THE COMMONWEALTH OF MASSACHUSETTS
OFFICE OF THE ATTORNEY GENERAL
ONE ASHBURTON PLACE
BOSTON, MASSACHUSETTS 02108

ANDREA JOY CAMPBELL
ATTORNEY GENERAL

(617) 727-2200
www.mass.gov/ago

August 31, 2026

Peter A. Ray, Secretary
Department of Public Utilities
One South Station, 3rd Floor
Boston, MA 02110

Re: ***Investigation into the Design and Implementation of Time-Varying Rates*, D.P.U. 26-62**

Dear Secretary Ray:

On June 30, 2026, the Department of Public Utilities ("Department") voted to open an investigation concerning the design and implementation of time-varying rates ("TVR").[1] The Department states that this investigation will examine: (1) "rate design considerations for the TVR framework that the Department approved in 2014" in Orders D.P.U. 14-04-B and 14-04-C; (2) "the merits of incorporating transmission and distribution costs into the TVR framework;" (3) "customer protections for vulnerable populations[;]" (4) "the [EDCs'] plans for the implementation of TVR;" and (5) "marketing, education, and outreach ('MEO') plans for the transition to TVR."[2]

Subsequently, the Department issued a memorandum requesting stakeholder comments by August 31.[3] Accordingly, the Office of the Attorney General ("AGO") files these comments responding to the Department of Energy Resources' ("DOER") Time-of-Use ("TOU") Proposal[4] and the Department questions to all interested stakeholders.[5] Where applicable, the AGO references the TVR framework adopted by the Department in D.P.U. 14-04-B and 14-04-C.[6] The

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1 Vote & Order Opening Inquiry, at 13–14 (Jun. 30, 2026)

2 *Id.* at 1–2 (footnote omitted).

3 Deadline for the Electric Distribution Companies ("EDCs") to respond to the Department's Order and Deadline for Stakeholder Comments, at 2 (Jul. 21, 2026).

4 DOER Petition, Exh. A ("DOER TOU Proposal").

5 *See* Vote & Order Opening Inquiry, at 1–2, 10, 13.

6 The Department recalls that the TVR framework adopted in D.P.U. 14-04 included: "(1) a default TOU rate with a [critical peak pricing ('CPP')] component;[6] and (2) an option to opt out of the default TOU rate in favor of a flat rate with a peak time rebate ('PTR') component." Vote &

AGO's positions are preliminary and are subject to review of specific rate design proposals and the associated bill impacts, as well as review of the forthcoming filings from the EDCs and other stakeholders.[7]

Before addressing the Department's questions, the AGO provides its positions on several key elements of TVR, which the AGO hopes will assist the Department in its deliberations through this preliminary stage. With regards to future input, the AGO respectfully requests that the Department provide stakeholders with the opportunity to: (1) issue information requests on the EDCs' responses to the request for information;[8] (2) submit comments on the EDCs' Joint MEO Plan, to be filed by September 30, 2026;[9] and (3) provide testimony on specific rate proposals that the Department is considering adopting.

The AGO respectfully requests an opportunity to review estimated bill impacts for income-eligible customers and for each usage quartile of each rate class before the Department approves any TVR.

AGO Positions on Elements of TVR

As discussed in more detail below, the AGO recommends that the Department establish a default TOU rate for all customers and an opt-in CPP rate. Although DOER's recommendation is limited to a default TOU rate,[10] the AGO urges the Department to establish both types of rates through this proceeding, in time for full deployment of advanced metering infrastructure ("AMI"), to more effectively support peak load management and to reduce peak-related electric system costs in the near-term. This recommendation is consistent with the Interagency Rates Working Group's ("IRWG")[11] recommendations.[12] While well designed TOU rates can incentivize customers to shift load, a CPP rate sends a stronger price signal and can have a more pronounced and targeted

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Order Opening Inquiry, at 4, citing *Investigation into Time Varying Rates*, D.P.U. 14-04-C, Order, at 2 (Nov. 5, 2014), and *Investigation into Time Varying Rates*, D.P.U. 14-04-B, Order, at 8–12 (Jun. 12, 2014).

7 Any Department decisions on changes to reconciling mechanisms and fixed changes as part of D.P.U. 25-200 *may* impact the AGO's preliminary positions below.

8 Vote & Order Opening Inquiry, at 11–12.

9 *Id*. at 12.

10 *Id*. at 13.

11 The IRWG member organizations were the AGO, DOER, Executive Office of Energy & Environmental Affairs ("EEA"), and Massachusetts Clean Energy Center.

12 The IRWG stated: "The Working Group recommends that each EDC work to develop an opt-in residential CPP rate as soon as practical so that the rate can be offered to customers as AMI meters are deployed." IRWG Long-Term Recommendations, at 22 (Mar. 2025).

impact.[13] More advanced rate design offerings should also be developed and offered to customers in the future.

A. Applicability for All Customer Classes

The AGO agrees with DOER's central recommendation that the EDCs should implement TOU rates for all customer classes, for the same reasons discussed by DOER,[14] provided key consumer protection measures are also implemented. These measures are discussed in Question 1.

B. Time-Vary Supply, Transmission, and Distribution Service in a Single Peak[15]

The AGO agrees with DOER that the Department should establish a year-round afternoon peak period, with time-varying components for supply, transmission, and distribution service.[16] The AGO also recommends that the Department and stakeholders consider the merits of an additional non-summer morning peak period to reflect the high energy prices during those hours. Further, the AGO supports DOER's requests that the Department direct the EDCs to offer TOU basic service rates and that the Department enables time-varying supply rates for municipal aggregators and competitive supply expeditiously.[17]

C. Peak/Off-Peak Seasonal Component for the Transmission & Supply Components of TOU Rates

The AGO agrees with DOER that transmission rates should differ seasonally[18] and further recommends that seasonal transmission rate differences apply to any customers with volumetric transmission rates, even if they also pay demand-based transmission rates. As noted above, and

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13 *Id.*; *see* DOER TOU Proposal, at 14, 29, 37.

14 *See* DOER TOU Proposal, at 13 (detailing a host of benefits to implementing TOU rates). The AGO notes that the D.P.U. 14-04 TVR framework was limited to time-varying basic service supply. *See Investigation into Time Varying Rates*, D.P.U. 14-04-B, Order, at 14; *Investigation into Time Varying Rates*, D.P.U. 14-04-C, Order, at 17, 21.

15 In D.P.U. 14-04-B, the Department recognized that "[r]educing peak load can result in a reduction or deferment of investments in generation, transmission, and distribution resources, as new investments will not be required to meet peak load, which is expected to grow." *Investigation into Time Varying Rates*, D.P.U. 14-04-B, Order, at 6.

16 DOER TOU Proposal, at 1, 3, 18, 39–44.

17 *Id.* at 30–34. The AGO notes that the Department did not intend the D.P.U. 14-04 TVR framework to apply to competitive supply or municipal aggregation. *See Investigation into Time Varying Rates*, D.P.U. 14-04-B, Order, at 15–16; *Investigation into Time Varying Rates*, D.P.U. 14-04-C, Order, at 17. At the time, the Department stated its expectation that the competitive market would provide TVR options in the future, *Investigation into Time Varying Rates*, D.P.U. 14-04-C, Order, at 17, and a small percentage of customers received supply through municipal aggregators. *Investigation into Time Varying Rates*, D.P.U. 14-04-B, Order, at 15–16. Significantly more customers participate in municipal aggregation compared to a decade ago.

18 DOER TOU Proposal, at 3.

unlike DOER, the AGO recommends that the Department and stakeholders consider the merits of a seasonal non-summer morning peak period to reflect the high energy prices during those hours.

D. <u>Timing for Implementation</u>

Consistent with DOER's position, the AGO supports implementation of rates enabled by AMI in time for the full deployment of AMI.[19] The AGO also supports DOER's position that TOU basic service rates should be implemented as soon as practicable,[20] and that the Department should take steps to enable TOU rates for municipal aggregation and competitive supply expeditiously,[21] as noted above. Finally, the AGO strongly supports the Department's intent to establish AMI-enabled rates before the EDCs' anticipated AMI deployment in 2027.[22]

E. <u>On-/Off-Peak Periods</u>

Although a 3-period rate (on-, mid-, and off-peak periods) may help to mitigate the significance of rebound or timer peaks (which are peaks that directly follow the end of a peak period), the AGO agrees with DOER that a 2-period rate (on- and off-peak periods) is likely to be easier for customers to understand and adapt to through behavioral changes.[23]

F. <u>Peak Period</u>

With regard to DOER's proposed four-hour peak period of 4–8pm,[24] the AGO agrees that peak periods should "reflect actual peak period system costs" and 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."[25] In selecting peak period hours, DOER has considered several relevant cost drivers. The AGO supports the addition of distribution peak analysis and looks forward to evaluating the EDCs' forthcoming analysis in response to the Department's direction to assess the coincidence of distribution system peak demand with Independent System Operator New England ("ISO-NE") system peaks.[26] The AGO recommends that the Department create an opportunity in this docket for subsequent stakeholder input regarding the impact, if any, of distribution equipment peaks on peak period selection.

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[19] *See* <u>DOER Petition</u>, at 1, 13 (stating that DOER's TOU Proposal "facilitates the implementation of fully time-varied basic service, transmission, and distribution rates by August 1, 2028, so that customers may receive the benefits of TVRs as soon as practicable.").

[20] <u>DOER TOU Proposal</u>, at 3.

[21] *Id.*

[22] *Seasonal Heat Pump Rates*, D.P.U. 25-08-A, <u>Order</u>, at 17 (Jun. 1, 2026).

[23] <u>DOER TOU Proposal</u>, at 1, 18.

[24] *Id.* at 1, 3.

[25] *Id.* at 18.

[26] <u>Vote & Order Opening Inquiry</u>, at 10.

Length: Similar to DOER, the AGO supports a narrow peak period to maximize customers' ability to shift their use.[27] Four hours is a reasonable peak period length.

4–8pm Peak: The AGO agrees with DOER that its recommended 4–8pm peak period captures most of the hours likely to contribute to system peak as well as the afternoon and evening hours of the day with relatively high day-ahead energy prices throughout the year.[28] As noted above, the AGO further recommends that the Department and stakeholders consider the merits of a seasonal non-summer morning peak period to reflect the very high energy prices during those hours.

G. Identical Peaks Across EDCs

Regarding DOER's proposal for all EDCs to have the same peaks,[29] the AGO does not object to this as an initial approach, for the same reasons discussed by DOER.[30] However, in the future, the reported data may suggest that the time periods which will most benefit from load-shifting behavior are not aligned across the EDCs. In that case, the AGO will likely support EDC-specific peaks.

H. Peak to Off-Peak Ratio

The AGO recommends a gradual and incremental transition to cost-reflective default TOU rates with a mild to moderate initial price ratio (2:1 to 3:1) for peak and off-peak rates. The AGO agrees with DOER that a customer will likely focus on the peak/off-peak ratio of the total rate, rather than the ratio for particular bill components.[31]

I. Steps Ahead of Revisions to the Peak Period(s)

DOER recommends that the EDCs conduct two new studies to support future revisions of the peak period: (1) an annual report reviewing and proposing amendments to the peak period to align with changes in energy prices and usage; and (2) a marginal cost of service study ("MCOSS") to inform distribution rate design.[32] The AGO supports DOER's position that the peak period may need to be evaluated and revised over time as the power system changes, and recommends that the Department develop criteria that would trigger revisions to the peak period. The AGO further recommends that the Department consider the frequency of changes to the peak period, as annual changes may be too frequent. The AGO also agrees with DOER that a carefully executed MCOSS

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[27] *Id.* at 22.

[28] *Id.* at 22–23.

[29] *Id.* at 18, 24.

[30] *Id.* at 24–25 (discussing that a consolidated, single peak across the EDCs will provide a simple price signal, and that the additional granularity with multiple peak periods may be outweighed by the simplicity of a consolidated peak); *see also* DOER Petition, Exh. C.

[31] *See* DOER TOU Proposal, at 25.

[32] *Id.* at 42.

could provide valuable system cost information; however, developing an MCOSS will involve numerous assumptions and methodological choices and stakeholder input should be incorporated.[33]

J. Default/Opt-Out TOU Rates

The AGO does not object to default/opt-out TOU rates for all electric customers,[34] as opposed to *opt-in* TOU rates, provided key consumer protections in place. The AGO discusses these key consumer protections in response to Question 1.

K. Opt-In Critical Peak Pricing

The AGO supports the IRWG's recommendation that CPP be offered as an opt-in rate for customers.[35] Notably, DOER has not recommended that CPP rates be pursued at this time. The AGO strongly recommends that the Department consider the appropriate rate design for CPP for residential, commercial & industrial ("C&I") customers through this proceeding. The AGO is concerned that failure to seriously consider and adopt a CPP through this proceeding is a missed opportunity to reduce peak demand and recommends that an opt-in CPP is offered along with default TOU rates.

L. Phasing Out Heat Pump Rates with AMI-Enabled Whole House TOU Rates

The AGO supports the Department's intent to phase out heat pump rates when AMI-enabled rates become available.[36] This approach is consistent with DOER's TOU Proposal.[37]

Responses to Department Questions[38]

Q1 Please identify and describe any consumer protections necessary for a successful design and implementation of TVR in Massachusetts.

The AGO appreciates the Department's focus on consumer protections and agrees that several consumer protection measures will be necessary to support a successful roll out of TVR. Consumer protections are essential because TVR will not impact all customers in the same way,[39]

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33 *Id.* at 18–21, 23–24.

34 *Id.* at 1, 13, 44–46.

35 IRWG Long-Term Recommendations; *see also* DOER TOU Proposal, at 37, 44 (discussing the IRWG's recommendation and the Department discussion of CPP rates in D.P.U. 14-04).

36 *Seasonal Heat Pump Rates*, D.P.U. 25-08-A, Order, at 17 (citing D.P.U. 25-55, at 23, 27; D.P.U. 23-150, at 512; D.P.U. 23-80/D.P.U. 23-81, at 409).

37 DOER TOU Proposal, at 54–55.

38 Notice of Inquiry and Request for Comments, at 1–2 (Jul. 21, 2026).

39 For example, customers who use electric resistance heating, who are more likely to be low-income and/or rental households, will be especially susceptible to higher winter peak rates due to

and some customers will be able to shift usage more readily than others.

The AGO generally supports the customer protection measures proposed by DOER.[40] With regards to residential customers, the AGO does not object to the Department implementing default/opt-out TOU rates,[41] as opposed to opt-in TOU rates, provided key consumer protections in place, including the following:

- **Opt-out option**: The majority of customers should be offered the choice to opt-out.[42]
- **Moderate peak/off-peak differentials**: Setting an appropriate peak to off-peak price ratio is an important consumer protection measure. While a higher ratio may incentivize more load shifting, the transition to default TOU rates should be gradual and incremental to maximize customer acceptance and minimize rate shock. An initial default TOU rate should have a mild or moderate peak to off-peak price differential to mitigate the impacts on vulnerable customers and allow customers time to develop familiarity with the rate and with load shifting strategies before large differentials are implemented. A mild or moderate price ratio may also decrease the number of customers choosing to opt-out of the rate. Thus, the AGO recommends a price ratio of around 2:1, or up to 3:1 pending the results of comprehensive bill impact analysis. The peak to off-peak price ratio is discussed further in Question 5.
- **Shadow billing**: The AGO supports DOER's position that shadow billing be offered for one year following TOU implementation.[43] However, to improve the customer experience, to minimize rate shock, and to increase predictability, the AGO recommends that the EDCs provide shadow billing for several months before (as well as for at least one year after) TOU rates are implemented.
- **Bill stabilization**: Bill stabilization protects customers by allowing them to pay the lower of their bill under either a time-varying or uniform rate. DOER recommends that the EDCs analyze the impacts of bill stabilization for one year after TOU rates are

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the relative inefficiency of resistance heating. *See* https://www.belfercenter.org/research-analysis/opportunities-cost-effective-residential-heat-pump-adoption-massachusetts.

40 *See* DOER TOU Proposal, 47–49.

41 *Id.* at 1, 13, 44–46.

42 *See id.* at 1, 4. The AGO recommends that the Department consider whether it is appropriate to require certain customers, such as heat pump and EV customers, to participate in TVRs.

43 *Id.* at 49 (stating, "DOER [] 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.").

implemented for residential customers on the Tiered Discount Rate.[44] Rather than direct the EDCs to analyze the impacts of bill stabilization, the AGO recommends that the Department direct the EDCs to file estimated incremental costs associated with bill stabilization for customers on the Tiered Discount Rate. Preliminarily, the AGO recommends bill stabilization for at least the first year that TOU rates are implemented for residential customers enrolled in the Tiered Discount Program so that they do not experience financial hardship if they are unable to shift usage.[45]

- **Enhanced data-driven methods to identify vulnerable customers**: The EDCs should develop a plan for how to flag customers who appear to be exhibiting energy limiting behavior and then target those customers with communications and outreach regarding bill protections (Tiered Discount Program, Arrearage Management Plans, Home Energy Assistance Program).[46]
- **Identify and Provide Rate Options for Non-Shiftable Loads**: Identify non-shiftable loads (such as medical devices or increased refrigeration requirements due to medication refrigeration) and offer customers rate options that do not increase energy burden associated with the costs for these non-shiftable loads[47] and/or provide the residential TOU rate as opt-in rather than opt-out for these customers.
- **Transition Plan and MEO Plan**: The EDCs, trusted community partners, and state agencies[48] should ensure that customers receive effective and robust communications and education regarding TOU rates. The AGO supports DOER's requests related to a transition plan and MEO plan.[49] As discussed above, the AGO requests the opportunity to comment on the EDCs' Joint MEO Plan.

In addition to these customer protection measures, the AGO also supports DOER's recommendation that the Department "direct the EDCs to conduct load research based on available

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44 *Id.* (stating, "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.").

45 The AGO further notes that low-income customers, as well as renters, may have less access to appliances or temperature control that can be timed to avoid the peak period.

46 *See* DOER TOU Proposal, at 48.

47 *See id*.

48 The EDCs are certainly key entities responsible for educating their customers on TOU rates, however, the utilities are not always trusted in the communities they serve, and their efforts should be augmented and complemented by efforts of EEA, DOER, and community groups. In D.P.U. 14-04-B, the Department noted that "[MEO] will require a concerted effort by all stakeholders, including distribution companies, ratepayer advocates, and the Commonwealth." *Investigation into Time Varying Rates*, D.P.U. 14-04-B, Order, at 18

49 DOER TOU Proposal, at 50–52.

AMI data ahead of TOU rollout to support more granular and distributional bill impact analyses and report on the findings at a technical session."[50] While the AGO does not wish to delay TVR implementation, it is the AGO's understanding that the EDCs have already deployed AMI and other enabling technology in large portions of their service territory.[51] Assuming that these deployments enable near-term data collection on representative customer usage that can inform bill comparisons under different rate structures and prices, for different segments of the customer population, the EDCs should conduct that analysis to inform stakeholder positions and the Department's consideration of TVR.

Q2 Please describe implementable strategies for guiding customer behavior to avoid creating a new system (or grid pocket) peak immediately following the end of a peak rate period.

The AGO supports the Department's inquiry into solutions to avoid impacts of a rebound or timer peak. DOER describes a "rebound peak" as an "unintended consequence of shifting peak demand to the beginning of the off-peak period" and recommends that future load management programs be designed to help avoid new system peaks after TVR is implemented.[52] The AGO agrees that a rebound peak could result from TOU rates, which could trigger avoidable system costs. The AGO recommends that the Department consider how active load management, electric vehicle ("EV") charging programs, and staggered peak periods can mitigate rebound peaks. The AGO also recommends that the Department address the topic of rebound peaks in a technical session and looks forward to reviewing recommendations from other stakeholders.

A rebound peak that results from TOU rates may be costly as well as avoidable. DOER appropriately discusses EV load as an example.[53] A TOU rate with a 4–8pm peak period incentivizes reduced consumption from 4–8pm. While a variety of household loads may increase after 8pm as consumers discontinue load shifting, EV charging is unique because an EV consumes energy at a substantially higher capacity than most home appliances. Homeowners can also program their vehicles to automatically charge as soon as the peak is over, raising the likelihood that EV charging contributes disproportionately to a demand spike right after the peak period ends.

A demand spike right after the peak period ends, particularly from EV charging and particularly as EV adoption increases, is very likely to cause costs at the distribution system level. If the load is locally concentrated, a relatively small number of EVs charging simultaneously can overload distribution equipment such as service transformers and feeders. While demand at

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[50] *Id.* at 48.

[51] For example, as of a July 2025 presentation to the Electric Rate Task Force, Eversource stated that it was on track to complete network construction for Western Massachusetts by August 2025, with mass meter deployment for Western Massachusetts expected to start in September 2025. *See* DOER Petition, Exh. F. (July 2025 presentation of Eversource, "Eversource MA AMI Implementation"), at 4.

[52] DOER TOU Proposal, at 57.

[53] *Id.*

distribution substations tends to be more diverse and therefore less susceptible to a local EV load pocket, a substation approaching its load limit could reach that limit prematurely due to a rebound peak caused by EV load responding to TOU rates. Aligning demand—whether EV charging or otherwise—with local system constraints requires dynamic responsiveness to changing load conditions on a very local level, and will likely be best achieved through active load management.[54] As the EDCs roll out distribution management systems that allow them to monitor conditions at the circuit level in real-time, the EDCs, stakeholders, and the Department should ensure that the EDCs utilize this technology as soon as it is available to facilitate cost-effective dynamic load management to avoid expensive distribution infrastructure upgrades.[55]

In addition to the distribution system, an off-peak demand spike could impact the bulk power system by raising energy prices and even potentially shifting the system peak to later in the day. However, that would likely happen only if load was already particularly high at that time. In a such case, a CPP rate—which the Department has previously endorsed[56]—should reflect those dynamic system conditions and help mitigate some of the contributing load.[57] CPP rates are discussed further in Question 5.

In addition to active load management, the AGO recommends that the Department consider staggered peaks. Under this scenario, there could still be alignment across the EDCs, but rather than a single peak period, customers could choose between three time periods, such as 3:30–7:30pm, 4–8pm, and 4:30–8:30pm. If appropriate based on localized constraints, the EDCs could alternatively assign a specific time period to a specific geographic designation.

Another approach, which some jurisdictions have pursued,[58] but which neither DOER nor

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54 *See id.* at 10 (stating, "[l]oad management, and peak demand reduction in particular, can be enabled through rate design and targeted programs to different effect. Efficient rate designs can be complemented by targeted programs to address more granular challenges, such as localized grid constraints." (footnote omitted)).

55 The EDCs are exploring location-specific EV load management, including active load management. In its recent Phase IV EV Program application, National Grid proposed to target off-peak charging to reduce distribution peak load "in areas of the distribution system that are engaged in Non-Wires Alternatives initiatives for load reduction and where peak loads can be forecasted." However, using active managed charging to do so will require an implementation vendor(s), with varying capabilities regarding technology access and charging management. *National Grid*, D.P.U. 25-189, Exh. NG-EVPP-1, at 81–90.

56 DOER TOU Proposal, at 44, referencing *Investigation into Time Varying Rates*, D.P.U. 14-04-B, Order, at 9–11.

57 *Id.* at 14, 29, 37.

58 For example, Concord Municipal Light Plant recently introduced a default residential TOU rate with peak, off-peak, and super off-peak periods. Public Service Enterprise Group, Inc., in New Jersey offers an opt-in residential TOU rate with peak, mid-peak, and off-peak periods. *See* https://concordma.gov/4060/Time-of-Day-Electric-Rates, http://nj.myaccount.pseg.com/myservicepublic/time-of-use.

the AGO recommend at this time, is to have three-period TOU rates, which would include a "shoulder" (or mid-peak) period immediately before and/or immediately after the peak period, during which the price would be lower than the on-peak price but higher than the off-peak price. This incentivizes customers to continue to shift load before and/or after the on-peak period and could thus potentially avoid supply and transmission price impacts by delaying and/or diversifying the timing of load increases on both sides of the peak. However, shoulder period timing and pricing should reflect power system conditions, which, based on DOER's system peak and energy price analysis,[59] currently suggest a greater need for load shifting *before* the on-peak period, not after. A three-period rate is also more challenging to implement, particularly when it comes to customer acceptance and understanding; thus, the AGO does not recommend a three-period TOU rate at this time as a two-period rate is more simple. Furthermore, a shoulder peak may simply delay an eventual demand spike, thus failing to mitigate the concern about a rebound peak, especially the potential associated distribution system costs.

Q3 Please identify any additional changes to AMI functionalities, billing systems, or other operational functions required by the EDCs to enable TVR supply rates for non-demand customers who receive supply from competitive suppliers or municipal aggregation providers.

The AGO does not currently have an opinion on this topic but looks forward to reviewing forthcoming filings from the EDCs and other stakeholders regarding any operational changes that the EDCs must make to enable competitive suppliers and municipal aggregation providers to offer TVR supply rates for non-demand customers. However, the AGO recommends that the EDCs also identify any additional changes to AMI functionalities, billing systems, or other operational functions required by the EDCs to enable TVR supply rates for demand customers who receive supply from competitive suppliers or municipal aggregation providers, as these supply rates are volumetric and should also be time-varied.[60]

Q4 Please identify and describe key elements for inclusion in the EDCs' implementation and MEO plans, discussed above.

a. <u>MEO Plans</u>

As an initial matter, the AGO supports calls from the Department and DOER for the EDCs and stakeholders to work together to develop and to implement MEO plans.[61] The AGO looks forward to collaborating with the EDCs on these efforts.

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59 <u>DOER TOU Proposal</u>, at 20–21, Figs. 3 & 4.

60 The AGO recommends that the Department consider adopting consumer protection measures ahead of implementing TVR for competitive supply.

61 *See* <u>Vote & Order Opening Inquiry</u>, at 2, 13; <u>DOER TOU Proposal</u>, at 51–52. The AGO notes that the timeline between the August 31, 2026 deadline for comments and the September 30 deadline for the EDCs' Joint MEO Plan may make robust collaboration among stakeholders challenging.

The AGO supports the specific MEO plan components in DOER's TOU Proposal[62] and recommends that the EDCs integrate MEO-focused recommendations from the IRWG[63] and the Energy Burden Working Group ("EBWG") convened by the Department in D.P.U. 24-15.[64] The AGO additionally recommends that the EDCs' Joint MEO Plan include a discussion on the proposed role of key stakeholders, including DOER, EEA, the Department's Division of Public Participation, and the AGO.

Turning first to the IRWG's MEO recommendations, the AGO highlights the following, which should be integrated into the EDCs' MEO efforts:

- MEO efforts should be customer-centric.[65]
- MEO efforts should be tailored "to mitigate or remove [] barriers to create an experience for customers that is easy, convenient, and as frictionless as possible."[66]
- "The effectiveness and success [ ] will depend on customer awareness and adoption of such offerings."[67]
- "In designing MEO efforts, EDCs [] should draw from best practices; MEO professionals; and the experience of other utilities, including utilities in the Commonwealth as well as other jurisdictions."[68]
- "To ensure that MEO efforts are effective, they should be evaluated regularly and revised as needed."[69]

Although the proceedings are focused on different subject matter, the topic of MEO has been discussed extensively within D.P.U. 24-15. In that regard, the AGO recommends that the EDCs consider integrating the following specific recommendations into their MEO efforts, which are aligned with the EBWG co-chairs' reports:

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62 DOER TOU Proposal, at 51–52.

63 *See* IRWG Near-Term Recommendations, at 3, 25–28 (Dec. 2024). The AGO notes that the IRWG's recommendations related to MEO are generally consistent with the AGO's advocacy in *National Grid*, D.P.U. 23-150, and *Energy Affordability*, D.P.U. 24-15. *See National Grid*, D.P.U. 23-150, AGO In. Br., at 168–71, 172–76, 182–85; *Energy Affordability*, D.P.U. 24-15, AGO March 1, 2024 Comments, at 28–29.

64 *Energy Affordability*, D.P.U. 24-15, Low-Income Discount Rate Process Report (May 14, 2026), and MEO Co-Chairs' Report (Aug. 10, 2026).

65 IRWG Near-Term Recommendations, at 25.

66 *Id.*

67 *Id.*

68 *Id.* at 26.

69 *Id.*

- Plan to engage with community-based organizations and municipalities, as they may be trusted community leaders and partners;[70]
- Equip trusted community partners with materials to educate the community members they serve;
- Use consistent terminology across utilities;
- Use customer-centered language;
- Integrate message testing with the intended audience for communications;
- Multilingual outreach is important;
- Provide materials through digital and non-digital channels; and
- Align and coordinate efforts with related efforts, including energy efficiency educational efforts.[71]

The AGO reiterates its request, above, that the Department provide stakeholders with the opportunity to review the EDCs' Joint MEO Plan. Further, the AGO intends to review estimated MEO costs and reporting requirements to ensure that ratepayer funds are used cost-effectively.

b. Transition Plans

As a corollary to its recommendations that the EDCs develop a Joint MEO Plan, DOER also requests that the EDCs: (1) develop a joint transition plan in the near term; and (2) file EDC-specific transition plans when proposing changes to TVRs in the future.[72] The AGO supports these recommendations and expects that such filings, which should be accompanied by opportunities for stakeholder input, will provide important opportunities for both collaboration and early notification of upcoming changes to rate offerings.

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[70] *Energy Affordability*, D.P.U. 24-15, Low-Income Discount Rate Process Report, at 10 (V-5), MEO Co-Chairs' Report, at 10.

[71] *Energy Affordability*, D.P.U. 24-15, MEO Co-Chairs' Report, at 9–12.

[72] *See* DOER TOU Proposal, at 50.

Q5 Please provide information and analysis on items 3, 5, and 6 in the information request to the EDCs in Section V of the Vote & Order Opening Inquiry.

Item 3. <u>Empirical analyses and discussion of the appropriateness of a single four-hour peak window from 4:00 p.m. to 8:00 p.m. for each day (weekday, weekend, holiday) during summer, shoulder, and winter seasons, with definitions for each season.</u>

a. <u>The AGO supports DOER's methodology for identifying peak period hours and DOER's recommendations calling for more data on distribution system costs.</u>

DOER selected its recommended peak period based on two key drivers of electricity costs: (1) ISO-NE system peak hours, because reducing load during peak hours should lower transmission costs and capacity-related supply costs in the long run;[73] and (2) ISO-NE day-ahead energy prices, because reducing energy consumption during the costliest hours should lower energy-related supply costs.[74] DOER does not incorporate distribution system analysis into its peak period selection due to lack of data and recommends that the Department direct the EDCs to report on the coincidence of distribution system peak demand with ISO-NE system peaks,[75] which the Department has requested.[76]

Given the data currently available, the AGO supports DOER's approach of aligning the peak period hours with ISO-NE system peaks and/or the highest day-ahead energy prices, because those are key electric system cost drivers. The AGO also agrees with DOER's point that distribution peak analysis should inform peak period selection and looks forward to evaluating the EDCs' August 31, 2026 filings. The AGO recommends that the Department create an opportunity in this docket for subsequent input regarding the impact, if any, of distribution peaks on peak period selection.

Optimally, the EDCs would set the on-peak TOU period and rates by identifying the highest marginal cost hours across the year.[77] However, the EDCs likely do not currently have hourly marginal transmission and distribution cost data. As DOER has noted, an MCOSS would provide such data, at least at the distribution level. Accordingly, DOER recommends that the Department: (1) direct the EDCs to conduct MCOSSs to inform distribution rate design; and (2) provide

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73 *Id.* at 30, 38.

74 *Id.* at 27.

75 *Id.* at 24.

76 <u>Vote & Order Opening Inquiry</u>, at 10.

77 Doing so entails combining the average hourly supply (energy and capacity) and delivery (transmission and time-varying distribution) costs for each hour of the year—based on forecasted hourly marginal costs, if possible—and then comparing system cost variations by time of day and by season using a heat map analysis.

guidance on MCOSS requirements within this investigation.[78] The AGO agrees that a carefully-executed MCOSS could provide valuable system cost information for rate design and other uses, such as for setting appropriate Distributed Energy Resource compensation levels.[79] Because developing an MCOSS will involve numerous assumptions and methodological choices, the AGO recommends that, through this proceeding, the Department solicit proposed MCOSS frameworks and allow stakeholders the opportunity to provide testimony in response to proposals.[80]

b. The AGO generally supports DOER's proposed peak period and seasonal differentiation, with some modifications.

1. 4–8pm Peak Period

DOER recommends that the Department adopt an initial peak period of 4–8pm across all three Massachusetts EDCs, for all customer classes.[81] The 4–8pm peak period would apply year-round to supply, distribution, and transmission. The AGO supports a year-round four-hour afternoon peak period[82] for the same reason that DOER provided—to maximize customers' ability to shift their usage away from high-cost hours.[83] The AGO also agrees that DOER has selected the highest-load and/or highest-cost afternoon and evening hours of 4–8pm. Because energy prices and the probability of system peak are likely lower on weekends, it would be appropriate to exclude weekends from the on-peak periods if substantiated by ISO-NE data.[84]

2. TOU Seasons

DOER's proposal appears to include two seasons—summer, and the rest of the year—with just the transmission rate differentiated between the two seasons at this time. The AGO considers DOER's two-season approach to be reasonable for a default TOU rate, as three-season TOU rates

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78 DOER TOU Proposal, at 42–43.

79 The AGO does not, however, agree with or endorse DOER's statement that minimal marginal system costs are associated with consumption nor DOER's implication that the prevailing balance of costs recovered through the monthly customer charge as opposed to volumetrically is flawed. *Id.* at 22–23. The AGO cautions against drawing such conclusions without an up-to-date, approved MCOSS that uses agreed-upon methodologies.

80 This approach will provide the opportunity for stakeholders to weigh in and for the Department to provide direction before the EDCs file MCOSSs in upcoming rate cases, rather than reacting to substantial new studies in addition to numerous other rate case activities.

81 DOER TOU Proposal, at 3.

82 In response to Eversource and National Grid's proposed optional EV TOU rates, the AGO has previously advocated a four-hour peak period. While best practices may differ for default and optional TOU rates, the reasoning behind a four-hour peak period remains the same. *Eversource and National Grid*, D.P.U. 23-84/D.P.U. 23-85, AGO In. Br., at 18.

83 DOER TOU Proposal, at 22.

84 It is unclear whether DOER's proposed 4–8pm peak period applies to weekends as well as weekdays.

are quite rare around the country, let alone for an opt-out rate, and may be more confusing for customers.

3. Seasonal Differentiation of Transmission Rates

DOER recommends higher transmission rates from June through September to reflect the summer peaking New England bulk power system,[85] which the AGO supports. DOER explains that this would apply to non-demand customers who pay for transmission via a uniform volumetric energy rate ($/kWh) that does not vary throughout the year, but not to medium and large C&I customers, who pay based on demand ($/kW).[86] The AGO notes, however, that some general service demand customers do pay volumetric transmission rates in addition to transmission demand rates, such as customers in National Grid's and Unitil's G-2 and G-3 customer classes.[87] The AGO agrees with DOER that transmission rates should differ seasonally and further recommends that seasonal transmission rate differences apply to any customer with volumetric transmission rates, even if they also pay transmission demand rates.

4. Seasonal Differentiation of Distribution Rates

For distribution, DOER recommends using a MCOSS and an analysis of hourly peaks on primary distribution infrastructure to inform the proportion of costs collected in the peak period.[88] The AGO finds this reasonable, pending review of the EDCs' forthcoming filings on distribution peaks and the development of appropriate marginal cost methods.

5. Seasonal Differentiation of Supply Rates

For supply, DOER notes that a cost-reflective basic service rate would likely reflect higher supply rates in the summer and winter compared to shoulder seasons, but does not recommend differentiating supply pricing by season, noting the Department's prior direction to minimize significant rate differences due to high wholesale electricity prices in the winter months.[89] The AGO emphasizes the importance of rate design that reflects the seasonal differences in supply costs, both in peak period selection and potentially in peak period pricing and therefore recommends that the Department consider seasonally differentiating supply costs, such as by implementing a seasonal morning peak period alongside a full year afternoon peak of 4–8pm. This recommendation is discussed in subsection c, below.

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[85] DOER notes the Department's prior finding that seasonal pricing for transmission service was reasonable and cost-based for Eversource's heat pump rate. DOER TOU Proposal, at 40.

[86] *Id.* at 39.

[87] https://www.nationalgridus.com/MA-Business/Rates/Service-Rates; https://unitil.com/sites/default/files/2024-01/MA-Commercial-Electric-Rates.pdf.

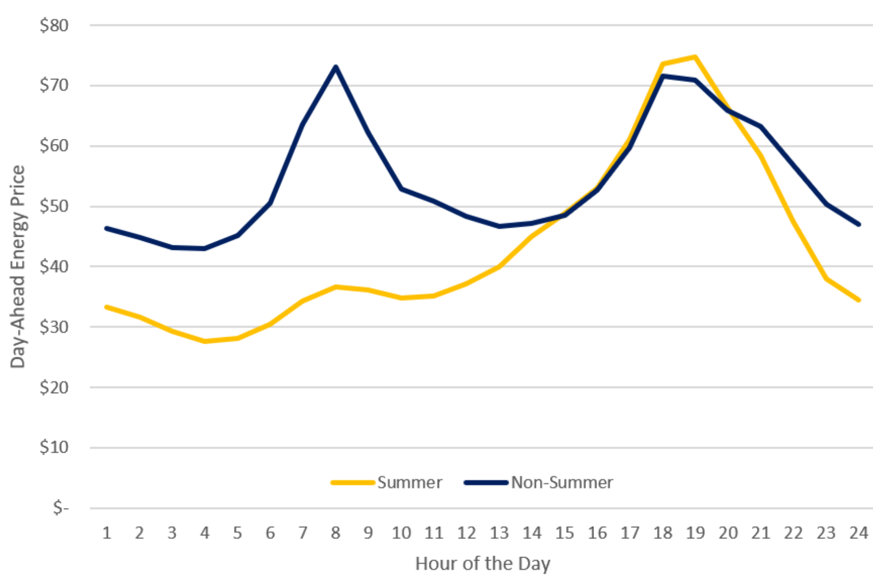
[88] DOER TOU Proposal, at 43.

[89] *Id.* at 34.

c. **<u>The AGO recommends that the Department consider an additional non-summer morning peak period.</u>**

As previously mentioned, DOER's petition acknowledges high winter energy prices, but does not recommend additional on-peak periods or differentiated pricing that would reflect these high winter energy prices at this time.[90] DOER stresses "the suitability of its recommended peak period of 4–8pm throughout the year as an incremental step to more cost-reflective rates, and the potential for further development in the future."[91] The AGO contends that although DOER's proposed peak period covers many of the highest energy-cost hours, it does not cover winter mornings, when energy prices are substantially higher than many of the hours that are not included in DOER's proposed peak. As illustrated in Figure 1 below, an additional, non-summer morning peak period is likely to better reflect system costs. Figure 1 graphs the average hourly 2023–2025 day-ahead energy price data from DOER's Figure 4[92] by season, showing that average morning energy prices during the eight non-summer months (October to May) reach nearly the same level as the evening energy prices during the hours that are included in DOER's proposed peak period.

Figure 1: Average Hourly Day-Ahead Energy Prices by Season, 2023–2025



The magnitude of winter energy costs is important to recognize because supply costs represent a substantial portion of customer bills, with energy costs representing over 75 percent of

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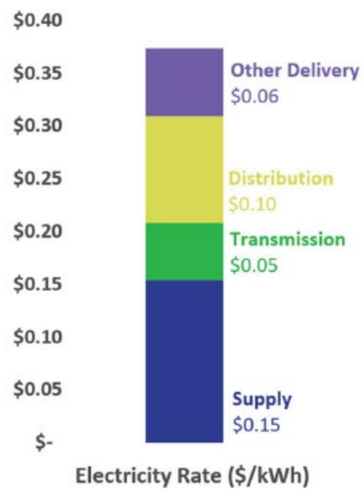
90 *Id*.

91 *Id.*

92 DOER's Figure 4 includes separate graphics for Northeast Massachusetts and Boston, Southeast Massachusetts, and West/Central Massachusetts. *See id.* at 21. However, because the seasonal curves were nearly identical across the three load zones, AGO Figure 1 averages the data for all three.

supply costs.[93] Figure 2 below, demonstrates that certain components of the power system are responsible for greater customer costs, with supply representing the costliest component. Thus, the cost drivers for those components should be prioritized in TOU rates, especially where the cost drivers for multiple components overlap. Figure 2, originally included in DOER's petition, breaks down an illustrative residential electric rate by component, based on National Grid's delivery and Basic Service rates.[94]

Figure 2: Illustrative Residential Electric Rate, Reproduced from DOER TOU Proposal



Given the high winter morning energy prices and the relative significance of energy supply costs on the total bill, the AGO recommends that the Department and stakeholders consider a non-summer morning peak period in addition to the year round 4–8pm peak period. Considerations should include: (1) whether a non-summer morning peak period is appropriate, and, if so, whether it should apply year-round, which would maintain continuity for customers but would needlessly discourage consumption during summer mornings; (2) the impact on households that are less likely to be able to automate and/or shift their heating load;[95] and (3) the impact of a second peak period on customer understanding and acceptance. For example, will customers respond more positively to an initial rate with two peaks, paired with extensive customer education; or to an initial rate with

93 DOER explains that "energy and capacity costs accounted for 78% and 17% of non-transmission wholesale electricity costs in 2024, respectively." *Id.* at 27.

94 *Id.* at 8. It would be overly simple to assume that the relative magnitude of each component of the $/kWh rate represents the proportional importance of each power system component for TOU rate-making. For example, there are some categories of distribution system costs (i.e., line transformers and secondary infrastructure) that should be recovered through a uniform rate rather than through time-varying rates (i.e., with different prices in peak and off-peak periods).

95 The AGO notes that the largest residential winter morning load is likely to be from electric heating. Some customers will be able to automate their heating to kick on before 6am and to use a lower set point during a potential winter morning peak period. However, customers without smart thermostats may be less able to automate their heating load.

a single peak, followed by a second peak period (i.e., a non-summer morning peak) introduced after customers have acclimated to the concept of TVR.

Finally, if the default TOU rate approved by the Department does not include a non-summer morning peak period, the EDCs could offer that rate structure through an optional, opt-in TOU rate as an alternative to the default TOU rate. The more cost-reflective rate may appeal to particular customers by enabling greater bill savings.

d. **The AGO recommends the Department establish a process for future revisions to the peak period.**

DOER recommends that the Department require the EDCs to jointly prepare an annual report that reviews the peak period and proposes amendments, if necessary, to align with changes in energy prices and usage trends.[96] The AGO supports DOER's position that the peak period may need to be re-evaluated and revised over time as the power system changes. Accordingly, the AGO recommends that the Department develop criteria that would trigger future revisions to the peak period. For example, revisions to the peak period may be appropriate following a clear movement of system costs and peaks to a later hour of the day, or when additional analysis enables more refined peak period selection methods, such as when data from distribution MCOSSs are available.[97]

The AGO notes that the criteria that would trigger a rate change for all service territories should also justify establishing different peak periods and rates for individual service territories. Regarding potential peak period revisions, the AGO requests that the Department clarify the process for changing the TOU periods, such as whether it must occur through a rate case or a different type of proceeding. The AGO recommends that the Department provide stakeholders with the opportunity to issue information requests and testimony on proposed TOU period changes.

Finally, for the sake of rate stability and customer acceptance, the AGO recommends that the Department consider the frequency of changes to peak periods. Annual changes, as suggested by DOER,[98] may be too frequent for customers. Thus, the AGO suggests the Department consider limiting the frequency of changes to the peak period. This restriction may be reasonable from a cost perspective as well, as a peak period change would require additional MEO efforts.

Item 5. **A discussion of the appropriateness of CPP for distribution and transmission.**

Massachusetts decision-makers and stakeholders have consistently acknowledged the

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[96] DOER TOU Proposal, at 23.

[97] Distribution MCOSS data may change the existing understanding of temporal power system costs and thus may warrant a different peak period.

[98] DOER TOU Proposal, at 23.

potential value of CPP rates. In 2025, the IRWG recommended that an opt-in residential[99] CPP rate be considered as a supplemental rate, in addition to a seasonal, default TOU rate.[100] In 2014, the Department found that opt-out TOU rates with a CPP component would benefit customers by lowering system costs.[101] Although DOER's proposal does not call for the Department to establish CPP rates, DOER does acknowledge that such a rate can be layered on top of TOU rates to maximize cost-reflectivity.[102] DOER notes that providing interested customers with greater exposure to dynamic system conditions and costs can in turn deliver additional system benefits and cost saving opportunities.[103] Because of the high potential for CPP rates to incentivize load shifting, the AGO strongly supports the EDCs offering an optional, opt-in CPP rate for residential customers, as well as for C&I customers. In terms of timing, CPP offerings should be available on the same expeditious timeframe that DOER has recommended for any other TVR approved in this docket.

A CPP rate charges a substantially higher price during constrained periods on the bulk power system, such as during high load or high cost hours. This higher price is typically limited to a few hours at a time, for a total of approximately 75 hours per year. Participating customers pay a lower price the rest of the year, particularly during the off-peak period. Because the CPP structure incentivizes demand reduction during bulk power system constraints, CPP rates are well-suited to target supply costs. CPP rates can also target transmission costs to the extent that transmission cost drivers overlap system peak demand.[104] Therefore, to the extent that the highest cost supply hours and transmission peaks overlap, the AGO views CPP rates as appropriate to address transmission costs, in addition to supply costs.[105]

CPP rates are likely to have the most impact on supply and transmission costs as opposed to distribution system costs, due to the more localized nature of distribution infrastructure peak

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99 The IRWG's recommendations were limited to residential rate design. The recommendation to consider a residential CPP rate does not preclude C&I CPP rates.

100 IRWG Long-Term Recommendations, at 21–22.

101 DOER TOU Proposal, at 44, referencing *Investigation into Time Varying Rates*, D.P.U. 14-04-B, Order, at 9–11.

102 *Id.* at 14.

103 *Id.* at 14, 29.

104 DOER writes that long-run marginal transmission costs are driven by annual peak demand. *Id.* at 37. While that is a reasonable assumption, the AGO anticipates that the EDCs should be able to verify this assumption in their forthcoming analysis in response to the Vote & Order Opening Inquiry, at 10, which directs each EDC to assess the coincidence of transmission system peak demand with ISO-NE system peaks.

105 The Federal Energy Regulatory Commission ("FERC") transmission cost allocation is based on a coincident monthly peak allocator, while a large portion of transmission costs are caused by coincident peak demand. Despite the fact that FERC transmission cost allocation is inconsistent with transmission system cost causation, the AGO agrees with DOER that peak load reduction should lower long-run transmission infrastructure costs. *See* DOER TOU Proposal, at 38.

constraints, as discussed in Question 2, above. Some utilities have offered rates targeting local distribution circuit peaks, such as San Diego Gas & Electric's ("SDG&E") EV Grid Integration Pilot in California[106] and Southern California Edison's ("SCE") Critical Peak Pricing rate for business customers,[107] but further analysis would be necessary regarding the feasibility and cost-effectiveness of distribution-driven or localized CPP events in Massachusetts. Nonetheless, to the extent that distribution infrastructure peaks align with bulk system peak demand, a CPP rate may indeed help mitigate those distribution costs.

Although the Department has ordered the EDCs to report on the costs of implementing TVR based on DOER's recommendations,[108] these cost estimates are not likely to reflect an opt-in CPP rate option because DOER did not formally propose a CPP rate. The AGO therefore recommends that the Department direct the EDCs to provide an incremental cost estimate for implementing opt-in residential and C&I CPP rates. The AGO also recommends that the EDCs quantify the potential cost savings associated with billing the CPP rate on the delivery portion of the bill for customers taking basic service supply, which could help avoid additional upfront billing system upgrades to enable CPP billing for basic service. It may also be cost-effective for the EDCs to contract with a third-party provider who can dispatch CPP events using an add-on module to the EDCs' billing systems.[109]

Item 6. Empirical analyses of demand elasticity across all customer groups and seasons, including discussion of appropriate pricing ratios given varying percentages of volumetric costs per customer bill at the 25th percentile, 50th percentile, 75th percentile, and mean usage.

The AGO has not conducted the requested empirical analysis and looks forward to reviewing the EDCs' forthcoming analysis. In that regard, the AGO recommends that the Department provide an opportunity in this docket for stakeholder input regarding appropriate price ratios after the EDCs file data on demand elasticities and volumetric costs at different usage percentiles.

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106 SDG&E's highly advanced, dynamic rate has both a wholesale market adder and a distribution adder. The Distribution Capacity Component Hourly Adder is over eleven times greater than the base distribution rate and applies to the top 200 annual hours of the circuit feeding the eligible charging station, https://tariffsprd.sdge.com/afadc4b8-9c1d-45a6-b7fc-726b4c0678d3.

107 Forecasts of SCE system emergencies may be declared at the generation, transmission, or distribution circuit level. *See* https://www.sce.com/business/rates-financing/rate-plans/critical-peak-pricing.

108 Vote & Order Opening Inquiry, at 11.

109 *Quantifying the Value of Add-on Billing Engines vs. CIS Customization*, GUIDEHOUSE (Q2 2026) (commissioned by GridX), https://20562761.hs-sites.com/hubfs/GridX%20Modular%20Billing%20Engine%20FINAL.pdf?hsCtaAttrib=210695920792.

Ahead of reviewing the EDCs' responses to this question, the AGO offers its preliminary recommendations. For default residential TOU rates, the AGO recommends that the peak to off-peak price ratio initially be set around 2:1. A price ratio of up to 3:1 may be appropriate if comprehensive bill impact analysis demonstrates minimal harm to vulnerable customers. As discussed above, setting an appropriate peak to off-peak price ratio is itself an important consumer protection measure.

The AGO contends that the initial price ratio for a default residential TOU rate should consider peak and off-peak costs, but that it is not appropriate to establish fully cost-based rates at this time. The Department notes that DOER asks "the Department [to] determine the appropriate ratio for [ ] supply, transmission, and distribution service by examining the underlying cost structure of each component[.]"[110] The AGO agrees that it would be instructive for the EDCs to quantify actual on- and off-peak costs to the extent possible,[111] however, there are important policy reasons to set TVRs administratively (rather than establishing fully cost-based rates), especially at first. Widely-recognized rate design principles, including public acceptability of rates and gradualism should be prioritized when first introducing default TVRs to residential customers. Automatically transitioning residential customers from a flat volumetric rate (with no time-varying differentials) to a rate where some hours are priced multiple times higher than others would be inconsistent with these principles.[112] The AGO recognizes that a 2:1 or 3:1 peak to off-peak price ratio is likely not fully cost reflective, and that a cost-reflective rate would have a higher peak to off-peak ratio.[113]

The AGO's recommendation for a mild to moderate initial peak to off-peak price differential is informed by the experiences of other jurisdictions.[114] Jurisdictions that have implemented default TOU rates have typically adopted mild price differentials. For example, default TOU rates in Michigan, Missouri, California, and Colorado show price ratios of less than 2:1.[115] Furthermore, jurisdictions like Minnesota and Missouri, which initially proposed greater price differentials for default TOU rates experienced strong backlash, as described below.

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110 Vote & Order Opening Inquiry, at 6.

111 As mentioned above, the EDCs do not have hourly transmission and distribution costs.

112 The AGO recommends that even an opt-in CPP rate should be capped administratively to avoid serious adverse consequences to customers.

113 As DOER notes, the average peak to off-peak price ratio for day ahead energy prices in 2025 was 1.5:1 for a 4–8pm peak period, and that ratio would be far greater if accounting for capacity-related supply costs, transmission costs, and time-varying distribution costs. DOER TOU Proposal, at 34.

114 *See* DOER Petition, Exh. F., at 370–84.

115 *See id.* at 378 (listing the price differentials established for several default or mandatory TOU rates, offered by DTE Energy Consumers Energy Evergy, PG&E, and Public Service Colorado (Xcel), which include price ratios of less than 2:1, with the exception of Public Service Colorado (Xcel)).

Minnesota: Xcel Energy[116] planned to enroll customers in a default TOU rate but withdrew that plan after backlash over steep peak to off-peak price ratios. The company even lowered the price ratio for its subsequent proposed opt-in TOU rate to below 3:1.[117]

Missouri: The Public Service Commission ("PSC") directed Evergy[118] to implement an opt-out TOU rate with a relatively steep peak to off-peak price ratio of 4:1.[119] Due to concerns regarding customer bill impacts, Missouri legislators sent a letter urging the PSC to return to an opt-in TOU model, threatening legislative action "to protect consumers from unnecessary rate hikes and government mandates."[120] In response to the backlash, the PSC allowed Evergy to adopt an extremely mild peak to off-peak price differential, with only a two cent differential in the summer (1.2:1) and a one cent differential in the winter (1.1:1).

As stated above, the AGO's recommendation of a price ratio of 2:1, and possibly up to 3:1, for default residential TOU rates, is preliminary. Before supporting a 3:1 price ratio, the AGO would like to understand the magnitude of bill impacts under each price ratio. While the elasticity information that the Department has requested from the EDCs may help stakeholders consider customers' price-responsiveness and potential ability to shift load, the bill impact analysis that the AGO and DOER have requested[121] is essential to understanding just how much particular customers will be impacted under a particular price ratio if they cannot shift load or are unaware of the importance of shifting load. Finally, a mild price ratio could also reduce the number of people who opt-out, exposing more customers to a cost-reflective price signal while minimizing serious financial consequences.

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116 Xcel Energy is a regulated electric utility and natural gas delivery company based in Minneapolis, Minnesota, serving approximately 3.9 million electricity customers and 2.2 million natural gas customers across parts of eight states.

117 *After backlash, Xcel retreats from Minnesota plan for higher peak rates, lower overnight costs*, MINNESOTA STAR TRIBUNE (Aug. 22, 2024), https://www.startribune.com/after-backlash-xcel-retreats-from-minnesota-plan-for-higher-peak-rates-lower-overnight-costs/601127975.

118 Evergy is a regulated utility that serves millions of customers, communities, and businesses across Kansas and Missouri.

119 Missouri Public Service Commission, File No. ER-2022-0129 and ER-2022-0130, Amended Report and Order (Dec. 8, 2022).

120 Letter to Chairman Rupp from State Senators Cindy O'Laughlin and John Rizzo (Aug.7, 2023), https://efis.psc.mo.gov/Document/Display/175531.

121 *See supra* AGO Response to Question 1.

Respectfully submitted,

/s/ Jessica R. Freedman
Jessica R. Freedman
Assistant Attorney General

Enclosure

cc: Elizabeth McNamara, Hearing Officer
Service List

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Investigation into the Design and Implementation of Time-Varying Rates	**D.P.U. 26-62**

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in this proceeding in accordance with the requirements of 220 C.M.R. 1.05(1) (Department's Rules of Practice and Procedure). Dated at Boston this 31st day of August, 2026.

/s/ Jessica R. Freedman
Jessica R. Freedman
Assistant Attorney General
Massachusetts Attorney General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, MA 02108
(617) 727-2200