit quarterly progress reports covering enrollment metrics, rollout progress, MEO adherence and cost, opt-out rates and trends, bill impact metrics after enrollment, and changes in load shape and peak demand.[31] We support this recommendation and ask that it be applied across the full customer base rather than to residential customers alone, and that the reporting be disaggregated to the most granular level the data supports. At minimum, we ask that enrollment, opt-out rates, bill impacts, and load shape change be reported by rate class, and, where the EDCs can do so, by customer segment, by whether the customer takes basic service or competitive supply or municipal aggregation, and by geography. Reporting that aggregates all commercial accounts into a single line will not reveal whether small nonprofits are opting out at a materially higher rate than large institutions, which is the kind of signal the Department will need in order to act while intervention is still useful.

5. Information and analysis on items 3, 5, and 6 of the Section V information requests

We do not hold the load data necessary to respond empirically to these items, and rather than substitute assertion for analysis, we offer the following on each:[32]

Item 3, the appropriateness of a four-hour 4:00 p.m. to 8:00 p.m. window. As stated in Section II.C, we support a four-hour window because it corresponds to the common discharge duration of the storage assets our Members have installed and the ceiling of a realistic duration of building curtailment. A window that exceeds the physical capability of the available response produces bill impact without a corresponding opportunity to avoid it. We ask the Department to test the proposed window against day type and season with the same rigor it applies to the hour selection, and to confirm that weekend and holiday inclusion is supported by the data. We also ask that season definitions be stable and announced in advance, for the budgeting reasons described above.

Item 5, the appropriateness of critical peak pricing for distribution and transmission. We see arguments on both sides and do not take a position at this stage. Critical peak pricing sharpens the price signal at the hours when system costs are highest, and for customers with dispatchable storage or curtailable load, it can convert an existing asset into an avoided cost opportunity. Against that, an event-based structure introduces bill variance, and a customer that lacks the flexibility to respond to an event will pay more than it would under a conventional peak and off-peak design without any corresponding ability to avoid the charge. Our recommendation is therefore that critical peak pricing, if adopted, be offered on an opt-in basis to commercial customers for whom it is operationally and financially appropriate, rather than applied by default in a manner that increases cost for the broader ratepayer base. That approach is consistent with the position stated in Section II.A above regarding the preservation of existing opt-in options such as coincident peak transmission billing, which similarly pair greater complexity and a sharper price signal with self-selection by the customers best positioned to respond.

Item 6, demand elasticity and pricing ratios. We highlight one structural point that the Department's framing of this item already anticipates in asking about pricing ratios in light of the

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[31]Exh. A at 52; Vote and Order at 9.

[32]Vote and Order at 10-12 (items 3, 5, and 6 of the information request to the EDCs); Notice at 2 (question 5).

varying share of volumetric costs on a customer's bill. For demand-metered commercial and industrial customers, volumetric energy represents a minority of the delivery bill. Any given peak-to-off-peak ratio therefore delivers a materially weaker marginal incentive to those customers than the same ratio delivers to a customer whose bill is predominantly volumetric. The existing tariffs described in Section II.A illustrate the point, since a structure in which the time-differentiated component is a small share of the total delivery charge produces a weaker signal regardless of the ratio embedded within that component. We ask the Department to account for bill composition when setting pricing ratios rather than applying a uniform ratio across classes with fundamentally different rate structures.

We also caution against transferring elasticity estimates derived from residential pilots to commercial and institutional customers, whose response tends not to be continuously price elastic but instead arrives in steps, as controls are reprogrammed, equipment is replaced, or an operating schedule is revised. Those steps are taken when the price signal is stable enough to justify the change and to survive review by whoever must approve it. We therefore ask the Department to evaluate enabled flexibility alongside observed elasticity, and to pair the setting of pricing ratios with the program coordination and durability discussed in Section II.E above.

IV. Conclusion

TEC and PowerOptions support the Department's investigation and the direction of DOER's proposal. We ask the Department to keep three things in view as the record develops:

First, this reform should be holistic, because a substantial share of the Commonwealth's near-term load flexibility potential sits behind demand meters, in facilities our Members operate, and a framework built around non-demand accounts and supported by analysis built around residential customer profiles will not reach that potential. The Department should state where demand-metered rate classes fit in the TVR framework and on what timeline, and should require analysis of commercial, institutional, municipal, and nonprofit customer types before it sets the framework.

Second, the price signal must actually reach the customer, which for the majority of our Members requires resolving ISO-NE load settlement and building the data access and authorization infrastructure that allows competitive suppliers, municipal aggregators, and authorized third parties to offer products that respond to the same signal the default rate sends. Absent that, default TVR delivers exposure to our Members without opportunity.

Third, the price signal must be stable enough to be acted upon, since our Members respond to prices when the peak period, the seasonal definitions, and the compensation framework hold steady long enough to justify a change in operations or equipment, and when the resulting effect on cost is predictable enough to be planned for. Stability is not in tension with cost reflectivity here, because it is what allows cost reflectivity to translate into the load reduction the Commonwealth is seeking.

TEC and PowerOptions appreciate the Department's attention to these matters. We welcome the opportunity to participate further as this investigation advances, including through technical sessions on the commercial and institutional issues raised above.

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