STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 24-10-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO AMEND ITS RATE SCHEDULE

October 28, 2025

By the following commissioners:

David Arconti, Jr.

Michael A. Caron

DECISION

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DECISION

I. INTRODUCTION

A. SUMMARY

The Public Utilities Regulatory Authority (Authority or PURA) approves an annual revenue requirement for The United Illuminating Company (UI or Company) in the amount of $450,789,348 for the rate year November 1, 2025, through October 31, 2026. The Company may recover an additional $413,541 in executive compensation, provided the Company achieves certain performance targets. The revenue requirement includes an allowed return on equity of 9.45%; however, the Authority reduces the allowed ROE by an aggregate 20 basis point reduction, to 9.25%, to address certain performance and management issues.

In its application (Application), the Company proposed a 27.4% increase, or $105,418,797, over currently authorized revenues of $384,865,000, for a total revenue requirement of $490,283,797. The Application included a 10.5% return on equity (ROE)—a 140 basis point increase from the currently allowed 9.10% ROE.[1]

In addition to determining the revenue requirement, the Authority makes findings on a myriad of issues, including cost allocation and customer service.

B. BACKGROUND OF THE PROCEEDING

UI is a public service company within the meaning of General Statutes § 16-1. UI is a subsidiary of Avangrid Networks Inc. (Avangrid). Hr'g Tr., 950:5–15.[2] The Company currently provides electric service to over 341,000 residential, commercial, and industrial customers in 17 towns and cities in the southwestern part of Connecticut.

UI most recently increased its base distribution rates in 2023 by $22.957 million to $384.865 million. 22-08-08 Decision, p. 1. UI appealed that decision in September 2023. On March 13, 2025, the Superior Court issued a memorandum of decision largely affirming the 22-08-08 Decision but remanding two minor items back for further proceedings.

On July 9, 2025, the Authority issued a supplemental decision to address the two items on remand. In the supplemental decision, the Authority increased UI's approved annual revenue requirement by $165,000 to $385.030 million.

C. CONDUCT OF THE PROCEEDING

On October 1, 2024, UI submitted formal notice of its intent to file an application to amend its existing rate schedule. On November 12, 2024, the Company filed the

[1] The 9.10% ROE reflects a 47 basis points reduction to address performance and management issues. See Decision, Docket No. 22-08-08, Aug. 25, 2023, Application of The United Illuminating Company to Amend its Rate Schedules (22-08-08 Decision), pp. 91–102.

[2] The Authority held an evidentiary hearing on April 28, 29, and 30, 2025, and on May 1, 2, 5, and 6, 2025, with a late filed exhibit hearing continuing on May 22 and 23, 2025.

Application to amend its existing rate schedules pursuant to General Statutes §§ 16-19 and 16-19e, Conn. Agencies Regs. §§ 16-1-46 and 16-1-53 et seq., and the Standard Filing Requirements (SFRs).

The Authority held a noticed scheduling conference on December 2, 2024, at the Authority's offices, Ten Franklin Square, New Britain, Connecticut (PURA's Offices).

The Authority conducted a noticed revenue audit on December 16, 2024, and a noticed audit of the books and records of the Company on December 17, 19, and 20, 2024, at the Company's offices, 180 Marsh Hill Road, Orange, Connecticut.

The Authority held two noticed in-person public comment hearings; the first on January 27, 2025, at 5:30 p.m., at the Margaret Morton Government Center in Bridgeport, Connecticut, and the second on March 10, 2025, at 5:30 p.m., at the Fairfield Public Library in Fairfield, Connecticut. The Authority also held one noticed virtual public comment hearing on March 18, 2025.

The Authority held noticed evidentiary hearings on April 28, 29, and 30, 2025, and on May 1, 2, 5, and 6, 2025, at PURA's Offices.

The Authority held late filed exhibit hearings on May 22 and 23, 2025, at PURA's Offices. The parties and intervenors filed approximately 120 motions over the course of the proceeding.[3]

Parties and intervenors had the opportunity to file briefs on or before June 30, 2025, and reply briefs on or before July 16, 2025.

The Authority issued a proposed final decision in this matter on September 10, 2025, and provided an opportunity for the parties and intervenors to file written exceptions thereto.[4]

D. PARTIES AND INTERVENORS

The Authority recognized the following as parties to this proceeding: UI, 180 Marsh Hill Road, Orange, CT 06477; the Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, CT 06051; the Authority's Office of Education, Outreach, and Enforcement (EOE), Ten Franklin Square, New Britain, CT 06051; and the Commissioner

[3] The commissioners have reviewed all of the motion filings, objections, and associated rulings. Any motions pending as of the issuance of this Final Decision are denied or moot.

[4] A majority of the commissioners heard this matter or read the record. Consequently, a proposed final decision was not a required procedural step. However, the Authority elected to do so as a beneficial adjudicatory mechanism given the volume and complexity of the issues to be considered. The proposed final decision provides notice of the determinations under consideration by the Authority along with an opportunity for parties and intervenors to comment on the proposed determinations (and to identify errors). The proposed determinations are afforded no deference and given no evidentiary weight. The commissioners considered the full record, including written exceptions and oral argument, when issuing a final decision.

of the Department of Energy and Environmental Protection (DEEP), 79 Elm Street, Hartford, CT 06106.

The Authority granted intervenor status to the following: the Connecticut Office of the Attorney General (OAG); the Connecticut Industrial Energy Consumers (CIEC); the New England Connectivity and Telecommunications Association, Inc. (NECTA); Netspeed LLC (GoNetspeed); and Crown Castle Fiber LLC (Crown Castle).

E. POSITION OF THE PARTIES AND INTERVENORS

The Company seeks an increase in revenues of $105.4 million. Application, p. 2. UI attributes the revenue deficiency to four categories of factors driving its request, including, alleged methodology deficiencies used to set base distribution rates in Docket No. 22-08-08,[5] costs that were not allowed to be recovered in Docket No. 22-08-08; increased inflationary costs related to labor, contracts, and distribution investments; and other factors affecting the Company's operations, such as environmental remediation costs related to East Shore and changes in capital market conditions. Id. On October 17, 2025, UI submitted a motion to adopt its "Alternative Resolution Position" (Motion No. 120). In Motion No. 120, the Company stated that a revenue increase of $63.7 million "is sufficient to enable the Company to operate its business and continue providing excellent service to its customers in Connecticut." Id., Ex. 1, p. 6.

OCC actively participated in this proceeding, issuing hundreds of interrogatories, providing expert testimony, conducting cross examination during the evidentiary and late filed exhibit hearings, and by filing a brief. OCC recommends the Authority reject UI's application seeking a rate increase of approximately $25 per month for the average residential customer and instead adopt OCC's recommendations. OCC Brief, p. 4. OCC's recommendations include disallowing at least $16,744,768 in Rate Year expense and authorizing a Rate Year rate of return on rate base no higher than 6.95%. Id. Further, OCC suggests the Authority maintain an ROE reduction to incentivize UI to make improvements to its customer service. Id., p. 8. Additionally, OCC requests the Authority address the Company's incentive compensation plan, which currently benefits shareholders at the expense of ratepayers, and notes other extraneous employee perks and expenses paid for by customers without justification. Id., pp. 8–9. Also, OCC notes several unjustified in-service plant investments and recommends removal of future plant funding from the rate base until the Authority determines a cost recovery mechanism for such investments. Id., p. 9. Finally, in terms of rate design, OCC recommends use of the basic customer method rather than UI's minimum system study, and that the Authority require UI to create a more comprehensive proposal for an opt-out time-varying rate. Id.

DEEP participated in this proceeding by issuing 17 interrogatories, conducting cross examination during the evidentiary and late filed exhibits hearings, and by filing a brief. DEEP recommends the Authority maintain the adjustment to UI's ROE as a result of the Company's continued failure to comply with its public commitments to remediate English Station. DEEP Brief, p. 1. Further, DEEP recommends the Authority direct UI to

[5] Docket No. 22-08-08, Application of The United Illuminating Company Amend its Rate Schedule (Aug. 25, 2023).

adjust residential opt-in rates to reflect a gradual transition from current rates to a greater time varying rate on-peak and off-peak differential and to improve customer understanding of time varying rates. Id. Lastly, DEEP recommends the Authority direct the Company to study the behavior of customers more willing to change their usage patterns on a time varying rate and accordingly evaluate how to best create time varying rates that require a change in behavior to benefit from the rate. Id.

OAG also participated in this proceeding by filing a brief. OAG recommends the Authority reject UI's rate hike request. OAG Brief, p. 24. OAG asserts that UI failed to meet its evidentiary burden for a distribution rate increase and the rates proposed are unaffordable to its customers. Id. Further, OAG suggests the Authority should "disallow costs for the East Shore Remediation and continue to impose a 20 basis point, or $2 million per year, ROE penalty on UI for its English Station imprudence" until the Company meets state requirements. Id. Lastly, in order to encourage improvement in customer service, OAG supports the continuation of a 20 basis point ROE reduction. Id.

EOE[6] actively participated in this proceeding, issuing hundreds of interrogatories, providing expert testimony, conducting cross examination during the evidentiary and late filed exhibit hearings, and by filing a brief. EOE recommends the Authority deny both UI's 10.50% ROE request and UI's capital structure request consisting of 54.00% equity and 46.00% debt. EOE Brief, p. 1. Instead, EOE recommends the Authority consider EOE's witness, Aaron Rothschild's, approach of an 8.43% ROE and a capital structure of 50.00% common equity and 50.00% debt. Id. Additionally, EOE recommends the Company's ROE reduction imposed in Docket No. 22-08-08 should continue due to poor customer service performance. Id., p. 25. Furthermore, EOE notes that due to poor customer service, additional ratepayer funds should not be used to assist UI's recovery of executive compensation in reference to the 22-08-08 Decision. Id., p. 40. Also, EOE states UI did not satisfy time-of-use (TOU) and rate design requirements and requests that the Authority should consider the Company's TOU rate design and its potential to skyrocket the cost of the low-income discount rate (LIDR), increasing costs for all ratepayers. Id., pp. 41, 45. Lastly, EOE suggests a reduction in UI's recoverable storm costs and cites various concerns over UI's handling of storm expenses. Id., pp. 45-46.

CIEC participated in this proceeding, issuing four interrogatories, providing expert testimony, conducting cross examination during the evidentiary hearings, and by filing a brief. CIEC opposes the revenue allocation proposed by UI and recommends adjusting the limits on the upper and lower bounds of revenues allocated to the rate classes. CIEC Brief, p. 2. Further, CIEC recommends the Authority not adopt the changes proposed in the cost-of-service study provided by OCC. Id. CIEC also disagrees with UI's proposal to differentiate the class GST and LPT rates based on time and season, which would have adverse impacts on customers, and recommends instead that the Authority direct UI to propose alternative rates. Id. Lastly, CIEC supports UI's proposed special contracting policy but recommends the Authority consider modifications regarding

[6] Pursuant to General Statutes § 16-19j(b), the Authority appointed EOE as a party to this proceeding.

eligibility, applicant validation, and the nature and value of the discount provided. Id., p. 15.

NECTA participated in this proceeding, issuing 37 interrogatories, providing expert testimony, conducting cross examination during the evidentiary hearings, and by filing a brief. NECTA recommends the Authority reject UI's $21.78 proposed pole attachment rental rate for cable operators and rather adopt a $17.78 pole attachment rental rate provided by NECTA's expert witness, Ms. Patricia Kravtin. NECTA Brief, p. 2. NECTA supports denying UI's proposal to allocate funds for the purposes of the pole rental calculations from Account 592 to 593 as well as directing UI to adjust charges and credits booked to Account 593. Id., p. 24. Finally, NECTA recommends UI's annual pole attachment rental rate should be based on the maximum rate of return with consideration of intrastate services, including reductions for penalties and other factors. Id.

Finally, GoNetspeed and Crown Castle also participated in this proceeding, issuing six interrogatories, conducting cross examination during the evidentiary hearings, and by filing a joint brief. GoNetspeed and Crown Castle note that the Company's proposed Telecom rate calculation contains several errors and does not comply with the FCC methodology, including, authorized Rate of Return, appropriate Appurtenance Factor, and the maintenance charge UI is required to use in determining the Telecom pole attachment rate. GoNetspeed and Crown Castle Brief, p. 3. In addition, GoNetspeed and Crown Castle argue that UI's proposed 8.36% differential between cable and telecom rates is discriminatory and does not approach parity as required. Id., p. 12; see Decision, Sept. 12, 2012, Docket No. 11-11-02, Petition of Fiber Technologies Networks LLC for Authority Investigation of Rental Rates Charged to Telecommunications Providers by Pole Owners (Fibertech Decision). As such, GoNetspeed and Crown Castle suggest the Authority has the discretion to correct this differential and adjust the Telecom rate downward to avoid unreasonable discrimination. Id.

F. PUBLIC COMMENT

The Authority held two in-person public comment hearings and one virtual public comment hearing. UI presented a PowerPoint explaining its request at the start of each session before the admission of any public comment.

The first in-person public comment hearing took place on January 27, 2025, at the Margaret Morton Government Center in Bridgeport, Connecticut, with approximately 30 people attending.[7] Six attendees provided testimony to the Authority, with five opposing the rate increase and one supporting the increase for infrastructure maintenance. Public Hr'g Tr., Jan. 27, 2025, 14–24. Fairfield representative and chair of the Committee on Energy Initiatives, John Kuhn, attended and expressed transparency concerns over the $286 million that UI has financed for plant additions as well as concerns over storm costs paid to out-of-state companies for line repairs. Id., 23:11–19. UI customers who spoke at the hearing expressed concerns regarding a myriad of topics, including: the environmental impact on delivery; the difficulties an increase would cause seniors with

[7] The number of hearing attendees includes members of the public, state agency staff, and UI staff members.

fixed incomes; needed improvements to the electric buyback program for customers with solar panels; and the current rates being too expensive. Id., 15:1–6, 11–13, 17:17–19, 22:6–9. The President and Secretary of the Board of the Bridgeport Economic Development Corporation, Edward Lavernoich, attended and acknowledged concerns for high energy costs for residents and businesses but nonetheless offered support for investments in electrical service in order to maintain reliability. Id., 18:13–15, 19:1–5.

The second in-person public comment hearing took place on March 10, 2025, at the Fairfield Public Library in Fairfield, Connecticut, with approximately 30 people attending. Six attendees provided testimony to the Authority, with one for the increase, two against, and three providing comments without stating a position. Public Hr'g Tr., Mar. 10, 2025, pp. 23–34. UI customers who spoke expressed concerns over the current high rates for those on a fixed income and fear that the rates will be unaffordable if they are further increased. Id., 24:9, 19–20, 34:23–25. Additionally, one customer with solar panels suggested canceling the "on-peak and off-peak" program while another was concerned that continued investment in a monopoly like UI will discourage residents from adopting clean energy alternatives. Id., 23:19–24:3, 31:3–13. Alternatively, other customers expressed appreciation for the infrastructure updates completed so far and understood the need for a rate increase but requested the Company cover the public benefit charge and invest in future planning such as underground power lines. Id., 30:14–17, 23:13–19, 24:22–25:3, 28:19–21. Lastly, Fairfield representative and chair of the Committee on Energy Initiatives, John Kuhn, requested further investigation into funding used for antiquated equipment UI claims to have and if it truly needs to be updated, alleging that the Company has not been truthful in the past. Id., 32:7–15.

At the virtual comment hearing on March 18, 2025, eight individuals were in attendance, and two individuals provided testimony to the Authority. Public Hr'g Tr., Mar. 18, 2025, 18–20. The first speaker supported the rate increase for infrastructure upgrades to maintain reliability for all UI customers. Id., 19:15–20. The second speaker requested further clarification on how the rate increase will affect customers and how those predictions were determined. Id., 20:1–10.

Through the close of the evidentiary record on May 27, 2025, the Authority received a total of 279 written comments. Of these, 270 expressed opposition to the rate increase application while nine were in favor. The primary concerns expressed by the letters and emails in opposition were the negative financial impact on customers, particularly senior citizens, and low-income families. Given the current cost of living and inflation, the requested increase would place additional financial strain on customers. Senator Jason D. Perillo submitted his concerns regarding the impact a rate increase will have on households and businesses and urged the Authority to prioritize the interests of the ratepayers. Perillo Corresp., Mar. 13, 2025. Senator Perillo recognizes the importance of grid investments; however, UI customers have endured a 32% rate increase since January of 2019, which is unreasonable to residents struggling with increasing expenses. Id. The Mayor of Bridgeport, Joseph P. Ganim, also provided his opposition to the rate increase, stating that it would impact over 150,000 city residents. Ganim Corresp., Oct. 21, 2024. The mayor stated many residents are spending over 50% of their income on housing security and an additional 9% rate increase would be

burdensome. Id. Lastly, Mayor Ganim recognizes the increase would support infrastructure plans located in disadvantaged communities but asserts it should not be paid for by said community. Id.

Regarding other written comments submitted to the Authority opposing the rate increase application, overall, the UI customers' main concern was the financial burden a rate increase would put on families, seniors, and those on a fixed income (see various comments filed as Correspondence in the docket). Other comments focused on complaints of excessive corporate profit and lack of budget transparency, as well as calls for removal of the public benefits charge. Id.

The vast majority of the comments in support of the rate increase focused on the importance of funding the Reliability Investment Plan. These supporting businesses understand the hardships a rate increase will cause but argue investments need to be made to ensure grid reliability and resiliency as the demand for electricity continues to grow. Savy & Sons Corresp., Feb. 6, 2025. Landis & Gyr adds continuing investments must be made in order for UI to achieve Connecticut's robust policy objectives. Landis & Gyr Corresp., Feb. 24, 2025. Finally, commenters believe that these types of investments will provide additional employment opportunities and strengthen the community. Asplundh Tree Expert, LLC Corresp., Jan. 23, 2025.

II. STANDARD OF REVIEW

The Authority is statutorily charged with regulating the rates of Connecticut's public service companies. General Statutes § 16-19. The term "public service company" is defined to include electric distribution companies, such as UI. See General Statutes § 16-1. Consequently, UI must "file any proposed amendment of its existing rates with the [A]uthority in such form and in accordance with such reasonable regulations as the [A]uthority may prescribe."[8] General Statutes § 16-19(a). Once a proposed rate amendment has been filed, the Authority is responsible for making "such investigation of such proposed amendment of rates as is necessary to determine whether such rates conform to the principles and guidelines" in General Statutes § 16-19e, and the Authority must investigate whether the rates "are unreasonably discriminatory or more or less than just, reasonable and adequate, or that the service furnished by such company is inadequate to or in excess of public necessity and convenience . . . ." General Statutes § 16-19(a).

Importantly, a public service company bears "the burden of proving the proposed rate under consideration is just and reasonable." General Statutes § 16-22. In placing the burden on the company in rate cases, the General Assembly has attempted to remedy a critical challenge in setting rates — asymmetric access to information. The utility maintains most of the relevant and critical information necessary for the Authority to make findings of fact and associated determinations on rates. Therefore, the Authority and other parties are at an information disadvantage compared to the utility and must rely on the utility's application materials, the utility's responses to interrogatories, and the utility's witness testimony. Accordingly, the burden of proof established by General Statutes §

[8] Conn. Agencies Regs. § 16-1-53 et seq. apply to rate amendment applications.

16-22 addresses the information imbalance by imposing an affirmative obligation on the utility to present sufficient evidence to support its proposed rate amendment.

In administrative proceedings, which are subject to the provisions of the Uniform Administrative Procedures Act (UAPA), General Statutes § 4-166 et seq., the appropriate standard of proof is the preponderance of the evidence. See Jones v. Connecticut Medical Examining Board, 309 Conn. 727, 734–35, 741 n.7 (2013) ("default rule is the preponderance of the evidence standard in the absence of legislation to the contrary"); Goldstar Medical Services, Inc. v. Dept. of Social Services, 288 Conn. 790, 821 (2008) (same). "That burden of proof is met when [the company] shows the facts supporting [its] case are found to be more probable than not." Connecticut Light & Power Co. v. Connecticut Dept. of Public Utility Control, No. CV094019951S, 2010 WL 797137, at *10 (Conn. Super. Ct. Feb. 5, 2010) (citing Tianti v. William Raveis Real Estate, Inc., 231 Conn. 690, 702 (1995)). Consequently, to carry its statutory burden, the utility must provide (or ensure the record contains) evidence that, inter alia, the requested rates are consistent with the principles that rates be "sufficient, but no more than sufficient," General Statutes § 16-19e(a)(4), and "reflect prudent and efficient management." General Statutes § 16-19e(a)(5).

Notably, the utility bears the burden of providing more than mere declarations of fact. Connecticut Natural Gas Corp. v. Public Utilities Commission, 29 Conn. Supp. 379, 394 (1971) (finding "no sacrosanctity about the testimony of any company officer regardless of his position which gives such testimony any godlike fiat that must be accepted out of hand" by the Authority). "Bald statements need to be covered with some evidential hair" before they are acceptable. Id. Further, "[a]n administrative agency is not required to believe any witness, even an expert." Goldstar, 288 Conn. at 830. It is the province of the trier of fact, in this case, the Authority, to "make determinations of credibility, crediting some, all, or none of a given witness' testimony." Id.

The Authority's review of the proposed rates is guided, in part, by the principle "that the level and structure of rates be sufficient, but no more than sufficient, to allow public service companies to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable." General Statutes § 16-19e(a)(4). That language "tracks, almost verbatim, the language that the United States Supreme Court used in Hope when it interpreted the 'just and reasonable' requirement under the Natural Gas Act and the federal constitution." Connecticut Light & Power Co. v. Dept. of Public Utility Control, 216 Conn. 627, 635 (1990) (referencing Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944)). A regulated utility is entitled to an opportunity to recover prudent operating expenses as well as capital costs, including a fair and reasonable rate of return on capital investments. See Hope, 320 U.S. at 603; Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 690 (1923) (company entitled to ask for fair return upon value of capital employed for public convenience); see also Duquesne Light Co. v. Barasch, 488 U.S. 299, 310 (1989) (affirming the holding in Hope that "[i]f the total effect of the rate order cannot be said to be unreasonable, judicial inquiry . . . is at an end."). "The prudence of a management decision depends on good faith and reasonableness, judged at the time

the decision is made." Connecticut Light & Power Co. v. Dept. of Public Utility Control, 216 Conn. at 645.

Ultimately, however, rate setting requires "a balancing of the investor and consumer interests." Woodbury Water Co. v. Public Utilities Commission, 174 Conn. 258, 264 (1978) (quoting Federal Power Commission v. Hope Natural Gas Co., 320 U.S. at 603). Further, the constitution does not bind the Authority "to the use of any single formula or combination of formulae in determining rates," and the ratemaking process may involve "pragmatic adjustments." Woodbury Water Co. v. Public Utilities Commission, 174 Conn. at 264 (1978) (quoting Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942)). In striking this balance and making pragmatic adjustments, the Authority is guided by the principles of General Statutes § 16-19e(a), noted above.

III. TEST YEAR

A test year "is employed to show what the probable operating and financial condition of the company will be in the immediate future, in order that rates may be fixed which will compensate the company for all operating expenses and provide it with a fair return." Southern New England Telephone Co. v. Public Utilities Commission, 29 Conn. Supp. 253, 258 (1970). The test year in each rate application must "consist of the most recent twelve-month period available ending at a calendar quarter." Conn. Agencies Regs. § 16-1-54. Test year financial data is "limited to the actual income and expenses as determined on the accrual basis during the subject period without adjustment or alteration." Id. Applicants are required to present financial data through the SFRs. See Conn. Agencies Regs. § 16-1-53.

Here, UI proposed the period beginning January 1, 2023, and ending December 31, 2023, as the test year (Test Year). Application, p. 2.

IV. RATE BASE

A. SUMMARY

Rate base is a fundamental concept of cost-of-service ratemaking. Rate base is the investor-supplied facilities and other investments necessary to supply a utility service to consumers in a safe, reliable, and cost-effective manner. For ratemaking, rate base is the capital on which the investor may earn a return. See Federal Power Commission v. Hope Natural Gas Co., 320 U.S. at 596 (rate base calculated from "'actual legitimate cost' of the company's interstate property less depletion and depreciation and plus unoperated acreage, working capital and future net capital additions"). A "company is entitled to ask [for] a fair return upon the value of that which it employs for the public convenience." Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. at 690.

Cost-of-service ratemaking provides a return on rate base, which is the capital that has been prudently invested by shareholders and put to public use. Id. Consequently, determining rate base requires a two-prong assessment. First, the utility must prove that the company's plant is in use and is serving the public. See Cedar Island Improvement

Association. v. Clinton Electric Light & Power Co., 142 Conn. 359, 370 (1955) ("public utility company is entitled to a fair return upon the fair value of such of its property as is useful and being used in providing service"). Second, the company must prove that the capital investment was prudent and reasonable. See General Statutes § 16-19e(a)(5) ("the level and structure of rates charged customers shall reflect prudent and efficient management").

The "used and useful" standard is a "bedrock principle of utility regulation." Kentucky Utilities Co. v. Federal Energy Regulatory Commission, 760 F.2d 1321, 1324 n.4 (D.C. Cir. 1985). "Generally speaking, property not employed in the public service should not be incorporated into the base to be used to compute the fair rate of return . . . whether utility property is used or useful for inclusion in the rate base is a factual determination rather than a legal question." Southern New England Telephone Co. v. Public Utilities Commission, 29 Conn. Supp. 253, 259–60 (1970). The Authority does not allow for the inclusion of incomplete system additions or improvements into a company's pro forma rate base. See, e.g., Decision, May 19, 2021, Docket No. 20-10-31, Application of Jewett City Water Company to Amend its Rate Schedules, pp. 23–24 ("ratepayers benefit from the plant additions when they are in-service and . . . ratepayers should not be responsible for providing a return on plant that is not in-service").

Once a company has proven that property is used and useful, the company must also establish that the capital investment was prudent and reasonable. See General Statutes § 16-19e(a)(5). Specifically, "there exists a distinction between, on one hand, utility property and, on the other hand, the cost of utility property allowed in rate base, because only that portion of utility property that is the result of prudent and reasonable management is included in rate base." Connecticut Light & Power Co. v. Dept. of Public Utility Control, 219 Conn. 61, 68 (1991). To demonstrate prudency, the utility must provide evidence that the decision to undertake the investment was reasonable at the time it was made and that the capital project was managed in a reasonable and cost-effective manner. In sum, to establish its rate base for ratemaking purposes, the company must demonstrate, by a preponderance of the evidence, that the capital proposed for inclusion in rate base (1) is used and useful and (2) was invested prudently.

Rate base is calculated by taking the test year net book value of prudent capital investments and accounting for other factors, including accumulated depreciation, working capital, and non-rate base capital such as deferred taxes. The test year is intended to "be representative of conditions which will probably prevail in the immediate future when the rates will be effective." Connecticut Natural Gas Corp. v. Public Utilities Commission, 29 Conn. Supp. at 390. Certain pro forma adjustments may be permitted to recognize capital investments and other changes to rate base that occur after the test year. Id., p. 390 ("company should be permitted to adjust the test year forward for a reasonable period of time where definitely ascertainable expenses are involved during such future period").

Here, the Company proposes rate base balances as shown below. UI proposes a Rate Year average rate base of $1,384,647,638, an increase of approximately 25% from the $1,105,196,000 rate base approved on August 25, 2023. 22-08-08 Decision, p. 12.

Table 1: Proposed Pro Forma Rate Base Balances

Component	End of Test Year (Dec. 31, 2023) ($)	Rate Year Beginning ($)	Rate Year Ending ($)	Rate Year Average ($)
Plant-in-Service	2,492,095,978	2,640,121,922	2,739,061,244	2,688,443,466
Accumulated Depreciation	(818,930,242)	(954,229,601)	(1,021,351,870)	(987,931,399)
Other Rate Base	(388,719,316)	(323,287,439)	(308,441,418)	(315,864,430)
Rate Base	**1,284,446,420**	**1,362,604,882**	**1,409,267,956**	**1,384,647,638**

Late Filed Ex. 1, Att. 2 Supp., Sch. B-1.0.

Based on the record evidence, the Authority approves a Rate Year average rate base of $1,354,956,818, an adjustment of $29,690,819, as summarized in Table 2, below.

Table 2: Rate Year Average Rate Base

Component	Proposed ($)	Adjustment ($)	Approved ($)
Plant-in-Service	2,688,443,466	(86,167,557)	2,602,275,909
Water Heater Rental NBV	(11,959,711)	-	(11,959,711)
Accumulated Depreciation	(987,931,399)	67,830,475	(920,100,925)
Additions:			
Working Capital	45,846,453	(17,212,858)	28,633,595
Prepaid Expenses	4,485,635	(1,680,871)	2,804,764
Regulatory Asset - SFAS 158	53,986,199	(53,986,199)	-
Pension Cost Recovery	926,735	(926,735)	-
Environmental Deferral	240,832	(240,832)	-
Isaias Penalty Over-Under	72,393	(72,393)	-
Regulatory Proceeding Costs	637,629	(637,629)	-
Deductions:			
Rate Case Storm Reserve	(1,036,691)	1,036,691	-
Allowance for Bad Debt	-	(14,700,000)	(14,700,000)
Reserve for Injuries and Damages	(7,917,963)	-	(7,917,963)
Customer Advances for Construction	(1,156,736)	-	(1,156,736)
Pension Liabilities	(74,633,139)	74,633,139	-
Accrued Vacation	(5,007,111)	-	(5,007,111)
Customer Security Deposits	(1,136,913)	-	(1,136,913)
OPEB Deferral	(489,887)	489,887	-
Fee Free Program Deferral	(926,432)	926,432	-
Accumulated Deferred Income Tax	(317,795,723)	1,017,632	(316,778,090)
Rate Year Average Rate Base	**1,384,647,638**	**(29,690,819)**	**1,354,956,818**

B. PLANT-IN-SERVICE

1. Summary of Approved Plant-in-Service

The Authority approves plant-in-service of $2,602,275,909. The Company proposes a pro forma Test Year plant-in-service value of $2,492,361,817.[9] Late Filed Ex. 1, Att. 3 ("3-GrossPlant" tab). The Company also proposes plant additions of $148,025,943 from January 1, 2024, through October 31, 2025 (the Interim Period, the period after the Test Year and before the Rate Year) and plant additions of $98,939,323 during the Rate Year, for total proposed additions of $246,965,266[10] and a Rate Year ending balance of $2,739,061,244. For purposes of its revenue requirement, the Company proposed a 13-month average of its Rate Year plant-in-service at $2,688,443,466. Late Filed Ex. 1, Att. 2, Sch. B-1.0.

The Company's Rate Year plant-in-service consists of plant additions and retirements purportedly made (or forecast to be made) through October 31, 2026. Late Filed Ex. 1, Att. 3, Sch. 4, Sch. 5. As shown in Table 3, below, the Authority does not approve $136,785,335 of the Company's requested plant-in-service because the Company did not provide sufficient evidence to demonstrate that these projects are used and useful.[11]

Table 3: Approved Plant-in-Service

	Proposed ($)	**Adjustment ($)**	**Approved ($)**
Prior Approved	2,273,831,000	-	2,273,831,000
Net Additions through Test Year	218,530,817	(3,392,530)	215,138,287
Test Year (2023)	**2,492,361,817**	**(3,392,530)**	**2,488,969,287**
Pro Forma Additions	246,699,427	(133,392,805)	113,306,622
Total Plant-in-Service (End of RY)	**2,739,061,244**	**(136,785,335)**	**2,602,275,909**

22-08-08 Decision, p. 12; Late Filed Ex. 1, Att. 2, Sch. B-1.0.

[9] The ending Test Year plant-in-service balance originally requested in the Company's Application was $2,494,327,737. This amount was subsequently reduced to $2,492,095,978 in the Company's final update to its revenue requirement exhibits. Late Filed Ex. 1, Att. 2, Sch. B-1.0; Late Filed Ex. 1, Att. 3; Interrog. Resp. RSR-030, Att. 1. The Company-proposed pro forma Test Year plant-in-service amount of $2,492,361,817 referenced in this section of the Decision does not reconcile with the $2,492,095,978 figure reflected in the Company's revenue requirement "B" schedules, specifically Late Filed Ex. 1, Att. 2, Sch. B-1.0. As discussed in Section IV.B.4.b.i, Test Year Beginning Balance Correction, the discrepancy arises because the Company's Plant Model incorporates a different amount than the value presented in the revenue requirement schedules.

[10] This value ($246,965,266) is different than that depicted in the table ($246,699,427) because the source documents do not agree. See Section IV.B.4.b.i, Test Year Beginning Balance Correction, below, for further discussion.

[11] Section IV.C, Accumulated Depreciation, below, contains a discussion of the corresponding accumulated depreciation the Authority approves, based on the approved plant-in-service.

2. Audit Procedures

To investigate the reasonableness of the capital additions proposed by UI, PURA Staff conducted an engineering and accounting audit at the Company's headquarters. The audits were aimed at promoting transparency, verifying responsible decision-making, and validating the legitimacy of project expenditures.

A critical component of the Authority's review involved comparing the $2,273,831,000 plant-in-service balance from the Company's previous rate case with the $2,739,061,244 plant-in-service Rate Year ending balance that the Company proposed in this proceeding. See 22-08-08 Decision, p. 13; Late Filed Ex. 1, Att. 2, Sch. B-2.0. The Authority evaluated a net $465,230,244 of plant additions, plant transfers, and plant retirements. 22-08-08 Decision, p. 13; Late Filed Ex. 1, Att. 2, Sch. B-2.0. The Authority conducts an audit to help ensure that ratepayers are only paying for incremental plant additions that provide service and constitute prudent investments.

During the audit, PURA Staff evaluated property records, including supporting work orders and vendor invoices, of the Company supporting new plant additions placed in-service between September 1, 2022, and December 31, 2024. See PURA Corresp., Jan. 28, 2025. PURA Staff reviewed those records to ensure that all incremental capital investments being sought for recovery in rate base were fully disclosed and accounted for, thereby safeguarding ratepayer interests. The Authority also investigated a sample of projects and programs for new plant additions to verify compliance with procurement policies and to test the Company's invoice controls. See PURA Corresp., Jan. 31, 2025. To investigate the legitimacy of project expenditures, PURA Staff conducted an in-depth review of invoices and supporting documentation provided by the Company. This examination aimed to verify that claimed costs were accurate, reasonable, and directly related to the capital additions under review.

Concurrently, PURA Staff examined the Company's procurement policies and practices to assess whether they reflect prudent and efficient management. See General Statutes § 16-19e(a)(5). Another key aspect of the audit was the evaluation of alternative analyses presented by the Company for various projects. Specifically, PURA Staff evaluated different project execution decisions to assess whether they were cost effective and consistent with prudent and efficient management.

3. Plant Model

The Company submitted a plant model spreadsheet (Plant Model), which includes calculations of post-Test Year plant-related items, including gross plant, depreciation expense, accumulated depreciation, and depreciation-related deferred taxes. Application, Ex. UI-RRP-3, updated in Late Filed Ex. 1, Att. 3. The Company testified that it performed validation procedures on the Plant Model to ensure amounts between exhibits reconcile and errors are quickly identified. Application, Ex. UI-RRP-1, p. 108.

The Authority validated the Plant Model, including reviewing it for mathematical accuracy and verifying appropriate internal cell-referencing. During the review of the Plant Model filed with the Company's Application, the Authority identified a discrepancy

on tab 6 ("6-DepreciationExpense") of the Plant Model, wherein the January 2024 balance was inaccurately calculated. The Company admitted the error and corrected it in its updated Plant Model. Interrog. Resp. RSR-250; Late Filed Ex. 1, Att. 3. The Authority modified the Plant Model as necessary for purposes of calculating the plant-related adjustments described below.

4. Test Year Plant-in-Service

a. Summary

To determine the Test Year plant-in-service, the Authority adds the amount of prudently completed capital investments made by the Company through the end of the Test Year to the Company's previously approved utility plant. As explained above, to establish its rate base for ratemaking purposes, UI must demonstrate, by a preponderance of the evidence, that the plant proposed for inclusion in rate base (1) is used and useful and (2) the capital spent on such plant was invested prudently. To meet this burden, the Company must provide supporting evidence for each of these two prongs. The testimony of a company officer alone may not be adequate evidence that capital investments were made prudently and resulted in used and useful plant-in-service. See Connecticut Natural Gas Corp. v. Public Utilities Commission, 29 Conn. Supp. at 394.

The Company failed to satisfy its burden of proof with respect to several of the projects that it proposes to add to its plant-in-service. Accordingly, the Authority makes several adjustments to the Test Year plant-in-service, as summarized in Table 4, below.

Table 4: Test Year Plant-in-Service Adjustments

	Proposed ($)	Adjustments ($)	Approved ($)
Prior Approved (2022)	**2,273,831,000**		**2,273,831,000**
Adjustments			
Test Year Beginning Balance Correction	-	(265,839)	(265,839)
Net Metering	2,226,469	(2,226,469)	-
Municipal Dashboard	900,222	(900,222)	-
All Other Proposed Plant Additions	215,404,126	-	215,404,126
Test Year (2023)	**2,492,361,817**	**(3,392,530)**	**2,488,969,287**

22-08-08 Decision, p. 12; Late Filed Ex. 1, Att. 2, Sch. B-1.0.

b. Test Year Plant Additions

i. Test Year Beginning Balance Correction

The ending Test Year (2023) gross plant-in-service included in the Company's Plant Model does not agree with the plant-in-service listed on Schedule B-2.0 of the Company's Revenue Requirement Model. Specifically, the amount listed on the Plant Model is $2,492,361,817 and the amount listed on the Company's Schedule B-2.0 is

$2,492,095,978, a difference of $265,839. Late Filed Ex. 1, Att. 2, Sch. B-2.0; Late Filed Ex. 1, Att. 3 ("3-GrossPlant" tab). Because the Company provided no explanation for this difference, $265,839 has been removed from the Plant Model gross plant-in-service.

ii. Net Metering Plant Additions

The Company seeks to include $2,226,469 in plant additions associated with Project No. PRJ-003394, "UI – Net Metering Changes," for "information technology (IT) development and implementation necessary to deliver the new net metering tariffs to customers" under the Residential Renewable Energy Solutions program. Interrog. Resp. OCC-425; OCC Brief, p. 118; Ex. UI-CIP-3 Supp. 5, ln. 43; Ex. UI-CIP-4, p. 310.

OCC recommends disallowing the entire $2,226,469 request because the Authority ordered UI to recover its costs through the Rate Adjustment Mechanism (RAM), not base rates. OCC argues that the Authority explicitly directed UI to recover such costs through the RAM. OCC Brief, p. 118 (citing Interim Decision, Feb. 10, 2021, Docket No. 20-07-01, PURA Implementation of Section 3 of Public Act 19-35, Renewable Energy Tariffs and Procurement Plans (20-07-01 Interim Decision), pp. 47–48 (Order No. 23); Decision, June 30, 2021, Docket No. 20-07-01, PURA Implementation of Section 3 of Public Act 19-35, Renewable Energy Tariffs and Procurement Plans (20-07-01 Decision) p. 54 (Order No. 22)).

With respect to the Residential Renewable Energy Solutions (RRES) Program, the Authority ordered UI to "seek recovery of all reasonable and prudently incurred expenses [related to the RRES Program] in the applicable Rate Adjustment Mechanism proceeding (e.g., 21-01-03 or 21-01-04). All such expenses will be subject to a full prudence review." 20-07-01 Interim Decision, pp. 47-48 (Order No. 23). The Authority subsequently ordered UI to seek recovery of reasonable and prudently incurred expenses related to the Non-Residential Renewable Energy Solutions (NRES) Program in RAM. See 20-07-01 Decision, pp. 47, 54 (Order No. 22); OCC Brief, p. 119. The Authority's orders are consistent with General Statutes § 16-244z(e), which states that: "[t]he costs incurred by an electric distribution company pursuant to [General Statutes § 16-244z] shall be recovered on a timely basis through a nonbypassable fully reconciling component of electric rates for all customers of the electric distribution company."

In response to OCC's recommended disallowance, UI argues that, "in general, the Company does not recover capital costs through its RAM mechanism" and that it "does not have a separate capital cost recovery mechanism in its RAM." UI Reply Brief, pp. 35–36; Late Filed Ex. 16. The Company contends that recovery in base rates is appropriate because the project is used and useful and that excluding the costs from rate base would create "intergenerational inequities." UI Reply Brief, pp. 35–36; Late Filed Ex. 16.

The Authority finds OCC's arguments persuasive. The record demonstrates that the costs associated with Project No. PRJ-003394 fall squarely within the scope of the RAM recovery mechanism, as required by the Authority's prior orders and as consistent with applicable statutory language. See 20-07-01 Interim Decision, pp. 47-48 (Order No. 23); 20-07-01 Decision, pp. 47, 54 (Order No. 22); General Statutes § 16-244z(e). The

Company's argument that the RAM mechanism does not accommodate capital cost recovery does not overcome the clear directive in the Authority's orders that these implementation costs must be recovered through the RAM mechanism. If the Company believed a modification to the RAM process was necessary to accommodate such recovery, it could have sought such relief through a separate petition or docketed request.

UI requests that the Authority "confirm that these costs may be presented for recovery in the RAM." UI Written Exceptions, p. 22. The Authority reiterates that UI was previously ordered to seek recovery of all reasonable and prudently incurred expenses for the RRES and NRES Programs in the applicable RAM proceeding, in which those expenses would be subject to a full prudence review." See 20-07-01 Interim Decision, pp. 47–48 (Order No. 23); 20-07-01 Decision, pp. 47, 54 (Order No. 22).

If UI seeks recovery in a future RAM proceeding, it must provide sufficient evidence for the Authority to conduct a full prudence review. In this proceeding, the Company failed to substantiate the prudency of its $2,226,469 request. Although the Company identified general reasons for the increase in costs since its initial and even revised estimate, UI has not adequately explained in this proceeding why the final plant addition amount exceeds the most recent estimate by nearly 47%. As noted by OCC, UI originally estimated project implementation costs at $500,000. OCC Brief, p. 118; see 20-07-01 Interim Decision, pp. 10, 12. This figure was not wholly inclusive of all net metering investments and only included IT functionality to provide net metering functionality on a customer's bill. Late Filed Ex. 68. However, in compliance with an order in the 20-07-01 Interim Decision, on June 30, 2021, UI reported a revised IT cost estimate of $1,515,792, which included additional functionality, such as front-end application portal development and website and accounting system integration costs. Order No. 1 Compliance, June 30, 2021, Docket No. 20-07-01, Att. 1. This additional functionality was included to comply with Order Nos. 13 and 20 of the 20-07-01 Interim Decision, which required updates to the Company's website and net metering portal. Late Filed Ex. 68; see also 20-07-01 Interim Decision, pp. 46-47. OCC contends that the Company did not adequately explain why the $2,226,469 it now seeks to include in rate base is nearly 47% higher than UI's updated $1,515,792 estimate. OCC Brief, pp. 118–119.

Accordingly, the Authority adopts OCC's recommended adjustment and does not grant recovery of the $2,226,469 in requested plant additions in this proceeding, because UI failed to comply with the Authority's order to seek recovery in a RAM proceeding.

iii. Municipal Dashboard

In the instant proceeding, the Company seeks to include capital expenditures related to Project No. PRJ-002266, the municipal dashboard (Dashboard), in rate base. Interrog. Resp. RSR-251. The Dashboard is an online portal developed to provide municipalities with real-time outage information during storm events. Ex. UI-CIP-4 REDACTED, p. 346. In response to discovery in the instant proceeding, the Company stated that its rate base request pertains to "capital additions for the development, integrations (sic) and implementation of the [Dashboard]." Interrog. Resp. RSR-251.

The Dashboard project was originally introduced in Docket No. 22-08-08, in which the Company sought recovery of $825,000 each year for the three proposed rate years for costs associated with the Dashboard. 22-08-08 Decision, p. 160. The Authority reviewed the request and denied rate base treatment of the costs, instead approving recovery as an operating expense. 22-08-08 Decision, p. 46. The record evidence presented by the Company in Docket No. 22-08-08 clearly indicated that the $825,000 request included the development costs for the Dashboard and the Company did not make known an intention to seek future recovery of additional development costs in a subsequent proceeding. Specifically, the Company's Emergency Preparedness Panel testified in Docket No. 22-08-08 that the $825,000 request for recovery in that proceeding encompassed the "costs of developing and maintaining the [Dashboard]," Docket No. 22-08-08, Ex. UI-EPP-1, pp. 23, 25 (emphasis added). The capital additions UI now requests would constitute an improper recovery for the same project. Allowing recovery of the proposed additional costs would not only result in unjustified overcollection from ratepayers but would also set an adverse precedent by signaling that utilities may segment project costs across multiple rate cases in a manner that obscures the true and total cost of a given investment. Accordingly, the Authority does not allow the inclusion of $900,222 of pre-2024 net plant related to this project and ($9,711) of post-2024 net plant related to this project.[12] Ex. UI-CIP-3 Supp. 5, ln. 53.

iv. Pole Attachment Make-Ready Capital Costs

UI seeks to include $23,556,152 in capital additions in rate base relating to Project No. PRJ-002110, "Make Ready Cap – Pole Attachments" for costs incurred by the Company to perform engineering and construction work necessary to accommodate new third-party attachments on utility poles.[13] Ex. UI-CIP-3 Supp. 5, ln. 47; Late Filed Ex. 1, Att. 3 ("4.1-PlantAdditionsDetail Update" tab). According to UI, this work was completed "to render its poles safe and to facilitate the expansion of broadband in the state, consistent with state policy." UI Reply Brief, p. 47. The Company has not produced sufficient records in this proceeding to demonstrate that the $23,556,152 in requested costs were prudently incurred and that those costs should be borne by ratepayers.

OCC recommends disallowance of the full amount. OCC asserts that the project largely "reflect[s] non-billable capital costs incurred by UI to complete make ready engineering and construction to accommodate a new attachment on a pole." OCC Brief, p. 132 (citing Ex. UI-CIP-4, pp. 327–339). In support of its position, OCC states that "[i]n any scenario where the work would not be necessary 'but for' a new request to attach to a pole, the incremental cost should be assigned to the new attacher," yet "the Company is requesting that ratepayers absorb nearly $25 million of make ready costs while new

[12] See Section IV.B.5, Pro Forma Plant Additions, below, for the adjustment of the proposed post-2024 plant additions related to the Municipal Dashboard.

[13] UI's request of $23,556,152 in capital additions consists of $15,839,517 of proposed Test Year plant additions and $7,716,635 of post-Test Year plant additions. Ex. UI-CIP-3 Supp. 5, ln. 47 (test year plant additions); Late Filed Ex. 1, Att. 3 ("3-GrossPlant" and "4.1PlantAdditionsDetail Update" tabs) (post-test year plant additions).

attachers pay less than $400,000."[14] OCC Brief, p. 132. OCC further contends that the Company's supporting documentation includes "lists of an estimated 2,000 projects, the majority of which include rate base additions reflecting non-billable capital costs," but that Exhibit UI-CIP-4 "includes no accompanying information to ascertain the need for the additions; reconcile actual plant investments against proposed work; determine how the Company concluded that the investments were non-billable; and most importantly, [determine] why the Company incurred such extraordinary costs to accommodate third party attachments." OCC Brief, p. 132.

OCC further argues that the Company failed to implement the Authority's directive in Docket No. 19-01-52RE01 to apply the FCC's cost-sharing rule (47 CFR §1.1408(b)). In that proceeding, the Authority directed that "where there is a preexisting safety violation and a pole replacement is required, but it cannot be determined who caused the violation and if there are no unauthorized attachers, then all entities attached to the pole – plus the new attacher – should equitably and proportionately share in the cost to fix the violation." Decision, May 11, 2022, Docket No. 19-01-52RE01, PURA Investigation of Developments in the Third-Party Pole Attachment Process – Make Ready (19-01-52RE01 Decision), p. 43. OCC noted that the Company acknowledged that "if an issue is identified, and the cost causer cannot be readily determined, the Company remediates the issue." OCC Brief, p. 137; Interrog. Resp. OCC-791.

The Company's current practice—allocating nearly all make-ready costs to ratepayers while attachers bear minimal costs—does not comport with the clear directives articulated in the 19-01-52RE01 Decision. 19-01-52RE01 Decision, p. 65 (Order No. 14). Nor is there evidence of prudent and efficient management of this aspect of the Company's franchise, because the Company is attempting to recover from ratepayers a cost that the Company can and should recover from its contract counterparties (i.e., pole attachers). In short, the Company seeks to be indemnified for a cost that it has created through improper financial management of the make-ready process.

The Company did not offer sufficient evidence that it has implemented an internal process to apportion costs among attachers where the cost causer is uncertain. Nor has UI shown that its methodologies ensure that make-ready costs are assigned based on cost causation principles. The Company also failed to supply adequate supporting documentation for the requested rate base additions. The Company stated that "mapping cost data on an individual pole basis is not feasible," and concedes that it did not supply "all the information requested due to the extensive manual effort that would be required." OCC Brief, pp. 132–133 (quoting Interrog. Resp. OCC-791, p. 2). Although the Company indicates that its internal systems retain survey data and annotated photos, it has not produced sufficient records in this proceeding to show that the requested costs were prudently incurred. See Late Filed Ex. 87, Att. 1; Interrog. Resp. OCC-791, pp 2–3; Hr'g Tr., 1587:10–1589:25.

[14]OCC's brief quantifies this adjustment as approximately $25 million, whereas the Authority's adjustment is $23,556,152. These two figures differ because OCC refers to gross plant as shown on Ex. UI-CIP-4, whereas the Authority refers to net plant as calculated within the Plant Model.

Further, UI concedes that it does not follow the Authority's directives in the 19-01-52RE01 Decision and instead provides a number of reasons for not doing so. Interrog. Resp. OCC-870, pp. 4–5. These reasons include UI's belief that attachers will not abide by UI cost allocation decisions, leading to billing disputes and delayed make-ready work. Id. Instead, UI simply remediates the issue, bills the other pole owner if the pole is jointly owned, and does not bill any existing attacher. Interrog. Resp. OCC-791, p. 3.

Finally, as OCC notes in its brief, there is an "overwhelming disparity between the contributions of pole attachers – just $362,523 – and the requested $25 million contribution from ratepayers. Interrog. Resp. OCC-794; Ex. UI-CIP-3 Supp. 5. Between these two exhibits, ratepayers are expected to shoulder 98.5% of the total cost."[15] OCC Brief, p. 135. This disparity is important because even a well-managed pole attachment program might result in some residual costs that the Company could not reasonably recover from the responsible party. In that case, such costs could be shown to be prudent and could be recovered from ratepayers.

Here, however, the large disparity between the costs incurred and the amount recovered from responsible parties supports a finding that the Company has not acted prudently and efficiently. And the Company has not offered sufficient evidence to contradict such a finding. The Company's financial management of its make-ready process is inconsistent with cost causation principles and imposes on electric customers costs, most of which are related to third-party broadband deployment, that result from the Company's financial mismanagement of its make-ready process.

Accordingly, in the Company's next rate amendment application, the Authority may not allow the Company to include similar costs in rate base unless the Company provides sufficient evidence that:

(1) UI has implemented an internal process to apportion costs among attachers where the cost causer is uncertain;[16]
(2) UI's methodologies ensure that make-ready costs are assigned based on cost causation principles; and
(3) UI's costs are reasonable, prudently incurred, and supported by adequate documentation for the requested rate base additions.

In this proceeding, however, the Authority allows in rate base the $15,839,517 of pre-2024 net plant and $7,716,635 of post-2024 net plant related to this project.

v. Barnum Avenue Bridge Replacement Project

UI seeks to include $16,906,514 of capital additions in rate base relating to Project No. 801941.01, the Barnum Avenue Bridge Replacement Project, for costs incurred by

[15]OCC refers to the gross plant costs related to pole attachments.

[16]As the Authority has previously directed, "where there is a preexisting safety violation and a pole replacement is required, but it cannot be determined who caused the violation and if there are no unauthorized attachers, then all entities attached to the pole – plus the new attacher – should equitably and proportionately share in the cost to fix the violation." 19-01-52RE01 Decision, p. 43

the Company to relocate, design, and rebuild a new underground system from Barnum Substation to accommodate, in part, a Connecticut Department of Transportation (CT DOT) bridge construction project. Ex. CIP-3 Supp. 5, ln. 19; Ex. CIP-4, p. 132; Late Filed Ex. 1, Att. 3 ("4.1-PlantAdditionsDetail Update" tab).[17] Part of the project included $1,776,064 to install 12 conduits across the newly constructed bridge. Late Filed Ex. 67. According to UI, this work was completed to support future capacity and reliability needs, as well as to avoid later work that would disrupt traffic on the bridge and include costly roadway repairs. Late Filed Ex. 67; Hr'g Tr., 1101:5–1102:15.

OCC recommends a disallowance of $1,776,064, related to the 12 duct lines installed as part of the project. OCC Brief, p. 44. OCC argues that the Company provided insufficient evidence demonstrating the need for additional duct lines and that the duct lines are not currently used and useful. OCC Brief, p. 111. Regarding the need for the unused duct lines, OCC argued that UI has simply made claims about future needs without providing any supporting evidence justifying the necessity or the benefit to customers. OCC Brief, p. 111. OCC also argued that it is inappropriate to include costs associated with the duct lines because they are not currently being used. Id.

According to the Company, the installation was "an opportunity for the future for the reliability of Stratford for . . . additional electrification to get more circuits out of that area in a more efficient way than . . . going up the railroad right-of-way." Hr'g Tr., 1102:8–15. The CT DOT bridge replacement project created a one-time opportunity to reconfigure the area around its Barnum Avenue substation in a manner that will promote reliability. Specifically, the Company testified that "[t]he opportunity to . . . get across that bridge . . . is once in a hundred [years]," and that the project allowed UI "to be able to get out of there and serve that community for the next hundred years." Hr'g Tr., 1123:4–1126:3. The one-time opportunity nature of this investment certainly warrants consideration, as "there is a benefit to customers when those projects are going on to do it once, do it the right way and share the cost with the State so we're not doing it twice." Id., 1104:11–14. The Company stated, "we could have spent a little less dollars here but then come back and inconvenience them more and spend more in totality on delivering the same scope that I think is in the best interest of customers." Id., 1106:6–10.

The circumstances surrounding this project warrant heightened scrutiny, because the principle that plant must be "used and useful" before being included in rate base is a foundational standard of public utility regulation. Indeed, the concept that ratepayers should only pay for property that is actively providing service is a critical safeguard that helps ensure just and reasonable rates. That said, the Authority also recognizes that a rigid, mechanical application of the used and useful standard may, in extremely rare cases, disincentivize utilities from making strategic decisions that would reduce long-term costs to ratepayers or improve system efficiency. Based on the unique facts of this project, the Authority finds that such a rare circumstance is present here. As explained

[17] UI's request of $16,906,514 in capital additions consists of $17,237,237 of proposed Test Year plant additions and ($330,723) of post-Test Year plant additions. Ex. UI-CIP-3 Supp. 5, ln. 19 (test year plant additions); Late Filed Ex. 1, Att. 3 ("3-GrossPlant" and "4.1-PlantAdditionsDetail Update" tabs) (post-test year plant additions).

at the evidentiary hearing, the Company's decision to undertake additional work in connection with the CT DOT bridge replacement project created a one-time opportunity to reconfigure the area around its Barnum Avenue substation in a manner that promotes long-term system reliability. The Company testified regarding the once in a century nature of the opportunity, and that the project will prepare UI to serve that community in the coming years. See Tr., May 6, 2024, 1123:4–1126:3. The Authority finds this testimony persuasive.

Given the exceedingly rare opportunity related to this project, the Authority is making a narrow exception in this proceeding based on the Company's specific and credible testimony that this was a "once in a hundred year" opportunity. The used and useful standard is a binary threshold: either a plant addition is providing utility service, or it is not. Here, the Authority renders a narrow, fact-specific determination based on what the Authority finds to be a credible opportunity to avoid significant future costs and to improve system resiliency in a high-priority area. Although OCC is correct that a portion of UI's investment in the Barnum Avenue Bridge Replacement Project is not currently in use, the Authority acknowledges the practical reality that, had the Company deferred this work, future execution of the same system improvements would likely have been substantially more expensive or potentially infeasible. Encouraging utilities to act logically and strategically when a once-in-a-hundred-years' cost-saving or system-enhancing opportunity arises is consistent with the broader goals of prudent utility planning and responsible stewardship of ratepayer funds. Accordingly, the Authority will allow the inclusion in rate base of the full net plant additions associated with the Barnum Avenue Bridge Replacement Project. The Company shall provide a report to the Authority of the status of the plant and when the Company anticipates the plant will be used for the supply of electricity to customers, filed as compliance in this proceeding, every six months until the plant is being used for the supply of electricity to customers.[18]

The fundamental rule that plant must be used and useful before being included in rate base remains unchanged. The Company should have proactively identified this project as a special circumstance in its Application and specifically categorized it as plant not currently providing service to customers but nonetheless warranting rate base inclusion due to a rare opportunity.

In future rate proceedings, the Authority will not consider for rate base inclusion any completed plant that is not used and useful—no matter how rare the opportunity to construct the plant may have been—unless the utility clearly and proactively identifies the plant in its application as demonstrative of extenuating circumstances and with documentation and analysis showing that the construction was the result of prudent utility planning and responsible stewardship of ratepayer funds. In future applications, if UI requests inclusion in rate base any completed plant that is not used and useful, its application must contain sufficient information for the Authority to consider whether there exists a special circumstance justifying that inclusion. Such documentation includes

[18]Before allowing such requests in future, the Authority will consider the status of previously allowed projects, which may indicate whether the Company's ability to forecast future needs should be relied upon.

information about (1) the anticipated cost of completing the plant at a later date (i.e., the anticipated cost savings of the project), (2) the risk that the plant will never be put into service for ratepayers benefit (i.e., the likelihood that the plant will not be used), (3) the Company's plan for future use of the plant, including the forecasted date it will be used, and (4) any other available information relating to whether the plant was prudently constructed at the time.

vi. New Congress Getaway South

The Company seeks recovery of $3,662,777 for Project No. PRJ-003425, relating to plant additions associated with the installation of duct infrastructure under a floodwall near the New Congress substation.[19] According to UI, "the objective of this project was to provide a reliable duct structure through the floodwall to meet the needs of customers in Bridgeport." OCC Brief, p. 120 (citing Ex. UI-CIP-4, p. 614). The identified benefit was to "[p]rovide cable-ready conduits for NuPower and provide a reliable path out of the substation for current customers and future growth." OCC Brief, p. 120 (quoting Ex. UI-CIP-4, p. 614).

OCC argues that "[a]lthough the project is complete, no ducts in the conduit system contain energized cables." OCC Brief, p. 12 (citing Interrog. Resp. OCC-472). OCC also states that the Company has identified the project as a reimbursable project "because NuPower may eventually reimburse UI for approximately $591,000," which is one-sixth of the total cost of Project No. PRJ-003425. OCC Brief, p. 120 (citing Ex. UI-CIP-4, pp. 619, 625). OCC asserts that, "[a]t minimum, the additional ducts reserved for NuPower should be excluded from rate base because the project will either not proceed, or UI will be reimbursed—and in either instance it is inappropriate to charge general ratepayers for this portion of the project." OCC Brief, p. 120.

There is no reasonable dispute that the project is not currently used and useful. Interrog. Resp. OCC-472; Hr'g Tr., 1161:16–19; Interrog. Resp. OCC-479.[20] In Section IV.B.4.b.v, Barnum Avenue Bridge Replacement Project, above, the Authority stated that, under certain narrow circumstances, completed plant may be included in rate base, even though it is not currently used and useful. According to the Company, the "scope of the New Congress Getaway South project was to create usable conduit systems from the Substation to points outside of the floodwall."[21] Interrog. Resp. OCC-478. The Company did not demonstrate any foreseeable use of the project within a short period, but provided

[19]UI's request of $3,662,777 in capital additions consists of $3,647,506 of proposed Test Year plant additions and $15,271 of post-Test Year plant additions. Ex. UI-CIP-3 Supp. 5, ln. 102 (test year plant additions); Late Filed Ex. 1, Att. 3 ("3-GrossPlant" and "4.1-PlantAdditionsDetail Update" tabs) (post-test year plant additions).

[20]The Company argued that projects "become used and useful when ready for service under the Company's accounting standard." UI Reply Brief, p. 37 (citing Hr'g Tr., 1123–24, 1162). However, the Company's accounting standards do not supersede applicable ratemaking principles, nor do they dictate when plant is deemed used and useful. The Company is not currently using the conduits; therefore, they are not used and useful.

[21]The plan to allocate 1/6 of the conduits to NuPower appears to be the only plan associated with this project. However, NuPower would likely be responsible for its share of the costs to interconnect, meaning that the Company will be compensated directly by NuPower for this amount. Hr'g Tr., 1159–1161.

evidence that the conduits would serve customers in the long term. Hr'g Tr., 1161:23-25 ("they are in the place they need to be, you know, to serve customers in the long term."). As to timing, the Company testified:

> we don't have a need to [pull cables in the conduits] right now. . . . we could have that conduit extended . . . if we have a need, but we -- we stop short of that cost until we have the need. And that need might be NuPower, or NuPower may not go forward, and -- and we would execute that in the future.

Hr'g Tr., 1162:21–1163:9.

In consideration of the likely benefits to ratepayers compared to the risk of inutility, the Company asserts that performing the floodwall penetration after construction "would have been more complex, costly, and disruptive." Interrog. Resp. OCC-478. The Company also posited that penetrating the floodwall after construction would be "more costly than incorporating the exits in the current construction." Interrog. Resp. OCC-479; see also Hr'g Tr., 1158:17–18 ("we took an opportunity to punch through that substation wall as it was being constructed, because doing it after the fact is going to be a significant cost."). [22]

Under the limited circumstances presented here, the Authority will allow the inclusion in rate base of the full net plant additions associated with the New Congress Getaway South Project. [23] The Company shall provide a report to the Authority of the status of the plant and when the Company anticipates the plant will be used for the supply of electricity to customers, filed as compliance in this proceeding, every six months until the plant is being used for the supply of electricity to customers.

5. Pro Forma Plant Additions

a. Summary

The Authority permits utilities to make pro forma adjustments to the test year plant-in-service for plant additions identified in the application but made after the test year. Specifically, a utility is permitted to include new plant additions, provided the company can demonstrate that (1) the plant is used and useful and (2) the costs were prudently incurred. Further, a utility is permitted to submit evidence to meet this evidentiary burden through the close of the record; however, projects first *identified* after the filing of the rate application may constitute an amendment to the application subject to Conn. Agencies Regs. § 16-1-58.

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[22] The Company did not quantify the savings from performing the work when it did versus the work that would be required if the specific need for the plant arises in the future. As such, it is impossible to determine whether the relative savings are worth the risk that the plant may not be used. A higher level of savings may justify some degree of uncertainty as to the need for or timing of the project. In future requests, the Company must provide information about the potential savings and the risk of inutility.

[23] The Company testified that NuPower may reimburse a portion of the project cost; if such a payment occurs, ratepayers must receive the benefit of that reimbursement. Hr'g Tr., 1160:2–1161:11.

Here, the Company proposes a total of $246,699,427 in pro forma adjustments to the Test Year plant additions. Specifically, the Company identified $114,241,388 of plant additions in the 16-month period after the Test Year, i.e., between January 1, 2024, through April 30, 2025 (Interim Period).[24] Late Filed Ex. 1, Att. 3 ("4.1-PlantAdditionsDetail Update" tab). In addition, the Company seeks $132,458,039 of plant additions projected to be made in the 18-month period from May 1, 2025, through its proposed 12-month Rate Year (i.e., to October 31, 2026) (Future Period). Late Filed Ex. 1, Att. 3 ("4.1-PlantAdditionsDetail Update" tab).

As summarized in Table 5, below, the Authority approves $113,306,622 of pro forma plant additions to rate base, which is supported by the evidence in the record.[25]

Table 5: Pro Forma Net Plant Addition Adjustments

Description	Amount ($)
Proposed Pro Forma Plant Additions	**246,699,427**
Adjustments	
Interim Period	
Rider LIDR	(944,477)
Municipal Dashboard	9,711
Future Period	(132,458,039)
Total Adjustment	**(133,392,805)**
Allowed Pro Forma Plant Additions	**113,306,622**

b. Interim Period Plant Additions

i. Rider LIDR (PRJ-003494)

The Company seeks to recover net plant additions of $944,477, related to the Rider LIDR Project (PRJ-003494). Late Filed Ex. 1, Att. 3 ("3-GrossPlant" and "4.1-PlantAdditionsDetail Update" tabs). The Company states that the incurred costs were related to SAP upgrades to implement the Low-Income Discount Rate (LIDR), automate enrollment through data exchanges with state assistance programs, handle annual recertification with required correspondence, and remove customers who fail to recertify. Interrog. Resp. CAE-050, Att. 1.

The inclusion of the Rider LIDR Project costs in rate base, however, is inconsistent with the explicit order of the Authority in a prior proceeding. Decision, Oct. 19, 2022, Docket No. 17-12-03RE11, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – New Rate Designs and Rates Review (2022 System Planning Decision), pp. 29–30, 43. In that proceeding, "UI estimated that the total cost for [LIDR] implementation could run from $0 to $700,000." Id., p. 29.

[24] April 30, 2025, is the last date the Company identified plant additions before the close of the record.

[25] Table 5 includes the plant addition adjustments beginning in 2024 for the Municipal Dashboard, as discussed in Section IV.B.4.b.iii, above.

The Authority directed UI to seek recovery of these costs through the applicable RAM proceeding, stating:

> The Authority directs . . . UI to submit their incurred costs associated with the implementation of a LIDR in a given calendar year they believe to be prudently incurred into the subsequent year's annual review of the Revenue Adjustment Mechanisms (RAM) proceeding (e.g., costs incurred in 2023 shall be submitted into the 2024 RAM proceeding, etc.). All costs shall be reconciled through the [Systems Benefits Charge] and included as separate line items in the corresponding RAM exhibits (i.e., discount provided v. LIDR design IT costs vs. administration costs, etc.) . . . .

2022 System Planning Decision, p. 29 (Section IV.F., Cost Recovery). In addition, the Authority ordered UI to recover its LIDR implementation costs in RAM:

> In future Rate Adjustment Mechanism proceedings, each EDC shall include the following, as directed in Section IV.F of this Decision:
>
> a. Submit its prudently incurred costs associated with the implementation of a LIDR as separate line items . . . .

Id., p. 43 (Order No. 11). Further, the Authority stated that "the approval of any implementation costs will be done through the appropriate RAM proceedings." Id., p. 30.

With the launch of any new or innovative initiative – particularly a legislatively-directed one such as the LIDR, it is imperative that the Authority and all stakeholders benefit from the transparency that is derived from accounting for an initiative's costs in a clear and concise manner. By directing the recovery of LIDR implementation costs through the RAM (i.e., the same mechanism through which other LIDR programmatic costs flow), the Authority recognized that a future evaluation of the efficacy of the LIDR program would benefit from a streamlined consideration of the costs through RAM – and not across multiple proceedings and rate recovery mechanisms.

When asked at the evidentiary hearing why the Company did not seek recovery of these costs through the RAM, the Company's witness stated that, "capital costs don't -- have not flown through the SBC," and they did not know why "it would be appropriate to change that for this" project. Hr'g Tr., 236:8–9, 237:9–11. The Company did not, however, object to or seek reconsideration of PURA's explicit order at any time after the Authority issued it on October 19, 2022. There is no evidence that the Company sought recovery in this proceeding because it believed recovery through a RAM proceeding to be improper or unlawful. Instead, the Company either intentionally or inadvertently failed to follow the Authority's orders in 2022 System Planning Decision. Neither is permissible.

The Authority expressly ordered the Company to seek recovery of LIDR implementation costs through the RAM and not through base rates. Inclusion of these costs in rate base is inconsistent with the explicit directive of the 2022 System Planning Decision and, as such, the Authority does not allow recovery of the Company's requested Rider LIDR net plant additions of $944,477 in this proceeding.

c. Future or Incomplete Plant

The Company proposed a pro forma adjustment of $132,458,039[26] for net plant additions projected to be made in the Future Period, after the record closed in this proceeding and continuing through the 12-month Rate Year. Late Filed Ex. 1, Att. 3 ("4.1-PlantAdditionsDetail Update" tab). Inclusion of forecasted incomplete plant deviates from the fundamental principle that rate base should solely reflect prudently invested capital actively serving the public interest. See Cedar Island Improvement Association v. Clinton Electric Light & Power Co., 142 Conn. at 370 (public utility company entitled to fair return upon useful property that is being used to provide service). Consequently, the Authority does not allow the inclusion of proposed plant additions in rate base because forecasted plant investment, by its nature, is not used and useful, and it is not currently employed in the public service.

6. Plant-in-Service Reconciliation Mechanism

With regard to the future period plant additions, the Company proposes a reconciliation mechanism that it states will be used as one of the "guardrails" to "prevent customers from paying for plant additions that do not materialize . . . ." UI Brief, pp. 78-79. The Authority acknowledges that the Company's proposal is a "downward-only" reconciliation—meaning that the Company would not seek to reconcile overages. Ex. UI-RRP-1, pp. 111–112. Nevertheless, the Company's proposal does not address the Authority's fundamental concern with future period plant additions — namely, that such additions are, by their very nature, not yet used and useful, and as such, should not be incorporated into the base used to compute a fair rate of return. Southern New England Telephone Co. v. Public Utilities Commission, 29 Conn. Super. 253, 259-260 (1970). Accordingly, the Authority declines to adopt the Company's proposed reconciliation mechanism.

C. ACCUMULATED DEPRECIATION

The Company proposes an average Rate Year balance for accumulated depreciation of ($987,931,399). Late Filed Ex. 1, Att. 2 Supp., Sch. B-1.0. As shown in Table 6, below, the Authority approves an average balance depreciation reserve of (920,100,925), which reflects an adjustment of $67,830,475.

Table 6: Accumulated Depreciation Summary

Description	Proposed ($)	Adjustment ($)	Approved ($)
Average Balance Accumulated Depreciation Reserve	(987,931,399)	67,830,475	(920,100,925)

[26]The adjustment of $132,458,039 was determined by removing all plant additions after May 1, 2025, itemized on tab 4.1 ("4.1-PlantAdditionsDetail Update") from the Plant Model (Late Filed Ex. 1, Att. 3). The date of May 1, 2025, was selected because April 30, 2025, is the last date on which the Company identified plant additions before the close of the evidentiary record. As such, no further evidence is available in the record on which to assess the prudency of plant additions scheduled for completion after May 1, 2025.

Accumulated depreciation (or depreciation reserve) reflects the amount of depreciation expense that has been allowed in rates and accumulated to date, less any retirements and net salvage received as an offset to rate base. See 22-08-08 Decision, p. 20; Decision, July 28, 2021, Docket No. 20-12-30, Application of the Connecticut Water Company to Amend its Rate Schedule (20-12-30 Decision), p. 70. As such, the depreciation reserve reflects the asset deterioration of in-service plant and is maintained in anticipation of future asset replacement or retirement needs. Id. The accumulated depreciation should be based on the depreciation rates and useful service lives that fall within the National Association of Regulatory Utility Commissioners (NARUC) guidelines and have been allowed or approved by the Authority. Id. Ideally, assets are depreciated consistently, i.e., proportionally, with the rate of the actual deterioration of assets until they are retired or replaced. Id.

The product of the depreciation rate and plant-in-service balance is the annual depreciation expense, which is recorded to reflect the annual recovery or amortization of previously expended capital investment. The depreciation expense impacts the calculation of accumulated depreciation as any depreciation expense allowed for in rates, past or current, should be accounted for in some way in the calculation of accumulated depreciation. Section VI.B, Depreciation Expense, below, details the Authority's analysis of the allowed annual depreciation expense of $84,026,124, which is $2,923,090 less than UI's proposed depreciation expense.

The Authority may calculate the depreciation reserve to include all depreciation that occurs through the beginning of the Rate Year (i.e., November 1, 2025), because the Company's rate base does not cease depreciating at the close of the evidentiary record. See Aquarion Water Company of Connecticut v. Public Utilities Regulatory Authority, No. HHB-CV-23-6078177-S, 2024 WL 1403433, at *9 (Conn. Super. Ct. Mar. 25, 2024) (holding a utility's "rate base does not somehow cease depreciating after [a date following which the utility] failed to present sufficient evidence demonstrating that capital investments made by [the utility] after that date were reasonable and prudent. Depreciation continues to occur regardless, even if [the utility] fails to meet its evidentiary burden as necessary to enter investments into rate base."). Nonetheless, after examining the specific facts of the instant proceeding, the Authority exercises its discretion regarding the accumulated depreciation accrual date in recognition of the statutory obligation to set just and reasonable rates while "faced with varied and complex accounting procedures when considering rate increase applications." See Aquarion Water Company of Connecticut v. Public Utilities Regulatory Authority, No. HHB-CV-23-6078177-S, 2024 WL 1403433, at *9 (Conn. Super. Ct. Mar. 25, 2024) (quoting Woodbury Water Co., 174 Conn. at 266). The Authority "must remain flexible in order to meet its overall obligation of setting just and reasonable rates that balance the interests of the consumer as well as that of the company." Woodbury Water Co., 174 Conn. at 267. Accordingly, the Authority elects not to include the accumulated depreciation of $37,029,884 for the period May 1, 2025, through October 31, 2025, based on the Authority's allowed plant-in-service, for purposes of calculating rate base in this proceeding.

The Authority calculated the approved depreciation reserve by summing the Test Year depreciation reserve, the 2024 depreciation accrual, and the depreciation accrual

for January through April 2025. The 2024 depreciation accrual and the January 2025 through April 2025 depreciation accruals were derived by modifying the Plant Model with the Authority's specific plant-in-service adjustments.[27] Accordingly, the Authority's approved depreciation reserve of (920,100,925) ($818,930,242 + $75,906,134 +$25,264,549) is a change of $67,830,475 from the Company's proposed reserve of ($987,931,399). See Late Filed Ex. 1, Att. 2, Sch. B-1.0. This difference is a result of the flow-through impact of the adjustments to the Company's proposed plant-in-service, as discussed in Section IV.B, Plant-In-Service, above. Specifically, the depreciation reserve is primarily a function of depreciation expense, which in turn is largely driven by depreciable plant. Accordingly, when the approved plant-in-service is less than the Company's proposed plant-in-service, both depreciation expense and the depreciation reserve are also reduced. Table 7, below, summarizes the depreciation reserve, as approved in this Decision.

Table 7: Depreciation Reserve

Description	Amount ($)
Previously Approved Depreciation Reserve (Dkt. 22-08-08)	(800,575,000)
Test Year Depreciation Reserve	(818,930,242)
2024 Depreciation Accrual	(75,906,134)
Jan. 1, 2025 – April 30, 2025 Depreciation Accrual	(25,264,549)
Depreciation Reserve as of November 1, 2025	**(920,100,925)**

22-08-08 Decision, p. 12; Late Filed Ex. 1, Att. 2 Supp., Sch. B-3.0 (second row); see Late Filed Ex. 1, Att. 3 (7-AccumulatedReserve tab) (used to calculate third and fourth row).

D. WORKING CAPITAL

1. Approved Working Capital

The Company proposes a working capital balance of $45,846,453 consisting of $38,948,809 for cash working capital (CWC) and $6,897,644 for Materials and Supplies (M&S). Late Filed Ex. 1, Att. 2 Supp., Sch. B-1.0, Sch. B-4.0. The Authority approves a working capital balance of $28,633,595.

Table 8: Approved Working Capital

Working Capital	Proposed ($)	Adjustment ($)	Approved ($)
Cash Working Capital	38,948,809	(15,309,743)	23,639,066
Materials & Supplies	6,897,644	(1,903,115)	4,994,529
Total	**45,846,453**	**(17,212,858)**	**28,633,595**

[27] The output obtained from Plant Model tab 7 ("7-AccumulatedReserve") was utilized for these calculations.

2. Cash Working Capital

a. Summary

The Authority approves a CWC allowance of $23,639,066 reflecting a reduction of $15,309,743 from the Company's proposed $38,948,809. Late Filed Ex. 1, Att. 2 Supp., Sch. B-1.0, Sch. B-4.0. The adjustments to the Company's proposed CWC, summarized in Table 9 below, result from the exclusion of non-cash items, a revised collections lag, disallowance of the payment lag adjustment, and flow-through impacts of PURA's expense adjustments.

Table 9: CWC Adjustments

Adjustment Name	Adjustment ($)
Non-Cash Items	(12,018,421)
Collections Lag	(1,769,819)
Payment Lag	(734,365)
Expense Adjustments	(787,138)
Total CWC Adjustments	**(15,309,743)**

Late Filed Ex. 1, Att. 2 Supp., Sch. B-4.0 WP (modified for PURA adjustments).[28]

It is a customary regulatory practice to include a CWC allowance – an adjustment to rate base in recognition of the timing difference between when revenues are received and when expenses are paid. For larger utilities, the Authority has established a preference that a lead-lag study be conducted to determine the appropriate CWC allowance, rather than to rely on a heuristic approach (such as a percentage of an operation and maintenance (O&M) expense).

There is a myriad of issues present with respect to UI's proposal for its cash working capital allowance. First, the Company's proposed cash working capital calculation is inconsistent with the calculation methodology approved by the Authority in Docket No. 23-11-02. 23-11-02 CNG Decision, pp. 24–28. The Company's calculation methodology includes non-cash items that were explicitly not allowed in the prior case by the Authority. 23-11-02 CNG Decision, pp. 25–26. In addition, the Collection Lag for the Test Year in this proceeding is 2.41 days shorter than the Collection Lag for 2021. Interrog. Resp. RSR-267. Using the Collection Lag for 2021 improperly inflated the Company's CWC request by $1,769,819. Finally, the Company utilized an unsupported Payment Lag. The Company's inclusion of the unsupported Payment Lag inflated the Company's CWC request by $734,365.

b. Lead/Lag Study

For purposes of calculating its proposed cash working capital allowance in the instant proceeding, UI relied on a lead-lag study that was originally developed for Docket

[28]The Authority applied the adjustments consecutively from top to bottom in succession to avoid any potential duplication. The adjustment quantifications within this table represent the incremental impact of the individual adjustments.

No. 22-08-08. This study detailed the lead/lag period to expenses and revenues. The "lag" is measured in days and represents the time between when customers receive service and the date customers' payments are received. These "lag" days are offset by "lead" days, which represent the time between when a Company receives goods and services and when it pays for them. 22-08-08 Decision, pp. 22–23.

i. Non-cash Items

In its calculation of CWC, the Company included non-cash items, such as depreciation, amortization expense, and deferred taxes. Ex. UI-RRP-1, pp. 123–124. OCC argued that non-cash expenses should not be part of the calculation of CWC. Defever PFT, p. 5.

In support of its inclusion of non-cash items, the Company argues that there are two "broad approaches to performing lead-lag studies." Ex. UI-RRP-1, p. 120. The Company refers to one methodology as the "O&M approach" (Approach 1), which does not include non-cash items, and focuses "on O&M cash expenses, plus taxes." Ex. UI-RRP-1, p. 120. The Company refers to the other methodology as the "non-O&M approach" (Approach 2), which uses all cash flows but also incorporates "items that are considered 'non-cash' from an accounting definition" but that UI claims have "cash-flow implications for the Company." Ex. UI-RRP-1, p. 120. The Company proposes to use this second methodology. Ex. UI-RRP-1, pp. 125–126. Although the Company proposes Approach 2, it claims that "[i]f utilized correctly, either method will produce a reasonable estimate of cash working capital requirements, and regulators in various jurisdictions have relied on both methods." Ex. UI-RRP-1, p. 120.

Based on the evidence in the record, the Authority finds that Approach 1 is the more appropriate methodology by which to calculate CWC and, therefore, does not allow the inclusion of non-cash items in the CWC calculation. Notably, the Company's own definition of CWC does not allow for the inclusion of non-cash items in CWC. 22-08-08 Decision, p. 22 ("[CWC is] the amount of funds required to be kept on hand to finance the day-to-day operations of the Company."). Because CWC is fundamentally cash-based, inclusion of non-cash data is incompatible with its purpose.

Additionally, the Company's claim that Approach 1 and Approach 2 both produce a "reasonable estimate" of CWC is not supported by the evidence in the record. The Company's own analysis found that the Company's preferred approach (Approach 2) resulted in CWC that is over $12 million higher than when calculating with Approach 1. Late Filed Ex. 1, Sch. B-4.0 WP ($38.981 million vs. $26.963 million).

For the foregoing reasons, the Authority approves the use of Approach 1, which removes uncollectibles, depreciation, amortization, deferred taxes, interest, net income – external dividend, and net income – retained, from the CWC calculation. The exclusion of all non-cash items results in a CWC that is $12,018,421 less than that proposed by UI.

ii. Collections Lag

The Collections Lag is a component of the Company's proposed revenue lag computation. Interrog. Resp. RSR-266, Att. 1. In the instant proceeding, the Company proposes the same collections lag of 44.27 days that it used in Docket No. 22-08-08. Ex. UI-RRP-1, p. 119. Calendar year 2021 data was used to calculate the proposed collections lag. Interrog. Resp. RSR-267.

When asked in discovery whether the Company conducted any analysis to determine whether the proposed collection lag remains appropriate, the Company stated that it did not perform such analysis, but that reliance on a lead-lag study for multiple year periods is consistent with prior cases. Interrog. Resp. RSR-267. The Company also asserted that the calculated collections lag is similar to the amounts accepted in previous proceedings (specifically, Docket Nos. 13-01-19 and 16-06-04) and that using the 2021 financial data "has the further benefit of being calculated over a period consistent with the period over which expense leads were calculated." Interrog. Resp. RSR-267.

The Company's reliance on seven- to ten-year-old rate case data is unpersuasive, as such data points provide little—if any—meaningful information in this particular instance. Additionally, evidence in the record demonstrates that, when the Test Year data for the instant proceeding (2023) is used to calculate the collections data, the results are significantly different than the Company's proposed collections lag. The Company's proposed collections lag (using 2021 data) is 44.27 days, whereas the collections lag using 2023 data is 41.86 days, a reduction of 2.41 days. Interrog. Resp. RSR-267. The Authority also does not find compelling the Company's claim that there is a "benefit" to the 2021 data being used because the data is "consistent with the period over which expense leads were calculated." The Company could have chosen to update all elements of its lead-lag study with 2023 data if it had deemed such a factor to be important. The fact that it chose not to does not preclude the Authority, where supported by the record, from adjusting individual components of the lead-lag study to be more reflective of current data. Accordingly, the Authority adopts a collections lag of 41.86 days based on 2023 data, reducing the Company's proposed lag by 2.41 days and lowering CWC by $1,769,819.

iii. Payment Lag

Similar to the Collections Lag, the payment processing lag is a component of the Company's proposed revenue lag computation. Interrog. Resp. RSR-266, Att. 1. For purposes of the Company's calculation, UI assumed a payment lag of one day. Interrog. Resp. RSR-266, Att. 1. The Company's assumption of a one-day lag lacks evidentiary support. Specifically, the spreadsheet provided as support for this figure contained a hard-coded "1" in the column titled "Average Lag Time Days" with no underlying calculation for how the "1" was derived. Interrog. Resp. RSR-269, Att. 1.

The Company also made assumptions in its calculations that appear inconsistent with the underlying data. For example, the Company used a one-day payment lag for "Wires/ACH" payments, even though the description of this item states that these payments are processed "same-day." Interrog. Resp. RSR-269, Att. 2.

Accordingly, the Authority finds that the Company's proposed payment lag adjustment of $734,365 is not supported by the evidence and is therefore not allowed.

iv. Expense Adjustments

Finally, the Authority adjusts the CWC to account for the disallowance of certain operating expenses, which results in a lower CWC requirement.[29] A summary of the CWC impact of the Authority's expense adjustments is noted in Table 10, below.

Table 10: Impact of Expense Adjustments on CWC[30]

Expense Category	PURA Expense Adjustment ($)	CWC Adjustment Factor	CWC Adjustment ($)
Compensation	(301,500)	0.1113	(33,557)
Employee Benefits	(227,626)	0.1468	(33,415)
Income Tax	(4,917,242)	0.0640	(314,703)
Other O&M	(14,971,618)	0.0261	(390,759)
Other Taxes	(2,787,959)	(0.0276)	76,948
Property Tax	(343,518)	0.2668	(91,651)
Total	(**23,549,463**)		**(787,138)**

3. Material and Supplies

The Company proposes the inclusion of $6,897,644 for distribution Materials and Supplies (M&S) in the working capital balance for Rate Year 2025/2026. The Company recorded distribution M&S of $7,940,791 in the Test Year and made a ($1,043,146) pro forma adjustment for a Rate Year request of $6,897,644. Late Filed Ex. 1, Att. 2 Supp., Sch. B-4.0. The Authority approves distribution M&S of $4,994,529, as shown in Table 11, below.

Table 11: Proposed and Approved Distribution M&S

	Test Year 2023 ($)	Pro Forma Adjustment ($)	Pro Forma Test Year ($)	Adjustment ($)	Approved ($)
Distribution M&S	7,940,791	(1,043,146)	6,897,644	(1,903,115)	4,994,529

The Company applied a 65.14% distribution allocation factor to its proposed $10,589,194 13-month average for total M&S, which includes distribution and transmission. Interrog. Resp. RRU-060, Att. 1. The 65.14% distribution allocation is derived as the percentage of distribution plant to total Company plant as noted in FERC Form 1, pp.

[29]The "CWC Adjustment Factor" utilized for purposes of this adjustment incorporates the impact of the adjustments (such as the disallowance of the payment processing lag) discussed in the preceding sections.

[30]The expense adjustment contained in Table 11 may not correspond exactly to the tax expenses, detailed in Section VI.C, Taxes, approved by the Authority, due to the impact of the CWC adjustment on the approved tax expenses.

204–207, lns. 58 and 75. Application, Sch. H-1.1. The Authority has reviewed FERC Form 1 and finds that the distribution amount is accurately represented at 65.14%.

The Company's reported total M&S has increased significantly overall from 2019 to 2023, from $5,985,670 in 2019 to $11,998,198 in 2023; although, the total M&S balance showed a decline in 2021 to $5,756,792 from the 2020 balance of $6,263,828. The Company provided no explanation for this variation in amounts over the years or the 100% increase from 2019 to 2023 in total M&S balances, as shown in Table 12, below.

Table 12: Materials and Supplies, 2019-2023

	2019	2020	2021	2022	2023	Average
Total M&S ($)	5,895,670	6,263,828	5,756,792	8,332,396	11,998,198	7,667,377
Distribution %	61.92%	62.61%	62.95%	64.46%	66.18%	65.14%
Distribution M&S ($)	3,706,289	3,921,818	3,623,933	5,371,076	7,940,791	4,994,529

Interrog. Resp. RRU-060, Att. 1.

Although the Company proposed a pro forma Test Year adjustment of ($1,043,146), the proposed Rate Year balance of $6,897,644 still represents an 86% increase over the 2019 balance of $3,706,289 for distribution M&S. Due to the large increase in M&S and the provision of no explanation by the Company for such an increase, the Authority will utilize the average of the 2019-2023 total M&S balances of $7,667,377, multiplied by the 65.14% distribution allocation factor, for an allowed distribution M&S balance of $4,994,529, as shown in Table 12, above.

E. RESERVES AND REGULATORY LIABILITIES

1. Summary

The Company proposes regulatory liabilities with a total rate year average of $92,304,872 (($103,985,756 + $80,623,985) / 2) to reduce the Company's rate base. Late Filed Ex. 1, Att. 2 Supp.; Sch. B-1.0; Sch. B-8.0; Sch. WP C-3. The Authority instead allows costs relating to the rate case storm reserve, OPEB deferral, pension liabilities, and fee free program deferral to be treated as O&M expenses and amortized outside of rate base, as detailed in Section VI.A.17, Other Deferred Expenses, below. In addition, the Authority determines that the Company's $14,700,000 reserve for uncollectible expenses or bad debts represents an accumulation of allowed recoveries that are not yet expended and should be treated as an offset to rate base. Accordingly, the Authority approves regulatory liabilities with a total rate year average of $29,918,723 to reduce the Company's rate base.

Table 13: Approved Reserves and Regulatory Liabilities

Category	Company Test Year ($)	Company Pro Forma ($)	Rate Year Beginning Balance ($)	Rate Year Ending Balance ($)	Proposed Rate Year Average ($)	PURA Adjustment ($)	Approved Rate Year Average ($)
Rate Case Storm Reserve	-	(2,073,381)	(2,073,381)	-	(1,036,691)	1,036,691	-
Allowance for Bad Debt	(14,700,000)	14,700,000	-	-	-	(14,700,000)	(14,700,000)
Reserve for Injuries and Damages	(7,917,963)	-	(7,917,963)	(7,917,963)	(7,917,963)	-	(7,917,963)
Customer Advances for Construction	(1,156,736)	-	(1,156,736)	(1,156,736)	(1,156,736)	-	(1,156,736)
Pension Liabilities	(119,175,775)	34,710,208	(84,465,567)	(64,800,711)	(74,633,139)	74,633,139	-
Accrued Vacation	(3,476,000)	(926,559)	(4,402,559)	(5,611,662)	(5,007,111)	-	(5,007,111)
Customer Security Deposits	(1,136,913)	-	(1,136,913)	(1,136,913)	(1,136,913)	-	(1,136,913)
OPEB deferral	-	(979,774)	(979,774)	-	(489,887)	489,887	-
Fee Free Program deferral	-	(1,852,863)	(1,852,863)	-	(926,432)	926,432	-
Total Distribution Reserves	(147,563,387)	43,577,631	(103,985,756)	(80,623,985)	(92,304,872)	62,386,149	(29,918,723)

Late Filed Ex. 1, Att. 2 Supp.; Sch. B-1.0; Sch. B-8.0; Sch. WP C-3.21.

2. Allowance for Bad Debts

The Company proposed a pro forma adjustment to zero out the $14,700,000 Test Year allowance for bad debts in UI's proposed rate base. Sch. B-8.0. The Authority disallows the Company's pro forma adjustment to remove $14,700,000 of allowance for bad debts as a reduction to rate base.

UI stated that its lead-lag study reflects an "expense lead associated with uncollectible accounts . . . as an element of the Company's proposed working capital allowance in rate base," and that the allowance for bad debts was removed from rate base to avoid "double counting." Ex. UI-RRP-1, p. 130; Ex. UI-REBUTTAL-1, p. 13. However, UI asserted that its concerns about double counting were "not the primary reason why the allowance for bad debt" should be removed from rate base, and that UI proposed the removal "to be consistent with the approach to setting uncollectible expense for revenue requirements purposes that reflects write-offs, but not reserve adjustments. In other words, customers have not 'funded' this reserve and, accordingly, should not receive the benefit of this reserve in the form of a rate base reduction." Ex. UI-REBUTTAL-1, p. 13. UI also argued that its "approach is consistent with the precedent set by UI's gas affiliates, [The Southern Connecticut Gas Company], and [the Connecticut Natural Gas Corporation], in their recent base distribution rate cases, Docket No. 23-11-02."[31] Ex. UI-REBUTTAL-1, p. 13; Interrog. Resp. OCC-554.

UI testified that once a provision for bad debts is determined, the bad debts or write-off account is either debited or credited, with offsetting entries to the reserve or provision account. Interrog. Resp. RRU-65, p. 2. UI also noted that "[n]on-Hardship reserve calculation is based on an estimated movement of aged receivables against an

[31]UI did not propose such an adjustment to remove the allowance for bad debts from rate base in Docket No. 22-08-08, and the Company did not make an argument about double counting in Docket No 23-11-02.

estimated Non-Hardship Uncollectible factor against total active Customer Accounts Receivable." Interrog. Resp. RRU-65, Att. 1, p. 1. The adjustments to the reserve balance reflect uncollectible factors, which are used to determine the levels of customers' account receivables to be written off as bad debt expenses. The growth in bad debt expenses correspondingly increases the allowance for bad debts. Interrog. Resp. RRU-65, Att. 1, pp. 1–3. The bad debt or uncollectible expenses allowed in rate cases are based on averages of historical uncollectible factors or expenses.

The uncollectible expense that the Company reflected as a credit in the working capital calculation only returned about 30% of the annual uncollectible expense, not the total amount in the allowance for bad debts. In addition, there is no double counting of uncollectible expense in the cash working capital and as the allowance for bad debts, because the Authority approves the O&M approach to calculating cash working capital.[32]

F. REGULATORY ASSETS

The Company proposes including regulatory assets with an average Rate Year balance of $55,863,788 in rate base. The Authority instead allows costs relating to the regulatory assets contained in Table 14, below, to be treated as O&M expenses and amortized outside of rate base, as detailed in Section VI, Allowable Expenses, below.

Table 14: Adjustments to Regulatory Assets

Category	Proforma Rate Year Beginning Balance ($)	Proposed Rate Year Average ($)	PURA Adjustment ($)	Approved Rate Year Average ($)
Regulatory Asset - SFAS 158	57,317,577	53,986,199	(53,986,199)	-
Pension Cost Recovery	1,853,470	926,735	(926,735)	-
Environmental Deferral	481,664	240,832	(240,832)	-
Isaias Penalty Over-Under	144,785	72,393	(72,393)	-
Regulatory Proceeding Costs	1,275,258	637,629	(637,629)	-
Total	**61,072,754**	**55,863,788**	**(55,863,788)**	**-**

Late Filed Ex. 1, Att. 2 Supp., Sch. B-1.0, Sch. B-6.0, Sch. WP C-3.21.

G. PREPAID EXPENSES

UI proposed and included in rate base a Rate Year average balance of $4,485,635 for prepaid expenses or prepayments, which includes $2,581,320 for prepaid software maintenance costs as well as costs related to the PURA Assessment. Late Filed Ex. 1, Att. 2 Supp., Sch. B-1.0; Sch. B-5.0; Interrog. Resp. RRU-57, Att. 1. UI initially agreed that $784,365 for the PURA Assessment should be removed from rate base because of a "potential overlap," due to the same amount being included the Company's proposed cash working capital. See Interrog. Resp. OCC-557. However, the Company ultimately

[32] OCC's witness also recommends that the working capital allowance calculation should not include uncollectible expense, and explains, therefore, that the Company's argument of a double counting would not apply. Defever Errata Prefiled Test, Feb. 24, 2025, p. 6.

included approximately $392,183 or 50% of the $784,365 in the proposed average rate base. Late Filed Ex. 1, Att. 2 Supp., Sch. B-1.0; Sch. B-5.0.

The PURA Assessment is not appropriately included in the approved prepaid expenses and, accordingly, the Authority does not allow $392,183 of UI's proposed average rate base. In addition, the Authority does not include $1,288,688 in proposed prepaid expenses for software maintenance. In the aggregate, the Authority approves the inclusion of $2,804,764 prepaid expenses and does not allow $1,680,871 of the Company's proposed costs in rate base, as shown in Table 15, below.

Table 15: Summary of Approved Prepaid Expenses, Average Rate Year

Category	Proposed ($)	Adjustment ($)	Approved ($)
Insurance	820,558	-	820,558
Fibertech	137,837	-	137,837
PURA Assessment	392,183	(392,183)	-
SBC Loan	198,887	-	198,887
Transmission ROW	101,612	-	101,612
Workers Comp	199,683	-	199,683
Software Maintenance	2,581,320	(1,288,688)	1,292,632
Other	53,554	-	53,554
Total	**4,485,635**	**(1,680,871)**	**2,804,764**

UI indicated that the main cause of the increase in the software maintenance prepaid expenses is that "the Company's Operational Smart Grids organization began using the prepaid process in 2022 to enhance efficiencies, evenly distribute costs over the contract period, and secure vendor discounts with multi-year agreements." Interrog. Resp. RRU-57. The prepaid software maintenance cost increased from $0 in 2021 to $366,014 in 2022 and $3,431,685 in 2023, which is the primary reason for the difference in the total prepaid expense balances between 2022 and 2023. See Late Filed Ex. 1, Att. 2 Supp., Sch. B-1.0, Sch. B-5.0; Interrog. Resp. RRU-57, Att. 1. The average prepaid expense in UI's proposed rate base is $4,485,635 [($5,026,573 + $3,944,646) / 2]. The proposed average prepaid amount includes an average of $2,581,320 ([$2,730,076 + $2,432,564] / 2) for software maintenance expenses. See Late Filed Ex. 1, Att. 2 Supp., Sch. B-5.0. Table 16, below, shows UI's proposed prepaid expenses.

Table 16: Summary of Proposed Prepaid Expenses

Category	Test Year 2023 ($)	Proforma Adjustment ($)	Rate Year Beginning Balance ($)	Proforma Adjustment ($)	Rate Year Ending Balance ($)
Insurance	1,031,435	(210,877)	820,558	-	820,558
Fibertech	173,260	(35,423)	137,837	-	137,837
PURA Assessment	985,941	(201,576)	784,365	(784,365)	-
SBC Loan	250,000	(51,113)	198,887	-	198,887
Transmission ROW	127,726	(26,114)	101,612	-	101,612
Workers Comp	251,000	(51,317)	199,683	-	199,683
Software Maintenance	3,431,685	(701,609)	2,730,076	(297,512)	2,432,564
Other	18,984	34,570	53,554	-	53,554
Total	**6,270,031**	**(1,243,458)**	**5,026,573**	**(1,081,877)**	**3,944,696**

Late Filed Ex. 1, Att. 2 Supp., Sch. B-5.0; Interrog. Resp. RRU-57, Att. 1.

The Company's proposed balances for software maintenance costs included in the calculation of the proposed average prepaid expense are overstated. UI failed to correctly reflect the 2024 pro forma adjustment and employed incorrect 2024 and 2025 amortization expenses for the prepaid software maintenance expense. First, UI included the 2024 pro forma adjustment as $701,609, instead of a 2024 pro forma adjustment of $166,986 and an amortization of $988,966.[33] See Late Filed Ex. 1, Att. 2 Supp., Sch. B-5.0 (column H "Pro Forma Adjustments"); Interrog. Resp. RRU-57, Att. 1, p. 1 (column P "2024 Adjustments" and column T, "2024 Total Charged to Expense"). UI also improperly calculated the 2025 amortization expenses for the prepaid software maintenance expense; the reported "2025 Total Charged to Expense" of $637,599 must be prorated for the 10 months of 2025 that precede the Rate Year. Accordingly, the 10-month amortization expense through October 31, 2025, is $531,332. Accordingly, as shown in Table 17, below, $1,292,632 of UI's proposed prepaid costs for software maintenance are included in rate base.

Table 17: Adjustment to Proposed Average Prepaid Software Maintenance

Category	Identifier	Amount ($)
2023 Ending Balance	A	3,544,347
2024 Proforma Adjustment	B	(166,986)
2024 Amortization Expense	C	(988,966)
2025 10-Month Amortization Expense (October)[1]	D	(531,332)
Balance as of November 1, 2025	E=A+B+C+D	1,857,063

[33]The Company reported individual 2024 expenses totaling $988,966 but summed those expenses as $268,446. Interrog. Resp. RRU-57, Att. 1, p. 1 (column T, "2024 Total Charged to Expense").

Category	Identifier	Amount ($)
Distribution Portion at 79.55% (as of November 1, 2025)	F= E x 79.55%	1,477,294
Rate Year Amortization Based on 48 months	G=F/4	(369,323)
Balance as of October 31, 2026	H=F+G	1,107,970
Allowed Average Software Maintenance in Rate Base	**I=F/2+H/2**	**1,292,632**
Proposed Average Software Maintenance in Rate Base	J	2,581,320
Adjustment to Average Software Maintenance in Rate Base	K=I-J	**(1,288,688)**

Late Filed Ex. 1, Att. 2 Supp., Sch. B-5.0; Interrog. Resp. RRU-57, Att. 1.

H. DEFERRED EXPENSES AND CREDITS

1. Summary

The Company proposed a total rate base balance of $36,575,480 related to deferred expenses and credits. The Authority will exclude $36,575,480 of the Company's deferred expenses from rate base, as summarized in Table 18, below. Instead, the Company will be permitted to recover total deferred expenses of $28,942,312 as amortized O&M expenses, as detailed in Section VI.A.17, Other Deferred Expenses.

Table 18: Summary of Approved Deferred Expenses (Credits)

Deferred Expense (Credit)	Proposed Balance as of Nov. 1, 2025 ($)	Adjustment ($)	Approved Balance as of Nov. 1, 2025 ($)
Pension deferral	6,767,774	(6,767,774)	-
OPEB deferral	(284,085)	284,085	-
Storm deferral (22-08-08 Balance)	9,453,741	(9,453,741)	-
COVID deferral	1,862,157	(1,862,157)	-
CAM GET deferral	(1,026,348)	1,026,348	-
Isaias Penalty Over/(Under)	(16,867)	16,867	-
Pension deferral – Interim Period	1,853,470	(1,853,470)	-
OPEB Deferral – Interim Period	(979,774)	979,774	-
Isaias Customer Credit Over/(Under)	144,785	(144,785)	-
Storm deferral – New	(2,073,381)	(2,073,381)	-
Environmental deferral	481,664	(481,664)	-
Fee Free Program deferral	(1,852,863)	1,852,863	-
Regulatory proceeding costs	1,275,258	(1,275,258)	-
Earnings Sharing Mechanism Over/(Under)	276,191	(276,191)	-
Rate Case Expense	3,163,323	(3,163,323)	-
Water Heater Rental Program – Phase Out	12,019,711	(12,019,711)	-
Storm deferral – 2025 Event	5,510,724	(5,510,724)	-
Total	**36,575,480**	**(36,575,480)**	**-**

See Application, Sch. B-6.0, Sch. WPC-3.21, pp. 1–3, Ex. RRP-22D, pp. 1–8.

I. ACCUMULATED DEFERRED INCOME TAXES

1. Summary

The Company proposes net accumulated deferred income taxes (ADIT) of $317,795,723 to offset rate base proposed for the Rate Year. Late Filed Ex. 1, Att. 2 Supp.; Sch. B-7.0; Sch. WP B-7.0. The ADIT amount represents the average of the Rate Year beginning balance of $319,289,753 and ending balance of $316,303,692. Id. Consistent with accepted utility ratemaking practice, the Company uses net ADIT to offset rate base. Here, the Company proposed an offset of $317,795,723 consisting of FERC Account-related, plant-related, and deferral-related ADIT. The Authority will adjust net ADIT by $1,017,632, as summarized in Table 20 below.

Table 19: Summary of Proposed and Approved ADIT

Category	Proposed ($)	Adjustment ($)	Approved ($)
FERC Account-Related	(318,332,191)	-	(318,332,191)
Regulatory Asset/Liability-Related	2,105,858	(1,797,791)	308,067
Excess ADIT	2,158,805	-	2,158,805
Plant-Related	(3,728,194)	3,217,604	(510,590)
Provision for Deferred Income Taxes	-	(402,181)	(402,181)
Total	**(317,795,723)**	**1,017,632**	**(316,778,090)**

2. Plant Related Adjustments

The Authority utilized the outputs from the Plant Model (modified for PURA adjustments) to calculate a revised Rate Year plant-related ADIT balance.[34] The Company proposed an average plant-related ADIT balance of ($3,728,194).[35] The Authority approves an average plant-related ADIT balance of ($510,590) based on a $3,217,604 adjustment.

Specifically, the plant-related ADIT adjustment reflects the reduction in deferred tax liability corresponding to the Authority's adjustments to the Company's plant-in-service. The Authority derived the adjustment from the Plant Model by computing the difference in deferred tax amounts before and after incorporating the Authority's plant adjustments. The Authority calculated the difference in plant-related ADIT for the period prior to the beginning of the Rate Year as $2,200,124. The Authority then calculated the difference in ADIT for the rate year as $1,017,479. To reflect the average rate base convention, the balance for the Rate Year was reflected at 50%. The Authority computed

[34]The Authority identified an apparent error on tab 6 ("6-DepreciationExpense") of the Plant Model. Specifically, the Company left the June 2024 balance on line 13 (cell V32) blank. The Authority corrected this error for purposes of its calculations.

[35]This figure was derived by summing cell D62 and one-half of cell D63 from the Plant Model, tab 1.2 ("1.2-SummaryRRInput").

the resulting adjustment to plant-related ADIT as: $2,200,124 + ($2,034,959 x 50%) = $3,217,604.[36] See Late Filed Ex. 1, Att. 2, Sch. B-7.0; Late Filed Ex. 1, Att. 3, Sch. 1.2.

3. Provision for Deferred Income Taxes

The Authority reduces the Company's proposed depreciation expense by $2,923,090. Thus, based on an income tax composite rate of 27.5175%, the Authority increases the Company's provision for deferred income tax by $804,361 ($2,923,090 x 27.5175%). As a result, the Company's average ADIT increases by $402,181 ($804,361 x 50%).

4. Regulatory Asset/Liability Related Adjustments

The Company reports deferred income tax (DIT) asset balances related to regulatory assets and liabilities of $649,895 as of October 31, 2025, and $3,561,820 as of October 31, 2026. Late Filed Ex. 1, Att. 2 Supp., Sch WP B-7.0. The Company's average DIT asset related to regulatory assets and liabilities for the Rate Year is $2,105,858 (($649,895 + $3,561,820) / 2). Id. The Authority reduces this amount by $1,797,791 to reflect changes made in this Decision.

As discussed in Section IV.F, Regulatory Assets, above, the Authority excludes $55,863,788 of the Company's proposed regulatory assets from rate base. Also, as discussed in Section IV.E, Reserves and Regulatory Liabilities, above, the Authority removes $62,386,149 from the Company's proposed average rate base. These adjustments resulted in a net reduction to the proposed reserves/regulatory liabilities of $6,522,362 ($62,386,149 - $55,863,788). Thus, the Company's proposed ADIT for Regulatory Asset/Liability Related Changes is reduced by $1,794,791 ($6,522,362 x 27.5175%). The Authority allows ADIT for regulatory asset/liability related changes of $308,067 ($2,105,858 - $1,794,791) in the average rate base.

Table 20: Allowed Regulatory Asset/Liability Rate Year Balance

Category	Amount ($)
Total Regulatory Asset Adjustments	55,863,788
Total Reserve/Regulatory Liability Adjustments	(62,386,149)
Net Reduction to Reserves/Regulatory Liabilities	**(6,522,362)**

Late Filed Ex. 1, Att. 2 Supp., Sch. WP B-6.0, Sch. WP B-8.0.

[36]This figure is calculated as the difference between the Company's proposed plant-related ADIT balance and the sum of (1) Deferred Income Tax from January 2024 through October 2025 and (2) one-half of Deferred Income Tax from November 2025 through October 2026, as shown on tab 9 ("9-DeferredIncomeTaxes") of the Plant Model (adjusted for PURA plant disallowances). See Late Filed Ex. 1, Att. 3 ("9-DeferredIncomeTaxes" tab).

J. CAPITAL PLAN

1. Summary

As part of its capital plan, UI must comply with Reliability Framework requirements and Resilience Framework requirements as well as create a Climate Change and Vulnerability Plan. As discussed below, UI's capital plan complies with those requirements.

2. Compliance with the Reliability Framework

UI's Reliability Plan complies with the Reliability Framework requirements established by the Authority on August 31, 2022. See Decision, Aug. 31, 2022, Docket No. 17-12-03RE08, PURA Investigation into the Distribution System Planning of the Electric Distribution Companies – Resilience and Reliability Standards and Programs (17-12-03RE08 Decision), pp. 35-57. The Authority established the Reliability Framework "to incentivize programs that maintain consistent top-quartile reliability performance while minimizing or reducing ratepayer impact." Id., p. 42. To accomplish this, the Reliability Framework outlined planning parameters that should enable UI to maintain top quartile reliability, while also improving upon it when necessary or cost-effective to do so. Id., p. 43. Multi-year reliability investment plans must include an analysis that targets a 5% blue-sky reliability improvement over prior four year-average reliability improvement. Id., p. 44. The 5% improvement is a planning parameter, not a standard. Id.

The plan may depend also on (1) whether the Company achieved top-quartile reliability performance in the prior four years, (2) whether the Company achieved General Statutes § 16-244i(d) reliability targets in the last 10 years, and (3) an affordability analysis. Id. The affordability analysis is done by analyzing the past 10-year "baseline" reliability category spending and then escalating those costs by the GDP Deflator index as published by the U.S. Bureau of Economic Analysis. Id., p. 45. If the proposed UI reliability investment plan exceeds the affordability analysis, then UI must include some reliability improvement target for the incremental spend. Id., p. 46. If the proposed budget is under the threshold, UI may target a 0% reliability improvement. Id. UI may also propose a different affordability definition (i.e., threshold analysis). Id.

First, UI has achieved top-quartile reliability performance as measured by both System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) from 2019-2023 (both comparing to utilities nationally and in the northeast). Interrog. Resp. OCC-581. Second, the Company met minimum reliability thresholds articulated in General Statutes § 16-244i(d) from 2014-2023 with two exceptions. In 2014 and in 2018, UI exceeded the General Statutes § 16-244i(d) threshold for SAIDI. All other years were under the threshold for both SAIDI and SAIFI. When looking at the four-year rolling average, UI did not exceed the threshold for SAIDI or SAIFI. Interrog. Resp. RSR-191, Att. 1.

Third, regarding the affordability analysis, UI's Rate Year capital plan does not exceed the 10-year inflation-adjusted (using GDP Deflator index) historical capital spend for reliability programs. Ex. UI-CIP-9, p. 10. UI's Capital Plan breaks investments down

into eight major categories: capacity, customer, reliability, infrastructure replacement (substations and distribution system), resiliency, system operations, business effectiveness, and modernization. Ex. UI-CIP-7, p. 1. UI divides reliability programs into two main categories, as shown in Table 21, below: (1) baseline programs needed to *maintain* reliability (as measured by system SAIDI and SAIFI); and (2) incremental programs made to *improve* reliability performance. Ex. UI-CIP-9, p. 12.

Table 21: UI Investment Categories

Baseline Programs (Maintain Reliability)
Modernization
Business effectiveness
Customer service technology
Facilities
Fleet
Metering
Compliance and safety
Customer lighting
State/municipal projects
Third-party pole attachment make ready
Infrastructure replacements
Certain resilience programs
Operations
Capacity
Incremental Programs (Improve Reliability)
Corrective reliability (worst-performing circuits)
Certain modernization like distributed automation
“Other” system resilience projects

Ex. UI-CIP-9, pp. 12, 14–15.

The affordability analysis considers average 10-year capital spend of Baseline and Incremental program escalated by the GDP Deflator index to set the threshold. For purposes of the affordability analysis, UI excludes new customer connections and customer projects from baseline and incremental because they are exempt from the affordability analysis in the 17-12-03RE08 Decision. Ex. UI-CIP-9, p. 15. Those investments are not planned by UI to address system reliability or operational needs but are done to meet specific customer needs (e.g., new customer connections). 17-12-03RE08 Decision, p. 46.

The affordability analysis shows that the Rate Year capital plan falls within the affordability threshold. The affordability threshold of 10-year baseline and incremental programs using the GDP Deflator Index is $131.3 million ($176.4 million using Handy Whitman Index as a cost escalator). Ex. UI-CIP-9, p. 42; Interrog. Resp. OCC-374, Att. 1. UI’s proposed Rate Year baseline and incremental program capital expenditures are $121.0 million, which is under the threshold. Id. UI’s five-year capital plan (2024-2028) Incremental and Baseline program (excluding customer programs) forecasted CapEx is

$110.2 million, which is also under the threshold. UI does not propose an incremental reliability benefit with the Rate Year investments, instead settling on a maintenance of reliability performance, which is permitted in the Reliability Framework. See Ex. UI-CIP-9, p. 10; Ex. UI-CIP-1, p. 46; 17-12-03RE08 Decision, p. 47. UI does propose a 5% reliability improvement for its five-year capital plan, which the Company claims is dependent upon PURA approving funding requested in the Application. UI-EOP-1, p. 18.

Although UI's affordability analysis in the application uses the GDP Deflator index to normalize costs, UI proposes that the Handy-Whitman (HW) Index is a better measure to reflect costs experienced by a utility over time. The choice of index does not have a material effect on this Application, as the proposed CapEx is under the affordability threshold using the GDP Deflator Index. However, the Authority notes that the HW Index is typically a better reflection of utility costs. The GDP deflator is a formula that measures the real value of the U.S. economy's total output reduced by inflation over time and, therefore, measures the change in costs over time based on the entire U.S. economy and is reflective of how costs impact consumers. See Ex. UI-CIP-9, p. 35. The Handy-Whitman Index reflects escalation of utility costs over time and has an index specific to northeast utilities (rather than the entire country, as the GDP Deflator Index reflects). Id. Specifically, the GDP Deflator Index considers economy-wide measures such as personal consumption expenditures, private domestic investment, exports of goods and services, and government expenditures and consumption. Ex. UI-CIP-9, p. 36. By contrast, the HW Index considers utility construction costs by FERC plant account (e.g., transformers, meters, overhead conductors, station equipment). Id. The HW Index better reflects costs of utilities doing business, while the GDP Deflator reflects costs from the consumer's perspective. Cost escalation according to the HW Index has outpaced that of the GDP Inflator, particularly since 2021/2022. Ex. UI-CIP-9, p. 37. As of 2024, the GDP Deflator-measured inflation was 5% since 2022 (13% since 2021) and the HW Index-measured inflation was 35% since 2022 (49% since 2021). Ex. UI-CIP-9, p. 37. Key contributors to the significant escalation rates of the HW Index since 2021 have been for major distribution equipment: transformers, overhead and underground conductors, and meters (though not as significant as the other contributors). See Interrog. Resp. OCC-374, Att. 1, p. 2.

3. Compliance with the Resilience Framework

UI's Resilience Plan complies with the Resilience Framework requirements established by the Authority on August 31, 2022. 17-12-03RE08 Decision, pp. 57-71. "[W]hen seeking approval for resilience program expenditures, each EDC must design and submit a [Resilience] plan in accordance with the Resilience Framework." 17-12-03RE08 Decision, p. 58. The Resilience Framework requires that UI identify "zones" of the system and prioritize them based primarily on historical SAIDI data as well as other data and criteria including: other outage-based data (SAIFI and CAIDI); system characteristics (feeder type, vegetation density, etc.); and community priorities (critical facilities, areas of distressed municipalities, etc.). 17-12-03RE08 Decision, p. 61.

The Resilience Plans also must include methodology to determine how different resilience measures are evaluated and selected for each identified zone. Id., p. 62. There

must be more than one mitigation measure evaluated for the selected zones. Id. The Resilience Plan must include 5-, 10-, 20-, and 30-year BCA's, comparing the costs of the Resilience Plan against avoided interruption costs, avoided restoration costs, avoided VM costs, and avoided pole replacement costs. Id., pp. 64–65. UI selected nine circuits as priority zones using, primarily, system SAIDI and SAIFI, while also factoring in all the other criteria of the 17-12-03RE08 Decision. See Ex. UI-CIP-10, pp. 10 (specific weighting of criteria). UI analyzed different mitigation measures for those nine circuits ranging from least cost topology improvements like adding line reclosers, switches, and cutouts to higher costs of selective undergrounding and installation of aerial cable to highest costs of full undergrounding of each mainline. Ex. UI-CIP-10, pp. 11–12. From this analysis, UI established a five-year Resilience Plan, which made the most cost-beneficial resilience selections using the established BCA framework. See Ex. UI-CIP-10, pp. 20–26 (UI's application of interruption cost estimate); Ex. UI-CIP-10, pp. 26–28 (storm occurrence estimation); Interrog. Resp. RSR-270, Att. 1 (analysis of how mitigation measures were selected for the nine zones). The final Resilience Plan includes investments totaling $24.47 million from 2026-2031. Ex. UI-CIP-10, p. 30. The resulting BCA considers two storm scenarios: scenario 1 is more conservative (using actual events 2019-2023 as a baseline, with one Isaias-level event in that time); and scenario 2 is more aggressive (an Isaias-level event occurs twice in the five-year period). Ex. UI-CIP-10, pp. 27–28. The BCA analysis provides a 30-year BCA of the Resilience Plan of 1.0 (break-even) under the storm 1 scenario and 1.57 under the storm 2 scenario. Ex. UI-CIP-10, p. 37. For benefit evaluation periods of less than 30 years, the BCAs were all less than 1.

4. Compliance with Climate Change and Vulnerability Study

UI's Climate Change and Vulnerability Study (CCVS) complies with the Authority's requirements. See 17-12-03RE08 Decision, p. 80. The Climate Change and Vulnerability Study is required to include (1) a list of identified vulnerabilities, (2) proposals addressing vulnerabilities, and (3) long-term goals for addressing climate risk; all of which should inform the Reliability and Resilience Plans. 17-12-03RE08 Decision, p. 80. UI's CCVS is comprehensive and includes identification of vulnerabilities, plans to address vulnerabilities (which include specific substation flood mitigation, updated construction standards, etc.), and the development of long-term goals for several different climate risks (extreme heat, flooding, etc.). See Ex. UI-CIP-11.

5. Five-Year Capital Plan

UI proposed recovery in rates of plant additions through the end of the Rate Year. Table 22, below, shows plant additions requested in the Application.

Table 22: Actual and Planned Plant Additions

Actual and Planned Plant Additions ($)				
9/1/22-12/31/22	**2023**	**2024**	**2025**	**2026**
100,635,703	159,985,638	101,556,138	77,171,756	95,837,457

Application, Ex. UI-CIP-3, Ex. UI-CIP-5.

As detailed in Section IV.B.5.c, Future or Incomplete Plant, above, the Authority does not permit plant additions to be recovered in rate base from customers until such time that those additions have been deemed by the Authority as prudent and used and useful.

Table 23, below, shows UI's total capital expenditures (CapEx) in the Test Year and in the Company's proposed five-year capital plan (2024-2028).

Table 23: Test Year and Five-Year CapEx

Test Year CapEx	Five-Year Capital Plan CapEx ($)				
2023	2024	2025	2026	2027	2028
142,803,21	85,224,970	90,131,915	149,105,717	149,223,931	139,663,809

Application, Sch. F-7.0D.

The Company claims that it has been unable to invest according to the capital plan submitted in Docket No. 22-08-08. Ex. UI-CIP-1, p. 31. Following the 22-08-08 Decision, the Company prioritized the following capital projects: customer connections; state highway needs; pole replacements for broadband expansion; capital power restoration; infrastructure replacement for imminent failures; IT/OT compliance upgrades; safety-related work; and Pequonnock Substation completion. Ex. UI-CIP-1, p. 32. UI claims to have deferred a number of programs/projects as a result of this prioritization, notably: substation replacements; fleet vehicles; facilities improvements; IT/OT replacements; certain capacity investments; reliability projects; the remaining 10% of non-smart meters; and resilience and Equitable Modern Grid modernization efforts, such as costs associated with the Energy Storage Solutions program, Light-Duty Electric Vehicle Charging program, etc. Ex. UI-CIP-1, p. 33.

The Company states that it will continue its reduced level of investment if its Application in the instant proceeding is not approved in full, including approval of Rate Year investments. Ex. UI-CIP-1, pp. 31-33; see also Interrog. Resp. RRP-1, pp. 32–36; Interrog. Resp. EOP-1, pp. 33–35. UI claims that a diminished level of investment will erode its system reliability with time, causing degradation of its reliability performance within three to seven years. Ex. UI-CIP-1, p. 34; Ex. UI-CIP-Interim Rates-1, p. 7. UI also states that deferring projects, especially infrastructure replacement projects, builds up a backlog of infrastructure that needs to be addressed at some future point, leading to degraded reliability and making the solutions more costly and complex. Ex. UI-EOP-1, p. 12; Ex. UI-CJE-Interim Rates-1, p. 11. UI argues that its actions (i.e., reduced investment following the 22-08-08 Decision) conflict with its responsibility to develop a long-term (20-year) infrastructure replacement program. See Ex. UI-EOP-1, pp. 11–12; Decision, Aug. 14, 2013, Docket No. 13-01-19, Application of the United Illuminating Company to Increase Rates and Charges (13-01-19 Decision), pp. 174–175 (Order No. 14). UI further argues that its deferral of infrastructure replacement programs and projects will create another large bubble of projects in future years. Id.

Importantly, the Company has an ongoing obligation to prudently invest capital in furtherance of its statutory duties under Title 16 of the General Statutes of Connecticut to, among other responsibilities, provide safe and reliable service to its customers. The Company is also obligated to implement solutions in compliance with the Authority's direction, decisions, and rulings in furtherance of the regulatory goals and priority public outcomes identified in Docket No. 21-05-15. See Decision, Apr. 26, 2023, Docket No. 21-05-15, PURA Investigation into a Performance-Based Regulation Framework for the Electric Distribution Companies. The Company may seek recovery in a future rate case for any future capital additions that are not incorporated into rate base or reflected in rates approved in this Decision. The Company continues to have the opportunity to earn a reasonable return on all prudent and used and useful investments, but rates must be set based on the fair value of the property being used for the convenience of the public. See Hope, 320 U.S. at 605. Requiring ratepayers to essentially prepay the costs of future additions, with no evidence that the additions are used and useful and the result of prudent investment,[37] would allow the Company to reallocate all the risk of capital investment to ratepayers while also requiring ratepayers to pay the Company a return on equity, which compensates the Company for that risk.

V. COST OF CAPITAL

A. SUMMARY

The Authority approves a weighted average cost of capital as depicted in the tables below.

Table 24: Weighted Average Cost of Capital Without ROE Reductions

Capital Source	Allocation	Cost	Weighted Cost
Common Equity	51%	9.450%	4.820%
Long-Term Debt	49%	4.739%	2.322%
Total Capitalization	**100%**		**7.142%**

Table 25: Weighted Average Cost of Capital with ROE Reductions

Capital Source	Allocation	Cost	Weighted Cost
Common Equity	51%	9.250%	4.718%
Long-Term Debt	49%	4.739%	2.322%
Total Capitalization	**100%**		**7.040%**

B. PROXY GROUP

The Authority identified a group of 26 prospective companies to ascertain the market-based range of the cost of equity (COE) for the Company. The Authority uses certain criteria (Authority Screening Criteria) to identify companies that have risk and

[37] The Authority does not determine the prudence of future, planned expenditures, which may never materialize or may require substantial changes due to market changes or other unforeseeable circumstances.

investment profiles similar to that of the Company. Generally, a company will be considered a proxy company if it:

(1) derives at least 70% of revenue from regulated utilities, as reported by Value Line;
(2) derives at least 50% of regulated revenue from regulated electric distribution, as reported by Value Line;
(3) is publicly traded and reported by Value Line;
(4) has paid consistent dividends for eight quarters and is expected to continue;
(5) is not in financial distress;
(6) is not the target of an acquisition or merger activity;
(7) has credit ratings that are at least investment grade, as determined by S&P Global (BBB- and above) and/or Moody's Investor Service (Moody's) (Baa3 and above); and
(8) is not projected to have negative earnings growth as reported by Value Line.

See 22-08-08 Decision, p. 59. Applying the Authority Screening Criteria produces a proxy group that has similar revenues and a similar credit profile to the company being analyzed as well as robust data to use in the COE methodologies.

The Authority considered the proxy groups proposed by the Company, OCC, and EOE. All parties recommended proxy group companies consisting of publicly traded electric companies followed by Value Line - Electric Utility East, Central, and West sectors.

To develop its proposed proxy group, the Company began with the group of 36 companies followed by Value Line and classified as electric companies. Bulkley Prefiled Test., Nov. 12, 2024, pp. 17–18. The Company then applied the following screening criteria to *exclude* companies that:

(1) Do not pay consistent quarterly cash dividends because such companies cannot be analyzed using the Constant Growth DCF model;
(2) Do not have positive long-term earnings growth forecasts from at least two equity analysts;
(3) Do not have investment grade long-term issuer ratings from both S&P and Moody's;
(4) Were party to a merger or transformative transaction during the analytical period considered; and
(5) Do not derive at least 70% of the company's operating income from regulated electric operations.

Id. The Company's screening criteria resulted in the inclusion of 19 companies (Company Proxy Group). Id., p. 18.

In rebuttal testimony, the Company excluded Eversource Energy from its original proxy group. Bulkley Rebuttal Test., Mar. 12, 2025, p. 26. On November 12, 2024, Eversource Energy agreed to sell its subsidiary Aquarion Water Company, Inc., for $2.4

billion to the Aquarion Water Authority and South Central Connecticut Regional Water Authority; thus, the Company determined that Eversource Energy is excluded from its proxy group under its fourth screening criteria. Id.

OCC determined that to develop a fair rate of return recommendation for the Company, it is appropriate to evaluate the common stock of a proxy group of publicly held electric utility companies (OCC Electric Proxy Group). Woolridge Prefiled Test., Feb. 13, 2025, p. 20. OCC also evaluated the group developed by the Company (Company Proxy Group). Id.

OCC's screening criteria incorporated slight variations to the Company's selection criteria. Specifically, OCC's screening criteria included the following considerations regarding whether a company:

(1) Receives at least 50% of revenues from regulated electric operations as reported in its SEC Form 10-K Report;
(2) Is listed by Value Line Investment Survey as a U.S.-based electric utility;
(3) Holds an investment-grade corporate credit and bond rating;
(4) Has paid a cash dividend for the past six months, with no cuts or omissions;
(5) Is not involved in an acquisition of another utility, and not the target of an acquisition; and
(6) Its analysts' long-term EPS growth rate forecasts are available from Yahoo, S&P Cap IQ, and/or Zacks.

Id., p. 21.

OCC's assessment is that the OCC Electric Proxy Group on average receives 85% of its revenues from regulated operations, has an S&P bond rating of BBB+ and a Moody's bond rating of a Baa2, has a common equity ratio of 40.9%, and has an earned return on common equity of 9.36%. Id., p. 21. OCC regards bond ratings as a good assessment of a company's investment risk. Woolridge PFT, p. 22. UI's S&P and Moody's issuer credit ratings are A- and Baa1. Id. The averages of the two proxy groups are BBB+ and Baa2, and this indicates that the investment risk of UI is below that of the two proxy groups. Id. Additionally, in assessing the comparative risk profiles of the proxy groups, OCC uses five different risk measures: beta; financial strength; safety; earnings predictability; and stock price stability. Id. These risk measures indicate that the two proxy groups are similar and low in investment risk. Woolridge PFT, p. 22. The comparisons of the risk measures for the OCC Electric Proxy Group versus the Company's Proxy Group include beta (0.94 vs. 0.95), financial strength (A vs. A), safety (1.9 vs. 1.9), earnings predictability (87 vs. 87), and stock price stability (87 vs. 88). Woolridge PFT, p. 22; Woolridge PFT, Ex. JRW-3.2.

EOE used a proxy group consisting of 19 publicly traded electric utility companies covered by Value Line. Rothschild Prefiled Test., Feb. 14, 2025, p. 57. EOE chose this group as it contains companies that have relatively comparable risk to UI. Id. EOE's witness noted that the model results based on this Proxy Group should be viewed as

conservative, as UI is an electric distribution company only, and therefore is a less risky company than those with unregulated operations. Id.

Each of the parties used reasonable proxy groups derived from relevant screening criteria. The proxy groups each have their limitations and are, of course, not perfect representations of the Company. The Authority finds that one company excluded from the Company Proxy Group but included in the OCC Proxy Group is appropriate for inclusion in the Authority Proxy Group. Specifically, the Authority determines that Consolidated Edison, Inc. should be included in the Authority Proxy Group as this company meets the Authority Screening Criteria that the company's regulated electric utility revenue exceeds 70% of the company's total revenue (74%); Consolidated Edison also meets the remaining Authority Criteria. See Woolridge PFT, Ex. JRW 3.1. Conversely, relying on the same 70% threshold criteria for electric utility revenue, the Authority declines to include the following companies from the OCC Electric Proxy Group, as they fell below the 70% revenue threshold: (1) CMS Energy Corporation; (2) MGE Energy, Inc.; and (3) Public Service Enterprise Group. Id. Eversource Energy is excluded from the Authority Proxy Group under its sixth screening criteria.

Consequently, the Authority finds that the following 19 companies are closely aligned with UI's business and financial characteristics and have met the specifications indicated in the Authority Screening Criteria. As such, these companies comprise a reasonable proxy group for analyzing the Company's cost of capital analysis. Further, the larger set of proxy group companies determined by the Authority provides a more holistic profile of the returns expected by equity investors for regulated utilities.

Table 26: Proxy Group Company Summary

No.	Utility Company	Company	OCC	EOE	Authority
1	Alliant Energy Corporation	Y	Y	Y	**Y**
2	Ameren Corporation	Y	Y	Y	**Y**
3	American Electric Power Company, Inc.	Y	Y	Y	**Y**
4	Avista Corporation	Y	Y	Y	**Y**
5	DTE Energy Company	Y	N	Y	**Y**
6	Duke Energy Corporation	Y	Y	Y	**Y**
7	Edison International	Y	Y	Y	**Y**
8	Entergy Corporation	Y	Y	Y	**Y**
9	Consolidated Edison, Inc.	N	Y	N	**Y**
10	Evergy, Inc.	Y	Y	Y	**Y**
11	FirstEnergy Corporation	Y	N	Y	**Y**
12	IDACORP, Inc.	Y	Y	Y	**Y**
13	NextEra Energy, Inc.	Y	Y	Y	**Y**
14	NorthWestern Corporation	Y	Y	Y	**Y**
15	OGE Energy Corporation	Y	Y	Y	**Y**
16	Pinnacle West Capital Corporation	Y	Y	Y	**Y**
17	Portland General Electric Company	Y	Y	Y	**Y**

No.	Utility Company	Company	OCC	EOE	Authority
18	Southern Company	Y	Y	Y	**Y**
19	Xcel Energy Inc.	Y	Y	Y	**Y**
20	CMS Energy Corporation	N	Y	N	**N**
21	Exelon Corporation	N	Y	N	**N**
22	MGE Energy, Inc.	N	Y	N	**N**
23	PPL Corporation	N	Y	N	**N**
24	Public Service Enterprise Group Incorporated	N	Y	N	**N**
25	Eversource Energy	N	Y	Y	**N**
26	WEC Energy Group	N	Y	N	**N**

C. CAPITAL STRUCTURE

1. Summary

The Authority finds that a capital structure consisting of 51% common equity and 49% long-term debt is reasonable. The table below summarizes the authorized allocation.

Table 27: Approved Capital Structure

Capital Component	Allocation
Common Equity	51%
Long-term Debt	49%
Total Capitalization	**100%**

2. Position of the Parties

The Company proposes a capital structure consisting of 54% common equity and 46% long-term debt. Bulkley PFT, pp. 6, 50–51. The Company's capitalization analysis is based on a comparison of the capital structure of the utility operating subsidiaries of the companies in the Company Proxy Group, rather than the proxy companies themselves. Id., p. 50. Specifically, the Company calculated the average proportion of common equity, long-term debt, and preferred equity for the most recent eight quarters for each of the utility operating subsidiaries included its Proxy Group. Id., p. 51. The Company's analysis concluded that the average common equity ratio for the operating subsidiaries of the Company's Proxy Group was 52.03% and the median was 52.04% (within a range from 39.41% to 60.80%). Id., p. 51; Application, Ex. UI-AEB-12.

OCC recommends a capital structure consisting of 50% common equity and 50% long-term debt. Woolridge PFT, p. 27. OCC determined the capitalization mix by using the common equity ratios of the utility holding companies, which results in a 40.90% average common equity ratio for the parent holding companies in the OCC Electric Proxy Group and a 39.20% average common equity ratio for the parent holding companies in the Company's Proxy Group as of December 31, 2021. Id., pp. 23, 27; Woolridge PFT, Att. JRW-3.1. Therefore, OCC's proposed capital structure includes more common equity and, therefore, less financial risk. Woolridge PFT, p. 23.

In determining the recommended capitalization mix, OCC deems it appropriate to use the common equity ratios of the holding companies because holding companies are publicly traded, and because their stocks are used in the cost-of-equity capital studies. Woolridge PFT, p. 23. OCC argues that, conversely, the equities of the operating utilities are not publicly traded, and therefore their stocks cannot be used to compute the cost-of-equity capital for UI. Id. Additionally, OCC highlights that the 50%-50% capitalization mix is consistent with the Authority's past policies and more reflective of the capital structures of the proxy group. Woolridge PFT, p. 27. Further, OCC advised that, although it has not recommended short-term debt in the capital structure, short-term debt should be considered when evaluating the capital structures and financial risk of the proxy companies. Id.; Woolridge Surrebuttal Test., Mar. 24, 2025, pp. 8, 10.

Similar to OCC, EOE also recommends a capital structure consisting of 50% common equity and 50% long-term debt. Rothschild PFT, p. 9. EOE notes that the reported capital structure of a regulated subsidiary is often not representative of how it was financed, because, for example, "the parent of a regulated utility can report funds raised through debt financing at the holding company level as equity financing on the books of its regulated utility subsidiary." Id., p. 6. EOE argues that the Authority should reject UI's requested capital structure because the proposal represents a significantly higher common equity ratio (54.00%) than the average common equity ratio (42.4%) used by other electric distribution utility companies in the country, as indicated by the Company's own Proxy Group. Id., pp. 9 n.4, 101; Rothschild PFT, Ex. ALR-5, p. 5. Further, EOE argues that it is the capital structure of the utility holding company that matters, not the operating company, as evidenced by the fact that the Company and EOE both apply their financial models to the stock prices of the utility holding companies. Rothschild Surrebuttal Test., Mar. 24, 2025, pp. 43–44.

In response, the Company argues that it is not appropriate to compare the proposed equity ratios of the Company to the average equity ratio of the proxy group at the holding company level because the holding company data includes corporate-level debt that is not part of the regulated or financial capital structure of the operating utilities. Bulkley Rebuttal, pp. 127–128. Additionally, the Company argues that if the capital structures at the holding company level are considered, the correct calculation of the capital structure is to rely on the market value of debt and equity, not the book value of debt and equity as OCC and EOE have done. Id., pp. 127, 129–132.

3. Capital Structure Analysis

The Authority establishes the ratemaking capital structure by carefully weighing several factors, including: the actual capital structure of the utility and its parent company; the range of capital structures of the proxy group; and the credit rating agency metrics. The Authority is obligated to balance both investor and consumer interests in reaching a determination on the appropriate capital structure. Woodbury Water Co., 174 Conn. At 264. Generally, the utility will advocate for a higher equity component in its capital structure because a higher equity component generally provides a higher return for its investors. At the same time, a higher equity component also decreases the financial risk of the Company as it holds less debt in its capital structure. Conversely, parties such as

OCC will often advocate for a lower equity component in the Company's capitalization structure because debt is generally less expensive for ratepayers than equity.

Nonetheless, investor and consumer interests in capital structure are not entirely divergent. Specifically, a capital structure with too little equity could maximize the benefits of lower cost debt but would ultimately increase the Company's risk profile and, therefore, the cost of equity. On the other hand, a capital structure with too much equity would unnecessarily burden ratepayers with a more expensive capital structure and not achieve the lowest cost of capital for the Company that balances both risk and the overall cost of capital. Consequently, the Authority must account for a variety of factors to find an optimal capitalization mix for the Company's cost of capital.

a. Approved and Actual Capital Structure

The first factor to consider when determining a reasonable capital structure for ratemaking purposes is the approved and actual capital structure of the Company. In both the February 4, 2009, Decision in Docket No. 08-07-04, Application of The United Illuminating Company to Increase its Rates and Charges (08-07-04 Decision), and the 13-01-19 Decision, the Company proposed, and the Authority approved, a capital structure of 50% common equity and 50% long-term debt. 08-07-04 Decision, pp. 6, 139; 13-01-19 Decision, pp. 86, 95. In both the December 14, 2016 Decision in Docket No. 16-06-04, Application of The United Illuminating Company to Increase its Rates and Charges (16-06-04 Decision) and the 22-08-08 Decision, the Company proposed a capital structure consisting of 52% common equity and 48% long-term debt, while the Authority again approved, in both instances, a capital structure of 50% common equity and 50% long-term debt. 16-06-04 Decision, pp. 60, 63; 22-08-08 Decision, p. 63. Said another way, while the Company has proposed progressively higher equity capitalization ratios since 2008, ranging from 50% to the 54% proposed here, the Company's approved equity capitalization for ratemaking purposes during this time period has remained at 50%.

The Company's average Debt to Equity capitalization from January 2022 to September 2024 was 41.54% debt and 58.46% equity. Interrog. Resp OCC-534, Att. 1; Interrog. Resp. RRU-200. The Company indicated that it has managed its capital structure since September 2023 to produce an equity ratio ranging from roughly 57.00% to 65.00%. Interrog. Resp. RRU-83. Thus, since the Company's most recent rate case, in which a 50% equity capitalization was approved, the Company has maintained an equity structure containing significantly more equity.

b. Proxy Group Capital Structure

The second factor to consider when determining a reasonable capital structure for ratemaking purposes is the capital structure of the proxy groups.

During this proceeding, two distinct methodologies were used to calculate the capital structure of the proxy group companies. The first, which was employed by the Company, is to calculate the debt/equity ratio using the consolidated financial information of the subsidiary operating companies in the proxy group for the most recent eight

quarters (2022 Q3 – 2024 Q2). Ex. UI-AEB-1, pp. 50–51; Application, Ex. UI-AEB-12. Applying this methodology, the average common equity ratio for the operating subsidiaries of the Company Proxy Group companies was 52.03% (within a range from 39.41% to 60.80%). Ex. UI-AEB-1, p. 51; Application, Ex. UI-AEB-12. The Company argues that the operating utility subsidiaries of the proxy group companies are more risk-comparable to the Company. Ex. UI-AEB-1, p. 50.

The second methodology, which was employed by OCC and EOE, relies on the capital structures of the publicly traded holding companies' common equity ratios as the basis for the allowed ratemaking capitalization mix. Woolridge PFT, pp. 23, 26–27; Rothschild PFT, p. 6; Ex. ALR-5, pp. 4–5; Rothschild Surrebuttal, pp. 43–44. OCC used the holding companies' actual capital structure from the 2023 SEC Form 10-K filings, supplemented with data from S&P Capital IQ and the Value Line Investment Survey. Woolridge PFT, Ex. JRW-3.1. Next, OCC analyzed the average equity structure of the holding companies in the proxy group to arrive at an average common equity ratio of 40.90% as of December 31, 2023. Woolridge PFT, Ex. JRW 3.1. Similarly, EOE analyzed holding company capital structures from 2019 to 2023 to arrive at an average equity structure range from that time period of 42.40% to 45.90%. Rothschild PFT, Ex. ALR-5, p. 5.

The Authority generally weighs the results of an equity capitalization calculated using subsidiary company data (i.e., the approach used by the Company) less heavily as the approach indicates a capital structure that is equity biased and not necessarily reflective of an optimal capital structure. See 23-11-02 CNG Decision, p. 50; 23-08-32 Decision, p. 40 (finding that "double leveraging . . . can artificially skew the capital structure of operating subsidiaries towards equity"); 22-08-08 Decision, p. 66 ("the Authority weighs the equity capitalization calculated using holding company data more heavily than values calculated using subsidiary data"); 16-06-04 Decision, p. 62 (finding that "the holding company level matters since the cost of capital methods are relying on market data and not decisions made by individual management").

The analysis of proxy group capitalization produces a disparate range of possible values depending on which methodology is used. The first methodology indicates a common equity ratio average of 52.03% (Company), while the second methodology yields averages of 40.90% (OCC) and a range between 42.40% to 45.90% (EOE).

c. Credit Rating Effect

Another factor the Authority considers is how the capital structure may affect the credit rating of the Company. The record indicates that the Company maintains an A-rating from S&P, Baa1 from Moody's, and A- from Fitch ratings supported by an allowed capital structure of 50% Equity and 50% Debt. Ex. UI-AEB-1, p. 17; Interrog. Resp. RRU-54, Att. 1, p. 234. Indeed, these ratings generally reflect improvements over time dating back to at least the 13-01-19 Decision. Specifically, in its 2013 Rate Case, the Company recorded a rating of Baa2 by Moody's and BBB by S&P, 13-01-19 Decision, p. 91; by several years later in its 2016 Rate Case, Moody's had upgraded UI to Baa1 and S&P to BBB+ while the company recorded a rating of BBB+ by Fitch, 16-06-04 Decision, p. 58; the Company was upgraded in 2016 (after parent Iberdrola was upgraded) from BBB+ to

A-/Stable by S&P, Interrog. Resp. OCC-540, Att. 2, and, between 2018 and 2022, Moody's held UI steady at Baa1, while S&P and Fitch both raised the Company to A- during this time period. 22-08-08 Decision, p. 104. All of these developments occurred while the Company maintained an approved 50%/50% capitalization structure for ratemaking purposes.

The Company counters that the ratings agencies have noted that high interest rates and increased capital spending will place pressure on credit metrics, which underscore the importance of adequate cash flow metrics for the industry as a whole. Ex. UI-AEB-1, pp. 51–52. The Company indicated that the proposed equity allocation of 54.00%, all else equal, would produce stronger credit metrics than the current allowed capitalization mix; however, the Company would not expect this change alone to result in higher ratings or to materially lower borrowing costs. Interrog. Resp. RRU-84.

UI has operated under an approved equity ratio of 50% since at least the 08-07-04 Decision. In that time, UI has sustained the relevant credit metrics to maintain its current ratings, inclusive of through the COVID-19 pandemic and other economic gyrations that have occurred in the United States over the last 10 plus years.

d. Conclusion

Regarding the overall capital structure, the Authority considered (1) the approved and actual capital structure of the utility, (2) the capital structures of the companies in the proxy groups, and (3) the credit rating effects. The evidence indicates that UI has maintained an allowed equity ratio of 50% since at least the 08-07-04 Decision, while recently employing an actual equity capitalization of between seven and 15 percentage points higher. Further, the credit rating averages of the two proxy groups are BBB+ and Baa2, while UI maintains an A- rating from S&P, Baa1 from Moody's, and A- from Fitch and overall represents an investment risk below that of the proxy groups.

After considering each factor, the Authority allows a 51.00% equity component in the Company's capital structure.

D. COST OF DEBT

The Authority approves a cost of 4.739% for the Company's long-term debt. The Authority determines the cost of long-term debt by calculating a weighted average of the Company's existing long-term debt issuances as well as any known and measurable long-term debt expenses. Table 28, below, summarizes the Company's long-term debt costs.

Table 28: Cost of Long-Term Debt

Interest Rate	Debt Series	Date Issued	Maturity Date	Average Carrying Value ($000)	Annual Expense ($000)
4.50%	Series A	10/2/2003	10/3/2033	63,841	2,984
5.61%		12/10/2009	3/10/2025	-	-
3.96%		12/12/2018	12/12/2025	4,167	166
4.07%		10/4/2018	10/4/2028	99,872	4,123
2.02%		12/1/2020	12/1/2030	74,810	1,557
2.25%		1/31/2022	1/31/2032	149,548	3,454
4.62%		12/15/2022	12/15/2032	49,804	2,340
6.09%	Series N	12/13/2023	12/13/2034	155,355	9,575
6.29%	Series O	12/13/2023	12/13/2038	33,849	2,151
6.51%	Series E	9/5/2007	9/5/2037	15,985	1,043
6.51%	Series F	12/6/2007	12/6/2037	11,988	782
6.09%		7/27/2010	7/27/2040	99,795	6,104
4.89%	Series D	1/30/2012	1/30/2042	51,897	2,543
4.89%	Series E	4/2/2012	1/30/2042	34,931	1,712
4.61%	Series G	6/29/2015	6/29/2045	49,812	2,315
4.52%		1/15/2019	1/15/2049	49,790	2,269
5.67%	Series P	8/15/2024	9/30/2039	99,042	5,737
Unamortized Redemption Premium				(3,042)	499
Total				**1,041,443**	**49,353**
Cost of Embedded Debt					**4.739%**

Interrog. Resp. RRU-391, Att. 1.

In addition to its existing debt, the Company proposed the inclusion of two new senior note issuances of $150 million in September 2025 and $65 million in September 2026. The Authority finds that the debt expense for the new senior notes, which remained unissued before the close of the evidentiary record, is not sufficiently known and measurable to permit an adjustment to the Company's long-term cost of debt. There is insufficient evidence with respect to these issuances in terms of amount, coupon rate, and fees to make a known and measurable adjustment to the Test Year cost. In summary, after removing the 2025 and 2026 New Issues, which had yet to occur during the evidentiary phase of this proceeding, the Authority approves a cost of long-term debt of 4.739%.

E. RETURN ON EQUITY

1. Summary

The Authority finds that a net ROE of 9.25% reflects a commensurate rate of return based on variety of factors, including current market conditions, the regulatory environment, and the level of service and management provided by the Company. Specifically, the Authority finds that an unadjusted ROE of 9.45% provides a utility that offers expert, efficient, and prudent management of the utility franchise a reasonable

return on its investment. In reaching this determination, the Authority considered a variety of factors, including widely accepted financial models for calculating commensurate ROEs, comparable approved ROEs, current economic and market conditions, and the impact on the Company's creditworthiness. The Authority further finds that a reduction of 20 basis points is warranted to account for certain deficiencies in the Company's performance and to incentivize improvement.

2. Discounted Cash Flow (DCF) Model

a. DCF Model Description

The DCF model is a market-based financial model that attempts to replicate the valuation process used by investors. The DCF model assumes that investors evaluate stocks in a classical economic framework and buy and sell securities rationally at prices that reflect the assets' value. Under the DCF model, the value of a financial asset is based upon the present value principle. Specifically, the present value of a financial asset equals the discounted value of its expected future cash flow. Investors discount these expected cash flows at their required rate of return (i.e., the COE or ROE). Therefore, by using proxy company data, the DCF model provides evidence of commensurate ROEs for utilities with corresponding risk profiles.

The traditional constant growth DCF Model requires the following assumptions: a constant growth rate for earnings and dividends; a stable dividend payout ratio; a constant price-to-earnings ratio; and a discount rate greater than the expected growth rate.

The DCF model is represented by the formula of K = D1 / Po + G, where:

K = the market-required ROE

D1 = the forecasted dividend paid one period into the future;

Po = an estimate of the current market price of the stock; and

G = investors' long-run growth expectations.

In short, the ROE (K) can be determined by summing the expected dividend yield (D1/Po) and the expected growth rate (G).

b. Expected Growth Rate

The Authority first considers the expected growth rate for the companies in the Authority Proxy Group because the expected growth rate is also a factor in calculating the expected dividend yield. The constant growth form of the DCF Model assumes a single growth estimate in perpetuity. To reduce the expected growth rate to a single measure, the constant payout ratio, earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS) are assumed to all grow at the same constant rate. The distinction between the Parties' approaches to the expected growth rate is (1) the specific growth measures considered and (2) the weighting of the measures.

For its expected growth rate, the Company uses the EPS growth estimates from Zacks Investment Research, Yahoo! Finance and Value Line. Ex. UI-AEB-1, p. 22. The Company's decision to limit its analysis to EPS growth estimates is based on the Company's presumption that dividend growth can only be sustained by earnings and therefore EPS growth is the appropriate measure of a company's long-term growth. Id., p. 23. As a result, the Company calculated a mean growth rate for the Company Proxy Group of 6.90% (Zacks), 6.90% (Yahoo! Finance), and 5.63% (Value Line). Application, Ex. UI-AEB-4 CGDCF. In rebuttal testimony, the Company noted that Yahoo! Finance no longer reports consensus projected three- to five-year EPS growth rates. Bulkley Rebuttal, p. 26. The Company is now relying on the consensus projected three- to five-year growth rates reported by S&P Capital IQ pro in its constant growth DCF model. Id. The Company's new mean growth rates for Value Line, Zacks, and S&P Cap IQ are 5.69%, 7.12%, and 6.93% respectively, for a calculated average growth rate mean of 6.58% and a median of 6.54%. PFT, Ex. AEB-4 CGDCF.

OCC proposed a growth rate methodology that considers a range of growth measures rather than only EPS growth estimates. Woolridge PFT, pp. 43–44. OCC asserts it is well known that the long-term EPS growth-rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. Id. This has been demonstrated in a number of academic studies over the years. See, e.g., Woolridge PFT, p. 44, n.18. OCC concludes that exclusively using these growth rates as a DCF growth rate will provide an overstated equity cost rate. Woolridge PFT, p. 44. OCC "reviewed thirteen growth rate measures, including historical and projected growth rate measures, and have evaluated growth in dividends, book value, and earnings per share." Id., p. 5. In addition, OCC examined the internal growth rate (i.e., sustainable growth rate) using the retention rate of earnings times the return on equity. Id., pp. 41–42. In weighing the various growth measures, OCC gives "primary weight" to the projected EPS growth rate of Wall Street analysts and Value Line but recognizes the upward bias nature of these forecasts." Id., p. 49.

Applying this methodology to the OCC Electric Proxy Group, OCC identified a projected growth rate range of 5.25% to 6.85% and proposed to use the midpoint (6.05%) of that range for the DCF growth rate in its DCF calculation. Woolridge PFT, p. 49; Woolridge PFT, Ex. JRW-5. Using the same methodology for the Company Proxy Group, OCC proposed a projected growth rate of 5.25% to 7.05% and proposed the midpoint (6.15%) as the DCF growth rate for the Company Proxy Group. Woolridge PFT, pp. 49–50.

EOE approaches the growth rate calculation differently, asserting that the growth rate must be representative of the constant sustainable growth. Rothschild PFT, p. 60. According to EOE, "[t]o obtain an accurate constant growth DCF result, the mathematical relationship between earnings, dividends, book value, and stock price must be respected." Id. EOE also asserts that "[a]nalysts' five-year earnings per share growth rates are earnings per share growth rates that measure earnings growth from the most currently completed fiscal year to projected earnings five years into the future." Id., p. 131. EOE states that "[t]hese growth rates are not indicative of future sustainable growth rates in part because the sources of cash that flow to an investor are dividends and stock

price appreciation." Id. Rather than using Value Line or analysts' EPS estimates of five-year growth, EOE calculated the growth rate as the internal rate of return growth rate. Rothschild PFT, p. 66. EOE bases its value of the future expected return on equity "r" on the average return on book equity expected by Value Line, adjusted in consideration of recent returns. Id., p. 62. EOE also makes "a computation that is based on a review of both the earned return on equity consistent with analysts' consensus earnings growth rate expectations and on the actual earned returns on equity." Id.

Using this approach, EOE proposed a growth rate of 4.71% based on the average market price ending December 31, 2024, and 4.77% based on the market price as of December 31, 2024. Rothschild PFT, Ex. ALR-3, p. 1. In addition, EOE proposed using a Non-Constant Growth Form of the DCF, for which it proposed an average growth rate of 4.19% based on market prices and 4.19% based on the last twelve months' average stock price. Rothschild PFT, Ex. ALR-3, pp. 3–4.

The Authority typically uses an expansive approach to determining expected growth rates, which is consistent with OCC's methodology of considering a number of growth measures in addition to EPS growth. See, e.g., 22-08-08 Decision, p. 71; 23-08-32 Decision, p. 45; 23-11-02 CNG Decision, p. 59. Here again, the Authority finds credible OCC's testimony that exclusive reliance on EPS growth results in an improper upward bias. See Woolridge PFT, pp. 44, 49. Therefore, although EPS growth is a key contributing factor in estimating future growth, the Authority finds that other measures, including projected DPS, BVPS, and retention growth, should be considered.

The Authority has previously considered whether to include Value Line's historical DPS and BVPS growth rates in its analytical models. In prior rate cases, the Authority reviewed but ultimately excluded the Value Line historical EPS, DPS, and BVPS rates. See, e.g., 13-01-19 Decision, pp. 127–129; 16-06-04 Decision, p. 83; Decision, Mar. 15, 2023, Docket No. 22-07-01, Application of Aquarion Water Company of Connecticut to Amend its Rate Schedules (22-07-01 Decision), p. 46; 22-08-08 Decision, p. 70 n.62; 23-08-32 Decision, p. 44 n.21; 23-11-02 CNG Decision, p. 57 n.50. For the same reasons previously articulated in the prior rate cases, the Authority will not include historical EPS, DPS, and BVPS growth rates in its analysis. However, the Authority has previously included Value Line *projected* DPS and BVPS growth rates in its analysis, primarily due to the Authority's expectation that investors will likely examine all the projected growth rate data available. See, e.g., 13-01-19 Decision, p. 129; 16-06-04 Decision, p. 83; 22-07-01 Decision, p. 46; 22-08-08 Decision, p. 71; 23-08-32 Decision, pp. 45–46; 23-11-02 CNG Decision, p. 59.

Accordingly, PURA determined the expected growth rate for the Authority Proxy Group by considering six growth measures: (1) S&P Capital IQ 5-year EPS growth; (2) Zacks 5-year EPS growth; (3) Value Line 5-year EPS growth; (4) Value Line's projected DPS growth; (5) Value Line's projected BVPS growth; and (6) retention growth rates using Value Line projected EPS, DPS, or BVPS data into its analysis.[38] See, e.g., 13-01-19

[38]As stated above, in rebuttal testimony, the Company noted that Yahoo! Finance no longer reports consensus projected three- to five-year EPS growth rates. Bulkley Rebuttal PFT, p. 26.

Decision, pp. 127–129; 16-06-04 Decision, p. 83; 22-07-01 Decision, p. 46; 22-08-08 Decision, p. 71; 23-08-32 Decision, p. 46; 23-11-02 CNG Decision, p. 59. Specifically, the Authority weighs the averages of the three EPS growth rates for each company equally with the average of the other three growth measures for a composite growth estimate. The table below depicts the outputs for the Authority's model.

Table 29: DCF Expected Growth Estimates

	EPS Growth 50% Weighting			Other Growth 50% Weighting			Weighted
Proxy Group	VL EPS	S&P Cap IQ EPS	Zacks EPS	VL DPS	VL BVPS	VL Retention Ratio	Expected Growth
Alliant Energy Corporation	6.00%	6.54%	6.73%	6.00%	4.00%	5.71%	5.83%
Ameren Corporation	6.50%	6.95%	6.95%	6.50%	6.50%	5.57%	6.49%
American Electric Power	6.50%	6.80%	6.43%	5.50%	6.00%	5.24%	6.08%
Avista Corporation	5.50%	5.98%	6.07%	4.00%	2.00%	2.10%	4.28%
Consolidated Edison Inc.	6.00%	5.79%	5.57%	4.50%	4.00%	3.55%	4.90%
DTE Energy Company	4.50%	7.31%	7.64%	3.00%	1.00%	7.05%	5.08%
Duke Energy Corporation	6.00%	5.79%	6.33%	3.50%	3.50%	3.92%	4.84%
Edison International	6.50%	6.38%	7.01%	6.00%	6.00%	5.50%	6.23%
Entergy Corporation	3.00%	8.57%	9.46%	5.50%	4.50%	2.76%	5.63%
Evergy, Inc.	7.50%	5.70%	5.70%	7.00%	3.50%	3.68%	5.51%
FirstEnergy Corporation	4.50%	5.62%	6.43%	4.50%	5.50%	4.49%	5.17%
IDACORP, Inc.	6.00%	6.42%	8.13%	5.50%	4.50%	3.92%	5.74%
NextEra Energy, Inc.	8.50%	8.09%	7.72%	9.50%	8.00%	5.22%	7.84%
NorthWestern Corporation	4.50%	N/A	6.87%	1.50%	2.50%	2.80%	3.98%
OGE Energy Corporation	6.50%	7.70%	6.32%	3.00%	5.50%	4.42%	5.57%
Pinnacle West Capital	5.50%	5.80%	2.12%	1.50%	4.00%	3.43%	3.72%
Portland General Electric	6.50%	6.53%	3.44%	5.50%	4.50%	3.31%	4.96%
Southern Company	6.50%	4.76%	6.55%	3.50%	3.50%	7.75%	5.43%
Xcel Energy Inc.	7.00%	4.76%	7.52%	6.50%	5.50%	4.58%	5.98%
High	8.50%	8.57%	9.46%	9.50%	8.00%	7.75%	**7.84%**
Average	5.97%	6.42%	6.47%	4.87%	4.45%	4.47%	**5.44%**
Low	3.00%	4.76%	2.12%	1.50%	1.00%	2.10%	**3.72%**

Interrog. Resp. RRU-406 Supp., Att. 2 ("OCC" and "Company" tabs) (source of S&P and Zacks estimates:); Interrog. Resp. RRU-406 UI Supp., Att. 5 (Value Line inputs).

Table 30, below, summarizes the data with respect to expected growth rates for the DCF model.

Table 30: DCF Expected Growth Estimates (%)

	Range (%)	Mean/Proposed (%)
Company – Company Proxy Group	5.69 – 6.93	6.58
OCC – OCC Electric Proxy Group	5.25 – 6.85	6.05
OCC – Company Proxy Group	5.25 – 7.05	6.15
EOE – Constant Growth	-	4.77
EOE – Non-Constant	-	4.19
Authority Proxy Group	3.72 – 7.85	5.44

The Authority's analysis indicates that, based on the specific proxy group and weighting of growth measures, the average data for the expected EPS growth rates falls within a range of approximately 4.19% to 6.58%. The Authority's equal weighting approach, which includes non-EPS growth measures, results in an expected growth rate near the middle of that range (5.44%).

c. Expected Dividend Yield

The second input into the DCF model is the Expected Dividend Yield. For purposes of the DCF model, the Expected Dividend Yield is estimated by taking a company's current annual dividend yield and escalating the yield to account for anticipated growth and the timing of dividends.

A company's current dividend yield is not subject to much dispute since a company's dividend and stock price are both published market data. To avoid stock price fluctuations, an average daily stock price is typically used, with the time period ranging from 30 to 180 trading days. Here, as has been found in other recent rate cases, the Authority finds a 30-trading day average stock price to be appropriate because it represents the most current pricing data over a reasonable duration of time and does not reflect any significant market disruptions that might unreasonably impact the average stock price. See, e.g., 22-07-01 Decision, p. 43; 22-08-08 Decision, p. 73; 23-08-32 Decision, p. 48; 23-11-02 CNG Decision, p. 61. Given the relative similarities in the proxy groups, the expected dividend yields calculated by the parties fell within a fairly narrow range.

The Company's dividend yield is based on the proxy group companies' current annual dividend and average closing prices over the 30-, 90-, and 180-trading days ended September 30, 2024. Ex. UI-AEB-1, p. 22. The Company also adjusts the dividend yield by one-half the expected annual dividend rate to calculate the expected dividend yield for the DCF model. Id. The Company's updated expected dividend yield in rebuttal testimony had a mean of 4.04% and median of 4.01%. Bulkley PFT, Ex. AEB-REB-3 CGDCF.

OCC determined the Expected Dividend Yield using the same basic methodology as the Company (i.e., escalating the dividend yield using the 1+.5g approach and using 30-day, 90-day, and 180-day average stock prices). Woolridge PFT, pp. 39–40; Woolridge PFT, Ex. JRW-5.2. OCC applied the methodology to two proxy groups (i.e.,

Company Proxy Group and the OCC Proxy Group). Id. For the OCC Proxy Group, the mean and median dividend yields range from 3.4% to 3.6%, and OCC used 3.50% as the dividend yield for the OCC Proxy Group. Id. For the Company Proxy Group, the mean and median dividend yields range from 3.6% to 3.8%, and given these results, and applying more weight to more recent yields, OCC used 3.7% as the dividend yield for the Company Proxy Group. Id. Applying estimated growth rates of 6.05% for the OCC Proxy Group and 6.15% for the Company Proxy Group, OCC calculated an Expected Dividend Yield of 3.61% (3.50% x 1.03025[39]) and 3.81% (3.70% x 1.03075[40]) for the OCC Proxy Group and the Company Proxy Group, respectively. Woolridge PFT, p. 50, Ex. JRW-5.1.

For the constant growth DCF model, EOE calculated dividend yields of 4.08% and 4.07% based on the weighted averages and spot market values as of December 31, 2024. EOE then escalated the yield using an expected growth rate, resulting in an Expected Dividend Yield of 4.17% (4.08% + 0.09%) and 4.16% (4.07% + 0.09%), respectively, for the weighted average calculation and spot market calculation. Rothschild PFT, Ex. ALR-3, p. 2.

As shown in the table below, the parties' estimates for the Expected Dividend Yield fall within a range of approximately 3.61% to 4.17%.

Table 31: Expected Dividend Yield

	Mean Expected Div. Yield (%)
Company – Company Proxy	4.04
OCC – OCC Electric Proxy Group	3.61
OCC – Company Proxy Group	3.81
EOE – Company Proxy Group Weighted/Spot	4.17/4.16

The Authority has previously expressed a preference to use Value Line Column (f) data for projected dividends because Value Line is a well-known and disseminated source and the Value Line algorithm incorporates years of data such that Value Line projects the timing and amount of dividend payments for the next twelve months. The Authority finds that this data is equally reliable as compared to the growth assumptions supporting the 1+.5g factor. See, e.g., 22-07-01 Decision, p. 43; 22-08-08 Decision, pp. 74–75; 23-08-32 Decision, p. 49; 23-11-02 CNG Decision, p. 62. Therefore, the Authority examined the projected dividend yields for the next 12 months that are calculated and made commercially available by Value Line. The projected dividend is available at Value Line: Summary & Index's column (f), Estimated Dividend Yield Next 12 Months (Value Line Column (f)). Interrog. Resp. RRU-406. Supp., Att. 6. Value Line determines the projected dividends in Column (f) based upon Value Line's proprietary algorithm that projects the specific timing and amount of dividend payments for each company. By contrast, the 1+.5g approach is a generalized, rule-of-thumb approach for projecting future dividends.

[39] 6.05/2=3.025%.
[40] 6.15/2=3.075%.

Consequently, the Column (f) data provides a more nuanced financial analysis from a trusted source.

Here, calculating the Expected Dividend Yield using the Value Line Column (f) projections provide results that are consistent with those from the 1+.5g approach. Specifically, as shown in the table below, using the Value Line Column (f) data from the Authority Proxy Group provides an average Expected Dividend Yield of 3.82%.

Table 32: DCF Expected Dividend Yield Estimates

	VL Est Next 12-Month Div'd ($)	30-day Stock Price as of May 15, 2025 ($)	Authority Proxy Group Div. Yield (%)
Alliant Energy Corporation	2.03	60.87	3.33
Ameren Corporation	2.85	97.64	2.92
American Electric Power Company, Inc.	3.80	105.12	3.61
Avista Corporation	1.92	40.60	4.73
Consolidated Edison	3.45	108.85	3.17
DTE Energy Company	4.36	134.09	3.25
Duke Energy Corporation	4.24	119.31	3.55
Edison International	3.41	56.25	6.06
Entergy Corporation	2.40	82.50	2.91
Evergy, Inc.	2.71	67.20	4.03
FirstEnergy Corporation	1.80	41.70	4.32
IDACORP, Inc.	3.44	115.94	2.97
NextEra Energy, Inc.	2.33	67.67	3.44
NorthWestern Corporation	2.65	57.10	4.64
OGE Energy Corporation	1.76	44.38	3.97
Pinnacle West Capital Corporation	3.61	92.54	3.90
Portland General Electric Company	2.12	42.30	5.01
Southern Company	2.96	89.82	3.30
Xcel Energy Inc.	2.32	68.82	3.37
High			**6.06**
Average			**3.82**
Low			**2.91**

Interrog. Resp. RRU-406 Supp., Att. 1, Att. 6.

As noted above, the parties' estimates for Expected Dividend Growth span a fairly narrow range, with the evidence indicating that a reasonable range for the Expected Dividend Yield is 3.61% to 4.17%. The Authority's analysis using the Authority Proxy Group and commercially available dividend projections results in a similar finding, with an average of 3.82%.

d. DCF Results

Once the Expected Growth Rate and Expected Dividend Yield are determined, the ROE is determined by adding the two. As discussed in Section V.E.2.b, Expected Growth

Rate, PURA determined a composite average expected growth rate for the Authority Proxy Group is in the range of 3.72% to 7.84%. In the preceding section, PURA found that a reasonable Expected Dividend Yield for the Authority Proxy Group is in the range of 3.61% to 4.17%. As such, applying the DCF formula (i.e., D1/Po + G) to these ranges results in an estimated ROE range between a low of 7.33% to a high of 12.01%.

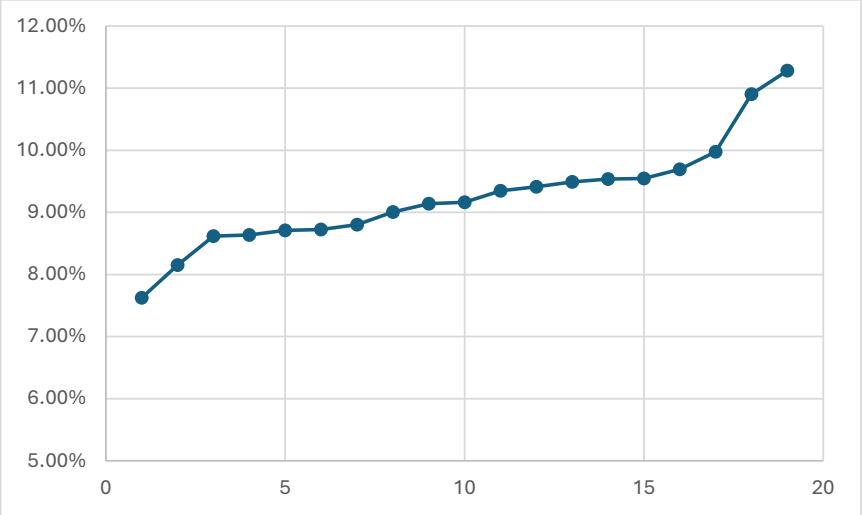
Applying the DCF formula to the proxy group companies confirm this range with the results summarized in the table below.

Table 33: DCF Results

Company	Forecasted Div'd Yield (%)	Composite Growth Rate Average (%)	Yield + Growth Rate (%)
Alliant Energy Corporation	3.33	5.83	9.16
Ameren Corporation	2.92	6.49	9.41
American Electric Power	3.61	6.08	9.69
Avista Corporation	4.73	4.28	9.00
DTE Energy Company	3.25	4.90	8.15
Duke Energy Corporation	3.55	5.08	8.64
Edison International	6.06	4.84	10.90
Entergy Corporation	2.91	6.23	9.14
Consolidated Edison	3.17	5.63	8.80
Evergy, Inc.	4.03	5.51	9.55
FirstEnergy Corporation	4.32	5.17	9.49
IDACORP, Inc.	2.97	5.74	8.71
NextEra Energy, Inc.	3.44	7.84	11.28
NorthWestern Corporation	4.64	3.98	8.62
OGE Energy Corporation	3.97	5.57	9.54
Pinnacle West Capital	3.90	3.72	7.62
Portland General Electric	5.01	4.96	9.98
Southern Company	3.30	5.43	8.72
Xcel Energy Inc.	3.37	5.98	9.35
High	**6.06**	**7.84**	**11.28**
Low	**2.91**	**3.72**	**7.62**
Mean	**3.82**	**5.44**	**9.25**
Median			**9.16**

The ROEs for the 19 companies in the Authority Proxy Group ranged from 7.62% to 11.28%, with a mean of 9.25%, a median of 9.16%. Figure 1, below, illustrates the distribution of the ROEs and shows an aggregation of proxy group ROEs between 8.7% and 9.6%.

Figure 1: DCF ROE Distribution



Consequently, the Authority finds that the DCF model indicates that an ROE in the range of 8.7% to 9.6% would be consistent with the ROEs of UI's peer companies.

3. Capital Asset Pricing Model (CAPM)

a. CAPM Model Description

The CAPM evaluates the relationship between the expected return and risk of investing in a security; CAPM can be used to calculate the expected return of an asset. Therefore, like the DCF model, by incorporating proxy company data, the CAPM provides evidence of commensurate ROEs for utilities with corresponding risk profiles.

To determine the COE, the CAPM first determines the appropriate risk-free rate and then adds a beta, or the degree of co-movement of the security's rate of return with the market's rate of return, multiplied by the expected equity risk premium (ERP), which is the amount by which investors expect the future return on equities, in general, to exceed that on the risk-free asset.

The CAPM model is represented by the formula Ke = Rf + β (Rm-Rf), where:

Ke= the required market ROE;

β = Beta coefficient of an individual security;

Rf = the risk-free rate of return; and

Rm = the required return on the market; the term (Rm - Rf) represents the ERP.

Consequently, once the Beta (β) and ERP (Rm- Rf) are determined, an ROE can be calculated.

b. Beta Coefficient

The measure of Beta in the CAPM analysis represents the volatility of a proxy group of companies as compared to the aggregate market.

In its CAPM model, the Company used the betas of the Company Proxy Group as reported by Bloomberg and Value Line. Ex. UI-AEB-1, p. 29. The Bloomberg betas are calculated using 10 years of weekly returns relative to the S&P 500 Index. Id. The Value Line betas are based on Value Line's calculation of five years of weekly returns for the New York Stock Exchange Composite Index. Id. The Company also did a historical beta analysis using long-term average betas as sourced from Value Line over the period 2013 through 2023. Id.; see Application, Ex. UI-AEB-5, Ex. UI-AEB-6. Using Bloomberg and Value Line data for the Company Proxy Group, the Company identified a range of betas of 0.67 to 1.05, and the long-term historical Value Line beta at 0.76. Application, Ex. UI-AEB-5, Ex. UI-AEB-6. The average of Value Line betas for its proxy group was 0.94 and the average of Bloomberg betas was 0.78. Application, Ex. UI-AEB-5. The updated calculated average for Value Line and Bloomberg betas is 0.88 for Value Line betas and 0.82 for Bloomberg betas. Bulkley Rebuttal, Ex. UI-AEB-Rebuttal-4.

OCC used the same beta data from Value Line as the Company, and also used betas published by S&P Capital IQ, which computes beta over a five-year period using monthly return and the S&P 500 as the market return. Woolridge PFT, p. 56. S&P Capital IQ does not use the Blume adjustment, but OCC adjusts the beta to include it. Id., pp. 56–57. OCC averaged the Value Line betas and its adjusted S&P Capital IQ betas for the proxy groups. Id., pp. 57; Woolridge PFT, Ex. JRW-6.3. OCC's median betas for the OCC Proxy Group and the Company Proxy Group are 0.80 and 0.80, respectively. Id.

OCC also used beta data from Value Line, which indicated an average beta of 0.93 for the Company Proxy Group and 0.95 for the OCC Proxy Group. Woolridge PFT, Ex. JRW-6.3. In addition, OCC provided betas from S&P Capital IQ. Id.; Woolridge PFT, p. 56. S&P-IQ computes betas over a five-year period using monthly returns from the S&P 500. Woolridge PFT, p. 56. To make the S&P-IQ comparable to the Value Line betas, OCC included the Blume adjustment to S&P-IQ betas as S&P-IQ does not use the Blume adjustment.[41] Id., pp. 56–57. The adjusted S&P-IQ betas indicated an average beta of 0.73 for the Company Proxy Group and 0.74 for the OCC Proxy Group. Woolridge PFT, Ex. JRW-6.3. Combining the data together results in a mean and median beta of 0.84 and 0.82, respectively, for the Company Proxy Group, and a mean and median beta of 0.84 and 0.82, respectively, for the OCC Proxy Group. Id. Consequently, OCC proposed a beta of 0.82 for the Company Proxy Group and 0.82 for the OCC Proxy Group. Woolridge PFT, Ex. JRW-6.1; Woolridge PFT, p. 65.

EOE used an alternative means to calculate beta by incorporating investors' return expectations by calculating option implied betas. Rothschild PFT, pp. 71–81. Specifically, EOE uses two betas, a forward beta that is based on expectations of non-diversifiable risk, and historical beta that is based on historical return data over six-month, two-year, and five-year periods. Id., p. 71. EOE calculates betas based on investors' expectations

[41]The Blume Adjustment uses historical regression to estimate future market beta.

of the probability distribution of future returns using prices of stock options. Id. The selection of option implied betas is based on EOE's observation that option implied betas provide information regarding future perceived risks and expectations. Id., p. 72. EOE calculated its betas under two scenarios: (1) historical blend consisting of 50% Historical Beta (6 months) + 30% Historical Beta (2 years) plus 20% Historical Beta (5 years); and (2) forward Beta consisting of 100% Options-Implied Beta. Id., p. 73; Rothschild PFT, Ex. ALR-4, p. 3.

> According to EOE, the calculation of the Option-Implied beta requires:
>
> (1) obtaining stock option data for that company and a market index, (2) filtering the stock option data, (3) calculating the option-implied volatility for the company and for the index, (4) calculating the option-implied skewness for the company and for the index, and (5) calculating option-implied betas for the company based on implied volatility and skewness for the company and for the index.

Rothschild PFT, p. 76. EOE relied upon the Chicago Board of Options Exchange's VIX and SKEW Index to filter stock option data and to calculate the option-implied volatility and skewness. Id., pp. 76–77.

EOE Historical Blended Beta and Forward Beta analysis resulted in betas of 0.52 and 0.62, respectively. Id., p. 84; Rothschild PFT, Ex. ALR-4, pp. 1, 3. Additionally, for its Spot Beta dated December 31, 2024, EOE uses 0.62 for its forward Beta and 0.55 for its historical blended Beta. Rothschild PFT, Ex. ALR-4, pp. 3, 5.

The Authority generally considers both Value Line and Bloomberg Betas to be reliable and has typically averaged the two sources to develop a composite Beta for each proxy company. See 23-11-02 CNG Decision, pp. 65–66; 23-08-32 Decision, p. 52; 22-08-08 Decision, pp. 79–80; 22-07-01 Decision, p. 50.

This data indicates that a reasonable beta range is 0.75 to 0.85. Table 34, below, summarizes the beta data for the Authority Proxy Group.

Table 34: Beta Summary

Company	Value Line Beta	Bloomberg Beta	Average
Alliant Energy Corporation	0.95	0.75	0.85
Ameren Corporation	0.9	0.72	0.81
American Electric Power Co.	0.85	0.71	0.78
Avista Corporation	0.75	0.71	0.73
DTE Energy Company	1	0.78	0.62
Consolidated Edison, Inc.	0.65	0.59	0.89
Duke Energy Corporation	0.7	0.68	0.69
Edison International	0.9	0.82	0.86
Entergy Corporation	1	0.83	0.92
Evergy, Inc.	0.95	0.75	0.85
FirstEnergy Corp.	0.75	0.76	0.75
IDACORP, Inc.	0.75	0.74	0.75
NextEra Energy, Inc.	0.9	0.78	0.84
NorthWestern Corporation	0.8	0.82	0.81
OGE Energy Corp.	1.05	0.87	0.96
Pinnacle West Capital Corp.	0.8	0.78	0.77
Portland General Electric Company	0.8	0.74	0.77
Southern Company	0.75	0.74	0.75
Xcel Energy Inc.	0.75	0.7	0.73
Average	**0.84**	**0.75**	**0.8**
Min	**0.62**	**0.59**	**0.62**
Max	**1.02**	**0.87**	**0.96**

Interrog. Resp RRU-406 (Value Line March 7, 2025, April 18, 2025, May 9, 2025; Bloomberg, 10-Year adjusted beta as of May 16, 2025).

c. Risk-Free Rate (Rf)

The Company identified three possible sources for risk-free rates: (1) the current 30-day average yield on 30-year US Treasury Bonds (UST 30), which was 4.07% as of September 30, 2024; (2) the average projected UST 30 yield for next year (Q1 2025 through Q1 2026), which was 4.02% as of October 1, 2024; and (3) the average projected UST 30 yield for the next five years (2026 through 2030), which was 4.30% as of May 31, 2024. Ex. UI-AEB-1, p. 29; Application, Ex. UI-AEB-5. In its rebuttal testimony, the Company updated the yields to: (1) the current 30-day average yield on UST 30, which was 4.82% as of January 31, 2025; (2) the average projected UST 30 yield for next year (Q2 2025 through Q2 2026), which was 4.66% as of January 31, 2025; and (3) the average projected UST 30 yield for the next five years (2026 through 2030), which was 4.30% as of November 27, 2024. Bulkley Rebuttal PFT, Ex. UI-AEB-Rebuttal-4. Consequently, the Company's proposed risk-free rates ranged from approximately 4.02% to 4.82%.

OCC's risk-free estimate was based on a review of the yield of UST 30 over the 2010 to 2025 time period, which ranged from 1.3% to 5%. Woolridge PFT, p. 52; Woolridge PFT, Ex. JRW-6.2. The current yield is at the upper end of that range. Id.

According to OCC, Kroll, a division of the investment firm Duff & Phelps, recommends using a normalized risk-free rate of 3.5%, or if the spot yield on US Treasury 20-year Bonds (UST 20-year) is above 3.5%, to use UST 20-year yield. Id., pp. 52–53. OCC noted that these yields have been distorted currently due to lack of liquidity in the 20-year U.S. Treasury market. Id., p. 53. Therefore, OCC recommends using 4.70% as the proxy for the risk-free rate of interest in the CAPM. Id. OCC does not take forecasts of higher rates into consideration as the 4.70% effectively synchronizes the risk-free rate with the market risk premium, which is essential to implement the CAPM approach. Id., pp. 53–54.

EOE uses market yield on short-term U.S. Treasury securities as the risk-free rate as these assets have a beta close to zero. Rothschild PFT, p. 69; Rothschild PFT, Appendix D, p. 139. Further, EOE indicates that it is not appropriate to use a risk-free rate based on interest rate forecasts because it does not represent investor expectations. Rothschild PFT, p. 71; Rothschild PFT, App. D, p. 140.

Instead, EOE's short-term risk-free rate is based on the yield of three-month U.S. Treasury bills, while EOE's long-term risk-free rate is based on the yield of UST 30. Rothschild PFT, pp. 69–70. EOE's spot and weighted average short-term risk-free rates are 4.37% and 4.51%, respectively, and the spot and weighted average long-term risk-free rates are 4.78% and 4.57%, respectively. Id., p. 70; Rothschild PFT, Ex. ALR-4, p. 2. As this data shows, given the inverted yield curve, the rates for long-term and short-term debt are presently very similar.

The range of risk-free rates presented by the parties is summarized in Table 35, below.

Table 35: Proposed Range of Risk-Free Rates

Party	Risk Free Rates
Company, Jan. 31, 2024	4.30% – 4.82%
OCC	4.70%
EOE	4.37% – 4.78%

The Authority agrees with EOE on the point that the risk-free rates based on forecasted data are inherently less certain. Notably, the Authority has traditionally relied on UST 30-year as the proxy for the risk-free rate over many rate proceedings. See, e.g., 23-11-02 CNG Decision, p. 67; 23-08-32 Decision, p. 54; 22-08-08 Decision, p. 81; 22-07-01, p. 51; 16-06-04 Decision, pp. 84–85; 20-12-30 Decision, pp. 38–39. As such, the Authority gives greater weight to methodologies using the UST 30-year rate. Based upon the evidence provided by the parties, including updated rate information, the Authority finds that an appropriate Rf is in the range of 4.57% to 4.82%.

d. Equity Risk Premium

The equity risk premium (ERP) is equal to the expected return on the S&P 500 (Rm) minus the risk-free rate of interest (Rf). In short, ERP = Rm-Rf. The ERP is difficult to measure because it requires an estimate of the expected return on the market (Rm).

The Company defined the market risk premium as the difference between the implied expected equity market return and the risk-free rate. Ex. UI-AEB-1, p. 30. The Company calculated the expected return on the S&P 500 Index by using the constant growth DCF model for the companies in the S&P 500 Index. Id.; Application, Ex. UI-AEB-7. The Company's estimated required market return for the S&P 500 Index, as of September 30, 2024, is 12.04%, based on an estimated market capitalization weighted dividend yield of 1.52% and a weighted long-term growth rate of 10.45%. Ex. UI-AEB-1, p. 42; Application, Ex. UI-AEB-7. The Company then determined an ERP (Rm-Rf) by using three estimates of the risk-free rate, the current 30-day average of 30-year T-Bond (4.07%), the average projected 30-year U.S Treasury bond yield for the first quarter of 2025 through the first quarter of 2026 (4.02%), and the average projected 30-year U.S. Treasury bond yield for 2026 through 2030 (4.30%), resulting in a market risk premium range of 7.74% to 8.02%. Ex. UI-AEB-1, pp. 29–30.

On rebuttal, the Company updated its ERP to a range of 8.58% to 8.75%. Bulkley Rebuttal PFT, UI-AEB-Rebuttal-4B.

OCC examined four different approaches to determining the ERP: (1) studies of historical risk premium (i.e., ex-post returns); (2) ex-ante market risk premium studies; (3) financial surveys (e.g., CFOs, analysts, financial forecasters); and (4) the building blocks approach. Woolridge PFT, p. 61; Woolridge PFT, Ex. JRW-6.5, Ex. JRW-6.6. The building blocks approach is a hybrid approach employing elements of both historical and ex-ante models. OCC provided a study to assess the effects of the earlier studies, which can be as old as 50 years. Woolridge PFT, p. 60; Woolridge PFT, Ex. JRW-6.5. The mean and median market risk premium estimate for this subset of studies is 4.65% and 4.55%, respectively. Woolridge PFT Ex. JRW-6.5. OCC reconstructed the studies and eliminated all studies dated before January 2, 2010. Woolridge PFT, p. 60; Woolridge PFT, Ex. JRW-6.6. Citing to several sources in each category, OCC calculated average ERPs for the Historical Risk Premium approach of 5.57% (range 4.40% to 6.80%, median 5.62%), Ex-Ante Models average of 4.74% (range 2.51% to 6.00%, median 5.00%), Financial Surveys average of 4.80% (range 3.40% to 5.70%, median 5.05%), and the Building Blocks approach average of 4.08% (3.00% to 5.21%, median 4.06%), with an overall average of 4.92% (median of 5.03%). Woolridge PFT, p. 61; Woolridge PFT, Ex. JRW-6.6.

OCC stated that the "more timely and relevant studies" were the Pablo Fernandez survey (range of 5.00% to 5.70% in recent years, average of 5.50% in 2024), the Aswath Damordan study (range of 4.0% to 6.0% since 2010, as of October 1, 2024 was 3.96%), the most recent Kroll (formerly Duff & Phelps) recommendation (most recently was in a range of 6.00% to 5.50% on June 23, 2023 and is 5.00% as of June 5, 2024), the KPMG recommendation (5.00% as of September 30, 2023), and, lastly, JP Morgan's estimate of 4.40%. Woolridge PFT, pp. 61–64. Giving "most weight to the market risk-premium

estimates of Kroll, KPMG, JP Morgan, Damodaran, and the Fernandez and Duke-CFO surveys," OCC asserted that the "appropriate market risk premium in the U.S. is in the 4.0% to 6.0% range." Id., p. 65. OCC used an expected market risk premium of 5.00%, which is the midpoint of the relevant range. Id. Finally, OCC argued that the Company's proposed ERP exceeds market risk premiums; found in studies of the MRP of leading academic scholars, produced by analysis of historic stock and bond returns, and found in surveys of financial professionals. Id., p. 78. OCC concludes, given the aforementioned sources of ERPs (Historical Risk Premium: 4.40% to 6.80%, Ex-Ante Models: 2.51% to 6.0% and Financial Surveys: 3.40% to 5.70% respectively), that there is no support from historical return data, surveys, and academic studies to support a market risk premium of 7.97% as used by the Company. Woolridge PFT, pp. 61, 78–79.

EOE calculated its ERP by subtracting the risk-free rate by the expected return on the S&P 500. Rothschild PFT, p. 81. The expected return on the S&P 500 is calculated using option-implied return expectations. Id., pp. 81–82. Under EOE's approach, once the option-implied growth rate of the S&P 500 has been estimated, the dividend yield is added, and the risk-free rate is subtracted, to arrive at the ERP. Id., p. 82; Rothschild PFT, Ex. ALR-4, pp. 4, 6. EOE used both spot values as of December 31, 2024, and weighted averages over the three months ending on the date of option-implied growth, dividend yields, and short- and long-term risk free rates to arrive at four estimates of market risk premium. Rothschild PFT, p. 82; Rothschild PFT, Ex. ALR-4.4, Ex. ALR-4.6. For the Weighted Average CAPM analysis with short- and long-term risk-free rates, EOE used ERPs of 3.55% and 3.50%, respectively. Rothschild PFT, p. 82; Rothschild PFT, Ex. ALR-4.4. For the Spot CAPM analysis based on short- and long-term risk-free rates, the ERP was 3.77 and 3.36%, respectively. Rothschild PFT, pp. 82–83; Rothschild PFT, Ex. ALR-4.6.

The Authority has previously accepted OCC's methodology in arriving at the ERP. See 23-11-02 CNG Decision, p. 69; 23-08-32 Decision, p. 55; 22-08-08 Decision, p. 89; 22-07-01 Decision, p. 52; 13-01-19 Decision, p. 133. Additionally, in past analyses, the Authority incorporated OCC's survey of methodologies (OCC ERP Survey) into the PURA analysis. Woolridge PFT, Ex. JRW-6.5, Ex. JRW-6.6. While the Authority considered the Company's approach of using a DCF analysis on dividend paying companies in the S&P 500 to derive the equity risk premium, the Authority declines to adopt such an approach. See 23-11-02 CNG Decision, p. 69; 23-08-32 Decision, pp. 55–56; 22-08-08 Decision, p. 89; 22-07-01 Decision, p. 52; 13-01-19 Decision, p. 133. Here, the Authority credits the OCC's assessment that, while the Company's approach can be described as an Ex-Ante approach and is a valid methodology to estimate ERP, the Company's assumptions rely on potentially unreasonably high estimates of long-term EPS growth, expected market returns, and market risk premium. Consequently, the Authority gives more weight to OCC's proposed ERP.

Table 36, below, summarizes the data considered by the Authority in determining the appropriate ERP.

Table 36: ERP Data

	Range	Mean/Proposed
Company (application)	7.74% to 8.02%	-
Company (updated)	8.58% to 8.75%	-
OCC Proposed ERP	-	5.00%
Historical Risk Premium Studies	4.40% to 6.80%	5.57%
Financial Surveys		
Kroll (formerly Duff & Phelps)	5.00% to 6.00%	5.00%
KPMG		5.00%
Fernandez	5.00% to 5.70%	5.35%
Damodaran	4.0% to 6.0%	3.96%
JP Morgan	-	4.40%
Ex-Ante Models	2.51% to 6.0%	4.25%
Building Blocks Approach	3.00% to 6.22%	4.06%
EOE	3.36% to 3.77%	-

Ex. UI-AEB-1, pp. 29–30, 42; Application, Ex. UI-AEB-7; Bulkley Rebuttal, Ex.AEB-REB-4B CAPM; Woolridge PFT, p. 61; Woolridge PFT, Ex. JRW-6.6; Rothschild PFT, pp. 82–83; Rothschild PFT, Ex. ALR-4.4.

Ultimately, the Authority finds the methodology employed by OCC to be the most credible. Specifically, the Authority places more weight on the data available from recognized studies, surveys, and publications. Notably, the Company's recommended ERP is substantially higher than any of the recognized sources. Given the above, the Authority finds that an ERP in the range of 5.00% to 6.00% reflects the best available information and current market risk premium.

e. CAPM Results

Using the components as determined above, the Authority's CAPM results for the Authority Proxy Group provide an ROE range of 8.32% to 9.86%, as summarized in the table below.

Table 37: CAPM Results

Range	Rf	Beta	ERP	ROE
Low	4.57%	0.75	5.00%	8.32%
High	4.82%	0.84	6.00%	9.86%
Average	**4.70%**	**0.795**	**5.50%**	**9.067%**

4. Empirical Capital Asset Pricing Model

The Company also included the results of an Empirical CAPM (ECAPM) or the Zero Beta CAPM in its Application. The ECAPM calculates the product of an adjusted beta coefficient and market risk premium by applying a weight of 0.25 to the market risk premium and 0.75 to the beta. Ex. UI-AEB-1, pp. 31–32. The Company's ECAPM formula is represented by:

Ke = Rf + 0.75 β(Rm – Rf) + 0.25(Rm – Rf); where:

Ke is the required market ROE;

β is Adjusted Beta coefficient of an individual security;

Rf is the risk-free rate of return;

Rm is the required return on the market as a whole.

Id.

OCC indicated that the ECAPM has not been theoretically or empirically validated in journals. Woolridge PFT, p. 73. Beyond the lack of validation, OCC states that the Company's ECAPM has two main flaws: (1) there are no known tests of the CAPM that use adjusted betas as posed by the Company; and (2) adjusted betas address the empirical issues with CAPM. Id.

The Authority has previously reviewed the ECAPM approach and excluded this method. See, e.g., 22-08-08 Decision, pp. 84–85; 23-08-32 Decision, p. 57; 23-11-02 CNG Decision, p. 79. Here, the Authority reviewed the proposed ECAPM and sees no difference from past submissions. The most recent rationale for rejection of the ECAPM holds true today: the Authority believes that the 0.75/.25 factor is out-of-date (based on 30 plus year old data) and incorporates another level of conjecture that is unnecessary given that the simple CAPM formula is widely accepted in cost of equity literature. Second, given that ECAPM is only discussed within the regulatory cost of capital sphere, ECAPM has not been theoretically or empirically validated in financial journals. Third, the purpose of adjusted betas such as those from Value Line and Bloomberg address the empirical issues with the CAPM. Hence, there is no need for an additional adjustment factor to adjust for what is being addressed by using Value Line and Bloomberg betas. Interrog. Resp. RRU-167; Interrog. Resp. RRU-169.

The Authority reaffirms its rejection of ECAPM and will not incorporate the model's results as its main purpose is to artificially inflate cost of equity estimates derived from the CAPM methodology based on a faulty application of financial principles.

5. Bond Yield Risk Premium

The Company also proposed using the bond yield plus risk premium (BYPRP) model for determining ROE. Ex. UI-AEB-1, pp. 33–37. The BYPRP approach "is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders." Id. The Company states that "because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk." Id. Further, the Company explains that "the risk premium approach estimates the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds." Id.

The Company developed the BYPRP model by regressing authorized ROEs for electric utilities to the US Treasury yield and adding risk premium. Woolridge PFT, p. 88. OCC maintains several reasons why this approach is flawed. First, it is a gauge of Commission behavior and not investor behavior. Id. Second, this approach "produces inflated measures of the risk premium because it uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury Yields." Id., p. 89. Third, utility stocks have been selling above book value for the last decade, so OCC claims authorized ROEs are above what investors require, and the rate cases used in the Company's analysis include vertically integrated electric utilities that have averages that are 30 to 40 basis points above distribution companies such as UI. Id.

The Authority reaffirms its determination that the BYPRP approach is not widely accepted today in utility ratemaking as this benchmarking-comparison methodology has been replaced by market-based approaches, such as DCF or CAPM.

The Authority most recently rejected the BYPRP approach in the 2023 Aquarion Rate Case Decision. At that time, the Authority reconsidered the risk premium plus approaches that used Commission-allowed ROEs as inputs and found the methodology was highly dependent on the number of companies included in the proxy group and the time period covered. 22-07-01 Decision, pp. 52–53. The Authority further found that the approach was not a measure of investors' market-based required returns but an assessment of prior regulatory commission behavior. Id. Consequently, since no evidence or rationale has been offered to the contrary, the Authority will continue to reject any approach using commission-allowed ROEs as the input data, including the BYPRP model.

6. Comparable Allowed ROEs

Although the Authority will not consider financial models based on other public utility commission allowed ROEs, the Authority will examine the ROEs approved in other jurisdictions. Notably, the authorized ROE is supposed to reflect the economic and financial conditions expected during the Rate Year. Previously allowed ROEs are, by their nature, not based on the most current financial data and generally provide a historical snapshot only. Because allowed ROEs from other jurisdictions are historical and do not necessarily reflect current market conditions, the Authority finds that such allowed ROEs are limited to serving only as a point of reference.

To that end, the Authority reviewed data on authorized ROEs nationwide compiled by Regulatory Research Associates (RRA). RRA provides electric utility ROE data disaggregated by, among other things, case type (e.g., all cases, general rate cases, limited issue riders, etc.), by utility type (e.g., vertically integrated, distribution only), and by resolution (e.g., settled or fully litigated cases).

According to S&P Global RRA Regulatory Focus, in 2024, with nearly 155 decisions issued by state and public utility commissions, the average authorized returns on electric and gas authorized returns rose slightly in 2024. Interrog. Resp RRU-188 Att. 8, p. 3. The average authorized ROE for electric utilities was 9.74% in 2024, above the 9.60% average in 2023. Id. For distribution-only rate cases, there was an increase in

ROEs from 9.24% in 2023 to 9.53% in 2024. Id. For purposes of the instant proceeding, the Authority focused on the distribution-only cross section because UI is a distribution-only electric utility. Vertically integrated utilities are not comparable to UI and are much riskier due to their generation functions. This risk difference is demonstrated by the higher average ROE for vertically integrated electric utilities (9.84% in 2024) versus the average for distribution-only utilities (9.53% in 2024). Id.

OCC indicated that ROEs for delivery or distribution companies have consistently been below those of vertically integrated utilities, reasoning that distribution companies do not own and operate electric generation, which is perceived to be the riskier part of electric utility operations. Woolridge PFT, p. 15. Therefore, OCC believes that states that have deregulated electric utility models recognize that those businesses are less risky and have awarded ROEs 30 to 50 basis points below those of vertically integrated electric utilities in recent years. Id.

Additionally, the Authority reviewed data on authorized ROEs presented by OCC. OCC indicates that authorized ROEs were in a downward trend with interest rates and capital costs over the past 15 years. Woolridge PFT, p. 13. Average authorized ROEs fell below 10% for electric utilities in 2012, and in 2020 and 2021, authorized ROEs hit an all-time low. Id.

OCC also highlighted a 2022 Werner and Jarvis study, which evaluated the authorized ROEs in 3,500 electric and gas rate case decisions in the U.S. from 1980 to 2021. Id., p. 19; Karl Dunkle Werner and Stephen Jarvis, “Rate of Return Regulation Revisited,” Working Paper, Energy Institute, University of California at Berkeley, 2022. This empirical study compared the allowed ROE to a number of capital cost benchmarks (government and corporate bonds, CAPM equity cost rate estimates, and U.K. 10 authorized ROEs). Woolridge PFT, p. 19. One of the focused aspects was the extent to which utilities are allowed to earn excess ROE by regulators. Id. OCC summarized the study by indicating that the real inflation adjusted return regulators have granted has allowed utilities to earn steady returns over the last 40 years, while many different measures of cost of capital have declined. Id. An assessment of the return gap between approved ROEs and benchmarks for market returns suggests the ROE gap ranges between 0.50% to 5.50% above cost of equity estimates. Id. Overall, based on the gap, consumers may be paying $2–$20 billion per year more than if authorized ROEs had fallen in line with other capital market indicators. Woolridge PFT, p. 20. OCC asserts that, over the last four decades, authorized ROEs have not declined in line with capital costs and, therefore, past authorized ROEs overstated the actual cost of equity. Id. Consequently, OCC argues that the Authority should not be concerned if an authorized ROE is below those from other jurisdictions. Id.

Overall, because allowed ROEs from other jurisdictions are historical and do not necessarily reflect current market conditions, the Authority finds that such allowed ROEs are limited to serving only as a point of reference.

7. Current Economic Conditions

The Authority reviewed changes to certain financial indicators comparing current yields to those present at the 22-08-08 Decision. The purpose of this static analysis is to provide a barometer to establish the direction in ROE as compared to the prior authorized ROE. For example, if economic indicators such as interest rates increase, then that would suggest an increase to the allowed ROE, all else equal. In addition to trends in economic conditions, the Authority also relies on its COE models to establish the ultimate allowed ROE.

To assess current economic conditions, the Authority reviewed several indicators. For example, from January 2022 to December 2024, US Gross Domestic Product (GDP) increased 9.05% (i.e., 11.07/115.16) and the Consumer Price Index (CPI) increased 12.25% (34.46/281.15), while national unemployment increased slightly to 4.10% from 4.00% over the same time period. Interrog. Resp. RRU-187, Att. 1 ("RRU-187" tab). Interest rates, especially on the short end of the curve, have had a significant rise since the 22-08-08 Decision, but the increase in interest rates was greater at the short end of the yield curve (i.e., 90- and 180-day US Treasury Bills) as compared to the long-end (i.e., 20- and 30-year US Treasury Bonds). Id. For example, 90-day US Treasury Bill yields increased from 0.15% to 4.39% and 180-day US Treasury Bills increased from 0.33% to 4.32%, while US Treasury Bonds of 10-year maturities increased from 1.76% to 4.39%, 20-year maturities from 2.15% to 4.66%, and 30-year maturities increased from 2.10% to 4.58%. Id. Furthermore, the Treasury Inflation-Protected Securities (TIPS) spread, currently about 2.25%, suggests that investors expect long-term inflation to be below 2.5%. Additionally, Connecticut unemployment decreased to 3.00% in December 2024, from 4.90% in January 2022, and remains below the 4.10% national unemployment level. Interrog. Resp. RRU-187, Att. 1 ("CT Unemployment" tab).

The Company indicated that interest rates and inflation have remained elevated since the Company's last rate case. Ex. UI-AEB-1, p. 11. Core inflation increased steadily in early 2021 from 1.41% rising to 6.64% in September 2022. Id. Core inflation has since declined in response to the Federal Reserve's monetary policy but continues to remain above the Federal Reserve's target level of 2.00%. Id. The Federal Reserve has pursued an aggressive normalization of monetary policy in response to the dramatic increase in inflation. Id., p. 13. The Federal Funds Rate was at 2.32% at the time of the filing of the Company's last rate case (July 31, 2022), and as of September 30, 2024, it was at 4.83%. Ex. UI-AEB-1, p. 11. As the Federal Reserve increased the Federal Funds Rate, yields on 10-year Treasury bonds are approximately 230 basis points higher than December 2021 (1.47% percent on December 15, 2021, as compared to 3.81% at the end of September 2024). Id., pp. 13–14.

As of the September Federal Open Market Committee (FOMC) meeting, the Chairman noted that risks associated with both inflation and the labor market have become more balanced given the effectiveness of the Federal Reserve's monetary policy in response to inflation. Id., p. 14. As a result, the FOMC indicated a change to monetary policy and decided to lower the Federal Funds Rate by 50 basis points to a range of 4.75% to 5%. Id., pp. 14–15. The monetary policy of the Federal Reserve is considered

in the forecasting of long-term government bond yields, and the projections are that they will remain elevated through the first quarter of 2026 while the Company's rates will be in effect. Ex. UI-AEB-1, p. 15.[42] The Company concludes that as interest rates are forecasted to remain elevated during the period that the Company's rates are to be in effect, the cost of equity is "directionally higher" than at the time of the 22-08-08 Decision. Id.

The Company also noted that capital costs are higher now than they were at the time of the Company's last rate case and should allow for a higher authorized ROE for the Company. Ex. UI-AEB-Rebuttal pp. 4-5; UI Reply Brief p. 31.

OCC indicated that there were several factors that lead to the increase in interest rates in the 2022–2024 time period. Woolridge PFT, p. 10. One factor was the increase in GDP of 5.95% in 2021, 2.06% in 2022, and 3.25% in 2023, compared to a decline of 3.4% in 2020. Id. In the 2022–2024 time period, the improving economy put upward pressure on inflation and interest rates. Id., pp. 10–11. Year-over-year inflation, which was as high as 9.20% in 2022, has since declined to 2.5%–3.0%, and stood at 2.9% as of January 2025. Id., p. 11. OCC observed that the Federal Reserve increased the Federal Funds Rate to as high as 5.50% until September 18, 2024, when it began an easing cycle. Id.

OCC noted a measure of investor inflation expectations can be seen by computing the difference between yields on treasuries and yields on inflation-protected securities. Woolridge PFT, p. 11. The measure has decreased since the inflation highs of 2022 to an expected inflation rate of 2.5%. Id., pp. 11–12. OCC contends that interest rates will not increase in 2025. Id., p. 12. OCC supports this claim by noting that the yield curve is once again positively sloped, which is normal as investors require higher returns to commit capital for longer periods of time, which is primarily a function of the Federal Reserve cutting short-term interest rates and long-term rates remaining in the 4.00%–5.00% range. Id., pp. 12–13. Also, political influence is skewed toward lower interest rates so there is little expectation for rates to rise, given the lower inflation expectations and aforementioned political stance. Woolridge PFT, p. 13. OCC indicates that the Federal Reserve has begun the process of lowering the discount rate, which OCC says signals lower rates are forthcoming. Woolridge Surrebuttal, p. 4. OCC states that President Trump and the Treasury Secretary would like to see lower interest rates, and that the Federal Reserve is expected to lower the discount rate two times in 2025. Hr'g Tr., 44:1–5. OCC acknowledged that while it is possible that President Trump's policies on tariffs could lead to a higher rate of inflation, it is also possible that they could lead to a recession, which will probably lower interest rates. Id., 44:18–47:7. Despite the market uncertainty, OCC notes that utility stocks have done well in the markets in 2025, up 3–4% while the S&P 500 lowered by 7–8%, and saw a lot of volatility, and that the tariffs will likely impact companies other than utilities more. Id., 47:16–48:10.

[42]The Company cites to the most recent consensus estimates published in the Blue Chip Financial Forecasts, which show that the average yield on the 30-year Treasury bond is 4.02% through 1Q/2026 and 4.30% over the longer term through 2030. Bulkley PFT, p. 15; *Blue Chip Financial Forecasts*, Vol. 43, No. 10, October 1, 2024, p. 2; *BlueChip Financial Forecasts*, Vol. 43, No. 6, May 31, 2024, p. 14.

OCC reviewed trends in authorized ROEs for gas and electric utility distribution companies. Woolridge PFT, pp. 13–14. OCC noted that while ROEs trended down with interest rates and capital costs for the past 15 years, the average ROE fell below 10% for electric utilities in 2012 and hit all-time lows in 2020 and 2021 due to the record low interest rates and capital costs. Id., p. 13.

Acknowledging that authorized ROEs did increase in 2022–2024, OCC argues that the higher interest rates during those two years did not necessarily mean that ROEs increased in line with the interest rates. Woolridge PFT, p. 16; Woolridge Surrebuttal PFT, p. 14. OCC points out that even though authorized ROEs reached record lows in 2020 and 2021, the authorized ROEs did not decline to the extent interest rates declined in the same two years. Id.; see Woolridge Surrebuttal PFT, p. 13, Table 3. OCC concludes that while the utilities benefited from the low-cost interest environment, the savings were not proportionally passed on to ratepayers and, as such, utilities have been relatively over-compensated at the expense of ratepayers. Id. Therefore, OCC states that the opposite is also true, that higher interest rates in 2022–2024 did not mean that authorized ROEs increased in line with interest rates. Id.

OCC illustrated this dichotomy by measuring the average decline in 30-year treasury yields from 2018–2019 of 2.85% to 1.81% in 2020 and 2021, a decrease of 104 basis points. Woolridge PFT, p. 16; Woolridge Surrebuttal PFT, p. 12. Conversely, authorized ROEs for electric and gas distribution companies averaged 9.38% and 9.65% in 2018 and 2019, respectively, and declined to an average of 9.07% to 9.51% in 2020 and 2021, respectively, which denotes a decline of only 31 and 14 basis points. Id.

As interest rates increased in 2022, the average daily 30-day Treasury yield increased by 105 basis points to 3.11% while authorized ROEs for electric and gas distribution companies increased by 0.04% and 0.02% to 9.11% and 9.53%, respectively.[43] Woolridge PFT, p. 16; Woolridge Surrebuttal PFT, p. 13. Long-term interest rates continued to increase in 2023; the average daily 30-year Treasury yield increased by 92 basis points to 4.03% in 2023, while authorized ROEs for electric and gas distribution companies increased by 0.15% and 0.13% to 9.26% and 9.66%, respectively. Woolridge PFT, pp. 16–17; Woolridge Surrebuttal PFT, p. 13. Further, the average daily 30-year Treasury yield increased by 38 basis points to 4.41% in 2024, while authorized ROEs for electric and gas distribution companies increased by 0.29% and 0.08% to 9.53% and 9.72%, respectively. Woolridge Surrebuttal PFT, p. 13. While the average 30-year Treasury yield increased by 2.04% or 204 basis points in the post-Covid years (2022–2024), the authorized ROEs for electric and gas distribution companies only increased by 0.22% and 0.12%, respectively. Id.

EOE presented a similar view of current economic conditions, pointing out that rising bond yields and rising Federal Funds Rates present borrowing challenges for capital-intensive industries like utilities. Rothschild PFT, p. 33. EOE also pointed out that the COE increased along with the Federal Funds Rate and the bond yields initially, but

[43]OCC's pre-filed testimony included a math error; the correct numbers are displayed above. See Woolridge PFT, p.16.

the increase was not one for one, and the COE for electric utility stocks has been mostly trending down since reaching highs at the end of 2022. Id. The market-based COE for electric utility stocks is below authorized ROEs because the market-to-book ratios of these stocks is significantly above one (1.79 to 1.78). Id.; Rothschild PFT, Ex. ALR-3, p. 1; Rothschild PFT, Appendix A. EOE concludes that despite increased uncertainty about inflation and interest rates, utility stock prices remain strong because investors are willing to pay a premium above book value to own a portion of a utility company, meaning conditions are favorable for utilities to raise capital. Rothschild PFT, pp. 33–34.

EOE echoed OCC's inflation expectations for investors with the use of the difference between the interest rate of nominal Treasuries and TIPS. Rothschild PFT, p. 37. The relative market price of inflation-protected bonds as compared to regular Treasury bonds as of December 31, 2024, indicates that investors expected the inflation rate to decline from the current 2.60% to only 2.38% over the next five years and to about 2.30% over the 30-year horizon. Id., pp. 37–38.

The Authority finds the argument presented by OCC compelling; as interest rates declined, ROEs did not decline in lock step. Additionally, investors' inflation expectations are expected to decline over the next five years as demonstrated by the TIPS spread. Although the recent tariffs enacted may increase investor inflation expectations, the pressure by the federal Administration for the Federal Reserve to cut rates will potentially reduce short-term rates and in the future lead to lower long-term rates, which in turn will reflect lower costs of equity as measured by the market-based methodologies employed by the Authority and COE witnesses in this proceeding.

8. Other Factors

a. Company's Financial Risk

The Authority considers the financial risk of the Company as it compares to the Authority Proxy Group to determine if there are unique financial risks or risk mitigations to consider when establishing an ROE.

The Authority concurs with OCC that bond ratings provide a data point in assessing a Company's risk profile. See Woolridge PFT, p. 22. UI's S&P and Moody's issuer ratings are A- and Baa1, respectively. Ex. UI-AEB-1, p. 17. OCC compared the investment risk of UI to the Company's Proxy group and to OCC's Electric Proxy group. Woolridge PFT, pp. 21–22. The averages of the two proxy groups were BBB+ for S&P and Baa2 for Moody's. Id., p. 21. As some of the Companies in the OCC Electric Proxy Group had different business models and non-regulated business, they are considered riskier than a company such as UI, which is a distribution-only EDC with no unregulated, or power generation business.

Furthermore, the regulatory framework in Connecticut, by design, also provides certain risk mitigation mechanisms that should be considered in setting a reasonable allowed ROE. Specifically, the Company benefits from two provisions — the RAM and the Conservation and Load Management (C&LM) program. The Company's RAM is multi-tiered and provides stable revenue streams by reducing the risk of actual revenues

diverging from the Company's allowed revenues. Specifically, the mechanism reconciles the rates in the difference between the actual revenues of an electric company and allowed revenues. General Statutes § 16-19b. The C&LM mechanism allows the Company to contemporaneously recover the costs associated with mandated conservation and energy efficiency programs. These C&LM costs are reconciled annually between planned and actual expenses; thus, the Company's risk associated with conservation is reduced while simultaneously enjoying the opportunity to earn several performance incentives and to accrue goodwill. The Authority notes that these programs provide multi-tiered risk mitigation. On the revenue side, the risk of under-recovery is essentially eliminated, while on the expense side the Company can fully recoup all costs associated with conservation and efficiency programs, all while having the opportunity to earn a fair and reasonable return on investments.

As such, the Authority does not consider UI to have a risk profile that warrants consideration in determining the ROE.

b. Environmental, Social, and Governance Scores

When determining an appropriate ROE, the Authority considers a utility's environmental, social, and governance (ESG) score in assessing the utility's risk profile. An ESG score measures how well a company addresses risk with respect to environmental, social, and governance issues. "ESG scores can be used by investors to gain a better understanding of a company's long-term potential for value creation as it considers material non-financial impacts that could provide risks or opportunities to the company." Interrog. Resp. RRU-389, p. 1.

A higher ESG score generally indicates a lower long-term business risk profile because it reflects stronger risk management and alignment with regulatory, environmental, and social expectations. Conversely, a lower ESG score may suggest higher exposure to regulatory, reputational, or operational risk, resulting in a higher risk profile.

Here, the Company's ESG scores indicate that the Company's risk profile is not substantively affected by ESG issues. According to an October 31, 2024 report, Moody's assigned the Company an ESG Credit Impact Score of CIS-3. Interrog. Resp. RRU-389, Att. 1, p. 6. Moody's scoring scale ranges from CIS-1 (lowest credit impact from ESG factors) to CIS-5 (highest credit impact), with CIS-3 representing a neutral-to-moderate influence. Similarly, Fitch assigned ESG credit relevance scores of 3. Interrog. Resp. RRU-389, Att. 2, p. 3. According to the Fitch report, a "score of '3' means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity." Id. Consequently, the ESG scores are not a significant factor in assessing the Company's relative risk profile.

c. General Statutes § 16-kk Factors

In establishing a Company's authorized return, the Authority must consider:

> Quality, reliability and cost of service provided by the Company, the reduced or shifted demand for electricity, gas or water resulting from the Company's conservation and load management programs approved by the authority, the Company's successful implementation of programs supporting economic development of the state and the Company's success in decreasing or constraining dependence on the use of petroleum or any other criteria consistent with the state energy or other policy.

General Statutes § 16-19kk. The Authority considered these statutory factors and finds that the record does not support an adjustment to the Company's ROE based on these considerations.

9. Approved ROE

In determining a reasonable ROE, the Authority considers the analytical models for commensurate utility returns, allowed ROEs in other jurisdictions, the prevailing market conditions, and the Company's risk profile. The Authority considers the two analytical models (DCF and CAPM) to provide a target range for commensurate ROEs. The Authority generally weighs the DCF model results more heavily than the CAPM results because the DCF model relies on directly observable proxy company market data and provides a better measure of the COE for similarly situated utilities. Conversely, the CAPM relies primarily on risk-premium studies and market predictions, which are more subjective in nature.

Here, the DCF model as applied to the Authority Proxy Group indicates an ROE range of 8.70% to 9.60%, with a mean of 9.25% and a median of 9.16%. The CAPM model produced an ROE range of 8.05% to 9.86%, with a mean of 9.067%.

Given this range, the Authority must determine an ROE such that the Company has an opportunity to "cover . . . [its] capital costs, to attract needed capital and to maintain [its] financial integrity." General Statutes § 16-19e(a)(4). This statutory standard reflects the long-standing principle that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks and should also be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." Connecticut Light & Power Co. v. Dept. of Public Utility Control, 216 Conn. at 634–35. In determining an ROE, the Authority "is not bound to the use of any single formula or combination of formulae" but again must balance "investor and consumer interests" and make "pragmatic adjustments." Woodbury Water Co., 174 Conn. at 264.

Cognizant of this legal framework, the Authority has analyzed a wide array of considerations in reaching a determination, including, without limitation, the Company's capital structure, its financial condition, ROEs from other jurisdictions, analytical models of commensurate returns, prevailing and anticipated market conditions, risk factors, and the regulatory environment.

In brief, the Company is financially stable, maintaining an A- Rating from S&P, Baa1 from Moody's, and A- from Fitch. The Company is a subsidiary of AVANGRID, Inc.

and Iberdrola S.A., providing additional financial flexibility and potential synergies for cost sharing and risk mitigation. In addition, the Company operates in a regulatory environment that reduces risk through the RAM and C&LM mechanisms. In light of these and other factors, the Authority adopts a 9.45% ROE.

10. Reductions to ROE

a. Introduction

The approved ROE is based on a similarly situated electric utility providing expert, efficient, and prudent management of the utility franchise; therefore, the Authority must consider whether to adjust the ROE for the Company's actual management of its franchise. As discussed in detail below, the Authority concludes that a cumulative twenty (20) basis point reduction to the Company's allowed ROE is necessary to reflect the Company's deficient performance in managing certain parts of its utility franchise and to incentivize the Company to improve its performance. The interrelationship between investor returns and utility performance is well-established. Importantly, the "rate-making process . . . involves a balancing of the investor and the consumer interests." Hope, 320 U.S. at 603. Similarly, a utility's rate of return should be "reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." Bluefield, 262 U.S. at 692-93 (emphasis added).

Indeed, courts interpreting the "under efficient and economical management" language in Bluefield have determined that a utility's rate of return may be adjusted to account for imprudent and inefficient management. In re Citizens Utilities Co., 171 Vt. 447, 460-61 (2000) ("Like Vermont, most other jurisdictions now accept the general principle that rates may be adjusted depending on the adequacy of the utility's service and the efficiency of its management."); D.C. Transit System, Inc. v. Washington Metropolitan Area Transit Comm., 466 F.2d 394, 423 (D.C. Cir. 1972) ("We believe the constitutionality of governmental recognition of the interrelationship between fair return and quality service can hardly be doubted today."); see also Richard J. Pierce & Emest Gellhorn, Regulated Industries in a Nutshell, pp. 134–135 (3d ed. 1994) ("The phrase 'under efficient and economical management' [in Bluefield] is an important qualification. If an agency finds that a firm is not being managed efficiently and economically, it can lower the firm's allowed rate of return below the level otherwise required to meet the comparable risk test.").

Specific to UI, "[b]ecause § 16-19e(a) explicitly authorizes PURA to consider UI's managerial expertise, its ability to meet its public responsibilities, and the prudency with which UI manages Connecticut's natural environment, this court concludes that PURA has discretion to consider UI's [performance] when determining UI's authorized ROE." March 13, 2025 Superior Court Decision, pp. 9–11.

In Connecticut, the statutes governing rates reflect this important balance. On one hand, "the level and structure of rates [must] be sufficient, but no more than sufficient, to allow public service companies to cover their operating costs including, but not limited to,

appropriate staffing levels, and capital costs, to attract needed capital and to maintain their financial integrity, . . ." General Statutes § 16-19e(a)(4). On the other, the Company has an affirmative obligation to be "technically, financially[,] and managerially expert and efficient," and must perform its "public responsibilities with economy [and] efficiency" and rates must "reflect prudent and efficient management of the franchise." General Statutes § 16-19e(a)(2), (3), and (5). This constitutional and statutory balance is the foundation of the so-called "regulatory compact" between regulators and investor-owned utilities. In a quid pro quo, the utilities are entitled to recover operating expenses and reasonable return on capital, and ratepayers, in exchange, are entitled to expert, efficient, and prudent management.

Consequently, if a utility fails to uphold its end of the bargain by not providing expert, efficient, and prudent management, the regulator must adjust the scales to maintain the balance required by Hope, Bluefield, and General Statutes § 16-19e(a). Hope, 320 U.S. at 603; Bluefield, 262 U.S. at 692-93. One way to accomplish this rebalancing is to reduce a utility's allowed ROE. See, e.g., Decision, December 17, 2014, Docket No. 14-05-06, Application by The Connecticut Light and Power Company to Amend Rate Schedules, p. 152 (ordering a 15 basis point ROE reduction for deficient storm response); Decision, April 27, 2011, Docket No. 10-09-08, Application of United Water Connecticut, Inc. to Amend Rate Schedules, p. 83 (ordering a 50 basis point ROE reduction for imprudent management of accounting, record keeping, and billing methods).

An ROE adjustment is not a penalty for a specific act; rather, it serves as a mechanism to set rates commensurate with the level of service the ratepayers are receiving and, more generally, with the company's adherence to its broader public responsibilities. See In re Citizens Utilities Co., 171 Vt. 447, 454 (2000) ("the purpose of a rate-of-return reduction is not to penalize a company for specific acts of misconduct, but rather to set reasonable rates in cases where the consumers are not being adequately served due to inefficiency or improvidence or other like reasons.").

In this proceeding, the Authority identified several areas in which the Company's performance did not reflect expert, efficient, and prudent management. Importantly, some are not new. The Authority and the Parties engaged in a robust discovery process, culminating in days of hearings, the filing of late filed exhibits and subsequent late filed exhibit hearings, post-hearing briefs and reply briefs. Evidence from this lengthy adjudicatory process led the Authority to conclude that a reduction to the Company's allowed ROE is warranted so that rates reflect the level of service and performance of the Company.

b. English Station

The Authority determines that the Company's continuing failure to complete remediation of English Station represents both ongoing non-compliance with a condition of its Authority-approved merger with Iberdrola and deficient management by the Company. Additionally, UI's failure to appropriately track internal employee labor costs for English Station remediation has allowed such costs to be included in base distribution rates, in violation of Authority direction to the contrary. See Decision, June 29, 2000, Docket No. 00-04-05, Petition of the United Illuminating Company to Sell English Station

(English Station Transfer Decision), p. 5 (prohibiting UI from recovering any English Station remediation costs – except those related to bulkhead repair – from ratepayers). While the Company has documented improvements to site security and coordination with police and emergency response officials since its last rate case, a 10 basis point reduction to the Company's allowed ROE is warranted to incentivize more efficient management by the Company, to ensure compliance with both the merger conditions and related Authority decisions, and ultimately to expedite the Company's protracted efforts to remediate English Station.

i. Background

In December 2015, the Authority approved the merger of UI and Iberdrola based on a settlement agreement. Decision, Dec. 9, 2015, Docket No. 15-07-38, Joint Application of Iberdrola, S.A., Iberdrola USA, Inc., Iberdrola USA Networks, Inc. Green Merger, Sub. Inc. and UIL Holdings Corporation for Approval of a Change of Control (Merger Decision). Under the heading of "Merger-Related Direct Economic Benefits," the settlement agreement stated that UI had executed a partial consent order (PCO) that "requires UI to investigate and remediate . . . the English Station site." Merger Decision, App. 1, p. 3. Importantly, the settlement agreement further stated that the remediation of English Station "will benefit the City of New Haven, . . . further the State's broader goals of revitalizing contaminated sites . . . . [and] provide a public interest benefit estimated at $30 million." Id. In approving the settlement agreement and merger, the Authority noted that the "commitment to clean up English Station [under the PCO] should expedite the environmental remediation process by eliminating the need for potential future litigation, . . ." Merger Decision, p. 21.[44]

The PCO contained two provisions relevant to the merger. First, the PCO required the Company to commit at least $30 million towards investigating and remediating English Station. Ex. UI-ERP-6, pp. 39–40. Second, the PCO required the remediation to "be completed within 3 years . . . unless a later completion date is specified in writing by the Commissioner." Ex. UI-ERP-6, p. 48. Consequently, the remediation of English Station within three years was a substantive condition of the Company's merger with Iberdrola.[45]

[44]English Station is located in an environmental justice community, as defined by General Statutes § 22a-20a.

[45]The Authority defers to the Superior Court on adjudication and enforcement of compliance with the PCO itself. The Authority remains focused on ensuring the Company's compliance with the conditions of the merger, as established by the Authority in the Merger Decision. UI argues that the record does not support the notion that completion of the Company's remediation obligations under the PCO was a condition of its merger with Iberdrola. UI Exceptions pp. 62-64. The Authority's position on this issue in the present proceeding, however, remains the same as in UI's prior rate case. 22-08-08 Decision, p. 99 ("the remediation of English Station within three years was a substantive condition of the Company's merger with Iberdrola"). That determination was expressly upheld by the Superior Court on appeal. March 13, 2025 Superior Court Decision, pp. 12–13 ("it is clear that UI sought PURA's approval for a corporate merger and that PURA expressly conditioned its approval of that merger on UI's compliance with a settlement agreement in which UI promised to spend at least $30 million to clean up the English Station site or pay the State of Connecticut the difference.· The court holds that PURA plainly has the statutory authority and regulatory discretion to consider whether compliance with PURA's own orders

In the Company's last base distribution rate case, the Authority found that "the Company ha[d] not managed the English Station remediation with economy, efficiency, or care for public safety as required by General Statutes § 16-19e(a) and, in doing so, had failed to comply with the conditions of the Merger Decision." 22-08-08 Decision, p. 99. Specifically, the Authority found, inter alia, that the Company neither justified its failure to remediate the site within the three-year window required by the PCO; nor took adequate measures to secure the site and to address vandalism in a timely fashion. Id.

As a result, the Authority applied a twenty (20) basis point reduction to the Company's ROE, to remain in effect until the earlier of (1) UI complying with the Merger Decision or (2) the conclusion of its next rate case, "based on the facts specific to that proceeding." Id., p. 100, n.90.

ii. Current Status of Remediation Efforts

There is no dispute that UI has still not completed remediation of English Station. See generally Ex. UI-ERP-1, pp. 19–54. Unlike in its last rate case, however, the Company has provided voluminous filings and testimony to argue that continued delays are the result of "unanticipated conditions," "challenges," and "complexities," as well as time spent awaiting DEEP or property owner approvals of various Scopes of Study, Investigative Reports, and Remedial Action Plans (RAPs). See, e.g., id., pp. 15, 21, 33, 39, 42, and 51; see also Interrog. Resp. RSR-213. As an example, the Company cites the discovery of unsafe work conditions resulting from improper remediation and disposal activities by the prior property owners as a significant source of delay. See UI-ERP-1, pp. 31–38.

While these repeated arguments are offered in extenuation and mitigation, they call into question the due diligence (and therefore, the efficient and economical management) the Company undertook prior to committing to the terms of the PCO in the first place. Regardless, and despite the voluminous record offered by the Company on this issue, it is difficult to discern what actual remediation has been achieved since the conclusion of the Company's last rate case. The majority of actions discussed throughout the filings and testimony in the present case pre-date the 22-08-08 Decision. See, e.g., Ex. ERP-1, pp. 28–44 (section entitled "The Company Continues to Advance Work Under the PCO" largely recounting pre-2023 difficulties). Thus, the Company's submissions at times seem more aimed at re-litigating the Authority's prior ROE reduction than in documenting subsequent substantive progress.[46] Although the record contains references to numerous Company site investigation and remediation (SIR) activities, the

reflects 'prudent and efficient management' when setting the 'level and structure of rates charged to customers' under § 16-19e(a). UI cannot creditably contend that a utility company's failure to abide by an express commitment to its regulator reflects 'prudent and efficient' management of the company, or, at a minimum, that PURA does not have the discretion to consider whether such conduct is not 'prudent and efficient' management.").

[46] Indeed, the Company continues to challenge the Authority's jurisdiction to consider this issue at all. See, e.g., Ex. UI-ERP-1; UI Brief, June 20, 2025, pp. 158–170; UI Exceptions, pp. 64–65. The prior ROE reduction regarding English Station was upheld on appeal. March 13, 2025 Superior Court Decision, pp. 9–15. The Company, however, has appealed that decision. The United Illuminating Company v. The Public Utilities Regulatory Authority, Docket No. A.C. 48591.

majority of those occurring since August of 2023 are investigation and inspection focused, not physical remediation related.[47] See, e.g., Ex. UI-ERP-7 (providing list of milestone PCO submittals); Interrog. Resp. RSR-212, Att. 1 (updating Ex. UI-ERP-7).

One notable exception is the 2022-2023 Boiler #13 Interim Remedial Measure. Ex. UI-ERP-7. This effort involved "removal of approximately 1,120 tons of soil/fill, concrete, bottom solids, and debris under Boiler #13 that were contaminated by a release of polychlorinated biphenyls (PCB)-containing oil." UI Interrog. Resp. EOE-2.

Similarly, the Authority is pleased to find that the Company has improved its site security through upgrades at English Station in 2023 and 2024 and has better coordinated with City of New Haven police and emergency response officials. See generally Ex. UI-ERP-1, p. 46; Interrog. Resp. RSR-207; Interrog. Resp. RSR-208; Interrog. Resp. RSR-209, Att. 1, pp. 34–35, 54, 59, 64. Such improvements, however, are tempered by the amount remediation work that remains, as well as the Company's failure to appropriately document internal labor costs at English Station, as discussed further below.

Regarding what remains of the Company's commitment to remediate English Station, it is clear from the record that since the Merger Decision, the Company has spent only just over half of the $30 million it committed back in 2016. Ex. UI-ERP-8, p. 3 (noting UI spent $17.183 million in eligible remediation expenses as of September 30, 2024). Given the realities of generally rising costs and the effects of even minimal inflation over time, the real value of remaining funds will continue to decrease, ultimately increasing the cost of a complete remediation of English Station. Time is thus of the essence in this endeavor, yet the remediation of English Station lingers nearly a decade after the Authority approved the Merger Decision with remediation as an express condition thereof.

The Authority finds unpersuasive the Company's repeated attempts to essentially attribute all delays to unforeseen circumstances, complexities, or the inaction of others. UI asserts that it "has consistently worked closely with DEEP while investigating and remediating this property." UI Exceptions, p. 66. The fact that DEEP has initiated an enforcement action against the Company suggests otherwise, or, at a minimum, that "closely" does not mean collaboratively. See Commissioner of Energy and Environmental Protection v. The United Illuminating Company, Docket No. HHD-CV24-6179720-S. The Merger Decision made clear the Authority's expectation that UI's commitments under the PCO would expedite the remediation of English Station. Merger Decision, p. 21. Taken as whole, however, the record shows that UI has been inefficient in following through on its obligations.

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[47] UI argues that any distinction between site investigation and physical remediation creates an "unfair narrative that the Company has not advanced remediation under the PCO." UI Exceptions, p 66. The Authority acknowledges that investigation is an integral part of the remediation process. It remains the physical remediation, however, that ultimately provides the benefits touted in the settlement agreement on which the Merger Decision was based. See, Merger Decision, App. 1, p. 3. Regardless, the sum total of the Company-provided milestone PCO submissions to DEEP since the last rate case, beyond monthly status updates—whether involving investigatory efforts, sampling, report submissions, document revisions, inspections, or physical remediation—is just 10 entries. Ex. UI-ERP-7; Interrog. Resp. RSR-212, Att. 1.

Perhaps in a tacit acknowledgement of the slow progress of UI's remediation efforts, UI argues that the Authority's discretion in reducing its ROE is constrained to specific findings based on identifying individual imprudent remediation decisions. UI Exceptions, p. 60. This argument ignores the plain language of the statutory provisions that require the Authorly to consider the extent to which public service companies are "technically, financially[,] and managerially expert and efficient," and "perform all of their respective public responsibilities with economy, efficiency and care for public safety." General Statutes § 16-19e(a)(2) and (3). Specific to setting an appropriate rate of return, the Authority is also required to consider "the company's compliance with state law, regulations and the decisions and policies of the authority and the Department of Energy and Environmental Protection. General Statutes §16-19gg(b)(2)(emphasis added). While the Company cites the correct legal standard for assessing the prudence of a public service company's actions and expenditures, a prudency determination is neither the exclusive nor dispositive analysis in establishing an appropriate rate of return.

The Authority's broad regulatory authority and discretion allow it to set rates, including rates of return, based on consideration of any of its statutorily required considerations, or any combination thereof. See Hope, 320 U.S. 591 (1944) (holding that what matters from a Constitutional perspective is the end result, not the analysis used to derive it); see also Barasch, 488 U.S. 299, 310 (1989) (affirming the holding in Hope that "[i]f the total effect of the rate order cannot be said to be unreasonable, judicial inquiry . . . is at an end."); Woodbury Water Co., 174 Conn. at 264 (1978) (quoting Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942)) (the Constitution does not bind the Authority "to the use of any single formula or combination of formulae in determining rates," and the ratemaking process may involve "pragmatic adjustments."); March 13, 2025 Superior Court Decision, p. 27 (articulating the Authority's broad regulatory authority and discretion in the related context of allowing or disallowing the recovery of specific costs in rates).

The protracted timeline on which the remediation of English Station continues to proceed, and the company's failure to direct more of its resources (including the balance of its original $30 million commitment) to expediting the remediation effort, constitutes inefficient management. Accordingly, a continued ROE reduction is warranted to provide continued incentivization for a more efficient and expedient completion of the Company's remediation responsibilities as contemplated by the Merger Decision.

iii. Non-Compliance with Authority Direction related to English Station Costs

The Company's decision to forego tracking internal employee labor costs at English Station violates an express condition of the Authority's prior approval for the Company's sale of the facility. English Station Transfer Decision, p. 5. Non-compliance with Authority direction constitutes evidence of imprudent and inefficient management and is a statutory consideration in rate setting. See General Statutes § 16-19gg(b) ("During each proceeding on a rate amendment under section 16-19 proposed by an electric distribution company . . . [the Authority] shall consider . . . the company's compliance with state law, regulations and the decisions and policies of the authority . . . ."). As detailed

below, this finding further justifies an ROE reduction related to English Station in the present proceeding.

The Company originally applied for Authority approval to sell English Station on April 4, 2000. English Station Transfer Decision, p. 1. In assessing that application, the Authority acknowledged that "the precise cost of the environmental remediation [for English Station] will not be known until removal of the contamination is accomplished in approximately two to three years, and this cost could be higher or lower [than originally estimated]." Per the terms of the proposed transaction then under Authority review, UI agreed to pay 61% of the environmental remediation costs determined by the final RAP estimate. Id. Importantly, in approving the transaction, and in consideration of its terms, the Authority made clear that ratepayers were not to bear any future costs associated with English Station other than those related to an environmental bulkhead repair. Id., p. 5.

In the present proceeding, the Company admitted that sometime during, or shortly after, 2020 it determined that internal company labor costs, among other items, were not chargeable against the Company's subsequent $30 million PCO remediation commitment. Hr'g Tr., 1282:7–1285:4. As a result, UI employees working at English Station started to "charge their default payroll order," for time spent on work there. Id., 1285:2. Without any mechanism tracking internal labor costs to English Station activities as such – whether or not within the provisions of the PCO – the Company is unable to articulate how it removes its English Station internal labor costs from its general distribution revenue requirement. See id., 1282:7–1285:4. Accordingly, the Authority finds that the Company's decision to stop accounting for staff time devoted to English Station, id., 1285:12-14, means that UI is necessarily recovering its English Station-related internal labor, at least in part, through base distribution rates, despite express, standing Authority direction[48] that ratepayers not bear "any future costs for any reasons other than costs related to bulkhead repair" for English Station. English Station Transfer Decision, p. 5 (emphasis added); see also March 13, 2025 Superior Court Decision, p. 13 (noting, in another context, how "the fact that UI may have also made a binding commitment to DEEP regarding cleanup of the English Station site does nothing to abrogate PURA's own, separate authority to consider whether adherence to PURA's own orders reflects prudent and efficient management when setting rates.").

While conceding that the Authority stated it would not permit any future costs for English Station to revert to ratepayers, UI argues that the wording of the English Transfer Decision did not expressly address, and therefore should not apply to, a scenario where Quinnipiac Energy (QE) failed to fulfill its obligations pursuant to the sale transaction, leaving UI responsible to remediate the site. UI Exceptions, p. 68. This argument is not supported by the English Transfer Decisions itself. OCC expressly raised this scenario for consideration, which the Authority duly noted in its decision. English Station Transfer

[48]The PCO did not supersede the Authority's conditions for approving the original sale of English Station. Any argument to the contrary overlooks the fact that the Authority was not a party to the PCO. Nor did the Authority's act of conditioning its approval of the Company's corporate merger on compliance with a Settlement Agreement that included a commitment to remediate English Station somehow alter the Authority's previously stated direction that ratepayers should no longer bear costs associated with the site.

Decision, pp. 3–4 ("OCC states that it is possible that responsibility for decommissioning English Station could revert to UI, in the event of default by QE. OCC Brief, p. 8. Therefore, QE could operate the plant and not fulfill its obligations to decommission it, leaving UI with that responsibility.") Accordingly, while the Authority approved the transfer application as presented, which included the presumption that QE would assume decommissioning and dismantling responsibilities for English Station, the inclusion of language describing a scenario in which UI could be left primarily responsible for remediation indicates such a contingency was, in fact, considered. See generally, Finley v. Inland Wetlands Commission of Town of Orange, 289 Conn. 12 (2008) (citing Samperi v. Inland Wetlands Agency, 226 Conn. 579, 587–88, (1993)) (an administrative agency need not have expressly stated all reasons for its findings and determinations, which may be inferred from facts and arguments in the record as a whole). Thus, the fact that such a contingency has occurred does not justify disregarding the decision's express direction. The Authority will continue to enforce the unequivocal language of the English Transfer Decision. The Company's failure to follow that direction, whether willful or negligent, constitutes imprudent management.

iv. Conclusion

In balancing the limited progress that UI has made against the Authority's continued concerns with the Company's lingering remediation efforts and concerns with the Company's failure to comply with the English Station Transfer Decision, the Authority finds that a ten (10) basis point reduction is warranted to continue incentivizing management to proceed prudently and efficiently in completing remediation in compliance with the Merger Decision, and to incent better compliance with all relevant Authority decisions and direction related to English Station. This ROE reduction is to remain in effect until the earlier of (1) UI complying with the Merger Decision or (2) the conclusion of its next rate case based on the facts specific to that proceeding.

c. Advanced Metering Infrastructure Plan and Benefits Cost Analysis

The Authority determines that a five (5) basis point reduction to the Company's ROE is warranted for failure to comply with Authority orders and requirements for submitting an Advanced Metering Infrastructure (AMI) Plan. See Decision, Jan. 3, 2024, Docket No. 17-12-03RE02, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Advanced Metering Infrastructure (AMI Decision), Order Nos. 1-3.

i. Background and AMI Plan Requirements

As part of its broader efforts to accelerate the modernization of Connecticut's electric grid in innovative, cost-effective, and equitable ways, the Authority previously identified the deployment and effective utilization of AMI[49] as a key objective to achieving a modernized grid. See generally Interim Decision, Oct. 2, 2019, Docket No. 17-12-03,

[49]AMI meters or "smart" meters are digital meters that can collect, store, process, and transmit electric system data, including energy and demand data, instrumentation data, and power quality data. The meters are only one component of a fully implemented AMI program, which also includes data collection and analysis.

PURA Investigation into Distribution System Planning of the Electric Distribution Companies (Equitable Modern Grid Decision). Given the significant capital investment required for AMI implementation, the Authority established an AMI framework that: (1) provides a regulatory roadmap for EDCs; (2) protects ratepayers; and (3) ensures AMI investments align with and advance the state's economic, economic, and environmental policy goals. See AMI Decision.

The AMI Decision established, inter alia, the structure and requirements for a Benefit Cost Analysis (BCA) to be included in each EDC's AMI Plan. AMI Decision, pp. 22–25. The primary goal of AMI deployment is to identify and realize the full spectrum of benefits from AMI. Id., p. 11. Simply acknowledging the potential benefits and assuming that they will be realized is insufficient. Id. Consequently, the Authority specified a detailed BCA framework with the aim of monitoring actual costs and the realization of AMI benefits.

The BCA framework requires tracking metrics for a minimum of fifteen quantified benefits and at least six categories of costs. Id., App. A, App. B. Appendices A and B of the AMI Decision outline the benefit and cost categories and the targets and metrics that capture the availability and the realization of benefits. Id. For example, reduced meter reading costs are an AMI benefit. AMI Decision, App. A, p. 1. The number and percent of meters read via AMI monthly are metrics that capture the availability of the benefit. Id. Monthly expenses and capital costs to support AMR meter reading (based on a historical average) and actual monthly expenses and capital costs to support AMI meter reading activities are metrics that capture the realization of this benefit. Id. Additionally, the calculation of benefits and costs is required to span a 20-year timeframe. AMI Decision, pp. 14, 18.

The Authority ordered the development of a BCA scorecard to standardize the tracking of the AMI benefit metrics and to assist with an ongoing evaluation of whether AMI investments are providing service to customers. The Authority approved the scorecard template via motion ruling on September 18, 2024. See Motion No. 32 Ruling, Docket No. 17-12-03RE02. However, a crucial input to the BCA scorecard and a required element of the AMI Plan is the initial BCA calculation and the establishment of benefit targets. AMI Decision, p. 14. The Authority specified that the following information be included in each EDC's Final AMI Plan with respect to each identified AMI benefit:

(1) Benefit Type and Description;
(2) List and Description of All Necessary AMI Infrastructure and O&M Costs Necessary to Unlock the Benefit;
(3) Benefit Calculation Methodology and Establishment of a Benefit Target;
(4) Annual Benefit Calculation;
(5) Data to Track the Availability of the Benefit; and
(6) Data to Track Benefit Realization.

AMI Decision, p. 14.

An initial, reasonable benefit calculation as conducted by the EDC will, at least in part, be used to assess AMI deployment and, therefore, will serve as one metric by which the Authority will evaluate the decision-making of an EDC and the used-and-usefulness of an EDC's AMI investment. Id. Once the initial benefit calculation has been completed, the EDC will be responsible for measuring and ultimately meeting the targets set forth in its Final AMI Plan to substantiate that the EDC's AMI investments are providing service to customers (i.e., used and useful). AMI Decision, p. 14.

UI submitted material purporting to be its complete Final AMI Plan as part of the pending Application. See Ex. UI-CIP-1, p. 39; Ex. UI-CIP-8. As detailed below, UI's submission is materially deficient in numerous respects, despite specific Authority guidance as to its required contents.

ii. Analysis of UI's Submission

The BCA portion of UI's AMI Plan submission does not comply with the framework and requirements established in the AMI Decision for at least three reasons. First, the BCA does not provide most of the requested data and metrics to demonstrate benefit availability and benefit realization. Ex. UI-CIP-8, pp. 4–10, Att. 1. Second, it does not establish benefit targets. Id. Third, it does not properly cover a 20-year planning horizon. Id. As a result, UI's AMI Plan lacks crucial information the Authority requires to evaluate whether UI's AMI investments are currently providing value to customers. Further, because the AMI plan does not establish benefit targets and lacks much of the requested data, it fails to serve as an initial baseline for measuring the value of AMI deployment to customers over the 20-year planning horizon. Consequently, the Authority is unable to evaluate whether the incremental investment to deploy AMI and AMI-related infrastructure over traditional metering infrastructure is used and useful.

The Company's BCA does not provide most of the requested data and metrics to demonstrate benefit availability and benefit realization. UI's AMI meter deployment is approximately 90% complete as of September 2024. Ex. UI-CIP-8, p. 3. There are roughly 40,000 AMR meters remaining on UI's distribution system out of a total of 359,878 meters as of year-end 2024. Ex. UI-CIP-1, p. 33; Interrog. Resp. RSR-41. UI therefore argues that the benefits of AMI have mostly been realized and, for nearly all the quantified benefits, claims that there are no incremental benefits to track. Ex. UI-CIP-8, pp. 7–9. The only quantified benefits included in UI's AMI BCA are (1) an estimated $12.9 million of avoided distribution line sensor costs, and (2) an estimated $11.7 million of incremental conservation voltage reduction/voltage optimization benefits (CVR/VO) over the 20-year planning horizon. Ex. UI-CIP-8, Att. 1.

The Company did not establish benefit targets as required. Although UI states that for most of the benefit categories there are no incremental benefits to track, it provides no supporting evidence that the benefits have been fully realized. The Authority developed a rigorous, data-driven BCA approach in the AMI Decision to definitively measure the benefit availability and benefit realization. AMI Decision, pp. 6–38. Moreover, the Authority specifically enumerated the quantitative metrics required to illustrate realization of AMI benefits. See AMI Decision, App. A. AMI benefits are proven to be realized when the provided metrics meet the targets established in the initial

baseline BCA. The AMI Decision is clear that targets must be established in the Final AMI Plan. AMI Decision, p. 52. However, UI did not provide any targets for AMI benefit realization.

Importantly, the requested data points are generally available to the Company.[50] For example, regarding the meter reading benefit, the Company did not provide the number and percent of meters read via AMI monthly, it did not provide its baseline capital and O&M monthly expenses to support AMR meter reading based on a historical average, it did not provide its actual monthly expense and capital costs to support AMI meter reading activities, and it did not provide any reduction in the miles driven as a result of AMI deployment. Ex. UI-CIP-8, p. 3. These are all metrics required in the AMI Decision. AMI Decision, App. A. Indeed, it is undisputed that the data for these metrics is available to the Company. See Interrog. Resp. RSR-260. A similar analysis holds for the Remote Service Connect/Disconnect benefit, the Reduced No Trouble Found Calls benefit, and the Reduced Theft and Line Loss benefit. See Interrog. Resp. RSR-261, Att. 1; Interrog. Resp. RSR-262; Interrog. Resp. RSR-265.

UI's failure to submit the requested metrics and its claim that the benefits of AMI have already been essentially fully realized despite the plan's lack of targets is particularly troubling given that the Authority specifically directed the Company to develop an AMI Plan that quantifies the going-forward benefit for each category defined in the AMI Decision. AMI Decision, p. 16, n.13.[51] In other words, UI did not properly conduct the BCA during the proceedings in Docket No. 17-12-03RE02, see AMI Decision, pp. 8–9, was directed by the Authority to develop an AMI plan that properly quantifies the going forward benefits, AMI Decision, Order Nos. 1-3, and subsequently submitted an AMI Plan that was deficient in the same way as before.

Additionally, the Company did not appropriately incorporate and consider a 20-year planning horizon. Specifically, on the cost side of the analysis, the Company did not properly account for the costs of AMI and AMI-related infrastructure over 20 years. The only cost included in UI's AMI BCA is the $11,953,947 cost of replacing the remaining AMR meters on the distribution system. Ex. UI-CIP-8, Att. 1. The Company did not include the planned costs for AMI meters over the 20-year planning horizon, though it expects to install approximately 320,500 meters over the next 20 years. Interrog. Resp.

[50] UI asserts that because it started deploying AMI meters in 2010, due to data retention policies and system changes it does not have all the data upon which a baseline or certain benefit-cost analyses could be made. UI Exceptions, p. 82. The Authority understands this valid concern. The lack of certain data does not, however, preclude the Company from otherwise complying the Authority direction to the extent it can. Yet, UI failed to do so.

[51] Importantly, the AMI Decision provided an explicit statement of the Authority's expectations specific to UI. "The Authority recognizes that UI has to some degree realized a number of these benefits and expects the benefits to continue to accrue and even increase as the existing, remaining AMR meters are replaced with AMI meters and as other future systems are deployed. UI's Amended AMI Plan, however, did not attempt to identify and quantify future benefits, except in the case of [Volt / VAR Optimization], avoided sensor costs, and avoided AMR capital costs. The Authority expects UI to develop an AMI Plan that quantifies the going-forward benefit for each category defined herein." AMI Decision, p. 16, n.13 (internal citations omitted). Despite this explicit statement of Authority expectations regarding an updated AMI BCA, the Company's AMI submission in the present proceeding remained essentially unchanged.

RSR-255, Att. 1. UI states that the CVR/VO and avoided sensor benefits require the implementation of an advanced distribution management system (ADMS), which the Company expects to complete in 2032. Ex. CIP-8, p. 5. However, the Company does not include the expected cost of implementing an ADMS even though system infrastructure costs are included in the cost categories. AMI Decision, App. C, p. 1. Among UI's capital projects is an $859,000 project to procure more storage for its Meter Data Management System (MDMS), though this is also not included as a cost in the BCA. See Ex. UI-CIP-4, p. 2240-44.

iii. Due Process

UI asserts that its due process rights have been violated because the Company was not put on notice that the Authority was considering a ROE reduction based on its AMI Plan (and other issues)[52] and because no party or intervenor in the proceeding advocated for an ROE reduction with respect to the Company's AMI plan. UI Exceptions, p. 80, n.59. UI is conflating the notice that due process requires with respect to an opportunity to be meaningfully heard on substantive issues under consideration, see generally Burton v. Connecticut Siting Council, 161 Conn. App. 329, 341 n.12 (2015) ("A fundamental principle of due process is that each party has the right to receive notice of a hearing, and the opportunity to be heard at a meaningful time and in a meaningful manner"), with the Authority's broad regulatory authority and discretion in setting just and reasonable rates. See Hope, 320 U.S. 591 (1944); see also Barasch, 488 U.S. 299 (1989); Woodbury Water Co., 174 Conn. 258 (1978).

Here, the substantive matter under consideration is UI's AMI Plan and its required Benefits-Cost Analysis (BCA). The Company submitted its plan with its rate application in this proceeding. See Ex. UI-CIP-1, p. 39 ("The Company's Final AMI Plan, required in PURA's Decision dated January 3, 2024 in Docket No. 17-12-03RE02, is being presented as Exhibit UI-CIP-8"); Ex. UI-CIP-8. The Authority then requested clarifying information on various costs and benefits associated with AMI, which, per the Authority's prior orders, should have been included in UI's Final Plan and BCA. See, e.g., Interrog. RSR-255, Interrog. RSR-256, Interrog. Interrog. RSR-258, Interrog. RSR-259, Interrog. RSR-260, Interrog. RSR-261, Interrog. RSR-262, Interrog. RSR-263, Interrog. RSR-264, and Interrog. RSR-265. Moreover, the Authority expressly asked UI why certain costs were not included in the BCA portion of the Company's Final AMI Plan. Interrog. RSR-259.

Thus, the Company was on notice that its AMI Plan was under review. See Kinsey v. World PAC, 152 Conn. App. 116, 132 (2014) (noting, in the context of an administrative workers compensation proceeding, "a party may be apprised that a given claim is at issue by other means [than formal pleadings], such as the statements of parties at trial, the evidence they have introduced, or the papers they have filed....")

[52]The Company makes similar due process claims with respect to ROE reductions for UI's failure to (1) file a detailed plan for development or procurement of a centralized DERMS platform in the present rate case application, and (2) proceed with the phase out and retirement of the Company's rental water heater fleet to ensure completion by September 1, 2025. The Authority's analysis here applies with equal force in both other contexts, which are discussed below.

Whether or not the Authority, or any other party or intervenor, opted to cross-examine the company further on its AMI Plan at the hearing, or opted to argue for specific Authority treatment related thereto, is irrelevant.[53] There is no due process or other legal requirement that compels the Authority to forecast precisely how it intends to exercise its discretion. See Kinsey, 152 Conn. App. at 131–32 (2014) (quoting Goldstar Medical Services, Inc. v. Dept. of Social Services, 288 Conn. 790, 823–24 (2008)) ("[T]he fundamental reason for the requirement of notice is to advise all affected parties of their opportunity to be heard and to be apprised of the relief sought.... [N]otice of a hearing is not required to contain an accurate forecast of the precise action which will be taken on the subject matter referred to in the notice."); see also General Statutes § 4-179 (proposed final decisions only required in an agency proceeding when a majority of the members of the agency who are to render the final decision have not heard the matter or read the record, and the decision will be adverse to a party).

Moreover, to the extent the Authority has indicated its intended actions through publishing a PFD in this proceeding, all parties were free to argue concerning any aspects thereof for the Authority's further consideration, as UI has done. Accordingly, the Authority finds no due process infirmities for lack notice with respect to the ROE reductions for the deficiencies in the Company's AMI Plan and BCA, as applied in this case.

iv. Conclusion

The Authority determines that a five (5) basis point reduction to the Company's ROE is warranted for failure to comply with the orders and requirements of the AMI Decision regarding the required content of a Final AMI Plan to be presented in the present Application. This ROE reduction is to remain in effect until the earlier of (1) UI submitting an AMI Plan that complies with the Authority's express guidance to UI, as reiterated herein, or (2) the conclusion of its next rate case based on the facts specific to that proceeding.

d. Non-Compliance with Other Authority Orders

In addition to the foregoing adjustments, the Authority finds an additional five (5) basis points reduction is warranted to address other instances where the Company failed to comply with express Authority direction. A hallmark of prudent and efficient management is a public utility's ability and commitment to adhere to applicable state and federal laws, as well as to the policies and direction of the entity designated to regulate its monopoly. General Statutes § 16-19gg(b)(2); see also In re Citizens Utilities Co., 171 Vt. 447, 451 (upholding reduction to ROE based on "systemic mismanagement and willful defiance of the [utility regulator's] authority"). Ratepayers expect and deserve nothing less. The Company failed to live up to this expectation in each of the following instances.

[53]The Authority solicited written comments from docket parties and intervenors regarding whether PURA should continue various ROE reductions imposed during UI's last rate case, as well as what, if any, other circumstances or issues might warrant consideration in setting a reasonable rate of return. Notice of Request for Written Comments, Feb. 11, 2025. This notice was neither intended to, nor did it, limit the Authority to ROE reductions for issues raised in the request, or discussed in the comments that were submitted in response.

i. DERMS Proposal

On March 14, 2024, UI, together with Eversource, submitted a plan to allow multiple Distributed Energy Resource Management Systems (DERMS) to participate in the Energy Storage Solutions (ESS) Program. UI Order No. 19 Compliance, Mar. 14, 2024, Docket No. 23-08-05, Annual Energy Storage Solutions Program Review – Year 3. In ruling on the corresponding motion for review and approval of UI's plan (Motion No. 18), the Authority directed UI to file a detailed plan for development or procurement of a centralized DERMS platform, including anticipated costs and timelines, in its next rate case application. Motion No. 18 Ruling, Apr. 26, 2024, Docket No. 23-08-05, Annual Energy Storage Solutions Program Review – Year 3, p. 3. This direction was in support of the Authority's commitment to long-term improvements in distributed energy resource management across resource types and programs. Id. Such improvements cannot be made without the active participation of the EDCs. Nonetheless, it is undisputed that UI failed to comply with this direction. Interrog. Resp. CAE-43. The Company attributes its lack of compliance to PURA's reduction to the Company's proposed operations and maintenance expenditures in its last rate case – a decision that was rendered nearly 18 months prior to the March 14, 2024 direction. Id.[54] Regardless of the rationale, it is clear that the Company made an affirmative decision to disregard the Authority's direction.

As with the ROE reduction related to the Company's Final AMI Plan, UI argues that because "[n]o party to this proceeding argued in favor of . . . reducing the Company's ROE by 5 basis points for failure to comply with PURA's directives related to DERMS and the Water Heater Rental Program [discussed below], and because "[n]o notice was given to the Company that PURA was considering, *sua sponte*, reducing the Company's ROE for an alleged failure to comply with directives related to DERMS and the Water Heater Rental Program, "it would be a violation of the Company's due process rights for PURA to reduce the Company's ROE by 5 basis points due to DERMS or the Water Heater Rental Program compliance." UI Exceptions, p. 77, n.58. UI again conflates the notice it is due on the substantive issues under review in the rate proceeding itself, with the Authority's exercise of its regulatory authority and discretion in setting just and reasonable rates. See Section V.E.10.c.iii, above.

[54]Specifically, UI attributed its lack of a DERMS plan submission, in part, to the Authority's "drastic reductions to the Company's proposed O&M expenditures and capital plan, which forced the Company to scale back its spending to focus available resources on core business issues." Interrog. Resp. CAE-43. The Company also explains that it previously provided a plan for implementing a centralized DERMS as part of a multi-year rate plan in its previous rate case application, but that the Authority adopted only a portion of the rate plan, which did not include the Company's proposed DERMS implementation. Id. In its written exceptions, UI shifts away from blaming the Authority for the Company's lack of a DERMS plan, recharacterizing its decision not to submit a DERMS plan in the present proceeding as "a practical choice made in good faith, and in part due to timing issues" upon recognizing that "a meaningful proposal could not be assembled under the circumstances." UI Exceptions, p. 76–77. The Authority declines to accept the notion that implementation proposal development costs or timing prevented UI from including the Authority-directed information into its present rate amendment application. The Company itself controls the timing of its rate applications. Moreover, contrary to the Company's assertions, its planning and submissions for the prior rate proceeding should serve to mitigate the costs and time needed to complete the required submission.

The Authority asked the Company in discovery about where in its application the Authority could find the DERMS plan that it had been directed to submit. Interrog. CAE-43. Thus, UI knew, or reasonably should have known, that the directed DERMS submission to be at issue in this proceeding. Should the Company have desired to supplement its original explanation, or to submit additional DERMS planning details at any time during the proceeding, it was free to do so. Moreover, by virtue of the Authority issuing a PFD, UI has also had the opportunity to argue about the appropriateness of an ROE reduction related to its lack of submission. Accordingly, the Authority finds no due process infirmities for any alleged lack notice with respect to an ROE reduction for the Company's failure to submit a DERMS plan as required.

ii. Water Heater Rental Program

As also discussed in Section VI.A.17.j, Water Heater Rental Program, below, in the Company's last rate case the Authority ordered UI to close participation to new customers in its longstanding Water Heater Rental Program as soon as possible, but no later than, September 1, 2023, and to develop a plan to phase out remaining equipment by September 1, 2025. 22-08-08 Decision, Section VI.A.21, Order Nos. 6, 33. This decision was based on the Company's own assessment that the program was unsustainable over time, should be closed to new customers, and should phase out existing customers. Id., p. 184. The Company submitted alternative plans to do so to the Authority for review and approval through a series of post-decision motions in Docket No. 22-08-08, with the Authority ultimately directing the Company "to begin phase-out activities to retire the entire water heater fleet in the field as soon as possible, but no later than January 2, 2025. . . . Further, the Authority directed the Company to complete Program phase-out activities and to file as compliance in Docket No. 22-08-08 confirmation of the same no later than September 1, 2025." Ex. UI-WHRP-1, p. 7.

The Company subsequently requested, in post-decision Motion No. 95 of Docket No. 22-08-08, that the Authority approve a new cost recovery mechanism for the cost of shutting the program down. Ex. UI-WHRP-2, p. 1. The Authority declined to do so and clarified that the present rate case was the appropriate mechanism through which to seek cost recovery. Id., p. 2. Nothing in the Motion No. 95 Ruling, however, superseded the Authority's express direction to begin phase out activities no later than January 2, 2025 so that phase out could be completed no later than September 1, 2025. See id.

Rather than proceed with the phase out and retirement of the water heater fleet to ensure completion by September 1, 2025, as directed, however, UI delayed implementation to wait for a decision in this docket related to cost recovery. Interrog. Resp. CAE-49. In doing so, the Company incurred additional, preventable or otherwise imprudent costs. See Section VI.A.17.j, Water Heater Rental Program, below.

The Company appears to have taken the position that it must be authorized to receive contemporaneous cost recovery, or some other pre-approval of specific costs, prior to complying with Authority direction related to completing the phase out of its Water Heater Rental Program. See, e.g. Ex. UI-WHRP-1, p.13 ("the Company requires a decision on cost recovery in order to continue the phase out of the Program, which would extend beyond the original deadline provided in Order No. 33. . . . Cost recovery is a

necessary prerequisite to UI's ability to complete the phase out of the Water Heater Rental Program."); Ex. RPP-24, p. 4 ("The Company cannot agree to the sale or closure of the program unless it receives guaranteed recovery for the total phase out cost including the Net Book Value ("NBV") of undepreciated assets that are not recouped through a sale.") This posture violates core principles of utility ratemaking, which the Company well knows – or should. See Hope, 320 U.S. 591,602 (establishing that the standard for "just and reasonable" rates does not guarantee specific costs as they are incurred to the extent "it is not theory but the impact of the rate order which counts"); Barasch, 488 U.S. 299 (1989) (affirming that timing mismatches between when costs are incurred and when they are recovered are Constitutionally permissible); James C. Bonbright, Principles of Public Utility Rates (1961), pp. 53, 147 n.1, 262 (explaining how regulatory lag is an inherent feature of utility ratemaking, and often serves as an incentive for efficiency). As such, the lack of pre-approved funding does not justify non-compliance, especially where the Company has incurred additional, preventable costs, see Section VI.A.17.j, Water Heater Rental Program, below, because of its non-compliance with the timeline prescribed by the Authority to wind down a program that the Company itself deemed unsustainable.

Despite the Authority's clear direction to phase out the program entirely no later than September 1, 2025, UI also appears to claim that it has a continuing duty to replace failing water heaters with new ones for customers in its rental program while awaiting definitive approval of its program wind-down costs in this docket.[55] UI Exceptions, pp. 78-79. Specifically, the Company argues that "to abandon its commitment to service the water heaters and replace failed units under the Program, prior to establishing a definitive plan for retiring remaining water heaters in the field and transiting ownership and maintenance responsibilities to the customers, would expose customers to both financial and health and safety harms." Id. (emphasis added). Yet, the Company filed its "Comprehensive Phase-Out Plan" as compliance in Docket No. 22-08-08 on June 1, 2024. The Authority approved and directed the Company to proceed with the retire-in-place option of that plan on December 11, 2024. Ex. UI-WHRP-2, p. 1. Furthermore, the Company indicates it has already developed – but not yet deployed – a customer communications campaign to notify participating customers of the impending end of its program. Ex. UI-WHRP-1, p. 12. Thus, aside from implementing the plan that UI has already developed and the Authority has approved – i.e., notifying customers, retiring the water heaters in place, and removing them from UI's systems – the only pending aspect is cost recovery itself. See, e.g., Ex. UI-WHRP-1, p.13; see also Interrog. Resp. CAE-49. As discussed above, conditioning implementation actions on pre-approval of specific cost recovery is inconsistent with core principles of utility ratemaking. Further, the Company's decision to defer further phase out efforts pending resolution of cost recovery in this

[55]The argument that UI cannot stop replacing failing water heaters with new ones unless and until it is relieved of its tariff obligations—thereby increasing the overall cost to ratepayers for stranded investments when the new replacement water heaters are shortly retired in place—appears to have been raised for the first time in the Company's written exceptions. This position is in tension with UI's prior submissions regarding how quickly the Company anticipated ending the rental program once approved. Interrog. Resp. CAE-049 ("the estimated time of six months needed to retire the water heater program remains unchanged"). Similarly, there is no mention of any anticipated delay or requirement to alter tariffs before moving forward with winding down the program in the Company's Comprehensive Phase-Out Plan. See Ex. RRP-24.

docket has enabled the very costs, see Section VI.A.17.j, Water Heater Rental Program, below, that prompted the Authority to require an expeditious wind down of the program. 22-08-08 Decision, p. 185 ("the Authority agrees that the program should be phased out as quickly as possible in order to avoid the replacement of such heaters and the possibility of future stranded assets") (emphasis added).

Based on the record before it, the Authority finds that the Company's continued insistence on securing a definitive wind-down cost recovery decision as a condition precedent to further phase-out efforts is unsupported by applicable law, and constitutes a violation of express Authority guidance to move expeditiously to meet the established September 1, 2025 phase out deadline. As UI's actions amount to intentional non-compliance with a timeline established by the Authority, an ROE reduction is appropriate. See General Statutes § 16-99gg(b)(2) (listing compliance with decisions and policies of the Authority as a factor to be used in setting a reasonable rate of return).

iii. Conclusion

Even in isolation, individual instances of non-compliance with specific Authority orders and direction are concerning. Taken together, though, the above examples paint a broader picture of non-compliance with Authority orders and direction that requires corrective action. The Authority finds an additional five (5) basis point reduction warranted to reflect and correct the imprudent management evinced by the Company's repeated non-compliance with specific Authority direction. This ROE reduction is to remain in effect until the Company's next rate case, at which time the Authority will reassess UI's compliance with Authority orders and direction.

e. Summation of ROE Reductions

Based on the above, the Authority concludes that a cumulative twenty (20) basis point reduction to the Company's ROE is warranted to account for instances where UI failed to provide expert, efficient, and prudent management of its franchise; to set rates commensurate with the level of service the ratepayers are receiving; and to incentivize the Company to do better. Accordingly, the Authority adjusts UI's allowed ROE from 9.45% to 9.25%.

VI. ALLOWABLE EXPENSES

A. OPERATIONS AND MAINTENANCE EXPENSES

1. Summary

Allowable operating expenses must "reflect prudent and efficient management of the franchise operation." General Statutes § 16-19e(a)(5). Therefore, those expenses that are reasonable and necessary to provide service to the public may be included as an allowable expense. The Company has the burden of proving that expenses under consideration for inclusion in rates are just and reasonable. See General Statutes § 16-22. In addition to being prudent, pro forma adjustments must be "known and measurable" and supported by a preponderance of evidence, with the burden resting on the utility to make such a showing. See Connecticut Natural Gas Corp. v. Dept. of Public Utility

Control, 51 Conn. Supp. 307, 322 (2009) (affirming agency's decision that, in part, applied the "known and measurable" standard to pro forma adjustments); see also Aquarion Water Company of Connecticut v. Public Utilities Regulatory Authority, No. HHB-CV-23-6078177-S, 2024 WL 1403433, at *9 (Conn. Super. Ct. Mar. 25, 2024) (application of known and measurable standard for depreciation within PURA's regulatory discretion). Consequently, the Authority will consider reasonable historical test year expenses, as adjusted for known and measurable changes, to determine a utility's allowable expenses.

The Company has proposed allowable O&M expenses of $184,902,644[56] to be included in its revenue requirement. Late Filed Ex. 1, Att. 2, Supp, Sch. C-1.0; Sch. WP C-3.0, p. 1. Based on its review of the record, the Authority makes modifications, as described below, and approves O&M expenses of $166,405,683 ($184,902,644 - $18,496,961). Table 38, below, summarizes the modifications and approved O&M expenses.

Table 38: Operations and Maintenance Expenses

Section	O&M Expenses	Proposed ($)	Adjustment ($)	Approved ($)
	Regulatory Assessment	2,499,141	-	2,499,141
VI.A.3	Outside Services - Customer Services	5,613,847	(274,336)	5,339,511
VI.A.4	Outside Services - Electric Dist. System	6,565,685	(2,977,921)	3,587,764
VI.A.5	Outside Services - Professional Services	10,909,253	(3,568,912)	7,340,341
VI.A.60	Outside Services - Line Clearance	16,660,423	(826,034)	15,834,389
VI.A.6	Storm Expense	6,623,074	(434,949)	6,188,125
VI.A.80	Environmental Remediation Expense	3,800,144	-	3,800,144
VI.A.9	Computer Expense	4,702,214	(521,296)	4,180,918
	Insurance Expense	1,589,288	-	1,589,288
	Rent and Lease Expense	851,490	-	851,490
	Telecommunications Expense	1,492,562	-	1,492,562
VI.A.10	Transportation Expense	2,234,308	(242,827)	1,991,481
VI.A.11	Uncollectible Expense	4,320,426	(911,602)	3,408,824
VI.A.12	Employee Compensation	49,832,152	(301,500)	49,530,652
VI.A.13	Employee Benefits	16,795,138	(227,626)	16,567,512
VI.A.14	Interest on Security Deposits	24,438	(10,324)	14,114
VI.A.15	Corporate Service Charges	31,124,964	(5,229,978)	25,894,986
VI.A.16	Residual O&M	6,528,418	(703,582)	5,824,836
	Caregiver - Bright Horizons	-	(37,444)	(37,444)
VI.A.13.f.vii	Cafeteria Subsidy	-	(144,015)	(144,015)
VI.A.17	Other Deferred Expenses	12,735,679	(2,084,615)	10,651,064
	Total Expenses	**184,902,644**	**(18,496,961)**	**166,405,683**

[56]The $184,902,644 figure includes $12,735,679 in deferred expenses moved to O&M, as discussed in Section IV.E, Reserves and Regulatory Liabilities, as well as $977,402 in uncollectible expense attributable to the Company's proposed revenue increase.

Late Filed Ex. 1, Att. 2 Supp., Sch. C-1.0; Sch. C-3.0 WP, p. 1; Sch. C-3.21 WP, pp. 1–3.

2. Inflation Adjustment

The Company proposes to escalate a number of Test Year expenses using an inflation adjustment factor of 8.15%, resulting in a pro forma expense of $4,505,562. Late Filed Ex. 1, Att. 2, Sch. WP C-3.0, p. 2; Sch. WP C-3.19, p. 3 (Updated). The Authority finds that escalating a Test Year expense by a generic inflation rate does not satisfy the requirement that a pro forma adjustment be known and measurable. In certain circumstances, the escalation of specific costs by an inflation rate may meet the known and measurable standard; however, such an escalation would require an evidentiary showing that the rate and its application constitutes a reasonable known and measurable change.

Applying a broad index inflation factor to specific Test Year expenses is the exception rather than the rule because it is an imprecise methodology and not necessarily predicative of the Company's actual Rate Year costs. Indeed, such a methodology permits a utility to cherry-pick which expenses are escalated by inflation and which are escalated by other known and measurable changes. With a utility incentivized to project higher expenses, this methodology likely results in broad-based inflation serving as the floor for expense escalation, thereby creating further upward pressure on rates.

In the present case, the Company applied a generic inflation factor to 13 of the 18 categories of O&M expenses for which it seeks recovery. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.0. In most instances, the Company failed to demonstrate that the use of a generic inflation adjustment constitutes a reasonable known and measurable change. In fact, the Company often utilized a generic inflation factor when there were contracts that set forth pricing terms in the Rate Year, failed to utilize a more specific and reasonable methodology to project its Rate Year expenses, proposed inflation adjustments when the historical data it submitted suggested that the expenses had not increased with the rate of inflation, or otherwise made little attempt to explain historical expense trends and why the application of a generic inflation adjustment was reasonable. While the Authority largely disallows the Company's proposed generic inflation adjustments, it examines each of the inflated O&M expenses on a case-by-case basis and, in some instances, notwithstanding the Company's failure to provide evidence to support various inflation adjustments, the Authority exercises its discretion and permits the Company to adjust certain Test Year expenses using an inflation rate.

3. Outside Service– Customer Services

a. Summary

The Company proposes $5,613,847 in outside customer service expenses, which is the Company's $4,623,509 pro forma Test Year expense and a $990,338 pro forma Rate Year adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.0 WP, p. 1. The Authority allows the Company to recover $5,339,511 in outside customer services expenses in the Rate Year. The table below summarizes the proposed and approved Rate Year outside customer service expenses.

Table 39: Outside Customer Services Expense

Expense	Requested ($)	Adjustment ($)	Approved ($)
Active and Final Collections	237,748	(17,911)	219,837
Outsource Call Taking Vendor	910,055	-	910,055
Customer Experience and Communications	142,466	(8,251)	134,215
Contact Center Services	57,163	(4,306)	52,857
Billing, Autopay, Payment Agencies	1,842,802	(138,832)	1,703,970
Credit Card Fee	1,892,932	(65,055)	1,827,877
Services Performed by Affiliates	373,272	(28,122)	345,150
Customer Programs	157,409	(11,859)	145,550
Total Expense	**5,613,847**	**(274,336)**	**5,339,511**

Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.03.

b. Active and Final Collections

The Company proposes a $237,748 expense for the Rate Year for Active and Final Collections, which is the Company's $226,457 Test Year amount, a ($6,620) pro forma adjustment to the Test Year amount attributed to nonrecurring expenses related to the Company's bill forgiveness program, and a subsequent $17,911 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.03. The Authority allows the Company to recover $219,837 for active and final collections expenses for the Rate Year because the Company failed to demonstrate that its proposed inflation adjustment constitutes a reasonable known and measurable adjustment.

The Company's active and final collections expenses are primarily attributable to outside vendors that receive a commission based on the amounts they collect on ratepayer balances sent to collections. Interrog. Resp. RRU-104; Interrog. Resp. RRU-105, Att. 1 (Redacted). Rather than proposing a pro forma adjustment based on the commission the Company expects to pay to its vendors in the Rate Year, the Company applied a generic inflation adjustment to all vendors utilized in the Test Year. Interrog. Resp. 104, Att. 1, p. 3. The Company posits that using historical data from 2019 through the Test Year, which shows a decline in its active and final collections expense, to make a known and measurable adjustment is not representative of its proposed Rate Year expense because such a decline in expenses is largely attributable to a reduction in accounts UI referred to outside legal firms for collections, a trend the Company does not expect to continue since the Authority has authorized legal collections for all residential customers to resume in November 2024. Interrog. Resp. RRU-226; Decision, Nov. 6, 2024, Docket No. 24-05-01, Annual Review of Affordability Programs and Offerings (Energy Affordability Annual Review) (24-05-01 Decision), p. 22. Moreover, based on the 24-05-01 Decision, the Company states that it will be pursuing a request for proposal (RFP) for a new legal collections firm for active customer accounts, but that it does not have a timeline for hiring a firm and, therefore, while it expects some impact to its collections expense, such impact is not yet known. Interrog. Resp. RRU-226.

While the Company provides an explanation of various factors that purportedly prevent it from making a proposed known and measurable adjustment to the Rate Year, it does not provide any evidence indicating that applying a generic inflation rate across its Test Year collections expenses is a reasonable proxy to project its Rate Year expenses and thus constitutes a reasonable known and measurable adjustment. Rather, the evidence indicates that the Company's collections expenses are driven by a number of variables that are not known and measurable and do not support a pro forma adjustment to the Company's Test Year expenses, such as the expense being driven by commissions on amounts collected, which has varied from year to year between 2019 and 2023, and the Company's anticipated RFP for a new legal collections firm. Thus, the Company's argument that a generic inflation rate serves as a reasonable known and measurable adjustment is unpersuasive and unsupported by the record. As such, the Authority finds that the Company's proposed $17,911 inflation adjustment does not represent a reasonable known and measurable adjustment, and, accordingly, the Authority permits the Company to recover $219,837 for active and final collections expenses for the Rate Year, which is the Company's pro forma Test Year collections expense less its proposed inflation adjustments.

c. Outsource Call Taking Vendor

The Company proposes a $910,055 expense for the Rate Year for outsource call taking vendors, which is the Company's $2,044,250 Test Year amount, with a ($1,134,195) adjustment made to the Rate Year amount to reflect the Company's projected cost savings from transitioning its outsource call taking vendor. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.03; Ex. UI-RRP-1, pp. 61–62. The Authority allows the Company to recover $910,055 for outsource call taking vendor expenses in the Rate Year.

The Company's outsource call taking vendor expenses are attributable to customer credit and move-in move-out (MIMO) calls handled by an outside vendor that is compensated on a per-call basis. Ex. UI-RRP-17A-REDACTED. The Company calculated its projected Rate Year expense by multiplying its cost per call by the number of projected credit and MIMO calls that its call taking vendor are expected to process in the Rate Year, adjusted to account for abandoned calls. Id.; Interrog. Resp. RRU-106. More specifically, the Company utilized historical data to create call volume forecasts for 2025 and 2026 to arrive at its expected Rate Year call volume for MIMO and credit calls, respectively. The Company subsequently applied a 72.85% distribution percentage to account for calls related to distribution. Ex. UI-RRP-17A-REDACTED.[57]

Notably, the Company utilized different time periods when projecting Rate Year call volumes for MIMO and credit calls, respectively. Interrog. Resp. RRU-106, Att. 1. For MIMO calls, the Company's 2025 call volume forecasts represent 95% of the Company's

[57]The Company calculated a 72.85% distribution allocation percentage based on Test Year data for credit and MIMO calls. Ex. UI-RRP-17A Redacted. The Authority concludes that the 78.25% distribution percentage is reasonable to utilize in this instance in lieu of the Massachusetts Formula because the Company identified specific cost drivers for which to allocate its outsource call taking vendor expenses. See Interrog. Resp. UPA-11 (explaining that the Massachusetts Formula is utilized where a consumption driver cannot be identified).

call volume between May 2023 and April 2024, and the 2026 MIMO forecast represents 96% of its 2025 MIMO call volume projections. Id. The Company states that this methodology accounts for an expected decrease in MIMO call volume due to a variety of self-service and web-based options that will not necessitate a customer phone call to the Company. Interrog. Resp. RRU-106. For credit calls, the Company based its 2025 call volume forecasts by using historical call volume data from May through December 2019 and January through April 2023. Interrog. Resp. RRU-267, Att. 1.

The Authority finds that the methodology used by the Company to calculate its call taking vendor expenses represents a reasonable projection of its Rate Year expenses, unlike the generic inflation adjustment applied to other O&M expenses. Therefore, the Authority permits the Company to recover $910,055 in outsource call vendor costs for the Rate Year.

d. Customer Experience and Communications

The Company proposes $142,466 in customer experience and communications expenses for the Rate Year, which is the Company's $101,278 Test Year amount, an $8,251 generic inflation adjustment, and a $32,937 Rate Year adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.03; Interrog. Resp. RRU-270. The Authority allows the Company to recover $134,215 for customer experience communications expenses for the Rate Year.

The Company's customer experience and communications expenses are attributable to customer research, including a contact satisfaction survey, alerts, notifications, and digital and non-digital customer communications channels, including direct mailings and emails. Interrog. Resp. RRU-104. Notably, these expenses have increased from $41,000 in 2019; $14,000 in 2020; and $46,000 in 2021; to $99,000 in 2022 and $101,278 in the Test Year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.03.

The Company testified that it contracts with outside vendors that charge for contact satisfaction surveys, direct emailing and mailing, and its alert notification services on a per-call, per-text, or per-contact basis. Hr'g Tr., 202:19–23, 203:4–9, 205:4–25. Moreover, the Company stated that contracts for such services were in place for the Rate Year, with the exception of the contact satisfaction survey vendor, which the Company expects to conduct a competitive request for pricing or to extend its existing contract prior to October 1, 2025. Id., 204:11–16; 206:9–11, 23–25, 207:1–17.

The Authority concludes that adjusting the Company's customer experience and communications expenses by a standard inflation factor does not represent a reasonable known and measurable change. To the contrary, the Company's testimony indicates that such expenses are driven by the number of calls, texts, mailings, or other forms of contact the Company's vendors make in a given year. As such, a reasonable known and measurable adjustment to the Rate Year would require consideration of how many such communications are expected to occur in the Rate Year. Absent such an analysis, the Authority is unable to conclude what a reasonable known and measurable adjustment for the Rate Year would be and, accordingly, permits the Company to recover $134,215 in

customer experience communications expenses for the Rate Year, which reflects the Company's Rate Year request less its inflation adjustment.

e. Contact Center Services

The Company proposes $57,163 in contact customer services expenses for the Rate Year, which is the Company's $62,832 Test Year, with a ($9,975) pro forma adjustment, and a $4,306 inflation adjustment. Late Filed Ex. 1, Att. 2, Supp, Sch. WP C-3.03. The Authority permits the Company to recover $52,857 for contact center services expenses for the Rate Year.

The Company's contact center services expenses are related to inbound fax usage, language translation services, and Equifax services for credit monitoring and ID theft protection. Interrog. Resp. RRU-104. The Company testified that it has contracts in place with the vendors for the Rate Year based on a per unit cost. Hr'g Tr., 208:1–16. 209:3–5.

Based on the Company's testimony, the Authority finds that escalating the Company's contact center services for inflation does not represent a reasonable known and measurable change because the cost drivers for the expenses are based on per unit pricing. As such, a reasonable known and measurable adjustment to the Rate Year would require consideration of the cost per unit included in the relevant contract by the expected usage of the services in the Rate Year. Absent such an analysis, the Authority is unable to conclude what a reasonable known and measurable adjustment for the Rate Year would be and, accordingly, permits the Company to recover $52,857 in contact center services expenses for the Rate Year, which reflects the Company's Rate Year request less its inflation adjustment.

f. Billing, Autopay, Payment Agencies

The Company proposes $1,842,802 for billing, auto pay, and payment agencies expenses for the Rate Year, which is the Company's $1,703,970 Test Year expense plus a $138,832 adjustment for inflation. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.03. The Authority permits the Company to recover $1,703,970 for billing, autopay, and payment agencies expenses.

The Company states that billing, autopay, and payment agency expenses consist of expenses paid to third parties for agent, services, bill print services and bill print postage services, collections notice printing, autopay services, eBill services, and professional services. Interrog. Resp. RRU-104. The Company does not provide any evidence indicating that applying a generic inflation rate across its Test Year billing, autopay, and payment agencies expense constitutes a reasonable known and measurable adjustment. To the contrary, the historical data provided in the Company's rate application indicates that the expenses fluctuate from year to year but have not risen with the rate of inflation over the past five years. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.03. As such, the Authority finds that the Company's proposed $138,832 inflation adjustment does not represent a reasonable known and measurable adjustment, and, accordingly, the Authority permits the Company to recover $1,703,970 for billing, auto

pay, and payment agencies expenses for the Rate Year, which reflects the Company's Rate Year request less its inflation adjustment.

g. Credit Card Fees

The Company proposes $1,892,932 in credit card fee expenses for the Rate Year, which is an expense for which the Company did not report a Test Year expense but expects to incur in the Rate Year.[58] Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.03. The Company further proposes that the $1,892,932 in expected Rate Year credit card fee expenses be used as a baseline for a deferral mechanism that would be trued-up during the Company's next rate case, which the Company states is consistent with the 22-08-08 Decision. Ex. UI-RRP-1, p. 90. The Authority permits the Company to recover $1,827,877 in credit card fee expenses but declines to defer credit card fee expenses for going forward expenses.

The Company states that its credit card fee expenses are related to the Fee Free Program, which was implemented on April 30, 2024, and allows residential customers to pay their bills using a credit or debit card or Automated Clearing House (ACH) for no fee.[59] Ex. UI-CSP-1, p. 51. The Company's projected Rate Year expenses are composed of two distinct components: credit and debit card fees, and ACH fees (i.e., when a customer pays electronically using a bank account), which the Company determined by multiplying the cost per transaction by the number of payment transactions it expects to occur in the Rate Year. Ex. UI-RRP-17B-REDACTED.

The Company states that it has experienced a 42% increase in credit and debit card usage between May and August 2024 as compared to the same time period in 2024, and that it expects usage to increase as customers learn that convenience fees have been eliminated. Ex. UI-CSP-1, p. 51; Interrog. Resp. OCC-110. Moreover, the Company utilized historical data from an Avangrid affiliate with a similarly sized customer base, Rochester Gas and Electric (RGE), to project its expected credit card fee expenses for the Rate Year, arguing that RGE saw a 47% average increase in credit and debit card usage in the three years after it implemented a fee free program in 2016. Interrog. Resp. OCC-110. The Company further adjusted its Rate Year projections to factor in that the Company has approximately 55,000 less customers than RGE, leading to a projected 30% increase in credit and debit card usage in 2025 and a 2.5% increase between 2025 and 2026. Interrog. Resp. OCC-110. Similarly, the Company calculated its expected Rate Year ACH expense by assuming a five percent increase in 2024 volumes for 2025 and 2026. Interrog. Resp. RRU-376 (b).

The Company subsequently updated its calculations to incorporate actual credit and debit card usage data, noting that usage grew 39% from January through March 2024 to January through March 2025. Interrog. Resp. OCC-165 Supp. Accordingly, the

[58]The Company did report a deferred credit of ($747,000) related to Fee Free Program expenses. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.21.

[59]The Company states that non-residential customers will continue to pay a contracted fixed rate convenience fee of $6.50 per transaction for utilizing the above-referenced payment methods. Ex. UI-CSP-1, p. 51.

Company revised its forecast to show a 39% increase over 2024 actual volumes for April through December 2025, as well as a projected 30% usage increase in 2026 based off 2025 volumes. Interrog. Resp. OCC-165 Supp. Based on its revised forecast, the Company estimated that it would incur $2,895,269 in credit and debit card Rate Year expenses. Id. The Company also updated its ACH forecast for actual volumes through March 2025, resulting in a projected $195,998 ACH fee expense for the Rate Year and $3,091,257 in Rate Year credit, debit, and ACH fees, of which $1,892,932 is allocated to distribution rates.[60] Id.

The Authority finds that utilizing a projected 39% increase in credit and debit card usage for April through December 2025 is appropriate since the percentage reflects actual data collected for 2025 thus far. Conversely, the Authority also finds that there is no basis for the Company's revised, projected 30% usage volume increase for 2026. While utilizing an affiliate's historical transaction volume as a proxy for expected transaction volumes in the Company's Rate Year could serve as a useful measuring stick for expected payment volume trends in the absence of Company-specific historical data, it is unclear how the Company derived its revised 30% estimate using its affiliate's historical data, particularly since the Company initially projected a 2.5% volume increase using the same affiliate data. Absent a clear methodology and forecasting data to project 2026 volumes, the Authority relies on its experience and expertise in deriving a projection that reasonably recognizes that volumes are likely to increase and then decelerate in 2026, per the Company's initial projected trend. Specifically, the Authority endeavored to determine a reasonable escalation rate that acknowledges that the Company's 2.5% initial escalation projection was overly conservative in light of the Company's reported 39% increase in credit and debit card usage for April through December 2025, while also balancing that the Company's revised 30% 2026 estimate is unsupported by any data or explanation and likely overstates the continued growth of credit and debit card usage.

Accordingly, the Authority concludes that half of the Company's revised, proposed 30% escalator represents a reasonable approximation of the increase in credit and debit card usage in 2026. Thus, the Authority applies a 15% escalator to 2026 volumes, which results in a projected $2,520,826 in Rate Year credit and debit card fees, of which $1,696,011 is appropriately allocated to distribution rates ($2,520,826 x 67.28). Utilizing the projected 2025 and 2026 volumes, the Authority approves a $1,696,0119 credit and debit card expense for the Rate Year. The Authority also finds that the Company's projected ACH forecast is reasonable and approves a $131,866 ACH usage expense for the Rate Year ($195,997 x 67.28%). In sum, the Authority determines that a $1,827,877 total credit card fee expense for the Rate Year is reasonable ($1,696,011+ $131,866) = $1,827,877).

Finally, the Authority declines to defer expenses resulting from the Fee Free Program on a going forward basis. The Authority, recognizing that certain customer

[60]Applying a 67.28% distribution allocation factor to the Company's projected $3,091,257 expenses results in a $2,078,870 Rate Year expense. The Company appears to have derived its $1,892,932 by applying the distribution allocator to the $2,814,514 projected Rate Year expenses reflected in an earlier filing in the proceeding. Interrog. Resp. RRU-377.

benefits could be realized through successful program implementation, permitted the Company to deviate from the known and measurable standard in its last rate case by authorizing the Company to move forward with the Fee Free Program despite testimony indicating that the timeline and costs for the program were uncertain. 22-08-08 Decision, pp. 164–165. As such, the deferral mechanism as well as the $3.95 per transaction cap on cost recovery were necessary ratepayer protections to ensure that costs related to the program were reasonably within the Company's projected range and that ratepayers did not overpay for an unproven program. In this proceeding, however, the Fee Free Program will have been in place for nearly a year and a half at the time of the Authority's final decision, leaving enough historical data to analyze and set forth a known and measurable adjustment for the program in the Rate Year. As such, the speculative nature of the program's costs present in the Company's last rate case should be abating and, therefore, a deferral mechanism for Fee Free Program expenses is no longer necessary. Accordingly, the Authority declines to defer expenses resulting from the Fee Free Program on a going forward basis.

h. Service Performed by Affiliates

The Company proposes $373,272 for customer services performed by affiliates, which is the Company's $345,150 Test Year amount plus a $28,122 adjustment for inflation. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.03. The Authority permits the Company to recover $345,150 in customer services performed by affiliates in the Rate Year.

The Company states that the above-referenced services represent work performed by the Company's affiliates on behalf of UI and are generally performed by professional, supervisory, or management level employees working in areas of natural overlap between operating companies, such as customer service communications and remittance processing. Interrog. Resp. RRU-104. The Company indicates that no external vendors are utilized in providing such services. Interrog. Resp. RRU-105, Att. 1 (Redacted). Notably, the Company has proposed wage inflation factors in its rate application. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.15, p. 3. As such, the Company has already accounted for wage inflation for the employees' performing services on behalf of UI in the service performed by affiliate line item. Accordingly, in order to prevent double counting wage inflation related to services performed by affiliates, the Authority permits the Company to recover $345,150 in customer services performed by affiliates, which is the Company's Test Year expense less the generic inflation adjustment.[61]

i. Customer Programs

The Company proposes $157,409 in customer programs expenses for the Rate Year, which is the Company's $139,572 Test Year expenses plus a $5,978 pro forma adjustment and an $11,859 inflation adjustment. Sch. WP C-3.03. The Authority permits the Company to recover $145,550, in customer programs expenses.

[61]The Company asserts that the Authority's finding regarding double counting is "flat wrong," but provides no references to the record or otherwise explains why such a finding is incorrect. UI Exceptions, p. 100.

The Company states that its customer programs expenses include customer service-related systems such as key account management, customer engineering, and metering services. Interrog. Resp. RRU-104. Once again, the Company does not provide evidence indicating that a generic inflation adjustment serves as a reasonable known and measurable adjustment for its customer programs expenses. In fact, the Company's customer programs expenses have varied since 2021.[62] Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.03. Thus, the Authority finds that the Company's proposed inflation adjustment for customer programs expenses does not represent a reasonable known and measurable adjustment, and, accordingly, the Authority permits the Company to recover $145,550 in the Rate Year.

4. Outside Services – Electric Distribution System

a. Summary

The Company proposes $6,565,685 in outside electric distribution system expenses, which the Company described as third-party work on operations and maintenance projects and third-party contractors supporting its efforts to process pole attachment applications. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.04; Ex. UI-RRP-1, p. 62. The Company categorizes its outside electric distribution system expenses as "Electric Operations," "Joint Use– Third Party Pole Attachments," and "Services Performed by Affiliates." Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.04. The Authority allows the Company to recover $3,587,764 in outside electric distribution system expenses for the Rate Year. The below table summarizes the approved Rate Year outside services electric system distribution system expenses.

Table 40: Allowed Outside Services– Electric Distribution System Expenses

Expense	Proposed ($)	Adjustment ($)	Approved ($)
Electric Operations	3,115,402	(57,347)	3,058,055
Joint Use - Third-Party Pole Att.	2,612,117	(2,612,117)	-
Services Performed by Affiliates	838,166	(308,457)	529,709
Total	6,565,685	(2,977,921)	3,587,764

b. Electric Operations

The Company proposes $3,115,402 in Rate Year expenses for electric operations expenses, which is the Company's $2,880,696 Test Year amount plus a $234,706 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.04. The Authority allows the Company to recover $3,058,055 in electric operations expenses for the Rate Year.

The Company's reported electric operations expenses related to third-party contractors working on Company operations and maintenance. Ex.-UI-RRP-1, p. 62. The Authority audited the invoices the Company received from third-party contractors for the

[62]The Company's historical data indicates that its customer programs expenses increased from $165,430 in 2021 to $238,899 in 2022 before declining to $139,572 in the Test Year. Late Filed. Ex. 1, Att. 2 Supp., Sch. WP C-3.03. The Company did not offer an explanation for year-to-year variability in customer programs expenses.

Test Year and determined that the Company incurred $3,303,924 in Test Year expenses, of which $49,844 was accrued but not invoiced to the Company, $423,212 was reclassified to other line items, and $49,860 was allocated to transmission expenses rather than distribution. Interrog. Resp. RSR-155, Att. 1. The reclassified items should be accounted for in other line items in the Company's revenue requirement and must be removed to prevent double counting of the expense. Similarly, amounts allocated to transmission should be removed so as to not be included in the Company's distribution revenue requirement. After removing reclassifications and allocations to transmission, the Authority concludes that the Company's Test Year expense should be $2,880,696.

Additionally, the Authority finds that utilizing a generic inflation adjustment for electric operations expenses does not constitute a reasonable known and measurable adjustment because the various Master Services Agreements (MSAs) in place for the Rate Year include contractual escalation rates. Consequently, the MSAs provide sufficient evidence to support an escalation of the Test Year electric operations expense, albeit not the escalation requested by the Company. Accordingly, the Authority finds that a weighted average escalation rate derived from MSAs in place during the Rate Year, as described below, provides a reasonably accurate projected Rate Year expense. Applying the calculation described below, the Authority authorizes the Company to recover $2,952,229 in electric operations expenses for the Rate Year.

Specifically, the Company provided 17 MSAs related to electric operations expenses, of which three will not be in place for the Rate Year, one that does not provide pricing terms for Connecticut, and one that does not list the Company as receiving services. Interrog. Resp. RSR-157, Att. 1-17, Atts. 3, 12, and 13, Att. 15, p. 10; Late Filed Ex. 35. Of the 14 relevant MSAs, seven contain annual escalation rates representing $1,050,000 of the Company's Test Year expenses. Late Filed Ex. 36; Interrog. Resp. RSR-157, Att. 4, pp. 33–34, Att. 5, p. 34, Att. 11, p. 82, Att. 16, p. 85; Late Filed Ex. 35, Att. 1, p. 47, Att. 2, p. 20. The remaining MSAs did not contain escalation factors and were excluded from the calculation because the record does not contain a reliable basis for which to project their Rate Year totals. Interrog. Resp. RSR-157, Atts. 2, 3, 6, 7, 8, 9, 12, 13, and 17. The Authority subsequently weighted each MSA's escalation rate by its proportional share of the $1,050,000 total Test Year expense for the appliable MSAs, which resulted in a 2.13% escalation rate. Late Filed Ex. 36; Interrog. Resp. RSR-157, Att. 4, pp. 33–34, Att. 5, p. 34, Att. 11, p. 82, Att. 16, p. 85; Late Filed Ex. 35, Att. 1, p. 47, Att. 2, p. 20. The Authority finds that the weighted average escalation rate of 2.13% represents a reasonable known and measurable adjustment given that it is derived from the actual contracts related to the expense. The availability of this data precludes the use of a generic inflation factor.

To calculate the known and measurable adjustment, the Authority applied the 2.13% escalation rate to the $2,8880,696 Test Year expense ($2,880,696 x (1.0213)^2), resulting in a $3,004,721 figure that represents the increase in electric operations expense from 2023 to 2025. To account for 2026 expense escalation, the Authority multiplied $3,004,721 by the escalation factor, resulting in a $3,068,721 expense. Finally, the Authority pro-rated the 2025 electric operations expense to reflect 2 months of Rate Year expenses in 2025 and 10 months of Rate Year Expenses in 2026, resulting in an

approved $3,058,055 (0.833 x 3,068,721 + 0.167 x 3,004,721) in Rate Year electric operations expense.

Accordingly, the Authority authorizes the Company to recover $3,058,055 in electric operations expenses for the Rate Year.

c. Joint Use - Third-Party Pole Attachments

The Company proposes $2,612,117 in the Rate Year for joint use, third-party pole attachment expenses, which is the Company's $1,379,022 Test Year amount plus a projected $1,233,095 in incremental expenses the Company expects to incur in the Rate Year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.04; Ex. UI-RRP-1, p. 62. The Authority does not permit the Company to recover joint use, third-party pole attachment expenses for the Rate Year because the Company should be able to utilize more internal resources to process pole attachment applications and reduce external contractor costs, and the revenue derived from pole attachment application and processing fees should cover the Rate Year expense for utilizing external contractors and internal staff to process and engineer new pole attachment applications.

The Company states that its third-party pole attachment expenses are derived from third-party contractors supporting the Company's efforts to process pole attachment applications. Ex. UI-RRP-1, p. 62. The Company separated its projected third-party pole attachment expenses into $1,103,091 in engineering contractor expenses and $1,509,026 in single pole administrator (SPA) expenses. Interrog. Resp. RSR-174, Att. 1, p. 1. The Company calculated its estimate of Rate Year engineering and SPA contractor expenses by adding three months of estimated contractor expenses in 2025 and nine months of estimated 2026 expenses. Interrog. Resp. RSR-174, Att. 1, p. 1.

The Company's 2025 and 2026 contractor estimates were based on 2025 and 2026 pole volume estimates and the backlog of pole applications received in 2023 and 2024. Id. Specifically, the Company estimates that it will need to engineer 90,382 poles in connection with attachment requests through 2026, which consists of 61,306 poles engineered through 2024 plus an estimated 29,526 additional poles engineered based on a projected number of requests received in 2025 (19,026) and 2026 (10,500) combined. Id. Thus far, the Company reports that it has engineered 19,789 of the 90,832 poles, leaving an estimated 71,043 poles to be engineered through 2026. Interrog. Resp. RSR-174, Att. 1, p. 1. Of the 71,043 poles to be completed, the Company estimates that it can engineer 20,000 using internal resources and 51,043 using external contractors. Interrog. Resp. RSR-174, Att. 1, p. 1.

The Authority finds that the Company's internal resources are capable of engineering more than 20,000 poles by the end of 2026. The Company currently has 17 field technicians and has plans to employ 21 (17 field technicians and four field technicians supervisors) in 2025 and 24 (21 field technicians and three field technician supervisors) in 2026. Interrog. Resp. OCC-436. In 2022, the Company internally processed 302 pole attachment applications and engineered 8,574 poles with two (2) single pole administrative analysts and 14 field technicians. Interrog. Resp. RSR-131; Interrog. Resp. RSR-16. While the Company's internal staff engineered fewer poles in

2023 (4,875 poles) and 2024 (4,419 poles) as compared to 2022, the Company explained that the decrease was primarily attributable to a lack of internal staff and time spent training third-party pole attachment contractors on their electric distribution system. Interrog. Resp. RSR-15; Interrog. Resp. RSR-175; Interrog. Resp. RSR-176. Moreover, the Company testified that it is now capable of transitioning its internal workforce from training external contractors back to engineering poles. Hr'g Tr., 1555:6–11. Based on the Company's ability to engineer 8,574 poles with 14 field technicians, or approximately 612 poles per field technician, the Authority concludes that the Company could reasonably internally engineer 12,852 poles in 2025 (21 x 612) and 14,688 poles in 2026 (24 x 612 = 14,688). This means the Company should be able to engineer 27,540 poles (12,852 + 14,688) rather than the Company's 20,000 estimate. As such, only 43,503 poles would be engineered by external contractors (71,043 – 27,540).

The Authority also finds that the Company's application overstates the amount of poles the Company expects its contractors to engineer during the Rate Year. The Company expects to engage four contractors in the Rate Year and projects that Contractor 1 will engineer 15,000 poles in 2025 and 23,623 poles in 2026; Contractor 2 will engineer 3,600 poles in 2025 and 2,000 in 2026; Contractor 3 will engineer 2,000 poles in 2026; and Contractor 4 can engineer 1,200 poles in 2025 and 920 in 2026. Interrog. Resp. RSR-174, Att. 1; Late Filed Ex. 90. Notably, however, the Company's 2024 engineering estimates for its contractors did not come to fruition; particularly, estimates for Contractor 1 (12,000 estimated versus 5,174 actual), Contractor 3 (3,600 estimated versus 2,288 actual), and Contractor 4 (1,200 estimated versus 867 actual). Ex. UI-RRP-17C, p. 1; Interrog. Resp. RSR-174, Att. 1, p. 1. The Company explained that the discrepancy between its estimates and poles actually engineered in 2024 was a result of the contractors needing to be trained in the field. Interrog. Resp. RSR-176.

For 2025, the Company estimated it could engineer 33,400 poles, of which 23,400 or nearly 70% would be performed by outside contractors. Interrog. Resp. RSR-174; Late Filed Ex. 90. As of April 2025, the Company indicated that it has engineered 13,341 poles, putting it on pace to meet its 2025 projections. Interrog. Resp. RSR-174; Late Filed Ex. 90. While the record indicates that the Company is on pace to meet its 2025 pole engineering projections, the Company has not clearly indicated how many of the poles were completed by the Company's internal resources or outside contractors or demonstrated why the Company's proposed Rate Year expense is necessary to maintain the pace of poles engineered in 2025 thus far. Indeed, the Company's Rate Year forecast of poles engineered relies on a 56.8% increase (15,000 in 2025 and 23,523 in 2026) in poles engineered by Contractor 1, but the Company did not provide any data or historical information to support its projections. Interrog. Resp-174, Att. 1 REDACTED. To the contrary, the Company indicated that Contractor 1 has established a "stable production rate" of 1,000 poles per month. Interrog. Resp. RSR-175. Accordingly, the Authority finds that the Company's projections of poles engineered in the Rate Year are overstated and that a projection of 12,000 poles in both 2025 and 2026 is more consistent with the Company's indication of what a stable production rate represents. Adjusting the projected poles engineered by Contractor 1 results in an estimated backlog of 5,293 poles by the end of 2026. Interrog. Resp. RSR-174, Att. 1. Accordingly, the Company's projected contractor expense for the Rate Year is more appropriately stated as $849,631. As

described in more detail below, the Company's allowed contractor expenses for the Rate Year should be covered by pole attachment fees and as such, are not permitted to be recovered in the Company's base distribution rates.

Additionally, the Authority finds that the Company's internal SPA resources should be able to process more pole attachment applications in the Rate Year. The Company indicated that it hired one SPA analyst in 2024 and has four SPA analysts working on processing pole attachment applications and managing the AldenOne system. Interrog. Resp. RSR-15. The Company reported that it processed 302 pole attachment applications in 2022 with two SPA analysts and 304 applications with four SPA analysts in 2024. Interrog. Resp. RSR-131; Interrog. Resp. RSR-16. The Company asserts that it only processed two more applications in 2024 due to resource challenges with field technicians. Interrog. Resp. RSR-185. However, the record demonstrates that the number of pole attachment applications processed do not correlate with the number of poles engineered. For instance, in 2021, the Company states that it processed 371 applications and engineered 4,990 poles, but in 2022 it processed 302 applications and engineered 8,574 poles. Interrog. Resp. RSR-131. As such, it is unclear why the Company is unable to leverage its internal resources to process additional pole attachment applications and manage the AldenOne system in the Rate Year, particularly since the Company has doubled the amount of SPA analysts employed between 2022 and 2024. Indeed, the Company processed 531 applications between internal resources and external resources in 2024, which is a reasonable target to process using internal resources only given that the Company was able to process 302 pole applications in 2022 with half of its existing internal resources. Accordingly, the Authority does not permit the Company to recover $1,509,026 in Rate Year expenses for external SPA contractors.

Finally, the Authority concludes that pole attachment application and per-pole survey fees collected from pole attachment applicants should cover any Rate Year costs related to serving as a single pole administrator. Here, the Company projects that it will incur $3,439,046 in pole attachment expenses inclusive of all SPA costs ($858,473 in internal pole attachment expenses and $2,580,573 in external pole attachment expenses) in the Rate Year. Interrog. Resp. RSR-183, Att. 1. The Authority has previously determined that approximately 10% of pole attachment costs were not attributable to specific pole attachment applications, but rather to the Company's role as a SPA. 22-08-08 Decision, p. 170. Here, the Company projects that it will incur $858,473 in pole attachment expenses in the Rate Year. Interrog. Resp. RSR-183, Att. 1. Therefore, approximately $343,905 of Company-anticipated Rate Year expenses are expected to be due to UI's role as a SPA and not attributable to any pole attachment applications. Notably, the Company charges pole attachers an application processing and survey fee of $150 - $170 and a per pole fee of $125. 22-08-08 Decision, p. 170. Based on the Company's projected pole application and pole volumes in 2025 and 2026, it should collect $1,834,884 in revenues. After subtracting $849,631 in pole attachment engineering costs, the Company should collect a $985,253 balance, which the Company may elect to utilize towards supplementing external SPA work to process applications and manage the AldenOne system.

Importantly, the Authority's findings are consistent with its prior determination that pole attachment applicants, not ratepayers, should incur the costs attributable to third-party pole attachment work since attachers are the cost causers and direct beneficiaries of the pole attachments. 22-08-08 Decision, p. 170; Decision, May 11, 2022, Docket No. 19-01-52RE01, PURA Investigation of Developments in the Third-Party Pole Attachment Process – Make Ready (19-01-52RE01 Decision), pp. 36–39. The Company could have and still may increase the application and per pole survey fee to cover all expenses related to Joint Use Third-Party pole attachments.

d. Services Performed by Affiliates

The Company proposes $838,166 in expenses related to services performed by affiliates for the Rate Year, which is the Company's $775,021 Test Year amount plus a $63,145 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.04. The Authority permits the Company to recover $529,709 in expenses related to services performed by affiliates for the Rate Year.

The Company states that the services by affiliates line item encompass a variety of costs related to affiliate employees contributing to various projects. Interrog. Resp. RSR-272, Att. 2. Notably, the Company's Rate Year expense included $245,312 in affiliate work that included "supporting rate case efforts, both during pre-filing activities and during hearings." Id. Although the record is unclear whether the reported rate case expenses relate to the current proceeding or the Company's last rate case in Docket No. 22-08-08, the reported rate case expenses are not recoverable in the Rate Year.

Rate case expenses incurred in relation to this proceeding are barred by General Statutes § 16-243p(b), which states in relevant part "[f]or any rate proceeding initiated on or after January 1, 2024, no electric distribution company. . . shall recover through rates its direct or indirect costs associated with its attendance in, participation in, preparation for, or appeal of such proceeding." Such expenses include "the portion of employee salaries associated with such attendance, participation, preparation or appeal of a rate proceeding and related costs identified the Authority." Id. This proceeding was initiated after January 1, 2024, and thus, to the extent the Company's reported affiliate work relates to this proceeding, such expenditures are barred from recovery as a matter of law. Moreover, to the extent the Company's reported expenses relate to a rate case proceeding initiated prior to January 1, 2024, such expenses are nonrecurring and should not be expected to be incurred in the Rate Year. Accordingly, the Authority disallows $245,312 in reported expenses related to affiliates support of rate case efforts, both during pre-filing activities and during hearings.

Additionally, the Authority finds that the $63,145 inflation adjustment does not represent a reasonable known and measurable adjustment from the Company's Test Year expense. The Company explained that its services performed by affiliates expense fluctuates year to year based on the time affiliate employees charge the Company, indicating that the expense does not increase at the rate of inflation. Interrog. Resp. OCC-694. Additionally, the Company provided three MSAs for affiliates to substantiate its proposed 8.15% inflation adjustment. Interrog. Resp. RSR-157, Att. 25, 26, 27. The first MSA described services GenConn Energy LLC (GenConn) would receive from the

Company, not what the Company would receive from GenConn. Interrog. Resp. RSR-157, Att. 26, p. 1. Further, GenConn was not an affiliate listed as charging services to the Company for the line item at issue. Interrog. Resp. RSR-62. The two other MSAs provided between the Company and UIL Holdings Corporation (UIL) and Avangrid Services Company (ASC), respectively, discussed the different categories of services provided and how employee time should be reported, they do not provide any pricing terms or escalation rates. Interrog. Resp. RSR-157, Att. 27, pp. 3,15; Att. 25, pp. 1–2, 5–6, 11–15. Moreover, the Company did not provide MSAs for several entities that charged time to the line item in question during the Test Year, including RGE, New York State Electric & Gas Corporation, and Central Maine Power Company. Therefore, the Authority concludes that the Company has not demonstrated that the $63,145 inflation adjustment represents a reasonable known and measurable adjustment from the Company's Test Year expense. Accordingly, the Authority permits the Company to recover $529,709 in expenses related to services performed by affiliates for the Rate Year, which deducts the rate case expenses and inflation adjustment from the Company's proposed Rate Year expenses.

5. Outside Services – Professional Services

The Company proposes $10,909,253 in professional services expenses, which is the Company's $9,819,426 Test Year amount plus a $1,089,827 pro forma adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06. The Company states that its professional service expenses consist of various professional and legal services performed by outside contractors. Ex. UI-RRP-1, p. 63. The Authority permits the Company to recover $7,340,341 in professional service expenses in the Rate Year. The table below summarizes the approved professional services expenses for the Rate Year.

Table 41: Approved Outside Professional Services Expenses

Expense	Requested ($)	Adjustment ($)	Approved ($)
Professional Services	230,117	(17,336)	212,781
Operational SmartGrids	5,101,497	(345,734)	4,755,763
Process & Technology	1,165,553	(281,007)	884,546
Audit	1,124,867	(604,806)	520,061
Facilities Maintenance	457,968	(344,452)	$113,516
IT, Security & Safety	665,826	(152,451)	513,375
Services Performed by Affiliates	2,700	(203)	2,497
Electric Vehicles[63]	-	-	-
Legal	2,160,726	(1,822,923)	337,803
Total	**10,909,253**	**(3,568,912)**	**7,340,341**

Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06.

[63]The Company indicated that it removed electric vehicle program expenses from the professional services line items because it recovers such costs outside of base rates and does not expect costs to recur in the line item in the Rate Year. Sch. WP C-3.06, n.4.

a. Professional Services

The Company proposes $230,117 in professional services expenses for the Rate Year, which is the Company's $1,172,211 Test Year expense minus a ($959,430)[64] pro forma adjustment, plus a $17,336 generic inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06. The Authority permits the Company to recover $212,781 in professional services in the Rate Year.

The Company's professional services line item consists of a variety of expenses that the Company deemed did not fit squarely within other line items in its rate application. See Hr'g Tr., 809:22–25, 810:11–17 (explaining generally how the Company assigns expenses from its income statement to its rate application). The Company, however, did not demonstrate that a generic inflation adjustment represents a reasonable known and measurable adjustment for the expenses in the Rate Year. Notably, the Company's expenses for its professional service line item have fluctuated between 2019 and 2023 ($700,802 in 2019; $2,154,613 in 2020; $422,261 in 2021; $1,395,399 in 2022; and $1,172,211 in the Test Year). Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.06 WP. Accordingly, the Authority does not permit the Company to recover $17,336 in an inflation adjustment for the Rate Year and instead permits the Company to recover $212,781, which is the Company's pro forma Test Year expense.

b. Operational Smart Grids

The Company proposes $5,101,497 in operational smart grid expenses for the Rate Year, which is the Company's $4,642,408 Test Year expense plus a $459,089 pro forma adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06. The Company's pro forma adjustment consists of a $170,000 reduction for nonrecurring outside service costs, a $580,000 increase for costs attributable to the Company's vendor, Landis & Gyr, and a $49,089 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06, n.2; Ex. UI-RRP-17D. The Authority permits the Company to recover $4,755,763 in operational smart grid expenses in the Rate Year.

A majority of the Company's expected Rate Year operational smart grid expenses are related to the Company's contract with Landis + Gyr to provide automatic meter reading (AMR) / Advanced Metering Infrastructure (AMI) meter reading services, which include upgrading, operating, and maintaining the head end systems and networks. Interrog. Resp. RRU-027. A contract is in place between Landis & Gyr and the Company that runs through the Rate Year. Interrog. Resp. RSR-308, Att.1. The Company's calculations in its Application applied a five percent inflation factor per year to its expenses related to its contract with Landis & Gyr. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06.[65]

[64]The Company states that the pro forma adjustments mostly relate to the removal of litigation costs associated with Docket No. 22-08-08 that it is not seeking recovery for in this proceeding. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06; Interrog. Resp RRU-26.

[65]The Company's calculations can be observed in an unlocked version of Late Filed Ex. 1.

Notably, however, the Company later provided escalation calculations for Landis & Gyr of 2.53% in 2024 and 2.33% in 2025.[66] Interrog. Resp. RSR-308, Att. 1.

The remainder of the Company's other operational smart grid expenses consist of items for which there are fixed price contracts in place for the Rate Year that do not provide for an escalation factor. Interrog. Resp. RSR-308, Att. 1. Accordingly, applying a standard inflation adjustment to the Rate Year expenses is inappropriate because it does not represent a known and measurable change to the Company's Rate Year expenses.

After adjusting the Landis & Gyr escalation rate for the Rate Year to match the Company's provided calculations and removing the Company's proposed inflation adjustments for the remainder of the Company's price-fixed contracts in place for the Rate Year, the Authority permits the Company to recover $4,755,763 in operational smart grid expenses in the Rate Year.

c. Process & Technology

The Company proposes $1,165,553 in process and technology expenses in the Rate Year, which is the Company's $884,546 Test Year expense plus $208,939 in expenses related to implementing a quality management system (QMS) and a $72,068 inflation adjustment for the Company's Test Year expenses. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06; Interrog. Resp. RRU-218. The Authority allows the Company to recover $884,546 in process and technology expenses.

The Company included $208,939 in Rate Year expenses that are allocated from Avangrid for implementing a QMS, which the Company states will create a standardized system to document, store, and control its internal processes, leading to improved Company effectiveness and efficiency. Sch. WP C-3.06; Interrog. Resp. RRU-029; Ex. UI-RRP-17E. The Company expects the project to span four years, although the Company has only begun "preliminary work" and has not begun incurring external expenses related to the QMS. Ex. UI-RRP-17E; Interrog. Resp. RRU-29. Moreover, the Company's projected Rate Year expenses appear to consist of internal labor costs for nine full-time equivalents (FTEs) employed by Avangrid or another affiliate. Ex. UI-RRP-17E Redacted, p. 3. Notably, the exhibit the Company provides in support of its QMS Rate Year expenses provides job descriptions of "ideal candidates" for the FTE position. Ex. UI-RRP-17E. Thus, the record does not indicate whether the Company has hired the FTEs to implement and support the QMS system and, if so, when the employees started and their corresponding compensation figures. Therefore, the Authority finds that the Company's Rate Year projected QMS system costs are speculative and do not meet the known and measurable standard; thus, they are not eligible for recovery in this proceeding. Accordingly, the Authority makes an adjustment to remove $208,939 in QMS system expenses from the Rate Year. For avoidance of doubt, the Authority is not

[66]The Company incorrectly asserts that the contract states the costs will escalate by inflation. UI Exceptions, p. 100. The 2.53% and 2.33% escalation figures the Company provided clearly indicate that the costs were not increased with the rate of inflation but were instead increased in accordance with the "lesser of" contract language publicly disclosed in the Company's interrogatory responses. Interrog. Resp RRU-027, Att. 1, p. 44.

rendering a prudency determination on the QMS project in this proceeding, and the Company, in its sole discretion, may proceed prudently with the project.

Additionally, the Company has failed to make an evidentiary showing that adjusting its Test Year process and technology expenses by a generic inflation factor constitutes a reasonable known and measurable change. In fact, the record demonstrates that the Company's process and technologies expenses have fluctuated since 2021; specifically, the Company reported expenses of $343,109 in 2021; $194,847 in 2022; and $884,546 in the Test Year.[67] Late Filed Ex. 1, Att. 2 Supp. Sch. WP C-3.06. As a result, the Authority does not permit the Company to recover a $72,068 inflation adjustment for process and technology expenses in the Rate Year.

In sum, the Authority permits the Company to recover $884,546 in process and technology expenses, which is the Company's proposed $1,165,553 less the $208,939 in QMS system expenses and the $72,068 inflation adjustment.

d. Audit Expense

The Company seeks to recover $1,124,867 in direct audit expenses for the Rate Year, which is the Company's $1,040,122 reported Test Year expense plus an $84,745 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06. The Authority considers the interests of the Company's shareholders and ratepayers to determine the appropriate level and structure of rates that will allow the Company to cover its necessary operating costs while ensuring just and reasonable rates. See General Statutes §§ 16-19(a), 16-19e(a). Accordingly, the Authority allows the Company to recover 50% of the Company's allocated audit expense, less the proposed $84,745 inflation factor, or $520,061 in Rate Year audit expenses.

The Company indicates that its audit expenses in Schedule WP C-3.06 are direct charges that consist of financial statement audits that the Company directly incurred or that were allocated to the Company. Interrog. Resp. RRU-214, Att. 1. The Company further posits that its FERC Form 1 filing, credit rating agencies, lenders in the Avangrid Revolving Credit Facility, and external investors that participate in long-term debt issuances require audited financial statements from UI. Interrog. Resp. RRU-359, p. 2. Additionally, the Company testified that KPMG has been selected as its auditor for 2025, but it does not have agreed upon fees or a draft engagement letter. Hr'g Tr., 854:13–16.

The Authority does not permit the Company to recover any portion of its proposed $84,745 inflation adjustment because it does not represent a known and measurable adjustment. As previously stated, the Company acknowledged that its audit expenses are set by contract, which it had yet to solidify in the Rate Year. Additionally, the Company indicated that its direct auditing expenses have largely been unchanged since 2021. Interrog. Resp. RRU-214, Att. 1. Accordingly, the Authority does not permit the Company to recover a $84,745 inflation adjustment for direct auditing expenses in the Rate Year.

[67]The Company's historical data indicates that the Company began tracking process and technology professional services expense as a distinct line item in 2024. Late Filed Ex. 1, Att. 2 Supp.

For the remainder of the Company's proposed $1,040,122 Rate Year direct audit expenses, the Authority, after balancing the relevant ratepayer and stakeholder interests, concludes that it is just and reasonable to include 50% of the Company's proposed allocated audit expense in rates, while the shareholders bear the expense of the remaining 50%. While the audit expenses may support debt financing for certain capital projects or other Company initiatives that benefit ratepayers, shareholders earn a reasonable rate of return from such capital projects as well. Moreover, the external auditors are accountable to the Company and Avangrid's board of directors, who represent the interest of Avangrid's shareholders. See Interrog. Resp. RRU-214, Att. 3, Redacted (indicating that auditor issues written reports to Avangrid's board of directors). Additionally, the auditing activities support investment from "external investors" as the Company identified, who utilize the audit information to inform investment decisions. Interrog. Resp. RRU-214, Att. 3. Accordingly, the Authority allows the Company to recover $520,061 for direct audit expenses in the Rate Year.

e. Facility Maintenance

The Company proposes a $457,968 facility maintenance expense in the Rate Year, which is the $423,466 Test Year expense plus a $34,502 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C.3.06. The Authority permits the Company to recover $113,516 in facility maintenance expenses, which removes $309,950 in nonrecurring fire suppression system repairs.

The Company states that its facilities maintenance costs are related to outside contractor costs UI incurs to maintain its facilities, such as snow removal, grounds maintenance, and trash removal. Interrog. Resp. RRU-219. Moreover, $418,751 of the Company's Rate Year costs relate to a line item entitled "SEC-Fire UI-D," which the Company states accounts for inspections, testing, and maintenance of fire detection and suppression systems as required by state and national fire codes, including repair work as needed. Interrog. Resp. RRU-219, Att. 1. Notably, the Company's expense for the line item has fluctuated between $66,137 in 2021, $69,950 in 2022, $392,299 in 2023, and $141,124 in 2024. Interrog. Resp. RRU-219, Att. 1. Further, the Company explained that, during the Test Year, the Company discovered a corroded pipe in its parking garage facility that resulted in $309,950 in repairs; the Company confirmed that such repairs did not occur in 2024. Interrog. Resp. RRU-305.

The Authority finds that the repairs the Company described were a nonrecurring cost that should have been removed from the Company's estimated Rate Year expenses. The Company's fluctuating facility maintenance expenses over a four-year period and its indication that it did not incur the same repair costs in 2024 as it did in 2023 demonstrate that the Company cannot predict whether it will incur similar repair costs stemming from a similar occurrence in the Rate Year and, therefore, such a projected expense does not meet the known and measurable standard. Accordingly, the Authority removes the $309,950 nonrecurring repair costs included in the Rate Year.

Additionally, the Authority finds that the Company did not meet its burden of demonstrating that applying a standard inflation adjustment to its Test Year facility maintenance expenses represents a reasonable known and measurable adjustment. As

previously stated, the Company's facilities maintenance expenses have fluctuated since 2021, indicating that such expenses are driven by other factors besides the rate of inflation. Interrog. Resp. RRU-219, Att. 1. Accordingly, the Authority permits the Company to recover $113,516 in facilities maintenance expenses for the Rate Year, which is the Company's proposed $457,968 expense minus the $309,950 nonrecurring repair costs and the $34,502 inflation adjustment.

f. IT, Security, & Safety

The Company proposes $665,826 in Rate Year IT, security, and safety expenses, which is the Company's $615,665 Test Year expense plus a $50,161 inflation adjustment. Sch. WP C-3.06. The Authority permits the Company to recover $513,375 in the Rate Year for IT, security, and safety expenses.

The Company explains that its IT, security, and safety expenses are related to outside contractor costs incurred for the safety and security of UI's employees, assets, and IT. Interrog. Resp. RRU-220. The Company's reported expenses include a line item entitled "SEC-Guards UI-D" that relates to staffing contracted security guards at UI facility locations. Interrog. Resp. RRU-220. Notably, the Company's expenses for the line item have fluctuated between $361,625 in 2021, $229,276 in 2022, $534,776 in 2023, and $189,707 as of September 2024. Interrog. Resp. RRU-220, Att. 1. The Company indicated that its increase in its Rate Year expense for the line item was related to staffing two security guards at the Company's 180 Marsh Hill Road location, but that it has since reduced staffing back to one security guard. Interrog. Resp. RRU-307.

The Authority finds that the additional expense for staffing a second security guard at the 180 Marsh Hill Road location in the Test Year is a nonrecurring expense that should be removed from the Company's projected Rate Year expenses. The Company indicated that it made payments of $51,921 and $50,369 for an additional security guard in the Test Year. Interrog. Resp. RRU-388.[68] Accordingly, the Authority disallows $110,565 in nonrecurring expenses, which is the $102,290 sum of the invoices for an additional security guard ($51,921 + $50,369=$102,290) and $8,337 in Rate Year inflation of the nonrecurring expense ($102,290 x .0815=$8,337). Additionally, the Company did not demonstrate that increasing its Rate Year IT, security, and safety expenses by a generic inflation factor is a known and measurable adjustment to its Test Year expenses; to the contrary, the Company's historical expenses have fluctuated from year to year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06. As such, the Authority does not permit the Company to recover $41,824 in Rate Year inflation adjustments, which is the Company's $50,161 inflation adjustment minus the $8,337 inflation adjustment already applied to the Company's nonrecurring security guard expense. In total, the Authority permits the Company to recover $513,375 in Rate Year IT, security, and safety expenses.

[68]The Company indicated that $50,369 of billings were related to 2022 expenses that were recorded in 2023 due to delayed contractor invoicing. Interrog. Resp. RRU-338.

g. Services Performed by Affiliates

The Company proposes that it recover $2,700 in services performed by affiliates, which is the Company's $34,696 Rate Year expense, a ($32,199) pro forma adjustment, plus a $203 generic inflation adjustment. The Company did not demonstrate that increasing its Rate Year expenses by the generic inflation factor is a known and measurable change and, as such, the Authority permits the Company to recover $2,497 for services performed by affiliates in the Rate Year, less the inflation amount.

h. Legal Expense

The Company proposes that it recover $2,160,726 in the Rate Year for legal expenses, which is the Company's $2,669,579 Test Year expense, a ($671,637)[69] pro forma adjustment, and a $162,784 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06. The Authority allows the Company to recover $337,803 in legal expenses in the Rate Year.

The Company calculated its Rate Year legal expenses by taking the sum of its Test Year legal vendor expenses for various matters, making various pro forma adjustments to remove costs related to certain matters, and inflating the adjusted Test Year expenses by the Company's standard inflation factor. Interrog. Resp. RRU-222 Supp., Att. 1. The Company's proposed Rate Year expenses, however, contain various nonrecurring expenses from the Test Year, project Rate Year expenses that do not meet the known and measurable standard or have not been demonstrated to be prudent, and presume legal expenses barred from recovery by statute are nonetheless recoverable.

The Company identified various legal matters that were resolved prior to the Rate Year but were nonetheless included in the Company's proposed revenue requirement.[70] Moreover, the Company included costs in the Rate Year related to its appeal of Docket No. 20-08-03, Investigation Into Electric Distribution Companies' Preparation for and Response to Tropical Storm Isaias, which was already resolved by the Connecticut Supreme Court. See United Illuminating v. Public Utilities Regulatory Authority, 350 Conn. 66 (2024); Interrog. Resp. RRU-222, Att. 1. Such expenses, therefore, should not be included in the Company's projected Rate Year legal costs because the Company did not assert nor provide any evidence that legal fees related to the matters would be incurred in the Rate Year. Interrog. Resp. ADJ-001; Interrog. Resp. ADJ-002. The Company also included legal fees in the Rate Year for filing an interim rate request in Docket No. 22-08-08, which has already been completed, and the Company did not assert additional

[69]The Company's pro forma adjustments removed English Station litigation costs and costs related to Docket No. 22-08-08, excluding the costs of appealing the 22-08-08 Decision. Interrog. Resp. RRU-222 Supp., Att. 1; Interrog. Resp. ADJ-003.

[70]Specifically, the Company stated that the following matters were resolved before the beginning of the Rate Year: UI v. Cazarin, Luis *et al.*; UI v. Romeo Simeone *et al.*; Lemmo v. UI *et al.*; Wols-Pawlak v. UI; Oakley v. UIL Holdings Corp; Gillette v. UI *et al.*; Simkes v. UI *et al.*; Jefferson Solar v. FuelCell Energy *et al.*; *Allco Finance Ltd. et al.*; and UI v. Whiting-Turner Contracting Co. Late Filed Ex. 44, Interrog. Resp. ADJ-001; Interrog. Resp. ADJ-002; Hr'g Tr., May 1, 2025, 904:17-25.

expenses in connection with the request that would be incurred in the Rate Year. Interrog. Resp. RRU-222 Supp., Att. 1.

Additionally, the Company included $1,296,567 in Rate Year expenses for the Company's appeal of the 22-08-08 Decision.[71] Interrog. Resp. RRU-222, Supp, Att. 1. The Company ostensibly included such expenses in the Rate Year because of its assertion that its appellate expenses are "necessary to correct erroneous, unlawful or unwarranted legal outcomes that affect the Company's ability to provide safe and reliable service to customers and meet its underlying public-service obligation." Interrog. Resp. OCC-561.

The Company has already litigated an administrative appeal of the 22-08-08 Decision, in which the Superior Court largely rejected the Company's assertions that the 22-08-08 Decision was legally flawed. United Illuminating Company v. Public Utilities Regulatory Authority, Superior Court, Judicial District of New Britain, Docket No. HHB-CV-23-6081616-S (Mar. 13, 2025) (dismissing the Company's appeal with respect to all claims except for a two basis point reduction to the Company's allowed ROE and the disallowance of non-industry dues expenses). As such, the Company's expenses to litigate an appeal of the 22-08-08 Decision before the Superior Court are nonrecurring expenses that will not reoccur in the Rate Year.

Notably, the Company has also appealed the Superior Court's decision to the Connecticut Appellate Court. See Docket No. HHB-CV-23-6081616-S, Entry No. 133.00, Mar. 28, 2025. To the extent the Company's application can be construed to recover further appellate expenses in connection with Docket No. 22-08-08 in the Rate Year, the Company has not met its burden of demonstrating that such costs are known and measurable and prudent. Indeed, the Company simply projected its Docket No. 22-08-08 Superior Court appellate expenses into the Rate Year and made a generic inflation adjustment and did not engage in an analysis of what its expected Rate Year legal expenses would be to bring an appeal before the Connecticut Appellate Court. The Company provided a description of the services rendered in connection with the appeal of the 22-08-08 Decision, which included reviewing and analyzing the administrative record, and preparing the administrative record; all tasks that would be duplicative in an appeal to the Connecticut Appellate Court. Interrog. Resp. RRU-033, Att. 1. Additionally, the Company indicated that several different law firms performed the same services, without providing evidence to support the rationale for engaging multiple law firms to perform the same or similar tasks. Interrog. Resp. RRU-033, Att. 1.

Furthermore, although ambiguous in the Company's Application, to the extent the Company is utilizing its appellate expenses in connection with Docket No. 22-08-08 as a proxy for Rate Year expenses connected with future appeals of the Authority's rate case decisions, the Company is barred from recovering such future appellate expenses under General Statutes § 16-243p(b), which states in relevant part "[f]or any rate proceeding

[71]The Authority derived this figure by updating the Company's reported Rate Year expenses to reflect its updated proposed generic inflation rate. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.19 WP, p. 3 Updated; Interrog. Resp. RRU-222 Supp., Att. 1.

initiated on or after January 1, 2024, no electric distribution company. . . shall recover through rates its direct or indirect costs associated with its attendance in, participation in, preparation for, or appeal of such proceeding" (emphasis added).

Finally, the Company did not demonstrate that applying a generic inflation adjustment to its Test Year expenses serves as a reasonable known and measurable adjustment for its projected Rate Year expenses. To the contrary, the Company's legal expenses have fluctuated between 2019 and the Test Year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.06.

In sum, the Authority permits the Company to recover $337,803 in Rate Year legal expenses, which is the Company's $2,160,726 requested Rate Year expense less $1,296,567 in Docket No. 22-08-08 appellate expenses, $495,896 in nonrecurring legal expenses,[72] and $30,460 ($2,160,726 - $1,296,567 - $495,896 = $368,263; $368,263 x 8.15% = $30,013) in generic inflation adjustments of the remaining Rate Year expenses.

6. Outside Services– Line Clearance

The Company proposes $16,660,423 in line clearance expenses, which is the Company's $15,405,272 Test Year expense plus a $1,255,151 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.05; Interrog. Resp. RSR-148, p. 2. The Company's outside line clearance expenses relate to outside contractor costs for its utility protection zone (UPZ) and reliability maintenance (RM) programs. Id. The Authority allows the Company to recover $15,834,389 in outside line clearance expenses. The below table delineates between approved UPZ and RM expenses for the Rate Year.

Table 42: Approved Outside Line Clearance Expense

Expense	Proposed ($)	Adjustment ($)	Approved ($)
UPZ Protection Zone	15,197,098	(840,308)	14,356,790
Reliability Maintenance	1,463,325	14,274	1,477,599
Total	**16,660,423**	**(826,034)**	**15,834,389**

Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.05.

i. UPZ Expense

The Company proposes $15,197,098 in UPZ expenses for the Rate Year, which is the Company's $14,052,190 Test Year expense plus a $1,144,908 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp.; Interrog. Resp. RSR-148, p. 2. The Authority allows $14,356,790 in UPZ expenses for the Rate Year.

[72]Specifically, the Authority removed projected Rate Year expenses for nonrecurring expenses in connection with the following matters: UI v. Cazarin, Luis *et al.*; UI v. Romeo Simeone *et al.*; UI v. Whitting-Turner Contracting Co.; Lemmo v. UI *et al.*; Jefferson Solar v. FuelCell Energy *et al.*; Allco Finance Ltd. *et al.*; the Company's interim rate application in Docket No. 22-08-08, and appellate costs in relation to Docket No. 20-08-03. Late Filed Ex. 44, Interrog. Resp. ADJ-001; Interrog. Resp. ADJ-002; Hr'g Tr., 904:17–25.

The Company states that its UPZ program has been in place since 2014 and seeks to clear all trees and limbs that have the potential to impact utility infrastructure in a rectangular area extending horizontally for a distance of eight feet from any outermost electrical conductor or wire installed from pole to pole and vertically from the ground to the sky. Application, Ex. UI-EOP-1, p. 44. In the Company's last rate case, the Authority directed the Company to implement a new sequence of trimming priorities in the UPZ program and to develop a four-year work plan (2024-2027) to implement the new trimming priorities (UPZ Plan).[73] 22-08-08 Decision, pp. 176, 286. More specifically, the Authority indicated that the UPZ must demonstrate planned work for the identified trimming priorities, including a budget, mileage planned, and cost per mile. 22-08-08 Decision, p. 177. The Authority subsequently determined that the Company's UPZ plan complied with direction given in the 22-08-08 Decision. Motion No. 5 Ruling, Oct. 27, 2023, Docket No. 23-08-09, Annual Electric Distribution Company and Reliability and Resiliency Framework Review.

The Company utilizes two contractors to carry out its UPZ Plan work, both of which have contracts in place with the Company through the Rate Year. Hr'g Tr., 694:6–13. Moreover, the Company has on average from 2021-2024 exceeded planned UPZ miles trimmed goals for single-phase and three-phase circuits as set forth in the UPZ Plan. Interrog. Resp RSR-23; Interrog. Resp. OCC-698. Over the same period, the Authority's analysis of the reported data indicates that the Company has also met or improved on the cost per mile target figures given in the UPZ plan, with the cost per mile for the three-phase portion of the UPZ exceeding the UPZ Plan estimates by 0.5% and the cost per mile for single-phase estimates by 5.7%. Interrog. Resp RSR-23; Interrog. Resp. OCC-698. Therefore, the Company's UPZ miles trimmed projections and cost estimates contemplated in the UPZ Plan serve as a reasonable estimate for the UPZ miles that will be completed in the Rate Year.

The UPZ Plan estimates that the Company will incur UPZ expenses of $14,342,000 in 2025, $14,356,780 in 2026, and $14,371,513 in 2027, which the Company indicated were contingent on finalized contractor bids. Ex. UI-EOP-2, p. 10. The Authority concludes that it is inappropriate to apply a generic inflation factor to the Company's projected UPZ Rate Year expenses because the Company has contracts for such services in place for the Rate Year and the estimated UPZ miles to be completed in the Rate Year in accordance with the UPZ Plan represents a reasonable known and measurable adjustment, rather than a generic inflation factor. Moreover, the Company did not provide an explanation for why the generic inflation factor was the only reasonable method to determine its Rate Year UPZ expense, particularly since it already engaged in an analysis of projected UPZ costs by projecting its cost per mile by year in the UPZ Plan. Accordingly, the Authority permits the Company to recover $14,356,780 in Rate Year UPZ

[73]The Authority identified three new trimming priorities: (1) transition to a four-year trimming cycle while maintaining UPZ clearance specification in areas already addressed in the UPZ; (2) apply UPZ specifications to areas on the single-phase distribution system that have not already been addressed; and (3) complete a second pass on the three-phase distribution system to achieve full UPZ clearance in those areas. 22-08-08 Decision, p. 176.

expense, which represents the Company's Rate Year expenses as reported in the Company's UPZ Plan.

ii. RM Expense

The Company proposes $1,463,325 in RM expenses for the Rate Year, which is the Company's $1,353,082 Test Year expense plus a $128,243 inflation adjustment. The Authority allows $1,477,599 in RM expense for the Rate Year.

The Company states that its RM program is independent of the UPZ program and is intended to address hazardous conditions, such as hazardous trees and direct tree contact with conductors, or to address customer requests. Ex. UI-EOP-2, p. 11. The Company utilizes two vendors in place through the Rate Year that work on the RM program. Interrog. Resp. RSR-68, Att. 4. Importantly, each of the relevant contracts contain a yearly escalation factor, including "Hot Spot" and time and material work that falls within the purview of the RM program. Interrog. Resp. RSR-68, Att. 1, Sec. D, pp. 63–65; Hr'g Tr., 697:13–21. Accordingly, the Authority finds that inflating the Company's RM expenses by a generic inflation factor is inappropriate because the Company did not prove that using such a factor is the only reasonable method to determine its Rate Year expense, particularly since there are contracts in place for the Rate Year with established escalation factors. Nonetheless, the Authority's own analysis of the operative contract terms indicates that, by averaging the escalation factors of the two vendors provided for in the contracts in place for the Rate Year, the Company may reasonably incur $1,477,599 in RM expenses for the Rate Year.[74] Interrog. Resp. RSR-68, Att. 4.

7. Storm Expense

The Company proposes $6,623,074 in storm expenses for the Rate Year, which is the Company's $9,531,643 Test Year amount less a $2,908,569 Test Year pro forma adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.07. The Company's proposed Rate Year storm expenses consist of $2,919,689 in minor storm expenses, a $1,644,951 Handy Whitman adjustment,[75] $14,844 in major storm expenses, and a $2,000,000 allowance for annual storm reserve. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.07a. The Authority allows the Company to recover $6,188,125 in storm expenses for the Rate Year.

Previously the Company accounted for minor and major storm expenses, as well as mutual aid expenses and reimbursements, according to the nature of the underlying expenses (e.g., outside contractors were reflected on a schedule related to outside services). Revenue Requirements Panel Rebuttal PFT, p. 68; Interrog. Resp. RSR-3, Att. 1. In its Application, the Company has consolidated all storm activity onto newly created

[74]The Company provided the escalation rates utilized to calculate the $1,477,599 figure under protective cover and, thus, are not disclosed herein.

[75]"The Handy-Whitman Index is an industry-standard index used to reflect prior utility construction costs in current dollars and is appropriate to both capital projects and O&M costs, such as those costs incurred during storms. . . . The Handy-Whitman Index is updated biannually (on July 1 and January 1) and has an index specific to North Atlantic utilities." 22-08-08 Decision, p. 152 (citations omitted).

and standalone Schedule C-3.07, Storm Expenses and Mutual Aid. Revenue Requirements Panel Rebuttal PFT, p. 68.

The table below shows the various Storm Expense line items where there is a proposed rate year impact.

Table 43: Company Proposed Storm Expenses

Category	Test Year ($)	Proposed Rate Year ($)
Minor Storm	4,648,421	2,919,689
Minor Storm Labor	441,748	-
Handy Whitman Adjustment	-	1,644,951
Major Storm	1,111,315	14,844
Storm Reserve	2,000,000	2,000,000
Total	**8,201,484**	**6,579,484**

Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.07a.

The minor storm cost category reflects costs incurred by UI to respond to non-major storms. In 2013, the Authority established a threshold to distinguish "normal" storms from storms that are catastrophic and require large pay outs (major storms). 13-01-19 Decision, pp. 28–29. At that time, the major storm costs threshold was set at $1 million. If incremental storm costs[76] reach that major storm threshold, then that storm is classified as a major storm, and all of the total incremental storm costs for that event may be deferred for recovery in a storm regulatory asset. 13-01-19 Decision, pp. 33–34. In the 16-06-04 Decision, the Authority added pre-staging or "lean-in" costs to the type of expenses allowable for deferred accounting. 16-06-04 Decision, p. 110.

In the 22-08-08 Decision, to ensure the major storm threshold remained reflective of actual utility costs and captures only catastrophic storm costs, the Authority increased the major storm threshold by using the Handy-Whitman Index for utilities in the North Atlantic region to convert July 1, 2013 dollars to July 1, 2022 dollars. 22-08-08 Decision, p. 152. Accordingly, beginning in 2023, the Authority set the major storm threshold for charging storms to the reserve at $1.43 million. Id., p. 153. The Authority directed UI to apply the Handy-Whitman index on an ongoing basis with each biannual release of the index on January 1 and July 1, to update its major storm threshold each January 1 and July 1 accordingly, and to retain documentation demonstrating it applied the Handy-Whitman Index when it next requests recovery of major storm costs in the storm reserve. Id.

[76]Here, incremental storm costs refer to costs incurred outside of base rates such as costs for external lineworkers and their travel and lodging to respond to that specific event. In other words, incremental storm costs are expenses that are not normal business operations. 13-01-19 Decision, p. 33. Non-incremental storm costs refer to internal labor hours and overheads that are already included in base distribution rates. Id.

The Company states that the most recent threshold as of the filing of their application is $1.924 million based on the most recently published Handy-Whitman Index value. Revenue Requirements Panel Rebuttal PFT, p. 65. If a storm's expenses rise above that threshold, it is considered a major storm and is handled instead as a storm deferral expense. See infra, Section VI.A.17.f., New Storm Deferral.

a. Discrepancy Between Schedule C-3.07 and C-3.07 WP

Schedule C-3.07 provides a Rate Year amount of $6,623,074, but the total Rate Year amount supported by the work papers totals only $6,579,483, a difference of $43,591. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.07 and Sch. 3.07 WP. Since the Rate Year amount of $6,623,074 in Schedule C-3.07 is unsupported by the work papers, and since there is no explanation in the record justifying the difference, the Authority reduces the overall requested Rate Year amount for Schedule C-3.07 by $43,591.

b. Minor Storms

The Company proposes a Rate Year cost of $2,919,689 in minor storm expenses. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.07a. UI derived this value by taking a three-year average of its minor storm costs over the period of 2021–2023. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.07a, n. 2.

The Authority reviewed the actual incurred minor storm costs reported by UI during the period of 2021–2023 (which includes the Test Year). The Authority disallows some of the costs associated with external labor expenses. The Company incurred external labor expenses of $945,600 in 2021; $612,116 in 2022; and $864,049 in 2023. Interrog. Resp. RSR-166, Att. 1. According to the Company, it validates external labor invoices by requesting timesheets to confirm labor and equipment time, and receipts related to meals, lodging, and fuel. Application, Ex. RRP-15, p. 7. After the Tropical Storm Isaias Decision, the Company instituted the Contractor Daily Time & Work Report. See Interrog. Resp. RSR-162. The Company provided time sheets and corresponding invoices totaling approximately $55,834 for external labor expenses in 2022. Interrog. Resp. RSR-162, Atts. 1 & 2. Additionally, the Company provided timesheets and corresponding invoices totaling approximately $288,069 for external labor expenses in 2023. Id. However, the Company did not follow its own accounting practices and failed to provide timesheets and corresponding invoices for the remaining external labor expenses over the period of 2022–2023. Therefore, the Authority is unable to verify approximately $1,132,097 in external labor expenses from 2022 and2023. As such, the Authority disallows $556,166 external labor expenses for calendar year 2022 and $575,931 in external labor expenses for calendar year 2023. The table below shows the new corrected minor storms costs after these disallowances.

Table 44: Minor Storm Costs, 2021–2023

Year	Proposed[77] ($)	Adjustment ($)	Adjusted ($)
2021	2,631,028	-	2,631,028
2022	1,480,076	(556,166)	923,910
2023	4,650,516	(575,931)	4,074,585
Average	**2,920,540**		**2,543,174**

Interrog. Resp. RSR-166, Att. 1.

Accordingly, the new three-year average of supported minor storm costs to be used for the Rate Year is, $2,543,174 (2,631,028 + 923,910 + 4,074,585 / 3).

c. Major Storms

The Company states that there is no incremental major storm activity, either expense or deferral, reflected in the Rate Year on Schedule C-3.07a; however, it reflects a $14,844 Rate Year expense for major storms in this Schedule. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.07a, n. 4; Revenue Requirements Panel Rebuttal PFT, p. 66.

The anticipated Rate Year expense is based on a Test Year major storm expense of $1,111,315. Late Filed Ex. 1, Att. 2 Supp., C-3.07a. UI made a pro forma adjustment to reduce the Test Year amount by $1,097,589 because incremental major storm costs are recovered through UI's storm deferral. Id., n.4. UI, however, failed to remove the full Test Year amount resulting in a Rate Year expense of $14,844 (after factoring standard inflation factor). Late Filed Ex. 1, Att. 2 Supp., C-3.07a.

Non-incremental major storm expenses – such as standard labor, allocated overheads, and travel – may be included for recovery in base rates. See 13-01-19 Decision, pp. 31–34; see also supra, Section VI.A.7, Storm Expense (describing incremental storm expenses). However, UI has failed to provide support in the record that validates these costs as non-incremental and related to storms. In Schedule C-3.07a, UI correctly identifies and removes from the major storm Rate Year amount the non-incremental labor because base labor expenses are already reflected in Schedules C-3.15 and C-3.16. Late Filed Ex. 1, Att. 2 Supp., C-3.07a, n.5. The $14,844 Rate Year request should not include any labor costs. However, the exhibit provided by UI in support of the costs include both (1) labor costs and (2) costs apparently incurred in 2022 (i.e., the year prior to the Test Year). See Interrog. Resp. EOE-170, Att. 1. Based on the information provided by UI, the Authority cannot validate the source of the costs to determine whether they are properly recoverable as non-incremental "major storm" expenses in the Rate Year.

[77]Note that the 2021–2023 average proposed minor storm costs in this table ($2,920,540) do not match what is proposed in Late Filed Exhibit 1, Attachment 2 Supplement, Schedule C-3.07a ($2,919,689). The Authority elects to use the costs reported in Interrogatory Response RSR-166, Attachment 1, to determine the adjusted amount.

Accordingly, the Authority disallows $14,844 in major storm expenses. The Company already can access an established cost recovery mechanism of recovering costs from major storms through its major storm deferral. Revenue Requirements Panel Rebuttal PFT, p. 66. Allowing $14,844 in rates for major storms would constitute double recovery.

d. Storm Reserve

Lastly, the Company is not requesting any changes to its $2,000,000 storm reserve currently collected in rates to offset major storm expenses. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.07a; Revenue Requirements Panel Rebuttal PFT, p. 66. The Authority approves the continued collection of $2,000,000 for the Company's storm reserve.

The primary purpose of the storm reserve has always been to help mitigate rate shocks that are often associated with the accrual of significant storm recovery costs. 22-08-08 Decision, p. 151. The storm reserve accrual is also useful to the extent that it encourages UI to prepare for potential storms by leaning in; thus, the reserve should not be eliminated altogether. Id., p. 151. The Company incurred $1,083,000 in lean-in costs for the Test Year that it charged to its storm reserve. Application, Ex. UI-RRP-22C, p. 3. Therefore, the reserve remains effective in encouraging UI to prepare for storms. Accordingly, the Authority approves the continuation of the $2,000,000 annual storm reserve accrual.

e. Summary of Allowed Storm-related Expenses

As explained in the preceding sections and summarized in the table below, the Authority approves $6,188,125 of storm expenses.

Table 45: Approved Storm Expenses Summary

	Proposed Rate Year ($)	Adjustment ($)	Approved ($)
Schedule C-3.07 Discrepancy	43,591	(43,591)	-
Minor Storm	2,919,689	(376,514)	2,543,174
Handy-Whitman Adjustment	1,644,951	-	1,644,951
Major Storm	14,844	(14,844)	-
Storm Deferral	2,000,000	-	2,000,000
Total	**6,623,074**	**(434,949)**	**6,188,125**

8. Environmental Remediation Expense

The Company proposes to recover $3,800,144 in environmental remediation expenses, which is comprised of: the Company's $1,331,269 Test Year Expense; as well as a ($1,130,863) pro forma adjustment to eliminate English Station remediation costs barred from recovery, to eliminate East Shore deferral activities recorded in the Test Year, and to remove historical provision costs from the Rate Year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.08. Additionally, the Company's proposed Rate Year expense includes a $3,744,144 adjustment for East Shore recovery activities, and $56,000 for groundwater monitoring and reporting expenses for the Company's Bridgeport Avenue site. Late Filed

Ex. 1, Att. 2 Supp., Sch. WP C-3.08. The Authority permits the Company to recover $3,800,144 in environmental remediation costs for the Rate Year.

a. East Shore

The Company proposes that it recover $3,744,144 in projected East Shore remediation expenses in the Rate Year, which represents half of the Company's expected $7,488,288 Rate Year expenses to conduct remediation activities at the East Shore site. Ex. UI-ERP-1, pp. 11–12. The Company posits that permitting recovery of half of its Rate Year expenses will offset the deferral balance the Company is permitted to record according to the 22-08-08 Decision. Ex. UI-ERP-1, p. 11. The Authority permits the Company to recover its projected East Shore remediation expenses for the Rate Year, and the Company may continue to defer the accounting of its additional East Shore remediation costs as previously authorized in the Company's last rate case. 22-08-08 Decision, p. 190.

The East Shore site is a decommissioned manufactured gas plant located in New Haven that was originally developed in the 1920s. Ex. UI-ERP-1, p. 9. The Company purchased the site in 1958, although the plant buildings were operated and owned by the previous landowner until July 1968. Ex. UI-ERP-1, p. 9. Presently, the Company uses the property for equipment storage and contractor laydown. Ex. UI-RRP-1, p. 9.

The Company is now conducting remediation activities on the site in accordance with the Connecticut Voluntary Remediation Program under General Statutes § 22a-133x, the DEEP Remediation Standard Regulations under Conn. Agencies Regs. §§ 22a-133k-1-3, the Connecticut Significant Environmental Hazard (SHE) rules under General Statutes § 22a-6u, and the Federal Toxic Substances Control Act. Ex. UI-ERP-1, pp. 9–10. Specifically, the Company expects that its SIR activities on the site will include soil excavation, offsite disposal, installation of an engineered control, and site restoration, in addition to support activities that include permitting, contractor oversight, and preparation of a final report. Ex. UI-ERP-1, p. 11.

The Authority previously permitted the Company to use deferred accounting for East Shore Project expenses starting with the 2023/2024 Rate Year, subject to a prudency review in the Company's next rate proceeding, although the Authority explicitly denied the recovery of carrying charges on the deferred expenses. 22-08-08 Decision, p. 190.

In this proceeding, the Company seeks recovery of $3,744,144, or half of the amount of expected Rate Year East Shore expenses outside of its proposed deferral. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.08, WP C-3.21. The Company states that it expected to commence a competitive RFP process for a contractor and to complete an Engineered Control application by the end of 2024, and to engage in remedial field work in 2025 and 2026, including soil removal, groundwater monitoring, and engineered controls and controls, as well as completing a Remedial Action Report following field work. Ex. UI-ERP-4, p. 29; Ex. UI-ERP-1, p. 11. The Company further asserts that it has retained Arcadis to provide environmental, consulting, and engineering services and expects the competitive bid process for a remediation contractor, to be complete in the third quarter of 2025. Ex. UI-ERP-1, pp. 11–12; Interrog. Resp. OCC-705, Att. 1, p. 3.

. The Authority finds that it is reasonable to conclude that various East Shore remediation activities will occur in the Rate Year. Indeed, the Company's submitted timeline suggests that a majority of its remediation activities will take place between the fourth quarter of 2025 and fourth quarter of 2026. Ex. UI-ERP-1; Interrog. Resp. OCC-752. Moreover, permitting the Company to recover certain East Shore remediation expenses likely to occur in the Rate Year will reduce the East Shore deferral balance and better align the timing of the remediation activities and cost recovery from ratepayers. Interrog. Resp. OCC-752. As such, the Authority permits the Company to recover $3,744,144 in East Shore remediation expenses in the Rate Year, and the Company may continue to utilize deferred accounting to track the remainder of its East Shore remediation expenses as set forth in the 22-08-08 Decision. Any such deferred expenses shall be subject to a prudency review in the Company's next distribution rate case; the Authority's direction regarding the denial of carrying charges on the deferred expenses remains.

b. Bridgeport Avenue

The Company proposes to recover $56,000 in Rate Year expenses related to monitoring and reporting obligations for the Company's Bridgeport Avenue site, which is the Company's $41,591 Test Year expense plus a $14,409 adjustment to account for expanded testing requirements. Sch. WP C-3.08; Ex. UI-ERP-1, p. 14. The Authority permits the Company to recover $56,000 in the Rate Year.

The Company sold the Bridgeport Avenue property in 2018, but as a condition of the sale must conduct post remedial groundwater monitoring for petroleum constituents pursuant to the Connecticut Transfer Act, General Statutes §§ 22a-134 *et seq*. Ex. UI-ERP-1, pp. 12-13. UI retained HRP Associates, Inc. (HRP) as a licensed environmental professional to conduct monitoring services. Ex. UI-ERP-1, p. 13. HRP conducted an initial sampling that utilized an alternative groundwater monitoring process, which was accepted by DEEP, which found that the contaminates are likely within DEEP regulation standards and would render further testing unnecessary beyond the Rate Year. Interrog. Resp. RSR-71, Att. 1, p. 1; Ex. UI-ERP-1, p. 13. Accordingly, the Company states that HRP will conduct additional groundwater monitoring and develop a final verification report.

The Authority finds that the testing costs to be incurred in the Rate Year are reasonable, particularly since pursuing HRP's alternative testing methodology may eliminate the need for the Company to conduct further groundwater monitoring activities on the Bridgeport Avenue site. Thus, the Authority permits the Company to recover $56,000 in Rate Year expenses related to Bridgeport Avenue monitoring and reporting obligations.

9. Computer Expense

The Company proposes $4,702,214 in computer expenses for the Rate Year, which is the Company's $3,710,906 Test Year expense plus a $991,308 pro forma adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP-C-3.09. The Company categorizes its computer expenses as operational smart grid (OSG), customer service, and software

licensing expenses. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.0. The Authority allows the Company to recover $4,180,918 in the Rate Year for computer expenses. The table below provides the approved computer expenses by category for the Rate Year.

Table 46: Approved Computer Expenses

Expense	Proposed Rate Year ($)	Adjustment ($)	Approved ($)
Operational Smart Grids	2,608,107	(144,584)	2,463,523
Customer Service	607,663	(198,262)	409,401
Software Licensing	1,486,444	(178,450)	1,307,994
Total	**4,702,214**	**(521,296)**	**4,180,918**

a. Operational Smart Grids

The Company proposes $2,608,107 in OSG expenses for the Rate Year, which is the Company's $1,774,562 Test Year expense plus a $833,545 Rate Year adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.09 WP. The Test Year and Rate Year expense for the OSG category include cybersecurity prepaid agreements and software licenses with third-party vendors. See Interrog. Resp. RSR-47, Att. 1 (showing a list of all vendors). The $833,544 Rate Year adjustment includes new anticipated costs for "prepaid expense for Cybersecurity software and licensing agreements . . . and . . . Software related cost increases." Late Filed Ex. 1, Att. 2 Supp., n.1. The Rate Year adjustment also includes a generic inflation factor applied to certain Test Year contracts. See Interrog. Resp. RSR-47, Att. 1.

The Authority reviewed the Test Year costs and finds that $1,774,562 of costs were reasonably incurred and that those contracts and agreements are expected to continue in the Rate Year. The evidentiary record, however, indicates that UI's Rate Year expenses are inflated because the Company (1) does not provide support for a number of new Rate Year expenses and (2) inappropriately applies a generic inflation factor to Test Year expenses.

Regarding the first item, the Company only demonstrates known and measurable incremental Rate Year costs of $297,512 for cybersecurity prepaid agreements and $391,449 for software licenses. Interrog. Resp. RSR-47, Att. 1. Total new OSG Rate Year agreements and licenses therefore equal $688,961 ($297,512 + $391,449).

A review of the prepaid agreements and software licenses indicates that UI's application of an inflation factor to the Test Year costs is inappropriate. Importantly, 57 of the 62 agreements have fixed cost pricing terms (i.e., there are no contractual escalation rates) through the Rate Year. Interrog. Resp. RSR-144, Att. 1. For the remaining five agreements, there is no evidence in the record to suggest that the cost of the licenses at issue will increase with the rate of inflation (or at all). Interrog. Resp. RSR-144, Att. 1 (UI indicating "N/A" or "TBD" for annual escalations).

The Authority concludes that only the costs related to Test Year expenses and the supported new Rate Year agreements as discussed above represent a reasonable known

and measurable adjustment for the Rate Year. As such, the Authority permits the Company to recover the Test Year amount of $1,774,562, plus the documented cybersecurity prepaid agreement amount of $297,512 and the documented software and maintenance licenses amount of $391,449. Therefore, the total recoverable amount is $2,463,523 for OSG expenses in the Rate Year.

b. Customer Service

The Company proposes $607,663 in customer service-related computer expenses for the Rate Year, which is the Company's $561,833 Test Year expense plus an inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.09. The Authority permits the Company to recover $409,401 in Rate Year customer service-related computer expenses.

The Company provided its actual contract amounts with vendors for customer service software for each year between 2023 and 2026. Interrog. Resp. RSR-144, Att. 1. Based on the Authority's review of the relevant contract amounts, the Authority finds that certain vendors, including Oracle, Kubra Notify Services, Cognizant/Utegrarion, and Alclara, are not being utilized in the Rate Year and should have been removed from the Company's Rate Year amount. Interrog. Resp. RSR-144, Att. 1. Moreover, the contract amounts provided indicate what the Company's actual Rate Year expenses will be, rendering an inflation adjustment for the Rate Year inappropriate. After removing the vendors who will not be utilized in the Rate Year as well as the inflation adjustment, the Authority permits the Company to recover $409,401 in Rate Year customer service-related computer expenses.

c. Software Licensing

The Company proposes $1,486,444 in software licensing expenses, which is the Company's $1,374,460 Test Year expense plus an inflation adjustment. Sch. WP C-3.09. The Authority permits the Company to recover $1,307,994 in software licensing expenses in the Rate Year.

The Authority reviewed the Company's reported Test Year expenses and determined that the total contract amounts reflected a $1,307,994 Test Year expense rather than the $1,374,459 expense presented in the Company's Application. Interrog. Resp. RSR-144, Att. 1. Additionally, the Company provided a list of contracts in place for software licensing expenses through 2026. Interrog. Resp. RSR-144, Att. 1. Accordingly, the Authority determines that an inflation adjustment is unwarranted for such expenses and instead uses the known contract amounts for the Rate Year because they reflect the actual known and measurable expense for the Rate Year. Thus, the Authority permits the Company to recover $1,307,994 in software licensing costs in the Rate Year.

10. Transportation Expense

The Company proposes $2,234,308 in transportation expenses in the Rate Year, which is the Company's $1,792,910 Rate Year expense, a $273,072 pro forma adjustment, and a $168,327 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.0, p. 2; Sch. C-3.13. Specifically, the Company indicated that it made a $59,000 pro forma adjustment for repairs that should have taken place in 2023 but were delayed until

2024 and a $214,000 adjustment that reflects increased repair costs for the Company's fleet as it ages. Late Filed Ex. 1, Att. 2 Supp, Sch. WP C-3.13, n.1. The Authority permits the Company to recover $1,991,481 in transportation expenses in the Rate Year.

To calculate its $214,000 pro forma adjustment, the Company utilized a three-year average of major repairs, adjusted for repairs recorded as O&M expenses and attributable to the Company's distribution operations. Interrog. Resp. RRU-182 e.; Interrog. Resp. OCC-563, Att. 2. The Company further states that it calculated a 15% average expected increase in major component breaks in the Rate Year with a $15,000 average cost per major component using data from 2022, 2023 and 2024. Late Filed Ex. 1, Att. 2. Supp., Sch. WP C-3.13, n.1, Interrog. Resp. RRU-182 e. The Company states that this data shows that annually on average 17.2% of aged vehicles need a major repair at an average cost of $18,340. Interrog. Resp. RRU-182 e.

However, the data also shows that major repairs have varied, sometimes dramatically, from year to year. Indeed, the Company's major repair costs have fluctuated from $315,000 in 2021, $609,000 in 2022, to $589,000 in 2023. Interrog. Resp. OCC-563, Att. 2. Moreover, the historical data provided indicates that each year the Company is impacted by a selection of vehicles in its fleet that are aged and must undergo major repair or be replaced. In other words, at least some expected major repair costs for vehicles passed their replacement dates should already be factored into the Company's Test Year expenses.

In order to balance the consideration that at least some major repair costs were already factored into the Test Year with the likelihood that major repair costs for vehicles passed their replacement dates will continue into the Rate Year, the Authority exercises its discretion to make an adjustment to the Company's Test Year transportation expense for the Rate Year to factor in that older vehicles in the Company's fleet may face increased repair costs. Specifically, the Authority adjusts the Company's $214,000 figure by $74,500 to reflect a $139,500 incremental Rate Year expense. The Authority calculated this figure, i.e., $74,500, by determining that 166 vehicles had already passed their replacement date prior to the Test Year and, thus, were already at risk for major repairs during the Test Year. Interrog. Resp. RRU-346, Att. 1. Next, the Authority assumed 10% of these aged vehicles would require major repair in the Test Year, at a $10,000 cost per major repair. Notably, the Company should maintain its fleet in a manner that reflects prudent and efficient operation of the franchise operation.

Finally, the Authority does not permit the Company to recover its proposed $168,327 inflation adjustment because it failed to demonstrate that applying a generic inflation factor to its Rate Year expenses is a reasonable known and measurable adjustment. Indeed, the Company's reported transportation expenses have fluctuated between 2019 and the Test Year.[78] In sum, the Authority permits the Company to recover $1,991,481 in transportation expenses in the Rate Year ($2,234,308-$74,500-$168,327).

[78]The Company also indicated that its year-to-date distribution transportation expenses were $1,177,616, i.e., below its Test Year expenses. Interrog. Resp. OCC-563.

11. Non-hardship Uncollectible Expense

The Company proposes a total non-hardship uncollectible expense of $4,320,426 for the Rate Year, which is the Company's $3,452,950 Test Year expense, a ($109,926) pro forma adjustment, plus a $977,402 adjustment related to the Company's requested revenue requirement increase. Late Filed Ex. 1, Att. 2 Supp., Sch. A-1.0, ln. 9; Sch. C-1.0; Sch. WP C-3.14. The Authority allows the Company to recover a non-hardship uncollectible expense of $3,408,824 in the Rate Year.

To calculate its Rate Year uncollectible expenses, the Company utilized a 0.9283% non-hardship uncollectible factor, which used a seven-year average of non-hardship uncollectibles between 2017 and 2023. Ex. UI-RRP-1, pp. 76–79. More specifically, the Company utilized a seven-year "cumulative" total, meaning that it divided its seven-year total non-hardship expenses by the seven-year total of distribution base revenues. Late Filed Ex. 1, Att. 2 Supp., Sch. WP, C-3.14. The Company explained that, although it is not aware of any rate proceeding in which the Authority has utilized a seven-year historical average to calculate a company's uncollectible expense, such a historical average is nonetheless justified in this proceeding because historical and future uncollectible expense data is volatile and hard to project due to the COVID-19 pandemic, the implementation of a shut-off moratorium and subsequent resumption of non-hardship and hardship disconnections for nonpayment, and the implementation of a low-income discount rate (LIDR). Ex. UI-RRP-1, pp. 77–78.

The Authority finds that utilizing a five-year non-hardship uncollectible average from 2020 through 2024 is more appropriate than a seven-year average because a five-year data set provides a large enough data set that smooths volatility experienced in 2021 and 2022 while also excluding stale data from 2017 and 2018 that does not factor in LIDR implementation in 2022. See Decision, Oct. 19, 2022, Docket No. 17-12-03RE11, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – New Rate Designs and Rates Review (establishing LIDR). As indicated in the table below, utilizing non-hardship uncollectibles data from 2020 to 2024 results in a non-hardship uncollectible factor of 0.7583%. Interrog. Resp. OCC-354, Att. 1 and 2. Importantly, the five-year average also better reflects a notable downward trend in non-hardship write-offs in 2023 and 2024. Interrog. Resp. OCC-354, Att. 2. The Authority expects that non-hardship uncollectibles will continue to decline as the effects of the COVID-19 pandemic abate.

The Company asserts that the Authority incorrectly utilizes Company wide data, rather than distribution segment-only data to calculate the Company's Rate Year non-hardship uncollectible expense. UI Exceptions, p. 141. Notably, however, the Company's bad debt estimates used to calculate its non-hardship uncollectible calculation are based on the total account receivables for all of UI's operations, not just distribution accounts receivable. Interrog. Resp. RRU-065, Att. 1. Accordingly, utilizing the Authority's accounting expertise, the Authority concludes that the Company's non-hardship uncollectible factor and expense must then include total net billed revenues not recoverable. Absent this approach, the non-hardship uncollectible expense recovered through base distribution rates would reflect a significantly higher non-hardship

percentage as compared to certain uncollectible expense collected through various RAM components such as the GSC, NBFMCC, and TAC. Such a result would be quizzical since both base distribution rates and the various RAM components are paid by the same customer base and should be expected to be the same.

Table 47: Non-Hardship Uncollectibles Calculation

Year	Non-Hardship Write-offs ($)	Retail Revenues ($)	Non-Hardship (%)
2020	3,649,459	799,651,590	0.4564
2021	7,175,126	781,898,370	0.9153
2022	9,490,524	828,375,040	1.1457
2023	6,624,841	905,358,018	0.7317
2024	4,238,824	781,699,769	0.5423
		5-Year Average	**0.7583**

Interrog. Resp. OCC-354, Att. 1, Att. 2.

Therefore, based on the reported Rate Year revenue at present rates of $360,135,545, the Authority calculated an uncollectible expense of $2,730,908 ($360,135,545 x 0.7583%). As a result, the Company's proposed uncollectible expense for the Rate Year revenue at present rates is reduced by $612,116 ($3,343,024 - $2,730,908).

Moreover, the Authority reduces the Company's proposed additional revenue by $439,494,450 ($33,765,586 + $5,728,864) in this Decision. As a result, the Authority disallows an additional uncollectible expense of $299,486 ($39,494,450 x 0.7583%). Therefore, the Company's proposed total uncollectible expense for the Rate Year is reduced by $911,602 ($612,116 + $299,486).

12. Employee Compensation

a. Summary

The Company proposes that it recover $49,832,152 in total compensation expense for the Rate Year, a $13,473,028 increase from the Test Year. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.15. The Authority permits the Company to recover $49,530,652 in compensation expenses in the Rate Year. Specifically, the Authority makes a ($282,563) payroll adjustment and a ($18,937) adjustment for employee volunteer time.

The total compensation expense consists of the non-capitalized base payroll for the Test Year full-time equivalents (FTE) and projected new hire FTEs in the Rate Year. Ex. UI-RRP-1, p. 47. The total compensation expense also includes a vacancy rate offset, overtime payroll, and an offset for the capitalized overhead portion. Ex. UI-RRP-1, p. 47. The Company also included a 4% base pay escalation in the total compensation expense for non-union employees. Ex. UI-RRP-1, p. 47. Union base pay escalations are based upon the provisions of the current union contracts. Ex. UI-RRP-1, p. 47.

To determine the base payroll expense for the Rate Year, the Company: (1) multiplied the Test Year-end FTEs, i.e., 529.14 FTEs, by the average Test Year salaries to calculate the annualized base payroll for the existing employee complement; (2) escalated the annualized base payroll using the escalation factors; and (3) increased the escalated annualized base payroll by 1.5% to reflect promotions. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.15; Ex. UI-RRP-1, pp. 47–48.

The Company used a similar process to calculate base payroll for post Test Year hires. Specifically, the Company multiplied the number of post-Test Year hires, i.e., 165 Interim Period FTEs and 5 incremental Rate Year FTEs, by the average Test Year salaries to calculate the annualized base payroll and then escalated the annualized base payroll using the escalation factors. Ex. UI-RRP-1, p. 48.

Table 48, below, summarizes the adjustments to the total compensation expense for the Rate Year proposed by the Company. The Company did not provide specific compensation information for various proposed FTEs and, thus, the Authority calculated a $282,563 adjustment to the Company's proposed compensation expense by dividing the Company's proposed Rate Year annualized base payroll for new hires of $18,302,680 by the 145.32 requested distribution FTEs to arrive at a $125,947 average compensation expense per employee. The Authority subsequently multiplied the average compensation figure by the Incremental FTE adjustments made herein and applied a 7.03% vacancy factor and capitalization adjustment as determined below.

Table 48: Total Compensation Expense Adjustments

Expense	Proposed	Adjustment	Allowed
Annualized Base Payroll	$66,643,276	-	$66,643,276
Promotions (1.5% Base Payroll	$999,649	-	$999,649
Net New Hires (FTEs)	145.32	(4.32)	141
Annualized Base Payroll- Net New Hires	$18,302,680	($544,092)	$17,758,585
Subtotal FTEs: Base Payroll	674.46	4.32	670.14
Annualized Payroll	$85,945,600	($544,092)	$85,401,510
Payroll Vacancy	($6,041,976)	$38,250	($6,003,726)
Total Base Payroll	$79,903,626	($505,842)	$79,397
Overtime & Premium Payroll	$15,713,996	-	$15,713,996
Less: Capitalized Payroll (Incl. OT)[79]	($42,202,863)	$223,279	($41,979,58)
Less: Non-Storm Intercompany Credits	($2,561,869)	-	($2,561,869)
Less: Pool Costs incl. Overhead Expense[80]	($1,020,738)		($1,020,738)
Less: Volunteer Time		($18,937)	($18,937)
Total Expense	**$49,832,152**	**($301,500)**	**$49,530,652**

Late Filed Ex. 1, Att. 2 Supp., Sch. WP -3.15, p. 2.

[79]Interrog. Resp, RRU-409.
[80]Interrog. Resp. RRU-409.

b. Full Time Equivalent Compensation

The Company requests 674.46 FTEs for the Rate Year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.15, p. 1.[81] As described below, the Authority permits the Company to support the inclusion of 670.14 base distribution FTEs in determining its compensation expense. This figure is reached by using the Company's methodology, and application of the vacancy factor to the total number of FTEs, which consists of 529.14 Test Year distribution FTEs, 141 Interim Period FTE positions projected to be filled as of October 31, 2025, and 0 incremental FTEs. Table 49, below, summarizes the number of FTEs allowed by the Authority. This level of staffing represents an increase of 141 FTEs from the Company's Test Year headcount of 529 FTEs.

The Company's proposed 674.5 FTE positions include: 529.14 Test Year FTE positions; 141 FTE positions projected to be filled during the Interim Period of January 1, 2024, through October 31, 2025; and 4.32 incremental FTE positions. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.15, p. 1.

Table 49: Allowed FTEs

	Requested	Approved
Test Year FTEs	529.14	529.14
Interim Period FTEs	141	141
FTEs subtotal (as of October 31, 2025) (A)	**670.14**	**670.14**
Incremental FTEs		
Customer Service	1.32	-
Environmental Health & Safety	1.0	-
General Services	2.0	-
Incremental FTEs total (B)	4.32	-
Total FTEs (C)=(A) + (B)	**674.46**	**670.14**

Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.15., p. 1.

i. Test Year FTEs

The Authority finds that the Company's 529.14 Test Year FTEs are reasonable. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.15, p. 1.

ii. Interim Period FTEs

The Authority finds that the Company's proposed 141 Interim Period FTEs are reasonable. The Company explained that its projection of 69 Interim Period FTEs in its rate application was an accurate estimate at the time of its application because it assumed that the Company would receive assistance from shared services employees, which would be recovered through the Company's corporate service charge. UI Exceptions, p. 87. The Company further stated that while its Interim Period projected headcount increased to 165 FTEs at the time of the close of the evidentiary record, the various

[81]The Company admitted that the 603 FTEs included in Schedule WP C-3.15 of its Application was an error. Interrog. Resp. OCC-759.

shared service employees transferred to UI, which lead to a corresponding reduction to the Company's proposed Rate Year corporate service charge. Id. Although the Authority determines that the Company's 141 Interim Period headcount is reasonable, the Authority seeks to better understand the process by which employees are transferred from service companies to UI and how frequently such employees are transferred between the various UI affiliates. Of particular concern is that ratepayers could be compensating UI for employees transferred to UI in the Interim Period, but who are subsequently transferred back to the service company during the Rate Year. As such, the Authority directs the Company to submit as compliance in this proceeding no later than January 15, 2026, and every six months thereafter until the Company's next rate amendment application is filed, UI's total distribution headcount and the number of employees transferred from UI to any service company or from the service companies to UI since the Company's last compliance filing. The Authority also directs the Company to file a compilation of these compliance filings in its next rate amendment proceeding at the time of filing its rate application with the Authority.

iii. Incremental FTEs

The Company requests five (5) incremental FTEs in the Rate Year,[82] which include: a Customer Experience Manager, a Customer Experience Lead Analyst,[83] a Mechanic, a Fleet Supervisor, a Lead Environmental, Health, and Safety Analyst; and a Green Digital Connect Digital Business Analyst. Ex. UI-RRP-1, p. 49; Ex. UI-EOP-1, pp. 51–52; Ex. UI-EOP-5. The Authority does not permit recovery of compensation expense for the five requested FTEs in the Rate Year.

To determine whether the Company's requested compensation expenses for five incremental FTEs should be permitted in the Rate Year, the Authority must determine whether the Company, having not retained the additional staffing during the Test Year or Interim Period, has now demonstrated that additional staffing is a known and measurable change. The "known and measurable" standard is, rightfully, a heavy burden because, if the proposed staff are purportedly necessary in the Rate Year, such staffing levels were likely necessary during the Test Year, if not during the Interim Period. Accordingly, the actual costs for necessary staffing should be reflected in the Test Year and Interim Period. In short, rate cases are generally not the venue in which to ask ratepayers to pay for services that might come to fruition during the Rate Year on a speculative basis. A mere goal to hire more staff is not a known and measurable adjustment.

The Authority finds that the Company has failed to meet its heavy burden under the known and measurable standard. Of particular concern is that the Company has yet to fill certain incremental positions requested and approved by the Authority in the 22-08-08 Decision, which indicates that the Company is unable to accurately project when employees may be hired in the Rate Year. Late Filed Ex. 20; Late Filed Ex. 20, Att. 2.

[82]The five requested incremental FTEs equate to 4.32 distribution FTEs after multiplying the five requested FTEs by the 88.48% distribution wage allocator. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.15, p. 1.

[83]The Customer Experience Lead Analyst and Customer Experience Manager would devote 50% of their time to UI matters and are requested as 0.5 FTEs each. Ex. UI-EOP-5.

Moreover, the Company indicated that it has not submitted any postings for the five requested incremental FTEs to its talent acquisition team or created any job requisitions or postings. Interrog. Reso. OCC-689. Thus, the Authority is unable to conclude that the Company is likely to create the requisitions and postings, recruit for the incremental FTE positions, and hire a candidate within the Rate Year.

Additionally, the Customer Experience Manager and Customer Experience Lead Analyst positions reside within the Company's proposed Customer Redesign Program. Interrog. Resp. OCC-94; Interrog. Resp. OCC-99. The Authority does not authorize recovery for the Customer Redesign Program in the Rate Year in this proceeding and, therefore, the corresponding staff positions are not necessary to provide safe and reliable service to ratepayers.

Moreover, the Company asserts that its Lead Digital Business Analyst will be associated with the Green Button Connect Program and would serve as the "point of contact for all Green Button Connected related engagements with customers, staff, and third parties." However, the Company also asserted that there is limited customer interest in the program currently. Ex. UI-CSP-1, pp. 45–47. Accordingly, it is unclear why an FTE specifically retained to engage with customers, staff, and third parties is necessary if there is low program demand as the Company asserts.

In sum, the Authority concludes that the Company has not met the known and measurable standard with respect to any of the five requested incremental FTEs.

iv. Vacancy Rate

The vacancy rate offset recognizes that, at any given time, some positions are not filled due to the timing of the hiring and replacement process. Here the Company applied a 7.03% vacancy rate, which the Company based on its five-year average for 2019-2023. Interrog. Resp. RRU-127. The Authority reviewed the Company's calculated 7.03% vacancy rate and concludes that it is reasonable.

v. Volunteer Time

The Company estimates that approximately $18,937 of Test Year employee expense compensated the Company's employees while volunteering for Avangrid events during working hours. Interrog. Resp. RRU-286; Interrog. Resp. OCC-360. Although the Company's employees volunteering in local communities is commendable, such activities are not necessary for the provision of safe and reliable and, therefore, such costs related to volunteer activities should be borne by the Company's shareholders rather than ratepayers. Accordingly, the Authority does not permit the Company to recover $18,937 of employee volunteer time from ratepayers.

13. Employee Benefits

The Company proposes an employee benefits expense of $16,795,138 in the Rate Year. Table 50, below, summarizes the employee benefits expense allowed for the Rate Year.

Table 50: Employee Benefits Expense

Expense	Proposed ($)	Adjustment ($)	Approved ($)
Medical	8,291,279	(57,123)	8,234,156
Dental & Vision	258,797	(1,784)	257,013
Pension OPEB	946,523	-	946,523
Incentive Expense	1,598,115	(6,713)	1,591,402
Workers Comp.	426,356	(433)	425,923
401(k)	3,009,488	(4,799)	3,004,689
Other Employee Benefits			
Loyalty Gifts	97,453	(97,453)	-
Life Insurance	53,168	(4,005)	49,163
Mitigation Payments	289,404	-	289,404
Scholarships	33,518	(2,525)	30,993
Relocation Payments	36,815	(36,815)	-
Student Loans	15,976	(15,976)	-
Misc. Other Benefits	89,672	-	89,672
Union Ratification	1,648,574	-	1,648,574
Total Expense	**16,795,138**	**(227,626)**	**16,567,512**

a. Medical, Dental, and Vision Expenses

The Company proposes combined medical, dental, and vision expenses of $8,550,076 in the Rate Year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16. Based on the evidence presented, the Authority finds sufficient evidence of $8,491,169 in the Rate Year medical, dental, and vision expenses and allows the Company to recover that amount in its revenue requirement.

Table 51: Medical, Dental, and Vision Expenses

Expense	Proposed ($)	Adjustment ($)	Allowed ($)
Medical Benefits	8,291,279	(57,123)	8,234,156
Dental and Vision Benefits	258,797	(1,784)	257,013
Total Expense	**8,550,076**	**(58,907)**	**8,491,169**

i. Medical Benefits

The Company proposes medical benefits expenses of $8,291,279 for the Rate Year, which is $2,856,941 more than the Test Year medical benefits expenses of $5,434,337. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16. Based on the evidence presented, the Authority permits the Company to recover $8,234,156 in Rate Year medical benefits expenses.

In determining the medical benefits expense for the Rate Year, the Company did not propose specific known and measurable changes to the Test Year expenses. Instead, the Company's proposed medical benefits expenses were based on the projected per-

employee costs developed by the Company's insurance consultant, Aon Consulting Inc. (Aon). Ex. UI-RRP-1, p. 56. Specifically, the Company calculated medical insurance expense by first determining the projected annual medical cost per employee and then applying that cost to the projected number of employees, adjusted for vacancy rates and capitalization. Ex. UI-RRP-1; Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16a. Thus, the Rate Year projected medical expense of $8,291,279 reflects the Company's projected $23,670 medical insurance costs per employee for 674.5 distribution-only employees, or $13,223 per employee after applying a 44.14% capitalization rate. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16a. The Company then applied this per-employee cost to its requested 674.5 distribution FTEs, adjusted for the 7.03% vacancy rate, resulting in the proposed expense of $8,291,279. Id. Notably, the Company did not follow governing ratemaking principles in proposing an expense for Rate Year medical benefits. Specifically, the Company is required to start with its Test Year medical benefits expenses and then make pro forma adjustments for known and measurable changes.

Notwithstanding this deviation, the Authority finds the Company's medical expense of $13,223 per employee is reasonable. Accordingly, based on the reduction of 4.32 FTEs as discussed in Section VI.A.12.b, Full Time Equivalent Compensation, the Authority does not permit the Company to recover $57,123 in medical expenses in the Rate Year and instead approves a $8,234,156 Rate Year expense.[84]

ii. Dental and Vision Benefits

The Company proposes dental and vision benefits expenses of $258,797 for the Rate Year, which is $55,521 less than the Test Year dental and vision benefits expenses of $314,318. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16. Based on the evidence presented, the Authority permits the Company to recover $257,013 in Rate Year dental and vision benefits expenses.

In determining the dental and vision expense for the Rate Year, the Company did not propose specific known and measurable changes to the Test Year expenses. Instead, the Company's proposed dental and vision benefit expenses were based on the projected per employee costs developed by the Company's insurance consultant, Aon Consulting Inc. (Aon). Ex. UI-RRP-1, p. 56. Specifically, the Company calculated dental and vision benefits expense by first determining the projected annual cost per employee and then applying that cost to the projected number of employees, adjusted for vacancy rates and capitalization. Ex. UI-RRP-1; Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16a. Thus, the Rate Year projected dental and vision expense of $258,797 reflects the Company's projected $739 dental and vision costs per employee for 350.2 distribution-only employees, or $413 per employee after applying a 44.14% capitalization rate. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16a. The Company then applied this per employee cost to its requested 674.5 distribution FTEs, adjusted for the 7.03% vacancy rate, resulting in the proposed expense of $258,797. Id. Notably, the Company did not follow governing ratemaking principles in proposing an expense for Rate Year dental and vision benefits.

[84]The $13,223 per employee medical expense multiplied by 4.32 FTEs results in a $57,123 disallowance.

Specifically, the Company is required to start with its Test Year dental and vision benefits expenses and then make pro forma adjustments for known and measurable changes.

Notwithstanding this deviation, the Authority finds the Company's dental and vision benefits expense of $413 per employee reasonable. Accordingly, based on the reduction of 4.32 FTEs as discussed in Section VI.A.12.b, Full Time Equivalent Compensation, the Authority does not permit the Company to recover $1,784 in medical dental and vision benefits expenses in the Rate Year and instead approves a $257,013 Rate Year dental and vision expense.[85]

b. Pension and OPEB Expenses

The Company proposes a pension and Other Post-Employment Benefits (OPEB) expense of $946,523 in the Rate Year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16. The Authority finds the $946,523 in Rate Year pension and OPEB expense to be reasonable.

The Company stated that it provides benefit offerings, including defined pension plans, defined contribution 401(k) plans, and OPEB, to qualified employees depending on their date of hire, age at retirement, and years of service. Ex. UI-CBP-1, p. 40. The Company has, however, closed its legacy defined pension plans and self-insured retiree medical plans to new hires and instead offers 401(k) plans and flat dollar health care reimbursement arrangements on post-65 Medicare exchanges. Ex. UI-CBP-1, p. 40.

The Company calculated its Rate Year expenses by utilizing actuarial forecasts for 2025 and 2026. Ex. UI-CBP-1; Ex. UI-CBP-14. The Company's actuarial assumptions project that its pension expense will decrease from 2025 to 2026 primarily due to a reduction in interest cost as a result of a decrease in projected benefit obligations. Ex. UI-CBP-1, p. 44. The Company's OPEB is also expected to decrease from 2024 to 2026 due to increases in the expense component of expected return on assets and a decline in service costs. Ex. UI-CBP-1, p. 49; Ex. UI-CBP-14. Moreover, the Company projects higher gain amortizations in 2025 and 2026, which decreases its expense. Ex. UI-CBP-1, p. 49; Ex. UI-CBP-14. Accordingly, the Company may recover $946,523 in Rate Year pension and OPEB expense.

c. Non-Executive Employee Incentive Compensation

The Company proposes an incentive compensation expense of $1,598,115 in the Rate Year for 627 non-executive non-union employees, or an average of $2,527 per employee ($1,598,115 / 627). Sch. WP C-3.16d. The Authority allows the Company to recover 61.5%, or $1,554 per employee in the Rate Year. The Authority finds that the Company has not shown that the remaining amount is reasonable and necessary because the proposed incentive compensation is primarily based on financial goals that serve the interests of the Company's shareholders, rather than Connecticut ratepayers,

[85]The $413 per employee dental and vision expense multiplied by 4.325 FTEs results in a $1,784 disallowance.

and thus are not reflective of rates that reflect prudent and efficient management of the franchise operation. General Statutes § 16-19e(a).

The Company determined the incentive compensation expense for the Rate Year by calculating the incentive compensation expense per FTE in the Test Year and applying that ratio to the Company's requested FTEs in the Rate Year. Ex. UI-RRP-1, pp. 57–58. The Company subsequently applied the same escalation factors that were applied to labor expense. Ex. UI-RRP-1, p. 58. The Company asserts that the primary driver of the Company's projected Rate Year expenses is due to an increase in FTEs, while the remainder of the increase is attributable to the normal annual merit increase to base payroll since incentive pay is based upon a percentage of base payroll. Ex. UI-RRP-1, p. 58.

Non-union employees receive incentive compensation under the Company's Annual Performance Award (APA) Plan, which the Company states is based on the achievement of certain Company objectives that can include customer, financial performance, safety, and similar factors. Ex. UI-CBP-1, p. 14. The Company further asserts that a variable pay program incentivizes employees to achieve higher performance, creates a results-oriented culture, and supports employee engagement while providing employees with market competitive rewards that allow the Company to attract and retain talent. Ex. UI-CBP-1, pp. 14–15.

The Company's APA Plan utilizes a 1,000 "point" structure weighted against Avangrid, business area and corporate area objectives, and individual performance. Ex. UI-CBP-1, p. 17. Non-union employees are subsequently evaluated on a scale of 1 (Partial) through 3 (Exceeding) in each of the three areas. Ex. UI-CBP-1, p. 17. Employees receiving a "partial" rating in a given area are awarded 10% of the possible points, while an "exceeding" rating results in 100% of the points being awarded in the relevant area. Ex. UI-CBP-1, pp. 17–18. A payout award is subsequently granted based on the employee's base pay and the total number of points received versus the maximum amount of points that could be awarded. Ex. UI-RRP-1, p. 18. In order to receive any incentive compensation, an employee must receive a "partial rating" of 10%. Interrog. Resp. OCC-129.

The Company argues that its total compensation package is below its peer group median and, if employees received no incentive compensation, their total compensation would be below market competitive and would render the Company unable to attract employees. Hr'g Tr., 641:13–21. The Company relies on an Aon compensation study, which concludes that the Company's total compensation and benefits package, inclusive of incentive compensation, is 9.8% below its peer median group and 10.5% below its peer group average. Ex. UI-CBP-1, 37; Ex. UI-CBP-2. The Company also asserts that the study demonstrates that the Company's variable pay as a percentage of total cash compensation is below its peers. Ex. UI-CBP-1, p. 38.

OCC argues that many of the objectives the APA Plan sets forth benefit shareholders rather than ratepayers and that certain customer focused goals are misaligned with beneficial customer service objectives. For instance, OCC notes that

customer service goals emphasize speed of answering phone calls rather than ensuring that correct information is being conveyed or that an objective regarding customer complaints focuses on those escalated in some form rather than being adequately addressed. Interrog. Resp. OCC-238; Interrog. Resp. OCC-141. Moreover, OCC argues that the APA Plan does not incentivize employees to perform at their best because every employee receives incentive compensation, even if only receiving a "partial" rating across the various areas assessed. Interrog. Resp. OCC-294; Interrog. Resp. OCC-299.

The Company's and OCC's respective arguments highlight the dilemma the Authority faces in determining whether the Company's APA Plan should be recoverable from ratepayers. On one hand, the Authority is charged with ensuring that rates are sufficient, but no more than sufficient, to allow the Company to support adequate staffing levels. General Statutes § 16-19e(a)(4). Thus, disallowing non-executive compensation in its entirety may result in below market compensation for the Company's employees. Conversely, the Authority must also set rates that reflect prudent and efficient management of the franchise operation. General Statues § 16-19e(a)(5). As OCC highlights, various objectives tied to the APA Plan benefit shareholders rather than ratepayers, and certain ostensibly ratepayer-focused objectives should be improved to better serve ratepayer needs. Moreover, there is only anecdotal evidence in the record that the program truly incentivizes employees, particularly if 100% of eligible employees receive employee incentive compensation. Interrog. Resp. OCC-294; Interrog. Resp. OCC-299.

Thus, in balancing the interests of ratepayers and shareholders, the Authority concludes that at least a portion of the Company's objectives in the APA Plan are shareholder focused and do not otherwise represent prudent and efficient management of the franchise operation. Indeed, by the Company's own admission, 38.5% of its APA Plan goals are focused on shareholder or other interests, while the remaining 61.5% of its goals are focused on customer interests. Interrog. Resp. OCC-137, Att. 1. Consequently, the Authority allows the Company to recover 61.5%, or $1,554 per employee, in non-executive incentive compensation to balance the interests of ratepayers and shareholders. In total the Authority permits the Company to recover $1,591,402, which also reflects the reduction in allowed FTEs as discussed in Section VI.A.12.b.

d. Workers Compensation Expense

The Company proposes a workers compensation expense of $426,356, or $433 per employee, for the Rate Year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16e. Based on the evidence presented, the Authority finds sufficient evidence of $395,635 in a Rate Year workers compensation expense.

The Company calculated its Rate Year worker's compensation expense per FTE in the Test Year, adjusted to exclude incurred but not reported amounts, and applied the per employee expense to the Company's requested Rate Year FTEs. Ex. UI-RRP-1, p. 59. The Company then relied on Aon's projection that worker's employee compensation expense would increase by 4% on a yearly basis. Ex. UI-RRP-1, p. 59.

The Authority finds the Company's projected workers compensation of $433 per employee reasonable. Accordingly, based on the reduction of 76.32 FTEs as discussed in Section VI.A.12.b, Full Time Equivalent Compensation, the Authority does not permit the Company to recover $1,871 in workers compensation expense in the Rate Year and instead approves a $424,923 workers compensation expense in the Rate Year.[86]

e. 401(k) Expense

The Company proposes a 401(k) expense of $3,009,488 in the Rate Year, or $4,799 per employee. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16f. Based on the evidence presented, the Authority permits the Company to recover $3,004,689 of 401(k) expense in the Rate Year.

The Company's 401(k) expense includes the cost of 401(k) matching contributions for employees for employees hired after April and May 2005 who are not enrolled in the defined benefit pension plan. Ex. UI-RRP-1, p. 60. The Company determined its Rate Year 401(k) expense by calculating the Test Year per employee 401k expense, escalated by the Company's calculated payroll escalation rate, and by applying the per employee rate of $4,799 to the Company's requested number of Rate Year FTEs. Ex. UI-RRP-1.

The Authority finds the Company's 401(k) expense per employee reasonable. Accordingly, based on the reduction of 76.32 FTEs as discussed in Section VI.A.12.b, Full Time Equivalent Compensation, the Authority does not permit the Company to recover $340,489 in 401(k) expenses in the Rate Year and instead approves a $3,004,689 Rate Year expense.[87]

f. Other Employee Benefits Expenses

i. Loyalty Gifts

The Company proposes a loyalty gift expense of $97,453 in the Rate Year, which includes a $7,342 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.16g. The Authority does not allow the $97,453 Rate Year loyalty gift expense because the Company has not met its burden demonstrating that loyalty gifts are reasonably certain to be incurred within the Rate Year nor are such gifts necessary to provide service to customers or to maintain appropriate staffing levels. See General Statutes § 16-19e(a).

The Company indicated that its loyalty gift expense consists of signing and retention bonus expenses, which can vary from year to year and, in some instances, are not made at all. Interrog. Resp. OCC-704. Indeed, the Company described signing bonuses as dependent on a candidate's "specific situation," and the payment of retention bonuses as "few and far between" that are based on critical skills or need for a particular position. Hr'g Tr., 518:16-25, 519:1-11. Given the variability and discretionary nature of the expense, the Company has not met the known and measurable standard because it

[86]The $433 per employee workers compensation expense multiplied by 4.32 FTEs results in a $1,8711 disallowance.

[87]The $4,799 per employee 401(k) expense multiplied by 4.32 FTEs results in a $20,732 disallowance.

is uncertain how many employees, if any, will receive sign-on or retention bonuses in the Rate Year and the amount of such bonuses.

Moreover, the Company asserted that such bonuses are necessary to attract and retain top talent; however, these bald statements were not supported by evidence. Furthermore, disallowing cost recovery associated with employee awards is consistent with prior decisions. See, e.g., 23-08-32 Decision, p. 110; 22-08-08 Decision, p. 134. Consequently, the Authority disallows the $97,453 loyalty gifts expense.

ii. Scholarships

The Company proposes to include a scholarship expense of $33,518 in the Rate Year, which includes $2,525 in an inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.16g. The Company did not provide any historical data indicating that its scholarship expense increases with the rate of inflation, nor did it explain why applying a generic inflation adjustment is appropriate for the expense. As such, the Company failed to demonstrate that the inflation adjustment represents a known and measurable change, and the Authority does not permit the Company to recover its proposed $2,525 inflation adjustment.

iii. Life Insurance

The Company requests that it recover $53,168 in life insurance expenses for the Rate Year, which is the Company's $49,163 Test Year expense plus a $4,005 generic inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16g. Once again, the Company failed to provide any historical information to demonstrate that its life insurance expense has increased with the rate of inflation or explain why a generic inflation adjustment serves as a reasonable known and measurable adjustment in the Rate Year. As such, the Authority disallows the Company's proposed $4,005 generic inflation adjustment.

iv. Relocation Payments

The Company proposes to include $36,815 for a relocation payment expense in the Rate Year, which includes a generic inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.16g. The Authority disallows the $36,815 Rate Year relocation expense because the Company did not meet its burden of demonstrating that its projected Rate Year relocation expenses are known and measurable or necessary to provide safe and reliable service to customers or to maintain appropriate staffing levels. See General Statutes § 16-19e(a).

The Company describes its relocation program as a "strategic initiative" used to attract talent, claiming that the program allows the Company to recruit skilled professionals not locally available. Interrog. Resp. RRU-137 Supp. The Company relies on anecdotal statements that the professionals that are hired and utilize the program "significantly enhance the Company's services and customer experience," but does not provide any concrete examples of such enhancements or data to quantify how the payments specifically enhance the Company's services and customer experience.

Interrog. Resp. RRU-137 Supp. As such, the Authority concludes that the expense is not reasonable and necessary to the provision of safe and reliable service.

Moreover, the record demonstrates that the relocation payment expense is nonrecurring. Although the expenses fluctuate from year to year, there is no projection of how many employees are expected to be relocated in the Rate Year nor is there any reasonable certainty that the Company will relocate employees in the Rate Year. Interrog. Resp. OCC-340. The relocation expense, therefore, is not known and measurable and therefore not appropriate for inclusion in rates. Accordingly, the Authority disallows the Company's relocation expense of $36,815, including the inflation adjustment.

v. Student Loan Payments

The Company proposes a $15,976 student loan payment expense for the Rate Year, which is the Company's $14,772 Test Year expense plus a $1,204 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.16g. The Authority does not permit the Company to recover $15,976 because the Company has not met its burden to demonstrate that the expense is reasonable and necessary to provide safe and reliable service or to maintain adequate staffing levels. See General Statutes § 16-19e(a).

The Company indicated that its student loan repayment program provides non-union employees with $250 per month to repay student loans, but that the loans do not have to be for education expenses related to an employee's job function or a completed degree. Interrog. Resp. OCC-348. Moreover, while the Company makes an unsubstantiated assertion that its student loan repayment program aids in attracting, recruiting, and retaining talent, and by increasing employee morale, such statements are anecdotal and are unsupported by any data demonstrating that the program has led to greater retention rates and recruiting success. As such, the Authority concludes that the Company has not met its burden to demonstrate that the expense is reasonable and necessary to provide safe and reliable service. Accordingly, the Authority disallows the Company's proposed Rate Year student loan payments expense of $15,976.

vi. Caregiver – Bright Horizons

The Company proposes $37,444 in a caregiver program expense in the Rate Year. Interrog. Resp. OCC-257.[88] The Authority disallows recovery of the $37,444 caregiver expense as the Company has not demonstrated that this expense is reasonable and necessary to provide safe and reliable service or to maintain adequate staffing levels. See General Statutes § 16-19e(a).

The Company offers employees subsidized caregiver benefits, such as Bright Horizons Back Up Care, which provides employees access to backup dependent care services for children and aging family members, and Bright Horizons Enhanced Family Support, which provides employees free access to Sittercity. Interrog. Resp. OCC-257. The Company asserts that the caregiver program enables it to provide a "more supportive

[88]The Company previously removed $27,929 of its requested $65,373 in caregiver program expense. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.18, p. 1.

and productive work environment for everyone involved, which enables the Company to attract and retain its skilled workforce." Id. However, the Company also concedes that there is no Company-specific study or data to support its assertions. Id. Although the Company submitted a study stating that a childcare benefit can deliver positive returns on investment, there is no indication or analysis which supports that such is the case for the Company. Furthermore, disallowing cost recovery associated with a caregiver program is consistent with prior decisions. See, e.g., 22-08-08 Decision, p. 137. Consequently, the Authority disallows $37,444 in caregiver program expense.

vii. Cafeteria Subsidy

The Company proposes a $144,015 cafeteria subsidy Rate Year expense.[89] Interrog. Resp. OCC-278. The Authority concludes that the Company has not demonstrated that the expense is reasonable or necessary to provide safe and reliable service and, therefore, does not permit the Company to recover the $144,015 cafeteria subsidy expense in the Rate Year.

The Company states that the cafeteria expense is for a monthly subsidy the Company pays to its cafeteria vendor, which "acts as a safeguard to prevent substantial loss for the vendor," even though the vendor operates independently and manages its own profits and losses. Id. The Company broadly asserts that the workplace cafeteria "improves employee welfare and productivity," saves time relative to "off-campus" food options, allows employees to have impromptu meetings and "share knowledge," and provides a quick and easy option for storm response teams during non-business hours. Revenue Requirements Panel Rebuttal PFT, p. 41. Moreover, the Company asserts that it "conservatively" estimates that the cafeteria saves each employee 15 minutes of time during lunch versus going to an outside establishment, resulting in $1.14 million in savings per year. Id.

The Authority is unpersuaded by the Company's testimony. First, the Company's "conservative" estimate assumes all 1,200 employees with access to the cafeteria utilize it. Id. Moreover, the Company's assertion regarding saving work time is inapposite since the amount of time an employee spends on their lunch break would presumably be fixed regardless of whether they frequent an onsite or offsite food option. Moreover, the Company's assertion that the cafeteria improves employee welfare and productivity is anecdotal and not reinforced with any supporting data. Finally, it is unclear how many storm response teams actually use the cafeteria, particularly if they are dispersed through the Company's service territory during storm events. Accordingly, the Authority concludes that the Company has not demonstrated that the expense is reasonable or necessary to provide safe and reliable service and, therefore, does not permit the Company to recover the $144,015 cafeteria subsidy expense in the Rate Year.

[89]The Company did not specify which line item of its proposed revenue requirement included the requested cafeteria subsidy expense. As such, the Authority categorizes the expense as an "other employee benefit" within the Company's O&M expense.

14. Interest on Security Deposits

The Company includes a $24,438 expense in the Rate Year for interest expense paid on security deposits. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.17. The Company asserts that it pays interest on cash deposits at a rate calculated in accordance with General Statutes § 16-262j. Interrog. Resp. OCC-268. During the Test Year, the Company stated that the interest rate paid was 1.5%. Interrog. Resp. OCC-268. During the proceeding, the Company provided updated average customer deposit balances for 2024. Interrog. Resp. OCC-268. Accordingly, the Authority permits the Company to recover $14,114 in Rate Year interest on security deposit expenses, which is the 1.5% interest rate for the Company's 2024 average security deposit balance ($940,945.45 x 1.5%).

15. Corporate Service Charges

a. Summary

The Company proposes corporate service charge expenses of $31,124,964 for the Rate Year, which is the Company's $34,277,936 reported Test Year expense, a ($6,014,776) pro forma adjustment, and a $2,861,804 Rate Year adjustment, which includes a $676,198 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.0, p. 2, WP C-3.18, p. 1. The Authority permits the Company to recover $25,894,986 in corporate service charge expenses in the Rate Year. Table 52, below, summarizes the Authority's adjustments to the Company's requested Rate Year corporate service charge.

Table 52: Corporate Service Charges Expense

Category	Proposed ($)	Adjustment ($)	Approved ($)
Mass Formula Adjustment	-	(643,415)	(643,415)
Severance	45,818	(45,818)	-
Annual Bonus	2,390,106	(920,191)	1,469,915
Loyalty Gifts	223,227	(223,227)	-
Culture & Sport	1,282	(1,282)	-
Relocation/ Student Loan	349,213	(349,213)	-
Branding	1,163,747	(1,163,747)	-
Investor Relations	65,801	(65,801)	-
BOD	418,669	(314,002)	104,667
Executive Compensation	3,308,330	(827,084)	2,481,246
Remainder of Corp. Serv. Charge	22,482,573	-	22,482,573
Inflation Adjustment	676,198	(676,198)	-
Total	**31,124,964**	**(5,229,978)**	**25,894,986**

The Company receives shared services from ASC, Avangrid Management Company (AMC), and UIL for services that include information technology, finance, human resources, legal services, and various administrative functions. Ex. UI-RRP-1, p. 75. The shared services provided to the Company fall into two categories, Corporate

Services,[90] which include shared services provided to both Avangrid Networks and Avangrid Renewables, and Technical Services,[91] which include shared services provided only to Avangrid Networks. Ex. UI-RRP-1, pp. 33–34.

The Company explained that its cost allocation manual dictates the assignment of Corporate and Technical Services, which are charged in a "cascade" manner. Ex. UI-RRP-1, p. 35. Under the "cascade" model, the shared services charged to the Company are usually charged to it by UIL either directly or indirectly. Ex. UI-RRP-1, p. 35. The costs that UIL charges to the Company include costs allocated to it by ASC. Ex. UI-RRP-1, p. 35. In turn, ASC's costs include those allocated to it by AMC. Ex. UI-RRP-1, p. 35. The Company further stated that costs are directly charged to it for goods and services utilized by or deemed to be solely for the benefit of the Company. Ex. UI-RRP-1, p. 36. Moreover, the Company indicated that, where it is impractical to administer and track costs directly, costs are assigned based on cost causation principles. Ex. UI-RRP-1, p. 36. Finally, the Company stated that UIL-level costs are allocated based on the Massachusetts formula, in which each operating company's pro-rata average share of total revenue, less the commodity (such as excluding Generation Services Charge revenue for UI), payroll, and net plant-in-service plus construction work in progress. Ex. UI-RRP-1, p. 36.

UI further allocates its costs between its distribution and transmission business segments. Interrog. Resp. RRU-216, Att. 1. In addition to allocating expenses allocated to it into distribution and transmission "business areas," the Company further delineates expenses allocated to its distribution business into seven "profit centers": System Benefits Charge (SBC), Generation Services Charge (GSC), Renewable Energy Investment (REI), Renewable Distribution Resources (RDR), C&LM, nonbypassable federally mandated congestion charge (NBFMCC), and base distribution. Interrog. Resp. RRU-216; Interrog. Resp. RRU-216, Att. 1. The Company asserts that it determines the amount allocated to its transmission business area by following the allocations approved by FERC. Hr'g Tr., 1772:5–10. The Company reflects all of its business segments, other than transmission, as distribution for the purpose of developing the FERC-approved allocation percentage. Hr'g Tr., 1771:22-1773:25, 1774:1–2.

Conversely, the Company's distribution wage allocator is reflected in its Authority-approved revenue requirement. Hr'g Tr., 1774:8–17. Notably, the Company utilizes the FERC-approved allocation for purposes of determining the distribution wage allocator applied in its requested revenue requirement. Hr'g Tr., 1775:2–12. Thus, for purposes of calculating its distribution wage allocator, the Company includes not only its base distribution "profit center," but also rate mechanisms recovered outside of base distribution rates: the SBC, GSC, REI, RDR, C&LM, and NBFMCC.[92] Hr'g Tr., 1775:17–

[90]Corporate Services include human resources, training and recruitment, purchasing, real estate and general services, tax, security services, and insurance services. Ex. UI-RRP-1, pp. 33–34.

[91]Technical Services include customer service, electric and gas operations, asset management, commodity planning, and regulatory services. Ex. UI-RRP-1, p. 34.

[92]For example, the SBC, GSC, and NBFMCC, among other revenue adjustment mechanisms, are set outside of base distribution rates in the Authority's annual Rate Adjustment Mechanism (RAM)

23; Interrog. Resp. RRU-264. While the Company asserts that it is not seeking costs related to the distribution rate mechanisms in this proceeding, the Authority is not persuaded because, by virtue of including its non-distribution rate mechanisms in its base distribution allocation calculations, the Company is in fact allocating costs related to non-distribution rate expenses to base distribution rates. Hr'g Tr., 1775:17–23. Further, although the Company cautions that 100% of its prudently incurred costs must be recovered through either transmission or distribution rates, the Company's assertion lacks the additional nuance that prudently incurred costs may be recovered through FERC-approved transmission rates, Authority-approved distribution rates, or Authority-approved rate adjustment mechanisms. In other words, the Company can be made "whole" by recovering allocated labor costs in the appropriate rate adjustment mechanism. Based on these findings, effective November 1, 2025, the Company shall calculate its distribution wage allocator when proposing base distribution rates such that it does not include SBC, GSC, REI, RDR, C&LM, NBFMCC, or other non-distribution profit centers. Rather, the Company shall pursue such wage expenses in the applicable rate proceeding where such rates are set (e.g., the annual RAM proceeding).

b. Massachusetts Formula Allocation

In the present case, the Company allocated certain costs to its combined transmission and distribution business segments by computing and applying a Massachusetts Formula allocator of 61.78%. Late Filed Ex. 1, Att. 2 Supp., Sch. B-2.4; Hr'g Tr., 1782:24–25. The Company then allocated the combined transmission and distribution expenses to its distribution business center by calculating a 63.93% allocator. Hr'g Tr., 1787:8–10; Late Filed Ex. 1, Att. 2 Supp., Sch. B-2.4. Furthermore, the Company utilized 2022 data to calculate its Massachusetts Formula allocation rather than Test Year data. Late Filed Ex. 1, Att. 2 Supp., Sch. B-2.4; Hr'g Tr., 1780:22–25, 1781:1–2.

Accordingly, the Authority adjusts the Company's Massachusetts Formula allocation to its distribution business segment from 63.93% to 62.73% to utilize the Company's Test Year data and to correct the Company's allocation methodology such that it avoids including rate adjustment mechanism profit centers in the calculation. Specifically, the Authority calculated the 62.73% by utilizing 2023 data provided by the Company and by designating profit centers besides base distribution as transmission costs for the purposes of the calculation.[93] Interrog. Resp. RRU-239, Att. 2 (2023 Data).[94] The Authority subsequently applied the 62.73% allocator to the applicable expenses on the Company's Schedule C-3.18, resulting in a disallowance of $643,415. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.18; Hr'g Tr., 1787:10–13 (indicating that Schedule C-3.18 is the only location in the Application where the relevant Massachusetts Formula allocation is

proceeding. See, e.g., Decision Aug. 13, 2025, Docket No. 25-01-04, Annual Review of the Rate Adjustment Mechanisms of The United Illuminating Company.

[93]Such an approach ensures that other profit centers are not being included in the base distribution profit center, essentially mirroring the approach the Company uses to calculate its transmission wage allocation.

[94]The Authority conducted a step-by-step calculation with the Company during the May 22, 2025 Late Filed Exhibit hearing, in which the Company concurred that such a calculation would compute to a 62.73% allocation factor. Hr'g Tr., May 22, 2025, 1785:17-25, 1786:1-4.

applied). Additionally, effective November 1, 2025, the Company shall calculate its Massachusetts Formula allocator when proposing base distribution rates such that it does not include SBC, GSC, REI, RDR, C&LM, NBFMCC, or other non-distribution profit centers as discussed herein.

c. Severance Payments

The Authority does not permit the Company to recover $45,818 in severance expenses allocated to UI in the Rate Year. Interrog. Resp. OCC-346 Supp. The Company asserts that employment contracts with severance arrangements benefit customers because such arrangements enable the Company to attract top talent; UI claims that it is standard practice in both the utility and non-utility industries for such provisions to be included in executive employment agreements. Ex. UI-Rebuttal-1, pp. 21–22. The Company further argues that severance payments serve as a "safety net" for executives if they are unexpectedly terminated due to factors beyond their control. Ex. UI-Rebuttal-1, p. 22.

First, the Authority concludes that the Company has failed to demonstrate that severance pay is a recurring expense that meets the known and measurable standard. The Company disputes that severance pay is a nonrecurring and unpredictable expense; it asserts that it is "based on specific facts and circumstances that occur with employees in the Company." Hr'g Tr., 888:9–18. The number of employees receiving severance pay and the amount of severance paid has varied from year to year. Interrog. Resp. OCC-346; Late Filed Ex. 53. Thus, the Authority concludes that severance pay is not known and measurable because the Company is unable to discern how many terminated employees will receive severance pay and the amount of such severance pay in the Rate Year.

Second, even if severance payments could be discerned for the Rate Year, the Authority finds that the Company's assertions are anecdotal and unsupported by the record. In particular, the Company did not submit any data demonstrating that such packages are necessary to ensure appropriate staffing levels to provide safe and reliable service. Moreover, it is unclear under what circumstances an executive would be entitled to severance payments, including whether such circumstances are primarily shareholder focused, such as due to a failure to meet financial targets or around restructurings designed to enhance shareholder value. As such, the Authority does not permit the Company to recover $45,818 in severance expenses allocated to it in the Rate Year.

d. Annual Bonus

The Authority does not permit the Company to recover $920,191 in annual bonus expenses allocated to UI in the Rate Year. The Company indicates that $2,390,106 in annual bonuses are included in its revenue requirement, which the Company clarified refers to its Annual Performance Award (APA) Plan. Interrog. Resp. RRU-365, p. 2; Interrog. Resp. RRU-365, Att. 1 "RRU 240 & RRU 241 Summary" Tab; Interrog. Resp. OCC-293, Att. 7. As discussed in Section VI.A.13.c, Non-Executive Employee Incentive Compensation, the Authority does not permit the Company to recover 38.5% in APA plan compensation that is targeted toward shareholder objectives. Accordingly, the Company

may not recover 38.5%, or $920,191 in APA Plan expenses allocated to it in the Rate Year.

e. Loyalty Gifts

The Authority does not permit the Company to recover $223,227 in loyalty gifts allocated to UI in the Rate Year. Interrog. Resp. RRU-365, Att. 1. The Company indicates that the allocated loyalty gifts encompass sign-on and retention bonuses. Interrog. Resp. RRU-365, p. 2. The Authority concludes that such an expense does not represent a reasonable known and measurable change, nor has the Company demonstrated that such expenses are reasonable and necessary to provide safe and reliable service.

While the Company did not provide specific details on sign-on bonuses and retention bonuses related to loyalty gifts allocated to the Company, UI did provide Company-level information showing that sign-on and retention bonus expenses vary from year to year and, in some instances, are not made at all. Interrog. Resp. OCC-704. Indeed, the Company described signing bonuses as dependent on a candidate's "specific situation," and the payment of retention bonuses as "few and far between" that are based on critical skills or need for a particular position. Hr'g Tr., 518:16–25, 519:1–11. Given the variability and discretionary nature of the expense, the Company has not met the known and measurable standard because it is uncertain how many employees will receive sign-on or retention bonuses in the Rate Year and the amount of such bonuses.

Moreover, the Company only baldly asserted that such bonuses are necessary to attract and retain top talent without any evidence to support its claims. As such, the Authority does not permit the Company to recover $223,227 in loyalty gifts allocated to UI in the Rate Year.

f. Cultural and Sport Activities

The Authority does not permit the Company to recover $1,282 in culture and sport activities expense in the Rate Year, which the Company asserts are "small token items" given to employees to reinforce corporate security best practices, health and safety messaging and reminders, and the reinforcement of Company values. The Company failed to demonstrate that such an expense is reasonable and necessary to the provision of safe and reliable service. Interrog. Resp RRU-165, p. 6.

g. Other Employee Benefits- Relocation and Student Loans

The Authority does not permit the Company to recover $349,213 in relocation and student loan reimbursement expenses allocated to it in the Rate Year.[95] The Company indicated that its student loan repayment program provides non-union employees with $250 per month to repay student loans, but that the loans do not have to be for education expenses related to an employee's job function or a completed degree. Interrog. Resp. OCC-348. Moreover, while the Company makes an unsubstantiated assertion that its student loan repayment program aids in attracting, recruiting, and retaining talent, and by

[95]The Company included employee relocation expenses in the "Other Emp Benefits" and "Other Var. Rem Actu" line items in its breakdown of the corporate service charge. Interrog. Resp. RRU-365, Att. 1.

increasing employee morale, such statements are largely anecdotal and are unsupported by any data demonstrating that the program has led to greater retention rates and recruiting success. As such, the Authority concludes that the Company has not met its burden to demonstrate that the expense is reasonable and necessary to provide safe and reliable service.

Similarly, the Company describes its relocation program as a "strategic initiative" used to attract talent, claiming that the program allows the Company to recruit skilled professionals not locally available. Interrog. Resp. RRU-137 Supp. Once again, the Company relies on anecdotal statements that the professionals that are hired and utilize the program "significantly enhance the Company's services and customer experience," but does not provide any concrete examples of such enhancements or data to quantify how the payments specifically enhance the Company's services and customer experience. Interrog. Resp. RRU-137 Supp. As such, the Authority concludes that the expense is not reasonable and necessary to the provision of safe and reliable service.

h. Branding

The Authority does not permit the Company to recover $1,163,747 in branding expenses allocated to UI in the Rate Year. The Company indicated that it removed $238,580 in Rate Year branding and communications expenses allocated to it but is still seeking recovery of $1,163,747 in allocated Iberdrola branding expenses. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.18, lns. 12, 21; Interrog. Resp. RRU-212, Att. 1.

The Company indicates that its branding expenses consist of a charge for licensing for the Company to pay for the use of Iberdrola's name. Interrog. Resp. RRU-212, Att. 1., n.4. The Company further states that the use of the Iberdrola name "grants the Company access to different technologies, a global supply chain, and business opportunities that serve as mitigating factors related to risks affecting the UI business for financing, technology, supply chain, and infrastructure." Interrog. Resp. RRU-212, Att. 1.

The Company, however, has not demonstrated that the expense reflects prudent and efficient management or otherwise benefits the efficient operation of the Company. Indeed, the Company has not demonstrated that, but for the license, the Company would not have access to different technologies, global supply chains, and business opportunities. Accordingly, the Authority disallows the inclusion of $1,163,747 in Iberdrola branding expenses in the Rate Year.

i. Investor Relations

The Authority disallows an additional $65,801 in investor relations expenses that were not yet removed from the Company's proposed Rate Year corporate service charge. The Company indicated that it removed $219,610 of investor relations expense from its revenue requirement in response to OCC interrogatories. Interrog. Resp. OCC-671; Interrog. Resp. OCC-314; Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.18, lns. 13, 29. A subsequent interrogatory response, however, indicated that the Company was allocated an additional $84,070 in Rate Year Investor Relations expense. Interrog. Resp. RRU-365, Att. 1, "investor relations" tab.

General Statutes § 16-243gg(b) prohibits the recovery "through rates [of] any direct or indirect cost associated with . . . investor relations." As such, the Authority disallows the remaining reported investor relations expenses. However, the Authority adjusts its disallowance by $18,269, from $84,070 to $65,801, to avoid double counting overlapping items previously disallowed that were reported by the Company as investor relations expenses.[96] Interrog. Resp. RRU-365, Att. 1, "investor relations" tab.

j. Board of Directors

The Company proposes $418,669 in board of directors (BOD) expenses. Interrog. Resp. OCC-708, Att. 1. After balancing the shareholder and ratepayer interests that the BOD serves, the Authority concludes that $314,002 or 75% of the Company's requested BOD costs are not recoverable from ratepayers because the BOD has a fiduciary duty to, and primarily serves the interests of, shareholders, rather than ratepayers. Moreover, such a disallowance is consistent with the Authority's findings in recent rate cases. See 23-11-02 SCG Decision, p. 128; 23-08-32 Decision, pp. 108-109.

The Company argues that it must have a board of directors and that such expenses are not optional or discretionary. Ex. UI-REBUTTAL-1, p. 17. Moreover, the Company asserts that the BOD provides important governance and oversight of utilities and obtains financing from external sources to fund the Company's capital needs. UI-REBUTTAL-1. Although the Authority considered the Company's arguments in weighing the interests of shareholders and ratepayers, the Authority also considered that the Company's shareholders are the primary beneficiaries of the BOD's actions and decisions. Indeed, the BOD owes a fiduciary duty to its shareholders, whose oversight largely focuses on protecting and enhancing shareholder value rather than directly improving service quality or reliability for ratepayers. As such, ratepayers only incidentally benefit from the BOD's activities.

Balancing the benefits shareholders receive from a BOD with the tangential benefits ratepayers receive, the Authority uses its discretion to disallow 75% or $314,002 of the Company's requested BOD Rate Year expenses.

k. Inflation

The Authority concludes that the Company failed to demonstrate that its proposed $676,198 inflation adjustment for corporate services expenses represents a reasonable known and measurable adjustment and, accordingly, does not permit the Company to recover the proposed expense in the Rate Year. Indeed, the Company's corporate service charge expenses have declined each of the past five years from $38,991,679 in 2019 to $34,277,936 in the Test Year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.0, p. 2. While the Company did assert that it does not expect a year over year decline in its Corporate Service Charges to continue, it attributed such a change to the allocation of costs to the Company under the Massachusetts formula and moving certain expenses barred by

[96]The Authority calculated the $18,269 adjustment by removing $2,355 in loyalty gifts, $15,022 in annual bonuses, $516 in other employee benefits, and $376 in variable compensation that were included in the Company's reported investor relations expense but already disallowed. Interrog. Resp. RRU-241, Att. 1, "investor relations" tab.

Public Act 23-102 “below-the-line." Interrog. Resp. OCC-573. Thus, the Company’s explanation did not demonstrate that its corporate service charges have increased with the rate of inflation or that the inflation adjustment serves as a reasonable proxy for a known and measurable change in the Rate Year. Indeed, the Company concedes that its actual distribution service charges fluctuate in a given year depending on various factors. Interrog. Resp. OCC-573. Accordingly, the Authority does not permit the Company to recover the Company’s proposed $676,198 inflation adjustment to its Rate Year corporate service charge expenses.

I. Executive Compensation

i. Summary

The Company proposes to recover $3,308,330 in compensation for all executive compensation expense, consisting of $3,075,408 for officers and $232,922 for directors. Late Filed Ex. 23, Att. 1, 2023 Test Year; Hr’g Tr., 526:4–527:19, 545:21–547:2. The Authority approves 75%, or $2,481,248, of UI executive compensation to be recovered in base rates.

The requested amount of executive compensation consists of UI executive compensation, as well as ASC and AMC executive compensation allocated to UI. Hr’g Tr., Apr. 30, 2025, 527:14-16. Specifically, a portion of compensation expense for one UI executive was allocated to the Company for a total of $243,865, and a portion of compensation expense for 54 AMC and ASC executives was allocated to the Company for a total of $2,831,543. Late Filed Ex. 23, Att. 1, 2023 Test Year; Hr’g Tr., 546:23–547:2.

Executive compensation is allocated to the Company using consumption drivers identified in its cost allocation manual. Interrog. Resp. UPA-011. Where a consumption driver cannot be identified, the Company uses the Massachusetts formula, a cost allocation methodology commonly used by regulated utilities. Id. Additionally, the Test Year executive compensation includes both fixed compensation and variable (incentive) compensation. Late Filed Ex. 23, Att. 1, “2023 Test Year” Tab. Incentive compensation includes Bonus, Stock Awards (Long-term Incentive Plan or LTIP), and the Non-Equity Incentive Plan. Hr’g Tr., 536:19–537:10. However, the Company is not including recovery of any executive bonus compensation in this Application; the LTIP has been excluded from the Company’s proposed revenue requirement. Late Filed Ex. 23, Att. 1, 2025/2026 Rate Year; Interrog. Resp. UPA-013, p. 1. For the UI executive with compensation allocated to the Company, 48% of the executive’s total compensation was incentive-based and funded through revenue requirements in the Test Year. Late Filed Ex. 23, Att. 1, “2023 Test Year” Tab. For the 54 ASC and AMC executives with compensation allocated to the Company, 41% of their total compensation was incentive-based and funded through revenue requirements in the Test Year. Id.

The Authority approves 75%, or $2,481,248, of UI executive compensation to be recovered in base rates. The remaining 25% of executive compensation is subject to reconciliation as described further below. The Authority approves this amount to better equalize Company executive incentives to benefit key stakeholders, including customers, employees, and shareholders. The Company’s Executive Variable Pay (EVP) Plan’s

objectives for ASC and Avangrid Networks, as proxies for executive compensation overall, have little direct benefit for customers. Ex. UI-CBP-9; Interrog. Resp. UPA-013, p. 3. ASC dedicates 79% of its objectives toward financial and economic goals that primarily benefit shareholders. Ex. UI-CBP-9; Interrog. Resp. UPA-013, p. 3. Among the remaining 21% of the EVP Plan's objectives, customers are the primary beneficiaries. Id. As a proxy for the EVP Plan, only 18.6% of the Avangrid CEO's objectives are related to customer outcomes (SAIDI, SAIFI, customer service standards, diversity, and LTAs), while 32.7% of the UIL Business CEO's objectives (diversity, volunteer program, customer journey redesign, employee engagement, and TRIR-related) relate to customers. Ex. UI-CBP-9. Combined, these provide an average of approximately 25% of EVP Plan objectives benefiting customers. Increasing this 25% weighting toward customer benefits by an additional 25% would result in executive compensation that reflects one half of EVP Plan objectives being attributed to customers. Therefore, the Authority reduces the recoverable amount of total executive compensation in the Test Year by 25% to better balance Company executive accountability between customers and shareholders through their compensation.

The Authority approves the inclusion of 50% of the remaining 25% of executive compensation, or $413,541 ($3,308,330 x 25%)(50%)), in base rates, but subjects such amount to reconciliation, and the inclusion of the other 50% of the remaining 25%, or $413,541, to be recovered through the RAM, with recovery of both portions contingent on the Company achieving the metrics discussed in Section VI.A.3.b., Performance Metrics. See 22-08-08 Decision, pp. 129-131 (applying similar metrics-based standard for officer compensation).

The amount the Company may ultimately recover from ratepayers is dependent on the percentage by which UI meets the metrics. For example, if the Company meets 50% of the metrics, then 12.5% of the total executive compensation included in rate base would be used to recover that portion of UI, AMC, and ASC executive compensation. With respect to the 12.5% of the total executive compensation for which recovery is disallowed (due to the Company achieving only 50% of the defined metrics), the Company would take no action toward seeking recovery of the remaining 12.5% of the executive compensation from customers in RAM. If, however, the Company meets less than half of the metrics, then the Company is directed to return the proportional share of the total Test Year executive compensation included in rate base ($413,541) to customers through the RAM as a credit and will again forego recovery of the other 12.5% through the RAM. The Company may seek recovery from its shareholders of any portion of the total executive compensation for which recovery from customers is disallowed. The Authority directs the Company, no later than March 1, 2026, and annually thereafter until the conclusion of the Company's next rate case, to file as a compliance filing in the applicable year's RAM proceeding the amount of UI, AMC, and ASC executive compensation customers are paying through base rates and through the RAM, or conversely the amount being returned to customers through the RAM.

ii. Performance Metrics

The Authority is required in a rate case to "consider the implementation of financial performance-based incentives and penalties and performance-based metrics." General Statutes § 16-19a(b). Additionally, in exercising its discretion regarding whether to allow the recovery through rates of any portion of the compensation package for executives or officers or of any portion of any incentive compensation for employees of an electric distribution company, the Authority must consider whether to require that any such compensation recoverable through rates be dependent upon the achievement of performance targets. General Statutes § 16-19yy. If the Authority approves such performance-based incentives and penalties for a particular company, PURA is required to include it in the framework for periodic monitoring and review of the company's performance pursuant to metrics developed by the Authority. General Statutes § 16-19a(b). Based on the record of this proceeding, the Authority continues to find it appropriate and necessary to tie a portion of executive compensation to performance metrics to provide the executives of UI and its parent companies with greater accountability to customers. Moreover, as discussed below, the Authority finds it necessary to adjust or alter the previous performance metrics set forth in the 22-08-08 Decision. Indeed, the Company has continued to show, by aligning no more than 25% of its executive incentive compensation, which is funded through revenue requirements, with metrics that benefit customers, that its executive compensation program does not prioritize accountability to customers. While the Company certainly bears responsibility to the investors who provide it with capital, the Company must be similarly responsible to the customers who provide it with revenue, and the Authority is empowered to make "pragmatic adjustments" that ensure a balance between investor and consumer interests. Woodbury Water Co., 174 Conn. at 264.

The Authority previously directed the Company to follow three performance metrics in order to earn the full revenue requirement request for executive compensation. The three performance metrics were: (1) Low-income customer identification metric; (2) Comprehensive and accurate customer communications metric; and (3) Payment arrangements for medical protection customers metric. Parties have suggested that the performance metrics set forth in the 22-08-08 Decision be adjusted or altered for a variety of reasons.

Regarding the low-income customer identification and payment arrangements for medical protection customers metric, the Company submitted evidence detailing its successful completion of each metric, while explaining that successful completion of the comprehensive and accurate customer communications metric was beyond the control of the Company. UI Order No. 26 Compliance, Jan. 15, 2025, Docket No. 22-08-08. OCC explained that due to the legally-required data sharing with the Department of Social Services (DSS), the low-income customer identification metric is no longer relevant. OCC Brief, p. 80. Similarly, OCC asserted that due to DSS data-sharing, the payment arrangements for medical protection customers metric has been affected and should be modified. Id., p. 81. OCC states that many medical protection customers are identified by DSS and should be excluded from this metric, thus measuring only medical protection customers without a financial hardship. Id. Regarding the comprehensive and accurate

customer communications metric, EOE asserted that it is not a suitable metric on which to base incentive compensation. EOE Brief, p. 41. The Authority finds the partes' arguments persuasive and, accordingly, sets forth revised performance metrics as discussed below.

The Company contends that its senior most executives provide "leadership, strategic direction, and oversight services" to UI and the other Avangrid companies. Interrog. Resp. UPA-009, p. 1. This leadership, direction, and oversight manifests itself in setting performance expectations, in which executives set the customer service, financial, and operational goals. Id. Further, the Company explained that the variable pay plan's objectives are measured through scorecards that include customer, financial, safety, and other factors, such as corporate responsibility. Ex. UI-CBP-1, p. 14; Ex. UI-CBP-9. While admirable and important, corporate responsibility initiatives, such as the increased use of sustainable suppliers, does not directly provide customers with accountability for the actions and decisions of the Company's executives. Ex. UI-CBP-9.

Though scorecards could provide a measure of executive accountability to customers, the Authority finds that the Company's executive incentive compensation policies implemented through scorecards most heavily weight the Company's and its parent companies' financial performance. In fact, the scorecards purported to provide customer accountability are in fact imbalanced in favor of shareholders. Accordingly, the Authority finds it is necessary and appropriate to connect some portion of the recovery of UI, AMC, and ASC executive compensation from UI ratepayers to achievement of certain customer-focused metrics.

The Authority will use the performance metrics described below to measure UI's performance. The metrics provide a means to track UI's performance with respect to customer outcomes that are not known to be a focus of the Company's current executive compensation plan, therefore providing additional accountability of the executives to UI's customers. The Historical Period shall be the average of the data from January 1, 2021, through December 31, 2025, unless the Authority finds that such data is unreliable due to missing or incomplete data, in which case the Historical Period shall be data from the Test Year. If the Company meets or exceeds the performance metrics, it may recover 100% of the executive compensation tied to performance metrics. Table 53, below, shows the recovery permitted at differing levels of performance.

Table 53: **Compensation Recovery at Different Levels of Performance**

Current Year ÷ Historical Period	Allowable Performance Metric Compensation
≥130%	100%
127 – 129.99%	90%
124 – 126.99%	80%
121 – 123.99%	70%
118 – 120.99%	60%
115 – 117.99%	50%
112 – 114.99%	40%

Current Year ÷ Historical Period	Allowable Performance Metric Compensation
109 – 111.99%	30%
106 – 108.99%	20%
103 – 105.99%	10%
≤102.99%	0%

The specific executive compensation performance metrics are:

(1) **Comprehensive and Accurate Customer Communications Metric:** The Company shall measure comprehensive and accurate customer communications by counting the number of calls reviewed by the Company's internal audit (IA) team and deemed by them to provide customers with accurate and comprehensive information for 50 calls randomly selected and reviewed by IA on a quarterly basis. The comprehensive and accurate customer communications metric shall calculate the percent of accurate and comprehensive calls in the Current Year (numerator) in relation to the percent of accurate and comprehensive calls in the Historical Period (denominator). For additional guidance on this metric's calculation methodology, see the Authority's Rulings on Motion Nos. 81 and 87 (Motion No. 81 Ruling and Motion No. 87 Ruling, respectively) in Docket No. 22-08-08.[97] See Motion No. 81 Ruling, Apr. 11, 2024, Docket No. 22-08-08, pp. 2–4; Motion No. 87 Ruling, June 25, 2024, Docket No. 22-08-08, p. 2.

(2) **Overall Arrears Metric:** The purpose of this metric is to quantify the extent to which UI has reduced overall arrearages in each category (Category) as follows: residential hardship; residential non-hardship; and small business accounts. The Company shall calculate the average number of accounts in arrears monthly. The average number of accounts in arrears monthly in the Historical Period (numerator) will be divided by the average number of accounts in arrears monthly in the Current Year (denominator).

(3) **Successful Arrears Payments Metric:** The purpose of this metric is to quantify the extent to which UI accomplishes the goal of reducing overall arrearages by helping customers on a payment arrangement successfully complete their payment arrangement. UI shall calculate the average number of accounts that leave a payment arrangement without successful completion in relation to the total number of customers in a payment arrangement monthly. The average monthly number of accounts leaving a payment arrangement without successful completion in the Historical Period (numerator) will be divided by the average monthly number of accounts leaving a payment arrangement without successful completion in the Current Year (denominator).

[97] For clarity, the Authority's reference to its Motion No. 81 and 87 Ruling are not intended as direction for EOE to continue reviewing the Company's audited calls as it pertains to the comprehensive and accurate customer communications metric.

(4) **Payment Arrangements for Medical Protection Customers Metric:** The purpose of this metric is to measure the extent to which UI has engaged medical protection customers without a financial hardship but with an arrearage in a payment arrangement. UI shall calculate the percentage of medical protection customers without a financial hardship but with an arrearage that are enrolled and participating in a payment arrangement in relation to the total number of medical protection customers without a financial hardship with an arrearage. The average number of medical protection customer accounts without a financial hardship but with an arrearage in a payment arrangement monthly in the Current Year (numerator) will be divided by the average number of medical protection customer accounts without a financial hardship and with an arrearage in the Historical Period (denominator).

The Authority directs the Company to submit as a motion for review and approval no later than January 31, 2026, the data for each year from 2021 through 2025 required to calculate the baseline for each of the performance metrics. In its ruling on the motion, the Authority will approve the Company's use of either an average of the data from 2021 through 2025, or the data from the Test Year for UI's calculation of the various performance metrics in the Test Year, depending on whether the Authority finds the data submitted for 2021 through 2025 is unreliable due to missing or incomplete data. In addition, the Authority directs the Company to annually, on or before March 1, submit in the applicable annual RAM proceeding as a compliance filing detailed information regarding whether UI met or exceeded each of the metrics during the preceding calendar year. The compliance filing shall include an unlocked workable Excel spreadsheet providing the data on which the Company relied in making its determination.

16. Residual O&M Expense

a. Summary

The Company proposes that it recover $6,528,418 in the Rate Year for residual O&M expenses, which it categorizes as advertising, bank fees, membership dues and association fees, postage, training, travel, and "Other O&M." Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.19. The Authority adjusts the residual O&M expense for the Rate Year as summarized in Table 54, below.

Table 54: Summary of Residual O&M Expenses

Components	Proposed ($)	Adjustment ($)	Allowed ($)
Advertising	150,754	(11,357)	139,397
Bank Fees	204,782	(15,427)	189,355
Membership Dues and Association Fees	239,398	(229,785)	9,614
Postage	6,657	(502)	6,155
Training	160,864	(12,119)	148,745
Travel	1,015,051	(76,471)	938,580
Other O&M	4,750,911	(357,921)	4,392,990
Total Expense	**6,528,418**	**(703,582)**	**5,824,836**

Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.19.

b. Advertising

The Company proposes $150,754 in advertising expense for the Rate Year, which is the Company's $139,137 Test Year expense plus a $11,357 generic inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.19. Although the Company labels the reported expenses as "advertising" expenses, they largely consist of customer communication expenses, such as bill inserts, listing fees to include its emergency contact information in the Yellow and White Pages, and customer educational materials. Interrog. Resp. RRU-251, Att. 1. However, there is no indication that inflating its Test Year advertising expenses by the generic inflation factor represents a known and measurable change. To the contrary, the Company's advertising expenses have fluctuated up and down since 2019 without any discernible trend tied to the rate of inflation. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.19; Interrog. Resp. OCC-254, Att. 1. As such, the Company is permitted to recover $139,137 in advertising expenses for the Rate Year, which is the Company's Test Year total without the $11,357 generic inflation factor added.

c. Bank Fees

The Company proposes to recover $204,782 in bank fees in the Rate Year, which is the Company's $189,355 Test Year expense plus a $15,427 generic inflation adjustment. Late Filed Ex. 1, Att. 2 Supp. The Company stated that its bank fees are related to banking transaction fees and other bank account related fees. Hr'g Tr., 873:20–25. There is no evidence in the record to demonstrate that a generic inflation adjustment represents a reasonable known and measurable change for the Company's Rate Year bank fee expenses. Notably, the Company's bank fee expense has fluctuated from $186,777 in 2021, to $210,984 in 2022, and to $189,355 in the Test Year. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.19. As such, the Company may recover $189,355 in bank fees for the Rate Year, which is the Company's Test Year expense without the $15,427 generic inflation adjustment added.

d. Membership Dues and Association Fees

The Company proposes $239,398 in membership dues and association fee expenses for the Rate Year, which is the Company's $365,068 Test Year industry dues expense, a ($355,454) pro forma adjustment to remove items the Company deemed barred from recovery according to General Statutes § 16-243gg(a), as amended by Public Act 23-102, plus a $229,001 Rate Year adjustment to include dues for membership in various sections of the Electric Power Research Institute (EPRI) and JD Power, and a $784 generic inflation adjustment of the Company's pro forma Test Year expenses. Late Filed Ex. 1, Att. 1; Late Filed Ex. 1, Att. 2 Supp., Sch. WP 3.19. The Authority does not permit the Company to recover proposed expenses related to the EPRI and JD Power memberships in the Rate Year. Rather, the Authority permits the Company to recover $9,614 in Rate Year expenses categorized as membership dues and association fees by the Company.

General Statues § 16-243gg(a) states in relevant part:

> no electric distribution company . . . shall recover through rates any direct or indirect cost associated with membership, dues, sponsorships or contributions to a business or industry trade association, group or related entity under Section 501 of the Internal Revenue Code of 1986, or any subsequent corresponding internal revenue code of the United States, as amended from time to time.

The Company seeks $201,671 in the Rate Year to rejoin EPRI. Late Filed Ex. 1, Att. 1; Late Filed Ex. 1, Att. 2 Supp., Sch. WP 3.19. The Company describes EPRI as an "industry organization" that "performs research and provides guidance on emerging trends in the power sector," such as the clean energy transition and maintaining safe, reliable, affordable, and resilient service. Interrog. Resp. OCC-695. The Company further describes EPRI as a "research organization" that pools the research dollars from most of the electric utilities in the United States and many utilities abroad and creates a platform for utilities to collaborate and share in the learnings and results." Interrog. Resp. OCC-695. Finally, the Company indicated that the organization is "made up of many utilities in the US that bring their ideas . . . EPRI provides input and the member utilities provide input." Hr'g Tr., 709–719.

The Company indicated that pricing for an EPRI membership depends on the size of the utility and the amount of various programs in which the member utility participates. Hr'g Tr., 713:18–24. The Company indicated that it intends to participate in the same programs that it did prior to declining to renew its EPRI membership following the 22-08-08 Decision. Hr'g Tr., 717:9–16. Thus, based on an invoice the Company provided, its proposed EPRI membership in the Rate Year would include the following programs: composite structure management; line design tools and practices for construction; polymer and composite overheard transmission line 1; porcelain and glass overhead transmission line; HVDC lines; underground transmission; HCDC converter stations; and flexible alternating strategic intelligence and industry collaboration, DER integration, distribution systems, and operations and planning. Interrog. Resp. OCC-695. Moreover,

OCC opined that the Company has met its burden to demonstrate that its EPRI expenses is appropriately recovered from ratepayers. OCC Brief, pp. 91–92.

Although the Authority likewise recognizes that EPRI membership could constitute a reasonable expense to be recovered from ratepayers and provide valuable insights to the Company, the Authority is constrained by the plain language of General Statutes § 16-243gg(a) which bars recovery from ratepayers for direct or indirect costs associated with membership, dues, sponsorships, or contributions to a business or industry trade association, group, or related entity under Section 501 of the Internal Revenue Code of 1986. As previously discussed, the Company refers to EPRI as an "industry organization" or "research organization." The Company later argued that EPRI membership does not constitute dues, sponsorships, or contributions, but constitutes the Company "purchasing access" to programs offered by EPRI.[98]

Regardless of the Company's description of EPRI, it is clearly a collective of peers that are in the utility industry and, thus, fits the broad description of a business or trade association, group, or related entity under Section 501 of the Internal Revenue Code of 1986 . Moreover, an invoice from EPRI indicates in the lower right-hand corner that it is a nonprofit United States Corporation and, therefore, appears to be an entity that falls within Section 501 of the Internal Revenue Code and is intended to not be recoverable from ratepayers under General Statutes § 16-243gg(a). Interrog. Resp. OCC-691, Att. 1. Accordingly, the Authority cannot not permit the Company to recover $201,671 to rejoin EPRI in the Rate Year as a matter of law.

The Company also requests that it recover $27,330 in Rate Year expenses for JD Power. Late Filed Ex. 1, Att. 1; Late Filed Ex. 1, Att. 2 Supp., Sch. WP 3.19. The Authority finds that the Company did not satisfy its burden of demonstrating that its proposed Rate Year JD Power expenses are prudent. The Company indicated that JD Power is a "subscription to a syndicated customer satisfaction survey provided by a market research company." Interrog. Resp. OCC-109. The Company further explained that JD Power is a "relatively low-cost option" that offers it "valuable insights through industry benchmarking studies, which are highly beneficial for understanding customer opinions and informing strategic planning," which help the Company maintain a "competitive edge" that ensures it provides high-quality service to customers. Interrog. Resp. OCC-109.

The Authority finds that the Company's stated benefits of participating in JD Power are nonspecific and anecdotal and, therefore, the Company has failed to meet its burden of demonstrating that such an expense is prudent. Indeed, the Company did not identify any specific learnings, actions, or initiatives it undertook based on past JD Power survey results, nor did it explain what "competitive advantage" it needed to maintain as a monopoly utility company. Moreover, despite asserting that JD Power surveys help to obtain quicker response times or effective resolutions, the Company did not provide any

[98]Neither the Company's nor OCC's written exceptions offered a thorough legal analysis of General Statutes § 16-243gg(a) and why EPRI membership is not barred from recovery from ratepayers.

data to support such claims. Interrog. Resp. RRU-308. Accordingly, the Authority does not permit the Company to recover $27,330 in Rate Year expenses for JD Power.

Finally, the Company has not satisfied its burden of demonstrating that applying a generic inflation adjustment to the remainder of the Company's $9,614 in pro forma Test Year expenses represents a reasonable known and measurable change for such expenses in the Rate Year. Accordingly, the Company does not permit the Company to recover $784 in inflation expenses for the Rate Year.

e. Postage

The Company proposes $6,657 in Rate Year postage expense, which is the Company's $6,155 Test Year expense plus a $502 generic inflation adjustment. Late Filed Ex. 1, Att. 2 Supp. There is no evidence indicating that applying a generic inflation adjustment to the Company's Test Year expense is a reasonable known and measurable adjustment. Therefore, the Authority permits the Company to recover $6,155 in postage expenses for the Rate Year.

f. Training

The Company proposes $160,864 in the Rate Year for training expenses, which is the Company's $148,745 Test Year amount plus a $12,119 generic inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.19. The Company, however, did not meet its burden to demonstrate that a generic inflation adjustment to its Rate Year expenses constitutes a reasonable known and measurable change. Notably, the Company's training expenses since 2019 have varied from year to year and have not steadily risen with inflation. Interrog. Resp. OCC-352, Att. 3. Accordingly, the Company is permitted to recover $148,745 in training expenses in the Rate Year, which is the Company's Test Year expenses without the generic inflation adjustment added.

g. Travel Expense

The Company proposes $1,015,051 in Rate Year travel expenses, which is the Company's $961,573 Test Year expense, a ($22,993) pro forma adjustment to remove entertainment costs barred from recovery under General Statutes § 16-244gg, plus a $76,471 generic inflation adjustment. Late Filed Ex. 1, Att. 2 Supp, Sch. C-3.19 WP, p. 1. The Authority does not permit the Company to recover the $76,471 because the Company did not meet its burden to demonstrate that a generic inflation adjustment constitutes a reasonable known and measurable change to the Company's travel expenses in the Rate Year. Rather, the Company's travel expenses have varied between 2019 and the Rate Year. Interrog. Resp. OCC-352, Att. 23. Accordingly, the Authority permits the Company to recover $938,580 in Rate Year travel expenses.

h. Other O&M

The Company proposes that it recover $4,750,911 in the Rate Year for "other O&M" expenses, which is the Company's $5,731,385 Test Year expense, a ($1,338,395) pro forma adjustment, plus a $357,921 inflation adjustment. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.19. The Company did not meet its burden of demonstrating that a generic

inflation factor is a reasonable known and measurable adjustment for the Company's Rate Year expenses. The Company's Other O&M expenses include miscellaneous expenses such as sundry uncollectible expenses and the Company's overhead occupancy pool. Hr'g Tr., 866–899. Notably, the Company's other O&M expenses have varied between 2019 and the Test Year and have declined since 2021. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.19. The Authority concludes that the Company's Other O&M expenses do not increase at the rate of inflation. Accordingly, the Authority permits the Company to recover $4,392,990 in Rate Year other O&M expenses, which is the Company's Test Year amount less the pro forma adjustment.

17. Other Deferred Expenses

a. Summary

The Authority includes the amortized recovery of certain deferred costs, with carrying costs, as expenses in the Company's revenue requirement. This method of recovery outside of rate base will allow the Company to recover its operating expenses while allowing rates to be "no more than sufficient" to cover declining annual balances. Accordingly, the Company is allowed to recover the deferred expenses itemized below.

For these expenses, the Authority allows amortized recovery over a three-year period, November 1, 2025, through October 31, 2028. If the Company has not filed an application to amend its existing rate schedules by November 1, 2028, the Company is directed to submit, as part of its 2029 rate adjustment mechanism RDM filing, an accounting of any overcollection as a result of the expiration of the three-year amortization period, and a proposed RDM rate to reflect such overcollections. The tables below summarize the amortized recovery approved for the deferred expenses. Unless specified otherwise, the Authority's adjustments shown herein reflect the recalculation of carrying costs to reflect a three-year amortization period.

Table 55: Deferral Rate Year Beginning Balances

Deferred Expense	Reported Balance, October 31, 2025 ($)	Adjustment ($)	Approved Balance, November 1, 2025 ($)
Pension - Deferral	6,767,774	229	6,768,003
Pension - Interim Period	1,853,470	(26,292)	1,827,178
OPEB - Deferral	(284,085)	(417)	(284,502)
OPEB - Interim Period	(979,774)	200,739	(779,035)
Storm - Deferral (22-08-08)	9,453,741	69	9,453,810
Storm Deferral 2025 Event	5,510,724	(1,292,094)	4,128,630
New Storm Deferral	(2,073,381)	(2,096,406)	(4,169,787)
COVID - Deferral	1,862,157	(149)	1,862,008
CAM GET - Deferral	(1,026,348)	262	(1,026,086)
Isaias Penalty	(16,867)	16,867	-
Isaias Customer Credit Over/(Under)	144,785	(35,064)	109,721
Environmental Deferral	481,664	(51,429)	430,235
Fee Free Program	(1,852,863)	(308,376)	(2,161,239)
Regulatory Proceeding Costs	1,275,258	-	1,275,258
Earnings Sharing Mechanism	276,191	-	276,191
Rate Case Expense	3,163,323	(2,201,089)	962,234
Water Heater Rental Program	12,019,711	(1,840,018)	10,179,693
Total Expense	**36,575,480**	**(7,633,168)**	**28,942,312**

Late Filed Ex. 1, Att. 2 Supp., Sch. B-1.0; Sch. B-6.0; Sch. B-8.0; Sch. WP C-3.21, p. 1; Ex. RRP-22D, pp. 1–8.

Table 56: Approved Annual Amortization Expense (Deferral and Interim Period)

	Approved Balance, Nov. 1, 2025 ($)	Allowed Carrying Costs ($)	Total Deferred Amounts Amortized ($)	Proposed Annual Amortization ($)	Adjustment ($)	Allowed Annual Amortization ($)
Pension	8,595,181	907,651	9,502,832	4,429,642	(1,262,031)	3,167,611
OPEB	(1,063,537)	(112,310)	(1,175,847)	(1,269,676)	877,727	(391,949)
Storm (22-08-08, 2025 Event, New Storm)	9,502,653	1,003,480	10,506,133	3,351,641	150,403	3,502,044
COVID Deferral	1,862,008	196,628	2,058,636	1,904,987	(1,218,775)	686,212
CAM GET	(1,026,086)	(108,355)	(1,134,441)	(1,049,770)	671,623	(378,147)
Isaias (Penalty, Customer Credit)	109,721	11,587	121,308	127,592	(87,156)	40,436
Environmental	430,235	0	430,235	481,664	(338,252)	143,412
Fee Free Program	(2,161,239)	(228,227)	(2,389,466)	(1,852,863)	1,056,374	(796,489)
Regulatory Proceeding	1,275,258	134,667	1,409,925	1,275,258	(805,283)	469,975
Earnings Sharing Mechanism	276,191	29,166	305,357	276,191	(174,405)	101,786
Rate Case Expense	962,234	101,612	1,063,846	1,054,441	(699,826)	354,615
Water Heater Rental	10,179,693	1,074,976	11,254,669	4,006,570	(255,014)	3,751,556
Total	**28,942,312**	**3,010,875**	**31,953,187**	**12,735,679**	**(2,084,615)**	**10,651,064**

Late Filed Ex. 1, Att. 2 Supp., Sch. B-1.0, Sch. B-6.0, Sch. B-8.0, Sch. WP C-3.21, p. 1; Ex. RRP-22D, pp. 1–8.

b. Pension

The Authority permits the Company to recover a total of $9,502,832 in pension deferral expenses over a three-year period for a Rate Year amortization expense of $3,167,611.

The Company reported a pension deferral balance of $13,053,936 as of August 2023. Ex. UI-RRP-22A, pp. 1–2. However, the Authority previously permitted the Company to recover a pension deferral of $12,880,858, which included an approved pension cost of $11,226,758 and carrying costs of $1,654,100. 22-08-08 Decision, p. 191; Ex. UI-RRP-22d, p. 3. The Company explained that the Authority's approval of the $12,880,858 deferred pension expense in the 22-08-08 Decision was for amounts accrued as of June 30, 2022. Ex. UI-RRP-1, p. 85. Thus, the Company's $13,053,936 pension deferral balance as of August 2023 consisted of $11,226,758, the remaining balance of the amortized pension costs approved in the 22-08-08 Decision and $1,827,178 in incremental pension costs incurred between July 1, 2022, and August 2023. Ex. UI-RRP-22d.

Through the close of the Interim Period, the Company reported a $6,767,774 deferral balance for pension expense approved in the 22-08-08 Decision, and $1,853,470 in additional pension expense, which consists of the Company's $1,827,178 incremental pension costs plus $26,292 in carrying charges. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C- 3.21, p. 1.

The Authority previously explained that a regulatory asset for ratemaking purposes arises only after the Authority has scrutinized a deferred expense for consistency with General Statutes § 16-19e(a) and authorized recovery via an order in a rate proceeding. 22-08-08 Decision, p. 27. Additionally, the Authority further stated that carrying charges are not permissible on deferred expenses without prior Authority approval, noting, among other things, that allowing carrying charges to accrue on deferred expenses that have not been subject to scrutiny and prudence review is inconsistent with general ratemaking principles. Id., p. 28. Conversely, however, the Authority concluded that carrying charges are permissible on regulatory assets during the recovery period. Id. Specifically, when a deferred expense is deemed prudent, it becomes a ratemaking regulatory asset that is amortized over a period of time, and the Company may include carrying charges to compensate the Company for the time it will take to fully recover the regulatory asset from ratepayers. Id., pp. 28-29.

In the present case, while the Authority scrutinized and subsequently approved a $12,880,858 regulatory asset for pension expenses, which included carrying charges during the recovery period, the Authority did not do so for the $1,827,178 in pension expenses accrued after the 22-08-08 Decision. As such, the Authority did not approve or permit the Company to treat its newly accumulated pension expense as a regulatory asset that accrues carrying charges. As such, the Authority does not permit the Company to recover $26,292 in carrying charges it claims to have accrued in the intervening years. Nevertheless, the Authority will permit the Company to accrue carrying charges on the $1,827,178 incremental pension balance going forward because the Authority is authorizing the Company to treat the expense as a regulatory asset in the Rate Year.

In sum, the Authority permits the Company to amortize $9,502,832 in pension expenses over a three-year period, which is a $8,595,181 balance[99] as of the beginning of the Rate Year plus $907,651 in carrying costs. Thus, the amortized Rate Year pension expense is $3,167,611.

c. OPEB

The Authority approves an OPEB credit of ($1,175,847), which is to be amortized over a three-year period, resulting in a Rate Year credit of ($391,949).

The Company reported a $1,576,130 deferred OPEB liability accrued as of August 31, 2023. Ex. UI-RRP-22A, pp. 1, 4. The Authority previously approved an OPEB deferred regulatory liability of $791,694 amortized over three years, resulting in an annual amortization credit of $263,898. 22-08-08 Decision, p. 189. However, the Company reported a ($1,263,859) total deferred OPEB balance as of October 31, 2025, which consists of ($289,902) in deferred amounts approved in the 22-08-08 Decision plus ($979,774) of additional OPEB liabilities that accrued between July 2022 and August 2023. Ex. UI-RRP-22A, pp. 1-5; Ex. UI-RRP-1, pp. 85-86. The Company proposed to amortize the credit over one year. Ex. UI-RRP-22A.

Utilizing the same logic regarding the treatment of regulatory liabilities as described in the pension amortization section above, the Authority removes $200,322 net carrying credits related to the $979,774 in accumulated OPEB liabilities since the 22-08-08 Decision. Thus, the Authority allows $1,063,537 ($1,263,859 - $200,322) as total net OPEB liabilities as of November 1, 2025. However, carrying credits on the incremental $1,063,537shall accumulate starting with the beginning of the Rate Year. Accordingly, the Company shall amortize a regulatory liability balance of ($1,175,847) (($1,063,537)+($112,310)) as of October 31, 2025, which, for consistency with the 22-08-08 Decision, shall be amortized over a three-year period, resulting in a ($391,949) Rate Year credit.

d. Storm Deferral (Continuing Amortization Approved in 22-08-08 Decision)

The Authority concludes that the Company correctly calculated the balance and associated carrying charges associated with the amortized storm expenses approved in the Company's last rate case. Late Filed Ex. 1, Att. 2 Supp, Sch. WP C-3.21, p. 1; 22-08-08 Decision, p. 191. For efficiency, the Authority includes the $9,502,653 remaining storm balance with the new storm deferral discussed below and amortizes the total expense over a three-year period.

e. Isaias Deferral and Customer Credit

The Company proposes that it recover a $127,918 regulatory asset in connection with a penalty imposed on the Company following Tropical Storm Isaias that was not returned to customers as of the Company's 2022 rate case. Ex. UI-RRP-1, p. 88; Late

[99]The Authority also makes a nominal $229 increase to the Company's October 31, 2025, based on the Authority's calculation of the Rate Year balance.

Filed Ex. 1, Att. 2, Supp, Sch. WP C-3.21. More specifically, the Company's request includes ($16,867) for the remaining balance of a regulatory liability approved in the 22-08-08 Decision and $144,875 for an excess credit issued to customers during August 2022 through October 2024. Ex. UI-RRP-1, pp. 88-89; Ex. RRP-22F, pp. 1–3. The Authority permits the Company to amortize $121,308 over a three-year period for a Rate Year amortization expense of $40,436.

As of August 31, 2021, the Company needed to return $1,187,647 to ratepayers. Interrog. Resp. RRU-394, Att. 1. The Company subsequently returned $1,264,991 to customers between August 31, 2021, and August 31, 2023, and reported $12,601 in carrying credits, resulting in a reported excess credited amount of $64,473 ($1,264,991 - $1,187,647 - $12,601) as of August 31, 2023. The Authority subsequently directed the Company to return a $46,878 unrefunded balance to ratepayers over 36 months. 22-08-08 Decision, p. 189.[100] Accordingly, the Company is expected to refund an additional $33,909 by October 31, 2025 (($46,951/36 months) x 26 months). Therefore, with the addition of $11,069 in carrying charges, the total excess credit, as of October 31, 2025, is $109,721 ($64,473 + $33,909 + $11,069). After applying $11,587 in carrying charges over the amortization period, the Authority permits the Company to amortize $121,308 over three years, resulting in a $40,436 Rate Year amortization expense.

f. New Storm Deferral

In its Application, the Company is requesting two new storm deferrals. Late Filed Ex. 1, Att. 2, WP C-3.21, p. 1, lns. 14 and 21. The first storm deferral is a refund of $2,073,000 to be amortized over 12 months. Late Filed Ex. 1, Att. 2, WP C-3.21, p. 1 (line 14 - "Storm deferral"); Interrog. Resp. EOE-249 Supp. 2, Att. 2. This deferral includes the following storms: Elsa, Hurricane Henri, Izzy, Blizzard, Flooding, and Hurricane Lee – Lean-In Costs (Storm Deferral Refund). Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 3. The other storm deferral the Company is reporting is a balance of $5,511,000 to be amortized over 36 months. Late Filed Ex. 1, Att. 2, WP C-3.21, p. 1 (line 21 - "Stor[m] Deferra[l] – 2025 Event"); Interrog. Resp. EOE-249 Supp. 2, Att. 3. This deferral only includes one storm, referred to as "Thunderstorms" (Thunderstorms Deferral). Interrog. Resp. EOE-249 Supp. 2, Att. 3, p. 3.

As described above in Section VI.A.7., Storm Expense, the Company is permitted to charge expenses to a storm reserve if the incremental expenses for that storm exceed a certain threshold (major storm threshold). The major storm threshold is determined by applying the Handy-Whitman Index[101] to a major storm threshold of $1 million established in the 13-01-19 Decision. 22-08-08 Decision, pp. 152–153. The current major storm threshold is $1.924 million as of the filing of the Application. Ex. UI-RRP-1, p. 65.

Incremental storm expenses that exceed the major storm threshold are permitted deferred recovery because catastrophic storm costs of a certain level are unpredictable and could have the potential to affect the financial health of the Company. 13-01-19

[100]The figures in the 22-08-08 Decision were rounded.

[101]The Handy Whitman Index is an industry standard indexing tool that reflects prior utility construction costs in current dollars. 22-08-08 Decision, p. 152.

Decision, p. 25. The Authority established the major storm threshold to identify which costs were allowable for deferred recovery. The Authority has permitted the Company $2 million in storm reserve accrual per year to be applied to the deferred major storm expenses. 22-08-08 Decision, p. 151. The storm reserve was established to help mitigate rate shocks that are often associated with the accrual of significant storm recovery costs. Id. The storm reserve accrual is applied as a monthly credit of $166,667 credit to the storm reserve. See Ex. UI-RRP-22C, p. 2.

i. Summary of Allowed New Storm Deferrals

The new storm deferral allowed for recovery as a deferred expense is the sum of the Storm Deferral Refund and the Thunderstorm Deferral. Table 57 shows the allowable balance for recovery of the two deferrals. These deferrals result in a balance of $48,843.

Table 57: Total New Storm Deferral Balance, October 31, 2025

	Requested ($)	Adjustment ($)	Allowed ($)
Tropical Storm Elsa Expense	(7,896)	-	(7,896)
Hurricane Henri Expense	97,782	(10,592)	87,190
Storm Izzy Expense	76,010	(38,427)	37,583
Blizzard Expense	14,656	-	14,656
Flooding Event Expense	1,292,571	(74,130)	1,218,441
Hurricane Lee Expense	1,082,185	(12,023)	1,070,162
Storm Accrual	(2,666,667)	(1,666,666)	(4,333,333)
Mutual Aid Reimbursements	(1,881,623)	-	(1,881,623)
Carrying Charges	(80,343)	(294,568)	(374,911)
Total Storm Deferral Refund	**(2,073,381)**	**(2,096,406)**	**(4,169,787)**
Deferred Expenses	5,158,530	(939,899)	4,218,630
Carrying Charges	352,195	(352,195)	-
Total Thunderstorm Deferral	**5,510,724**	**(1,292,094)**	**4,218,630**
Total	**3,437,343**	**(3,388,500)**	**48,843**

ii. Storm Deferral Refund

For the Storm Deferral Refund, the Company reported $2,555,251 in storm costs from August 2021 through December 2024 associated with six storm events. Interrog. Resp. EOE-249 Supp. 2, Att. 2. The Company also reported mutual aid reimbursements of $1,882,623 and a storm accrual balance of $2,667,667 between September 2023 and December 2024. Id. The Company also reports $9,091 in carrying costs from August 2021 through December 2024. Id. Lastly, the Company forecasts a refund of $89,434 in carrying costs between January 2025 and September 2025, which results in the total forecasted refund balance of $2,073,381 by September 30, 2025. Id.

The Authority reviews and adjusts deferred storm costs for five of the six storms where deferred expenses are sought for recovery by the Company. Due to the number of individual events, each storm event is addressed individually in separate sections below.

(a) Tropical Storm Elsa Deferred Expenses

The Company reports a refund of $7,896 for Tropical Storm Elsa as an accounting accrual for contractors and materials. Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 3. The Authority approves the refund of $7,896 for Tropical Storm Elsa.

(b) Hurricane Henri Deferred Expenses

For Hurricane Henri, which occurred on August 21, 2021, the Company reported expenses and accounting accruals relating to external vendors totaling $97,782 in total storm costs. Interrog. Resp. EOE-164, Att. 1, Att. 2; Interrog. Resp. EOE-249, Att. 1. The Authority finds issues with the time charged for travel submitted by one of the vendors, ASPLUNDH Tree Expert, LLC. Interrog. Resp. EOE-164, Att. 1; Interrog. Resp. EOE-164, Att. 2, pp. 52–79. Various timesheets submitted by the vendor show that the charged amount of travel time exceeds the supporting documentation submitted by the Company, which include various maps showing the travel time from Orange, CT to Lancaster, NY or Buffalo, NY ranging from 6 hours and 53 minutes to 7 hours and 32 minutes. Interrog. Resp. EOE-164, Att. 2, pp. 53, 55, 57, 59, 61, 63, 67, 69, 73, 75. The difference from Google Map supporting documentation to travel time charged was approximately six hours. Id. Additionally, for the same storm, the same vendor and same crews charged fewer hours of travel time for the trip from New York to Connecticut. Id., pp. 24, 29, 34, 48. The supporting documentation submitted for this trip from New York to Connecticut is the Google Map estimate from Connecticut to New York, which is not indicative of the actual travel time going in the opposite direction. Id., pp. 26, 31, 36, 43, 50. The difference from Google Map supporting documentation to travel time charged for this trip from New York to Connecticut was approximately three hours. Id. Neither the Company nor the vendor timesheets provided substantial or persuasive reasoning for the extra travel time charged, and, therefore, the Authority finds it reasonable to adjust the travel time charged for the trip to New York to match the shorter travel time charged for the trip to Connecticut. After equalizing the travel time for both trips, the approved costs for this vendor are $231,190, an adjustment of $10,592.[102] Interrog. Resp. EOE-164, Att. 2, pp. 52–79. The new total for Hurricane Henri would be $87,190 when taking the sum of all expenses.

(c) Storm Izzy Deferred Expenses

As for Storm Izzy, which occurred on January 17, 2022, the Company submitted expenses related to overtime, materials, and accounting accruals totaling $76,010. Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 3 (“Incremental Costs” column). The

[102]The Authority does not present the calculation used to determine the disallowed amount because the data it is based on (i.e., the individual travel times and the travel rates) have been redacted. See Interrog. Resp. EOE-164, Att. 2 Confidential.

Company asserts that Avangrid employees have a role in the storm restoration process, either directly engaging in restoration activities or supporting personnel and business function required for day-to-day operations regardless of their day-to-day responsibilities. Ex. UI-EOP-1, p. 49. Based on this expectation that internal employees are expected to perform storm related duties, the Authority considers a small portion of tools, supplies, fuel, and PPE as normal operation expense; therefore, it is reasonable to disallow 25% of those costs. See Decision, Apr. 17, 2019, Docket No. 18-11-12, Petition of The Connecticut Light and Power Company d/b/a Eversource Energy for Approval to Recover its 2017-2018 Catastrophic Storm Costs (18-11-12 Decision), pp. 13–14. Additionally, EOE also believes that some of the materials include items that are available for use post-storm and suggests the Authority apply an approach similar to the historical reductions imposed on The Connecticut Light and Power Company d/b/a Eversource Energy (Eversource) in the 18-11-12 Decision. EOE Brief, p. 50. The Authority agrees with EOE's assertion and, as a result, reduces the materials expense of $89,164.90 by 25%, which is $64,623.68. Interrog. Resp. EOE-165, Att. 2.

The Company reports $9,381.88 in shared service expenses for Storm Izzy. Late Filed Ex. 39, Att. 1. EOE argues that the summarized expense for shared services generally aligns with allocated storm costs, but the documentation the Company provided does not explain or support how the shared services costs were necessary incremental costs. EOE Brief, pp. 48–49; Interrog. Resp. EOE-255, Att. 1; Late Filed Ex. 39, Att. 1. Additionally, EOE believes it is unclear whether the expenses reported were incremental given that affiliate costs, including security costs, are allocated to the Company within its revenue requirements. EOE Brief, p. 49. Like EOE, the Authority is unable to determine if these shared services costs are truly incremental in the aggregate; however, the Company did provide an invoice from Securitas for $246.42 for services rendered to Avangrid Service Company during the storm, which the Authority deems to be incremental. Late Filed Ex. 39, Att. 1 & 2. Therefore, the Authority allows $246 and disallows $9,135 in shared service expenses for Storm Izzy.

The Company reports $4,739 in overtime costs for Storm Izzy. Interrog. Resp. RSR-10, Att. 1; Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 3. EOE questions how internal labor overtime costs could apply to a storm that was sought for recovery in the 22-08-08 Decision. EOE Brief, p. 49. The Authority concurs and also questions how new internal labor overtime costs could apply to a storm that was already reviewed and addressed in the 22-08-08 Decision. Although there may be a delay in the reporting of shared service expenses and external vendor invoices, the Authority cannot reconcile how these overtime costs were unknown at the time the Company was seeking recovery. The Company failed to provide any evidence to verify that these costs were not already included in the last storm deferral and, therefore, the Authority disallows $4,739 in overtime for this storm. Table 58, below, summarizes the proposed and approved costs for Storm Izzy.

Table 58: Storm Izzy Deferred Expenses and Adjustments

	Proposed ($)	Adjustment ($)	Approved ($)
Overtime	4,739	(4,739)	-
Fleet Fuel	(30,356)	-	(30,356)
Contractors and Affiliates	12,451	(9,135)	3,316
Materials	89,176	(24,553)	64,623
Total	**76,010**	**(38,427)**	**37,583**

See Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 3; Interrog. Resp. EOE-165, Att. 1.

(d) Flooding Event Deferred Expenses

The Company is requesting $1,292,571 in storm expenses relating to a Flooding event (Storm #7) on December 23, 2022. Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 3. For this storm, the Company is reporting $477,359 related to overtime costs. Id. As part of its methodology, the Company allocates internal labor costs to storms by charging only hours worked more than an employee's "regular time", because all expenses related to "regular time" is already collected in base rates. Ex. UI-RRP-1, pp. 67–68. As evidence in support of the overtime expense, the Company provides an employee, their positions, salary, date they worked overtime, the overtime hours they worked, and the cost of the overtime hours worked. Interrog. Resp. EOE-260, Att. 1. The documentation the Company provided reflects the employees involved, the dates and number of overtime hours worked, and the associated costs. The Authority permits $477,359 in overtime costs.

The Company also submitted invoices and corresponding documentation through timesheets to verify expenses charged by external vendors for this storm. Interrog. Resp. EOE-167, Att. 1, Att. 2; Interrog. Resp. EOE-261, Att. 1; Interrog. Resp. EOE-262, Att. 1, 2, Att. 3. Tempest Energy, LLC was one of these vendors, charging $253,904. Interrog. Resp. EOE-167, Att. 1; Application, Ex. UI-RRP-22C, p. 3; Interrog. Resp. EOE-249, Att. 1. The Authority was unable to verify the costs associated with one of the employees of Tempest Energy, LLC that submitted costs for this storm. See Interrog. Resp. EOE-167, Att. 2, pp. 22–23 (showing an invoice for Tempest Energy, LLC totaling $10,511.62 with no corresponding timesheet in Interrog. Resp. EOE-261, Att. 1); Interrog. Resp. EOE-261 (Company was asked to present timesheets to support the costs related to the vendor Tempest Energy). Following Tropical Storm Isaias, the Authority established certain storm response requirements, one of which was that UI must document in time sheets work done by external or contractor line crews and damage assessors. 20-08-03 Decision, p. 119. The contractor timesheets are required to include the following information for contractor crews: number or amount of work performed; description and location of work performed; beginning and ending locations; paid time spent traveling at start and end of shift; paid time traveled for mobilization and demobilization; paid stand-by time; and employee names, dates, and hours worked. Id., p. 119. The Company instituted the Contractor Daily Time and Work Report requirements in 2022 and confirmed that it requires contractors to provide the UI Contractor Daily Time & Work Report prior to the

processing of invoices. Interrog. Resp. RSR-162; Application, Ex. UI-RRP-15, p. 7. Nonetheless, the corresponding time sheet for the Tempest Energy, LLC employee was not provided here. Accordingly, the Authority removes $10,512 in expenses for this vendor, making their new total $250,778.[103] Interrog. Resp. EOE-167, Att. 2, p. 19.

Another vendor, ASPLUNDH Tree Expert LLC (ASPLUNDH), charged $75,780 for the same event. Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 3; Interrog. Resp. EOE-262, Att. 2, pp. 62–81; Late Filed Ex. 41. EOE argues that the Company allowed approximately 9.2% of the hours to be inaccurately billed at an Overtime (OT) rate in lieu of the Standard Time (ST) rate. EOE Brief, p. 52. EOE argues that the specific OT rules that were in effect for this vendor allow for OT to be charged for activities that occurred "outside of the hours of 7 a.m. to 4:30 p.m. Monday – Friday or after 45 scheduled hours." Id. (citing Late Filed Ex. 40). EOE highlights that the vendor incorrectly billed more ST hours between Monday and Thursday resulting in excess OT hours to be billed to the Friday storm event, which resulted in an incorrect, larger amount of deferred storm costs. Id. The Authority agrees with EOE's assertions and will adjust the ST and OT hours being charged by the vendor to determine the allowable expense. The new ST and OT hours are as follows: for L1, 18 hours of ST and 33.5 hours of OT; for L2, 144 hours of ST and 239.5 hours of OT; for L4, 162 hours of ST and 271.5 hours of OT; and for P1, 9 hours of ST and 12 hours of OT. See Interrog. Resp. EOE-262, Att. 2, p. 62. This results in a disallowance of $4,274 resulting in an allowed amount for ASPLUNDH of $73,710.[104]

The Authority previously found that it is reasonable to disallow 25% of costs associated with materials, fuels, supplies, and PPE. See Decision, Apr. 17, 2019, Docket No. 18-11-12, Petition of The Connecticut Light and Power Company d/b/a Eversource Energy for Approval to Recover its 2017-2018 Catastrophic Storm Costs, pp. 13–14; EOE Brief, p. 50. The Company reports $123,877 in materials and $62,195 in fleet fuel for this storm. Interrog. Resp. EOE-167, Att. 4; Interrog. Resp. EOE-249, Att. 1. Therefore, after applying the 25% disallowance established by the 18-11-12 Decision, the Authority allows $92,909 in materials and $46,646 in fleet fuel for the Flooding event.

The Company also reported $23,495 in shared service expenses. Interrog. Resp. EOE-249 Supp. 2, Att. 1; Interrog. Resp. EOE-263, Att. 1; Late Filed Ex. 39, Att. 4, Att. 5. The Authority previously discussed that UI already receives money in rates for affiliate services, and the information the Company provided is not enough to demonstrate that the costs the Company is requesting are truly incremental. Additionally, EOE believes it is unclear whether the expenses reported were incremental given that affiliate costs, including security costs, are allocated to the Company within its revenue requirements. EOE Brief, p. 49. The Authority largely agrees with EOE. While the Company already

[103]The Company submitted a total of $261,290 of invoices for Tempest but requested only $253,904 of expenses for this vendor. Interrog. Resp. EOE-167, Att. 2. Therefore, the Authority reduced the total amount of invoices of $261, 290 by the unsupported amount of $10,512 resulting in a total allowed amount of $250,778. This results in an "effective" disallowance of $3,126 ($253,904 - $250,778).

[104]The Company submitted a total of $77,984 of invoices for this storm but requested recovery of $75,780. See Interrog. Resp. EOE-262, Att. 2. Therefore, the Authority reduced the total amount of invoices of $77,984 by the disallowed amount of $4,274 resulting in total allowed amount of $73,710. This results in an "effective" disallowance of $2,070 ($75,780 - $73,710).

recovers shared services expenses through base rates, raising uncertainty as to whether the requested costs are truly incremental, the Company did provide an invoice from Allied Universal ($1,079) for services rendered to Avangrid Service Company during this storm, which the Authority deems incremental. Therefore, the Authority allows $1,079 and disallows $22,416. Late Filed Ex. 39, Att. 5, pp. 1–2. Table 59, below, shows a summary of the requested and allowed incremental expenses for the Flooding event totaling $1,218,441.

Table 59: Flooding Event Requested and Approved Expenses

	Proposed ($)	Adjustment ($)	Approved ($)
Overtime	477,359	-	477,359
Fleet Fuel	62,195	(15,549)	46,646
Contractor - Tempest	253,904	(3,126)	250,778
Contractor -Asplundh	75,780	(2,070)	73,710
Other Contractors	220,549	-	220,549
Affiliates	23,495	(22,416)	1,079
Materials	123,877	(30,969)	92,908
Meals and Lodging	1,844	-	1,844
Agency Staffing	53,568	-	53,568
Total	**1,292,571**	**(74,130)**	**1,218,441**

See Interrog. Resp. EOE-249 Supp. 2, Att. 2.

(e) Blizzard Event Deferred Expenses

The Company is also requesting $14,656 in storm expenses relating to a Blizzard Storm on January 29, 2022. Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 3. The expenses for this storm were for overtime and external vendors. Interrog. Resp. EOE-166, Att. 1 & 2. The Authority authorizes a total for the Blizzard Storm of $14,656.

(f) Hurricane Lee Lean-In Event Deferred Expenses

The Company requests $1,082,185 in storm expenses for the Hurricane Lee – Lean-In event. Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 3 ("Incremental Costs" column"). The Company reports expenses related to overtime ($125,482), fleet fuel ($9,968), external contractors ($928,275), and meals, travel, and lodging (18,460). Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 3. The Company revised its overtime costs to $115,951 after finding that 174.5 hours of overtime were incorrectly charged to this event. Interrog. Resp. EOE-264, Att. 1. The Company did not reflect this change in the Storm Deferral Refund deferred expense update. See Late Filed Ex. 1, Att. 2 Supp. Due to this, the Authority permits only $115,951 of overtime costs and therefore disallows $9,531 ($125,482 – $115,951) in overtime expenses for this storm. Additionally, as previously discussed, the Authority finds it reasonable to disallow 25% of costs associated with materials, fuels, supplies, and PPE. See 18-11-12 Decision, pp. 13–14; EOE Brief,

p. 50. Therefore, the Authority allows $7,476 of the requested $9,968 in fleet fuel. The new total for the Hurricane Lee – Lean-In event is $1,070,162. Table 60, below, shows the requested and allowed expenses for the Hurricane Lee Lean-In event.

Table 60: Hurricane Lee Lean-In Event Deferred Expenses

	Proposed ($)	Adjustments ($)	Approved ($)
Overtime	125,482	(9,531)	115,951
Fleet Fuel	9,968	(2,492)	7,476
Contractors	928,275	-	928,275
Meals, Travel, and Lodging	18,460	-	18,460
Total	**1,082,185**	**(12,023)**	**1,070,162**

See Interrog. Resp. EOE-249 Supp. 2, Att. 2; Interrog. Resp. EOE-264, Att. 1.

(g) Storm Deferral Refund Expense Adjustment Summary

In sum, Table 61, below, shows the total adjustments made to the Storm Deferral Refund deferred expenses.

Table 61: Storm Deferral Refund Expenses

	Proposed ($)	Adjustment ($)	Approved ($)
Tropical Storm Elsa	(7,896)	-	(7,896)
Hurricane Henri	97,782	(10,592)	87,190
Storm Izzy	76,010	(38,427)	37,583
Blizzard	14,656	-	14,656
Flooding Event	1,292,571	(74,130)	1,218,441
Hurricane Lee	1,082,185	(12,023)	1,070,162
Total	**2,555,308**	**(135,172)**	**2,420,136**

(h) Storm Deferral Refund Carrying Charge Adjustment

In calculating the Storm Deferral Refund balance, the Company included carrying charges on the monthly net balance of storm deferral expenses, storm accrual, and mutual aid reimbursements. Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 2. The Company also stops recording monthly storm reserve accruals as of December 2024, and further, stops the balance as of September 31, 2025. Id. The Authority adjusts each of these items as set forth below.

The Authority finds that UI improperly calculated carrying charges on a monthly basis based on the net of deferred expenses and the storm reserve accrual. See Ex. UI-RRP-22C, p. 2. The Authority previously determined that carrying costs on deferred expenses are not permissible without explicit prior Authority approval, and allowing

carrying charges to accrue on deferred expenses that have not yet been subject to a prudence review is inconsistent with general ratemaking principles. 22-08-08 Decision, p. 28. That said, carrying charges should apply to the reserve accrual, which the Company collects from ratepayers as an offset to storm costs. The reserve is the equivalent of a prefunded ratepayer loan (or the equivalent of a reduction to rate base), therefore it should accrue the applicable carrying costs (i.e., WACC) on amounts that have been collected from customers. This finding is consistent with Authority findings in prior rate cases where reserves funded by ratepayers created to pay future claims are essentially regulatory liabilities and should therefore accrue carrying charges. See 23-11-02 CNG Decision, p. 40; 23-11-02 SCG Decision, p. 49. Therefore, the Authority disallows the Company's calculation of a credit of $80,343 of carrying charges through September 31, 2025, since it was calculated from the net of deferred expenses and the reserve accrual. The Authority recalculates the Storm Deferral Refund balance to include carrying charges on the storm reserve, but to exclude the application of carrying charges on deferred expenses and mutual aid reimbursements.

The Authority does this by calculating the storm accrual balance separately from the storm cost balance. The resulting carrying charge balance as calculated on a monthly basis on the reserve accrual balance from August 2022 through October 2025 is a credit of $374,911.

When calculating the storm accrual balance, the Authority also continues recording monthly storm accruals through October 31, 2025, which is the start of the Rate Year (the Company stops recording storm accruals as of December 2024). Therefore, the storm accrual balance as of October 31, 2025, including carrying charges, is a credit of $4,708,244, which is shown in Table 62, below.

Table 62: Storm Deferral Refund Accrual Balance, October 31, 2025

Category	Amount ($)
Storm Accrual, August 2022 – October 2025	(4,333,333)
Carrying Costs, August 2022 – October 2025	(374,911)
Total Storm Accrual Balance, October 31, 2025	**(4,708,244)**

See Interrog. Resp. EOE-249 Supp. 2, Att. 2, p. 2.

When calculating the deferred storm expense balance, the Authority removes the application of carrying charges improperly recorded by UI and also includes the reduction to the deferred expenses of $735,003 outlined in the previous section. The deferred expenses balance as of October 31, 2025, is a credit of $538,457, which is shown in Table 63.

Table 63: Storm Refund Deferral Deferred Expenses Balance October 31, 2025

Category	Amount ($)
Storm Costs, August 2021 – December 2024 [105]	2,555,252
Mutual Aid Reimbursements, September 2023 – December 2024	(1,881,623)
Authority Deferred Storm Cost Adjustments	(135,172)
Actual Balance, October 31, 2025	**538,457**

See Interrog. Resp. EOE-249 Supp. 2, Att. 2.

(i) Storm Deferral Refund Final Balance

The total approved Storm Refund Deferral balance as of October 31, 2025, is the sum of the storm accrual balance credit minus the deferred expenses balance, which equals a credit of $4,169,787 ($4,708,244 - $538,457).

iii. Thunderstorms Deferral

For the Thunderstorms Deferral, the Company reports a balance of $5,510,724 to be amortized over 36 months. Late Filed Ex. 1, Att. 2, WP C-3.21, p. 1. The Company is reporting one storm (Thunderstorm) totaling $5,158,351 in storm costs between August 2024 and December 2024. Interrog. Resp. EOE-249 Supp. 2, Att. 3, p. 3. The Company also reports $114,000 in carrying costs between August 2021 and December 2024. Id., p. 1. Additionally, the Company is forecasting $238,000 in carrying costs between January 2025 and September 2025, which results in the storm deferral balance of $5,510,724. Id.

The Authority previously determined that carrying costs are not permissible on deferred expenses without explicit prior Authority approval, and allowing carrying charges to accrue on deferred expenses that have not been subject to scrutiny and a prudence review is inconsistent with general ratemaking principles. 22-08-08 Decision, p. 28. Accordingly, the Authority disallows application of all carrying costs prior to October 31, 2025.

Regarding deferred storm expenses, the Company reports expenses related to overtime ($850,823), materials ($528,202), external vendors ($2,863,472), affiliate services ($630,792), and meals, travel, and lodging ($171,000). Id., p. 3.

The Company used various external vendors in response to this storm. Interrog. Resp. EOE-249 Supp., Att. 1; Interrog. Resp. EOE-249 Supp. 2, Att. 3, p. 3. For three of these vendors, the Authority either (1) was unable to verify the costs or (2) found that costs were imprudently incurred. These vendors are LaBella Associates PC (LaBella), PTAG Inc. (PTAG), and Coutts Brothers Inc. (Coutts). For LaBella, the Authority was only able to verify $26,363 of the $37,030 being requested by the Company. The Authority

[105]This figure differs from that reported in Table 67 by $56 (2,555,308 - 2,555,252 = 56) which exists because of the differing storm costs amounts reported in Late Filed Ex. 1, Attachment 2 Supplement and response to Interrogatory RSR-166, Att. 1.

was unable to clearly read pages submitted by the Company that may have verified the remaining costs. Interrog. Resp. EOE-249 Supp., Att. 1, pp. 36–37, 39–45.

For PTAG, the Company submitted invoices and vendor timesheets but submitted no UI Contractor Daily Timesheets. Id., pp. 48–53. As stated above, the Company confirmed that it requires contractors to provide the UI Contractor Daily Time & Work Report prior to the processing of invoices. Application, Ex. UI-RRP-15, p. 7; Engineering Audit Request 5; Interrog. Resp. RSR-162. The Company provided vendor and UI Contractor Daily Time & Work Reports for other vendors in this same storm. See, e.g., Interrog. Resp. EOE-249 Supp. 1, Att. 1, pp. 55–57. Therefore, the Authority disallows $12,804 being requested for expenses associated with PTAG.

Regarding Coutts, the Authority finds issue with the vendor charging for 1,817 hours worked for this storm for a total of $464,317, as the timesheets submitted show only 1,334 hours. Interrog. Resp. EOE-249 Supp., Att. 1, pp. 2–23. The vendor reported that 23 of their employees worked 19 hours on August 4, 2024; 24 hours on August 5, and 6, 2024; and 12 hours on August 7, 2024. Id., p. 4. The timesheets the Company provided show that the employees worked 17 hours on August 4, 5, and 6, 2024; and 7 hours on August 7, 2024. Id., pp. 7–22. The Company provided no contract terms to substantiate the Company being overcharged by the vendor for its services and the Authority can find no instance in other storms or with other vendors in this storm where the Company is paying for more hours than the hours reported through timesheets. When adjusting the hours reported by this vendor from 1,817 to 1,334, the Authority changed all reported hours from 79 hours (in the invoice) down to 58 hours (which matches the timesheet) and determined the new sum of the labor totals of $307,117. Interrog. Resp. EOE-249 Supp., Att. 1, p. 4. Adding this new total to the unadjusted meals ($3,200) and equipment costs ($55,541) yields $365,858.

Additionally, EOE argues that the costs related to vendor East Coast Power LLC were imprudent. EOE Brief, p. 54. EOE states that the vendor billed for 8 hours of travel time on August 7, 2024, in support of demobilization, which far exceeds the typical travel time between West Haven, CT and Albany, NY. Id. EOE believes that the Company's payment of 8 hours of travel time is excessive and demonstrates an ineffective invoice review. Id. The Authority agrees with EOE's position and will instead only approve four hours of travel time for this vendor. When changing the labor and equipment hours from eight to four hours, the new labor expense for this vendor is $438,251 and the new equipment expense is $71,156, making the new total for this vendor $519,967. Interrog. Resp. EOE-249 Supp., Att. 1, p. 493.

Regarding the $629,793 in affiliate charges, the Company provided no documentation to support the expense and has not demonstrated that these costs are truly incremental to other costs recouped in base rates for payroll and overtime; therefore, the Authority disallows all affiliate charge expenses for this storm.

The Authority previously discussed that it finds it reasonable to disallow 25% of expenses associated with materials, fleet fuel, supplies, and PPE. See 18-11-12 Decision, pp. 13–14; EOE Brief, p. 50. The Company reports $115,060 in fleet fuel and

$528,202 in materials. Interrog. Resp. EOE-249 Supp., Att. 1 & 2. After applying the 25% disallowance, the Authority disallows $28,765 (0.25 x $115,060) in fleet fuel costs and $132,050 (0.25 x $528,202) in materials costs. The Authority, therefore, approves recovery of $86,295 in fleet fuel ($115,060 - $28,765) and $396,152 in materials ($528,202 - $132,050). When accounting for these adjustments, the new total for the storm should be $3,366,719.

Lastly, the Company includes an unexplained $178 in deferred expense in its final Thunderstorm Deferral balance. Interrog. Resp. EOE-249 Supp. 2, Att. 3, (where page 3 shows total storm costs of $5,158,351 but page 1 shows $5,158,530 of storm costs). The Authority disallows this unexplained expense.

For the Thunderstorms Deferral, the Authority allows a total balance of $3,367,807 as of October 31, 2025. Table 64 shows the Company's request, PURA disallowances, and the final allowed balance for the Thunderstorms Deferral.

Table 64: Thunderstorm Deferral Adjustment and Allowed Expenses

Expense	Requested ($)	Adjustment ($)	Allowed ($)
Overtime	850,823	-	850,823
LaBella	37,030	(10,667)	26,363
PTAG	12,804	(12,804)	-
Coutts	464,317	(98,459)	365,858
East Coast Power	547,150	(27,183)	519,967
Affiliates	629,793	(629,793)	-
Other Contractors	1,802,173	-	1,802,173
Materials	528,202	(132,050)	396,151
Fleet Fuel	115,060	(28,765)	86,295
Meals, Travel, Lodging	171,000	-	171,000
Unexplained Expense	178	(178)	-
Carrying Charges	352,195	(352,195)	-
Total	**$5,510,724**	**($1,292,094)**	**$4,218,630**

See Interrog. Resp. EOE-249 Supp. 2, Att. 3, pp. 2–3.

Accordingly, the allowed Thunderstorms Deferral balance as of October 31, 2025, is $4,218,630.

g. Environmental Deferral

The Company proposes to amortize $481,664 in environmental remediation expenses related to its East Shore site over a 12-month period. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.21, p. 1. The Authority permits the Company to recover $430,235 over a three-year period, resulting in a $143,412 amortization expense.

The Authority previously denied the deferred accounting of $458,00 in past East Shore remediation expenses but permitted deferred accounting treatment for prudent East Shore remediation expenses after the start of the September 1, 2023 Rate Year. 22-08-08 Decision, p. 190. The Authority also determined that any deferred remediation expenses were to be offset by amounts of remediation expense in the Company's allowed revenue requirement and that carrying charges would not be permitted on deferred remediation expenses. Id.

The Company applied carrying charges to its deferred expenses totaling $51,429. Ex. UI-RRP-22B, p. 1. Consistent with the determination in the 22-08-08 Decision, the Authority does not permit the Company to recover carrying charges for its deferred East Shore remediation expenses. As such, the Authority permits the Company to recover $430,235 ($481,664 - $51,429) amortized over three years, resulting in a $143,412 Rate Year amortization expense.

h. Fee Free Program

The Company proposes to amortize a ($1,852,863) credit related to the difference between its actual credit card transaction fee costs and the amount embedded in distribution rates for such costs as ordered in the 22-08-08 Decision. Ex. UI-RRP-1, p. 90; 22-08-08 Decision, p. 162. The Authority adjusts the Company's proposed credit by ($308,376) and carrying credit of $228,227 to reflect a ($2,389,466) deferred credit to be amortized over three years, or a ($796,489) Rate Year credit.

The Authority calculated that the Company will recover $3,868,531 over a 26-month period from ratepayers between September 2023 and October 31, 2025 ($1,785,475.87 recovered/ 12 months x 26 months). Ex. UI-RRP-22G. Notably, the Company reported its expected Fee Free Program expenses without allocating such expenses between distribution and transmission. Ex. UI-RRP-22G; Interrog. Resp. RRU-377. Herein, the Authority calculated a distribution ratio of 67.2561% to allocate costs between transmission and distribution business segments based on the Company's assertion that $1,892,932 of $2,814,514 of Fee Free expenses would be allocated to distribution ($1,892,932/$2,814,514). Interrog. Res. RRU-377. Finally, absent actual cost data, the Authority projected monthly Fee Free Program expenses between April 2025 and October 2025 by using the 11-month average of Fee Free Program costs incurred from May 2024 through March 2025. In sum, the Authority calculated that the Company would incur $1,880,186 in distribution adjusted Fee Free Program costs through October 31, 2025.

Therefore, the Authority calculated that the November 1, 2025 deferral balance of ($2,161,239) would be the difference between the $3,868,531 collected from ratepayers, less $1,880,186 in projected program costs through October 2025, and ($172,894) in carrying credits through October 2024 ($3,868,531-$1,880,186+$172,894). After calculating an additional $228,227 in carrying credits over the amortization period, the Authority approves a ($2,389,466) deferred credit to be amortized over three years, representing a ($796,489) Rate Year credit.

i. Rate Case Expense

The Company proposes to recover $3,163,323 in rate case expenses, amortized over three years, resulting in a $1,054,441 Rate Year amortization expense. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.21, p. 1. General Statutes § 16-243p(b) expressly prohibits, for any rate proceeding initiated on or after January 1, 2024, an electric distribution company with more than 75,000 customers from recovering through rates direct or indirect costs associated with attendance in, participation in, preparation for, or appeal of such a rate proceeding. The statute further specifies that such costs include attorney's fees, expert witness or consultant fees, and employee salaries associated with attendance, participation, preparation, or appeal of a rate proceeding and related costs identified by the Authority. General Statutes § 16-243p(b).

In this instance, the Company's proposed deferred expense includes legal fees, consultant fees, and "people and organization" fees related to the current proceeding and, accordingly, are barred from recovery under General Statutes § 16-243p(b). However, the Company may recover certain consultant fees incurred by the Authority and parties in this proceeding that are billed and paid for by the Company. Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.21, p. 3. As such, the Authority permits the Company to recover $1,063,846 in amortized rate case expense, which is the $962,234 in allowed rate case fees plus $101,612 in carrying costs, resulting in a $354,615 Rate Year amortization.

j. Water Heater Rental Program

The Company proposes to recover $12,019,711 in expenses related to phase-out costs of its Water Heater Rental Program, amortized over 36 months, resulting in a Rate Year amortization expense of $4,006,570. Late Filed Ex. 1, Att. 2, Supp., Sch. WP C-3.21. The Authority permits the Company to recover $10,179,693 in Water Rental Program phase-out costs over three years which, after the inclusion of $1,074,976 in carrying charges, results in a $11,254,669 total amortization expense ($10,179,693 + $1,074,915) or a $3,751,556 ($11,254,669 / 3) Rate Year amortization expense.

As previously discussed in Section V.E.10.d.ii, Water Heater Rental Program, the Authority previously ordered the Company to end new enrollments in the Water Heater Rental Program by September. 1, 2023 (Order No. 6), and, by June 1, 2024, file a plan to phase out all remaining equipment in the water heater rental program by September 1, 2025 (Order No. 33). 22-08-08 Decision, pp. 284, 288.

In response to Order No. 33, the Company presented three options to fulfill the phaseout activities directed by the Authority. Motion No. 92 Ruling, Dec. 11, 2024, Docket No. 22-08-08 (Motion No. 92 Ruling).[106] The Authority directed the Company to pursue its third option and retire the fleet in the field because the Company's estimated $8.1 million to $8.7 million cost estimate was the least expensive to implement, was the most efficient and timely solution, and it permitted customers to own the water heaters and afford them the option of maintaining the unit or replacing it with a more efficient water

[106]The Company originally filed its Order No. 33 compliance on August 28, 2024. However, the Authority determined that it required more information before determining how the Company should proceed with phasing out the Program. Motion No. 88 Ruling, Aug. 28, 2024, Docket No. 22-08-08, p. 1.

heater, among other options. Motion No. 92 Ruling, p. 4. The Authority directed UI to begin phaseout activities pursuant to the third option by January 2, 2025, and file compliance as confirmation that phase-out activities under Scenario 3 had begun by January 15, 2025. Id.

The Company subsequently filed a motion requesting that the Authority establish a cost recovery mechanism for the cost of phasing out the Program. Ex. UI-WHRP-2, p. 1. The Authority declined to do so and clarified that the present rate case was the appropriate venue to seek cost recovery. See Motion No. 95 Ruling, Feb. 10, 2025, Docket No. 22-08-08 (Motion No. 95 Ruling)

The Company now seeks to recover $12,019,711 in Program phaseout costs, nearly $4 million more than the low end of the projections provided to and relied upon by the Authority in its Motion No. 92 Ruling. Late Filed Ex. 1, Att. 2, Supp., Sch. WP C-3.21. The Company explained that the costs in excess of its estimate were due to it continuing to replace water heaters in the field, an additional $30,000 in mailing communications expense, and an additional $30,000 for IT upgrades not previously identified. Ex. UI-WHRP-1, p. 12; Interrog. Resp. CAE-45; Interrog. Resp. CAE-48. Most notably, the Company disregarded the Authority's direction to phase out all remaining equipment in the Water Heater Rental Program by September 1, 2025, and instead, chose to delay the phaseout until the decision in this proceeding. Interrog. Resp. CAE-49.

As previously discussed, the Company's lack of preapproved funding does not justify its non-compliance with Authority orders, and the Company, as a result of its noncompliance, has continued to incur additional costs, particularly by continuing to replace customer's water heaters rather than retire them in the field as directed. The Company indicates that it has installed 445 replacement water heaters after the Authority directed the Company to close the program to new participants and develop a plan for phasing out existing equipment pursuant to Orders 6 and 33 in the 22-08-08 Decision. Interrog. Resp. CAE-44 Att. 1; Interrog. Resp. CAE-48. Of those, 99 replacement water heaters were installed after the Authority's December 11, 2024 ruling directing UI to begin phase-out activities pursuant to the third option by January 2, 2025, when the Company knew or should have known that replacing water heaters in the field when phaseout activities were expected to end in less than nine months, did not reflect prudent operation of the franchise operation. Moreover, the Company's estimated net book value (NBV) of existing equipment assumes that water heater replacements will continue until May 2026, when UI says phaseout will be complete. Interrog. Resp. CAE-48, Att. 1. Based on the Company's failure to comply with the Authority's orders, particularly the Company's failure to proceed with Program phaseout activities and complete them by September 1, 2025, the Authority concludes that the continued replacement of customer's water heaters in lieu of retiring them in the field as ordered does not demonstrate prudent management of the franchise operation. As such, the Authority does not permit the Company to recover $1,780,018, which represents the NBV of the water heaters replaced or projected to be replaced after the Authority's December 11, 2024, Motion No. 92 Ruling, explicitly directed the Company to begin Program phaseout activities. Interrog. Resp. CAE-44; Interrog. Resp. CAE-48, Att. 1

Additionally, the Authority finds that the Company's $30,000 in incremental IT costs and $30,000 in incremental communication costs do not demonstrate prudent management of the franchise operation. While the Company explained that it discovered that technology upgrades were needed to simultaneously remove each unit from its billing system, these costs were considered only after the Company had submitted costs estimates to the Authority and it had been ordered to begin phaseout activities pursuant to option three when the Company conducted internal meetings to implement its selected phase out plan. Ex. UI-WHRP-1, p. 9; Interrog. Resp. CAE-045. Moreover, the Company did not explain why $30,000 in incremental communications costs were necessary or were not included in the Company's initial cost estimates.

Further, the Company did not provide any supporting documentation to substantiate its requested incremental IT and communication expenses. Rather, the Company indicated that its technology upgrade expenses were a rough estimate, and that its incremental communication expenses would be "approximately" $30,000. Ex. UI-WHRP-1, p. 9. Thus, mere unsubstantiated, "rough" estimates do not meet the known and measurable standard and cannot be included in the Company's projected Rate Year expenses. Accordingly, the Authority does not permit the Company to recover $60,000 in incremental IT and communications expenses.

In conclusion, the Authority permits the Company to recover $11,254,669 amortized over three years, which is the $10,179,693 in water heater rental program phase-out cost ($12,019,711 - $1,780,018 - $30,000 - $30,000), plus $1,074,976 in carrying costs, resulting in a $3,751,556 Rate Year amortization.

B. DEPRECIATION EXPENSE

A depreciation rate study proposes annual depreciation rates to be applied to plant-in-service balances. The product of the depreciation rate and corresponding plant balance is the annual depreciation expense, which is a charge to a company's operating expense reflecting the annual recovery or amortization of previously expended capital investment. While depreciation expense is a function of both the depreciation rate and the related plant balance, this section focuses only on the Authority's rationale for adjusting the Company's proposed depreciation rates. The Authority's determinations related to the Company's plant balances are described in Section IV.B, Plant-In-Service, above.

UI seeks to use the depreciation rates approved by the Authority in the Company's previous rate amendment proceeding. Ex. UI-RRP-1, p. 81. The Company asserts that, "[g]iven the short passage of time since" the Company's prior rate case, the previously approved rates "remain reasonably applicable" and would eliminate the added expense of conducting a depreciation study. Id. Depreciation studies rely heavily on historical data, and studies generally do not provide new information if sufficient time has not passed to change the historical data. Application, Ex. UI-RRP-27, p. 1. Depreciation studies should be conducted approximately every three to five years. Id. Neither OCC nor any other party contested the proposed depreciation rates. The Authority approves the Company's proposed depreciation rates as shown in Table 65, below.

Table 65: Proposed and Approved Depreciation Rates

FERC Category	Proposed (%)	Approved (%)
Distribution Plant	2.83	2.83
General Plant	5.24	5.24
Intangible Plant	12.50	12.50

To determine the approved depreciation expense, the Authority utilized the Plant Model, which calculates depreciation expense by applying the corresponding depreciation rates to monthly plant balances. Specifically, the Authority modified the Plant Model to reflect (1) the Authority's approved plant balances and (2) revised depreciation rates. The Company's proposed Rate Year depreciation expense is $86,949,214. After incorporating all Authority modifications into the Plant Model, the resulting approved Rate Year depreciation expense is $84,026,124, a downward adjustment to Rate Year depreciation expense of $2,923,090. Table 66, below, summarizes the Authority's adjustments to the Company's proposed depreciation expense.

Table 66: Rate Year Depreciation Expense

Test Year ($)	Proposed ($)	Adjustment ($)	Approved ($)
77,473,188	86,949,214	(2,923,090)	84,026,124

Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.22; Late Filed Ex. 1, Att. 3 ("6-DepreciationExpense" tab).

C. TAXES

1. Summary

The Company proposes $108,526,743 as total Rate Year tax expenses, which includes $3,686,196 in Fixed Capital Investment Credits (FCIC) the Company estimates it will use in the Rate Year. Late Filed. Ex. 1, Att. 2 Supp., Sch. A-1.0; Sch. C-1.0; Sch. WP C-3.22a- 22c; Sch. WP C-3.23; Interrog. Resp. RRU-145. To that amount, the Authority adds the Fixed Capital Investment Tax Credit (FCIC) of $3,686,196 and determines that the overall tax proposed is $112,212,939. The Authority allows $104,968,582 in the Company's revenue requirement for tax expenses, as set forth in Table 67, below.

Table 67: Rate Year Tax Expenses

Expense	Proposed ($)	Adjustment ($)	Approved ($)
Payroll Taxes	7,565,503	(45,774)	7,519,729
Property Taxes	44,034,963	(343,518)	43,691,445
Gross Earnings Taxes	32,739,761	(2,742,185)	29,997,576
Deferred Income Taxes	-	804,361	804,361
State Income Taxes	8,195,961	(1,474,234)	6,721,727
Federal Income Taxes	19,676,751	(3,443,008)	16,233,743
Total Tax Expense	**112,212,939**	**(7,244,357)**	**104,968,582**

Late Filed Ex. 1, Att. 2 Supp., Sch. A-1.0, Sch. C-1.0; Sch. WP C-3.22a-22c.

2. Payroll Taxes

The Company proposes a payroll tax expense of $7,565,503 for the Rate Year, which is based on a total compensation expense of $49,832,152 for the Rate Year.

The Authority will reduce payroll taxes to account for the reduction of $301,500 in the employee compensation expense described in Section VI.A.12, Employee Compensation.[107] Specifically, the Authority reduces the Company's proposed payroll tax expenses by $45,774 ($301,500 x 15.182% payroll tax ratio)[108] and allows $7,519,729 in the Company's revenue requirement.

3. Property Taxes

The Company proposes a property tax expense of $44,034,963 for the Rate Year. Late Filed Ex. 1, Att. 2, Sch. WP C-3.22. The Company's pro forma Test Year property tax expense is $39,250,021. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.22 WP. The Authority approves a $43,691,445 property tax expense for the Rate Year.

The Company calculated its Test Year (2023) property tax expense using the second tax payment related to the 2021 Grand List bills (July 2022 through June 2023 period) and the first tax payment related to the 2022 Grand List bills (July 2023 through June 2024 period). Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.22 WP; Ex. UI-RRP-1, pp. 99–100. The Company calculated the $44,034,963 Rate Year property tax expense by summing both the first and second tax payments related to the 2023 Grand List bills and multiplying this amount by the applicable allocators for electric distribution operations. Ex. UI-RRP-1, pp. 99–100. The Company then determined the incremental plant (i.e., plant additions less retirements and change in depreciation reserve) for the period October 2023 through September 2025. Ex. UI-RRP-1, pp. 99–100. The Company then multiplied

[107]Section VI.A.12, Employee Compensation, provides the calculation for the $301,500 disallowed payroll amount.

[108]The Authority determined the Company's payroll tax ratio of 15.182% by dividing the Company's proposed payroll tax expense by its proposed payroll expense ($7,565,503 proposed payroll tax expense / $49,832,152 proposed employee compensation). Late Filed Ex. 1, Att. 2 Supp., Sch. C-22b WP; Sch. C-3.15, p. 2.

the incremental plant by 70%, which is the assessment ratio used by the State of Connecticut when valuing assets for annual property tax purposes, and multiplied this product by the composite mill rate for the interim period.[109] Ex. UI-RRP-1, p. 100.

The Company's proposed Rate Year property tax expense is $4,784,942 higher than the Test Year pro forma property tax expense ($44,034,963 - $39,250,021). Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.22 WP. Since the Authority is disallowing net plant additions, as discussed in Section IV.B.5, Pro Forma Plant Additions, which include net plant additions made after April 30, 2025, as well as certain net plant additions made during the Test Year and the Interim Period, the incremental property tax expense associated with the disallowed net plant additions must also be excluded. In the following tables, the Authority quantifies the reductions to property tax resulting from the plant-in-service disallowances for the three applicable time periods (i.e., Test Period, Interim Period, Future Period).[110]

Table 68: Property Tax Adjustment – Test Year Plant-in-Service

Line	Description	Value
1	Plant-in-Service Adjustment	($3,392,530)
2	Months of Depreciation Assumed	33
3	Monthly Depreciation Rate	0.2358%
4	Total Change in Depreciation Reserve (Product of Lines 1, 2, and 3)	($263,986)
5	Distribution Plant Additions, Less Reserve Change	($3,128,544)
6	Assessment %	70%
7	Distribution Plant Additions, Less Reserve Change and Net of Assessment Adjustment (Product of Lines 5 and 6)	($2,189,981)
8	Composite Distribution Mill Rate	36.92
9	Change in Property Tax Expense	($80,854)

Late Filed Ex. 1, Att. 2 Sch. C-3.22a WP.

[109] Although not explicitly stated in the Company's testimony, the plant activity for October 2024 through September 2025 was also multiplied by 33%. This appears to have been applied to reflect the four months of Fiscal Year 2026-2027 (i.e., July 2026 through October 2026) in the Rate Year.

[110] For adjustment calculation purposes, the Authority has assumed 33 months of depreciation (i.e., January 2023 through September 2025) for the disallowances related to the test period; 21 months of depreciation (i.e., January 2024 through September 2025) for the disallowances related to the interim period; and five months of depreciation (i.e., May 2025 through September 2025) for the disallowances related to the future period.

Table 69: Property Tax Adjustment– Interim Period Plant-in-Service

Line	Description	Value
1	Plant-in-Service Adjustment	($934,766)
2	Months of Depreciation Assumed	21
3	Monthly Depreciation Rate	0.2358%
4	Total Change in Depreciation Reserve (Product of Lines 1, 2, and 3)	($46,288)
5	Distribution Plant Additions, less Reserve Change	($888,478)
6	Assessment %	70%
7	Distribution Plant Additions, less Reserve Change and Net of Assessment Adjustment (Product of Lines 5 and 6)	($621,935)
8	Composite Distribution Mill Rate	36.92
9	Change in Property Tax Expense	($22,962)

Late Filed Ex. 1, Att. 2, Sch. WP C-3.22a; Late Filed Ex. 1, Att. 3 ("4.1-PlantAddtionsDetail Update" tab).

Table 70: Property Tax Adjustment–Future Period

Line	Description	Value
1	Plant-in-Service Adjustment[111] (net plant-in-service disallowances for the period May 2025 through September 2025)	($28,441,294)
2	Months of Depreciation Assumed (May 2025 through September 2025)	5
3	Monthly Depreciation Rate	0.2358%
4	Total Change in Depreciation Reserve (Product of Lines 1, 2, and 3)	($335,323)
5	Distribution Plant Additions, less Reserve Change	($28,105,971)
6	Assessment %	70%
7	Distribution Plant Additions, less Reserve Change and Net of Assessment Adjustment (Product of Lines 5 and 6)	($19,674,180)
8	Partial Year Multiplier (to Reflect Four Months of Fiscal Year 2025-2026 Within Rate Year)	33%
9	Distribution Plant Additions, less Reserve Change and Net of Assessment Adjustment (Product of Lines 5 and 6)	($6,492,479)
10	Composite Distribution Mill Rate	36.92
11	Change in Property Tax Expense	($239,702)

Late Filed Ex. 1, Att. 2, Sch. WP C-3.22a; Late Filed Ex. 1, Att. 3 ("4.1-PlantAdditionsDetail Update" tab).

In the aggregate, the Authority reduces the Company's proposed Rate Year property tax expense by $343,518, resulting in an approved Rate Year property tax expense amount of $43,691,445. This adjustment is shown in Table 71, below.

[111]The future period applicable to this adjustment is May 2025 through September 2025.

Table 71: Rate Year Property Tax

Proposed ($)	Adjustment ($)	Approved ($)
44,034,963	(343,518)	43,691,445

Late Filed Ex. 1, Att. 2 Supp., Sch. WP C-3.22; Late Filed Ex. 1, Att. 3 ("4.1-PlantAdditionsDetail Update" tab).

4. Gross Earnings Tax

The Company proposes a gross earnings tax (GET) expense of $32,739,761 for the Rate Year. Late Filed Ex. 1, Att. 2 Supp., Sch. C-1.0; Sch. WP C-3.22c. The Company's GET expense is based on a GET ratio of 6.94322% as of the Test Year. Id. The requested GET expense consists of $25,356,111 ($365,192,569 x 6.94322%) related to Rate Year revenues at present rates, and a $7,383,650 increase associated with the $105,418,797 additional revenue requested for the Rate Year. Id.

Since the Authority is disallowing $39,494,450 of the Company's proposed total revenue requirement, any GET associated with the disallowed revenues must also be disallowed. Accordingly, the Authority disallows $2,742,185 ($39,494,450 x 6.94322%) of the Company's proposed GET expense. Therefore, the Authority allows a $29,997,576 ($32,739,761 - $2,742,185) GET expense in the Rate Year.

5. Deferred Income Taxes

The Authority increases the provision for deferred income tax by $804,361 to reflect a $2,923,090 reduction to the Company's proposed depreciation expense.

As discussed in Section VI.B, Depreciation Expense, the Authority reduces the Company's proposed depreciation expense by $2,923,090. Using the composite income tax rate of 27.5175%, the Authority calculates the deferred tax effect of $804,361 ($2,923,090 x 27.5175%). Late Filed Ex. 1, Att. 2, "Assumptions" tab.

6. State Income Taxes

The Company proposes a net state income tax (SIT) expense of $4,509,765 based on the operating income at current rates. Ex. UI-RRP-1, pp. 103-104; Late Filed Ex. 1, Att. 2 Supp., Sch. C-1.0; Sch. WP C-3.23. The Company calculated its Rate Year SIT expense by adding its SIT at current rates ($36,533), the FCIC credit of ($3,686,196), and the additional SIT expense of $8,232,494 based on incremental revenue proposed in the Rate Year. Id. The Authority adds the FCIC credit and determines that the total proposed SIT is $8,195,961 ($4,509,765 + $3,686,196). Based on the total adjustment of $13,295,615 to the current STI taxable income, the Authority increases the current SIT expense by $1,096,888 ($13,295,615 x 8.25%). Moreover, the Authority reduces the Company's proposed additional revenue by $33,765,586. Thus, the Authority reduces

the proposed incremental SIT expense by $2,571,123 ($33,765,586 x 7.6146%).[112] The Authority disallows $1,474,234 ($8,195,961 - $6,721,727) of the Company's proposed SIT expense, to reflect adjustments of $13,295,615 to the current taxable income and $33,765,586 to the proposed revenue increase, as discussed in more detail in Section VI, Allowable Expenses, and Section VII, Approved Revenue Requirement.

Table 72: Summary of Adjustments to Current Taxable Income

Expense/(Revenue) Adjustments at Current Rates	Amount ($)
Payroll Taxes	45,774
Property Taxes	343,518
GET Expense	397,767
Other Revenue	(5,728,864)
O&M	18,240,917
Interest Synchronization	(3,497)
Total Current Taxable Income Adjustment	**13,295,615**

Table 73: Rate Year State Income Taxes

	Proposed ($)	Adjustment ($)	Approved ($)
SIT at Current Rates	(36,533)	1,096,888	1,060,355
Incremental SIT	8,232,494	(2,571,123)	5,661,371
Total Rate Year SIT	**8,195,961**	**(1,474,234)**	**6,721,727**

7. Federal Income Taxes

The Company proposed a net Federal Income Tax (FIT) of $450,136 ($2,336,977 - $729,732 - $1,157,109) based on the operating income at current rates. Late Filed Ex. 1, Att. 2 Supp., Sch. WPC-3.23 WP. The Company proposed an additional FIT expense of $19,226,615 based on incremental revenue proposed in the Rate Year. Id., Sch. C-1.0. Thus, the total FIT expense proposed for the Rate Year is $19,676,751 ($450,136 + $19,226,615). Id.

The Authority disallows $3,443,008 of the Company's proposed FIT expenses, to reflect adjustments of $12,198,727 ($13,295,615 - $1,096,888) to the current taxable income and $33,765,586 to the proposed revenue increase as discussed in more detail in Section VI, Allowable Expenses, and Section VII, Approved Revenue Requirement. As a result, the Authority allows FIT expenses of $16,233,743 for the Rate Year. Table 74, below, summarizes FIT expenses allowed for the Rate Year.

[112]The 7.614625 % and 92.2985% figures reflect 100% less the sum of the uncollectible factor of 0.7583% and GET rate of 6.9432%.

Table 74: Rate Year Federal Income Taxes

	Proposed ($)	Adjustment ($)	Approved ($)
FIT at Current Rates	2,336,977	2,561,733	4,898,710
Investment Tax Credit	(729,732)	-	(729,732)
EADIT Amortized	(1,157,109)	-	(1,157,109)
Incremental FIT	19,226,615	(6,004,740)	13,221,875
Total Rate Year FIT	**19,676,751**	**(3,443,008)**	**16,233,743**

8. Interest Synchronization

Table 75: Calculation of Interest Synchronization Adjustment

Proposed Average Rate Base	(A)	1,384,647,638
Adjustment to the Proposed Weighted Cost of LTD	(B)	0.0500%
Increased to the Allowed Interest Expense	(C)	**692,324**
Adjustment to the Proposed Average Rate Base	(D)	(29,690,820)
Allowed Weighted Cost of LTD	(E)	2.3200%
Reduction to the Allowed Interest Expense	(F)	**(688,827)**
Total Interest Synchronization Adjustment	(G = C + F)	**(3,297)**

The Authority makes a $3,297 interest synchronization adjustment in the calculation of the allowed state and federal income taxes to reflect the allowed rate base and weighted cost of long-term debt as discussed herein.

VII. APPROVED REVENUE REQUIREMENT

Table 76, below, summarizes the various components of the Company's approved revenue requirement, as adjusted by the Authority, and provides the total approved revenue requirement for the Rate Year.

Table 76: Approved Revenue Requirement

Section	Revenue Component	Amount ($)
IV.A	Allowed Rate Base	1,354,956,818
V.A	Weighted Average Cost of Capital	7.040%
	Allowed Cost of Capital	**95,388,960**
	Allowed Expenses:	
VI.A	Operations & Maintenance	166,405,683
VI.B	Depreciation	84,026,124
VI.C.2	Payroll Taxes	7,519,729
VI.C.3	Property Taxes	43,691,445
VI.C.4	Gross Earnings Taxes	29,997,576
VI.C.5	Deferred Income Taxes	804,361
VI.C.6	State Income Tax	6,721,727
VI.C.7	Federal Income Tax	16,233,743
	Allowed Revenue Requirement	**450,789,348**

VIII. RATE DESIGN

A. LEGAL STANDARD

The Authority is statutorily charged with regulating the rates of Connecticut's public service companies and UI is a public service company within the meaning of General Statutes § 16-1. General Statutes § 16-19. Consequently, UI must "file any proposed amendment of its existing rates with the [A]uthority." General Statutes § 16-19(a). Once a proposed amendment has been filed, the Authority:

> [s]hall make such investigation of such proposed amendment of rates as is necessary to determine whether such rates conform to the principles and guidelines set forth in section 16-19e, or are unreasonably discriminatory or more or less than just, reasonable, and adequate, or that the service furnished by the company is inadequate to or in excess of public necessity and convenience . . . .

General Statutes § 16-19(a).

Rate design objectives include: (1) the approval of cost-based just, and reasonable rates that promote further equalization of rates across the Company's divisions; and (2) revenue stability. See General Statutes § 16-19e(a).

In striking this balance and making pragmatic adjustments, the Authority is guided by General Statutes § 16-19e(a), which states, in relevant part, that the Authority shall examine proposed rates in accordance with the following principles:

> (4) that the level and structure of rates be sufficient, but no more than sufficient, to allow public service companies to cover their operating costs including, but not limited to, appropriate staffing levels, and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable . . . [and] (5) that the level and structure of rates charged customers shall reflect prudent and efficient management of the franchise operation.

In furtherance of this statutory framework, the Authority typically employs the rule of cost causation, which allocates costs to customers and cost categories based on the costs they cause a utility to incur. The Authority also generally attempts to equalize class rates of return, as such practice ensures that rates are not unreasonably discriminatory, while balancing the regulatory philosophy of gradualism to, among other reasons, avoid customer rate shock. See J Lazar *et al*., Electricity Regulation in the US: A Guide (2d Ed. 2016), p. 67, available at https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-electricity-regulation-US-june-2016.pdf ("sudden large rate changes should be avoided where possible to avoid undue new burdens on some classes of customers"). Consistent with the philosophy of gradualism, the Authority typically requires rate class revenue reductions or increases to be within one and one quarter times the overall distribution revenue increase. See 16-06-04 Decision, p. 108; see also 13-01-19

Decision, p. 153. Finally, the Authority considers whether "existing or future rate structures place an undue burden upon those persons of [low-income] status" as contemplated by General Statutes § 16-19e(b). The Authority weighs the above principles and considerations in determining appropriate cost and revenue allocation approaches and rate designs.

B. SALES FORECASTS AND REVENUE

1. Summary

UI seeks to increase revenues by $105,418,797 [113] above the total revenues that would be recovered under the Company's current rate schedules. Late Filed Ex. 1, Att. 2 Supp., Sch. A-1.0. Specifically, under current rates, total operating revenues for the rate year would be approximately $384,865,000 but would increase to approximately $490,283,797 under UI's proposed rates. Late Filed Ex. 1, Att. 2 Supp., Sch. C-1.0, Sch. C-3.01. The revenue at issue in this proceeding primarily consists of distribution revenue, with other operating revenues contributing less than 10% of the amount of distribution revenue. The Company's distribution revenues at current rates are approximately $389,258,301 and would increase to approximately $465,554,342 under UI's proposed rate increase. Other operating revenues are estimated to contribute $24,729,455 under both current and proposed rates. Id.

Table 77: UI Forecast Rate Year Operating Revenues

Revenue Source	Current Rates ($)	Proposed Change ($)	Proposed Rates ($)
Sales of Electricity	389,258,301	76,296,041	465,554,342
Other Operating Revenue	24,729,455	-	24,729,455
Revenue Decoupling Mechanism	(29,122,756)	29,122,756	-
Total Operating Revenues	384,865,000	105,418,797	490,283,797

2. UI's Delivery & Customer Forecasts

The Company utilized econometric modeling for its sales forecasts for all rate classes, with the exception of street lighting. Econometric modeling applies statistical techniques, such as linear regression, to determine the relationship between independent variables (price variables, weather variables, economic variables, and binary variables) to dependent variables (billed sales and customer sales forecasts). The Company sourced economic data from an information services provider, IHS Markit. Ex. UI-MP-1, p. 6. For the street lighting sales forecast, the Company applied the average growth rate from years 2022 and 2023 for sales deliveries to forecast 2025 and the monthly percentages to allocate months in the forecast period. Id., p. 11. UI utilized the same forecast methodology and sources of data for out-of-model adjustments in its sales

[113] The Company's original Application revenue requirement increase was revised from $105,469,566. Late Filed Ex. 1, Att. 2, Sch. A-1.0.

forecast that were used in its last rate case, Docket No. 22-08-08. Interrog. Resp. RRU-12.

UI used actual monthly billed sales data from January 2022 through April 2024, and a forecasted period of monthly billed sales units and the number of customers from May 1, 2024, through the Rate Year, ending October 31, 2026. Ex. UI-MP-1, pp. 2–3. The Company used calendar year 2023 (i.e., the 12-month period ending December 31, 2023) as the historical test year. Id., Executive Summary. The Company forecasts overall electric deliveries volume to increase, on average, by 1.67% annualized between the Test Year and Rate Year. Id., p. 12. The total increase in billed deliveries is driven by forecasted annualized increases for the Rate Year of 4.54% for the residential customer classes, which is partially offset by forecasted annualized decreases of 0.43% in the commercial classes, 0.63% in the industrial class, and 4.92% in the street lighting class. Ex. UI-MP-1, pp. 10–11.

The Company made out-of-model adjustments to its delivery forecast to account for the growth of (1) distributed energy resources (DER), including solar photovoltaic (PV) generation, (2) fuel cells, and (3) beneficial electrification, such as heat pump (HP) conversion and electric vehicles adoption (EVs). Ex. UI-MP-1, pp. 7–8. The Company developed its solar PV out-of-model adjustment based on the installed nameplate capacity as of December 31, 2023, multiplied by the ISO-New England capacity factor for Connecticut PVs of 14.7% and monthly generation output estimates based on historical seasonal load shapes. Id., p. 8. ISO-New England's PV growth/adoption rates for Connecticut, published in the 2023 Capacity, Energy, Loads, and Transmission (CELT) report, were used to forecast incremental PV generation during the Rate Year. Id. The Company used 2025 to 2034 estimates for fuel cell generation from the Avangrid Clean Energy Policy Group. Ex. UI-MP-1, p. 8. The Company estimated the incremental impacts of HP conversions and EV adoption on sales delivery volumes derived from ISO-NE CELT Connecticut forecasts, scaled to UI. Id.

UI forecasts that the overall number of customers will increase, on average, by 0.53% annually between the Test Year and Rate Year 2025/2026. Ex. UI-MP-1, p. 13. The overall forecasted increase in customers is driven by a forecasted 0.57% growth in the number of residential customers, 0.28% growth in commercial customers, 3.43% decrease in industrial customers, and 0.14% decrease streetlight customers. Ex. UI-MP-2, Sch. B, p. 6. UI's forecast relied on IHS Markit's Connecticut households forecast as the main explanatory variable for residential customer growth. Ex. UI-MP-1, p. 12.

3. Validation of Sales Forecasts

The Company analyzes summary data through statistical tests to determine whether the econometric models used to develop its sales delivery and customer forecasts fit the data sets and generalize well. Id., p. 14. Specifically, UI performs two validation tests, the Coefficient of Determination (R-squared) test and the Mean Absolute Percent of Error (MAPE) test. Id.

The R-squared test measures how the dependent variable, the sales forecasts, is explained by the independent variables (e.g., price, weather, and economic variables).

Id. The validation test results range from 0 to 1. The closer the test result is to 1, the greater the likelihood that the dependent variable is explained by the independent variables, and the more reliable the econometric models are for the data set. Ex. UI-MP-1, p. 14.

For the sales delivery R-squared test, residential class test results were 0.967, commercial class results were 0.895, and industrial class results were 0.859. For UI's customer forecasts, the results of the R-squared test were 0.996 for residential customers, 0.979 for commercial customers, 0.997 for industrial customers, and 0.945 for streetlight customers. The Authority finds that the R-squared test results statistically indicate the econometric model is a good fit for the customer forecast.

The MAPE test calculates "the ratio of the absolute value difference between the monthly forecast value derived from the model and the actual monthly value averaged over the entire dataset of values."[114] Ex. UI-MP-1, pp. 14–15. "The smaller the MAPE, the better the model estimate[d] the dataset." Id. UI performed forecast tests for billed sales delivery and customers to test the validity of its model over a two-year period.[115] Id. Generally, MAPE results of 10% or less are an indicator that validates the econometric model's estimate of the dataset.

Table 78: MAPE Test of Forecast, Customers

Customers	MAPE	2-year Post MAPE
Residential	0.11%	0.11%
Commercial	0.24%	0.45%
Industrial	0.48%	0.36%
Streetlight	0.28%	0.23%

Application, Ex. UI-MP-3, p. 1.

Table 79: MAPE Test of Forecast, Sales Delivery

Customers	MAPE	2-year Post MAPE
Residential	2.84%	3.97%
Commercial	3.08%	3.76%
Industrial	0.30%	0.25%
Streetlight[116]	-	-

[114]UI also described the MAPE as the "Average Absolute Value of the Error divided by the Actual Value." Application, Ex. UI-MP-3, p. 1.

[115]UI performed an "Ex Post forecast test" by withholding a portion of data, with the model estimated on the remaining sample and the results compared to the actual (withheld) data. Application, Ex. UI-MP-1, p. 15. "Ex Post forecast tests were performed on all customer and billed unit models . . . for two periods to demonstrate how well the models forecast two years out." Id.

[116]As noted above, the Company's streetlight usage forecast relied on historical data and average growth rates to determine the billed sales forecast; no MAPE analysis was performed with respect to streetlight customers.

Application, Ex. UI-MP-3, p. 1.

The Company provided additional MAPE results for the 2024 forecast that ranged from 0.28% to 5.75% for the billed sales usage and 0.25% to 0.70% for the customer forecast. Interrog. Resp. RRU-11, Att. 1. The Authority finds the Company's sales and revenues forecast, as well as the Company's out-of-model adjustments, to be reasonable. Additionally, the risk of misstating unit rates is minimized by revenue decoupling, whereby any under- or over-collection against the approved revenue requirement is either recovered by the Company or returned to ratepayers, respectively, in the next available period. Accordingly, the Authority accepts UI's sales forecast for the Rate Year without any adjustments.

C. COST-OF-SERVICE STUDY

The Company filed an allocated cost-of-service study (ACOSS) based on the historical test year and rate year costs and revenues. Application, Ex. UI-BR-1, p. 12. The Company's proposed ACOSS utilizes the Minimum System Study (MSS) approach to classify distribution assets into customer- and demand-related costs.[117] Id., p. 15. The Company followed the Authority's directive to use embedded costs rather than replacement costs. See 22-08-08 Decision, p. 228.

To arrive at customer-related costs, the Company selected the minimum sized piece of equipment for each cost category and multiplied its embedded cost by the number of units in service. Ex. UI-BR-1, p. 16. The residual demand-related costs were calculated as the difference between total plant costs in each category and the customer-related costs. Id., pp. 16–17. The MSS approach is one of the two recommended methods in the NARUC Electric Utility Cost Allocation Manual (NARUC Manual). NARUC Manual, p. 90. In its initial proposal, the Company did not attempt to quantify the minimum system's load carrying capacity, i.e., the delivery capacity of each category of equipment included in the MSS approach.

The Authority requested that the Company and OCC submit alternative ACOSS models. Late Filed Ex. 71; Late Filed Ex. 83. The Authority directs the Company to adopt the ACOSS models filed in Late Filed Ex. 71, with the modifications discussed below. The Authority requested that the Company and OCC submit alternative ACOSS models that calculate a per-customer load-carrying capacity value and credit each customer class that value when allocating residual demand-related costs. Late Filed Ex. 71; Late Filed Ex. 83.

The Company implemented this request by calculating the load-carrying capacity of transformers and conductors (adjusted by a 90% power factor), then multiplying that capacity by the quantity of deployed equipment (number of transformers for line transformers and number of circuits for conductors), and finally dividing by the number of

[117] CIEC supports the Company's use of the MSS approach. Chait Rebuttal Test., Mar. 12, 2025, pp. 1–2. CIEC argues that allocating AMI costs based on the benefits of AMI technology does not constitute cost-based allocation. Id., p. 14.

customers in each rate class to arrive at a per-customer load-carrying capacity that was applied to each class's demand allocator. Late Filed Ex. 71.

OCC implemented the Authority's request by applying a universal load-carrying capacity adjustment to the non-coincident peak demands used to allocate demand-related costs. Late Filed Ex. 83. In the absence of more granular data, OCC presented two scenarios with adjustment values of 0.4 kW and 1.5 kW, based on recent proceedings in Minnesota and Ontario, respectively. Id.

Table 80, below, shows the relative rate of return for each rate class under the Company's initial ACOSS model, the revised model UI submitted, and the revised models OCC submitted.

Table 80: Proposed Relative Rate of Return for Each Rate Class

Rate Class	UI Initial Proposal OCC-362, Att. 22	UI Modified LFE-71, Att. 1	OCC LFE-83, 0.4 kW per Customer	OCC LFE-83, 1.5 kW per Customer
R	0.03	0.52	0.32	1.92
GS	2.08	1.91	1.83	0.78
GST	4.18	2.24	3.12	(0.29)
LPT	3.85	2.04	2.68	(0.87)
M	(1.62)	(1.71)	(1.67)	(1.90)
U	5.74	4.78	5.26	3.33
Total	**1.00**	**1.00**	**1.00**	**1.00**

OCC suggests that the Company's original MSS approach was unsound as the basis for determining cost causation and would inflate cost allocations to residential customers. Palmer Prefiled Test., Feb. 13, 2025, p. 9. As an alternative, OCC proposed the basic customer method, in which only costs associated with services, meters, meter reading, and billing are classified as customer related. Id., p. 14. OCC also proposed that the Company allocate "no demand-related costs to the customer classes whose peak demands can generally be met through the identified 'customer-related' portion of the system," if the MSS is approved in any capacity (either for all of distribution plant or only primary distribution). Id., p. 16; Hr'g Tr., 1489:23–1490:2. OCC also states that AMI costs should be classified proportionally according to the benefits in the customer, demand, and energy categories. Id., p. 22.

As UI noted, the Authority has accepted the MSS approach in prior rate case proceedings, including the Company's most recent rate case. Rates Panel Rebuttal Test., Mar. 12, 2025, pp. 7–10. UI challenged OCC's assertion that examining the marginal costs of adding a new customer is a reasonable test for allocating embedded costs. Id., pp. 5–7. The Company also criticized OCC's recommendation to omit certain customer classes from allocation of demand-related expenses on the grounds that the minimum system is capable of meeting their demands. Id., pp. 11–12. Finally, the Company clarified that while the cost of AMI meters was classified as 100% customer-related, other

costs associated with AMI infrastructure were classified using the labor allocator, which has both customer and demand components. Id., pp. 13–14.

Although the Authority acknowledges OCC's concerns with the MSS approach, it is not clear that the basic customer method is a superior alternative. Costs classified as demand-related under the basic customer method, such as poles and conductors, are unaffected by changes in demand. Both the Company and OCC acknowledge that these costs are primarily driven by the geographic dispersion of customers (i.e., circuit miles). Rates Panel Rebuttal PFT, p. 12; Palmer Surrebuttal Test., Mar. 24, 2025, p. 3. Unfortunately, geographic dispersion does not offer a clear billing determinant. As such, the Authority accepts the premise that the number of customers is an acceptable, if imperfect, proxy for costs unrelated to demand, and that the MSS approach is an appropriate method for categorizing these costs in this proceeding. Primary distribution infrastructure has both demand- and customer-related components. Rates Panel Rebuttal, p. 12. Even in a hypothetical sense, there can be no minimum-sized system that contains only secondary distribution while meeting any non de minimis level of demand. Therefore, the reasoning supporting the use of the MSS approach extends to both primary and secondary distribution plant. The Authority affirms the Company's proposed classification of AMI meters as 100% customer-related, which is consistent with cost causation principles, as argued by CIEC.

The MSS approach is a just and reasonable approach to cost classification, but the minimum system's load-carrying capacity should be considered when allocating residual demand-related costs. The Company did not consider the minimum system's load-carrying capacity because customers benefit equally from minimum system costs since "all customers impose some lowest common denominator amount of minimum load on the system." Rates Panel Rebuttal PFT, pp. 11–12; Late Filed Ex. 83. All customers benefit equally from the minimum system, and this benefit can be quantified, although the Company did not attempt to do this. See Hr'g Tr., 1328:19. Specifically, each customer should be allocated an equal share of the load-carrying capacity affiliated with the hypothetical minimum system, applied towards the relevant demand allocators.

The Ontario Energy Board approved a similar approach, with an adjustment value of 0.4 kW per customer, following an extensive stakeholder engagement process. Hr'g Tr., 1487:13–15; Palmer Surrebuttal PFT, Att. CP-Surrebuttal-2. OCC incorporated the 0.4 kW per customer adjustment value into a modified ACOSS model, as shown in Table 80, above. See Late Filed Ex. 83, Att. 5. OCC recommended that the Company engage in thoughtful analysis with stakeholder engagement to determine an appropriate adjustment value for its minimum system. Late Filed Ex. 83, p. 1. There is not sufficient time to convene a stakeholder group for this proceeding, however. Accordingly, the Authority determines that it is appropriate to use the Company's load-carrying capacity adjustment values for poles and conductors, with two modifications. See Late Filed Ex. 71, Att. 4. Specifically, in the Company's adjusted ACOSS model, the Company applied the adjustment only for line transformers and conductors (overhead and underground). Id. Although the Company did not explain this choice, the Authority assumes that a similar load-carrying capacity adjustment was not applied to poles and conduits because those components do not physically deliver electricity. Conductors and line transformers cannot

deliver electricity without poles and conductors, however, and these components are assigned a demand-related cost in the minimum system study. Therefore, conductors and line transformers also have an associated load-carrying capacity. The Authority determines that the most reasonable correction is to apply the primary and secondary overhead conductor load-carrying capacity values to primary and secondary poles, respectively, and the underground primary and secondary load-carrying capacity values to primary and secondary conduits, respectively.

Table 81, below, shows the final load-carrying capacity adjustments for each equipment type for the Rate Year.

Table 81: Rate Year Load-Carrying Capacity Adjustments

Equipment Type	Capacity (kW)	Customers	Capacity per Customer (kW)
Primary Overhead	138,270	349,495	0.396
Primary Poles	138,270	349,495	0.396
Secondary Overhead	6,396	349,033	0.018
Secondary Poles	6,396	349,033	0.018
Primary Underground	12,614	349,495	0.036
Primary UG Conduit	12,614	349,495	0.036
Secondary Underground	4,044	349,033	0.012
Secondary UG Conduit	4,044	349,033	0.012
Line Transformers	1,095,525	349,495	3.135

Late Filed Ex. 71, Att. 4.

The use of a load-carrying capacity is consistent with the NARUC Manual cited by the Company and CIEC, which states that "[w]hen using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost." NARUC Manual, p. 95. This approach helps avoid allocating demand-related costs to customer classes that have already paid for those costs through the customer-related minimum system costs. OCC Brief, p. 149. Omitting certain customer classes based on whose demands can "generally" be met by the minimum system is too imprecise to be a reasonable approach. See Palmer Surrebuttal PFT, p. 5.

The Authority directs the Company to adopt the ACOSS models filed in Late Filed Ex. 71, with the modifications outlined above. For resulting allocators that are below zero for a certain class after applying the adjustment, that class should not be assigned any costs in that category, as is currently reflected in Late Filed Ex. 71, Att. 4.

Lastly, as part of its next rate amendment application, the Authority directs the Company to further refine the load-carrying capacity adjustment values in alignment with

OCC's suggestions, inclusive of stakeholder engagement.[118] Specifically, the Company is directed to (1) propose an alternative ACOSS with a load-carrying capacity adjustment developed in consultation with OCC and other stakeholders, (2) state whether UI recommends the alternative ACOSS, and (3) explain in narrative form why UI does or does not recommend the alternative ACOSS. UI should also explore the use of proxies that align more closely with geographic dispersion as a cost driver, rather than defaulting to MSS, as part of the stakeholder engagement.

D. COST ALLOCATION

The Company used non-coincident peak (NCP) demand to allocate demand-related costs from the ACOSS to each customer class, except for costs associated with distribution substations, for which the Company used class-wide coincident demand with system peak (1CP). Ex. UI-BR-1, p. 20. In the final decision in Docket No. 22-08-08, the Authority directed the Company to explore alternative allocators using its AMI data. 22-08-08 Decision, p. 243. The Company computed each class's contribution to substation and feeder peaks using hourly load data, with which it developed weighted allocators. Ex. UI-BR-5. The Company elected not to use these alternative allocators in its ACOSS but stated that the alternative allocators were "very similar" to the NCP and 1CP allocators. Rates Panel Rebuttal PFT, pp. 17–18.

To move closer to equalized rates of return (ROR) among customer classes, the Company employed an iterative approach. Application, Ex. UI-RP-1, p. 14. The Company first allowed rate increases equal to 75% to 125% of the average increase across all classes, then reallocated remaining revenues among classes with non-binding constraints. Id. This approach was consistent with the Authority's directive in the Company's previous rate case. See 22-08-08 Decision, p. 244. The Company then made a manual adjustment to its model, reducing the lower rate increase constraint from 75% to 50%. Ex. UI-RP-1, p. 15. Although this approach violated the Authority's 125%/75% rule, it achieved closer ROR parity among customer classes compared to the unadjusted model. Id.

UI asserts that its use of the 1CP and NCP allocators in the ACOSS reflects the industry standard. Rates Panel Rebuttal PFT, p. 16. The Company asserts that it "seems reasonable to rely on allocators that are easy to understand and readily available," compared to the alternative allocators, which were data- and resource-intensive to develop. Id., p. 18. The Company also argued that this simpler approach is the most cost-reflective approach. Hr'g Tr., 1334:14.

OCC recommends that the Company use alternative demand allocators for substations and primary feeders. Palmer PFT, p. 30. OCC suggests that UI's approach to developing alternative demand allocators was reasonable but could be improved by considering such factors as duration of the peak, near-peak hours, and pre-peak loads.

[118] The phrase "in alignment with OCC's suggestions" refers to OCC's suggestions to conduct a stakeholder engagement process to develop an appropriate adjustment value, similar to the process followed by the Ontario Energy Board. The final adjustment value should not be dictated solely by OCC, a concern articulated by CIEC. CIEC Exceptions, p. 6.

Id., p. 28. OCC suggests that the Authority could balance the opposing results of its proposed class revenue increase (based on the basic customer ACOSS method) by implementing an equal percentage increase for all rate classes. Palmer PFT, p. 33. OCC also noted that the NARUC Manual, on which the Company relied to propose use of the NCP and 1CP allocators, was published in 1992, prior to the advent of AMI, which enables more cost-reflective allocators. Palmer Surrebuttal PFT, p. 12; Hr'g Tr., 1496:22–1497:5.

CIEC opposes the Company's proposed revenue allocation. Chait PFT, p. 12. CIEC states that the Authority has historically allowed for a revenue increase tolerance band outside 75% to 125% if there is significant disparity between class rates of return. Id. CIEC proposes a +/-40% tolerance band to mitigate overcollection from customers on schedules GST, LPT, and U. Id., p. 13.

The Company demonstrated analytical rigor in its development of alternative demand allocators; ultimately though, the Company proposed to continue to use NCP and 1CP allocators in its ACOSS due to their simplicity and historical precedent. Nonetheless, the Authority agrees with OCC that the alternative demand allocators better reflect cost causation. The fact that the two approaches produce similar results is not a valid justification to employ a less cost-reflective method, particularly given the possibility that load patterns will shift in the future in response to TOU rates. Unlike rates, it is not important for demand allocators to be easy to understand, and simplicity is not sufficient justification for using an inferior method. However, due to the difficulty of incorporating the load-carrying capacity adjustments outlined in Section VIII.C, Cost-of-Service Study, above, to the alternative demand allocators, the Authority accepts, for this proceeding, the Company's use of the simple NCP allocators (adjusted for the load-carrying capacity). The Authority directs the Company to adopt the alternative substation allocator for demand-related substation costs. Table 82, below, shows the final allocators for the Rate Year. The substation allocators come from Late File Ex. 71, Att. 3. The remaining allocators come from Late File Ex. 71, Att. 1.

Table 82: Demand Allocators

Allocator	R	GS	GST	LPT	M	U
Substation	51.87%	12.23%	23.36%	12.55%	0.00%	0.00%
NCP for Transformers	0.00%	13.04%	63.53%	22.48%	0.77%	0.19%
NCP Primary – Overhead Conductors and Poles	46.56%	11.33%	27.93%	13.77%	0.33%	0.08%
NCP Secondary – Overhead Conductors and Poles	56.29%	12.02%	24.63%	6.66%	0.32%	0.08%
NCP Primary – Underground Conductors and Conduit	50.77%	10.95%	25.47%	12.44%	0.30%	0.07%
NCP Secondary – Underground Conductors and Conduit	56.36%	12.01%	24.59%	6.64%	0.32%	0.08%

The Authority reviewed the Company's revenue allocation scheme using the updated ACOSS model outlined in Section VIII.C, Cost-of-Service Study, above. The Company's approach starts by allocating either the maximum allowable rate increase

(125% of the class average increase) *or* the rate increase at equal rates of return (whichever is lower). Interrog. Resp. OCC-362, Att. 38 Second Rev. Supp. The Company then eliminates rate decreases (which occur in cases where the revenue requirement at equal rates of return is lower than the delivery revenues at present) and allocates the remaining revenue shortfall to each class proportional to that class's base revenue at present, subject to the 125% rule. Id. In the final step, the Company performs a manual adjustment (using hardcoded values) and uses the residential rate class to balance the system to the overall revenue target. Ex. UI-RP-1, p. 15. The resulting revenue requirements yield rate increases equal to 50% of the class-wide average for the GS, GST, LPT, and U rate classes.

The Authority finds that after the load-carrying capacity adjustments were made to all components of the minimum system, an alternative revenue allocation approach achieves closer revenue-to-cost (RTC) and ROR parity among the rate classes compared to the Company's approach without a manual adjustment.[119] Under the alternative revenue allocation approach, in the first step, each class receives the greater of either the minimum increase (i.e., 75% of the class-wide average increase) *or* the rate increase at equal rates of return. The resulting excess revenue is subtracted from the classes with rate increases higher than the minimum increase, proportional to base distribution revenues at present. The ultimate revenue increases adhere to the 75/125 rule. Table 83, below, lays out the steps for applying the alternative allocation approach, compared to the Company's approach.

[119] In implementing this alternative allocation, the Authority discovered an apparent formula error in the Company's revenue allocation spreadsheet. Interrog. Resp. OCC-362, Att. 38 Second Rev. Supp. ("Revenue Allocation" tab). To calculate the equiproportional rate increase ("Revenue Allocation" tab, ln. 25) for the residential class, the Company subtracted the Delivery Revenue at Present (Line 8) from the Rate Year Revenue at Equiproportional Change (Line 24). Id. However, for the other rate classes, the Company subtracted the Tota Delivery Revenues at Present (Line 10, inclusive of Other Revenues) from the Rate Year Revenue at Equiproportional Change (Line 24). This produced a disparity in the Equiproportional Factor (19.6% in cell D24, 20.0% in cell D25), which impacts the maximum proportional increase cap factor (Line 28) and subsequent calculations. This factor was the subject of another interrogatory response. Interrog. Resp. OCC-685, pp. 1–2. The Authority corrected this error when applying the alternative allocation scheme.

Table 83: Alternative Revenue Allocation Approach

Step	Company's Approach	Alternative Approach
1	Allocate to each class the *lesser* of the: (1) maximum allowable increase under 75/125 rule (125% of class-wide average increase) or (2) increase at equalized rates of return. Then, eliminate rate decreases.	Allocate to each class the *greater* of the: (1) minimum allowable increase under 75/125 rule (75% of class-wide average increase) or (2) increase at equalized rates of return.
2	Calculate the revenue shortfall (the difference between the revenue target and the sum of class revenues in Step 1). For classes below the 125% cap, allocate the revenue shortfall proportional to each class's base revenue at present.	Calculate the revenue excess (the difference between the revenue target and the sum of class revenues in Step 1). For classes above the 75% floor, return the revenue excess proportional to each class's base revenue at present.
3	Repeat Step 2 using the remaining revenue shortfall.	
4	Perform manual adjustment and use the residential class to balance the system to the overall revenue target.	

Figures 2 through 5 show the class revenue increases, relative ROR values, and relative RTC values for the Company's proposal compared to the adjusted ACOSS and revenue allocation scheme described in this and the preceding section. Had the Company performed the revenue allocation using the load-carrying capacity-adjusted ACOSS, a different manual adjustment may have been made to move each class closer to ROR and RTC ratios of 1.00. However, in the absence of information on how these manual adjustments were calculated, the Authority was unable to produce a third scenario that used the adjusted ACOSS with the Company's revenue allocation model.

Figure 2, below, shows the rate increases for each rate class, using the Company's proposal and the adjusted ACOSS with alternative revenue allocation. The percentage increases shown in Figure 2 are based on the Company's proposed increases, and do not represent the actual increases that will be approved as a result of the revenue requirement approved in this decision. In addition, the Company is directed to make adjustments to the adjusted ACOSS, which are not represented in the results shown in Figure 2.

Figure 2: Rate Increase Comparison Between the Company's Proposal and Adjusted ACOSS with Alternative Revenue Allocation

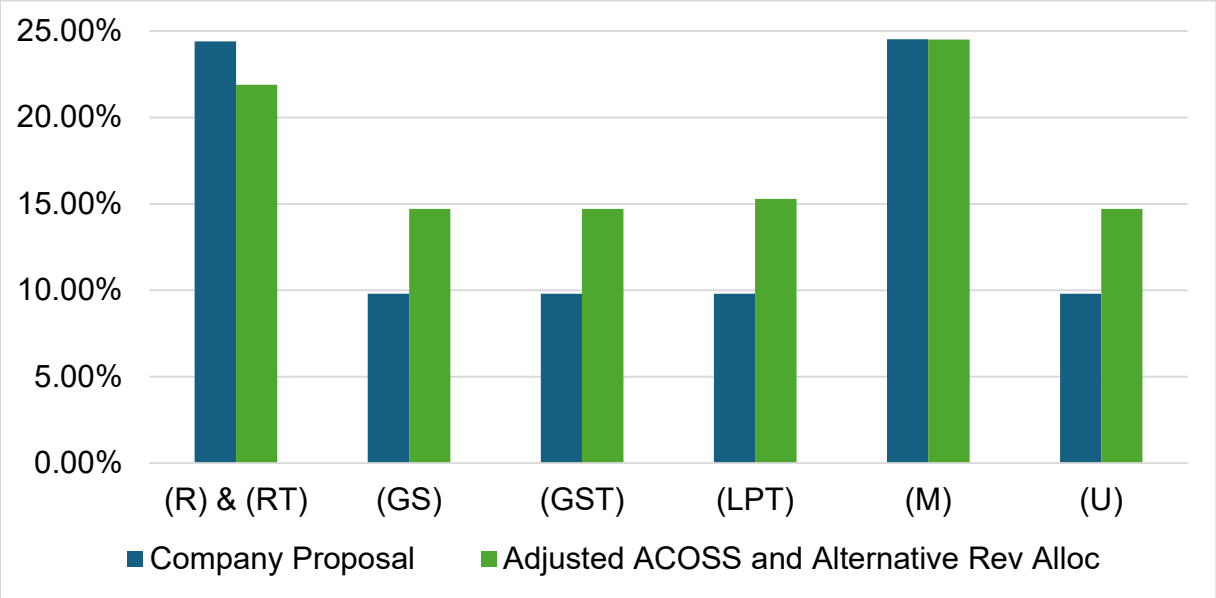


Table 84 shows the rate increases for each class (absolute and percentage increases) used to produce Figure 2, based on the Company's proposed increases.

Table 84: Rate Increases Based on UI's Proposed Revenue Requirement

		R and RT	GS	GST	LPT	M	U
Absolute Increase	Company Proposal	$62,106,593	$3,797,425	$6,225,275	$2,457,460	$1,705,802	$54,256
	Adjusted ACOSS & Alt. Rev. Allocation	$55,696,050	$5,696,138	$9,337,912	$3,830,893	$1,704,434	$81,383
Percent Increase	Company Proposal	24.40%	9.81%	9.81%	9.81%	24.52%	9.81%
	Adjusted ACOSS and Alt. Rev. Allocation	21.89%	14.71%	14.71%	15.29%	24.50%	14.71%

Figure 3, below, shows the rate increases for each rate class relative to the class average increase, using the Company's proposal and the adjusted ACOSS with alternative revenue allocation. The adjusted ACOSS with alternative revenue allocation adheres to the 75/125 rule, whereas the Company's proposal permits rate increases equal to 50% of the class average for the GS, GST, LPT, and U classes.

Figure 3: Rate Increase Relative to System Average Comparison Between the Company's Proposal and Adjusted ACOSS with Alternative Revenue Allocation

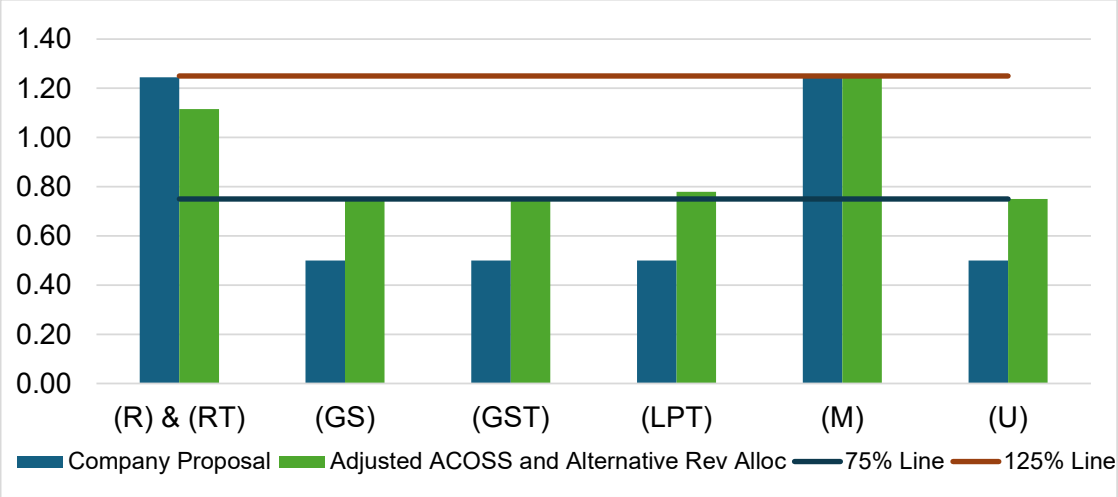


Figure 4, below, shows the RTC ratio for each rate class using the Company's proposal and the adjusted ACOSS with alternative revenue allocation. A rate class's RTC ratio is calculated by dividing the revenue requirement under the proposed allocation by the revenue requirement at equalized rates of return. If there were perfect parity among rate classes, each would have an RTC value of 1. The adjusted ACOSS with alternative revenue allocation achieves better parity (i.e., lower average discrepancy between actual RTC and the target of 1.00) compared to the Company's proposal.

Figure 4: Revenue-to-Cost Ratio Comparison Between the Company's Proposal and Adjusted ACOSS with Alternative Revenue Allocation

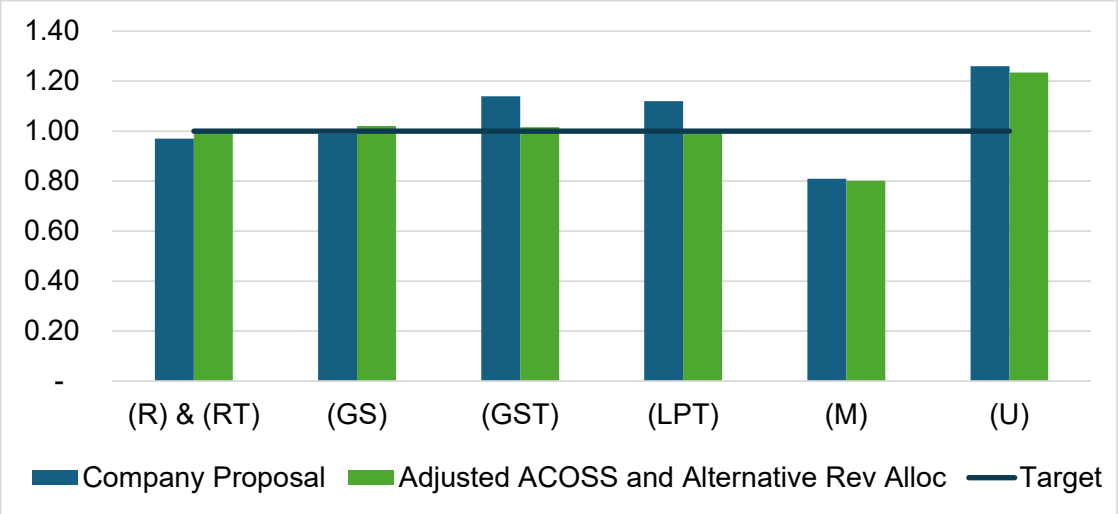
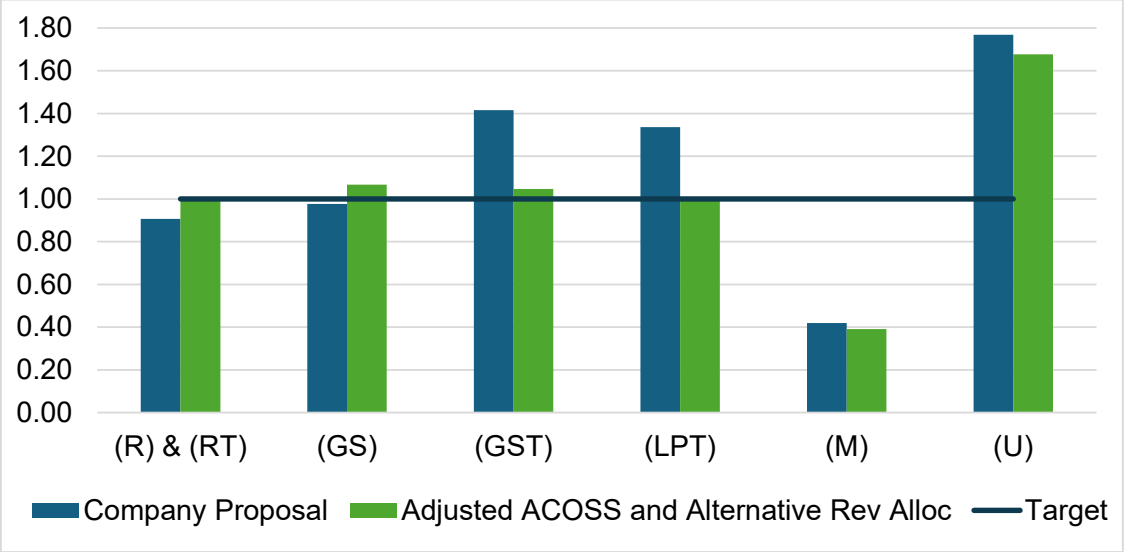


Figure 5, below, shows the ROR ratio for each rate class using the Company's proposal and the adjusted ACOSS with alternative revenue allocation. A class's ROR ratio is calculated by dividing its return by the system total return. The return is calculated by dividing operating income by total rate base. An ROR ratio of 1 means that the class's return is equal to the system total return. Similar to RTC ratios, the adjusted ACOSS with alternative revenue allocation achieves better parity compared to the Company's proposal.

Figure 5: Rate of Return Ratio Comparison Between the Company's Proposal and Adjusted ACOSS with Alternative Revenue Allocation



The Company has made progress since its previous rate case in developing a methodology to move closer to equalized rates of return among all rate classes. However, the alternative revenue allocation scheme outlined above better balances the goal of achieving class-by-class rate of return parity with the rate design principle of gradualism and the 75/125 rule. See 22-08-08 Decision, p. 244. As such, the Authority directs the Company to adopt the alternative revenue allocation scheme, including correcting the apparent error in the Company's revenue allocation spreadsheet. See footnote 119, above.

E. RATE DESIGN

1. Time of Use Rates

In the Company's previous rate case, the Authority directed the Company to propose TOU rates with a shorter, more concentrated on-peak time, an appropriate price differential between on- and off-peak rates consistent with empirical research by rate design experts, time-differentiation of all electric rate components (time-of-day and seasonal), and a proposal to make TOU rates opt-out. 22-08-08 Decision, pp. 243–244. The Company's TOU proposal includes near-term (i.e., effective November 1, 2025) opt-

in TOU rates and end-state opt-out rates, with no concrete implementation date. For the near-term TOU rates, the Company proposed to maintain the existing on- and off-peak windows, time-differentiate the distribution charge, and introduce seasonal differentiation. Ex. UI-RP-1, p. 36. The Company is unable to update the hours for on- and off-peak rates until modifications are made to its billing and metering systems; the Company issued an RFP in December 2024 for an external system integrator to determine the most appropriate modifications, with an estimated cost of $276,000 for the project to determine the most appropriate modifications. Id., pp. 71–73. The Company did not provide an estimate of when these modifications will be complete or the costs that will be involved in modifying the system(s). Interrog. Resp. EOE-97.

The Company proposed to allocate the revenue requirement to the various time periods using the results of the ACOSS. Ex. UI-RP-1, p. 39. Specifically, the Company identified components of the ACOSS that vary by time and are coincident with system peaks, then allocated those costs according to the percentage of substations and feeders peaking in each season and time period. Id., pp. 39–43. The Authority identified three anomalies[120] in the Company's rate design model:

(1) The Company explained that primary feeder-related demand costs were allocated to the different seasons and time periods. Ex. UI-RP-1, p. 43. Yet for rates LPT and GST, the Company assigned 50% of primary demand costs as non-time-varying. Interrog. Resp. OCC-362, Revised Att. 24 ("GST_11.1.25" tab); Interrog. Resp. OCC-362, Revised Att. 24 ("LPT_11.1.25" tab);

(2) In calculating final cost-based rates for rate LPT, the Company added the cost of the non-summer off-peak period to the cost of each other period. Interrog. Resp. OCC-362, Revised Att. 24, LPT_11.1.25 tab. Based on similar calculations for Rates RT and GST, the Authority determines that the Company likely intended to add the cost of the non-time-varying component to each of the time-varying components; and

(3) For rates GST and LPT, the Company did not use its cost-based rates for the summer off-peak and winter demand charges. Interrog. Resp. OCC-362, Att. 38 Second Rev. Supp. ("GST" tab); Interrog. Resp. OCC-362, Att. 38 Second Rev. Supp. ("LPT" tab). Instead, the Company used the same value for the summer off-peak demand charge and winter on- and off-peak demand charges and offered no explanation for how that value was derived. Id. For rate RT, the Company used the exact, unmodified cost-based rates for all time periods and seasons directly from its ACOSS model. Interrog. Resp. OCC-362, Att. 38 Second Rev. Supp. ("R and RT" tab); Interrog. Resp. OCC-362, Revised Att. 24 ("R+RT_11.1.25" tab).

For the near-term TOU rates, the Company proposed to recover NBFMCC and transmission costs entirely in the on-peak period, consistent with how those costs are currently recovered. Ex. UI-RP-1, p. 45. The Company also proposed an illustrative

[120]Because the Authority does not approve the rate design proposed by UI, these anomalies have no bearing on the rates approved in this Decision. UI, however, should correct or, if applicable, explain the justification for its methodology, if it uses the same or similar methodology in a future proceeding.

methodology to allocate non-distribution components to align TOU rates across utility functions. Id., pp. 60–70.

To determine the appropriate periods for its end-state rates, the Company evaluated the probability of peak (both UI and ISO-NE) for each hour in the year. Ex. UI-RP-1, pp. 47–53. The Company also analyzed historical locational-marginal prices in the ISO-NE wholesale market. Id., pp. 53–57. The Company proposed the same time-of-day and seasonal periods for residential (Rate RT) and commercial (Rate GST) classes. Id., p. 47. The Company performed bill impact analyses to assess the impact of the proposed bill increases on each class and for different usage profiles within each class. Interrog. Resp. OCC-362, Att. 38. The Company performed similar analyses for two additional rate design scenarios with summer on-peak to off-peak ratios of 3:1 and 2:1. Interrog. Resp. RRU-386, Att. 1.

OCC is critical of various aspects of the Company's rate design proposal. OCC suggests that while the Company's proposed end-state periods and seasons appeared reasonable, certain methodological changes would improve the rigor of the analysis, including incorporating forecast data and considering only weekday cost drivers. Palmer PFT, p. 37. OCC also suggests that the end-state opt-out rates include only two seasonal periods, summer and non-summer, to reduce complexity and increase the likelihood of customer acceptance. Id., p. 41. OCC argues that the price differential between on- and off-peak rates, for both near-term and end-state rates, is too extreme and will introduce bill shock. Id., pp. 42–45. OCC provided data showing that the average summer peak to off-peak ratio in utility territories with opt-out TOU rates is 1.5:1. Id., p. 48. OCC states that the Company did not provide an adequate transition plan to opt-out TOU rates and suggests components of such a plan should include, at minimum, a bill comparison tool, customer protections, and a milder peak to off-peak price differential. Id., pp. 46–50. Finally, OCC recommends that the Company develop an opt-in critical peak pricing rate, which has been shown to induce significant load reductions compared to TOU rates, especially when coupled with enabling technology like smart thermostats. Id., pp. 51–52.

The Company defended the high price differential in its near-term and opt-out end state rates, stating that the rates are cost-based and are intended to provide an incentive to shift usage. Rates Panel Rebuttal PFT, p. 25. The Company did not provide references to research conducted into best practices on rate design, indicating instead that they took a purely cost-based approach. Interrog. Resp. RRU-169. The Company indicated that its decision to allocate 39% of revenue recovery to the demand charge and 61% to the energy charge was based on the proportion of revenues collected from demand charges and energy charges under current rates; UI did not provide justification for this split other than that it had been used in previous rate cases. Interrog. Resp. RRU-385; Hr'g Tr., 1350:14–1351:14.

The Authority generally accepts the Company's analysis and the methodology used to determine appropriate on- and off-peak periods and seasons for its end-state rates. The proposed on-peak time periods capture likely Company system peaks, ISO-NE peaks, and high locational marginal price periods in the ISO-NE energy market. The Authority concurs with OCC, however, that having three seasonal periods adds

unnecessary complexity, especially given that the winter and shoulder periods, as proposed, have the same time periods. Especially during the transition period to opt-out TOU rates, simplicity in rate design will be key for customer understanding. The Authority agrees with both OCC and the Company that excluding weekends from peak periods is merited and should be incorporated into the analysis. If available, forecast data should be considered in the selection of peak periods.

In evaluating the Company's rate design proposal, the Authority must consider how to best balance the goals of providing a strong signal to shift load to off-peak periods with generally accepted rate design principles of gradualism, customer acceptance, and understandability. The Company has not provided sufficient justification for allocating substation- and feeder-related demand costs to the on- and off-peak and seasonal periods based on the percentage of substations and feeders peaking in those periods. The Company's approach may be appropriate to *guide* cost allocation but should not be used without modification, as it implies that there are no substation- or feeder-related demand costs associated with serving load outside the hour when that substation or feeder peaks.

As UI acknowledges, rate design is an art and a science, yet the Company's approach to allocating substation- and feeder-related demand costs attempts to make the exercise purely quantitative. Ex. UI-RP-1, p. 11. Rates should be set according to both cost causation and empirical research into appropriate price differentials that can be reasonably expected to induce customer behavioral change without unduly penalizing customers. Although the Company conducted a thorough analysis to determine appropriate timing of on-peak periods in its end-state rates, the price differential in the proposed near-term rates is concerning. Setting a large price differential without changing the on-peak window (currently eight consecutive hours, from 12:00 to 8:00 p.m.) may dissuade enrollments and penalize customers currently enrolled on Rate RT that would not have a reasonable opportunity to shift their demand away from the on-peak period. Equally concerning is that an average customer enrolled on Rate R will save money by enrolling on Rate RT without changing their consumption patterns. Interrog. Resp. RRU-172, Att. 1, p. 2; Hr'g Tr., 1347:9–11. This implies that if all residential customers transitioned to Rate RT, it may lead to an under collection of revenue, because all underlying costs would remain identical. This reality also may help explain the Company's conclusion that customers transitioning from Rate R to Rate RT did not change their consumption behavior; existing rates provide little impetus to change behavior if the average customer can save money by doing nothing. See Hr'g Tr., 1464:20–1465:16. The proposed rates, therefore, may create both bill shock and free-ridership problems for customers. The Authority is particularly concerned that the high price differential will have the opposite result from that intended by causing a net reduction in enrollment on Rate RT.

The Company proposes to continue to recover transmission and NBFMCC costs exclusively in the on-peak period for near-term rates for purposes of "simplicity and continuity." Interrog. Resp. RRU-343. This method may have produced an appropriate outcome when the distribution charge was not time-differentiated, but it is important to evaluate the aggregate of all line items when determining the reasonableness of a rate

proposal. Although changing the allocation approach for transmission and NBFMCC costs may ultimately be appropriate, the record development around rate design in the instant proceeding dealt exclusively with the base distribution charge.

There is already a 2.28:1 on-to-off-peak ratio for existing rates due to the recovery of NBFMCC and transmission costs exclusively in the on-peak period, as shown in Table 85, below, which shows the distribution and total volumetric rate, peak to off-peak ratio, and average bill for Rate RT customers under four scenarios: (1) existing rates; (2) the Company's proposed rates; and rates with a summer peak to off-peak ratio of (3) 3:1 and (4) 2:1.[121] Based on the Company's proposal, the summer on-peak volumetric rate under the RT tariff would be $0.76 per kWh. Even if the *average* Rate RT customer only consumes 10% of their energy during the summer peak period, there are likely some customers whose summer peak usage far exceeds that level and who will be unduly burdened under the Company's proposal without a fair opportunity to lower their costs due to the long on-peak period. See Interrog. Resp. OCC-362, Att. 38; Hr'g Tr., 1346:7–15. There is no reason to believe, based on evidence presented in the record, that increasing the peak to off-peak ratio from 2.28 to 3.34 will produce a significant change in consumption behavior. With a low potential benefit and high potential cost increases for a subset of customers enrolled in Rate RT, the Authority determines that the Company's proposal is neither just nor reasonable.

Table 85: Comparison of Rate RT, Proposed and Alternatives

	Existing Rates				Proposed Rates				3:1 Distribution				2:1 Distribution			
	Summer		Winter		Summer		Winter		Summer		Winter		Summer		Winter	
	On	Off	On	Off	On	Off	On	Off	On	Off	On	Off	On	Off	On	Off
Distribution	$0.08	$0.08	$0.08	$0.08	$0.33	$0.08	$0.08	$0.07	$0.25	$0.08	$0.08	$0.08	$0.19	$0.09	$0.09	$0.09
Total	$0.52	$0.23	$0.52	$0.23	$0.76	$0.23	$0.51	$0.22	$0.69	$0.23	$0.52	$0.23	$0.62	$0.24	$0.53	$0.24
Peak/Off Peak Ratio	2.28		2.28		3.34		2.39		3.00		2.26		2.61		2.22	
Average Bill	$298.48		$286.35		$374.53		$285.55		$355.13		$296.73		$341.73		$304.28	

Interrog. Resp. RRU-386, Att. 1.

In light of these concerns, the Authority directs the Company to modify its rate design proposal so that the distribution charge continues to be not time-differentiated. Although cost-reflective TOU rates are an important goal, the Authority cannot approve a half-measure (adding time-differentiation without modifying the on-peak window) that risks penalizing customers already enrolled on these rates without any reasonable expectation of incremental load shifting. Under existing rates, there is already a meaningful price differential due to the recovery of transmission and NBFMCC costs exclusively in the on-peak period. The Authority may consider methodologies to time-differentiate non-distribution rates in relevant future proceedings. For residential customers especially, given the low level of awareness of TOU rates, it is important not

[121] Though not shown here, the Authority conducted the same analysis for Rates GST and LPT and found similar results: a substantial differential between on- and off-peak existing rates due to the recovery of NBFMCC and transmission costs exclusively in the on-peak period.

to confuse customers with a new rate structure (i.e., the near-term rates, effective November 1, 2025) that will become obsolete when end-state rates are implemented. 17-12-03RE02 UI Compliance with Order No. 11. The Authority acknowledges CIEC's concern that the Draft Decision did not provide the Company with specific guidelines for differentiating distribution rates for GST and LPT classes. CIEC Exceptions, p. 9. While the Authority agrees that special attention must be given to the unique capabilities of customers in different rate classes to respond to price signals when designing rates, this concern is addressed by the Authority's directive not to differentiate distribution charges for near-term rates.

The Company indicated that its customers prefer opt-in rates, based on a survey conducted in 2024. Interrog. Resp. RRU-176. The importance of opt-out rates is not based solely on consumer preference; rather it is grounded in cost causation principles and long-term affordability. Customers must face cost-reflective price signals to make informed decisions about their electricity consumption, which will lead to efficient investments in the distribution system. Masking true price signals with flat volumetric rates does not protect ratepayers and only ensures that underlying time-varying costs are recovered inefficiently. It is concerning that the proposed end-state rates have almost no price differential between the winter on-peak and off-peak periods. Behavioral change is difficult and will not happen instantly. For many customers, the transition to opt-out TOU rates will be the first time they are exposed to the concept that the cost of electricity varies by the time of day. As customers become familiar with TOU rates, it is important for rates to induce behavior changes during hours that drive costs both today and in the future. In light of the projected transition to a winter-peaking grid in the state and region, providing a muted winter price differential risks reinforcing undesirable behaviors.

The Company indicated that there is no timetable for its implementation of end-state rates, which will depend on the findings on the external system integrator. Interrog. Resp. EOE-095. Because the proposed end-state rates are merely "illustrative," the Authority is unable to rule on their reasonableness. Rates Panel Rebuttal PFT, p. 26.

In sum, the record indicates that the Company's preparation and progress towards implementing opt-out TOU rates have been inadequate. The Company acknowledged that it has not developed a detailed customer education plan, attributing this to the fact that the details of such a plan are dependent on when opt-out TOU rates will become effective. Rates Panel Rebuttal PFT, p. 27. The information presented by the Company in Exhibit UI-CSP-1 lacks important details, including the timing of the transition, proven consumer protection mechanisms such as shadow billing and bill stabilization, and a specific plan for low-income discount rate (LIDR) customers. The Company testified that there is not an automated process for customers to calculate their bill savings under TOU rates, which will be critical for customers deciding whether to opt out of the TOU rate. Hr'g Tr., 1399:18–21. The Company stated that besides issuing an RFP for an external system integrator, it has not conducted any work to update its billing or metering systems to support more granular rates, as ordered in the final decision of Docket No. 22-08-08. Interrog. Resp. RRU-175.

The Company's actions—or rather inaction—with respect to this topic are particularly confounding given the Authority's unambiguous direction requiring the Company to propose more granular TOU rates in its subsequent rate case. 22-08-08 Decision, pp. 239–241 (Order No. 41). The Authority did not order the Company to suggest illustrative rates, but actual rates with a clear implementation timeline. Despite this clear directive, the Company testified that it did not begin internal discussions regarding retaining an external system integrator until September 2024, even though the Company identified its billing system as a barrier to proposing new rates in its previous rate case. Hr'g Tr., 1389:22–23. Although the Company made significant strides since its last rate case in analyzing its AMI data to allocate costs to different periods, the Company failed to leverage best practices in rate design and lessons learned from other jurisdictions that have successfully rolled out both opt-in and opt-out TOU rates, opting instead for a strictly cost-based approach. Regardless of when the Company began discussions and analysis of end-state TOU rates, there is no evidence in the record to support a conclusion that the Company began developing the RFP for an external system integrator until a full year after the 22-08-08 Decision, which, in light of the existing billing system's limitations, does not reflect expert, efficient, or prudent management.

On July 1, 2025, Governor Ned Lamont signed Public Act No. 25-173, An Act Concerning Energy Affordability, Access and Accountability, into law. Among other things, Public Act No. 25-173 provides extensive direction regarding the development and implementation of time-varying rate proposals, culminating in a filing due to the Authority from each EDC no later than October 1, 2027. Public Act No. 25-173, §§ 19–21; see also General Statutes § 16-243n(a). As such, although the Authority will avoid restating the direction now codified in law, the Company should be aware that it will risk a violation of both regulatory directives and state law if it files a proposal with similar substance and detail to that provided in this proceeding. See General Statutes § 16-243n. Lessons learned from the instant proceeding shall be reflected in any subsequent Company filing. Updated end-state rates that are neutral with respect to revenue with the prevailing rates and that align TOU rates across all utility functions constitute a baseline expectation, and the filing must also include:

(1) A robust customer transition plan and a plan to engage stakeholders during the plan's implementation;
(2) An alternative methodology for allocating substation and feeder costs to on-peak and off-peak periods;[122] specifically, a method that recognizes the average demand at each substation and feeder for cost allocation to all time periods in addition to the incremental capacity necessary to meet maximum demands of each substation and feeder attributable to the on-peak or off-peak time periods; and

[122]As discussed earlier in this section, the Company allocates substation and feeder costs based on single historical maximum load times for individual substations and feeders and then develops time period ratios for determination of the costs to be included in each time period. Allocating costs based on ratios developed from single maximum load times, despite the fact that those substations and feeders deliver benefits to customers throughout all time periods, is not reasonable. Although the Company's methodology presented here is a good first step, it must further evolve by incorporating recognition of the base, or average demand needs, of the substations and feeders during all hours and time periods.

(3) Analysis of other opt-in rate structures that may enhance consumer choice and increase load shifting, including critical peak pricing, peak time rebates, and per-kW capacity subscriptions for residential customers. These rates all rely on the billing and metering system modifications that will also enable the Company's proposed opt-out TOU rates.

See General Statutes § 16-243n.

2. Tariff Changes

a. Terms and Conditions

The Authority reviewed the Terms and Conditions and Billing Glossary in UI's proposed tariff, which are not rate-impacting. Application, Ex. E 1.0, pp. 1–16. The Company made no revisions to those tariff pages, which were previously approved by the Authority. The Authority accepts UI's Terms and Conditions and Billing Glossary.

b. Miscellaneous Service Fees

The Company's miscellaneous service fees are cost-based and include supplier[123] relations, standard field, and billing fees. Application, Sch. E-1.0, pp. 17–24; Interrog. Resp. RRU-7, Att. 1, Att. 2, Att. 3. UI did not propose changes to its miscellaneous billing fees. Application, Sch. E-1.0, pp. 23–24. Table 86, below, summarizes UI's proposed changes to supplier relations and standard field fees.

Table 86: Proposed Miscellaneous Service Fees, effective Nov. 1, 2025

Fee	Proposed Modification
Supplier Relations Fees:	
Cancel/Rebill (partial loader)	Increase the labor fee from $78.00 to $80.34/hour. Increase the per bill fee from $0.62 to $0.64.
Initialization (partial loader)	Increase the set up and testing fee from $7,123.00 to $7,337.00. Increase the rate configuration hourly rate from $137.40 to $141.52.
Meter Test (partial loader)	Increase the single-phase meter test from $104.13 to $113.44. Increase the three-phase test rate from $124.95 to $141.45.
Interval Meter Data (partial loader)	Increase installation fee from $759.04 to $791.00. Increase the monthly fee from $14.92 to $15.83.
Theft of Service (TOS) Investigation (full loader), hourly rate	Increase the investigation fee from $75.81 to $87.42/hour. Increase the supervisory fee from $95.23 to $104.08/hour. Increase the billing support fee from $74.18 to $89.68/hour. Increase the standard field force fee from $81.81 to $92.19/hour.
Web Presentment Fee (partial loader)	Eliminate the tariff language and fee as the service will no longer be available after 07/01/2025.
Customer Requested Usage/Load Data Load Analysis (Partial Loader)	Increase the analysis fee from $93.46 to $96.26/hour.

[123]Suppliers are defined as licensed electricity suppliers. Application, Sch. E-1.0, p. 13.

Fee	Proposed Modification
Standard Field Fees:	**Proposed Modification (effective Nov. 1, 2025)**
Meter Reconnect Fee (straight time)	Increase the straight time fee from $19.35 to $22.58.
Overhead Reconnect – Cut Tap	Increase the cut tap reconnect straight time fee from $170.00 to $230.86 /hour. Increase the cut tap reconnect overtime fee from $217.59 to $291.49/hour.
Lockout Second Field Visit	Increase the first quarter hour straight time rate from $39.67 to $45.84. Increase the additional quarter hour rate from $19.83 to $22.90. Increase the first quarter hour overtime rate from $50.77 to $54.16. Increase the additional quarter hour overtime rate from $25.38 to $27.08.

Application, Sch. E-1.0, pp. 17–23.

Supplier relations fees recover the costs associated with accommodating retroactive supplier billing; setting up new suppliers, including Electronic Data Interchange (EDI) testing, EDI training, and configuring a supplier's initial set of rates; meter tests; interval meter data; and TOS investigations. Id., pp.18–19. Some supplier fees may be billed to the supplier or customer, dependent upon the requesting entity.[124] Id., pp. 19–21. Standard field fees recover the costs for reconnection following a discontinuance of service due to failure to pay a bill or meet other customer obligations to the Company. Application, Sch. E-1.0, p. 22. The Company provided cost support for its proposed supplier and standard service fees. Interrog. Resp. RRU-7, Att. 1, pp. 2–5. The cost support included wage and benefit costs, relative job titles, and time estimates for the work performed associated with each fee and accounting for inflation.[125] Id.

The Company proposes increases of 4.2% to 35.8% from the current service fee rates. Interrog. Resp. RRU-235, Att. 1, p. 1. The Authority reviewed the proposed fees and cost support for the Company's supplier relations and standard fees. Many of the proposed service fee increases are driven by increases in the hourly labor costs associated with the personnel who perform the work associated with the required service fee.[126] The proposed rates also reflect employee wage increases through January 1, 2025. Interrog. Resp. RRU-7, Att. 1.

Revenues collected from miscellaneous service fees are categorized as "other revenues." Late Filed Ex. 1, Att. 2 Supp., Sch. WP-C-3-01. Other revenues collected from service fees, although small, combine with other revenue streams to offset the distribution revenue requirement, which ultimately benefits UI ratepayers. In addition, some fees apply only to electric suppliers, not UI ratepayers. The Authority has reviewed

[124]For TOS investigations, the outcome of the investigation may determine whether the supplier or customer is charged the investigative fees. Application, Sch. E-1.0, p. 20.

[125]The hourly rates provided for Miscellaneous Tariff Charges in UI's response to Interrogatory RRU-7 were not impacted by the responses to interrogatories RRU-123 and RRU-125 that addressed new hires, leavers, net transfers, job requisitions, and the hiring process. Interrog. Resp. RRU-387.

[126]For example, the 35.8% increase in the overhead reconnect cut tap fee resulted from the Company's increase of the estimated duration of the labor required to provide this service from 0.75 hours per 2-person crew as included in Docket No. 22-08-08 to 1 hour per 2-person crew. Late Filed Ex. 75.

the record and finds that no party has objected to UI's proposed service fee increases. The Authority finds the proposed service fees acceptable.

3. Maximum Residential Customer Charge

General Statutes §16-243bb, enacted in 2015, required the Authority to adjust each EDC's residential customer's[127] fixed charge to recover only the fixed costs and O&M expenses "directly related to metering, billing, service connections and the provision of customer service" (MRCC Statutory Functions). The Authority considered the O&M costs that are directly related to the MRCC Statutory Functions in Docket No. 17-01-12. Decision, Dec. 20, 2017, PURA Establishment of a Maximum Residential Customer Charge (MRCC) Formula for Non-Electric Heating Residential Service (MRCC Decision). The Authority directed each EDC to follow the instructions set forth in the MRCC Decision and to submit a conforming MRCC calculation and to propose a residential non-heating customer charge in future rate cases. MRCC Decision, p. 6.

Here, UI initially proposed a residential customer charge of $13.20 that would apply for both Rates R and RT. Ex. UI-RP-1, p. 4; Ex. UI-RP-4. Subsequently, in response to a discovery request from OCC, the Company revised its MRCC calculation; UI stated that it had mistakenly applied the cost of debt and return on equity ratios that were approved by the Authority in Docket No. 16-06-04, instead of those approved in Docket No. 22-08-08. Interrog. Resp. OCC-362, Revised Att. 36, p. 1. The revised MRCC calculation reduced the proposed residential customer charge amount by ($0.16) to $13.04. Interrog. Resp. OCC-362, Revised Att. 36, p. 1; Interrog. Resp. RRU-294. The proposed MRCC represents an increase of $1.70 above the current residential customer charge of $11.34. Interrog. Resp. RRU-386, Att. 1, p. 4. Table 87, below, shows the current and proposed MRCC amounts for the general accounting components of return on rate base, expenses, and taxes.

Table 87: Current & Proposed MRCC Monthly Residential Charge (Rates R & RT)

MRCC Components	Current MRCC	Proposed MRCC	Variance
Total Return on Rate Base	$1.19	$1.39	$0.20
Expenses	$9.07	$10.40	$1.33
Taxes	$1.07	$1.25	$0.18
Total (*rounded)	**$11.34***	**$13.04**	**$1.71 (15%)**

Interrog. Resp. OCC-362, Revised Att. 36, p. 1; Interrog. Resp. RRU-5, Att. 1, p. 1.

The majority of the proposed MRCC increase is due to increased expenses when compared to the current MRCC. For example, depreciation and amortization expense (FERC accounts 403, 404, and 407) account for $2.85 of the proposed MRCC compared to $1.75 under the current MRCC. Id. Conversely, under the MRCC formula, there are also some offsets where expenses are lower than current rates. For example, proposed

[127] General Statutes § 16-243bb(d) specifically exempts "residential electric heating service rate class" customers.

meter expenses (FERC accounts 586 and 597) were reduced to $0.09 from $0.59 under the current MRCC rate. Id.; Late Filed Ex. 72. The meter expenses were lower in the current Test Year (2023) than in 2021, which resulted in lower expenses assigned to the meter statutory function. Interrog. Resp. RRU-5, p. 2.

The Company did not introduce any additional FERC accounts in its MRCC calculation. Interrog. Resp. RRU-5. The Company calculated its proposed MRCC using only the FERC accounts allowed in the MRCC Decision. Id. In addition, no evidence was submitted that refuted or otherwise brought into question the Authority's findings in the MRCC Decision. Although the Company's proposed total delivery usage rate percentage increases for Rates R & RT ranged from 24% to 34% based on customer usage, the proposed fixed residential fixed charge increase is only 15%. Application, Sch. E-2-3.

The Authority finds that the MRCC formula continues to reflect the intent of General Statutes §16-243bb, limiting the customer fixed rate charge amount to the MRCC Statutory Functions, and associated FERC accounts previously vetted by PURA in the MRCC Decision. The Authority reviewed UI's MRCC calculation and finds that its methodology is consistent with the MRCC Decision. Although the Authority accepts UI's MRCC methodology, the Company shall update its residential fixed charge rate as part of its post-decision rates revenue proof and tariff compliance filing to reflect the Authority's findings in Section VII., Approved Revenue Requirement, above. Specifically, the Company is directed to include an updated final MRCC calculation, in a similar format as contained in Interrog. Resp. OCC-362, Att. 36, that reflects any changes to the rate base expense amounts included in the MRCC eligible FERC accounts as a result of this Decision.

F. RATE/REVENUE ADJUSTMENT MECHANISMS

1. Revenue Decoupling Mechanism

The Authority approves the revenue elements included herein to be included as "other revenues" for purposes of the Company's Revenue Decoupling Mechanism (RDM) calculation.

Generally, an EDC may only charge rates that have been approved by the Authority in a general rate proceeding under General Statutes § 16-19. However, the General Assembly established several statutory schemes that allow the EDCs to recover specific costs through adjustment mechanisms, including the RDM. General Statutes § 16-19tt. The Authority conducts an annual proceeding to determine rates for the various adjustment mechanisms. Specific to the RDM, the Authority adjusts the Company's actual distribution revenues to its allowed distribution revenues and orders an adjustment to rates to reflect any over- or under-recovery captured in the RDM during the Company's annual rate adjustment mechanism (RAM) proceeding. General Statutes § 16-19tt. The Authority has defined the term "allowed distribution revenues" as used in General Statutes § 16-19tt to refer to the EDC's annual revenue requirement as approved by the Authority in its most recent distribution rate case pursuant to General Statutes § 16-19(a). Decision, Jan. 29, 2025, Docket No. 22-01-04, PURA Annual Review of the Rate Adjustment Mechanisms of the United Illuminating Company, p. 6. Additionally, the Authority defines

"actual distribution revenues" as all revenues realized during the course of the Company's distribution business in a calendar year, with the exception that revenues accounted for or reconciled through another established mechanism are excluded from the RDM calculation. Decision, Jan. 29, 2025, Docket No. 22-01-04, PURA Annual Review of the Rate Adjustment Mechanisms of the United Illuminating Company, p. 9.

During a distribution rate case, the Authority sets the Company's annual revenue requirement that will be utilized as the "allowed distribution revenues" figure in the Company's RDM calculation and adjudicates any proposed changes to what sources of revenue are to be included or excluded from the RDM calculation for the purposes of calculating the Company's "actual distribution revenues." In this case, the Company's proposed "other revenues" are already included in the RDM and reflected in the Company's latest annual RDM filings with PURA. Ex. UI-RRP-1, p. 40. Table 88, below, depicts the sources of revenue included in the Company's RDM calculation.

Table 88: "Other Revenue" Included in RDM Calculation

"Other Revenue"	Description
Company Use Revenues	Consumption of electricity by UI at UI facilities.
Late Payment Charges	Interest added to customer bills for late payment.
Reconnect Service Fees	Revenue collected from customers to reconnect or disconnect service.
Returned Checks	Revenue attributable to returned checks.
Income from Sale of Scrap	Total annual sales of scrap allocated to UI Distribution.
Water Heater and Surge Protector Lease Programs	Revenues produced by the water heater and surge protector programs.
Intercompany Lease Revenues	Rent monies received by UI from its affiliates for Central Facility space.
Miscellaneous Other Electric Revenues	Various minor revenue items.

Ex. UI-RRP-1, p. 40.

Applying the Authority's articulated definition of "actual distribution revenues," the Authority concludes that the above-referenced revenues are properly included as "other revenues" for purposes of the Company's annual RDM calculation. Finally, consistent with the Authority's direction in the 22-08-08 Decision, the Company shall continue to utilize revenues collected from late payment fees in its annual RAM filing as a "surplus" for RAM purposes that will serve to offset potential distribution revenue shortfalls. 22-08-08 Decision, p. 207.

2. Earnings Sharing Mechanism

The Company proposes that its earnings sharing mechanism (ESM) continue as it is currently constructed with two adjustments: (1) the ESM calculation should reflect UI's actual equity ratio, not its authorized equity ratio; and (2) the ESM should not exclude

disallowed expenses. Ex. UI-RRP-1, p. 131. The Authority declines to adjust the calculation of the ESM as the Company proposes and instead directs the Company to continue calculating the ESM with a 50/50 split between ratepayers and shareholders from the first dollar of over-earnings above the allowed ROE calculated on a calendar year basis.

The Authority rejects the Company's proposals on the same basis articulated in the Company's last rate case. 22-08-08 Decision, pp. 220-221. First, adjusting the ESM such that it reflects the Company's actual equity ratio subverts the Authority's determination of what constitutes a reasonable capital structure for ratemaking purposes. Indeed, as demonstrated in Section V.C.3., Capital Structure Analysis, the Authority undergoes a vigorous exercise to set an appropriate ratemaking capital structure that weighs several factors while balancing both investor and consumer interests. The Company's proposal unsettles the balancing of such interests by adjusting the point at which a 50/50 split of earnings is executed to the benefit or detriment of shareholders or consumers, depending on the Company's actual capital structure.

Second, including disallowed expenses in the ESM as the Company proposes distorts the delineation between revenue collected from ratepayers through rates and the Company's earnings. The Authority applies the legal principles articulated in Section II, Standard of Review to determine the Company's revenue requirement. Thus, disallowed expenses have been deemed not to meet the legal requirements necessary to be included in base distribution rates. Importantly, the Authority in approving a revenue requirement is not mandating the Company to cease all expenditures not included in the revenue requirement; rather, the Company can elect to continue paying for disallowed costs from its earnings after any overearnings are appropriately allocated to ratepayers in accordance with the ESM. In other words, disallowed expenses should not be included in the ESM calculation to determine the Company's earnings subject to a 50/50 split; they are elective expenses the Company may pay for out of its own earnings.

Accordingly, the Authority directs the Company to continue calculating the ESM with a 50/50 split between ratepayers and shareholders from the first dollar of over-earnings above the allowed ROE calculated on a calendar year basis as set forth in the 22-08-08 Decision.

G. OTHER RATE-RELATED TOPICS

1. Pole Attachment Rates and Revenue

a. Summary

The Authority approves Pole Attachment Revenue of $6,585,847, which increased from UI's proposal of $4,953,552 in its original Application, based on adjustments, including:

(1) Unification of pole rates, using the telecom formula;
(2) The Authority's adjustment to the appurtenance factor;

(3) UI's adjustment to maintenance carrying charge factor due to re-allocation of vegetation management costs to FERC Account 593;
(4) The Authority adjustment of maintenance carrying charge factor to credit reimbursements for storm mutual aid to Account 593; and
(5) The Authority's approved ROR in this Decision.

In its Application, UI proposed semi-annual pole attachment rental rates for community antenna television (cable) providers and telecommunications service (telecom) providers. See Application, Sch. E-1.1, pp. 196, 201. UI proposed rates of $8.64 ($17.28 annually) for cable providers and $9.395 ($18.79 annually) for telecom providers. Application, Sch. E-1.1, pp. 200, 205. UI subsequently updated the pole attachment rates to account for a change in the recording of vegetation management costs in FERC Form 1 reporting. See Interrog. Resp. NECTA-5. On May 15, 2025, the Company reported a total of $7,879,793 in estimated pole attachment revenues, reflecting both a proposed change in pole attachment rates and an anticipated level of pole attachment applications and survey fees. Late Filed Ex. 1, Att. 2, Sch. C-3.01 WP.

As discussed in Section VIII.G.1.b, Unifying Pole Rates, below, the Authority finds that the rates for cable and telecom providers should be unified. Accordingly, the Authority approves a semi-annual rate of $11.89 ($23.78 annually) for cable and telecom providers. Table 89, below, shows the rates authorized in the 22-08-08 Decision, UI's original proposal, UI's proposal in response to interrogatory NECTA-5, and the rates approved by the Authority.[128]

Table 89: Proposed and Approved Annual Pole Attachment Rates

Provider	Approved in 22-08-08	Original Application	NECTA-5 Update	Approved
Cable	$18.23	$17.28	$21.78	$23.78
Telecom	$19.74	$18.79	$23.68	$23.78

22-08-08 Decision, p. 263; Ex. UI-RP-10, pp. 1–2; Interrog. Resp. NECTA-5, Att. 1, pp. 2–3.

Pole attachment rental rates contribute to "Other Operating Revenues." See Sch. C-3.01 WP. UI categorizes this revenue as "Pole Attachment Revenues," which include both revenue from pole rental fees as well as income from pole attachment application and survey fees. Late Filed Ex. 1, Att. 2 Supp., Sch. C-3.01 WP. UI reported Test Year Pole Attachment Revenue of $5,011,832 and proposed Rate Year Pole Attachment Revenue of $7,879,793. Id. The portion of the Rate Year Pole Attachment Revenue that is attributable to rental fees is $6,243,181. See Interrog. Resp. RSR-11, Att. 1, p. 1; Interrog. Resp. NECTA-5, Att. 1. UI calculated its proposed revenue by multiplying the anticipated average number of attachments for the Rate Year (including temporary attachments) for each type of attacher by the proposed attachment rates for each type.

[128] See Appendix A for the details of the approved pole rental rate.

Interrog. Resp. RSR-11, Att. 1, p. 2. Table 90, below, provides UI's calculation for the Rate Year pole attachment rates revenue, using the updated figures.

Table 90: UI Proposed Pole Rental Revenue

Rental Revenue	No. Attachments	Annual Rental Rates	Proposed Rental Revenue
Cable	165,774.5	$21.78	$3,610,569
Telecom	107,766.5	$23.68	$2,551,911
Wireless[129]	3,408	$23.68	$80,701
Total			$6,243,181

Interrog. Resp. RSR-11, Att. 1, p. 2; Interrog. Resp. NECTA-5, Att. 1 (using updated rental rates).

Table 91: Approved Pole Rental Revenue

Rental Revenue	No. Attachments	Annual Rental Rates	Approved Rental Revenue
Cable	165,774.5	$23.78	$3,942,118
Telecom	107,766.5	$23.78	$2,562,687
Wireless	3,408	$23.78	$81,042
Total			$6,585,847

Accordingly, Rate Year Pole Attachment Revenue is adjusted from $7,879,793 (as reported in Late Filed Ex. 1, Att. 2, Sch. C-3.01 WP) to $6,585,847.

b. Unifying Pole Rates

i. Unification of Rates

In calculating the proposed rates, the Company followed the formulas established by the Federal Communications Commission (FCC) and adopted by the Authority. See Fibertech Decision, p. 8. The Company also followed the Authority's directives for how to apply certain components of the FCC formula. Ex. UI-RP-1, p. 74. Based on the evidence in the record, the Authority determines that the rates for Cable and Telecom providers should be unified.

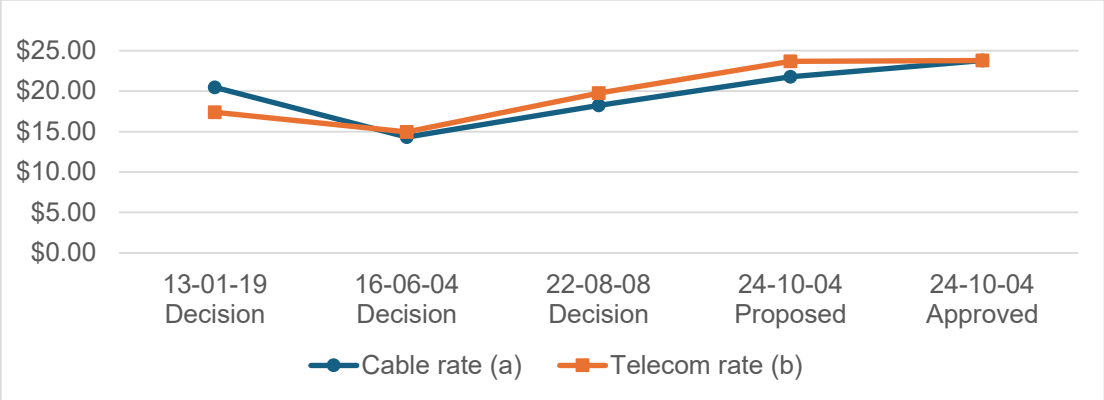
On September 12, 2012, the Authority adopted a revised version of the telecom rate, which adopted the revised FCC telecom rental rate formula and brought the telecom rate closer to the assessed cable rate. Fibertech Decision, pp. 1, 7. The new telecom rate formula resulted in a decreased telecom rate, which brought the telecom rate closer to the cable rate. Fibertech Decision, p. 7. The Authority's findings in the Fibertech Decision relied on FCC conclusions that the telecom rate would be just and reasonable for pole owners and of a level sufficient to support telecommunications infrastructure

[129]The rate for Telecom providers also apples to wireless attachers.

deployment (i.e., the rates are not too high for telecom attachers to promote broadband). Fibertech Decision, pp. 6–7.

Crown Castle argues that the cable and telecom rates should approach parity, citing the Fibertech Decision as support. Crown Castle Brief, pp. 11–12. Crown Castle notes that instead of approaching parity, cable and telecom rates have been diverging in recent years. Id. A review of cable and telecom rates since the Fibertech Decision indicates that, after approaching parity in [the year of the 16-06-04 Decision], the telecom rate's growth has outpaced the cable rate; Figure 6, below, shows the cable and telecom rates since the Fibertech Decision, including UI's proposed rates in this case.

Figure 6: Cable and Telecom Rates



Interrog. Resp. RSR-135, Att. 3, Att. 4, Att. 5; Interrog. Resp. NECTA-5, Att. 1.

Unification of attachment rates will ensure that one type of attacher is not unduly burdened with rental costs above its competitors. Although there may be legal differences in the definition of cable and telecom attachers, this difference is becoming a distinction without any practical difference. Fibertech Decision, p. 7. As a practical matter, there is little, if any, difference in pole attachment equipment between attachers paying the cable rate and those paying the telecom rate. The Fibertech Decision recognized that cable companies provide more than just video products; they also provide voice, broadband, internet products, and other communications services, and the distinction between cable and telecommunications attacher services is diminishing.[130] Fibertech Decision, p. 7. Cable companies are aggressively marketing non-cable services. Id. Cable and telecom attachers install very similar equipment, including fiber optic cable, risers, antennas, splice boxes, amplifiers, and power supplies. Interrog. Resp. RSR-138, pp. 1–2. Although cable attachers traditionally use coaxial cable, which can affect pole loading

[130]NECTA has seemingly recognized this transition, as it has changed its name a number of times over the years to emphasize its members' roles as telecommunications providers rather than cable providers; NECTA was formerly known as the "New England Cable Association," subsequently renamed as "New England Cable and Telecommunications Association," and then "New England Connectivity and Telecommunications Association." See Fibertech Decision, p. 7; see also Kravtin PFT, p. 1.

issues due to its physical characteristics, and telecom attachers traditionally use copper cable, there is little practical distinction between the attachments; UI follows the same process in the engineering survey and design to attach cable or telecom facilities. Interrog. Resp. RSR-138, pp. 1–2; Interrog. Resp. RSR-274. Therefore, there is insufficient distinction between cable and telecom attachers to justify different rates.

ii. Unified Pole Rate Formula

After determining that a single rate should be used for all attachers, the Authority must consider how that rate should be calculated. The FCC formula for cable and telecom attachers differs only in how the "space factor" is determined. The space factor is intended to account for the space of a utility pole that the attachment uses, and it is then multiplied by the other factors of the FCC formula to assign costs to attachers based on that useable space. See Ex. UI-RP-10, p. 1. The formula utilizes the pole costs (initial pole and installation costs, ongoing maintenance costs, etc.) and assigns an estimate of those costs to each attacher based on the space the attacher uses on the pole. 22-08-08 Decision, p. 262.

The cable formula for determining usable space is the simpler, taking the average pole height in feet (from UI records) and subtracting 24 feet, the "unusable space" of a utility pole (a constant value established by the FCC).[131] See Ex. UI-RP-10, pp. 1–2. UI's poles average 39.49 feet, leaving usable space of 15.49 feet (39.49 - 24). Cable attachments are assumed to use 1 foot of space on the pole, so the space factor of 6.46% is determined by dividing 1 foot of cable space by 15.49 feet of total usable space (1 / 15.49). Id., p. 2. Accordingly, 6.46% of the costs allocable to attachers (as determined by the FCC formula) are assigned to each attacher because that is the estimated space used by each attacher.

The telecom formula is slightly more complex, because it adds back a portion of the 24 feet of "unusable space." Ex. UI-RP-10, p. 1. The telecom formula space factor begins by assigning each attacher 1 foot of usable space, just as the cable formula does. Ex. UI-RP-10, p. 1. The telecom formula then divides two-thirds of the 24 feet of unusable space among 5 attachers (a number predetermined by the FCC) presumed to be sharing the pole ((2 / 3)x(24 / 5) = 3.2). Id. The portions of usable space and unusable space are added, and that sum is divided by 39.49 feet, the total average pole size, to arrive at a space factor of 10.64% ((1 + 3.2) / 39.49 = 10.64%). Id. The telecom formula then reduces the space factor by 0.66 to arrive at 7.02% (10.64% x 0.66). Id.

Both cable and telecom attachments are subject to National Electric Safety Code (NESC) clearance requirements that require the cables to maintain a minimum height above roadways. Interrog. Resp. RSR-317. Because the 24-foot clearance requirements are required for all attachers, the inclusion of a portion of the unusable space into the pole attachment formula properly reflects that attachers require that portion of the pole to provide service and is commensurate with its use. Applying the telecom rate to cable attachers will not harm those attachers nor inhibit broadband expansion or service

[131]The unusable space of 24 feet reflects the lower portion of the pole, which may not be used by cable attachers.

offerings. When the FCC implemented the current telecom formula, it found that the telecom rate formula would promote the deployment of broadband and telecommunications services. Interrog. Resp. RSR-136, Att. 1, pp. 77–78. The FCC also found that the new telecom rate would enable cable attachers to expand their services beyond traditional cable offerings, enhancing competition and leading to better service offerings for customers. Interrog. Resp. RSR-136, Att. 1, pp. 79–80. Further, on April 3, 2000, the FCC stated that the telecom rate should apply to all cable providers providing telecommunications services after February 8, 2001. Interrog. Resp. UI-NECTA-3, Att. 3, p. 5.

Both NECTA and Crown Castle argue that the increase in pole attachment rates will inhibit broadband deployment. Crown Castle argues specifically that the "dramatic increase" will compel broadband providers to "delay or postpone" fiber deployment and that such an increase is therefore inconsistent with the goals of the FCC and the state of Connecticut. Crown Castle Exceptions, p. 15. NECTA argues there is no evidence in the record to demonstrate that the application of the new telecom rates is not harmful to cable providers. NECTA Exceptions, pp. 5-6.

A comparison to CATV rates in Eversource service territory, however, indicates that the attachment rates approved in this decision are in line with current pole attachment rates and thus are neither too high nor will they inhibit the deployment of broadband. CATV and Telecom attachment rates in Eversource service territory are updated annually and were last established in December 2024 at annual rate of $21.94 and $24.32, respectively. See Motion No. 61, Att. 1 pp. 1–2, Att. 2, pp. 6, 18, Docket No. 17-10-46, Application of the Connecticut Light and Power Company d/b/a Eversource Energy to Amend its Rate Schedules. Accordingly, a rate of $23.78 aligns with existing attachment rates applied in Connecticut and so reflects reasonable pole attachment rates. Lastly, the claim that the telecom rate will inhibit broadband deployment is without merit, because the FCC itself concluded that the telecom rate would be just and reasonable for pole owners and of a level sufficient to support telecommunications infrastructure deployment (i.e., the rates are not too high for telecom attachers to promote broadband deployment). Fibertech Decision, pp. 6–7.

Accordingly, the Authority finds that the telecom rate is the most appropriate rate to apply to all attachers.

c. Appurtenance Factor

The appurtenance factor is used to identify and reduce FERC Plant Account 364 by the percentage of investments of non-pole related investments in that account, such as cross-arms, braces, and transformer brackets. Kravtin Prefiled Test., Feb. 24, 2025, p. 11. Because those items are not directly related to utility poles themselves (on which attachers are renting space), the FCC formula attempts to exclude those costs from the formula. Id. The FCC has established a rebuttable presumption of an appurtenance factor of 15%. Kravtin PFT, p. 11.

The Company proposed an appurtenance factor of 22.67% based on a methodology that was approved by the Authority in the 22-08-08 Decision. See Interrog.

Resp. NECTA-5, Att. 1, pp. 2–3; Interrog. Resp. NECTA-3, Att. 1 ("Summary Analysis" tab). UI "developed a manual simulation of unitization on the test year capital spend, keeping separate the Bare Pole [costs] and Other Allowable Investment in FERC 364."[132] Interrog. Resp. NECTA-3. The sample included 651 work orders, and UI determined the percentage of capital pole costs and the percentage of capital appurtenance costs. See Interrog. Resp. NECTA-3, Att. 1. UI then averaged these percentages to extrapolate an estimate of an appurtenance factor of 22.67% for FERC Account 364. Interrog. Resp. NECTA-3, Att. 1. Under this analysis, UI assumes that Test Year capital spend is an adequate representation of the total population of FERC Account 364 investments regarding the percentage of appurtenance additions. Id. Although based on a sample and including some assumptions, the Authority will accept UI's analysis rather than employ the FCC's rebuttable presumption of 15%.

NECTA argues that UI is wrong to take the average of appurtenance for each investment sample. Kravtin PFT, p. 12. Specifically, NECTA argues that averaging the appurtenance factor on an individual work order basis is inappropriate because it gives equal weight to appurtenance factors for small dollar and large dollar investments. Kravtin PFT, p. 13. NECTA also raised this issue in Docket No. 22-08-08, and the Authority approved UI's methodology in that docket. 22-08-08 Decision, p. 260 (finding UI's testimony convincing that "that it is more representative and precise to extrapolate the appurtenance factor on a project-by-project basis"). There is no convincing evidence in the record to support the change in methodology suggested by NECTA.

NECTA also argues that UI should use two years of data, including the data used in the prior rate case to determine the appurtenance factor. Kravtin PFT, p. 14. The Authority agrees that using two years' worth of data is "more representative of the entire embedded base of Account 364 investment." Kravtin Surrebuttal Test., Mar. 24, 2025, p. 6. However, only one year of data is available in the record in this proceeding, so the Authority must rely on UI's most recent set of data, which is in the record.[133] Utilizing sample data from 2023 as provided in this proceeding, the appurtenance factor percentage is equivalent to the one determined by UI of 22.67%. Interrog. Resp. NECTA-3, Att. 1 ("Pole Cots Analysis" tab).

d. Maintenance Carrying Charge Adjustment for Vegetation Management Costs

The maintenance carrying charge is a component of the FCC pole attachment rental rate formula, the purpose of which is to ensure that attachers pay the pole owner

[132]This sampling was done because manual tracking of FERC Plant Account 364 units of property is not required by FERC accounting, nor is it tracked by the Company's work order system. See Interrog. Resp. NECTA-3, p. 1; 22-08-08 Decision, p. 260. Providing a comprehensive manual accounting of all FERC Account 364 investments is not practical. See Interrog. Resp. NECTA-3, Att. 1 (showing the level of detail for one year of investment data).

[133]NECTA utilized UI's sample data from the instant proceeding and from Docket No. 22-08-08 to determine its recommended appurtenance factor, which includes data from two years. See Kravtin PFT, Ex. PDK-2. NECTA, however, did not provide the source sample data from Docket No. 22-08-08 or request that the Authority take notice of that data. See id; see also Interrog. Resp. UI-NECTA-1, Att. 1 (NECTA referenced, but did not provide, the appurtenance sample data from Docket No. 22-08-08).

for a portion of the wide range of capital and operating costs associated with a pole. 22-08-08 Decision, p. 261. The maintenance carrying charge component seeks to do this by taking UI's overhead maintenance costs, as reported in FERC Form 1 for FERC Account 593 ("Maintenance of Overhead Lines"), and dividing that amount by UI's total reported net investment in poles (using FERC Plant Accounts 364, 365, and 368). See Interrog. Resp. NECTA-5, Att. 1, p. 4. The result gives a percentage that reflects the maintenance costs for the pole that can be recovered from pole attachers through the FCC formula.

UI initially underreported the amount of the maintenance carrying charge, due to a recording error. See Interrog. Resp. NECTA-5. UI subsequently reported that it mistakenly and incorrectly recorded vegetation management costs in the FERC Form 1 in Account 592 instead of Account 593.[134] Id.; Hr'g Tr., 1625:5–12. After UI uncovered the mistake, it reallocated vegetation management costs to Account 593, which resulted in an increase in the maintenance carrying charge factor and an increase in pole attachment rates.

No party or intervenor disputes that vegetation management costs are properly recorded in FERC Account 593. NECTA does, however, argue that UI cannot make such change during the proceeding; instead, NECTA argues that the Company should be forced to rely on the initial FERC Form 1 reported data. Kravtin PFT, pp. 17-18. NECTA argues that for reasons of transparency, uniformity, and ease of implementation, UI should rely on the original FERC Form 1 filing. Id., p. 17.

The Authority will calculate the pole attachment rate using the correct data. First, it is undisputed that vegetation management costs are properly recorded in FERC Account 593. See 18 CFR 101. Second, UI corrected its error in the subsequent FERC Form 1 report (the 2024 FERC Form 1 Report). Hr'g Tr., 1623:12–24. Third, although the corrected data increases the pole attachment rate, using the incorrect data would unfairly require ratepayers to bear the cost that is properly apportioned to attachers. The pole attachment formula should be based on the most accurate information available, and UI has acted properly to reclassify vegetation management costs to the proper account. This reclassification of the vegetation management costs modifies the maintenance carrying charge factor from 6.13% to 9.32%. Ex. UI-RP-10, pp. 1–2; Interrog. Resp. NECTA-5, Att. 1, pp. 2–3.

e. Maintenance Carrying Charge Adjustment for Mutual Aid Reimbursement

NECTA argues that UI should offset FERC Account 593 expenses in the FCC formula with reimbursements the Company received from other utilities. Kravtin Surrebuttal PFT, p. 4; NECTA Brief, pp. 18–19. UI receives reimbursements from other utilities when it sends crews to work on other utilities' systems after major storm events.

[134]Account 593 is not used to determine the FCC formula maintenance carrying charge. See Interrog. Resp. NECTA-5, Att. 1, p. 4. Account 592 is not used to determine the maintenance carrying charge (592 is for substation maintenance). 18 CFR 101.

Interrog. Resp. NECTA-19. When this occurs, the other utilities reimburse UI for these costs.

UI's FERC Form 1 Report Account 593 included $2,011,421 of mutual aid expenses for crews to work supporting other utilities following storm events. Interrog. Resp. NECTA-19. UI received $1,497,247 in reimbursements from the other utilities but only credited $261,149 of that reimbursement in FERC Account 593. Id. The remaining $1,236,098 reimbursement was instead credited to FERC Account 456; FERC Account 456 is a valid account to credit these reimbursements, although Account 456 is not an input into the FCC pole attachment rental formula. Id.; see also Interrog. Resp. NECTA-5, Att. 1, p. 2 (showing that the FCC formula does not use Account 456 data). UI may properly record reimbursements in Account 456. See 19 CFR 101. That said, because the credits were for mutual aid expenses, UI should apply the reimbursement as a credit to Account 593 when using the FCC formula to determine pole rental rates. Not including these credits in the FCC formula would result in inflated overhead maintenance costs being passed on to attachers (because the work was not done on UI's system and it was later reimbursed). Accordingly, the Authority will adjust the maintenance factor calculation to include the $1,236,098 reimbursement received by UI. This adjustment results in a change of maintenance carrying charge factor from 9.32% to 9.02%.

f. Adjustment for Allowed Rate of Return

The Authority allows the use of UI's ROR in the FCC formula using the full approved ROR (pre-ROE reductions) in this Decision, 7.142%. The FCC formula utilizes UI's allowed ROR to help determine pole attachment rental fees. In the 22-08-08 Decision, the Authority approved the use of UI's approved rate of return (ROR) as specified in that Decision, without including ROE reductions. 22-08-08 Decision, p. 263. In prior rate cases, the Authority approved the use of ROR to determine the rental rates without reducing the ROR by including ROE reductions. Id. UI used the allowed ROR from the 22-08-08 Decision, 6.71%, when calculating the FCC formula. See id.; Interrog. Resp. NECTA-5, Att. 1, p. 4.

2. New Rate Recommendation

The Authority is satisfied with the Company's analysis regarding the appropriateness of a new small commercial rate. In the Company's previous rate case, the Authority directed the Company to provide a recommendation for a demand threshold update between rates GS and GST, as well as a recommendation for whether a new, third rate for Commercial & Industrial (C&I) customers would be beneficial. 22-08-08 Decision, p. 243. The Company analyzed historical consumption data and determined that the choice between Rate GS and Rate GST is already addressing the needs of C&I customers and that the current threshold is appropriate. Ex. UI-RP-1, p. 28. The Company conducted a sensitivity analysis and subclass ACOSS with a hypothetical third C&I rate, which indicated that the distribution of load factors and average cost per kWh were nearly identical among C&I customers whose peak demand exceeded 100 kW (the

existing GS-GST breakpoint). Id., pp. 29–32. The Authority concurs with the Company's conclusion that a new rate is unnecessary.[135]

The Authority required UI to provide a recommendation for a threshold update between rates GS and GST and to include a recommendation for kW monthly demand thresholds if a new, third rate was added to benefit small businesses (e.g., 100 kW and 300 kW).[136] 22-08-08 Decision, p. 243. To fulfill this requirement, the Company was directed to include histograms consistent with the Authority's decision, an analysis of the hourly load profile of customers in the GS and GST rate classes for all four seasons, and recommendations on updating the distribution charges for each class based on daily and/or seasonal TOU. Id.

The Company submitted testimony, including an analysis of rates GS and GST; UI provided the annualized number of customers accounts associated with rates GS and GST, the annual distribution revenues from the rate, and histograms that reflect customer counts and annual kWh sales broken out by peak annual demand in 5 kW tranches (0-5 kW, 5-10 kW, etc.). Ex. UI-RP-1, pp. 25-26. Additionally, UI included load factor histograms to supplement its analysis and recommendation. Id., p. 26. Table 92, below, reflects UI's annualized customer and demand data for Rate GS on a cumulative basis based on the maximum peak load thresholds.

Table 92: Rate GS Analysis - Customers

Maximum Peak Load Increment Threshold (by 5 kW Tranche)	Number of Customers (Annualized)	% of Customers (by 5 kW Tranche)	Cumulative % of Customers (Sum of 5 kW Tranches)
0-5 kW	4,202	28.3%	28.3%
5-10 kW	3,512	23.6%	51.9%
10-15 kW	2,797	18.8%	70.7%
15-20 kW	1,490	10.0%	80.7%
20-25 kW	878	5.9%	86.6%
25-30 kW	550	3.7%	90.3%
30-35 kW	364	2.4%	92.8%
35-40 kW	262	1.8%	94.6%
40-45 kW	206	1.4%	95.9%
45-50 kW	124	0.8%	96.8%
50-55 kW	115	0.8%	97.5%
55-60 kW	93	0.6%	98.2%
60-65 kW	79	0.5%	98.7%
65-70 kW	65	0.4%	99.1%
70-75 kW	40	0.3%	99.4%
75-80 kW	23	0.2%	99.6%

[135]No party or intervenor contested UI's conclusion.

[136]Under UI's current tariffs, Rate GS is available to commercial customers whose demand does not exceed 500kW in two consecutive months. Application, Sch. E-1.1, p. 61. Customers with demands of 100kW or greater are placed on time-of-use rates GST or Large Power Time-of-Use (LPT). Id.

Maximum Peak Load Increment Threshold (by 5 kW Tranche)	Number of Customers (Annualized)	% of Customers (by 5 kW Tranche)	Cumulative % of Customers (Sum of 5 kW Tranches)
80-85 kW	30	0.2%	99.8%
85-90 kW	16	0.1%	99.9%
90-95 kW	10	0.1%	99.9%
95-100 kW	9	0.1%	100.0%
Total	**14,865**	**100%**	**100.0%**

Application, Ex. RP-6, p. 1.

As shown in the Table 93, below, 94.6% of rate GS demand-metered customers' annual maximum peak load demand is at or below 40 kW. Id. Further, using UI's demand frequency distribution data, the total maximum annual billed demand for rate GS customers was 192,080 kW, of which 146,500 kW (approximately 76.3%) was billed to customers with a maximum annual billed demand of 40 kW or less. Application, Ex. RP-6, p. 1.

Table 93: Rate GS Analysis – Maximum Annual Billed Demand

Maximum Peak Load Increment Thresholds (by 5 kW Tranche)	Maximum Annual Billed Demand (kW)	Maximum Annual Billed Demand (%)	Cumulative Annual Maximum Billed (%)
0-5 kW	3,965	2.1%	2.1%
5-10 kW	26,628	13.9%	15.9%
10-15 kW	34,269	17.8%	33.8%
15-20 kW	25,568	13.3%	47.1%
20-25 kW	19,507	10.2%	57.2%
25-30 kW	15,028	7.8%	65.1%
30-35 kW	11,779	6.1%	71.2%
35-40 kW	9,756	5.1%	76.3%
40-45 kW	8,719	4.5%	80.8%
45-50 kW	5,851	3.0%	83.9%
50-55 kW	6,005	3.1%	87.0%
55-60 kW	5,332	2.8%	89.8%
60-65 kW	4,944	2.6%	92.3%
65-70 kW	4,376	2.3%	94.6%
70-75 kW	2,896	1.5%	96.1%
75-80 kW	1,780	0.9%	97.0%
80-85 kW	2,465	1.3%	98.3%
85-90 kW	1,408	0.7%	99.1%
90-95 kW	923	0.5%	99.5%
95-100 kW	881	0.5%	100.0%
Total	**192,080**	**100.0%**	**100.0%**

The Authority finds that maintaining the current Rate GS/Rate GST 100 kW threshold is effectively serving the majority of customers based on customer and demand data.

The Company also examined rate GST to determine if additional rate GST sub-classes are warranted as part of its compliance requirement. Potential demand breakpoints of 100 kW, 300 kW, and over 300 kW were examined and considered. The Company also provided rate GST histograms. Table 94, below, shows the summary results of the Company's analysis.

Table 94: Rate GST Subclass Breakpoint Analysis

kW Breakpoint	Number of Customers	Billed Max (kW)	Billed (kWh)	Average Load Factor
GST-1 (100 kW)	6,572	159,676	414,711,155	30%
GST-2 (300 kW)	891	146,101	396,775,203	31%
GST-3 (Over 300 kW)	311	208,579	535,728,053	29%
Total	**7,774**	**514,356**	**1,347,214,411**	**30%**

Ex. UI-RP-1, p. 29.

On a customer basis, UI's data shows approximately 84.5% of current Rate GST customers' maximum annual demand is 100 kW or less, 11.5% is between 100 kW and 300 kW, and only 4% is above 300 kW. The average load factors for each GST grouping are consistent, at approximately 30%. UI's data and histograms show little load diversity between the Rate GST breakpoint-subgroups. Id., p. 34. Higher load factor customers have the option to migrate to Rate LPT, a pure demand rate, which provides better value to these customers. Id., p. 33.

Accordingly, the Authority finds that UI provided adequate information and analysis regarding the examination of Rate GST. The data indicates that the creation of a new sub-class demand threshold for rate GST is not warranted at this time, based on customer, demand, and load data.

3. Special Contract Policy

The Authority approves UI's proposed special contract policy, with modification, and finds that, as modified, the policy meets the just and reasonable standard, providing sufficient flexibility while limiting the risk of free ridership. As part of the Application, the Company filed its special contract policy for load retention purposes in compliance with the Authority's order in Docket No. 22-08-08. See Application, Ex. UI-RP-11; 22-08-08 Decision, pp. 254, 289 (Order No. 38). The special contract policy specifies customer eligibility criteria, components of the bill eligible for discounts, and the approach for calculating the discount, including a price floor based on the long-run marginal cost. Ex. UI-RP-11, pp. 4–7. The Company shared draft versions of the policy with the Department of Economic and Community Development and the Office of the Governor in July 2024 and October 2024, as directed by the Authority, but did not receive feedback from either party prior to submitting its rate application. Ex. UI-RP-1, pp. 79–80.

CIEC recommended several changes to the special contract policy submitted by the Company, including (1) setting the discount at no less than 15% or 20% of that available under the Economic Discount Rider (EDR) and formally incorporating the EDR, (2) expanding the discount to include the NBFMCC and generation components of the bill, adjusting the price floor, and applying the special contract retention rate as a discount to the participating customer's bill, similar to the approach approved by the Authority for the LIDR, (3) removing the requirement for applicants to provide a profit and loss statement, (4) not conditioning eligibility on a total loss of load but rather a significant reduction, and (5) clarifying the eligibility requirement that customers "not [be] engaged in local commerce." Chait Prefiled Test., pp. 22–25; CIEC Brief, pp. 18–19, 22.

First, UI agreed with CIEC's recommendation to include the EDR in the special contract policy and amended the proposed policy's language to clarify the intent to retain sales that would be lost due to "the cost of electric distribution service or availability of lower cost alternative fuels cost." Rates Panel Rebuttal PFT, p. 34; Late Filed Ex. 79. The Authority approves UI's amended language.

Second, as to CIEC's recommendation to adjust the price floor, the Authority finds the Company's proposal to use the long-run marginal distribution cost as the price floor for the discounted distribution rate to be reasonable. Although existing load does not impose long-run marginal delivery costs, setting a rate lower than the marginal cost would provide a distorted price signal and create the risk that the Company does not fully recover the customer's cost to serve. Rates Panel Rebuttal PFT, p. 34. The Authority determines that there is no evidence in the record to support setting the discount at 15% or 20% of the EDR's discount. The Authority is not aware of any examples where an electric distribution utility has set a rate based on the actual delivery capacity in a specific part of the grid, as recommended by CIEC. See CIEC Brief, p. 25. However, in circumstances where the price floor is insufficient to retain at-risk load, the Company may propose larger discounts for the Authority's consideration. The Authority also approves the Company's proposal to only include the delivery component of the bill as eligible for a discount, consistent with statutory requirements. Unlike the low-income discount rate, which provides a bill discount, the special contract policy is a framework to negotiate a specific discounted delivery rate.

Third, the Authority agrees with the Company that a profit and loss statement is a reasonable requirement (considered among other factors) to assess the risk of the business terminating or reducing operations in Connecticut. Hr'g Tr., 1417:19–1418:11. UI defended the proposed requirement for applicants to submit a profit and loss statement as a means to reduce the risk of free ridership. Hr'g Tr., 1417:19–1418:11. UI highlighted that load retention discounts "involve a greater risk of negatively impacting future utility rates as compared to incentives aimed at expanding existing load or attracting new load." Rates Panel Rebuttal PFT, p. 34. UI clarified its belief that an "at-risk" customers' decision to reduce its load or terminate operations would be based on the bundled cost of electricity rather than the cost of individual bill components, although the cost of supply is outside the Company's control. Hr'g Tr., 1427:17–1428:11. UI also emphasized that any discounts must be approved by the Authority and therefore must be adequately supported. Rates Panel Rebuttal PFT, p. 34. The Authority concurs with the Company

that there is no "one size fits all" approach for special contracts and shares the Company's concern of free ridership. Hr'g Tr., 1424:3–6. Thus, the submission of a profit and loss statement may be required on a case-by-case basis, if the Company or the Authority require its submission.[137]

Finally, UI's proposed amended special contract policy language does not imply that eligibility is contingent on total loss of load. Late Filed Ex. 79. However, for greater clarity, the Authority directs the Company to amend Section 1.2 of the Special Contract Policy Details, regarding eligibility, to replace "lost due to customers moving out of UI's service territory or going out of business due to the cost of electricity" with "lost due to customers curtailing all or a material portion of their electricity consumption." See CIEC Brief, p. 19. The Authority does not, however, agree with CIEC that "not engaged in local commerce" is vague.[138] CIEC Brief, p. 19.

Accordingly, the Authority finds that the proposed special contract policy, with the aforementioned changes, provides sufficient flexibility while limiting the risk of free ridership and meets the just and reasonable standard.

4. Pleasure Beach Island

The Company serves two customers located on Pleasure Beach Island (PBI) — the WICC radio station and a pavilion owned by the City of Bridgeport. Ex. UI-RRP-1, p. 134. In its application, the Company states that it includes costs for a "solar-plus-Battery Energy Storage System ("BESS") microgrid project" designed to serve PBI in its revenue requirement. Ex. UI-RRP-1, p. 133. Subsequently, however, UI clarified that the project will not be used and useful before the end of the Rate Year, "the associated plant in service is not reflected in UI's proposed revenue requirement in this proceeding" and it "is not seeking to recover from ratepayers any O&M costs associated with the project in this case, and as such no O&M expense is included in the Test Year or Rate Year." Interrog. Resp. OCC-701 Supp., p. 1; see also Interrog. Resp. RSR-150.

The Authority previously approved the proposed solar plus storage project on PBI as a "cost-effective solution to providing electricity to customers in a hard-to-reach area of UI's service territory." 22-08-08 Decision, p. 214. The BESS microgrid project is intended to replace a 6.9 kV submarine cable that was installed in 1940. Id.

In Docket No. 22-08-08, the Authority "authorize[d] deferred accounting to allow the Company to track the costs of the PBI solar plus storage project." 22-08-08 Decision, p. 216. In that decision, the Authority stated:

> The tracked costs will be reviewed for the prudence and reasonableness of any incurred costs during the Company's next rate case proceeding. The

[137]Although CIEC is concerned about sharing sensitive financial information, there is no evidence in the record to demonstrate that sharing profit and loss information confidentially would put a customer at risk of competitive disadvantage.

[138]Customers should not be able to use the special contract discount to gain an unfair competitive advantage over other local businesses.

> Company may also request inclusion of any annual expenses related to O&M in the same rate case proceeding. The Authority will review such O&M costs for prudence and reasonableness at that time.

Id.

The Company states that it "will seek recovery of the costs of the PBI project once the project is in service" and that "UI is currently anticipating that the PBI project will be in service in early 2027." Interrog. Resp. OCC-701 Supp., p. 1; see also Interrog. Resp. RSR-150.

The Company also reported its conclusions from an investigation into developing a new tariff for the two PBI customers:

> UI recommends against constructing a new tariff for these two customers for the following reasons: (1) any cost-based tariff will be prohibitively high for both customers; (2) the Company has not offered location-specific tariffs in the past and believes that this application is not suitable for the first tariff of that type; and (3) the costs and effort to construct and maintain the tariffs under which just two customers will take service will be costly and inefficient.

Ex. UI-RP-1, p. 75. UI also "proposes to recover the lease payments for the photovoltaic system through the State-Mandated Energy Purchases component of the unbundled non-bypassable FMCC." Id., p. 77.

In its Application UI "proposes to recover the revenue requirement of the PBI Project through the distribution rates ultimately approved by PURA in this docket." Ex. UI-RP-1, pp. 77–78. Additionally, UI stated in its brief that "The Company further proposes . . . to recover the revenue requirement of the PBI project through the distribution rates approved by PURA in this proceeding." OCC Brief, p. 218. UI stated, however, that it "is not seeking to recover from ratepayers any O&M costs associated with the project in this case, and as such no O&M expense is included in the Test Year or Rate Year." Interrog. Resp. OCC-701 Supp., p. 1; see also Interrog. Resp. RSR-150. Accordingly, the Authority does not address recovery of the revenue requirement of the PBI project in this decision.

IX. CUSTOMER SERVICE

A. BILLING, POLICIES, AND PRACTICE

1. Standard Bill

The Company's standard bill complies with the applicable regulations. See Application, Sch. H-2.0. The standard bill reflects modifications to the EDCs' residential customer bills established by the Authority. Decision, July 27, 2022, Docket No. 14-07-19RE06, PURA Investigation into Redesign of the Residential Electric Billing Format – Five-Year Review (Bill Redesign Docket); see also Motion No. 13 Ruling, Oct. 21, 2022, Bill Redesign Docket. Further, EOE reviewed the Company's standard bill filing and found it to comply with applicable regulations. EOE Brief, June 30, 2025, p. 38.

2. Termination Notices and Customer Rights

The Company's customer rights and termination notices generally comply with the applicable regulations. See Application, Sch. H-2.1; Interrog. Resp. EOE-42, Att. 1. EOE also reviewed the Company's customer rights notice and termination notice and found them to comply with applicable regulations. EOE Brief, June 30, 2025, p. 38.

Regarding the Company's customer rights notice, the Company states that it issues the "Your Rights" bill insert to new customers and to existing customers on an annual basis. Interrog. Resp. EOE-42. Further, the Company states that customers may request that the Company mail them a copy of their rights at any time, regardless of how they receive their bill (i.e., via mail or e-billing). Id. E-billing customers may view the customer rights notice by clicking a link available in the monthly bill notification email. Id. The Company did not originally include the customer rights notice in its application. See Application, Sch. H-2.1. The Authority reminds the Company that Schedule H-2.1 must include both the termination and customer rights notices in rate amendment applications; otherwise, an application may be treated as administratively incomplete.

Customers are contacted using various communication touchpoints prior to termination. Interrog. Resp. OCC-19; Interrog. Resp. EOE-5. The Company provided sample communications it uses to alert residential and non-residential customers about their delinquent balances. Interrog. Resp. OCC-19, Att. 1, Att. 2. Table 95, below, shows the chronological order of all contacts typically made with a delinquent customer.

Table 95: Company Contacts with Delinquent Customers

Company Action	Timing
Invoice with delinquent balance	Day 1
Shut off notice	Day 6
Text alert (if no opt out by the customer)	Day 6
Final Reminder notice	Day 13
Reminder Call	Day 13

Interrog. Resp. OCC-19; Interrog. Resp. EOE-5.

The Company's termination notices comply with applicable regulations. The Company's Termination Notices appropriately do not include any unregulated charges. See Interrog. Resp. EOE-3; Interrog. Resp. OCC-28. Moreover, the Company states that customers are not billed unregulated charges; rather, "every charge on the UI bill is included in the PURA-approved tariff." Id. The Company's termination notices only include utility charges and exclude any "miscellaneous" charges, such as energy efficiency loans, late payment charges, and equipment rental fees. Id. Finally, the Company does not terminate customers' service for failing to pay such miscellaneous charges. Interrog. Resp. EOE-35.

The Company has a standardized method of issuing termination notices to customers. Currently, all UI termination notices are sent to customers via first class mail. Interrog. Resp. EOE-4. The Company states that the number of scheduled termination

notices are matched daily "via dunning jobs in the billing system against the number of termination notices mailed through the Company's mailing services vendor." Id. Additionally, the Company states that its process for issuing termination notices to customers enrolled in e-billing is the same for customers who are not enrolled. Interrog. Resp. EOE-5, p. 1. This process includes mailed termination notices as well as a text message. Id.; Interrog. Resp. EOE-44. In addition, the Company conducts outbound delinquent reminder calls seven days after termination notices are mailed. Interrog. Resp. EOE-16. E-billing customers are also able to view and download all termination notices through their online account. Interrog. Resp. OCC-29, Att. 1.

The Company suggested during this proceeding that it could "add a static banner" at the top of a customer's online account webpage that alerts customers of an existing termination notice. Interrog. Resp. OCC-192. In order to implement this modification, the Company initially estimated a cost of $10,000 and timeline of several months. Id. Subsequently, the Company reported that the active termination notice banner was "currently in testing and will be deployed live" by April 1, 2025, and that the associated development and testing was completed "just under the $10,000 estimated cost." Interrog. Resp. CAE-36. The Authority directs the Company to file as compliance, no later than November 10, 2025, an update on the Company's implementation of the static pending termination notice banner on customers' online account webpages that includes final implementation costs and images of the banner.

3. Estimated Bills

UI provided its policies and procedures for generating estimated bills. The Company calculates an estimated bill for accounts that have not had an actual meter reading. Application, Sch. H-2.2, p. i.[139] The Company's calculation is based on the account's kWh usage in the corresponding month of the previous year. Id. If that data is not available, then the Company will base the estimate on the account's kWh usage from the previous month. Id. Further, the Company reports that if the billing system is unable to estimate a bill, "a clerical estimate may be required." Id., p. 4; Interrog. Resp. EOE-7. A clerical estimate "should be based on prior 'good' billing history," meaning that estimated bills are "based on actual usage" and not prior estimated bills. Application, Sch. H-2.2, p. 4. Specifically, if the "basis to estimate has a billing period that is an estimate," the Company uses the first actual reading after the estimated bills to determine the kWh per day. Id. For example, if a bill must be estimated for July 2025, and the bill for July 2024 was estimated, the Company will look to August 2024, and then September 2024, etc., until an actual reading was obtained. Id., p. 4. However, if there is no billing history, the Company will use "the generic periodic consumption table by rate category," potentially using "factors such as number of persons in the household, size of the property, time of year and any other variables provided by the customer" to estimate usage. Interrog. Resp. EOE-8.

If the Company issues an estimated bill, a message is included on the first page of the bill to notify the customer that their charges are based on estimated readings.

[139]The first page of the nine-page Schedule H-2.2 is not numbered, and the second page is labeled page "1 of 8." Accordingly, the Authority refers to the unnumbered page as "page i" to reduce confusion.

Interrog. Resp. EOE-6, Att. 2. Additionally, the Company has incorporated its telephone number in the same location as the message informing the customer about the estimated bill. Interrog. Resp. EOE-6, Att. 2; see 22-08-08 Decision, p. 285 (Order No. 14).

EOE reviewed the estimated bill form and notices issued to customers and found they comply with applicable regulations. EOE Brief, p. 39. The Authority concurs that the materials, policy, and procedures associated with UI's estimated billing generally follow the applicable regulations.

4. Security Deposit Policies

The Authority reviewed the current policies and procedures UI utilizes to administer customer security deposits and found them to generally comply with applicable regulations and PURA directives. See Application, Sch. H-2.3.

The Company states that it intends to resume collecting security deposits for non-residential customers; however, it does not have an estimated timeline to do so. Hr'g Tr., 355:7–13. Prior to the COVID-19 service termination moratorium, the Company assessed security deposits for some non-residential customers. Avangrid Compliance, Mar. 1, 2023, Docket No. 23-05-01, Annual Review of Affordability Programs and Offerings (Energy Affordability Annual Review); see also 22-08-08 Decision, pp. 270–271. According to the Company, customers assessed a security deposit were mailed a letter explaining the security deposit after it was applied to the customer's account. Interrog. Resp. EOE-13.

In March 2020, the Authority directed the Company to temporarily suspend the collection of security deposits. See Motion No. 2 Ruling, Mar. 18, 2020, Docket No. 20-03-15, Emergency Petition of William Tong, Attorney General for the State of Connecticut, for a Proceeding to Establish a State of Emergency Utility Shut-off Moratorium, p. 2 (Order No. 3). On October 11, 2023, the Authority permanently suspended security deposits for residential customers. Decision, Oct. 11, 2023, Docket No. 23-05-01 (23-05-01 Decision), p. 52. The Authority also allowed the Company to reinstate the collection of security deposits for non-residential customers. Id., p. 53. Nonetheless, the Company has not resumed assessing security deposits for non-residential customers in the two years following the Authority's approval. Interrog. Resp. EOE-13. The Company states that it has not resumed security deposits "due to necessary billing system updates to automate the management" of them. Interrog. Resp. EOE-12.

When reinstated, the Company asserts that security deposits will be assessed "at the time of a new move-in and after termination for non-payment in order to reinstate service." Interrog. Resp. EOE-12. Finally, any assessed security deposit, along with accumulated interest, will be returned to the customer after 12 months of continuous on-time payments. Id.

5. Late Payment Charges

The Company collects a late payment charge (LPC) or interest fee of 1.25% per month for residential and non-residential customers for bills not fully paid within 28 days.

Application, Sch. E-1.0, pp. 23–24; see Decision, Oct. 1, 1998, Docket No. 92-06-05, Application of The United Illuminating Company for an Increase in Rates, p. 2 (approving 1.25% rate); see also Interrog. Resp. OCC-733.

In response to the Authority's directives pertaining to the COVID-19 pandemic, UI suspended the collection of LPCs in March 2020. 22-08-08 Decision, p. 271. The Company suspended late fees as of March 17, 2020. Interrog. Resp. OCC-315. In October 2022, the Company initially resumed assessing LPCs to residential non-hardship and non-residential customers; however, due to incorrectly assessing late fees to certain customers, the Company paused LPCs later that month to make programming changes and conduct further testing; any LPCs charged during that time were reversed. 22-08-08 Decision, p. 271; Interrog. Resp. OCC-315. The Company resumed assessing LPCs on May 1, 2023, after completing the necessary programming changes and testing. Interrog. Resp. OCC-315.

On October 11, 2023, after examining the Company's assessment of LPCs and any resulting impacts on uncollectibles from 2018 through 2022, the Authority found it appropriate to continue the Company's practice to waive late payment charges for "financial hardship or medically protected customers enrolled in an AFP program and during the winter moratorium." 23-05-01 Decision, pp. 53–54. The Authority has not modified the Company's LPC practices to date. See 24-05-01 Decision, pp. 31–32. The Company must file relevant LPC data in each annual energy affordability review proceeding (i.e., Docket No. XX-05-01) for review by the Authority and stakeholders. 23-05-01 Decision, p. 65 (Order No. 14).

Accordingly, the Authority does not make any modifications to the Company's existing LPC practices in this proceeding. The Authority will continue to review and evaluate the Company's imposition of LPCs in its annual energy affordability proceedings, and, if necessary, make modifications.

6. Collections Process

The Company's current collection policies comply with applicable regulations. See Conn. Agencies Regs. § 16-3-100. The Authority notes, however, that the Company's collections practices have been the subject of scrutiny in several completed and ongoing proceedings, including the most recent Annual Energy Affordability Review proceeding (i.e., Docket No. 25-05-01). See Decision, Dec. 7, 2022, Docket No. 22-03-16, Petition of the Office of Consumer Counsel for an Investigation into The United Illuminating Company and Eversource Energy Regarding Collections Practices During the COVID-19 Moratorium; Notice of Violation, Oct. 31, 2022, Docket No. 22-03-16RE01, Petition of the Office of Consumer Counsel for an Investigation into the United Illuminating Company and Eversource Energy Regarding Collections Practices During the COVID-19 Moratorium – Avangrid NOV; Docket No. 22-03-16RE02, Petition of the Office of Consumer Counsel for an Investigation into the United Illuminating Company and Eversource Energy Regarding Collections Practices During the COVID-19 Moratorium – Wage Garnishment Working Group and Related Matters (Collections Working Group); 22-08-08 Decision, pp. 272–276; 24-05-01 Decision, pp. 15–23. Notably, in response to the Collections Working Group final report and stakeholder feedback, the Authority

allowed the Company to resume legal collections activities for all customers and wage garnishment for customers above 75% of the State Median Income level in November 2024. 24-05-01, pp. 22–23. The Company has yet to contract with a legal collections firm and does not have an expected timeline for hiring a firm. Interrog. Resp. RRU-226.

B. ENVIRONMENTAL, SOCIAL, AND GOVERNANCE STRATEGY

1. ESG Initiatives

The Company promotes environmental, social, and governance (ESG) topics as part of its broader engagement with external stakeholders in the UI service territory. Interrog. Resp. UPA-33. UI's Community Relations team coordinates with the Avangrid Sustainability team to respond to specific requests or concerns raised by stakeholders, including municipal governments, local nonprofits, and community-based organizations. Id. To advance ESG priorities within the state, UI's Community Relations personnel engage with the 17 municipalities in its service territory by maintaining relationships with municipal stakeholders and non-profit organizations. Interrog. Resp. UPA-34. UI also seeks to respond to the concerns of environmental justice (EJ) communities by participating in customer enrollment and tabling events, often in partnership with local non-profits, throughout the year. Id.

Avangrid incorporates Connecticut's clean energy and emissions targets into its broader sustainability goals. Interrog. Resp. UPA-33. For example, state-level commitments to renewable electricity were factored into Avangrid's corporate carbon neutrality objective. Id. These goals are established and tracked at the corporate level, however, and UI does not provide Connecticut-specific greenhouse gas (GHG) emissions progress metrics. Interrog. Resp. UPA-16. Although the Company asserts that UI's initiatives are aligned with and contribute to achieving Avangrid's corporate sustainability goals, which are also consistent with Connecticut's clean energy objectives, the record lacks sufficient evidence to independently verify UI's specific role or impact. Table 96, below, illustrates Avangrid's corporate GHG-related goals and the ways that UI claims to support them.

Table 96: Avangrid's Greenhouse Gas Emissions Goals and the Supporting Actions Taken By UI

Avangrid GHG Emissions-Related Goals	UI Supporting Actions
Carbon neutral for GHG scopes 1 and 2 emissions by 2030	GHG Scope 1 Emissions: • Rate of Return Ratio Comparison Between the Company's Proposal and Adjusted ACOSS with Alternative Revenue Allocation GHG Scope 2 Emissions: • Energy procured following state level RPS targets • Energy efficiency and clean energy initiatives • Renewable electricity in corporate buildings
Storage capacity	• Deployment of Company-owned storage capacity aligned with Docket No. 22-06-05.
Network EV charging points	• Investment in network EV charging points infrastructure aligned with annual RAM proceedings.
Transition vehicle fleet to clean energy vehicles by 2030	• Transition of the current fleet of Compression Ignition (CI) engines to run on sustainable fuels (Renewable Diesel). • Replace gasoline engine fleet vehicles with CI engine running on sustainable fuels or hybrid/full electric alternatives.
Renewable electricity in corporate buildings	• Increased renewable electricity aligned with Connecticut state RPS target

Interrog. Resp. UPA-16.

The Authority recognizes that UI's ESG-related activities, particularly those led by its Community Relations team, reflect a genuine effort to engage stakeholders and support EJ communities within its service territory. However, the record lacks clear examples or data that demonstrate the effectiveness or impact of these efforts. Similarly, although UI describes coordination with the Avangrid Sustainability team to align local initiatives with corporate ESG goals, including Connecticut's clean energy and emissions reduction targets, there is insufficient evidence to assess the outcome of these activities. Because these goals are established and tracked exclusively at the corporate level, there is limited visibility into UI's specific contributions. UI does not maintain Connecticut-specific ESG targets or report measurable progress at the operating company level, which hinders the Authority's ability to evaluate alignment with the state's statutory goals or understand the local impact of these efforts. Without utility-level performance reporting, it is not possible to meaningfully assess UI's progress or effectiveness with respect to GHG emissions reduction.

The Authority finds that UI lacks Connecticut-specific ESG targets and tracking mechanisms, which limits transparency and accountability. Although UI claims that its initiatives support Avangrid's broader goals, the absence of disaggregated data by

operating company prevents the Authority from determining the extent to which local actions contribute to those objectives. To address this gap, the Authority directs UI, in its next rate amendment application, to report operating company-level metrics to measure and report its contributions to corporate sustainability goals. Specifically, such metric reporting shall include UI's GHG emissions and measurable EJ engagement outcomes. Additionally, the Company shall provide clearer documentation of how its local actions, programs, and initiatives support corporate and state-level GHG emissions and EJ engagement objectives.

2. Operating Company Accountability in ESG Initiatives

The Company states that Avangrid does not assign UI a pro-rata share of responsibility, nor does it define separate obligations for UI in contributing to corporate sustainability goals. Interrog. Resp. UPA-15. Avangrid also does not allocate short- or long-term sustainability targets specifically to UI, as it evaluates performance exclusively at the corporate level. Interrog. Resp. UPA-26.

The Company asserts that Avangrid establishes a "robust" governance framework to monitor sustainability goals at the highest levels of the organization. Interrog. Resp. UPA-40. Senior leaders own each goal, develop implementation plans during the first quarter, and report progress quarterly. Id. During the evidentiary hearing, the Company testified that a steering committee and designated goal owners meet quarterly to ensure local decision-making remains part of corporate ESG efforts. Hr'g Tr., 474:3–10. The committee includes representatives from each business segment and senior leaders across the organization. Hr'g Tr., 474:10–15. The Company did not identify whether any members of the steering committee or goal owners are based in Connecticut. According to the Company, this structure promotes broad participation and maintains a strong connection between corporate goals and business operations. Hr'g Tr., 474:17–21. Goal owners collect and coordinate information across UI's business functions to assess progress and determine next steps when goals fall off track. Hr'g Tr., 475:2–7.

Avangrid's CEO and CFO review these updates and present them to the Audit Board Committee and Avangrid reports the annual results in its Sustainability Report. Interrog. Resp. UPA-40. However, the record does not include examples of the specific sustainability goals assigned to senior leaders, nor the content of the quarterly implementation plans or progress updates. Moreover, there is no indication that these goals are aligned with Connecticut-specific ESG policies or targets at UI. Further, UI employees do not have assigned responsibilities or incentive structures tied to sustainability goals. Interrog. Resp. UPA-41. As such, there is no explicit governance structure at the operating company level to implement and monitor these goals. Hr'g Tr., 475:16–18. Therefore, UI does not maintain mechanisms to ensure consistent implementation or oversight of ESG objectives. Hr'g. Tr., 475:19–22. In addition, it remains unclear whether the goals managed at the corporate level are aligned with Connecticut-specific ESG policies or statutory targets.

During the evidentiary hearing, in a discussion with OCC, the Company confirmed that while UI does not have defined sustainability goals, its activities can contribute to Avangrid's broader ESG objectives. Hr'g Tr., 584:21–23. The Company further testified

that Avangrid's actions may support Iberdrola's sustainability goals, reflecting a cascading structure of ESG contributions across corporate entities. Hr'g Tr., 584:24–25. For example, UI's resiliency investments could align with broader emissions reduction efforts, even though resiliency is not an explicit goal at the Iberdrola level. Hr'g Tr., 585:4–7. However, the Company did not offer documentation or data to demonstrate how UI's resiliency investments directly advance emissions reduction targets or contribute to other defined ESG outcomes.

The Company further testified that Avangrid considers sustainability goals across the organization, however, it bases them at least partly on assumptions. H'rg Tr., 475:23–25. For example, state policies inform renewable energy expectations, but the Company does not clearly incorporate or operationalize these expectations at the utility level through specific UI policies or programs. Hr'g Tr., 475:25; 476:13. As such, UI does not have any oversight mechanism to ensure that the objectives are effectively implemented and monitored at UI. Hr'g Tr., 475:19–22.

Finally, the Company does not explicitly articulate these commitments, in part because some outcomes remain uncertain. Hr'g Tr., 476: 6–8. Therefore, Avangrid takes a holistic approach to meeting its goals and recognizes that various elements, such as fleet management, can contribute to emissions reduction. Hr'g Tr., 476:8–10. For example, while the Company may consider procuring electric vehicles, it does not have guaranteed cost recovery for those investments, nor does it always control whether the vehicles are available. Hr'g Tr., 476:10–16. As a result, these goals remain at the corporate level and Avangrid coordinates across business areas but does not establish direct commitments at the operating company level. Hr'g Tr., 476:16–19. However, the Authority finds this rationale insufficient, as effective ESG implementation typically requires goal setting, despite uncertainty. Goals serve not only to signal intent but also to guide long-term planning and accountability.

The Authority concludes that without operating company-level integration, Avangrid's ESG governance framework fails to ensure meaningful alignment between corporate commitments and UI's operations in Connecticut. Although the Company describes a corporate steering committee and goal owner structure, it does not assign ESG responsibilities, incentives, or measurable targets to UI or its employees. Moreover, while UI asserts that its activities may contribute to broader ESG outcomes, the Company did not offer evidence demonstrating how its actions, such as resiliency investments, advance specific emissions reduction or sustainability targets. As such, the Authority directs the Company to include that information in its next rate case application.

3. Measuring and Tracking ESG Performance

a. Employee Compensation

The Company affirms that the Executive Variable Plan (EVP) serves as the short-term incentive plan for Executives and Senior Leaders, and that sustainability objectives, formerly referred to as ESG objectives, account for approximately 30% of the total performance objectives. Interrog. Resp. UPA-21. The remaining 70% of objectives fall

under financial and growth categories. Id. The Company notes that all EVP participants, including Management Committee Members (Business CEOs, Senior Vice Presidents, and Vice Presidents), are assigned individual targets for sustainability objectives, while Legal representatives have specific compliance and governance related objectives. Id. However, there are no UI employees in the EVP. Interrog. Resp. UPA-22, p. 2.

The Company testifies that employees who are not executives receive incentive awards based on three components: 35% tied to Avangrid's overall performance, 35% to their specific business unit or functional area, and 30% to their individual performance. Hr'g, Tr., 481:7–11. Further, ESG goals are incorporated into both the Avangrid-wide and business unit components, meaning employees' financial incentives are purportedly influenced by ESG outcomes. However, the Company does not provide specific details or documentation regarding how these ESG objectives are communicated to employees, tracked over time, or used to determine individual incentive payouts. Hr'g Tr., 481:12–15. As such, the Authority is unable to evaluate the effectiveness or consistency of these incentive structures.

Additionally, individual goals tailored to each employee's department or role contribute to the incentive award. Hr'g Tr., 481:15–19. Employees receive their incentive payments based on annual performance reviews and achievement of these goals. Hr'g Tr., 482:2–5.

The Company states that union employees' compensation is governed by the applicable Collective Bargaining Agreement. Interrog. Resp. UPA-22, p. 3. UI's union variable pay program targets 0.5% of each employee's prorated, annualized base salary. Id. The program evaluates performance based on three equally weighted metrics: SAIDI, SAIFI, and Safety, each accounting for 33.33%. Id. In 2023, union employees met the SAIDI and Safety targets but did not meet the SAIFI target, resulting in a payout of $141,281. Id. While these metrics, particularly SAIDI and SAIFI, are tied to system reliability, and Safety is a core operational value, they are not explicitly aligned with broader ESG objectives. Therefore, the Authority finds limited evidence that ESG performance influences union compensation in a measurable or intentional manner.

The Authority directs the Company to strengthen transparency regarding the influence of ESG objectives on compensation across all employee levels. This includes clarifying how ESG-related expectations are defined, communicated, and measured, particularly at the operating company level. The Authority directs the Company to report on the role of ESG goals with employee compensation and employee incentive compensation in its next rate case application.

b. Supplier Diversity

UI reports supplier diversity data at the operating company level. Hr'g Tr., 875:10–11. To expand relationships with diverse Connecticut-based businesses, the Company engages in several initiatives, including participating in events hosted by local chambers of commerce and minority business organizations such as the Greater New England Minority Development Council and the Southern Connecticut Black Chamber of

Commerce. Hr'g Tr., 875:13–20. The Company also conducts outreach with suppliers to better understand their capabilities and challenges and incorporates second-tier reporting requirements in its prime contracts to reinforce the importance of supplier diversity. Hr'g Tr., 874:20–25.

According to the Company, these efforts have yielded measurable outcomes, such as adding diverse suppliers to bid lists and awarding contracts to some of those suppliers. Hr'g Tr., 875:3–9. In 2024, UI implemented operating company-level metrics to better measure engagement with Connecticut-based suppliers, improving on prior corporate-level reporting. Hr'g Tr., 875:11–21.

For 2023, UI notes that Avangrid reported diverse spend only at the corporate level, not by operating company or supplier state. Interrog. Resp. UPA-37. Avangrid's 2023 Diverse Spend Goal was $230,000,000, and it achieved $243,557,455. Id. The $230 million target appears to be a corporate-level internal benchmark, though the Company does not identify how this amount was determined or what percentage of Avangrid's total procurement it represents. Without this context, it is difficult to assess the scale or ambition of the target. The table below illustrates Avangrid's diverse spend for 2023. Id.

Table 97: 2023 Avangrid Diverse Spend by Sub-Categories

Diverse Supplier Sub-Category	Avangrid Diverse Spend ($)	No. of Suppliers
LGBTQI+	61,344	1
Minority	82,264,995	57
Veteran	13,706,200	46
Woman	147,524,916	164
2023 Total Diverse Spend	**243,557,455**	**268**

Interrog. Resp. UPA-37, p. 1.

In 2024, Avangrid enhanced its reporting tool to enable reporting by operating company and supplier state. Interrog. Resp. UPA-37. Avangrid's 2024 Diverse Spend Goal was $270,000,000, and it achieved $289,825,996. Id. However, the Company does not provide information on what proportion of Avangrid's total customer base or procurement spending is attributable to UI. Without this proportional context, it is not possible to determine whether UI's diverse spend aligns with its relative operational scale in Connecticut. The table below shows diverse spend totals for both Avangrid and UI by sub-category. Id.

Table 98: 2024 Avangrid and UI Diverse Spend by Sub-Categories

Diverse Supplier Sub-Category	Avangrid Diverse Spend ($)	UI Diverse Spend ($)
Disability	2,065,487	-
LGBTQI+	30,719	-
Minority	176,227,806	4,266,520
Service-Disabled Veteran	1,828,700	-
Veteran	14,688,516	288,494
Woman	94,984,768	4,220,088
2024 Total Diverse Spend	289,825,996	8,775,102

Interrog. Resp. UPA-37, p.2.

Although UI reports the number of Connecticut-based suppliers, the Company does not provide a benchmark to assess whether this participation rate is proportionate to its share of Avangrid's business activity or supplier base.

With the enhanced reporting tool, UI is now able to identify the number of Connecticut-based diverse suppliers. Interrog. Resp. UPA-37. The table below presents Connecticut-based suppliers for Avangrid and UI by sub-category.

Table 99: Number of Connecticut-based Suppliers for Avangrid and UI by Sub-Categories

Diverse Supplier Sub-Category	No. of Avangrid CT Suppliers	No. of UI CT Suppliers
Disability	-	-
LGBTQI+	-	-
Minority	8	6
Service-Disabled Veteran	-	-
Veteran	5	2
Woman	10	3
Total CT-Based Suppliers	**23**	**11**

Interrog. Resp. UPA-37, p. 2.

The Authority acknowledges UI's progress in reporting supplier diversity at the operating company level and acknowledges the Company's efforts to engage diverse Connecticut-based suppliers through outreach events, supplier capability assessments, and second-tier contracting requirements. The implementation of operating-level metrics in 2024 represents a meaningful improvement over prior years when supplier diversity reporting occurred only at the corporate level.

However, the data shows that UI's diverse spend remains a small portion of Avangrid's overall totals. For example, while Avangrid reported more than $287 million in diverse spend in 2024, UI accounted for approximately $8.8 million. UI reports no spending with suppliers in sub-categories such as disability, LGBTQI+, and service-

disabled veterans. These gaps highlight opportunities to strengthen outreach and supplier engagement in underrepresented categories.

The Authority directs the Company to continue refining operating-level reporting and developing targeted strategies to increase participation in all diverse supplier categories in Connecticut. Expanding engagement with local diverse suppliers supports Connecticut's small business ecosystem, fosters local economic opportunities, and promotes more inclusive access to utility-related contracts. Accordingly, the Authority directs UI to provide context regarding the scale of its procurement operations relative to Avangrid's total, to help evaluate whether its supplier diversity performance is proportionate and effective. In its next rate amendment application, UI shall report on annual diverse supplier spend, including showing UI's proportional share of overall Avangrid spend as context, new Connecticut-based diverse suppliers engaged, and contract outcomes by category.

c. Environmental Justice Communities

Avangrid outlines its equity strategy through the Just Transition framework in its 2023 Sustainability Report. Interrog. Resp. UPA-31, p. 1. The Company asserts that the strategy focuses on four stakeholder groups—customers, communities, workforce, and suppliers, with the goal of minimizing negative impacts and enabling positive outcomes as the Company transitions to a clean energy economy. Id. Avangrid's Board periodically reviews corporate policies that support these objectives, including commitments to health and safety, human rights, people management, and stakeholder engagement. Id. The Company indicates that these policies guide its equity approach and are publicly available on its corporate governance webpage. Id.

For each stakeholder group, Avangrid identifies core principles and related implementation strategies. Interrog. Resp. UPA-31, p. 1. For customers and communities, these strategies include promoting equitable access to energy technologies, providing usage and affordability tools, supporting economic development, and ensuring proactive communication around capital projects. Id. For workforce and suppliers, strategies include upskilling, local workforce development, supplier adaptability support, and expanding opportunities for equal opportunity suppliers. Interrog. Resp. UPA-31, p. 2.

At the operating company level, UI states that its Community Relations personnel engage all 17 municipalities in its service territory and maintain a presence in environmental justice communities. Id. These activities include tabling and customer enrollment events, typically in partnership with local nonprofit organizations. Id. UI also participates in several Connecticut programs that target low-income and distressed municipalities. Interrog. Resp. UPA-18. These programs include:

(1) The **Community Partnership Initiative**, which promotes participation in energy efficiency programs;
(2) The **Neighborhood Assistance Act Tax Credit Program**, which supports nonprofit-led energy initiatives;

(3) The **CT EV Charging Program**, which offers enhanced site incentives for projects in distressed municipalities;
(4) The **Residential Renewable Energy Solutions** program, which provides additional incentives for qualifying projects in designated municipalities;
(5) The **Shared Clean Energy Facilities** program, which allocates on-bill credits to low- and moderate-income and distressed municipality customers;
(6) The **Home Energy Solutions – Income Eligible** program, which offers no-cost assessments and energy-saving services to qualifying customers; and
(7) The **Energy Storage Solutions** program, which provides enhanced incentives for low-income and underserved communities.

Interrog. Resp. UPA-31, pp. 3–4.

Several of these programs, such as the Community Partnership Initiative and participation in local enrollment events, reflect UI's voluntary engagement beyond compliance requirements. Others, like the Residential Renewable Energy Solutions program and Energy Storage Solutions, are mandated or administered under PURA or state-directed frameworks. The Company does not distinguish which programs are discretionary versus required, limiting the Authority's ability to assess the extent of UI's proactive involvement.

Regarding stakeholder engagement, the Company states that ESG is among the various topics UI communicates to external stakeholders within its service territory. Interrog. Resp. UPA-33. When specific concerns or requests arise, UI's Community Relations team collaborates with the Avangrid Sustainability Team. Id. However, the Company does not provide examples of specific stakeholder concerns addressed through this collaboration or indicate how frequently these interactions occur. Without documentation or case studies, the Authority is unable to assess the consistency or effectiveness of UI's engagement with Avangrid's Sustainability team. Avangrid incorporates Connecticut's clean energy and emissions targets into its broader goals, including consideration of state-level renewable energy commitments to support its carbon neutrality objective. Id.

UI's Community Relations personnel maintain relationships with municipal and nonprofit organizations across its service territory and the state. Interrog. Resp. UPA-39. The Company indicates that it gathers feedback through regular, direct stakeholder engagement and customer surveys conducted at community events. Id. In addition, Avangrid's Sustainability team collaborates with the Connecticut Community Relations team to incorporate this feedback into the Just Transition framework. Id.

While Avangrid and UI describe a broad equity strategy under the Just Transition framework and participate in a range of Connecticut-based programs, the record lacks clearly defined metrics to evaluate EJ progress at the operating company level. The Company does not provide measurable goals, tracked outcomes, or performance indicators specific to EJ communities. Furthermore, although stakeholder engagement is described as a component of UI's equity efforts, no evidence is offered to demonstrate

how feedback from EJ communities materially shapes program design, funding decisions, or investment prioritization.

The Authority directs UI to report operating company-specific EJ performance metrics in its next rate amendment application. Such EJ performance metrics shall include clearly identifying all relevant annual program participation levels in EJ communities and EJ community outreach and engagement reporting. The Authority further directs UI to include an explanation of how external and internal stakeholder feedback informs program planning and resource allocation.

d. Workforce Diversity and Inclusion

Avangrid publicly commits to increasing women's representation in executive and senior leadership roles, as stated in its 2023 Sustainability Report. See 2023 Sustainability Report Goals Scorecard.[140] Specifically, Avangrid has established goals to reach 40% representation of women in executive roles by 2025 and 50% in senior leadership positions by 2030. Id. As of 2023, women hold 35% of executive roles and 27% of senior leadership positions across Avangrid. Id. However, UI's ESG-related interrogatory responses did not reference Avangrid's publicly stated gender representation goals.

During the evidentiary hearing, when asked how UI contributes to Avangrid's 2025 goal to increase women in senior leadership, the Company stated that any "female employee at UI would contribute toward the corporate goal." Hr'g Tr., 486:20–25. The Company further explains that it supports advancement opportunities for women through succession planning and targeted leadership development programs. Hr'g Tr., 487:5–10. These efforts, according to the Company, predate the 2025 goal and are part of a longstanding workforce planning strategy. Hr'g Tr., 488:2–5.

To support career development for women, UI states that it monitors career progression through monthly reviews and ongoing internal discussions. Hr'g Tr., 487:13–25. However, when asked whether it uses measurable data or defined metrics to assess the effectiveness of these pathways, the Company testified that such evaluations are conducted primarily through informal check-ins and conversations, not through formalized performance tracking. Hr'g Tr., 495:12–22.

The Company also states that UI uses a workforce diversity dashboard to monitor internal DEI metrics and guide its People & Organization strategy. Hr'g Tr., 485:17–22. The Company updates the dashboard monthly and reviews it during workforce planning and program development sessions. Hr'g Tr., 486:14–17. More broadly, the Company conducts internal reviews of this dashboard data to inform training efforts and the design of targeted DEI programs. Hr'g Tr., 486:5–11.

In response to a request for disaggregated workforce data by gender, as well as new hires and promotions by race and gender for 2023 and 2024, the Company stated

[140] Available at: https://www.avangrid.com/documents/453723/3563912/24-10817+2023+Sustainability+Report_Scorecards.pdf/6b502bf6-c34e-81eb-c4f1-e611dc815f07?t=1717510639939.

that it does not publicly report this data at the operating company level. Interrog. Resp. UPA-035. While Avangrid's 2023 Sustainability Report includes demographic information at the statewide level, Avangrid has not disclosed operating company-specific data or 2024 updates. Id. Consequently, the Company submitted a redacted attachment in response; however, UI did not include any analysis or explanation of how UI's workforce trends align with equity or leadership representation goals.[141] Id. The table below summarizes gender representation, along with the number of hires and promotions at UI for 2023 and 2024.

Table 100: UI 2023 and 2024 Workforce Gender, Hires and Promotions Data

	Head count		Hires		Promotions	
Employee	**2023**	**2024**	**2023**	**2024**	**2023**	**2024**
Female	171	194	14	25	6	7
Male	448	493	59	41	14	13
Non-binary	-	2	-	-	-	-
Undeclared	-	-	-	1	-	-

Late Filed Ex. 19, Att. 1.

In a separate data request regarding how UI's hiring and promotion trends support Avangrid's 2025 leadership diversity goals, the Company reaffirmed its commitment to equal employment opportunity. Interrog. Resp. UPA-036. The Company emphasized that hiring and promotion decisions across Avangrid and its subsidiaries, including UI, rely solely on candidate qualifications and do not consider any protected category. Id. The Company also submitted workforce data for senior leadership at UI. Interrog. Resp. UPA-35, Att. 1. Based on the information provided, no women held senior leadership positions at UI in either 2023 or 2024. Interrog. Resp. UPA-35, Att. 1; Late Filed Ex. 19, Att. 1. The table below summarizes the gender composition of senior leadership during this two-year period. Id.

Table 101: UI 2023 and 2024 Senior Leadership Gender Data

Senior Leadership	2023	2024
Female	-	-
Male	7	9
Non-Binary	-	-
Undeclared	-	-

Late Filed Ex. 19, Att. 1

To provide a broader view of workforce diversity, the Company submitted employee race and ethnicity data. Interrog. Resp. UPA-035, Att. 1. UI maintained a

[141] On April 30, 2025, the Authority denied the Company's request for a motion of protective order to keep the data confidential. The Company was directed to refile Interrog. Resp.UPA-35, Att. 1. See Motion No. 95 Ruling.

predominantly white workforce in both years, reporting 372 white employees or 60.1% in 2023 and 381 or 55.3% in 2024. Interrog. Resp. UPA-035, Att. 1; Late Filed Ex. 19, Att. 1. The table below summarizes UI's workforce for 2023 and 2024 separated by race or ethnicity.

Table 102: UI 2023 and 2024 Workforce Race or Ethnicity Data

	Head Count		Hires		Promotion	
Race or Ethnicity	**2023**	**2024**	**2023**	**2024**	**2023**	**2024**
American Indian or Alaskan Native	2	3	-	-	-	-
Asian	23	27	4	1	-	-
Black or African American	94	102	12	11	5	5
Hispanic/Latino	109	142	15	28	8	5
Native Hawaiian or Other Pacific Island	-	-	-	-	-	-
Two or More Races	12	17	1	4	-	-
White	372	381	34	21	7	7
Did Not Provide	7	17	7	2	-	3

Late Filed Ex. 19, Att. 1

In addition, white employees held the majority of senior leadership positions at UI in both 2023 and 2024. Interrog. Resp. UPA-035, Att. 1. Specifically, white employees represented 85.7% of senior leadership in 2023 and 77.8% in 2024, while Hispanic or Latino employees held the remaining positions, comprising 14.3% and 22.2% respectively. Id. Further, male employees accounted for 100% of senior leadership roles during both years. Id. The table below summarizes the racial, ethnic, and gender composition of UI's senior leadership in 2023 and 2024.

Table 103: UI 2023 and 2024 Senior Leadership Race or Ethnicity Data

Senior Leadership	**2023**	**2024**
American Indian or Alaskan Native	-	-
Asian	-	-
Black or African American	-	-
Hispanic/Latino	1	2
Native Hawaiian or Other Pacific Island	-	-
Two or More Races	-	-
White	6	7
Did Not Provide	-	-

Late Filed Ex. 19, Att. 1

Although Avangrid has publicly committed to increasing the representation of women in executive and senior leadership roles, UI has not demonstrated meaningful alignment with these goals at the operating company level. Despite the prominence of these commitments in Avangrid's 2023 Sustainability Report, UI did not reference the

Company's 2025 or 2030 gender representation targets in any ESG-related interrogatory responses. This omission suggests a lack of internal accountability and raises questions about whether corporate-level DEI commitments are being operationalized in Connecticut.

Although the Company testified that succession planning and leadership development programs are in place to support the advancement of women, UI acknowledged that it does not use defined metrics to evaluate the success of these programs. Instead, assessments rely on informal conversations and subjective reviews, offering no measurable basis for evaluating progress. As such, UI's contribution to Avangrid's gender equity goals remains anecdotal and unsubstantiated.

Further, the workforce data submitted by the Company underscores this disconnect. Not a single woman held a senior leadership position at UI in either 2023 or 2024, and 100% of those roles were held by men. The data also show that white employees continued to dominate these leadership positions, accounting for 85.7% in 2023 and 77.8% in 2024. These facts directly contradict Avangrid's stated ambition to increase women's representation and reinforce the conclusion that UI has failed to reflect those goals at the operating company level.

Although UI maintains a workforce diversity dashboard and reports conducting monthly internal reviews, these tools have not resulted in measurable leadership diversity gains. The Company presented no evidence linking internal demographic trends to targeted strategies for promotion or advancement, particularly for women and people of color. UI's lack of alignment between corporate goals and local performance undermines the credibility of its equity commitments.

The Authority therefore directs UI in its next rate amendment application to report clearly defined workforce diversity objectives at the operating company level, supported by disaggregated reporting and a discussion of the Company's policies and practices to assess internal advancement opportunities for its diverse workforce. Without these measures, UI's contribution to Avangrid's equity objectives will remain aspirational rather than actionable.

e. DEI Training

The Company states that it offers a variety of Equal Opportunity (DEI) training programs through both live (synchronous) and on-demand (asynchronous) formats. Interrog. Resp. UPA-042. These trainings aim to enhance participation, access, engagement, and inclusion across the organization. Id. Training topics cover onboarding, orientation, policy updates, continuing education, and addressing personnel complaints or issues. Id. The Company designates each training as either voluntary or mandatory based on the employee group. Id.

UI provided examples of notable DEI trainings, including Allyship & Disability Inclusion, Digital Accessibility for the Modern Workplace, and Sexual Harassment and Discrimination for Employees. Interrog. Resp. UPA-042. While some of these trainings,

such as those addressing sexual harassment and discrimination, are legally required and standard across most workplaces, the Company includes them in its DEI training portfolio. As such, the inclusion of mandatory compliance courses may overstate the breadth of voluntary or equity-focused DEI programming. Further, UI requires mandatory sustainability training focused on Environmental Health and Safety (EHS) topics, such as general environmental awareness and waste management. Id.

Additionally, the Company explains that it engages internal stakeholders in the development and execution of workforce-related ESG initiatives through structured processes, feedback mechanisms, and cross-functional collaboration. Interrog. Resp. UPA-038. Although these activities support broader ESG implementation, their relevance to DEI outcomes is limited. The majority of these initiatives pertain to EHS or cybersecurity, rather than diversity, equity, or inclusion. As such, their inclusion in the DEI section may conflate compliance-driven operational programs with equity-specific initiatives. Avangrid aligns key workforce sustainability initiatives, including Safety (TRIR), ISO 45001 certification, employee training, and cybersecurity awareness, with its corporate sustainability goals. Id. Senior leadership holds responsibility for integrating EHS objectives into business processes through operational planning, risk assessments, safety training, and change management. Id. The Company promotes employee participation through programs such as the Good Catch Program, which encourages proactive hazard identification. Id.

To gather feedback, Avangrid consults with employees and union representatives on EHS matters, including training needs assessments, policy development, and performance monitoring. Interrog. Resp. UPA-038. The Skilled Safety team, composed of union and management representatives, facilitates this engagement. Id. Additional feedback mechanisms include incident reporting and investigation, weekly review calls, internal audits, surveys, and feedback sessions. Id. Avangrid supports cross-functional collaboration through EHS Governance bodies, support functions embedded across business units, and a stakeholder engagement model that guides interactions on relevant topics. Id.

For employee training, the Company follows the ADDIE instructional design model, which includes Analysis, Design, Development, Implementation, and Evaluation. Interrog. Resp. UPA-038. The training team collaborates with business leaders and subject matter experts to develop targeted learning solutions and measures effectiveness using the Kirkpatrick Model. Id. Metrics include Net Promoter Scores, employee self-assessments of preparedness, behavioral assessments tied to performance management, and tracking of retention and internal mobility. Id.

Regarding cybersecurity training, Avangrid provides mandatory annual courses, phishing simulations, in-person meetings, webinars, and internal awareness communications. Interrog. Resp. UPA-038. Feedback mechanisms include a dedicated email inbox, a 24/7 Security Operations Center, training events, and employee surveys. Id. Cross-functional collaboration supports these initiatives through working groups such as the Corporate Security & Resilience Steering Committee, Business Continuity Liaisons, Security Ambassadors, Global Cybersecurity Champions, and the

Cybersecurity Culture working group. Id. The Company states that these workforce-related processes, feedback mechanisms, and cross-functional collaborations support the implementation of Avangrid's corporate sustainability goals. Id.

While UI participates in Avangrid's DEI and sustainability training programs, covering topics such as workplace inclusion and EHS, the Company does not provide operating company-specific data to evaluate training outcomes or workforce DEI progress in Connecticut. Instead, UI describes corporate-driven engagement processes like safety initiatives, employee feedback loops, and cross-functional planning, none of which are shown to advance measurable equity outcomes at the local level.

Moreover, the inclusion of mandatory compliance trainings, such as sexual harassment prevention, within UI's DEI portfolio raises concerns about the substance of the Company's equity-focused education efforts. Without clear evidence of how these initiatives support Avangrid's broader DEI commitments or improve inclusion within UI's workforce, the Company's approach appears procedural rather than transformative.

In the absence of disaggregated metrics or Connecticut-specific tracking, it is difficult to ascertain if the Company's training and workforce initiatives contribute to ESG and DEI objectives at the operating company level. To improve transparency and accountability, the Authority recommends that UI begin measuring and reporting on workforce training participation, performance outcomes, and DEI progress specific to its Connecticut operations. UI should also establish formal mechanisms to assess how employee engagement drives continuous improvement in these areas.

4. ESG Conclusion

OCC raises significant concerns regarding the lack of operating company-level ESG governance, transparency, and accountability at UI. OCC Brief, p. 45. OCC highlights that, although Avangrid promotes robust corporate ESG commitments, UI has not demonstrated local implementation, oversight structures, or measurable outcomes. Id., p. 46. OCC also emphasizes that Connecticut ratepayers—not shareholders—fund 100% of UI's ESG contributions, despite Avangrid benefiting from investor confidence tied to ESG positioning. Id. In OCC's view, these deficiencies directly undermine the Company's request for a higher return on equity. Id.

The Authority agrees and finds that Avangrid has not established sufficient operating company-level ESG governance structures, targets, or oversight mechanisms at UI, despite its stated extensive corporate sustainability commitments. Throughout this proceeding, the Company consistently acknowledged that ESG responsibilities and performance tracking reside exclusively at the corporate level. Interrog. Resp. UPA-15; Interrog. Resp. UPA-26. UI employees do not hold defined sustainability responsibilities or incentives, nor does the utility maintain utility-specific metrics to track ESG implementation. H'rg Tr., 475:16–22.

Although the Company points to Avangrid's Just Transition framework and participation in several Connecticut-based programs, such as the Community Partnership Initiative, Energy Storage Solutions, Residential Renewable Energy Solutions, and the

CT EV Charging Program, the Company has not demonstrated how UI evaluates its equity or sustainability impact within these programs, nor how stakeholder input shapes program delivery or outcomes. Interrog. Resp. UPA-31; Hr'g Tr., 474–476. Without utility-level performance indicators or internal accountability mechanisms, UI cannot show whether these initiatives are effectively reaching environmental justice communities or driving measurable ESG progress.

Furthermore, UI is not in alignment with Avangrid's gender diversity commitments. While Avangrid's public ESG goals include increasing the representation of women in senior leadership to 40% by 2025, UI did not reference this target in any ESG-related interrogatory responses. Interrog. Resp. UPA-35. As of 2023 and 2024, no women held senior leadership roles at UI. Late Filed Ex. 19, Att. 1. Additionally, the Company confirmed that it does not formally measure the effectiveness of internal advancement or succession planning strategies designed to support women or other underrepresented groups. Hr'g Tr., 495:12–22.

This disconnect between public ESG claims and operating company-level execution reflects a shortcoming in implementing Avangrid's ESG priorities in Connecticut. While the Company's 2022-2023 sustainability reports frame Avangrid as a leader in ESG transparency, its Connecticut operations did not demonstrate operating company-specific contributions, oversight, or measurable outcomes. In addition, UI's contributions to Avangrid's ESG performance—through programs that advance environmental and social goals—are funded by Connecticut ratepayers.

The Company has also linked its continued participation in clean energy initiatives to an increase in its allowed return on equity, indicating that its support for these programs is contingent upon cost recovery certainty rather than embedded in its long-term strategy. Hr'g Tr., p. 1760:22–25; 1761:1–9. This includes statements suggesting that the current earned return is insufficient to sustain participation and that modernization investments may be deferred until the Company earns a higher return. Ex. UI-RPP-1, p. 34–35. This disconnect between Avangrid's public ESG positioning and UI's local implementation reflects a failure to translate corporate commitments into operating company-level accountability, transparency, or measurable outcomes. While Avangrid has emphasized the reputational and financial advantages of its ESG positioning, those benefits are not shared equitably between shareholders and ratepayers.

As such, the Authority finds that improvement in the Company's ESG governance is needed to ensure UI ratepayers and local operations tangibly benefit from Avangrid's ESG goals and actions. Despite repeated claims of leadership in sustainability and corporate responsibility, the Company has made no meaningful effort to operationalize those commitments at the operating company level. The Authority finds this disconnect—between stated values and on-the-ground execution—both troubling and inconsistent with the public positioning the Company has chosen to promote. As such, in the Company's next rate amendment application, the Company shall report ESG metrics demonstrating its contributions to Avangrid's ESG performance as discussed herein. Such reporting serves as a targeted performance signal to reinforce the expectation that ESG related claims—particularly those used to bolster public image or attract investor

interest—must be matched by transparent action, measurable results, and equitable cost sharing at the operating company level. Failure to demonstrate operating company-level contributions to Avangrid's ESG goals could warrant a potential downward adjustment to the Company's authorized ROE in a future proceeding. Such an outcome would serve as a targeted performance signal of the expectation that ESG participation, particularly when funded by ratepayers, must be matched by transparent reporting.

The Company asserts that the Authority oversteps by imposing ESG-related directives that are inconsistent with UI's corporate discretion. UI Exceptions, p. 88 (citing Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U.S. 276, 289 (1923)). UI claims that the Authority is effectively micromanaging the Company by requiring the Company to make business decisions based on PURA's judgment and not that of the Company's management. UI Exceptions, p. 158. However, the Authority's directives are narrowly focused on operating company-level reporting and accountability, not on substituting business judgment or mandating expenditures. Consistent with the Authority's statutory obligations to ensure transparency, just and reasonable rates, and alignment with public interest goals under General Statutes §§ 16-19e and 16-244i(d), enhanced local ESG reporting is necessary to assess the prudency of cost recovery, the effectiveness of implementing ESG initiatives, and the proportionality of shareholder versus ratepayer benefits. Moreover, the record reflects the Company's own admissions regarding the absence of defined ESG responsibilities, performance metrics, and governance structures at the operating company level—facts that support narrowly tailored reporting requirements. See Interrog. Resp. UPA-15; Interrog. Resp. UPA-26; Interrog. Resp.UPA-40; Interrog. Resp. UPA-41; Hr'g Tr., 475:16–22.

Finally, the Company's assertion that Avangrid may eliminate UI-specific ESG contributions does not demonstrate that such contributions are integral to the Company's long-term strategy or embedded within its sustainability values, but it suggests that they are discretionary and contingent on favorable regulatory outcomes. See UI Exceptions, p. 159. Such actions would undermine Avangrid's public ESG commitments and result in inconsistent and unsubstantiated local implementation. Enhanced transparency requirements are necessary, and any potential future ROE adjustment may depend on the level of operating company integration, local implementation, and broader ESG outcomes. Participation in programs that advance the public interest should not depend on earnings enhancements but should reflect the Company's core obligations and sustained accountability to the communities it serves.

C. CUSTOMER SERVICE TRAINING AND OPERATIONS

1. Customer Service Performance

Despite significant prior Authority direction to the Company, customer service performance over the period since UI's last rate case, while showing recent signs of improvement, has remained below the level expected of a franchise providing expert, efficient, and prudent management. In the 22-08-08 Decision, the Authority identified numerous areas of insufficient Company customer service performance, including in its live energy affordability calls with CSRs, oversight of its third-party call center, provision

of information to CSRs, and updating of standard operating procedures and corporate policies. 22-08-08 Decision, pp. 100–102 (detailing various needed improvements to customer service performance), 120–122 (detailing the insufficient oversight of UI's third-party call vendor, iQor), 123–124 (detailing that the CSR tool to search updated information during calls is "updated 'not nearly as often as we would like,'" and that CSRs often referenced up-to-date information in self-drafted word documents), 276–279 (detailing EOE's identification of numerous deficiencies on call recordings, as well as the revision lag for Company policy and procedure documents).

As a result of these findings, the Authority issued a number of directives, including but not limited to (1) approving an increase of 12 CSR FTEs and one Lead Analyst Customer Service Quality FTE, (2) finding it appropriate to hire an additional five UIL-level Customer Experience and Shared Services team FTEs, (3) directing the Company to investigate the benefits of transitioning credit and collections calls from the third-party call center to the Company's internal CSRs, and (4) directing the Company to rectify all EOE-identified violations. Id., pp. 100–102, 119–125, 276–278. Through these efforts, the Authority endeavored to allow the Company to incorporate new resources to better support CSRs, customer service staff, and ultimately customers, in order to improve overall customer service performance and minimize violations. Ultimately, the Authority also determined it necessary to apply a twenty (20) basis point reduction to the Company's ROE in order "to incentivize much needed improvement to the Company's customer service performance." 22-08-08 Decision, p. 100.

Nonetheless, the Company's customer service performance since UI's last rate case remains concerning. EOE again identified numerous CSR failures in its review of recorded customer credit and collections calls. See EOE Brief, pp. 26–33; OCC Brief, pp. 54–60. The Company admits that its CSRs provided customers with incorrect information, neglected to accurately determine customer financial hardship status, incorrectly enrolled customers in less or more beneficial programs than they were eligible for, and incorrectly calculated customers' arrears balances. Interrog. Resp. EOE-55, Interrog. Resp. EOE-122; Interrog. Resp. EOE-135; Interrog. Resp. EOE-150; Interrog. Resp. EOE-187, Interrog. Resp. EOE-229, Interrog. Resp. EOE-231, Interrog. Resp. EOE-232, Interrog. Resp. EOE-238, Interrog. Resp. EOE-240, Interrog. Resp. OCC-803, Interrog. Resp. OCC-805. Notably, these errors occurred in calls handled by both the Company's old vendor, iQor, and its new vendor, Alorica. See, e.g., Interrog. Resp. EOE-126; Interrog. Resp. EOE-214; Interrog. Resp. EOE-224.

The Company stresses iQor handled many, if not all, of the calls identified as problematic, and that iQor is no longer handling such calls for UI. UI Reply Brief, p. 165, see also Interrog. Resp. EOE-55; Interrog. Resp. EOE-58; Interrog. Resp. EOE-64; Interrog. Resp. EOE-140; Interrog. Resp. EOE-141; Interrog. Resp. EOE-151; Interrog. Resp. EOE-155; Interrog. Resp. EOE-194; Interrog. Resp. EOE-198; Interrog. Resp. EOE-229; Interrog. Resp. EOE-230; Interrog. Resp. EOE-231; Interrog. Resp. EOE-232; Interrog. Resp. EOE-238; Interrog. Resp. EOE-240. Further, the Company argues that any poor performance attributed to its new vendor's CSRs can largely be attributed to the recency of their installation on the UI account. See UI Comments, p. 21; see also Interrog. Resp. EOE-126; Interrog. Resp. EOE-214; Interrog. Resp. EOE-224.

The reasons suggested by the Company do not excuse customer service underperformance. The totality of record evidence shows that UI's customers continued to experience an unacceptably high rate of substandard customer service since the Company's last rate case.[142] At best, 16–20% of UI EA customer service calls still involve the failure of Alorica CSRs to provide adequate or accurate assistance to UI's customers. Interrog. Resp. CAE-1; UI Comments, p. 23.

Relatedly, both OCC and EOE raise concerns about the lack of adequate provisions in the Company's recently enacted contract with Alorica, see Interrog. Resp. OCC-10, Att. 4 (Alorica Contract), to hold Alorica accountable for poor performance from its CSRs; noting, inter alia, that any financial performance penalties are contingent on Authority involvement. OCC Brief, pp. 60–61 (citing Interrog. Resp. OCC-82, Interrog. Resp. OCC-96); EOE Brief, pp. 34–36 (citing Alorica Contract). The Authority has previously expressed concern about the Company's lack of appropriate contract terms to incentivize stronger vendor performance. See, e.g., 22-08-08 Decision, p. 101. For its part, the Company argues that it has ample ability to penalize its vendor for failing to comply with the terms of its new agreement, UI Reply Brief, p. 167; Interrog. Resp. OCC-15, and that any supposition "that other agreements or terms were available or should have been entered into" amounts to an impermissible "hindsight" prudency review. UI Brief, p. 168. At the same time, the Company concedes that while penalties have been discussed for a couple of years, "there is nothing in the contract right now that penalizes [its customer service call vendor] for a certain amount" outside of customer escalations to the Authority. Hr'g Tr., 224:3–23. Regardless of any contract provisions (or lack thereof), the Authority will hold the Company accountable for the level of customer service provided by its vendors, including Alorica. That performance remains insufficient.

Concerningly, many of the Company's actions and investments suggest more of an interest in collecting positive satisfaction scores than in improving lagging customer service areas. For example, in 2023 the Company tested the use of e-mail customer satisfaction surveys in place of its usual outbound telephone survey. Interrog. Resp. OCC-674. UI reverted to phone surveys "after it was observed that the scores dropped significantly." Id. The Company summarily concluded that because the survey script and target audience remained the same, the "only variable affecting the scores was the distribution channel used." Id., p. 1. Critically, the Company did not further investigate why the change in communication channel affected the scores, nor did it take steps to determine which scores might be a more accurate survey-based approximation of actual customer sentiment. Id., p. 2.

Similarly, the Company continues to highlight its efforts on improving customers' digital interactions with the Company above any efforts to improve non-digital and call

[142]UI argues that the customer service call deficiencies EOE reported in the present proceeding are the same types as the Authority noted in the 22-08-08 Decision because "the Test Year calls reviewed in this docket occurred largely during the litigation of Docket No. 22-08-08 (which was decided in August 2023)." UI Exceptions, p. 71. This is incorrect. The Proposed Final Decision erroneously labeled the calls in question as occurring in the Test Year. As the underlying record confirms, however, the calls cited herein were taken from each month in 2024, after the test year concluded, and well after the Authority issued the 22-08-08 Decision. See Interrog. Resp. EOE-1; Interrog. Resp. EOE-142.

center customer interactions. For example, in their Application the Company included a report on customer service Key Performance Indicators (KPIs). Application, Ex. UI-CSP-2. However, the KPI results only discuss digital initiatives and call center average speed of answer (ASA). Id. Neither of the reported KPI results focus on the quality of CSR customer service or the provision of accurate information to customers. The Company highlights that these new initiatives are associated with "high customer sentiment scores and interaction rates." Application, Ex. UI-CSP-1, pp. 20–23. Yet such initiatives are all digital and the corresponding customer sentiment scores are measured using the Net Promoter Score (NPS), which the Authority has previously questioned. 22-08-08 Decision, p. 280 (questioning relevance to a regulated monopoly). Of note, of the 23 items the Company listed as undertaken since its last rate case, eight are focused on improving the customer's digital interactions. Interrog. Resp. CAE-1, Att. 1. While improving such interactions is a laudable undertaking, which the Authority supports, more is required to ensure satisfactory service to all customers, and especially those in need of energy assistance.[143]

Ultimately, though, the most recent call performance data for Alorica CSRs who have been servicing UI customers for 120 days or more is indeed better than the unsatisfactory 41% success baseline established with iQor as UI's vendor. See Interrog. Resp. CAE-1, p. 2. While the switch and transition to Alorica ideally should have occurred much sooner and quicker, and while the Authority still recommends that UI employ more financial performance incentives to hold its contractors accountable for what its customers actually experience, the Authority is hopeful that the recent improvements in customer service will continue. Accordingly, the Authority is not continuing any ROE reduction with respect to Customer Service at this time. Based on the continued concerns noted above, however, the Authority will continue to closely review the Company's customer service performance in future rate proceedings and in the annual energy affordability review proceedings (i.e., Docket No. XX-05-01).

Additionally, the Authority directs UI to contact each of the individuals that were harmed because of incomplete or inaccurate information in the sample of calls sent to EOE and identified with violations in the instant proceeding. See Interrog. Resp. EOE-1; Interrog. Resp. EOE-142; see also EOE Brief, pp. 28–33. The Company shall ensure these customers are placed in the appropriate program or payment arrangement to meet their needs and refund any fees (late payment or reconnection charges) assessed to them as of the date of the call if they are not already so situated. The Company shall submit as compliance in both this docket and Docket No. 26-05-01, no later than January 15, 2026, a report that includes, at a minimum: (1) the nature of the call and the misinformation or incomplete information the customer received; (2) how the Company rectified the situation (i.e., change in payment arrangement, refund of fees assessed, or

[143]At the same time the Company seeks to draw attention to improvements in its digital interactions with customers, UI "takes exception to the narrow focus of 'customer service management' on the quality of Energy Affordability Calls. UI Exceptions, p. 70, n.51. While the Authority agrees that interactions with all customers are important, the Authority views the Company's interactions with, and guidance to, those in need of energy assistance as especially important and worthy of focused attention.

change in program enrollment); and (3) the disciplinary action, if any, taken by the Company for the CSR(s) involved in each call.

2. Standard Operating Procedures Revision Lag

The Authority previously identified a significant lag in the Company's updates of the Standard Operating Procedures (SOPs). 22-08-08 Decision, p. 278. Specifically, the SOPs had not been updated to incorporate recent statutory and Authority directives that modified energy affordability and customer service policies. Id. As such, the Authority directed the Company to file updated versions of all corporate procedure documents submitted as part of its 2022 rate application and to "prospectively revise all corporate procedure documents no later than 30 days after PURA directs any changes to programs or procedures." Id.

The Company claims to have complied with such directives and updated all customer service SOP documents submitted in its Application. Application, Sch. H-2.10. Further, the Company states that the customer service policies "are updated regularly throughout the year, either annually or biannually based on the revisions dates shown on each procedure, or within thirty days of a change directed by [the Authority]." Interrog. Resp. OCC-252. Nonetheless, Parties in the instant proceeding identified multiple errors in the Company's customer service SOP documents that spurred the Company to make additional modifications during the pendency of the proceeding. Interrog. Resp. EOE-17, Interrog. Resp. EOE-21. The Authority emphasizes the importance of maintaining accurate, up-to-date SOP documents that allow Company staff and customer service representatives to provide the most accurate information to customers. The Authority expects the Company to continue this effort and will continue to review policy updates in future energy affordability annual review proceedings (i.e., Docket No. XX-05-01) and through future rate amendment applications.

3. Customer Experience Initiatives

In its Application, the Company detailed several completed customer experience initiatives and proposed initiatives to enhance the customer experience. Application, Ex. UI-CSP-1, pp. 36-48.

As of the date of its Application, the Company completed numerous initiatives to improve the digital customer experience, including: (1) redesigning the digital sign-up and enrollment process for those seeking self-service; (2) implementing a new online payment process that accommodates any digital device and allows digital payment via Google and Apple Pay; (3) migrating the Company's website to a new cloud-based platform to provide customers a more stable and robust experience; and (4) implementing a disconnection notification on customers' online account webpage when they enter the disconnection process. Id., pp. 36-38. Further, in compliance with Order No. 34 of the 22-08-08 Decision, the Company has "proposed a dedicated initiative" that "specifically aims to improve the customer experience with the Company's CSRs and contact centers and customers who do not have access to digital offerings." Id., p. 39.

The Company highlights the positive digital performance metrics and emphasizes the importance of further investments. Id., pp. 39–40. As a result, the Company proposes 13 customer experience enhancement initiatives, specifically:

(1) Disconnection SMS notifications;
(2) Energy Manager enhancements for mobile use and high-bill usage alerts;
(3) Outage alert experience enhancements;
(4) Mobile app payment experience redesign;
(5) Virtual energy assistant for 24/7 digital customer support;
(6) Support center website improvements;
(7) Start, stop, and transfer service enhancements for both off- and online customers;
(8) High bill/high usage/energy affordability experience;
(9) Green Button Connect functionality;
(10) Streamline new connections requests via a digital platform;
(11) Pro-active data-led customer insights;
(12) Customer identity and access management (CIAM) to enhance digital security; and
(13) Digital technology maintenance enhancements.

Application, Ex. UI-CSP-1, pp. 41-47. In total, the Company proposes including approximately $4.6 million for the above listed customer experience capital projects in its revenue requirement request in the instant proceeding. Id., pp. 47-48; see also Interrog. Resp. CAE-14, Att. 1.

Notably, while portions of many of the proposed enhancement projects have begun, none have been completed, and all have projected end dates between 2026 and 2028. Interrog. Resp. CAE-14, Att. 1; Hr'g Tr., 232:7–234:15, 246:8–25. As such, none of the proposed customer experience initiatives meet the required "used and useful" standard for capital projects. Accordingly, the Authority declines to pre-approve any proposed customer experience enhancement initiatives nor does the Authority pre-approve the recovery of any associated implementation expenses.

4. EOE Recommendations for Customer Service

EOE identified two opportunities for the enhancement of the Company's customer service and energy assistance offerings. EOE Brief, pp. 32-33. First, EOE highlighted the Company's considered modification to customers' online account webpage that would allow customers to "upload [income verification] documents directly to the Company's website portal." Id., p. 32. As the Company and EOE state, customers do not currently receive a receipt confirmation if they email financial hardship verification documents to the Company. Id., citing Interrog. Resp. EOE-148. Allowing customers to upload required documents to their online account webpage and receive positive confirmation that such documents have been received would improve the customer experience, lessen customer calls, and possibly encourage greater customer participation in available assistance programs.

Additionally, EOE proposed that the Company could improve its current procedures in handling customers that are pre-qualified for financial hardship. EOE Brief,

pp. 32-33. Specifically, EOE recommended that the Company use email reminders to encourage customers that are pre-qualified for financial hardship to submit the required income verification documentation to the Company. Id. Rather than waiting until the end of the 60-day financial hardship account hold period, the Company could develop a more frequent communications schedule to encourage customers to complete their financial hardship verification and enrollment. Id., p. 30.

The Authority appreciates EOE's recommendations regarding the Company's customer service and energy assistance offerings and finds it appropriate to investigate such proposals further. As such, the Authority directs the Company to submit for review and approval, no later than June 1, 2026, as part of the Company's annual Arrearage Forgiveness Plan filing in Docket No. 26-05-01, a detailed implementation proposal that incorporates (1) modifications to the online customer account portal to allow income verification document uploading; and (2) modifications to the customer communications procedures where customers have been pre-qualified for financial hardship yet have not submitted the required income verification documentation. The proposal shall include detailed implementation costs and timeline estimates for each item.

X. CONCLUSION AND ORDERS

A. CONCLUSION

The Authority approves an annual revenue requirement for UI in the amount of $450,789,348 for the rate year commencing November 1, 2025. This represents an increase of $65,924,348 from the Company's currently authorized revenue of $384,865,000. The revenue requirement includes an allowed return on equity of 9.45%; however, the Authority reduces the allowed ROE by an aggregate 20 basis point reduction (i.e., to 9.25%) to address certain performance and management issues. In addition, the Authority makes determinations on various issues, including cost allocation, rate design, revenue adjustment mechanisms, and customer service.

B. ORDERS

For orders requiring a filing, the Company shall file an electronic version through the Authority's website at www.ct.gov/pura. Submissions filed in compliance with the Authority's orders must be identified by: Docket Number, Title, and Order Number. Compliance with orders shall commence and continue as indicated in each specific order or until the Company requests and the Authority approves that the Company's compliance is no longer required after a certain date. Unless otherwise provided or determined by the Authority, filings submitted in compliance with an order shall constitute satisfaction of the order. Filings requiring Authority approval must be filed as a motion.

1. No later than 10 days after issuance of the Decision, the Company shall submit as compliance a revised single year rate design plan consistent with the Authority's findings contained in the Decision, including revised tariffs, revenue proof, and ACOSS models.

2. Effective November 1, 2025, and until directed otherwise in a subsequent Authority order, the Company shall calculate its distribution wage allocator when proposing base distribution rates such that it does not include SBC, GSC, REI, RDR, CLM, NBFMCC, or other non-distribution profit centers .

3. Effective November 1, 2025, and until directed otherwise in a subsequent Authority order, the Company shall calculate its Massachusetts Formula allocator when proposing base distribution rates such that it does not include SBC, GSC, REI, RDR, CLM, NBFMCC, or other non-distribution profit center.

4. No later than November 10, 2025, the Company shall file as compliance an update on the Company's implementation of the static pending termination notice banner on customers' online account webpages that includes final implementation costs and images of the banner, as discussed in Section IX.A.2, Termination Notices and Customer Rights.

5. No later than January 15, 2026, the Company shall file as compliance, in both this docket and Docket No. 26-05-01, a report that includes, at a minimum: (1) the nature of the call and the misinformation or incomplete information the customer received; (2) how the Company rectified the situation (i.e., change in payment arrangement, refund of fees assessed, or change in program enrollment); and (3) the disciplinary action, if any, taken by the Company for the CSR(s) involved in each call.

6. No later than January 31, 2026, the Company shall file as a motion for review and approval in this proceeding, the data for each year 2021 through 2025 required to calculate the baseline for each of the performance metrics set forth in Section VI.A.15.I.ii, Performance Metrics

7. No later than March 1, 2026, and annually thereafter until the conclusion of the Company's next rate case, the Company shall file as compliance in the applicable year's RAM proceeding the amount of UI, Avangrid Management Company, and Avangrid Services Company executive compensation customers are paying via base distribution rates and through the applicable RAM components or, conversely, the amount being returned to customers through the applicable RAM components.

8. No later than May 1, 2026, and every six months thereafter, until the entirety of the plant is being used for the supply of electricity to customers, the Company shall provide a report to the Authority of the status of the 12 duct lines installed as part of the Barnum Avenue Bridge Replacement Project, including when the Company anticipates that some or all of the 12 duct lines will be used for the supply of electricity to customers, as discussed in Section IV.B.4.b.v, Barnum Avenue Bridge Replacement Project. The Company shall also report any reimbursement received for any portion of the project cost.

9. No later than May 1, 2026, and every six months thereafter, until the entirety of the plant is being used for the supply of electricity to customers, the Company shall provide a report to the Authority of the status of the duct infrastructure under a floodwall near the New Congress substation installed as part of the New Congress Getaway South Project, including when the Company anticipates that some or all of the duct infrastructure will be used for the supply of electricity to customers, as discussed in Section IV.B.4.b.vi, New Congress Getaway South. The Company shall also report any reimbursement received for any portion of the project cost.

10. No later than June 1, 2026, as part of the Company's annual Arrearage Forgiveness Plan filing in Docket No. 26-05-01, the Company shall file a detailed implementation proposal that incorporates (1) modifications to the online customer account portal to allow income verification document uploading; and (2) modifications to the customer communications procedures where customers have been pre-qualified for financial hardship yet have not submitted the required income verification documentation. The proposal shall include detailed implementation costs and timeline estimates for each item.

11. No later than January 15, 2026, and every six months thereafter, until the Company's next rate amendment application is filed, the Company shall file as compliance in this proceeding UI's total distribution headcount and the number of employees transferred from UI to any service company or from any service company to UI since the Company's last compliance filing. The Company shall also file a compilation of these compliance filings in its next rate amendment proceeding at the time of filing its rate application with the Authority.

12. In the event the Company does not file an application to amend its existing rate schedules by November 1, 2028, the Company shall, as part of its 2029 RAM RDM filing, include an accounting of any overcollection as a result of the expiration of the three-year amortization period, and a proposed RDM rate to reflect such overcollections.

13. In its next rate amendment application, the Company shall submit operating company-specific data regarding its contributions to or performance against, at minimum, the following components of the Avangrid ESG strategy as discussed in Section IX.B, Environmental, Social, and Governance Strategy: GHG emissions; EJ engagement metrics outcomes; employee and executive performance related to ESG goals; supplier diversity; and workforce diversity and inclusion.

14. In its next rate amendment application, UI shall report on annual diverse supplier spend, including showing UI's proportional share of overall Avangrid spend as context, new Connecticut-based diverse suppliers engaged, and contract outcomes by category, as discussed in Section IX.B, Environmental, Social, and Governance Strategy.

15. In its next rate amendment application, the Company shall propose opt-out TOU distribution rates in accordance with the direction in Section VIII.E, Rate Design.

The proposal shall include rates that are neutral with respect to revenue with non-time differentiated rates and incorporate the analysis described in the instant proceeding to determine on- and off-peak periods, with the following modifications: (1) combine the winter and shoulder seasons into a single non-summer period; (2) exclude weekend cost drivers in determining on- and off-peak hours; and (3) use forward-looking forecast data if available.

16. In its next rate amendment application, the Company shall specifically identify any proposed rate base inclusion of completed plant that is not yet used and useful, as discussed in Section , . For any proposed inclusion in rate base of any completed plant that is not used and useful, the application must contain sufficient information for the Authority to consider whether there exists a special circumstance justifying that inclusion. Such documentation shall include information about (1) the anticipated cost of completing the plant at a later date (i.e., the anticipated cost savings of the project), (2) the risk that the plant will never be put into service for ratepayers benefit (i.e., the likelihood that the plant will not be used), (3) the Company's plan for future use of the plant, including the forecasted date it will be used, and (4) any other available information relating to whether the plant was prudently constructed at the time.

17. In its next rate amendment application, the Company shall further refine the load-carrying capacity adjustment values in alignment with OCC's suggestions, inclusive of stakeholder engagement, as discussed in Section VIII.C, Cost-of-Service Study. Specifically, the Company is directed to (1) propose an alternative ACOSS with a load-carrying capacity adjustment developed in consultation with OCC and other stakeholders, (2) state whether UI recommends the alternative ACOSS, and (3) explain in narrative form why UI does or does not recommend the alternative ACOSS. UI should also explore the use of proxies that align more closely with geographic dispersion as a cost driver, rather than defaulting to MSS, as part of the stakeholder engagement.

18. The Company shall, unless directed otherwise in a subsequent Authority order, continue calculating the ESM with a 50/50 split between ratepayers and shareholders from the first dollar of over-earning above the allowed ROE calculated on a calendar year basis.

19. The Company shall, unless directed otherwise in a subsequent Authority order, continue to utilize revenues collected from late payment fees in its annual RAM filing as a surplus for RAM purposes that will serve to offset potential distribution revenue shortfalls.

DOCKET NO. 24-10-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO AMEND ITS RATE SCHEDULE

This decision is adopted by the following commissioners:



David Arconti, Jr.



Michael A. Caron

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the decision issued by the Public Utilities Regulatory Authority, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.



Jeffrey R. Gaudiosi, Esq.
Executive Secretary
Public Utilities Regulatory Authority

October 28, 2025
Date

APPENDIX A: POLE ATTACHMENT RATE CALCULATION

Line #	Item Description	Amount	Source
	Net Pole Investment to Recover:		
	Embedded Cost		
1	Net Pole Investment	$156,653,072	Interrog. Resp. NECTA-5, Att. 1, p. 4, ln. 8
2	Multiply by (1 - Appurtenance Factor)	$121,139,821	Line 1 x (1 – 22.67%)
3	Divided by Number of Poles	115,151	Interrog. Resp. NECTA-5, Att. 1, p. 4, ln. 13
4	**Per Pole Investment (A)**	$1,052	Line 2 / Line 3
	Carrying Charge Components:		
5	Administrative	1.50%	Interrog. Resp. NECTA-5, Att. 1, p. 4, ln. 16
6	Maintenance	9.02%	Adjusted Interrog. Resp. NECTA-5, Att. 1, p. 4, ln. 19 [1]
7	Depreciation	7.56%	Interrog. Resp. NECTA-5, Att. 1, p. 4, ln. 23
8	Taxes	6.98%	Interrog. Resp. NECTA-5, Att. 1, p. 4, ln. 28
9	Return	7.142%	Adjusted Interrog. Resp. NECTA-5, Att. 1, p. 4, ln. 29 [2]
10	**Total Carrying Charge (B)**	32.20%	Sum of Lines 5 through 9
11	**Annual Carrying Charge: (A) x (B) = (C)**	$338.77	Line 4 x Line 10
	Calculation of Usable Space: (D)		
12	Space Occupied [feet] (a)	1	CS Docket No. 97-151
13	Unusable Space [feet] (b)	24	CS Docket No. 97-151
14	Number of Attaching Entities (c)	5	CS Docket No. 97-151
15	Pole Height (d)	39.49	Interrog. Resp. NECTA-5, Att. 1, p. 7, ln. 6
16	Telecom Space Factor [(a) + 2/3 x (b) / (c)] / (d)	10.64%	(Line 12 + (2/3 x Line 13 / Line 14)) / Line 15 per CS Docket No. 97-151
17	47 U.S.C. § 224(e) "Cost" [3]	66.00%	
18	**Annual Rate Per Attachment: (C) x (D) x (E)**	$23.78	Line 11 x Line 16 x Line 17
19	**Unauthorized Attachment Penalty (5x Annual Attachment Rate)**	$118.90	5 x Line 18

[1] 2023 FERC Form 1, p. 322, ln 149, column (b) + adjustment from UI response to NECTA-008 - PURA adjustment to Mutual Aid Reimbursement / Net Investment in accounts 364, 365 and 369 ($36,204,582 / $401,540,665 = 9.02%).

[2] Weighted Average Cost of Capital Without ROE Reductions.

[3] WC Docket No. 07-245 and GN Docket No. 09-51 Report and Order and Order on Reconsideration FCC, April 7, 2011, paragraph 149.