

November 22, 2024

VIA ELECTRONIC MAIL ONLY
Interagency Rates Working Group
c/o Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114
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Subject: Comments on the Interagency Rates Working Group Long-Term Ratemaking Draft Study

Dear Interagency Rates Working Group Members,

Sierra Club appreciates the opportunity to provide feedback on the Interagency Rates Working Group's (IRWG) Long-Term Ratemaking Draft Study. We strongly support the IRWG's rate design and regulatory goals. Sierra Club agrees that effective rate design is critical to advancing transportation and building electrification, promoting efficient use of the grid through appropriate price signals, and minimizing impacts on ratepayers, especially low- and moderate-income customers. We also support the IRWG's objectives of identifying regulatory and ratemaking mechanisms that incentivize efficient grid investments and promote distributed energy resources (DERs) for decarbonization.

Sierra Club acknowledges the substantial effort involved in preparing these studies. Both the Long-Term Ratemaking Draft Study and Near-Term Rates Report provide valuable insights and analysis that greatly enhance informed discussions and decision-making, and we commend the IRWG and the E3 consultant team for their thoughtful work.

In the comments below, we offer our thoughts and recommendations on how Massachusetts can effectively implement long-term ratemaking strategies in conjunction with the rollout of advanced metering infrastructure (AMI). We also offer recommendations with respect to the roll-out of near-term rate designs. Sierra Club retained Synapse Energy Economics, Inc. to assist with the preparation of these comments.

I. TIME-VARYING RATES

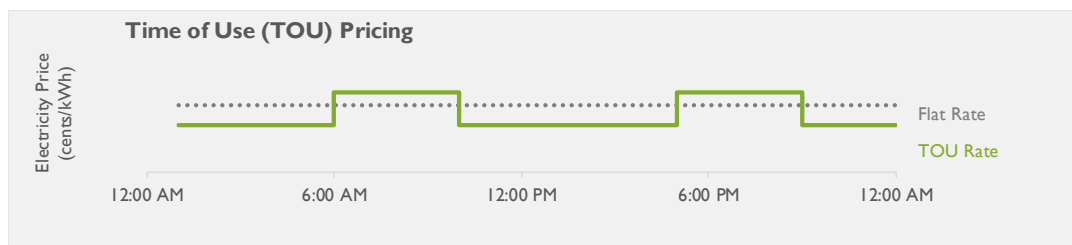
Sierra Club appreciates the IRWG's focus on minimizing peak demand growth in order to limit the cost associated with electrification. We are pleased that the Long-Term Draft Study emphasizes the potential for time-varying rates to mitigate peak demand, while also acknowledging that some end uses (such as heating) will have limited flexibility. Sierra Club also notes that lower-income populations will likely have less-flexible loads, as lower-income

customers are less likely to have electric vehicles.¹ While Sierra Club supports the widespread adoption of time-varying rates in the Commonwealth, we emphasize that the roll-out of such rates should be gradual, beginning with well-marketed opt-in time-varying rates before transitioning to default (opt-out) time-varying rates coupled with adequate protections for vulnerable populations, as discussed in more detail in the following sections. Further, we observe that Critical Peak Pricing (CPP) tends to produce much greater load shifting than time-of-use (TOU) rates, and thus should be offered as an opt-in rate and marketed to customers as soon as advanced metering infrastructure is installed.

a. Assessment of Time-Varying Rate Options

There are multiple types of time-varying rates, each with its own advantages and disadvantages. We briefly describe these below, followed by our recommendations for adoption of time-varying rates in Massachusetts.

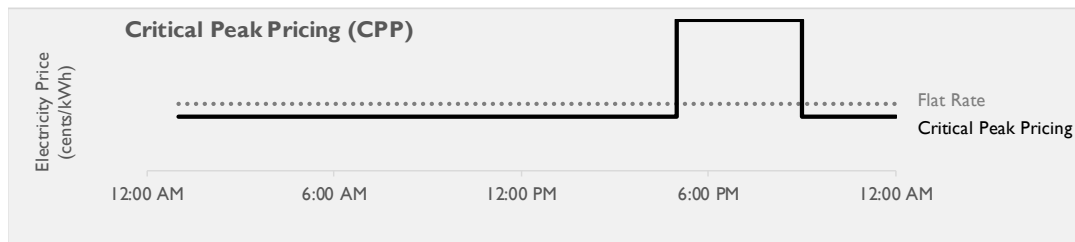
Time-of-Use (TOU) Rate: Under this rate design, electricity prices vary during the day according to a set schedule, which is designed to roughly represent the costs of providing electricity during different hours. A simple TOU rate would have two different prices: one for on-peak periods and another for off-peak periods. This rate design approach can provide customers with a more accurate price signal, which encourages customers to shift their usage from on-peak periods to off-peak periods, thereby reducing system costs. It is also relatively simple to understand, and can be designed with mild on-peak to off-peak price ratios, thereby mitigating risk for customers who cannot always shift their load away from peak periods. A simple TOU rate is illustrated below in green, as compared to a standard flat rate (dotted line).



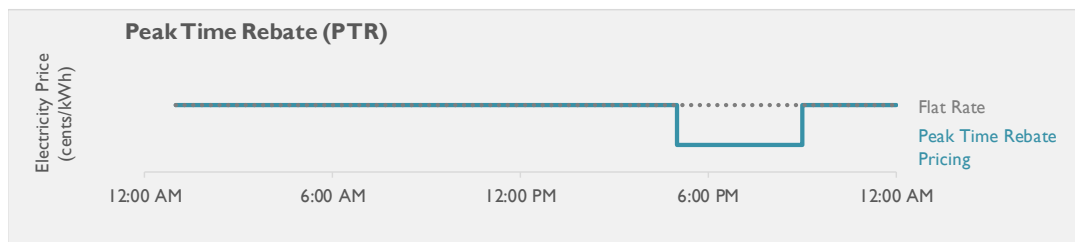
Critical Peak Pricing (CPP): A critical peak price would assess an extremely high price during only a small number of event hours per year, in return for a lower price during the rest of the hours of the year. Customers are generally notified the day before an event. For example, a utility may call ten critical peak pricing events during the year, each of which lasts for four hours. During the events, electricity is priced at \$1.00/kWh. Critical peak pricing can be easily layered on top of a standard TOU rate. The advantage of this rate is that it can effectively target

¹ Although electric vehicles are becoming more affordable, lower-income households tend to own fewer vehicles in general, with 30% of low-income households not owning or leasing a vehicle at all. *See:* Bureau of Transportation Statistics. “The Household Cost of Transportation: Is it Affordable?” July 2, 2024. Available at <https://www.bts.gov/data-spotlight/household-cost-transportation-it-affordable>.

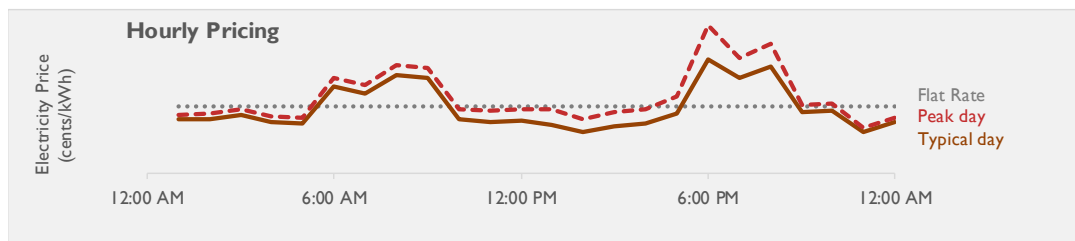
the hours when the system is most stressed, and it can provide significant cost savings for customers who shift load. Because of the strong price signal and the relative infrequency of events, customers on CPP rates tend to respond strongly by shifting a large amount of load to non-event hours. A CPP rate is illustrated below in black, as compared to a standard flat rate (dotted line).



Peak Time Rebates (PTR): A peak-time rebate is the inverse of a CPP rate. Instead of paying a higher price during event hours, a customer is rewarded for reducing his or her demand during those hours. While PTR is very popular with customers, a key challenge with this rate structure is measuring the baseline of what the customer's demand would have been. It also does not provide as strong of an incentive for customers to shift load, as customers tend to react more strongly to the risk of paying higher prices than they do to the reward of saving money. A PTR rate is shown below in blue, as compared to a standard flat rate (dotted line).



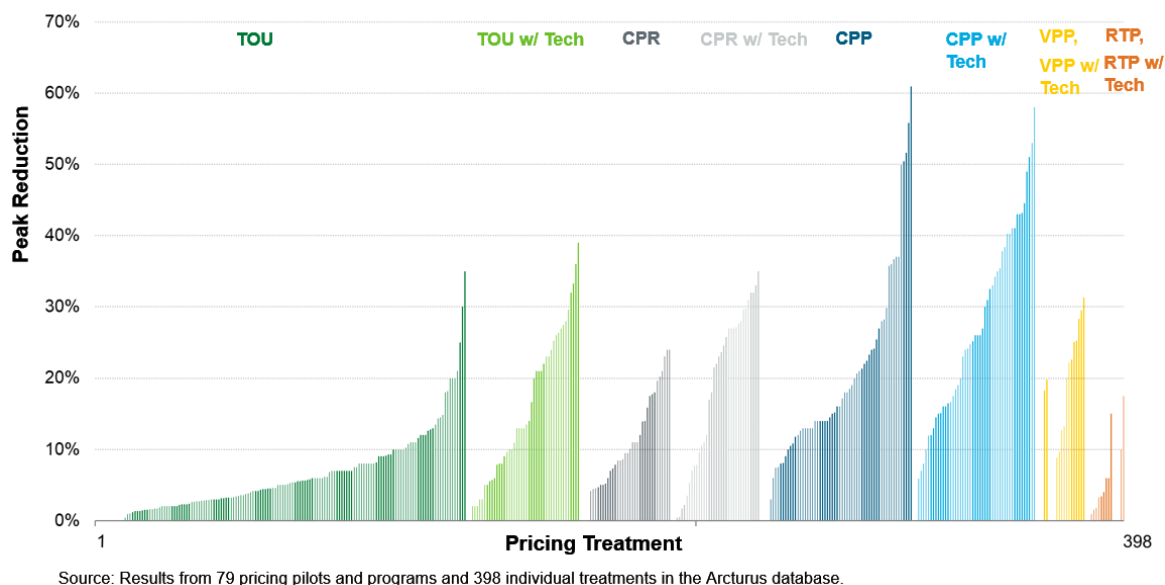
Hourly Pricing: Under hourly pricing, electricity rates change hourly based on actual system costs. The manner in which rates change is not pre-set; rather, rates change dynamically in response to system conditions. This form of rate design is generally too complex for most residential customers. An example of hourly pricing is illustrated below for both a peak day and a typical day, as compared to a standard flat rate (dotted line).



As noted above, peak time rebates tend to produce less load shifting than other time-varying rates and require the establishment of a counterfactual level of consumption for each customer. Hourly pricing is too complex for most customers and is therefore unlikely to produce significant benefits. In contrast, both critical peak pricing and time-of-use rates have potential to provide substantial benefits in Massachusetts.

Critical peak pricing is particularly promising. Research from the Brattle Group covering 79 pilots and programs shows that the median TOU rate tends to achieve peak load reductions of approximately 7-8%, while the median CPP rate produces peak load reductions of 20-25%, or approximately three times more than TOU rates, as shown in the figure below.

FIGURE 1. BRATTLE PEAK REDUCTION EVIDENCE FROM ~400 TREATMENTS BY RATE TYPE²



b. Peak Period Demand Charges

Demand charges (beyond a very small charge related to a customer's line transformer) are not appropriate for most residential customers, as they are difficult to understand. While peak period demand charges represent an improvement over non-coincident demand charges, they are generally less efficient than other time-varying rates, particularly CPP. This is because during the peak periods, the demand charge only encourages customers to not exceed their monthly peak demand, since reducing demand below his or her monthly maximum will have no financial

² Sergici, Sanem. Time-of-Use Rate Design and Roll-out: Learnings from Other Jurisdictions. Maine PUC Docket No. 2024-00231. October 8, 2024, slide 5.

benefit for the customer. In contrast, a time-of-use rate encourages customers to reduce consumption during all hours of the on-peak window, because the customer avoids the peak period price for all kilowatt-hours not consumed. For these reasons, Sierra Club does not recommend pursuing peak period demand charges.

c. Opt-In vs. Opt-Out Rates

Sierra Club recommends introducing rates on an opt-in basis, with the potential to transition to default TOU rates after customers have gained experience with opt-in rates. Stakeholders should also consider that effectively marketed opt-in CPP rates may even produce *greater* demand reductions than default (opt-out) TOU rates. This is because under default (opt-out) TOU rates, a large portion of customers remain unengaged. These customers may be unwilling or unable to shift load, or they may lack awareness of the fact that prices vary by time of day. For this reason, the average load reduction under default TOU rates tends to be quite low. Indeed, the Brattle Group found that after default TOU had been in place for several years in Ontario, peak load reductions had declined to approximately 1 percent.³

In contrast, aggressively marketed opt-in rates may be able to achieve similar, or even greater levels of peak load reductions as default TOU. As discussed above, CPP tends to produce much greater load-shifting per customer than TOU rates, requiring fewer participating customers to achieve sizeable load reductions. For example, Nova Scotia Power’s recently-filed evaluation report⁴ showed that opt-in CPP customers achieved approximately *four times* as much peak load reductions as opt-in TOU customers, as shown in the table below.

TABLE 1. TOU VERSUS CPP LOAD SHIFTING IN NOVA SCOTIA’S TIME-VARYING PRICING PILOT, YEAR THREE

Tariff	Average Absolute Reduction per Household		Average Percentage of Total Household Load Reduction	
	Morning Peak	Evening Peak	Morning Peak	Evening Peak
TOU	0.154 kW	0.153 kW	7.4%	7.0%
CPP	0.768 kW	0.943 kW	27.0%	32.2%

Source: Nova Scotia Power. *Evaluation of the Time-Varying Pricing Pilot, Phase 3. Matter M11823. July 23, 2024*

³ Lessem, N., Faruqui, A., Sergici, S., and Mountain, D. The Impact of Time-Of-Use Rates in Ontario. *Public Utilities Fortnightly*. February 2017, at 59.

⁴ Nova Scotia Power. *Evaluation of the Time-Varying Pricing Pilot, Phase 3. Matter M11823. July 23, 2024*. Available at <https://uarb.novascotia.ca/fmi/webd/APP/connector/0/855/dl/20240731+NSPI+to+NSUARB+TVP+Pilot+Program+Year+Three+Evaluation+Report.pdf>.

d. Customer Protections

As discussed above, we recommend that time-varying rates be implemented on an opt-in basis initially, due to the potential for adverse bill impacts on vulnerable customers, as well as customer confusion and backlash.⁵ Transitioning customers to time-varying rates can result in significant negative impacts for “structural losers”—those whose energy usage patterns are likely to lead to higher bills under time-varying rates, particularly if the customer is unable to shift load away from higher-priced on-peak periods. This is especially concerning for vulnerable populations, including low and middle-income households who do not have the means to absorb significantly higher costs, resulting in disproportionate hardship relative to other customers. It is therefore imperative that the potential impacts on vulnerable populations from default time-varying rates are well understood, and customer protections are in place prior to implementing default time-varying rates.

California provides a useful example of a jurisdiction that has made time-of-use rates the default option for residential customers while mitigating adverse impacts on customers, particularly vulnerable populations. The transition to time-of-use rates in California has been long, iterative, and deliberate, which has enabled regulators and the utilities to collect substantial quantities of empirical data and develop meaningful protections for vulnerable customers. In addition, the long timeline has allowed for robust marketing, education, and outreach, which has allowed customers to develop an understanding and familiarity with the rates prior to implementation. Finally, the default TOU rates in California have been implemented with mild on-peak to off-peak price ratios (generally less than 2:1) to enable customers time to learn how to shift their usage without experiencing large bill impacts in the early years.

The Commission required the California investor-owned utilities to evaluate customer responsiveness to time-varying rates, develop effective education and outreach plans, measure differences in impact by region and customer profile, and study other aspects of rate design and implementation. Specifically, the utilities were required to:

- 1) Conduct analysis regarding bill impacts on vulnerable customers and their ability to shift load.⁶
- 2) Establish a Marketing, Education, and Outreach (ME&O) working group; hire a consultant to advise the working group on appropriate metrics, goals, and strategies; and

⁵ See, for example: Orenstein, Walker. Minnesota Star Tribune. “After backlash, Xcel retreats from Minnesota plan for higher peak rates, lower overnight costs.” August 22, 2024. Available at <https://www.startribune.com/after-backlash-xcel-retreats-from-minnesota-plan-for-higher-peak-rates-lower-overnight-costs/601127975>.

⁶ The Commission found that economically vulnerable customers in hot climate zones may be more likely than other customers to experience high summer bill impacts on a TOU rate while being unable to shift their energy usage patterns to mitigate these negative bill impacts. In order to ensure that economically vulnerable customers do not experience unreasonable economic hardship on TOU rates, the Commission in D.17-09-036 excluded customers eligible to receive income-based assistance in hot climate zones from being defaulted to TOU.

deliver a comprehensive ME&O plan that including a vision, metrics, timeline, and budgets through the implementation of default TOU rates.⁷

- 3) Provide significant information and support to customers well in advance of the transition to default rates, including:⁸
 - a. A bill comparison tools to allow customers to choose the rate schedule that best meets their needs
 - b. Information that will help potential benefiter opt-in to TOU rates ahead of default and enroll said customers
 - c. Information to help structural non-benefiter understand what actions to take to mitigate bill impacts, and information on how to opt-out to other rate options (such as the inclining block rate) for structural non-benefiter who are unable to shift load sufficiently.⁹
 - d. In addition, the Commission required the utilities to offer multiple rate options to customers, including an inclining block (non-TOU) rate, and provide bill protection (hold harmless provision) for a year.

We recommend that a similar process be adopted in Massachusetts if default time-varying rates are contemplated. Specifically, we recommend:

- Only time-of-use rates or peak-time rebates be considered for implementation on a default (opt-out) basis.
- The utilities provide significant education and outreach, including tools to help customers choose the rate schedules that best meet their needs.
- Any default TOU rate should initially have a mild price differential to mitigate the impacts on vulnerable customers, avoid rate shock, and allow customers time to develop familiarity with the rate and with load shifting strategies. Rates with larger differentials (or other types of TVR) can still be offered on an opt-in basis.
- In collaboration with stakeholders, the utilities should develop approaches for identifying low-to moderate income and medically vulnerable customers.
- Low-income, medically-reliant, and any other identified cross-section of vulnerable customer populations should be exempted, and instead only moved to a TOU rate if the customer affirmatively opts in. Identifying such customers requires thoughtful process and stakeholder engagement.

⁷ CPUC Decision 17-12-023 in docket R.12-06-013, December 20, 2017, at 3-4.

<http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K231/201231862.PDF>

⁸ *Id.*, at 10.

⁹ *Ibid.*

II. HIGHER FIXED CHARGES

Both the Long-Term Ratemaking Draft Study and the Near-Term Rates Report note the potential for higher fixed charges to reduce electrification costs. As discussed below, while it may be reasonable to move recovery of some costs from the volumetric rate to the fixed charge, Sierra Club recommends that higher fixed charges be approached with caution so that rates provide efficient price signals and do not hinder affordability for low-income customers. Because low-income customers tend to use less electricity than higher-income customers, a fixed charge that is not income-graduated would tend to increase low-income customers' bills. Further, although income-graduated fixed charges can theoretically help protect low-income customers, we note that the implementation of this concept is challenging.

a. Recovering Policy Costs in Fixed Charges

Recovering certain policy costs in fixed charges may be appropriate to the extent that those policy costs are largely unrelated to volumetric energy consumption. If the policy costs are driven by volumetric energy consumption, then it is appropriate to continue to recover those costs through volumetric charges. For example, because our electricity system is not yet decarbonized, increasing electricity consumption generally results in increased greenhouse gas emissions. Thus, the principle of cost causation would hold that policy costs related to reducing greenhouse gas emissions should be recovered in proportion to energy consumption; i.e., through the volumetric charge.

b. Recovering Embedded Costs in Fixed Charges

Sierra Club has concerns regarding the concept of recovering embedded costs through fixed charges, as shown on slide 22 of the Long-Term Ratemaking Draft Study. This slide seems to suggest that an electric distribution utility's revenue requirement can be divided into a portion that is "embedded" or "sunk" and a portion that is "avoidable," and that the fixed charge would recover the "embedded" costs while the volumetric charge would be set to recover the "avoidable" or variable costs. This seems to imply that the volumetric rate should be set based on average variable cost, which is contrary to the principle of setting rates based on marginal costs to maximize economic efficiency.

Economic theory holds that economic efficiency is maximized when customers face prices that reflect *marginal* costs, not average variable costs. The marginal cost refers to the cost associated with meeting a relatively small increase in demand, and may be significantly higher than the average variable cost. Prices should not be set below the marginal cost, because doing so creates an economic inefficiency where the value customers derive from using an additional quantity of electricity (their marginal benefit) is less than the cost of producing that additional quantity of electricity (marginal cost).

It is also important to define the appropriate timeframe for determining marginal costs. In electric utility regulation, it is generally accepted that the rates that customers face should be relatively stable, and thus customers should not face wild swings in rates associated with capacity constraints and the lumpy investments required to relieve those constraints. Because short-run marginal costs can be highly variable (skyrocketing when there is a need to expand capacity, but falling to near-zero when there is adequate capacity), long-run marginal costs tend to be used in rate design. In *Principles of Public Utility Rates*, James Bonbright writes:

I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs.¹⁰

In other words, electric utility rates should be set on the basis of long-run marginal costs in order to provide relatively stable, but efficient price signals. It is therefore critical that prices not be set below marginal cost (e.g., at the average variable cost), or rates will provide inefficient price signals.

To determine the proportion of revenue collected through volumetric rates, one should begin by multiplying the marginal cost by the volumetric sales. If the resulting revenue is less than the utility's revenue requirement (which is based on embedded costs), then rates can be scaled to meet the utility's revenue requirement, or the fixed charge can be set to recover the remaining revenue requirement.

c. Income-Graduated Fixed Charges

Both the Long-Term Ratemaking Draft Study and the Near-Term Rates Report reference the potential to use income-graduated fixed charges to mitigate impacts on low-income, low-usage customers. Income-graduated fixed charges are tiers of fixed charges that are intended to align with different levels of income. While this tiering is sensible in theory, it can be challenging to implement in practice. California's experience with introducing an income-graduated fixed charge highlights these challenges.

The main issue is whether and how to confirm whether lower-income customers are eligible for the lower fixed charges.¹¹ The California Public Utility Commission's decision on income-graduated fixed charges summarizes multiple approaches proposed by stakeholders, from relatively simple to increasingly complex, including: self-attestation without verification,

¹⁰ James Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), p. 336.

¹¹ Whether and how to confirm whether higher-income customers should be charged the higher fixed charge may also be an issue, though it seems to be a lower priority.

verification leveraging existing processes for low- and moderate-income programs (to the extent they differ from other processes/data sources), self-attestation with verification, and verification using credit agency or tax data.¹²

The challenge with the simplest process, self-attestation without verification, is fraud. Without verification, customers who may not deserve lower fixed charges may receive them. All other approaches have some form of verification, with the difference being the rigor of the verification.

The most straightforward way to verify low- and moderate-income customer eligibility for a portion of customers may be by confirming whether they are also enrolled in other existing low- and moderate-income programs. A key benefit of this approach is better alignment of definitions of low- and moderate-income customers across program efforts. A key challenge with leveraging existing low- and moderate-income programs for enrollment concerns the ability to reach all eligible customers. Specifically, existing low- and moderate-income programs may not reach all low- and moderate-income customers.

Another relatively straightforward way to verify eligibility for all customers may be by conducting verification using the same processes that are in use for existing low- and moderate-income programs. However, this can strain existing program resources and add cost as many more customers may require verification. In addition, the verification process may remove eligible customers if customers do not respond to the request for verification. In California, between 49 and 78 percent of households selected for verification in the California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) low-income programs were unenrolled when they did not respond to the income verification request.¹³

Challenges with the most complex processes—such as using new data sources and verification processes—concern relevance, access, security/privacy, cost, and time. The data in some sources may not directly tie to program eligibility requirements. For example, property tax assessment values may be a poor proxy for income, especially for low-income residents who may face higher tax assessments relative to their actual sale price of their homes.¹⁴ Some sources of data may be inaccessible to utilities due to privacy concerns or customer protections. Utilities may not want to integrate income data into their databases, resulting in the need for a third-party

¹² The Public Utilities Commission of the State of California. Rulemaking 22-07-005. Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates. *Decision Addressing Assembly Bill 205 Requirements for Electric Utilities*. March 27, 2024. Table 1: Opening Testimony Income Verification Proposals. Pages 38 and 39. Available at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M531/K686/531686019.PDF>.

¹³ *Ibid.*

¹⁴ Berry, Christopher. *Reassessing the Property Tax*. The University of Chicago, Harris School of Public Policy and the College. March 1, 2021. Available at: <https://bpb-us-w2.wpmucdn.com/voices.uchicago.edu/dist/6/2330/files/2019/04/Berry-Reassessing-the-Property-Tax-3121.pdf>

to manage the verification. Some sources of data may be costly to acquire. New verification processes can take years to implement and may require significant utility resources to support.

The California Public Utility Commission's decision relies on customer enrollment in its existing low income programs (CARE and FERA) for verification of customers eligible for income-graduated fixed charges as a starting point for simplicity and efficiency reasons. However, this creates only three tiers: CARE households would be assessed a \$6 fixed charge, FERA households would be assessed a \$12.08 fixed charge, and all other customers would be assessed a fixed charge of \$24.15. Because there are only three tiers, customers with incomes of \$50,000 or more are all assessed a fixed charge of \$24 per month, which limits the fixed charge's ability to address equity concerns for more moderate-income customers.

The California Public Utility Commission will continue discussions of the more complex processes, and the process may evolve over time.¹⁵ The Commission's decision also identifies an interest in designing and implementing an income verification process that can better differentiate between moderate- and high-income customers, as a lower proportion of moderate-income customers are enrolled in FERA as compared to the proportion of low-income customers enrolled in CARE.¹⁶

III. REGULATORY REFORMS

a. Performance-Based Ratemaking

The Long-Term Ratemaking Draft Study identifies Performance-Based Ratemaking (PBR) as a potential method to align utility performance with the public interest. PBR is generally defined as the combination of a multi-year rate plan and performance incentive mechanisms (PIMs).

- A multi-year rate plan is a set of rules governing the rates or allowed revenues of the utility for multiple years into the future, with a regulatory requirement that the utility not have another rate case until the end of a stay-out period.
- Performance incentive mechanisms are comprised of performance metrics, targets, and financial incentives (positive or negative) in order to encourage optimal utility performance in key areas.

The description of PBR on slide 23 of the Draft Study refers only to one component of PBR: the metrics and performance incentive mechanisms that track utility performance and potentially reward or penalize the utility based on that performance. Sierra Club acknowledges the potential for performance incentive mechanisms to better align utility performance with

¹⁵ Id, Page 43.

¹⁶ Id, Pages 43 and 44.

public policy objectives and supports their careful adoption. Whether or not PIMs should be combined with a multi-year rate plan is discussed below.

We also note that “earnings sharing mechanisms” are referenced in the performance-based ratemaking bullet, but we believe that this was intended to refer to “shared savings mechanisms” instead. Earnings sharing mechanisms are primarily implemented in the context of multi-year rate plans as a customer protection measure. They typically cap a utility’s earnings at a certain level and require that the utility share some of its over-earnings with customers. This ensures that utility earnings do not become excessive during multi-year rate plans.

In contrast, a shared savings mechanism is often applied as a form of performance incentive mechanism. If a utility delivers net benefits to customers (through, for example, implementing a lower-cost non-wires alternative), the utility is entitled to keep a portion of the net savings. Sierra Club supports the use of shared savings mechanisms.

b. Multi-Year Rate Plans and Formula Rates

The Long-Term Ratemaking Draft Study also identifies Multi-year Rate Plans and Formula Rates as options to align utility performance with the public interest. Although Sierra Club acknowledges that a well-designed multi-year rate plan can provide incentives for utilities to reduce costs, we strongly oppose the use of formula rates, as these plans eviscerate utilities’ cost control incentives.

Specifically, a formula rate plan is devoid of cost containment incentives because it formulaically ensures that revenues track costs. A formula rate plan generally accomplishes this by measuring deviations in the utility’s earned return on equity (ROE) from its target ROE. If a utility’s earned return is above its ROE target (meaning that its revenue exceeds its costs), it will be required to reduce its rates. Likewise, if a utility’s earned return is below its target return (meaning that costs exceed revenues) it will be allowed to increase its rates.¹⁷ Because this allows rates to increase to match the utility’s costs, it provides no incentive for the utility to reduce costs.

In contrast, multi-year rate plans establish a utility’s allowed revenue requirement at the outset of the rate plan, and do not adjust revenues to equal costs during the course of the plan. This provides the utility with an incentive to reduce its costs below its allowed revenue requirement so that it can keep all or a portion of the difference between its revenues and costs.

During the rate plan, revenues may either be held at a fixed level or be adjusted according to a predefined formula called an “attrition relief mechanism” or “ARM.” An ARM may be based on an external cost index (such as inflation), cost forecasts, or a combination of the two.

¹⁷ Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, “Alternative Regulation for Emerging Utility Challenges: 2015 Update” (Edison Electric Institute, November 11, 2015), 47.

Importantly, the formula does not track the utility’s *actual incurred* costs. As explained in the Edison Electric Institute’s survey of alternative regulatory mechanisms, “[t]he rate adjustments provided by ARMs are largely “external” in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth.”¹⁸

Massachusetts has a rich history with multi-year rate plans, primarily based on index-based ARMs (particularly the US Gross Domestic Product Price Inflation). However, in recent years, utilities have argued that such external indexes will not provide sufficient revenues to enable electrification. In National Grid’s most recent rate case, the multi-year rate plan with its inflation-based ARM was reduced in scale so that now it only applies to operating expenses. Capital costs are recovered through a capital tracker, rather than a PBR mechanism.¹⁹ Given the extent of the investment necessary to enable electrification, it is unclear whether multi-year rate plans broadly applied to a utility’s total revenue requirement will continue to be used in Massachusetts.

IV. COMMENTS ON NEAR-TERM RATE DESIGN OPTIONS

Sierra Club appreciates the thorough analysis undertaken of various rate options for this study. Below we provide feedback on each of the four rate designs analyzed in the Near-Term Rates Report.

a. Higher Fixed Charge

As discussed in Section II above, Sierra Club has concerns with substantial increases in the fixed charge due to the potential impacts on low-income customers and attenuation of efficient price signals. If higher fixed charges are considered, they should be income-graduated to mitigate impacts on lower-income customers, and they should include multiple tiers to better reflect customers’ ability to pay. However, we emphasize that the successful deployment of income-graduated fixed charges with multiple tiers would be challenging for the enrollment and verification reasons discussed previously.

b. Seasonal (Universal)

¹⁸ Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, “Alternative Regulation for Emerging Utility Challenges: 2015 Update” (Edison Electric Institute, November 11, 2015), 34.

¹⁹ Massachusetts Department of Public Utilities. Order in D.P.U. 23-150. Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service, a Performance-Based Ratemaking Plan, and a Capital Recovery Mechanism. September 30, 2024.

Sierra Club supports movement towards a seasonal rate for all customers in the near-term. This movement should be gradual in order to avoid sharp bill increases for customers. However, we agree that universal adoption of a seasonal rate is appropriate for several reasons:

- 1) Such a rate is more cost-reflective because the Massachusetts utilities are summer peaking. A seasonal rate would be more equitable by recovering more revenue from customers who use more electricity in the summer, and who drive more of the system peak-related costs.
- 2) The universal seasonal rate modeled would result in much lower bill increases for non-electrifying low-income customers relative to the modeled fixed charge increase.
- 3) A high volumetric price in the summer would also encourage customers to install more energy efficient summer-use appliances (namely air conditioning).
- 4) The seasonality of the prices could be gradually reduced over time as the system becomes more winter-peaking.
 - One approach would be to allocate distribution costs according to the load squared method, in which distribution costs are allocated to each hour in proportion to the square of the class load in that hour. As more load emerges in the winter, the seasonality of the rate would gradually flatten.
 - Another option would be to allocate costs proportionate to the peak demand in each season, with corrections for the higher grid carrying capacity in the winter versus the summer due to lower loss rates in colder weather.

We note that if there are concerns regarding over-compensation of customers with solar, the compensation level could be completely separated from consumption rates and set at the level necessary to meet the Commonwealth's energy policy goals. It is our understanding that the SMART program is generally designed to function this way already.

Finally, we recommend that seasonality also be reflected in any time-of-use rates that may be adopted in the future to ensure that the rates are cost-reflective.

c. Seasonal – Technology Specific (Electric Heating)

The seasonal, technology-specific tariff presented in the Near-Term Rates Report has the potential to provide even greater savings to electrifying customers than the universal seasonal rate modeled by E3, and a technology-specific seasonal rate option could be offered alongside a more mild universal seasonal rate.

While Sierra Club supports rates that have strong seasonal differentiation on an opt-in basis, such rates should still be based on cost causation. A rate that recovers 100% of demand-related distribution costs in the summer may be appropriate as long as virtually all substations peak during the summer months. However, the rate should be adjusted as the system slowly becomes winter-peaking.

V. CONCLUSION

Sierra Club appreciates the opportunity to provide feedback on the IRWG's Long-Term Ratemaking Draft Study and Near-Term Rates Report. We commend IRWG and E3 for the detailed analysis presented in these studies which helps to lay a strong foundation for advancing sustainable energy policies in an equitable manner.

Our comments underscore the importance of cautious implementation of higher fixed charges and the necessity of aligning rates with long-term marginal costs. We strongly support a long-term move to time-varying rates, while encouraging a measured approach to rolling out default (opt-out) time-varying rates. Additionally, we highlight the importance of implementing effective customer education programs and designing mechanisms to mitigate adverse impacts on vulnerable populations. These considerations are essential to achieving the Commonwealth's policy objectives while ensuring fairness and affordability for all ratepayers.

Moving forward, we encourage the IRWG to adopt a balanced approach to rate design, incorporating stakeholder feedback to refine recommendations. This will ensure that Massachusetts continues to lead in crafting innovative, inclusive, and effective energy policies that meet the needs of today and anticipate the challenges of tomorrow. We look forward to continued engagement in this vital process.

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