BEFORE THE

STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY

Docket No. 24-10-04

APPLICATION OF THE UNITED ILLUMINATING COMPANY TO AMEND ITS RATE SCHEDULES

Prefiled Direct Testimony of

Caroline Palmer

On Behalf of

The Office of Consumer Counsel

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I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, title, and employer.

A My name is Caroline Palmer. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse"), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics, Inc.

A Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 40 professional staff with extensive experience in the electricity industry.

Q Please summarize your professional and educational experience.

A I am a Principal Associate at Synapse, where I provide expert witness and consulting services on behalf of public interest clients in regulatory proceedings. The issues I cover in these cases include marginal and embedded cost-of-service studies, revenue allocation, advanced rate design, low-income rate design, load management, decoupling, distributed energy resource ("DER") interconnection and compensation, electric vehicle ("EV") infrastructure investments, and pilot frameworks. Prior to joining Synapse I worked at

Strategen Consulting for five years performing similar work. I have submitted expert testimony in thirteen dockets across eight jurisdictions.

I was awarded a Fulbright Research Fellowship to Greece in 2019 and supported clean energy policy consulting at Meister Consultants Group (now Cadmus) before that. I hold a Master of Public Policy from the Goldman School at UC Berkeley and a Bachelor of Science from Georgetown University. I have 10 years of professional experience. My resume is attached as Attachment CP-1.

Q Have you previously testified before the Connecticut Public Utilities Regulatory Authority?

A No. I have sponsored testimony before a number of other commissions, including the New Hampshire Public Utilities Commission, Missouri Public Service Commission, New York Public Service Commission, the Massachusetts Department of Public Utilities, Maine Public Utilities Commission, the Oklahoma Corporation Commission, the North Carolina Utilities Commission, and the Nova Scotia Utility and Review Board. I have also assisted with testimonies and regulatory analyses in numerous other jurisdictions.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Office of Consumer Counsel ("OCC").

Q What is the purpose of your testimony?

A In this testimony I address certain aspects of The United Illuminating Company ("UI" or "Company")'s allocated cost of service study ("ACOSS"), revenue allocation, and rate design proposals. The absence of discussion of other topics in this testimony should not be construed as support for, or opposition to, the Company's positions.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your conclusions.

A My conclusions are as follows:

- The Company's use of the minimum system method for classifying substantial portions of its distribution system in its ACOSS does not accurately reflect cost-causation principles and inflates cost allocations to residential customers.
- The Company's classification of AMI meter costs as 100 percent customer-related does not reflect cost causation, specifically the fact that the Authority approved AMI investment in part to enable energy savings and demand reductions.
- UI's alternate demand allocators better reflect cost causation by recognizing that substations and feeders vary in size, serve more than one class, and may peak at different times. The alternate allocators also better align cost allocation with rate design, specifically the differentiated distribution TOU rates that PURA ordered UI to implement in this case.
- The Company's allocation of revenue requirement among the customer classes should reflect cost causation associated with an ACOSS that does not include a minimum system study, classifies AMI meters in a way that reflects the additional services they provide, and utilizes alternate demand allocators.
- UI's End-State TOU periods and seasons, and its methodology for selecting those periods and seasons, generally appear reflective of cost causation.
- The complexity of UI's End-State TOU periods and seasons may confuse customers and therefore potentially limit the effectiveness of the rates at achieving their intended load shifting.

- The Company's cost-based TOU rates are extreme, resulting in summer peak residential rates of $0.94/kWh in 11/1/25 rates and $1.17/kWh in End-State rates. Implementing such high rates immediately and without any transition would result in rate shock and likely limit the effectiveness of the rates and their acceptance by customers. While high peak prices may enhance customer response and make the TOU rate more effective, the transition should recognize the principles of gradualism and customer acceptance.
- More work is needed to develop a plan for transitioning to opt-out TOU rates to mitigate the backlash that other jurisdictions have encountered in their transition to opt-out TOU.

Q What are your recommendations?

A I recommend that the Authority direct the Company to:

- Discontinue the minimum system method and adopt the basic customer method for distribution cost classification, which limits customer-related costs to those directly tied to the number of customers, such as metering and billing.
- Classify AMI meters as customer, demand, and energy related proportionally to the relative benefits that accrue to each of the three cost drivers based on UI's quantification of AMI benefits, or, in the absence of such benefits categorization, as 50% customer-related, 25% energy-related, and 25% demand-related.
- Use the alternate demand allocators in its proposed ACOSS in this case. In the next case, the Company should improve upon its temporal analysis by considering the duration of the peak, near-peak, and pre-peak loads that also contribute to asset overheating and aging.

- Allocate revenue requirement among customer classes based on an ACOSS that uses the basic customer method rather than a minimum system study, classifies AMI meters as customer, demand, and energy related, and uses alternate demand allocators. Using the Company's proposed revenue requirement, this translates into a 17% revenue increase for Class R, 13.7% for Class U, and 24.5% for all other classes.[1]
- Use two seasons, not three, for opt-out TOU rates. If the Company offers an opt-in TOU rate in addition to its opt-out rate, it might then be appropriate to include three seasons; in such case, November should be part of the shoulder season.
- Propose an adjusted set of 11/1/25 TOU opt-in rates that includes a more modest on-peak summer rate and lesser price differential between summer peak and off-peak periods, somewhere around three times higher.
- For End-State, opt-out TOU rates: propose a milder on-peak to off-peak price differential for initial implementation; develop a comprehensive marketing, education, and outreach plan with input from stakeholders and customer surveys; evaluate the expected bill impacts (with and without load shifting) of the opt-out TOU rate, particularly for vulnerable customers; exempt vulnerable customers from opt-out TOU rates; and conduct an opt-out pilot in preparation for the deployment of the full-scale, permanent opt-out TOU default rate to better understand customer understanding and acceptance of the rate. UI should initiate a stakeholder process to develop an opt-out TOU transition plan that addresses

[1] The use of the Company's revenue requirement to illustrate changes in class cost allocation does not imply endorsement of that revenue requirement.

these improvements and submit its initial transition plan within 180 days following PURA's final order.

- Investigate opt-in time-varying rates, particularly Critical Peak Pricing.

III. ALLOCATED COST OF SERVICE STUDY

Overview of Cost of Service Studies

Q What is the purpose of a COSS?

A A COSS is used to assign the utility's revenue requirement to each customer or rate class in proportion to the costs imposed on the system by those customers. Thus, a cost of service study seeks to determine what costs are incurred to serve each class of customers.

Q How is a COSS performed?

A An allocated cost of service study ("ACOSS") typically follows three steps: first, costs are functionalized by separating utility plant and expenses according to the primary functions served. Second, the functionalized rate base and operating costs are classified according to the primary cost driver, as related to energy/commodity, demand/capacity, or customer. Finally, the costs are either directly assigned to customers or allocated among customer classes using allocation factors based on energy use, demand/capacity maximums, or the number of customers.

Q How do analysts determine the appropriate approaches to cost classification and allocation?

A When selecting classification factors or allocators, the goal is to fairly allocate costs among different customer classes based on cost causation. Cost causation reflects the notion that the customer or set of customers that caused a cost should pay for the cost.[2] To determine cost causation, analysts often rely on economic theory and power system engineering considerations.

Q In your view, has the Company selected appropriate ACOSS methods?

A No. I have three primary concerns with the Company's ACOSS methods:

1. The Company classifies portions of the distribution system as partially "customer-related" based on a flawed minimum system methodology;
2. The Company's meter classification does not reflect AMI cost causation; and
3. The Company's demand allocators do not reflect temporal cost causation.

My testimony recommends alternative approaches that are better supported by economic theory and power system engineering.

Q How should a COSS be used in a rate case?

A Parties and the Authority should exercise judgement when using a utility COSS to inform revenue allocation or rate design, as it is an inherently imprecise tool in which cost analysts make numerous subjective determinations that may dramatically impact the study results. As such, utility cost of service studies should be one of several considerations used to guide decision-makers in revenue allocation and rate design, rather than being viewed as the sole determinant or final authority.

[2] UI states that its guiding principle in performing an ACOSS is cost causation. *See* Exhibit UI-BR-1 at 6.

UI Should Not Classify Distribution System Costs Using a Minimum System Study

Q Did the Company classify certain distribution system costs as both customer-related and demand-related?

A Yes. The Company considers poles, underground and overhead conductors and conduits, and transformers (FERC accounts 364, 365, 366, 367, and 368) to have both demand- and customer-related components.[3] The Company used a minimum system study to determine the share of each of these accounts to classify as customer-related versus demand-related.

Q What is the minimum system study?

A The minimum system study is a cost analysis that estimates what the cost of the distribution system would be if the total system inventory was composed of the smallest equipment size. For each FERC account evaluated, the Company considers the cost of the minimum-sized equipment in the account to be customer-related, reasoning that this "portion of the distribution system costs are incurred simply to attach a customer to the system and are the same regardless of the amount of energy that the customer might consume."[4] The Company considers the remaining cost of the actual distribution system to be demand-related.

Q Does the minimum system study deem significant portions of plant to be customer-related?

A Yes. The minimum system study classifies two thirds of poles, half of overhead conductors, and a third of underground conductors, conduits, and transformers as customer-related.[5]

[3] Exhibit UI-BR-1 at 12 and 15.
[4] Exhibit UI-BR-1 at 22.
[5] OCC-362 UI Attachment 28 - WP-1.0 - Primary Secondary and Minimum System Study_CORRECTED.

Q What are your concerns with the minimum system methodology?

A I have three concerns with the minimum system methodology:

- It does not align with the Company's definition and treatment of customer costs;
- It inflates the costs classified as customer-related; and
- It is unsound to use as the basis for determining cost causation.

I discuss each concern sequentially.

Q Why doesn't the minimum system methodology align with the Company's definition and treatment of customer costs?

A Per the Company, customer-related costs "are largely a function of the number of customers served and continue to be incurred whether or not the customer uses any electricity."[6] This definition complements the 1992 National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual* ("NARUC Electric Manual"), which defines customer costs as "directly related to the number of customers served."[7] Indeed, after classifying customer-related costs, the Company allocates those costs based on the number of customers associated with each rate class.

Although the minimum system study classifies large portions of distribution plant as customer-related, to be allocated based on the number of customers, the equipment in those accounts does not vary directly with the number of customers, i.e., when a customer is added to the grid; rather, it varies with those customers' demand.

For example, if the Company adds a new residential customer with a negligible level of demand in a populated area, the additional distribution costs to serve that customer—aside from dedicated customer infrastructure—would generally also be

[6] Exhibit UI-BR-1 at 7.
[7] NARUC Electric Manual at 20.

negligible, because residential customers share the majority of the distribution system. A new customer would generally only impose costs for distribution system upgrades to the extent that the customer increases peak demand on the distribution system. Thus, these costs are primarily driven by demand, rather than by the number of customers. It is only when the distribution system must be expanded to a new geographic area that an incremental customer impacts distribution system costs independently from the customer's level of demand.

This example demonstrates that the presence of a residential customer does not necessarily impose additional distribution costs (apart from costs related to that customer's demand) unless the system must be expanded to a new geographic area. Thus, there is little justification for classifying costs in these accounts as customer-related.

Q Is it particularly inappropriate to classify the primary electric system as customer-related?

A Yes. Primary distribution voltage is 600 to 34,500 volts, while secondary distribution is under 600 volts.[8] The residential customer class, for example, does not receive service directly at primary voltage.[9] Per the example above, it is unreasonable to suggest that the cause for installing primary equipment is the presence of a residential customer on the distribution system, regardless of that customer's demand, when residential customers likely receive service at a fraction of primary voltage.

Further, the Company's rate design approach reinforces the fact that primary infrastructure is shared and unrelated to the number of customers on the system. UI notes that "upstream distribution facilities such as substations and feeders are *shared* and more

[8] Exhibit UI-BR-1 at 13.
[9] OCC-656.

likely to coincide with system peaks" (emphasis added) and therefore UI includes primary feeder costs in its on-peak period rates.[10] The fact that the Company offers customers a financial incentive to avoid those costs during peak hours certainly suggests that the costs vary with aggregate customer demand.

Q Does the Company's minimum system also meet customers' demands?

A Yes. Any size of equipment in FERC accounts 364–368 has load-carrying capacity and will necessarily serve a portion of customers' demand. In fact, the Company's minimum system is so extensive that it generally meets certain customer classes' peak demand requirements. For example, the minimum size transformer can meet 25 kVA of demand;[11] almost all of the residential and non-demand GS classes' maximum demand requirements can be met with this equipment, with 99.96% of Rate R customers, 99.78% of Rate RT customers, 99.85% of Rate GSN customers, and 98.7% of Rate GSTN customers estimated to have a maximum kW demand below 25 kW.[12] Even the maximum customer demand for the Rate GS Demand class is generally well below the Company's minimum system capacity, with a 13.6kW average and with only 13.5% of customers' maximum demands exceeding 25 kW.[13]

[10] Exhibit UI-RP-1 at 39 and 43.
[11] The Company did not provide the kW capacity of the minimum size conductor or cable because the "kW or kVA capacity of the conductors will depend on the voltage the equipment is operating at and the power factor." *See* OCC-655.
[12] Confirmed via correspondence between OCC and UI.
[13] There appear to be a few thousand accounts with 0kW annual peak demand. Even when excluding the accounts with 0 demand, the average is 17kW and only 16.9% of customers' maximum demand exceeds 25kW. *See* OCC-654 UI Attachment 1.

Q If the minimum size equipment is large enough to accommodate certain customer classes' peak demands, is it reasonable to classify such a large portion of the system as "customer-related"?

A No. Such a "minimum" system exceeds even the Company's intended theoretical scope, which is "a system sized to simply connect customers"[14] regardless of usage, not also a system that meets their maximum usage. It is unreasonable to assign customers hefty distribution system costs based on such a flawed representation of the "customer" portion of the distribution system.

Q Do other limitations of the minimum system methodology also inflate the costs classified as customer-related?

A Yes. Further sources of imprecision in the Company's minimum system study arise due to reliance on blunt accounting cost records. Several minimum system accounts include equipment that is constructed far upstream from individual customer loads and is thus typically built based on diversified, combined demands, not built based on the presence of individual customers. For example, plant accounting data does not distinguish sub transmission feeders,[15] which often connect high voltage distribution substations, from other conductors in FERC accounts 365–367. Thus, the Company includes sub-transmission costs in its "minimum system," inappropriately treating them as customer-related even though they are likely driven by coincident peak demands at the substation. The substations themselves are classified as demand-related. Including these costs in the hypothetical minimum system inflates the costs that are classified as customer-related by an unknown amount.

[14] Exhibit UI-BR-1 at 16.
[15] OCC-658.

Q What are the cost allocation impacts of using a study that inflates the costs classified as customer-related?

A Inflating the costs classified as customer-related—whether because of imprecise accounting data or by calculating a minimum system that may meet customer peak demands—has meaningful implications for the residential class. Customer-related costs are far more heavily allocated to residential customers compared to demand-related costs simply because the residential class has many more customer accounts than the other classes. Thus, assigning costs based on the number of customers will allocate the majority of these costs to the residential class. In contrast, the ACOSS assigns demand-related costs based on the relative class non-coincident peak demand ("NCP"), to which the residential class contributes a relatively lower level of demand.

Q Can you demonstrate how cost allocation varies when customer allocators are used rather than demand allocators?

A Yes. For accounts 364 – 368, using the number of customers to allocate costs results in 90 percent of costs being assigned to residential customers, whereas using demand would allocate only 51-56 percent of costs to the residential class.[16]

Q Is the minimum system method unsound to use as the basis for determining cost causation?

A Yes. The method requires distinguishing a hypothetical system that serves only customers, not their electricity demand. To create this imaginary system, the Company makes subjective assumptions that oversimplify system engineering and impact the study results in unquantifiable ways. The accumulation of falsely precise approximations forms

[16] Schedule E-6.0 WP-6.0 - Class Allocation Factors.

an unreliable basis on which the Company has assigned substantial costs among classes with significant impacts on revenue allocation and rate design.

Q What method do you recommend instead of the minimum system method?

A I recommend classifying distribution costs using the basic customer method. As described in the Regulatory Assistance Project's manual *Electric Cost Allocation for a New Era*, this method is used by states across the country and is intuitive and data-based, as it includes only costs that are directly related to the number of customers on the system. Specifically, the basic customer method generally classifies only costs associated with services, meters, meter reading, and billing as customer-related. This cost allocation approach would be consistent with Connecticut's rate design approach to recover in the monthly residential customer charge only the costs directly related to metering, billing, service connections and the provision of customer service.[17]

Not only have utilities in numerous states used the basic customer method,[18] but public utility commissions have also explicitly rejected the minimum system method or otherwise required that utilities classify primary and secondary distribution costs as 100 percent demand-related. For example:

- The Rhode Island Public Utilities Commission has repeatedly rejected the minimum system study.[19]
- The Maryland Public Service Commission has repeatedly rejected a minimum cost of

[17] https://law.justia.com/codes/connecticut/2015/title-16/chapter-283/section-16-243bb/.

[18] For example, National Grid in Massachusetts does not use a minimum system study for classification. *See* Exhibit NG-PP-1 in D.P.U. 23-150 (November 16, 2023) at 18, stating "the Company has not performed a minimum system study in its last four distribution rate cases, or more, and…did not perform a minimum system study for this ACOSS."

[19] Decision and Order, *In Re: The Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electic[sic] Base Distribution* Rates, at 142 (April 29, 2010), Docket No. 4065 (State of Rhode Island and Providence Plantations Public Utilities Commission).

service methodology.[20]

- The Arkansas Public Service Commission found that accounts 364–368 should be classified as 100 percent demand-related due to insufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes.[21]
- The Illinois Commerce Commission has repeatedly rejected the minimum distribution or zero intercept approach.[22]
- Washington administrative code specifies approved electric cost of service classification and allocation methodologies, requiring distribution substations, line transformers, and poles and wires to be classified as demand related.[23]
- Alaska administrative code prohibits customer-related costs from including "any portion of the distribution system costs, which will be considered and classified as demand-related costs."[24]

Q If PURA chooses not to approve the basic customer method, would a hybrid classification method be more appropriate than the full minimum system approach?

A Yes. If the Authority does not approve the basic customer method, it is still possible to better align the minimum system study with system cost drivers. In that case, I recommend that the Company classify primary distribution costs as 100 percent demand-related and only apply the minimum system methodology to secondary distribution costs, which are the lower-voltage lines that connect most customers to the grid. As described

[20] Order No. 83907, *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base* Rates, at 81–82 (March 9, 2011) Case No. 9230 (Public Service Commission of Maryland).
[21] Order, *In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service*, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission).
[22] Lazar, J. et al., *Electric Cost Allocation for a New Era: A Manual.* Montpelier, VT: Regulatory Assistance Project (2020) (Hereafter: "RAP Electric Manual"). at 145
[23] Washington Administrative Code 480-85-060. https://app.leg.wa.gov/WAC/default.aspx?cite=480-85-060.
[24] 3 Alaska Admin. Code § 48.540.

earlier, primary infrastructure is shared, is more likely to peak at the same time as system peaks, and is much higher-voltage than the customer-specific equipment (meters and services) directly serving the majority of electricity customers.

Q If the Authority approves any form of minimum system study, whether for only secondary plant, or for all distribution plant, should any adjustments be made to recognize that the minimum system also meets all or a portion of customers' maximum demands?

A Yes. As recognized by the Staff of the Ontario Energy Board, "A Minimum System has a certain load carrying capability which can be viewed as being demand-related. As a result, the customer-related costs will have a demand component in them. If no adjustment is made, some customers (e.g. small users) may be allocated a disproportionate share of demand-related costs. If the Minimum System Method is preferred for categorization, Staff would recommend that distributors be required to also adjust for the [Peak Load Carrying Capacity] of the assumed Minimum System."[25]

Likewise, for any FERC accounts classified using a minimum system study, I recommend that the Company allocate no demand-related costs to the customer classes whose peak demands can generally be met through the identified "customer-related" portion of the system, which includes the residential and GS non-demand classes as noted above. The "customer-related" portion of the system can already meet those customers' peak demands without requiring any further equipment cost. Even for Rate GS demand, which has a higher proportion of customers exceeding the minimum equipment capacity, the minimum load-carrying capacity classified as customer-related and allocated on

[25] Ontario Energy Board. Cost Allocation Review: Staff Discussion Paper. September 2005. At 21-22. Available at https://www.oeb.ca/documents/cases/EB-2005-0317/staffdiscussionpaper_160905.pdf.

customer count should be credited to the class, reducing their demand costs to reflect only the capacity above the minimum system level.

National Grid recently proposed this approach in New York, allocating residential and small commercial customer classes $0 of the demand-related portion of the minimum-system distribution infrastructure, reasoning that "the minimum system would be able to meet the peak load for all or almost all customers in [the relevant classes]; that is, no further investment in higher capacity conductors would be required. Therefore, no demand-related costs for Overhead Assets or Underground Assets were allocated" to Residential, Residential Time of Use, and Small General Non-Demand classes.[26]

Q If the Authority approves a minimum system study for all plant, as UI has proposed, do you recommend updating the cost accounting to allow for more granular classification and allocation?

A Yes. I recommend that PURA require the Company, in its compliance filing, to propose and commit to an approach for disaggregating its plant account data in order to distinguish between primary step and service line or secondary transformers[27] and between the costs of sub-transmission, trunkline, upstream or backbone primary feeders from the rest of plant in Accounts 365–367.

Q What is the ACOSS impact of using the basic customer distribution classification?

A Using the basic customer method significantly impacts the ACOSS output, which the Company uses to inform both the direction and magnitude of proposed class revenue

[26] Testimony of the Electric Rate Design Panel for Niagara Mohawk Power Corporation d/b/a National Grid in 24-E-0322. May 2024. At 33-34.

[27] In OCC-657, the Company states that it excluded primary transformers from its minimum system study, even though the transformer plant in FERC Account 368 does not distinguish between primary step transformers and secondary service line transformers. More granular accounting data would improve transparency.

increases.[28] Table 1 shows the relative rate of return ("RROR") by customer class under the Company's ACOSS,[29] the basic-customer ACOSS,[30] and the secondary-minimum-system ACOSS.[31] UI describes the RROR as indicating which customer classes are either providing a surplus of revenues to the system (RROR ratio greater than 1) or are deficient in covering their allocated costs (RROR ratio less than 1).[32] Under the scenario with no minimum system study (basic customer method), the residential RROR increases from 0.03 to 2.93 – nearly three times the system average ROR – while the GS RROR shrinks from 2.08 to 0.29 and the GST and LPT RRORs move from positive to negative – indicating negative operating income. These higher-usage classes show cost deficiencies under the basic customer method due to their relatively higher contributions to class NCP demand.

Table 1. Relative Rate of Return Under Different Classification Methods

Rate Class	Company's ACOSS	Basic Customer Method	Secondary Minimum System
R	0.03	2.93	2.07
GS	2.08	0.29	0.83
GST	4.18	-1.61	-0.49
LPT	3.85	-2.39	-1.68
M	-1.62	-2.04	-1.92
U	5.74	2.56	3.37
Total System	**1.00**	**1.00**	**1.00**

[28] Exhibit UI-RP-1 at 11.
[29] OCC-362 UI Attachment 23 Supplement - Relative ROR Comparison.
[30] OCC-653 UI Attachment 1 CONFIDENTIAL.
[31] OCC-653 UI Attachment 2 CONFIDENTIAL.
[32] Exhibit UI-RP-1 at 12.

Q What is the ACOSS impact of using a minimum system study only for secondary equipment?

A Per Table 1, under the scenario using the minimum system methodology for only secondary infrastructure, the residential RROR is 2.07 (though this is likely an underestimation). The higher-usage classes again show cost deficiencies.

Q Why is a 2.07 RROR for the residential class likely an underestimation?

A The 2.07 RROR would be higher if the ACOSS did not allocate the demand-related costs of the minimum-system-classified infrastructure to the customer classes whose peak demands can be met through the "customer-related" portion of the system, as described above and proposed by National Grid New York.

Q Should the results of the Basic Customer and Secondary Minimum System ACOSS impact the Company's revenue allocation?

A Yes. I discuss those impacts in Section IV.

UI Should Classify and Allocate Advanced Metering Infrastructure ("AMI") Meter Costs Based on Customer, Energy, and Demand

Q Describe the extent of AMI meter deployment in the Company's territory.

A AMI meters represent 90.4 percent of UI's deployed meters as of January 1, 2025 and the Company plans to complete AMI meter deployment by year-end 2026.[33]

Q How does the Company classify and allocate meter costs?

A The Company classifies meter costs as customer-related and allocates them based on the relative cost of providing meters for each class and the number of customers in each

[33] OCC-662a.

class.[34] For traditional meters, this approach follows the principle of cost causation by recognizing that the weighted number of customers in a class drives traditional meter costs.

Q What are your concerns with UI's AMI meter classification and allocation approach?

A UI's approach does not reflect the realities of an evolving power system. Technology and cost responsibility are changing rapidly to meet evolving market demands and to support state policy goals. Technological advances are impacting the services provided on the power grid and how those services are provided, which requires utilities to re-evaluate cost allocation issues that may previously have been considered settled. Traditional cost of service techniques do not necessarily reflect the modern power system or a modernized understanding of cost causation on the system.

The Regulatory Assistance Project explains that the main purpose of meters was once customer billing, but that "advanced meters serve a broader range of functions, including demand management, which in turn provides system capacity benefits, and line loss reduction, which provides a system energy benefit. This means the benefits of these meters flow beyond individual customers, and logically so should responsibility for the costs."[35]

[34] Exhibit UI-BR-1 at 23.
[35] RAP Electric Manual at 18.

Q Do UI's new AMI meters enable services beyond customer-related functions?

A Yes. UI's AMI will enable significant new functionality beyond the analog metering associated with traditional meters. UI reports that AMI will enable operational benefits,[36] such as:

- Proactive Outage Planning: avoided transformer failures through better monitoring of customer load
- Optimizing Power Flow and Customer Voltage Reduction Improvement: reduced loss factor though voltage optimization
- Avoided Sensor Benefits: reduced need for distribution capital investments
- Load Balancing Benefits: reduced system losses and reduced capital investments, including due to Time of Use rate designs
- Load Disaggregation Benefits: better information to support conservation efforts and identify devices or equipment that are inefficient

Q Do these new functionalities and their associated benefits change cost causation for AMI meters compared to traditional meters?

A Yes. The operational improvements that UI reported clearly extend the role of AMI meters beyond traditional metering, which do not enable energy savings and demand reductions in this way. The Company proposed, and PURA approved,[37] its AMI investment based on the services AMI would provide, The Authority explicitly stated that the "purpose of AMI is to promote better system utilization and empower customers to engage with their own energy usage; therefore, an EDC will need to demonstrate that the

[36] Exh UI-CIP-8 - Final AMI Report: 17-12-03RE02 Final AMI Plan at 5-8.

[37] In its January 3, 2024 Decision in Docket No. 17-12-03RE02, PURA recognizes "that AMI will require significant capital investments" and authorizes the electric distribution companies to continue AMI deployment under conditions intended to maximize AMI's potential and value.

AMI investments are able to provide these services and…[provide] its plan to make the services (i.e. benefits) available to customers."[38] Thus, cost causation for AMI investments is dictated by those services and benefits.

Q Does the Company intend to continue classifying AMI as customer-related?

A Yes.[39]

Q How do you recommend that UI classify AMI meter costs?

A The Company should distinguish the AMI meter costs included in its approved revenue requirement and classify those costs as customer, demand, and energy related, because AMI meters provide services and benefits that can be categorized into each of the three cost drivers. Specifically, UI should classify AMI meter costs across those categories proportionally according to the relative benefits that accrue to each of the three cost drivers, based on UI's formal quantification of AMI benefits. In the absence of such benefits categorization at this time, I propose an initial classification approach that treats AMI meter costs as 50% customer-related, 25% energy-related, and 25% demand-related.

Q Have other Commissions approved similar AMI meter classifications?

A Yes. The Maryland Public Service Commission approved "a benefits approach for allocating AMI costs among rate classes" in 2016, when it approved a proposal to assign 25% of AMI costs using a customer-based allocator, 37.5% using a demand-based allocator, and 37.5% using an energy-based allocator in Pepco's distribution rate case.[40] The approved proposal was based on the fact that an early report on AMI benefits

[38] *Ibid* at 7.
[39] OCC-662d.
[40] In the Matter of the Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (Hereafter, "MD PSC, Case No. 9418"). Order No. 87884. November 15, 2016. https://www.psc.state.md.us/wp-content/uploads/Order-No.-87884-Case-No.-9418-Pepco-Rate-Case-1.pdf. At 105-106.

assigned just over 75 percent of the benefits to energy and demand management outcomes, justifying a customer, demand, and energy based allocation.[41] The PSC concluded that the "hybrid approach most fairly spreads the costs and related benefits of AMI throughout the Pepco service territory."[42]

Q Does Maryland continue to use a composite allocator for AMI meters?

A Yes. The PSC ordered Baltimore Gas and Electric Company ("BGE") to update its electric AMI benefit analysis in its 2023 rate case to ensure that the AMI allocators reflect updated benefit weights. BGE analyzed six years of data and proposed to allocate 56% of AMI meters based on the replacement cost of AMI meters (customer), 26% based on NCP (demand), and 18% based on MWH sales (energy).[43]

Q What is the likely class impact of your recommended AMI meter classification?

A As with my basic customer method recommendation, this alternative classification reduces the costs treated as customer-related, in this case treating portions as energy and demand related. Table 2 compares customer, demand, and energy allocators,[44] showing that demand and energy allocators tend to allocate fewer costs to small consumers and

[41] MD PSC, Case No. 9418. Direct Testimony of Shelley Norman. July 6, 2016. https://webpscxb.psc.state.md.us/DMS/case/9418 Item No. 33. At 21-23.

[42] MD PSC, Case No. 9418. Order No. 87884. November 15, 2016. https://www.psc.state.md.us/wp-content/uploads/Order-No.-87884-Case-No.-9418-Pepco-Rate-Case-1.pdf. At 106.

[43] Baltimore Gas and Electric Company's Application for an Electric and Gas Multi-Year Plan. Case No. 9692. Direct Testimony of April M. O'Neill. February 17, 2023. https://webpscxb.psc.state.md.us/DMS/case/9692 Item No. 1. At 15-17.

[44] Because UI does not identify costs that vary with the amount of kilowatt hours ("kWh") sold to customers in its distribution cost of service, the ACOSS does not have an energy allocator. I estimated an energy allocator based on the Test Year Adjusted kWh in Workpaper 4.0. *See also* Schedule E-6.0 WP-6.0 - Class Allocation Factors. Witness Norman in Maryland also had to use "a manually constructed energy allocator based on billing determinants in the CCOSS, which approximates an allocation based on total kWh sales at the meter" in Pepco's distribution rate case, which the PSC approved for Pepco to implement in its CCOSS. *See* MD PSC, Case No. 9418. Direct Testimony of Shelley Norman. July 6, 2016. https://webpscxb.psc.state.md.us/DMS/case/9418 Item No. 33. At 21.

greater costs to larger consumers than the customer allocator does, due to larger users' higher utilization of the power system.

Table 2. Customer, Demand, and Energy Allocators for AMI Allocation

	Total	R	GS	GST	LPT	M	U
Customer: Meters	100%	84%	11%	4%	0%	0%	0%
Demand: NCP @ Secondary	100%	56%	12%	25%	7%	0%	0%
Energy: Test Year Adjusted kWh	100%	45%	9%	27%	19%	0%	0%

Q Have you implemented your proposal in the Company's ACOSS to determine its impact on UI's ACOSS results?

A Although UI has worked with OCC to provide an editable COSS model that flows from centralized inputs to summary results, implementing my proposal requires assigning costs using an energy allocator, which does not currently exist as an input in the model, because UI does not currently allocate any costs according to the amount of kWh sold to customers. Adding the energy allocator that I developed in Table 2 for AMI meters into the ACOSS would require ensuring that the new energy allocator properly flowed through all portions of the model, which is not easily enabled by the model's centralized inputs. Thus, the Company is best qualified to adapt its model to include this new classification and allocation approach if PURA approves it. As discussed above, the new approach would allocate fewer costs to small consumers and greater costs to larger consumers than the customer allocator does, due to larger users' higher utilization of the power system and relatively fewer customers.

UI Should Allocate Demand Costs Based on Class Contribution to Asset Peaks

Q Describe PURA's directive on alternate demand allocation in Docket No. 22-08-08.

A PURA ordered UI to "begin exploring alternatives to demand allocation, considering specific circuit information and sizing relating those to customer usage," to be filed in an alternative ACOSS, and to utilize all AMI data available to conduct relevant customer load research.[45] The Authority encouraged UI to incorporate "OCC's philosophical approach to the topic," highlighting OCC's concern over the Company's use of class NCP and argument that nearly all distribution systems serve more than one class, with circuits sized to serve all the classes in an area.[46]

Q Has UI explored and filed alternatives to demand allocation in an ACOSS?

A Yes. Unlike its proposed rate year ACOSS, UI's "Scenario ACOSS" (1) allocates substation costs using a weighted substation allocator rather than based on class contribution to system peak (1CP), and (2) allocates the costs associated with the demand portion of primary poles and conductors (FERC accounts 364-367) based on a weighted feeder allocator rather than based on class NCP.[47]

Q How did UI develop the weighted allocators?

A UI identified the 2023 peak for each substation and feeder, then calculated the contribution of each class to each equipment's peak using data that maps customers to individual substations and hourly load profiles for every metered customer built from AMI and AMR data. The Company then developed weighted allocators based on the size

[45] Decision in Docket No. 22-08-08 at 228.
[46] *Ibid* at 227-228.
[47] OCC-683.

of each substation or feeder and the contribution of each class to the specific substation or feeder peak.[48]

Q Is the Company's approach reasonable?

A At a high level, the Company's approach seems like a reasonable initial improvement to the NCP and 1CP allocators. It accounts for the fact that substations and feeders vary in size, serve more than one class, and may peak at different times. This more granular approach captures the varying class contribution to each peak and the varying impact of that contribution on the overall equipment account costs. The methodology addresses a number of the concerns raised by OCC's witness in 22-08-08.

However, I cannot evaluate the technical reasonableness of each step of the Company's approach because the Company did not provide the exact data that it used to map customers to individual equipment nor the load profiles that it built on AMI or AMR data nor the workpapers for building those profiles.

Q Could the alternative distribution demand allocators better reflect cost causation?

A Yes. While the allocators focus on the single peak hour of the year for each piece of equipment, the equipment size is often determined by more hours than the single equipment peak, depending on energy requirements throughout the year. Performance ratings relate to sustained heating overloads rather than to a single hour of peak demand. According to the Regulatory Assistance Project:

> A transformer that is very heavily loaded for a couple of hours a year and lightly loaded in other hours may last 40 years or more until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but also to many smaller overloads in each year, may burn out in 20 years.[49]

[48] UI-RP-1 at 27-29.
[49] RAP Electric Manual at 148.

In the next case, the Company should improve upon its temporal analysis by considering the duration of the peak, near-peak, and pre-peak loads that also contribute to asset overheating and aging. For example, the Company could evaluate the contribution of class loads to each hour within a certain percent of the peak load. The Company should also extend its temporal analysis to transformers.

Q Does UI propose to use its alternative demand allocations to inform revenue allocation and rate design?

A No. The Company proposes to allocate substation costs based on 1CP "because the allocator is simple to understand and is readily available."[50] The Company also notes that the allocation to each class under the two methodologies is not significantly different. UI proposes to continue allocating primary pole and conductor costs using NCP.

Q Do you recommend that UI use the alternate demand allocators in its proposed ACOSS?

A Yes. PURA did not order UI to explore alternate demand allocators because they would be simple to understand or readily available, but because they better reflect cost causation. Further, recognizing the temporal nature of cost causation reflects an evolving power system and customer paradigm. The Company and PURA have prioritized time-varying cost recovery by time-differentiating these very distribution costs in TOU rates, as I discuss later in this testimony. Time-varying, and seasonally-differentiated cost recovery recognizes the importance of incentivizing load flexibility in an era of intermittent renewable resources and costly grid upgrades. Using the alternate demand allocators better aligns cost allocation with this cost recovery.

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[50] Exhibit UI-BR-1 at 20.

Q What is the class impact of UI's alternate demand allocators?

A Table 3 compares UI's proposed allocators to allocators based on contribution to asset peaks.

Table 3. Allocators Based on Contribution to Asset Peaks versus Proposed

	Total	R	GS	GST	LPT	M	U
Substation (Alternate)	100%	52%	12%	23%	13%	0%	0%
Substation (1CP)	100%	53%	11%	24%	13%	0%	0%
Primary Feeder (Alternate)	100%	49%	13%	26%	12%	0%	0%
Primary Feeder: (NCP)	100%	51%	11%	25%	12%	0%	0%

Q What are the combined impacts of your distribution classification and demand allocation recommendations on the ACOSS results?

A Table 4 shows the relative rate of return ("RROR") by customer class under the Company's ACOSS,[51] the basic-customer-alternative-demand ACOSS,[52] and the secondary-minimum-system-alternative-demand ACOSS.[53] Under the scenario with no minimum system study (basic customer method) and alternative demand allocators, the residential RROR increases from 0.03 to 3.28 – over three times the system average – while the GS, GST and LPT RRORs move from positive to negative, indicating negative operating income. These higher-usage classes show cost deficiencies under the basic customer method and alternative demand allocators due to their relatively higher demand versus customer allocators, and specifically their relatively higher contributions to individual distribution asset peaks than to NCP demand.

[51] OCC-362 UI Attachment 23 Supplement - Relative ROR Comparison.
[52] OCC-684 UI Attachment 1 CONFIDENTIAL.
[53] OCC-684 UI Attachment 2 CONFIDENTIAL.

Table 4. Relative Rate of Return Under Different Classification & Allocation Methods

Rate Class	Company's ACOSS	Basic Customer (Alt Demand)	Secondary Minimum System (Alt Demand)
R	0.03	3.28	2.38
GS	2.08	-1.04	-0.63
GST	4.18	-1.67	-0.58
LPT	3.85	-2.34	-1.62
M	-1.62	-1.45	-1.31
U	5.74	7.53	9.08
Total System	**1.00**	**1.00**	**1.00**

IV. REVENUE ALLOCATION

Q How does UI determine what revenue increase to apportion to each customer class?

A The Company used the results of the ACOSS to guide allocation of its approved total revenue requirement among the various customer classes, adjusting iteratively to produce rates that achieve class rate of returns as close as practicable to the system average (i.e., equalized ROR).[54] UI does not propose to "change rates such that each class produces fully the system average" ROR but "moves towards the goal of equalized" ROR.[55] The Company notes that it follows PURA's 22-08-08 Decision, which prioritized moving customer classes closer to ROR parity in the current rate case, while balancing the rate design principles of gradualism and the Authority's rule that the rate increase for any customer class should be between 75% and 125% of the overall average increase.[56]

[54] Exhibit UI-RP-1 at 10-11.
[55] *Ibid* at 12.
[56] Decision in Docket No. 22-08-08 at 244.

Q Describe UI's quantitative methodology for customer class revenue allocation.

A The Company describes its methodology for allocating the proposed revenue requirement among the customer classes as an iterative revenue allocation calculation,[57] which follows five steps: 1) identify each class's required delivery revenue increase, per the ACOSS, if each class achieved the proposed equalized ROR on its rate base, 2) cap each class's revenue increase by 125% of the system revenue increase and eliminate any revenue reductions, which leaves UI with a revenue shortfall, 3) allocate the revenue shortfall proportionally to each class's present delivery revenues, continuing to cap each class's revenue increase by 125%, 4) repeat step 3, and 5) manually allocate the final revenue shortfall without explanation for the amounts selected. By the end of the process UI maintains the 125% cap and allows the majority of classes to collect 50% of the system average increase, rather than the Authority's preferred 75%.

Q Do you recommend alternative revenue allocations based on your ACOSS results?

A Yes. I recommend revenue allocations based on my ACOSS recommendations to use the basic customer method for distribution cost classification, UI's alternative demand allocators for substations and primary feeders, and customer, energy and demand allocators for AMI meters. Although I do not have an ACOSS result for the latter recommendation, I would expect it to amplify the trend of my other recommendations and therefore directionally align with the COSS results.

Q How did you develop your revenue allocation recommendations?

A I followed UI's iterative revenue allocation calculation step-for-step as described above, substituting the results associated with my ACOSS recommendations for the Company's

[57] Exhibit UI-RP-1 at 14.

ACOSS results in step 1. For the manual allocation in step 5, I allocated the entire remaining revenue shortfall to the residential class for both scenarios.[58] Table 5 compares the original, unchanged increases in class revenue requirements required under the Company's ACOSS[59] and my recommended basic-customer-alternative-demand ACOSS[60] and secondary-minimum-system-alternative-demand ACOSS.[61] As would be expected given the RRORs in Table 4, the class revenue requirement increases differ dramatically across the various ACOSS methods. Table 6 provides the output from the Company's iterative revenue allocation calculation for each of the scenarios in Table 5.

Table 5 demonstrates that under either of my recommended ACOSS scenarios, all classes except residential and municipal customer-owned street lighting would require increases well above 125% of the system average increase (24.5%) to achieve equalized RORs. Thus, UI's iterative revenue allocation calculation assigned them that maximum in Table 6. The allocations for the remaining two classes increase significantly from the ACOSS outputs to make up the difference, with residential customers seeing greater than 75% of the system average increase. Rate class U comes closest to 75% of the system average increase (15%) under the basic customer-alternative-demand approach.

[58] About $4.7 million for the basic-customer-alternative-demand results and about $2.8 million for the secondary-minimum-system-alternative-demand results.
[59] OCC-362 UI Attachment 38 - rate design model CORRECTED_NL.
[60] BasicCust_OCC-362 UI Attachment 38 - rate design model CORRECTED_NL.
[61] SecMinSys_OCC-362 UI Attachment 38 - rate design model CORRECTED_NL.

Table 5. Class Revenue Increases per ACOSS Results

Rate Class	Company	Basic Customer (Alt Demand)	Secondary Minimum System (Alt Demand)
R	28%	2%	8%
GS	11%	43%	37%
GST	-4%	56%	40%
LPT	-2%	68%	55%
M	53%	50%	48%
U	-13%	-21%	-28%

Table 6. Class Revenue Increases After UI's Revenue Allocation Method

Rate Class	Company	Basic Customer (Alt Demand)	Secondary Minimum System (Alt Demand)
R	24.4%	17.0%	17.1%
GS	9.8%	24.5%	24.5%
GST	9.8%	24.5%	24.5%
LPT	9.8%	24.5%	24.5%
M	24.5%	24.5%	24.5%
U	9.8%	13.7%	8.2%

Q Comment on the implications of your ACOSS results and revenue allocation in the context of PURA's 22-08-08 Decision.

A In the 22-08-08 Decision, PURA noted that certain classes "lagged" others, imparting a de facto subsidy to those lagging classes. Accordingly, the Authority adopted a class revenue allocation below that began to "address this subsidy."[62] My alternative ACOSS indicates that all classes lag class R and U, which means that classes R and U are subsidizing the others and that decision-makers should begin to address this subsidy.

[62] Decision in Docket No. 22-08-08 at 231-232.

Q What revenue allocation do you recommend?

A As discussed earlier, a cost of service study consists of countless subjective methodological decisions that can dramatically impact the study results. Indeed, my testimony demonstrates that modifying a couple of distribution classification and allocation approaches to better represent power system engineering and more granular cost causation nearly reversed the revenue allocation results. One measured way to balance these nearly-opposite results would be to implement an equal percentage increase for each rate class, of 19.6%. However, because the Authority stated in 22-08-08 that it seeks to begin moving towards class equalized rate of return over time,[63], I recommend the revenue allocation resulting from the basic customer-alternative-demand ACOSS shown in Table 6.

V. RATE DESIGN: TIME-OF-USE RATES

Overview of PURA's TOU Directives, UI's Proposals, and OCC's General Concerns

Q Please summarize the TOU provisions in PURA's 22-08-08 Decision.

A PURA required that the Company's TOU rates proposal must include:

- A shorter, more concentrated on-peak period that is likely to capture ISO-NE and UI distribution system peaks and to incent the cost-effective shifting of load to off-peak periods.
- The appropriate price differential between on- and off-peak rates, reflecting and consistent with empirical research.
- Alignment of TOU rates across utility functions that recover time-differentiated costs of generation, transmission, and distribution service.

[63] Decision in Docket No. 22-08-08 at 232.

- Opt-out TOU rates, with the appropriate phase-in period over which time customers could adjust to opt-out TOU rates without severe rate and bill shock.
- Energy and demand rates across all functions differentiated into summer and non-summer periods at a minimum, and if cost differences are substantial, winter and shoulder month periods.
- The appropriate phase-in period over which time customers could adjust to seasonal rates without severe rate and bill shock.[64]

Q Please summarize UI's TOU proposals.

A The Company proposes a phased approach to changing its TOU rates, with one TOU rate change effective November 1, 2025 (11/1/25 TOU rates) and a second TOU rate change (End-State TOU rates)[65] after reconfiguring its existing billing and metering systems to use interval data, which they are not currently capable of doing. The reconfiguration will be completed at an unknown future time.[66]

For 11/1/25 TOU rates, UI proposes to retain the existing seasons and time period definitions,[67] introduce time- and seasonally-differentiated distribution rates, maintain existing non-distribution rate methodologies,[68] and maintain the rates as opt-in for residential customers and mandatory for commercial customers using in excess of 100 KW of demand.[69]

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[64] Decision in Docket No. 22-08-08 at 243-244.

[65] Exhibit UI-RP-1 at 36.

[66] To make the requisite changes, UI states that it must retain an external system integrator as the Company does not possess the expertise to identify the most cost effective method to implement interval billing. The Company intended to issue an RFP for system integrator in December 2024 and conclude the RFP in the second quarter of 2025, expecting the system integrator to take an additional 17 weeks to complete its evaluation and present the Company with options to implement changes. The Company has not provided an estimate of the further time required to implement those changes and effectuate End-State TOU rates, due to its reliance on the system integrator's findings for determining next steps. *See* Exhibit UI-RP-1 at 70-73 and EOE-95.

[67] Due to "significant changes required to its billing system to accommodate new time periods and seasons." Exhibit UI-RP-1 Executive Summary.

[68] Exhibit UI-RP-1 at 70.

[69] Exhibit UI-RP-1 at 38.

The Company's End-State TOU rates contain shorter, more concentrated on-peak periods (four or five evening hours as opposed to eight), use the same time periods for all customers, and will be opt-out for all residential and general service customers. UI also recommends refining TOU pricing methodologies across all functions (including transmission and supply) to align with its proposed TOU periods.

Q What are UI's proposed seasons and time periods?

A Tables 7 and 8 show UI's proposed seasons and time periods.

Table 7: UI's Proposed Seasons and Time Periods for 11/1/25 TOU Rates

<table>
<tr><th>Rate</th><th>Winter</th><th>Summer</th><th>Peak</th><th>Off-Peak</th><th>Shoulder</th></tr>
<tr><td>RT</td><td rowspan="4">Oct-May</td><td rowspan="4">Jun-Sep</td><td>12 PM –
8 PM Weekdays</td><td>after 8 PM and before 12 PM on weekdays, and all weekend hours</td><td rowspan="3">n/a</td></tr>
<tr><td>GSTN</td><td rowspan="3">10 AM –
6 PM Weekdays</td><td rowspan="2">after 6 PM and before 10 AM on weekdays, and all weekend hours</td></tr>
<tr><td>GSTD</td></tr>
<tr><td>LPT</td><td>11 PM - 7 AM Weekdays, and all weekend hours</td><td>7 AM - 10 AM Weekdays;
6 PM - 11 PM Weekdays</td></tr>
</table>

Table 8: UI's Proposed Seasons and Time Periods for End-State TOU Rates

Season	Peak	Off-Peak
Summer (Jun-Sep)	2 PM – 7 PM (Weekdays)	All Other Hours
Winter (Nov-Feb)	6 AM – 9 AM and 4 PM – 8 PM (Weekdays)	All Other Hours
Shoulder (Mar-May; Oct)	6 AM – 9 AM and 4 PM – 8 PM (Weekdays)	All Other Hours

Q What are your concerns with UI's TOU rate proposals?

A I have four concerns with UI's TOU rate proposals:

- Although UI's End-State TOU periods and seasons, and its methodology for selecting those periods and seasons, generally appear reasonable and reflective of cost causation, UI should further prioritize and improve the data behind its analysis;
- The complexity of UI's many End-State TOU time periods and seasons may confuse customers and therefore potentially limit the effectiveness of the rates at achieving their intended load shifting;
- The Company's cost-based TOU rates are too extreme, resulting in summer peak residential rates of $0.94/kWh in 11/1/25 rates and $1.17/kWh in End-State rates. Such high rates would result in rate shock and likely limit the effectiveness of the rates at achieving their intended load shifting; and
- More work is needed to develop a plan for transitioning to opt-out TOU rates.

I discuss each concern sequentially.

UI's End-State TOU Period and Season Selection Generally Reflect Cost Causation

Q Do UI's End-State TOU periods and seasons generally appear reasonable and reflective of cost causation?

A Yes. UI considered several cost drivers across the various power system functions and generally aligned its TOU periods and seasons with cost causation. Specifically, UI based its selection on analysis of historical hourly system loads for both the Company and ISO New England (ISO-NE); hourly location marginal prices (LMPs); and hourly substation loads.[70]

[70] Exhibit UI-RP-1 at 47.

Q Do certain cost drivers more significantly impact system costs than others?

A Yes. While UI considered numerous cost drivers in its time period analysis, it is instructive to compare the magnitude of the time-varying cost drivers and to prioritize time periods and seasons accordingly. Per Table 9, energy supply costs, which are determined by LMPs, are a particularly critical cost driver, accounting for 50% of time-varying residential revenue requirements. UI doesn't specify whether it prioritized particular cost drivers, though its TOU periods reflect prioritization in line with Table 9. In the future, UI should identify which cost drivers most heavily inform its TOU period and season selections.

Table 9: Illustrative[71] and Proposed Residential Revenue Requirements by Function

Function/Equipment	Revenue Requirement	Percent
Supply: Energy Cost[72]	$189,356,630	50%
Supply: Capacity Cost[73]	$35,655,423	9%
Unbundled Non-bypassable FMCC[74]	$18,994,485	5%
Transmission[75]	$35,508,048	9%
Distribution: Substation Demand[76]	$28,908,422	8%
Distribution: Primary Demand[77]	$67,099,127	18%

Q How should UI improve the data it used for selecting TOU periods and seasons?

A UI should improve its analysis by considering only weekday cost drivers and by incorporating forecast data.

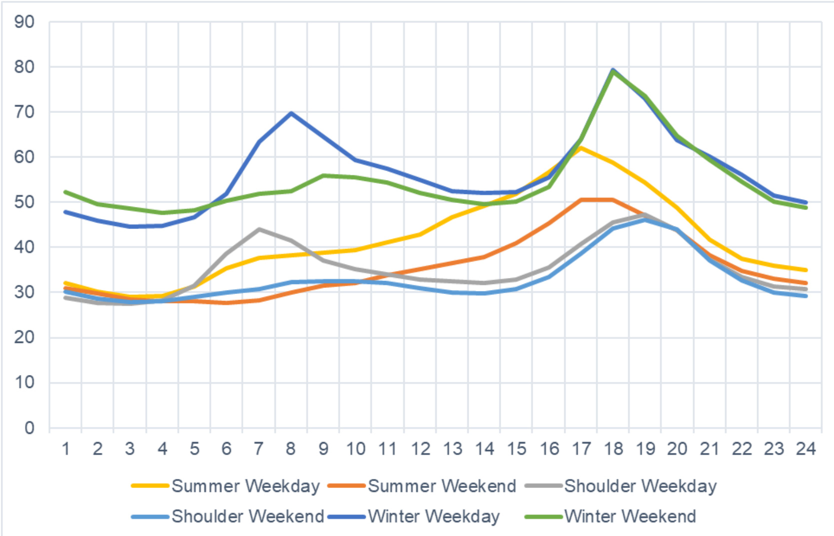
[71] UI presented illustrative cost analysis for the non-delivery rate components.
[72] OCC-362 UI Attachment 41 - Support_for_Exhibit UI-RP-9 Non-Delivery RT_TOU_Rates_End-State.
[73] *Ibid.*
[74] *Ibid.*
[75] *Ibid.*
[76] Exhibit UI-RP-8, corrected by UI in OCC-362 UI Attachment 24 - CONFIDENTIAL UI_ECOS_Model_RATE_YEAR_CORRECTED.
[77] *Ibid*. Note: distribution primary demand costs would increase significantly under my recommendation that UI use the basic customer method rather than the minimum system method for classifying distribution infrastructure.

Q Why should UI base its TOU periods and seasons on weekday analysis?

A It is important to compare weekends to weekdays to determine whether to apply the on-peak period to weekends as well as weekdays. Figure 1 shows that while winter and shoulder evenings have similar LMPs weeklong, the rest of the seasons and times do not. Because average LMPs are generally substantially lower on weekends, it is appropriate to exclude weekends from the on-peak periods, as UI has done. Therefore, UI should also base its TOU periods on weekday LMPs; however, UI combined weekend and weekday LMPs in its LMP analysis.[78] While the impact of this inconsistency is not significant at this time, it could make a difference in future analyses. Likewise, the probability of annual ISO-NE peak is vastly higher on weekdays (93%) compared to weekends (7%),[79] justifying focusing on weekday ISO-NE analysis as well.

[78] Exhibit UI-RP-1 at 55.
[79] OCC-115 UI Attachment 2.

Figure 1: Average LMP by Season and Type of Day (2019-2023)[80]



Q Why should UI incorporate cost forecasts?

A Incorporating high quality forecasts, in addition to historical actuals, into TOU period analysis and cost allocation could reflect shifting peaks in future. Reflecting these shifts in TOU periods and seasons may allow UI to avoid having to change TOU periods too often as the power system evolves. Maintaining consistent TOU periods and seasons over several years is helpful for customer understandability and acceptance. Therefore, instead of – or at least in addition to – using historical hourly LMPs and historical probability of annual ISO-NE peak, UI should use multi-year forecasts where reasonable forecasts exist.

Q Nonetheless, does LMP analysis support UI's TOU period selections?

A Yes. Because LMPs, or energy-related supply costs, are a significant driver of UI's costs, it is appropriate to tailor the non-summer evening peak to the highest winter LMP hours

[80] OCC-114 UI Attachment 4, tab "LMP_day."

of 6-9am and 4-8pm and the summer peak to the highest summer LMP hours of 2-7pm, as shown in Figure 1.

Q Does ISO-NE annual peak analysis support UI's TOU period selections?

A Yes. ISO-NE assigns the Company capacity-related supply costs based on the coincidence of UI's load with the ISO-NE system peak.[81] Thus, it is important to align the peak with the highest probability of annual ISO-NE peak. Figure 2 further supports having different on-peak periods for summer and non-summer seasons because 2-7pm during summertime best captures the probability of ISO-NE annual system peak.

Figure 2: Probability of Annual Peak – ISO-NE (Weekday, 2019-2023)[82]

	Month											
Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.7%	0.0%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	2.6%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	5.9%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	3.5%	8.8%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	5.1%	11.0%	0.0%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	6.0%	12.2%	0.0%	0.0%	0.0%	0.0%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	6.2%	11.8%	0.0%	0.0%	0.0%	0.0%
19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%	6.8%	0.0%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	2.9%	0.0%	0.0%	0.0%	0.0%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	1.0%	0.0%	0.0%	0.0%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

[81] Exhibit UI-RP-1 at 53.
[82] OCC-115 UI Attachment 2.

Q Do ISO-NE monthly peak analysis and distribution substation and feeder peak analysis support UI's TOU period selections?

A Yes. As with the other cost drivers covered above, transmission and distribution cost causation also generally support UI's TOU period selections.

UI's End-State TOU Periods and Seasons are Overly Complex

Q Why do you say UI's End-State TOU periods and seasons are overly complex?

A UI has three different TOU seasons and two different sets of on- and off-peak periods, resulting in six different electricity rates alternating on customer bills throughout the year. This would likely be overly complex for customers to understand and accept even if the TOU rates were self-selected and well-advertised. Although these rates generally reflect cost causation, the fact that these are opt-out TOU rates increases the importance of balancing their cost basis with customer acceptance and understandability.

Q Do established rate design principles prioritize acceptance and understandability?

A Yes. One of James Bonbright's widely recognized rate design principles[83] encompasses simplicity, understandability, public acceptability, and feasibility of application.

Q How do you recommend that UI reduce the complexity of its rate design?

A For opt-out rates, UI should only use two seasons: summer and non-summer, as currently defined. It is extremely rare to see three-season TOU rates around the country, let alone for an opt-out rate. Although simplifying TOU seasons (or time periods) will inevitably dilute the price signal compared to system costs, the price signal based on system costs is likely already too extreme and in need of dilution, as I discuss in the next section.

[83] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

Q If the Company offers an opt-in TOU rate in addition to its opt-out rate, might it be appropriate to include three seasons?

A Yes. If the Company offers an opt-in rate with three seasons, November should be part of the shoulder months. Per Figure 3, November LMPs have been consistently far lower than the other winter months and more closely aligned with the shoulder month LMPs. Given that LMPs are the main winter cost driver, shifting November into the shoulder season would allow for sending a stronger price signal in winter months without November prices bringing down the average

Figure 3: Average Weekday LMPs by Month (2019-2023)[84]

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
Jan	55	52	50	51	53	57	69	76	71	67	66	63	60	58	59	61	70	87	80	72	67	62	58	58	63
Feb	50	48	46	46	49	55	69	76	71	65	63	60	57	56	55	57	61	81	81	69	65	60	54	53	60
Mar	33	32	32	33	36	44	52	51	43	38	36	34	33	32	32	34	39	46	54	47	41	37	34	33	39
Apr	26	25	25	26	29	37	42	38	34	33	32	30	29	29	29	32	36	40	45	44	35	31	29	28	33
May	28	27	26	27	30	35	37	35	32	32	32	32	32	32	33	36	40	42	43	43	37	33	31	30	34
Jun	29	28	27	27	29	32	35	35	36	36	37	38	40	42	43	47	51	50	46	43	38	34	33	32	37
Jul	33	31	29	29	31	34	36	38	40	41	45	48	53	56	62	67	72	67	61	53	46	40	38	37	45
Aug	35	33	32	32	34	38	40	41	42	44	46	49	55	58	61	66	72	67	60	54	46	41	39	39	47
Sep	31	29	28	29	32	37	39	39	37	37	37	37	39	41	42	47	52	51	50	44	37	35	33	33	38
Oct	28	27	27	27	30	39	45	43	39	37	36	35	35	35	37	41	48	55	48	41	36	33	31	31	37
Nov	36	35	35	35	36	41	50	54	48	42	41	40	39	40	41	45	53	65	55	48	45	43	39	37	44
Dec	50	48	47	47	49	54	66	73	68	63	59	56	54	54	55	59	72	85	76	66	64	60	55	52	60

The Magnitude of UI's On-Peak Rates and On- to Off-Peak Price Differential is Excessive

Q Why do you say that UI's cost-based rates are extreme?

A UI presented illustrative TOU rate calculations for the non-delivery rate components. In Tables 10 and 11, I've combined the illustrative non-delivery rates with the proposed TOU delivery rates in this docket, which results in total TOU rates that near and even exceed a dollar per kWh during the summer peak ($0.94/kWh in 11/1/25 rates and $1.17/kWh in End-State rates). This on-peak summer price is over four times higher than

[84] OCC-114 UI Attachment 4, tab "LMP_day."

the off-peak summer price in both TOU scenarios. For comparison, the current Rate RT summer on peak is 0.55/kWh, which is just 2.3 times the current summer off peak of 0.24/kWh. The current Rate R price throughout the year is $0.35/kWh.[85]

Table 10: UI's Illustrative[86] and Proposed[87] Residential 11/1/25 TOU Rates

	Summer		**Winter**	
	Peak	Off-Peak	Peak	Off-Peak
Supply				
Standard Service Generation	$ 0.273	$ 0.077	$ 0.169	$ 0.149
Bypassable FMCC	$ -	$ -	$ -	$ -
Public Benefits				
Public Benefits	$ 0.034	$ 0.034	$ 0.034	$ 0.034
NBFMCC Component				
New England Grid Operator Cost	$ 0.007	$ -	$ 0.007	$ -
State Mandated Energy Purchases: Contract for Differences	$ 0.075	$ -	$ 0.000	$ -
State Mandated Energy Purchases: PPAs	$ 0.022	$ -	$ 0.030	$ -
Customer Produced Energy	$ 0.012	$ -	$ 0.016	$ -
Misc. & Other Mandates	$ 0.010	$ -	$ 0.012	$ -
Transmission				
Transmission Charges	$ 0.181	$ -	$ 0.175	$ -
Combined Non-Delivery Rate	**$ 0.615**	**$ 0.111**	**$ 0.443**	**$ 0.184**
Non-Delivery On- to Off-Peak Ratio	*5.5*		*2.4*	
Distribution				
Distribution	$ 0.329	$ 0.083	$ 0.080	$ 0.070
Combined Total Rate	**$ 0.944**	**$ 0.194**	**$ 0.523**	**$ 0.254**
Total *On- to Off-Peak Ratio*	*4.9*		*2.1*	

[85] https://www.uinet.com/web/uinet/account/understandyourbill/pricing/time-of-day-rate-rt.

[86] Exhibit UI-RP-9 (also OCC-362 UI Attachment 40 - Support_for_Exhibit UI-RP-9 Non-Delivery RT_TOU_Rates_11.1.25_Rates).

[87] Exhibit UI-RP-7, corrected by UI in OCC-362 UI Attachment 24 - CONFIDENTIAL UI_ECOS_Model_RATE_YEAR_CORRECTED.

Table 11: UI's Illustrative[88] and Proposed[89] Residential End-State TOU Rates

	Summer		Winter		Shoulder	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Supply						
Standard Service Generation	$ 0.332	$ 0.086	$ 0.221	$ 0.179	$ 0.130	$ 0.094
Bypassable FMCC	$ -	$ -	$ -	$ -	$ -	$ -
Public Benefits						
Public Benefits	$ 0.034	$ 0.034	$ 0.034	$ 0.034	$ 0.034	$ 0.034
NBFMCC Component						
New England Grid Operator Cost	$ 0.009	$ 0.001	$ 0.006	$ 0.000	$ 0.002	$ 0.001
State Mandated Energy Purchases: Contract for Differences	$ 0.088	$ 0.007	$ 0.000	$ 0.000	$ 0.000	$ 0.000
State Mandated Energy Purchases: PPAs	$ 0.010	$ 0.006	$ 0.011	$ 0.009	$ 0.007	$ 0.005
Customer Produced Energy	$ 0.005	$ 0.003	$ 0.006	$ 0.005	$ 0.004	$ 0.002
Misc. & Other Mandates	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003
Transmission						
Transmission Charges	$ 0.234	$ 0.017	$ 0.165	$ 0.007	$ 0.044	$ 0.035
Combined Non-Delivery Rate	**$ 0.714**	**$ 0.156**	**$ 0.445**	**$ 0.237**	**$ 0.223**	**$ 0.176**
Non-Delivery On- to Off-Peak Ratio	*4.6*		*1.9*		*1.3*	
Distribution						
Distribution	$ 0.452	$ 0.112	$ 0.085	$ 0.082	$ 0.085	$ 0.082
Combined Total Rate	**$ 1.166**	**$ 0.269**	**$ 0.530**	**$ 0.320**	**$ 0.308**	**$ 0.258**
Total *On- to Off-Peak Ratio*	*4.3*		*1.7*		*1.2*	

Q What are the implications of UI's proposed near-term 11/1/25 rates?

A The fact that the summer peak rates will increase by 171% could introduce significant rate shock to current RT customers who are not aware of the rate change or unable to do anything about it. At the same time, the high summer peak rate is likely to strongly dissuade non-participating customers from joining rate RT and nudge participating customers to leave the rate. Because the 11/1/25 rates continue to use the current on-peak period, customers will face nearly doubled peak rates for eight consecutive hours, which also coincide with the hottest hours of the day. Maintaining such a high peak price for so long makes it challenging for customers to meaningfully shift consumption out of the peak period. Those who cannot shift consumption will likely suffer significant bill

[88] Exhibit UI-RP-9 (also OCC-362 UI Attachment 41 - Support_for_Exhibit UI-RP-9 Non-Delivery RT_TOU_Rates_End-State).
[89] Exhibit UI-RP-8, corrected by UI in OCC-362 UI Attachment 24 - CONFIDENTIAL UI_ECOS_Model_RATE_YEAR_CORRECTED.

impacts. While the Authority ordered a shorter, more concentrated on-peak period, this necessarily *long* yet more concentrated on-peak period is not very reasonable, and merits an administrative adjustment to ameliorate the magnitude of the cost-based rates.

Q What rate adjustment do you recommend for near-term 11/1/25 rates?

A I recommend that UI propose an adjusted set of 11/1/25 rates that includes a more modest on-peak summer rate and lesser price differential between summer peak and off-peak periods, somewhere around three times higher, rather than almost five times higher. This means weakening the distribution price signal in the near term, because UI states that it cannot change the non-delivery rate components in this case. This may also mean collecting more costs in the winter, in the interest of gradualism.

Q What are the implications of UI's proposed longer-term End-State rates?

A Although the peak period will be shorter in the eventual End-State TOU rates, the summer on-peak rate proposal is unreasonably high, which is seriously exacerbated by the proposal to make the rates opt-out. As described below, opt-out rates, which would expose all customers to these price signals if they are not informed and engaged enough to opt out, require careful implementation and close attention to rate shock. The importance of consumer protection in the transition to opt-out rates precludes exposing customers to a summer peak price that will more than triple for customers automatically transitioned from rate R. Even if the rate were an opt-in rate, it could yield better results to moderate the high on-peak price.

Q What rate adjustment do you recommend for End-State TOU rates?

A I do not propose specific rate changes at this time. In the next section, I discuss my concerns with opt-out rate implementation and I present recommendations that encompass pricing.

More Work is Needed to Develop a Plan for Transitioning to Opt-Out Rates

Q Did UI propose opt-out TOU rates with an "appropriate phase-in period over which time customers could adjust to opt-out TOU rates without severe rate and bill shock"?

A No. UI simply states that its End-State TOU Rate proposal would "transition the residential and general service rates to an opt-out structure."[90] However, UI has not presented an analysis of the likely customer bill impacts of its End-State TOU Rates proposal, nor has it proposed a phase-in period over which time customers could adjust to the new TOU rates. UI notes that it will review bill impacts that accompany any future changes to non-distribution charges under End-State TOU Rates and make specific recommendations for mitigating any unacceptable impacts that become apparent through that review,[91] but it does not discuss possible mitigation strategies or the feasibility of holistically considering and implementing them outside of this rate case.

Q Are you concerned that UI has not provided a bill impact analysis or a detailed transition plan?

A Yes. Although TOU rates are more cost reflective and can help lower costs by reducing peak demand, they must be implemented with great care. TOU rates represent a

[90] Exhibit UI-RP-1, at 38.
[91] Exhibit UI-RP-1, at 68.

significant change for most residential and commercial customers and could result in large bill impacts for customers who tend to use more electricity during peak periods. Without careful implementation, the transition to opt-out TOU rates could result in customer confusion, backlash, and substantial bill increases for vulnerable populations, undermining the success of the rates. Indeed, UI itself has recognized that "Successful TOU implementation hinges on proactive communication, with time and effort needed to educate customers about the TOU structure."[92]

For these reasons, the transition to opt-out TOU rates should be carefully planned and gradually rolled out over several years to provide UI, PURA, and other stakeholders with sufficient time to:

- Gather critical information about potential TOU bill impacts;
- Create meaningful customer protections;
- Develop effective marketing, education, and outreach strategies; and
- Create tools to provide customers with the information needed to choose the rates that would be best for them.

Q Have other jurisdictions encountered backlash in the transition to opt-out TOU?

A Yes. One recent example comes from Missouri. In December 2022, the Missouri Public Service Commission directed Evergy to implement an opt-out TOU rate with a relatively steep on-peak to off-peak price ratio of 4:1 ($0.38/kWh on-peak and $0.09/kWh off-peak).[93] Due to concerns regarding customer bill impacts, Missouri State Senate Majority and Minority leaders sent a letter to the Missouri PSC urging the Commission to return to

[92] Exh UI-CIP-8 - Final AMI Report
[93] Missouri Public Service Commission. Amended Report and Order. File No. ER-2022-0129 and ER-2022-0130. December 8, 2022.

an opt-in TOU model. The letter further threatened legislative action, stating that "If the commission is unwilling to make this commonsense change, the General Assembly will be forced to pursue bipartisan legislation to protect consumers from unnecessary rate hikes and government mandates."[94]

In response to this backlash, the Commission allowed Evergy to adopt a much milder on-peak to off-peak price differential, with only a 2 cent differential in the summer and a 1 cent differential in the winter.

Q What price ratios typically accompany opt-out TOU rates?

A Jurisdictions that have implemented opt-out TOU rates have typically adopted mild on-peak to off-peak price differentials. To illustrate, I compiled examples of opt-out residential TOU rates from Michigan, Missouri, California, and Colorado and found that the average summer on-peak to off-peak ratio was 1.5:1, while the average ratio in winter was 1.2:1. These rates are shown in Table 12.

Table 12. Examples of Price Ratios for Opt-Out TOU Rates

	DTE Energy	Consumers Energy	Evergy (<600 kWh)	PG&E (Rate E-TOU-B)	PG&E (Rate E-TOU-C)	PG&E (Rate E-TOU-D)	Public Service Colorado (Xcel)
Summer							
On-peak	$0.22	$0.22	$0.15	$0.58	$0.61	$0.56	$0.21
Off-Peak	$0.17	$0.17	$0.14	$0.46	$0.50	$0.43	$0.14
Super off-peak			$0.13				$0.08
Winter							
On-peak	$0.12	$0.16	$0.12	$0.44	$0.49	$0.48	$0.13
Off-Peak	$0.12	$0.16	$0.12	$0.40	$0.46	$0.44	$0.10
Super off-peak	$0.11		$0.11				$0.08
Summer Price Ratio	1.3	1.3	1.2	1.3	1.2	1.3	2.7
Winter Price Ratio	1.1	1.0	1.1	1.1	1.1	1.1	1.7

[94] Letter to Chairman Rupp from state senators Cindy O'Laughlin and John Rizzo, August 7, 2023. Available at: https://efis.psc.mo.gov/Document/Display/175531.

Q Do you have any specific recommendations for how opt-out TOU rates be implemented in Connecticut?

A Yes. I provide five recommendations regarding opt-out TOU rates below:

1. **Mild Differential:** While a higher ratio may enhance customer response and make the TOU rate more effective, the transition should recognize the principles of gradualism and customer acceptance. A new opt-out TOU rate should initially have a mild on-peak to off-peak 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.
2. **Customer Education and Tools:** UI, or perhaps an experienced third party, should develop a comprehensive marketing, education, and outreach plan with input from stakeholders and customer surveys. Customer education and outreach should begin well ahead of the transition – at least one year in advance, but preferably longer.[95] UI should also develop and implement a bill comparison tool to allow customers to choose the rate schedule that best meets their needs and understand how shifting appliance loads can impact their bill.[96]
3. **Bill Impact Analysis:** UI should evaluate the expected bill impacts (with and without load shifting) of the opt-out TOU rate, particularly for vulnerable customers (such as low-income and medically-reliant customers). UI should attempt to identify the types of customers who are most likely to be negatively

[95] For example, shadow billing could begin a year in advance. Shadow billing refers to providing a comparison of a customer's bill under a different rates on their monthly bill.

[96] UI describes some customer education initiatives in Exhibit UI-CSP-1, including online calculators that allow customers to calculate potential savings based on their usage patterns, but these don't necessarily help customers compare their bills across rates to select the best rate schedule.

affected by the transition and develop proposals to mitigate these impacts. The analysis and proposals should be presented to stakeholders and PURA for input.

4. **Customer Protections:** Vulnerable customers should be exempted from opt-out TOU rates, and instead only moved to a TOU rate if the customer affirmatively opts in. Other customer protections, such as a one-year hold-harmless provision, should be considered. UI should also evaluate the potential interplay between the proposed TOU framework and the Low Income Discount Rate, as well as whether the current Low Income Discount Rate should be adjusted to reflect the total bill impacts of the proposed TOU framework. The overall design of the Low Income Discount Rate itself may also be impacted.

5. **Pilots:** While UI is undergoing the information technology changes needed to implement a full-scale TOU rate, it should conduct an opt-out pilot to better understand customer understanding and acceptance of the rate, expected load shifting impacts, and the effectiveness of customer education initiatives.[97] The pilot should include customer surveys to understand the most effective marketing techniques, customer acceptance, understanding of the rates, and reasons why customers opt out.

[97] UI has indicated that either its billing system or its Meter Data Management System would require significant customization to use interval data; therefore, while the Company investigates technological solutions for widespread opt-out TOU implementation, perhaps in the interim it could update the existing register reads to the proposed End-State TOU periods for only a representative sample of customers in order to gain valuable insights from a pilot.

Q What steps should UI and PURA take in this proceeding to begin the transition to opt-out TOU rates?

A I recommend that within 30 days of the final order in this proceeding, PURA require UI to initiate a stakeholder process to develop an opt-out TOU transition plan that addresses my five recommendations above: a mild price differential, development of customer education and tools, a bill impact analysis, customer protections, and an opt-out pilot while undergoing the information technology changes needed to implement a full-scale TOU rate. PURA should then require UI to submit its initial transition plan within 180 days following the final order, with annual updates to the plan. I also recommend that UI meet with stakeholders prior to filing its annual plan update, and that stakeholders be afforded the opportunity to file comments on the UI's annual plans.

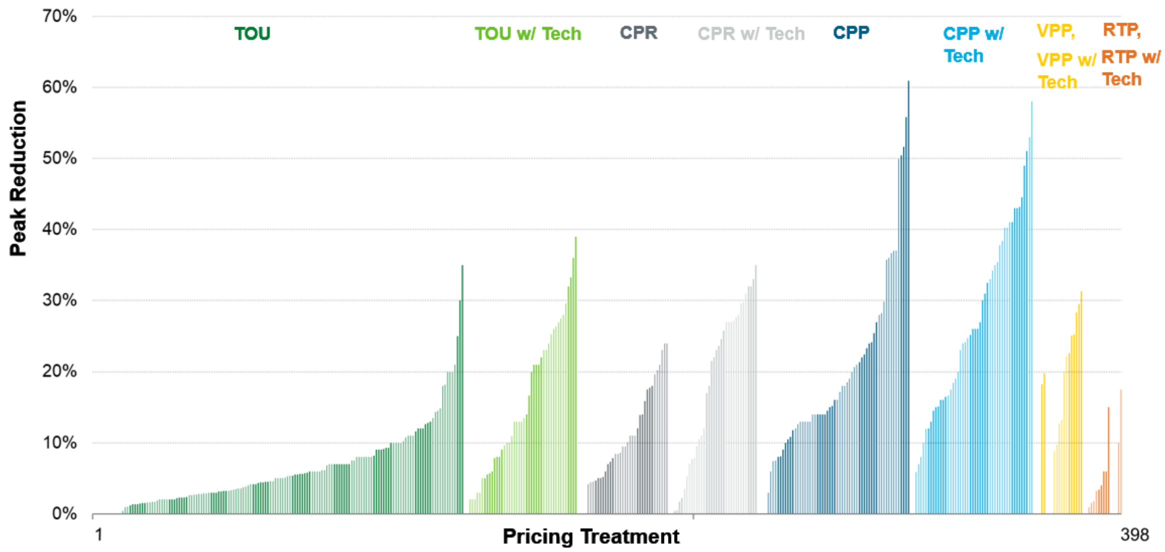
Q Do you have any other recommendations about implementing opt-out TOU rates?

A Yes. I recommend that PURA consider other rates for achieving substantial peak load reductions in addition to or as an alternative to opt-out TOU rates. Experience from other jurisdictions has shown that opt-out TOU rates provide only slight peak load reductions per participant compared to other opt-in tariffs, such as critical peak pricing (CPP).

Q What evidence suggests that CPP provides greater peak load reductions on a per customer basis than opt-out TOU rates provide?

A Data from evaluations in other jurisdictions supports this conclusion. As shown in the figure below, the Brattle Group has compiled a database of peak reductions from approximately 400 time-varying rates. The figure illustrates that the median TOU pilot achieved peak load reductions of approximately 7-8%, while the median CPP rate produced peak load reductions in the range of 20-25%.

Figure 4. Brattle Peak Reduction Evidence from ~400 Treatments by Rate Type[98]



Source: Results from 79 pricing pilots and programs and 398 individual treatments in the Arcturus database.

In addition, the Brattle Group's research has also shown that opt-out TOU rates tend to produce peak load reductions toward the lower end of the range because a large portion of customers remain unengaged, even though they are enrolled in the rate. 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. Further, these load impacts may decline over time. Brattle estimated peak load reductions from Ontario's default TOU rate. In the initial years (pre-2012), the opt-out TOU rate produced peak load reductions of approximately 3 percent. By 2014, these results had declined to approximately 1 percent.[99]

This evidence suggests that other opt-in rate options that could potentially provide similar, or even greater, load shifting results that opt-out TOU. I recommend that PURA direct UI to investigate and implement these opt-in alternatives as well, particularly CPP.

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

99 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.

VI. CONCLUSION

Q Does this conclude your testimony?

A Yes, it does.