STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY

Application of The Connecticut Light and Power Company d/b/a Eversource Energy to Amend its Rate Schedules	)	**Docket No. 26-05-10**

Rebuttal Testimony and Exhibit of

James R. Dauphinais

On behalf of

Connecticut Industrial Energy Consumers

November 18, 2026

BRUBAKER & ASSOCIATES, INC.

Project 12126

STATE OF CONNECTICUT

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Rebuttal Testimony of James R. Dauphinais

I. INTRODUCTION AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME JAMES R. DAUPHINAIS WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A Yes. I filed Direct Testimony on behalf of the Connecticut Industrial Energy Consumers ("CIEC") on October 21, 2026. CIEC's members are commercial and industrial organizations, including but not limited to traditional manufacturers, that purchase a substantial amount of electric delivery service from The Connecticut Light and Power Company d/b/a Eversource Energy ("CL&P," "Eversource," or "Company").

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL TESTIMONY?

A Yes. I am sponsoring Exhibit JRD-4, which contains copies of by CL&P's, Conservation Law Foundation and Sierra Club's ("CLF-SC"), and Office of Consumer Counsel's ("OCC") responses to the data requests cited in my rebuttal testimony.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A My rebuttal testimony responds to specific positions taken in the direct testimony of: (i) OCC Witness Melissa Whited regarding CL&P's Allocated Cost of Service Study ("ACOSS") and CL&P's proposed Economic Development Rider ("EDR"); (ii) CLF-SC Witness Juan-Pablo Velez regarding his proposed residential heat pump rate ("Rate HP"); and (iii) University of Connecticut ("UConn") Witness Eben Perkins regarding his proposed Coincident Peak Transmission ("CPT") rate option and distribution rate design study for large customers. My rebuttal testimony is organized by witness.

My silence in this testimony with regard to any issue raised by these witnesses, or any other witness in this proceeding, in direct testimony should not be construed as an endorsement of their respective positions on that issue.

Q PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY CONCLUSIONS.

A For the reasons detailed in my testimony herein, I recommend that the Public Utilities Regulatory Authority ("PURA" or "Authority"):

- Reject OCC Witness Whited's recommendation to classify Advanced Metering Infrastructure ("AMI") meter costs as 38% customer-related, 47% demand-related and 15% energy-related based on projected AMI program benefits, just as the Authority rejected a similar OCC proposal for The United Illuminating Company ("UI") in Docket No. 24-10-04, and continue to classify AMI meter costs as customer-related;

- Reject OCC Witness Whited's recommendation to replace CL&P's minimum distribution system method with the "basic customer method," which the

Authority declined to adopt for UI in Docket No. 24-10-04 and which, as Ms. Whited's own testimony shows, would further reduce the already below-average rates of return of Rate 39 and Rate 57;

- To the extent the Authority requires a load-carrying capability adjustment to CL&P's minimum distribution system method, base it on the load-carrying capability of the specific minimum-sized facilities in CL&P's study, as the Authority did for UI, rather than on generic values from other jurisdictions;

- To the extent the Authority requires CL&P to prepare an equipment-level distribution allocation study for its next rate case as Ms. Whited proposes, treat it as a supplement to, not a replacement for, the conventional ACOSS, and require that it continue to differentiate costs by the voltage level at which customers take service;

- Decline to adopt Ms. Whited's proposed categorical exclusion of data center loads from the EDR or, if the Authority adopts such an exclusion, define it narrowly and objectively, such as by limiting it to facilities of at least 50 MW classified under NAICS code 518210, so that it does not exclude manufacturing or other industrial loads;

- Reject Ms. Whited's recommendation that EDR participants be required to take service under a time-of-use ("TOU") rate, including but not limited to one that has yet to be designed or filed;

- Clarify that, in applying any hurdle rate analysis and discount cap the Authority adopts for the EDR, costs the customer pays directly through a Contribution in Aid of Construction ("CIAC") or otherwise are not counted again as costs of serving the incremental load;

- Reject CLF-SC Witness Velez's proposed Rate HP, which by his own estimate would reduce the distribution and transmission revenue CL&P collects by approximately $57.2 million per year from the automatic enrollment of existing heat pump customers alone, whose load is already on the system, and which, as he acknowledges, would shift approximately $28 million per year of that shortfall to non-residential customers through CL&P's reconciling mechanisms until the next rate case;

- Require that any heat pump rate the Authority approves be revenue neutral within the residential class, so that no revenue shortfall from that rate is shifted to other rate classes through revenue allocation, the Revenue Decoupling Mechanism ("RDM"), the Transmission Adjustment Clause ("TAC") or any other mechanism;

- Approve UConn Witness Perkins' proposed CPT rate option on the voluntary, opt-in basis he proposes, because it aligns with how CL&P incurs transmission costs under the ISO New England Inc. Open Access Transmission Tariff, but reject any mandatory application of that rate, which could have severe unintended affordability consequences for customers that cannot control their load during the hours that determine their charges; and

- Treat any study of time-differentiated distribution demand charges and the distribution demand ratchet that the Authority directs in response to Mr. Perkins as informational, and require that any resulting proposal be supported by class- and customer-specific bill impact analysis and considered in a future rate proceeding.

II. RESPONSE TO OCC WITNESS WHITED

A. Classification of AMI Meter Costs

Q WHAT DOES MS. WHITED RECOMMEND WITH RESPECT TO THE CLASSIFICATION OF AMI METER COSTS?

A Ms. Whited recommends that AMI meter costs be classified as 38% customer-related, 47% demand-related and 15% energy-related, rather than 100% customer-related.[1] She derives these percentages by assigning each category of benefit in CL&P's AMI benefit-cost analysis to a classification of her choosing and weighting each category by its net present value.[2] As she acknowledges, the "[c]lassification is my own."[3]

Q HAS THE AUTHORITY PREVIOUSLY ADDRESSED A PROPOSAL TO CLASSIFY AMI METER COSTS BASED ON AMI BENEFITS?

A Yes. In UI's most recent rate case, Docket No. 24-10-04, OCC proposed that AMI costs be "classified proportionally according to the benefits in the customer, demand, and energy categories."[4] CIEC opposed that proposal on the grounds that "allocating AMI costs based on the benefits of AMI technology does not constitute cost-based allocation."[5] The Authority agreed with CIEC and affirmed UI's "classification of AMI meters as 100% customer-related, which is consistent with cost causation principles."[6]

[1] Whited Direct at 4, lines 11-15, and 12, lines 1-4 (Table 1).
[2] *Id*. at 11, lines 3-15, and 12, line 1 (Table 1).
[3] *Id.* at 12, line 2.
[4] Docket No. 24-10-04, October 28, 2025 Decision at 197.
[5] *Id*. at 196, footnote 117.
[6] *Id.* at 198.

Ms. Whited does not mention that determination. In discovery, she confirmed it and stated that her only basis for a different result is that CL&P, unlike UI, has quantified AMI benefits.[7] But the Authority affirmed UI's classification because it is "consistent with cost causation principles," not for lack of benefit data. Quantifying the benefits of AMI does not change what causes the cost of a meter.

Q WHY IS IT INAPPROPRIATE TO CLASSIFY AMI METER COSTS BASED ON PROJECTED AMI BENEFITS?

A Cost classification is intended to identify what causes a cost to be incurred. The cost of an AMI meter is incurred because each customer must be metered in order to be served and billed, and that cost varies with the number and type of meters installed, not with the customer's peak demand or energy usage. That is why the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("NARUC Manual") states that meters "are generally classified on a customer basis," with any demand component intended "to show that larger-usage customers require more expensive metering equipment."[8] CL&P's ACOSS follows that approach by allocating meter plant using a weighted meter cost allocator that reflects the relative installed cost of the meters serving each class.[9] Ms. Whited's approach would instead classify meter costs according to who she believes benefits from the AMI program, which is a value-of-service concept rather than cost causation.

Ms. Whited herself agrees that "[c]lassifying traditional meters as customer-related is reasonable, because their primary function is to measure each

[7] OCC Response to Data Request CIEC-9(a)-(c). Copies of the data request responses cited in my rebuttal testimony are provided in alphanumeric order by responding part in Exhibit JRD-4.
[8] NARUC Manual at 96.
[9] CL&P Witness Nieto ACOS Direct (Exhibit CLP-ACOS-1) at 6, lines 21-25.

customer's usage for billing."[10] An AMI meter performs that same function. Its additional capabilities do not change why the meter is installed or what drives its cost. Moreover, most of those capabilities produce benefits only if CL&P takes further action (such as deploying Volt/VAR Optimization ("VVO")) or customers respond to price signals, and the time-varying and demand-based rate designs Ms. Whited associates with AMI were in use long before AMI.

Q DO THE BENEFITS MS. WHITED RELIES UPON CORRESPOND TO THE COST OF AMI METERS?

A No. First, the benefits Ms. Whited uses are the benefits of CL&P's entire AMI program, which includes a new customer information system, a meter data management system, a communications network and VVO enablement, not just the meters.[11] For example, she classifies $163.8 million of VVO benefits as energy and demand, $106.2 million and $57.6, respectively, and $96.4 million of "Asset Optimization" benefits as demand-related.[12] CL&P's benefit-cost analysis separately includes $212.3 million (net present value) of VVO enablement costs, and the "Asset Optimization" benefit consists of the line sensors that AMI would allow CL&P to avoid "as part of the VVO build-out."[13] Those benefits are attributable to the VVO investment at least as much as to the meters, yet Ms. Whited uses them to reclassify the cost of the meters. CL&P's $97.3 million of six-year VVO enablement capital consists of regulators, capacitors, transformer load tap changer controller upgrades and related integration costs, none of which are meters.[14] Ms. Whited concedes that the VVO benefits also require other

[10] Whited Direct at 9, lines 13-14.
[11] CL&P Witnesses Lawrence and Horton Direct (Exhibit CLP-AMI-1) at 4, lines 14-20, and 5, lines 1-4; Exhibit CLP-AMI-3 at 17-18, Figure 7.
[12] Whited Direct at 12, line 1 (Table 1).
[13] Exhibit CLP-AMI-3 at 17, Figure 7, and 47.
[14] CL&P Response to Data Request CIEC-039(c).

investments, that "it would be reasonable to only attribute a portion of these benefits to the meters themselves," and that "it is unclear what proportion should be attributed to the meters themselves."[15] Her classification nonetheless attributes all of them to the meters.

Second, the benefits in CL&P's analysis do not even equal its costs. On a net present value basis, CL&P's benefit-cost analysis shows total AMI benefits of $1,205.4 million, a net benefit of negative $351.9 million, and a benefit-cost ratio of 0.77.[16] A classification derived from projected benefits is therefore not a measure of the costs being classified. Ms. Whited also acknowledges that her classification would change whenever the estimated or actual benefits change,[17] even though the meters and their cost would not.

Third, the assignment of benefits to classifications is subjective. For example, Ms. Whited classifies $162.4 million of "Improved Restoration – Significant Storms" benefits as demand-related.[18] That single category accounts for about 42% of the $388.2 million of benefits she classifies as demand-related.[19] Yet CL&P bases that benefit on reduced storm restoration expense and on the value of reduced customer outage time, which it describes as "a savings benefit realized directly by customers," and it acknowledges that the realized avoided cost "will be nearly impossible to calculate."[20] CL&P has since confirmed that $157.2 million of the $162.4 million is avoided storm restoration expense, and that its ACOSS allocates storm restoration costs to rate classes on total rate base, so that their classification between demand and customer "implicitly followed the same classification as the sum of the components

[15] OCC Response to Data Request CIEC-4(a)-(b).
[16] Exhibit CLP-AMI-3 at 17-18, Figure 7.
[17] OCC Response to Data Request CIEC-6(b).
[18] Whited Direct at 12, line 1 (Table 1).
[19] $162.4 million / $388.2 million = 41.8%.
[20] Exhibit CLP-AMI-3 at 66-67.

that make up the overall rate base."[21] CL&P does not treat those costs as 100% demand-related. Ms. Whited's only support for classifying this benefit as demand-related is that the plant being restored would be 100% demand-related under the basic customer method she proposes,[22] which the Authority has declined to adopt, as I discuss in Section II.B.

Q ARE CL&P'S LARGE INDUSTRIAL CUSTOMERS THE REASON FOR THE AMI INVESTMENT?

A No. CL&P's large industrial customers are already billed under time-differentiated demand rates. Rate 39 and Rate 57 both have defined on-peak and off-peak periods. Rate 57 bills its distribution and transmission demand charges per kVA and sets its customer charge based on the customer's highest average 30-minute demand.[23] Rate 39, Rate 57 and Rate 58 customers already have meters that record interval data, and because these installations commonly involve metering complexities, CL&P will evaluate them case by case to determine whether AMI meters can meet their needs at all.[24] Ms. Whited has not reviewed the metering capabilities of Rate 39 or Rate 57 customers.[25] The Connecticut statute under which CL&P proposes to securitize AMI-related costs describes the AMI deployment as replacing "existing traditional non-interval metering infrastructure."[26] The capabilities Ms. Whited emphasizes, such as time-varying rates and granular load data, are therefore primarily new capabilities for residential and small commercial customers. Shifting AMI meter costs onto demand

[21] CL&P Response to Data Request CIEC-041(a) and (b).
[22] OCC Response to Data Request CIEC-5(a).
[23] Exhibit CLP-RATES-3 at 89 and 108-109.
[24] CL&P Response to Data Request CIEC-038(b) and (c).
[25] OCC Response to Data Request CIEC-7.
[26] Lawrence and Horton Direct at 31, lines 11-21 (quoting Conn. Gen. Stat. § 16-245e(a)(21)(B)).

and energy allocators would require large customers, whose more costly meters are already reflected in the weighted meter cost allocator, to also subsidize the replacement of meters for smaller customers. Ms. Whited's own illustration shows the magnitude. For every $1 million of AMI meter revenue requirement, her classification would increase the amount allocated to Rate 39 about 17-fold (from $182 per million to $3,118 per million), to Rate 57 about six-fold (from $3,090 per million to $18,276 per million) and to Rate 58 about 7.5-fold (from $4,261 per million to $31,867 per million), while reducing the amount allocated to Rate 1 by about $113,000 per million, or 17%.[27]

Q DOES THE MARYLAND DECISION MS. WHITED CITES WARRANT A DIFFERENT CONCLUSION?

A No. A single decision by another state commission ten years ago, based on the record in that case, carries less weight than this Authority's own determination for UI last year. Moreover, the classification Ms. Whited proposes here (38% customer, 47% demand and 15% energy) differs considerably from the one approved in Maryland (25% customer, 37.5% demand and 37.5% energy),[28] which illustrates how dependent a benefits-based classification is on the analyst's judgment and on the particular benefit-cost analysis used. Furthermore, in response to discovery, Ms. Whited could only identify two additional state commission decisions supporting a benefits-based classification (Minnesota and Colorado) and, in the case of one of those (Colorado), 83% of AMI costs were classified as customer-related, more than twice the 38% Ms. Whited proposes.[29]

[27] OCC Response to Data Request CIEC-8(b), Attachment "Response to CIEC-8 (b) Allocation of AMI meter costs.xlsx."

[28] Whited Direct at 12, lines 5-9.

[29] OCC Response to Data Request CIEC-9(d); Colorado PUC Decision No. C24-0117, Proceeding No. 23AL-0243E, at 22-23, ¶¶ 61-64.

Q WHAT DO YOU RECOMMEND?

A Consistent with its determination for UI in Docket No. 24-10-04, the Authority should reject Ms. Whited's recommendation and direct that AMI meter costs continue to be classified as customer-related. CL&P agrees. It expects to record the full cost of its AMI meters, including installation, in FERC Account 370 (Meters), and expects that AMI meter costs "will be properly classified as customer-related costs, consistent with treatment of meter costs in the allocated cost-of-service study."[30] Consistent with my direct testimony, those costs should be allocated using the weighted meter cost allocator in CL&P's ACOSS.

B. Minimum Distribution System Method

Q WHAT DOES MS. WHITED RECOMMEND WITH RESPECT TO CL&P'S MINIMUM DISTRIBUTION SYSTEM METHOD?

A Ms. Whited recommends that the Authority reject CL&P's Minimum Distribution System ("MDS") method and instead adopt the "basic customer method," under which only meters, services, meter reading and billing costs would be classified as customer-related, and all of the costs of poles, conductors and line transformers in FERC Accounts 364 through 368 would be classified as demand-related.[31] She also recommends that CL&P develop a customer density-based classification approach for its next rate case and, if the MDS method is retained, that each class's Non-Coincident Peak ("NCP") demand be reduced by the load-carrying capability of the minimum system.[32]

[30] CL&P Response to Data Request CIEC-039(a) and CIEC-040(d).
[31] Whited Direct at 18, lines 8-17, and 19, lines 8-9.
[32] *Id*. at 4, lines 3-10.

Q HAS THE AUTHORITY CONSIDERED THIS RECOMMENDATION BEFORE?

A Yes. OCC made the same recommendation in UI's last two rate cases. In Docket No. 22-08-08, the Authority found the minimum system method "generally acceptable" and accepted its use.[33] In Docket No. 24-10-04, OCC again proposed the basic customer method. The Authority found that "it is not clear that the basic customer method is a superior alternative," explaining that "[c]osts classified as demand-related under the basic customer method, such as poles and conductors, are unaffected by changes in demand." It accepted "the premise that the number of customers is an acceptable, if imperfect, proxy for costs unrelated to demand," and concluded that the minimum system approach "is a just and reasonable approach to cost classification."[34] Ms. Whited cites the same decision for its load-carrying capacity adjustment,[35] but does not acknowledge that the Authority rejected the basic customer method in that decision. In discovery, Ms. Whited confirmed both of those determinations. The reason she offers for a different result here is that the basic customer method would reduce the costs allocated to the residential class, given the size of CL&P's proposed rate increase.[36] That is an argument about who should pay, not about what causes the costs.

Q IS THE AUTHORITY'S DETERMINATION IN DOCKET NO. 24-10-04 CONSISTENT WITH THE NARUC MANUAL?

A Yes. The NARUC Manual explains that distribution plant Accounts 364 through 370 "involve demand and customer costs," and that "the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on

[33] Docket No. 22-08-08, August 25, 2023 Decision at 227-228.
[34] Docket No. 24-10-04, October 28, 2025 Decision at 198.
[35] Whited Direct at 17, lines 11-15.
[36] OCC Response to Data Request CIEC-10(a), (b) and (d).

the utility's system."[37] It identifies two methods for determining the customer component of these accounts: the minimum-size method and the minimum-intercept (zero-intercept) method.[38] The basic customer method does not determine a customer component of poles, conductors and line transformers at all. It simply assumes there is none.

Ms. Whited's own example illustrates why that assumption is wrong. She explains that a new customer located in a rural area "may require investments in additional distribution system poles and wires to extend service to the customer's residence."[39] Those costs are incurred to connect the customer, and would be incurred even if the customer's demand were negligible. They are not incurred to meet its demand. Ms. Whited confirmed this in discovery, and she also confirmed that the costs of the poles and wires required to connect customers vary with the number and geographic dispersion of customers rather than with their peak demand.[40] Classifying them as demand-related, as the basic customer method would, assigns them to classes based on their peak demands even though peak demand is not what caused them. Her argument that customer density affects these costs goes to how much customer-related cost each customer causes, not to whether the cost is caused by demand.

Q DOES THE BONBRIGHT DISCUSSION MS. WHITED CITES SUPPORT CLASSIFYING THESE COSTS AS DEMAND-RELATED?

A No. As Ms. Whited describes it, Professor Bonbright argued that the costs of the minimum system "should be excluded from demand-related costs" and treated as "a

[37] NARUC Manual at 90.
[38] *Id*. at 90-95.
[39] Whited Direct at 15, lines 12-14.
[40] OCC Response to Data Request CIEC-11(a) and (c).

strictly unallocable portion of total costs."[41] Ms. Whited's recommendation does the opposite: it classifies all of those costs as demand-related. Whatever the merits of Professor Bonbright's view, it does not support the basic customer method. Ms. Whited concedes that the basic customer method is not consistent with it.[42]

Q WHAT WOULD BE THE EFFECT OF THE BASIC CUSTOMER METHOD ON CL&P'S LARGE INDUSTRIAL RATE CLASSES?

A Ms. Whited's Table 3 shows that, at current rates, the basic customer method would reduce the rate of return for Rate 39 from negative 3.5% to negative 4.4%, and for Rate 57 from negative 0.8% to negative 2.2%, while increasing the rate of return for Rates 1 and 7 from 0.4% to 1.2%.[43] In other words, it would shift additional distribution costs to the two large industrial classes whose rates of return are already well below the 1.05% system average return at current rates.

Q HOW SHOULD THE AUTHORITY ADDRESS MS. WHITED'S RECOMMENDATION FOR A LOAD-CARRYING CAPABILITY ADJUSTMENT?

A In Docket No. 24-10-04, the Authority required a load-carrying capacity adjustment to UI's minimum system study. In doing so, it used the load-carrying capacity of the specific minimum-sized poles, conductors and line transformers in UI's own study, rather than the generic per-customer values of 0.4 kW and 1.5 kW from other jurisdictions that OCC had presented, and it found that excluding classes whose demands can "generally" be met by the minimum system "is too imprecise to be a reasonable approach."[44] The Authority also directed that further refinement of the

[41] Whited Direct at 15, lines 19-20, and 16, lines 1-2.
[42] OCC Response to Data Request CIEC-12(b).
[43] Whited Direct at 20, line 1 (Table 3).
[44] Docket No. 24-10-04, October 28, 2025 Decision at 197-199.

adjustment occur through a stakeholder process, and clarified that the final adjustment value "should not be dictated solely by OCC."[45]

Ms. Whited does not propose any specific adjustment values for CL&P. She agrees that, ideally, any adjustment should be calculated from the load-carrying capability of the specific minimum-sized facilities in CL&P's study, and she has not quantified the effect of her proposed adjustment on any class.[46] If the Authority requires an adjustment here, it should be calculated on the same basis as for UI, using the load-carrying capability of the specific minimum-sized facilities in CL&P's MDS study and applied only to the demand allocators for those facilities. Any customer density study the Authority directs CL&P to prepare should similarly be developed through a stakeholder process, as the Authority directed for UI, with the MDS method remaining in place unless and until the Authority approves a demonstrably better alternative. Ms. Whited is not aware of any U.S. jurisdiction that has adopted a density-based classification of distribution plant, and she confirms that such an approach would still classify a portion of distribution plant as customer-related.[47]

C. Distribution Demand Allocation

Q WHAT DOES MS. WHITED RECOMMEND WITH RESPECT TO THE ALLOCATION OF DEMAND-RELATED DISTRIBUTION COSTS?

A Ms. Whited recommends that CL&P retain hourly AMI interval data in a form suitable for equipment-level aggregation and file, in its next rate case, an equipment-level allocation study "alongside its conventional class cost of service study, so the Authority can compare the results before adopting a new method."[48]

[45] *Id*. at 199-200 and footnote 118.
[46] OCC Response to Data Request CIEC-14(a), (c) and (e).
[47] OCC Response to Data Request CIEC-13(b) and (c).
[48] Whited Direct at 21, line 20, through 22, line 10.

Q DO YOU OBJECT TO THAT RECOMMENDATION?

A Not to the filing of such a study alongside the conventional ACOSS, as Ms. Whited describes it. The Authority directed UI to develop similar alternative allocators, and UI reported that the results were "very similar" to its NCP and coincident peak allocators.[49] In that case the Authority adopted the alternative allocator only for distribution substations and retained NCP allocators, adjusted for load-carrying capacity, for poles, conductors and line transformers.[50] Any equipment-level study for CL&P should similarly be evaluated against the conventional ACOSS before any change is adopted.

Any such study should also continue to recognize the voltage level at which customers take service, so that the loads of customers served at primary or transmission voltage are excluded from the allocation of facilities they do not use, as the NARUC Manual directs.[51] CL&P's current ACOSS already applies this principle by excluding customers served from customer-owned transformers from the allocation of line transformers.[52] That feature should be preserved in any alternative allocation study. All of CL&P's distribution-level Rate 39 and Rate 57 customers take service at primary voltage.[53] Ms. Whited confirmed that her proposed study would be filed alongside, not in place of, the conventional ACOSS; would exclude the loads of customers served at primary or transmission voltage from the allocation of lower-voltage facilities; would preserve the exclusion of customers served from customer-owned transformers; and would directly assign substations or feeders dedicated to a single customer.[54]

[49] Docket No. 24-10-04, October 28, 2025 Decision at 200.
[50] *Id*. at 201.
[51] NARUC Manual at 97.
[52] Nieto ACOS Direct at 6, lines 8-10.
[53] CL&P Response to Data Request CIEC-043(c).
[54] OCC Response to Data Request CIEC-16(a)-(c) and (f).

The Authority should also be cautious in adopting any new allocator because a change in allocation method, by itself, can shift substantial costs among rate classes even though CL&P's total costs and customers' use of the system are unchanged. Ms. Whited herself counsels caution, recommending that the equipment-level study be filed alongside the conventional study "so the Authority can compare the results before adopting a new method."[55] Large commercial and industrial customers, such as those served under Rate 39 and Rate 57, compete in regional, national and global markets, and a significant increase in their delivery rates can affect whether they remain, expand or curtail operations in Connecticut. If those customers reduce load or leave the system, the fixed costs they now pay must be recovered from the customers who remain, worsening affordability for every class. Before adopting any new allocator, the Authority should therefore require that the study quantify the resulting change in each class's revenue requirement and typical bills. If a new method is adopted, the Authority should phase in any material cost shifts gradually.

D. Economic Development Rider

Q WHAT DOES MS. WHITED RECOMMEND WITH RESPECT TO CL&P'S PROPOSED EDR?

A Ms. Whited recommends that the Authority reject CL&P's proposed EDR and instead adopt an EDR based on the one approved for UI, with modifications that would: (i) exclude data center loads; (ii) require EDR customers to take service on an "enhanced TOU rate" to be filed by CL&P within six months of the Authority's decision; and (iii) adopt fixed discounts of 20% for facilities sited in an Environmental Justice

[55] Whited Direct at 22, lines 9-10.

Community and 15% for facilities sited elsewhere, with a discount cap of 50% of the net present value of incremental revenues.[56]

Q DO YOU AGREE WITH ANY OF THESE RECOMMENDATIONS?

A Yes. Ms. Whited's recommendation that the discount be fixed over the five-year term, rather than negotiated and declining, is consistent with my direct testimony, although I recommended discounts no lower than 15% and 20%, with the 20% level also applying in Distressed Municipalities, as the Authority approved for UI.

Q WHAT SHOULD THE AUTHORITY KEEP IN MIND IN EVALUATING MS. WHITED'S PROPOSED MODIFICATIONS TO THE EDR?

A The EDR is meant to attract new and expanded operations that bring jobs and capital investment to Connecticut, and the conditions placed on it should not undermine that objective. Under CL&P's proposal, a qualifying project must provide "economic value to customers within its service territory, including job creation or capital investment." Applicants must describe the "changes in employment levels or jobs expected to be created."[57] Ms. Whited herself recognizes "the economic benefits (including jobs) of new load."[58] In approving UI's EDR, the Authority found that "the discount must not only provide substantial benefits to existing ratepayers, but sufficient incentive to attract incremental load as well."[59]

Ms. Whited describes the primary objective of the EDR as improving affordability.[60] That objective and job creation are complementary. Incremental load

[56] Whited Direct at 5, lines 4-13.
[57] CL&P Witnesses Davis and Parsons Direct (Exhibit CLP-RATES-1) at 26, lines 12-13, and 27, lines 1-2.
[58] Whited Direct at 44, lines 5-7.
[59] Docket No. 22-08-08, August 25, 2023 Decision at 250.
[60] Whited Direct at 39, lines 1-2.

that would not otherwise locate in CL&P's service territory that produces revenue above the incremental cost to serve it puts downward pressure on rates for existing customers, but only if the load actually comes. An EDR weighed down by conditions that add cost, complexity or uncertainty for prospective participants will attract fewer projects, and so will deliver neither the jobs nor the rate benefits intended by the incentive. Each of Ms. Whited's proposed modifications should therefore be judged by whether it is needed to protect existing customers, given the protections already in the EDR, or whether it would simply discourage the projects the EDR is meant to attract. I respond below to her proposed data center exclusion, her proposed TOU requirement, and the calculation of her proposed discount cap.

1. Data Center Exclusion

Q SHOULD THE AUTHORITY ADOPT A CATEGORICAL EXCLUSION OF DATA CENTER LOADS FROM THE EDR?

A It is not necessary. Ms. Whited's concern is that data center loads can require new generation, transmission and distribution investments that increase costs for existing customers.[61] The EDR, however, discounts only distribution charges. CL&P has explained that it has not proposed discounts to transmission, supply or public benefits charges; that customers connected at transmission voltage take minimal distribution service, so the EDR "may have little practical applicability" to them; that the incremental distribution revenue must exceed the incremental cost to serve; and that the customer "remains responsible for interconnection and system upgrade costs."[62] CL&P has also stated that there are currently no active requests or firm commitments for data center

[61] Whited Direct at 38, lines 3-19, and 39, lines 1-2.
[62] CL&P Response to Data Request OCC-464(a) and (b).

load additions on its distribution system.[63] Ms. Whited has not identified any generation or transmission cost that would be borne by other customers as a result of a discount applied only to distribution charges.[64] These protections address the cost concerns Ms. Whited raises without singling out one type of customer by its end use.

Notably, the UI EDR on which Ms. Whited proposes to model CL&P's EDR contains no such exclusion. The Authority made that EDR "available to all C&I customers, without any cap on participation," subject only to an exception for customers directly participating in local commerce, and relied instead on a hurdle rate analysis of each application to protect existing customers.[65] Ms. Whited's other concern, that a discount is unlikely to influence a data center's siting decision,[66] applies equally to any applicant whose decision would not be affected by the EDR. Ms. Whited confirms that the UI EDR does not exclude data center loads, and she is not aware of any Connecticut-specific evidence that data center siting decisions are insensitive to utility rates.[67] The Authority addressed that concern for UI by requiring each applicant to provide a narrative description of why its load is increasing or, if new load, why the discount is a prerequisite for locating in the service territory,[68] not by excluding an entire category of customers.

[63] CL&P Response to Data Request OCC-465(a).
[64] OCC Response to Data Request CIEC-18(b).
[65] Docket No. 22-08-08, August 25, 2023 Decision at 250-252.
[66] Whited Direct at 39, lines 3-10.
[67] OCC Response to Data Request CIEC-18(a) and (c).
[68] Docket No. 22-08-08, August 25, 2023 Decision at 252.

Q IF THE AUTHORITY NONETHELESS ADOPTS A DATA CENTER EXCLUSION, HOW SHOULD IT BE DEFINED?

A Ms. Whited's testimony does not define "data center loads," and CL&P has no definition of its own.[69] In discovery, Ms. Whited proposed that the exclusion apply to facilities classified under North American Industry Classification System ("NAICS") code 518210 (Data Processing, Hosting, and Related Services), with an interim minimum size of 50 MW, and stated that it would not apply to load from the electrification of industrial processes.[70] Many manufacturing facilities include significant computing, automation and process control loads, and some industrial customers may add load by electrifying processes such as process heating, which CL&P has indicated may be eligible for the EDR.[71] Any exclusion should therefore be defined narrowly and objectively in the EDR tariff, for example by limiting it to NAICS code 518210 facilities of at least 50 MW, as Ms. Whited proposes, and expressly excluding load from process electrification, so that it does not exclude manufacturing or other industrial facilities.

2. Mandatory TOU Rate

Q WHAT DOES MS. WHITED PROPOSE WITH RESPECT TO TOU RATES FOR EDR CUSTOMERS?

A Ms. Whited recommends that CL&P file TOU rates for industrial customers within six months of the Authority's decision, with time-differentiated distribution, transmission and generation charges and a shorter on-peak period, and that EDR customers be required to take service under those rates.[72] Her rationale is that CL&P's marginal cost

[69] CL&P Responses to Data Requests CIEC-036 and CIEC-047(a).
[70] OCC Response to Data Request CIEC-17(a), (b) and (d).
[71] CL&P Response to Data Request OCC-464(c).
[72] Whited Direct at 41, lines 16-20.

test for the EDR considers only distribution costs and does not account for the impact of incremental load on transmission and supply costs.[73]

Q IS THAT CONCERN WELL FOUNDED?

A No. The EDR discount applies only to the distribution component of service. Transmission service to the incremental load "would continue under otherwise applicable retail rates."[74] An EDR customer would therefore pay full transmission charges on its incremental load, including the on-peak transmission demand charge that Ms. Whited acknowledges already applies under Rate 57 and Rate 58.[75] The EDR customer would also pay for the supply serving its incremental load. Under CL&P's Terms and Conditions for Electric Suppliers, each customer's hourly load, including its coincident peak capacity values, is assigned to the customer's electric supplier (including Standard Service or Last Resort Service) for settlement in the ISO New England Inc. ("ISO-NE") wholesale market.[76] The energy and capacity costs of the incremental load are therefore borne by the supplier serving it and passed through to the EDR customer. Because the EDR does not discount any of those charges, it does not shift transmission or supply costs to other customers. CL&P confirms that the transmission and supply charges for an EDR participant's incremental load would be the participant's responsibility.[77] Moreover, the transmission, supply and other non-distribution charges for these customers are already priced on a time-of-day basis, and those time-varying structures are mandatory for the large customers who would take service under the EDR.[78]

[73] *Id*. at 40, lines 7-22.
[74] CL&P Response to Data Request OCC-464(b).
[75] Whited Direct at 41, lines 3-9.
[76] Exhibit CLP-RATES-3 at 38-40.
[77] CL&P Response to Data Request CIEC-046(a).
[78] CL&P Response to Data Request CIEC-045(a).

Q DOES A MANDATORY TOU RATE ADDRESS MS. WHITED'S CONCERN THAT NEW LOAD ADDED DURING PEAK HOURS MAY REQUIRE NEW DISTRIBUTION CAPACITY?

A No. Ms. Whited states that new load added primarily to peak hours "may necessitate new investments in distribution capacity."[79] CL&P's proposed EDR already addresses that cost. The incremental distribution revenue must exceed the incremental cost to serve, and the customer remains responsible for interconnection and system upgrade costs.[80] Ms. Whited does not claim CL&P's test understates the distribution cost of serving the incremental load. Her only criticism is that the test does not include transmission and supply costs.[81]

Q IS MS. WHITED'S CONCERN ABOUT TRANSMISSION AND SUPPLY COSTS SPECIFIC TO THE EDR?

A No. A new or expanding Rate 57 or Rate 58 customer pays the same transmission charges and supply costs whether or not it takes the EDR, because the EDR does not discount either. Ms. Whited's concern therefore applies to all new load on those rates, not to EDR load in particular. It is not a reason to place conditions on EDR eligibility. Her view that new load benefits the system most when it is added off-peak[82] also favors the high load factor industrial loads the EDR is meant to attract. Ms. Whited notes that the on-peak period under Rate 57 and Rate 58 is eight hours long.[83] Even if that period applied every day of the year, a customer operating at a constant load would use two-thirds of its energy in off-peak hours.[84]

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[79] Whited Direct at 40, lines 9-11.
[80] CL&P Response to Data Request OCC-464(a) and (b).
[81] Whited Direct at 40, lines 12-15.
[82] Whited Direct at 40, lines 16-19.
[83] *Id.* at 41, lines 9-10.
[84] 16 off-peak hours ÷ 24 hours = 67%.

Q ARE THERE OTHER PROBLEMS WITH MS. WHITED'S PROPOSAL?

A Yes. First, it would make EDR participation contingent on a rate that does not yet exist. A customer evaluating whether to locate or expand in CL&P's service territory could not determine what its rates would be until the new TOU rate is filed and approved. That is exactly the type of uncertainty that undermines an EDR's ability to influence siting and expansion decisions. Ms. Whited confirms that the EDR would be unavailable to customers until her proposed industrial TOU rates are approved, and she has neither proposed an on-peak period for those rates nor analyzed their bill impacts.[85]

Second, Ms. Whited states that, unless the incremental load is separately metered, the TOU requirement would apply to the customer's entire load.[86] In that case, an existing customer would have to move its existing load to a new and untested rate as a condition of receiving a discount on its expansion, which would discourage the very expansions the EDR is intended to attract.

Third, many industrial processes operate continuously or on production schedules that cannot readily be shifted. A mandatory TOU rate would not change those operations; it would simply change the customer's bill. Ms. Whited recognizes that new load improves system efficiency when the revenue the utility receives from it is greater than its marginal cost to serve,[87] which is what CL&P's requirement that "the incremental distribution revenue must exceed the incremental cost to serve" is designed to ensure.[88] The Authority did not impose a TOU requirement on participants in UI's EDR. Ms. Whited confirms this, is not aware of any jurisdiction that requires economic development rate customers to take service under a TOU rate, and has not

[85] OCC Responses to Data Requests CIEC-20(b) and CIEC-21(b)-(c).
[86] OCC Response to Data Request CIEC-20(a).
[87] Whited Direct at 40, lines 7-8.
[88] CL&P Response to Data Request OCC-464(a).

analyzed the load profiles, load factors or load flexibility of Rate 57 and Rate 58 customers.[89]

Finally, the design of Rate 57 and Rate 58, including the length of their on-peak periods, affects all customers on those rates. Changes to that design should be considered in a rate design proceeding in which all affected customers have notice and an opportunity to participate, not imposed only on EDR participants as a condition of eligibility.

Q WHAT DO YOU RECOMMEND?

A The Authority should reject Ms. Whited's proposal to require EDR customers to take service under a new TOU rate. If CL&P develops a TOU option for large commercial and industrial customers, EDR participants should be free to choose it, but it should not be a condition of EDR eligibility.

3. Discount Cap

Q HOW DOES MS. WHITED PROPOSE TO CALCULATE THE EDR DISCOUNT CAP?

A Ms. Whited recommends "a discount cap equal to 50 percent of the net present value of the incremental distribution revenues, accounting for the cost of connecting the customer and any other electric infrastructure investments made to serve the incremental load."[90] In her summary of recommendations, she describes the cap as "50 percent of the net present value of incremental revenues."[91]

[89] OCC Response to Data Request CIEC-20(d)-(f).
[90] Whited Direct at 44, lines 9-12.
[91] *Id.* at 5, lines 12-13.

Q DO YOU HAVE ANY CONCERNS WITH THIS FORMULATION?

A Only one. For UI, the Authority required a hurdle rate analysis of each application to ensure that the net present value of the revenue stream over the term, inclusive of the discount, exceeds the incremental cost to serve, "inclusive of any connection and any other electric-related infrastructure improvements required." It capped the discount at "50% of the difference between the standard rate revenues over the Term for the additional load, less the incremental cost to serve."[92] Ms. Whited confirms that her formulation is meant to replicate the UI cap and hurdle rate analysis,[93] and I do not object to the Authority adopting the UI structure for CL&P. However, CL&P has stated that EDR customers "would be responsible for all costs associated with the installation of a new service pursuant to the Company's new business policies."[94] Costs that the customer pays directly, through a CIAC or otherwise, are not costs CL&P incurs to serve the incremental load. The Authority should clarify that such costs are not counted again as a cost of serving the incremental load in the hurdle rate analysis or the discount cap. Ms. Whited's own numerical example counts any CIAC as revenue while counting the connection cost as a cost, so that the two offset.[95] CL&P, however, states only that the portion of upfront costs paid by the participant would be included in the evaluation of the discount, without saying whether the payment would also be credited.[96]

[92] Docket No. 22-08-08, August 25, 2023 Decision at 250-251 and 255 (Table 86).
[93] OCC Response to Data Request CIEC-22(b).
[94] CL&P Response to Data Request OCC-932(a).
[95] OCC Response to Data Request CIEC-22(a) and (d).
[96] CL&P Response to Data Request CIEC-046(c).

III. RESPONSE TO CLF-SC WITNESS VELEZ

A. Mr. Velez's Proposed Rate HP

Q PLEASE SUMMARIZE MR. VELEZ'S PROPOSED RATE HP.

A Mr. Velez proposes a new residential rate schedule, Rate HP, for customers with heat pumps. During the winter months of November through March, Rate HP would reduce the distribution energy charge by approximately 71% and the transmission service rate by approximately 75% compared with Rate 1. Summer rates, generation rates and the customer charge would remain at Rate 1 levels.[97] All known existing heat pump customers and all customers newly installing heat pumps would be automatically enrolled.[98]

Q WHAT IS THE BASIS FOR MR. VELEZ'S PROPOSAL?

A Mr. Velez claims that fossil fuel-heated customers who install heat pumps are "overcharged" by an average of $1,040 per year for distribution and transmission, because their distribution and transmission charges under Rate 1 increase by about $1,051 per year while, in his estimation, the incremental marginal distribution and transmission costs caused by the heat pump load are only about $10 per year.[99] Rate HP is designed to reduce the distribution and transmission revenue collected from heat pump customers so that their incremental charges equal his estimate of their incremental marginal cost.[100]

[97] Velez Direct at 6, lines 15-23, 7, lines 1-2, and 81, lines 10-16.
[98] *Id.* at 7, lines 3-8.
[99] Velez Direct at 20, lines 5-8, and 23, lines 2-10.
[100] *Id.* at 81, lines 17-23, and 82, lines 1-3.

B. The Claimed "Overcharge" Is a Contribution to Embedded Costs

Q IS THE $1,040 PER YEAR THAT MR. VELEZ CHARACTERIZES AS AN "OVERCHARGE" ACTUALLY AN OVERCHARGE?

A No. CL&P's rates are set to recover its embedded cost revenue requirement, which consists predominantly of the fixed costs of facilities already in service. Mr. Velez acknowledges that this existing infrastructure "does need to be paid for."[101] Marginal cost, on the other hand, measures only the cost of serving additional load. Where the system has spare capacity, the marginal cost of serving additional load will be well below the embedded cost per unit. That does not mean that customers paying embedded cost-based rates are overcharged. It means that their usage is contributing to the recovery of existing fixed costs that would otherwise have to be recovered from other customers. The $1,040 Mr. Velez calls an overcharge is that contribution. Mr. Velez confirms the point. He agrees that the approximately $1,055 per year by which the average fossil fuel-heated customer's distribution and transmission charges exceed its marginal cost before it installs a heat pump is that customer's "contribution to the embedded costs of the existing system," and that his testimony "does not call that contribution an overpayment."[102] Yet he contends that "incremental heat pump load should not contribute to embedded T&D costs" at all.[103] The same excess of charges over marginal cost cannot be a legitimate contribution to fixed costs before a customer installs a heat pump and an "overcharge" afterward.

CL&P has explained that keeping incremental heat pump load "priced above the marginal cost of serving it" places "downward pressure on average rates for all

[101] Velez Direct at 13, line 23, and 14, lines 1-2.
[102] CLF-SC Response to Data Request CIEC-4(b) and (c) of CIEC Set 2.
[103] CLF-SC Response to Data Request CIEC-17(a) of CIEC Set 2.

customers over time" by "spreading fixed costs over a larger sales base."[104] That is a benefit of load growth that is shared with all customers, not an inequitable cross-subsidy.

Q DOES CL&P'S MARGINAL COST OF SERVICE STUDY SUPPORT SETTING HEAT PUMP CUSTOMERS' CHARGES AT MARGINAL COST?

A No. Mr. Velez relies on CL&P's Marginal Cost of Service ("MCOS") study to conclude that heat pump load causes near-zero winter distribution costs.[105] CL&P, however, presented that study "to be used as a guide for rate design."[106] CL&P's class revenue targets "are decided primarily on the basis of the Company's allocated cost of service study (ACOS)." The MCOS results are used only to ensure that each rate class pays "at least the corresponding marginal costs of service."[107] That is the proper role of a marginal cost study: to inform rate design and to serve as a floor. It should not determine how embedded costs are allocated or how much of those costs any group of customers pays. Rate HP departs from that role. It treats marginal cost as the full measure of what heat pump load should pay for distribution and transmission, so that load would make essentially no contribution to CL&P's embedded costs. The Authority should limit the use of the MCOS study to informing rate design, and should not use it to allocate embedded costs or to exempt any customer's load from contributing to them.

[104] Velez Direct at 31, lines 15-17, and 60, lines 1-4 (quoting CL&P Response to Data Request CLF-003(a)).
[105] Velez Direct at 20, lines 11-12.
[106] CL&P Witness Nieto MCOS Direct (Exhibit CLP-MCOS-1) at 2, lines 13-15.
[107] *Id.* at 6, lines 17-21.

Q HOW DOES RATE HP COMPARE WITH CL&P'S PROPOSED RATE 6 IN THIS RESPECT?

A The two differ in three important ways. First, CL&P priced the Rate 6 winter block "based on, but above marginal cost to ensure positive contribution to distribution costs." Rate HP would set incremental charges at Mr. Velez's estimate of marginal cost. Second, under Rate 6, "a customer must add new heat pump load not already included in the underlying revenue requirement." Rate HP would automatically enroll existing heat pump customers whose load is already reflected in CL&P's revenue requirement. Third, under Rate 6, "[p]ricing for other components of service including transmission, public benefits and supply are unchanged relative to Rate 1." Rate HP would reduce the winter transmission rate by 75%.[108]

Q WHY DOES THE AUTOMATIC ENROLLMENT OF EXISTING HEAT PUMP CUSTOMERS MATTER?

A For a customer that already has a heat pump, Rate HP would not attract any new load. It would simply reduce the revenue collected from load that is already on CL&P's system and already contributing to its fixed costs. The Authority has recognized this type of risk. In Docket No. 24-10-04, the Authority approved a load retention special contract policy for UI that is limited to customers whose load is at risk of being lost, and even then it expressed concern about free ridership. Under that policy, discounts are negotiated on a case-by-case basis, are subject to the Authority's approval, and are subject to a price floor based on long-run marginal distribution cost.[109] Rate HP would provide marginal-cost pricing automatically to every enrolled heat pump customer, without any showing that the discount is needed to cause or retain any load.

[108] CL&P Response to Data Request OCC-475(a); Velez Direct at 6, line 20, through 7, line 8.
[109] Docket No. 24-10-04, October 28, 2025 Decision at 229-231.

Q HAS THE AUTHORITY ADDRESSED A SIMILAR QUESTION FOR INCREMENTAL COMMERCIAL AND INDUSTRIAL LOAD?

A Yes. In approving UI's EDR, the Authority required that revenue from incremental load exceed the incremental cost to serve it and capped the discount at 50% of the projected savings, so that "at least 50% of the benefit from the incremental or new load is allocated to existing ratepayers."[110] Rate HP takes the opposite approach. By setting the incremental distribution and transmission charges for heat pump load equal to its estimated marginal cost, Rate HP would leave essentially none of that load's contribution to fixed costs for the benefit of other customers.

Q DOES MR. VELEZ'S RELIANCE ON MARGINAL COST SUPPORT RATE HP?

A No. I agree that distribution and transmission fixed costs are driven principally by peak demands rather than by energy consumption. That principle governs how embedded costs are classified and allocated among and within classes. It does not mean that embedded costs can go unrecovered. The residential class's share of CL&P's revenue requirement is determined through the ACOSS and revenue allocation, and does not decline because some residential customers are placed on Rate HP. If heat pump customers pay less, other customers must pay more. To the extent there is an intra-class issue within the residential class, CL&P's marginal cost witness identifies the appropriate remedy: rebalancing cost recovery within the class from usage charges toward fixed charges.[111] That remedy does not require any other class to make up revenue.

[110] Docket No. 22-08-08, August 25, 2023 Decision at 250-251.
[111] Nieto MCOS Direct at 4, lines 20-22, and 5, lines 1-7.

C. Rate HP Is Not Revenue Neutral

Q IS RATE HP DESIGNED TO BE REVENUE NEUTRAL?

A No. Mr. Velez confirms that Rate HP is not designed to be revenue neutral with respect to the residential class as a whole,[112] and he expressly rejects a revenue-neutral design. He states that a seasonal design that lowers the winter rate but raises the summer rate "merely shifts the overpayment between seasons, defeating the entire purpose of a heat pump rate," and that neither season's rates should be set higher than those in Rate 1.[113] He also states that no heat pump customer would be made worse off by being placed on Rate HP.[114] Mr. Velez recognizes that a revenue-neutral redesign of the retail transmission charge would involve "lowering it in winter and raising it in summer,"[115] and that a lower rate available to all customers "would create a revenue shortfall under heavy enrollment."[116] However, his direct testimony does not quantify the revenue shortfall Rate HP itself would create or identify who would pay it. In discovery, he states that he considered how that shortfall would be recovered between rate cases "but did not address it in [his] testimony."[117]

Q HOW LARGE COULD THAT REVENUE SHORTFALL BE?

A Mr. Velez has now quantified it. He estimates that automatically enrolling the approximately 55,000 existing heat pump customers who have received Energize CT rebates, as he recommends, would reduce CL&P's revenue by $39.8 million in distribution and $17.4 million in transmission, or about $57.2 million in total, in the first

[112] CLF-SC Response to Data Request CIEC-2(a) of CIEC Set 2.
[113] Velez Direct at 101, lines 6-17.
[114] *Id*. at 95, lines 1-4.
[115] *Id*. at 83, footnote 75.
[116] *Id.* at 95, lines 14-16.
[117] CLF-SC Response to Data Request CIEC-2(d) of CIEC Set 2.

rate year and by approximately the same amount every year thereafter.[118] He agrees that these customers' load is already on CL&P's system and already reflected in the sales used to set rates in this proceeding, and that enrolling them in Rate HP would produce no new load and no reduction in CL&P's costs.[119] The $57.2 million is therefore a pure revenue reduction. Mr. Velez estimates that recovering it solely from the residential class would raise Rate 1 distribution and transmission charges by about 0.61¢ per kWh, or about $4.24 per month for the average residential customer not on Rate HP.[120]

Q WHO WOULD PAY THE SHORTFALL?

A Mr. Velez's direct testimony does not say. In discovery, he states that it should be paid by other residential customers, but he acknowledges that CL&P's reconciling mechanisms would not produce that result.[121] He estimates that approximately $19.7 million per year of the distribution shortfall would be recovered from non-residential classes through the RDM, and approximately $8.3 million per year of the transmission shortfall through the TAC, each year until the next rate case.[122] CL&P's description of those mechanisms confirms this. Between rate cases, any shortfall in distribution revenue relative to CL&P's authorized revenue target would be recovered through the RDM, and CL&P proposes that the RDM rate "be set at a flat kWh rate across all rate classes."[123] Rate 39 and Rate 57 are both subject to the RDM per-kWh charge.[124] CL&P confirms that the RDM rate would be a single per-kWh rate

[118] CLF-SC Response to Data Request CIEC-1(a) and (b) and CIEC-12(c) of CIEC Set 2. $39.8 million + $17.4 million = $57.2 million.
[119] CLF-SC Response to Data Request CIEC-12(a) and (b) of CIEC Set 2.
[120] CLF-SC Response to Data Request CIEC-3(c) and CIEC-6(c) of CIEC Set 2.
[121] CLF-SC Response to Data Request CIEC-2(b) and (d) of CIEC Set 2.
[122] *Id.*
[123] Davis and Parsons Direct at 22, lines 16-21.
[124] Exhibit CLP-RATES-3 at 87 and 109.

applied to all rate classes, including Rate 39, Rate 57 and Rate 58.[125] Based on current billing determinants, Rate 1 bears only 38.8% of any RDM charge, while Rates 39, 57 and 58 together bear 13.7%.[126] Similarly, the TAC reconciles the transmission revenues billed to customers against CL&P's transmission costs "on a fully reconciling basis," applies to all customers taking delivery service, and, as proposed, is determined by dividing the transmission revenue requirement and any true-up by anticipated kWh sales.[127] In practice, however, CL&P first allocates the transmission revenue requirement, including any true-up, among rate class groups in proportion to their demands coincident with CL&P's twelve monthly system peaks, and only then converts each group's share to a per-kWh rate.[128] In other words, the distribution revenue that Rate HP fails to collect from heat pump customers would be recovered from all customers, including CIEC's members, on a per-kWh basis, which falls most heavily on high load factor industrial customers. The transmission revenue that Rate HP fails to collect would likewise be recovered from all rate classes, including those in which CIEC's members take service, in proportion to their demands at CL&P's monthly system peaks.

CIEC's members and other non-residential customers should not be required to fund a discount whose stated purpose is to address what Mr. Velez characterizes as a cross-subsidy "within the residential customer class."[129] Mr. Velez agrees. He states that no portion of the revenue reduction should be recovered from customers outside the residential class, and that he "would welcome" a requirement that it be recovered

[125] CL&P Response to Data Request CIEC-048(b) and (d) (Table 2). 1.3% + 4.1% + 8.3% = 13.7%.

[126] *Id.*

[127] Exhibit CLP-RATES-3 at 186-187.

[128] CL&P Response to Data Request UCONN-024(a)-(b), as referenced in CL&P Response to Data Request CIEC-049(a); CLF-SC Response to Data Request CIEC-2(d) and CIEC-8(a) of CIEC Set 2.

[129] Velez Direct at 5, lines 10-13.

solely from the residential class.[130] That result, however, would require affirmative action by the Authority, because, as Mr. Velez acknowledges, neither the RDM nor the TAC "currently works this way."[131] By contrast, the seasonal TOU rate proposed by OCC Witness Whited is designed to be revenue neutral with Rate 1.[132]

D. Winter Load Affects CL&P's Transmission Costs

Q MR. VELEZ CONCLUDES THAT HEAT PUMP LOAD IN WINTER CAUSES ESSENTIALLY NO TRANSMISSION COST. DO YOU AGREE?

A No. Mr. Velez estimates marginal transmission cost by spreading an avoided Pool Transmission Facility cost from the 2024 Avoided Energy Supply Components study across hours based on the probability of the New England system peak, which places that cost almost entirely in the summer.[133] That is not how CL&P incurs the transmission costs recovered through its retail transmission rates. As OCC Witness Whited notes, ISO-NE allocates transmission costs based on monthly coincident peak demand ("12CP").[134] Under a 12CP method, CL&P's share of regional transmission costs depends on its load at the time of the peak in each month, including each of the five winter months in which Rate HP would reduce the transmission service rate by 75%. Heat pump load that increases CL&P's monthly peak loads in the winter therefore increases the transmission costs allocated to CL&P, and the TAC passes those costs through to CL&P's retail customers. CL&P confirms that its RNS and Local Network Service charges are based on its network load at the time of each monthly peak, and that each 1 MW increase in that load increased its 2026 RNS charges by

[130] CLF-SC Response to Data Request CIEC-2(c), CIEC-3(b) and CIEC-16(b) of CIEC Set 2.
[131] CLF-SC Response to Data Request CIEC-2(d) of CIEC Set 2.
[132] Whited Direct at 29, lines 6-13.
[133] Velez Direct at 15, lines 5-10, and 16, lines 1-5.
[134] Whited Direct at 34, lines 18-20.

$14,802 per month.[135] Each MW of additional load at the monthly peaks of November through March would therefore add approximately $74,000 per year in RNS charges alone.[136] CL&P also allocates its retail transmission revenue requirement among rate classes using a 12CP allocator.[137] Mr. Velez agrees that ISO-NE bills CL&P for regional network service each month based on CL&P's load in a single peak hour of that month, "including in November through March," and that if CL&P's load in a January peak hour rises, CL&P "pays a larger share" of regional transmission costs.[138] He has not estimated the effect of heat pump adoption on CL&P's November through March monthly peak loads or on the transmission costs allocated to CL&P.[139]

Q DOES THE MASSACHUSETTS PRECEDENT MR. VELEZ CITES SUPPORT HIS TRANSMISSION PROPOSAL?

A No. According to the language Mr. Velez quotes, the Massachusetts Department of Public Utilities directed National Grid and Unitil to calculate their winter transmission charges "to recover the winter transmission revenue requirement over the adjusted winter sales."[140] That is a cost recovery approach under which winter transmission charges are designed to recover the transmission revenue requirement attributable to the winter. It is not a reduction of winter transmission charges to an estimate of marginal cost. Mr. Velez now concedes that the Massachusetts winter transmission charges "were designed to recover a winter transmission revenue requirement" and "were not set at an estimate of marginal transmission cost," and that he is not aware of

[135] CL&P Response to Data Request CIEC-050(a) and (c).
[136] $14,802 per month x 5 months = $74,010.
[137] CL&P Response to Data Request UCONN-024(a)-(b), as referenced in CL&P Response to Data Request CIEC-049(a).
[138] CLF-SC Response to Data Request CIEC-7(b) of CIEC Set 2.
[139] CLF-SC Response to Data Request CIEC-7(c) of CIEC Set 2.
[140] Velez Direct at 84, footnote 76.

any jurisdiction that has set a heat pump rate's retail transmission charge at an estimate of marginal transmission cost.[141] He also acknowledges that, in Massachusetts, revenue shortfalls from heat pump rates are recovered through company-wide reconciling mechanisms, so that part of them is paid by non-residential customers.[142] Similarly, the fact that Rate 5 has a transmission service rate about 3% lower than that of Rate 1[143] does not show that a 75% winter reduction for heat pump customers is cost-based.

E. Winter Distribution Costs Will Not Remain Near Zero

Q IS IT REASONABLE TO ASSUME THAT WINTER HEAT PUMP LOAD WILL CONTINUE TO CAUSE NEAR-ZERO DISTRIBUTION COSTS?

A No. Mr. Velez's conclusion depends on CL&P's distribution system remaining summer peaking with substantial winter headroom.[144] CL&P's marginal cost of service study, on which he relies, finds that CL&P will remain summer peaking only "through year 2031, which is the study period covered by the analysis."[145] Although CL&P does not currently project a transition to winter peaking within its ten-year forecast horizon, one of its substations already has winter and summer peaks on par, and CL&P plans to begin developing a substation-level winter peak load forecast with its 2028 forecast.[146] CL&P's marginal cost witness also cautions that "[i]n the longer-term, additional electrification will shift more cost responsibility to the winter evening hours."[147] Rate HP, combined with automatic enrollment, would deeply discount the very winter

[141] CLF-SC Response to Data Request CIEC-8(b) and (c) of CIEC Set 2.
[142] CLF-SC Response to Data Request CIEC-8(d) of CIEC Set 2.
[143] *Id.* at 83, lines 13-14. (5.050 - 4.901) / 5.050 = 3.0%.
[144] Velez Direct at 20, lines 9-12, 21, lines 1-8, and 22, lines 1-14.
[145] Nieto MCOS Direct at 6, lines 9-14.
[146] CL&P Response to Data Request CIEC-051(a) and (b).
[147] Nieto MCOS Direct at 19, lines 3-4.

load that would drive that shift. Once winter loads begin to drive distribution investment, heat pump customers would be paying winter distribution energy charges set at roughly 29% of Rate 1 levels for the load causing that investment.[148] Mr. Velez's recommendation to recalibrate Rate HP in later proceedings[149] does not address the costs that would be shifted in the interim, and rate discounts that customers have come to rely upon are difficult to unwind. Mr. Velez has not analyzed when CL&P's system, substations or feeders would become winter peaking, and he would not support a requirement that Rate HP automatically expire if winter loads begin to drive distribution capacity investment.[150]

F. Recommendations

Q WHAT DO YOU RECOMMEND WITH RESPECT TO MR. VELEZ'S PROPOSAL?

A The Authority should reject Rate HP. To the extent the Authority approves any heat pump rate in this proceeding, whether Rate 6 as proposed by CL&P, the seasonal TOU rate proposed by Ms. Whited, or another design, it should require that: (i) the rate be designed to be revenue neutral within the residential class; (ii) any revenue shortfall resulting from the rate be recovered solely from the residential class and not be shifted to other rate classes through revenue allocation, the RDM, the TAC or any other mechanism; and (iii) the transmission charges under the rate recover the transmission costs attributable to the customers taking service under it.

[148] 100% - 71% = 29%.
[149] Velez Direct at 7, lines 9-12.
[150] CLF-SC Response to Data Request CIEC-9(b) and (c) of CIEC Set 2.

IV. RESPONSE TO UCONN WITNESS PERKINS

Q PLEASE SUMMARIZE MR. PERKINS' RECOMMENDATIONS.

A Mr. Perkins makes two recommendations. First, he recommends that the Authority require CL&P to introduce a voluntary, opt-in CPT rate option for customers taking service under Rates 55, 56, 57 and 58.[151] A participating customer's monthly transmission demand charge would be based on its average 60-minute kW demand during CL&P's monthly peak load hour in the prior month, as determined for reporting Regional Network Service ("RNS") loads to ISO-NE. The customer's distribution, public benefits and supply charges would retain their existing billing determinants.[152] Second, he recommends that the Authority direct CL&P to examine time-of-day and seasonal differentiation of distribution demand charges for large customers.[153] I respond to each recommendation below.

Q WHAT IS YOUR RESPONSE TO MR. PERKINS' PROPOSED CPT RATE OPTION?

A I support the CPT rate option on the voluntary, opt-in basis Mr. Perkins proposes. As Mr. Perkins explains, and as I discuss in Section III.D, ISO-NE allocates regional transmission costs to CL&P based on its monthly coincident peak load, and CL&P's RNS charges equal the annual RNS rate multiplied by its Monthly Regional Network Load.[154] A transmission charge based on a customer's demand during CL&P's monthly peak hour mirrors how CL&P actually incurs the transmission costs it recovers from its customers. It also gives customers that are able to reduce their load during those hours a price signal to do so. Those reductions can lower the transmission costs allocated

[151] UConn Witness Perkins Direct at 15, lines 7-14, and 17, lines 4-10.
[152] *Id*. at 27, lines 5-11, and 28, lines 1-7.
[153] *Id*. at 15, lines 15-17.
[154] Perkins Direct at 11, line 19, through 12, line 2, and 19, lines 13-14; see also Whited Direct at 34, lines 18-20.

to CL&P and, in turn, the transmission costs recovered from all customers through the TAC. Offered as an option, the rate lets customers that can respond to that price signal do so, without forcing a change on customers that cannot.

However, I oppose any mandatory application of the CPT rate option, whether in this proceeding or a future one. Mr. Perkins suggests that the option should remain voluntary only "[u]ntil Eversource provides its RNS data publicly."[155] Better data would not solve the underlying problem. A CPT rate concentrates a customer's transmission charges on its load during just twelve hours each year. Many customers cannot control their load in those hours. Manufacturing processes that must run continuously or on fixed production schedules, facilities whose loads peak on the same hot summer afternoons or cold winter evenings that drive the monthly system peaks, and operations dictated by their own customers' demands would all see their transmission charges determined largely by circumstances beyond their control. For such customers, mandatory application could produce severe and unexpected bill increases, as well as transmission charges that swing from year to year depending on the timing of a few hours of load. Because the rate would recover the same transmission revenue requirement, any reduction in charges to customers that can shift load would be made up by customers that cannot. Those consequences could be severe enough to affect whether some customers can continue operating in Connecticut, which would in turn harm affordability for the customers who remain.

The Massachusetts precedent Mr. Perkins cites does not support mandatory application either. The only CPT rate he describes that applies automatically is Eversource's Rate T-5 in Western Massachusetts, which is limited to customers with maximum demands above 2,500 kW.[156] That rate design was proposed by those large

[155] Perkins Direct at 29, lines 12-14.
[156] Perkins Direct at 31, lines 9-17.

customers' own representative, and the Massachusetts Department of Public Utilities made it mandatory for only 20 customers, in part to obtain "useful data" to evaluate whether a broader redesign would be in the public interest.[157] In the more than ten years since, every expansion of the CPT rate design that Mr. Perkins describes has been voluntary and opt-in, including Eversource's Rate G-3 customers across Massachusetts, National Grid's Rate G-3 customers, Central Maine Power Company's non-residential customers and Liberty Utilities' Rate G-1 customers.[158] Mr. Perkins himself describes his voluntary proposal as "a prudent, measured first step."[159]

Accordingly, I recommend that the Authority approve the CPT rate option on a voluntary, opt-in basis, as Mr. Perkins proposes, and make clear that it will not be mandatory for any customer or rate class. Any future proposal to extend the rate beyond voluntary participation should be supported by a customer-specific bill impact analysis and considered in a proceeding in which all affected customers have notice and an opportunity to participate.

Q WHAT IS YOUR RESPONSE TO MR. PERKINS' RECOMMENDATION THAT CL&P STUDY ITS DISTRIBUTION DEMAND CHARGES FOR LARGE CUSTOMERS?

A I do not oppose the study Mr. Perkins describes. It would examine a time-differentiated distribution demand charge for Rates 55 through 58, including a 4 to 9 P.M. weekday on-peak period, as well as CL&P's eleven-month distribution demand ratchet and alternatives to it.[160] As with the equipment-level allocation study Ms. Whited proposes, however, the study should inform the Authority's decision, not determine it. Changes to the hours in which distribution demand is measured, or to the ratchet, could shift

[157] *Id*. at 35 (quoting D.P.U. 10-70-B at 5-7).
[158] *Id.* at 32, lines 3-4; 33, lines 7-18; and 34, lines 3-11 and 15-18.
[159] *Id*. at 28, lines 17-18.
[160] Perkins Direct at 43, lines 6-15.

substantial costs among customers within those classes and significantly increase bills for customers whose operations cannot be moved out of the new on-peak hours. Any proposal resulting from the study should therefore be supported by class and customer-specific bill impact analysis and considered in a future rate proceeding in which all affected customers have notice and an opportunity to participate. If changes are adopted, any material cost shifts should be phased in gradually.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

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The Connecticut Light and Power Company
d/b/a Eversource Energy
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Date Filed: November 09, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

With reference to the Panel's response to OCC-464, explain whether:

a. The term "large-scale computational loads" includes only data centers, or if it also may be applied to other non-residential loads.

b. There are specific criteria that Eversource uses to define what constitutes a "data center"? If the answer is in the affirmative, provide and explain the criteria.

Response:

a. The Company's response relied on "data center" as the context for what is meant by the term "large scale computational load" referred to.

b. There may be many different types of customers and loads whose characteristics fall within the classification of a data center. The State of Connecticut's Office of Legislative research report, "Data Center Energy Impacts and State Responses" refers to a description of a data center as, generally, "a physical facility that houses and runs large computer systems." The report further provides: "A data center typically contains multiple computer servers, data storage devices, and network equipment to store, manage, process, and transmit large amounts of data". [1] The term "large-scale" provides additional specificity regarding what might be attributable to a specific data center. As stated in response to OCC-464, the Company believes the appropriate treatment of such loads, including whether a specific rate or customer-specific terms are warranted should be determined through deliberations with state agencies when that load materializes.

[1] "Data Center Energy Impacts and State Responses", Connecticut General Assembly, Office of Legislative Research, 2025-R-0164, Mary Fitzpatrick, October 14, 2025.

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d/b/a Eversource Energy
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Date Filed: November 12, 2026

Witness: Jared A. Lawrence, Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the AMI Panel Testimony at page 15, lines 12-21.

a. Please provide the number of meters the Company expects to replace with AMI meters, by rate class (including Rate 39, Rate 57 and Rate 58).
b. Please provide the number of Rate 39, Rate 57 and Rate 58 customers whose existing meters record interval demand or energy data, and identify the type of meter installed for those customers.
c. Please state whether the meters of Rate 39, Rate 57 and Rate 58 customers that already record interval data will be replaced with AMI meters under the AMI Implementation Plan. If so, explain why replacement is necessary for those customers.
d. Please provide the average installed cost per meter, by rate class, of (i) the existing meters and (ii) the AMI meters the Company plans to install.

Response:

a. The table below presents the Company's best estimate of the number of meters that will be eligible for replacement with an AMI meter, disaggregated by rate class. These numbers are expected to change slightly based on population growth and technical limitations that prevent AMI meters for certain customer configurations that are not easily discernable from the rate class alone (such as the use of KYZ pulses or the need for real-time data).

Rate	Count
01	1,089,364
05	137,777
07	842
11	315
12	381
18	173
19	3
27	524
29	232
30	109,281
35	1,276

37	1,772
39	1
40	1,739
41	13
55	330
56	877
57	74
58	67
70	70
71	37
72	38
73	4
87	22,724

b. The table below lists the counts and various meter types on Rate 39, 57, and 58 that record interval data. There is some overlap between the meters on the table below and meters listed on the first table above because some interval meters will be eligible to move to AMI.

Rate	Meter Type	Count
39	A3 Meter	1
39	ION Meter	2
57	A3 Meter	71
57	ION Meter	4
57	KV2C Meter	1
58	A3 Meter	65
58	ION Meter	2
58	KV2C Meter	1

c. The Company will pursue installing AMI meters wherever possible for the Company and the customer to realize the benefits of AMI. With that said, these rates represent some of the largest electric delivery points that commonly include additional metering complexities such as totalization, KYZ pulses, real time data, or other contractual obligations. At a later date, the Company will evaluate all complex metering customers on a case-by-case basis to determine if AMI meters can meet the specific needs of each site/customer.

d. Please refer to CIEC-038 Attachment 1, CONFIDENTIAL, for the requested pricing information.

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Date Filed: November 16, 2026

Witness: Jared A. Lawrence, Douglas P. Horton, Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the AMI Panel Testimony at page 19, lines 1-6, and Exhibit CLP-AMI-3 at pages 16-17 (Figure 6).

a. Figure 6 shows $309.2 million of six-year capital for "Meters," consisting of $302.4 million for Meters and $6.8 million of Undepreciated Meter Balance. Please separate the $302.4 million into (i) meter equipment and (ii) meter installation labor and other costs, and identify the amount the Company expects to record in FERC Account 370.

b. For each cost category shown in Figure 6, please identify the FERC account or accounts in which the Company expects to record the capital investment.

c. Please identify the VVO Enablement facilities (e.g., substation and line equipment, software) included in the $97.3 million of six-year VVO Enablement capital shown in Figure 6, and state whether the Company proposes to recover those costs through the PBMRP as AMI costs or through another mechanism, and how it proposes to classify and allocate those costs to rate classes.

Response:

a. A full breakdown of the six-year capital for meters is shown in the table below[1]. Please refer to CLP-AMI-3 starting on page 108 for a complete breakdown of all capital.

6-Year Meters – Nominal Capital Cost	
Meters - Deployment	$208.8M
External Labor – Deployment	$51.8M
Internal Labor – Deployment Returns/Follow-ups	$7.0M
Meters – Replacements	$2.8M
Internal Labor - Replacements	$1.1M
Corporate Overhead	$3.8M
Contingency	$27.1M
Total	**$302.4M**

[1] Note: these are rounded figures.

The Company expects to record the full cost of the meter equipment, the cost to install, and all associated costs, including overhead costs and allocations, to FERC Utility Account 370 - Meters. Please see Table 1 below.

b. For each cost category shown in Figure 6, please see Table 1 below, which provides the Plant FERC Utility Account in which the Company expects to record the capital investment, once it is placed in service and unitized (final as built) to FERC Account 101010 (Electric Plant in Service).

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Cost Category	Capital Investment / O&M Expense	Plant FERC Utility Account
Meters	Meters	370 – Meters & Metering Equipment
Communications	Communications Upgrades	370 – Meters & Metering Equipment
Back Office Systems	Meter Data Management System (MDMS)	363.1 – Computer Hardware; 363.2 - Computer Software
	Customer Information System (CIS)	363.1 – Computer Hardware; 363.2 - Computer Software
	Load Settlement	363.1 – Computer Hardware; 363.2 - Computer Software
Labor and Standard Operating Plan	Organizational Readiness	363.1 – Computer Hardware; 363.2 - Computer Software
	Contact Center	363.1 – Computer Hardware; 363.2 - Computer Software
	Revenue Assurance (Non-Technical Line Loss)	363.1 – Computer Hardware; 363.2 - Computer Software
Supporting Services and Platforms	OMS Integration	363.1 – Computer Hardware; 363.2 - Computer Software
	Customer Experience Portal	363.1 – Computer Hardware; 363.2 - Computer Software
	Engineering and Customer Usage Analytics	363.1 – Computer Hardware; 363.2 - Computer Software
	Green Button Connect	363.1 – Computer Hardware; 363.2 - Computer Software
VVO Enablement	VVO Enablement	363.1 – Computer Hardware; 363.2 - Computer Software; 363.3 - Communication Equipment 368 - Line Transformers 362 - Station Equipment
Customer	Customer Engagement	N/A
Data	Cybersecurity	363.1 – Computer Hardware; 363.2 - Computer Software
	Data Storage and Processing	N/A

c. A listing of the VVO Enablement facilities is shown in the table below. As described in the Company's response to CIEC-040[i], the Company expects that AMI meter costs will be properly classified as customer-related costs, consistent with treatment of meter costs in the allocated cost-of-service study conducted and submitted in this docket as part of the Company's Rate Application. The Company's further expectation is that capital costs and expenses associated with AMI implementation would be collected from customers

consistent with allocation of costs and rate design allowed in this proceeding for distribution rates or another applicable rate mechanism.

6-Year VVO Enablement – Nominal Capital Cost	
Regulators	$37.5M
Capacitors	$27.3M
Transformer LTC Controller Upgrades	$16.0M
Integration - Software	$0.5M
Integration – External Labor	$1.0M
Integration – Internal Labor	$0.5M
Corporate Overhead	$0.5M
Contingency	$8.3M
AFUDC	$5.7M
Total	**$97.3M**

Prior Referenced Responses:

[i] CIEC-040 Question:

Please refer to the AMI Panel Testimony at page 20, lines 9-21.

a. Please confirm that, as stated at lines 9-11, the Company must be able to accurately and timely bill customers for service, and metering infrastructure is necessary to that end.
b. Please confirm that, as stated at lines 12-15, the Company expects to migrate to AMI as its existing AMR meters reach the end of their useful lives, regardless of the BCA results.
c. Please explain the statement at lines 18-20, that "optionality in taking advantage of many AMI benefits will be within the customer's control," and identify the AMI benefits in Exhibit CLP-AMI-3, to which that statement applies.
d. When AMI meter costs are reflected in base distribution rates, does the Company intend to continue classifying AMI meter costs as customer-related, consistent with its treatment of meter costs in the ACOS Direct Testimony at page 4, lines 5-7? If not, explain why not.

CIEC-040 Response:

a. Yes, the Company must always be in a position to bill customers for service on a timely and accurate basis and metering infrastructure is necessary to that end. However, the manner in which the Company achieves this objective can take several forms.
b. Based on the information available to the Company today, and the expectation that PURA and stakeholders' consideration of the AMI Implementation Plan would benefit from a comparison with an AMR lifecycle alternative approach, the Company presented an analysis of a hypothetical AMR end-of-life scenario in its BCA. Should PURA not grant approval of the Company's proposed AMI Plan, the Company would develop and consider alternative scenarios using the best information at that time, including an AMR end-of-life approach, in view of any additional guidance PURA provides in its order.
c. The quantified AMI benefits largely within customer control are associated with their choice of participation in Time-of-use/Time-varying Rates. The non-quantified benefits largely within customer control arise in

relation to their election to receive outage restoration notifications; their receptiveness to detailed billing data and notifications; and their receptiveness to load disaggregation insights.

d. Yes, the Company expects that AMI meter costs will be properly classified as customer-related costs, consistent with treatment of meter costs in the allocated cost-of-service study conducted and submitted in this docket as part of the Company's Rate Application. The Company's further expectation is that capital costs and expenses associated with AMI implementation would be collected from customers consistent with allocation of costs allowed in this proceeding for distribution rates or another applicable rate mechanism.

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d/b/a Eversource Energy
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Date Filed: November 13, 2026

Witness: Jared A. Lawrence, Douglas P. Horton, Edward A. Davis, Kimberly R. Parsons and Amparo Nieto
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the AMI Panel Testimony at page 20, lines 9-21.

a. Please confirm that, as stated at lines 9-11, the Company must be able to accurately and timely bill customers for service, and metering infrastructure is necessary to that end.

b. Please confirm that, as stated at lines 12-15, the Company expects to migrate to AMI as its existing AMR meters reach the end of their useful lives, regardless of the BCA results.

c. Please explain the statement at lines 18-20, that "optionality in taking advantage of many AMI benefits will be within the customer's control," and identify the AMI benefits in Exhibit CLP-AMI-3, to which that statement applies.

d. When AMI meter costs are reflected in base distribution rates, does the Company intend to continue classifying AMI meter costs as customer-related, consistent with its treatment of meter costs in the ACOS Direct Testimony at page 4, lines 5-7? If not, explain why not.

Response:

a. Yes, the Company must always be in a position to bill customers for service on a timely and accurate basis and metering infrastructure is necessary to that end. However, the manner in which the Company achieves this objective can take several forms.

b. Based on the information available to the Company today, and the expectation that PURA and stakeholders' consideration of the AMI Implementation Plan would benefit from a comparison with an AMR lifecycle alternative approach, the Company presented an analysis of a hypothetical AMR end-of-life scenario in its BCA. Should PURA not grant approval of the Company's proposed AMI Plan, the Company would develop and consider alternative scenarios using the best information at that time, including an AMR end-of-life approach, in view of any additional guidance PURA provides in its order.

c. The quantified AMI benefits largely within customer control are associated with their choice of participation in Time-of-use/Time-varying Rates. The non-quantified benefits largely within customer control arise in relation to their election to receive outage

restoration notifications; their receptiveness to detailed billing data and notifications; and their receptiveness to load disaggregation insights.

d. Yes, the Company expects that AMI meter costs will be properly classified as customer-related costs, consistent with treatment of meter costs in the allocated cost-of-service study conducted and submitted in this docket as part of the Company's Rate Application. The Company's further expectation is that capital costs and expenses associated with AMI implementation would be collected from customers consistent with allocation of costs allowed in this proceeding for distribution rates or another applicable rate mechanism.

The Connecticut Light and Power Company
d/b/a Eversource Energy
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Date Issued October 29, 2026
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Date Filed: November 16, 2026

Witness: Jared A. Lawrence, Douglas P. Horton, Edward A. Davis, Kimberly R. Parsons and Amparo Nieto
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to Exhibit CLP-AMI-3 at pages 17-18 (Figure 7) and pages 65-67.

a. Please separate the $162.4 million NPV "Improved Restoration – Significant Storms" benefit into (i) avoided Company storm restoration expense and (ii) the value of reduced customer outage time estimated with the interruption cost estimate calculator.

b. For the benefit quantified in part (a)(i), please explain how storm restoration costs are classified and allocated to rate classes in the Company's ACOSS or recovered through the Company's storm cost recovery mechanisms.

c. Please state whether the Company has quantified any of the benefits in Figure 7 by rate class. If so, provide the quantification, including for Rate 39, Rate 57 and Rate 58.

d. Please identify any benefit in Figure 7 that the Company expects to be realized by Rate 39, Rate 57 or Rate 58 customers, and explain the basis for that expectation.

Response:

a) Out of the $162.4M NPV, an estimated $157.20M NPV is associated with avoided storm-restoration expenses and an estimated $5.18M NPV is associated with reduced customer outage time. This is broken down as Business-As-Usual Costs, Benefit Targets and Annual Benefit Calculation. Please refer to CLP-AMI-3, page 69, subsection (c) to see a breakdown of calculations - also shown below.

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c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline Significant Storm Restoration Expense Costs	Baseline Significant Storm Customer Outage Costs	Baseline Total	Significant Storm Avoided Costs from Improved Restoration	Significant Storm Customer Outage Savings from Improved Restoration	Benefit Total
Year 1	$215.79	$42.58	**$258.37**	$0.00	$0.00	**$0.00**
Year 2	$220.11	$44.08	**$264.19**	$0.00	$0.00	**$0.00**
Year 3	$224.51	$45.64	**$270.15**	$2.95	$0.10	**$3.04**
Year 4	$229.00	$47.25	**$276.25**	$9.01	$0.30	**$9.31**
Year 5	$233.58	$48.92	**$282.50**	$15.32	$0.50	**$15.83**
Year 6	$238.25	$50.64	**$288.89**	$18.76	$0.62	**$19.37**
Year 7	$243.02	$52.43	**$295.45**	$19.13	$0.63	**$19.76**
Year 8	$247.88	$54.28	**$302.16**	$19.51	$0.64	**$20.16**
Year 9	$252.83	$56.20	**$309.03**	$19.90	$0.66	**$20.56**
Year 10	$257.89	$58.18	**$316.07**	$20.30	$0.67	**$20.97**
Year 11	$263.05	$60.24	**$323.28**	$20.71	$0.68	**$21.39**
Year 12	$268.31	$62.36	**$330.67**	$21.12	$0.70	**$21.82**
Year 13	$273.67	$64.56	**$338.24**	$21.54	$0.71	**$22.25**
Year 14	$279.15	$66.84	**$345.99**	$21.98	$0.72	**$22.70**
Year 15	$284.73	$69.20	**$353.93**	$22.42	$0.74	**$23.15**
Year 16	$290.43	$71.65	**$362.07**	$22.86	$0.75	**$23.62**
Year 17	$296.23	$74.17	**$370.41**	$23.32	$0.77	**$24.09**
Year 18	$302.16	$76.79	**$378.95**	$23.79	$0.78	**$24.57**
Year 19	$308.20	$79.50	**$387.71**	$24.26	$0.80	**$25.06**
Year 20	$314.37	$82.31	**$396.68**	$24.75	$0.81	**$25.56**
20-Year Total	$5,243.14	$1,207.83	**$6,450.98**	**$351.64**	**$11.58**	**$363.22**
20-Year NPV	$2,658.55	$592.44	**$3,250.99**	**$157.20**	**$5.18**	**$162.37**

For a full breakdown of "Improved Restoration – Significant Storms" please refer to CLP-AMI-3, page 65, Section (b)(6) – Early Outage Detection which explains the calculation methodology, inputs, and assumptions on how these figures are created.

b) The average annual amortization expenses related to storm restoration (equal to $211.177 million for Rate year 1) were included in Exhibit ACOS CLP-Exhibit-2 (Confidential), Table 9. These costs were treated as the rest of other amortization expenses and were allocated to rate classes according to the allocations of total rate base by class. Therefore, classification between demand and customer-related implicitly followed the same classification as the sum of the components that make up the overall rate base.

c) As provided in Exhibit CLP-AMI-3, including referenced sections and pages 85-92, the Company has quantified and provided descriptions of benefits on a customer-class level

and with respect to advanced rate design that would extend to various components of service at a rate class and individual customer level, but not for these specific rate classes.

d) Please refer to the Company's response in subpart (c).

The Connecticut Light and Power Company
d/b/a Eversource Energy
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Set CIEC-09
Date Issued October 29, 2026
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Date Filed: November 12, 2026

Witness: Amparo Nieto
Request from: Connecticut Industrial Energy Consumers

Question:
Please refer to the ACOS Direct Testimony at page 6, lines 1-10.

a. Please explain how the demand allocators for primary and secondary distribution facilities exclude the loads of customers that take service at primary or transmission voltage from the allocation of facilities at lower voltage levels.
b. Please provide the class NCP demands used for each demand allocator, by voltage level.
c. Please identify the number of Rate 39 customers served at each delivery voltage and the number of Rate 57 customers served at each delivery voltage.

Response:

a. The demand allocators for Primary facilities include the total distribution class NCP corresponding to each class. The demand allocators for the Secondary facilities exclude the portion of the NCP load associated with customers served at Primary; this is approximated using the ratio of secondary customers to total distribution customers in the class. All of the demand allocators refer to NCP of customers that take service at distribution level; no NCP for transmission-connected customers was included.

b. The class NCP demands used for each demand allocator by voltage level are included in Exhibit CLP ACOS-2 Confidential, in tab "*Appendix 1.B Allocator_Input"*. See rows 20 and 21, for allocators "NCP_P" and "NCP_S", respectively.

c. The number of Rate 39 distribution customers is 3, all served at Primary. The number of Rate 57 distribution customers is 72, all served at Primary voltage

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Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the Rates Panel Testimony at page 30, lines 6-12.

a. Please identify each non-distribution component of the rates applicable to large commercial and industrial customers that the Company considers time-varying and that, as stated at lines 6-8, "provide additional incentive and opportunity for customer benefit through efficient utilization of electric service."
b. Please state the Company's position on a requirement that EDR participants take service under a new TOU rate with time-differentiated distribution, transmission and generation charges that has not yet been designed or approved, and explain the basis for that position.
c. Please state whether the Company's billing system can currently bill an EDR participant's incremental load under a different rate structure than the participant's pre-existing load.

Response:

a. The transmission, non-bypassable FMCC, CTA and energy supply components of service are all priced on a time-varying (time-of-day) basis. While supply rates depend on whether a customer takes Last Resort Service or competitive supply, these time varying structures are mandatory for larger customers who would take service under the EDR (e.g., Rate 55-Rate 58).

b. To the extent such rate is a general service rate and is the only option compared with existing offerings (that would continue to be available or applicable in the future), it would seem, hypothetically, it would be inevitable that a future EDR participant would be on a time-differentiated rate offering, one way or another (noting, the context of the question contemplates distribution as a time-varying rate, which currently applies for only intermediate, large and MHD EV TOU rate customers).

c. Billing capabilities are currently limited in this regard. The Company performs special handling (i.e., manual) billing for Rate 39 customers, where load is bifurcated, analyzed in detail, and billed under two different rate structures.

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Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the Rates Panel Testimony at page 29, lines 1-12, and page 31, lines 5-6, and Exhibit CLP-RATES-3 at pages 38-40.

a. Please identify any transmission or supply cost associated with an EDR participant's incremental load that the Company expects would be borne by customers other than the EDR participant, and explain why.
b. Please confirm that, under the Terms and Conditions for Electric Suppliers at pages 38-40 of Exhibit CLP-RATES-3, the hourly load of an EDR participant, including its coincident peak capacity values, would be assigned to the participant's electric supplier (including Standard Service or Last Resort Service) for ISO-NE settlement.
c. Please state whether interconnection, system upgrade or make-ready costs paid directly by an EDR participant (including through a contribution in aid of construction) would be included as a cost of serving the incremental load in determining whether revenues exceed incremental cost of service or in determining the discount cap.

Response:

a. The referenced Rates Panel Testimony on pages 29 and 31 refer to Distribution Service. The charges for transmission and supply for the incremental load of an EDR participant would be the responsibility of that participant, consistent with the applicable rate schedule for service to such participant, and with the applicable provisions of the Company's terms and conditions of service, including those cited in Exhibit CLP-RATES-3.

b. The Company expects that the future provisions of the referenced terms and conditions, and the application of those provisions in determining hourly load and electric supplier assignment would apply in a like manner as current practice, absent any changes in proposed terms and conditions relative to current terms and conditions, or to future practices as applied to an individual customer's electric supplier service arrangement or in supplier load assignment methodologies.

c. Yes. Determination of the portion of upfront costs paid by the EDR participant would be included in the evaluation to determine the level of discount. This can also be viewed as; the level of discount would have a bearing on the portion of such costs that would be paid directly by the participant.

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Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the Rates Panel Testimony at page 24, lines 18-22, and page 25, lines 1-8.

a. Please state whether the Company has a definition of "data center" or "large-scale computational load" that it would use to determine whether a customer's load is data center load. If so, provide it.
b. Please identify the number of inquiries the Company has received since January 1, 2024 regarding new or expanded load from (i) data centers and (ii) manufacturing or other industrial customers, by size range.

Response:

a. Please see the Company's response to CIEC-036[i].

b. Such information is not readily available.

Prior Referenced Response:

[i] CIEC-036 Question:

With reference to the Panel's response to OCC-464, explain whether:

a. The term "large-scale computational loads" includes only data centers, or if it also may be applied to other non-residential loads.
b. There are specific criteria that Eversource uses to define what constitutes a "data center"? If the answer is in the affirmative, provide and explain the criteria.

CIEC-036 Response:

a. The Company's response relied on "data center" as the context for what is meant by the term "large scale computational load" referred to.

b. There may be many different types of customers and loads whose characteristics fall within the classification of a data center. The State of Connecticut's Office of Legislative research report, "Data Center Energy Impacts and State Responses" refers to a description of a data center as, generally, "a physical facility that houses and runs large computer systems." The report further provides: "A data center typically contains

multiple computer servers, data storage devices, and network equipment to store, manage, process, and transmit large amounts of data". 1 The term "large-scale" provides additional specificity regarding what might be attributable to a specific data center. As stated in response to OCC-464, the Company believes the appropriate treatment of such loads, including whether a specific rate or customer-specific terms are warranted should be determined through deliberations with state agencies when that load materializes.

[1] "Data Center Energy Impacts and State Responses", Connecticut General Assembly, Office of Legislative Research, 2025-R-0164, Mary Fitzpatrick, October 14, 2025

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Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to the Rates Panel Testimony at page 22, lines 14-21.

a. Please confirm that any shortfall in actual distribution revenue relative to the authorized revenue target, regardless of its cause, would be reconciled through the RDM.
b. Please confirm that, as proposed, the RDM rate would be a single per-kWh rate applied to all rate classes, including Rate 39, Rate 57 and Rate 58.
c. For each of the Company's last three RDM reconciliation filings, please provide the total RDM amount and the amount recovered from or credited to each rate class, including Rate 39, Rate 57 and Rate 58.
d. Please explain how a reduction in distribution revenue resulting from a heat pump rate, such as Rate 6 or Rate HP, would be recovered between rate cases, and identify the share that would be recovered from non-residential rate classes.

Response:

a. Differences in revenue between actual and target, and flow through of such differences for charges or credits through the RDM are subject to a prudence review and authorization by PURA.

b. Yes, as proposed and as is currently designed, the RDM rate would be a single per-kWh rate applied to all rate classes, including Rate 39, Rate 57 and Rate 58.

c. Please refer to Table 1 for the requested information, which has been provided in previous RAM filings:

Table 1

	2024 (DN 24-01-03)	2025 (DN 25-01-03)	2026 (DN 26-01-03)
Rate 1	$15,426,873	$7,990,329	$870,234
Rate 5	$3,256,347	$1,686,621	$183,691
Rate 7	$10,701	$5,543	$604
Rate 18	$1,443	$748	$81
Rate 27	$165,744	$85,847	$9,350

Rate 29	$5,296	$2,743	$299
Rate 30	$6,662,626	$3,450,898	$375,840
Rate 35	$1,188,616	$615,642	$67,050
Rate 37	$2,299,083	$1,190,807	$129,692
Rate 40	$196,280	$101,663	$11,072
Rate 41	$29,925	$15,500	$1,688
Rate 55	$1,211,754	$627,627	$68,355
Rate 56	$3,534,218	$1,830,544	$199,366
Rate 57	$1,638,061	$848,431	$92,403
Rate 58	$3,291,659	$1,704,911	$185,683
Rate 115	$105,636	$54,714	$5,959
Rate 116	$150,310	$77,853	$8,479
Rate 117	$60,300	$31,232	$3,402
Rate 39	$534,357	$276,770	$30,143
Rate 119	$13,940	$7,220	$786
Total	**$39,783,171**	**$20,605,642**	**$2,244,179**

d. Please refer to the Company's response to OCC-473[i]. The Company has not proposed a Rate HP. Please refer to Table 2 below for the allocation percentage of the RDM rate based on billing determinants currently in effect.

Table 2

Rate	Allocation %
1	38.8%
5	8.2%
7	0.03%
18	0.0%
27	0.4%
29	0.01%
30	16.7%
35	3.0%
37	5.8%
40	0.5%
41	0.1%
55	3.0%
56	8.9%
57	4.1%
58	8.3%

115	0.3%
116	0.4%
117	0.2%
39	1.3%
119	0.04%
Total	100.0%

Prior Referenced Response:

[i] OCC-473 Question:

(Rate 6 – Residential Space Heating Rate) Refer to Exhibit CLP-RATES-1, at 23-24. Please state whether the Revenue Decoupling Mechanism is designed to capture any revenue shortfall arising from Rate 6 enrollment diluting Rate 1 revenues. If so, explain how Rate 6-driven revenue loss will be treated under the RDM and which customer classes ultimately bear that cost.

OCC-473 Response:

The Revenue Decoupling mechanism is designed to reconcile differences in aggregated (i.e.,. total) actual vs. targeted revenues, and not specifically to capture such revenue shortfall that may occur. While the question does not define or explain what is meant by diluted revenues, if the context of an assumed difference in revenue is due to the migration of Rate 1 customers to Rate 6, such migration may in a given month result in higher revenue for first block kWh sales, and lower revenue for second block kWh sales, which potentially include both kWh sales that would otherwise have been charged under Rate 1 and kWh sales associated with incremental, new heat pump load. The Company does not agree that Rate 6 enrollment which reflects increased kWh sales would reduce overall revenue compared with revenue under Rate 1 which would exclude such increased kWh sales.

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Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to Exhibit CLP-RATES-3 at pages 186-187 (Transmission Adjustment Clause).

a. Please describe how the Company allocates its transmission revenue requirement among rate classes in setting retail Transmission Service Rates, and provide the allocation factors used for the rates proposed in this proceeding.
b. Please explain the basis for the difference between the proposed Transmission Service Rates for Rate 5 and Rate 1.
c. Please explain how any under-collection of transmission revenue from a particular rate schedule is recovered through the TAC reconciliation, and state whether it is recovered from all rate classes.
d. Please explain how an under-collection of transmission revenue resulting from a 75% reduction in the winter (November through March) Transmission Service Rate for heat pump customers, as proposed for Rate HP, would be recovered.

Response:

a. Please refer to the Company's response to UCONN-024[1] for the requested information.

b. The respective allocation of costs and rate design for these rate classes are dependent on their specific demand allocation factors and billing determinants, which in combination can result in a material difference in the rate per kWh of the Transmission service rates in each rate class.

c. Please refer to the Company's response to UCONN-024 for the requested information.

d. The Company has not proposed a Rate HP. For its alternative space heating rate, Rate 6, the Company has not proposed a percentage reduction to transmission rate. The allocation of cost responsibility, and setting of the transmission rate for such service would be based on that class's transmission cost allocation and rate design, as applied in developing the transmission rate for Rate 1.

Prior Referenced Response:

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[i] UCONN-024 Question:

(Affordability & Customer Engagement) Refer to Exhibit CLP-ELP-1 at pp. 25-26 which states that "transmission costs are shared across the region" and are "proportionally allocated" to Connecticut. Exhibit CLP-RATES-3 at pp. 186-187 describes the overall calculation of the total Transmission Adjustment Clause ("TAC").

a. Please explain the formula and methodology used to apportion the total costs of transmission across customer classes in the Connecticut service territory.
b. Please explain how this methodology is consistent with cost-causation and fairness principles.
c. For each of Rates 55, 56, 57, and 58, please provide (i) the percentage of total TAC revenue allocated to each rate class, and (ii) the total dollar amount of TAC revenue collected from each rate class, in each case for the most recent TAC reconciliation period.

UCONN-024 Response:

a. Please refer to UCONN-024, Attachment 1, for the Transmission exhibits provided in the Company's most recent RAM filing, Docket No. 26-01-03.

- Page 1 shows the determination of the average Transmission rate on line 31.
- Page 2 shows the time-of-use breakout for applicable rate classes.
- Page 3 shows a comparison versus the current and proposed Transmission rates by rate class.
- Page 4 shows the Transmission Allocation. The Transmission Revenue Target (cell F13) is calculated by multiplying the average Transmission rate from page 1 by the Rate Year total sales. This Revenue Target is allocated to each rate class based on a 12 CP kW Demand Allocator (Columns C and D).

b. The Company uses a 12 coincident peak ("12 CP") allocation factor to assign transmission revenue requirements to rate schedules. This methodology is designed to reflect the methodology used in the development of the NEPOOL OATT revenue requirement and the resulting charges billed to the Company for transmission service under that tariff. From this perspective, the allocation is a "financial" nature, in that it is based only on the amount billed to the EDC's (noting, it is the amount billed first to the transmission service customer and then allocated to CL&P that is used for determining the corresponding class allocation.

   Despite the diversity of customer loads that make up the monthly peak, or the load levels or utilization of the transmission system by individual customers throughout all other hours of a given month, where such demands may be greater than during the system peak, it is only the single monthly peak that is applied using this allocation method). Unlike with a resource-based distribution cost allocation, the billed transmission charge is what is being allocated. Under the current paradigm, the allocated charges and coincidence of demand for determining the share of load contributing to such charges provides a reasonable basis for allocation of costs. To the extent consideration is given to alternative approaches for class cost allocation, a review of underlying costs and consideration of utilization of the system that such charges represent might be of interest with regarding to equitable allocation, along with other rate design principals to evaluate.

c. Please refer to UCONN-024, Attachment 1, for the requested information.

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Date Filed: November 12, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Connecticut Industrial Energy Consumers

Question:

Please refer to Exhibit CLP-RATES-3 at page 186 (Transmission Adjustment Clause), which refers to "the transmission costs of acquiring such services."

a. Please identify the billing determinants ISO-NE uses to assess Regional Network Service and Local Network Service charges to the Company, including whether those charges are based on the Company's network load at the time of the monthly peak.
b. Please provide the Company's monthly network load used to determine Regional Network Service charges for each month from January 2023 through the most recent month available.
c. Please provide the Company's estimate of the change in its annual Regional Network Service charges that would result from a 1 MW increase in its network load at the time of the monthly peak in each of the months of November through March.

Response:

a. CL&P's monthly regional network load reported to ISO-NE is derived from its network load at the time of the monthly transmission peak. Both the Regional Network Service (RNS) and Local Network Service (LNS) charges use this peak-load billing determinant multiplied by the applicable RNS and LNS rates applied to calculate the respective charges each month.

b. The following table provides the monthly network load used to determine Regional Network Service charges for January 2023 to September 2026.

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CL&P's Monthly Peak Network Load (MW)

Month	2023	2024	2025	2026
January	3,037	3,319	3,588	3,628
February	3,509	3,046	3,423	3,702
March	2,849	2,702	3,068	3,271
April	2,807	2,677	2,734	2,949
May	2,545	3,098	2,524	3,617
June	3,460	4,340	4,955	4,322
July	4,292	4,523	4,734	4,831
August	3,671	4,318	4,095	4,421
September	4,521	2,972	3,169	3,510
October	2,994	2,532	2,768	
November	3,026	2,726	2,915	
December	3,027	3,456	3,541	

c. Based on the annual RNS rate, a 1 MW increase in CL&P's monthly network load would increase the RNS charges as follows:

- 2023: $11,804 per month.
- 2024: $12,863 per month.
- 2025: $15,440 per month.
- 2026: $14,802 per month.

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Date Filed: November 13, 2026

Witness: Lavelle A. Freeman, Gerhard Walker, Juan F. Martinez and Amparo Nieto
Request from: Connecticut Industrial Energy Consumers

Question:
Please refer to the MCOS Direct Testimony at page 6, lines 9-14; page 18, lines 4-13; and page 19, lines 1-4.

a. Please provide any analysis or forecast the Company has of when its system, or individual bulk or distribution substations, would become winter peaking as a result of heat pump adoption, including for years after 2031.
b. Please identify the bulk substations that experienced an annual peak load in December or January in any of the years 2022 through 2025.
c. Please provide the heat pump adoption assumptions used in the MCOS study's analysis of load shapes through 2031.
d. Please explain the statement at page 19, lines 3-4, that "[i]n the longer-term, additional electrification will shift more cost responsibility to the winter evening hours," including the time frame the Company expects.

Response:

a. The Company has not developed a substation-level forecast that identifies when its system or individual substations would transition to winter peaking as no such transition is currently projected to occur within the 10-year forecast horizon. However, starting with the 2028 vintage forecast, the Company is planning to develop a stand-alone substation-level winter coldest day load forecast.

b. The Company currently has only one substation where winter and summer peak are on par and no substations where the winter peak exceeds the summer. The station in question is in Waterbury.

c. Ms. Nieto used ISO-NE's 2026 CELT Report assumptions of heat pump winter peak MW additions for the state of CT (tab 1.7, *Table 3 Winter Peak*). ISO-NE estimates a winter peak load impact of 224 MW by 2030/31. The MCOS used 80% of that value (179.2 MW) reflecting the portion of the state load that is in Eversource's service area, as the highest hourly electrification load expected in Eversource by the 2030/31 winter.

d. Ms. Nieto's referenced statement in her direct testimony is alluding to the expected impact of increased adoption of heat pumps for space heating on hourly load shapes over time. The load profile for space heating used in the MCOS analysis assumes electric space

heating will increase winter loads in all 24 hours, but more markedly in the morning, between 5 and 8 am, followed by a less noticeable but still impactful increase in the evening hours after about 5 pm. The referenced statement in her testimony emphasizes the winter evening hours because the focus of her analysis is the next five years, and currently the highest winter loads occur in the evening of the coldest winter months of December and January. In the near term, the winter evening loads will hold higher cost responsibility relative to the winter morning, though this situation will begin to reverse after 2031.

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Date Filed: September 15, 2026

Witness: Edward A. Davis, Kimberly R. Parsons, Matthew Nelson and Michael Goldman
Request from: Office of Consumer Counsel

Question:

(Economic Development Rate Rider) Please clarify whether the following customer types would be able to qualify for the proposed EDR:

a. Customers with large-scale computational loads (i.e., data center);
b. Customers connected to the transmission system;
c. Customers switching from natural gas to electricity, such as for process heating load.

Response:

a. Customers with large-scale computational loads (i.e., data centers) are not categorically excluded from the Economic Development Rate ("EDR"), nor are they categorically eligible. Any customer seeking to participate in the EDR will be evaluated to determine if they meet the requirements to qualify for service under the EDR and to ensure that their participation continues to provide affordability benefits to customers. Part of future considerations would be whether a specific rate for data centers makes sense or whether it may be beneficial to consider customer-specific characteristics when determining rates for potential data center customers. The load must be new or incremental, the incremental distribution revenue must exceed the incremental cost to serve, the discount is subject to the cap tied to incremental distribution revenue, and the customer remains responsible for interconnection and system upgrade costs.

   As previously noted in OCC-465, there are currently no active requests or firm commitments for data center load on the Company's distribution system. The Company recognizes that large computational loads raise broader policy questions, and if there are future requests for data centers to take service from the Company, the Company would work closely with the state on potential rates specific to large-scale computational loads. Understanding that there are larger policy implications associated with data centers, the Company believes it is best to carefully deliberate, with input from the relevant state agencies and stakeholders, on how to determine a rate for data centers that is mutually beneficial for the state, the interconnecting customer, and the Company, and ensures that existing customers are not harmed.

b. The EDR discount applies to charges for the Distribution component of service (Exhibit CLP-RATES-1, at 30). Customers connected at the transmission voltage take minimal distribution service, and the EDR therefore may have little practical applicability to such customers. The Company has not proposed discounts to transmission, supply, or public benefits components of service, and transmission service to such customers would continue under otherwise applicable retail rates.

c. Customers switching from natural gas to electricity, such as for process heating load, may be eligible for this rate but would be evaluated on a case-by-case basis if the load is new or incremental and the customer satisfies all other requirements of the rider. Fuel switching may be an appropriate criterion to evaluate for consideration in discounted distribution rates, and is one potential scenario where the customer may be bringing new, incremental electric load to the system and would be applied to a fuel-switching customer on the same basis as any other applicant. Note that the primary evaluation contemplated in the proposed EDR is on the distribution service requirement and corresponding cost to provide such service.

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Date Filed: September 08, 2026

Witness: Edward A. Davis, Kimberly R. Parsons and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

(Economic Development Rate Rider) Please provide the anticipated capacity of data center load additions in the Company's service territory each year for the next 10 years.

a. Provide separate estimates for load requests and firm commitments.
b. Provide any analysis the Company has conducted on the extent to which the anticipated data center load impacts system costs and customer bills. Include associated workpapers in live Excel format with all formulas intact.

Response:

a. There are currently no active requests or firm commitments for data center load additions within the Company's distribution system.

   With regards to "Requests," while Eversource does record requests for future customer connected loads, these include significant speculative inquiries by customers, the Company does not include them in any forecasts for substation capacity needs and has not budgeted any funds in direct support of these projects until a signed workorder is in-hand and design deposits have been made. Based on the Company's historical experience many of these projects fail to materialize and, to avoid unnecessary costs and inefficiency, the Company does not dedicate or plan capacity for these projects until such time as a firm commitment is received from the customer.

   Requests or firm commitments for data center load additions within the transmission system are excluded.

b. This is not applicable as there are currently no active requests or firm commitments for data center load additions within the Company's distribution system. Such calculations are not feasible until the project specifics are known, including costs to interconnect and revenue credits -- all off which are highly dependent on a given project.

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OCC-475
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Date Filed: September 08, 2026

Witness: Edward A. Davis and Kimberly R. Parsons
Request from: Office of Consumer Counsel

Question:

(Rate 6 – Residential Space Heating Rate) Refer to Exhibit CLP-RATES-1, at 35-36, which acknowledges that incremental load from EV charging can also benefit from the Rate 6 discount for usage above 700 kWh.

a. Was the discount sized to account for this "free rider" effect? If so, how? If not, why not?
b. What percentage of Rate 6 enrollees does the Company expect to also have EV charging load?
c. Has the Company modeled the revenue impact if a significant share of Rate 6 bill savings is attributable to EV charging rather than heat pump load? If so, provide the associated workpapers in live Excel format with all formulas intact. If not, why not?

Response:

a. Yes. The Winter Block 2 rate for Rate 6 is based on marginal distribution costs and a reconciling adjustment that effectively marks up the rate on an average load basis to ensure an additional share of demand related distribution costs are charged to incremental load (please refer to the Company's response to OCC-474[i]). As a prerequisite to the rate, a customer must add new heat pump load not already included in the underlying revenue requirement applied in the rate design for Rate 1. By moving fixed cost recovery into the customer charge and the "tier 1" volumetric rates for Distribution, the Winter Block 2 rate that applies to incremental load, whether primarily for the heat pump load or secondarily any other incremental load, we are pricing that block based on, but above marginal cost to ensure positive contribution to distribution costs. Pricing for other components of service including transmission, public benefits and supply are unchanged relative to Rate 1. This helps mitigate the free rider effect.

b. The Company does not have such an estimate.

c. The Company has not conducted such an analysis. The workpapers provided in Exhibit CLP-RATES-6 may be utilized to estimate bill impacts for various levels of usage, which may be assumed to include incremental heat pump and EV charging load.

Prior Referenced Response:

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[i] OCC-474 Question:

(Rate 6 – Residential Space Heating Rate) Please explain how the two volumetric discount levels (4.7 cents/kWh for heating season usage above 700 kWh and 2.8 cents/kWh for all other usage) were derived. Specifically:

a. Were the discounts calibrated to the incremental cost of serving heat pump load? If so, please provide the calculation and workpapers in live Excel format with all formulas intact. If not, why not?
b. Did the Company consider other discount levels? If so, explain the alternatives considered and why they were ruled out. If not, why not?

OCC-474 Response:

a. Please refer to Exhibit CLP-RATES-6, at page 2. An Excel version of that exhibit was provided as part of the Company's filing. Costs and the associated proposed incremental load rate is calibrated with the marginal cost of providing service, as detailed on page 2 of the exhibit.

b. Please note, the Company did not develop the 2.8 cents/kWh rate as a discount from the 4.7 cents/kWh rate, so no other level of discount was considered. Rather, the Winter Block 2 Rate is based on the marginal cost of service and reconciling adjustments that allocate a proportional share of the corresponding volumetric rate, as detailed in Exhibit CLP-RATES-6, at page 2.

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Set OCC-25
Date Issued October 05, 2026
OCC-932
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Date Filed: October 19, 2026

Witness: Edward A. Davis, Steven Lamontagne and Kimberly R. Parsons
Request from: Office of Consumer Counsel

Question:

(ECONOMIC DEVELOPMENT RATE) Refer to Exh. CLP-RATES-1, at 29.

a. Please explain what equipment is included in the "interconnection, system upgrade, or make-ready costs" for which EDR customers would be responsible (e.g., substations, transformers, conductors, etc.).
b. If upgrades to shared infrastructure, such as substations, are required, explain how the costs of the upgrades are recovered.

Response:

a. Customers would be responsible for all costs associated with the installation of a new service pursuant to the Company's new business policies. These costs are determined when such applications are made to the Company and would vary depending on the site conditions and work required for each location. Discounted revenues contemplated under the term of an EDR would be considered in the context of any CIAC or similar evaluation for a prospective EDR applicant.

b. Such upgrades and the recovery of costs would be considered pursuant to the Company's new business policy guidelines and any other considerations at the time of application for service.

Conservation Law Foundation and Sierra Club
PURA Docket No. 26-05-10
Set CIEC-02
Date Issued: October 29, 2026
CIEC-001
Page 1 of 6

Date Filed: November 16, 2026

Witness: **Juan-Pablo Velez**
Request from: **Connecticut Industrial Energy Consumers**

Question CIEC-1:

Please refer to Velez Direct Testimony at page 6, lines 11-23; page 7, lines 1-12; and page 81, lines 10-16.

a. Please provide Mr. Velez's estimate of the total annual reduction in (i) distribution revenue and (ii) transmission revenue that the Company would collect under Rate HP, relative to Rate 1, for each of the first five years after Rate HP takes effect. Provide all workpapers in Excel format with formulas intact.

b. Please provide Mr. Velez's estimate of the number of existing heat pump customers who would be automatically enrolled in Rate HP, and identify the source of that estimate.

c. Please provide Mr. Velez's estimate of the number of customers who would be newly enrolled in Rate HP in each of the first five years after it takes effect, and identify all assumptions used.

d. If Mr. Velez has not prepared the estimates requested in parts (a) through (c), please explain why not.

Response:

a. The revenue reduction that would result from heat pump customers enrolling in Rate HP rather than Rate 1 depends largely on whether PURA decides to auto-enroll known customers who already have heat pumps ("existing heat pump customers") and are currently overpaying under Rate 1. Customers who currently heat with fossil fuels and choose to install heat pumps in the future ("new heat pump customers") and are automatically switched from Rate 1 to Rate HP at the time of installation would actually produce slightly more revenue for the Company upon enrolling in Rate HP, on average, not less.

1. **Existing heat pump customers**: When Massachusetts rolled out seasonal heat pump rates comparable to Rate HP, its investor-owned utilities auto-enrolled more than 100,000 customers who had received heat pump rebates through Mass Save in the first year.[1] If PURA decides to follow suit by asking the Company to auto-enroll every customer who has received a heat pump rebate through Energize CT, as I recommend in my testimony, I estimate that about 55,000 of the Company's existing heat pump customers would be switched from Rate 1 to Rate HP in a one-time mass auto-enrollment (see part (b) for details on that estimate). If that enrollment occurs in 2027, the Company would collect **$39.8 million** less in distribution and **$17.4 million** less in transmission that year, and approximately the same amount less every year thereafter.

   These customers who would be auto-enrolled in this scenario already have heat pumps and are presently enrolled in Rate 1. This means they are already overpaying for T&D under Rate 1, by an

[1] NEEP, *Getting the Price Signals Right: Aligning Rate Design With Heat Pump Usage*, at 27 (Nov. 2026) ("Any customer that received a heat pump rebate through Mass Save was automatically enrolled. In the first year, this led to more than 100,000 residents enrolling in the rate.").

average of $1,040 a year, on a T&D bill of $2,377. Under Rate HP, they would instead pay an average of $1,337 per year.[2] Because the Company is presently overcharging these customers every year, the average per-customer revenue reduction of $1,040 per year that would result from switching an existing heat pump customer from Rate 1 to Rate HP represents a revenue shortfall that would need to be recouped from other residential customers. Indeed, this is intentional: one goal of Rate HP is to unwind an unfair cross-subsidy that flows from residential customers who already have heat pumps to those who heat with fossil fuels.[3]

However, PURA could instead choose to make existing heat pump customers *eligible* for Rate HP, but without auto-enrolling Energize CT rebate recipients en masse. In that scenario, I would expect an order of magnitude fewer customers to enroll, because each would have to become aware of the rate and take steps to apply on their own. This added friction is why opt-in heat pump rates elsewhere have drawn very little participation: Central Maine Power's seasonal heat pump rate pilot peaked at 3,134 enrolled customers, well under the pilot's 5,000-customer cap, and Con Edison's Steady Use Rate — designed to save a typical heat pump customer roughly $500 a year — had enrolled only about 500 households as of December 2025, barely 1% of the more than 40,000 heat pump installations that have received rebates.[4]

2. **New heat pump customers**: If PURA decides to auto-enroll all customers who currently heat with fossil fuels but choose to install a heat pump in the future, I estimate that between 3,460 and 10,976 customers a year would be auto-enrolled (see part (c) for details on this estimate). Unlike switching an existing heat pump customer, switching a new heat pump customer from Rate 1 to Rate HP at the same time that they install their heat pump *increases* the revenue the Company collects from that customer, rather than decreasing it.

That is because customers who choose to install heat pumps in the future are not yet paying an additional $1,051 a year for T&D: they are currently on Rate 1, but they have yet to electrify their heating, so their winter kWh have not gone up yet. Switching them from Rate 1 to Rate HP at the same time that they install their heat pumps (and increase their winter kWh) does not decrease the amount of revenue the Company collects from them — revenue that would need to be collected from other residential customers.

On the contrary, auto-enrolling these customers onto Rate HP at install time would slightly *increase* the annual T&D revenue the Company collects from each of them ($1,337, on average) after heat pumps, compared with what they paid under Rate 1 ($1,326) before heat pumps. This is not an accident: Rate HP is purposefully designed so that, on average, customers with heat pumps pay their pre-heat-pump T&D

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[2] Direct Testimony of Juan-Pablo Velez on behalf of Conservation Law Foundation and Sierra Club ("Velez Direct"), at 23:9–10 (Oct. 21, 2026) (the average fossil-heated customer overpays by $1,040 a year), 23 n.19 (their post-heat-pump T&D bill is $2,377 under Rate 1). Their Rate HP bill is the Rate 1 bill less the overpayment, which Rate HP is designed to remove (*id.* at 85:2–7). These T&D bills include the customer charge.

[3] *Id.* at 27:11–13 (a cross-subsidy within a rate class arises when one identifiable group "systematically pays more than their cost of service, and that excess revenue allows the customers of another identifiable group to pay less"), 28:19–21 (heat pump customers' overpayment "contributes directly to a cross-subsidy to electric customers that heat with fossil fuels"), and 29:7–17 (that cross-subsidy "violates intra-class equity" and is "*systematic*, *substantial*, and will continue to *grow with electrification*").

[4] Me. P.U.C. Docket No. 2022-00152, Central Maine Power Company, *Final Report*, Attachment 1 at 2 (Dec. 5, 2025) (3,134 customers enrolled in the Seasonal Heat Pump rate in December 2024, net of disenrollments); Me. P.U.C. Docket No. 2021-00325, *Investigation into Transmission and Distribution Utility Rate Design to Promote State Policies*, *Order Approving Seasonal Rate*, at 2 (Oct. 26, 2022) (pilot rate "would be available to no more than 5,000 customers"); Mona Zhang, "How NY heat pump users got stuck with higher bills," *E&E News* (Mar. 3, 2026) (Con Edison: "only about 500 households — barely 1 percent" enrolled in the Steady Use Rate as of December, of "more than 40,000 heat pumps" installed; the rate can reduce winter heating bills "by an average of roughly $500 a year").

bill, plus an additional $10 to cover the incremental T&D costs their heat pump causes.[5] Auto-enrolling new heat pump customers would therefore not reduce the total revenue the Company collects from this population. It would increase it.

Tables 1 and 2 below put these revenue increases and decreases together to give the *net* change in the Company's distribution and transmission revenue that would result from Rate HP in each of the first five rate years, in millions of dollars, for my low and high estimates of new heat pump customers. Every figure appears on the revenue sheet of CIEC-1 Attachment 1 (Excel, formulas intact).[6]

Table 1. Net revenue change from mass auto-enrollment of existing heat pump customers and ongoing auto-enrollment of new customers, low estimate of new customers (millions of dollars)

Rate year	Existing customers enrolled	New customers enrolled	Revenue reduced, dist	Revenue reduced, tx	Revenue increased, dist	Revenue increased, tx	Net change, dist	Net change, tx
2027	55,000	3,460	39.799	17.420	0.008	0.028	-39.791	-17.392
2028	55,000	6,920	39.799	17.420	0.015	0.056	-39.783	-17.364
2029	55,000	10,380	39.799	17.420	0.023	0.084	-39.776	-17.336
2030	55,000	13,840	39.799	17.420	0.031	0.112	-39.768	-17.308
2031	55,000	17,300	39.799	17.420	0.038	0.140	-39.760	-17.280

Table 2. Net revenue change from mass auto-enrollment of existing heat pump customers and ongoing auto-enrollment of new customers, high estimate of new customers (millions of dollars)

Rate year	Existing customers enrolled	New customers enrolled	Revenue reduced, dist	Revenue reduced, tx	Revenue increased, dist	Revenue increased, tx	Net change, dist	Net change, tx
2027	55,000	6,272	39.799	17.420	0.014	0.051	-39.785	-17.369
2028	55,000	13,328	39.799	17.420	0.030	0.108	-39.769	-17.312
2029	55,000	21,168	39.799	17.420	0.047	0.171	-39.752	-17.249
2030	55,000	30,576	39.799	17.420	0.068	0.247	-39.731	-17.173
2031	55,000	41,552	39.799	17.420	0.092	0.336	-39.706	-17.084

Notes on Tables 1 and 2

- The initial mass auto-enrollment of Energize CT recipients is likely to miss some existing heat pump customers, who may voluntarily enroll in the first five years. The number of such customers is likely to be an order of magnitude lower than the number auto-enrolled, but I have no basis for estimating it, so I have left it out. By the same token, if PURA declines to auto-enroll existing heat pump customers, I would expect an order of magnitude fewer of them to voluntarily opt in. In that

[5] Velez Direct at 23:2–5 (average fossil-fuel heated customer's post-heat pump T&D charges rise $1,051 a year under Rate 1), 20:7–8 (incremental marginal T&D cost of $10 a year), 85:2–7 (Rate HP sets the post-heat-pump T&D bill equal to the pre-heat-pump bill plus that incremental cost).

[6] CIEC-1 Attachment 1, CIEC-1a_rate_hp_revenue_reduction.xlsx, sheet revenue: the per-customer decrease and increase in rows 4–5, and the low and high estimates year by year below them. The README sheet explains each input.

scenario, the revenue reduction from existing heat pump customers would likely shrink by an order of magnitude or more.

- Assumptions: Both tables assume every customer who has already received a heat pump rebate through Energize CT is auto-enrolled, that every new heat pump customer receives an Energize CT rebate and is likewise auto-enrolled, and that no auto-enrolled customer opts out. Loads and rates are held constant.
- Rate HP would take effect at the start of the Rate Year, July 1, 2027. I number each rate year by the calendar year in which it begins, from 2027 (July 2027 through June 2028) to 2031.
- The customer archetype use to represent both existing and new heat pump custoemrs is the average fossil fuel-heated electricity customer in the Company's territory, the same customer my direct testimony uses to set Rate HP.[7]
- As in my testimony, switching an existing heat pump customer from Rate 1 to Rate HP reduces the revenue collected from them by **$1,040.34** a year: **$723.61** in distribution and **$316.73** in transmission, because Rate HP lowers both charges from November through March.[8]
- Enrolling a new heat pump customer in Rate HP at the time of installation increases revenue by **$10.30** a year: **$2.22** in distribution and **$8.08** in transmission — the incremental marginal T&D cost the heat pump imposes, which Rate HP is designed to recover. The customer archetype for both figures is the average fossil fuel-heated electricity customer in the Company's territory, the same customer my direct testimony uses to set Rate HP.

b. My direct testimony recommends that the Company auto-enroll every residential customer who received a heat pump incentive through Energize CT or another state or utility program.[9] (Customers who installed a heat pump outside those programs would be able to voluntarily enroll in Rate HP by attestation.[10])

How many Eversource customers have received a heat pump incentive through the Company's Conservation and Load Management programs, branded Energize CT, and would therefore be auto-enrolled in the first rate year? About **55,000**, or 4.5% of the residential customers the Company filed for the Rate Year.[11]

This figure is an estimate, because the Company publishes the number of heat pump systems that were installed, not the number of customers who installed them, and these numbers are not the same[12] The

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[7] Ex. JPV-2, Section 2 (representative home profiles); *see also* CIEC-1 Attachment 1, sheet revenue, rows 4–5 (the revenue decrease and increase per customer of this archetype).

[8] Rate HP lowers the distribution energy charge from 12.196¢ to 3.533¢ per kWh and the transmission charge from 5.050¢ to 1.258¢ per kWh in November through March. Summer rates, other riders, generation rates, and the customer charge are those of Rate 1. *See* Velez Direct at 82:10–83:2.

[9] *Id.* at 93:7–12 ("the Company should auto-enroll all known electric customers who have previously installed heat pumps. . . . a portion of these customers are readily identifiable by the Company, those that previously received a heat pump incentive through EnergizeCT or any other relevant state or utility program").

[10] *Id.* at 96:9–11 ("For customers who installed heat pumps outside of incentive programs, an attestation process — as Massachusetts uses — can identify them.").

[11] CIEC-1 Attachment 1, CIEC-1a_rate_hp_revenue_reduction.xlsx, sheet enrollment, table "Existing customers" (installations by heat pump type, systems per home, and homes, with the total rounded to the nearest thousand).

[12] CLF and Sierra Club asked the Company for this count. It gave about 4,400 customers, counting only full-displacement rebates from a program that began in 2023. This number is note accurate: Energize CT's dashboard shows 33,852 installations since

Company's Energize CT dashboard tallies heat pump installations that received a program incentive. For residential customers, it shows 67,306 space-heating heat pump installations from 2017 through 2026 to date, across mini-split, ducted air-source, ground-source, packaged terminal, and variable refrigerant flow heat pumps. The count includes every rebated installation, including both full and partial displacement of the prior system, regardless of whether the prior system used fossil fuels or electricity.[13]

An installation is not a customer, and counting installations overcounts customers in three ways. First, a mini-split installation is one outdoor unit, and many homes have more than one. Second, a home can install more than one kind of heat pump, such as a ducted system and a mini-split. Third, a home can receive incentives in more than one year. Correcting for the first problem brings the count to about 55,000 customers.[14] The other two problems cannot be corrected from the published data, so **55,000** customers is an upper estimate.

Although the Company only publishes statistics about *installations*, it knows which *customers* received these rebates because the rebate application requires the customer's electric account number.[15]

c. I estimate that between **3,460** and **10,976** customers a year would install heat pumps and be enrolled into Rate HP, or a total of 17,300 to 41,552 between 2027 and 2031. The low end of that range comes from the Company's own forecast of heat pump installations, and the high end from ISO New England's equivalent forecast. I discuss each in turn.[16]

The low estimate is the Company's forecast of residential customers who will install a heat pump through Energize CT: 3,528 in 2026 and 3,460 in 2027. The forecast ends in 2027, so I hold the 2027 figure flat for each year from 2028 through 2031.[17] It excludes heat pumps installed outside the programs, which is why I treat this forecast as a floor.[18]

The ceiling is ISO New England's forecast of homes in the Company's territory adding a heat pump for space heating: 6,272, 7,056, 7,840, 9,408 and 10,976 customers in 2027 through 2031.[19] ISO New

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2023 alone. CL&P Response to CLF-SC-003(a), at 1 ("rebate program which began in 2023 . . . approximately 4,400 customers who have received heat pump rebates that indicate full displacement of other heat sources").

[13] Eversource Connecticut, *Energize CT Heat Pump Installations, 2017 through November 2026*, at sheets Detail and Export (downloaded Nov. 10, 2026).

[14] Mini-split installations divided by 1.37, the outdoor units per home among 90 surveyed ductless heat pump (mini-split) rebate participants, from a 2019 evaluation of 2015–2016 installations; every other installation counts as one home. DNV GL, *R1617 Connecticut Residential Ductless Heat Pumps Market Characterization Study*, at 4-2 (June 20, 2019) ("The 90 participants surveyed installed 123 DHP outdoor compressor units with a total of 210 indoor heads.").

[15] The application requires the customer's "Electric Account Number (as stated on bill)," even when the rebate check is made payable to the installing contractor. Eversource and UI, *2023 Residential Air Source Heat Pump Energy Optimization Rebate Form*, at 1–2.

[16] CIEC-1 Attachment 1, CIEC-1a_rate_hp_revenue_reduction.xlsx, sheet enrollment, tables "New customers enrolling each year" and "Cumulative customers enrolled in Rate HP".

[17] The forecast ends in 2027 because it is built from the program budgets of the 2025–2027 Energy Efficiency Plan. CL&P Response to CLF-SC-002(c), at 1 ("The Electrification forecast through the C&LM program are based on projected Program budgets through 2025-2027. . . . the C&LM forecast does not project Electrification outside our programs.").

[18] CL&P Response to CLF-SC-001, Attach. 1, sheet Heat Pump Analysis, cells C23–C24 (Sep. 18, 2026) ("Planned Residential Customer installing Heat pump in 2026 and 2027 through C&LM program": 3,528 for 2026 and 3,460 for 2027); CL&P Response to CLF-SC-001, at 1 ("these are customers that will be using C&LM incentives. Other heat pumps not installed though the C&LM program are not captured in the attachment.").

[19] ISO New England forecasts Connecticut as a whole: 8,000, 9,000, 10,000, 12,000 and 14,000 homes in 2027 through 2031. I scale each year to the Company's territory by multiplying it by the Company's share of the households served by Connecticut's

England's forecast is a less direct guide to enrollment than the Company's: it is a regional planning forecast, based on each county's building stock, state policy, and economic factors, rather than on utility program budgets.[20] It also counts every home that adds a heat pump, whether or not it receives an incentive. For both of these reasons, I treat it as the ceiling.

Every customer who installs a heat pump is assumed to enroll and stay enrolled, joining in the rate year that begins in July of the year they install. These are *new* customers: as part (a) explains, they pay their bill from before the heat pump plus the incremental marginal T&D cost the heat pump causes, so they produce more revenue under Rate HP than under Rate 1.

d. The estimates are provided in parts (a) through (c).

two investor-owned electric utilities. ISO New England, *Final 2026 Heat Pump Forecast*, at 8 (May 1, 2026) (Annual Incremental Increase in HP Stock (1,000 Housing Units), residential space heating, CT: 8, 9, 10, 12, and 14 for 2027 through 2031). Each year's additions are multiplied by 78.4%, Eversource's share of the households served by Eversource and United Illuminating: the survey's population frame counts 586,270 Eversource households and 477,106 Eversource households in environmental justice communities, out of 1,356,355 Eversource and United Illuminating households in total ((586,270 + 477,106) ÷ 1,356,355 = 78.4%). NMR Group, *R2202 Residential Appliance Saturation Survey (RASS) Report*, at 17 (Sep. 17, 2025) (Table 6, Sample Size and Achieved Completes).

[20] ISO New England forecasts adoption "at the county level considering building stock characteristics, state policy, and economic factors," then applies "Market Segmentation Parameters" to reach a forecast by sector, pathway, building type and county. ISO New England, *Final 2026 Heat Pump Forecast*, at 4, 6. For 2026 it cut its adoption forecast by 5% across all sectors and heating types. *Id.* at 5.

Date Filed: November 16, 2026

Witness: Juan-Pablo Velez
Request from: Connecticut Industrial Energy Consumers

Question CIEC-2:

Please refer to Velez Direct Testimony at page 95, lines 1-16, and page 98, lines 10-18.

a. Please confirm that Rate HP is not designed to be revenue neutral with respect to the residential class as a whole.

b. Please identify who Mr. Velez contends should bear any reduction in distribution and transmission revenue resulting from Rate HP (*e.g.*, other residential customers, non-residential customers, or the Company's shareholders), and explain the basis for that position.

c. Does Mr. Velez recommend that any portion of the revenue reduction resulting from Rate HP be recovered from customers outside the residential class? If so, identify each class and the amount. If not, explain how his recommendations would prevent that result.

d. In developing his recommendations, did Mr. Velez consider how any revenue reduction resulting from Rate HP would be recovered between rate cases through the Company's reconciling mechanisms? If so, describe that consideration and provide any analysis. If not, explain why not.

Response:

a. The term "revenue neutral" is used in many different ways, so I define it precisely here to clarify what my Rate HP proposal does and does not do.

Rate HP is *not* designed to be revenue neutral with respect to the residential class as a whole, in the following sense: if *all* customers currently on other residential rate schedules were switched to Rate HP — whether or not they had a heat pump — the Company would experience a revenue shortfall.

Rate HP is also *not* designed to be revenue neutral with respect to residential heat pump customers as a whole, *relative to what they would pay under Rate 1*: under Rate 1, a heat pump customer overpays by $1,040 a year, on average, and Rate HP is designed specifically to remove this overcharge, while still charging these customers for any additional T&D costs caused by their heat pump.

b. From other residential customers.

My complete proposal *is* designed to be revenue neutral with respect to the residential class as a whole, in the sense that any revenue reduction that occurs when *existing* heat pump customers who are currently on Rate 1 enroll in Rate HP would be recouped from the residential customers left on Rate 1, by slightly increasing Rate 1's charges. (As shown in CIEC-1(a), any *new* heat pump customers enrolled in Rate HP at install time would produce more revenue after the switch, not less.)

In other words, the basis for my position that other residential customers should bear any revenue reduction resulting from existing heat pump customers joining Rate HP is this: the Company should have been collecting this revenue from non-heat pump customers in the first place, not from heat pump customers. Rate 1 unfairly shifts costs from non-heat pump customers to heat pump customers; Rate HP

unwinds this significant and growing cross-subsidy *within the residential class* to improve *intra*-class equity.[1]

c. No. I recommend that no portion be recovered from customers outside the residential class, because Rate HP addresses an intra-class equity problem.

My recommendations prevent that result by proposing Rate HP as a *residential* rate schedule, and changing how the residential class's allocated costs are split between Rate 1 and Rate HP, not the cost allocation across classes. So when rates are set, any revenue Rate HP gives up is recovered by slightly raising Rate 1's charges. Nothing moves to other classes. (Reconciling mechanisms work slightly differently; see the following question.)

d. I considered this but did not address it in my testimony. I do so here. The two reconciling mechanisms relevant to Rate HP are the Revenue Decoupling Mechanism (RDM) for distribution and the Transmission Adjustment Clause (TAC) for transmission. Rate HP does not change any other riders — customers on Rate HP pay the same SBC, CTA, FMCC, and SCRAF rates as Rate 1 — so the remaining reconciling mechanisms are unaffected.[2]

How the RDM and TAC work. Between rate cases, the RDM reconciles the Company's actual distribution revenue against the fixed revenue target approved in this proceeding.[3] If actual revenue falls short of the target — because customers used less electricity than forecast, or, in this case, because customers switched to a rate schedule that lowered the per-kWh distribution charges applied to their same usage — the RDM adds a surcharge in the following year to recover the difference. If actual revenue exceeds the target, the RDM credits the difference back. The surcharge or credit is set as a flat ¢/kWh and applied to every rate class.[4] The TAC works similarly for transmission. Each year, it recovers the Company's projected transmission costs (external charges from ISO New England (ISO-NE) that the Company passes through) plus the prior year's under- or over-recovery, and allocates the total among classes by each class's demand at the Company's twelve monthly system peaks rather than by kWh.[5]

New heat pump customers. When a customer installs a heat pump and enrolls in Rate HP, their electricity consumption rises, with winter kWh roughly tripling. By design, even at Rate HP's lower winter distribution and transmission rates, the volume increase means the Company collects more total revenue from this customer than it collected before the heat pump was installed. As shown in CIEC-1(a), each new heat pump customer enrolled in Rate HP at installation adds roughly $10 a year in T&D

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[1] Direct Testimony of Juan-Pablo Velez on behalf of Conservation Law Foundation and Sierra Club ("Velez Direct"), at 28:20–21 (Oct. 21, 2026) (heat pump customers' overpayment "contributes directly to a cross-subsidy to electric customers that heat with fossil fuels"), 29:7–17 (that cross-subsidy "violates intra-class equity" and is "*systematic*, *substantial*, and will continue to *grow with electrification*"), and 82:5–7 (the "ultimate objective of Rate HP is to fix the intra-class equity and building electrification policy problems that Rate 1 creates").

[2] *Id.* at 85:1–2 (generation rates, the monthly customer charge, and all distribution riders remain the same as under Rate 1).

[3] Joint Direct Testimony of Edward Davis and Kimberly R. Parsons on behalf of The Connecticut Light and Power Company d/b/a Eversource Energy ("Davis-Parsons Direct"), Exhibit CLP-RATES-3 at 404 (July 14, 2026) (the RDM reconciles "annual authorized distribution revenue with annual actual distribution revenue").

[4] Davis-Parsons Direct, Exhibit CLP-RATES-1 at 22:21 ("the rate will be set at a flat kWh rate across all rate classes").

[5] Davis-Parsons Direct, Exhibit CLP-RATES-3 at 409 (the TAC recovers "the difference between the Company's TAC revenue and the Company's TAC costs from the prior period"); Docket No. 26-01-03, *PURA Annual Review of the Rate Adjustment Mechanisms of The Connecticut Light and Power Company*, CL&P Rates Filing, Attachment 1, Exhibit 4 ("RAM Exhibit 4"), at 4:60 (Feb. 17, 2026) (class shares of the transmission revenue requirement are based on "Average rate class KW demands coincident to the Company's 12 monthly system peaks").

revenue above what they paid previously. Between rate cases, this added revenue raises the Company's actual revenue relative to the targets the reconciling mechanisms true up to, pushing them toward a credit.

Existing heat pump customers. When an existing heat pump customer switches from Rate 1 to Rate HP, their kWh do not change — they already have a heat pump. They simply pay a lower per-kWh rate in winter. This reduces the Company's distribution and transmission revenue by $1,040.34 per customer per year ($723.61 distribution, $316.73 transmission), as shown in CIEC-1(a).

At the next rate case. The shortfall is addressed properly: Rate 1's rates are recalculated without the kWh of the heat pump customers who have moved to Rate HP, and the distribution and transmission revenue shortfalls are recovered from the remaining residential customers, helping to unwind the cross-subsidy between heat pump and non-heat pump residential customers.

Between rate cases. Until then, the RDM and TAC reconcile these revenue shortfalls: all else equal, they push each mechanism toward a surcharge in the next Reconciling Adjustment Mechanism (RAM) period, so the Company still recovers its revenue between rate cases.[6] That by itself is not a problem. If these mechanisms recovered each class's revenue variance from that class alone, residential customers would bear the shortfall between rate cases just as they would at the next one, and no other class would be affected.

The problem is that neither mechanism currently works this way. The RDM pools every class's distribution revenue variance and recovers the net through one ¢/kWh rate charged to every class.[7] The TAC pools the transmission true-up with the current year's transmission revenue requirement and divides the total among classes by their demand at the Company's twelve monthly system peaks.[8] Either way, any shortfall that arises entirely within the residential class leaks to non-residential classes until the next rate case — and vice versa.[9]

Which way the leak runs today. This leak is not new, and so far it has favored non-residential customers. Every Rate 1 residential customer who installs a heat pump between rate cases contributes more revenue than expected, which flows to the RDM as an over-collection credited to all classes, including non-residential customers. The Authority itself recognized this dynamic: "beneficial electrification will result in increased kWh sales and a net RDM credit to customers."[10] Non-residential classes have been receiving a share of heat pump customers' overpayment for years, and new heat pump customers enrolled in Rate HP would keep that credit flowing.

How large the leak could be. If PURA chose to auto-enroll the 55,000 existing heat pump customers identified in CIEC-1(b), the annual distribution shortfall would be $39.8 million, and approximately 50%

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[6] Davis-Parsons Direct, Exhibit CLP-RATES-3 at 404 (RDM), 409 (TAC) (each "will be applied as a separate line item on Customer bills for the 12 months beginning approximately 120 days following the annual period subject to reconciliation").

[7] *Id.* at 404 (the RDM Adjustment divides "the difference in the approved distribution revenue target and actual distribution revenue for the preceding annual period" by "the kWh sales anticipated for the 12-month period over which the RDM Adjustment will be applied"); Davis-Parsons Direct, Exhibit CLP-RATES-1 at 22:21.

[8] Davis-Parsons Direct, Exhibit CLP-RATES-3 at 409 (the TAC is set by dividing "(1) the current period's Transmission revenue requirement; plus (2) a true-up of any under or over recoveries . . . from the prior year's TAC charges or credits"); RAM Exhibit 4 at 1:20, 29, 4:60.

[9] Non-residential share of Rate Year billed sales: 20,457,507 MWh total billed sales minus 10,319,093 MWh residential (Rate 1, Rate 5, and Rate 7) = 50% non-residential. Davis-Parsons Direct, Exhibit CLP-RATES-2 at 3; also in CIEC-2 Attachment 1, CIEC-2d_rdm_tac_nonres_impact.xlsx, sheet inputs, rows 12–14.

[10] Docket No. 23-01-03, *PURA Annual Review of the Rate Adjustment Mechanisms of The Connecticut Light and Power Company*, Decision, at 30 (Aug. 16, 2023).

of it — about $19.7 million — would fall on non-residential classes through the RDM until the next rate case. The same dynamic applies to the TAC for the winter transmission rate reduction: about 47% of the $17.4 million annual transmission shortfall, or $8.3 million, would be allocated to non-residential classes by demand — each year, until the next rate case.[11]

Spread over company-wide sales, the distribution shortfall works out to 0.195 ¢/kWh on every customer's bill.[12] I have not calculated a comparable figure for the transmission shortfall, which the TAC allocates by each class's demand at the Company's twelve monthly system peaks rather than by kWh.

These figures are a worst case, however, and most of the shortfall can be avoided.

Avoiding the existing heat pump customer auto-enrollment reconciliation shortfall. The shortfall above arises only if existing heat pump customers are auto-enrolled into Rate HP *after* Rate 1 and Rate HP are set. If the Authority instead sets both rates in this rate case using billing determinants that already place existing heat pump customers' load on Rate HP, then no reconciliation shortfall would arise from those customers. Instead of waiting until the next rate case for a fix, the Authority could address the problem proactively in this rate case.

Later existing heat pump customer enrollees. If the Authority auto-enrolls the 55,000 existing heat pump customers who received rebates from Energize CT at the start of the rate period, that mass enrollment happens once. Thereafter, the only reconciliation shortfalls would come from existing (not new) heat pump customers who were "missed" by the Company's initial auto-enrollment and who enroll in Rate HP between rate cases. These customers would likely be far fewer in number, because opt-in heat pump rates have achieved negligible participation elsewhere (see my response to CIEC-1(a)).

Keeping any remainder within the residential class. For any reconciliation shortfall that remains, PURA has existing regulatory tools that can keep the RDM and TAC from passing it through to non-residential classes, and I recommend that the Authority use them.

One tool is transparency. In June 2026, the Massachusetts Department of Public Utilities (DPU) directed the state's three electric distribution companies, which all offer seasonal heat pump rates, to report "the billed revenues recorded from heat pump customers in their annual revenue decoupling filings and to compare those revenues to the amounts that would have been billed if those customers had not enrolled in the heat pump rates."[13] In other words: every year, each company must show how much revenue it actually collected from heat pump rate customers and how much it would have collected had those customers stayed on the default rate. That comparison makes the shortfall — or the surplus — visible to the regulator and all parties, rather than burying it in the company-wide RDM true-up. I recommend that the Authority adopt the same reporting requirement here.

Another tool is targeted recovery. If the reporting shows a net shortfall from existing heat pump customers enrolled in Rate HP beyond the amount built into rates, the Authority can direct the Company to recover that amount from the residential class only, rather than spreading it across all classes through

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[11] 55,000 customers × $723.61 distribution and $316.73 transmission revenue decrease per customer (CIEC-1(a)), times each mechanism's non-residential share: 50% of billed kWh for the RDM, and 47% of demand at the twelve monthly system peaks for the TAC (RAM Exhibit 4 at 4:18, 20, 56). CIEC-2 Attachment 1, CIEC-2d_rdm_tac_nonres_impact.xlsx, sheet shortfall, rows 6–7; inputs and sources on sheet inputs.

[12] $39.8 million annual distribution shortfall ÷ 20,457,507 MWh company-wide billed sales (× 1,000 kWh/MWh). CIEC-2 Attachment 1, CIEC-2d_rdm_tac_nonres_impact.xlsx, sheet shortfall, row 10.

[13] D.P.U. 25-08-A, *Inquiry by the Department of Public Utilities on its own Motion into a Seasonal Heat Pump Rate*, Order on Seasonal Heat Pump Rates, at 41 (June 1, 2026).

the company-wide RDM. There are at least two ways to do this. One is a residential-only adjustment — a separate line item on residential bills that recovers the identified shortfall from the class that Rate HP serves. The other uses the Company's existing RDM Rider, which already contains a provision excluding from the company-wide calculation any revenue "specifically identified and approved for exclusion by PURA."[14] The Authority could invoke that provision to exclude the Rate HP shortfall from the company-wide RDM, and instead recover it through a residential-specific mechanism. Either way, the result is the same: the shortfall stays where it belongs — with the class whose rate caused it.

This is not a radical redesign of the RDM. In December 2025, the Authority considered — and declined — a proposal to allocate the entire RDM by class, which would have tracked revenue variances for every rate class separately. The Authority found that approach "indicated significant potential swings to the volumetric rate for certain rate classes" and concluded that "at this time, the current allocation methodology used for the RDM is appropriate."[15] What I recommend is far narrower: it is one identifiable dollar amount, attributable to one rate, assigned to the one class that rate serves. Connecticut's decoupling statute leaves the design of the decoupling mechanism to the Authority, and asks it to consider whether that design is "in the best interest of ratepayers."[16] Keeping a residential shortfall with residential customers would meet that test: it shields non-residential customers from a cost they did not cause, and leaves the RDM unchanged for every other class.

[14] Davis-Parsons Direct, Exhibit CLP-RATES-3 at 404.

[15] Docket No. 24-12-05, *PURA Procedural Review of the Annual Rate Adjustment Mechanisms of The Connecticut Light and Power Company and The United Illuminating Company*, Decision, at 22 (Dec. 10, 2025).

[16] Conn. Gen. Stat. § 16-19tt(b) ("The authority shall have the discretion to determine the decoupling mechanism and methodology . . . ." and "shall consider factors, including . . . (1) whether the decoupling mechanism and methodology is in the best interest of ratepayers"). I am not an attorney and do not offer a legal opinion. My understanding is that the statute does not require that every revenue variance be spread company-wide; it leaves the choice of mechanism to the Authority.

Date Filed: November 16, 2026

Witness: **Juan-Pablo Velez**
Request from: **Connecticut Industrial Energy Consumers**

Question CIEC-3:

Please refer to Velez Direct Testimony at page 83, footnote 75, and page 101, lines 5-17.

a. Please explain why Mr. Velez did not propose a revenue-neutral seasonal design under which the winter reductions in Rate HP would be offset by higher summer distribution and transmission rates.

b. Would Mr. Velez object to a requirement that any revenue reduction resulting from Rate HP be recovered solely from the residential class? If so, explain why.

c. If any revenue reduction resulting from Rate HP were recovered solely from the residential class, please provide Mr. Velez's estimate of the resulting increase in Rate 1 distribution and transmission charges, with supporting workpapers.

Response:

a. I repeat part of my response to CIEC-2(a): Rate HP is *not* designed to be revenue neutral with respect to residential heat pump customers as a whole, *relative to what they would pay under Rate 1*. Under Rate 1, a heat pump customer overpays by $1,040 a year, on average.[1] Rate HP is designed specifically to remove this overcharge, while still charging these customers for any additional T&D costs their heat pumps cause.[2]

A revenue-neutral seasonal design would charge heat pump customers $1,040 less in winter, only to charge them $1,040 more in summer. As my testimony explains, such a design "merely shifts the overpayment between seasons, defeating the entire purpose of a heat pump rate."[3]

b. No. I would welcome it. As explained in CIEC-2(b), such a requirement would make explicit both the rationale and the aim of Rate HP: residential heat pump customers are cross-subsidizing other residential customers, and fair rates can fix this *intra*-class inequity.[4]

c. The increase in Rate 1 charges depends almost entirely on whether PURA decides to auto-enroll existing heat pump customers in Rate HP. If PURA directs the Company to auto-enroll every existing customer

[1] Direct Testimony of Juan-Pablo Velez on behalf of Conservation Law Foundation and Sierra Club ("Velez Direct"), at 23:9–10 (Oct. 21, 2026) ("fossil fuel-heated customers that install heat pumps overpay by an average of $1,040 a year").

[2] *Id.* at 85:2–7 (the winter rate reductions produce "a population-average T&D bill equal to the customer's pre-heat-pump T&D bill plus the incremental marginal T&D cost of serving the new electrified heating load").

[3] *Id.* at 101:9–10.

[4] *Id.* at 28:20–21 (heat pump customers' overpayment "contributes directly to a cross-subsidy to electric customers that heat with fossil fuels"), 29:15–17 (that cross-subsidy is "a significant violation of intra-class equity"), and 82:5–7 (the "ultimate objective of Rate HP is to fix the intra-class equity and building electrification policy problems that Rate 1 creates").

who has received a heat pump rebate through Energize CT, as my testimony recommends,[5] and the resulting revenue reduction is recovered solely from the residential class, as I propose in CIEC-2(b), Rate 1 distribution and transmission charges would rise by about **0.61¢ per kWh** (0.43¢ distribution, 0.18¢ transmission). That is about **3.7%** of Rate 1's proposed 16.335¢ per kWh delivery rate.[6] However, if PURA decides not to auto-enroll existing heat pump customers who received Energize CT rebates, the increase would likely be an order of magnitude smaller.

This increase is driven entirely by *existing* heat pump customers, not new ones. As explained in CIEC-1(a), each of the roughly 55,000 existing heat pump customers who would be auto-enrolled (CIEC-1(b)) would pay $1,040.34 less per year in distribution and transmission charges, on average. The resulting revenue reduction would be recovered from the residential customers who remain on Rate 1.[7] This is intentional: it is the cost of unwinding a cross-subsidy that currently overcharges residential heat pump customers by $1,040 a year, on average.[8] New heat pump customers, by contrast, do not reduce the Company's revenue when they enroll in Rate HP at installation: each pays $10.30 *more* per year in distribution and transmission charges than before the retrofit, on average.[9]

Because the increase comes from existing customers, it hinges on how many of them enroll. If PURA makes existing heat pump customers eligible for Rate HP without auto-enrolling them, I would expect an order of magnitude fewer of them to enroll, because each would have to learn about the rate and apply on their own. That friction is why opt-in heat pump rates elsewhere have drawn little participation, as discussed in CIEC-1(a): Central Maine Power's seasonal heat pump rate pilot peaked at 3,134 enrolled customers, and only about 500 households had enrolled in Con Edison's Steady Use Rate as of December 2025, barely 1% of the more than 40,000 heat pumps its customers have installed.[10] Without auto-enrollment, the increase in Rate 1 charges would likely shrink by an order of magnitude or more, to roughly 0.06¢ per kWh or less.

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[5] *Id.* at 93:7–12 ("the Company should auto-enroll all known electric customers who have previously installed heat pumps. . . . a portion of these customers are readily identifiable by the Company, those that previously received a heat pump incentive through EnergizeCT or any other relevant state or utility program").

[6] Net revenue reduction ÷ kWh of residential customers not on Rate HP, in 2031, the year with the highest cumulative enrollment. The estimate is essentially the same in every rate year and under both the low and high estimates of new heat pump customers in CIEC-1(c): 0.599¢ to 0.609¢ per kWh. Year-by-year figures, both estimates, and all inputs are in CIEC-3 Attachment 1, CIEC-3c_rate1_charge_increase.xlsx.

[7] CIEC-1 Attachment 1, CIEC-1a_rate_hp_revenue_reduction.xlsx, sheet revenue, rows 4–5 (the revenue decrease per existing customer and increase per new customer), and sheet enrollment, table "Existing customers".

[8] Velez Direct at 23:9–10 ("fossil fuel-heated customers that install heat pumps overpay by an average of $1,040 a year"), 28:20–21 (that overpayment "contributes directly to a cross-subsidy to electric customers that heat with fossil fuels").

[9] New customers affect the per-kWh increase only slightly, and only because each one leaves Rate 1, shrinking the kWh over which the existing customers' reduction is recovered. This is why the high estimate of new customers yields a marginally higher increase than the low estimate.

[10] Me. P.U.C. Docket No. 2022-00152, Central Maine Power Company, *Final Report*, Attachment 1 at 2 (Dec. 5, 2025) (3,134 customers enrolled in the Seasonal Heat Pump rate in December 2024, net of disenrollments); Mona Zhang, "How NY heat pump users got stuck with higher bills," *E&E News* (Mar. 3, 2026) (Con Edison: "only about 500 households — barely 1 percent" enrolled in the Steady Use Rate as of December, of "more than 40,000 heat pumps" installed).

Conservation Law Foundation and Sierra Club
PURA Docket No. 26-05-10
Set CIEC-02
Date Issued: October 29, 2026
CIEC-004
Page 1 of 2

Date Filed: November 16, 2026

Witness: **Juan-Pablo Velez**
Request from: **Connecticut Industrial Energy Consumers**

Question CIEC-4:

Please refer to Velez Direct Testimony at page 9, lines 1-7; page 17, lines 1-6; and page 18, lines 3-6.

a. Please confirm that, based on the figures in Velez Direct Testimony, the average fossil fuel-heated customer pays approximately $1,178 per year in distribution and transmission charges ($814 + $364) before installing a heat pump, while causing approximately $123 per year in marginal T&D costs.

b. Please explain why, under Mr. Velez's methodology, the difference of approximately $1,055 per year between those two amounts is not also an "overcharge" or "overpayment."

c. Please confirm that this difference represents the customer's contribution to the recovery of the embedded costs of the Company's existing transmission and distribution facilities. If Mr. Velez does not agree, explain what that difference represents.

Response:

a. Confirmed. Before installing a heat pump, the average fossil fuel-heated customer pays $1,178 a year in distribution and transmission charges,[1] while causing $123 a year in marginal T&D costs: $28 upstream distribution and $95 bulk transmission.[2]

b. Confirmed that, before installing a heat pump, the average fossil fuel-heated electric customer pays $1,055 a year more than the marginal T&D costs it causes. That amount is the customer's contribution to the embedded costs of the existing system (part (c)). Those costs are sunk: no customer's usage today causes them, but they still have to be paid, and nearly every customer pays something toward them.[3] The testimony does not call that contribution an overpayment.

Installing a heat pump transfers other customers' embedded costs onto the heat pump customer. Under Rate 1, the customer's T&D charges go up by $1,051 a year, but the heat pump causes only $10.30 a year in new T&D costs. The remaining $1,040 goes toward the existing system, nearly doubling the customer's contribution to it, from $1,055 to $2,095.[4] The existing system costs the same as before, so the heat pump customer has taken $1,040 of embedded costs off everyone else, who now pay that much less.[5]

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[1] Velez Direct at 9:3–6 (distribution and transmission charges under Rate 1).

[2] Velez Direct at 18:3–6.

[3] Velez Direct at 13:23–14:2 (existing "infrastructure does need to be paid for, those are *sunk* costs tied to old investments, not *marginal* costs").

[4] After installing: ($1,178 + $1,051 in added T&D charges) − ($123 + $10.30 in added marginal T&D cost) = $2,095. *Id.* at 20:5–8, 23:3–5.

[5] The overpayment reaches other customers through two channels. Between rate cases, the RDM credits distribution revenue collected above the approved target back to all rate classes as a flat ¢/kWh, and the TAC trues up transmission revenue to the Company's actual transmission costs (CIEC-2(d)). At the next rate case, the heat pump customer's added kWh, about 6,432 a

That is why the testimony calls the $1,040 an overpayment and not the $1,055: the $1,040 is a *transfer*.[6] The $1,055 is the fossil fuel-heated customer's pre-existing share of embedded costs, the average amount it paid before installing the heat pump. The $1,040 is part of the embedded costs that other customers used to pay, which the heat pump customer takes on without causing any new costs that would justify it. That transfer is what the testimony calls a cross-subsidy, and it violates intra-class equity.[7]

The transfer also works directly against state policy: Connecticut has committed to heat pumps making up 65% of residential HVAC sales by 2030 and 90% by 2040, and is spending hundreds of millions of dollars to get customers to switch. But today, Rate 1 charges the average customer who does switch $1,040 a year to lower the electric bills of customers who keep heating with fossil fuels.[8] And this transfer spoils the economics of switching for gas-heated customers: under Rate 1, only 13% would see lower total annual energy bills after installing a heat pump; without the overpayment, 86% would.[9]

c. Confirmed.

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year for the average fossil fuel-heated home, are spread over the residential class's total kWh, which lowers the per-kWh rates that recover its revenue requirement. [Davis-Parsons Direct, Exhibit CLP-RATES-3] at 404 (RDM), 409 (TAC).

[6] Velez Direct at 24:8–10.

[7] *Id.* at 27:11–13, 29:7–17 (the cross-subsidy "violates intra-class equity").

[8] *Id.* at 34:1–3 (heat pump sales targets), 35:6–9 (Connecticut "is actively spending hundreds of millions of dollars to drive heat pump adoption"), 82:5–7 (the "ultimate objective of Rate HP is to fix the intra-class equity and building electrification policy problems that Rate 1 creates").

[9] *Id.* at 40:12–41:2, 41:3–5 (the overpayment is "the single largest barrier to favorable bill outcomes for natural gas-heated customers considering heat pumps").

Date Filed: November 12, 2026

Witness: **Juan-Pablo Velez**
Request from: **Connecticut Industrial Energy Consumers**

Question CIEC-6:

Please refer to Velez Direct Testimony at page 27, lines 3-8.

a. Please provide all analysis supporting the statement that the Company could eliminate the entire overpayment "without negatively affecting the bills of non-heat-pump customers."

b. Please explain how that statement is consistent with recovery of the Company's authorized revenue requirement between rate cases if revenue from heat pump customers is reduced.

c. Please provide Mr. Velez's estimate of the bill impact of Rate HP on (i) residential customers who do not take service under Rate HP and (ii) non-residential customers, including those taking service under Rate 39 and Rate 57.

Response:

a. The statement is about customers who heat with fossil fuels today and install a heat pump after Rate HP takes effect ("new heat pump customers"). The full sentence reads: "The Company could eliminate all of the entire overpayment — discount the rate all the way down to the floor — and *customers newly installing heat pumps* would still be paying their full incremental cost of service, still satisfying cost causation, without negatively affecting the bills of non-heat-pump customers" (emphasis added).[1]

The supporting analysis is already in the record. A new heat pump customer on Rate HP keeps paying its pre-heat-pump contribution to embedded costs, plus the new costs its heat pump causes (as explained in CIEC-4(b) and CIEC-5(a)). The underlying calculations are in Sections III and IV of the testimony and Exhibit JPV-2, Sections 2–4.

The statement does not concern customers who already heat with a heat pump and pay Rate 1 today ("existing heat pump customers"). Their effect on other customers is addressed in CIEC-1(a), CIEC-3(c), and part (c).

b. The statement concerns new heat pump customers, and the revenue the Company collects from them is not reduced. Relative to what Rate 1 was set to collect from them, it rises slightly, because they keep paying their pre-heat-pump bill and add the cost of their new load (CIEC-1(a)). A revenue reduction comes only from existing heat pump customers; how that reduction would be recovered, in this rate case and between rate cases, is addressed in CIEC-2(c) and (d).

c. Enrolling customers who heat with fossil fuels today and install a heat pump after Rate HP takes effect ("new heat pump customers") would raise no other customer's bill: they would pay the Company slightly more under Rate HP than they paid before installing their heat pumps (part (b)). Any bill impact comes from customers who already heat with a heat pump and pay Rate 1 today ("existing heat pump

[1] Direct Testimony of Juan-Pablo Velez on behalf of Conservation Law Foundation and Sierra Club ("Velez Direct"), at 27:5–8 (Oct. 21, 2026).

customers"). Moving them to Rate HP ends their overpayment and shifts those embedded costs back to the customers who paid them originally (CIEC-2(b) and CIEC-5(b)).

1. **Residential customers not on Rate HP.** If PURA auto-enrolls existing heat pump customers who have received a heat pump rebate from Energize CT, as my testimony recommends, and the resulting revenue reduction is recovered from the residential class, as I propose in CIEC-2(b), then the average residential customer not on Rate HP would pay about $4.24 more a month. That is the increase in Rate 1 distribution and transmission charges estimated in CIEC-3(c), about 0.61¢ per kWh, applied to that customer's annual usage.[2] Massachusetts has already taken this step: its investor-owned utilities automatically enrolled Mass Save heat pump rebate recipients, and about 140,000 customers were enrolled across the utilities before the 2025–2026 heating season.[3] Without auto-enrollment of existing heat pump customers, however, the increase would likely be an order of magnitude smaller, because enrollment would be voluntary, and enrollment in heat pump rates has been low (CIEC-1(a) and CIEC-3(c)).
2. **Non-residential customers, including Rates 39 and 57.** No increase, if the Authority adopts the steps I recommend in CIEC-2(c) and (d): setting Rate 1 and Rate HP in this rate case with existing heat pump customers' load already moved to Rate HP, and keeping any later shortfall within the residential class. Without those steps, the RDM and TAC would pass part of the existing-customer reduction to non-residential classes until the next rate case, as quantified in CIEC-2(d).

[2] Net revenue reduction ÷ residential customers not on Rate HP, in 2031 under the high estimate of new heat pump customers, the same year and estimate as CIEC-3(c). Across all five rate years and both estimates, it ranges from $50 to $51 a year. CIEC-6 Attachment 1, CIEC-6c_nonhp_bill_increase.xlsx, sheet bill_impact, row 9.

[3] Order on Seasonal Heat Pump Rates, D.P.U. 25-08-A (June 1, 2026), at 30. The 140,000 total includes customers who self-enrolled, not only those enrolled automatically.

Date Filed: November 16, 2026

Witness: **Juan-Pablo Velez**
Request from: **Connecticut Industrial Energy Consumers**

Question CIEC-7:

Please refer to Velez Direct Testimony at page 15, lines 5-10; page 16, lines 1-5; and page 62, lines 11-14.

a. Please explain why Mr. Velez estimated marginal transmission cost using an avoided Pool Transmission Facility cost and the probability of the New England system peak, rather than the method by which regional and local network transmission costs are actually allocated to the Company.

b. Please describe Mr. Velez's understanding of how ISO New England Inc. allocates regional network transmission service costs to the Company, including whether that allocation depends on the Company's load at the time of the peak in each month.

c. Has Mr. Velez estimated the effect of heat pump adoption on the Company's monthly peak loads during November through March, or on the transmission costs allocated to the Company? If so, provide the analysis. If not, explain why not.

d. Please explain how the 75% reduction in the winter Transmission Service Rate under Rate HP would affect the Company's recovery of its transmission costs, and identify who would pay any resulting under-recovery.

Response:

a. My testimony measures the cost of the new transmission facilities that a heat pump customer's added usage requires. That is a marginal cost. The cost allocation method the question describes measures something else entirely: how the cost of facilities *already built* is divided among the customers who use them. It cannot tell us what *new* facilities added load requires.[1]

The Company did not compute a marginal cost of transmission in this rate case.[2] I therefore constructed one. An hourly marginal cost has two parts: an annual cost per kilowatt of peak load, and a method for allocating that annual cost to the hours of the year, in proportion to how likely each hour is to fall at the peak that drives new investment. For the annual cost, I used the standard regional estimate. For the allocation to hours, I used the same probability-of-peak method the Company used for its distribution marginal cost. Because the transmission and distribution schedules are built the same way, they can be added together into one hourly marginal delivery cost, which I compared with the delivery charges a heat pump customer pays for its added usage.

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[1] *See* Synapse Energy Economics, *Avoided Energy Supply Components (AESC) in New England: 2024 Report* ("AESC 2024"), at 285 (May 24, 2024) (the avoided transmission cost does "not include any impact of changes in the cost or cost allocation of already-built regional transmission facilities"), 286 (it "is the value of avoiding or deferring projects associated with load growth").

[2] CL&P Response to CLF-SC-026, at 1 ("The Marginal cost of transmission was not computed for this rate design.").

The regional estimate is the avoided Pool Transmission Facility cost of $69/kW-year from AESC 2024: the cost of deferring regional transmission investment by one year through a one-year reduction in peak load.[3] The Company sponsors that study and uses it to screen its own energy efficiency programs, valuing avoided Pool Transmission Facility cost at $70.0 per kW.[4] I inflated the value to 2026 dollars, the dollar year of the Company's marginal cost of service study.[5]

To allocate that cost to hours, I applied the Company's method to New England system load rather than to the Company's distribution substation load,[6] because Pool Transmission Facilities are regional: as AESC puts it, "the transmission system is built to reliably meet the total system peak, each year."[7]

b. Regional Network Service is how ISO New England charges for the region's shared high-voltage transmission system, the Pool Transmission Facilities. ISO New England bills the Company for it every month, and each month's bill depends on the Company's load in a single peak hour of that month, including in November through March.[8] The bill is built in three steps.

1. **One regional cost pool and one rate.** Each year, the transmission owners' revenue requirements for the Pool Transmission Facilities are added together into a single New England total. That total is divided by the region's load at monthly peaks, averaged over the twelve months of the year, to give a rate per kilowatt-year.[9]
2. **One hour per month.** For billing, the tariff divides New England into zones it calls Local Networks, each covering the transmission systems of one transmission owner or group of affiliated owners.[10] The Company is in Eversource's zone, which also includes Eversource's systems in western Massachusetts and New Hampshire.[11] Each month, ISO New England finds the hour when

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[3] Direct Testimony of Juan-Pablo Velez on behalf of Conservation Law Foundation and Sierra Club ("Velez Direct"), at 15:6–9 (Oct. 21, 2026); AESC 2024 at 283 (the $69 per kW-year is "the cost of deferring the PTF investment by one year as a result of a one-year reduction in peak load").

[4] AESC 2024 at 4 (listing "Eversource (Connecticut Light and Power . . .)" among the sponsors); CL&P et al., *2025–2027 Conservation & Load Management Plan*, at 178 ("The electric and fossil fuel avoided costs are based on a regional avoided energy supply cost study completed in 2024 for New England ('2024 AESC')") and 181 (Figure 62 lists "Pooled Transmission Facilities" at "$70.0" per kW, sourced to "2024 AESC," on a "Connecticut counterfactual 1 using a 15-year levelized basis; all values are in 2024 dollars") (Nov. 1, 2024).

[5] Ex. JPV-2, Section 3, Step 1.

[6] Velez Direct at 15:9–16:3; Ex. JPV-2, Section 3, Step 2; CL&P Response to CLF-SC-033, at 1 (reprinting the Company's response to OCC-733, which fit the method on "historical hourly Substation Loads from January 2022, to December 2025").

[7] AESC 2024 at 283.

[8] CL&P Response to CLF-SC-031, at 1 (the costs of "transmission service provided (i.e., billed) to the distribution company . . . are determined on a monthly peak demand basis, at rates determined on a 12-month average peak demand").

[9] ISO New England, *Open Access Transmission Tariff, Section II*, at Schedule 9, Lines 1–3 and notes (b)–(c) (the revenue requirement "equals the aggregate of the ATRRs of the PTOs," and the denominator is "[t]he average for the twelve months of the calendar year on which the rate is based of the sum of the coincident Monthly Peaks for all Local Networks").

[10] *Id.* at Attachment E (listing each "Local Network of" a named transmission owner or group of companies) (effective Jan. 1, 2023, FERC Docket No. ER23-16-000).

[11] Attachment E lists the zone as "[t]he Local Network of the Northeast Utilities companies," Eversource's former name. *Id.* ISO New England, *Open Access Transmission Tariff*, Schedule 21-ES (Part A), at Section 1.5 (the "Eversource Companies" are "The Connecticut Light and Power Company, NSTAR Electric Company (West), and Public Service Company of New Hampshire") (effective Jan. 1, 2022, FERC Docket No. ER20-2054-001).

the combined load of that zone is highest. That is the only thing the zone does in the calculation: it fixes the hour in which the Company's load is measured.[12]

3. **The Company's bill.** The Company's load in that hour, times the rate, divided by 12, is its bill for the month.[13]

The monthly peaks therefore decide how the regional cost pool is shared, not how large it is. If the Company's load in a January peak hour rises, the Company pays a larger share of the same pool, and the other utilities in New England pay a smaller one.

c. No, for two reasons.

First, an estimate of the transmission costs allocated to the Company would not measure what my testimony measures. My testimony measures the cost of the *new* transmission facilities that a customer's added load requires (part (a)). A change in the Company's allocation adds no new facilities. As part (b) describes, load at a monthly peak changes the Company's share of the embedded cost of *existing* facilities.

Second, even if heat pump adoption raised the Company's November–March peak loads, its allocation would not necessarily grow. The Company's share is a ratio: its load at its monthly peaks, divided by the sum of all New England transmission customers' loads at their own monthly peaks. That share rises only if the Company's peak load grows faster, in percentage terms, than the region's. If peak load elsewhere grows as fast or faster, the Company's share stays the same or falls, because the same revenue requirement is spread over more kilowatts. And winter peak load is indeed forecast to grow across all of New England: ISO New England forecasts heat pumps adding to the winter peak in every New England state, 1,600 MW across the region by 2030, of which 224 MW is in Connecticut and 322 MW in Maine.[14]

d. Rate HP would not affect whether the Company recovers its transmission costs. The Transmission Adjustment Clause reconciles the Company's transmission revenue against its actual transmission costs, and carries any difference into the next year's rate (CIEC-2(d)).[15]

Who would pay any under-recovery depends on which customers enroll, and other responses already answer it:

- **New heat pump customers** cause no under-recovery. Even at the lower winter Transmission Service Rate, each would pay the Company $8.08 a year more in transmission than it paid before installing its heat pump (CIEC-1(a) and CIEC-6(b)).

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[12] ISO New England, *Open Access Transmission Tariff, Section II*, at Section II.21.2 (a customer's billing load is "its hourly load . . . coincident with the coincident aggregate load of all Network Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ('Monthly Peak')") (effective Sep. 1, 2021, FERC Docket No. ER21-2337-002).

[13] *Id.* at Section II.21.1 (each customer pays "an amount equal to its Monthly Regional Network Load for the month times the applicable Local Network RNS Rate"), Schedule 9 ("Amount to be Paid = ((RNS Rate per kilowatt-year) x (Transmission Customers [sic] Monthly Network Load (a)) x (1/12))").

[14] ISO New England, *Final 2026 Heat Pump Forecast*, at 8 (annual additions to the heat pump stock in each of the six states), 24 (Winter 50/50 Peak Demand by Load Zone: 224 MW for CT, 322 MW for ME and 1,600 MW for ISONE in 2030) (May 1, 2026).

[15] Davis-Parsons Direct, Exhibit CLP-RATES-3 at 409 (the TAC recovers "the difference between the Company's TAC revenue and the Company's TAC costs from the prior period").

- **Existing heat pump customers** would each pay $316.73 a year less in transmission (CIEC-1(a)). I recommend that other residential customers bear that reduction (CIEC-2(b)), and CIEC-3(c) estimates the resulting increase in Rate 1 charges. Although the Transmission Adjustment Clause is reset every year, what changes each year is the dollars: each annual filing divides each class's share of transmission costs by sales from a fixed past rate year, currently "RY 2020 Billed Sales," not current sales.[16] If the billing determinants approved in this rate case place existing heat pump customers' load on Rate HP, Rate 1's transmission rate is set high enough to cover their reduction, and no shortfall arises. If they do not, the reduction becomes a shortfall each year until the next rate case, and each year's true-up would spread part of it to non-residential classes, unless the Authority directs the Company to recover that shortfall from the residential class only, as I recommend in CIEC-2(d).

[16] RAM Exhibit 4 at 4:11–18; see also CL&P, Docket No. 25-01-03, Attachment 1, Exhibits 1–11, to Dave Thompson Rates Testimony, Exhibit 2 at 4 (the same "RY 2020 Billed Sales" a year earlier) (Feb. 14, 2025).

Date Filed: November 16, 2026

Witness: **Juan-Pablo Velez**
Request from: **Connecticut Industrial Energy Consumers**

Question CIEC-8:

Please refer to Velez Direct Testimony at page 83, lines 3-16, and page 84, lines 1-12 and footnote 76.

a. Please explain Mr. Velez's understanding of the basis for the difference between the Rate 5 and Rate 1 Transmission Service Rates, and state whether he contends that difference reflects marginal transmission cost.

b. Please explain Mr. Velez's understanding of whether the winter transmission charges in the Massachusetts heat pump rates he describes were designed to recover a winter transmission revenue requirement or were instead set at an estimate of marginal transmission cost.

c. Please identify any jurisdiction of which Mr. Velez is aware that has set the retail transmission charges for a heat pump rate at an estimate of marginal transmission cost, and provide a copy of the relevant decision or tariff.

d. For each Massachusetts heat pump rate Mr. Velez describes, please explain his understanding of how any reduction in distribution or transmission revenue resulting from the rate is recovered, including whether any portion is recovered from non-residential customers.

Response:

a. The difference between the Rate 5 and Rate 1 Transmission Service Rates comes from the method the Company uses to divide its transmission costs among its rate class groups. It does not reflect marginal transmission cost, and I do not contend that it does. The Company has not computed a marginal cost of transmission.[1]

The Company allocates transmission costs by "rate class group." A rate class group is either a single rate class, such as Rate 5, or several rate classes combined.[2] Rate 5 (Residential Electric Heating Service) serves homes that use electricity as their primary source of space heat and has been closed to new

[1] CL&P Response to CLF-SC-026, at 1 ("The Marginal cost of transmission was not computed for this rate design.").

[2] Docket No. 26-01-03, *PURA Annual Review of the Rate Adjustment Mechanisms of The Connecticut Light and Power Company*, CL&P Rates Filing, Attachment 1, Exhibit 4 ("RAM Exhibit 4"), at 4:11–20 (Feb. 17, 2026) (column headed "12 CP kW Demands by Rate Class," listing Rate 1, Rate 7 and Rate 5 separately); Joint Direct Testimony of Edward Davis and Kimberly R. Parsons on behalf of The Connecticut Light and Power Company d/b/a Eversource Energy ("Davis-Parsons Direct"), Exhibit CLP-RATES-3, at 429 (July 14, 2026) (table of allocators by "Rate Class Group," including "Rate 1 & Rate 7" and "Rate 5").

applicants since December 21, 2006.[3] For transmission, Rate 5 is a rate class group of its own, and Rates 1 and 7 are combined into another.[4]

The Company sets each rate class group's Transmission Service Rate in two steps, in its annual Reconciling Adjustment Mechanism filing:[5]

1. **A share of the Company's transmission costs.** The Company divides its total transmission revenue requirement among its rate class groups in proportion to each group's average demand at the Company's twelve monthly system peaks. This follows the way ISO New England bills the Company for regional transmission, based on its load at the peak hour of each month (CIEC-7(b)).
2. **A rate per kWh.** Each rate class group's share is divided by the group's annual sales, taken from a fixed past rate year (CIEC-7(d)), and grossed up for the gross earnings tax.

The Rate 5 and Rate 1 rates differ because the two groups' demand at the monthly peaks differs relative to their sales.[6]

Rate HP would not be a separate rate class group with its own share of transmission costs, as Rate 5 is. It would sit within the Rate 1 and Rate 7 rate class group, and would change how that group's share is divided among the customers in it (see CIEC-2(c)), not the size of the share relative to other rate class groups, including non-residential customer groups. Existing heat pump customers take service under Rate 1 today, so their demand at the monthly peaks is already counted in the group's share; moving them to Rate HP would leave that demand in the share. New heat pump customers' added demand would count toward the group's share in the same way, whether they took service under Rate 1 or Rate HP.

Moreover, rate classes within the same *group* can already have different Transmission Service Rates. Rate 7 is in the same group as Rate 1, but instead of Rate 1's 5.050¢/kWh in every hour, Rate 7 customers pay 11.741¢/kWh on-peak and 2.525¢/kWh off-peak.[7]

b. My testimony cites Massachusetts as precedent for a commission directing winter transmission reductions in heat pump rates.[8] The Massachusetts winter transmission charges were designed to recover a winter transmission revenue requirement. They were not set at an estimate of marginal transmission cost.[9]

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[3] Davis-Parsons Direct, Exhibit CLP-RATES-3 at 246 ("This rate is not available to new applicants after December 21, 2006"; available "only to customers who use electric energy as the primary space heating source").

[4] CL&P Response to CLF-SC-035, at 1 ("Rate 7 is included in the cost allocation and overall revenue requirement along with Rate 1"); RAM Exhibit 4 at 4:16–20 (Rates 1 and 7 combined, Rate 5 on its own).

[5] RAM Exhibit 4 at 4:11–20, 60 (each rate class group's share of the "Transmission & TAC Revenue Target" is its share of "12 CP kW Demands by Rate Class," defined as "Average rate class KW demands coincident to the Company's 12 monthly system peaks," and the rate is that share divided by "RY 2020 Billed Sales," plus gross earnings tax).

[6] RAM Exhibit 4 at 4:18, 20 (Rates 1 and 7 combined: 1,652,552.5 kW, $372,620 thousand, 7,916,705 MWh, 5.050¢/kWh with gross earnings tax; Rate 5: 338,287.6 kW, $76,278 thousand, 1,669,921 MWh, 4.901¢/kWh).

[7] Davis-Parsons Direct, Exhibit CLP-RATES-3 at 256; RAM Exhibit 4 at 2:17, 34 (Rate 7's "Transmission Target" of 5.050¢/kWh, divided into off-peak and on-peak rates using on-peak and off-peak shares of sales that are "set at Rate 1 percentages": 27.4% × 11.741¢ + 72.6% × 2.525¢ = 5.050¢).

[8] Direct Testimony of Juan-Pablo Velez on behalf of Conservation Law Foundation and Sierra Club ("Velez Direct"), at 84:3–12 (Oct. 21, 2026).

[9] D.P.U. 25-08-A, *Inquiry by the Department of Public Utilities on its own Motion into a Seasonal Heat Pump Rate*, Order on Seasonal Heat Pump Rates ("D.P.U. 25-08-A Order"), at 19 n.4 ("'cost-based' means that the winter transmission charges were structured to be revenue neutral, recovering the capital costs embedded in the transmission service revenue requirement through

The way they recover that revenue requirement, however, rests on the same premise as Rate HP: that the added winter electricity a heat pump uses adds little or no transmission cost. NSTAR Electric's method, which the DPU later directed National Grid and Unitil to follow, has four steps:[10]

1. Hold the residential class's transmission revenue target constant.
2. Estimate how much electricity the class would use if every residential customer heated with a heat pump. For NSTAR Electric, this nearly tripled winter usage, to 2.86 times its actual level, and slightly reduced summer usage, because heat pumps cool more efficiently than central air conditioners.
3. Set the summer rate so that summer still collects the same revenue as before. Because estimated summer usage is slightly lower, the summer rate rises slightly, from 4.545¢ to 4.890¢/kWh.
4. Divide the revenue that winter collected before by the much larger estimated winter usage.

In other words, the same winter dollars are spread over nearly three times as many kilowatt-hours, so the winter rate falls to about a third of the standard rate. NSTAR Electric's figures show this. Its standard transmission rate was 4.545¢/kWh, and its winter heat pump rate was 1.590¢/kWh, almost exactly 4.545¢ divided by 2.86.[11] Consider a gas-heated home that uses 1,000 kWh in the winter months and pays $45.45 in transmission charges on the standard rate. If it installs a heat pump and its winter usage rises to 2,860 kWh, it pays $45.47 on the heat pump rate: almost exactly the same transmission bill as before, despite nearly three times the usage.

For a typical heat pump household, then, the Massachusetts design adds nothing to the transmission bill for its added winter usage. Rate HP is more conservative: it charges a typical heat pump household the marginal cost of its incremental heat pump load.

The reason for charging heat pump customers less for transmission in winter is also the same as mine: transmission costs are driven by the summer peak. NSTAR Electric explained that transmission costs "are generally set in relation to system peak demand which typically happens in the summer." The DPU agreed that transmission costs are "well-suited to seasonal heat pump rate designs that reflect the timing and manner in which demand-related costs are incurred in a system that is currently summer peaking." It concluded that lowering winter transmission charges in National Grid's and Unitil's heat pump rates "is appropriate based on cost-causation principles and the need to advance the Commonwealth's climate and equity objectives."[12]

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adjusted winter sales"), 21 (directing National Grid and Unitil to "recover the winter transmission revenue requirement over the adjusted winter sales") (June 1, 2026); *see also* Velez Direct at 84 n.76 (quoting the same directive).

[10] D.P.U. 25-55, Direct Testimony of Richard D. Chin on behalf of NSTAR Electric Company d/b/a Eversource Energy ("Chin Direct"), Exhibit ES-HP-1, at 13:1–12 (winter sales adjusted by "2.86 times the original load," summer by "a nominal adjustment reflecting some efficiency gains over central air conditioning usage"; "The revenue target for Rate R-1/R-2 is held constant to produce revenue neutral seasonal rates"; the current rate "is multiplied against test year sales for the summer period and then divided by the adjusted summer period sales to arrive at a new summer period base distribution rate"), 13:15–19 (transmission rates "calculated in similar fashion to base distribution rates"; the winter transmission price "is then calculated to collect the remaining revenue requirement over the adjusted winter period sales") (Apr. 17, 2025); D.P.U. 25-55, *Petition of NSTAR Electric Company, d/b/a Eversource Energy for Approval of Residential Seasonal Heat Pump Rates*, Order, at 8 (July 29, 2025); D.P.U. 25-08-A Order at 21 (directing National Grid and Unitil to design winter transmission charges "consistent with the design of winter transmission charges approved for NSTAR Electric's heat pump rates").

[11] Chin Direct, Exhibit ES-HP-1 at 10:8 (Table 2). 4.545¢ ÷ 2.86 = 1.589¢; 1,000 kWh × 4.545¢ = $45.45; 2,860 kWh × 1.590¢ = $45.47.

[12] Chin Direct, Exhibit ES-HP-1 at 14:12–13; D.P.U. 25-08-A Order at 19, 20; *compare* Velez Direct at 16:4–5 (distribution and transmission marginal costs "are concentrated entirely in the summer").

The results are similar too. NSTAR Electric's winter transmission rate was 1.590¢/kWh when proposed, 65% below its annual rate of 4.545¢/kWh. Rate HP's winter transmission rate would be 1.258¢/kWh, 75% below Rate 1's 5.050¢/kWh.[13]

c. I am not aware of any jurisdiction that has set a heat pump rate's retail transmission charge at an estimate of marginal transmission cost. Nor do I propose that Rate HP do so.

Rate HP's winter Transmission Service Rate is not set at marginal cost. It is set so that a customer who switches from fossil fuel heating to a heat pump keeps paying the transmission bill they paid before (which continues to contribute to the embedded cost of the existing transmission system), plus the marginal cost of the load they add.[14] Only the added load is priced at marginal cost.

d. Each Massachusetts heat pump rate was designed as if every customer who enrolled were what I call in CIEC-1(a) a "new heat pump customer": a home that heats with fossil fuels, installs a heat pump, and enrolls at the same time. As described in part (b), each company estimated how much electricity its residential customers would use if every one of them switched from gas heating to a heat pump, and set its heat pump rates to collect the residential class's existing revenue target from that usage.[15] For a new heat pump customer, enrolling does not reduce revenue. Its winter usage rises by about the assumed amount, so it pays about what it paid before installing its heat pump (see the example in part (b)). This is essentially the same dynamic I describe for new heat pump customers under Rate HP in CIEC-1(a), except that under Rate HP they pay slightly more than before, because Rate HP also charges the marginal cost of their added load.

In practice, though, many of the customers who enrolled in Massachusetts were what I call "existing heat pump customers" (CIEC-1(a)): they already had heat pumps under the default rate. Before NSTAR Electric's rates launched, it automatically enrolled every customer who had received a Mass Save heat pump rebate since 2019.[16] National Grid likewise automatically enrolled customers who had previously received a Mass Save heat pump rebate.[17] NSTAR Electric's net enrollment was 71,490 customers in the rate's first month alone.[18] Unlike new heat pump customers, existing heat pump customers did not increase their usage when they enrolled, so they now pay less than they did on the standard residential rate. The Massachusetts companies did not raise their standard residential rates to make up that

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[13] Chin Direct, Exhibit ES-HP-1 at 10:8 (Table 2: Rate R-1/R-2 transmission of "$0.04545/kWh (Annual)"; heat pump rate transmission of "$0.01590/kWh (All other months)"); Velez Direct at 82 (Table 4).

[14] Velez Direct at 85:2–7.

[15] Chin Direct, Exhibit ES-HP-1 at 13:4–5; 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*, National Grid, Exhibit HP-1, Residential Heat-Pump Rate Implementation Plan ("National Grid Exhibit HP-1"), at 4 (Dec. 30, 2024).

[16] D.P.U. 25-08, NSTAR Electric Company Response to Information Request DPU-2-4 (Jan. 23, 2026) ("Before the launch of the rate on November 1, 2025, the Company automatically enrolled all customers who had received a heat pump from a Mass Save Sponsor after January 1, 2019.").

[17] National Grid Exhibit HP-1 at 8 ("all customers who previously received a Mass Save heat-pump incentive through the Company or Boston Gas (before the Heat-Pump Rate becomes effective) will be automatically enrolled into the Heat-Pump Rate").

[18] D.P.U. 26-143, NSTAR Electric Company d/b/a Eversource Energy, Revenue Decoupling Adjustment Factor Filing for Effect January 1, 2027 ("NSTAR 2026 RDAF Filing"), at 6 (Oct. 30, 2026; pending) (net enrollment of 71,490 in November 2025; "Customers who enrolled in a heat pump rate may have pre-existing heat pump installations in their homes.").

difference, as I propose doing with Rate 1's rates for Rate HP (CIEC-2(c) and CIEC-3(c)). Instead, the difference goes into decoupling. National Grid, for example, states that any shortfall "will be included in the Company's Revenue Decoupling Mechanism."[19]

How the difference is recovered. Like CL&P's Revenue Decoupling Mechanism and Transmission Adjustment Clause (CIEC-2(d)), the Massachusetts companies' reconciling mechanisms work at the level of the company as a whole, so a portion of the difference is recovered from non-residential customers:

- **Distribution.** All three companies' decoupling mechanisms compare actual base distribution revenue with the target for the company as a whole, then allocate the total over- or under-recovery to every rate class using fixed allocators set in the last rate case. Unitil computes the difference class by class, but then sums the differences "to develop a total Company shortfall or surplus" before allocating it. The allocators assign 39.4% of any shortfall to non-residential classes at National Grid, 49.2% at NSTAR Electric, and 38.8% at Unitil.[20]
- **Transmission.** National Grid and Unitil each track the transmission over- or under-recovery for the company as a whole, add it to the next year's cost forecast, and spread the total across all rate classes by their share of the system peak. National Grid's $44.4M under-recovery for October 2024 through September 2025 was allocated this way, with 46.4% going to non-residential classes. Unitil's 2027 transmission balances are spread the same way, with 54.9% going to non-residential classes. NSTAR Electric's tariff folds any over- or under-recovery into the next annual factor and does not limit it to the class that produced it. National Grid's new Heat Pump Transmission Service Charge changes how residential customers are billed, but nothing in its tariff keeps a shortfall in that charge with heat pump customers.[21]

What the DPU has done about it. The DPU anticipated that shortfalls could occur and that they would run through decoupling.[22] It now requires each company to report, in its annual decoupling filing, heat

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[19] National Grid Exhibit HP-1 at 4.

[20] National Grid, Revenue Decoupling Mechanism Provision, M.D.P.U. No. 1635, at 1 (Distribution Revenue Allocator of "Rate R-1/R-2 60.6%"), 3 ("The amount of over- or under-recovery shall be allocated to the rate classes by applying the Distribution Revenue Allocator") (effective Oct. 1, 2026); NSTAR Electric, Revenue Decoupling Adjustment Mechanism, M.D.P.U. No. 60N, at 4 (the revenue requirement "shall be allocated to all rate class groups by applying the Base Distribution Revenue Allocator," Residential 50.795%) (effective Feb. 1, 2026); Fitchburg Gas and Electric Light Company d/b/a Unitil, Revenue Decoupling Adjustment Clause (Schedule RDAC), M.D.P.U. No. 500, at Sheet 4 ("The RDAF shall be calculated by comparing the difference between Annual Target Revenue to Actual Base Revenue for each rate class with the resulting differences summed to develop a total Company shortfall or surplus."), Sheet 6 (allocators approved in D.P.U. 26-39: RD-1/RD-2 61.18%, with HP-RES and HP-RES IE in the Residential group) (effective Nov. 1, 2026).

[21] National Grid, Exhibit PP-8, at 1 (single company-wide balance, ending Sept. 2025 under-recovery of $44.4M), and Exhibit PP-9, at 1, lines 2 (adding the under-recovery to the 2026 forecast), 5 and 6 (allocating the total by coincident-peak share, R-1/R-2 at 53.6%), both filed in D.P.U. 26-02; National Grid, Transmission Service Cost Adjustment Provision, M.D.P.U. No. 1640, at 1 ("The Company shall allocate the forecast of transmission costs and the balance of any over- or under-recoveries to its rate classes") (effective Nov. 1, 2026); Unitil, Schedule SED-3, at 3, lines 4, 10 and 12–18, and Schedule SED-4, at 3, lines 18, 22 and 28–34 (prior-year reconciliation added to costs, then allocated to class groups by 12-CP; RD-1/RD-2 at 45.15%) (D.P.U. 26-154, filed Nov. 2, 2026; pending); NSTAR Electric, Transmission Service Cost Adjustment, M.D.P.U. No. 48A, at 1 ("a full reconciliation and adjustment for any over- or under-recoveries occurring under the prior year's adjustment") (effective Jan. 1, 2025).

[22] D.P.U. 23-150, Order, at 512 n.230 (Sep. 30, 2024) ("the Department expects there to be a reduced chance of significant revenue shortfalls . . . through the revenue decoupling mechanism").

pump customers' billed revenue alongside what they would have been billed on the standard rate.[23] In NSTAR Electric's first report, its heat pump rate customers were billed $10.3 million in base distribution revenue from their enrollment through April 2026, compared with $33.2 million on the standard rate for the same usage.[24] That comparison overstates the revenue the company lost, however, because it mixes existing and new heat pump customers — both of which were and are auto-enrolled across the state — and only existing heat pump customers reduce revenue (CIEC-1(a)). New heat pump customers enrolled on the heat pump rate at the same time they increased their winter usage, so enrolling did not reduce the revenue they paid. In short, Massachusetts produces an estimate of the shortfall, and an overestimate at that, but recovers the shortfall entirely through its reconciling mechanisms, so part of it is paid by non-residential customers.

How Rate HP improves on this. Connecticut can learn from Massachusetts's experience in two ways. First, Rate HP plans for existing heat pump customers. When rates are set, the revenue they would no longer pay (for example, after a one-time mass auto-enrollment of Energize CT rebate recipients, as described in CIEC-1(a) and CIEC-1(b)) is built into Rate 1's rates, within the same rate class group (part (a) and CIEC-2(c)). The Massachusetts companies, by contrast, did not raise their standard residential rates to make up the revenue that the existing heat pump customers they auto-enrolled no longer pay. Second, for any shortfall that arises between rate cases, for example because enrollment differs from the forecast, I recommend that the Authority adopt Massachusetts's reporting requirement and go one step further: direct the Company to recover the shortfall from residential customers only (CIEC-2(d)). Together, these would keep Rate HP's effect within the residential class, a result the Massachusetts rates do not achieve.

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[23] D.P.U. 25-08-A Order at 2, 41 (directing the companies to report "the billed revenues recorded from heat pump customers in their annual revenue decoupling filings and to compare those revenues to the amounts that would have been billed if those customers had not enrolled in the heat pump rates").

[24] NSTAR 2026 RDAF Filing at 6 (billed winter base distribution revenue from each customer's enrollment through April 2026 of $10,320,004 on the heat pump rate and $33,211,094 on the non-heat pump rate; "[t]he underlying usage used for the revenue comparison is the same").

Date Filed: November 16, 2026

Witness: **Juan-Pablo Velez**
Request from: **Connecticut Industrial Energy Consumers**

Question CIEC-9:

Please refer to Velez Direct Testimony at page 7, lines 9-12; page 20, lines 9-12; page 22, lines 6-14; and page 59, footnote 63.

a. In footnote 63, Mr. Velez states that "a kWh consumed during a winter peak hour imposes far higher upstream distribution costs than a kWh consumed on a mild spring afternoon." Please identify the winter peak hours to which this statement refers and explain how Rate HP's winter distribution rate reflects them.

b. Has Mr. Velez analyzed the level of heat pump adoption at which the Company's distribution system, or individual substations or feeders, would become winter peaking? If so, provide the analysis. If not, explain why not.

c. Please describe the specific process and timing Mr. Velez recommends for recalibrating Rate HP, and state whether he would support a requirement that Rate HP be recalibrated, or automatically expire, if winter loads begin to drive distribution capacity investment.

Response:

a. The words "winter peak hour" in footnote 63 are a drafting error; they should read "summer peak hour."[1] There are no winter peak hours on the Company's system today: no hour from November through March carries enough marginal distribution or transmission capacity cost to meet my testimony's definition of a peak hour.[2] Rate HP's winter distribution rate reflects this. Because added winter usage causes almost no marginal distribution cost, the winter rate is set low enough that it adds little to a heat pump customer's bill.[3]

b. No, because the data needed for that analysis has not been made available to me.

First, there is no single level of adoption at which the Company's system becomes winter peaking. Each feeder and substation transformer has its own peak, and each would become winter peaking at a different level of heat pump adoption, depending on how many heat pump customers it serves and how much spare capacity it has. Today, the Company itself states that its system remains summer peaking.[4]

Second, finding when individual feeders and transformers would become winter peaking requires their capacity ratings and their historical and hourly loads. CLF and Sierra Club asked the Company for exactly

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[1] Direct Testimony of Juan-Pablo Velez on behalf of Conservation Law Foundation and Sierra Club ("Velez Direct"), at 59 n.63 (Oct. 21, 2026).

[2] *Id.* at 16 n.9 (peak-hour definition), 17:1–3, 19:9–20:1.

[3] *Id.* at 85:2–7.

[4] CL&P Response to CLF-SC-020, at 1 (Sep. 18, 2026) ("The Company currently does not use a heat pump forecast to inform its substation capacity projects as the system remains summer peaking.").

this information in CLF-SC-012 through CLF-SC-019.[5] The Company designated it Critical Energy Infrastructure Information and will produce it only to parties that have signed a nondisclosure agreement with the Company.[6] CLF and Sierra Club have not yet reached mutually acceptable terms for that agreement with CL&P, so I have not received the data and have not been able to perform the analysis.

c. I recommend that Rate HP be recalibrated in each base rate case.[7] In each one, the Company would update its marginal cost study, basing the probability-of-peak analysis on actual substation and feeder loads, including heat pump load. It would then repeat the calculation in my testimony: set Rate HP's winter rates so that the average new heat pump customer pays their pre-heat-pump T&D bill plus the marginal cost of their added load.[8] Rate 1's rates would be reset at the same time, based on the customers who remain on Rate 1, so Rate 1's charges would account for existing heat pump customers who moved to Rate HP since the last rate case (CIEC-2(c)). Between rate cases, the Company would report heat pump customers' revenue as described in CIEC-8(d) and recover any shortfall from residential customers (CIEC-2(d)).

I would support a requirement that Rate HP be recalibrated. I would *not* support automatic expiry, because Rate HP is not justified only while the grid system remains summer peaking: it is justified for as long as Rate 1 charges heat pump customers more than the costs they cause.

A system that becomes winter peaking raises the costs that heat pump loads cause, but that alone does not make Rate 1's charges match them; what matters is how large those costs are. As feeders and substations become constrained in winter, winter loads would begin to drive distribution capacity investment. Recalibration would then move peak hours and marginal cost into winter, and Rate HP's winter rate would rise to match. Automatic expiry, by contrast, would end the rate as soon as the first feeders turned winter peaking, while heat pump customers as a group would still be paying far more than the costs they cause.

Today, Rate 1 charges the average converting household $1,051 a year more in T&D charges, about 102 times the $10 in added marginal cost it causes.[9] Even if the Company's entire system became winter peaking, and every hour of marginal capacity cost fell on the hours when heat pump homes use the most electricity, that added cost would rise to about $332 a year, and the household would still overpay under Rate 1 by about $718.[10]

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[5] Docket No. 26-05-10, CLF and Sierra Club's First Set of Interrogatories to CL&P (Corrected), CLF-SC-12 to CLF-SC-19, at 8–14 (Sep. 4, 2026).

[6] CL&P Response to CLF-SC-012, at 1–2 ("highly confidential Critical Energy Infrastructure Information"; "the Company plans to supplement this response with production for all parties having executed an non-disclosure agreement with the Company, once an executed NDA is obtained from CLF-SC"); *see also* CL&P Responses to CLF-SC-013(a), at 2; CLF-SC-015, at 2; CLF-SC-016, at 1–2; CLF-SC-017(a), at 2; and CLF-SC-019, at 2 (same); CL&P Response to CLF-SC-014(a), at 2 (referring to the response to CLF-SC-012).

[7] *Id.* at 7:9–12.

[8] *Id.* at 85:2–7.

[9] *Id.* at 23:3–5.

[10] Illustrative calculation. I took the Company's hourly marginal distribution and bulk transmission capacity costs used in my testimony, sorted them from highest to lowest, and assigned them to the November–March hours ranked by the average converting home's electricity use after installing a heat pump, then multiplied each by the home's added load in that hour. This assumes every hour of marginal cost coincides with the hours when heat pump homes use the most electricity, so it overstates the cost: applying the same method to April through October gives $76.65 a year, compared with the $10.30 from the testimony's

hour-by-hour analysis. CIEC-9 Attachment 1, CIEC-9c_winter_peak_marginal_cost.xlsx, sheet hourly: one row per hour in columns A–J, and the results as formulas in columns M–N. The README sheet explains each column.

Date Filed: November 16, 2026

Witness: **Juan-Pablo Velez**
Request from: **Connecticut Industrial Energy Consumers**

Question CIEC-12:

Please refer to Velez Direct Testimony at page 7, lines 3-8; page 93, lines 7-12; and page 96, lines 1-12.

a. Does Mr. Velez agree that the load of existing heat pump customers is already on the Company's system and reflected in the sales used to set the Company's rates in this proceeding? If not, explain why not.

b. Please identify any new load, or any reduction in the Company's costs, that would result from enrolling existing heat pump customers in Rate HP.

c. Please provide Mr. Velez's estimate of the annual reduction in distribution and transmission revenue attributable solely to the automatic enrollment of existing heat pump customers.

d. Please explain how the "pre-heat-pump T&D bill" referenced at page 85, lines 5-7 would be determined for an existing heat pump customer.

Response:

a. Yes. This is why I attribute the entire revenue reduction from Rate HP to existing heat pump customers, and none to new heat pump customers, who add load and revenue when they install (CIEC-1(a)). It is also why I recommend that the Authority set Rate 1 and Rate HP in this proceeding on billing determinants that already assign existing heat pump customers' load to Rate HP (CIEC-2(d)).

That their load is reflected in the sales used to set rates does not mean that their rates reflect the costs they cause. Under Rate 1, they overpay for T&D by an average of $1,040 a year (CIEC-1(a)).[1]

b. None. When existing heat pump customers enroll in Rate HP, their usage does not change; they pay a lower winter rate on the same usage (CIEC-2(d)). The purpose of enrolling them is to end the overpayment described in part (a), not to change the Company's load or costs.

c. As stated in CIEC-1(a), auto-enrolling the roughly 55,000 existing heat pump customers who received Energize CT rebates (CIEC-1(b)) would reduce the Company's revenue by about **$39.8 million** in distribution and **$17.4 million** in transmission a year, or $1,040.34 per customer. Tables 1 and 2 in CIEC-1(a) report this reduction separately from the revenue increase from new heat pump customers, in the "Revenue reduced" columns. If the Authority does not auto-enroll existing heat pump customers, I would expect the reduction to be an order of magnitude smaller (CIEC-1(a)).

d. It would not need to be determined. The pre-heat-pump T&D bill on page 85 is the *population-average* bill of the modeled fossil fuel-heated homes, which I used to calibrate the rate: I found the single winter

[1] Direct Testimony of Juan-Pablo Velez on behalf of Conservation Law Foundation and Sierra Club ("Velez Direct"), at 23:9–10 (Oct. 21, 2026) ("fossil fuel-heated customers that install heat pumps overpay by an average of $1,040 a year").

rate that makes their average T&D bill after installing a heat pump equal to that pre-heat-pump bill plus the incremental marginal T&D cost.[2] That one rate then applies to every enrolled customer, new or existing, without determining any individual customer's pre-heat-pump bill.

Charging only each customer's incremental heat pump load at its marginal cost, while ideal, would indeed require a baseline for each customer, and is not practical. As my testimony explains, there are three ways to set one, and each adds complexity. A separate meter on the heat pump would add cost and friction to enrollment, and rule out auto-enrollment entirely. Circuit-level energy monitors installed with each new heat pump could be compatible with auto-enrolling new customers, but not existing ones, and their savings would likely have to be delivered as credits by a third party rather than through the Company's bill. Billing software that estimates each customer's baseline from their past usage would avoid both problems, but only if the Company committed to building it.[3] Because the first two approaches would make auto-enrollment difficult or impossible, they would lead to low enrollment and leave the cross-subsidy largely in place.[4] I therefore propose a seasonal rate, which achieves largely the same result without a per-customer baseline.[5]

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[2] *Id.* at 85:2–10 ("I found the single winter ¢/kWh rate that, applied to a sample of post-heat-pump load profiles, produces a population-average T&D bill equal to the customer's pre-heat-pump T&D bill plus the incremental marginal T&D cost"; "[b]ecause this is a single rate applied to all customers, it zeroes out overpayment *on average*").

[3] *Id.* at 79:14–81:4 ("There are at least three ways to implement per-customer thresholds."; "in order to achieve a block rate with per-customer thresholds that heat pump customers could be auto-enrolled into, the Company would either need to commit to a software-based solution, or to EnergizeCT contractors installing circuit-level energy monitors whenever they install heat pumps").

[4] *Id.* at 80:16–18 ("The first two make auto-enrollment difficult to impossible, which would lead to single-digit rate enrollment and leave the cross-subsidy largely in place.").

[5] *Id.* at 81:5–7 ("a simpler alternative to per-customer thresholds exists that achieves largely the same result: a seasonal rate design that lowers volumetric charges for heat pump customers in winter, without relying on a block threshold at all").

Conservation Law Foundation and Sierra Club
PURA Docket No. 26-05-10
Set CIEC-02
Date Issued: October 29, 2026
CIEC-016
Page 1 of 1

Date Filed: November 16, 2026

Witness: Juan-Pablo Velez
Request from: Connecticut Industrial Energy Consumers

Question CIEC-16:

Please refer to Velez Direct Testimony at page 5, lines 10-13, and page 30, lines 9-17.

a. Please confirm that the cross-subsidy Mr. Velez identifies is a cross-subsidy within the residential class.

b. Please explain why any revenue reduction resulting from a remedy for a cross-subsidy within the residential class should, or should not, be borne by customers outside the residential class.

Response:

a. Confirmed. The passage CIEC cites says so (5:11–13), as does my response to CIEC-2(b).

b. It should not. My responses to CIEC-2(b) and (c) explain why, and my response to CIEC-2(d) explains how to keep it within the residential class between rate cases.

Date Filed: November 16, 2026

Witness: **Juan-Pablo Velez**
Request from: **Connecticut Industrial Energy Consumers**

Question CIEC-17:

Please refer to Velez Direct Testimony at page 100, lines 11-13.

a. Please explain what Mr. Velez means by pricing incremental heat pump loads at "(closer to)" marginal cost, and state whether he believes incremental heat pump load should make any contribution to the recovery of embedded T&D costs.

b. If Mr. Velez believes incremental heat pump load should make some contribution to embedded T&D costs, please quantify the contribution reflected in Rate HP.

Response:

a. "(Closer to)" means at marginal cost on average rather than for every customer: Rate HP is a single rate calibrated to the average heat pump customer, as I explained in my response to CIEC-12(d).

No, incremental heat pump load should not contribute to embedded T&D costs. I answered this in full in my response to CIEC-4(b): heat pump customers keep paying their pre-heat-pump share of embedded costs, and charging their new load for more shifts other customers' embedded costs onto them.

b. Not applicable (part (a)).

CIEC-4

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 1

Date Submitted: November 11, 2026

CIEC-4

Please refer to Whited Direct Testimony at page 11, lines 6-9, and page 12, line 1 (Table 1, rows "VVO" and "Asset Optimization").

a. Please state and explain in detail whether the VVO and Asset Optimization benefits shown in Table 1 would be realized if the Company installed AMI meters but did not make the VVO enablement investment included in its AMI cost estimates.
b. To the extent those benefits depend on the VVO enablement investment, please explain why they are an appropriate basis for classifying the cost of AMI meters.

Response:

a. No. Other investments such as line devices such as voltage regulators, capacitors, and LTC controllers at substations must also be installed to unlock these benefits.

b. The benefits associated with the VVO enablement investment also depend on the installation of AMI meters, as shown in Figure 16 on page 198 of Exhibit CLP-AMI-3. Because the benefits arise from multiple investments (i.e., in the meters themselves as well as other VVO enablement investments), it would be reasonable to only attribute a portion of these benefits to the meters themselves. However, to Ms. Whited's knowledge, the benefits have not been divided across the various investments, so it is unclear what proportion should be attributed to the meters themselves.

   The benefits of Asset Optimization are more clearly attributable to the meters themselves, as AMI enables the Company to avoid the cost associated with line sensors. As explained on page 40 of Exhibit CLP-AMI-3, "Asset Optimization details the benefits of avoided cellular charges and avoided line-sensor capital associated with the AMI supported VVO program."

CIEC-5

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 1

Date Submitted: November 11, 2026

CIEC-5

Please refer to Whited Direct Testimony at page 11, lines 8-9, and page 12, line 1 (Table 1, row "Improved Restoration – Significant Storms").

a. Please explain specifically how the cost of storm restoration, or the value of reduced customer outage time during significant storms, varies with class peak demand, and provide any study or analysis supporting the classification of this $162.4 million benefit as demand-related.
b. Please identify any regulatory decision or cost allocation authority that classifies storm restoration costs as demand-related.

Response:

a. Avoided storm restoration expense relates to reduced operation and maintenance (O&M) expense such as repairing or replacing poles, conductors, and line transformers on the distribution system. Such O&M expense is classified on the same basis as the plant it maintains or restores. This plant is primarily classified as demand-related in the Company's cost of service study. Under the basic customer method I recommend, distribution poles, conductors, and line transformers (FERC Accounts 364–368) are classified as 100 percent demand-related. The expense of restoring that plant is therefore demand-related as well.
b. Ms. Whited is not aware of how other jurisdictions classify storm-related costs; however her understanding is that these costs may be allocated using allocators associated with distribution or transmission plant, and that such allocators are typically based on various measures of demand. For example:
    a. In dockets E-7, SUB 1243 and E-2, SUB 1262, the North Carolina Utilities Commission approved Duke's storm recovery cost allocation as follows: the distribution-related costs are allocated based on a composite distribution plant allocator and the transmission-related costs are allocated based on a transmission demand factor, both from the 2019 Rate Cases.
    b. Texas law requires that "system restoration costs shall be functionalized and allocated to customers in the same manner as the corresponding facilities and related expenses are functionalized and allocated in the electric utility's current base rates." 2025 Texas Statutes, Utilities Code, Section 36.403(g).

CIEC-6

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 1

Date Submitted: November 11, 2026

CIEC-6

Please refer to Whited Direct Testimony at page 4, lines 13-15, and page 11, lines 4-5 and 12-15.

a. Please explain how a classification proportional to projected benefits reflects the causes of the costs being classified, particularly where the projected benefits of the AMI program are less than its projected costs (see Exhibit CLP-AMI-3 at 17-18, Figure 7).
b. If the Company's benefit estimates are revised in a future proceeding, or actual benefits differ from those projected, would Ms. Whited's proposed classification of AMI meter costs change accordingly? Please explain the answer in detail.

Response:

a. Please see the response to CIEC-2 (d). As noted in that response, the additional cost of AMI is incurred to obtain capabilities beyond billing, such as enablement of time-varying rates, outage detection, and voltage optimization. Classifying costs in proportion to the quantified benefits therefore assigns them according to the functions the investment is designed to serve. This is the same principle that underlies classification generally: costs are classified according to the purpose for which they are incurred. The fact that projected benefits are less than projected costs does not change this conclusion.

b. Yes, if the estimated or actual benefits were to change, it would be appropriate to update the classification of the AMI meters.

CIEC-7

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 1

Date Submitted: November 11, 2026

CIEC-7

Please refer to Whited Direct Testimony at page 9, lines 13-18.

a. Please identify each AMI capability referenced at lines 14-16 that Ms. Whited contends is not currently available to customers served under Rate 39 and Rate 57 through their existing metering.
b. Has Ms. Whited reviewed the number, type or cost of the meters currently serving Rate 39 and Rate 57 customers? If so, provide the information reviewed.

Response:

a. Ms. Whited has not conducted a review of the specific metering capabilities for customers on Rates 39 or 57.
b. Ms. Whited has not conducted this review.

CIEC-8

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 1

Date Submitted: November 11, 2026

CIEC-8

Please refer to Whited Direct Testimony at page 4, lines 11-15, and page 12, lines 3-4.

a. Please identify the allocation factors Ms. Whited would use to allocate the demand-related and energy-related portions of AMI meter costs to rate classes.
b. Please provide, by rate class (including Rate 39 and Rate 57), the allocation of an illustrative $1 million AMI meter revenue requirement under (i) Ms. Whited's proposed classification and (ii) the weighted meter cost allocator used for Account 370 in the Company's ACOSS (Exhibit CLP-ACOS-2 at 16-20). Provide workpapers for the foregoing in Excel format.
c. If Ms. Whited has not performed such an analysis, please explain why not.

Response:

a. As described in her testimony on pages 20-22, Ms. Whited recommends that the Company develop equipment-level allocators for its next base rate case. However, until such allocators are available, she recommends that AMI demand-related costs should be allocated on the same basis as other demand-related distribution costs. It is Ms. Whited's understanding that most of the distribution system benefits would relate to the primary system, and thus primary demand would likely be the appropriate allocator. However, it could also be reasonable to develop a blended allocator if it can be demonstrated that a portion of benefits would also accrue to the secondary system and line transformers, which have different allocators.
   For energy-related AMI costs, Ms. Whited proposes to use kilowatt-hour sales as the allocator. For customer-related AMI costs, Ms. Whited proposes to use the weighted cost of meters.

b. See attachment "Response to CIEC-8 (b) Allocation of AMI meter costs.xlsx"

c. N/A

OCC response to CIEC-8(b)

Illustrative AMI Meter Costs		**$1,000,000**
Demand	47%	$470,000
Energy	15%	$150,000
Customer	38%	$380,000

OCC PROPOSED ALLOCATION

9	ALLOCATOR NAME	ALLOCATOR	SOURCE WORKSHEET	SYSTEM	Rate 1	Rate 7	Rate 5	Rate 18	Rate 27	Rate 30	Rate 27A	Rate 30A	Rate 29	Rate 35	Rate 37	Rate 39	Rate 40	Rate 41	Rate 55	Rate 56	Rate 57	Rate 58	Rate 115	Rate 116	Rate 117	Rate 119 - I	Rate EV-S	Rate EV-M	Rate EV-L
22	Demand-non station	NCP_P	ALLOCATOR_INPUT	1.00	49.99%	0.05%	10.35%	0.00%	0.62%	14.53%	0.06%	0.74%	0.09%	1.76%	5.14%	0.29%	0.37%	0.07%	2.48%	6.01%	2.44%	4%	0.194%	0.127%	0.098%	0%	0%	0%	0%
35	Sales kWh	ENERGY	ALLOCATOR_INPUT	1.00	42%	0%	8%	0%	1%	16%	0%	1%	0%	2%	6%	1.12%	0%	0%	3%	8%	4%	7%	0.277%	0.137%	0.110%	0%	0%	0%	0%
92		METER_370	Meter Costs weights	1.00	66%	0.22%	8.85%	0.03%	0.37%	18.02%	0.05%	0.75%	0.07%	0.82%	1.66%	0.02%	0.58%	0.01%	0.47%	1.01%	0.31%	0.43%	0.00%	0.00%	0.00%	0.02%	0.02%	0.02%	0.03%

	SYSTEM	Rate 1	Rate 7	Rate 5	Rate 18	Rate 27	Rate 30	Rate 27A	Rate 30A	Rate 29	Rate 35	Rate 37	Rate 39	Rate 40	Rate 41	Rate 55	Rate 56	Rate 57	Rate 58	Rate 115	Rate 116	Rate 117	Rate 119 - I	Rate EV-S	Rate EV-M	Rate EV-L
Demand	$470,000	$234,947	$230	$48,658	$15	$2,937	$68,303	$286	$3,496	$446	$8,254	$24,181	$1,372	$1,742	$319	$11,638	$28,262	$11,455	$20,457	$913	$596	$460	$18	$52	$100	$863
Energy	$150,000	$62,606	$66	$11,802	$5	$1,193	$24,096	$89	$1,139	$13	$3,344	$9,738	$1,678	$562	$88	$4,777	$12,325	$5,646	$9,791	$415	$206	$165	$13	$6	$24	$215
Customer	$380,000	$251,740	$841	$33,628	$132	$1,404	$68,466	$191	$2,853	$262	$3,121	$6,318	$69	$2,200	$39	$1,789	$3,821	$1,174	$1,619	$0	$0	$0	$71	$81	$78	$102
AMI Meter Cost Allocation	$1,000,000	$549,293	$1,136	$94,088	$152	$5,535	$160,865	$567	$7,488	$721	$14,718	$40,236	$3,118	$4,505	$447	$18,204	$44,407	$18,276	$31,867	$1,328	$802	$624	$102	$139	$202	$1,180

CLP CURRENT ALLOCATION

92	METER_370	Meter Costs weights	1.00	66%	0.22%	8.85%	0.03%	0.37%	18.02%	0.05%	0.75%	0.07%	0.82%	1.66%	0.02%	0.58%	0.01%	0.47%	1.01%	0.31%	0.43%	0.00%	0.00%	0.00%	0.02%	0.02%	0.02%	0.03%
		AMI Meter Cost Allocation	$1,000,000	$662,474	$2,213	$88,494	$347	$3,695	$180,175	$504	$7,507	$691	$8,212	$16,626	$182	$5,790	$103	$4,707	$10,055	$3,090	$4,261	$0	$0	$0	$188	$213	$205	$268

DIFFERENCE	SYSTEM	Rate 1	Rate 7	Rate 5	Rate 18	Rate 27	Rate 30	Rate 27A	Rate 30A	Rate 29	Rate 35	Rate 37	Rate 39	Rate 40	Rate 41	Rate 55	Rate 56	Rate 57	Rate 58	Rate 115	Rate 116	Rate 117	Rate 119 - I	Rate EV-S	Rate EV-M	Rate EV-L
		($113,181)	($1,077)	$5,594	($195)	$1,839	($19,309)	$63	($19)	$30	$6,506	$23,610	$2,937	($1,286)	$344	$13,498	$34,352	$15,186	$27,606	$1,328	$802	$624	($86)	($74)	($4)	$912

Source: Exhibit CLP-ACOS-2, APPENDIX 1A. ALLOCATORS.

CIEC-9

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 2

Date Submitted: November 11, 2026

CIEC-9

Please refer to Whited Direct Testimony at page 12, line 5, through page 13, line 5.

a. Please confirm that in the 24-10-04 Decision (at 197-198), OCC recommended that AMI costs be classified according to benefits in the customer, demand and energy categories, and the Authority "affirm[ed] the Company's proposed classification of AMI meters as 100% customer-related, which is consistent with cost causation principles."
b. Please explain why Ms. Whited's testimony does not address that determination.
c. Please identify each fact specific to CL&P that Ms. Whited contends warrants a different classification of AMI meter costs than the Authority approved for UI.
d. Other than the Maryland decision cited at page 12, line 6 through page 13, line 5, please identify every regulatory decision of which Ms. Whited is aware that adopted or rejected a benefits-based classification of AMI meter costs, and provide a copy of each.
e. Please identify each proceeding in which Ms. Whited or Synapse Energy Economics, Inc. has recommended a benefits-based classification of AMI or smart meter costs, and state the outcome in each.

Response:

a. Confirmed.
b. The Authority decides each proceeding on the evidence before it. In docket 24-10-04, OCC's recommendation was not based on estimates of quantified benefits, as these were not available at the time because the Authority found UI's benefit-cost analysis was deficient. In this proceeding, CL&P has provided quantifiable estimates of AMI benefits upon which one can develop more precise allocation factors. OCC believes that these values provide the Authority with additional information to support the classification that OCC has proposed.
c. See response to (b).
d. Ms. Whited is aware of two other cases in which a similar approach was adopted.
    a. The Colorado Public Utilities Commission has adopted a benefits-based classification of AMI meter costs. This approach was initially approved in 2017. The current 83 percent customer-related and 17 percent demand-related split will be reexamined in PSCo's upcoming rate case, as per the 2023 rate case order (attached).
    b. In 2023, the Minnesota Public Utilities Commission stated that "the new meters would primarily serve to help reduce demand and energy for the class of customers receiving the new meters. But the purpose of the meters is to benefit the utility's

entire system, and society at large; accordingly, it may well make sense to allocate AMI costs to all utility customers—including wholesale customers." Thus, the commission stated that it would no longer give preference to the traditional method of treating customer costs as customer-related and instead "Minnesota Power will have to analyze how AMI meters are associated with customer costs as well as energy costs and demand costs—or, in the alternative, conduct its class cost-of-service study using the premise that AMI costs are allocated equally to customer, demand, and energy factors." *See:* Minnesota Power's 2021 rate case order in Docket E015/GR-21-335, Feb. 28, 2023, at 61.)

e. Ben Havumaki of Synapse proposed such a classification in Consumers Energy's most recent rate case (U-22070). The outcome of this case has not yet been decided.

CIEC-10

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 2

Date Submitted: November 11, 2026

CIEC-10

Please refer to Whited Direct Testimony at page 4, lines 7-10, and page 18, lines 8-21.

a. Please confirm that in the 24-10-04 Decision (at 198), in response to OCC's recommendation of the basic customer method, the Authority stated that "it is not clear that the basic customer method is a superior alternative" and found that "[t]he MSS approach is a just and reasonable approach to cost classification."
b. Please confirm that in the 22-08-08 Decision (at 227-228), the Authority found the minimum system methodology "generally acceptable" and accepted its use.
c. Please explain why Ms. Whited's testimony cites the 24-10-04 Decision for the load-carrying capacity adjustment (page 17, lines 11-15) but does not address the Authority's rejection of the basic customer method in that same decision.
d. Please identify any facts, data or analysis specific to CL&P, or developed since the 24-10-04 Decision, that Ms. Whited contends warrant a different result in this proceeding.

Response:

a. Confirmed.
b. Confirmed.
c. While the Authority did not accept the basic customer approach in docket 24-10-04, the Authority also did not provide blanket acceptance of the minimum system approach. Rather, the Authority acknowledged OCC's concerns with the minimum system approach and stated that it accepted the MSS approach "in this proceeding." Further, the Authority stated that the MSS approach was an imperfect proxy for geographic dispersion and, on page 200 of its decision, directed UI to "explore the use of proxies that align more closely with geographic dispersion as a cost driver, rather than defaulting to MSS…" My testimony in this proceeding responds directly to these concerns and recommends the basic customer method be implemented only until a customer density analysis can be performed.
d. Because CL&P has not conducted a customer density analysis, the Authority must choose between two imperfect cost allocation methods in the interim: the minimum system approach and the basic customer method. While the Authority accepted the minimum system approach in docket 24-10-04, it limited its acceptance to that particular proceeding. The adoption of the basic customer method in this proceeding would be reasonable given the magnitude of the Company's proposed rate increase and the affordability concerns that this raises, particularly for lower-income customers, since the basic customer method

would reduce the costs allocated to the residential class (as shown on Table 3 of Ms. Whited's testimony.)

CIEC-11

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 1

Date Submitted: November 11, 2026

CIEC-11

Please refer to Whited Direct Testimony at page 15, lines 6-16.

a. Please confirm that the "additional distribution system poles and wires" that a new rural customer "may require" in order "to extend service to the customer's residence" (lines 12-14) would be required even if that customer's demand were negligible, and are therefore not caused by that customer's peak demand.
b. Under the basic customer method Ms. Whited recommends, would the cost of those poles and wires be classified as demand-related and allocated to rate classes based on class NCP demand? If so, explain how that result is consistent with cost causation.
c. Please confirm that the costs of the poles and wires required to connect customers vary with the number and geographic dispersion of customers rather than with their peak demand.

Response:

a. Confirmed.
b. Yes, under the basic customer method, the costs of poles and wires are classified as demand-related and allocated based on class NCP. Please see the response to CIEC-10 (c)-(d). Ms. Whited acknowledges that both the minimum system method and the basic customer method are imperfect proxies for geographic dispersion. For this reason, Ms. Whited recommends that the basic customer method be implemented only until a better allocator is developed.
c. Confirmed.

CIEC-12

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 1

Date Submitted: November 11, 2026

CIEC-12

Please refer to Whited Direct Testimony at page 15, line 17, through page 16, line 2.

a. Please confirm that, as described at page 15, lines 19-20, Professor Bonbright argued that the costs of the minimum system "should be excluded from demand-related costs."
b. Please explain how Ms. Whited's recommendation to classify all costs in FERC Accounts 364-368 as demand-related (page 19, lines 8-9) is consistent with that view.
c. Please provide a copy of pages 347-348 of Principles of Public Utility Rates (1961) as relied upon.

Response:

a. Confirmed. Bonbright argues that these costs cannot be classified as either customer-related or demand-related.
b. As noted above, both the minimum system method and the basic customer method are imperfect proxies for geographic dispersion, and neither is consistent with Bonbright's observation that these costs should not be classified as either demand-related or customer-related. However, CL&P has not yet conducted a customer density study, and thus a better allocator is not readily available. For this reason, Ms. Whited recommends that the basic customer method be implemented only until a better allocator is developed.
c. Please see the attachment.

CIEC-13

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 1

Date Submitted: November 11, 2026

CIEC-13

Please refer to Whited Direct Testimony at page 4, lines 3-6; page 16, lines 3-11; and page 18, lines 15-21.

a. Please provide a copy of any Ontario Energy Board decision or order (as distinct from the Board Staff Discussion Paper cited in footnote 27) that approved the density-based classification method Ms. Whited describes.
b. Please identify each U.S. state regulatory commission of which Ms. Whited is aware that has adopted a customer density-based classification of distribution plant, and provide a copy of each relevant decision.
c. Please confirm that, under the density-based approach Ms. Whited describes, a portion of distribution plant in each density category would still be classified as customer-related.
d. Please identify the data the Company would need to develop the proposed density-based approach and whether, to Ms. Whited's knowledge, the Company currently maintains those data.

Response:

a. Please refer to the attachment.
b. Ms. Whited is not aware of any US jurisdiction that has approved a customer-density based classification of distribution plant.
c. Confirmed.
d. Please see the attachment for a description of the data and methods used to perform the density study for Hydro One in Ontario, including an overview of the customer, asset, and geographic data used on page 4. Note that the Company could conduct a Connecticut-based density study without strictly adhering to Hydro One's methodology. Ms. Whited does not know whether similar data is currently maintained by the Company.

CIEC-14

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

Page 1 of 1

Date Submitted: November 11, 2026

CIEC-14

Please refer to Whited Direct Testimony at page 16, line 12, through page 17, line 15, and page 19, lines 1-7.

a. Please identify the specific per-customer load-carrying capacity values, by equipment type (e.g., primary and secondary poles, overhead and underground conductors, line transformers), that Ms. Whited recommends be used for CL&P, and provide all supporting workpapers.
b. Please confirm that in the 24-10-04 Decision (at 197-199), the Authority adopted load-carrying capacity values based on UI's own minimum-sized equipment rather than the generic per-customer values of 0.4 kW and 1.5 kW that OCC presented, and found that omitting classes whose demands can "generally" be met by the minimum system "is too imprecise to be a reasonable approach."
c. Does Ms. Whited agree that any load-carrying capacity adjustment for CL&P should be calculated from the load-carrying capability of the specific minimum-sized facilities in the Company's MDS study? If not, explain why not.
d. Please explain how the proposed adjustment would be applied to classes, such as Rate 39, that take service at primary voltage and are not allocated the costs of secondary facilities.
e. Please provide any quantification Ms. Whited has performed of the effect of her proposed adjustment on class rates of return, including for Rate 39 and Rate 57.

Response:

a. Ms. Whited requested that the Company provide these values in OCC-738 (b), but the Company stated that it has not performed such analysis and calculations. However, the Company provided the capacity of the minimum size equipment in response to OCC-728 (b).
b. Confirmed.
c. Ideally, the load-carrying capacity adjustment for CL&P should be calculated from the load-carrying capability of the specific minimum-sized facilities in the Company's MDS study. Absent this data, it would be reasonable to adopt values from other utilities (such as those adopted in 24-10-04) until CL&P values can be developed.
d. A class would receive a load-carrying credit for a component only if it is allocated the customer-related minimum system cost of that same component.
e. Ms. Whited has not performed such analysis.

CIEC-16

The Office of Consumer Counsel **Witness: Melissa Whited**

Docket No. 26-05-10

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Date Submitted: November 11, 2026

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Please refer to Whited Direct Testimony at page 4, lines 16-22, and page 21, line 11, through page 22, line 10.

a. Please confirm that Ms. Whited proposes that the equipment-level allocation study be filed alongside, and not in place of, the Company's conventional class cost of service study in its next rate case, and that she is not recommending that the Authority adopt the equipment-level method in this proceeding.
b. Please confirm that, under Ms. Whited's proposal, the loads of customers taking service at primary or transmission voltage would be excluded from the allocation of facilities at lower voltage levels that they do not use, consistent with the NARUC Manual at 97.
c. Please confirm that Ms. Whited would preserve the Company's current exclusion of customers served from customer-owned transformers from the allocation of Account 368 line transformer costs (Exhibit CLP-ACOS-1 at 6, lines 8-10).
d. Please confirm that in the 24-10-04 Decision (at 200-201), UI reported that its alternative substation and feeder allocators were "very similar" to its NCP and 1CP allocators, and that the Authority retained NCP allocators, adjusted for load-carrying capacity, for poles, conductors and line transformers.
e. Please provide any estimate Ms. Whited has made of the cost to the Company of retaining, aggregating and analyzing hourly AMI data at the substation, feeder and line transformer level.
f. Please explain how the proposed study would allocate the costs of substations or feeders dedicated to serving a single customer.

Response:

a. Confirmed.
b. Confirmed.
c. Confirmed.
d. Confirmed.
e. Ms. Whited has not developed such an estimate.
f. These would be directly allocated to the customer.

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Please refer to Whited Direct Testimony at page 5, line 6, and page 39, lines 18-20.

a. Please provide the precise tariff definition of "data center loads" that Ms. Whited proposes for the EDR exclusion.
b. Please state whether the proposed exclusion would include a minimum size threshold and, if so, what that threshold would be.
c. Please state whether the exclusion would apply to a manufacturing facility with significant on-site computing, automation or process control load, and explain how such a facility would be distinguished from a data center.
d. Please state whether the exclusion would apply to incremental load resulting from the electrification of industrial processes, such as process heating.
e. Please explain how the exclusion would apply to a facility that combines data center and non-data center operations.

Response:

a. The exclusion from the EDR should apply to facilities that classified under the North American Industry Classification System (NAICS) code 518210 (Data Processing, Hosting, and Related Services).
b. The minimum size threshold should be temporarily set at 50 MW, before a permanent threshold can be determined in a dedicated proceeding on data center tariffs.
c. See answer to subpart (a) above.
d. No. The exclusion would not apply to incremental load resulting from the electrification of industrial processes such as process heating.
e. See answer to subpart (a) above.

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Please refer to Whited Direct Testimony at page 38, lines 3-19, and page 39, lines 3-10.

a. Please confirm that the EDR approved for UI in the 22-08-08 Decision (at 252) is "available to all C&I customers, without any cap on participation," subject only to an exception for C&I customers directly participating in local commerce, and does not exclude data center loads.
b. Please identify any generation or transmission cost that Ms. Whited contends would be borne by other customers as a result of a discount applied only to the distribution charges of a data center customer.
c. Please provide any Connecticut-specific evidence that the siting decisions of data center developers are insensitive to the level of distribution rates.

Response:

a. Confirmed.
b. Ms. Whited has not identified any generation or transmission cost that would be borne by other customers as a result of a distribution charge discount.
c. Ms. Whited is not aware of Connecticut-specific evidence that data center siting decisions are insensitive to utility rates. The statement indicates that data center developments tend to prioritize speed over cost reflects national trends. See:
    - "For data center developers, speed-to-power far outweighs other factors like the price of power or access to land." Center for Strategic & International Studies. 2025. The Electricity Supply Bottleneck on U.S. AI Dominance. https://www.csis.org/analysis/electricity-supply-bottleneck-us-ai-dominance
    - "While 24/7 power availability is a central goal for data centers and hyperscalers, the top priority remains speed to market." Ascend Analytics. 2026. Data Centers and Power: Speed, Reliability, and Tradeoffs. https://www.ascendanalytics.com/blog/data-centers-energy-tradeoffs-speed-reliability
    - "Power, not location or cost, will be the primary site selection criteria due to multiyear wait times for a grid connection." JLL. 2026. 2026 Global Data Center Market Outlook. https://www.jll.com/en-us/insights/market-outlook/data-center-outlook

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Please refer to Whited Direct Testimony at page 41, lines 15-20, and page 5, lines 7-9.

a. Please state whether the proposed TOU requirement would apply only to the EDR customer's incremental load or to the customer's entire facility, including its pre-existing load.
b. Please state whether the EDR would be unavailable to customers until the proposed industrial TOU rates are filed and approved by the Authority.
c. Please state whether Ms. Whited proposes that the new industrial TOU rates be mandatory, optional or unavailable for Rate 57 and Rate 58 customers that do not participate in the EDR.
d. Please identify each jurisdiction of which Ms. Whited is aware that requires customers to take service under a TOU rate as a condition of eligibility for an economic development rate, and provide the relevant tariff or decision.
e. Please confirm that the EDR approved for UI in the 22-08-08 Decision does not require participants to take service under a TOU rate.
f. Please provide any analysis Ms. Whited has performed of the load profiles, load factors or load flexibility of Rate 57 and Rate 58 customers.

Response:

a. If the incremental load is separately metered, the proposed TOU requirement would apply only to the EDR customer's incremental load. If the incremental load is not separately metered, the proposed TOU requirement would apply to the EDR customer's entire load.
b. The EDR would be unavailable to customers until industrial TOU rates are approved by the Authority.
c. The new industrial TOU rates would be optional for Rate 57 and 58 customers not participating in the EDR.
d. Ms. Whited is not aware of other jurisdictions that require economic development rate customers to take service under a TOU rate. However, many jurisdictions that offer economic development rates also have standard industrial rates that are time-varying. For example, see the attachments for Pacific Gas & Electric's and Public Service Company of Colorado's standard industrial tariffs.
e. Confirmed.
f. Ms. Whited has not performed an analysis on the load profiles, load factors, or load flexibility of Rate 57 and Rate 58 customers.

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Please refer to Whited Direct Testimony at page 41, lines 3-14.

a. Please provide all studies, data or other support for the statement at lines 9-11 that an eight-hour on-peak period "can make it difficult for customers to manage around."
b. Please identify the on-peak period Ms. Whited would recommend for the industrial TOU rates she proposes, and provide all supporting analysis.
c. Please identify any analysis Ms. Whited has performed of the bill impacts of her proposed industrial TOU rates on Rate 57 and Rate 58 customers.
d. The reference at line 12 to "Section V.29C" appears to be a typographical error. Please identify the section of Whited Direct Testimony intended.

Response:

a. This statement is based on the duration of common commercially-deployed battery storage systems. As stated by Enel, "Most commercially deployed battery energy storage systems have storage durations of two to four hours, used for short-duration applications like ancillary services and shaving demand peaks." https://www.enelnorthamerica.com/insights/blogs/battery-storage-101-everything-you-need-to-know
b. Ms. Whited is not recommending a specific on-peak period for the industrial TOU rates at this time. The selection of the appropriate on-peak period should consider the hours with highest system load, probability of peak, distribution marginal costs, and wholesale energy prices.
c. An analysis on the bill impacts of potential industrial TOU rates on Rate 57 and Rate 58 customers has not been performed.
d. The correct reference should be to Section V.C, which begins on page 29 of the testimony.

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Please refer to Whited Direct Testimony at page 5, lines 10-13; page 43, lines 13-15; and page 44, lines 7-12.

a. Whited Direct Testimony describes the proposed discount cap as "50 percent of the net present value of incremental revenues" (page 5, lines 12-13), as "50 percent of the total incremental distribution revenue from the incremental load" (page 43, lines 13-14, describing the UI EDR) and as "50 percent of the net present value of the incremental distribution revenues, accounting for the cost of connecting the customer and any other electric infrastructure investments made to serve the incremental load" (page 44, lines 10-12). Please reconcile these descriptions and state precisely how the cap would be calculated.
b. Please confirm that Ms. Whited intends the cap and associated hurdle rate analysis to replicate those the Authority approved for UI in the 22-08-08 Decision (at 249-251). If not, identify each difference and explain why it is warranted.
c. Please state whether "the cost of connecting the customer and any other electric infrastructure investments" would include costs that the EDR customer pays directly to the Company through a contribution in aid of construction or otherwise under the Company's new business policies (CL&P Response to OCC-932(a)).
d. Please provide a numerical example illustrating the calculation of the proposed cap.

Response:

a. The cap would be calculated as 50 percent of the net present value of incremental distribution revenues from the EDR customer. The net present value would be equal to the revenues expected from the customer minus the marginal costs to serve that customer, including the payments made by the customer and costs incurred by the Company to connect the customer to the grid under the Company's new business policies.
b. The recommended cap and associated rate hurdle analysis is meant to replicate those approved by the Authority for UI in the 22-08-08 Decision.
c. See response to subpart (a).
d. Assume expected distribution revenues of $10,000,000 from an EDR customer (inclusive of any contribution in aid of construction under Eversource's new business policies), and incremental distribution costs of $6,000,000 to serve that customer (inclusive of the costs to connect the customer to the system).
   The net present value of the incremental distribution revenues is $10,000,000 - $6,000,000 = $4,000,000.
   The cap on the total discount for this customer would be 50% x $4,000,000 = $2,000,000.