STATE OF CONNECTICUT

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

DOCKET NO. 22-08-08 **APPLICATION OF THE UNITED ILLUMINATING COMPANY TO AMEND ITS RATE SCHEDULE**

August 25, 2023

By the following Commissioners:

Marissa P. Gillett
John W. Betkoski, III
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 $384.865 million for the rate year commencing on September 1, 2023. This represents an increase of $22.957 million to the Company's currently approved base distribution revenue requirement from which the Company had sought a $131 million increase over three years. While the Company requests a 10.20% return on equity, the Authority determines that an allowed return on equity of 9.10% is appropriate; however, the Authority reduces the allowed ROE by an aggregate 47 basis point reduction (i.e., to 8.63%), subject to certain conditions and timelines, to address performance and management issues.

In addition, the Authority makes determinations on a myriad of issues including cost allocation, rate design, revenue adjustment mechanisms, and customer service.

B. BACKGROUND OF THE PROCEEDING

UI is a public service company within the meaning of Conn. Gen. Stat. § 16-1. UI is a subsidiary of Avangrid Networks Inc. (Avangrid). Ex. UI-1, p. 1. 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. Id., p. 4.

UI previously increased its base distribution rates in 2016. Decision, Dec. 14, 2016, Docket No. 16-06-04, Application of the United Illuminating Company to Increase its Rates and Charges (2016 Rate Case Decision).

On August 10, 2022, UI submitted formal notice of its intent to file an application to amend its existing rate schedule.

C. CONDUCT OF THE PROCEEDING

On September 9, 2022, UI filed an application to amend its existing rate schedules (Application) pursuant to Conn. Gen. Stat. §§ 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 September 29, 2022, via teleconference.

The Authority conducted a noticed revenue audit on Monday, October 24, 2022, via remote access, and a noticed audit of the books and records of the Company on November 1, 2, and 3, 2022, at the offices of the Company, 180 Marsh Hill Road, Orange, Connecticut.

The Authority held two noticed in-person public comment hearings; the first on Wednesday October 19, 2022, at the Edward Smith Library in Northford, Connecticut, and the second on Tuesday, November 29, 2022, at the City of New Haven Clerk Hearing

Room. The Authority also held two noticed virtual public comment hearings on December 13, 2022, and on December 15, 2022.

The Authority held noticed evidentiary hearings on February 16, 17, 21, 22, 23, 24, and 27, and March 1, 2, 6, 7, 8, and 9, 2023, at PURA's offices, Ten Franklin Square, New Britain, Connecticut (PURA's Offices).

The Authority held late filed exhibit hearings on March 21 and 22, 2023, at PURA's offices.

The Authority issued a Proposed Final Decision in this matter on July 21, 2023. All Parties and Intervenors were given the opportunity to file Written Exceptions to the Proposed Final Decision and to present Oral Argument.[1] The Authority heard Oral Argument on August 11, 2023, at PURA's Offices.[2]

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, Ten Franklin Square, New Britain, CT 06051; the PURA Office of Education, Outreach, and Enforcement, Ten Franklin Square, New Britain, CT 06051; and the Commissioner of the Department of Energy and Environmental Protection, 79 Elm Street, Hartford, CT 06106.

The Authority designated the following as Intervenors to this proceeding: the Connecticut Office of the Attorney General; the Connecticut Industrial Energy Consumers; the City of Ansonia; the City of Bridgeport; the City of Derby; the Town of Easton; the Town of East Haven; the Town of Fairfield; the Town of Hamden; the City of Milford; the City of New Haven; the Town of North Branford; the Town of North Haven; the Town of Orange; the City of Shelton; the Town of Stratford; the Town of Trumbull; the City of West Haven; the Town of Woodbridge; Netspeed, LLC; Vote Solar; Walmart Inc.; ChargePoint Inc.; CPower; Crown Castle Fiber, LLC; New England Cable and Telecommunications Association, Inc.; Operation Fuel; Utility Workers Union of America AFL-CIO, Local 470-1; and the Center for Children's Advocacy.

E. POSITIONS OF PARTIES AND INTERVENORS

UI seeks approval of a three-year rate plan commencing September 1, 2023, and extending through August 31, 2026, resulting in a distribution revenue requirement

[1] The Authority also received timely filings (i.e., filings made by 12:00 p.m. on August 7, 2023) on the Proposed Final Decision from The American Association of Retired Persons Connecticut and the Greater New Haven Chamber of Commerce. Although those individuals captioned their comments as Written Exceptions to the Proposed Final Decision in the Authority's docketing system, they were not Parties or Intervenors in this proceeding, and therefore, were ineligible to file Written Exceptions. Such filings instead were entered into the record as correspondence.

[2] A majority of the Commissioners heard the matter and/or read the record of the proceeding; therefore, although the Authority provided the opportunity for written exceptions and oral argument, it was not required to do so. Conn. Gen. Stat. § 4-179(a).

increase of $118.427 million,[3] representing a 32.12% increase in distribution revenues. Late Filed Ex., Att. 1, Sch., A-1.0, p. 1. UI requests a 10.20% return on equity (ROE). UI-Revenue Requirements Panel (RRP)-Direct Testimony, Ex. UI-RRP-1, pp. 6-8.

The Authority's Office of Education, Outreach, and Enforcement (EOE) participated in this proceeding,[4] issuing nearly 300 interrogatories, providing expert testimony, conducting cross examination during the evidentiary hearings and late filed exhibit hearings, and filing a brief. EOE recommends that PURA deny UI's requested rate increase. EOE Brief, p. 1. EOE also dedicates a significant portion of its brief to arguing that there are myriad problems with UI's customer service performance, which it deems warrants a reduction to the Company's allowed ROE. Id., p. 18. Finally, EOE argues that the Authority should authorize a ROE of 8.68%, as EOE's witness recommends. Id.

The Office of Consumer Counsel (OCC) also actively participated in this proceeding, issuing nearly 650 interrogatories, providing expert testimony, conducting cross examination during both the evidentiary hearings and late filed exhibit hearings, and filing a brief. The OCC recommends that the Authority reject UI's Application because UI failed to meet its evidentiary burden, arguing that there was a lack of documentation and factual support from the Company in its Application. OCC Brief, p. 6. Instead, the OCC recommends that the Authority adopt a one-year rate plan with a rate increase of no more than $49.2 million.[5] Id., p. 9. Finally, the OCC proposes that the Company's allowed ROE be no greater than 9.00%. Id., p. 12.

The Department of Energy and Environmental Protection (DEEP) actively participated in this proceeding as well, conducting cross examination in the evidentiary hearings and late filed exhibit hearings, and filing a brief. DEEP did not take a position on all issues presented in UI's Application, including the Company's proposed revenue requirement and capital structure. DEEP Brief, p. 2. DEEP did, however, make recommendations on a variety of other topics, including UI's Clean Energy Transformation Proposals, Performance Based Regulation, and the Company's remediation efforts at its English Station and East Shore facilities. Id., p. 1.

The Office of the Attorney General (OAG) also actively participated in this proceeding, issuing interrogatories, conducting cross examination during both the evidentiary hearings and the late filed exhibit hearings, and filing a brief. The OAG recommends that the Authority reject UI's three-year rate plan and instead approve a one-year rate plan making appropriate adjustments to UI's current distribution rates because the Company failed to meet its evidentiary burden that its proposed distribution rate increase is necessary to provide safe, adequate, and reliable electric service to its customers. Id., pp. 1-2.

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[3] UI proposes $91.055 million in additional revenues in the initial rate year, $20.120 million in rate year 2, and $19.466 million in rate year 3. The initial rate year includes a Revenue Decoupling Mechanism (RDM) target of $12.214 million. The RDM target amount is removed from the proposed revenue requirement increase of $130.641 million.

[4] Pursuant to Conn. Gen. Stat. § 16-19j(b), the Authority appointed EOE as a party to this proceeding.

[5] The OCC appended a schedule to its brief detailing a list of recommended adjustments to the Company's proposed revenue requirement.

The Connecticut Industrial Energy Consumers (CIEC) issued interrogatories, conducted cross examination during both the evidentiary hearings and the late filed exhibit hearings, and filed a brief. CIEC recommends that the Authority adopt UI's proposed rate design for Rate LPT and GSC classes, approve an economic development rate (EDR), and that PURA rely on the Company's allocated cost of service study (ACOSS) for purposes of revenue allocation and rate design. CIEC Brief, p. 1.

The Center for Children's Advocacy (CCA) participated in the proceeding by filing a brief arguing that UI has not provided adequate customer service and that current rates do not serve low-income UI customers. CCA Brief, p. 1. CCA's brief further provides various examples of what it argues highlights UI's poor customer service. Id., pp. 1-4.

ChargePoint, Inc. (ChargePoint) participated in the proceeding by offering expert testimony and by filing a brief recommending that the Authority approve the Company's proposed electric vehicle (EV) initiatives as proposed in its Application. ChargePoint Brief, p. 1.

Walmart, Inc. (Walmart) provided expert testimony and filed a brief. Walmart generally advocated that the Authority carefully consider how the Company's requested revenue requirement and ROE will impact UI's customers. Walmart Brief, p. 1. Walmart further argued that UI's proposed ROE is excessive and should be rejected. Id., p. 2. Finally, Walmart opines that the Authority should address above-cost rates for distribution paid by GS, GST, LPT, and U classes if PURA determines a revenue requirement below UI's request and that, if the Authority approves a lower revenue requirement for either Class GS or GST, it should first set the demand and customer charges for those classes at the levels the Company requested in its Application and then apply the reductions in revenue requirement to kWh-based rates on those schedules. Id., pp. 6-7.

The New England Connectivity and Telecommunications Association (NECTA) filed nearly 40 interrogatories, provided expert testimony, conducted cross examination during both the evidentiary hearings and the late filed exhibit hearings, and filed a brief. NECTA argues that UI's proposed pole attachment rental rates exceed the maximum just and reasonable rate under the Federal Communication Commission's (FCC) formula. NECTA Brief, p. 5.

Crown Castle Fiber LLC (Crown Castle) also actively participated in this proceeding, issuing 14 interrogatories, conducting cross examination during the evidentiary hearings, and filing a brief. Crown Castle states that the Authority should reject the Company's proposed pole attachment rates and instead order UI to revise its pole attachment tariff to reflect a unified rate structure because, among other reasons, the proposed rates do not comply with previous PURA decisions and because the Company did not meet its burden of proof. Crown Castle Brief, pp. 2-3, 27.

Netspeed, LLC (Netspeed) issued 10 interrogatories in this proceeding, conducted cross examination at the evidentiary hearing, and filed a brief. Netspeed's brief largely mirrors the arguments raised in Crown Castle's brief. Netspeed Brief, pp. 2-3, 27.

F. PUBLIC COMMENT

The Authority held four public comment hearings, two in person and two virtually. Fourteen people[6] attended the October 19, 2022, public comment hearing at Edward Smith Library; thirty people attended the November 29, 2022 hearing at the City of New Haven's Clerk's Office; approximately 32 people attended the December 13, 2022 remote public comment hearing; and approximately 18 people attended the December 15, 2022 remote public comment hearing. UI presented a PowerPoint explaining its request at the start of each session, prior to the admission of any public comment.

Through the close of the evidentiary record, the Authority received oral and written comments from 23 entities, comprised of 11 people who spoke and provided comments during the public comment hearings and 12 written comments submitted during the course of the public comment period.[7] Of those individuals or entities who submitted written comments, one was an elected official, four were organizations, and the remainder were individual customers. The American Association of Retired Persons Connecticut (AARP CT) filed comments on behalf of their 600,000 Connecticut members, many who live within UI's service territory, opposing the Company's Application.

Opposition to UI's application for a rate increase was unanimous. The most common theme of those objecting to the request was that the Company's proposed increase was excessive and/or unjustified. Comments of this nature were collected during the public comment hearings, as well as in written correspondence. Hr'g Tr., Nov. 29, 2022, 12:13-15, 14:14-25, 16:22-18:25, 20:14-24:16; State Representative Wood Corresp., Aug. 5, 2022; Lynch Corresp., Aug. 30, 2022; AARP Corresp., Oct. 14, 2022; Jensen Corresp., Dec. 7, 2022; Campbell Corresp., Dec. 13, 2022; and Corresp., Dec. 13, 2022.

One person expressed their specific disapproval of the Company's current fee for credit card payments – a subject that UI proposed to address within its Application. Lynch Corresp., Aug. 30, 2022. In addition, several individuals expressed interest in a proposed performance-based ratemaking model, as well as support for renewable energy incentives such as shared solar. Hr'g Tr., Nov. 29, 2022, 15:17-17:19.

Other reasons customers or organizations cited to in their opposition to the Application included: ensuring the lowest possible rates are maintained; UI's failure to remediate English Station in New Haven, CT; excessive Company salaries; a desire for UI to document vegetation management to increase resilience and reliability concerns; a desire for PURA to continue working on structuring clean and affordable energy rather than approving UI's request; and concerns with the proposed ROE and performance-based ratemaking models. Hr'g Tr., Nov. 29, 2022, 16:22-17:19, 19:9-20:11, 12:20-22, 23:10-12; Jones Corresp., Dec. 6, 2022; Hamden Alliance for Trees Corresp., Dec. 12, 2022; Yale Center Corresp., Dec. 14, 2022; Acadia Center Corresp., Dec 14, 2022.

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[6] The number of hearing attendees indicated herein may include state agency staff and UI staff members, as well as members of the public.

[7] The Authority issued a request for public comments encouraging public participation in the proceeding through attendance at a public comment hearing or by providing comments in writing. Notice of Request for Public Comments, Sep. 14, 2022. The Authority set a deadline of Thursday, March 23, 2023, i.e., the close of the evidentiary record, for such comments to be considered. Id.

II. STANDARD OF REVIEW

UI is a public service company within the meaning of Conn. Gen. Stat. § 16-1. The Authority is statutorily charged with regulating the rates of Connecticut's public service companies. Conn. Gen. Stat. § 16-19. 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." Conn. Gen. Stat. § 16-19(a).[8] Once a proposed amendment has been filed, the Authority "shall 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 such company is inadequate to or in excess of public necessity and convenience, . . ." Id.[9]

The statutory prerogative to establish just, reasonable, and sufficient utility rates is based upon principles established in two landmark United States Supreme Court cases, as recognized by the Connecticut Supreme Court. See Connecticut Light & Power Co. v. Dep't of Pub. Util. Control, 216 Conn. 627, 635 (1990). Specifically, 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. Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944) (Hope); Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 690 (1923) (Bluefield); see also Duquesne Light Co. v. Barasch, 488 U.S. 299, 310 (1989). "The prudence of a management decision depends on good faith and reasonableness, judged at the time the decision is made." Connecticut Light & Power Co., 216 Conn. at 645.

Ultimately, however, rate setting requires "a balancing of the investor and the consumer interests." Woodbury Water Co. v. Pub. Utilities Comm'n, 174 Conn. 258, 264 (1978) (citing Hope, 320 U.S. at 603). Further, the Authority "is not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function . . . involves the making of 'pragmatic adjustments.'" Id. (citations omitted).

In striking this balance and making pragmatic adjustments, the Authority is guided by Conn. Gen. Stat. § 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 . . . ;

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

[9] Conn. Gen. Stat. § 16-19(a) also permits the Authority to "(A) evaluate the reasonableness and adequacy of the performance or service of the public service company using any applicable metrics or standards adopted by the authority pursuant to section 1 of Sept. Sp. Sess., Public Act 20-5, and (B) determine the reasonableness of the allowed rate of return of the public service company based on such performance evaluation."

(5) that the level and structure of rates charged customers shall reflect prudent and efficient management of the franchise operation.

Importantly, the utility "has the burden of proving the proposed rate under consideration is just and reasonable." Conn. Gen. Stat. § 16-22. This burden requirement implemented by the General Assembly in rate cases is significant because it attempts to remedy a critical challenge in setting rates — asymmetric access to information. The utility retains the majority 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. The clarified burden under Conn. Gen. Stat. § 16-22 addresses this information imbalance by imposing an affirmative obligation on the utility to present sufficient evidence to support the proposed rate amendment.

In administrative proceedings, the appropriate standard of proof is the preponderance of the evidence. Jones v. Connecticut Med. Examining Bd., 309 Conn. 727, 734-735 (2013); Connecticut Light & Power Co. v. Connecticut Dept. of Pub. Util. Control, Docket No. CV094019951S, 2010 WL 797137, at *10 (Conn. Super. Ct. Feb. 5, 2010); Goldstar Med. Services, Inc. v. Dep't of Soc. Services, 288 Conn. 790, 821 (2008). Consequently, to carry its statutory burden, the utility must provide (or ensure the record contains) a preponderance of evidence that the requested rates are "sufficient, but no more than sufficient" and "reflect prudent and efficient management." See Tianti v. William Raveis Real Estate, Inc., 231 Conn. 690, 702, (1995) (finding that the preponderance of evidence standard is met when a fact is "more probable than not.").

Notably, this burden requires the utility to provide more than mere declarations of fact. Connecticut Nat. Gas Corp. v. Pub. Utilities Comm'n, 29 Conn. Supp. 379, 394 (1971) ("[t]here is 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 PUC."). More to the point, "[b]ald statements need to be covered with some evidential hair . . . ." Id. Further, "[a]n administrative agency is not required to believe any witness, even an expert." Goldstar, 288 Conn. at 830 (citations omitted). It is the Authority's province to "make determinations of credibility, crediting some, all, or none of a given witness' testimony." Id.

III. TEST YEAR AND MULTI-YEAR RATE PLAN

A. TEST YEAR

The test year is "the most recent twelve-month period available ending at a calendar quarter." Conn. Agencies Regs. § 16-1-54. Test year financial statements are "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. § 16-1-53a.

Here, UI has proposed the 12 months ending December 31, 2021, as the test year. Ex. UI-1, p. 9. Based on its review of the financial data provided, the Authority accepts

the period beginning on January 1, 2021, and ending on December 31, 2021, as the test year (Test Year).

B. MULTI-YEAR RATE PLAN

The Authority approves an amended rate schedule effective September 1, 2023, but declines to approve the three-year rate plan requested by the Company.[10] Specifically, in addition to the requested $102.1 million rate increase effective September 1, 2023, the Company requested two additional increases of $17.2 million each, effective September 1, 2024, and September 1, 2025. Ex. UI-1, p. 9. In its updated filing, UI revised its original proposal and requested additional distribution revenue of $91.055 million for the rate year beginning September 1, 2023; $111.175 million for the rate year beginning September 1, 2024; and $130.641 million for the rate year beginning September 1, 2025. Late Filed Ex. 1, Att. 1, Sch. A-1.0. The revised incremental revenue request includes current Revenue Decoupling Mechanism target revenue of approximately $12.214 million. Id.

The Company asserts that its proposed three-year rate plan was designed to provide adequate support to its utility operations, while providing a predictable path for its customers over the rate plan period. Ex. UI-1, p. 19. Notwithstanding the Company's assertions, granting UI's request in the present case is inappropriate due to pervasive errors in the Company's Cost of Service Study (COSS), among other reasons.

Generally, a utility performs a COSS to determine the cost of providing service to customers as a whole and by individual rate class. See Ex. UI-BR-3. A thorough and reasonably accurate COSS serves as a valuable measure of customer demand and total costs by customer that, in turn, is used in establishing revenue requirements and equitably allocating costs amongst customer classes. See 2016 Rate Case Decision, p. 92.

At the evidentiary hearing, the Company testified that the COSS relied on in this proceeding does not account for a low-income discount rate, electric vehicle tariffs, or other clean energy initiatives. Hr'g Tr., Feb. 16, 2023, 194: 6-25, 195: 1-23. Moreover, the Company conceded that its COSS is not representative of the future and is likely to be outdated shortly. Hr'g Tr., 194: 24-25, 195: 1-7. As a result, the COSS does not provide an accurate depiction of the Company's actual cost of service or a methodology to equitably allocate such costs to different rate classes in the future rate years covered in UI's proposed three-year rate plan. In other words, while UI is proposing a three-year rate plan that extends until 2026, it did not in this proceeding offer a forward-looking COSS that reflects how costs should be equitably allocated to its customers during the applicable time period. Tellingly, the Company did not use the COSS submitted with its rate application as the basis for either its rate class revenue allocation or its rate design proposals, indicating the Company's own concern with the COSS results. Hr'g Tr., 162: 20-25, 163: 1-20, 164: 11-25, 165: 1-8. As such, the Company did not demonstrate how its three-year rate plan is just and reasonable.

[10] The Company proposed three rate years: September 1, 2023, through August 31, 2024 (Rate Year 2023/2024); September 1, 2024, through August 31, 2025 (Rate Year 2024/2025); and September 1, 2025, through August 31, 2026 (Rate Year 2025/2026). Ex. UI-1, p. 9.

Moreover, the Authority recently released its final Decision in Docket No. 21-05-15, PURA Investigation Into A Performance-Based Regulation Framework for the Electric Distribution Companies, which adopted a comprehensive framework of four regulatory goals, five foundational considerations, and nine priority public outcomes to guide future electric utility regulation in Connecticut, including informing the development and implementation of specific regulatory reforms through the second phase of the Authority's investigation (Phase 2) into performance-based regulation (PBR) for the state's electric distribution companies (EDCs).[11] Decision, April 26, 2023, Docket No. 21-05-15 (PBR Decision). Together, the PBR Decision and decisions issued in Phase 2 will satisfy the Authority's obligations to implement PBR under Section 1 of Public Act 20-5, An Act Concerning Emergency Response by Electric Distribution Companies, the Regulations of other Public Utilities and Nexus Provisions for Certain Disaster-Related or Emergency-Related Work Performed in the State (Take Back Our Grid Act).[12]

Notably, the Authority identified multi-year rate plans in the PBR Decision as a topic for reevaluation so as to ensure the effectiveness of multi-year rate plans in achieving several outcomes identified in the PBR Decision including, but not limited to: Business and Investment Efficiency; and Affordable Service. PBR Decision, pp. 20, 22. Multi-year rate plans will be specifically reexamined in a reopener docket, Docket No 21-05-15RE01, PURA Investigation into the Establishment of Integrated Distribution System Planning within a Performance-Based Regulation Framework, which is scheduled to be completed by May 2024. Id., p. 33. The endpoint of Docket No. 21-05-15RE01 will be the explicit adoption of rules and guidance to govern multi-year rate plans submitted in future rate cases.

In the present case, the Company's proposed multi-year rate plan would expire on August 31, 2026, over two years after the Authority completes its examination of multi-year rate plans in Docket No. 21-05-15RE01. As such, even *if* the COSS proffered in this proceeding was sufficient to support a finding that the Company's proposed three-year rate plan was just and reasonable, it would be premature to approve the Company's multi-year rate plan while consideration of how to effectively structure such a tool in furtherance of a statutory directive is actively under consideration by the Authority.[13] Furthermore, the General Assembly, in requiring PURA to establish a proceeding by June 2021, clearly evinced its intention to have a PBR framework implemented post haste.

In conclusion, the Authority declines to approve the Company's proposed three-year rate plan and instead approves an amended rate schedule effective September 1, 2023. Although the Authority is not obligated to consider a multi-year rate plan, nor is there an explicit legal standard for reviewing such plans, the Authority nonetheless reviewed the Company's multi-year rate for adherence with Conn. Gen. Stat. §§ 16-19 and 16-19e. Ultimately, the Authority finds that the Company failed to demonstrate how

[11] Phase 1 of the Authority's investigation was conducted in Docket No. 21-05-15.

[12] Section 1 of the Take Back Our Grid Act, codified at Conn. Gen. Stat. § 16-244a, required the Authority to undertake a proceeding no later than June 1, 2021, to "investigate, develop and adopt a framework for implementing PBR." Conn. Gen. Stat. §§16-244aa(b).

[13] The Company acknowledged that the multi-year rate plan it submitted is based off its understanding of how multi-year rate plans may have previously been designed and that it would be open to changes based on new guidance. Hr'g Tr., 1316: 13-25, 1317:1-125, 1318: 1-17.

its three-year rate plan is just and reasonable, particularly in light of the COSS issues and the required timely implementation of a PBR framework, as discussed above.

Importantly, the denial of a multi-year rate plan is not a determination on or a disallowance of any future capital investments. Indeed, the Company is still obligated to 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 the furtherance of the regulatory goals and priority public outcomes identified in the April 26, 2023 Decision in 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 capital additions already incurred or incurred in the future, which are not incorporated into rate base or reflected in rates in this Decision.[14] As such, the Company continues to have the opportunity to earn a reasonable return on all prudent and useful investments.[15]

IV. RATE BASE

A. SUMMARY

Rate base is a fundamental principle of cost-of-service ratemaking. Rate base is the investor-supplied facilities and other investments necessary to provide a utility service to consumers in a safe, reliable, and cost-effective manner. For purposes of ratemaking, rate base is the capital on which the investor is able to earn a return. Bluefield, 262 U.S. at 690 ("This is so well settled by numerous decisions of this court that citation of the cases is scarcely necessary: What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.") (citations and internal quotation marks omitted); Hope, 320 U.S. at 605. ("We hold . . . that the basis of all calculation as to the reasonableness of rates to be charged by a [public utility] must be the fair value of the property being used by it for the convenience of the public.").

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. Consequently, determining rate base requires a two-prong assessment. First, the Authority must find that the Company's plant is in use and is serving the public. See Cedar Island Imp. Ass'n v. Clinton Elec. Light & Power Co., 142 Conn. 359, 370 (1955)("A 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."); Southern New England Telephone Co. v. Public Utilities Commission, 29 Conn. Super. 253, 259- 260 (1970) (citation omitted) ("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. It must be kept in mind, however, that whether utility property is used or useful for inclusion in the rate base is a factual

[14] As discussed in Sections IV.B., Plant-in-Service, the Authority was unable to make a prudence determination regarding certain plant additions submitted in this proceeding based on evidence provided by the Company. As such, the Company has the opportunity to seek recovery in a future rate case of investments not included in rate base in this Decision. Conversely, the Authority could have reached a finding of imprudence and disallowed such costs, which would have barred future cost recovery attempts.

[15] Indeed, this approach to providing an opportunity for a return on investment is, overwhelmingly, the most common approach used by regulators over the more than 100-year history of public utility regulation.

determination rather than a legal question."); Decision, May 19, 2021, Docket No. 20-10-31, Application of the Jewett City Water Company to Amend Rate Schedules, pp. 23-24 ("The Authority does not allow for the inclusion of incomplete system additions or improvements into a Company's proforma rate base . . . . The Authority finds that the ratepayers benefit from the plant additions when they are in-service and that the ratepayers should not be responsible for providing a return on plant that is not in-service."). In short, the "used and useful standard" is a "bedrock principle of utility regulation." Kentucky Utils. Co. v. FERC, 760 F.2d 1321, 1324 n.4 (D.C. Cir. 1985).

Second, the Authority must find that the capital investment was prudent and reasonable. See Conn. Gen. Stat. § 16-19e(a)(5) ("the level and structure of rates charged customers shall reflect prudent and efficient management of the franchise operation"). 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. Dep't of Pub. Util. Control, 219 Conn. 51, 67-68 (1991).

Consequently, to establish its rate base for ratemaking purposes, UI must demonstrate, by a preponderance of evidence, that the capital proposed for inclusion in rate base (1) is used and useful and (2) was invested prudently. From an accounting perspective, rate base is calculated by taking the test year net book value of prudent capital investments, which includes accumulated depreciation, and accounting for other factors, including working capital and non-rate base capital such as deferred taxes. Certain pro forma adjustments may be permitted so as to recognize capital investments and other changes to rate base that occurred subsequent to the test year. Connecticut Nat. Gas Corp., 29 Conn. Supp. at 390 (utilities are generally "permitted to adjust the test year forward for a reasonable period of time where definitely ascertainable expenses are involved during such future period. . . .").

In this case, approximately 20 months will have transpired between the end of the 2021 Test Year and the effective date of Rate Year 2023/2024. Pro forma adjustments to rate base are necessary to ensure rates are reasonably reflective of the Company's actual rate base. Importantly, the standard of review for pro forma rate base additions is the same as that for any rate base addition — the capital investment must be prudent and used and useful.

The Company proposed a Test Year rate base of $1.209 billion and an average pro forma rate base of $1.384 billion for Rate Year 2023/2024. Late Filed Ex. 1, Att. 1, Sch. B-1.0 A. As shown in the table below, and described further in the following sections, the Authority modifies certain components of the proposed rate base, reducing the average pro forma rate base by $278.412 million to approximately $1.105 billion.

Table 1: Pro Forma 2023/2024 Average Rate Base ($000)

	Rate Base Components	Company Pro Forma	Adjustment	Approved Pro Forma Rate Base
1	Plant-in-Service	2,496,233	(222,402)	2,273,831
2	Accumulated Depreciation	(824,588)	24,013	(800,575)
3	Working Capital	22,406	(17,229)	5,177
4	Regulatory Asset – SFAS 158	96,939		96,939
5	Pension Cost Recovery	13,344	(13,344)	0
6	COVID Deferral	6,979	(6,979)	0
7	CAM GET Deferral	(2,362)	2,362	0
8	Loss on Sale of Bridgeport Ave	12,985	(12,985)	0
9	UPZ Deferral	5,936	(5,936)	0
10	Deferred Taxes Assets	41,798		41,798
11	Other Additions	2,336	(382)	1,954
12	Storm Reserve / Deferral	23,126	(23,126)	0
13	Allowance for Bad Debt	(12,000)		(12,000)
14	Reserve for Injuries and Damages	(1,512)		(1,512)
15	Advances for Construction	(553)		(553)
16	Pension Liabilities	(141,689)		(141,689)
17	Accrued Vacation	(2,593)	(37)	(2,630)
18	Customer Security Deposits	(1,415)		(1,415)
19	Deferred Tax Liabilities	(351,761)	(2,367)	(354,128)
	Total Average Rate Base	**1,383,608**	**(278,412)**	**1,105,196**

Late Filed Ex. 1, Att. 1, Sch. B-1.0 A.

B. PLANT-IN-SERVICE

1. General

The Authority reduces the Company's requested plant-in-service of $2.496 billion by removing $222.402 million of plant additions and retirements purportedly made (or forecast to be made) through Rate Year 2023/2024. The adjustment is necessary because the Company did not demonstrate that these projects were used and useful. In addition, there was insufficient evidence to conduct a prudency review. The adjustment results in an approved plant-in-service of $2.274 billion. The Authority makes a corresponding reduction in accumulated depreciation for the reduction in plant-in-service.

Table 2: Approved Plant-in-Service ($000)

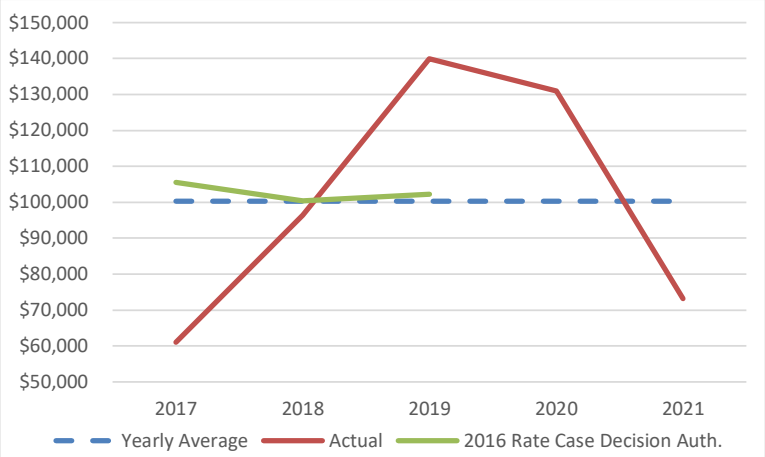
Test Year Plant-in-Service	2,207,041
UI Proposed Interim and Rate Year 2023/2024 Pro Forma Plant-in-Service	289,192
PURA Adjustment to Interim and Rate Year 2023/2024 Pro Forma Plant-in-Service	(222,402)
PURA-Authorized Plant-in-Service	**2,273,831**

2. Test Year Plant-In-Service

To determine the Test Year plant-in-service, the amount of completed capital investments made by the Company through the end of the Test Year is added 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 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 actual supporting evidence for each of these two prongs. Notably, "[t]here is 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 PUC." Connecticut Nat. Gas Corp., 29 Conn. Supp. at 394 ("Bald statements need to be covered with some evidential hair.").

Here, the Company identified $2.207 billion of plant-in-service at the end of the Test Year. Late Filed Ex. 1, Sch. B-2.0. This is the result of UI adding approximately $501 million of plant since the Company's 2016 Rate Case, averaging about $100 million of plant additions per year. Interrog. Resp. RSR-3, Att. 2; Interrog. Resp. RRU-346, Att. 1. In the 2016 Rate Case Decision, UI was authorized to recover $308 million in rates over the three rate years (2017-2019) for plant additions based on the Company's capital program. Interrog. Resp. RSR-2, Att. 1. Figure 1 below shows: (1) the amount authorized in the rate case for recovery; (2) the amount actually placed in service by UI; and (3) the yearly average of $100 million.

Figure 1: Plant Additions Since 2016 Rate Case Decision ($000)



Interrog. Resp. RSR-2, Att. 1; Interrog. Resp. RRU-346, Att. 1.

The Company's level of investment fluctuated on an annual basis but was generally consistent in the aggregate with the Company's projection in the 2016 Rate Case. The Authority finds that the $501 million of plant additions were in service (used and useful) because the Company provided an itemized list of project-level plant additions for each calendar year from 2016 through 2021. Interrog. Resp. RSR-3, Att. 2; Interrog. Resp. RRU-346, Att. 1.[16] However, the Company provided minimal information to substantiate its burden that the plant placed in service following the 2016 Rate Case Decision was prudently and reasonably incurred, leaving some doubt as to whether the Company met its burden on the second prong of the rate base analysis. See RRP PFT.

Specifically, the Company offered limited supporting documentation that would aid in a prudency analysis, such as documents that demonstrate the project needs, potential project alternatives, initial or detailed project engineering estimates, project scope changes (cost or timing), and internal approvals related to the above materials. Although the Company contends that it has such information within its control and uses it (at least monthly) as part of its own capital investment planning and execution process, it did not submit such information in this proceeding. Interrog. Resp. OCC-193; Interrog. Resp. RSR-26, Att. 1, pp. 6-10; Hr'g Tr., Feb. 22, 2023, 734:16-20. Rather, the Company submitted only rudimentary planning documents that described its own internal capital planning process instead of providing a comprehensive breakdown of plant additions that would enable the Authority to scrutinize each project (or, at least, a representative sample) and make an appropriate prudency determination. See Interrog. Resp. OCC-0193; Interrog. Resp. RSR-0026; Interrog. Resp. RSR-0026, Att. 1.

Further, when the OCC asked the Company to provide details on historical project-level plant additions, the Company again affirmed that it keeps detailed records of plant additions and purported to provide such material. Interrog. Resp. OCC-195. Notwithstanding the Company's assertions, the only documentation provided by the

[16] Notably, the itemized list was not included in the Company's Application, but rather was provided in response to an interrogatory.

Company in its Application included historical annual capital plan summaries used for governance reporting to account for annual capital plan changes for years 2017-2022. Id., Atts. 1-6. Indeed, contrary to UI's assertion, the documents from years 2017 through 2021 did not include plant additions, only yearly capital investments. Id., Atts. 1-5.

In sum, the Company is asking the Authority to obligate ratepayers for $500 million of plant additions with limited "evidential hair," resting largely on "bald statements" of Company executives. This presents the Authority with a Cornellian dilemma — a strict application of the burden of proof results in an unprecedented and dire reduction in the Company's rate base, whereas a lax application sends an erroneous economic signal to the Company (and the regulated community at-large) as to a utility's obligation to make prudent investments, potentially harming ratepayers for years to come.

For pragmatic purposes, given that no other Party took a specific position on the prudency of Test Year plant, the Authority will not make any adjustments and will allow a Test Year plant-in-service balance of $2.207 billion. However, the Authority cannot emphasize enough that this determination in no way is to be interpreted as an affirmation of the Company's approach to demonstrating the prudency of its capital investments on a going forward basis.

3. Interim Period Pro Forma Plant-in-Service

The Company is requesting a pro forma adjustment to rate base of $289.193 million for plant additions and retirements purportedly made (or forecast to be made) from January 1, 2022 (i.e., after the Test Year), through August 31, 2023 (Interim Period), and continuing through the Company's requested Rate Year 2023/2024 (i.e., September 1, 2023, through August 31, 2024). Late Filed Ex. 1, Sch. B-1.0A.[17] Of this $289.193 million in total pro forma plant additions, $222.423 million represents the requested plant additions ostensibly made during the Interim Period (i.e., January 1, 2022, through August 31, 2023). Id. The remaining $66.770 million is the proposed rate base increase to account for plant additions forecasted for Rate Year 2023/2024.

With respect to the Interim Period pro forma adjustment, the Authority must determine whether the Company has offered a preponderance of evidence to support a finding that the additional $222.423 million of plant-in-service is used and useful and that the investments are reasonable and prudent. Whether the Company has met this burden of proof has been a matter of substantial dispute among the Parties (particularly the Company and the OCC). The Company argues that it provided sufficient evidence in support of its capital additions and that such evidence is comprised of "detailed documentation" that demonstrates UI's capital additions are "reasonable and necessary to provide safe and reliable service to customers." UI Brief, p. 82. The Company also claims that the evidence it has provided is "at a level not seen in decades in a Connecticut rate case." UI Reply Brief, p. 2.

The OCC holds a starkly different view of what the Company has provided. The OCC notes that, "OCC's attempts to review the Company's request were hampered by the Company's failure to provide necessary information." OCC April 27, 2023 Brief, p.

[17] The $289.193 million is calculated by subtracting the Test Year pro forma ending balance ($2,207 million) from the thirteen-month average balance for Rate Year 2023/2024 ($2,496 million). Id.

51. The OCC further notes that "through [the Company's] failure to provide adequate documentation to support its Plant-In-Service calculations, it has not met its burden [of proof]." Id., p. 51.

Given the disparity of the Parties' views on this topic, the Authority thoroughly vetted the record (including written and oral testimonies of the experts, interrogatory responses, and briefs) to assess the Parties' positions and to determine the level of Interim Period plant adjustments supported by the record. The Authority finds that the Company did not meet its burden to demonstrate by a preponderance of evidence that the entirety of its proposed plant-in-service adjustments for the Interim Period are used and useful and are prudent and reasonable.

Although the Company generally complied with the standard filing requirements (SFRs) for a rate case and responded to hundreds of interrogatories related to plant additions, the volume of this proffered evidence does not compensate for the lack of substance.[18] Ultimately, the Company may have demonstrated that it spent $222 million on capital projects in the Interim Period, but that is not the applicable standard. Rather, the Company must demonstrate not only that money was spent but that it resulted in plant serving the public and that it was spent prudently.[19]

Notwithstanding this burden, the Company failed to provide relevant documentation and provided incomplete or conflicting data. For example, the OCC asked the Company to, "[p]rovide any document the Company relies on and/or utilizes that defines what is known and measurable and is required in the form of supporting documentation for a capital addition to be included in the projected plant additions during the interim period . . . and in each of the three respective rate years being requested." Interrog. Resp. OCC-193 (emphasis added). The OCC asserted that the Company provided *no* supporting documents in response to this request. Schultz, Defever PFT, p. 9. Indeed, the Company's response merely provided a one-paragraph, general response about the Company's capital planning process. At the evidentiary hearing, OCC Witness Schultz and UI Witness Eves had the following exchange, which confirmed the OCC's assertion that the Company provided no supporting documentation in its interrogatory response:

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[18] Similar to the pleading requirements that must be followed to initiate a civil action, the SFRs are merely the basic documents that must accompany a rate application to commence a rate case. See Conn. Agencies Regs. § 16-1-53a; Hr'g. Tr. Aug. 11, 2023, 83:25-84:7. Simply filing the SFRs does not satisfy the Company's burden of proof, just as a civil litigant who has plead sufficient facts to overcome a motion to strike has not prevailed in their action; the bare facts must be supplemented and proven with record evidence. Hr'g Tr., 84: 3-16.

[19] Referring to the SFRs and unspecified "past orders," the Company asserts that the Authority is changing "these standards." UI Written Exception, pp. 38-39. First, the SFRs do not constitute legal standards of review. As previously stated, they represent the minimum filing requirements to commence a rate case. Second, the Company notably does not identify the "past orders" that purportedly constitute a standard from which the Authority allegedly departs. Here, the Authority is applying the same well-established legal standard for rate base additions — a preponderance of evidence that the plant is in-service and the investment prudent. That a prior commission applying this same standard may have approved or disallowed plant additions in a different rate case with different evidence in no way supports the Company's claim that the decision is "an arbitrary and capricious departure from the Authority's established precedent and rate case standards." Id., p. 34.

MR. SCHULTZ: If you could, I would like you to look at the response to OCC-193, please.
MR. EVES: Okay. I am there.
MR. SCHULTZ: If you could read the question and answer before you answer this. Are you aware of whether any supporting documents were provided as an attachment to this response?
MR. EVES: The question is, am I aware of any supporting documents that were provided as an attachment to this response?
MR. SCHULTZ: Yes.
MR. EVES: I don't see an attachment to the response, so I don't believe there were.

Hr'g Tr., Feb. 23, 2023, 969:15-24

The documentation the OCC was seeking in OCC-193 is neither extensive nor administratively burdensome. Rather, the basic information the OCC requested is essential for the Authority to assess whether the Company's proposed pro forma additions are in-use and were prudent. OCC's interrogatories provided the Company with an opportunity to remedy a deficiency its application; however, the Company failed to take advantage of this opportunity. As such, the Authority shares the OCC's concerns regarding the Company's inability to produce even minimal documentation responsive to this request.

Additional discovery responses also demonstrate UI's inability to provide basic information to sustain its burden. In OCC-157, the Company was asked to provide a listing, by project, of additions made during the Interim Period. The request also asked that, "[f]or each project state whether it is complete and used and useful. For those not yet completed, provide the percentage completion and estimated completion date." Id. Although the Company provided a listing of projects, the project-level information was, in several cases, incomplete or illogical.

For example, although the Interim Period ends August 31, 2023, the Company's listing of projects included dozens of projects that had an expected completion date *after* the end of the Interim Period. Interrog. Resp. OCC-157, Att. 1. In its rebuttal testimony, the Company stated that "while full project or program completion may occur at a later date, only the additions forecasted to be used and useful prior to the end of the Interim Period were provided in the response to OCC-0157 as requested." Eves Rebuttal, p. 3. In addition to the discrepancy related to the expected completion dates and the end of the Interim Period, there were also several projects in which the Company provided neither a status nor an expected completion date. Rather, these projects were only listed as "ongoing." Interrog. Resp. OCC-157, Att. 1. Again, the Company referenced this apparent inconsistency in its rebuttal testimony, stating that plant additions related to the "ongoing programs are made when work is completed and closed to plant during the course of the year." Eves Rebuttal, p. 3.

However, the Company's explanation for not providing expected completion dates and project completion percentages for several projects is unconvincing and, ultimately, does not obviate the Company's obligation to provide information demonstrating that the capital expenditures are associated with plant placed into service that is used and useful. Further, the Company has an additional obligation to demonstrate prudency. Here again,

the lack of sufficient evidence regarding the prudency of the Interim Period plant additions largely precludes the Authority from finding that the Company met its burden.

Although the Company generally failed to meet its burden, there is sufficient evidence in the record for the Authority to find that a portion of the Interim Period plant additions included in the Application are complete and in use. In OCC-157, the OCC requested that the Company provide "a list . . . of all projects included in the Interim Period Additions Column [of the Application]" and to "state whether [the project] is complete and used and useful." In response, the Company provided a list of projects in an Excel spreadsheet (OCC-157, Att. 1). See Resp. OCC-157, Att. 1. One of the columns in OCC-157, Att. 1, is titled, "Complete?", which indicates whether each project is "complete and used and useful" as requested. The Company included 156 projects in OCC-157, Att. 1, of which 58 are identified as "No," or not complete and used and useful, 72 are identified as "Program – ongoing", and 26 are identified as "Yes", or complete and used and useful. As noted above, the status of the projects listed as "Program – ongoing" is unclear; thus, the Authority requested Late Filed Exhibit 17 to identify the portion of these projects placed in-service for public convenience.[20]

In Late Filed Exhibit 17, the Company identified expenditures for 66 projects totaling $79,458,060. Notably, the Company also included in this list 9 projects previously identified as not complete and used and useful. Interrog. Resp. OCC-157, Att. 1.[21] Absent evidence to the contrary and omitting the $8,846,028 associated with these 9 incomplete projects, the Authority finds that $70,612,032 of the Interim Period plant additions can reasonably be assumed to be used and useful based on OCC-157, Att. 1 and Late Filed Exhibit 17.

As to the remaining $151.811 million of pro forma Interim Period plant additions, the Authority finds that the Company did not demonstrate by a preponderance of evidence that the plant has been placed in service for public use (i.e., is used and useful) and, therefore, will exclude the amount from rate base. As such, the Authority need not reach the question of whether the excluded plant investments were prudent. This determination is based on the evidence presented in this proceeding and does not preclude the Company from ultimately incorporating these plant additions into its rate base in a future proceeding by providing sufficient evidence.

To determine the impact on rate base, the $70.612 million of allowed capital investment must be reduced by $3.822 million for retirements, depreciation, and other factors. The Company did not provide a quantification of the interim activity in plant retirements and other adjustments that occurred during the Interim Period; therefore, the Authority will assume for the purposes of calculating its adjustment that the activity incurred in these accounts was relatively consistent (with regard to timing) to that of plant additions. The $70.612 million of allowed plant additions represents 31.75% of the

[20] That obtaining this basic information (i.e., Interim Period expenditures) required an interrogatory and a late filed exhibit illustrates the degree to which the Company misunderstood its burden to provide a preponderance of evidence on the usefulness and prudency of capital additions.

[21] The Project IDs for the nine projects that were identified in OCC-157, Att. 1 as not used and useful but which were included in Late Filed Exhibit 17 are: 801128.01; 802268.01; PRJ-001111; PRJ-001112; PRJ-001160; PRJ-002541; PRJ-003403; 800842.01; PRJ-003280.

Company's requested $222.423 million of Interim Period plant additions. Late Filed Ex. 1, Att. 1, Tab WP B-2.1. The Authority netted the $70.612 million figure against plant retirements and other adjustments impacting gross plant (i.e., transmission allocation adjustment). Specifically, the Authority multiplied the interim activity of all components of the utility plant-in-service by 31.75% to derive the amount of activity incurred during the Interim Period. As illustrated in the table below, the Authority will allow a net increase to rate base of $66.790 million for Interim Period plant additions.

Table 3: Interim Period Plant-in-Service Activity ($000)

	Company Proposed	Percentage Allowed	Authority Allowed
Interim Period			
Plant Additions	222,423	31.75%	70,612
Plant Retirements	(16,213)		(5,147)
Transmission Adjustment	4,174		1,325
		Subtotal	**66,790**

Late Filed Ex. 1, Att. 1, Sch. B-1.0; Late Filed Ex. 17, Att. 1.

4. Rate Year 2023/2024 Pro Forma Plant-in-Service

The Company also included $66.577 million in its proposed rate base to account for plant additions and other rate base adjustments forecasted for Rate Year 2023/2024. The inclusion of forecasted plant additions in rate base constitutes an exception to the well-established principle that utilities may only earn a return on prudently invested capital that is being used for the public convenience. Bluefield, 262 U.S. at 690; Hope, 320 U.S. at 605. Specifically, it is an impossibility to provide sufficient evidence that a future plant addition is used and useful and that the investment was prudent. See UI Written Exceptions, p. 38 ("By definition, a projected plant addition cannot be known and measurable, for it occurs in the future."). Notably, including the cost of future investments in rate base creates the real risk that ratepayers are paying for plant that will neither be useful nor prudent. However, despite these challenges, utility commissions have recognized that allowing rate year plant additions, in some cases, may be beneficial. Reaching a determination on such a complex issue requires a requisite level of data and analysis.

Regardless, none of the Parties articulated a specific framework for implementing an exception to the constitutional standard for rate base and allowing a return on capital yet to be spent.[22] However, the Authority need not reach that issue here since the Company provided limited (and often unreliable) evidence, apart from merely identifying expected expenditures and providing high-level explanations, to justify the inclusion of these future investments in rate base. As discussed in detail in Section IV.K., Five-Year Capital Plan, the Authority examined the sufficiency of the evidence offered by the

[22] The Company refers to "the Authority's long-standing ratemaking framework that has, until now, allowed funding of pro forma capital expenditures in the Rate Years," UI Written Exceptions, p. 34; however, the Company elected not to identify said framework. OCC indicated that there was "a higher bar for the company to meet because they're asking the Authority to agree right now with the company's expectation of what will be in place at some future point." Hr'g Tr. Aug. 11, 2023, 80:1-10. OCC concluded "that's, in our view, what's missing from this case." Id., 82:20-22.

Company to substantiate future capital expenditures and found it lacking. Consequently, regardless of the applicable framework, the dearth of evidence offered by the Company prevents it from satisfying its burden.[23] As such, the Authority declines to include future capital investments in rate base.

In summary, the Company sought a total increase in rate base of $289.192 million for plant additions for the Interim Period and Rate Year 2023/2024. As discussed above, the Authority will allow a rate base increase of $66.790 million for projects found to be used and useful in the Interim Period and declines to adjust rate base for future capital expenditures. Consequently, PURA disallows $222.402 million of the Company's request as shown in the table below.

Table 4: Adjustment to Plant-in-Service ($000)

PURA-Authorized Plant-in-Service Adjustments	66,790
UI Proposed Increase to Plant-in-Service	289,192
Adjustment	**(222,402)**

C. ACCUMULATED DEPRECIATION

1. General

In its Application, the Company showed an accumulated depreciation of $824.588 million for Rate Year 2023/2024. Late Filed Ex. 1, Att. 1, Sch. B-1.0A. The Authority approves an average depreciation reserve of approximately $800.817 million and, accordingly, reduces the accumulated depreciation for the rate year by $24.013 million.

Table 5: Total Depreciation Reserve Disallowances ($000)

50% of Depreciation Expense Adjustment	5,020
Depreciation Reserve Plant Disallowances	18,993
Adjustment	**24,013**

The 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 Final Decision, July 28, 2021, Docket No. 20-12-30, Application of the Connecticut Water Company to Amend its Rate Schedule (CWC Decision), p. 70. As such, the reserve reflects the asset

[23] OCC recommended allowing plant additions based on a "five-year average of historical plant changes." OCC Brief, pp. 53-54. The use of historical data might be a valid mechanism for estimating future plant additions; however, the Company did not provide sufficient evidence to support this approach. Indeed, as OCC states, the Company appears to concede that their historical approach to Plant-in-Service projections "is entirely divorced from reality." Id., p. 52. Given the lack of certainty as to the accuracy of the Company's projections, the Authority declines this recommendation. The appropriate approach to capital forecasts, future test years, and multi-year rate plans for future rate cases will be further investigated by the Authority through Docket No. 21-05-15RE01 and, potentially, Docket No. 21-05-15RE03, PURA Investigation into The Establishment of Integrated Distribution System Planning Within A Performance-Based Regulation Framework; however, the Authority adopted applicable guidance already in its Decision in Docket No. 17-12-03RE08, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Resilience and Reliability Standards and Programs, which was not observed in the Application or supplemented during the discovery process.

deterioration of in-service plant and is 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 Commissioners (NARUC) guidelines and have been allowed or approved by the Authority. Id. Ideally, the amount accumulated is consistent (i.e., proportional) to the deterioration of the asset to date and the time frame until retirement or replacement. Id.

A depreciation rate study proposes annual depreciation rates to be applied to plant-in-service balances. The product of the rate and plant balance is the annual depreciation expense, which is a charge to a company's operating expense 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.

2. Impact of Depreciation Expense Adjustments

Section VI.B., Depreciation Expense, details the Authority analysis of the appropriate depreciation expense, which authorizes a reduction of $10.040 million to UI's proposed depreciation expense. As depreciation expense and accumulated depreciation are interrelated, 50% of the depreciation expense is applied to accumulated depreciation to reflect the half-year convention. Thus, the Authority reduces the authorized accumulated depreciation by $5.020 million to account for the modifications to depreciation expense.

3. Omitted Plant Additions

In Section IV.B, Plant-in-Service, the Authority allowed $70.612 million (or 31.75%) of the Company's requested $222.423 million of Interim Period plant additions. The Authority also declined to allow $66.577 million in its proposed rate base to account for plant additions and other rate base adjustments forecasted for Rate Year 2023/2024. Since disallowed plant will not be in rate base, the associated depreciation can be removed from the Company's proposed $824.588 million average depreciation reserve for Rate Year 2023/2024.

The Company included $6.092 million and $14.835 million of depreciation reserve for post-2021 plant additions, including reductions due to retirements, for the Interim Period and Rate Year 2023/2024, respectively. Late Filed Ex. No. 1, Sched. B-3.1 WP. The Authority estimated the amount of depreciation reserve associated with the disallowed plant by multiplying the $6.092 million depreciation reserve by the percent of disallowed plant (68.25%), resulting in a depreciation reserve adjustment of $4.158 million. Because no plant additions were permitted for Rate Year 2023/2024, the Authority will remove the $14.835 million of depreciation reserve for this period. This

ultimately results in a decrease to the Company's proposed Rate Year 2023/2024 average depreciation reserve of $18.993 million.[24]

Table 6: Depreciation Reserve Plant Disallowances ($000)

Interim Period	4,158
Rate Year 2023/2024	14,835
Adjustment	**18,993**

Late Filed Ex. 1, Att. 1, Sched. B-3.1 WP, line 52.

D. WORKING CAPITAL

1. General

Working capital is included in rate base and is comprised of two components: an allowance for Cash Working Capital (CWC) and an allowance for Materials and Supplies (M&S). The Test Year balance for working capital calculated by the Company was $24.499 million. Late Filed Ex. 1, Att. 1, Sch. B-4.0. The Company increased this amount to $24.571 million to reflect an Interim Period and 2023/2024 Rate Year adjustment to M&S of $0.072 million. Late Filed Ex. 1, Att. 1, Sch. B-4.0. UI also proposed to make an Interim Period and Rate Year 2023/2024 adjustment of $4.329 million to its CWC allowance. Late Filed Ex. 1, Att. 1, Sch. B-4.0. These adjustments ultimately resulted in a total ending working capital balance for Rate Year 2023/2024 of $20.242 million and an average working capital of $22.406 [($24.571+$20.2420)/2] million for Rate Year 2023/2024. Late Filed Ex. 1, Att. 1, Sch. B-1.0 A and B-4.0.

Table 7: Proposed Average Working Capital Balance ($000)

Descriptions	**Amounts**
Cash Working Capital	17,598
Materials and Supplies	4,808
Total Working Capital	**22,406**

Late Filed Ex. 1, Att. 1, Sch. B-4.0 A, Sch. B-1.0.

2. Cash Working Capital

a. Revisions to Application

CWC is "the amount of funds required to be kept on hand to finance the day-to-day operations of the Company." Adams PFT, p. 3. Specifically, CWC is a measure of the timing difference between the payment of expenses incurred by the Company and the receipt of payments from customers. The Company performed a lead/lag study as part of its Application, which 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. Adams PFT, p. 3. These "lag" days are

[24] The Company objects to the Authority's "disparate treatment of interrelated components of rate base." UI Written Exceptions, pp. 39-40. The Company did not explain how the Authority's adjustment to accumulated depreciation as a result of plant disallowance was "disparate," nor did UI identify an alternate methodology for adjusting accumulated depreciation. The objection is also curious because the reduction of depreciation reserve results in an increase to rate base and the Company's revenue.

offset by "lead" days, which represent the time between when a Company receives goods and services and when it pays for them. Id.

During the course of this proceeding, the Company modified the CWC allowance embedded in its proposed revenue requirement. In its Application, the Company calculated a beginning CWC balance of $19.763 million and an ending CWC balance of $14.442 million (which would result in an average CWC of $17.102 million) for Rate Year 2023/2024. Application, Sch. B-4.0A.

Subsequently, the Company increased its ending Rate Year 2023/2024 CWC balance by $991,000 to $15.433 million (which increased the average CWC balance to $17.598 million). Late Filed Ex. 1, Att. 1, Sch. B-4.0. The Company claims that the modifications in working capital are a result of a "flow-through effect" from "various revenue requirement adjustments." Late Filed Ex. 1. As support for its revised figure, the Company cites Exhibits UI-MJA-1, UI-MJA-2, and UI-MJA-3. Late Filed Ex. 1, Att. 1, Sch. B-4.0. However, the cited exhibits were not updated to reflect these "flow-through" changes.[25] Consequently, the Authority will disallow the $991,000 increase in the year-end balance.

b. Non-Cash Items

As part of its CWC calculation, the Company included a "lag" for depreciation expense and other non-cash items. Hr'g Tr. Feb. 17, 2023, 457:20-21. When OCC requested the Company define CWC, the Company stated:

> When a good or service is provided to the Company, the Company is expected to make payment to the service provider within a certain period of time. Such payment would typically be required to be made in advance of receipt of UI's customers' payment for monthly utility-provided services. Cash working capital represents the amount of funds the Company is required to have on hand in order to make timely payments for the goods or services it will be provided by vendors, service providers etc.

Interrog. Resp. OCC-198. The OCC argued that such a definition of CWC does not justify inclusion of depreciation and other non-cash items. Schultz, Defever PFT, pp. 14-15. The OCC states that since "depreciation does not require an outlay of cash, there is no timing gap and no need for additional funds. Depreciation does not fit the definition or purpose of cash working capital." Schultz, Defever PFT, p. 16. The OCC ultimately recommended that the impact of depreciation and amortization be removed from the Company's calculation of CWC, resulting in a reduction to CWC of $13.028 million for Rate Year 2023/2024. Schultz, Defever PFT, p. 16. In rebuttal, the Company primarily relies on the argument that the Authority previously allowed for the inclusion of non-cash items in CWC in a prior proceeding and should continue to do so here. UI-MJA-Rebuttal-1, p. 2-11; Interrog. Resp. OCC-202.

[25] Although the Company objects to this disallowance and asserts that "the Company provided al of the information need to validate the CWC amount," it does not dispute that the relevant exhibits were not corrected. UI Written Exceptions, p. 40.

The Authority finds the OCC's testimony credible and persuasive and, therefore, rejects the inclusion of non-cash items in the CWC calculation. Notably, the Company's own definition of CWC does not allow for non-cash items in CWC. Further, a substantial number of other jurisdictions exclude depreciation and non-cash items from cash working capital. Late Filed Ex. 13. To the extent the Authority has permitted non-cash items to be incorporated into CWC in prior decisions, the practice deviates from the purpose of CWC, which is to compensate a utility for capital held in the form of cash to timely pay for goods and services, and, as such, the Authority will depart from those precedents. The exclusion of all non-cash items (i.e., depreciation, amortization, deferred taxes, and pension accruals) reduces the beginning CWC balance by $15.697 million and reduces the ending CWC balance by $13.876 million to reflect disallowance of these items. Ex. UI-MJA-3.[26]

c. Expense Adjustments

Finally, the Authority will adjust the CWC to account for the disallowance of certain operating expenses (including, but not limited to Operations and Maintenance Expenses), which results in a lower working capital requirement. As noted, the Company did not update its CWC exhibits to reflect changes made throughout the proceeding and incorporated into Late Filed Ex. 1. Accordingly, the Authority has utilized information available in the record to adjust the original lead/lag study to coincide, to the extent feasible, with changes made to the Company's Application and reductions made by the Authority. A summary of the CWC impact of the Authority's expense adjustments (excluding non-cash items) are noted in the table below (dollar amounts shown in thousands):

Table 8: Impact of Expense Adjustments to CWC

Expense Category	PURA Expense Adjustment	CWC Adjustment Factor	CWC Adjustment
Compensation	($2,613)	0.123	($322)
Employee Benefits	($3,194)	0.159	($508)
Income Tax	($9,967)	0.076	($758)
Other O&M	($4,534)	0.038	($173)
Other Taxes	($5,930)	(0.016)	$92
Property Tax	($1,048)	0.279	($292)
Uncollectible Accounts	($1,097)	(0.297)	$326
		Total	**($1,636)**

Ex. UI-MJA-3.

d. Summary of CWC Adjustments

A summary of PURA's adjustments to the beginning, ending, and average CWC balance is provided in the table below (amounts shown in millions):

[26] OCC proposed adjustment is understated as it removes only depreciation and amortization from the Company's working capital calculation, even though OCC witnesses advocated for removal of all non-cash items. See Schultz, Defever PFT, p. 14. Indeed, OCC stated that it is "technically" correct for all non-cash items, not just depreciation, to be removed from the CWC calculation. Hr'g Tr., Feb. 24, 2023, 1337-22:23.

Table 9: Adjustments to CWC

CWC Balance	UI Proposed	Adjusted	Allowed
Beginning	$19.763		
Non-cash items		($15.697)	$4.066
End	$15.433		
Application Revisions		($0.991)	
Non-cash items		($13.876)	
Operating Expense Adj.		($1.636)	
Subtotal		($16.503)	($1.070)
Average	**$17.598**	**($16.100)**	**$1.498**

Late Filed Ex. 1, Att. 1, Sch. B-4.0 A, Sch. B-1.0; Ex. UI-MJA-3.

3. Materials and Supplies

UI proposed to include $4.808 million for M&S in the working capital balance for Rate Year 2023/2024 based on the application of an 82.28% wage allocation factor to the $5.844 million 13-month average for 2021 M&S. Late Filed Ex. 1, Att. 1, Sch. B-4.0A; Interrog. Resp. RRU-350, Att. 1.

The Authority will reduce the Company's proposed working capital balance for M&S by $1.129 million because the allocation factor is inconsistent with what UI reported on the Company's 2021 FERC Form 1 report (Form 1 report). The Authority finds that UI's use of the 82.28% wage allocator to assign M&S to distribution is not consistent with the allocation reported in the Company's Form 1 report. Specifically, the total 2021 M&S reported by the Company in its 2021 Form 1 report was $5.757 million. Sch. H-1.01, pp. 60-61. Based on the correlation between the investment in transmission and distribution segments as of December 31, 2021, $3.624 million or 62.95% ($3.624 / $5.757 million) of M&S was allocated to the distribution sector. Id.

Therefore, the Authority finds that the Company's allocation of $4.808 million M&S to UI distribution, based on a wage allocator, is inappropriate. Instead, the Authority will utilize the 2021 Form 1 M&S allocation factor of 62.95%. Accordingly, the Authority determines that the appropriate M&S for Rate Year 2023/2024 is $3.679 million ($5.844 * 62.95%). As a result, the Authority disallows the Company's proposed average rate base for M&S included in the CWC by $1.129 ($4.808 - $3.679) million.

4. Working Capital Summary

The Authority disallows working capital included in the Company's proposed average rate base by $17.229 million, as outlined in the above subsections and summarized in the table below.

Table 10: Allowed Average Working Capital Balance ($000)

	UI Proposed	Adjustments	Allowed
Cash Working Capital	17,598	(16,100)	1,498
Materials and Supplies	4,808	(1,129)	3,679
Total Working Capital	**22,406**	**(17,229)**	**4,117**

E. REGULATORY ASSETS

1. General

The regulatory treatment of deferred expenses and regulatory assets has created some degree of confusion in this proceeding. This confusion arises, in part, because deferred expenses and regulatory assets are governed by both the Generally Accepted Accounting Principles (GAAP) established by the Financial Accounting Standards Board (FASB) for accounting purposes and the statutory framework under Conn. Gen. Stat. §§ 16-19, 16-19e, et al., established by the General Assembly for ratemaking purposes. To provide regulatory transparency and predictability, the Authority will endeavor to clarify the treatment of deferred expenses and regulatory assets as they relate to ratemaking.

As an initial point though, the deferral and subsequent recovery of expenses is an exceptional departure from established rate-making principles and, therefore, should be used only for extraordinary expenses. Generally, ratemaking is an exercise in determining a utility's prudent and reasonable costs, including capital costs, for a future rate year and providing a utility the opportunity to recovery those costs on a prospective basis. Deferred expenses (i.e., carrying forward previously incurred expenses) run against this grain as manifested by the prohibitions against so-called "retroactive ratemaking" or "single-issue ratemaking." As such, there is an inherent conflict between the accounting treatment and the ratemaking treatment for regulatory assets.[27]

In the absence of a statute or regulation addressing regulatory assets, the Authority starts with legal precedent. The Connecticut Supreme Court has drawn a distinction between the creation and the recovery of a regulatory asset. See OCC v. DPUC, 279 Conn. 584, 601 (2006). Specifically, the Court found that "the creation of a regulatory asset—or, in the department's parlance, a deferred expense—is governed by [FASB] Statement No. 71, while the recovery of a regulatory asset in a rate proceeding is a matter within the department's broad discretion as limited by the considerations set forth in § 16–19e (a)(4)." Id. (emphasis added). Notably, FASB Statement No. 71 was generally codified as Accounting Standards Codification (ASC) 980-340-25-1 (Recognition of Regulatory Assets); therefore, the Authority will interpret the Court's decision to mean that the creation of a regulatory asset for accounting purposes is governed by applicable accounting standards (currently, ASC 980-340-25-1).[28]

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[27] See Decision, Aug. 14, 2013, Docket No. 13-01-19, Application of The United Illuminating Company to Increase Rates and Charges (2013 Rate Case Decision), p. 25. ("The creation of a regulatory asset is extraordinary ratemaking treatment, as rate recovery for these expense variances. . . would be retroactive ratemaking and improper regulatory practice. An exception to this retroactive ratemaking rule is for major expenses that are non-recurring and cannot be predicted but that could affect the financial health of a company. Even then, recovery is not guaranteed; rather, the company is allowed to claim it at the time of the next rate case rather than absorb it as is done with all other expenses between rate cases.").

[28] ASC 980-340-25-1 states in relevant part: "Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:

a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes.

b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the

Under this accounting standard, a regulatory asset exists when "[i]t is probable" that the previously "incurred cost" will be recoverable through rates. Id. Notably, the "[r]ate actions of a regulator can provide reasonable assurance of the existence of an asset." Id.[29] This language is consistent with the Court's determination that "a regulatory asset has been created when the department, at the time of the original deferral, gave reasonable assurances that recovery of the expense would be allowed at some future date." OCC v. DPUC, 279 Conn. at 601-602. Therefore, a regulatory asset can arise for accounting purposes when the Authority issues an accounting order permitting a utility to defer certain expenses (i.e., deferred accounting) or when the utility has some other indication that recovery is probable.[30] Importantly though, the regulatory asset is recognized by the utility based on its judgment in applying GAAP accounting standards, which consider, among other things, the actions of the regulator. As such, the Authority itself does not create a regulatory asset for accounting purposes. Id., p. 601 (noting that an accounting regulatory asset is "in the department's parlance, a deferred expense.").

Consequently, a regulatory asset permitted under GAAP is distinct from (albeit related to) a regulatory asset established by the Authority in a Conn. Gen. Stat. § 16-19 rate proceeding. The former is an accounting treatment effectuated by the utility to transfer an unanticipated expense from its income statement to its balance sheet; whereas the latter is the establishment by the Authority of "a future debt of the ratepayers that can be passed on, together with interest, to the ratepayers." Id., at 594 (quoting OCC v. DPUC, 252 Conn. 115, 126-27 (2000)). The utility is entitled under GAAP to recognize a regulatory asset once the Authority has authorized deferred accounting of certain costs incurred, thereby indicating that "[i]t is probable" the utility will recover the costs in a future ratemaking proceeding. Id., pp. 598, 600; ASC 980-340-25-1(a). However, a regulatory asset for ratemaking purposes arises only after the Authority has scrutinized the deferred expenses for consistency with Conn. Gen. Stat. § 16-19e(a) and authorized recovery via an order in a rate proceeding. Thus, for ratemaking purposes, an expense for which the Authority has previously authorized deferred accounting (i.e., an accounting regulatory asset) may become a ratemaking regulatory asset through a Conn. Gen. Stat. § 16-19 rate proceeding. Id., at 601 ("recovery of a regulatory asset in a rate proceeding is a matter within the department's broad discretion as limited by the considerations set forth in § 16–19e(a)(4)."). For linguistic clarity going forward, the Authority will refer to accounting regulatory assets recognized under FASB guidance for deferred expenses as

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revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost."

[29] For all intents and purposes, a utility would be ill-advised to recognize a regulatory asset unless it has obtained an approval from the Authority to defer a specific expense; however, the decision to recognize a regulatory asset under GAAP is exclusively the utility's. Only the recovery of the regulatory asset is within the Authority's purview.

[30] See, e.g., Decision, June 3, 2009, Docket No. 08-07-04, Application of The United Illuminating Company To Increase Its Rates and Charges - Reconsideration, p. 69 (stating that "With regards to future storm-related expenses, the Company is allowed to create a regulatory asset upon payment of such storm-related expense, to be recovered in rates as determined by the Department in a subsequent proceeding.").

"deferred accounting" and will refer to ratemaking regulatory assets (for which recovery has been granted via a rate proceeding) as "regulatory assets."[31]

Within this framework, carrying charges are not permissible on deferred expenses without explicit prior Authority approval. First, under ASC 980-340-25-1, an accounting regulatory asset is limited to "an incurred costs that would otherwise be charged to expense." Importantly, FASB distinguishes between "incurred cost" and "allowable costs. See ASC 980-10-20. Incurred cost is "a cost arising from cash paid out or obligation to pay for an acquired asset or service, a loss from any cause that has been sustained and must be paid for." Id. By contrast, an allowable cost is "all costs for which revenue is intended to provide recovery" and can "include interest costs and amounts provided for earnings on shareholders' investments." Id. Carrying charges are not assets, services, or losses that must be "paid for"; therefore, they are not "incurred costs that would otherwise be charged to expense." As such, an accounting regulatory asset recognized by the Company under GAAP is limited to the specific expenses that were paid for by the utility and authorized for deferred accounting. Any other costs, including carrying charges, are allowable costs subject to the Authority's determination of recovery in a rate proceeding.

Second, allowing carrying charges to accrue on deferred expenses that have not been subject to scrutiny and prudence review is inconsistent with general ratemaking principles. The regulatory asset is already an extraordinary form of relief for utilities as it permits recovery of certain expenses beyond the base distribution revenue requirement authorized at the time the expense was incurred. Stated another way, regulatory assets allow recovery of expenses that otherwise would be borne entirely by the utility. Therefore, expanding the deferred accounting beyond the actual "incurred costs" prior to a full prudency review and determination of recovery is applying extraordinary relief upon extraordinary relief. Moreover, enabling the collection of carrying charges on deferred expenses prior to a prudency review may incent a delay, perhaps indefinitely, in the presentation of costs to the Authority for review. See Decision, April 17, 2019, Docket No. 18-11-12, Petition of the Connecticut Light & Power Co. d/b/a Eversource Energy for Approval to Recover Its 2017-2018 Catastrophic Storm Costs, p. 22 ("Until the Authority assesses the prudency of storm costs to be recoverable and determines the allowed storm regulatory asset amount, the Company bears the financing costs associated with the storm costs. Hence, in the interim between when storm costs are incurred and when the Authority makes its determination on the allowed regulatory asset amount, ratepayers are not paying for the financing costs . . . ."); Decision, Dec. 17, 2014, Docket No. 14-05-06, Application of The Connecticut Light and Power Company to Amend Rate Schedules ("The Authority does not approve CL&P's proposal to assign carrying charges to either an over- or under-recovery or to any deferral.").

By contrast, the Authority finds that carrying charges are permissible on ratemaking regulatory assets during the recovery period. When a deferred expense is deemed prudent, it becomes a ratemaking regulatory asset that is amortized over a reasonable period of time. At the time the Authority establishes a recoverable regulatory

[31] This section refers primarily to deferred expenses and regulatory assets; however, the same analysis applies to deferred revenues and regulatory liabilities which result in a debt or liability of the utility to the ratepayer.

asset, the Authority may include a return calculation, or carrying charges, to compensate the Company for the time it will take to fully recover the regulatory asset from ratepayers (i.e., the amortization period). See OCC v. DPUC, 279 Conn. at 594-95. The Authority has historically applied the approved pre-tax weighted average cost of capital (WACC) to calculate carrying charges on ratemaking regulatory assets over the recovery period. However, rates, such as the utility's debt component of its WACC or the utility's incremental borrowing rate (e.g., prime rate), may also be used to calculate carrying charges associated with all or part of a ratemaking regulatory asset.[32] See, e.g., Decision, June 29, 2011, Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules. Ultimately, the appropriate rate is determined by the Authority as part of the recovery determination process in a rate proceeding.

By incorporating a regulatory asset into rate base during a rate proceeding, the utility recovers interest on the unamortized regulatory asset at the pre-tax WACC rate. In the context of a multi-year rate plan, the amount of the regulatory asset incorporated into rate base is reduced each year by the amortization expense associated with the regulatory asset. This reduction in rate base results in a reduction in the carrying charges incurred related to the regulatory asset. Absent a multi-year rate plan though, the inclusion of a regulatory asset in rate base would overstate the regulatory asset return, or carry charges, beyond the rate year because the reduction in the regulatory asset due to amortization expense would not be accounted for. Since the Authority is not adopting a multi-year rate plan in this Decision, see Section III.B., Multi-Year Rate Plan, the Authority will exclude all regulatory assets and liabilities from rate base and, instead, will amortize the regulatory assets and liabilities, along with carrying charges, to provide revenue sufficient for the recovery of the asset or liability.[33]

The below sections, Sections IV.E.2., Pension Cost Recovery, through IV.E.7, Storm Reserve / Tropical Storm Isaias Deferral, review all deferred expenses and liabilities for prudence and identify the amount the Authority approves for recovery. Subsequently, Section VI.C., Amortization of Regulatory Assets, outlines the cost recovery treatment and calculations for the approved regulatory assets and liabilities, along with a review of additional amortized expenses.

2. Pension Deferral

The Company submitted for recovery a regulatory asset of $14.826 million for previously capitalized non-service pension costs that were no longer allowed to be capitalized after the adoption of The Accounting Standards Update 2017-07, Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (ASU 2017-07) in 2018. The Authority finds that the Company's proposed Pension regulatory asset of $14.826 million is overstated by $3.599 million as a result of improperly accrued carrying charges. Therefore, the Authority decreases the deferred expense by $3.599 million. In addition, the Authority removes the $13.344 million regulatory asset and the related

[32] For clarity, the matter of carrying charges on deferred expenses and regulatory assets is separate and distinct from the applicability of carrying charges related to Rate Adjustment Mechanisms, other than the Revenue Decoupling Mechanism.

[33] The Authority utilizes the pre-tax WACC to calculate carrying charges for the approved ratemaking regulatory asset over the amortization period, thereby providing the financial equivalent to incorporating the regulatory asset in rate base.

deferred tax from the Company's proposed average rate base and instead amortizes the allowed $11.227 million outside of the rate base as discussed in Section VI.C.4., Pension Deferral.

In March 2017, the FASB amended ASC Topic 715, which provides certain accounting treatment for compensation and retirement benefits. Id. Specifically, ASU 2017-07 limited the components of pension and Other Post-Employment Benefits (OPEB) expenses that can be capitalized into plant in-service. Interrog. Resp. RRU-269, p. 2. Prior to ASU 2017-07, service costs and non-service costs were eligible for capitalization into assets, but the amendment limited the expense components of pension and OPEB that could be capitalized. Id. Thus, all non-service costs are recorded as Operation and Maintenance (O&M) expenses for financial accounting purposes. Id.

ASU 2017-07 is effective as of January 1, 2018, subsequent to UI's 2016 Rate Case which was finalized on December 14, 2016. Interrog. Resp. RRU-63, p. 1; Hr'g Tr., Mar. 1, 2023, 1691:22-1670:6. With the implementation of ASU 2017-07 in 2018, UI no longer capitalized pension and OPEB non-service costs for periods subsequent to 2017. Hr'g Tr., Mar. 1, 2023, 1707:15-23;1828:8-11. As a result, UI incurred an unforeseen increase in its expenses due to the new accounting treatment for non-service pension costs starting in 2018.

Subsequently, UI petitioned for and the Authority approved "the establishment of pension regulatory asset due to a change in pension accounting requirements." Motion No. 44 Ruling, May 17, 2018, Docket No. 16-06-04 (Motion No. 44 Ruling). Ex. UI-RRP-1, p. 39. The Company now seeks recovery of the $14.826 million in deferred non-service pension costs. Late Filed Ex. 1, Att. 1, Sch. B-6.2 A. The Company's deferred expenses include carrying charges of $3.599 million from January 1, 2018, to August 31, 2023. Interrog. Resp. RRU-63, Att. 2, p. 1. The Company proposed to amortize the recovery of the regulatory asset over a five-year period. Ex. UI-RRP-1, p. 39; Late Filed Ex. 1, Att. 1, Sch. B-1.0 A and B-6.2 A. Therefore, UI proposed an average rate base of $13.344 million for Rate Year 2023/2024 in this proceeding. Late Filed Ex. 1, Att. 1, Sch. B-1.0 A and B-6.2 A.

As discussed in Section IV.E.1., General, absent express permission from the Authority, carrying charges on deferred expenses are not permissible. In allowing deferred accounting of the non-service pension costs, the Authority provided no indication in the Motion No. 44 ruling, express or otherwise, that carrying charges would accrue during the deferral period. Cf. 2013 Rate Case Decision, p. 35 (expressly allowing carrying charges in Competitive Transition Assessment reconciliation); Decision, Jan. 23, 2019, Docket No. 18-01-15, p. 11 (expressly permitting UI to accrue carrying costs). Accordingly, the Authority denies carrying charges prior to September 1, 2023, as part of the Pension regulatory asset. This reduces the regulatory asset by $3,599,476.

In summary, the Authority determines that the Pension deferral as of the beginning of the proposed Rate Year 2023/2024 is $11.227 million ($14.826-$3.599). Moreover, the Authority removes the $13.344 million and the related deferred tax from the Company's proposed average rate base. However, the Authority amortizes the approved Pension regulatory asset of $11.227 million, applying the pre-tax WACC to calculate

carrying charges over the amortization period, outside of the rate base as discussed in Section VI.C.4., Pension Deferral.

3. COVID Deferral

a. Summary

The Authority finds that the Company's proposed COVID regulatory asset of $6.979 million is overstated by $0.827 million in carrying charges and $1.246 million in costs incurred from January 1, 2022, through June 30, 2022. Therefore, the Authority decreases the deferred expense by $2.074 million. In addition, the Authority removes the $6.979 million and the related deferred tax from the Company's proposed average rate base and instead amortizes the allowed $6.301 million outside of the rate base as discussed in Section VI.C.6., COVID Deferral.

b. Carrying Costs

The Company reported a COVID-19 deferral balance totaling $8.375 million, which it proposes to amortize in the amount of $2.792 million over three years. Sch. WPC-3.30, p. 1. The COVID-19 deferral balance includes $827,000 in carrying charges. Interrog. Resp. OCC-577, ODR-06, Att. 1. The Authority disallows the $827,000 in carrying charges from the $8.375 million balance because the Authority did not authorize the Company to recover carrying charges when directing UI to begin tracking its deferred costs and lost revenues as the result of PURA's Orders in 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. See Motion No. 2 Ruling, Mar. 18, 2020, Docket No. 20-03-15.

In the present case, the Authority only authorized the Company to track its costs related to the applicable orders in the April 29, 2020 Interim Decision in Docket No. 20-03-15 (20-03-15 Interim Decision) as a regulatory asset. As discussed in Section IV.E.1., General, absent express permission from the Authority, carrying charges on deferred expenses are not permissible.

In allowing deferred accounting of certain COVID-19 costs, the Authority provided no indication in Docket No. 20-03-15, express or otherwise, that carrying charges would accrue during the deferral period. Cf. 2013 Rate Case Decision, p. 35 (expressly allowing carrying charges in Competitive Transition Assessment reconciliation); Decision, Jan. 23, 2019, Docket No. 18-01-15, p. 11 (expressly permitting UI to accrue carrying costs). Accordingly, the Authority disallows the carrying charges of $0.827 million.

c. Deferred Expenses

The Authority directed the Company to maintain a detailed record for incurred costs and lost revenues as a direct result of: 1) implementing a shut-off moratorium for all residential customers; 2) implementing a shut-off moratorium for all non-residential customers; 3) eliminating financial security deposits or balance reduction payments to restore utility service; and 4) implementing the COVID-19 Payment Plan. Order No. 7, 20-03-15 Interim Decision, p. 6. The Authority further stated that the Company may establish a regulatory asset to recover the costs incurred as a direct result of implementing the above-referenced items. Id. Finally, the Authority clarified that working capital costs may be included in the Company's deferred expenses, calculated according to the Company's last rate case. Id., p. 4.

UI did not provide any record of deferred costs related to the four categories listed above, despite the explicit direction to do so in Order No. 7 and the additional opportunity provided through Late Filed Exhibit 112. Hr'g Tr., Feb. 27, 2023, 1398:18-1399:25. Instead, the Company applied the difference between its allowed non-hardship uncollectibles from the last rate case and actual non-hardship uncollectibles between March 2020 and June 2022, stating that "[g]enerally, the only cost incurred by the Company as a direct result of Order Nos. 1-3 in Docket No. 20-03-15 [the non-hardship shut-off moratoriums and eliminating security depositions or balance reduction payments to restore utility service] is an increase in uncollectible expense."[34] Late Filed Ex. 112, p. 2; Hr'g Tr., 1396:3-12.

While informative, the Company's methodology does not demonstrate that the incurred costs, or the lost revenues, are a direct result of the categories of costs identified in Order No. 7 of the 20-03-15 Interim Decision. Moreover, there is no evidence that the entire difference between non-hardship uncollectibles incurred from March 2020 to June 2022 and the level of non-hardship uncollectibles allowed in the prior rate case, which was based on an historical average prior to 2016, is attributable to the non-hardship shut-off moratoriums or the elimination of financial security deposits and balance reduction payments to restore utility service.[35] Indeed, the broader macroeconomic factors at play during the relevant period, including high inflation and the continued impact of the COVID-19 pandemic, likely contributed to the difference between actual non-hardship uncollectibles and the level of non-hardship uncollectibles allowed in rates. Lacking evidence that the $8.375 million requested for recovery is attributable to the four categories of costs allowable in the COVID regulatory asset, the Authority analyzes below whether the Company demonstrated that it is more likely than not that some or all of the $8.375 million is attributable to those cost categories.[36]

The Company was allowed to resume service terminations for non-residential customers on June 15, 2021, and for non-hardship residential customers on September 15, 2021, pursuant to the Authority's rulings on Motion Nos. 38 and 45 in Docket No. 20-

[34] The Company did not seek recovery of costs related to the fourth category of deferred expenses allowed in the COVID-19 regulatory asset pursuant to Order No. 7 of the 20-03-15 Interim Decision (i.e., the implementation of the COVID-19 Payment Plan). When raised, the Company indicated that there are no administrative costs associated with the COVID-19 Payment Plan as of March 7, 2023. Hr'g Tr., Feb. 27, 2023, 1370:23-1371:22; Hr'g Tr., March. 7, 2023, 2460:17-2461:6. The Company provided no other information regarding relevant COVID-19 Payment Plan administrative costs allowable in the COVID-19 regulatory asset.

[35] The impact of the COVID-19 Payment Plan on the level of uncollectibles between March 2020 and June 2022 is unclear; in fact, the payment plan may have had a positive impact as it included customer payments towards arrearages. Regardless, no evidence was provided as to whether and how the COVID-19 Payment Plan contributed to the difference between the allowed non-hardship uncollectibles from the last rate case and actual non-hardship uncollectibles between March 2020 and June 2022. As such, and as no administrative costs were identified for recovery, the Authority did not include the COVID-19 Payment Plan in its analysis of expenses allowable in the COVID regulatory asset.

[36] As the Company provided little to no testimony or evidence on this topic, the Authority is largely left with its own expertise in determining what is more likely than not.

03-15, respectively.[37] While other factors likely contributed to the delta between actual non-hardship uncollectibles and the non-hardship uncollectibles reflected in base distribution rates through September 2021, it is more likely than not that the majority of the delta was attributable to the non-hardship shut-off moratoriums as such moratoriums create a disincentive for customers to pay their utility bills. It is also more likely than not that some portion of the delta between actual non-hardship uncollectibles and the non-hardship uncollectibles reflected in base distribution rates after September 15, 2021, is attributable to the non-hardship shut-off moratoriums. However, since the causal relationship between the level of non-hardship uncollectibles and the non-hardship shut-off moratoriums is both more attenuated and more complex after the resumption of service terminations, several reasonable approaches could be used to determine deferred expenses attributable to the non-hardship shut-off moratorium after September 15, 2021.

Absent testimony by the Company or evidence in support of a specific methodology that attributes costs to the non-hardship moratoriums, the Authority adopts the approach that only non-hardship uncollectibles above the level allowed in rates through the end of 2021 are allowable in the COVID regulatory asset as the non-hardship uncollectibles attributable to the non-hardship shut-off moratoriums were more likely than not to have been written off by then.[38] The Authority's approach applies only the uncollectibles associated with customers eligible to receive their final bill before shut-off when service terminations resumed, i.e., customers with sufficiently aged arrearages on September 15, 2021, as attributable to the non-hardship shut-off moratoriums as it is less likely than not that a customer stopped paying their utility bill in late 2021 solely because of the shut-off moratorium given that the moratorium had been in place for more than a year. Due to the monthly nature of the utility billing cycle, the latest a non-hardship residential customer with a past due balance eligible for service termination on September 15, 2021, could receive their final bill before termination was October 15, 2021. Thus, as non-hardship arrearage balances are written off 77 days after the final bill is rendered, the Authority concludes that it is more likely than not that all uncollectibles attributable to the non-hardship residential shut-off moratorium were written off as of December 31, 2021.[39] Interrog. Resp. EOE-137.

Accordingly, the Authority will allow the inclusion of the delta between actual non-hardship uncollectibles and the non-hardship uncollectibles reflected in base distribution rates from March 2020 to December 2021 in the COVID regulatory asset, and disallows

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[37] The Company testified that it was "directionally accurate" to characterize the shut-off moratorium for non-hardship residential customers as having ended in late October 2021. Hr'g Tr., Feb. 27, 2023, 1398:10-17. The Authority interprets "directionally accurate" to include September 15, 2021, the date the Authority allowed non-hardship residential service terminations to resume.

[38] Contrary to the position taken by the Company in its Written Exceptions, the Authority is not contending that all non-hardship arrears should have been resolved by this date, but rather that arrears attributable to the existence of the non-hardship shut-off moratoriums were booked as uncollectibles by this date. UI Written Exceptions, p. 48.

[39] Similarly, the Authority concludes that all uncollectibles associated with non-residential customers with a past due balance eligible for service termination on June 15, 2021, and thus attributable to the non-residential shut-off moratorium, were written off as September 31, 2021. Thus, the Authority's methodology likely overstates, to the benefit of the Company, how much of the delta between actual non-hardship uncollectibles and the non-hardship uncollectibles reflected in base distribution rates is attributable to the non-hardship shut-off moratoriums in October through December 2021.

recovery of deferred expenses allegedly related to non-hardship uncollectibles after December 31, 2021. Consequently, the Authority disallows the recovery of $1.246 million related to the costs purportedly incurred from January 1, 2022, through June 30, 2022, which were improperly booked as COVID deferral expenses. See Interrog. Resp. OCC-577, ODR-6, Att. 1. Thus, while the Authority allows a COVID regulatory asset of $6.301 ($8.375-$0.827-$1.246) million, the $6.979 million and the related deferred tax are removed from the Company's proposed average rate base. Instead, the Authority amortizes the allowed $6.301 million, applying the pre-tax WACC to calculate carrying charges over the amortization period, outside of the rate base as discussed further in Section VI.C.6., COVID Deferral.

4. CAM GET Deferral

The Authority finds that the Company's proposed adjustment to the Conservation Adjustment Mechanism (CAM) Gross Earnings Tax (GET) regulatory liability is understated by $0.772 million. Therefore, the Authority decreases the deferred expense by $772,000. The Authority removes the $2.362 million and the related deferred tax from the Company's proposed average rate base and instead amortizes the revised CAM GET credit of $3.607 million outside of the rate base as discussed in Section VI.C.7., CAM GET.

UI proposed to refund to ratepayers $2.835 million of a regulatory liability associated with the CAM GET. Late Filed Ex. 1, Sch. B-6.6 A and Sch. WPC 3.30, p. 1. The Company proposed to amortize the CAM GET deferral over a three-year period. Id. The base distribution rates approved in the 2016 Rate Case Decision allowed for the recovery of GET on Conservation and Load Management (C&LM) charges. Id. On January 1, 2020, the Company began to recover GET on CAM revenues through the C&LM fund. Application Ex. UI-RRP-1, pp. 45-46. In Docket No. 20-02-01, Annual Reconciliation of the Conservation Adjustment Mechanisms filed by: The Connecticut Light and Power Company, The United Illuminating Company, Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company and Yankee Gas Services Company (2019 CAM Reconciliation), the Authority directed UI to accrue and record the CAM GET expense collected in base distribution rates, for the periods subsequent to January 1, 2020, as a regulatory liability to be refunded back to ratepayers. Id.; Interrog. Resp. RRU-179, Att. 9, p. 1.

The $2.835 million CAM GET deferral proposed by UI consists of $1.997 million accrued as of 2021, and a pro forma adjustment of $0.838 million for the 20-month Interim Period. Late Filed Ex. 1, Sch. B-6.6 A. To further disaggregate these amounts: the $1.997 million CAM GET deferral proposed by the Company as of the Test Year consists of $1.026 million for 2020, and $0.971 million for 2021. Sch. H-1.01, p. 85. Additionally, for the seven-month period of January through July 2022, UI accrued a CAM GET deferral of $0.564 million. Interrog. Resp. RRU-179, Att. 8, p. 1. Moreover, the $2.835 million CAM GET deferral included a $0.408 million carrying credit; and therefore, the actual CAM GET regulatory liability proposed for the Interim Period is approximately $2.427 ($2.835 - $0.408) million. Id.

The Company reported $1.538 million as the C&LM GET expense as of September 2022. Interrog. Resp. RRU-76, Att. 1, p. 1. However, because the CAM GET rate of three mills is 50% of the allowed C&LM GET rate of six mills approved in the 2019 CAM

Reconciliation, the Authority determines that the actual CAM GET deferral for the nine-month period ended September 2022 is $0.769 million ($1.538*50%). As a result, the Authority finds that the CAM GET pro forma adjustment of $0.564 million ($0.838 million less carrying credit of $0.274 million, i.e., the Company proposed amount for the 20-month interim period) is significantly understated. See Interrog. Resp. RRU-179, Att. 8, p. 1. Instead, the Authority determines that the CAM GET deferrals are $0.893 million and $0.788 million for the 11-month periods ended August 2021 and 2022, respectively. Interrog. Resp. RRU-76, Att. 1, p. 2; Interrog. Resp. RRU-179, Att. 8, p. 1. Further, as a proxy for the 11-month period from October 2022 through August 2023, the Authority determines an average CAM GET deferral of $0.841 million [($0.893+$0.788)/2] is appropriate.

As a result of the foregoing, the Authority determines the CAM GET deferral for the 20-month Interim Period is $1.610 million ($0.769+$0.841) – not the $0.564 million proposed by the Company. The $1.610 million consists of $0.769 million - the actual amount for the nine months ending September 2022, and $0.841 million - the estimated amount for the 11-month period ending August 2023. Given that a proxy value was used for the 11-month period ending August 2023, the Authority directs UI to true-up, through the appropriate CAM reconciliation proceeding, the estimated CAM GET credit of $0.841 million if the variance is more than plus or minus 10% compared to the actual amount for the 11-month period ending August 2023. Consequently, the Authority increases the CAM GET regulatory liability and correspondingly reduces the Company's proposed rate base by $0.638 million ($1.610 - $0.564 -$0.408).

In summary, the Authority determines that the CAM GET deferral as of the beginning of the proposed Rate Year 2023/2024 is $3.473 million ($2.835+$1.610-$0.408-$0.564). However, the Authority removes the $2.362 million and the related deferred tax from the Company's proposed average rate base. Instead, the Authority amortizes the revised CAM GET credit of $3.473 million, applying the pre-tax WACC to calculate carrying charges over the amortization period, outside of the rate base as discussed in Section VI.C.7., CAM GET.

5. Bridgeport Avenue Deferral

The Authority finds that the Company failed to justify and demonstrate the ratepayer benefits of the sale of the Bridgeport Avenue property. Accordingly, the Authority disallows the Company's requested regulatory asset of $15.583 million, which was reflected as $12.985 million for Rate Year 2023/2024.

a. Principal Balance

The Company's requested recovery of $15,583,240 for the loss on the sale of the Bridgeport Avenue property consists of $10,155,205 for the loss on the sale and $5,428,036 in carrying costs. Late Filed Ex. 27. The Company has been accruing carrying costs since June 2016 at its pre-tax WACC in effect for each year. Interrog. Resp. EOE-165, Att. 1; Interrog. Resp. OCC-551. The Company proposes to amortize this amount over three years for an annual amortization request of $5,194,413. Late Filed Ex. 1, Sch. WPC 3.30; Late Filed Ex. 27.

The Authority denies recovery of the loss of $10,155,205 related to the sale of the Bridgeport Avenue property because (1) the Company did not properly allocate the loss

between UI's transmission and distribution segment during the period it was in service and (2) the Company failed to submit sufficient evidence in the record demonstrating that ratepayer savings materialized as a result of the Bridgeport Avenue sale. Furthermore, the Authority disallows $5,428,036 in requested carrying costs because a portion of the carrying charges are allocatable to transmission plant and the Authority did not authorize the Company to track and recover carry charges with respect to distribution plant.

The property at 801 Bridgeport Avenue was known as the Electric System Work Center and System Operations Center (ESWC) and previously supported construction and field engineering activities in the western region of UI's service territory, as well as the system operations center for the entire service area. The sale of the property was part of UI's long-term plan, initiated in 2002, to consolidate UI's functions and activities at the Central Facility in Orange, Connecticut. RRP PFT, p. 47; UI Brief, p. 169. The consolidation plan and treatment of the Bridgeport Avenue property, as part of the consolidation plan, has been before the Authority on several occasions.

In the Company's 2005 rate case, the Authority declined to establish a regulatory asset for the ESWC sale because the property had yet to be sold. Decision, Jan. 27, 2006, Docket No. 05-06-04, Application of the United Illuminating Company to Increases its Rates and Charges (2005 Rate Case Decision), p. 22. However, the Authority stated "[b]ecause the sale of the ESWC is an integral part of the Central Facility plan, at the time of the actual sale, the Department will review the entire sale transaction, as is the case in any land sale, and allow UI to establish a regulatory asset at that time for the actual amount of loss on sale." Id., p. 22. In the 2005 Rate Case Decision, the Company provided a net present value (NPV) analysis, which purported to show a cumulative NPV ratepayer benefit of approximately $11.6 million over the period 2006 through 2026. Late Filed Ex. 29, Att. 1.

As of the Company's 2008 rate case, the ESWC was still not sold. Although the Authority expressed concern with rising capital costs estimates related to UI's consolidation plan, the Authority stated "[i]f UI is able to show in the future that the sale of the ESWC was still an integral part of the lowest cost option for consolidating its operations and the resulting net proceeds are negative, then UI may recover the loss upon the sale given the circumstances." Decision, Feb. 4, 2009, Docket No. 08-07-03, Application of The United Illuminating Company to Increase its Rates and Changes (2008 Rate Case Decision), p. 79.

In January 2018, the Authority approved the sale of the ESWC for $6,600,000, with an estimated loss on the sale of the property of $11,344,289. Decision, Jan. 10, 2018, Docket No. 17-10-40, The United Illuminating Company Application for Approval to Sell Improved Land at 801 Bridgeport Avenue, Shelton, CT, p. 3 (17-10-40 Decision).[40] In its decision, the Authority permitted the Company to establish a regulatory asset associated with the loss on the sale of the property but clarified that cost recovery would be determined in a future rate proceeding upon a comprehensive review of the lowest cost

[40] In approving the disposition of utility property under Conn. Gen. Stat. §16-43(a), the Authority examines the process for obtaining a fair market value but does not examine the prudency of the disposition.

option for consolidation. Id., p. 5.[41] Moreover, the 17-10-40 Decision referenced the above-quoted language from the 2008 Rate Case Decision, indicating that UI may only recover the loss on the sale if it demonstrated that the sale was an integral part of the lowest cost option for consolidating its operations and the resulting net proceeds were negative. Id., p. 3.

Accordingly, consistent with the 17-10-40 Decision and the 2008 Rate Case Decision, the Authority must determine in this rate proceeding whether UI submitted sufficient evidence in the record demonstrating that the ESWC sale was an integral part of the lowest cost option for consolidating its operations and that the resulting net proceeds were negative.

As an initial matter, although the Bridgeport Avenue property was used by UI's transmission and distribution segment during the period it was in service, the Company did not allocate any portion of the loss to the transmission segment. Hr'g Tr., Feb. 23, 2023, 904:9-19. Indeed, all Company application materials and information provided in interrogatory and late filed exhibit requests account for the Bridgeport Avenue property solely as distribution property. Interrog. Resp. EOE-165; Interrog. Resp. EOE-99. When the Authority requested the Company account for the transmission related portion of the Bridgeport Avenue property, the Company provided a transmission allocator of 17.72%, which is the Company's transmission wage allocator for this rate case. Late Filed Ex. 27. Applying the transmission wage allocator to the $10,155,205 loss results in an allocation of $1,799,502 to transmission plant and $8,355,703 to distribution plant. Consequently, the Authority denies recovery of $1,799,502 as it is allocable to transmission plant.

With respect to whether the sale was an integral part of the lowest cost option for consolidating its operations, the Company relied on several variations of an NPV analysis to support the conclusion that selling the ESWC property within its consolidation plan would provide benefits to ratepayers (i.e., negative NPV). In Docket No. 05-06-04, the Company provided an NPV analysis (2005 analysis) as a means to demonstrate benefits to ratepayers and attempt to provide support that its consolidation plan provided the lowest cost option for consolidating its operations and that the resulting net proceeds were negative. Hr'g Tr., 932: 9-10. The Company provided the NPV exhibits from the 2005 analysis, which purport to show cumulative NPV of approximately $11.6 million in summary form. Late Filed Ex. 29, Att. 1.

In the 2013 Rate Case, the Company again provided an NPV analysis (2013 analysis) of its consolidation plan and provided testimony purporting to show $31.8 million in savings for UI electric distribution customers. The Company references Late Filed Ex. 31, Attachments 1 and 2, to calculate savings as the difference between the discounted NPV of $188,273,000 under the alternative plan (Attachment 2) versus $156,537,000

41 The Authority originally approved a proposed sale in 2011, but the sale did not materialize. Decision, Nov. 16, 2011, Docket No. 11-08-08, Application of the United Illuminating Company for Approval and Sale of Improved Real Property Located at 801 Bridgeport Avenue, Shelton, CT. The Authority permitted UI to create a regulatory asset associated with the loss on the sale of the property, but deferred recovery until a future rate proceeding "upon a comprehensive review of the lowest cost option for consolidation of operations..." Id., p. 6.

under the Central Facility plan (Attachment 1). The 2013 analysis covers the period 2013-2032. Late Filed Ex. 31.

The NPV analyses relied upon by the Company contain incomplete and unreliable information. For example, in the 2005 analysis, the Company provided a spreadsheet that purportedly contains line items showing its built-up revenue requirement for the property by displaying O&M expenses, depreciation, interest, taxes, and returns; yet, the Company provides only raw data to support its calculations included in the spreadsheet and does not provide any documentation for the Authority to determine or verify the amounts or assumptions used in the Company's spreadsheet. Late Filed Ex. 29, Att. 2. Additionally, without explanation, the Company provided an updated schedule to its Late Filed Exhibit 29, Attachment 2 showing different decentralized alternative revenue requirement values, resulting in an NPV of $10.8 million versus the $11.6 million provided in the original attachment. Late Filed Ex. 29, Att. 3.[42] In another example, the Company assumed a loss on the sale of the property of approximately $7.1 million in its 2005 analysis, which is reflected as a cost for the central facility plan and amortized over 8 years or $887,000 annually, when, in fact, the Company actually incurred a $10,155,205 loss, which would increase the cost of the central facility plan. Late Filed Ex. 29, Att. 4. Indeed, the assumed $7.1 million loss reflects that the Bridgeport Avenue property was sold in 2006, whereas the property was actually sold in December 2018.

The 2013 analysis is similarly flawed. The 2013 analysis relied on a sale of the Bridgeport Avenue property in 2011 that did not materialize, as well as a UIL rent credit of $3.7 million beginning June 30, 2014, that escalates at 1.75% annually. However, in the Application, UI presently records a rent credit of $3.797 million, far short of projections in the 2013 analysis. Late Filed Ex. 1, Att. 1, Sch. WPC-3.01. There is no record evidence that any of the previous adjustments mentioned were considered in the NPV presented in the 2013 Rate Case.

The Company's assumptions that the property was sold before December 2018 also resulted in the site's revenue requirements not being fully captured in the NPV analyses. Although the Company calculated a $6.8 million cumulative revenue requirement for the site between 2012 and 2016, with an average annual revenue requirement of $2.2 million from 2012-2014, the Company, when asked if the amount was reflected in the NPV analyses, responded that the NPV would reflect anticipated future costs or benefits brought back to the present time based on what was known or knowable at the time the NPV was created. Hr'g Tr., Feb. 23, 2023, 934:21-25-935:1-12. The Company subsequently agreed that the NPV would not have shown that it was expecting to have that particular asset in rate base until the 2015 timeframe. Moreover, when asked about the revenue requirement for the site between 2006 and 2011, the Company stated that it did not have specific information on the revenue requirement associated with the property and cited record retention periods as the reason for lack of information.[43] Hr'g

[42] The Authority notes that Attachment 3 provides NPV through 2025 and not 2026 as UI stated.

[43] The Company subsequently supplemented Late Filed Ex. 29, which it asserts provides supporting workpapers for two specific cost categories (parking and facility lease expense), which were included in the Central Facility NPV analysis. These amounts were provided as schedules from previous rate cases, but it is unclear how these amounts relate to the assumptions included in the NPV analyses.

Tr. Feb. 23, 2023, 937:22-25-938:1-25-939:1-25-940:1-25-941:1-25-942:1-25-943:1, 951:18-22. No evidence was provided in the record demonstrating these savings.

In conclusion, the Authority is left with incomplete information in the record to support any finding that net benefits accrued to ratepayers as a result of consolidation. The assumptions that are known to have been made by the Company in its NPV analyses paint a picture of optimistic savings and timing of events that ultimately did not transpire until much later, if at all. The majority of assumptions offered by the Company provided no detail that could be verified as actually transpiring, and when assumptions were known, they fell far short of reality. The Company had the opportunity in this proceeding to justify and demonstrate the materialization of savings but has not done so. The Authority cannot confirm based on the record that the sale (and associated loss) was an integral part of the lowest cost option for consolidating its operations. The Authority, therefore, denies recovery of the loss of $8,355,703 allocatable to distribution plant related to the sale of the Bridgeport Avenue property.

b. Carrying Costs

UI contends that it properly calculated carrying charges on the Bridgeport Avenue Regulatory Asset. Specifically, the Company asserts that the loss on the sale of Bridgeport Avenue represents money expended on the provision of service to customers for which it has not yet received rate recovery. The Company also notes that the Authority has on several occasions addressed the inclusion of carrying charges on other regulatory assets and liabilities, including in the January 23, 2019 Decision in Docket No. 18-01-15, in which PURA required the Company to accrue carrying costs, calculated using its weighted average cost of capital, on its regulatory liability accounting for the difference in income tax expense attributable to the Tax Cuts and Jobs Act. UI Reply Brief, pp. 32-33.

In reaction to the OCC's retroactive ratemaking claims regarding carrying charges, the Company argues that the principle against retroactive ratemaking does not provide a blanket prohibition on the recovery of previously incurred costs, but rather provides that a rate cannot be changed after the fact.[44] The Company claims instead that it is seeking approval from the Authority for the recovery of costs on a prospective basis. UI asserts that its proposal would not change rates after the fact as the loss on the sale of Bridgeport Avenue was not previously included in the Company's rates, and, as such, the Company's proposal does not constitute retroactive ratemaking. Id., p. 33.

The Company did not originally record carrying charges until the first quarter of 2022. Hr'g Tr. Feb. 23, 2023, 952:17-23. Instead, the Company stated that it backdated carrying charges from 2022 through June 2016. Hr'g Tr. Feb. 23, 2023, 953:3-7. The Company was asked if it was regular practice to review regulatory asset balances internally as well as with external auditors on an annual basis; the Company's witnesses stated that it was their understanding that these balances are regularly reviewed. Hr'g Tr. Feb. 23, 2023, 953:8-15. This testimony calls into question the timing of the backdating of the carrying charges in early 2022 with the filing of the rate case in September 2022. More specifically, if the Company believed that carrying charges were

[44] In its brief, OCC asserted that the Company had not received approval from the Authority to accumulate carrying charges from June 30, 2016, through August 31, 2023, and that any such approval in the current proceeding would constitute retroactive ratemaking. OCC Brief, p. 254.

appropriate, it is unclear why it did not calculate them starting in 2016 or during any regular review between 2016 and 2022. Additionally, it is inappropriate for carrying charges to be applied to the loss associated with the sale of the property as such sale was not completed until December 2018.

As discussed in Section IV.E.1., General, absent express permission from the Authority, carrying charges on deferred expenses are not permissible. In allowing deferred accounting of the loss from the sale, the Authority provided no indication over the course of many dockets in which this transaction has been considered, express or otherwise, that carrying charges would accrue during the deferral period. Cf. 2013 Rate Case Decision, p. 35 (expressly allowing carrying charges in Competitive Transition Assessment reconciliation); Decision, Jan. 23, 2019, Docket No. 18-01-15, p. 11 (expressly permitting UI to accrue carrying costs). Further, the Company's own actions with respect to the timing of accrual of carrying charges demonstrate that the Company had the same understanding until just prior to the filing of its Application. Accordingly, the Authority disallows carrying charges accrued during the deferral period.[45] This reduces the regulatory asset by $5,428,036. When combined with the disallowances related to the principal balance, the Authority disallows the Company's request for a $15.583 million regulatory asset in its entirety.

The Company has reflected average rate base for the Bridgeport Avenue Regulatory Asset for Rate Year 2023/2024 of $12.985 million, which accounts for one half-year amortization ($15.583-$2.598 million); thus, the Authority reduces the approved rate base by $12.985 million.

6. UPZ Deferral

The Authority denies UI's request to amortize Utility Protection Zone (UPZ) costs. The Company asserts that this request is to align the costs of the program with its long-term benefits. CJE PFT, p. 59.

In the 2013 Rate Case, the Authority allowed the Company to amortize at the weighted cost of capital a portion of the UPZ expense. 2013 Rate Case Decision, p. 77. The Authority did this reluctantly, despite concerns that vegetation management costs are traditionally expensed and that capitalizing those costs would impose a financial burden on ratepayers. Id. Ultimately, the Authority permitted the amortization for the sole purpose of mitigating near-term rate impacts on customers that a new four-year, $100 million project would cause. Id. The amortization plan allowed UI to amortize the annual expenditures over five years. 2013 Rate Case Decision, p. 14.

In the very next rate case, however, the Authority phased out the amortization of the UPZ program and properly restored it as an expense item. 2016 Rate Case Decision, p. 7. Doing so reduced costs for ratepayers, who were paying higher costs due to carrying charges on the amortized amounts. Id. The Company failed to offer any compelling justification in support of reverting to an amortization schedule in the instant proceeding. Indeed, since the Company currently has a $14 million expense related to the UPZ program built into rates, and given that the Authority is not increasing program costs

[45] In addition, a portion of the carrying charges are allocatable to transmission plant and would also be unrecoverable for that reason.

herein as described further in Section VI.A.15, UPZ and Vegetation Management Expense, there is no significant incremental rate impact to address by amortization.

Accordingly, the Authority declines to re-implement the amortization of UPZ and directs UI to expense all UPZ program costs authorized herein. This eliminates all deferred UPZ costs and results in a reduction to rate base of $5.936 million.

7. Storm Reserve / Tropical Storm Isaias Deferral

a. Summary

The Company included a request to recover deferred storm costs in a regulatory asset, with a Rate Year 2023/2024 starting balance of $25.695 million and an average rate base balance of $23.126 million. Sch. B-1.0A. The Company proposed to amortize the amount over a five-year period. RRP PFT, p. 49.

The Authority adjusts the deferred expense to $15.060 million as discussed in the below section and approves recovery over a five-year period. The Authority removes the $23.126 million and the related deferred tax from the Company's proposed average rate base and instead amortizes the allowed $15.060 million outside of the rate base as discussed in Section VI.C.5., Storm Deferral. The following table summarizes the Authority adjustments.

Table 11: Adjustments to Storm Regulatory Asset ($000)

	UI Proposed	Adjustment	Allowed
Storm Costs	(40.298)		
Double Recovery		3.672	$ (36.626)
Carrying Charges	(6.963)	6.963	$ (0)
Accrual	21.566		$ 21.566
Total to be Amortized	**(25.695)**		**$ (15.060)**

Interrog. Resp. OCC-77, Att. 1.

b. Double Recovery of Vegetation Management Expenses

Only storm costs that are extraordinary and incremental are allowed to be recovered from ratepayers; costs that are currently contemplated in customer rates are not allowable for recovery, since that would constitute double recovery. Decision, April 28, 2021, Docket No. 20-08-03, Investigation into Electric Distribution Companies' Preparation for and Response to Tropical Storm Isaias (20-08-03 Decision), p. 126; 2013 Rate Case Decision, p. 31.

Notably, allowing UI (or any utility) to recover storm costs in a regulatory asset is an extraordinary measure. 2013 Rate Case Decision, p. 25. Between rate cases, the Company normally retains profits if it is able to reduce expenses below those determined in its last rate case, or it absorbs costs that are greater than its projections. Id. Allowing use of a regulatory asset deviates from that approach because the regulatory asset picks certain expenses of a utility that have been incurred between rate cases and enables the Company to seek rate recovery for them from future ratepayers. Id. This is essentially retroactive ratemaking and is generally an improper regulatory practice. Id. Exceptions have been made for major and non-recurring expenses that cannot be reasonably

predicted but that could affect the financial health of a company, such as major storm costs. Id.

Accordingly, if the Company is allowed to benefit from the selection of certain expenses it incurs in the course of doing business as eligible for extraordinary recovery mechanisms, the Company carries the burden to demonstrate that the costs are entirely incremental to business as usual and are not currently paid for by ratepayers.

In this vein, the Authority reviewed the Company's vegetation management expenses it incurred in 2020 and during Tropical Storm Isaias and determines that UI's vegetation management expenses incurred during Tropical Storm Isaias are not properly characterized as purely incremental costs.

In 2020, the Company was allowed $15.138 million of UPZ and reliability maintenance vegetation management expenses in rates. 2016 Rate Case Decision, pp. 9-10; Interrog. Resp. RSR-84 and 85.[46] In 2020, the Company spent only $11.646 million; an amount well below what was already in rates that year, resulting in an overcollection of $3.672 million. Interrog. Resp. RSR-84, Att. 1.

Thus, the question before the Authority is whether UI exceeded $3.672 million in vegetation management expense during Tropical Storm Isaias based on the evidence available in the record. In Tropical Storm Isaias, UI incurred total contractor, material, and lodging and travel costs of $10.164 million, which are all associated with external crews. Interrog. Resp. OCC-77, Att. 1. As shown in the table below, during the course of restoration, Contractor Tree full-time equivalents (FTEs) accounted for over 50% of the total contractor resources.

[46] 2019 was the third and last rate year of the prior rate case; as such, 2020 was outside the rate case. Since Tropical Storm Isaias occurred in 2020, it was outside the rate years. The Authority specifically authorized $14 million for UPZ trimming in 2020, but did not make an explicit authorization for a reliability maintenance budget. Interrog. Resp. RSR-85. Nevertheless, the final rate year budget for reliability maintenance trimming was $1.318 million, which was determined by the Authority as necessary for safety and reliability; as such, the Authority would consider the amount to continue on a going-forward basis. 2016 Rate Case Decision, p. 10.

Table 12: Total UI Resources by Day – Tropical Storm Isaias

Date	Contractor Line FTEs	Contractor Tree FTEs	Contractor Service FTEs	Total Contractor on Property	Percentage of Tree FTEs to Total Contractors
8/4/20	150	136	0	286	48%
8/5/20	150	136	0	286	48%
8/6/20	165	164	16	345	48%
8/7/20	165	260	14	439	59%
8/8/20	317	389	16	722	54%
8/9/20	372	405	39	816	50%
8/10/20	372	405	39	816	50%
8/11/20	115	193	39	347	56%
Total	**1,806**	**2,088**	**163**	**4,057**	**51%**

20-08-03 Decision, p. 46.

Based on the above table, it is reasonable to assume that UI incurred more than $3.6 million in vegetation clearing costs during Tropical Storm Isaias, if one assumes that the percentage of tree FTEs is an appropriate allocator to apply to the total costs incurred for the storm. Interrog. Resp. EOE-204, Att. 1; Interrog. Resp. RRU-426, Att. 7 (confidential).

Further, Tropical Storm Isaias directly prevented UI from achieving the approved level of UPZ and vegetation management spending in calendar year 2020. Hr'g Tr., 1003:10-16; 1273:2-10. Catastrophic storms require extensive tree clearing, as illustrated both by the number of crews utilized during Tropical Storm Isaias and by the amount of work that is undertaken to clear trees following storms like it. Hr'g Tr., 1007:7-19.

While tree clearing after major storms is not precisely the same as implementing the UPZ or the reliability maintenance trimming program, such activities are similar enough in scope to be treated together since the UPZ and reliability maintenance trimming program and major storm responses both require vegetation management contractors to clear trees and vegetation from electrical distribution facilities. Indeed, due to the interrelated nature of these functions, the UPZ and reliability maintenance trimming program budgets should be used to offset vegetation management-related expenses of the Tropical Storm Isaias regulatory asset. This results in a reduction to the Tropical Storm Isaias regulatory asset of $3.339 million.

The Company, however, argues that UI spent $3.339 million more in vegetation management expenses in 2019, thus offsetting the underspend in 2020. CJE Rebuttal, p. 12. While it is true that UI spent $3.339 million more than the authorized budget in 2019, when looking at all years elapsed since the 2016 Rate Case, UI underspent the authorized vegetation management expenses by $3.796 million, as reflected in the table below.

Table 13: Actual and Allowed Vegetation Management Spending ($000)

	2017	2018	2019	2020	2021	2022	Total
UPZ - Authrorized	$13.000	$13.800	$14.000	$14.000	$14.000	$14.000	$82.800
UPZ - Actual	$11.111	$13.612	$17.765	$10.806	$12.403	$15.433	$81.131
UPZ - Difference	$ 1.889	$ 0.188	$ (3.765)	$ 3.194	$ 1.597	$ (1.433)	$ 1.669
Reliability Maintenance - Auth.	$1.280	$1.294	$1.318	$1.318	$1.318	$1.318	$7.846
Reliability Maintenance - Act.	$0.806	$1.072	$0.892	$0.840	$0.933	$1.176	$5.719
Reliability Maintenance - Diff.	$0.474	$0.222	$0.426	$0.478	$0.385	$0.142	$2.127
Total - Difference	$ 2.363	$ 0.410	$ (3.339)	$ 3.672	$ 1.981	$ (1.292)	$ 3.796

Interrog. Resp. RSR-85; RSR-84, Att. 1.

Indeed, the money spent in prior or subsequent years on vegetation management is relevant to the question at hand. The Authority authorized $15.138 million of vegetation management expenses in base distribution rates in the 2016 Rate Case Decision. All vegetation management-related expenses in 2020 should first charge down the amount already authorized in rates before accruing any costs in a regulatory asset; any other treatment amounts to a double recovery from ratepayers for the same type of services. As discussed, regulatory assets are an extraordinary measure to capture incremental and extreme and unpredictable costs to protect the Company financially at the expense of future customers bearing costs for services provided in the past. They are not, however, considered in a vacuum outside of what is already allowed in base distribution rates. See, e.g., the Company's calculation of the COVID Deferral. Accordingly, the Authority disallows $3.672 million of Tropical Storm Isaias expenses.

c. Carrying Charge Adjustments

UI calculated carrying charges on the storm regulatory asset from 2017 through August 2023 to be $6.963 million. Interrog. Resp. EOE-204, Att. 2.

As discussed in Section IV.E.1., General, absent express permission from the Authority, carrying charges on deferred expenses are not permissible. In this instance, when the Authority established the storm regulatory asset, PURA never explicitly authorized carrying costs during the deferral period. 2013 Rate Case Decision, p. 35 (expressly allowing carrying charges in Competitive Transition Assessment reconciliation); Decision, Jan. 23, 2019, Docket No. 18-01-15, p. 11 (expressly permitting UI to accrue carrying costs). Had the Authority intended for the Company to accrue carrying charges for storm costs, it would have said so given that the Authority has previously denied carrying charges for storm costs incurred by an electric utility. See Decision, April 17, 2019, Docket No. 18-11-12, Petition of the Connecticut Light & Power Co. d/b/a Eversource Energy for Approval to Recover Its 2017-2018 Catastrophic Storm Costs, p. 22 (denying carrying charges for storm costs).

Accordingly, the Authority denies $6.963 million of carrying charges, as calculated by UI from 2017 through August 31, 2023, as part of the storm regulatory asset.

In summary, the Authority determines that the deferred storm cost as of the beginning of the proposed Rate Year 2023/2024 is $15.060 ($25.695 - $3.672 - $6.963)

million. However, the Authority removes the $23.126 million regulatory asset and the related deferred tax from the Company's proposed average rate base. Instead, the Authority amortizes the revised deferred storm costs of $15.060 million, applying the pre-tax WACC to calculate carrying charges over the amortization period, outside of the rate base as discussed in Section VI.C.5., Storm Deferral.

F. ACCRUED VACATION

The Authority increases the net Accrued Vacation reserve by $0.037 million. Thus, the average rate base is reduced by $0.037 million.

In developing the amount of distribution accrued vacation to include in rate base, the Company used the Test Year amount, adjusted pursuant to FERC rulemaking in Docket No. ER-20-2054, to arrive at an amount net of deferred taxes of ($1,895,000). Late Filed Ex. 1, Att. 1, Sch. B-9.3 A. The Authority must compare UI's proposed Test Year amount, including its employees' vacation time tendencies, to the Rate Year 2023/2024 amount to ensure that the figures match.

The Authority finds the FTEs included in the Test Year to differ from those included in Rate Year 2023/2024. Since the Company is expecting to add FTEs before and during Rate Year 2023/2024, it is appropriate to adjust for the difference between FTEs for the Test Year and for the rate year. See Hr'g Tr. Feb. 23, 2023, 887:20-25. While the Company is unsure of whether it specifically studied the relationship between FTEs and accrued vacation, the Company noted that the amount of vacation that is taken would be another component that could offset or vary independently. Hr'g Tr. Feb. 23, 2023, 888:1-4. The Authority finds it is likely that changes in the level of FTEs drive proportional changes in accrued vacation. Indeed, the Company concedes that FTEs could be one of a number of parameters driving accrued vacation. Hr'g Tr. Feb. 23, 2023, 888:1-4. Since the head count from the Test Year to Rate Year 2023/2024, as adjusted by the Authority, is increasing from 519 to 529, or by 1.927%, the Authority adjusted the distribution accrued vacation net of deferred taxes ($1,895,000) by 1.927% or $36,513 to $1,931,513.

G. ACCUMULATED DEFERRED INCOME TAXES

Line-item descriptions located on UI's FERC Form 1 indicate some components embedded in the Company's Accumulated Deferred Income Tax (ADIT) Asset Account (FERC Account 190) are related to non-distribution areas of the business. These items include: New Haven/Bridgeport Fuel Cell; Merger Items; and Transmission ROE. Application Sch. H-1.01, p. 234. When asked why these items were not excluded from the Account 190 deferred income tax asset, the Company did not directly respond nor did it provide any justification for the inclusion of these items. Rather, the Company merely confirmed that these items were not excluded. Late Filed Ex. 53. The Authority finds the Company did not provide sufficient evidence to justify inclusion of these amounts in FERC Account 190. Accordingly, these amounts are disallowed. The resulting adjustment is a reduction to the Company's ADIT asset account, and a corresponding reduction to the Company's rate base of $20.142 million.

Additionally, the Authority's decision to disallow pro forma plant additions has a flow-through impact on ADIT, which results in a reduction to the Company's ADIT liability accounts (and a corresponding increase in UI rate base) of $3.567 million. The table below summarizes the $2.367 million net increase to the Company's proposed ADIT.

These adjustments reflect the deferred tax effects of adjustments to plant additions, protected and unprotected EADIT, regulatory assets, and related amortization expenses.

Table 14: Summary of Deferred Tax Adjustments ($000)

Proposed Total ADIT	**351,761**
(Less) or add PURA Adjustments:	
Provision for DIT for Depreciation Expense Adjustment	1,352
FAS 190 Adjustment	20,142
Disallowed Plant Additions	(3,567)
UPZ Deferral DTL	(1,598)
Pension and OPEB Cost Deferral*	(3,593)
COVID-19 Cost Deferral*	(1,879)
CAM GET*	523
Storm Reserve Regulatory Asset*	(5,415)
Loss on Sale of Bridgeport Avenue*	(3,496)
Environmental Remediation*	(103)
Total Allowed ADIT	**354,128**

*Reflect 26.925% deferred tax effect of the adjustments to the related regulatory assets or liabilities.

H. MUNICIPAL DASHBOARD

The Authority declines to approve capitalized treatment for the Municipal Dashboard as this expense is of an annual nature and is thus properly categorized as an expense, rather than as capital. The Authority instead provides for an annual expense of $825,000 in Section VI.A.12.b., Municipal Dashboard, of this Decision. The capital costs proposed by the Company for the Municipal Dashboard have been removed from rate base as part of the reduction to Interim and Rate Year 2023/2024 Pro Forma Plant-in-Service of $222.402 million as outlined in Section IV.B., Test Year Plant-in-Service.

I. LIGHT-DUTY ELECTRIC VEHICLE CHARGING PROGRAM

1. General

In July 2021, the Authority established a statewide, nine-year light-duty electric vehicle charging program (EV Charging Program or Program). Decision, July 14, 2021, Docket No. 17-12-03RE04, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Zero Emission Vehicles (EV Decision). The Program, administered by the EDCs, established electric vehicle supply equipment (EVSE) deployment targets across a variety of use cases with accompanying incentives in order to help reach such targets. EV Decision, pp. 11, 17. The Authority directed the EDCs to recover the revenue requirement associated with implementing the EV Charging Program through electric distribution rates following a normal rate case proceeding, as such Program expenses are expected to be a core business function. EV Decision, p. 45.

Specifically, the Authority directed the EDCs to recover Program costs in two manners: (1) deferred to a regulatory asset; and (2) as capital costs. Id., pp. 45-46. All EVSE program costs, including rebates, program administration, and education and outreach were to be deferred to a regulatory asset and reviewed as part of the Company's next rate case proceeding. Id., p. 45. Once the regulatory asset is incorporated into the

Company's base rates, it shall be amortized over a five-year period. EV Decision, p. 46. Any capital or fixed asset costs are not to be included in the regulatory asset; rather, capital costs associated with the EV Charging Program "shall be treated as any other capital asset, i.e., included in rate base and depreciated over their useful lives." Id. The EV Decision directed the EDCs to assume a 15-year estimated useful life for capital assets. Id.

The Authority provided the EDCs' proposed budget for the first three-year Program cycle, i.e., 2022-2024, in its December 15, 2021 Decision in Docket No. 21-08-06, Annual Review of the Electric Vehicle Charging Program – Year 1 (EV Year 1 Decision). However, the Authority clarified that it "in no way pre-approv[ed] the estimated Program administrative costs provided to date" and that "the approval of any Program administrative costs will be done through the examination of each Company's regulatory asset as part of the Company's next base rate case proceeding." EV Year 1 Decision, p. 20.

As detailed below, the Authority denies the Company's request to include prospective EV Charging Program capital expenses in this rate case because a forward-looking multi-year rate plan is not being approved in this Decision and the capital expenses sought for recovery have not yet occurred (and, thus, are not used and useful). Moreover, as the Company did not seek recovery of any regulatory asset costs in its Application, the Authority is unable to grant recovery of any such costs. The disallowances related to the EV Charging Program are not included in the summary table in Section IV.A., Summary, as these costs were not included in the Application for the Test Year or Interim Period.

2. Capital Expenses

UI requested recovery for $1.4 million in capital costs for the first three-year Program Cycle in this rate case. King PFT, p. 9; Interrog. Resp. CAE-11, p. 1; Hr'g Tr., Mar. 7, 2023, 2711:5-16. The $1.4 million corresponds to what the Company initially budgeted for in the first three-year Program Cycle in the EV Year 1 Decision proceeding. Interrog. Resp. CAE-11, Att. 1, p. 5. The budgeted capital expenditures for 2022–2024 include assets related to Level 2 EVSE make-ready installation, DCFC make-ready installation, and the Level 2 Multi-Unit Dwelling (MUD) Lease Program. Id. Notably, the Level 2 MUD Lease Program was not approved by the Authority until its December 14, 2022 Decision in Docket No. 22-08-06, Annual Review of the Electric Vehicle Charging Program – Year 2 (EV Year 2 Decision), where it directed the EDCs to begin offering the lease program by February 1, 2023. EV Year 2 Decision, p. 42. Therefore, UI could not possibly have incurred capital expenditures related to the lease program in 2022, even though the requested $1.4 million in capital expenses includes a budgeted $141,750 for the Level 2 MUD Lease Program. Interrog. Resp. CAE-11, Att. 1, p. 5.

Furthermore, UI stated that it in fact incurred zero capital costs related to the Light Duty (LD) EV Charging Program in 2022. Hr'g Tr. Mar. 7, 2023, 2711:17-20, 2713:19-22; Hr'g Tr. Mar. 8, 2023, 2740:3-17. When asked, the Company acknowledged that it did not adjust the requested LD EV capital cost budget when submitting its Application as a result of actual incurred Program costs and that it is likely that the Company will incur capital costs below its $1.4 million projection by the end of 2024. Hr'g Tr. Mar. 7, 2023, 2713:9-18, 2713:23 – 2714:3.

Accordingly, the Authority denies the Company's requested recovery of $1.4 million in capital expenditures related to the Light-Duty EV Charging Program. The Company incurred zero capital costs in 2022 and provided no indication of what the Company actually expects to incur through 2023-2024. Therefore, the Authority finds no evidence to support the approval for recovery of potential future capital costs in this Program. Furthermore, the Authority directed UI to treat LD EV Charging Program capital costs as they would any other capital asset. EV Decision, p. 46. As such, capital assets must be demonstrated as used and useful prior to their recovery in a rate case proceeding. As the Company concedes, it did not incur any costs related to used and useful capital assets in 2022, and therefore, is not eligible to recover capital costs related to the LD EV Charging Program in this rate case proceeding.

3. Regulatory Asset

As stated previously, the Authority determined that "the approval of any Program administrative costs will be done through the examination of each Company's regulatory asset as part of the Company's next base rate case proceeding." EV Year 1 Decision, p. 20. Accordingly, the instant proceeding is the appropriate avenue in which to assess the Company's regulatory asset associated with EV Charging Program administration costs, as accrued since Program launch.

However, the Company declined to include any regulatory asset costs associated with the light-duty EV Charging Program in their cost recovery request in the instant proceeding. See Hr'g Tr., Mar. 7, 2023, 2717:5-14. Initially, UI stated that it did not propose cost recovery for such a regulatory asset because there were no deferred EV Charging program expenditures at the time of application filing. Interrog. Resp. CAE-13. Subsequently, however, UI identified a total of $334,166 in Program costs deferred to a regulatory asset prior to the Company's filing in the instant proceeding. Interrog. Resp. CAE-54. Furthermore, the Company stated that because of the small amount associated with the regulatory asset, i.e., $334,166, the Company "determined it would be more administratively efficient to continue deferring these costs … and seek rate recovery in its next base distribution rate proceeding when the deferred amount is more material." Id. UI stated that it is not requesting cost recovery for the light-duty EV Charging Program regulatory asset in this rate case and is planning to continue deferring such eligible costs, with carrying costs, until the next rate case. Hr'g Tr., Mar. 7, 2023, 2717:5-14.

In response to further Authority questioning, UI provided the Program costs associated with a regulatory asset as accrued through the end of August 2022, and through the end of December 2022; as shown in the tables below. Late Filed Ex. 126. In total, the Company reported $1.57 million in Program costs in 2022 that it seeks to defer to a regulatory asset for recovery in the Company's next rate case.

Table 15: EV Charging Program Regulatory Asset Costs (Jan. 2022 - Aug. 2022)

Expense	Residential	MUD (Level 2)	Destination (Level 2)	Workplace & Light-Duty Fleet (Level 2)	DCFC	Total
Program Administration	$240,424	$2,798	$2,798	$2,798	$2,799	**$251,617**
Program Incentives	$23,766	$18,783	$0	$40,000	$0	**$82,549**
Total	**$264,190**	**$21,581**	**$2,798**	**$42,798**	**$2,799**	**$334,166**

Late Filed Ex. 126.

Table 16: EV Charging Program Regulatory Asset Costs (Jan. 2022 – Dec. 2022)

Expense	Residential	MUD (Level 2)	Destination (Level 2)	Workplace & Light-Duty Fleet (Level 2)	DCFC	Total
Program Administration	$460,384	$48,798	$48,798	$48,798	$48,798	**$655,576**
Program Incentives	$136,672	$246,916	$120,032	$113,054	$300,000	**$916,674**
Total	**$597,056**	**$295,714**	**$168,830**	**$161,852**	**$348,798**	**$1,572,250**

Id.

The Authority endeavors to ensure that Connecticut electric ratepayers are not burdened with unnecessary or imprudent expenses, as is its statutory mandate. As relevant to the immediate question of recoverability, the Authority previously directed the Company to seek recovery of any accrued LD EV Program-related regulatory asset costs in its next base rate case proceeding (i.e., the instant case). The Authority's directive did not state that such costs could be continually deferred until future rate cases if the Company deems them to be "immaterial." Thus, the Company's opportunity to recover deferred LD EV Program-related expenses eligible for inclusion in the related regulatory asset incurred as of the date of UI's Application submission was the instant proceeding.

Nevertheless, the Authority finds that costs associated with the implementation of a new Program, such as the EV Charging Program, are necessary to ensure both the initial and the continued success of the program. Accordingly, the Authority will allow UI to seek recovery of any LD EV Program costs that should have been submitted for recovery in this proceeding in its next base rate case proceeding. Additionally, UI shall continue to defer any eligible Program costs incurred *after* the Company's Application filing to the regulatory asset and shall seek recovery for the regulatory asset in its next base rate case proceeding. For clarity, however, the Authority reminds the Company that it is not pre-approving any LD EV Program costs herein.

Also, for the avoidance of doubt, the Authority clarifies the following language included in the EV Decision stating that "carrying charges assessed to the regulatory asset shall be no more than the Company's last approved weighted average cost of capital." EV Decision, p. 45. The identified language affirms the Authority's planned use of past precedent in applying carrying charges to the regulatory asset only once it is

submitted for recovery and deemed prudent; the language does not permit the allowance of carrying charges to accrue prior to submission. Notably, the Authority used "assessed" to indicate the application of the carrying charge rate at the time the deferred expenses are submitted for recovery instead of "accrue" as was used in the January 23, 2019 Decision in Docket No. 18-01-15, which expressly allowed carrying charges on deferred revenues prior to a prudency determination. See Decision, Jan. 23, 2019, Docket No. 18-01-15, p. 11 ("Such regulatory liability shall accrue carrying costs calculated at UI's WACC." emphasis added).

J. ENVIRONMENTAL REMEDIATION

The Company proposed including the unamortized balance of its requested $458,000 in deferred remediation expenses in rate base. Ex. UI-RRP-1, p. 44. As discussed in Section VI.C.3, Environmental Expenses, the Authority denies the amortization of the environmental expenses and will, therefore, exclude from rate base the unamortized amounts ($382,000). See Table 1, Line 11, Other Additions.

K. FIVE-YEAR CAPITAL PLAN

1. Summary

UI proposes a five-year forward-looking capital plan. UI Brief, p. 4. The following table shows a high-level summary of the proposed five-year capital plan that the Company developed to support its multi-year rate plan. CJE PFT, p. 5.

Table 17: Five-Year Capital Plan Summary ($000)

Category	2023	2024	2025	2026	2027
Customer	50.170	43.630	35.942	32.173	32.634
Capacity	1.989	3.139	1.880	2.000	2.000
Corrective Reliability	3.040	3.210	3.281	3.355	3.559
System Resiliency	17.823	12.856	6.838	7.392	6.079
Infrastructure Repl. – Substations	9.612	12.458	9.981	3.604	0.000
Infrastructure Repl. – Dist. System	29.310	27.853	29.687	31.145	31.710
System Operations	20.285	20.527	23.501	23.092	17.596
Business Effectiveness	19.001	9.748	15.628	18.944	12.894
Modernization	5.355	6.840	13.841	32.186	21.758
Total Capital Expenditures	**156.587**	**140.261**	**140.580**	**153.890**	**128.231**

Id., p. 6.

The eight categories of the capital plan are Capacity, Customer, Reliability, Infrastructure Replacement (Substations and Distribution System), System Resiliency, System Operations, Business Effectiveness, and Modernization. Id., p. 7.

A utility's capital investment plan is generally not subject to Authority pre-approval. For one, a prudency determination with respect to future expenditures is a non sequitur.[47] Further, the development and execution of the utility's capital investment plan falls

[47] If the Authority were to approve a multi-year rate plan, the utility's capital plan would be a factor in establishing rates in future years; however, the adoption of a multi-year rate plan does not constitute an approval of the utility's capital investment plan, nor does it indicate whether such investment will later be found used and useful, as well as prudently and reasonably incurred.

exclusively within the domain of the utility's management team and board of directors. Ceding the power to approve or veto such a core corporate function to a utility commission would mark a landmark shift in the operation of investor-owned utilities (likely to the chagrin of investors). No doubt, the Authority has broad powers under Title 16 with respect to rates, service, safety, and the state's energy and environmental policies; however, supplanting the roles of the utility's management team and board of directors is not one of them.

Consequently, to the extent the Company seeks "approval" of its capital plan, the Authority demurs. However, the Authority strongly agrees with the Company that the Company's implementation of a capital plan is "critically important to maintain reliable system operations and a safe operating environment for the Company's employees, customers and the public" and expects UI, as a public service company, to effectively implement a capital plan that maintains the safety and reliability of the distribution system. UI Brief, p. 4. As it is well aware, the Company is entitled to recover used and useful, prudent future investments through its next rate proceeding.

The Authority also concurs with the Company that a comprehensive capital plan is an essential tool for developing a multi-year rate plan; therefore, if the Company intends to request multi-year rate plans in future rate case, the Authority offers guidance in two areas. First, the Authority provides insight on why the current five-year capital plan is inadequate as a basis on which to approve a multi-year rate plan. Second, the Authority provides guidance on how future capital plans should align with the Reliability and Resilience Frameworks established in August 2022, and the revised multi-year rate plan framework anticipated for completion in May 2024. PBR Decision, p. 33; Decision, Aug. 31, 2022, Docket No. 17-12-03RE08, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Resilience and Reliability Standards and Programs (RE08 Decision), p. 72.

2. Capital Plans as a Basis for a Multi-Year Rate Plan

The Company's current five-year capital plan is not adequate as a basis to approve a multi-year rate plan due, in part, to the following reasons: (1) the capital plan provided insufficient and unreliable information; (2) the Company has underspent its authorized capital expenditure budget in recent years; and (3) the Authority has reason to believe that certain planned program and project costs are overstated.

The Company generally provided insufficient information for each project, electing to instead make bald assertions without providing supporting documentation. When asked to provide supporting documentation for projects, UI elected to describe its internal planning process; the Company did not provide the relevant information that internal decision-makers rely on during that process to initiate, approve, prioritize, and execute capital projects.[48] Hr'g Tr., 1170:15-1171:18.

[48] The lone exceptions where the Company did submit some of the governance reporting documentation were for the Company's Clean Energy Transformation initiatives regarding electric vehicle programs. See, e.g., Ex. CETP-2 and CETP-3. While UI did not include the entirety of the IP supporting documents, the Company did include at least some level of project planning information such as project summary, project sponsor, project descriptions, estimated in service dates, project justification, expected project benefits, risk of no action, and other funding details. Application, Ex. CETP-2, pp. 1-3 and Ex. CETP-3,

For example, the OCC made a request for supporting documentation for all project-level plant additions from January 1, 2022 (the end of the Test Year) through August 31, 2026 (the end of the proposed third rate year). Larkin PFT, p. 9. UI did not provide the information, but rather provided a paragraph summarizing the planning process and stated that the underlying data and documents are available within an internal project management tool. Interrog. Resp. OCC-193.

Similarly, the Authority asked for project-level planning documents regarding specific projects in the capital plan, including the substation flood mitigation program, the substation getaway program, the stepdown bank removal program, and other system resiliency programs. Interrog. Resp. RSR-7 through RSR-10. UI did not make this information available and, instead, elected to describe its internal planning process. See, e.g., Interrog. Resp. RSR-7.

Again, the burden falls squarely on UI to provide sufficient evidence supporting the Company's request. Conn. Gen. Stat. § 16-22. The burden appropriately rests with UI because the Company is in possession of the relevant and critical information that it relies on to make decisions. Since the Authority and other parties are not in possession of this information, they must rely on what has been provided by the Company during the course of the proceeding. The Authority cannot simply take the Company at its word about a project's necessity, estimated costs, planned in-service dates, changes in scope, etc. without evidentiary backing.

UI has this project-level information available and relies on this information during the course of the Company's planning and execution of its capital projects. Interrog. Resp. OCC-193; Hr'g Tr., 734:16-20. Other utilities make this level of information available; for example, utilities in Vermont file supporting documentation that includes necessity of project, projected costs for future projects, including supporting documentation such as vendor quotes and cost estimating methodologies, cost-benefit analyses for projects, and detailed actual costs for completed projects. Hr'g Tr., 1334:17-1335:20; Late Filed Ex. 44, Ex. A. It is not unreasonable to expect UI to make similar information available in this proceeding, particularly upon request.

Furthermore, where UI did provide information, it was at times unreliable. As such, the mere fact that projects went through UI's IP approval process is not sufficient to ensure the reasonableness of the expenditures. Indeed, the Authority's review of projects in the capital plan reveals a number of instances where the projects did not follow the Company's own internal planning process.

For example, UI provided conflicting information for an ongoing project that tracks capital expenditures related to storm restoration (project ID: PRJ-002214). Interrog. Resp. RSR-36. The Authority asked UI to provide cost estimates for this project. Id. UI stated that this project is exempt from the IP governance process because costs are recorded only after actual restorations, and so UI does not develop forecast cost

pp. 1-2. The supporting documentation does not include all relevant information developed in the internal planning and review process.

estimates. Id. A review of the Company's capital plan indicates the opposite, however; UI does indeed budget for this item for future years. Interrog. Resp. RSR-4, Atts. 1 and 2. Not only that, but this project has received authorization to commit future funds (i.e., it has received IP3 gate approval), which indicates that it does go through the governance process. Late Filed Ex. 42, Att. 1.

As a second example, Project PRJ-002117 – "System Resiliency CAP" is an ongoing program design to house projects where the Company determines the need to upgrade distribution infrastructure to meet current design standards and NESC compliance. Interrog. Resp. RSR-52. While UI states that this is an ongoing project, it appears that the only work planned for this project is "in the definition stage in North Haven." Id. Despite the project being in the "definition" stage, the only information available currently is that the project will be approved at a future date as a sub-project that is itself, as of yet, unidentified. Id., pp. 2-3. Nevertheless, despite the lack of a specific sub-project, this project received approval from UI to commit $763,395 of capital expenditures in 2023, which is counter to the Company's stated policy that projects receive funding approval only after detailed project engineering is complete. Id.; Hr'g Tr., 822:2-6, 3295:13-3296:7.

Furthermore, a review of how UI has executed its approved capital plan in recent years demonstrates that UI has not accomplished the capital plans that have been authorized by the Authority in prior proceedings. In the Company's last two rate cases, for example, the Authority authorized a certain amount of capital expenditures for multi-year rate plans. 2013 Rate Case Decision, pp. 8-16; 2016 Rate Case Decision, pp. 19-20. In Docket No. 16-07-11, the Authority authorized incremental capital expenditures to be included in the Company's capital plan for certain storm resilience proposals, such as substation flood mitigation, step down bank removal projects, substation getaway projects, and perimeter feeder ties projects. 16-07-11 Decision, p. 4; 2016 Rate Case Decision, p. 14. The table below lists the total amount of capital expenditures approved by the Authority by year since 2013, as compared to the expenditures actually incurred by UI during that time.

Table 18: Total Actual and Authority Authorized Capital Expenditures ($000)

	2013	2014	2015	2016	2017	2018	2019
Actual Spend	103,180	117,353	124,395	96,016	100,780	100,825	126,013
Rate Case Authorized	143,910	137,297	117,899	98,557	105,526	100,394	102,191
16-11-07 Authorized					7,768	18,624	18,976
Total Authorized	143,910	137,297	117,899	98,557	113,294	119,018	121,167
Underspend	**40,730**	**19,944**	**-6,496**	**2,541**	**12,514**	**18,193**	**-4,846**

16-07-11 Decision, p. 4; Interrog. Resp. RSR-2, Att. 1.

Specifically, UI underspent the allowed capital expenditure budget for years 2013 through 2019 by more than $80 million, despite UI's claims to the contrary. Hr'g Tr.,

745:9-22.[49] For multi-year rate plans, this level of underspending introduces risk that customers pay for plant additions that are not actually in service. Even UI concedes the validity of the concern that customer rates may not accurately reflect actual plant in service under prospective rate plans. Hr'g Tr., 1318:1-16.

Based on an analysis of projects within the capital plan, the Authority has reason to believe that the risk that UI underspends its capital plan remains present. For example, projects that target proactive replacement of distribution poles and transformers before failure appear excessive in scope. CJE PFT, p. 18. The following table shows the Company's actual and projected capital expenditures for the two projects.

Table 19: Infrastructure Replacement Actual and Forecast Expenditures ($000)

	2017	**2018**	**2019**	**2020**	**2021**	**2022**
Transformer Replacement	9,763	6,686	5,548	6,881	2,176	1,217
Pole Replacement	5,364	7,908	6,863	5,416	2,815	2,983
	2023	**2024**	**2025**	**2026**	**2027**	
Transformer Replacement	5,013	5,137	5,210	5,343	5,467	
Pole Replacement	4,412	4,491	4,580	5,310	5,431	

Interrog. Resp. OCC-470, Att. 1.

The table reflects that for both projects, the Company reduced spending in 2021 and 2022 relative to prior years, while in 2023 and beyond, the Company plans capital expenditures closer to pre-2021 levels. The Company attempted to explain that the reductions in both categories were due to challenges sourcing replacement poles in 2022 and similar supply chain challenges limiting the number of transformers available for replacement. Interrog. Resp. RSR-53 and RSR-55. Notwithstanding this assertion, however, the Company did not provide any indication that the supply chain challenges had been resolved since 2022. Interrog. Resp. RSR-53; Interrog. Resp. RSR-55, p. 2.

By way of another example, the Company's estimates for capital pole work to accommodate installation of third-party pole attachments appear inflated as well. CJE PFT, p. 14; Interrog. Resp. OCC-310, Att. 1. The Company bases its budget on a prediction of the potential for 25,877 pole attachment requests to be received from third parties seeking to attach to poles (Attachers). CJE PFT, p. 14. This prediction was based on discussions at quarterly meetings the Company has held with the Attachers since April 2021. Interrog. Resp. OCC-131, RSR-82, p. 2. Based on these discussions, the Company projected 25,870 pole attachment requests for both 2023 and 2024. Interrog. Resp. OCC-131. Notably, when providing these estimates, the Attachers did not provide the Company with a deployment strategy, application sizes, or timing, but just a figure for the total number of attachments expected. Interrog. Resp. RSR-82, p. 2.

The 25,877 pole attachment projections are not realistic since the level of attachment requests have not materialized. Interrog. Resp. OCC-305; Hr'g Tr., 574:24-575:1. Specifically, certain Attachers that anticipated large volumes of attachments have

[49] Fortunately, this did not result in customers being unfairly charged in rates because system resilience expenditures allowed in the 16-07-11 Decision did not involve recovery through base rates by forecasted plant additions; rather costs pass through rate adjustment mechanisms. 16-07-11 Decision, p. 7.

not acted on those projections. Id. Furthermore, UI has only completed make-ready work on 50 poles since May 2022. Hr'g Tr., 870:23-871:2.

The table below demonstrates the historical and forecast values for number of pole attachments, number of poles requiring make-ready work and replacement, and the costs to perform make-ready work. It is clear from the table that UI's 2023 and 2024 estimates vastly exceed the historical values for these categories.

Table 20: Pole Attachment Applications and Make-Ready Work

	Requests Received	Requiring Make-Ready Work	Requiring New Pole	Canceled Requests	Capital Costs
2017	2,976	1,394	250	85	$2,589,656
2018	16,743	5,658	951	5,162	$2,793,284
2019	2,183	731	269	56	$2,920,488
2020	12,311	2,738	525	144	$5,135,685
2021	9,467	1,985	173	127	$8,557,111
2022	2,597	701	111	200	$11,497,665
2017-2022 Avg.	**7,713**	**2,201**	**380**	**962**	**$5,582,315**
2023	25,877	6,645	1,238		$13,629,182
2024	25,877	6,645	1,238		$13,901,765
2025	10,500	2,696	502		$7,299,168
2026	10,500	2,696	502		$7,407,019
2027	10,500	2,696	502		$7,517,027

Interrog. Resp. RSR-82, p. 2 and Att. 1; OCC-310, Att. 1.

UI's planned pole attachment make-ready work is vastly overstated since the Company's primary justification for the make-ready capital costs are based on unreliable estimates from Attachers. To justify such a massive increase in attachment volumes and resulting costs, the Company would need to present much more reliable information based on several credible sources. Therefore, in this instance, the Authority must find the forecasts unreasonable and overstated. Second, even if the Authority were able to deem UI's forecasts as reasonable (which they are not), it is unlikely that UI would be able to achieve such a dramatic increase in make-ready work since it is challenging for the Company to secure construction crews to address such volumes quickly. Hr'g Tr., 869:15-18.

For the reasons and examples provided herein, the Company's capital plan as presented is not an appropriate basis for a multi-year rate plan.

3. Capital Plans and the Reliability and Resilience Frameworks

The Authority established a Resilience Framework to aid in analyzing the benefits of resilience programs and projects to demonstrate how they reduce the number and

duration of outages in response to gray-sky and dark-sky events.[50] RE08 Decision, pp. 39-40. The Authority established the Reliability Framework to establish planning parameters and performance targets that reflect both reliability performance and cost-effectiveness of reliability programs. RE08 Decision, p. 44.

Regarding the Resilience Framework, the framework seeks to identify vulnerable portions of the distribution system, to enable the selection of mitigation measures, to ensure any selected resilience solutions are cost effective, and to ensure that benefits to customers and system/public safety are demonstrable and achievable. Id., p. 58.

Of all the resilience projects UI included in its five-year capital plan, only one set of projects was submitted pursuant to the Resilience Framework. Interrog. Resp. OCC-628, p. 2. This project includes nine of the Company's 400 circuits identified for hardening measures, including installation of aerial cable, circuit segmentation, distribution automation, and undergrounding. Interrog. Resp. OCC-312, Att. 1; RSR-11, Att. 2, pp. 6, 11. For these projects, the Company did attempt to perform the cost benefit analysis contemplated by the Resilience Framework, which included modeling potential for future storm, resulting damage, avoided outages, and avoided storm recovery cost. Id., pp. 12-17. UI did not perform such an analysis for all other resilience programs, however, including "Coastal Substations", "Step Down Bank Removals", "Substation Getaways", "Milvon ROW", and "System Resilience CAP" projects. CJE PFT, pp. 26-28; Hr'g. Tr., 812:20-25; Interrog. Resp. RSR-11.

The Authority did not intend that the Resilience Framework be utilized in a vacuum to develop new and incremental projects as UI has done here; rather, its purpose was to serve as a framework by which a Company's entire resilience is comprehensively and holistically assessed. RE08 Decision, p. 59. The purpose of doing so is to ensure that resilience benefits are demonstrable, achievable, and cost-beneficial to customers, and as a portfolio will enable the Company to maintain safe operation of its system during and after dark-sky and gray-sky events. Id. The Company understands the rationale and agrees that treating all resilience programs holistically is reasonable. Hr'g Tr., 807:1-18. In future five-year capital plans submitted in rate cases, UI must pass all resilience projects through the Resilience Framework. Doing so will be consistent with Authority orders and will enable the Authority and all stakeholders to conduct an after-the-fact prudence review of those projects.

As it stands, UI has included in its capital plan nine incremental circuits selected for hardening that have been subject to the Resilience Framework and where resilience benefits have been demonstrated on a project level basis. As explained above, this approach is contrary to the purpose of the Resilience Framework. All future capital plan resilience programs need to be subject, as a whole, to the Resilience Framework; doing so enables the Authority to conduct a prudency review of each individual project proposed and to appropriately assess the scale and scope of the entire resilience portfolio.

[50] The Authority defines Resilience as the ability of the distribution system to withstand and reduce the magnitude and/or duration of disruptive events. RE08 Decision, p. 57. Gray- and Dark-sky events are tied to the Company's storm classification matrix in its emergency response plan. Id., pp. 37-38. In common terms, dark-sky events are the most severe but rare events (with Tropical Storm Isaias as an example), and gray-sky events are the common, but significantly less damaging, events. Id., p. 37.

Regarding the RE08 Decision's companion Reliability Framework, while the Company has taken some steps to apply the framework to its reliability program portfolio, the Company did not fully implement it, as described below. The Authority provides the following guidance to ensure that UI's capital plan is appropriately assessed using the Reliability Framework moving forward, which will enable the Authority to conduct a prudency review of reliability projects and to appropriately assess the scale and scope of the overall reliability portfolio.

First, a key feature of the Reliability Framework is to enable the Authority to evaluate reliability programs based on the incremental reliability benefits the projects provide and whether customers are willing to pay for the incremental benefits those projects provide. RE08 Decision, pp. 61-62, 75. Doing so at this time is paramount since UI's blue-sky reliability performance is at historic highs when compared with other utilities regionally and nationally, where UI has been in the top quartile since 2013. Interrog. Resp. RSR-61. Thus, programs implemented to maintain and improve reliability need to be carefully considered by the Authority in light of increasing ratepayer impacts. RE08 Decision, p. 44. As such, the Reliability Framework established a process by which to appropriately scrutinize potential ratepayer impacts. As described more fully herein, it is necessary that reliability projects pass through the Reliability Framework so that the Company can demonstrate the value that projects and programs provide, and so that the Authority can subsequently evaluate investments on that basis.

To accomplish this, the Authority developed a standard to represent customers' willingness to pay. The Authority established a rebuttable presumption against which to assess affordability for customers. Id., p. 45. Specifically, the rebuttable presumption of what constitutes an unaffordable investment is as follows:

> [A] reliability program budget proposed … is unaffordable if it exceeds the Company's historic average annual reliability program budget, using a data set of the annual reliability program budgets from the 10 years preceding the chosen test year and factoring in reasonable escalation factors derived from Gross Domestic Product (GDP) Deflator index published by the U.S. Bureau of Economic Analysis.
>
> RE08 Decision, p. 45.

Regarding the affordability of UI's reliability programs, the Company performed the above analysis of its historical reliability costs but used the Handy-Whitman Index to escalate costs, not the GDP Deflator Index as required. Interrog. Resp. RSR-88.

In addition to not properly applying the affordability threshold, UI has not yet modified its worst-performing circuit program as required in the RE08 Decision. RE08 Decision, pp. 50-52. UI still follows the supplanted worst-performing circuit guidelines and does not yet follow the new program design, which prioritizes using customer-centric reliability metrics to make incremental reliability improvements. Id.; Interrog. Resp. OCC-584, p. 1. Although the Company claims it did not have sufficient time prior to filing its rate case to implement the Reliability Framework, a complete capital plan must fully comply with the Reliability Framework; further, the timing of the instant Application remained within the Company's sole purview in this instance. Doing so will enable the

Authority to conduct an appropriate prudency review of the Company's actual reliability investments. CJE PFT, p. 29.

L. INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

The Company requested that the Authority issue an order that would allow UI to recover or refund regulatory deferrals without any subsequent claims "or other contingent events, including in the event of no longer having a continuation of service." Ex. UI-RRP-1, p. 13. The Company states that such an order will allow UI to correlate its financial reporting with and be able to report deferred assets and liabilities "under IFRS similar to those allowed under" the United States Generally Accepted Accounting Principles" (US GAAP). Id. UI indicated that the reporting of deferred assets and liabilities under IFRS will not affect ratepayers and that such a recognition will align the financial statements under the US GAAP when combined into that of its "ultimate corporate parent," which currently reports under IFRS. Id.

The Authority denies UI's request to align its financial reporting with that of its "ultimate" foreign company that reports under IFRS because the Company failed to justify why such a request is necessary. UI will continue to report recognized activities, including deferred assets and liabilities, pursuant to US GAAP.

The Company confirms that the current US GAAP matches revenues and expenses by allowing regulated utilities to record regulatory assets and regulatory liabilities on their balance sheets. Additionally, currently deferred expenses or revenues "will be collected or refunded" in future years. Interrog. Resp, RRU-64, p. 2. Also, the Company indicated that under IFRS, expenses such as storm costs are not deferred but are recognized in the year in which they are incurred, and the associated revenues are eventually reported when billed to customers. Id. This creates "a mismatch between when the expenses are recognized and when the revenue is recognized." Id. The complementary recognition of revenues and expenses, as is currently done under the US GAAP, is necessary for IFRS because "both Avangrid and Iberdrola are publicly traded investor-owned utilities." Id. Moreover, UI stated that the guarantee of regulatory deferrals required under IFRS, irrespective of future or contingent events, would only affect rates if a conditional event "such as no longer having a continuation of services" were to occur. Id.

The Company's request to align its financial reporting with that of its foreign parent is basically a "solution in search of a problem." US GAAP already allows for the proper matching of revenues and expenses, including regulatory deferred transactions. The regulatory process is not a scheme for guaranteeing the recovery of costs under a speculative occurrence of the Company "no longer having a continuation of service." Additionally, the Company's request would result in the application of different and inconsistent accounting rules for essentially similar transactions for other regulated utilities in the state. This would occur simply because those other regulated entities do not have foreign parents requiring financial reporting under IFRS and have no need to align their US GAAP financial statements thereto. While the Company is not precluded from aligning its financial information for the purpose of combined reporting with Iberdrola, UI is directed to continue to recognize its transactions under US GAAP for information and reports to be filed with the Authority. In summary, the Company failed to provide any

compelling support for why the requested order is necessary; therefore, UI's proposal is denied.

V. COST OF CAPITAL

A. SUMMARY

The Authority approves a weighted cost of capital of 6.71% based upon a 9.10% return on common equity, a 4.32% cost of long-term debt, and a capitalization mix of 50% common equity and 50% long-term debt. However, the allowed cost of capital calculated after reflecting the forty-seven (47) basis point reduction in the Company's return on equity imposed in this Decision is 6.48%.

The allowed Capitalization and Weighted Average Cost of Capital are depicted in the tables below:

Table 21: Weighted Average Cost of Capital without ROE Reductions

Capital Source	Allocation	Cost	Weighted Cost
Long-term Debt	50.0%	4.32%	2.16%
Short-term Debt	0.0%	0.0%	0%
Common Equity	50.0%	9.10%	4.55%
Total	**100.00%**		**6.71%**

Table 22: Approved Weighted Average Cost of Capital with ROE Reductions

Capital Source	Allocation	Cost	Weighted Cost
Long-term Debt	50.0%	4.32%	2.16 %
Short-term Debt	0.0%	0.0%	0 %
Common Equity	50.0%	8.63%	4.32 %
Total	**100.00%**		**6.475%**

B. PROXY GROUP

The Authority identified a proxy group of 21 comparable companies that can be analyzed to ascertain the market-based range of the cost of equity for the Company. The Authority typically applies the following criteria (Authority Screening Criteria) in the selection process: the proxy company (1) is predominantly in the same utility industry as the subject utility (70% for electric, 50% for gas), as reported by Value Line; (2) is publicly traded and reported by Value Line; (3) has paid consistent dividends for eight quarters and is expected to continue; (4) cannot be in financial distress; (5) is not the target of an acquisition or merger activity; (6) has credit ratings that are at least investment grade, as determined by Standard & Poor's (BBB- and above) and/or Moody's (Baa3 and above); and (7) has similar revenues to the company being analyzed.

The Authority considered the proxy groups proposed by the Company, the 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 classified as electric companies published in Value Line East (Issue 1), Value Line West (Issue 11), and Value Line Central (Issue 5) editions, and then screened these companies for specific criteria. Bulkley Prefiled Test. Ex. UI-AEB-1, Sept. 9, 2022, p. 25. The screening criteria evaluated whether the proxy company (1) pays consistent quarterly cash dividends; (2) has positive long-term earnings growth forecasts from at least two equity analysts; (3) has investment grade long-term issuer ratings from S&P and Moody's; (4) was not a party to a merger or transformative transaction during the analytical period; and (5) derives at least 70 percent of the company's operating income from electric regulated operations. Bulkley PFT, pp. 25-26. The Company's screening criteria resulted in the inclusion of 17 companies (Company Proxy Group). Id., p. 26. See Table 24 below.

The OCC proposed a proxy group (OCC Proxy Group) of 24 companies based upon its own selection criteria. Woolridge Prefiled Test., Dec. 13, 2022, p. 25. The OCC's screening criteria incorporated slight variations to the Company's selection criteria. The OCC's screening criteria included the following considerations: the proxy company (1) receives at least 50% of revenues from regulated electric operations as reported in SEC Form 10-K Report; (2) is followed by Value Line as a US based electric utility; (3) holds an investment grade corporate credit and bond rating; (4) has paid a cash dividend in the last six months with no cuts or omissions; (4) was not involved in an acquisition of another utility and is not the target of an acquisition; and (5) has long-term ESP growth rate forecasts from Yahoo, S&P Cap IQ, and Zacks. Id., p. 25. The difference between the Company's proposed proxy group of 17 companies and the OCC's proposed proxy group of 24 companies is the deletion of Otter Tail (NYSE-OTTR) and the addition of eight other companies, including: (1) CMS Energy Corporation (NYSE-CMS); (2) Consolidated Edison, Inc. (NYSE-ED); (3) Dominion Energy (NYSE-D); (4) Hawaiian Electric Industries (NYSE-HE); (5) MGE Energy, Inc. (NYSE-MGEE); (6) Pinnacle West Capital Corporation (NYSE-PNW), (7) Southern Company (NYSE-SO); and (8) WEC Energy Group (NYSE-WEC). Woolridge PFT, Ex. JRW-3, p. 2. Ultimately, the OCC Proxy Group consists of 24 companies as shown in Table 24 below. Woolridge PFT, Ex. JRW-3, p. 2.

Moreover, the OCC's assessment is that the Company Proxy Group receives 85% of its revenues from regulated operations, has a S&P bond rating of BBB+ bond and a Moody's bond rating of a Baa1, has a common equity ratio of 42.48%, and has an earned return on common equity of 9.94%. Woolridge PFT, p. 26. The OCC, therefore, asserts, that the investment risk of UI is a bit lower than that of the electric utilities in the OCC Proxy Group. Id. Additionally, in assessing the comparative risk profiles of the Company's versus the OCC's proxy groups, the data indicates that the risk measures for the OCC and Company Proxy Groups present similarly with respect to beta (0.86 vs. 0.88), financial strength (a vs. a), safety (1.7 vs 1.7), earnings predictability (89 vs. 85), and stock price stability (91 vs. 91). As such, the assessment of these measures is that the investment risk of both groups is very low and similar to each other. Woolridge PFT, pp. 26-27; Ex. JRW-3.[51]

[51] The Woolridge PFT narrative cites to Exhibit JRW-5 as the source of these statistics but Exhibit JRW-5 is cited in error. The actual source of these exhibits is Woolridge PFT, Exhibit JRW-3.

EOE used two proxy groups in its cost of equity models: (1) the Company Proxy Group, and (2) 12 companies that trade LEAPS (Long-Term Equity Anticipation Securities) out of the 36 publicly traded electric utility companies for which Value Line provides quarterly full company reports (RFC LEAPs Proxy Group). Only three of the 12 RFC Electric LEAPs Proxy Group companies are also in the Company Proxy Group. The RFC LEAPs Proxy Group is used only in EOE's COE Term Structure Analysis because these 12 companies have traded options greater than a one-year investment horizon. Rothschild Prefiled Test., Dec. 13, 2022, p. 52.

After considering the Parties' respective positions regarding appropriate proxy group formation, when constructing the Authority Proxy Group, PURA finds that Otter Tail should not be included because Otter Tail does not meet the screening criteria that the company's regulated electric utility revenue exceeds 70% of the company's total revenue.[52] Specifically, Otter Tail "derived less than 70 percent of their total company revenue from regulated electric operations for the three-year period of 2019-2021." UI Interrog. Resp. RRU-051; Woolridge PFT, Ex. JRW-3.1; Hr'g Tr., Mar. 9, 2023, 2978:9 – 2979:5. To address this shortcoming, the Company proposed using "total operating income" rather than "total company revenue income" in applying the screening criteria. UI Interrog. Resp. RRU-051. However, the Authority declines to adopt this approach because PURA has consistently held that, for electric utilities, a proxy company should receive at least 70% of its revenues from regulated electric operations. The Authority previously determined that the percentage of electric revenues definition is appropriately linked to 70% of revenues from regulated electric operations (as per the OCC's definition),[53] rather than company operating income from electric regulated operations (as per UI's preferred definition). See, e.g., 2016 Rate Case Decision, p. 81. The rationale for using revenues from electric regulated operations rather than operating income is that a company's operating income includes accounting adjustments by the respective companies that may hinder a direct comparison with the utility in question.

The Authority also finds that several companies excluded from the Company Proxy Group but included in the OCC Proxy Group are appropriate for inclusion in the Authority Proxy Group. Using a similar analysis to recompute the revenue percentages as regulated electric revenues to total revenues, the Authority determines that the following companies should be included in the Authority Proxy Group as these companies meet the Authority Screening Criteria that the company's regulated electric utility revenue exceeds 70% of the company's total revenue: Consolidated Edison, Inc. (69.93%),[54] Dominion Energy (81.97%), Hawaiian Electric Industries (88.50%), Pinnacle West Capital Corporation (100%),[55] and Southern Company (72.95%). Woolridge PFT, Ex. JRW-3, p.

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[52] Notably, the exclusion of Otter Tail from the Authority Proxy Group has only a nominal impact on the cost of equity models.

[53] While the Authority adopts the OCC's definition generally, PURA departs from the OCC in its determination of the appropriate percentage of electric revenues to total, which the OCC suggests should be at least 50% versus the at least 70% required by the Authority.

[54] The Authority rounded 69.93% to 70%.

[55] The Company argued that Pinnacle West Capital Corporation should be excluded given the Arizona Commission's recent rate decision authorizing an 8.70% ROE. Hr'g Tr., Mar. 22, 2023, 2983:12 - 2984:11. However, the Authority is not persuaded that recent news about a company (unless it triggers a specified screening criteria) is a reasonable basis for excluding an otherwise comparable proxy company.

2; Late Filed Ex. 139; Late Filed Ex. 145; Hr'g Tr., Mar. 22, 2023, 3610:8 – 3614:25. However, for the same reason discussed above that led the Authority to exclude Otter Tail, PURA declines to include: (1) CMS Energy Corporation; (2) MGE Energy, Inc.; or (3) WEC Energy Group.

Consequently, the Authority finds that the following 21 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 equity. 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 23: Proxy Group

No.	Utility Companies	Company Proposed	OCC Proposed	Approved Proxy Group
1	ALLETE, Inc.	y	y	y
2	Alliant Energy Corporation	y	y	y
3	Ameren Corporation	y	y	y
4	American Electric Power Co.	y	y	y
5	Avista Corporation	y	y	y
6	Consolidated Edison, Inc.		y	y
7	Dominion Energy		y	y
8	Duke Energy Corporation	y	y	y
9	Edison International	y	y	y
10	Entergy Corporation	y	y	y
11	Evergy, Inc.	y	y	y
12	Eversource Corporation	y	y	y
13	Hawaiian Electric Industries		y	y
14	IDACORP, Inc.	y	y	y
15	NextEra Energy, Inc.	y	y	y
16	NorthWestern Corporation	y	y	y
17	OGE Energy Corporation	y	y	y
18	Pinnacle West Capital Corp.		y	y
19	Portland General Electric	y	y	y
20	Southern Company		y	y
21	Xcel Energy, Inc.	y	y	y
22	CMS Energy Corp.		y	
23	MGE Energy, Inc.		y	
24	WEC Energy Group		y	
25	Otter Tail Corp.	y		

C. CAPITAL STRUCTURE

1. Summary

The Authority finds that a capital structure consisting of 50.0% common equity and 50.0% long-term debt is reasonable. The table below summarizes the allocation authorized herein.

Table 24: Approved Capital Structure

Capital Source	Allocation
Long-term Debt	50.0%
Short-term Debt	0.0%
Equity	50.0%
Total	100.0%

2. Position of the Parties

a. Company

The Company proposed a capital structure consisting of 52.0% common equity and 48.0% long-term debt. Bulkley PFT, p. 63; Late Filed Ex. 1, Att. 1, Sch. D-1.0 A, Sch. D-1.0B, and Sch. D-1.0 C. The Company asserts that its proposal is based upon its actual capital structure and the capital structures of the utility operating subsidiaries of the 17 companies in the Company Proxy Group. Id., p. 64.

Importantly, UI did not use the capital structures of the *proxy companies;* rather, the Company used the capital structures of the *operating subsidiaries* of those proxy companies. As a result, the Company's analysis indicates that the simple average of the operating subsidiaries' capitalization mix ranges from 44.97% to 61.33% common equity, with an average of 52.23% common equity and 47.77% long-term debt over the most recent eight financial quarters (2020 Q2 to 2022 Q1). Id., p. 64; Ex. UI-AEB-13; UI Interrog. Resp. RRU-118.

The Company did not propose incorporating short-term debt into its ratemaking capitalization mix based upon its analysis indicating short-term debt did not support the rate base. Late Filed Ex. 137. Given that the Company was allowed a 50%-50% capitalization mix for both the 2013 Rate Case Decision and the 2016 Rate Case Decision, the Company inferred that credit rating agencies have an expectation that the 50%-50% mix will continue and that such expectation has essentially been built into the Company's current rating. Hr'g Tr. Mar. 8, 2023, 2926:22 – 2927:7.

b. OCC

The OCC's recommended capital structure is 50% common equity and 50% long-term debt. Woolridge PFT, p. 4. The basis for the OCC's recommendation was that the 50%-50% capitalization mix is: (1) consistent with the Authority's past policies; and (2) more reflective of the capital structures of the proxy group. Id.

The OCC disagrees with the Company's recommendation to use the operating companies' capitalization mix as the benchmark to set the allowed capitalization mix. Id., p. 28. The OCC instead used the capital structures of the holding companies because

the holding company's stock is publicly traded. Id. The OCC's analysis indicates that as of December 31, 2021, the average common equity ratios for the OCC Proxy Group and Company Proxy Group were 41.7% and 42.48%, respectively. Id., p. 27; Ex. JRW-3. Therefore, the average common equity ratio for the proxy group was significantly lower than the UI proposed common equity ratio of 52%. Id., p. 27.

Further, the OCC argues that, as a lower risk regulated utility, the Company should use more debt to leverage capital dollars. According to the OCC, an electric company can carry more debt in its capital structure than unregulated companies as it has less business risk than unregulated companies. The utility company must take advantage of its lower business and financial risk than unregulated companies and employ more financial leverage (i.e., debt). Typically, electric utility equity ratios range from 40% to 50% (i.e., 60%-50% long-term debt). Id., p. 30.

Consequently, the OCC recommended that the Authority either: (1) impute a more reasonable capital structure to be reflected in the revenue requirement; or (2) recognize that a higher equity component in the authorized capitalization mix lowers financial risk and, therefore, authorize a lower ROE to compensate. The OCC recommended a capital structure with an imputed common equity ratio of 50%, which is consistent with the Authority's past policies and is more reflective of the holding company capital structures of the Company and the OCC proxy groups. Id., p. 31.

c. EOE

EOE proposed a capital structure of 46.04% common equity and 53.96% long-term debt. Rothschild PFT, p. 46; Rothschild Surrebuttal, Jan. 17, 2023, pp. 36-37. According to EOE, 46.04% common equity is consistent with the average common equity ratio of the electric companies in the 17 member Company Proxy Group. Id. EOE's assessment is that the Company's proposed 52% common equity ratio is higher than the average common equity employed by the Company Proxy Group and that the Company has not provided evidence to demonstrate its proposal will minimize its weighted average cost of capital. Id., pp. 45-46.

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 requirements for maintaining the current utility rating. Generally, the utility will advocate for a more "equity rich" capital structure because earnings on equity provide a better return for investors; whereas parties such as the OCC will advocate for a less "equity rich" capital structure because debt is less expensive for ratepayers than equity. The Authority is obligated to balance both "investor and consumer interests" in reaching a determination on the appropriate capital structure, among other items, in a rate case proceeding. Woodbury Water Co., 174 Conn. at 264.

The actual capital structure of the Company and its parent company, Avangrid, Inc. (Avangrid), provides a data point for determining the appropriate capital structure for ratemaking purposes. Here, as of December 31, 2021, the Company maintains an equity capitalization of 59.15% while its parent company, Avangrid, has only 26.7% equity in its capital structure. UI Interrog. Resp. RRU-006, UI Att. 2; UI Interrog. Resp. RRU-0016, Att.

1, p. 5. This dichotomy illustrates the challenge of determining a reasonable capitalization mix for ratemaking purposes. Importantly, the Company's management team and parent company exercise control over the Company's operations and financial results, and may take actions in between rate proceedings to manipulate, for a variety of reasons, the capital structure of the subsidiary. Consequently, the Company's actual capital structure does not necessarily represent an optimal or reasonable capital structure for ratemaking purposes. Notably, in its 2013 Rate Case, the Company proposed (and the Authority approved) a capital structure of 50% common equity and 50% long-term debt. 2013 Rate Case Decision, p. 95. And again, in the 2016 Rate Case, the Authority likewise approved a 50%-50% capital structure. 2016 Rate Case Decision, p. 63.[56]

The second factor in determining a reasonable capitalization mix is the range of capital structures of the proxy group. 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. Bulkley PFT, Ex. UI-AEB-13. The second, which was employed by the OCC and EOE, is to use the capital structures of the publicly traded holding companies' common equity ratios as the basis for the allowed ratemaking capitalization mix. Woolridge PFT, p. 28; Rothschild PFT, p. 46.

The Company's methodology used SEC Form 10-k to calculate the percentage of regulated operating income from electric distribution services for each underlying operating company of the publicly traded holding companies. Thus, the Company had to separately examine each regulated subsidiary operating company's capital structure and develop an alternative or consolidated holding company capital structure. By contrast, the OCC and EOE used the holding companies' actual capital structure from the SEC Form 10-k filings, supplemented with data from S&P Capital IQ and Value Line. Bulkley PFT, p. 26; Ex. UI-AEB-3; Woolridge PFT, Ex. JRW-3, p. 1; Rothschild PFT, p. 46; Ex. ALR-5. The table below summarizes the application of these methodologies to the Authority Proxy Group.

Table 25: Authority Proxy Group Equity Capitalization

Equity Capitalization	Method 1 (Consolidated Operating Subs)	Method 2 (Holding Companies)
Low	44.97% (Edison Int'l.)	19.92% (Southern Co.)
High	63.33% (NEXTERA)	57.07% (IDACORP)
Average	**53.32%**	**41.25%**

Rothschild PFT, Ex. ALR-5, p. 5; Bulkley PFT, Ex. UI-AEB-13.[57]

[56] In the 2016 Rate Case, UI advocated for a 52% equity capitalization but acknowledged that "a reasonable outcome would be to at least allow . . .50.34 percent." UI Written Exceptions, Dec. 2, 2016, p. 16.

[57] These sources (i.e., Bulkley PFT, Ex. AEB-13; Late Filed Ex. 145, UI Supplemental, Woolridge PFT, Ex. JRW-3, p. 1) were revised to reflect the capital structures of the 21 companies in the allowed Authority Proxy Group.

Notably, the companies with the highest and lowest equity capitalization differ depending upon the methodology. This difference highlights that the capitalization mix chosen by the operating company's management does not necessarily reflect the holding company level capitalization mix. Operating companies have different criteria for establishing and maintaining certain capital structures. Importantly, the capitalization of operating subsidiaries is the result of management decisions and, in some cases, the allocation of parent company debt to the subsidiaries as equity.

In addition, the operating companies do not have publicly traded stocks; therefore, their financials are subject to less market scrutiny by investors. Consequently, the use of operating subsidiary financial data for determining equity capitalization is less direct than using holding company financial data and, as such, subject to influences not directly visible to the market. For this reason, the Authority weighs the equity capitalization calculated using holding company data more heavily than values calculated using subsidiary data. See 2016 Rate Case 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.").[58]

As a final factor, the Authority considers how the capital structure may affect the credit rating of the Company. The Authority analyzed the effect that the different capital structures and ROEs presented by the Parties would have on the Company's core metrics as it relates to the rating agency that provides ratings for the Company. (See Section V.F., Financial Condition and Flexibility for a full analysis).[59] The analysis concluded that the core metrics remained in the ranges that would allow the Company to maintain its current A- for S&P, Baa1 for Moody's, and A- for Fitch ratings with the Authority allowed capital structure of 50% common equity to 50% long-term debt. Hr'g Tr. Mar. 9, 2023, 3170:12 – 3171:6.

Consequently, for ratemaking purposes, the Authority will use a capital structure consisting of 50% common equity and 50% long-term debt. The allowed equity ratio accounts for the equity capitalization of the Authority Proxy Group of companies (mean of

[58] The Company appears to assert that, because the Authority "acknowledged" UI's proposed methodology, PURA "should reconsider and establish the Company's capital structure with an equity quotient of 52[%]." UI Written Exceptions, p. 71. However, the Authority considered and specifically rejected the Company's methodology of relying exclusively on the consolidated financial information of subsidiary operating companies, for the reasons discussed in this section.

[59] In its Written Exceptions, the Company contends that the analysis reflected in Section V.F., Financial Condition and Flexibility, represents a concession by the Authority that the ROE and capital structure authorized herein will "harm the Company's credit ratings." UI Written Exceptions, p. 70. For the avoidance of doubt, the Authority highlights the distinction between a financial metric, or ratio, and a credit rating. Specifically, while the authorized capital structure and cost of capital may impact (negatively *or* positively) some of the credit ratios analyzed in the Decision, all relevant ratios stay within the respective A-, Baa1, and BBB+ parameters published by the ratings agencies. See Section V.F., Financial Condition and Flexibility. Further, as explained in the below section, UI will have a reasonable opportunity to operate in a manner that allows the Company to sustain its current credit rating and associated financial flexibility. Id.

41.25%) and those of the operating company subsidiaries (mean of 53.32%). Further, this capitalization mix is appropriate for maintaining the Company's current credit rating.[60]

D. COST OF DEBT

The Authority approves the Company's proposed cost of 4.32% for its $991 million of long-term debt. Late Filed Ex. 1, Att. Sch. D-3.0A. Short-term debt is not a component of the Company's approved capital structure; therefore, the Authority did not analyze the Company's cost of short-term debt.

The Authority determines the cost of long-term debt by calculating a weighted average of the Company's existing and foreseeable long-term debt issuances. In addition to its existing debt, the Company proposed the inclusion of $125 million of new senior notes (2023 Note) to be issued later in 2023. Late Filed Ex. 1, Att. Sch. D-3.0A. The 2023 Note will be used to pay off a $75 million note maturing in October 2023. The Company forecasts that the interest rate on the 2023 New Note will be 5.05% using a 30-year US Treasury bond yield of 3.40 and a 1.65% spread for first mortgage bonds. UI Interrog. Resp. RRU-039, Att. 1. The Authority finds the inclusion of the 2023 Note and the associated cost to be reasonable.

Notably, both EOE and the OCC concurred with the 4.32% cost of long-term debt. Rothschild PFT, p. 9; OCC Brief, p. 170. The table below summarizes the Company's long-term debt costs.

[60] The Company asserts that "PURA arbitrarily and capriciously adopted a capital structure with 50 percent common equity" and that "PURA fails to provide any justification as to how it arrived at the 50/50 capital structure . . ." UI Written Exceptions, p. 70. However, as noted above, the 50%-50% capital structure has been in place since at least the Company's 2013 Rate Case. Therefore, it is the Company that, among other things, failed to justify why the Authority should deviate from a ratemaking capital structure that has been in place for almost a decade and for which there is substantial evidence in this record.

Table 26: Cost of Long-Term Debt

Debt Issue	Rate	% of Debt	Weighted Rate
Pollution Control Revenue Refunding Bonds			
October 2018 Notes- due October 2, 2023	2.80%	0.55%	3.91%
October 2023 Notes- due October 2033	3.91%	5.95%	4.00%
Senior Notes			
3.61%, 2012 Series C, due January 31, 2022	3.61%	0.00%	0.00%
3.61%, 2012 Series B, due January 31, 2022	3.61%	0.00%	0.00%
6.26%, 2007, Series C, due September 5, 2022	6.26%	0.00%	0.00%
6.26%, 2007, Series D, due December 6, 2022	6.26%	0.00%	0.00%
3.95%, 2013 Series F, due October 25, 2023	3.95%	1.12%	4.10%
5.61%, 2009, due March 10, 2025	5.61%	5.05%	5.62%
3.96%, 2018, due December 12, 2025	3.96%	5.05%	4.03%
4.07%, due October 4, 2028	4.07%	10.10%	4.14%
2.02%%, 2020, due December 1, 2030	2.02%	7.57%	2.08%
6.51%, 2007, Series E, due September 5, 2037	6.51%	1.62%	6.52%
6.51%, 2007, Series F, due December 6, 2037	6.51%	1.21%	6.65%
6.09%, 2010, due July 27, 2040	6.09%	10.10%	6.11%
4.89%, 2012 Series D, due January 30, 2042	4.89%	5.25%	4.90%
4.89%, 2012 Series E, due January 30, 2042	4.89%	3.53%	4.92%
4.61%, 2015 Series G, due June 29, 2045	4.61%	5.05%	4.65%
4.52%, due January 15, 2049	4.52%	5.05%	4.54%
2.25% Notes due January 31, 2032	2.25%	15.14%	2.31%
4.62% Notes due December 15, 2032	4.62%	5.05%	4.76%
NEW SENIOR NOTES:			
5.05% 07/01/2023, Notes due September 1, 2053	5.05%	12.62%	5.13%
Total Thru 2023			**4.32%**

Late Filed Ex. 1, Sch. D-3.0A.

E. RETURN ON EQUITY

1. Summary

The Authority finds an unadjusted ROE of 9.10% to be reasonable. However, the Authority will adjust this ROE downward by 0.47% to address UI's management and operational performance in certain areas, as described in detail in Section V.E.10, Reductions to ROE, below. Therefore, until the performance issues are addressed in accordance with the Authority's orders, the Company's allowed ROE is 8.63%.

In reaching this determination, the Authority weighed 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.

2. Discounted Cash Flow (DCF) Financial 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 determined by its ability to generate future cash flows. Specifically, the present value of a financial asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return (i.e., the cost of common equity 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 to 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 proxy companies 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 Thompson First Call (provided by Yahoo!Finance), Zacks, and Value Line. Bulkley PFT, p. 33. 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. UI

Interrog. Resp. RRU-151.[61] As a result, the Company calculated a mean and median growth rate for the Company Proxy Group of 5.83% and 5.81%, respectively. Ex. UI-AEB-Rebuttal 3B.

The OCC proposed a growth rate methodology that considers a range of growth measures rather than only EPS growth estimates. The OCC asserts that relying exclusively on EPS growth rates overstates DCF results "by using overly optimistic and upwardly biased [EPS] growth forecasts. . . ." Woolridge PFT, pp. 6, 47-50. Specifically, the OCC "reviewed 13 growth rate measures, including historical and projected growth rate measures, and have evaluated growth in dividends, book value, and earnings per share." Id., pp. 44-47.[62] In addition, the OCC examined the internal growth rate (i.e., sustainable growth rate) using the retention rate of earnings times the return on equity. Id., p. 46. In weighing the various growth measures, the OCC gives "primary weight" to the projected EPS growth rate of Wall Street analysts but recognize[s] the upward bias nature of these forecasts." Id., p. 53.[63]

Applying this methodology to the OCC Proxy Group, the OCC identified a range of 5.25% to 5.50% and proposed to use the midpoint (5.375%) in its DCF calculation. Id., p. 53; Ex. JRW-5. Using the same methodology for the Company Proxy Group, the OCC proposed a range of 4.0% to 5.8% and proposed 5.50% as the growth rate. Id.

EOE approaches the growth rate calculation differently, asserting that the growth rate must be representative of constant sustainable growth. Rothschild PFT, pp. 57-59. 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 growth rates such as five-year projected EPS growth are not indicative of long-term sustainable growth rates in cash flow. Id., p. 60. 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 (IRR Growth Rate). IRR Growth rate used estimates of internal sustainable growth rate defined as growth rate (g) equals the earnings retention rate (b) times return on common equity investment (r) plus the rate of continuous new stock financing (s) times the fraction of funds raised by the sale of new stock (v). Mathematically written as Cost of Equity, or K, equals D/P +(br+sv). Id., p. 56. Overall, EOE indicates the retention growth approach as developed (i.e., its Estimate of Investor Anticipated Growth) eliminates the mathematical error between expected EPS and DPS growth and the tendency that analyst EPS growth rates are higher than investor expectations. EOE Interrog. Resp. RRU-411.

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[61] In the Application, the Company used data as of July 31, 2022, for its financial models. Bulkley PFT, Ex. UI-AEB-4, p. 1. In its rebuttal testimony, the Company used financial data as of November 30, 2022. The OCC used data as of November 25, 2022. Woolridge PFT, p. 43; Ex. JRW-5. The Authority will use the data from November 2022 because it is more recent.

[62] In prior rate cases, the Authority considered but excluded the Value Line historical EPS, DPS, and BVPS rates from its analytical models. See, e.g., 2023 Aquarion Rate Case Decision, p. 46; 2021 CWC Rate Case Decision, p. 36; 2013 Rate Case Decision, pp. 127-129; and 2016 Rate Case Decision, p. 83. For the same reasons previously articulated in those rate cases, the Authority will not include historical EPS, DPS, and BVPS growth rates in its analysis.

[63] The Company incorrectly implies that OCC's growth rate estimate, like the Company's, relies exclusively on EPS growth rates. UI Written Exceptions, p. 73. OCC rejected exclusive reliance on EPS growth rates due to the "upward bias."

Using this approach, EOE proposed a growth rate of 4.42% based on one-year average stock prices and 4.40% based on current prices for the Company Proxy Group. Rothschild PFT; Ex. ALR-3, p. 1. In addition, EOE proposed using a Non-Constant Growth Form of the DCF, for which it proposed a growth rate of 5.08% based on average prices and 5.81% based on current prices. Rothschild PFT; Ex. ALR-3, p. 2.

The table below summarizes the growth rates proposed by the Parties:

Table 27: DCF Expected Growth Estimates (%)

	Mean Average
Company – Company Proxy Group	5.83%
OCC - OCC Proxy Group	5.38%
EOE - Constant Growth	4.40%
EOE - Non Constant	5.81%

The Authority has typically used an expansive approach to determining expected growth rates, which is consistent with the OCC's methodology of considering a number of growth measures in addition to EPS growth. Here again, the Authority finds credible the OCC's testimony that exclusive reliance on EPS growth results in an improper upward bias. Woolridge PFT, pp. 6, 47-50. Similarly, the Authority credits EOE's testimony that EPS growth rates are not indicative of future long-term sustainable growth rates and are not directly usable in their raw form in the simplified DCF. Rothschild PFT, pp. 98-101. Therefore, although EPS growth is a key contributing factor in estimating future growth, the Authority finds that other measures, including DPS, BVPS, and retention growth, must be considered. Notably, the Authority has consistently included Value Line DPS, BVPS, and retention growth rates in its analysis based on the reasonable expectation that investors will consider all of the available projected growth rate data, rather than considering only a subset of the data. See, e.g., 2023 Aquarion Rate Case Decision, p. 46; 2016 Rate Case Decision, p. 83.

Accordingly, the Authority determined the expected growth rate for the Authority Proxy Group by considering six growth measures: (1) Yahoo! Finance 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.[64] See 2023 Aquarion Rate Case Decision, p. 46; 2021 CWC Rate Case Decision, p. 36; 2013 Rate Case Decision, pp. 127-129; 2016 Rate Case Decision, p. 83. 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 result

[64] The Authority calculated the retention growth rates using the simple sustainable earnings/retention growth formula and respective data from Value Line's projections for 2026-2028. The Authority concurs with the OCC's assessment that the Value Line projections for BVPS growth rate include Value Line's algorithm for s x v component of the retention growth rate. OCC Interrog. Resp. RRU-388.

is a mean and median growth rate of 4.79% and 4.82%, respectively.[65] The table below summarizes the Authority's analyses.[66]

Table 28: DCF Expected Growth Estimates

Proxy Company	Value Line EPS Growth	Yahoo! Finance EPS Growth	Zacks EPS Growth	Ave. EPS Growth Rate	Value Line DVPS Growth	Value Line BVPS Growth	Value Line Retention Growth	Ave. Other G measures	Expected Growth
ALLETE, Inc.	6.00%	8.70%	9.30%	8.00%	3.50%	3.50%	3.24%	3.41%	5.71%
Alliant Energy Corporation	6.00%	5.53%	5.90%	5.81%	6.00%	5.00%	4.46%	5.15%	5.48%
Ameren Corporation	6.50%	6.26%	7.20%	6.65%	7.00%	6.50%	4.20%	5.90%	6.28%
American Electric Power Co., Inc.	6.50%	6.18%	6.20%	6.29%	6.00%	6.00%	4.24%	5.41%	5.85%
Avista Corporation	3.00%	5.20%	5.20%	4.47%	4.00%	3.00%	2.14%	3.05%	3.76%
Duke Energy Corporation	5.00%	6.15%	5.50%	5.55%	2.00%	2.50%	3.14%	2.55%	4.05%
Edison International	16.00%	4.40%	2.60%	7.67%	5.50%	4.50%	5.64%	5.21%	6.44%
Entergy Corporation	4.00%	6.19%	6.80%	5.66%	5.00%	5.00%	4.59%	4.86%	5.26%
Eversource Energy	6.50%	6.42%	6.20%	6.37%	6.50%	5.00%	3.72%	5.07%	5.72%
Evergy, Inc.	7.50%	2.43%	4.90%	4.94%	7.00%	3.50%	3.58%	4.69%	4.82%
IDACORP, Inc.	4.00%	3.40%	3.40%	3.60%	6.50%	4.00%	3.13%	4.54%	4.07%
NextEra Energy, Inc.	10.50%	9.40%	9.70%	9.87%	10.00 %	6.50%	5.82%	7.44%	8.65%
NorthWestern Corporation	2.50%	4.50%	1.70%	2.90%	2.00%	3.00%	2.64%	2.55%	2.72%
OGE Energy Corporation	6.50%	1.90%	5.00%	4.47%	3.00%	5.50%	5.38%	4.63%	4.55%
Portland General Electric Co.	4.50%	1.39%	5.30%	3.73%	6.00%	3.50%	3.38%	4.29%	4.01%
Xcel Energy Inc.	6.00%	6.80%	6.50%	6.43%	6.50%	5.50%	4.05%	5.35%	5.89%
Con. Edison	4.00%	4.93%	2.00%	3.64%	2.50%	3.50%	2.88%	2.96%	3.30%
Dominion	5.50%	6.18%	5.72%	5.80%	1.00%	4.50%	4.50%	3.33%	4.57%
Hawaiian Electric	4.00%	1.30%	2.57%	2.62%	3.50%	3.00%	3.33%	3.28%	2.95%
Pinnacle-	0.50%	-3.95%	5.38%	0.64%	2.50%	2.50%	2.61%	2.54%	1.59%
Southern Co	6.50%	6.68%	4.00%	5.73%	3.50%	3.50%	4.79%	3.93%	4.83%
Mean				5.28%				4.29%	**4.79%**
Median				5.66%				4.54%	**4.82%**

[65] Ignoring EOE's constant growth rate estimate of 4.40%, the Company asserts the Authority's median growth estimate of 4.82% is "clearly understated" solely on the basis that "the parties proposed higher growth rates." UI Written Exceptions, p. 73. However, PURA is not bound to the parties' positions nor is it required to believe any particular witness, even an expert. Goldstar, 288 Conn. at 830.

[66] The Value Line, Yahoo!Finance, and Zacks data is found at Exhibits UI-AEB-Rebuttal 3B and JRW-5.

The Authority's growth estimates are lower than the Company's for two reasons. First, as discussed above, the Authority takes into consideration a broader range of growth measures. Specifically, the table above indicates the average of the non-EPS growth rates (4.29%) is approximately 100 basis points lower than the EPS growth rates (5.29%); therefore, weighing these factors equally results in an approximately 50 basis point difference.[67] Second, the Authority Proxy Group is larger than the Company Proxy Group and includes some companies with lower growth estimates. The net result is that the Authority's DCF analysis incorporates a lower overall expected growth rate.

c. Expected Dividend Yield

The second input into the DCF model is the Expected Dividend Yield. Given the relative similarities in the proxy groups, the expected dividend yields calculated by the Parties fell within a fairly narrow range. 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 transient stock price anomalies, an average daily stock price is typically used, with the time period ranging from 30 to 180 trading days. Here, similar to 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 2023 Aquarion Rate Case Decision, p. 43; 2021 CWC Rate Case Decision, p. 35.

The Company calculated a mean and median Expected Dividend Yield for the Company Proxy Group of 3.82% and 4.03%, respectively.[68] Bulkley Rebuttal Test. Woolridge and Kronauer, Ex. UI-AEB-Rebuttal-B (Woolridge and Kronauer). The Company provided dividend yields for the Company Proxy Group using 30-, 90-, and 180-trading days. Id.[69] The Company then escalated the dividend yields by one-half of the expected growth rate (known as the 1+.5g approach), using the EPS growth rate described above (i.e., 5.83% average). Id.

The 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). Woolridge PFT, pp. 43-44; Ex. JRW-5. The OCC applied the methodology to two proxy groups (i.e., Company Proxy Group and the OCC Proxy Group). The OCC analyzed the dividend yield based on the 30-day, 90-day, and 180-day average stock prices, but only factored in the 30-day and 90-day results to estimate a composite dividend yield of 3.65% and 3.70% for the OCC Proxy Group and the Company Proxy

[67] Conversely, the OCC places a heavier than equal, albeit unspecified, weighting on the EPS growth rates; therefore, the OCC estimated growth rate (5.38%) is slightly higher than the Authority's.

[68] In the Application, the Company used data as of July 31, 2022, for its financial models. Bulkley PFT, Ex. UI-AEB-4, p.1. Proxy group stock prices declined between July 2022, and November 2022, resulting in an increase in dividend yields and, by extension, higher overall ROEs. Although the November data is more favorable for the Company, the Authority will use the data because it is more recent.

[69] The 30-trading day average stock price results in a higher average dividend yield than the 90- and 180-trading day averages.

Group, respectively. Ex. JRW-5, pp. 1-2. Applying estimated growth rates of 5.375% for the OCC Proxy Group and 5.50% for the Company Proxy Group, the OCC calculated an Expected Dividend Yield of 3.75% (3.65% x 1.026875) and 3.80% (3.70% x 1.0275) for the OCC Proxy Group and the Company Proxy Group, respectively. Id., p. 54; Ex. JRW-5, p. 1.

For the constant growth DCF model, EOE calculated dividend yields of 3.48% and 3.66% based on the one-day stock prices and one-year average stock prices, respectively, as of October 31, 2022. EOE then escalated the yield using an expected growth rate, resulting in an Expected Dividend Yield of 3.57% (3.48% + 0.90%) and 3.77% (3.66% + 0.11%), respectively, for the weighted average calculation and spot market calculation. Id.; Rothschild PFT, p. 56; Ex. ALR-3, p. 2.[70]

As shown in the table below, the Parties' estimates for the Expected Dividend Yield fall within a fairly narrow range, around 3.80%.

Table 29: Expected Dividend Yield

	Mean Expected Div. Yield
Company – Company Proxy	3.82%
OCC - OCC Proxy Group	3.75%
EOE - Company Proxy Group	3.77%

The Authority considered two different methodologies for determining the Expected Dividend Yield for the Authority Proxy Group. First, the Authority applied the basic methodology used by the Company and the OCC (1+.5g approach) using the 30-trading day average stock prices and the expected growth rate described in the previous section (i.e., mean/median of 4.79%/4.82%). As shown in the table below, this approach results in a mean Expected Dividend Yield of 3.93% (median of 4.06%). The result is slightly higher than those of the Parties due to using more recent data (30-trading day average) and the use of the Authority's Proxy Group, which includes companies with higher dividend yields and excludes the lower dividend yield of Otter Tail.

Second, as an alternative methodology, 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)).[71] 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. Consequently, the Column (f) data provides a more nuanced financial analysis from a trusted source.

As such, the Authority has previously expressed a preference for using Value Line

[70] EOE also performed a non-constant growth form of the DCF model (Non-Constant DCF). This approach is an iterative method using the internal rate of return function (IRR) built into the excel spreadsheet based on October 31, 2022 data. Rothschild PFT, p. 62.

[71] By Notice of Admitted Evidence dated October 27, 2022, the Authority took administrative notice of several commercially available data sources, including the Value Line: Summary & Index.

Column (f) data for projected dividends. See Decision, Mar. 15, 2023, Docket No. 22-07-01, Application of Aquarion Water Company of Connecticut to Amend Its Rate Schedule (2023 Aquarion Rate Case Decision), p. 43; Decision, 2016 Rate Case Decision, p. 82; 2013 Rate Case Decision, p. 127. Neither the OCC nor EOE objected to the use of Column (f) data, both finding that the difference in the data compared to the 1+.5g approach was nominal. OCC Interrog. Resp. RRU-381 and RRU-385; EOE Interrog. Resp. RRU-412.

Calculating the Expected Dividend Yield using the Value Line Column (f) projections provides results that are nominally lower than those using the 1+.5g approach. Applying the Value Line Column (f) data to the Company Proxy Group provides an average Expected Dividend Yield of 3.76%. By comparison, the Company and the OCC calculated an Expected Dividend Yield of 3.82% and 3.80%, respectively, applying the 1+.5g approach. Consequently, the 1+.5g approach, in this case, appears to be reasonably consistent with Value Line Column (f) data, and the Authority will accept the use of the 1+.5g approach in the DCF model, acknowledging that it contains a slightly upward bias in the Expected Divided Yield.

Table 30: DCF Expected Dividend Yield Estimates

Proxy Company	Dividend Yield	Expected Growth Rate	Expected Div. Yield (1+.5g)	Auth. Proxy Exp. Div. Yield (VL)	Co. Proxy Exp. Div. Yield (VL)
ALLETE, Inc.	4.42%	5.71%	4.55%	4.43%	4.43%
Alliant Energy Corporation	3.23%	5.48%	3.31%	3.32%	3.32%
Ameren Corporation	2.85%	6.28%	2.93%	2.99%	2.99%
American Electric Power Co., Inc.	3.71%	5.85%	3.82%	3.71%	3.71%
Avista Corporation	4.56%	3.76%	4.64%	4.54%	4.54%
Duke Energy Corporation	4.29%	4.05%	4.38%	4.29%	4.29%
Edison International	4.68%	6.44%	4.83%	4.67%	4.67%
Entergy Corporation	3.96%	5.26%	4.06%	3.95%	3.95%
Eversource Energy	3.29%	5.72%	3.39%	3.43%	3.43%
Evergy, Inc.	4.14%	4.82%	4.24%	4.15%	4.15%
IDACORP, Inc.	3.08%	4.07%	3.14%	3.08%	3.08%
NextEra Energy, Inc.	2.14%	8.65%	2.24%	2.31%	2.31%
Northwestern Corporation	4.69%	2.72%	4.76%	4.74%	4.74%
OGE Energy Corporation	4.41%	4.55%	4.51%	4.42%	4.42%
Portland General Electric Co.	3.95%	4.01%	4.03%	4.08%	4.08%
Xcel Energy Inc.	2.95%	5.89%	3.04%	3.11%	3.11%
Otter Tail					2.79%
Con. Edison -ED	3.44%	3.30%	3.50%	3.60%	
Dominion -D	4.26%	4.57%	4.35%	4.80%	
Hawaiian Electric -HE	3.59%	2.95%	3.64%	3.60%	
Pinnacle-PNW	4.78%	1.59%	4.82%	4.90%	
Southern Co-SO	4.14%	4.83%	4.24%	4.20%	
Mean	3.84%	4.79%	**3.93%**	**3.83%**	**3.76%**
Median	3.96%	4.82%	**4.06%**	**4.02%**	**3.95%**

d. DCF Results

Once the Expected Dividend Yield and expected growth rate are determined, calculating an ROE is simply a matter of summation.

In its rebuttal testimony, the Company updated its DCF results and produced a range of 8.23% to 11.13%, with a mean of 9.65% and a median of 9.59%, using the 30-day stock price average. Ex. UI-AEB-Rebuttal-A1, p. 19; Ex. UI-AEB-Rebuttal-2A. This data reflects the Company's average Expected Dividend Yield of 3.82% and an average expected growth rate of 5.83%, as described in the prior two sections.

The OCC presented its model in a somewhat different format, using the aggregate Expected Dividend Yield (3.75%) and the aggregate expected growth rate (5.38%) to estimate an ROE of 9.10% (rounded down from 9.12%) for the OCC Proxy Group. Woolridge PFT, p. 54; Ex. JRW-5, p. 1.[72] No range was specifically presented.

EOE used two constant growth DCF methods. One of those methods is based on the sustainable retention growth procedure and the other method is based on option-implied growth as indicated from stock option prices. EOE also used a non-constant DCF method. EOE's constant growth DCF Model results in a range between 7.98% and 8.14% for the 17 member Company Electric Proxy Groups when using a sustainable growth rate, and between 8.54% and 8.73% when using an option-implied growth rate. Rothschild PFT, pp. 60-62. EOE calculated a non-constant DCF ROE between 6.54% and 6.87%. Id., pp. 57-58; Ex. ALR-3, pp. 3-4.

The results are summarized in the table below.

Table 31: DCF Results

Party	Mean	Median/ Midpoint	Range
Company	9.65%	9.59%	8.23% to 11.13%
OCC	9.10%		
EOE			
Sustainable Growth Rate		8.06%	7.98% to 8.14%
Option Implied Growth Rate		9.12%	8.66% to 9.58%
Non-Constant Growth Rate		8.64%	8.54% to 8.73%

To determine a range of ROEs for the Authority Proxy Group using the DCF model, the Authority added the Expected Dividend Yield (mean/median of 3.84%/3.96%) to the

[72] The OCC also ran its DCF model using the Company Proxy Group. However, the Authority will primarily reference the results from the OCC Proxy Group. The two proxy groups have significant overlap; therefore, considering the results from both groups would improperly skew the results towards a subset of companies by essentially double counting the duplicate companies.

expected growth rates (mean/median of 4.79%/4.82%). The table below provides the calculated ROE for the Authority Proxy Group using the DCF model.[73]

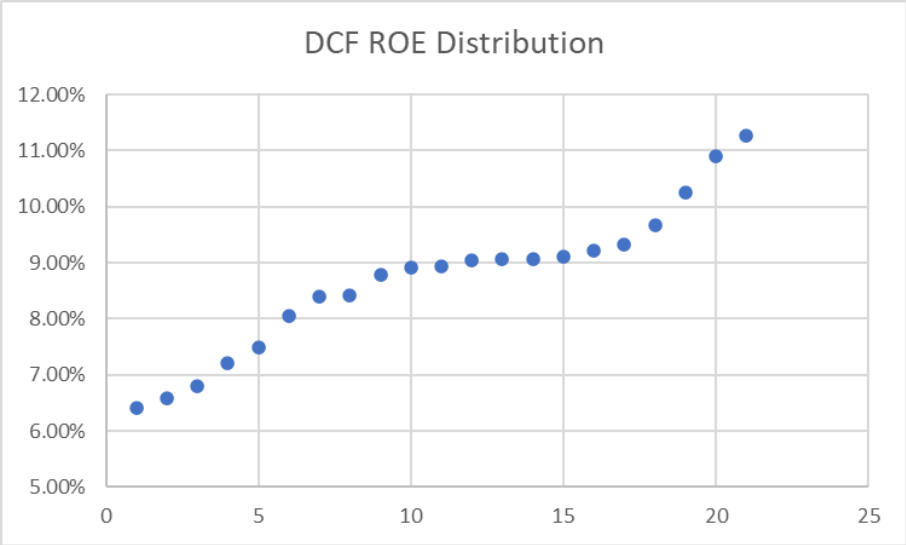
Table 32: DCF ROE – Authority Proxy Group

Proxy Company	Expected Div. Yield (1+.5g)	Expected Growth Rate	ROE
ALLETE, Inc.	4.55%	5.71%	10.26%
Alliant Energy Corporation	3.31%	5.48%	8.80%
Ameren Corporation	2.93%	6.28%	9.21%
American Electric Power Co., Inc.	3.82%	5.85%	9.67%
Avista Corporation	4.64%	3.76%	8.40%
Duke Energy Corporation	4.38%	4.05%	8.43%
Edison International	4.83%	6.44%	11.27%
Entergy Corporation	4.06%	5.26%	9.33%
Eversource Energy	3.39%	5.72%	9.11%
Evergy, Inc.	4.24%	4.82%	9.06%
IDACORP, Inc.	3.14%	4.07%	7.21%
NextEra Energy, Inc.	2.24%	8.65%	10.89%
NorthWestern Corporation	4.76%	2.72%	7.48%
OGE Energy Corporation	4.51%	4.55%	9.05%
Portland General Electric Co.	4.03%	4.01%	8.05%
Xcel Energy Inc.	3.04%	5.89%	8.93%
Con. Edison -ED	3.50%	3.30%	6.80%
Dominion -D	4.35%	4.57%	8.92%
Hawaiian Electric -HE	3.64%	2.95%	6.59%
Pinnacle-PNW	4.82%	1.59%	6.41%
Southern Co-SO	4.24%	4.83%	9.07%
Mean	**3.93%**	**4.79%**	**8.71%**
Median	**4.06%**	**4.82%**	**8.93%**

The ROEs for the 21 companies in the Authority Proxy Group ranged from 6.41% to 11.27%, with a mean of 8.71% and a median of 8.93%. The chart below illustrates the distribution of the ROEs and shows an aggregation of proxy group ROEs between 8.40% and 9.33%.

[73] The Authority considered excluding Pinnacle West given its relatively low ROE (6.41%) compared to other Authority Proxy Group companies. In addition, the Authority considered including Otter Tail (with a 6.61% ROE) as advocated for by the Company. However, because the two companies have similar ROEs, the effect on the model of replacing one with the other was negligible. In addition, Pinnacle West's ROE is no more of an outlier than Edison International (11.27%), which remains in the analysis. Ultimately, any proxy group will have a few lower and upper end results, and the purpose of a large proxy group is to average out these variations.

Figure 2: DCF ROE Distribution



Consequently, the Authority finds that the DCF model indicates that an ROE in the range of 8.40% to 9.33% 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 and can be used to calculate the expected return of an asset. Therefore, similar to the DCF model, by incorporating proxy company data, the CAPM provides evidence of commensurate ROEs for utilities with corresponding risk profiles.

To determine the cost of equity, 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, 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 equity risk premium (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 median betas of the Company Proxy Group as reported by Bloomberg and Value Line. The Bloomberg betas are calculated using 10 years of weekly returns relative to the S&P 500 Index. 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. Bulkley PFT, p. 38. The Company also did a historical beta analysis using long-term average betas as sourced from Value Line over the period 2011 through 2021. In its rebuttal testimony, the Company updated the betas for Bloomberg (0.81) and Value Line (.90), with the long-term historical Value Line beta at 0.73. Ex. UI-AEB-Rebuttal-4B.

The OCC used the same beta data from Value Line as the Company. The OCC's median Value Line betas for the OCC Proxy Group and the Company Proxy Group are 0.85 and 0.90, respectively. Woolridge PFT, p. 68; Ex. JRW-6, p. 3.

EOE used an alternative means to calculate beta by incorporating investors' return expectations by calculating option implied betas. The selection of option implied betas is based on EOE's observation that option implied betas provide information regarding future perceived risks and expectations. Rothschild PFT, p. 68. EOE calculated its betas under two scenarios:

(1) Hybrid Beta consisting of 50% Option-Implied Beta + 25% Historical Beta (6 months) + 15% Historical Beta (2 years) plus 10% Historical Beta (5 years); and
(2) Forward Beta consisting of 100% Options-Implied Beta. Id., p. 69.

According to EOE, the calculation of the Option-Implied beta requires: (1) obtaining stock option data for the company and market index, (2) filtering the stock option data, (3) calculating the option-implied volatility for the company and the index, (4) calculating the option-implied skewness for the company and the index, and (5) calculating the option implied betas for the company based on implied volatility and skewness for the Company and index. Id., p. 72. 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., p. 73.

EOE Hybrid Beta and Forward Beta analysis resulted in Historical Blended Beta and Forward Beta of 0.77 and 0.63 for its Weighted Average CAPM approach and 0.79 and 0.72 for its Spot CAPM approach, respectively. Id., p. 79; Ex. ALR-4, pp. 1 and 5.

The Authority generally considers both Value Line and Bloomberg Betas to be reliable and will often average the two sources to develop a composite Beta for each proxy company. See 2023 Aquarion Rate Case Decision, p. 50; 2021 CWC Rate Case Decision, pp. 38-39. Here, as the Company's data indicates for the Company Proxy Group, the Bloomberg Betas (0.81) are generally lower than the Value Line Betas (0.90). By averaging the two sources, the Authority seeks to minimize variations between

the data sets. Here, the Authority examined the difference between the Value Line Betas and the average of the Value Line and Bloomberg Betas. While the Value Line Betas were generally higher than the composite Betas, the difference was relatively minor. Taking the Value Line Betas used by the Company and the OCC for the Authority Proxy Group, the median Beta result is 0.85, which is the same as for the OCC Proxy Group – an unsurprising result given the similarities between these two proxy groups. Consequently, the Authority accepts the more conservative (i.e., higher) Value Line Betas for purposes of this CAPM analysis.

The table below illustrates the general consensus on the applicable Beta. Regarding the EOE Hybrid Beta and Forward Beta, the Authority considers the approach to be novel and outside the general scope of methodologies typically presented in cost of equity reviews. Although it is a new method, the Authority appreciates the alternative analysis, which lends credence to the Authority's finding that a Beta selection of 0.85 is conservative.

Table 33: Beta Summary

Proxy Company	Value Line (VL) Beta	Bloom-berg (BLM) Beta	OCC Proxy VL Beta	VL +BLM Beta	Auth. Proxy VL Beta
ALLETE, Inc.	0.90	0.84	0.90	0.86	0.90
Alliant Energy Corporation	0.85	0.80	0.85	0.83	0.85
Ameren Corporation	0.85	0.76	0.85	0.81	0.85
American Electric Power Company, Inc.	0.75	0.78	0.75	0.76	0.75
Avista Corporation	0.90	0.77	0.90	0.83	0.90
Duke Energy Corporation	0.85	0.73	0.85	0.79	0.85
Edison International	0.95	0.85	0.95	0.90	0.95
Entergy Corporation	0.95	0.86	0.95	0.91	0.95
Eversource Energy	0.90	0.81	0.90	0.86	0.90
Evergy, Inc.	0.90	0.80	0.90	0.85	0.90
IDACORP, Inc.	0.80	0.81	0.80	0.81	0.80
NextEra Energy, Inc.	0.90	0.83	0.90	0.86	0.90
NorthWestern Corporation	0.90	0.87	0.90	0.89	0.90
OGE Energy Corporation	1.05	0.93	1.05	0.99	1.05
Otter Tail Corporation	0.85	0.88	0.85	0.86	
Portland General Electric Company	0.85	0.79	0.85	0.82	0.85
Xcel Energy Inc.	0.80	0.76	0.80	0.77	0.80
CMS Energy Corporation (NYSE-CMS)			0.80		
Consolidated Edison, Inc. (NYSE-ED)			0.75		0.75
Dominion Energy Inc. (NYSE-D)			0.80		0.80
Pinnacle West Capital Corp. (NYSE-PNW)			0.90		0.90
Southern Company (NYSE-SO)			0.85		0.85
WEC Energy Group (NYSE-WEC)			0.80		
Hawaiian Electric			0.80		0.80
Median	**0.900**	**0.810**	**0.850**	**0.853**	**0.850**

c. Risk-Free Rate (Rf)

The Company identified three possible risk-free rates: (1) the current 30-day average yield on 30-year US Treasury Bonds (UST 30); (2) the projected UST 30-year yield for next year (Q4 2022 through Q4 2023); and (3) the projected UST 30 yield for the next 5 years (2024 through 2028). Bulkley PFT, p. 37. The Company "places more weight on the results of the projected yields on the 30-year Treasury bonds." Id. At the time of the Application, the projected yields (one-year and five-year) were 3.48% and 3.80%, respectively. Id. In its rebuttal testimony, the Company updated the projected yields to 4.06% and 3.90%, respectively, as of November 2022. Ex. UI-AEB-Rebuttal-4B.[74] Consequently, the Company's proposed risk-free rate ranged from approximately 3.50% to 4.00%.

The OCC's risk-free estimate was based on a review of the yield of UST 30 over the 2010 to 2021 time period, which ranged from 1.3% to 4.75%. The current yield is above that range. Woolridge PFT, p. 56. According to the OCC, Duff & Phelps recommends using a normalized risk-free rate of 3.5%, or if the spot yield on US Treasury 20 year (UST 20) is above 3.5%, to use UST 20 yield. Id.; OCC Interrog. Resp. RRU-391. Currently the US yield curve is inverted (i.e., long-term yields are lower than shorter term durations) with the UST 30 in the 3.5% range and the UST 20 in the 3.7% range. Id. Therefore, the OCC recommends using 3.6% as the risk-free rate, which the OCC finds effectively synchronizes the risk-free rate with the market risk premium, which is essential to implement the CAPM approach. Id., pp. 56-57.

EOE disagrees with using long-term US Treasury yields as the proxy for the risk-free rate in the CAPM as these bonds do not have a zero beta and may overstate the cost of equity. Rothschild PFT, p. 66; Appendix D. 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 expectation. Id., p. 66.

Instead, EOE's short-term risk-free rate is based on the yield of 3-month U.S. Treasury bills, while the long-term risk-free rate is based on the yield of UST 30. Rothschild PFT, p. 65. EOE's spot and weighted average short-term risk-free rates are 4.22% and 3.61%, respectively, and the spot and weighted average long-term risk-free rates are 4.22% and 3.84%, respectively. Id., 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 Authority agrees with EOE on the point that the risk-free rates should not be based on forecasted data because of the inherent uncertainty of reliance on analyst forecasts. Notably, the Authority has relied on UST 30 as the proxy for the risk-free rate for many rate proceedings. See, e.g., 2023 Aquarion Rate Decision, p. 51; 2016 UI Rate Decision, pp. 84-85; 2021 CT Water Rate Decision, pp. 38-39.

[74] UI asserts the updated data "demonstrated a risk-free rate of 4.07 percent . . . ." UI Written Exceptions, p. 74. However, the 4.07% rate is for the "current 30-day average of the 30-year [UST]." UI testified that the Company "places more weight on the results of the projected yields on the 30-year Treasury bonds," which are the 4.06% and 3.90% rates. Consequently, UI's claim that the 4.07% figure "should have been used" is belied by its own testimony.

The Authority notes that this rate case was filed during a time of both increasing and fluctuating rates, with respect to both short-term and long-term rates. See Section V.F., Financial Impact. As such, the Authority took into consideration both the increase in rates and the volatility of Treasury Market rates in its analysis. Based upon the trend in interest rate yields, and in an effort to smooth out interest rate volatility, the Authority finds an acceptable and conservative proxy for the return on long-term risk-free asset (Rf) to be 3.75%. The Authority's risk-free selection essentially incorporates each of the Party's recommendations.

As a final precaution given the fluctuating rate environment, the Authority examined the last 30 business days of UST 30 for the first quarter of 2023.[75] The current average 30-day yield, as of March 30, 2023, was 3.77%, which is slightly above the OCC's 3.6% recommendation and squarely within the Company's range of 3.50% to 4.00%.[76]

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 Parties each took a very different approach to determining the ERP.

In the Application, the Company calculated an expected return on the market of 12.94% by applying the Constant Growth DCF Model to the S&P 500 Index based upon an expected dividend yield of 1.71% and long-term growth rate of 11.14% on the S&P 500 Index. Bulkley PFT, p. 38; Ex. UI-AEB-8. The Company then determined an ERP (Rm-Rf) by using various estimates of the risk-free rate, resulting in an ERP ranging from 9.14% to 9.78%. Ex. UI-AEB-8. On rebuttal, the Company updated its ERP to a range of 8.58% to 8.75%. UI-AEB-Rebuttal-A1, Ex. AEB-REB-4A.

The OCC examined four different approaches to determining the ERP: (1) historical ex post returns, (2) financial surveys, (3) expected return models, and (4) the building blocks approach. Woolridge PFT, p. 64; Ex. JRW-6, p. 4. The building blocks approach is a hybrid approach employing elements of both historical and ex-ante models. Id., p. 63. Citing to several sources in each category, the OCC calculated average ERPs for the Historical Risk Premium approach (5.52%), Ex-Ante Models (5.50%), Financial Surveys (4.83%), and the Building Blocks approach (4.06%), with an overall average of 4.97% (median of 5.16%). Id., pp. 62-68; Ex. JRW-6, p. 6; Late Filed Ex. 142; OCC Interrog. Resp. RRU-322, Att. A, part RRU-98, part RRU-99, part RRU-100.

The OCC stated that the "more timely and relevant studies" were the Pablo Fernandez survey (average 5.60%), the Aswath Damordan study (average 5.30%),[77] the Duff & Phelps recommendation (6.00%), and the KPMG recommendation (6.00%).[78] Woolridge PFT, pp. 64-67. Giving "most weight to the market risk-premium estimates of Duff & Phelps, KPMG, the Fernandez survey, and Damodaran," the OCC asserted that

[75] The last 30 business days of UST 30 (^TYX) was extracted on March 30, 2023, from Yahoo.Finance.com.

[76] UI argues that "interest rates increased over the duration of the case"; therefore, the Authority's examination of updated UST 30 rates would seem to favor the Company. Nonetheless, UI objects to the consideration (but, notably, not the accuracy) of this data. UI Written Exceptions, p. 72.

[77] Updated to 4.78% as of March 2023. Late Filed Ex. 142.

[78] Updated to 5.75% as of March 2023. Late Filed Ex. 142.

the "appropriate market risk premium in the U.S. is in the 4.0% to 6.0% range." Id., p. 67. OCC used "an expected market risk premium of 6.00%, which is the upper end of the range." Id. The OCC concluded that "[t]his is a conservatively high estimate of the market risk premium. . . ." Id. Finally, the OCC argued that the Company's proposed ERP based upon the Constant DCF Model's application to the S&P 500 Index was "excessive" because it assumes 30% higher returns in the future than in the past. Woolridge PFT, p. 79; OCC Interrog. Resp. RRU-393.

EOE calculated its ERP using option-implied return expectations. Rothschild PFT, p. 76. 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 market risk premium. Id., p. 77. For the Weighted Average CAPM analysis with short- and long-term risk-free rates, EOE used ERPs of 7.54% and 7.31%, respectively. For the Spot CAPM analysis based on short- and long-term risk-free rates, the ERP was 7.01% and 7.01%, respectively. Id., p. 78; Ex. ALR-4, pp. 4 and 6.

The Authority has previously accepted the OCC's methodology in arriving at the ERP. See 2023 Aquarion Rate Case Decision, p. 52; 2013 Rate Case Decision, p. 133. Additionally, in past analyses, the Authority incorporated the OCC's survey of methodologies (OCC ERP Survey) into the PURA analysis. Woolridge PFT, Ex. JRW-6; Late Filed Ex. 142. 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 declined to adopt such an approach in the 2013 Rate Case Decision. 2013 Rate Case Decision, pp. 131-133. 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 unreasonable estimates of long-term EPS growth, expected market returns, and market risk premium. OCC Interrog. Resp. RRU-371, RRU-397 and RRU-398.

Here again, the Authority declines to adopt the Company's methodology for calculating the ERP and, instead, finds the methodology employed by the OCC to be more 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 those sources. The table below summarizes the data considered by the Authority in determining the appropriate ERP.[79]

[79] Woolridge PFT, pp. 64-68; Ex. JRW-6, pp. 5 and 7; Late Filed Ex. 142; Late Filed Ex. 143.

Table 34: ERP Data

Historical Risk Premium Studies		5.52%
Financial Surveys		4.83%
Ex Ante Models	Duff & Phelps	6.00%
	KPMG	5.75%
	Damodaran	4.78%
Building Blocks Approach		4.06%
Company Avg. Proposed ERP		8.64%
EOE Avg. Proposed ERP		7.22%
	Mean	5.85%

Given the above, the Authority finds that the 6.00% ERP recommended by the OCC reflects the best available information and the current market conditions.

e. CAPM results

Using the components as determined above, the Authority's CAPM result is 8.85%, based upon the CAPM formula Ke = Rf + β (ERP). The Authority's components and results are summarized as follows:

Table 35: CAPM Results

Component	**Rf**	**Beta**	**ERP**	**ROE**
CAPM Calculation	3.75%	0.85	6.0%	**8.85%**

4. Empirical Capital Asset Pricing Model (ECAPM)

The Company also included the results of an Empirical CAPM (ECAPM) or the Zero Beta CAPM. 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. Bulkley PFT, pp. 39-40. 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 the 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., p. 40.

The OCC indicated that the ECAPM has not been theoretically or empirically validated in journals. Beyond the lack of validation, 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. Woolridge PFT, p. 78; OCC Interrog. Resp. RRU-396.

The Authority has previously reviewed the ECAPM approach and excluded this method. See 2021 CWC Rate Case Decision, pp. 40-41. 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 finds that the 0.75/0.25 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. UI Interrog. Resp. RRU-167 and RRU-169.

The Authority reaffirms its rejection of ECAPM and will not incorporate its 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 plus Risk

The Company also proposed using the bond yield plus risk premium (BYPRP) model for determining ROE. Bulkley PFT, pp. 41-44. The BYPRP model is essentially the same as the Expected Earnings approach, and the Authority declines to adopt this model.

The Company developed the BYPRP model by regressing authorized ROEs for electric utilities to the US Treasury yield and adding risk premium. Woolridge PFT, pp. 91-92. Fundamentally, the BYPRP model uses allowed electric company ROEs resulting from state and federal regulatory proceedings as input variables. UI Interrog. Resp. RRU-172 and RRU-174. These allowed ROEs are not determined by competitive market forces, which set the standard for an investor's required return; therefore, the BYPRP is a gauge of past commission behavior rather than current and future market conditions. Woolridge PFT, p. 92. The Authority reaffirms its determination that the BYPRP (or Expected Earnings) approach is not widely accepted today in utility ratemaking as this benchmarking-comparison methodology has been replaced by regulators with market-based approaches, such as DCF or CAPM.

The Authority most recently rejected the BYPRP (i.e., Expected Earnings) 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. 2023 Aquarion Rate Case 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 herein 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 commission-allowed ROEs, the Authority will examine the ROEs approved in other jurisdictions as a point of reference. To that end, the Authority reviewed data on authorized ROEs nationwide by Regulatory Research Associates (RRA). RRA indicated there were 53 electric ROE determinations, with the electric utility average being 9.54% in 2022, compared to 9.38% in 2021 (i.e., 0.16% increase). See RRA Regulatory focus: Major Rate Case Decisions in the US-January-December 2022; OCC Interrog. Resp. RRU-372, Supplemental Filing, Feb. 23, 2023, p. 3. 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).

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 average ROE for vertically integrated electric utilities (9.69% in 2022 up from 9.53% in 2021) compared to the average ROE for distribution-only electric utilities (9.11% in 2022 up from 9.04% in 2021). Id., pp. 3, 7-8.

RRA has noted that interest rates and allowed ROEs declined at different rates between 1990 and 2020, with the gap between allowed ROEs and interest rates widening from 400 basis points in 1990, to 800 basis points in 2020. Id., p. 6. RRA suggests this is attributable to regulators not fully reflecting the decrease in interest rates in authorized ROEs under the reasoning that the decrease in interest rates was unusual. Id.

The OCC provided some explanation for RRA's observation with citation to a recent journal article that studied the relationship between authorized ROE and prevailing interest rates. Woolridge PFT, p. 23. One of the focused aspects of the empirical study was the extent to which utilities are allowed to earn excess returns on equity by regulators. The 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., p. 24. 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 estimate. Id. Overall, the 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. Consequently, the OCC argues that the Authority should not be concerned if an authorized ROE is below those from other jurisdictions. Id.

EOE takes a position similar to the OCC and recommends that the cost of equity be based on current market conditions rather than on past ROEs from other jurisdictions. Rothschild PFT, p. 18.

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. As noted above, the average 2022 ROE for distribution-only electric utilities was 9.11%, up slightly by 7 basis points from the

2021 average of 9.04%. OCC Interrog. Resp. RRU-372, Supplemental Filing dated Feb. 23, 2023, p. 3. The Authority also concurs with the OCC's assessment that authorized ROEs have not declined in lockstep with other capital costs and are potentially inflated by an amount ranging between 0.50% and 5.50%. As such, a review of recently allowed ROEs for distribution-only electric utilities indicates that 9% would be the upper limit for an ROE.

7. Current Economic Conditions

The Authority reviewed changes to certain financial indicators comparing current yields to those present at the 2016 Rate Case 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 cost of equity models to establish the ultimate allowed ROE.

To assess current economic conditions, the Authority reviewed several indicators. For example, US Gross Domestic Product (GDP) increased 21.2% (i.e., 22.48/106) and the Consumer Price Index (CPI) increased 23.15% (55.79/241), while unemployment decreased by 1.38% from 4.88% to 3.50% over that time period. UI Interrog. Resp. RRU-0078, Att. 1. Interest rates also were on the rise since the 2016 Rate Case 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). For example, 90-day and 180-day US Treasury Bills were up 2.92% (0.30% to 3.22%) and 3.31% (0.40% to 3.71%), while US Treasury Bonds of 10-year, 20-year, and 30-year maturities were up 2.02% (1.50% to 3.52%), 1.99% (1.82% to 3.82%), and 1.33% (2.23% to 3.56%), respectively. Id. Furthermore, Treasury Inflation-Protected Securities (TIPS) spread currently about 2.25% suggests that investors expect long-term inflation to be below 2.5%. OCC Interrog. Resp. RRU-373. Additionally, Connecticut unemployment had decreased to 4.2% in December 2022, from 5.2% in 2021, but remains above the 3.5% national unemployment level. OCC Interrog. Resp. RRU-375. The Authority's inferences derived from this inter-rate case macro financial data is that although US GDP and inflation (CPI) have increased relatively in lock step, these increased costs have been offset by a significant decrease to unemployment not observed in the US economy for some time.

Throughout this proceeding, the Parties presented the state of capital market conditions for the utility space. The data indicated the cost of equity for regulated utilities is presently affected by the following factors: (1) persistent high inflation, (2) changes to monetary policy, and (3) rising interest rates. Bulkley PFT, p. 11.

The Company indicated that capital market conditions have been significantly impacted by the economic repercussions of the COVID-19 pandemic and the subsequent Federal Reserve policy reaction to combat the economic effects of COVID-19. Id., p. 12. According to the Company, federal measures taken to contain the economic fallout from COVID-19 were extraordinary by any measure. In order to moderate economic consequences of the pandemic, the federal government took a series of unprecedented steps to stabilize financial markets. Id. The Company indicated the Federal Reserve decreased the federal funds rate in March of 2020, resulting in a target range of 0.00% to

0.25%, increased holdings of Treasury and Mortgage-Backed Securities (MBS), began expansive programs to support credit to large employers, and supported the flow of credit to consumers and businesses through Term Asset-Backed Securities Loan Facilities. Id., pp. 11-12. The Company argued that higher inflation will result in higher long-term interest rates, reducing investor's purchasing power and driving up yields on bonds. With higher interest rates, the Company indicated that investors require higher yields on long-term debt and higher yields on equity. Higher yields translate into higher required returns (i.e., ROE) on US utility stocks all else equal. Bulkley PFT, pp. 17-19.

Based on these current economic conditions, the Company offered that electric utility stock prices initially turned down but have since rebounded due to the conflict in Ukraine as investors turn to utility stocks as a safe haven. The result is higher electric utility stock prices and lower dividend yields. Id., p. 20. The Company concludes that the utility sector will most likely underperform over the near-term as the yield spread between the 10-year US Treasury Bond and dividend yield on the S&P Utilities Index presently 0.0% is below the long-term yield spread average of 1.45% since 2010. Id., p. 21. Under the presumption that the utility sector will underperform in the near term, the Company suggested the DCF model would likely underestimate investors' required return and supports ROE estimates derived from CAPM and ECAPM. Id., p. 24.

The OCC contends that: (1) despite the increase in year-over-year inflation, long-term inflation expectations are still below 2.50%; (2) the yield curve is currently inverted, suggesting that investors expect yields to decline and that a recession in the next year is very likely, putting downward pressure on interest rates; (3) interest rates have fallen significantly since their peak in October of 2022; (4) utility stock prices have held up very well in 2022, compared to the overall market; and (5) while authorized ROEs for utilities hit all-time lows in 2020 and 2021, these ROEs did not decline nearly as much as interest rates. Woolridge PFT, pp. 5-6 and pp. 10-22. The OCC's overall assessment of the current economic conditions is to focus on the current inverted yield curve, which has yields on short-term duration debt exceeding yields on longer-term securities and represents an anomalous condition that implies investors do not expect interest rates to remain at current levels and are expected to decline. Id., pp. 15-16. According to the OCC, every time the yield curve has been inverted over the last 50 years, a recession followed resulting in decreased interest rates. Id. The OCC indicated its position is being borne out as the prospects for a likely recession resulting from the inverted yield curve have already translated to lower interest rates as the yield on the 30-year US Treasury Bond declined from 4.40% to 3.40% in October 2022. Id., p. 17. Furthermore, the OCC disagrees with the Company's position that the current economic environment would result in future utility stock price declines and hence the DCF model underestimates the cost of equity. Id., p. 76.

EOE endorsed the OCC's assessment of the inverted yield curve and prospect for lower interest rates asserting that "despite recent increases in interest rates and market volatility, capital market data show that investors now expect a declining term structure for the cost of equity (COE), meaning they require a lower COE for a stock they plan to sell in five years than for a stock they plan to sell in one year." Rothschild PFT, pp. 24-25. EOE's overall assessment of the current and near future economic conditions is that (1) the Federal Reserve will continue to raise the federal funds rate over the next 6-8 months, so investors' inflationary expectations will sharply decrease, (2) long-term

interest rates will remain essentially at current levels, (3) investors will continue to find electric utilities attractive and subsequently electric utility stocks will perform better than the overall market, (4) stock volatility will remain elevated over the next five years, and (5) there is an expectation of a large stock price drop but the drop in utility stock prices should be less than that of the overall market. Id., pp. 25-26. Finally, EOE indicated that, despite high inflation, increasing interest rates, and volatile equity markets, investors' expectations are for a lower COE for companies as a whole. Id., p. 26. With a declining COE term structure, electric utility companies will be able to raise needed capital at reasonably low cost. Id.

Long-term interest rates have increased approximately 1.30% since the 2016 Rate Case Decision. Further, the COVID-19 pandemic and inflation resulted in increased market volatility rates; this volatility is still present in market trends. Notwithstanding this acknowledged volatility, the Authority finds that allowed ROEs should not increase in lock step with increases in interest rates. As discussed above, jurisdictional allowed ROEs declined much slower than yields on US Treasuries declined in the past. The Authority finds persuasive the reasoning presented by the OCC and EOE witnesses — particularly, that the correlation between interest rates and ROEs appears to be historically one-sided. Consequently, the Authority rejects the Company's suggestion that ROEs must increase in tandem with the increases in US Treasuries.

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 Company indicated that the cost of capital models such as DCF and CAPM only provide a range of estimates for the Company's ROE. Bulkley PFT, p. 45. The Company cites additional factors to consider in relation to the Company's overall risk profile including: (a) regulatory environment, (b) cost recovery mechanisms, and (c) other jurisdictions' authorized returns. Id., pp. 45-50. The OCC notes, however, that these risk factors are already considered by rating agencies when assessing the risk of the entity. Furthermore, the OCC's finding is that UI's investment risk is slightly below that of other electric utilities. For example, UI's S&P and Moody's ratings are A- and Baa1, respectively; yet the average risk of the Company Proxy Group and OCC Proxy Group are BBB+ (for S&P) and Baa1 (for Moody's). Woolridge PFT, p. 6; OCC Interrog. Resp. RRU-390.

The Authority finds that the risk profile of UI is lower than that of the Authority Proxy Group. The companies in the Authority Proxy Group have on average a BBB+ rating for S&P and a Baa1 for Moody's, similar to the credit rating of the OCC Proxy Group. As such, the Company's credit rating indicates it is less risky than the average proxy company. Less risk warrants a lower rate of return, not higher. 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 Rate Adjustment Mechanisms (RAM) and the C&LM program.

The Company's RAM is multi-tiered and provides a more stable revenue stream 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." Conn. Gen. Stat. § 16-19(b). 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.

b. Conn. Gen. Stat. § 16-19kk 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.

Conn. Gen. Stat. § 16-19kk(c). The Authority considered these statutory factors and finds that the record does not support an adjustment to the Authority-allowed ROE based on these considerations.

9. Approved ROE

In determining a reasonable ROE, the Authority considers the analytical models for commensurate electric 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 cost of equity for similarly situated utilities. Conversely, the CAPM relies primarily on risk-premium studies, which are more subjective in nature.

Here, the DCF model as applied to the Authority Proxy Group indicated an ROE range of 8.40% to 9.33%, with a mean of 8.71% and a median of 8.93%. The CAPM model produced a similar ROE result of 8.85%. Combined with the Authority's conclusion that ROEs approved in other jurisdictions indicated an upper limit of 9%, the data indicates that an ROE between 8.60% and 9.00% would be sufficient to provide a reasonable, market-based return.

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." Conn. Gen. Stat. § 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. Dep't of Pub. Util. Control, 216 Conn. at 634-635. In determining an ROE, the Authority "is not bound to the use of any single formula or combination of formulae" but 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, testimony from the Parties and Intervenors, prevailing and anticipated market conditions, and the regulatory environment.

In brief, the Company is financially stable, maintaining an A-/ Stable Rating from S&P, Baa1 from Moody's Investor services, and A- from Fitch. Since its last rate case, the Company merged with AVANGRID, Inc. a subsidiary of 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 will adopt a 9.10% ROE.

10. Reductions to ROE

a. Introduction

Having found that a 9.10% ROE is reasonable for a similarly situated electric utility providing expert, efficient, and prudent management of the utility franchise, the Authority considered whether to adjust the ROE for the Company's actual management of its franchise and concludes that a cumulative 47 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. 134–35 (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.").

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, ..." Conn. Gen. Stat. § 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." Conn. Gen. Stat. § 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 Conn. Gen. Stat. § 16-19e(a). 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 appear to reflect expert, efficient, and prudent management. Indeed, the Authority took the additional step of specifically requesting pre-hearing briefs on several of the areas where it was contemplating imposing ROE reductions.[80] Notice of

[80] The Company asserts that there is "a substantial deficiency in the notice underlying certain of the Authority's ROE reductions, particularly where those penalties are raised for the first time on brief at the

Request for Briefs, Jan. 18, 2023, pp. 1-2. Further, the Authority and the Parties engaged in a robust discovery process, culminating in fourteen days of hearings, the filing of late filed exhibits and subsequent late filed exhibit hearings, post-hearing briefs and reply briefs, written exceptions to the proposed final decision, and oral argument. Evidence from this lengthy adjudicatory process, as well as the various input from Parties and Intervenors through briefs, written exceptions, and oral argument 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. Incomplete COSS and Rate Design Considerations

The Authority determines that a two (2) basis point reduction to the Company's ROE is warranted for submitting an incomplete cost of service study and rate design analysis, as discussed in detail in Sections X.B., Cost of Service Study, X.C., Class Revenue Allocation, and X.D., Rate Design.

The Company filed its allocated cost of service study (ACOSS) as part of its standard filing requirements in its Application. Application, Ex. E-6.0. Traditionally, the ACOSS serves as a guideline for rate design for distribution rates for the various customer classes. Rather than relying on its ACOSS to support its rate design proposal, UI instead proposed an alternative rate design that applied equal percentage changes of the bundled[81] revenue requirements for each rate schedule. Colca & Marini Prefiled Test., Sep. 9, 2022, p. 5. Specifically, UI proposed to perform a detailed rate design in either Docket No. 17-12-03RE02, PURA Investigation into Distribution System Planning of the Electric Distribution Companies- Advanced Metering Infrastructure, or 17-12-03RE11, PURA Investigation into Distribution System Planning of the Electric Distribution Companies- New Rate Designs and Rates Review. However, both proceedings are part of the Authority's Equitable Modern Grid Initiative,[82] and Docket No. 17-12-03RE11 has been concluded. Hr'g Tr. Feb. 13, 2023, 100:11. As an active Party in Docket No. 17-12-03RE11, the Company was aware that a Proposed Final Decision was pending issuance within days of filing its Application on September 9, 2022.[83]

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end of the case when the Company is not able to put evidence on the record regarding the issue raised." UI Written Exceptions, p. 79. The record rebuts this claim. The Authority's Revised Notice of Proceeding specifically stated that the Authority would determine the Company's ROE in this proceeding and would, *inter alia*, contemplate adjustments based on the Company's response to Tropical Storm Isaias and failure to revise accounting treatment for the Transmission Adjustment Clause. Revised Notice of Proceeding, Nov. 9, 2022, p. 1. On January 18, 2023, the Authority issued a request for pre-hearing briefs covering a range of topics, including potential ROE reductions related to the topics identified in the Revised Notice of Proceeding, and "repeated occurrences of untimely submission of reconcilable expenses and credits." Notice of Request for Briefs, Jan. 18, 2023, pp. 1-2. Further, over the fourteen days of hearings, there was lengthy cross-examination and Company redirect examination related to English Station and the Company's Customer Service panel stemming from a myriad of discovery conducted by the Authority, EOE, the OCC, DEEP, and the Attorney General's Office on the Company's deficient performance in such areas. Further, the Company was afforded the additional opportunity to rebut the recommendations of other Parties and Intervenors through a Reply Brief, submitted on May 9, 2023, as well as to address the matter in its written exceptions and through oral argument.

[81] "Bundled" revenue requirements were defined as the sum of revenues from all generation and delivery services. Colca & Marini PFT, Sep. 9, 2022, p. 5.

[82] See https://portal.ct.gov/PURA/Electric/Grid-Modernization/Grid-Modernization.

[83] The Authority issued its Proposed Final Decision in Docket No. 17-12-03RE11 on schedule on September 14, 2022, as noticed in the external procedural calendar for the docket, and a Final Decision on October 19, 2022.

At the hearings, the Company offered several justifications for its proposed rate design and revenue allocation as opposed to utilizing its ACOSS, including:

a) Citing evolving industry changes and open dockets in Connecticut, which were not modeled in its filed ACOSS. Hr'g Tr. Feb. 13, 2023, 194:6 – 195:15;

b) Suggesting that it did not have time to interpret the relative rates of return differentials that came out of its ACOSS. See, e.g., Hr'g Tr., 195:20 – 196:7;

c) Claiming as a primary concern that potential migration between Rate RT and Rate R customers as a revenue recovery matter was justification for setting the ACOSS results aside. Hr'g Tr. Feb. 14, 2023, 417:3 – 419:14; and

d) Conceding that the Company is aware of the disparity between Rates R and RT ACOSS in June 2022, but did not feel the need to address this detail in the Company's September 9, 2022 testimony. Hr'g Tr. Feb. 14, 2023, 481:2 – 484:1, and 486:24 – 487:3.

Based on the above, as well as analysis provided in Sections X.B., Cost of Service Study, X.C., Class Revenue Allocation, and X.D., Rate Design, the Authority determines that UI neglected to perform a rigorous analysis of its ACOSS results and to provide a thorough proposal to equitably allocate its requested distribution revenue increase in accordance with well-established rate design principles. See Section X., Rate Design.

Accordingly, the Authority determines that a two (2) basis point reduction to the authorized ROE is warranted due to the Company's inexplicable failure to properly perform and to submit a current cost of service study and rate design in this rate case. This reduction shall be imposed until the effective date of a rate amendment that the Authority approves in a subsequent rate case proceeding conducted pursuant to Conn. Gen. Stat. §§ 16-19 and 16-19e, so long as the Company remedies the deficiencies identified herein with respect to its ACOSS, cost allocation, and rate design submitted in the subsequent proceeding and provides the additional, required analysis summarized in Section X.D.8., Summary of ACOSS Direction, in such proceeding.

c. Transmission Adjustment Clause and Customer Lost Benefits

In the Authority's August 17, 2022 Final Decision in Docket No. 22-01-04, PURA Annual Review of the Rate Adjustment Mechanism of The United Illuminating Company (22-01-04 Decision), PURA raised concerns regarding the timing of the Company's change in reporting regional network service (RNS) revenues and expenses on a net basis. 22-01-04 Decision, p. 15. The RNS revenues and expenses are captured in the Transmission Adjustment Clause (TAC) on customer bills. See 22-01-04 Decision, p. 14. As explained in the 22-01-04 Decision, UI was aware that Eversource had been reporting transmission revenue on a net basis since 2001, but UI did not request a change to its net reporting approach until 2018. Id. The approved accounting change resulted in a $10.090 million reduction in the Company's GET included in the 2021 TAC revenue requirement. Id.

The Authority concluded that the Company's adherence to its prior accounting treatment of the TAC, as well as its failure to recognize for approximately 15 years the customer benefits of reporting transmission on a net basis, is indicative of imprudent and inefficient management and operations of the Company. Id., p. 15. As a result, the Authority stated that it may consider whether the evidence gathered in the 22-01-04 Decision and the Authority's conclusion warrants a reduction in the Company's ROE when it files its next rates case. Id. The Authority concludes that it does and, accordingly, reduces UI's ROE by five (5) basis points.

Here, the Company testified that its management develops tax policy and monitors tax developments so that it may act to the benefit of both the Company and ratepayers. Hr'g Tr. Feb. 27, 2023, 1541: 20-25, 1542: 22-24. The Company further stated that it has relationships with external tax professionals and that, although such professionals do not ultimately set tax policy, the Company "take[s] good information [wherever] it comes from," including through FERC filings and in the Company's role as a New England Participating Transmission Owner. Hr'g Tr. Feb. 27, 2023, 1541-42: 21-25, 1543: 4-5.

To explain why it continued to report transmission revenues on a gross rather than net basis, the Company contends that it was not aware of Eversource's FERC request to report transmission revenue on a net basis until 2016, that it was not a party to the FERC proceeding approving Eversource's request to report transmission revenues and expenses on a net basis, and that it does not routinely monitor every FERC filing from peer utilities. Ex. UI-CJE/JC-Rebuttal-1, p. 19. The Company further argues that its external auditors did not recommend that it modify its accounting treatment for transmission revenue and expenses, that there is no single approach to record transmission revenue, and that utilities have the latitude to take an approach that meets its business needs. Id., p. 23. As an example, UI points to Versant Power, an Eversource affiliate, which until recently recorded RNS revenue and expenses on a gross basis. See UI Pre-Hr'g Brief, p. 30.

The Authority finds unpersuasive the Company's testimony and argument as to why it failed to implement an accounting change that would save ratepayers millions of dollars. Notably, Order 668, a 2005 FERC ruling, indicated that regional transmission operator (RTO) transactions should be reported on a net basis because purchase and sale transactions occurring in the same period to serve native load are done contemporaneously and should be combined. 22-01-04 Decision, p. 16. Specifically, Order 668 states that "[n]etting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load. Recording these transactions on a gross basis, in contrast, would give an inaccurate picture of a participant's size and revenue producing potential." Id., p. 16.

Consequently, irrespective of the Company's participation or knowledge of the 2001 FERC proceeding involving Eversource, it is unreasonable for UI management to be unaware of the FERC-identified best practice in Order 668 issued more than 15 years ago. Further, UI is a member of both the New England Power Pool (NEPOOL) and pooled transmission owners (PTOs) within ISO-New England and, as such, would be expected to have at least some engagement with its peers that would lead the Company's management to explore ways to drive efficiencies in its accounting practices. Id. This

notion is supported by UI's testimony that it "take[s] good information [wherever] it comes from." Hr'g Tr. Feb. 27, 2023, 1543: 4-5.

Importantly, 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." Conn. Gen. Stat. § 16-19e(a). The Authority finds that a reasonably expert and efficient utility management team should have been aware of the best accounting practices and implemented such practices to benefit ratepayers. UI's management team did not do so and, through its briefs, seemingly allocates blame to its external accountants and even the OCC and the Authority for not identifying FERC accounting best practices. Id., pp. 25, 29. However, as the Company conceded, management drives tax policy.[84]

Unfortunately, UI's failure to act sooner precluded the Company's retail customers from receiving significant benefits through reduced GET expenses built-in to the annual TAC revenue requirement, as evidenced by the $10.090 million reduction in the Company's GET expense in 2021 alone. See 22-01-04 Decision, p. 16. UI's failure in this case exemplifies the fundamental risk ratepayers bear when served by an investor-owned utility. Namely, absent a financial interest for management and shareholders, ratepayers' interests may not be served, and benefits may be left unrealized. Utility regulation exists, in large part, to monitor, correct, and discourage these occurrences. An ROE reduction is the most appropriate regulatory corrective action as it provides management with a direct incentive for improved performance and discourages similar behavior (i.e., a lack of proactive action on behalf of ratepayers) in the future.

As a result, a five (5) basis point reduction in the Company's ROE is warranted to incentivize management to identify opportunities more proactively and efficiently for ratepayer benefits in items included in the Company's annual RAM Filings and, in turn, to better align the Company's managerial and financial operations with the guidelines provided in Conn. Gen. Stat. § 16-19e(a) (2), (3), and (6). This will result in an approximately $405,000 reduction[85] in the Company's annual revenue requirement; however, this amount is a mere fraction of the costs unnecessarily imposed on ratepayers as result of UI's deficient accounting. The five (5) basis point ROE reduction will remain in place until the earlier of three years or the effective date of a rate amendment that the Authority approves in a subsequent rate case proceeding conducted pursuant to Conn. Gen. Stat. §§ 16-19 and 16-19e.

d. Tropical Storm Isaias

The Authority previously determined that UI's performance in response to Tropical Storm Isaias was deficient, inadequate, and imprudent, and, as a result, the Authority

[84] The Company argues that the Authority is "improperly engag[ing] in hindsight judgment." UI Written Exceptions, p. 89. Notably though, the Company does not cite to any specific information relied upon by the Authority that was only known after the fact. That UI management may have been ignorant of the best accounting practices adopted by its federal regulator (FERC) for reporting transmission revenues does not excuse UI's actions; rather, any such ignorance was the problem.

[85] UI estimates that each basis point reduction equates to approximately $81,000 in annual revenue impact. UI Written Exceptions, pp. 76-77, fn. 49.

would impose a fifteen (15) basis point reduction to the Company's ROE in its next rate case. 20-08-03 Decision, p. 127.

The Authority's decision to impose an ROE reduction to align improved storm performance with a financial incentive was based on findings made by the Authority that UI failed to perform certain emergency response functions properly, including:

1. UI did not follow the make safe protocol to ensure Bridgeport received a Make Safe crew when requested. Specifically, UI improperly removed Make Safe Crews on August 5 and August 6.
2. UI did not timely restore critical facilities. Bridgeport's emergency communications and operations center was not restored until August 8, 2020.
3. UI did not share timely or accurate information about availability of Make Safe crews, priority restoration locations, and outage information of vulnerable customers.
4. UI did not properly coordinate with Bridgeport to address its priority restoration needs.

Id., pp. 92-95.

The Authority deemed these failures sufficient to warrant a reduction in UI's ROE in order to incentivize the Company to improve its management of future storm responses. 20-08-03 Decision, p. 127. The Authority deemed the fifteen (15) basis point reduction consistent with prior storm performance-related actions imposed by PURA. Id., p. 127.

During this proceeding UI has provided evidence that it has remedied or effectuated operational changes that should remedy the deficiencies identified in the 20-08-03 Decision; therefore, the Authority finds that a downward modification of the ROE reduction contemplated in the 20-08-03 Decision is warranted. In many cases, UI has taken seriously the need to improve its storm performance and coordination with municipalities. For example, UI has taken steps to ensure make safe crews can muster efficiently with municipal road clearing crews. Interrog. Resp. RRU-88. UI has added a utility field coordinator position for emergency response to improve coordination with municipal personnel. CJE Rebuttal, p. 14; Interrog. Resp. RRU-88, p. 6. UI has taken other steps to improve communications with Bridgeport, including coordinating with the city annually to update Bridgeport's priority restoration list. Id., p. 6. In response to the delayed restoration of Bridgeport's Police Station during Tropical Storm Isaias, UI has modified its procedures to prioritize the location regardless of whether it has emergency back-up generation. Id., pp. 6-7. The Company also expedited the Municipal Dashboard, which was developed in direct coordination with the Town of Fairfield. EPP PFT, pp. 23-25. UI has developed a daily municipal storm call to activate with towns during events to share restoration information. Id., p. 16. Additionally, UI has proactively worked with municipalities, large customers, and critical facilities (e.g., hospitals) to prepare for the need for winter reliability energy emergencies. Id.

Although UI has improved its management of future storm responses, UI's compliance with certain orders in the 20-08-03 Decision was not entirely satisfactory. For example, Order No. 9 directed UI to develop a template to conduct outreach to

municipalities to determine the most useful information that UI can provide during the first 48 hours of emergency response and to formalize that information in a template. 20-08-03 Decision, p. 134. UI did not submit a template with this information, as required. Motion No. 65 Ruling, Aug. 11, 2021, Docket No. 20-08-03. Also, Order No. 10 required that the Company work with municipalities to identify areas to improve the system for communicating about blocked roads and to file a report with the Authority identifying improvements. 20-08-03 Decision, p. 135. UI did not include in its initial report the necessary information outlining specific improvements to the reporting process. Motion No. 67 Ruling, Aug. 11, 2021, Docket No. 20-08-03. Also, Order No. 11 directed UI to update its after-action reporting template to include a section to identify "corrective actions and lessons learned regarding performance efficiencies or cost saving measures." 20-08-03 Decision, p. 135. UI failed to make the required updates. Motion No. 68 Ruling, Aug. 11, 2021, Docket No. 20-08-03.

Notwithstanding, the Authority finds that the fifteen (15) basis point reduction identified in the 20-08-03 Decision appears to have achieved the Authority's objective of incentivizing UI to implement improved storm response systems overall. With this objective met, the Authority determines that the ROE reduction is not necessary to implement in this proceeding. However, the Authority will continue to closely monitor and review UI's storm preparation and response performance.

e. English Station

In their respective briefs, OAG and DEEP argue that the Company has mismanaged its English Station remediation responsibilities and, accordingly, should be assessed an ROE reduction to incentivize the Company to fulfill its obligation to remediate the site. OAG Brief, p. 11; DEEP Brief, p. 16. The Authority concludes that the Company's failure to remediate English Station represents both non-compliance with a condition of its Authority-approved merger with Iberdrola and deficient management by the Company. Accordingly, a twenty (20) basis point reduction to the Company's allowed ROE is warranted to ensure compliance with the merger conditions and to incentivize efficient management by the Company.

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), p. 21. 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." Id., App. 1, p. 3.[86] 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

[86] The executed PCO was accepted by DEEP though a final decision issued on August 4, 2016. UI Interrog. Resp. OCC-609, Att. 1.

environmental remediation process by eliminating the need for potential future litigation, . . ." Merger Decision, p. 21.[87]

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. Interrog. Resp. OCC-609, Att. 1, p. 40, ¶ B.24. Second, the PCO required the remediation to "be completed within 3 years . . . , unless a later completion date is specified in writing by the Commissioner." Id., p. 27, ¶ B.1. Consequently, the remediation of English Station within three years was a substantive condition of the Company's merger with Iberdrola.

There is no dispute that the Company has failed to complete the remediation of English Station. Hr'g Tr. Mar. 21, 2023, 3367:14-16. Further, UI did not present any evidence or argument that the Company was denied access to the site or that the DEEP Commissioner had specified a later completion date. Notably, the Company spent approximately $3.9 million in 2017, indicating that UI had access no later than 2017 to commence remediation. UI Resp. Interrog. OCC-610. The Company has cycled through six project managers at English Station during this period. Hr'g Tr. Mar. 21, 2023, 3343:18-21. Furthermore, despite acknowledging its responsibility for maintaining site security while remediation activities are ongoing, OAG's cross examination of Company witnesses revealed that English Station's surrounding fences and gates had been vandalized with graffiti and that the vandalism had yet to be addressed. Hr'g Tr. Mar. 21, 2023, 3352:16-24.

The Authority finds that the Company has not managed the English Station remediation with economy, efficiency, or care for public safety as required by Conn. Gen. Stat. § 16-19e(a) and, in doing so, has failed to comply with the conditions of the Merger Decision.[88] The evidence supports a finding that the Company, without any articulated justification, has not remediated English Station within three years, as required under the PCO. In addition, the record shows that the Company has not taken adequate measures to ensure site security as shown by its failure to prevent (or to timely address) vandalism around the remediation site. Further, given the well-documented delay in advancing the remediation, the Authority does not find credible the Company's assertion that revolving project managers has not hindered its completion of remediation activities. Indeed, the Company did not offer any testimony that provided a reasonable basis for its delay in completing remediation activities or to explain why it had not addressed vandalism on the property for over two years. Hr'g Tr. Mar. 21, 2023, 3343-3367.[89]

The Authority finds that a twenty (20) basis point reduction to the Company's ROE is warranted to incentivize management to proceed prudently and efficiently in completing

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[87] English Station is located in an environmental justice community as defined by Conn. Gen. Stat. § 22a-20a.

[88] The Company asserts that the Authority has no jurisdiction "to oversee or enforce compliance with the [PCO] . . . ." UI Written Exceptions, p. 85. This may be true; however, the Authority certainly has jurisdiction over the Merger Decision and the conditions of the Merger.

[89] Here again, the Company argues that the Authority is "improperly engag[ing] in hindsight judgment." UI Written Exceptions, p. 83. First, the so-called hindsight rule does not apply to the Company's obligation to comply with the Merger Decision. Second, the Company does not cite to any specific information relied upon by the Authority that was only known after the fact.

the English Station remediation in compliance with the Merger Decision. Importantly, by executing the merger settlement agreement, UI acknowledged the significance and value of the English Station remediation to the state and its residents, particularly ratepayers in New Haven. UI specifically agreed that the remediation "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." Merger Decision, Id., App. 1, p. 3. UI's mismanagement of the remediation and the resulting failure to deliver this significant "Merger-Related Direct Economic Benefit" as required by the Merger Decision has deprived the state and its residents both economically and environmentally. By contrast, the Company, which bears responsibility for the cost of remediation, has been able to defer such costs, spending just over half of the $30 million commitment over 6 years. UI Resp. Interrog. OCC-610. In doing so, the Company has demonstrated a willingness to prioritize the Company's and shareholders' interests over ratepayers and its obligations as a public service company.

The twenty (20) basis point reduction is commensurate with the significant economic and environmental benefits that the Company promised but failed to timely deliver and is necessary to achieve the balancing of interests required by Hope, Bluefield, and Conn. Gen. Stat. § 16-19e(a). The ROE reduction shall remain in effect until the earlier of the Company's compliance with the conditions in the Merger Decision or the effective date of a rate amendment that the Authority approves in a subsequent rate case proceeding conducted pursuant to Conn. Gen. Stat. §§ 16-19 and 16-19e.[90]

f. Customer Service Performance

The Authority concludes that a twenty (20) basis point reduction to the Company's ROE is appropriate to incentivize much needed improvement to the Company's customer service performance.

EOE's brief states that, despite extensive Authority guidance, its audits of UI's customer service calls still show that the Company does not comply with Authority orders and guidance. EOE Brief, pp. 18-35. For example, EOE noted that, despite the Authority requiring UI to pre-screen customers for financial hardship, UI still fails to ask hardship prequalification questions in every call, leading to customers being placed in incorrect assistance programs that, if appropriately placed, may have substantially lowered the customer's payments, or customers not being placed in any payment arrangement at all, hardship or otherwise. Id., p. 19; Interrog. Resp. EOE-180, 240, 243, 250; see Interim Decision, Dec. 2, 2020, Docket No. 17-12-03RE01, PURA Investigation Into Distribution System Planning of the Electric Distribution Companies – Energy Affordability, pp. 6-7.

The results of EOE's customer service audits are troubling, especially since the Authority has issued Notices of Violation in connection with similar customer service issues and provided extensive customer service guidance to the Company, particularly in its energy affordability proceedings (e.g., Docket Nos. 17-12-03RE01, 21-07-01, and 22-05-01). Indeed, the Authority has even approved fact sheets and customer service representative (CSR) scripts to use as training materials to ensure that CSRs provide

[90] If the Company does not demonstrate compliance with the Merger Decision at or prior to its next rate application, PURA will assess the appropriate ROE reduction amount and duration based on the facts specific to that proceeding.

accurate information to customers about their payment plan options. Interim Decision, July 1, 2020, Docket No. 17-12-03RE01, pp. 3-8. Moreover, the Authority approved a settlement agreement in Docket No. 20-30-15, Petition of William Tong, Attorney for the State of Connecticut for a Proceeding to Establish a State of Emergency Utility Shut-off Moratorium, in which the Company acknowledged that it fell short of expectations regarding customer communications and, accordingly, received extensive guidance from EOE regarding its customer communications. Motion No. 74, Mar. 30, 2022, Docket No. 20-03-15; Motion No. 74 Ruling, May 4, 2022, Docket No. 20-03-15.

EOE's brief chronicles further troubling UI customer service practices. For instance, the Company sends credit and collections (C&C) calls to its external vendors because it does not consider them to be complex calls. Interrog. Resp. EOE-61, EOE-111, and EOE-232. To the contrary, as EOE explains, C&C calls require CSRs to ask a series of questions according to scripts and to actively listen to the customer to determine if they indicate a need for financial or medical assistance. EOE Brief, p. 23. As highlighted above, the external vendor CSRs continue to have trouble correctly screening customers for hardship. Indeed, the Company acknowledged that external call centers for its vendor, iQor, handled all calls that subjected UI to previously levied Authority NOVs. Hr'g Tr. Mar. 7, 2023, 2558:10-25, 2559:1-3. Despite issues with iQor's customer call handling, UI's 2022 contract amendment failed to address or contemplate a penalty for iQor's poor customer call quality. Late Filed Ex. 108, Att. 2. Therefore, UI's vendor contract with iQor provides no manner to incentivize iQor to improve its customer call quality. To the contrary, UI's contract with iQor focuses on the speed in which calls are handled because iQor is paid on a per call basis. Interrog. Resp. EOE-263. Furthermore, UI relies primarily on a "check the checker" approach to evaluate vendor calls, meaning that the vendor screens its own calls and UI reviews the scores the vendor assigns itself while only periodically checking the vendor's calls directly. Hr'g Tr. Mar. 6, 2023, 2198-2201:22-18. In addition, UI stated that it has no policy or procedures to ensure that it reviews specific types of calls its vendor handles. Interrog. Resp. EOE-105, 108, 193. This compelling record evidence demonstrates that, despite myriad issues with its external CSRs, the Company has been ineffective and unfocused on ensuring its external CSRs are adequately screening customers for hardship eligibility or otherwise ensuring they are following PURA orders and guidance.

CCA and the OCC supported EOE's customer service analysis and resulting recommendation to reduce the Company's ROE. CCA Reply Brief, pp. 1-3; OCC Reply Brief, pp. 9, 11. Specifically, CCA recommended that the Authority reduce the Company's ROE "until a defined level of customer service and full compliance can be demonstrated." CCA Reply Brief, p. 3. Furthermore, the OCC recommended that the Authority reduce the Company's ROE by 25 basis points, "until such time as UI demonstrates improved customer service performance within its subsequent rate case filing." OCC Reply Brief, p. 11.

Based on the reported results of EOE's audit of the Company's customer service interactions, as well as the other deficiencies documented in the record and highlighted in EOE's brief, the Authority concludes that PURA guidance, NOVs, and an adopted settlement agreement have not been sufficient to change UI's deficient customer service practices. Moreover, as detailed above, the record evidence in this proceeding has uncovered that UI's oversight and management of its third-party call center vendors is

ineffective. Given the severity and pervasiveness of these customer service issues, the Authority reduces UI's ROE by twenty (20) basis points to incentivize Company management to improve its customer service performance, particularly in how it complies with Authority guidance regarding communications with customers. The ROE reduction will remain in effect at least until the implementation of PBR metrics for the Company's customer service, at which point the Company may submit a petition in the instant proceeding seeking the removal of this ROE reduction. Such petition must include documentation and quantification of how customer service has improved and been fully compliant with the General Statutes of Connecticut, the Regulations of Connecticut State Agencies, and the Authority's orders since the issuance of this Decision. If PBR metrics for the Company's customer service have not been implemented before UI files its next rate application pursuant to Conn. Gen. Stat. §§ 16-19 and 16-19e, the Company may include such petition with its rate application.

g. Conclusion

Based on the above, the Authority concludes that a cumulative 47 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. Accordingly, the Authority adjusts UI's allowed ROE from 9.10% to 8.63%, until otherwise modified in accordance with this Decision.

F. FINANCIAL IMPACT

The final issue with respect to cost of capital is whether the approved capital structure and cost of capital will permit the Company to generally maintain its financial condition and flexibility. Here, the Authority concludes that, although the approved capital structure and cost of capital (including the ROE reductions) may impact some of the Company's credit-related financial metrics, UI will have a reasonable opportunity to operate in a manner that allows the Company to sustain its current credit rating and associated financial flexibility.[91]

Since 2016, the Company has increased its operating income and rate base and reduced its embedded cost of debt. UI Interrog. Resp. RRU-009 and RRU-002, Att. 1. As a result, the Company has maintained an investment grade credit rating as follows:

Table 36 Current UI Credit Ratings

Standard & Poor's Global Ratings (S&P)	A-/Stable rating since 2016, upgraded from BBB+ to A- in September 2016
Fitch Ratings (Fitch)	A- rating, upgraded from BBB+ in April 2019
Moody's Investors Service (Moody's)	Baa1 rating, placed on positive outlook February 1, 2022

Id.

In its most current research report dated March 17, 2022, S&P affirmed the A-/Stable rating, indicating that UI's financial measures would remain at the higher end of

[91] The Company's management team and parent company exercise control over the Company's operations and financial results and may take actions that adversely affect the Company's credit outlook; therefore, the Authority can only assess whether the Company is positioned to, or has the opportunity to, preserve its credit status.

the range for its financial risk category, with funds from operations (FFO) to debt of about 21%-23% through 2023. UI Interrog. Resp. RRU-002, Att. 1, p. 35. S&P indicated that it could lower UI's ratings if the stand-alone financial measures weakened, including FFO to debt consistently below 15%. Id., p. 3. On February 1, 2022, Moody's affirmed the Company's Baa1 long-term debt issuer rating and UI's ratings outlook was changed to positive from stable. Id., pp. 87 and 93. The rationale for the positive rating outlook was that the Company: (1) was able to reach a constructive rate settlement agreement in June 2021, (2) continues to benefit from credit supportive federal regulation of its transmission rate base, and (3) should generate a ratio of CFO pre-WC to debt of 20% over the next two years - a level consistent with A3 rated peer ratios. Id.

The Company is owned by AVANGRID, Inc. (AVANGRID or Parent Company), which is owned by Iberdrola, S.A. (Iberdrola or Ultimate Parent Company). UI Interrog. Resp. RRU-001 and RRU-328. The following table provides the previous, as well as the most recent, credit ratings of Iberdrola, AVANGRID, and UI. Furthermore, since the acquisition by Iberdrola in 2016, UI has made no material changes to the way it sources external capital and external debt. Equity capital needs are now met by contributions from AVANGRID. UI Interrog. Resp. RRU-328.

UI's credit ratings remained consistent with its pre-merger ratings after the Iberdrola merger, except that UIL Holdings (UIL), UI's former holding company, ratings were withdrawn as it ceased to exist post-merger transaction. UI Interrog. Resp. RRU-329. UI's credit ratings are based principally on the strength of UI itself, but under the S&P rating methodology there is a stronger linkage to parent company ratings and financials. Consequently, post-merger AVANGRID's higher ratings as compared to former parent company UIL were a factor in UI's ratings upgrade in September 2016. Id.

Table 37: Credit Rating History

Company	UI	AVANGRID, Inc.	Iberdrola, S.A.
	S&P Issuer Credit Rating		
2018	A-	BBB+	-
2019	A-	BBB+	-
2020	A-	BBB+	BBB+
2021	A-	BBB+	BBB+
2022 YTD	A-	BBB+	BBB+
	Moody's Long-term Issuer Rating		
2018	Baa1	Baa1	Baa1
2019	Baa1	Baa1	Baa1
2020	Baa1	Baa1	Baa1
2021	Baa1	Baa2	Baa1
2022 YTD	Baa1	Baa2	Baa1
	Fitch Long-term Issuer Default Rating		
2018	BBB+	BBB+	BBB+
2019	A-	BBB+	BBB+
2020	A-	BBB+	BBB+
2021	A-	BBB+	BBB+
2022 YTD	A-	BBB+	BBB+

UI Interrog. Resp. RRU-002, Att. 3; UI Interrog. Resp. RRU-002, Att. 1, pp. 18, 31, 43, 53, 63, 78, 101, 123, 130, 144, and 158.

The Company provided historical results of several financial ratios that are typically reviewed by credit rating agencies for 2019, 2020, and 2021, valued as of December 31 of the respective year. UI Interrog. Resp. RRU-006, Att. 1. The Authority compiled in the tables below the actual, historical ratios for the Company and separately the rating agency benchmark for each ratio for comparison.

Table 38: Historical Ratios for the Company (Actual)

	2019	2020	2021
Moody's Ratios:			
CFO pre-WC+ Interest/Interest	6.8x	5.9x	5.5x
CFO pre-WC+ Interest/Debt	26.5%	24.5%	18.9%
CFO pre-WC - Dividends/Debt	18.5%	20.8%	9.4%
Debt/Capitalization	42.5%	40.1%	40.1%
S&P (Core) Ratios			
FFO/Debt	24.8%	25.2%	23.2%
Debt/EBITDA	3.5x	3.4x	3.6x
Fitch Key Metrics			
FFO Fixed-Charge Coverage	6.5x	6.1x	5.0x
FFO-Adjusted Leverage	3.0x	3.0x	4.0x
Total Adjusted Debt/Operations EBITDAR	3.2x	3.0x	3.3x
Total Debt/Total Capital	42.4%	41.6%	41.2%
Capex/Depreciation	167.2%	177.7%	177.7%

UI Interrog. Resp. RRU-006, p. 3.

The rating agency benchmarks for each of the historical ratios are included in the table below. The Authority takes into consideration the effect the allowed ROE has on these metrics and on the revenue requirement. The rating agency benchmarking ranges are provided in the tables below.

Table 39: Benchmarks for Ratios for the Company

	Baa Range	A Range	Weight
Moody's Ratios:			
CFO pre-WC+ Interest/Interest	3x-4.5x	4.5x-6x	7.5%
CFO pre-WC+ Interest/Debt	11%-19%	19%-27%	15.0%
CFO pre-WC - Dividends/Debt	7%-15%	15%-23%	10%
Debt/Capitalization	50%-59%	40%-50%	7.5%
	A- Range	**A+/A**	
S&P (Core) Ratios			
FFO/Debt	13%-23%	23%-35%	
Debt/EBITDA	3.5%-4.5%	2.5%-3.5%	
	BBB Midpoint	**A Midpoint**	
Fitch Key Metrics			
FFO Fixed-Charge Coverage	4.5x	5x	
FFO-Adjusted Leverage	4.25x	3.5x	
Total Adjusted Debt/Operations	3.75x	3.25x	
Total Debt/Total Capital	-	-	-
Capex/Depreciation	-	-	-

UI Interrog. Resp. RRU-006, p. 3.

The Company also projected the financial ratios reviewed by Moody's, S&P, and Fitch, and several other financial bank solvency ratios under a range of ROE scenarios as proposed by the cost of capital witnesses for the Company, the OCC, and EOE. The scenarios were as follows: the Company's proposed ROE of 10.2%, the OCC's 9.0% ROE recommendation, and EOE's 8.68% recommendation. The tables below provide UI's estimates for those ratios for the proposed multi-year rate plan, 2023-2025.

Table 40: Forecasted Financial Ratios at Various ROEs

Company 10.2% ROE Scenario:	Estimate	Estimate	Estimate
	2023	**2024**	**2025**
Moody's Ratios:			
CFO pre-WC+ Interest/Interest	6.8x	6.7x	6.7x
CFO pre-WC+ Interest/Debt	23.1%	22.4%	23.1%
CFO pre-WC - Dividends/Debt	16.9%	20.5%	15.7%
Debt/Capitalization	30.5%	31.1%	31.4%
S&P (Core) Ratios			
FFO/Debt	22.1%	22.6%	24.2%
Debt/EBITDA	3.9x	3.8x	3.6x
Fitch Key Metrics			
FFO Fixed-Charge Coverage	5.7x	5.5x	6.1x
FFO-Adjusted Leverage	4.0x	4.3x	3.8x
Total Adjusted Debt/Operations EBITDAR	3.5x	3.5x	3.3x
Total Debt/Total Capital	32.3%	32.9%	33.2%
Capex/Depreciation	245.6%	222.6%	155.6%

UI Interrog. Resp. RRU-006, p. 2.

OCC 9.0% ROE Scenario:	Estimate	Estimate	Estimate
	2023	**2024**	**2025**
Moody's Ratios:			
CFO pre-WC+ Interest/Interest	6.6x	6.4x	6.3x
CFO pre-WC+ Interest/Debt	24.6%	22.5%	21.7%
CFO pre-WC - Dividends/Debt	21.8%	21.3%	17.2%
Debt/Capitalization	38.0%	37.6%	38.7%
S&P (Core) Ratios			
FFO/Debt	25.6%	24.0%	23.9%
Debt/EBITDA	3.4x	3.6x	3.6x
Fitch Key Metrics			
FFO Fixed-Charge Coverage	5.9x	5.7x	5.6x
FFO-Adjusted Leverage	3.5x	3.9x	4.0x
Total Adjusted Debt/Operations EBITDAR	3.0x	3.3x	3.3x
Total Debt/Total Capital	42.7%	41.8%	43.0%
Capex/Depreciation	206.3%	216.6%	193.9%

UI Interrog. Resp. RRU-363.

EOE 8.68% ROE Scenario:	Estimate	Estimate	Estimate
	2023	**2024**	**2025**
Moody's Ratios:			
CFO pre-WC+ Interest/Interest	6.6x	6.3x	6.3x
CFO pre-WC+ Interest/Debt	24.6%	22.3%	21.5%
CFO pre-WC - Dividends/Debt	21.8%	21.3%	17.2%
Debt/Capitalization	38.0%	37.6%	38.7%
S&P (Core) Ratios			
FFO/Debt	25.5%	23.8%	23.6%
Debt/EBITDA	3.4x	3.6x	3.7x
Fitch Key Metrics			
FFO Fixed-Charge Coverage	5.8x	5.6x	5.6x
FFO-Adjusted Leverage	3.5x	3.9x	4.0x
Total Adjusted Debt/Operations EBITDAR	3.0x	3.3x	3.3x
Total Debt/Total Capital	42.7%	41.8%	43.0%
Capex/Depreciation	206.3%	216.6%	193.9%

UI Interrog. Resp. RRU-363.

The Company's proposed 10.2% ROE provides for higher debt service coverage ratios and lower use of leverage (total debt to total capital) compared to the 9.0% OCC and 8.68% EOE recommendations, thus offering the Company a greater financial cushion compared to the alternative recommendations. The Company must have sufficient financial flexibility to pay its existing debt and to weather financial events, but the Authority must also balance the interests of customers to provide for customer rates no higher than necessary for the Company to maintain reasonable financial flexibility. Focusing in on the difference between the estimates under the OCC and EOE ROE recommendations, the ratios weaken as the ROE decreases from 9.0% to 8.68%, but, even under an ROE of 8.68%, the Company's projections for the financial ratios do not move out of the relevant ranges for its three credit ratings (i.e., A- for S&P, Baa1 for Moody's, and A- for Fitch). The Company also provided several liquidity ratios of solvency such as Total Asset Turnover, Times Interest Earned, and ROE using the financial definition (i.e., Net Income/ Average Common Equity) as compared the cost of capital method definition for ROE. A review of these ratios shows the solvency ratios are strong and the financial definition of ROE (i.e., Net Income/ Avg. Common Equity) is also favorable to the cost of capital ROE. UI Interrog. Resp. RRU-364.

Under the recommendations offered by the Company, the OCC, and EOE, the Authority concludes that the metrics remain in the range of the core metrics published by the rating agencies to maintain the Company's current ratings.

Furthermore, the Authority considered the effects of the OCC's and EOE's proposed capital structures on the credit matrix. A ratings action could potentially take place for the Company: (1) if CFO pre-WC to debt drops below 17% for a sustained period (Moody's), and (2) if stand-alone financial measures weakened, including FFO to debt consistently below 15% (S&P). EOE Interrog. Resp. RRU-407; Hr'g Tr. Mar. 9, 2023, 3170:12 – 3171:6. The Authority finds that neither the OCC's nor EOE's capitalization mix recommendations would individually result in a ratings downgrade, all else equal.

The Authority weighed the multiple scenarios in its determination of the appropriate required ROE in its analysis to ascertain what the potential impact of various ROEs would be on credit metrics that are deemed significant to the credit rating agencies. Based on a comparison of the rating agency benchmarking criteria, the Authority concludes that the Company's credit metrics remain in acceptable ranges set by the credit rating agencies for any ROE within the ranges presented by EOE, the OCC, and the Company (i.e., 8.68% to 10.20%). Consequently, the 8.80% ROE determined by the Authority will not unreasonably affect the Company's credit metrics and financial flexibility.

The next question, then, is whether the forty-seven (47) basis point ROE reduction detailed above will do so. The ROE reductions result in an ROE totaling 8.63%, which is marginally below the 8.68% ROE proposed by EOE and analyzed above. Regardless, the Authority had the Company conducted a more current analysis of the financial ratios based on ROEs of 8.70%, as well as 8.20% to be conservative. The table below summarizes the impact on the relevant credit ratios for each of the rating agencies based on an 8.70% ROE.[92]

Table 41: Forecasted Financial Ratios at 8.70% ROE

8.70% ROE Scenario:	Estimate	Estimate	Estimate
	2023	**2024**	**2025**
Moody's Ratios:			
CFO pre-WC+ Interest/Interest	6.7x	6.5x	6.5x
CFO pre-WC+ Interest/Debt	22.8%	21.6%	22.3%
CFO pre-WC - Dividends/Debt	16.9%	20.5%	15.7%
Debt/Capitalization	30.5%	31.1%	31.4%
S&P (Core) Ratios			
FFO/Debt	21.7%	21.5%	23.0%
Debt/EBITDA	4.0x	4.0x	3.8x
Fitch Key Metrics			
FFO Fixed-Charge Coverage	5.6x	5.3x	5.9x
FFO-Adjusted Leverage	4.1x	4.5x	3.9x
Total Adjusted Debt/Operations EBITDAR	3.6x	3.7x	3.4x

[92] The financial ratios varied only slightly between the Company's analysis of the 8.20% and 8.70% ROEs. Because 8.70% is closer to the allowed ROE of 8.63%, only the 8.70% ROE results are shown here.

Total Debt/Total Capital	32.3%	33.0%	33.3%
Capex/Depreciation	245.6%	222.6%	155.6%

Late Filed Ex. 134, Att. 1.

The Authority compared the results of the 8.70% ROE estimated credit financial ratios to the rating agency credit benchmarks and finds that, although some of the credit ratios signified an increased credit weakness, other credit ratios signified an improved credit strength compared to the 8.68% ROE results. For example, debt leverage decreased from about 38% to 31% (Moody's Debt/Capitalization ratio). The Authority notes that the Moody's A range on Debt to Capitalization is 40%-50%; thus, the Company is curtailing debt leverage below the requirements to maintain a Moody's A rating let alone its actual Baa1, which has a Moody's range of 50%-59% Debt to Capitalization. Late Filed Ex. 134.

The results of this 8.70% ROE financial stress test on the S&P, Moody's, and Fitch credit ratios demonstrate that the relevant credit ratios stay within the respective A-, Baa1, and BBB+ parameters. Indeed, several of the financial ratios exceed the current ratings requirements by moving into the next credit notch given the lower leverage use. Although the Authority does not presume to know the inner workings of the rating agency methods, the analytical methodologies published by the rating agencies reasonably indicate that the Company can meet these financial metrics under an 8.70% ROE. To the extent the ROE adjustments adversely affect the Company's financial metrics, the Company is able to mitigate any such effects by improving its performance and addressing the deficiencies that gave rise to the ROE reductions, as articulated herein.

VI. ALLOWABLE EXPENSES

A. OPERATIONS & MAINTENANCE EXPENSE

1. Summary

Allowable operating expenses must "reflect prudent and efficient management of the franchise operation." Conn. Gen. Stat. § 16-19e(a)(5). Therefore, only those expenses that are reasonable and necessary to provide service to the public may be included as an allowable expense. To determine a utility's allowable expenses, the Authority will consider the historical test year expenses and adjust for "known and measurable" changes. The Company has the burden of proving that such expenses under consideration are just and reasonable. See Conn. Gen. Stat. § 16-22. Consequently, in addition to being prudent, the 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. Connecticut Nat. Gas Corp. v. Dep't of Pub. Util. Control, 51 Conn. Supp. 307, 322 (2009) (noting that the agency applied the "known and measurable" standard to pro forma adjustments); Conn. Gen. Stat. § 16-22.

For the purpose of establishing a revenue requirement, the Company has proposed allowable operating expenses of $162.068 million for Rate Year 2023/2024.

Late Filed Ex. 1, Att. 1, Sch. WP C-3.0 A.[93] The table below summarizes UI's proposed O&M expenses and the Authority's adjustments.

Table 42: Operations and Maintenance Expenses

O&M Expenses	Company Proposed	Authority Modification	Approved
FTE and Executive Compensation	37,739	(2,613)	35,126
Employee Benefits	24,816	(3,194)	21,622
Travel, Education and Training	589	0	589
Industry Association Dues	293	(293)	0
Computer Expenses	3,837	(395)	3,442
Telecommunications Expenses	3,464	(1,075)	2,389
Injuries & Damages	1,183	(550)	633
Corporate Service Charges	37,862	(3,646)	34,216
Storm Reserve	3,000	(1,000)	2,000
Professional Services	3,784	277	4,061
Customer Services	8,684		8,684
Electric Distribution System	7,761	(3,706)	4,055
UPZ and Vegetation Management	7,802	7,532	15,334
Facilities Maintenance	2,826		2,826
Security and Safety	712		712
Legal Expense	1,143		1,143
Advertising	89	(89)	0
Insurance Expense	1,008		1,008
Postage	1,002		1,002
Rent and Lease Expense	1,232	(1,975)	(743)
Transportation Expense	1,986		1,986
Uncollectible Expense**	4,341	(1,087)	3,254
Reconnect Service Fees	(1,015)	1,015	0
Regulatory Assessments	2,873		2,873
Interest on Customer Security Deposits	15		15
GSC Allocated Expense	(168)		(168)
Inflation Escalation Adjustment		(409)	(409)
Other O&M	5,210		5,210
Total O&M Expenses	**162,068**	**(11,208)**	**150,860**

Based on its review of the record, the Authority makes certain modifications as described in detail below and approves O&M expenses of approximately $150.860 million.

[93] The proposed uncollectible expense includes incremental $1.221 million related to the additional revenue requested for the Rate Year. Id., Sch. A-1.0. Therefore, the total requested O&M was increased from $160.847 million to $162.068 million.

2. Full Time Equivalent (FTE) Compensation

a. Summary

The below table summarizes the FTEs approved for inclusion in base distribution rates. In total, the Authority approves 529 FTEs, which is comprised of 485 FTEs as of February 2023, plus 44 incremental FTEs. The 44 incremental FTEs are calculated by applying the 6.2% vacancy rate to the 47 FTEs for which the Company met their burden to demonstrate that the requested FTEs are both known and measurable and reflect prudent and efficient management.

Table 43: Approved FTEs

	Requested	Approved
Base FTEs (A)	**468**	**485**
Incremental FTEs		
Clean Energy Transformation	6	2
Grid Modernization Programs	15.25	1
Customer Service	18	13
Operations	45	23
Pole Attachment	25	8
Incremental FTE Subtotal (B)	**109.25**	**47**
Incremental less Vacancy (C) = (B) – [(B)*6.2%]	102	44
Total (A) + (C)	570	529

The Company's request for 570 FTEs is reduced to 529, as noted in the table above. To calculate the reduction in payroll expense and rate base, the Authority applied the approximate $115,000 salary per FTE ($4,340/38) used by the Company to calculate its vacancy factor offset applied in Late Filed Ex. 1, Att. 1, Sch. WP C-3.23, p. 2. Thus, the FTE reduction of 41 FTEs (570-529) equals a reduction of $4,715,000 ($115,000 x 41). This amount is multiplied by the 48% expense factor, which results in a payroll expense reduction of $2,263,200. The Company's rate base is reduced by $2,451,800 to reflect a 52% capitalization factor.

b. FTE Count

For Rate Year 2023/2024, the Company requests $69.996 million in payroll, less $4.340 million to account for a 6.2% vacancy rate, for a total distribution payroll of $65.656 million. Added to this total is overtime and premium payroll of $13.643 million, for a total request of $79.299 million. The Company applied a 52% capitalization rate to arrive at a requested compensation expense of $37.739 million. Late Filed Ex. 1, Sch. WP C-3.23, p. 2. The number of FTE employees associated with the above amount is 570, which consists of 519 base FTEs and 89 new hires, less 38 vacancies. Late Filed Ex. 1, Att. 1, Sch. WP C-3.23, p. 2.

In evaluating the Company's requested 570 FTEs, the Authority first compared distribution employee levels allowed as a result of the Company's last rate case in Docket No. 16-06-04 with resulting actual Company FTE counts through 2022. Specifically, the Authority used the information provided in response to interrogatory OCC-60, Late Filed Ex. 77, and Late Filed Ex. 78 to construct the employee count comparison table below

and to calculate the FTE shortfall between FTEs allowed in base rates and the number actually employed by the Company. In the 2016 Rate Case Decision, the Authority allowed a distribution employee count of 704. 2016 Rate Case Decision, p. 41. In that proceeding, the Company applied a distribution allocator of 93% to its total employee count to arrive at the distribution employee count. Late Filed Ex. 80, Att. 1. In the instant rate case, the Company applies a distribution allocator of 82.28%. Late Filed Ex. 1, Att. 1, Sch. WP C-3.23, p. 2.

Table 44: Employee Count Comparison

Description	Docket No. 16-06-04	2018	2019	2020	2021	2022
Total UI employees	793	670	644	622	631	599
UI Distribution Employees	738	551	530	512	519	493
Vacancy Factor[94]	4.60%	N/A	N/A	N/A	N/A	N/A
UI Distribution Employee Complement	704	551	530	512	519	493
Actual Distribution Employee Count Compared to Decision Award		(153)	(174)	(192)	(185)	(211)

In the intervening years since the 2016 Rate Case Decision, the Company has not once met the distribution employee count that was approved therein, which the Company concedes. Hr'g Tr. Mar. 1, 2023, 1801:14-16. The Company provided several explanations for the discrepancy between allowed FTEs in the 2016 Rate Case Decision and actual FTEs over the 2018-2022 timeframe. First, the Company states that in 2018 Avangrid moved 110 employees from UI to UIL. Late Filed Ex. 78, p. 1. The Company also moved 26 employees in 2018 from UI to Avangrid Services Company (Service Company). The Company further noted that 2019 experienced an increase in retirements, 2020-2021 hiring was impacted by the global pandemic, and 2022 was again impacted by retirements. Id. During testimony, the Company reiterated the above arguments for not meeting head count and cited difficulty recruiting in a skilled labor market. Hr'g Tr. Mar. 1, 2023, 1801:23-25-1802:1-6.

UIL provides services to other Avangrid companies including The Southern Connecticut Gas Company (SCG), Connecticut Natural Gas Corporation (CNG), and Berkshire Gas Company. The Service Company provides services to all Avangrid entities, including UI, SCG, CNG, and Berkshire Gas Company. Hr'g Tr. Mar. 1, 2023, 1783:20-21. By moving UI employees to the service companies, the payroll expense that was

[94] Vacancy factors are used in the numbers included in the column title "Docket No. 16-06-04", as this amount included proposed new hires and the filling of vacant positions. The amounts from 2018 through 2022 are actual employee counts and, therefore, account for vacancies.

approved for UI as a result of the 2016 Rate Case Decision was effectively redeployed to UIL and the Service Company. These employees provided resources to affiliated companies beginning in 2018 while UI customers continued to solely fund these positions.

As noted, the Company's requested FTE count in this rate case consists of 519 base distribution FTEs plus 89 incremental new hires. The 89 new hires requested were itemized by the Company as 17 customer service-related positions, 25 positions related to pole attachment activities, 21 positions for electric operations, five positions for smart grids and automation, 17 for projects, and two for process and technology.[95] I-CSP PFT, pp. 9-10; Eves PFT, pp. 42-47. The Company provided updated actual employee count information during the proceeding for the end of the Test Year, as of the Application date, and as of February 28, 2023. Late Filed Ex. 79. The data is provided below.

Table 45: Updated Employee Count

Distribution FTEs	FTEs as of 12/31/21	FTEs at Application	FTEs as of 2/28/23
Headcount	519	498	485
Vacant, in hiring	11	30	36
New incremental requested	78		
Total incremental	89		
Total	**608**	**528**	**522**

As demonstrated above, the FTE headcount continues to steadily decline; specifically, at the end of Test Year, UI had 519 distribution FTEs, which fell to 498 at the time of the Application in September 2022, and to 485 as of February 2023.

The OCC advocates that payroll expense should be limited to the known and measurable FTE complement. Schultz and Defever PFT, p. 34. Specifically, the OCC observes that as of September 2022, the net current FTE complement was 599 and, after applying the distribution allocator of 82.28%, provides for a known and measurable count of 493 FTEs. Id., p. 35. The OCC suggests that the Company's request could be reduced by 77 FTEs, i.e., the difference between the Company's request of 570 and the 493 known and measurable FTE count as of September 2022. Id. Alternatively, when taking into consideration the average FTE complement through September 2022 of 611,[96] and after applying the distribution allocator of 82.28%, the OCC arrives at a distribution FTE count of 503 FTEs, which is 105 FTEs less than the Company request of 608. Applying the 38 vacancies to this amount results in a net reduction of 67 FTEs. Id., pp. 35-36. Using the second approach, the OCC arrives at a $3.601 million downward adjustment for payroll expense by multiplying 67 FTEs by an average annual salary of $115,000 and applying an O&M allocation of 46.7%. OCC Brief, Ex. LA-1, Sch. C-5.

[95] The Authority notes that the sum of the itemized new FTEs is 87, whereas the Company has requested funding for 89 new FTEs. Late Filed Ex. 1, WP C-3.23.

[96] The OCC calculates 611 as the average monthly actual UI FTE count for the period January 2022 through September 2022, using information provided in response to interrogatory OCC-60.

Considering the Company's history of significant underutilization of FTEs from its last rate case, the Authority adopts the OCC's suggested approach to begin with the Company's last known and measurable FTE count to determine the number of positions allowable in base distribution rates. The Company, as of February 28, 2023, had 485 distribution FTEs. Late Filed Ex. 79. Therefore, in determining an allowable distribution FTE count the Authority will start with the 485 known FTEs.

By starting with the Company's current FTEs, the Authority must next consider the requested increase in incremental employees based on the evidence provided in the record. The vacancy in hiring amount, as listed in the above table, constitutes open positions and active recruitment, which have not been filled as of the indicated date. Hr'g Tr. Mar. 21, 2023, 3468:12-20. As of February 28, 2023, the "vacant, in hiring" category count was 36, for an FTE headcount of 521. However, the Company offered conflicting information regarding currently open positions. Specifically, interrogatory RRU-443 requested information for all open positions; in response, the Company listed 62 open positions. The Authority attempted to reconcile this amount with the 89 requested incremental employees during the March 1, 2023 hearing. The Company responded that its current FTE levels were 592 as of February 2023. Hr'g Tr., 1814:3-13. Applying the 82.28% distribution allocator to this amount results in 487 distribution FTEs as of February 2023. This approximates the 485 listed in the table above. The Company testified that it currently has 45 open requisitions and that it has filled 30 positions since January of this year. Hr'g Tr. Mar 1, 2023, 1813:7-9. Subsequently, the Authority requested Late Filed Ex. 79 with the objective of reconciling the employee balance reported in the Application with the Company's claimed current employee count, and to identify what portion of currently filled positions counted towards the 89 incremental FTE request as opposed to a refill of existing vacancies. After reviewing Late Filed Ex. 79, it remains unclear to the Authority the exact number of employees that the Company has hired that are within the requested 89 incremental FTE request.

Based on the foregoing, the Authority finds that allowing 485 FTEs plus any incremental FTEs demonstrated by the Company to reflect prudent and efficient management is reasonable. However, as it is unclear whether any of the 89 incremental FTEs requested in the Application were included in the 485 FTE count, and in recognition of the traditional approach of applying a vacancy rate to the approved FTEs, the Authority will apply the proposed vacancy rate of 6.2% to any approved incremental FTEs. Below, the Authority details its approval of the 6.2% vacancy rate and provides its analysis regarding the incremental FTEs to be included in base distribution rates using the available record information.

c. 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. The Company applied a 6.2% vacancy rate in the Application, which represents the Company's four-year average vacancy rate for the period 2018 to 2021. RRP PFT, p. 19. The following data points are the vacancy rate percentages from 2017-2021, which represents the period between the last rate case and the Test Year:

2017: 9.79%
2018: 6.01%

2019: 6.09%
2020: 6.95%
2021: 5.75%
2022: 6.15%, as of October 2022

UI Interrog. Resp. OCC-207.

The 2017-2021 average vacancy rate is 6.92%. However, the Company omitted 2017 data from its calculation of the historical average vacancy rate and relied on the 2018-2021 average vacancy rate, because the 2017 vacancy rate was impacted by the Company's Voluntary Retirement Program. UI Interrog. Resp. OCC-207. Removing the 2017 vacancy rate and averaging 2018-2022 provides for an average of 6.2%. UI Interrog. Resp. OCC-207.

The Authority adopts the Company's 6.2% vacancy rate as it reasonably represents the Company's vacancy levels since the last rate case.

d. Incremental FTEs

i. Clean Energy Transformation Incremental FTEs

The Company requests six FTEs related to the Clean Energy Transformation Panel; specifically, three FTEs to directly support the proposed Medium- and Heavy-Duty (MHD) Make-Ready Program, one FTE to support ongoing planning and community and stakeholder engagement related to electric vehicles and beneficial electrification, one FTE to support the development and deployment of the existing and new energy storage projects and related UI storage activity, and one FTE to support the Advanced Load and DER Forecasting project. Ex. UI-CETP-1, pp. 16-17, 27, 32. In total, the Authority approves two of the six FTEs listed above and in Exhibit UI-CETP-1. Conversely, because the Authority is not approving the proposed MHD Make-Ready Program in this rate case, the Authority disallows the three FTEs requested to directly support the program at this time.[97] Similarly, as the Advanced Load and DER Forecasting project is not being approved in this rate case, the Authority denies approval of the proposed FTE to support the project.[98]

The Company states that the beneficial electrification FTE will "support engagement with communities, government, and other stakeholders on matters related to EVs," serve as a beneficial electrification subject matter expert, "perform research to help inform the Company on technology, standards, state and federal policies, and market trends and developments related to EVs…[and] participate in regional and national groups related to beneficial electrification to gather information, identify industry best practices, and support future program development." Id., pp. 16-17. Ongoing planning and community and stakeholder engagement related to beneficial electrification applies to both light-duty and MHD electric vehicles and is necessary to ensure an equitable and cost-effective electrification of the transportation sector in Connecticut. Further, significant work is ongoing at the state and federal level to prepare for and to undertake electrification of the LD and MHD sectors, which includes, but is not limited to, PURA

[97] See Section VII.A., Medium- and Heavy-Duty Vehicle Make-Ready Program.
[98] See Section VII.E, Integrated Distribution System Plan & Grid Modernization Roadmap.

Docket Nos. 23-08-06, Annual EV Charging Program Review - Year 3, and Docket No. 21-09-17, PURA Investigation into Medium and Heavy-Duty Electric Vehicle Charging, and intra- and inter-state coordination efforts related to the National Electric Vehicle Infrastructure (NEVI) Formula Program. Accordingly, the Authority approves the FTE supporting beneficial electrification as such position will aid the state in meeting its clean transportation goals in an equitable manner. Id., pp. 16-17.

The Authority also approves the FTE supporting the development and deployment of new and existing energy storage projects. Ex. UI-CETP-1, p. 27. The Company states that the FTE will be incremental to the resource already managing the Energy Storage Solutions Program and will "be a manager dedicated to developing internal and external processes to help facilitate energy storage development in the Company's service territory, manage storage related stakeholder engagement, and manage current and future energy storage RFPs and procurements." Id. The Authority notes that the Energy Storage Solutions Program, initiated through Docket No. 17-12-03RE03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Electric Storage, and updated annually, is growing, and that the Company is authorized through Public Act 22-55, An Act Concerning Energy Storage Systems and Electric Distribution System Reliability, to own and operate battery storage systems, including up to three pilot projects.[99] Accordingly, the Authority finds the proposed FTE to be reasonable and approves its inclusion in the calculation of incremental FTEs to be allowed in base distribution rates.

ii. Grid Modernization Incremental FTEs

The Company provided a detailed breakdown of the proposed FTEs for a number of initiatives, specifically the: (1) Energy Storage Solutions Program; (2) LD Electric Vehicle Charging Program; (3) Shared Clean Energy Facilities Program; (4) Residential Renewable Energy Solutions Program; (5) Non-Residential Renewable Energy Solutions Program; (6) Innovative Energy Solutions Program; and (7) Non-Wires Solutions (NWS) Program. Late Filed Ex. 127, pp. 1-3. The stated recovery mechanism for most of the six programs listed above is the Non-Bypassable Federally Mandated Congestion Charge (NBFMCC), which is reconciled and reviewed for prudency annually through the Rate Adjustment Mechanisms proceeding (e.g., Docket No. 23-01-04 for 2023). Id. The stated recovery mechanism for the LD EV Charging Program is through distribution rates after a normal base rate case proceeding. Id., p. 1. The Authority approves one FTE for the NWS Process for inclusion in the calculation of incremental FTEs to be allowed in base distribution rates, as outlined below.

For the LD EV Charging Program, the company proposes three FTEs across four positions: (1) one FTE commercial program manager that started in November 2021; (2) one FTE Commercial Energy Specialist that started in April 2022; (3) a ½ FTE Residential Program Manager that started in August 2021; and (4) a ½ FTE Residential Energy Specialist that started in November 2021. Late Filed Ex. 127, p. 1. The estimated annual cost of these FTEs is stated as $407,880 in 2023, increasing to $459,072 in 2027. Id. Prior to the onboarding of these three FTEs, the Company did not have any FTEs to

[99] The Authority is reviewing the Company's three proposed pilot projects in Docket No. 22-06-05, PURA Implementation of Public Act 22-55.

support the EV Charging Program. Id. Notably, the Authority previously ruled that zero-emissions vehicle "related expenditures shall be a core business function of the EDCs now and into the future. As such, distribution rates, through which the ratepayers will realize the benefits of lower rates as increased kWh sales are realized due to increased ZEV deployment, should reflect all ZEV-related costs." Late Filed Ex. 127, p. 1; Decision, Jul. 14, 2021, Docket No. 17-12-03RE04, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Zero Emission Vehicles, p. 45. Accordingly, the Authority finds that the three FTE equivalents across four positions dedicated to the LD EV Charging Program reflect prudent and efficient management. However, as all four positions have a start date prior to the Application date and the date on which the 485 FTEs were measured (i.e., February 2023), the Authority declines to approve the three FTEs for inclusion in the calculation of incremental FTEs to be allowed in base distribution rates as they are already reflected in the 485 FTE count.

The Company proposes two FTEs for the NWS Process: (1) a Program Manager with an expected start date in July 2023; and (2) a Lead Analyst with an expected start date in November 2023. The Company notes that the program is new and incremental, and previously had no existing FTEs to execute the associated responsibilities. Late Filed Ex. 127, p. 3. The annual cost estimate for the two FTEs is $125,000 for 2023, with a jump to $382,000 for 2024, and ranging up to $421,000 in 2026. Id. The Authority notes that while there is a Process Initiation Phase, the annual NWS Process steps and requirements are not scheduled to begin until January 2025. Decision, Nov. 9, 2022, Docket No. 17-120-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives, p. 49. Further, the Company has not made it clear why more than one FTE is required, particularly given that the majority, if not all, of the information required to be filed starting in 2025 is already in the Company's possession, existing Company personnel work on related distribution planning efforts, and the Company will have had over two years to compile the information required to first be filed in 2025. Accordingly, the Authority finds that the Program Manager FTE, but not the Lead Analyst FTE, is known and measurable and reflects prudent and efficient management.

In Late Filed Ex. 127, the Company identified the NBFMCC as the appropriate cost recovery mechanism for the FTEs associated with the NWS Process. Late Filed Ex. 127, p. 3. However, the November 9, 2022 Decision in Docket No. 17-12-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives, which authorized the NWS Process, made clear that it was permitting "interim cost recovery of incremental expenses through the NBFMCC mechanism [with the] eventual inclusion of relevant costs in base rates." Decision, Nov. 9, 2022, Docket No. 17-12-03RE07, p. 47. Thus, the Authority clearly intended for all NWS Process-related costs to eventually be included in base distribution rates. As the Authority found the above outlined personnel costs related to the NWS Process to be known and measurable and prudent, they should be included in the rates approved in this proceeding and not recovered through the NBFMCC. Thus, the Authority approves the Program Manager FTE for inclusion in the calculation of incremental FTEs to be allowed in base distribution rates.

It is unclear to the Authority whether the costs associated with any of the four FTEs discussed above (3 FTEs for the LD EV Charging Program and 1 FTE for the NWS

Process) are currently being recovered through the NBFMCC. As all four FTEs will be recovered through base distribution rates moving forward, the Company must maintain a strict accounting of any recovery provided through the NBFMCC for such positions. The Company must: (1) file in next year's annual Rate Adjustment Mechanism proceeding, i.e., Docket No. 24-01-04, a full accounting of any over-collection related to these FTEs through the NBFMCC for the period through April 30, 2024; (2) ensure that any over-collection through the NBFMCC for these positions is reflected in its Rate Adjustment Mechanism filing made on March 1, 2024, and any other filings, as appropriate, in Docket No. 24-01-04; and (3) ensure that the costs associated with these FTEs are not included in any going forward Rate Adjustment Mechanism costs submitted for recovery in Docket No. 24-01-04.

The Company included several additional FTEs in Late Filed Ex. 127. As noted above and in Late Filed Ex. 127, the cost recovery mechanism for these positions is the annual Rate Adjustment Mechanism proceeding, and more specifically, the NBFMCC. As such, the Authority does not make a determination on the prudence of such positions or costs in this Decision and does not allow for their inclusion in the calculation of incremental FTEs to be allowed in base distribution rates. However, the Authority notes that it plans to consider in Docket No. 21-05-15RE01 whether requiring all personnel-related costs, inclusive of the programs listed in Late Filed Ex. 127, to be incorporated into future multi-year rate plans (MRP) and base distribution rates would further the intended priority outcomes of an MRP, namely, ensuring utility business operations and investment efficiency and, thus, affordable electric service for all ratepayers. See Decision, April 26, 2023, Docket No. 21-05-15, pp. 19-22.

iii. Customer Service Incremental FTEs

UI proposed an additional 18 customer service FTEs consisting of (i) 12 internal CSRs that will be UI union employees, (ii) one Lead Analyst Customer Service Quality FTE that will also be allocated 100% to UI, and (iii) an equivalent four incremental FTEs for eight customer service FTEs located at UIL that will dedicate approximately 40% of their time to UI. Pelella and Paterson Prefiled Test., Sep. 9, 2022, pp. 9-10, n. 1, 2; Interrog. Resp. EOE-3, p. 2. The Company stated that it is requesting "similar resources within the sister rate case filings" for the other UIL subsidiaries. Hr'g Tr. Mar. 7, 2023, 2540:9-21.[100]

UI requested an increase of 12 CSR FTEs, which it asserts are needed to accommodate increasing call handle times, additional training and coaching, future increased collections activities, and forecasted higher call volumes. Pelella and Paterson PFT, p. 16. According to UI, average call handle times (AHT) have increased by 130 seconds since 2019, which annually, equates to approximately 15,000 additional hours

[100] UI did not include an FTE request for staff to support the implementation or administration of the low-income discount rate (LIDR) in its request for customer service FTEs. Pelella and Paterson PFT, p. 9:10-16; Hr'g Tr., Mar. 7, 2023, 2566:10-14, 2566:16-19. 2570:10-11. However, the Company estimated a potential need for four to eight additional FTEs to support the implementation and maintenance of the LIDR. Interrog. Resp. EOE-128, p. 2. Regardless, the Company is obligated to meet the full requirements of the October 19, 2022, Decision in Docket No. 17-12-03RE11 and all other relevant Authority Orders, Decisions, and directions regarding LIDR implementation and administration. Failure to do so may result in civil penalties pursuant to Conn. Gen. Stat. § 16-41.

of CSR work. Id. The Company aims to maintain a 90 second Average Speed of Answer (ASA) metric, and so proposed additional CSRs in order to handle increased call handle times without declining answer speeds. Pelella and Paterson PFT, p. 10:11-12; Interrog. Resp. EOE-3, pp. 1-2. Indeed, UI's internal ASA without Interactive Voice Response (IVR) (i.e., how long did a customer wait to speak with a CSR, without being averaged with how long a customer waited to choose an IVR option) averaged 261 seconds in 2022, with the highest monthly average of 521 seconds in October 2022. Interrog. Resp. EOE-103, Att. 1. Additionally, UI has increased its training and coaching of CSRs, which in turn increases the number of hours CSRs are away from answering phones. Id.; Pelella and Paterson PFT, p. 11:2-5. Finally, UI is anticipating a greater number of calls in 2024 as the shutoff moratorium ends and customers begin receiving more collections activities. Pelella and Paterson PFT, p. 16:16-19.

UI utilized its Genesys workforce management software to calculate the need for 12 additional CSR FTEs. Interrog. Resp. CAE-45, p. 1. The Company reported that it analyzed historical call volume and handle time, applied trends and other known impacts to a calculated baseline, and loaded those adjusted assumptions into the Genesys software. Id. The Company also input its goal ASA metric of between 90-120 seconds. Id., Hr'g Tr. Mar. 6, 2023, 2355:9-17. Additionally, UI's input includes various "shrinkage" impacts that will require CSRs to be away from answering phones, such as vacation time, absenteeism, paid breaks, training and coaching, and handling customer inquiries received via mail, email, fax, and/or the website. Interrog. Resp. CAE-45, p. 1; Pelella and Paterson PFT, App. B. As a result of those inputs, according to UI, the Genesys software calculated a need for 82 total CSRs. Hr'g Tr. Mar. 6, 2023, 2355:20-23. Given that the Company currently has 70 internal CSRs, this equates to an addition of 12 CSR FTEs. Pelella and Paterson PFT, p. 10:12-13.

UI handles customer calls through both its internal call center and a third-party call center vendor, iQor. Interrog. Resp. CAE-81, p. 1. Since 2018, UI has contracted with iQor to specifically handle service customer calls regarding moving in or out of a location (referred to as move-in/move-out, or MIMO) and calls regarding credit and collections inquiries. Interrog. Resp. CAE-44, p. 1. UI still receives and handles the majority of customer calls. Interrog. Resp. EOE-103, Att. 1. For example, in 2022, UI received approximately 56% of all calls and iQor received 44%. Id. While iQor CSRs are only trained on those specific topics, internal UI CSRs are ultimately trained on all topics and able to handle all types of customer inquiries. Interrog. Resp. CAE-44, p. 1. Therefore, iQor CSRs are trained to transfer calls back to UI's internal call center if they receive an inquiry outside of their scope of responsibility. Id. UI stated that it chose to route MIMO and credit and collections calls to a third-party vendor because of the volume of calls and the "straightforwardness" of handling these calls. Hr'g Tr. Mar. 7, 2023, 2530:8-11. Regarding collections calls, UI alleged that "enrolling a customer in … a payment arrangement program, or … securing a payment arrangement, it's … more singularly transactional than other types of calls[.]" Hr'g Tr., 2530:18-24. Additionally, the Company estimated that it saved about $2.03 million in 2022 through outsourcing MIMO and credit and collections calls to iQor. Interrog. Resp. CAE-46, p. 2.

However, during the Authority's review of the various call metrics that UI tracks, there appears to be a difference in performance quality between UI's internal call center and the iQor call center. For example, in 2022, the internal UI AHT ranged between about

550 and 600 seconds, whereas the iQor AHT was generally higher, and ranged between 550 and 650 seconds. Pelella and Paterson PFT, p. 17. Considering that iQor receives fewer and "simpler" calls than UI's internal CSRs, the Authority questions why iQor would have longer calls. Additionally, iQor experiences a higher abandonment percentage of calls than the internal UI call center. Interrog. Resp. EOE-103, Att. 1. Overall, in 2022, according to the Authority's calculations, iQor had an abandonment rate of 15%, comprised of 17.4% for credit-related calls and 10.7% for MIMO calls, whereas UI's internal call center had an abandonment rate of 12.2% for 2022. Id. Finally, UI confirmed that the Authority's recent penalties applied to UI in 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, resulted exclusively from calls and customer interactions with iQor CSRs. Hr'g Tr. Mar. 7, 2023, 2558:13 – 2559:3.

EOE recommended that the Authority deny UI's request for additional CSR FTEs. EOE Brief, p. 43. Specifically, EOE opined that UI did not provide adequate evidence and justification to support such FTE additions. Id. Furthermore, EOE questioned the Company's decision to direct credit and collections calls to a third-party call center, especially with the supporting reasoning that such calls are "straightforward." Id., p. 23; see also Hr'g Tr. Mar. 7, 2023, 2530:8-11. EOE opined that credit and collections calls are in fact the Company's most complex calls, requiring extensive knowledge of available payment arrangement and energy assistance offerings, as well as deep listening skills. EOE Brief, p. 23. In fact, EOE suggested that the only reasonable justification to allow additional CSR FTEs would be if UI handled difficult credit and collections calls internally, rather than sending them to a third-party vendor. Id., pp. 43-44.

CCA also questioned the need for additional customer service FTEs, opining that the Company incorrectly focuses on the quantity of customer services available, regardless of effectiveness, instead of on the quality of such services. CCA Brief, p. 1. CCA further recommended that the Authority deny any customer-related expenses that have not been demonstrated to benefit ratepayers. Id., p. 2.

The Authority concurs with EOE that credit and collections calls are indeed some of the more difficult calls received by the Company. Customers calling with collections-related inquiries are likely either in crisis or are otherwise in an emotionally vulnerable state. A customer reaching out to UI regarding bill payment questions is likely struggling to pay their current bill, received a delinquent notice, received a disconnection notice, has had their service disconnected, or even has received their final bill notice. All of the previous scenarios are likely high-stress and/or crisis circumstances for customers. Indeed, the challenge of managing electricity bills and potential disconnection on Connecticut residents can lead to malnutrition, depression, respiratory illness, and chronic stress. Yale Center on Climate Change and Health Corresp., Dec. 14, 2022, pp. 1-2, 8. Therefore, handling a collections call is not at all a "straightforward" endeavor – in fact, it requires thorough knowledge of all available energy assistance and payment arrangement offerings, as well as a depth of emotional intelligence and active listening skills. Furthermore, the lack of skilled assistance currently provided to struggling customers only increases the overall electricity costs for all customers. Enrolling customers in an inappropriate payment arrangement increases the likelihood of unpaid bills and eventual increase in uncollectible write-off expenses, to be recovered through

electric rates paid by all ratepayers. Therefore, all Connecticut residents stand to benefit from the provision of quality customer service to our most vulnerable neighbors.

Accordingly, the Authority approves UI's request for 12 CSR FTEs and one Lead Analyst Customer Service Quality FTE, for a total of 13 additional FTEs, to be included in the calculation of incremental FTEs to be allowed in base distribution rates. The Authority finds that additional training and coaching are important initiatives for improving the quality of customer service provided to UI customers. The Authority further finds the Lead Analyst Customer Service Quality FTE to be an appropriate addition, as it will support the monitoring of calls and provide assistance to CSRs regarding energy affordability matters, as proposed by UI. Furthermore, the Authority finds that it is preferable for credit- and collections-related calls to be handled by UI's internal call center representatives. Therefore, UI will require additional internal CSRs to handle such calls. As such, the Authority directs UI to adjust the percentage of credit and collections calls directed toward third-party call center vendors. Specifically, the Authority directs UI to develop a phase-out proposal that transitions credit and collections calls back to UI's internal call center and identifies potential call types handled internally that can instead be referred to a third-party call center. The phase-out proposal shall be submitted to the Authority for review and approval in the 2024 Energy Affordability Annual Review proceeding, Docket No. 24-05-01, by May 1, 2024, and shall include a plan for transitioning at least 35% of credit and collections calls directed toward third-party call center vendors to internal CSRs by September 1, 2024.

In addition to the 13 proposed customer service FTEs, UI requested the addition of four customer experience FTEs to be hired at the UIL level. Pelella and Paterson PFT, p. 9:12-15. As stated previously, the Company is proposing the addition of eight total UIL-level FTEs that will dedicate approximately 40% of their time to UI, resulting in an equivalence of four additional FTEs to UI. Id., p. 9:14-15; Interrog. Resp. EOE-3, p. 2. Of the eight total FTEs, four are proposed for the UIL Customer Experience team and four are proposed for the Shared Services team that will support the Customer Service group. Pelella and Paterson PFT, p. 14:10-11.

For the Customer Experience team, UI proposed the addition of a Customer Experience Manager, Customer Experience Lead Analyst, Senior Product Owner Digital Manager, and Lead Analyst Digital. Pelella and Paterson PFT, pp. 11:18 – 14:9. As proposed, the Customer Experience Manager and Customer Experience Lead Analyst would be responsible for increasing customer satisfaction through the management of projects under the Customer Journey Redesign program. Id., pp. 11:10-12, 11:18 – 12:18. The Senior Product Owner Digital Manager and Lead Analyst Digital would be responsible for improving various methods of customer's digital interactions with the Company and performing digital platform analytics to ensure that customers are satisfied with their experience. Id., pp. 12:19 – 14:9.

Regarding the Shared Services team, UI proposed the addition of two Customer Advocates, a Knowledgebase Analyst, and Lead Analyst – Speech Analytics. Pelella and Paterson PFT, pp. 14:13 – 15:21. The Customer Advocates would "serve as liaisons with local social services, other outside agencies, and customers in need of assistance with navigating the various programs." Id., p. 14:13-16. Further, the Advocates would assist in conducting customer outreach and promoting the available energy assistance

programs. Id., p. 14:16-19. According to UI, some of these responsibilities are currently managed by the Hardship Administrator, who is also responsible for administering various Matching Payment Program items. Id., p. 14:19-22. Therefore, there are currently no dedicated staff for local social service providers and other energy assistance groups to contact. Pelella and Paterson PFT, pp. 14:22 – 15:2. The Knowledgebase Analyst would be a dedicated staff member to manage and update the Knowledgebase tool, which provides CSRs with "key policies and procedures" while they handle customer calls. Id., p. 15:3-6. Updating the Knowledgebase tool is currently a shared task between "various Quality team members, trainers and supervisory team members" that all have other main responsibilities. Id., p. 15:9-12; Hr'g Tr. Mar. 6, 2023, 2396:15-22.

Furthermore, the Company stated that currently there is no standard updating schedule for the Knowledgebase tool and opined that it is updated "not nearly as often as we would like." Hr'g Tr. Mar. 7, 2023, 2544:7-18. The Company shared that regularly updating the Knowledgebase tool could "make sure that [CSRs are] informing our customers of … the right programs, [and] understanding how to perform … different procedures correctly." Hr'g Tr., 2544:19-23. Finally, the Lead Analyst — Speech Analytics FTE would be responsible for managing the Company's speech analytics software and would create, update, and modify queries and reports for call analysis. Pelella and Paterson PFT, p. 15:15-21. The speech analytics software is currently managed by the Quality Assurance team, which is also responsible for listening to and monitoring customer phone calls. Hr'g Tr. Mar. 7, 2023, 2578:25 – 2579:10. The Company stated that its research into speech analytics tools demonstrated that such tools are best utilized when there is a dedicated staff member responsible for refining and validating the models and queries used. Hr'g Tr., 2579:24 – 2580:8.

UI also reported on changes it has made to its customer service staffing since its last rate case. The Company testified that it created a Connecticut-level Vice President position for customer service and realigned the organization so that the Connecticut call centers, billing, and collections teams report directly to the Connecticut Vice President. Pelella and Paterson PFT, p. 7:19-23. Avangrid also created the Vendor Management and Quality Assurance teams that manage the third-party CSR vendor relationship and monitor customer call performance. Id., p. 8:13-22. Additionally, Avangrid created two project manager positions for Connecticut that are "focused on managing Customer Service initiatives designed to improve the customer experience." Id., p. 8:1-3.

The Authority concurs with the Company that improving digital platforms and customer digital interactions is a critical initiative to increase customer satisfaction. It is important that the Company's call center is not the only avenue for customers to receive information that can assist them, whether they need to pay their bill, explore payment arrangement offerings, or explore their energy usage. Such efforts are also important for customer empowerment, so that customers can build knowledge themselves about available options rather than relying on CSRs to provide information. Finally, the development of a robust digital presence may be a more efficient use of ratepayer resources, as customers may peruse digital offerings at their own leisure without the need to engage with a trained CSR. Therefore, the Authority finds the addition of the Senior Product Owner Digital Manager and Lead Analyst Digital FTEs to the Customer Experience team to be appropriate.

Second, the Authority finds that the Company's proposed FTEs for the Shared Services team will provide crucial support to Connecticut customer service staff. The Authority seeks to ensure that the provision of materials to CSRs, particularly while CSRs are handling customer calls, is accomplished in an understandable, accessible manner. As the Company stated, the Knowledgebase tool could provide CSRs with key information quickly as they handle customer inquiries; however, it is not currently updated at the frequency needed to realistically provide CSRs with that assistance. Further, the Company's Standard Operating Procedures, which provide CSRs with the knowledge of how to perform various transactions, were identified to be out of date and are just in the process of being updated now. Hr'g Tr. Mar. 7, 2023, 2547:24 – 2548:12. Finally, when the Company distributes updated talking points to CSRs regarding new offerings or initiatives, currently the CSR decides how best to reference relevant information during calls. Hr'g Tr. Mar. 22, 2023, 3533:9-12, 3534:3-9. For example, CSRs may choose to reference the information through their email, a team folder, or save meaningful talking points to their own desktop for reference when answering a common question. Hr'g Tr., 3534:6-12. However, the Company opined that the ideal manner for providing up-to-date information and talking points to CSRs is through the Knowledgebase tool. Hr'g Tr., 3533:12-22, 3534:12-16. The Authority finds that the provision of accurate, timely, and accessible information to CSRs is critical to the customer experience and ensuring that customers receive the information they need. Therefore, the Authority agrees that the addition of a Knowledgebase Analyst is necessary.

Additionally, the Authority is supportive of improved auditing and monitoring of customer calls to measure the quality performance in an ongoing manner. The Authority is currently exploring the use of speech analytics tools in order to aid UI, EOE, and other stakeholders to audit calls more efficiently. Decision, Oct. 12, 2022, Docket No. 22-05-01, 2022 Energy Affordability Annual Review, pp. 36, 47; see also Motion No. 20 Ruling, Mar. 1, 2023, Docket No. 22-05-01, 2022 Energy Affordability Annual Review. The addition of a speech analytics tool and the resulting expense requires that the tool actually be effective in aiding such parties in customer call auditing. Therefore, the Authority finds that the addition of the Lead Analyst – Speech Analytics FTE is appropriate to ensure that the tool is most effectively utilized.

Finally, the Authority agrees that providing a dedicated staff contact for local service agencies such as Community Action Agencies (CAAs) and other energy assistance groups is necessary. CAAs and groups like Operation Fuel are critical components of the provision of energy assistance. The actions of such groups also lighten the administrative burden for UI through verifying customers' income levels and investigating benefit program eligibility for customers. As such, providing quick feedback and information to such groups is an important component of improving UI customers' experience and satisfaction. However, as that task is now shared by multiple FTEs, the Authority does not find that moving from zero dedicated FTEs to two Customer Advocates is necessary. Accordingly, the Authority finds that the addition of one Customer Advocate FTE is appropriate at this time.

The Authority questions the necessity of adding the Customer Experience Manager and Customer Experience Lead Analyst FTEs to the Customer Experience team. The Authority's understanding of these roles is essentially project management initiatives under the Customer Journey Redesign project. However, the Company stated

that Avangrid has already added two Connecticut project manager positions that are responsible for managing Customer Service initiatives. Given that these roles already exist within the Customer Service organization, the Authority does not find that the Company met its burden in demonstrating that the additions of the Customer Experience Manager and Customer Experience Lead Analyst positions would reflect prudent and efficient management.

The Authority acknowledges and applies the cost allocation method of FTEs across UI affiliated companies based on the Massachusetts formula for shared services. However, the Authority clarifies that it is not directly approving the addition of these five FTEs at the UIL-level in this rate case,[101] as the Company has not sufficiently demonstrated the extent to which the five FTEs will directly benefit UI customers. For clarity, the Authority agrees that the positions may provide value to UI customers; however, given UI's history of not fully staffing positions funded through base distribution rates and shifting positions funded by UI ratepayers to assist affiliate companies (see Section VI.A.2., Full Time Equivalent (FTE) Compensation, the Authority is not inclined to allow recovery of these positions from UI ratepayers until further evidence and a demonstrable track record of the percentage of time the positions will work on matters related to UI customers is presented. Accordingly, the Authority directs UI to demonstrate that five employees have been hired and provide a detailed description of the capacity at which they are working for Connecticut ratepayers on or before May 1, 2024. Specifically, UI shall submit this information, along with a request to seek incremental recovery for the five FTE salaries through an adjustment to distribution rates effective on September 1, 2024, for Authority review and approval. The Authority is inclined to allow prospective recovery of such positions if sufficient evidence of the amount of time they are or will be working on behalf of UI customers is presented. Additionally, the Authority emphasizes that the approval of additional customer service and CSR FTEs is contingent on the Company improving the quality of customer service provided to UI ratepayers. Therefore, the Authority may consider disallowing recovery of customer service-related costs in a future rate case if it is found that customer service quality has not improved.

iv. Operational Incremental FTE Requests

In the Application, the Company requested approval to hire 70 incremental FTEs with 45 supporting capital plan operations and 25 supporting pole attachments. CJE PFT, p. 38. The number of FTEs for each system operations function or department are presented in the table below.

[101] Five FTEs at the UIL-level working on UI-specific matters 40% of the time would equate to two FTEs included in UI base distribution rates.

Table 46: UI Proposed Incremental FTEs

Function or Department	No. of FTEs
Operations	
Electric Field Operations	21
Operational Smart Grids	5
Projects – Resilience, Automation, and DER Integration	17
Process and Technology – Security	2
Pole Attachment	
Pole Attachment Process	25
Total	**70**

Id., pp. 42-46.

The Electric Field Operations FTEs include line apprentices, substation apprentices, test apprentices, and training support positions. Id., p. 43. UI states that the purpose of the incremental positions is to train the next generation of field crews in advance of substantial retirements. Id. The Company is currently recruiting all positions. Interrog. Resp. OCC-298.

The Operational Smart Grids positions include engineers, analysts, and technologists to support the Company's planned deployment of over 700 reclosers as part of its distributed automation program. CJE PFT, p. 45. UI has not hired any of the FTEs to date and does not plan to hire the positions until after the rate case decision. Interrog. Resp. OCC-299.

The 17 incremental positions in the Project group include a project manager, a field construction manager, and electrical engineering designer to support the Company's planned resilience and distributed automation projects. CJE PFT, p. 45. Two schedulers are intended to support the Company's capital plan. Id. The remaining 12 positions include managers and analysts to support the integration of DERs into the Company's system. Of these 17 FTEs, the Company is actively recruiting three positions: one project manager to support the resilience and automation programs; one DER interconnection engineer; and one senior engineer. Interrog. Resp. OCC-300. There is no indication that the positions were filled as of November 2022. Id.

The two FTEs in the Process and Technology group include a protection and control engineer and protection and control lead engineer. CJE PFT, p. 46. The positions are intended to support cybersecurity protections and other bulk power standards. Id., pp. 46-47. UI is not actively recruiting these positions until after the outcome of the rate case. Interrog. Resp. OCC-301.

Accordingly, the Authority approves 23 of the 45 operational FTEs for inclusion in base distribution rates. Specifically, the Authority approves the 21 FTEs for the Electric Field Operations group for inclusion in the calculation of incremental FTEs to be allowed in base distribution rates, as these resources support important blue- and gray-sky system operations functions. Moreover, the Authority has encouraged both EDCs to place a greater emphasis on building internal tree and line crew resources to be better

prepared for major storm events.[102] However, the Authority declines to approve any positions that UI is not actively recruiting for at this time, since if there was an imminent need for the FTE, UI would have been in the process of hiring instead of waiting on the outcome of the proceeding. This eliminates five positions from the Operational Smart Grids group, two FTEs from the Process and Technology group, and 14 of 17 FTEs from the Projects group. The Authority declines to approve the project manager to support the resilience and automation programs as the Authority declined to pre-approve the costs of such projects by not approving a multi-year rate plan herein and due to the deficiencies of such programs outlined in Section IV.K., Five-Year Capital Plan. Lastly, the Authority finds the remaining two FTEs in the Projects group to be prudent given the uptake in DER deployment in recent years and the need to address interconnection timelines,[103] so long as both FTEs are employed more than 75% of their time assisting in the interconnection process. Accordingly, the Authority approves 23 operational FTEs to be included in the calculation of incremental FTEs to be allowed in base distribution rates.

v. Pole Attachment FTEs

The Authority reviews the need for the 25 incremental FTEs that are proposed to support the pole attachment process in Section VI.A.14.a., Third-Party Pole Attachment. Therein, the Authority authorizes eight new pole attachment FTEs to be included in the calculation of incremental FTEs to be allowed in base distribution rates.

3. Executive Compensation

a. Allowed Compensation

The Company's Test Year shows $3,199,991 of executive compensation expense and $296,458 of executive compensation capitalized for a total of $3,496,449. Late Filed Ex. 72, Att. 1, p. 3. These amounts of executive compensation are comprised of both UI executive compensation and of Avangrid Service Company and Avangrid Management Company executive compensation allocated to UI. Late Filed Ex. 72. Specifically, a portion of compensation expense for two UI executives was allocated to the Company for a total of $219,996, and a portion of compensation expense for 46 Avangrid Management Company and Avangrid Service Company executives was allocated to the Company for a total of $2,979,995. Late Filed Ex. 72, Att. 1, pp. 1-2. Executive compensation is allocated to the Company using consumption drivers identified in its cost allocation manual. Where a consumption driver cannot be identified, the Company uses the Massachusetts formula, a cost allocation methodology commonly used by United States utilities. Late Filed Ex. 72; Hr'g. Tr., Mar. 1, 2023, 1750:13-25, 1751:1-8. Additionally, the Test Year executive compensation includes both fixed compensation and variable (incentive) compensation. Variable compensation includes three components: Bonus, Stock Expense, and Non-Equity Incentive Plan. Late Filed Ex. 72. For the two UI executives with compensation allocated to the Company, 51% of their total compensation was incentive-based in the Test Year. Late Filed Ex. 72, Att.1, p. 1. For the 46 Avangrid

[102] See RE08 Decision. Importantly, however, the Authority's primary focus is on ensuring the effective implementation of the Reliability and Resilience Frameworks authorized in the RE08 Decision, which includes a comprehensive cost-benefit analysis of resilience measures, of which internal tree and line resources are one component.

[103] See, e.g., Decision, Nov. 2, 2022, Docket No. 22-08-02 and Decision, Nov. 9, 2022, Docket No. 22-08-03.

Service Company and Avangrid Management Company executives with compensation allocated to the Company, 61% of their total compensation was incentive-based in the Test Year. Late Filed Ex. 72, Att.1, p. 2.

The Authority approves 80%, or $2,797,159 of UI executive compensation to be recovered in base rates. The Authority approves this amount to better equalize Company executive incentives to benefit both customers and shareholders. The Company's long-term executive incentive compensation, as a proxy for executive compensation overall, is based 70% on metrics that directly benefit shareholders. UI Interrog. Resp. RRU-250, Tr 1765 -1766. A 20% reduction to this 70% weighting toward shareholder benefits would result in executive compensation that reflects a 50 / 50 split of accountability to customers and shareholders. Therefore, the Authority reduces the recoverable amount of total executive compensation in the Test Year by 20% to help ensure Company executives are more equally accountable to both customers and shareholders through their compensation.

The Authority approves the inclusion of 50% of the remaining 20%, or $349,645 ($3,496,449 * 20%)(50%)), in base rates, but subjects such amount to reconciliation, and the inclusion of the other 50% of the remaining 20%, or $349,645 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 Docket No. 20-07-01, Application of Aquarion Water Company of Connecticut to Amend its Rate Schedule, p. 62 (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 the 10% of the total executive compensation included in rate base would be used to recover that portion of UI, Avangrid Management Company, and Avangrid Service Company executive compensation. With respect to the 10% 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 10% 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 ($349,645) to customers through the RAM as a credit and will again forego recovery of the other 10% 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 February 1, 2024, and annually thereafter, to file as a compliance filing in the applicable year's RAM proceeding[104] the amount of UI, Avangrid Management Company, and Avangrid Service Company executive compensation customers are paying through base rates and through the RAM, or conversely how much is being returned to customers through the RAM.

[104] The Company's annual RAM proceedings are docketed as the year followed by "01-04." For example, next year's filing should be made in Docket No. 24-01-04.

b. 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." Conn. Gen. Stat. § 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 that is recoverable through rates be dependent upon the achievement of performance targets. Conn. Gen. Stat. § 16-19yy. If the Authority approves such performance-based incentives and penalties for a particular company, PURA is required to include in the framework for periodic monitoring and review of the company's performance pursuant to metrics developed by the Authority. Conn. Gen. Stat. § 16-19a(b). Based on the record of this proceeding, the Authority finds 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. The Company has shown, by aligning over 70% of its long-term executive incentive compensation with metrics that directly benefit shareholders, that its executive compensation program prioritizes accountability to shareholders over 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 Company clearly states that its executive compensation program "is weighted heavily towards variable compensation, including short-term cash incentives and long-term equity incentives, to align executive compensation with company performance and shareholder interests." Ex. UI-DB/DRC-SUPP, Jan. 17, 2023, p. 8 (emphasis added). The Company contends, however, that its executives provide "oversight and leadership" to business teams responsible for producing customer outcomes, and that in the utility industry generally, executive officers provide accountability to customers, regulators, government officials and other stakeholders. Ex. UI-DB/DRC-SUPP, Jan. 17, 2023, pp. 11-13. When asked what specific forms of accountability executives at UI and its parent companies have to customers, the Company referred to balanced scorecards for individual executive performance reviews, volunteering in the community, and the Company's diversity, equity, and inclusion initiatives. Hr'g Tr. Mar. 1, 2023, 1776: 17-25, 1777:1-24.

While admirable and important corporate responsibility initiatives, community volunteering and the pursuit of diversity, equity, and inclusion do not directly provide customers with accountability for the actions and decisions of the Company's executives. With respect to the use of balanced scorecards, the Company indicated that these individual performance evaluations have implications for an executive's short-term and long-term incentives. The short-term incentives of UI executives are based on Avangrid objective results (20%), business area results (20%), and individual measurable objectives (60%). UI Interrog. Resp. RRU-250. Within short-term incentives the Company further indicated that more than 80% of Avangrid objectives and more than 50% of business area results are based on financial performance and rate base. UI Interrog. Resp. UPA-5, Att. 2. Long-term incentives for UI executives are comprised of 35%

Avangrid adjusted net income, 35% relative total shareholder return, and 30% sustainability projects. UI Interrog. Resp. RRU-250. In other words, 70% of UI executives' long-term incentives are tied to the Company's financial performance. The compensation scheme for Avangrid Management Company and Avangrid Service Company executives mirrors that of UI executives, except that the proportionality of the basis for short-term incentives was not provided. UI Interrog. Resp. RRU-251.

Though individual balanced scorecards could provide a measure of executive accountability to customers, the Authority finds that the evidence in the record suggests that the Company's executive incentive compensation policies implemented through balanced scorecards most heavily weight the Company's and its parent companies' financial performance. In fact, the balanced 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, Avangrid Management Company, and Avangrid Service Company 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 Company's current executive compensation plan, therefore providing additional accountability of the executives to UI's customers. UI is deemed to have met or exceeded the performance metrics if the difference between the data for the calendar year for which the Company is reporting (Current Year) is equal to or greater than 10% of the data for the Historical Period, based on the average of the results of all three metrics. The Company is deemed to have met 90% of the performance metrics if the data for the Current Year is between 9% but less than 10% greater than the data for the Historical Period, based on the average of the results of all three metrics; 80% if the difference between the data for the Current Year is between 8% and 9% greater than the data for the historical, based on the average of the results of all three metrics; 70% if the difference between the data for the Current Year is between 7% and 8% greater than the data for the historical, based on the average of the results of all three metrics, etc. The Historical Period shall be the average of the data from 2017 through 2022, 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. The specific executive compensation performance metrics are:

1. Low-income customer identification metric: The purpose of this metric is to quantify the extent to which UI has identified its low-income customers, a first step toward positively influencing low-income customer payment outcomes. Colton Prefiled Test., Dec. 13, 2022, p. 10. UI shall measure the low-income customer identification metric for residential customers by first estimating the total number of low-income customers in its service territory. Such estimation could be made by identifying customers who receive other public assistance program benefits for which there is an income qualification requirement, such as Low-Income Home Energy Assistance Program (LIHEAP), or through other mechanisms explored in Docket No. 17-12-03RE11. Colton Prefiled Test., Dec. 13, 2022, pp. 10-12. With the estimated total number of low-income customers established, the metric is calculated as the number of actual low-income customers identified by the

Company in the Current Year (numerator) divided by the estimated total number of low-income customers (denominator).

2. Comprehensive and accurate customer communications metric: The purpose of this metric is to quantify the extent to which UI's customer service calls result in customers receiving comprehensive and accurate information. EOE Brief, p. 47. UI shall measure comprehensive and accurate customer communications by counting the number of EOE-reviewed calls deemed to provide customers with accurate and comprehensive information for every 100 calls reviewed by EOE through its regular quarterly audits in the Current Year. The comprehensive and accurate customer communications metric is calculated as the number of EOE-reviewed calls deemed to provide customers with accurate and comprehensive information in the reported Current Year (numerator) divided by 100 (denominator).

3. Payment arrangements for medical protection customers metric: The purpose of this metric is to quantify the extent to which UI has engaged medical protection customers with an arrearage in a payment arrangement. UI shall measure the percentage of medical protection customers with an arrearage that are enrolled and participating in a payment arrangement. EOE Brief, p. 47. The payment arrangements for medical protection customers metric are calculated as the number of medical protection customers with an arrearage who are enrolled and participating in a payment arrangement in the Current Year (numerator) divided by the total number of medical protection customers with an arrearage in the Current Year (denominator).

The Authority directs the Company to submit as a motion for review and approval no later than October 1, 2023, the data for each year from 2017 through 2022 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 2017 through 2022, or the data from the Test Year for UI's calculation of the various performance metrics in Rate Year 2023/2024, depending on whether the Authority finds the data submitted for 2017 through 2022 is unreliable due to missing or incomplete data. In addition, the Authority directs the Company to annually, on or before January 15th, submit 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.

4. Employee Benefits

a. Incentive Compensation

The Authority denies the Company's request to recover $1.495 million for employee incentive compensation[105] because the Company failed to demonstrate that the incentive program is reasonable and necessary to provide service to its customers or to maintain appropriate staffing levels. The Company confirmed that it seeks to recover

[105] The Company also uses the term "variable pay" to describe its incentive compensation program. Hr'g Tr. Mar. 2, 2023, 1918: 4-12.

100% of incentive compensation paid, and that no amounts have been removed from the rate years.[106] UI Interrog. Resp. OCC-39.

The Company claims that the incentive compensation program is a "critical component" of its compensation structure because it attracts and retains qualified and motivated employees that assist in providing safe and reliable service to customers. Ex. UI-CBP-1, pp. 14-15. The Company awards variable compensation to an employee reflecting the achievement of organizational objectives of UI and individual performance objectives that include service reliability, health, and safety. Id., p. 15. A portion of employee variable compensation may also reflect achievement of collective financial and operational goals by UI and its regulated affiliates within Avangrid, including but not limited to meeting objectives for safety and reliability and to implement organization-wide standardization measures increasing efficiency. Id., p. 16. Upon achievement of such organizational objectives, the employee may receive incentive compensation based on their performance. If either Avangrid or Avangrid Networks fails to achieve the objectives at issue, the Company awards no incentive compensation to its employees. Id. The Company contends that employee and customer interests are aligned by rewarding employees for their part in achieving objectives that benefit customers. Id., pp. 14-15.

The Company posits that its incentive compensation structure is reasonable because its total cash compensation, including incentive compensation, is in line with or slightly below the comparable national market median data when adjusted for geographical differences. Id., pp. 15-16; Ex. UI-CBPP-1; Interrog. Resp. OCC-219 (Confidential). Credible testimony from the OCC, however, demonstrated that market-based incentive compensation does not equate to a reasonable operating expense recoverable from ratepayers. Hr'g Tr. Mar. 1, 2023, 1648:3-7. Indeed, the OCC testified that the compensation studies the Company relies on provide an "apples to oranges comparison" because they fail to differentiate between incentive compensation amounts that have been deemed reasonable and are allowed in the rates of peer utilities versus the amounts deemed unreasonable and precluded from recovery in customer rates. Larkin PFT, p. 39. Indeed, the Company conceded that it did not conduct a study comparing the Company's incentive compensation amount to that allowed in rates in other jurisdictions. Interrog. Resp. OCC-0034. Based on the OCC's credible testimony, the Authority concludes that the Company's compensation studies submitted in the record do not provide an adequate basis for the Authority to ascertain what is a reasonable incentive compensation expense to include in base distribution rates, and, accordingly, assigns the studies minimal evidentiary weight.

Importantly, the record supports the conclusion that the incentive program does not actually incentivize employees. Between 2017 and 2021, 100% of all eligible employees were awarded incentive compensation. Interrog. Resp. OCC-0033. If every employee is awarded incentive compensation every year, the motivational benefits of the plan are, at best, questionable. As the Company admitted, because either all or none will receive the incentive award, the plan rewards underperforming or overperforming

[106] In other words, the Company assumes the continued distribution of 100% of incentive compensation, such that the ratepayers would assume the burden of 100% of the costs of the plan, regardless of whether any metrics are achieved.

employees equally. Hr'g Tr., Mar. 2, 2023, 1904-1905.[107] In response to what possible scenario would result in the payment of no incentive compensation, the Company responded that objective achievements in the Avangrid and participant's business area for the performance period must be greater than 0% and the participant's individual performance objective achievement must receive a rating factor above satisfactory. UI Interrog. Resp. OCC-39. Similarly, the Company testified that the only circumstance in which an employee would not receive incentive compensation was if they were terminated or had an unsatisfactory service rating, Hr'g Tr. Mar. 2, 2023, 1668: 5-13, yet the Company also stated that it did not have an employee that received an unsatisfactory rating for the period 2017-2021. Hr'g Tr., 1868:14-25-1869:1-7. The Company argued that the percentage of payouts is attributed to non-performing employees leaving the Company and not being counted in the payout totals. UI Reply Brief, pp. 130-131. Nonetheless, the Company provided no evidence that its history of non-performing employees rose to a level that justified the remaining employee 100% payout. As such, although a properly designed and managed incentive program can provide substantial benefits to the Company and, in turn, ratepayers, the Company has not provided sufficient evidence that it has implemented such a plan.

The Company seems to imply that the burden of proof for legitimizing its incentive program falls on the other parties involved with the proceeding. The Company states that the OCC claims that the Company's incentive program is not well designed; in short, the Company complains that the OCC offers no evidence to substantiate its opinion. UI Reply Brief, pp. 127-128. The Authority reminds the Company that the burden of justifying any expense lies with the Company. Conn. Gen. Stat. § 16-22. The Company also implies that, since the Company's union workforce has arrived at these amounts through collective bargaining, that these payments must be included as a recoverable expense. UI Reply Brief, p. 126. This by itself is not a valid reason for approval of this expense, especially given that neither the Authority nor the OCC, nor any other Party or Intervenor to this proceeding, is a participant in the collective bargaining activities.

Moreover, in terms of quantification, the Company could not provide any analysis or studies performed that demonstrated its incentive compensation plan provides any benefit to ratepayers or is necessary to the provision of utility service or the retention of appropriate staffing levels. See UI Interrog. Resp. OCC-36, Hr'g Tr., Mar. 2, 2023, 1862:7-13. Instead, the Company offers bald assertions that there is a clear link between incentive plan goals and how they benefit customers. For instance, a union employee will receive incentive compensation to the extent the Company achieves pre-established performance goals that are directly linked to measurable standards consistent with the Company's goal of providing safe and reliable service to their customers, (see UI Interrog. Resp. OCC-36); yet the Company concedes that it has never performed a study to determine the dollar value benefit to customers. Hr'g Tr. Mar. 2, 2023, 1864:5-9.

[107] The OCC testified about incentive compensation plans derived from bonus compensation programs that were rejected by public utility commissions, and that utilities generally have developed incentive compensation programs in lieu of bonus programs. Hr'g Tr. Mar. 1, 2023, 1644:7:18, 1645:2-8. As such, the Authority must closely scrutinize such incentive programs to ensure they are not gratuitous bonus programs masquerading as an incentive compensation plan.

For union incentive metrics, the Company states that metrics for 2022 are the same as 2021; there was no indication by the Company that metrics are any different in 2023. CBP Panel PFT, p. 10. When asked if the metrics were met, the Company could not readily confirm if targets had been met. Hr'g Tr., Mar. 2, 2023, 1871:3-7. There are concerns with maintaining the same metrics over several years and the risk exists that metrics and targets become less impactful over time. More concerning, as the OCC points out, is that while the Company seeks to continue to receive incentive payments and increase them through this Application, the Company could not demonstrate during the proceeding that it is meeting previously established and stagnant metrics. OCC Brief, p. 29.

In making its request for recovery of this item, the Company focused its arguments on linking its ability to attract employees with its need for an incentive compensation component, which the Authority concludes was ultimately unsubstantiated through this proceeding. While the Company provided metrics for its incentive compensation plan, the manner of payout of these incentives is concerning, as was the inability of the Company to demonstrate its achievement of existing, stagnant metrics. Additionally, the Company has fallen short of demonstrating the customer benefit aspect allegedly achieved through incentive compensation. In short, the Company has not produced a preponderance of evidence that the incentive compensation program is prudent and reasonable. After the conclusion of significant discovery and cross examination, the customer benefit, unlike the benefit for shareholders, remains unclear. The Authority, therefore, denies recovery of incentive compensation of $1.495 million.

b. Employee Recognition Awards and Loyalty Gifts

The Authority disallows the Company's request to recover $94,000 for employee recognition awards and $69,000 for loyalty gifts in rates because the Company failed to prove that these awards are reasonable or necessary to provide service to customers, or to maintain appropriate staffing levels. Conn. Gen. Stat. § 16-19e(a); Late Filed Ex. 1, Sch. WPC 3.24g.

The Company refers to its employee awards program as "Gratitude," which is an online platform for eligible employees to recognize and appreciate one another and to celebrate the positive impact colleagues have on the businesses they support, customers they serve, and communities they engage in. All Company employees can experience giving and receiving some type of Gratitude across departments, roles, and geographies. UI Interrog. Resp. OCC-554. The program is used in two ways: (1) for "spot" Recognition when someone does something notable that a fellow employee would like to thank them for; and (2) for Service Anniversaries when specific years of service are achieved. All active Avangrid employees are eligible to participate in Service Anniversary celebrations. All active Avangrid non-union employees are eligible to participate in Recognition awards. Id.

The OCC recommends disallowance of the employee recognition awards, stating that the program is not necessary for the provision of utility service and asserting that ratepayers receive little, if any, benefit. Therefore, the OCC concludes that ratepayers should not be responsible for the cost. Schultz and Defever PFT, p. 44. The OCC also notes that the Authority has disallowed employee awards in previous dockets, including in Docket No. 13-02-20, Application of Aquarion Water Company of Connecticut to

Amend its Rates, and in Docket No. 20-12-30, Application of The Connecticut Water Company to Amend Its Rate Schedule. Id. The OCC also contends that the Company failed to satisfy its burden with respect to this program because it has failed to make clear the difference between loyalty gifts and employee recognition gifts, and also what employee recognition awards represent. Additionally, the Company has further failed to meet its burden with respect to these costs because it has not sufficiently connected employee recognition awards to ratepayer benefits. The Company promotes its employee recognition awards as a way to develop employee engagement, indicating that the point of the program is "[t]o increase engagement, to have people feel better about the work that they're doing." Hr'g Tr., Mar. 2, 2023, 1901:10-14. The Company fails to connect the point of the program to some measurable benefit to ratepayers. OCC Brief, p. 33.

Notably, UI could not justify the program based on employee retention and/or the need to attract talent. The Company's witness indicated the following in response to the OCC's question about whether employees are making the decision to work for the Company based on the rewards offered through this program: "I think that's an impossible question to answer. I have no idea what the employee is thinking." Hr'g Tr., Mar. 2, 2023, 1901:3-9. Similarly, there is no direct benefit to ratepayers for the part of the recognition program where employees nominate each other for awards. As these awards are not benefiting ratepayers and are not necessary for the provision of service, the OCC recommends removal of the full amount. OCC Brief, pp. 33-34.

The Company counters that the program serves to promote morale and to foster an inclusive and welcoming workplace that recognizes employee contributions. The Gratitude platform is the back-end platform that the Company uses to send recognition to eligible employees to recognize their length of service with the Company, as well as to recognize individuals for collaboration, agility, and projects that require a significant amount of time over their normal day to day responsibilities, all of which benefit customers. The Company claims that this platform has been especially important recently, given the continuing challenges from the pandemic and other demands. Further, the Company claims that in part, these awards are used to recognize employees who work on system upgrades, systems maintenance, or projects that help to improve the service and efficiency to UI customers. UI-CBP Rebuttal, p. 12. In differentiating between employee recognition awards and loyalty gifts, the Company stated that these loyalty gifts would be tied to length of service and recognition awards would be tied to recognition of a specific performance. Hr'g Tr., Mar. 2, 2023, 1842:21-25-1843:1-8.

In terms of justification provided, the Company has not specifically cited a persuasive connection to measurable customer benefits of these payments. The Company relies on generalized statements such as that the awards are used to recognize employees who contribute a significant amount of time above and beyond their normal responsibilities on projects, such as system upgrades, system maintenance, or projects that help to improve the service and efficiency to UI customers. Other generalized assertions include that UI must provide a competitive compensation package, including wages and benefits, to attract and retain employees that provide necessary utility service. UI-RRP-REBUTTAL-1, p. 28. Although the Company goal of making people feel better about the work that they do is admirable, the Company could not provide any substantiated or quantifiable connection to a specific customer benefit throughout the

proceeding, nor did the Company substantiate its assertion that these programs are necessary components of a competitive compensation package through comparisons to peer utilities or other relevant sectors. Indeed, there is no claim by the Company that examples of work cited would not have been completed had it not been for these payments, or that the work completed was not within the scope of responsibilities for which UI ratepayers already provide compensation in the form of employee salaries. Moreover, the OCC's point on retention is also well taken. Specifically, if the Company has no indication that these payments work as an employee retention tool, then the need to pay them has similarly not been justified. The Authority, therefore, disallows $94,000 for employee recognition awards and $69,000 for loyalty gifts, finding no substantiation of the claim that such costs are necessary to maintain appropriate staffing levels.

c. Workers' Compensation

In developing the amount of workers compensation expense to include in Rate Year 2023/2024, the Company used the Test Year amount, adjusted for changes in FTEs and for escalation, to arrive at an amount of $1.471 million for Rate Year 2023/2024. Sch. WPC-3.24e. The Company's methodology is flawed because it imports the level of workplace safety from the Test Year and neglects any improvements in this area. Indeed, the Company is in the process of initiating a review of workers' compensation to ensure observance of best practices and to find ways to minimize these costs. Hr'g Tr. Mar. 1, 2023, 1732:20-25-1733:1-5. This study could have been done earlier, prior to this rate proceeding, but was not; the timing of the Application was solely in the purview of the Company. While it is difficult to quantify the benefit of improvements to workers' compensation beyond the Test Year, some improvements should be expected, especially given the review being instigated. The Authority finds that a 10% reduction in the Rate Year 2023/2024 expense is reasonable in this instance, and allows a Rate Year 2023/2024 expense of $1.324 million, or a reduction of $147,000.

d. Caregiver Program

The Company provides subsidized caregiver benefits, including Bright Horizons Back-Up Care, which provides reimbursement for back-up care for children and adult dependents. Starting November 1, 2022, the Company also began offering subsidized back-up care for pets. Interrog. Resp. OCC-7. Bright Horizons Enhanced Family Supports provides free premium access to Sittercity, which is a solution for finding babysitters, virtual sitting, pet care providers, and housekeepers by posting jobs, reviewing profiles, and running basic background checks at no additional cost. The program also includes discounts on a local, high-touch nanny placement service for full-time childcare. Employees can access elder caregiving resources, learning pods, discounts on academic support, tutoring, test prep services, and special privileges for full-time childcare, such as preferred enrollment at Bright Horizons centers. Id. Bright Horizons Years Ahead provides employees with free access to an online elder care platform that connects them with elder care resources, including search tools and referrals. Employees can take a needs assessment online, learn about elder care options, access elder care resources, and get guidance in finding senior care providers near them. The Company estimates costs for 2022 of $30,000 to $45,000, with an expected increase of 10% per year. Id.

The OCC proposes that the Authority reduce the Company's request for this expense item, stating that the expense is not necessary for the provision of utility service

and that the Company has provided no direct links to customer benefits and has not shown that childcare, elder care, and pet care are industry standards. Schultz and Defever PFT, p. 42.

The Company states that the COVID-19 pandemic highlighted the increasing importance of providing back-up dependent care benefits for employees and their families. The Company further argues that the caregiver program enhances the Company's benefits and wellbeing package, at a reasonable cost, to differentiate itself in a competitive labor market. The program provides flexibility so that employees have a low-cost alternative option in an emergency, which the Company expects (but could not substantiate) will reduce unplanned absences and increase productivity over time. Rather, the Company concluded that because the caregiver program provides comprehensive wellbeing tools, resources, and support for families, specifically children, elders, and those with special needs, it will in turn help the Company's employees to stay focused on their jobs. The Company must provide a competitive and comprehensive benefits package to attract and retain key talent. The caregiver program is an innovative and cost-effective benefit that will serve this purpose, which is critical to meet the service needs of customers. Therefore, the Company asserts that the cost is reasonable as a component of the Company's overall benefit package. UI CBP Rebuttal, p. 11.

The Company claims that since the program was implemented on January 1, 2021, it has achieved $89,000 and 165 days in absentee savings. Hr'g Tr., Mar. 2, 2023, 1896:8-21. The Company calculated this number by the number of utilizations and average salary. The Company's assumption is that if the program did not exist, the employee would have stayed home from work that day. Id. The Company, however, is not aware of any comparison of absenteeism prior to implementation of the program. To support its claim that in terms of the caregiver program providing a benefits and well-being package that differentiates itself in a competitive labor market, the Company could not provide information on how many (or if any) employers in Connecticut offered a similar program. Hr'g Tr. Mar. 2, 2023, 1898:8-17.

The Company has not been able to provide any specific or substantial evidence of how the caregiver program benefits ratepayers, nor did the Company substantiate its claim that the inclusion of this non-industry standard, extraordinary benefit is necessary to attract and retain appropriate staffing levels. The fact that the Company could not provide a before and after measure of program absenteeism renders the Company's claimed calculation of savings to be both incomplete and unverifiable. Similarly, the Company's inability to cite any evidence of the program in aiding retention and therefore, providing benefits to customers, leaves its claims unsupported. The Authority, therefore, disallows $41,250, which is the midpoint of the estimated $30,000 to $45,000 expense with an expected increase of 10% per year.

e. Pension and 401k

The Company provides access to a range of benefit offerings, including defined benefit pension plans, defined contribution (401k) plans, and/or OPEB to qualified employees depending on their date of hire, age at retirement, and years of service. Application, Ex. UI-CBP-1, p. 16. Over time, the Company has closed the legacy defined benefit pension plans and self-insured retiree medical plans to new hires and shifted the focus to 401(k) plans. Id., p. 17. Consequently, transitioning to these benefits reduced

retirement plan expenses. Id. Consistent with the Companies' long-term philosophy of de-risking retirement plan expenses, effective June 30, 2022, the Companies froze pension benefit accruals for non-union employees. Effective July 1, 2022, non-union employees will instead receive an enhanced 401(k) match formula of 150 percent on 8%. Id., p. 18.

The amounts included in the Company's O&M expense are the gross costs, reduced by (1) amounts allocated to capital, (2) amounts for UIL employees included in the plan, which are allocated across the UIL utilities, and (3) amounts allocated to transmission or other non-distribution cost components. UI Interrog. Resp. RRU-518.

i. Defined Benefit Pension Plans

The Company provided a breakdown of the assumptions and methods used in the calculation of the pension plan expense. Application, Ex. UI-CBP-7. Pension and OPEB costs are developed annually with the Company's outside actuaries and include a review of all the key assumptions. UI Interrog. Resp. RRU-518. Plan expense calculations are completed in accordance with ASC 715. Application, Ex. CBP-1, p. 21; UI Interrog. Resp. 518. The Company provided actuarial valuation reports to support its proposed pension and OPEB expenses. Application, Ex. UI-CBP-7. The Company explained that its retirement plan consultants developed expected return, standard deviation, and correlation assumptions for approximately twenty asset classes on an annual basis. UI Interrog. Resp. RRU-521.

Expected return is driven mainly by forward-looking current market pricing, while standard deviation and correlation assumptions are influenced primarily by historical data. UI Interrog. Resp. RRU-521. For the qualified pension plan, the expense and cash contributions projections are based on assumptions that include: assets on record dated December 31, 2023; applying a discount rate of 2.96% for all future years; an expected return on assets; a salary scale administration expenses that are assumed to increase at 3% every year; and contributions that are assumed to equal the minimum required contributions. Application, Ex. UI-CBP-7, pp. 6-7. As the plans become better funded, the expected return on assets assumption decreases as a result of moving away from return-seeking asset classes and reducing investment risk. The range starts at 7.00% for plans with a funded ratio less than 85% and gradually decreases to 5.00% for plans with a funded ratio 100% or greater. Id. The salary increase is 3.8% for Non-Union and 3.00% for Union, with an inflation rate of 2.00%. Id.

The Expected Return on Assets (EROA) is 7.00% and is projected to remain constant over the forecasted period of July 1, 2023, to Jun 30, 2027. Application, Ex. UI-CBP-1, p. 18. The EROA is projected to decrease over the forecasted period. This is a function of the funding status of the fund. As it increases, there is an increased allocation to fixed income, which generally returns less over the long term. Id., p. 20. Depending on the change in funding status and market activity, the actual return on assets might differ slightly from the expected return. Id.

Pension plan contributions are determined by IRS mandated rules to calculate the funding target in order to determine the minimum required contributions and funded status of the plans. Application, Ex. UI-CBP-1, p. 20.

The Pension expense is projected to decrease over the forecasted period of June 1, 2023, through June 30, 2027, primarily due to the amortization of losses and reductions in active participant counts. Id.

In the Company's original filing, the Company proposed a Rate Year 2023/2024 pension expense of $1.312 million. Application, UI Revenue Model Ex. C 3.24c WP. The Company updated its forecast of Pension and OPEB expense to reflect the effects of a pension freeze, as a non-union pension freeze became effective on June 30, 2022, and all non-union employees now have the same 401(k) match formula of 150 percent on 8%. UI Interrog. Resp. RRU-519. The Company updated the effect of this change in Late Filed Ex. 1, Ex. C 3.24 c WP. The updated proposal resulted in a Rate Year 2023/2024 pension expense of $3.320 million. Id. The Company cited Exhibit UI-CPB-7 as the source of the actuarial assumption used in the computation of the updated rate year pension expense of $3.320 million; however, that source document was the original actuarial report Exhibit UI-CPB-7, which did not include an updated report to reflect the changes made by the pension freeze. As a result, the Authority was unable to reconcile the increase of rate year pension expense. Consequently, the Authority disallowed the requested update and instead allowed only the original Rate Year 2023/2024 pension expense of $1.312 million. In written exceptions, the Company provided clarity on the original pension expense submission and the updated pension expense. Based on the Company's review, the reference to Exhibit UI-CBP-7 in Late Filed Exhibit 1 was a typographical error, and a holdover from the Company's September 9, 2022 filing, where the Exhibit UI-CBP-7 did support the initial pension expense. The Company pointed to record evidence, citing RRU-519 Attachment 1, as the basis for the updated pension expense. The Company also pointed to record evidence that indicated it would be updating the pension expense projections when the information was available. The Authority reviewed the supporting information identified in written exceptions and concludes the Company has met its burden and will be allotted $3.320 million in pension expense.

Some of the assumptions for the OPEB projections are based on: December 31, 2021 assets; plan provisions as of December 31, 2021; a discount rate of 2.85% for all future years; and an EROA of 5.90%. Application, Ex. UI-CBP-7, p. 7. The expense for UI generally increases from 2022 to 2024, primarily due to the reductions in the amortization of gains and prior service credits (which trend downwards as accumulated gains are recognized). Expense generally decreases from 2024 to 2027 due to increases in the expense component of expected return on assets and a decline in service cost and interest cost. Id. The following table depicts the Company's projected Pension and OPEB expenses.

Table 47: Projected Pension & OPEB Expenses ($000)

	Request Per Application	Requested Per Late Filed Ex. 1	Adjustment[108] (Between Application and Late Filed Ex. 1)
Pension	$1,312	$3,320	$2,008
OPEB	($1,525)	($1,421)	$104
Total	($212)	$1,898	$2,110

Application UI Revenue Model Ex. WPC 3.24; Late Filed Ex. 1, Ex. WPC 3.24.

ii. Defined Contribution (401k) Plans

The Company provided key assumptions used to project 401(k) plans, as follows: (1) current job vacancies are filled with employees contributing enough to receive the maximum match; (2) current deferral percentages are used for existing employees; (3) no changes to current match formulas over forecast period; (4) eligible 401(k) compensation increases 3 percent per year; (5) employees retire at age 65; (6) and IRS compensation limit increases $5,000 per year. Application, Ex. UI-CBP-1, p. 25.

The Company works with an investment consultant to periodically benchmark 401(k) plan expenses and negotiate with investment managers to gain access to the lowest available share class, where appropriate. All plan expenses other than employer matching contributions are paid for by employees. Id., p. 26. The Company has incurred increased 401(k) expenses because, in lieu of new hires having access to a pension or retiree medical benefits, the Company provided richer 401 (k) formulas. Application, Ex. UI-CBP-1, p. 26. In addition, the Company automatically enrolls employees at 6% of eligible compensation, resulting in high participation and deferral rates. Id. Since the 401(k) plan is the primary retirement vehicle going forward and the only available option for new hires, 401(k) related expenses are projected to steadily increase over time. Id. The Company is exploring merging the consolidated union and consolidated non-union 401(k) plans together, which would have no adverse impact to customers and could generate additional administrative efficiencies. Id.

The Company's projected 401(k) is $7.718 million for Rate Year 2023/2024 based on a headcount of 570, an average cost per employee of $13,532, and an anticipated 10% payroll escalator. Late Filed Ex. 1, Ex. C-2.24f WP. The Authority reduces this amount by $554,797 to reflect the decrease in allowed FTEs as explained in Section VI.A.2., FTE Compensation.

f. Adjustments for FTE Reductions

The decrease in FTEs yields a corresponding decrease in related benefits that were associated with those FTEs. These related benefits cover the areas of medical, dental and vision, and 401(k), the corresponding disallowances for which are addressed below.

[108] The adjustment column in Table 48 represents both the change between the Application and Late Filed Ex. 1, and the PURA-authorized adjustment to the Rate Year 2023/2024 amounts.

i. Medical

The Company's medical expense per employee is approximately $18,576 per employee ($10.595 million / 570). Late Filed Ex. 1, Sch. WPC-3.24a. The reduction of 41 FTEs, as explained in Section VI.A.2., FTE Compensation, results in a decrease in medical expenses of $761,607.

ii. Dental and Vision

The Company's dental and vision expense per employee is approximately $759 per employee ($433,000 / 570). Late Filed Ex. 1, Sch. WPC-3.24b. The reduction of 41 FTEs, as explained in Section VI.A.2., FTE Compensation, results in a decrease in dental and vision expenses of $31,138.

iii. 401K

The Company's 401K expense per employee is approximately $13,532 per employee ($7.718 million / 570). Late Filed Ex. 1, Sch. WPC-3.24f. The reduction of 41 FTEs, as explained in Section VI.A.2., FTE Compensation, results in a decrease in 401K expense of $554,797.

Table 48: Summary of Adjustments for FTE Reductions

	Expense ($)
Medical	761,607
Dental and Vision	31,138
401k	554,797
Total	**1,347,542**

g. Summary of Benefits Expense Adjustments

The table below summarizes the adjustments related to employee benefits as described in the preceding sections.

Table 49: Benefits Expense Adjustments ($000)

	Proposed	Adjustment	Approved
Medical Expense	$ 10,595	$ (762)	$ 9,833
Dental & Vision Expense	$ 433	$ (31)	$ 402
Pension OPEB Expense	$ 1,898 [109]	$ (2,110)	$ (212)
Incentive Expense	$ 1,495	$ (1,495)	
Workers Compensation Expense	$ 1,471	$ (147)	$ 1,324
401(k) Plan Expense	$ 7,718	$ (555)	$ 7,163
Other Employee Benefits Expense	$ 1,209	$ (204)	$ 1,005
Annual Expense	$ 24,819	$ (5,304)	$ 19,515

[109] Company Sch. WP C-3.24 lists $1,895 for item whereas Company Sch. WP C-3.24c lists $1,898.

5. Travel, Education, and Training

The Company requests $589,000 for travel, education, and training expenses. Application, Sch. WPC-3.22. In support of its travel, education, and training expense, the Company provided invoices and a general explanation of possible benefits that the travel, education, and training expenses provide to UI and its customers. Interrog. Resp. OCC-148, OCC-80.

The Authority allows this requested expense for travel, education, and training, but requires supplemental information from the Company regarding all incurred expenses booked to these categories moving forward.[110] In an annual filing regarding the travel, education, and training expenses incurred by Company personnel, the Company shall provide the standard it applied over the preceding 12-month period to determine employee attendance at any event that causes the Company to incur a travel, education, and/or training expense, as well as sufficient rationale in support of why such costs should be funded by ratepayers. Information provided shall include, at a minimum: how the Company's standard considered whether and how such expense will help the Company meet its statutory obligations and provide benefits to ratepayers; a list and description of each event, including whether such event was hosted by an entity to whom the Company, an affiliate, or its parent company pay membership dues; a descriptive list of the individual(s) who attended any event, including titles of the individual(s), years of service with the Company, years of service in the current job classification, and whether such expense was necessary for maintenance of a specialized certification; and itemized costs for each event, by individual, accompanied by receipts for all expenses.

6. Industry Association Dues

The Company requests recovery of $293,000 for membership dues expense for Rate Year 2023/2024. The Company provided a dues schedule depicting the amount paid to each industry organization, and a general explanation of possible benefits the membership dues provide to the Company and its customers. UI Interrog. Resp. OCC-20; Late Filed Ex. 1, Application, Sch. WPC 3.03. These include $252,000 for Electric Power Research Institute (EPRI), $2,000 for Corporate, $7,000 for remaining business and civic organizations, $28,000 for JD Power, and $4,000 for the project management institute. In response to a request that the Company identify benefits provided to ratepayers associated with the industry association dues, the Company simply claimed that expenditures translate directly to customer benefit and promote continued customer satisfaction. UI Interrog. Resp. OCC-20. When asked to quantify any such benefits, the Company stated that while the benefits associated with these expenses are not readily quantifiable, the costs provide a reasonable, if not conservative estimate of their benefit. UI Interrog. Resp. RRU-465.

[110] This supplemental information is an example of routine information that mirrors best practices and minimum documentation requirements that state agencies must maintain. It is also necessitated by the Company's testimony during the proceeding. Specifically, when asked to quantify the benefit received through the incurrence of travel, education, and training expenses to ratepayers, the Company was unable to quantify any benefits and stated, "while the benefits associated with these expenses are not readily quantifiable, the cost to the Company of these expenses reflects a conservative estimate of their benefit." Interrog. Resp. RRU-467.

The Authority finds that the Company failed to demonstrate that memberships in these industry organizations provide a quantifiable benefit to ratepayers and are reasonable and necessary to provide service to ratepayers. Moreover, Public Act 23-102 (P.A. 23-102), commonly referred to as Senate Bill 7 (S.B. 7), was signed into law on June 29, 2023, before Rate Year 2023/2024 commences on September 1, 2023. Importantly, P.A. 23-102 § 3 (a), effective from passage, expressly prohibits a public service company such as UI from recovering through rates any direct or indirect costs associated with "membership, dues, sponsorships or contributions to a business or industry trade association or group or related entity incorporated 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." Accordingly, the Authority disallows recovery of 100%, or $293,000, of the Company's requested industry membership dues from ratepayers, as the Company neither demonstrated how such costs are necessary to the provision of utility service, and further because P.A. 23-102 operates to preclude such prospective recoveries.[111] Neither the Authority, nor P.A. 23-102, prohibit the Company from engaging in such activities, but rather the Company's shareholders must bear these costs should the shareholders support such continued engagements.

7. Computer Expenses

The Company's proposal includes an increase of $395,000 for Rate Year 2023/2024 associated generally with computer expenses. Application, Sch. WP C-3.13. During discovery, the Company was asked by the OCC to provide support for this $395,000 adjustment. In response, the Company provided no support beyond a narrative response stating that the $395,000 figure was the Company's "best estimate" of the increase in software costs and that the estimate reflected "the Company's experience to date with the new system." UI Interrog. Resp. OCC-129. The OCC recommended disallowance of these costs due to the lack of supporting evidence provided by the Company. As noted by the OCC in its prefiled testimony, "[s]imply stating that the increase is based on experience is not sufficient to support this cost." Schultz and Defever PFT, p. 65. The Authority finds the OCC's testimony compelling and, accordingly, denies the Company's request for recovery of $395,000 in incremental computer expenses.

8. Telecommunications Expenses

The Company requests recovery of $3.464 million of Distribution Telecommunications Expense for Rate Year 2023/2024. The Test Year telecommunications expense was $3.012 million. Late Filed Ex. 1, Sch. C-3.18A. The $3.012 million Test Year figure for this category of expense is over three times higher than the $879,643 of test year telecommunications expense noted in the Company's previous rate case. UI Interrog. Resp. RRU-345. To help ensure that the $2.13 million increase in Test Year costs since the last rate case was reasonable, the Authority requested that the Company provide "a listing of any and all reasons known to the

[111] The Company argues that, since P.A. 23-102 became effective July 1, 2023, the disallowance of "costs that were incurred before July 1, 2023, . . . is an impermissible, retroactive application of [P.A. 23-012]." UI Exceptions, p. 31. Even if this argument were true, it is irrelevant here. The Company seeks to recover industry association dues that will be incurred after September 1, 2023, in Rate Year 2023/202. Consequently, the costs at issue were not "incurred before July 1, 2023," and are, therefore, subject to any "new obligation" in P.A. 23-102.

Company for why" the Company's telecommunications expense rose so dramatically between these two test years. UI Interrog. Resp. RRU-345.

In response to this request, the Company stated that there were "multiple reasons" why these costs increased. Id. The Company then cited two items from Docket No. 16-06-04 that accounted for approximately $716,000 of the difference, as well as an alleged increase in support services. UI Interrog. Resp. RRU-345. However, based on the Company's own supporting schedules, the increase in support services (i.e., the line item titled "33425 Support Services – D") increased only $339,545 from 2015 to 2021. UI Interrog. Resp. RRU-552, Att. 1.

Therefore, while the Company provided an explanation for part of the cost increase, a significant amount of the increase in telecommunications expense remains unexplained. Specifically, of the $2.13 million increase in Test Year expense since the last rate case, the Company only provided clarification for approximately $1.055 million of this amount (i.e., $716,000 + $339,545). The remaining $1.075 million (i.e., $2.13 million - $1.055 million) is unexplained[112] and is, therefore, denied for recovery by the Authority.

9. Injuries and Damages

In developing the amount of injuries and damages expense to include in Rate Year 2023/2024, the Company used the Test Year amount, adjusted by an inflation factor, to arrive at an amount of $1.157 million for Rate Year 2023/2024. Sch. WP C-3.14. The trouble with this approach is that the injuries and damages expense has fluctuated significantly over the past five years, rendering any single year comparison suspect regarding its ability to adequately represent Rate Year 2023/2024. To remedy the disconnect, the OCC proposes using a five-year average in place of the Test Year in order to get a more representative starting point. The Authority finds this approach more reasonable. As such, using a five-year average results in a Rate Year 2023/2024 expense of $607,000 and a corresponding reduction of $550,000.

10. Corporate Service Charges

a. Summary

The Authority disallows $3.646 million in corporate services charges. UI's initial filing included $40.868 million in corporate service charges for Rate Year 2023/2024.[113] Application, Sch. C-3.27A. The Company subsequently reduced these costs to $37.862 million to reflect changes identified during the discovery process. Late Filed Ex. 1, Sch. WP C-3.27.

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[112] Further, the Company broadly asserted that telecommunications are a necessary and proper operating expense, but offered no evidence that the amount disallowed was required to provide adequate and reliable service for ratepayers, nor did the Company dispute the Authority's specific findings and calculations summarized herein regarding PURA's attempts to reconcile the delta between test year expenses. UI Written Exceptions, pp. 106-107.

[113] Notably, P.A. 23-102, effective from passage on June 6, 2023, and before Rate Year 2023/2024 commences on September 1, 2023, expressly prohibits a public service company such as UI from recovering myriad items included in UI's proposed Corporate Service Charges, including membership, dues, or contributions to business or trade associations, groups, or tax-exempt entities (P.A. 23-102 § 3 (a)), travel, lodging, or food and beverage costs for the Company or its parent company's officers or boards of directors, and investor relation expenses (P.A. 23-102 § 3 (d)).

The table below summarizes the Authority's disallowances and the approved corporate services costs.

Table 50: Adjustments to Corporate Service Costs ($000)

	Adjustment	2023/2024
Proposed		37,862.00
Inflation Adjustment	(2,806.00)	
Board of Directors Costs	(239.68)	
Investor Relations Costs	(142.00)	
Audit Services Costs	(260.50)	
Brand Services Costs	(129.00)	
Non-Industry Dues	(69.00)	
Adjustment Sub-total		(3,646.18)
Allowed Corporate Service Costs		**34,215.82**

b. Inflation Escalation

The Authority denies UI's proposed $2.806 million inflation escalation of Corporate Services charges for Rate Year 2023/2024 given the pattern of overall declining costs in this area.

According to the Company, the proposed increase from the Test Year is due to inflation. The Company proposes that corporate services charges should increase in Rate Year 2023/2024 to reflect an inflation adjustment of 11.06%.[114] The inflation adjustments for the subsequent years are much smaller (0.16% and 0.12%). However, UI's proposal does not commit that these inflation increases would be the final numbers. Instead, it would allow for further increases to match inflation in Rate Years 2 and 3, under its "inflation moderator" proposal.[115] Ex. UI RRP 1, p. 28. Using inflation forecasts from Blue Chip Economics, the Company proposed to "adjust those forecasts downward by 2% in each period," but then to include an "inflation reconciliation" in which a reconciliation to actual inflation rates would become a regulatory asset or liability, so that final revenues would be trued up for inflation. Interrog. Resp. OCC-84, Att. 14.

The OCC argues that no inflation escalation should be included in authorized corporate service charges. The OCC observes that the requested increase comes at a time during which corporate service costs have been decreasing and expenses have been below budget in four out of five years, i.e., from 2017 through 2021. Shultz and Defever PFT, Dec. 13, 2022, p. 24. The OCC points to a history of significant over-collection for Corporate Services charges. Id. The OCC recommends, rather than assuming costs will increase, holding authorized Corporate Service charges flat at the Test Year level.

[114] UI applied its inflation factor to all line items in Corporate Services, except for the $1,297 "Smart Grids" line item, which was removed entirely from Rate Years 2023/2024, 2024/2025, and 2025/2026.

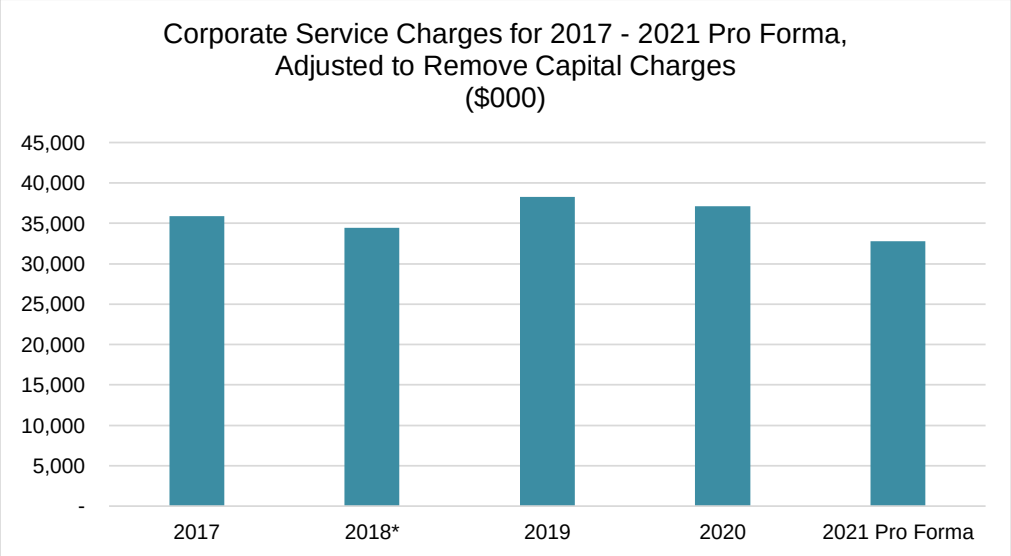
[115] UI's inflation moderator proposal would enable UI to collect (or refund) the difference between its projected inflation rate and actual inflation rates. Ex. UI-RRP-1, pp. 12-13.

In response, UI's RRP filed rebuttal testimony that argues that the apparent decline in Corporate Service charges reflects change in the treatment of capital costs related to shared assets (the "Corporate Capital Charge"), not a reduction in other costs. Between 2018 and 2021, UI gradually implemented a policy of allocating assets directly to individual companies and eliminating the "Corporate Capital Charge" as a shared charge. For this reason, UI says that corporate service costs have declined. UI-RRP-REBUTTAL-1, pp. 14-15.

UI argues that "a large portion of Corporate Service Charges are labor, and it is unreasonable to hold these costs flat when labor costs are expected to increase," stating that the annualized inflation growth over three years is "modest and reasonable." The Company further argues that this is consistent with PURA precedent and that the category of "Administrative and General" expenses, into which Corporate Services falls, are low on a per-quartile basis, compared to other utilities. UI-RRP-REBUTTAL-1, pp. 14-15.

Because UI asserts that the apparent decreasing trend in Corporate Services charges should be attributed to the removal of capital charges from this category and thus would not apply to the remaining charges, the Authority developed a comparison of corporate service charges since 2017, which removes capital charges from all years.[116] The Figure below shows that, with these adjustments made, corporate service charges have declined in the past three years as the OCC states, independent of the impact of removal of capital charges; however, that decline has not been dramatic.

Figure 3: Normalized Corporate Service Costs Comparison



[116] Figures in this chart reflect UI's updated Corporate Services charges figures as shown in Application, Late Filed Ex. 1, Att. 1, Sch. WP C-3.72. The source of capital charges expense data is Interrog. Resp. OCC-51, Att. 1.

This analysis confirms that corporate service costs have been flat or decreasing. Therefore, the Authority finds the OCC's analysis persuasive and, accordingly, denies the Company's requested inflation increase of $2.806 million for corporate service costs.

c. Board of Directors Costs

The Authority disallows $239,677 or 75% of UI's requested Board of Directors (BOD) costs, reflecting the fact that Boards of Directors have a fiduciary duty to and primarily serve the interests of shareholders, rather than ratepayers.

UI proposed $347,090 in BOD costs included in corporate service charges, as escalated by inflation from the $319,570 costs for the Test Year. Interrog. Resp. OCC-3, Att.1. The costs included for the BOD include the following items, with Test Year amounts indicated:

Table 51: BOD Cost Detail

BOD Items	Cost ($)
Other Infrastructure Fees	249,280
Insurance Premiums	14,740
Donations	4,400
Office Supplies	560
Travelling Expenses	9,730
Work Meals	470
Annual Meeting	40,390
Total	**319,570**

The OCC proposes that the share of BOD costs allocated to Corporate Services and passed on in rates should be adjusted to 25% of the total, arguing that the allocations proposed by UI overstate the benefits to ratepayers of these expenditures.

UI argues that BOD and public company expenses "are appropriate and necessary costs of running and investing in the utility business. If the expenses are not funded in rates, the Authority will be denying recovery of costs for critical business functions, including functions that provide oversight and enable the Company's access to capital." UI-RRP-Rebuttal-1, pp. 19-20.

The Authority finds that BOD activities are primarily focused on the interests of the Company's investors. Ratepayers may incidentally benefit from the activities of the BOD; however, ratepayer interests are not the main focus of the BOD's decisions. In recognition of the partial benefits, albeit likely overstated and not fully substantiated by the Company,[117] provided to ratepayers by the activities of the BOD, the Authority accepts OCC's proposal to allow 25% of the BOD costs in rates. Allowing 25% of BOD expenses in rates is also consistent with past precedent. See 2016 Rate Case Decision, p. 36. Accordingly, the allowed BOD costs are $79,893 ($319,570 x 25%) for Rate Year

[117] Notably, the Company provided only a line-item breakdown of BOD expenses as reflected in the above table and failed to submit any evidence demonstrating that the expenses were prudent and reasonable. See Interrog. Resp. OCC-003. Therefore, the Authority could disallow 100% of the BOD costs for UI's failure to demonstrate prudency.

2023/2024. As a result, the Authority disallows BOD costs of $239,677 ($319,570-$79,893).

Audit Services costs are not considered here, because, although they were previously included within reported BOD costs, such costs are now included in the category "Other Corporate," within Corporate Services, and thus are discussed in the "Other Corporate costs" section below.[118]

d. Investor Relations[119]

UI proposed to recover $154,000 in investor relations costs in Rate Year 2023/2024, as escalated by inflation from the $142,000 costs for the Test Year. Interrog. Resp. OCC-53, Att. 1. However, UI failed to submit evidence in the record demonstrating that investor relations costs are reasonable and necessary to provide service to its ratepayers, while conversely, the OCC's testimony argues that these expenses primarily benefit Company shareholders. Schultz and Defever PFT, p. 26. The Authority finds no evidence in the record to support that investor relations benefit ratepayers or that such costs are necessary to the provision of utility service; rather, the Authority finds that investor relations expenses primarily benefit shareholders. Finally, P.A. 23-102 § 3 (d), effective from passage on June 6, 2023, and before Rate Year 2023/2024 commences on September 1, 2023, expressly prohibits a public service company such as UI from recovering through rates any direct or indirect costs associated with investor relations. Therefore, the Authority disallows 100% of these costs.

e. Audit Services

UI identified $521,000 in audit services costs for the Test Year. Detailed audit services costs projections were not provided in the corporate services category; however, based on additional information provided by UI in discovery, the Authority calculated the 2021 audit costs included in the "other corporate" category to be $521,000, as shown in the below table.[120]

Table 52: Audit Services ($000)

	Avangrid 2021 Cost	Allocation to UI	UI 2021 Cost
External Audit	$58	81.4%	$47
Internal Audit	$582	81.4%	$474
Total Audit	$640	81.4%	$521

Interrog. Resp. RRU-256, Att. 3; Late Filed Ex. 1, Att. 1, Sch. C-2.1A.

UI noted that allowing 50% of BOD expenses associated with Audit and Accounting Services is consistent with the 2016 Rate Case Decision. UI Brief, p. 116.

[118] "Other Corporate" category includes: audit costs; general services; communications; compliance; development services; insurance; investor relations; regulation services; research, development, and innovation; and environmental costs. Late Filed Ex. 1, Sch. WPC-3.27, n. 1.

[119] Unlike in previous rate cases, UI is not requesting recovery of Directors & Officers Insurance or charitable contributions. Interrog. Resp. OCC-11 and OCC-19.

[120] Note that these audit costs do not include any audit costs that are directly incurred by UI. Interrog. Resp. RRU-256, Att. 1.

The Authority finds that audits benefit shareholders and ratepayers relatively equally. Accordingly, the Authority authorizes UI to recover 50% or $260,500 of these costs.

f. Brand Services

UI identified $129,000 in brand services costs for the Test Year. Detailed actual and projected communications cost were not provided in the corporate services category; however, based on additional information provided by UI in discovery, the Authority calculated 2021 communications costs included in the "other corporate" category to be $572,000, as shown in the below table.

Table 53: 2021 Communications Costs ($000)

	Avangrid 2021 Cost	Allocation to UI	UI 2021 Cost
Struc-Communications	$329	81.4%	$268
Internal Communication	$215	81.4%	$175
Brand Services	$159	81.4%	$129
Total Communications	**$703**		**$572**

Interrog. Resp. RRU-256, Att. 3; Late Filed Ex. 1, Att. 1, Sch. C-2.1A.

All of these charges are from UIL to UI; some or all of these are passed down from Avangrid through UIL to UI. Regarding an inquiry about whether the parent company "engage[s] in 'advertising', 'marketing', or 'communications' for the benefit of UI," the Company replied with an example of a 2022 "brand awareness" expenditure, and with reference to that fact that "AVANGRID also promotes state-specific content on its social channels when relevant throughout the year, including content relating to UI." Interrog. Resp. EOE-175.

The Authority finds no evidence to support that ratepayers benefit from "brand awareness" given that the ratepayers are captive customers of a regulated monopoly. As such, the Authority disallows the $129,000 in Brand Services allocated to UI-D within the "other corporate" category.

g. Non-Industry Dues

The Authority disallows $69,000 in non-industry dues included in UI's filing, because direct, substantial benefits to ratepayers have not been shown.[121]

In its filing, UI indicated that it allocates $69,000 in "non-industry dues" to the UI distribution sector, primarily for chambers of commerce and business councils. Application, Sch. G-2.8.

[121] Further, even in the event that the Company had provided evidence of direct, substantial benefits to ratepayers indicating that the expense is reasonable, prudent, and necessary to the provision of service (which it did not), P.A. 23-102, effective from passage on June 6, 2023, and before Rate Year 2023/2024 commences on September 1, 2023, expressly prohibits a public service company such as UI from recovering myriad items included in UI's proposed Corporate Service Charges, including membership, dues, or contributions to business or trade associations, groups, or tax-exempt entities (P.A. 23-102 § 3 (a)).

The OCC recommends that 50% of these dues be disallowed because "ratepayers do not receive all of the benefits from these costs," and cites previous Authority decisions.[122] Schultz and Defever PFT, p. 28.

UI offers a general statement that these expenses "provide benefits to the Company and its customers." UI-RRP-REBUTTAL-1, p. 21. In discovery, UI cites descriptions of the missions of the Greater New Haven Chamber of Commerce, the Bridgeport Regional Business Council, and the Connecticut Business and Industry Association from their respective websites; however, it does not make any explicit connection between the general mission of these groups and specific ratepayer benefits. Furthermore, UI acknowledges that the Chambers of Commerce and similar entities for which dues are included in the line item, "non-industry dues," do undertake "advocacy" activities. Interrog. Resp. OCC-21.

In the absence of a clear demonstration of specific ratepayer benefits, as well as the Company's concession that such organizations may engage in advocacy efforts, the Authority disallows the inclusion of the $69,000 of non-industry dues in the Corporate Services category.[123] The Authority's disallowance of these costs should not be construed as a commentary on the organizations listed above, but rather an outcome of the Authority's statutory obligation to not allow charges to be imposed on customers without a clear demonstration by the Company of the tangible benefits to ratepayers of such charges. In this instance, non-industry dues represent a transference of funds from all UI customers to organizations that work on behalf of a subset of vested interests, which may or may not align with UI ratepayers generally, nor correspond to the provision of utility service. The Authority typically does not authorize this type of financial subsidy without a public policy (e.g., executive order, finding in the Comprehensive Energy Strategy, etc.) or statutory directive.

11. Storm Reserve

a. Retain Current Storm Reserve Accrual

The Company proposes to increase the storm reserve allowance from $2 million per year to $3 million per year. RRP PFT, p. 25. UI argues that the additional funds are necessary to enable the Company to secure sufficient resources in advance of unpredictable storms. EPP PFT, p. 22.

UI monitors weather forecasts and makes judgements about potential impacts to its system and customers in advance of potentially damaging weather events. Id. Since weather forecasts are uncertain, UI must make judgement calls sufficiently early to secure outside line and tree clearance resources in advance of storms (i.e., "leaning-in"). Id. UI

[122] Docket No. 13-02-20, Application of Aquarion Water Company of Connecticut to Amend its Rates and Docket No. 20-12-30, Application of The Connecticut Water Company to Amend Its Rate Schedule.

[123] This standard is similar to that in Massachusetts, in which, in a recent Eversource rate case, the Commission approved the inclusion only of dues "for which the Company demonstrated a clear link between costs and ratepayer benefits," (for example, the Electric Utility Sustainable Supply Chain Alliance), and did not approve dues for any Chamber of Commerce memberships. Decision, Nov. 30, 2022, Massachusetts DPU, Docket No. 22-22, Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164 § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan, p. 211.

often needs to make decisions well before it is known whether storms will materialize or not. Id. Making decisions early is especially necessary for storms that track the eastern seaboard, since UI will have to compete with other utilities who are either securing outside resources themselves or are hesitant to release crews. Id. UI states that the increase in the storm reserve allowance will help it secure sufficient resources far enough in advance. Id.

The Company also asserts that there have been an increasing number, severity, and costs of storms in recent years, which justifies an increase to the accrual. Id., p. 19. The Company also asserts the need to increase the frequency of leaning-in activities to avoid reimbursing customers for long duration outages pursuant to Conn. Gen. Stat. § 16-32m. Id., p. 21.

Regarding the Company's assertion that there are more frequent storms requiring the Company to incur more leaning in costs and more restoration costs, the evidence suggests otherwise. From 2013-2015, the first three years following the initiation of the $2 million per year storm reserve, UI charged no storms to the storm reserve. Interrog. Resp. OCC-159. In 2016, UI only charged lean-in costs for one event that did not otherwise qualify for the reserve. Id., Att. 1. From 2017 through 2022, UI charged 11 events to the storm reserve. Id. During the 2016 Rate Case, the Authority declined to eliminate the storm reserve accrual despite no storms being charged and a reserve balance of $6.763 million that had accumulated during those quiet years. 2016 Rate Case Decision, p. 111. The Authority finds itself in a situation similar to the previous rate case. As it did in 2016, the Authority declines to hastily modify the storm reserve accrual here.

Regarding UI's claim that since reserve storm costs are increasing, the accrual should likewise increase, again the Authority finds the opposite. The requested storm regulatory asset balance in 2013 ($53 million) was more than two times larger than the balance presented in this case ($25.7 million). Sch. B-1.0; 2013 Rate Case Decision, p. 24. Prior to 2013, there was no accrual, and it was only during the 2013 Rate Case that UI requested and received a $2 million accrual. Id. This level was deemed sufficient at the time and remains sufficient now given insufficient evidence to the contrary. Id. In short, circumstances have not changed to warrant an increase in storm reserve accrual.

Furthermore, the Authority finds the Company's argument that it needs to increase the accrual due to lean-in costs unsupported by the record. There is nothing in the record to suggest that the current storm reserve accrual has been inadequate to support UI's ability to lean-in. Further, the Authority cannot evaluate UI's lean-in costs in detail because UI does not separate lean-in costs from storm recovery costs when a major storm occurs, so the Authority has no way to evaluate the level of lean-in costs. Interrog. Resp. RSR-68.

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. 2016 Rate Case Decision, p. 111. The storm reserve accrual is also useful to the extent it encourages UI to prepare for potential storms by leaning-in. Id. The Authority finds that the current accrual level continues to serve both purposes adequately.

Accordingly, the Authority denies UI's request to increase the accrual by $1 million. This adjustment decreases UI's Outside Services – Storm Reserve account expense by $1 million. Sch. C-3.06.

b. Increase Threshold Value for Major Storm

The Authority increases the threshold by which the Company can charge storm costs to the storm reserve account to recognize the Company's increased operating costs.

Currently, the Company is allowed to charge storm expenses to the storm reserve if the incremental expense for an event is at least $1 million (major storm threshold). 2013 Rate Case Decision, p. 30. The purpose of the threshold is to distinguish between storms that should be considered a normal part of business operations and catastrophic storms. Id., p. 29. Only catastrophic storms are appropriate for special regulatory treatment (i.e., accounting deferral) to protect the Company against events that require the Company to pay out large sums of money that are not immediately available from customers. Id., p. 28. The Authority determined that a $1 million threshold was appropriate in 2013. Id., p. 30.

This threshold has not changed since 2013, but utility construction costs have escalated since that time. Interrog. Resp. RSR-88. Not reflecting these changes in construction and operating costs in the major storm threshold tips the delicate balance of a storm reserve against the customers.

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. Hr'g Tr., 1086:1-13, 838:9-14. The Handy-Whitman Index is updated biannually (on July 1 and January 1) and has an index specific to North Atlantic utilities. Interrog. Resp. RSR-88, Att. 1.

To ensure the major storm threshold remains reflective of actual utility costs and captures only catastrophic storms, the Authority will increase 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. Id. Using the "Distribution Plant" category in the index gives an escalation factor of 1.43. Id., Att. 1. Applying the escalation factor to the $1 million threshold yields $1.43 million.

UI argues that changing the major storm threshold requires adding operating expenses to offset the costs of storms that no longer qualify for the major storm threshold. UI Exceptions, p. 113. UI states that it has not had an opportunity to identify such costs to enable fair recovery of them. Id. To determine the incremental expenses that UI may incur when the major storm threshold is increased, the Authority looked at the storms that qualified for the storm reserve since 2013 Rate Case Decision, and applied the Handy-Whitman Index to those storms to assess whether its application would have triggered the eligibility threshold for the storm reserve. Had the Handy-Whitman Index been used to update the major storm threshold since 2014, only three of the twelve events recorded to the storm reserve since 2014 would not have qualified for the storm reserve. These three events are:

1. July 8, 2021 storm (Elsa) with incremental cost of $1.076 million;
2. January 17, 2022 storm (Izzy) with incremental cost of $1.097 million; and
3. January 29, 2022 storm (blizzard) with incremental cost of 1.345 million.

Interrog. Resp. OCC-77, Att. 1; Interrog. Resp. RSR-88, Att. 1.

Had these storms been excluded from recovery from the storm reserve, the Company would have incurred a sum total of $3.518 million in expenses over a nine and a half year period (from January 2014 through July 2022), for an average annual expense of $370,316. Ex. UI-EPP-3. However, a portion of these costs were for lean-in (or storm preparation) costs. Interrog. Resp. RSR-68, Att. 1. Lean-in costs are allowable for assignment to the storm reserve regardless of whether the incremental storm costs meet the major storm threshold. 2016 Rate Case Decision, p. 110; Hr'g Tr., 1216:23-25. Although UI has a responsibility to provide lean-in costs for auditing, 2016 Rate Case Decision, p. 110, the Company failed to separately track or present lean-in costs for any of the events; therefore, the Authority is unable to determine how much of the $3.518 million would have been applied to the storm reserve regardless of whether the total storm costs met the threshold. Interrog. Resp. RSR-68, Att. 1; Hr'g Tr., 2005:15-2006:17. Nor did the Company provide the number of external line resources that were secured prior to the events. Interrog. Resp. RSR-68.

Nevertheless, the Authority has reason to believe a substantial portion of the total storm costs are attributable to lean-in costs because (1) the Company secures resources to be on-site prior to events to comply with its emergency response plan and has increased its reliance on this policy following lessons learned from Tropical Storm Isaias, and (2) external resource costs are a large portion of total incremental storm expenses. Interrog. Resp. OCC-77, Att. 1; Hr'g Tr., 1217:2-15; EPP PFT, p. 21. As such, the available evidence indicates that the Company would not incur significant incremental operating expenses as a result of the change to the major storm threshold.

The Authority will determine at a future rate proceeding whether an increase to operating expense is needed as an offset to increased major storm threshold when UI can provide the data to justify an offset. Such a plan is consistent with what the Authority did in the 2013 Rate Case Decision, when the major storm threshold of $1 million was first established.[124] 2013 Rate Case Decision, p. 28.

Accordingly, the Authority sets the new major storm threshold for charging storms to the reserve at $1.43 million. The Authority directs UI to apply the Handy-Whitman index on an ongoing basis with each biannual release of the index on January 1 and July 1, and to update its major storm threshold each January 1 and July 1 accordingly. The Authority directs UI to retain documentation demonstrating it applied the Handy-Whitman Index when it next requests recovery of major storm costs in the storm reserve.

[124] When faced with the same argument, the Authority found that "there is no evidence presented indicating the extent to which the storm reserve is either consistent or inconsistent with any O&M level, or what that O&M level might be. As a result, the Authority is limited to defining major storms on a basis consistent with catastrophic events. Meanwhile, the degree to which this definition makes storm-related O&M expenses now in rates too high, too low or just right will have to be decided in a future proceeding." 2013 Rate Case Decision, p. 28.

c. Logistics Vendor Costs in Storm Reserve

The Company seeks to enter into an agreement for $120,000 annually with a logistics vendor specializing in securing lodging to assist with storm preparation. EPP PFT, p. 22. The Company offers to charge the costs to the storm reserve. Id., p. 23. The Company claims that the benefits of such an agreement will take advantage of the vendor's expertise to find cost-effective lodging for external crews, while freeing up Company personnel (who are not experts in securing lodging) to focus on other logistics concerns. Id., pp. 22-23. UI expects that such an agreement would result in shorter travel times for crews and more and better lodging options. Id., p. 23.

The Company determined the costs of the proposed agreement based on the experience of Avangrid affiliates who utilize similar agreements in the pilot program, but UI does not have formal quotes from vendors. Interrog. Resp. OCC-286. UI's affiliates in New York have piloted the approach with a vendor from March 2021 through December 2023. Interrog. Resp. RSR-87.

The Authority finds no compelling reason to approve the project. At best, the project is premature; there are no actual vendor quotes, and the benefits appear theoretical. UI provided no results from its affiliate's pilot program. Interrog. Resp. RSR-87. Lastly, and unrelated to the agreement itself, it is inappropriate to charge known and foreseeable expenses to the storm reserve. Doing so would be an abuse of the reserve.

That said, the Authority is not opposed to UI using a vendor specializing in lodging. It may enter into such an agreement, but if it does so, such an agreement will have to be within the allowed expenses. The Authority will not authorize incremental ratepayer funds for such a project, particularly based on the unsubstantiated request made here.

d. Mutual Aid Revenue

The Company at times provides crews to other utilities (affiliate and otherwise unrelated) as mutual aid to assist in emergency storm restoration to affiliate and unrelated utility companies. Interrog. Resp. to OCC-546. The Company receives revenue for loaned crews, and the amount of revenue exactly offsets the incurred expenses resulting in a net impact of zero. Interrog. Resp. RSR-091. There is a timing difference between when the costs are incurred and when the Company receives the reimbursement, so the Company does not forecast these costs and revenues in the revenue requirement. Sch. WP C-3.28; Interrog. Resp. OCC-546.

While it may be true that there is a net zero revenue impact from the Company's perspective, it does not follow that this arrangement is entirely fair to customers.

When an employee is released for mutual aid to other utilities they are, obviously, not available to do work for UI customers. One of two things happens, since the work they would normally perform still needs to be completed: (1) either the work is delayed; or (2) the Company uses contractors or internal employee overtime to complete the work. Interrog. Resp. RSR-91, p. 2; Hr'g Tr., 1265:17-25. In the case where the work is delayed, UI customers are paying UI employees to perform work elsewhere since UI is not forecasting mutual aid revenue in revenue requirements. This cost is not de minimis, as the table below demonstrates. The table shows UI's total percentage of payroll that was

spent by employees in other jurisdictions by year. If, however, in this scenario ratepayers' expenses were offset by the mutual aid revenue, UI ratepayers would not be harmed by the project delays.

Table 54: Time Spent Away as a Percentage of Total Labor

	2017	2018	2019	2020	2021	2022
Mutual Aid Percentage of Gross Labor	n/a	n/a	2.3%	4.3%	0.8%	2.2%

Interrog. Resp. RSR-91, p. 2.

In the case where work is completed with employee overtime or contract crews, UI customers are paying higher costs for the same work. Hr'g Tr., 1267:11-14. The following table compares the costs of internal employee standard pay, internal employee overtime pay, and contractor pay for all the work hours that employees were away on mutual aid to other utilities.

Table 55: Estimated Costs for Employees Working at Other Utilities

	2019	2020	2021	2022
Total Estimated Cost Internal – Standard	$ 1.846	$ 1.925	$ 0.713	$ 1.496
Total Estimated Cost Internal – Overtime	$ 2.342	$ 2.345	$ 0.990	$ 1.934
Total Estimated Cost – Contractor	$ 3.735	$ 3.895	$ 1.299	$ 2.381

Interrog. Resp. RSR-91; Late Filed Ex. 41.

The above table demonstrates that if work is performed by contractors or with internal employee overtime, then UI is incurring more costs to complete the work when employees are supporting other utilities through mutual aid. However, as the Company's revenue is fixed, the increased crew cost is only relevant to ratepayers insofar as it reduces the amount of mutual aid revenue due to them. While the Authority is concerned that mutual aid revenue used to pay for more expense crews to do the same work incentivizes inefficient resource allocation, the Authority appreciates the reciprocal nature of mutual aid and defers to the Company's judgement as to when the work warrants prioritization such that replacement crews at higher costs are brought in to complete the work.

Ultimately, in either case, UI customers are paying for employees to work outside of UI's service territory on non-UI projects. As such, the net revenue received by UI for this practice needs to be returned to customers. Accordingly, the Authority directs UI to record all net mutual aid revenue in the storm reserve as an additional accrual to the storm reserve. The Authority defines net mutual aid revenue as those revenues in excess of the costs of replacement crews to perform the work planned to be completed by the crew during their absence, to the extent such crews are retained, and any incremental costs incurred to send the crews to another utility for a given storm event. The Company shall not accrue net negative mutual aid revenues associated with a storm event to the storm reserve, nor seek recovery of such net negative revenues.

12. Professional Services Expense

a. CLEAN EARTH Initiative

The Company proposed the creation of the CLEAN EARTH Initiative in its Application. The CLEAN EARTH Initiative would be located in The University of Connecticut's (UConn) Technology Park where it could collaborate with the Eversource Energy Center. Id. The Company proposes six key research areas for the CLEAN EARTH Initiative including: (1) Climate Change Impact Modeling; (2) Outage and Flooding Forecasting; (3) Transmission and Distribution Planning; (4) DER Adoption Analysis and Strategy; (5) Clean Hydrogen and Offshore Wind Integrations; and (6) State-of-the-Art Weather and Climate Information. Ex. UI-JA-1, pp. 10-12.

The CLEAN EARTH Initiative would be overseen by an executive committee including: the Principal Investigator (PI); the Dean of the School of Engineering; the Provost (or their designee); the Vice President of Research (or their designee); and a maximum of three Avangrid appointees. The executive committee would determine the overall strategic direction of the CLEAN EARTH Initiative. Avangrid and UConn members of the executive committee would each have one vote. All matters before the executive committee would be decided by consensus. Ex. UI-JA-2, p. 3.

The proposed total annual cost of the CLEAN EARTH Initiative is $423,000 for five years, which amounts to a total of $2.115 million. Interrog. Resp. CAE-15. The costs of the CLEAN EARTH Initiative include annual research and development costs of $250,000, which amounts to $1.25 million over five years, and annual program management costs of $173,000, which amounts to $865,000 over five years. Id. The research and development costs would be supported by a 90% / 10% cost share between UI customers and Avangrid, respectively. Id. This cost share proposal results in an annual expense charge to UI customers of $225,000 (.90 x $250,000 = $225,000). The program costs do not reflect receipt of any grants and UI states that any grant funding received in the projected rate years would be in addition to, and not a substitute for, the funding reflected in the Company's proposed revenue requirement. Interrog. Resp. OCC-226. The table summarizes the funding needs and sources to support the CLEAN EARTH Lab Initiative.

Table 56: Funding for the CLEAN Earth Lab Initiatives

	Annual Amount	**Total (Five Years)**	
Research & Development (90% R&D cost share)	$225,000	$1,125,000	Customer-funded
Research & Development (10% R&D cost share)	$25,000	$125,000	Company-funded
R&D SUBTOTAL	$250,000	$1,250,000	
1 FTE (Program Manager)	$173,000	$865,000	Customer-funded
TOTAL	**$423,000**	**$2,115,000**	

Interrog. Resp. CAE-15, with corrected FTE and total costs.

The Authority applauds the Company's proactive approach in developing the CLEAN EARTH Initiative and strongly supports the intention of the initiative and, specifically, the need for and potential benefits of fundamental research proposed. However, the Authority has several concerns with the proposed CLEAN EARTH Initiative as currently proposed. First, in applying traditional standards for cost recovery, the proposal is premature in its request as it lacks sufficient detail to approve full cost recovery from UI ratepayers. Second, the proposed governance structure is inadequate to ensure that the selected research projects will benefit the UI ratepayers who will be paying for the initiative. Third, although UI ratepayers will pay for the overwhelming majority of the costs of the initiative, Avangrid shareholders and affiliates will benefit from the insights and tools that result. Fourth, the Company has not adequately demonstrated a need for the program manager despite program management and FTE costs comprising nearly 40% of the total proposed costs. Lastly, the incremental value to Connecticut ratepayers of the CLEAN EARTH Initiative is unclear.

The CLEAN EARTH Initiative proposal's lack of sufficient details is evidenced by the fact that the Company identified broad research areas, but no specific projects, deliverables, or timelines. Hr'g Tr. Mar. 7, 2023, 2648: 22-24, 2668:13. The lack of concrete details regarding the research is in contrast with other research and development initiatives Avangrid is undertaking with the support of grant funding. For example, the $600,000 in grant funding Avangrid obtained through New York State's Energy Research and Development Authority's (NYSERDA) Program Opportunity Notice (PON) 4074: Electric Power Transmission and Distribution High Performing Grid required a cost schedule, an execution schedule, and a commercialization plan. Ex. UI-JA-1, p. 9; Hr'g Tr., Mar. 7, 2023, 2682: 2-4.

Regarding the proposal's governance structure, as the CLEAN EARTH Initiative is not fully defined, there is a risk that the selected research topics will primarily benefit Avangrid as opposed to UI ratepayers. Specifically, while some of the proposed key research areas, such as Outage and Flooding Forecasting, Climate Change Impact Modeling, and DER Adoption Analysis and Strategy, as defined, have clear potential benefits to UI's distribution customers; other proposed key research areas, such as Transmission and Distribution Planning, Clean Hydrogen and Offshore Wind Integrations, and State-of-the-Art Weather and Climate Information, are more nebulous in how much, if at all, they will directly benefit distribution ratepayers, particularly depending on how the executive committee decides to direct such research areas (e.g., more of a focus on transmission than distribution planning). Also, notably, there is no stakeholder participation in the executive committee's decision-making process. While the Company has indicated that it is not opposed to appointing a member of the Authority to the Committee, this position is not an adequate substitute for the stakeholder engagement that occurs in a docketed proceeding or other public process. Interrog. Resp. CAE-15. Further, the record is contradictory on which entity would have majority control of the committee's decision-making. While the Master Research Agreement (MRA) indicates the committee would be composed of four officials from UConn and a maximum of three Avangrid appointees, the Company witness stated that UI would have a majority influence on the committee. Ex. UI-JA-2, p. 3; Hr'g Tr. Mar. 8, 2023, 2858:14.

Relatedly, although the risks and costs of the investment are borne almost exclusively by UI ratepayers (the Avangrid cost share amounts to only 5.91% of the total

proposed program cost), Avangrid shareholders and other Avangrid affiliates would benefit from the results of the research. For example, one proposed key research area is Clean Hydrogen and Offshore Wind Integration. Ex. UI-JA-1, p. 12. One of Avangrid's two primary lines of business is Avangrid Renewables, which owns and operates a portfolio of renewable energy generation facilities across the United States. The Company specifically mentions Park City Wind (expected 804MW to Connecticut), Commonwealth Wind (expected 1,232MW to Massachusetts), and half of the Vineyard Wind 1 project (800MW to Massachusetts). Ex. UI-JA-2, pp. 1-2. The Authority notes that of the 2,836 MW of planned offshore wind generation described in the MRA, 72% would serve customers in Massachusetts. There is no offshore wind currently connected to Connecticut's distribution system, and none of the 2.4 GW of offshore wind Avangrid has contracted is operational today. Hr'g Tr. Mar. 7, 2023, 2666:3-4, 2667:4-6.

In short, the tangible benefits to UI ratepayers are tenuous, but the benefits to Avangrid and its renewable generation business are apparent. Indeed, conducting fundamental research to understand what level of curtailment offshore wind resources will experience or whether assets should be optimized for output capacity, cost, or time of availability is far more relevant to the economic operation of offshore wind and hydrogen generation assets, which would ultimately generate revenue for Avangrid Renewables. Interrog. Resp. RSR-103.

This line of research would also distort competition by allowing Avangrid to subsidize its competitive business ventures with funds from its monopoly business ventures. Insights into offshore wind and hydrogen integration could inform Avangrid Renewable's early-stage investments in hydrogen technologies and inform the Company on optimal operational strategies, which may give the Company an advantage over generation companies that cannot conduct fundamental research using funds from captive customers.

In addition to Avangrid Renewables, other Avangrid affiliates would benefit from the results of the CLEAN EARTH Lab initiative as well. As proposed, the initiative would be conducted on an Avangrid-wide level. Notably, the MRA states that the executive committee will include Avangrid appointees rather than UI appointees. Ex. UI-JA-2, p. 3. The subject matter experts (SME) who would play a key role in determining the scope of the research work with other Avangrid affiliates. Ex. UI-CETP-1, pp. 1-3. Consequently, the insights and tools that would result from the research would provide a direct benefit to those affiliates.

Another primary area of concern regarding the CLEAN EARTH Lab initiative is that a significant portion (40%) of funding needed for program management requires an additional FTE as proposed by the Company, which the Company has not adequately justified in its Application. The MRA states that the initiative will be led by a UConn PI and overseen by the executive committee. Ex. UI-JA-2, p. 3. There is no mention of the program manager in the MRA. Further, it is not clear that the responsibilities outlined in Ex. UI-JA-5 would be so extensive as to warrant an additional FTE. For instance, the need to "[w]ork with UI SMEs…to identify topics and areas to apply innovative research" would seem unnecessary given that the key research areas are already outlined in Ex. UI-JA-1. Ex. UI-JA-5, p. 2. The Authority recognizes that more granular research topics would be developed once the CLEAN EARTH Initiative was launched, but it is not clear

that UI SMEs, in collaboration with UConn staff and the executive committee, could not determine those topics without the assistance of an additional, 40-hour per week employee. Accordingly, the Authority disallows the annual $173,000 cost for program management and FTEs.

Lastly, there is no clear distinction between the resources already available to UI through the Eversource Energy Center and the resources that would be available to the Company through the CLEAN EARTH Initiative. The Company witness testified that UI already interacts with the Eversource Energy Center. Hr'g Tr. Mar. 2, 2023, 2045:14-18. The Company is requesting $150,000 in annual funding, as an entirely separate investment from the CLEAN EARTH Initiative, for weather modeling that would make use of the Eversource Energy Center. Ex. UI-EPP-1, pp. 26-27. While the Company states that the CLEAN EARTH initiative would be specifically tailored to UI's distribution grid through UI geographic and system load data, the Company has already provided funds to the Eversource Energy Center to develop the Damage Prediction Model using UI geographic and system data. Interrog. Resp. CAE-15; Interrog. Resp. CAE-55. Thus, the Company has not demonstrated that the CLEAN EARTH Lab Initiative will avoid duplicating the resources available through the Eversource Energy Center.

Despite these concerns, the Authority is cognizant of the potential benefits and timeliness of the CLEAN EARTH Lab. Fundamental research and innovation will be key to a resilient, affordable, and equitable energy transition. Additionally, the Authority recognizes that collaboration between the Company and UConn is a synergistic arrangement with benefits for the University, the Company, and the state. The CLEAN EARTH Initiative will allow UI to access UConn's exceptional resources, which will allow the Company to apply advanced data and analytical tools to support the Company's effective decision-making. Ex. UI-JA-1, p. 10. UConn will also benefit from the opportunity to engage with acute problems facing the energy sector today, especially those affecting Connecticut. The opportunity for students to work on real-world problems supports the development of a workforce that is ready to tackle these challenges directly out of school and may allow the Company to hire graduating students who want to continue working in the energy industry. Ex UI-CETP-REBUTTAL-1, p. 11.

The Authority finds research projects that yield analytical tools or actionable insights directly relevant to UI's operations or service territory to be the most promising. For example, the Company has demonstrated a need for improved flood forecasting tools as their current suite of flood forecasting products produce similar results and are no more than 70% accurate. Interrog. Resp. RSR-101. Additionally, the Company has indicated that UConn has a unique framework for evaluating compound flood risk scenarios involving heavy precipitation, surge, and sea level rise, which are critical flood risk factors for UI's coastal substations. Id. Research that is specifically tailored to UI's distribution system and relies on UI geographical, system, and load data are valuable research areas.

Additionally, there are opportunities to conduct fundamental research that would be aligned with the Authority's orders and guidance in other dockets. For example, the Authority has directed the EDCs to identify and quantify the incremental costs necessary to maintain or improve upon a baseline level of reliability performance. RE08 Decision, p. 42. The Company has proposed the Climate Change Impact Modeling key research area, which would study the effect of infrastructure improvement investments on grid

resilience. Ex. UI-JA-1, pp. 10-11. The Authority considers this line of research, one which is aligned with the Authority's directives in other dockets, to be an appropriate use of ratepayer funds.

Ultimately, the Authority finds that the proposed research areas of Outage and Flooding Forecasting, Climate Change Impact Modeling, and DER Adoption Analysis and Strategy are potentially promising for the provision of tangible, UI distribution-specific benefits to ratepayers. The Authority's Proposed Final Decision included an allowance of 25% of the requested CLEAN EARTH Initiative funding (i.e., $56,250 annually and $281,250 over five years) from UI ratepayers for the portion of the proposal that would directly benefit UI ratepayers. However, the Company stated that it is unwilling to proceed with the CLEAN EARTH Initiative if its full funding request is not paid for by UI customers and, accordingly, advised that the Authority should remove all expenses associated with the CLEAN EARTH Initiative. UI Exceptions, p. 116. Consequently, and reluctantly, the Authority removes the total annual expense of $398,000 for the CLEAN EARTH Initiative from the Company's revenue requirement. The Authority is sincerely disappointed that Avangrid's shareholders are unwilling to contribute a fair share towards the proposed CLEAN EARTH Initiative expenses, particularly given the clear benefits to their corporate interests, or to request a similar fair share from their other jurisdictions that would benefit greatly from the CLEAN EARTH Initiative. The Authority has great respect and admiration for the meaningful work performed at UConn and the professionals at that prestigious academic institution. The Authority encourages UConn to consider bringing a proposal to move forward with the CLEAN EARTH Initiative outside of this proceeding. The Authority respectfully requests that any independent proposal address how best to incorporate PURA, DEEP's Bureau of Energy and Technology Policy, and the OCC in the governance structure of the CLEAN EARTH Initiative to ensure that the interests of Connecticut's ratepayers, who would provide funding for the initiative, and the state's energy policy perspectives and expertise are explicitly represented in the direction of the organization.

b. Municipal Dashboard

The Company is implementing a Municipal Dashboard to facilitate emergency response coordination and communication with municipalities in its service territory. EPP PFT, p. 23. The Company proposed to capitalize each year the approximate $825,000 annual cost of the Municipal Dashboard as a software-as-a-service asset. Interrog. Resp. OCC-537; Interrog. Resp. OCC-310, Att. 1.

The Authority declined to approve the capitalization of the Municipal Dashboard in Section IV.H, Municipal Dashboard.

Following the Authority's investigation into the response to Tropical Storm Isaias, the Authority directed UI to perform outreach to municipalities to "identify the most relevant information for municipal leaders and best form(s) (e.g., call from municipal liaison, email from company and/or liaison, email and call from liaison, etc.) of communicating such information during the first 48 hours of a storm response." 20-08-03 Decision, p. 115. In response, UI conducted face-to-face outreach with each municipality. Interrog. Resp. OCC-611. One lesson from that outreach was using an

electronic dashboard to provide real-time situational awareness to town officials during events. EPP PFT, p. 24. UI worked closely with the Town of Fairfield to develop the tool. Id. UI held virtual and in-person training sessions with municipal representatives to receive feedback on desired features of the dashboard. Interrog. Resp. RSR-124. UI refined the Municipal Portal following emergency response exercises. Interrog. Resp. RSR-124, Att. 1, p. 25. The features of the Municipal Dashboard include real-time information about outages, blocked roads, critical facilities, and restoration work plans. Id.; Interrog. Resp. OCC-611.

The Authority approves funding for the municipal dashboard as the Authority deems coordination and communication with municipalities during emergency events a high priority. 20-08-03 Decision, p. 115. The dashboard will help UI coordinate with towns. In sum, the expense is reasonable and necessary. The Authority authorizes UI to recover an annual expense for the Municipal Dashboard. Accordingly, the Authority adjusts Schedule C-3.11 to include an annual expense of $825,000.

c. UConn Weather Modeling Costs

The Company requests $150,000 each year for three years to update an outage prediction model developed by UConn, to increase the accuracy of the current model and to add hydrodynamic (i.e., flood) modeling. EPP PFT, p. 26.

The Authority declines to approve such a project. The Company already uses multiple weather models, including a damage prediction model from a company, DTN. Id., p. 25. The agreements with the current weather services are a fraction of the cost, on the order of $10,000. Late Filed Ex. 89. The Authority appreciates that there may be some benefit to having multiple sources for damage and weather prediction, but sufficient benefits to justify the costs have not been demonstrated in this case.

In this case it is not clear that the product will be available in the next three years, nor is there certainty about whether it will be more accurate than the DTN model. Interrog. Resp. RSR-27, p. 2; Hr'g. Tr. Mar. 2, 2023, 1995:21-1996:1. Further, the Authority is not sure why this project is proposed separately from the CLEAN EARTH Initiative with UConn as that proposal also includes outage and flooding forecasting. Hr'g Tr., 1997:2-5; Rincon PFT, p. 11.

Furthermore, the Authority could not identify which expense item this project was proposed to be charged to, and neither could the Company. Hr'g Tr., 1994:7-11.

Based on the evidence in the record, the Authority finds this project premature and denies annual funding of $150,000. In the absence of identifying the expense schedule this project is charged to, the Authority will make the reduction in the Outside Service – Professional Services expense. Sch. WP C-3.11.

13. Fee Free Program

a. UI's Proposal

UI proposed a program to eliminate the convenience fee for residential and commercial customers who pay their bills using credit and debit cards (Fee Free program). Under this Fee Free program, instead of the customer being charged a

transaction fee when they pay their electric bill, UI would cover the fee through the Company's revenue requirement as a general cost of doing business. Pelella and Patterson PFT, p. 29. The Company will track the annual expenses incurred by the Fee Free program and reconcile any over-collection or under-collection in its next rate case.[125] Hr'g Tr. Mar. 6, 2023, 2367:4-14. The Authority approves the Fee Free program for residential customers only, subject to the conditions discussed below.

UI modeled its program after the fee free programs approved by the Authority for other Avangrid affiliates. Pelella and Patterson PFT, p. 29; see Decision, Dec. 18, 2017, Docket No. 17-05-42, Application of The Southern Connecticut Gas Company to Increase its Rates and Charges, Appendix A, Amended Settlement Agreement, 1.14; see Decision, Dec. 19, 2018, Docket No. 18-05-16, Application of Connecticut Natural Gas Corporation to Increase its Rates and Charges, pp. 18-19. In the Company's Application, the initial Fee Free program proposal covered the credit or debit card transaction fee for both residential and commercial customers. Pelella and Patterson PFT, p. 28; UI Interrog. Resp. RRU-453. The Company later expanded the proposal to also include the transaction fees associated with ACH (automated clearing house) payments (i.e., when a customer pays electronically using a bank account) asserting that including this payment method in the Fee Free program would further the goal of meeting customer expectations of removing transaction fees. See UI Interrog. Resp. RRU-73, see also Hr'g Tr. Mar. 21, 2023, 3503:22-3504:8 (Ms. Pelella "We . . . neglected to include the ACH [in the pre-filed testimony]"). By including ACH payments in the Fee Free program, the Company also proposes to include the fee associated with using a payment aggregator block in the Fee Free program.[126] See UI Interrog. Resp. RRU-73; see also Hr'g Tr. Mar. 22, 2023, 3519:21-24.

UI proposes to include both residential and commercial customer transaction fees in the Fee Free program. Currently, residential customers and commercial customers pay different transaction fees.[127] UI notes that 95% of customers who pay with credit or debit card are residential customers. UI Interrog. Resp. RRU-73, Att. 3. Since far fewer commercial customers pay using a credit or debit card, this program would be more beneficial if it focused on residential customers. Based on the evidence in the record, the Authority determines that the Fee Free program will only apply to residential customers.

UI's proposal is based on estimated payment transaction volume and expenses that may not be in place when the Fee Free program is implemented. As of the date of the Application, the Company contracted with a third-party vendor, Kubra, for payment processing; however, UI noted that it is in the process of issuing a request for proposals

[125] The Company's Application mistakenly stated the expenses of the Fee Free program would be reconciled on an annual basis. Pelella and Patterson PFT, p. 30. This statement was clarified during the evidentiary hearing to indicate that the program expenses would be trued-up at the Company's next rate case. Hr'g Tr. Mar. 6, 2023, 2367:1-14.

[126] As part of the ACH payment, the Company also pays a consistent fee of $5,000 per month to a payment aggregator. Payment aggregators work with banks by blocking individual payments from going through, and instead aggregating the payments and then passing them along to UI in a bundle as a credit card payment. Tr., Mar. 22, 2023, 3519:12-21. Instead of the Company getting a check from the bank account, it is processed like a credit card payment and therefore has the associated credit card fee. Id.

[127] Residential customers pay $3.95 per transaction and commercial customers pay $6.50 per transaction. UI Interrog. Resp. RRU-262.

(RFP) to select a new third-party payment processing vendor[128] and anticipates making a selection by Q3 of 2023. UI Interrog. Resp. RRU-454; Hr'g Tr. Mar. 6, 2022, 2127:22-2128:2. The Fee Free program cost estimates are based on Kubra's current pricing of $3.95 for residential customers. Hr'g Tr., 2296:12-17. The Company's proposal assumes that the fee the Company[129] ultimately negotiates will be similar to the $3.95 processing fee currently in use. Hr'g Tr., 2370:10-14 ("The current vendor that we do have is one of the main players in our industry in relation to payment processors. And so, you know, without seeing the responses to the RFP, I would imagine it is within a ballpark range."). As pointed out by the OCC, the Company is seeking approval for a program where the cost is speculative since UI does not have a signed contract with a third-party payment processor. OCC Brief, p. 165. As such, the new transaction fee could remain at $3.95, it could be less than $3.95, which would result in a lower program cost than proposed, or the transaction fee could be greater than $3.95, resulting in an unanticipated increased program cost. To be clear, a Fee Free program is in the best interest of ratepayers if the cost per transaction remains the same as currently in place (and as used in the proposal) or if the new negotiated rate is less than $3.95 per transaction. Upon completion of the RFP, the Company is directed to file a motion for review and approval containing an executed agreement with the selected third-party payment processor. Given that the actual cost of the Fee Free program will be reconciled at the Company's next rate case, if the transaction fee is greater than $3.95 as proposed by the Company and the costs of the Fee Free program exceed the expenses approved below, the Authority will not approve recovery of those expenses above the proposed cost of the program reviewed herein.

b. Fee Free Program Annual Expense

UI derived the value of the proposed cost of the Fee Free program based on credit card transaction volume and fees incurred in 2019.[130] Pelella and Patterson PFT, p. 30. In 2019, the average volume of monthly credit card payments was 27,700 customers, which totaled $1,361,749 in transaction fees for the year. Pelella and Patterson PFT, p. 30. The Company's proposal assumes that, in the first year, customer usage of credit and debit cards will increase by 5%, and by 2%[131] in years 2 and 3, respectively. Id. The proposed volume of ACH payments is based on historic data from 2020 because the Company was unable to obtain 2019 data. UI Interrog. Resp. RRU-73, Att. 3. The Company's proposed cost of the Fee Free program for Rate Year 2023/2024 is $1,619,089; this cost reflects the expected credit and debit card usage for residential

[128] As of the date of the Late Filed Exhibit Hearing, the Company had not issued the RFP to seek bids. Hr'g Tr. Mar. 15, 2023, 3507:19-22.

[129] The RFP will include all Avangrid Network companies in an effort to secure a more competitive transaction fee. UI Interrog. Resp. RRU-454.

[130] The Company is relying on pre-COVID 19 data to support this proposal. See UI Interrog. Resp. RRU-73, Att. 3.

[131] The Company cites to a 2021 Federal Reserve Payment study that indicates the number of remote credit and debit card payments increased by its most significant amount from 2019 to 2020. Pelella and Patterson PFT, p. 31. Furthermore, UI saw credit card usage post-pandemic increase over 7% and anticipates that with the new program, enrollment will initially increase, but then resume more normal collection activity. UI Interrog. Resp. RRU-463.

customers as well as payments made via ACH. Late Filed Ex. 110, Att. 1.[132] The Company subsequently updated its request to $1,786,000 ($1,490,000 Fee Free + $296,000 ACH). Late Filed Ex. 1, Sch. WPC-3.10.

UI is proposing the Fee Free program to improve customer satisfaction and to provide greater flexibility by allowing customers to choose a payment option that works best for them. Pelella and Patterson PFT, p. 29; UI Interrog. Resp. RRU-435. Paying with a credit or debit card allows customers to use self-service payment options, such as paying via the UI website. By allowing customers to use a payment option available at all times, UI asserts that it will receive payments quicker and more consistently, which reduces Accounts Receivable. Pelella and Patterson PFT, p. 32. Currently, customers cannot pay using a credit or debit card when logged into MyAccount, UI's customer portal, but the approval of the Fee Free program will allow customers to pay when logged into MyAccount instead of being redirected to the EZ-Pay section of the Company's website. Hr'g Tr. Mar. 7, 2023, 2424:3-8. The Company believes encouraging customers to enroll in MyAccount will lead to more self-service, thereby reducing the Company's cost to serve those customers, in addition to reducing bill print expenses for eBill customers. UI Interrog. Resp. EOE-134(d); Hr'g Tr. Mar. 7, 2023, 2423:7-19. The Company does not anticipate that the Fee Free program will reduce other forms of payment (e.g., electronic payment, checks, third-party payments). UI Interrog. Resp. RRU-435. Additionally, customers who pay using their bank account are not charged a transaction fee if they login to MyAccount to pay their bill. Hr'g Tr. Mar. 7, 2023, 2420:17-2421:12. However, when customers pay with their bank account outside of MyAccount, they are charged the same transaction fee as those customers who pay with a credit or debit card. Hr'g Tr., 2421:9-12. Through the implementation of the Fee Free program, UI believes that customer satisfaction will increase and the Company's cost to serve customers would decrease, thereby benefitting both ratepayers and UI.

c. Implementation and Tracking Metrics

UI did not propose a timeframe in which it could implement the Fee Free program but anticipates formal timelines to be submitted as part of the RFP process. Hr'g Tr. Mar. 7, 2023, 2426:13-15. However, when pushed to offer a best guess, the Company offered that it might take anywhere between two months to six months to implement the Fee Free program. Hr'g Tr., 2426:11-17. Implementation would include an internal operational review of procedures, which involves performance reporting on the quality of the platform, integrating the payment processing vendor's system with the Company's billing system, and weeks of testing the changes. Hr'g Tr., 2426:23-2427:24. All of these changes would be centered around the customer experience, as researched and reviewed through UI's Customer Journey Redesign Program. Hr'g Tr., 2428:1-10.

The Company indicated that it would track the success of the Fee Free program by reviewing participation rates, arrearage balances, and by using the Company's customer satisfaction framework to evaluate customer perception of the Fee Free program. Hr'g Tr. Mar. 7, 2023, 2428:15-2429:4; see UI Interrog. Resp. RRU-458 and

[132] Over the course of this proceeding, the Company's estimated annual operating expense for the Fee Free program changed numerous times. Compare Pelella and Patterson PFT, p. 30, with UI Interrog. Resp. RRU-73, Att. 3, and UI Interrog. Resp. RRU-435.

RRU-460. In addition to these metrics, the Authority directs UI to annually file compliance records that demonstrate the level of participation, associated costs, feedback from customers, and other metrics detailed in the Orders to this Decision. One of those tracking metrics is the number of financial hardship customers who make payments by credit or debit card. Although the Company currently does not have the capability to generate reports that would provide this information across all residential customers, based on testimony provided, the expectation is that the Company is working on this and will therefore be able to produce this data in its annual compliance filing. Hr'g Tr. Mar. 7, 2023, 2429:16-2430:13; see UI Interrog. Resp. RRU-455.

The approval of the Fee Free program for residential customers will continue through the Company's next rate case, at which time the Authority will determine whether the program should continue and in what form. Currently, UI covers the transaction fees associated with other forms of customer payments of bills. For example, customers enrolled in MyAccount do not pay when they use their bank account number. Hr'g Tr. Mar. 7, 2023, 2421:6-9. As the Company stated, "any costs associated with this payment option [should] be considered among the general costs of doing business . . ." Pelella and Patterson PFT, p. 29. Given this view of the Company absorbing the credit and debit card transaction fee, in the Company's next rate case, the Authority will consider whether the Fee Free program should exist as a standalone program when it ultimately operates like the other transaction fees the Company already covers.

The Company reiterated that the only costs covered by the Fee Free program "would be the cost associated with making that payment via credit or debit card." Hr'g Tr. Mar. 7, 2023, 2422:16-18; UI Interrog. Resp. RRU-462. Should the Company determine that there are other costs associated with paying bills that are offset or reduced as a result of implementing the Fee Free program, the Authority directs the Company to include such costs in its reconciliation during its next rate case. For example, the removal of the transaction fee may result in customers who typically pay via a check to pay with their credit card, thereby reducing the costs associated with processing check payments. As such, the Authority will reconcile the costs of the Fee Free program as well as its impact on other bill related costs at the Company's next rate case.

In summary, based on the facts and analysis presented by the Company, the Authority approves the proposed Fee Free program for residential customers, subject to the conditions outlined herein.

14. Electric Distribution System

a. Third-Party Pole Attachment

Based on discussions with Attachers, the Company is projecting a significant increase in pole attachment applications. CJE PFT, p. 14. Specifically, the Company forecasts that it has the potential to receive upwards of 25,877 pole attachment requests in both 2023 and 2024. Interrog. Resp. OCC-131.

Based on the forecast, the Company included in the Application a request for 25 incremental FTEs, including 20 field technicians, 2 managers, and 3 analysts to support application review and make-ready design. CJE PFT, p. 42. The 25 new employees

dedicated to this work add $2.4 million of fully-loaded labor costs. Interrog. Resp. RSR-116, Att. 1; Hr'g Tr. Feb. 24, 2023, 1256:13-16.

The Company also proposes to increase the use of contractors to support this work, which manifests as a $3 million increase over the Company's Test Year expense of $1.955 million for Outside Services – Electric Operations expense. Sch. WP C-3.09. The Company requests a Rate Year 2023-2024 Outside Services – Electric Operations expense of $5.123 million. Id.

The Company presents two fundamental reasons for the requested increase in FTEs and contractors. The first is based on the anticipated increase in pole attachment requests, with the Company forecasting 25,877 per year in 2023 and 2024. Interrog. Resp. OCC-131. The table below shows the historical number of pole attachment requests as well as the number forecast by the Company for future rate years.

Table 57: Pole Attachment Requests Received with Payment by Year

Year	Pole Attachments	Average Pole Attachments 2018-2022
2016	1,338	
2017	2,974	
2018	11,525	
2019	7,678	
2020	12,718	
2021	10,124	
2022	10,010	10,411
2023	25,877	
2024	25,877	
2025	10,500	
2026	10,500	

Interrog. Resp. OCC-305.

The Authority reviewed the historical data presented above. Notably, the average number of pole attachment requests received by UI for years 2018-2022 was 10,411.[133] The Authority took a conservative approach and excluded years prior to 2018 due to their extremely low volume. Comparing the historical average with the Company's forecasted number for 2023 and 2024 reveals that UI is expecting a 149% (25,877 / 10,411) increase in pole attachment requests.

[133] UI provided year-to-date (mid-November 2022) pole attachment applications of 8,759. The Authority normalized this number by assuming the same rate of pole attachment requests came in from mid-November to end of December 2022. Interrog. Resp. OCC-305. To do this, the Authority assumed 8,759 applications were received in 10.5 months out of 12 months, or 87.5% of the year. If the same rate of applications were received for the remaining 1.5 months, the total would be 10,010 attachments (87.5% of 10,010 = 8,759).

Since this forecast is significantly higher than actual historical values, the Company must substantiate its forecast with significant and reliable evidence. However, UI's forecasts were based on only two things: discussions UI has had with Attachers during quarterly meetings, and historical numbers. Interrog. Resp. OCC-131, RSR-82, p. 2.

The numbers derived from the discussions with Attachers have been shown to be unreliable. Hr'g Tr. Feb. 21, 2023, 574:21-575:5. The Attachers did not provide the Company with deployment strategies, application sizes, or timeframes, but instead provided merely the total number of attachments expected, without relying on mature plans. Interrog. Resp. RSR-82, p. 2.

Consequently, the forecasts do not constitute known and measurable changes on which to base allowable expenses. The Company itself acknowledges that projections driving the estimates have not materialized. Interrog. Resp. OCC-305; Hr'g Tr. Feb. 21, 2023, 574:24-575:1. Specifically, certain Attachers who anticipated large volumes of attachments have not acted on those projections. Id. Indeed, since the Decision dated May 11, 2022, in Docket No. 19-01-52RE01, PURA Investigation of Developments in the Third-Party Pole Attachment Process – Make Ready (19-01-52RE01 Decision), the Company has received only 1,380 pole attachment requests (distributed among 86 applications). Hr'g Tr. Feb. 24, 2023, 1261:16-19. Notably that decision established new attachment processes including a "One Touch Make-Ready" (OTMR) process, which requires that the applicant complete the engineering and survey work, rather than the pole owner (i.e., UI). 19-01-52RE01 Decision, App. B, p. 1. With the applications, the pole owner needs only to review the application on the merits. Id. It is reasonable to assume at this point that UI will see fewer traditional pole applications as OTMR becomes fully active in 2023. Id., p. 17. Therefore, after considering all the evidence, the Authority finds that UI's forecast of 25,877 pole attachment requests is unreasonable; conversely, the Company's 2025 and 2026 estimates of 10,500 are much more reasonable.

Further, the Authority finds that the Company's request for 25 new FTEs and an additional $3 million for contractor costs to support the pole attachment engineering work within the required timeframes is not reasonable for three reasons. CJE PFT, pp. 42-43; Hr'g Tr., 1257:11-18.

First, the new engineering phase timeframes established in May 2022 provide UI more time to process applications, perform survey work, and complete make-ready design as compared to prior requirements. Below, the table compares the old and new timeframes for completing application processing, engineering, and survey work.

Table 58: Application Review and Engineering Phase Timelines

Application Review and Engineering/Survey Review	Former	Current
less than 300 poles	45	45
300 – 3,000 poles	+0	+15
More than 3,000 poles	+0	N/A
Make-Ready Development	N/A	14
TOTAL Engineering Phase	**45**	**59-74 or N/A**

19-01-52RE01 Decision, p. 21.

UI now has 14 to 29 additional days (depending on the number of attachment requests) to complete the application review and Engineering Phase work.

The above table demonstrates a number of additional noteworthy items. First, there is now no defined time limit for applications with greater than 3,000 pole attachment requests; instead, the pole owner and the applicant must work collaboratively to establish a mutually agreed upon timeline. Id., pp. 21-22. The new timelines also enable UI to deviate from the timelines for good cause shown (such as major storm disrupting normal business operations). Id., pp. 22-23.

The flexibility granted to UI to complete engineering and survey work is no small thing. As shown in the table below, most of the pole attachment requests come in large batches of 3,000 or more. CJE PFT, p. 39. Therefore, most pole attachments requests coming to UI are likely exempt from fixed deadlines, which extends to UI sufficient flexibility to determine reasonable timelines to complete the engineering phase. CJE PFT, p. 39.

Table 59: Applications and Pole Attachments (Batches >3,000)

Year	Percentage of Applications with over 3,000 poles	Percentage of Poles in Applications with over 3,000 poles
2018	0.47%	41%
2019	0.00%	0%
2020	1.30%	88%
2021	0.70%	73%

Id.

Based on the above, UI's concern about meeting Authority timelines is unconvincing, and UI's proposal to increase FTEs by 25 *and* to increase contractor costs by $3 million is excessive. That said, the Authority does expect UI to secure sufficient resources to handle the applications and to complete the Engineering Phase in a timely manner. 19-01-52RE01 Decision, p. 24.

The Authority's preference is that UI begin to scale internal resources by adding incremental FTEs. UI itself states that there are not sufficient contractors available that possess the requisite skills, including a foundation in electric distribution engineering and construction, conducting field surveys, and coordinating with the joint pole owner, and knowledge of UI's work management system. CJE PFT, p. 39. The Company, therefore, needs to spend resources and time training contractors. Hr'g Tr. Feb. 23, 2023, 1027:20-1028:10. Since work comes in big patches of pole attachments, contractors are lost when work is complete, wasting the initial training. Id.

Based on this information, using contractors as needed to process large batches of applications makes sense, but not at the level proposed by UI. CJE PFT, p. 39. UI proposes to increase its third-party pole attachment external contractor expense item from $1.955 million to $5.123 million, a 162% increase. Sch. WP C-3.09. Not only is increasing the use of contractors inefficient for the reasons described above, but based on UI's own experience, it is not likely that UI would be able to find sufficient numbers of qualified contractors to effectuate a budget increase of that size. CJE PFT, p. 39. The Authority, therefore, denies UI's requested increase of $3 million.

The Authority does authorize UI to hire incremental FTEs, but not at the level proposed by UI. First and foremost, UI's proposed 25 FTEs were determined using the 25,877 pole attachment forecast. CJE PFT, p. 42. Since the Authority found the Company's forecast unreasonable and instead determined that an estimate of 10,500 pole attachment applications is more reasonable, the Authority will likewise scale back the Company's FTE request. Since 10,500 is 40% of 25,877, the Authority will accept at most 40%, or 10, of UI's requested FTEs.

The Authority will reduce this figure even further because it is unlikely that UI will be will able to hire 10 FTEs by the start of Rate Year 2023/2024. Indeed, the Company is actively recruiting only six of the 25 positions; and has hired only two of those six positions. Interrog. Resp. RSR-107. Accordingly, the Authority approves eight incremental FTEs.

The Authority deems that eight new FTEs are sufficient for UI to process applications and complete the Engineering Phase on reasonable timeframes for the reasons discussed above. Furthermore, UI is still able to supplement with external contractors and use the 14-15 existing employees that have performed this work as needed in the past. Hr'g. Tr. Feb. 24, 2023, 1258:4-9; Interrog. Resp. RSR-106. Previously, UI has pulled internal employees away from primary assignments to be trained and to work on pole attachment applications; the Authority expects UI will continue this practice if necessary. Hr'g Tr., 1257:18-22. Eight incremental FTEs, in addition to the other available resources, should ensure that UI has sufficient resources to perform the pole attachment application and Engineering Phase work properly.

As described next, based on revenue received from pole attachment applications and per pole survey fees, UI will likely incur more costs than revenues received from the pole attachment applications.

Above, the Authority deemed that a reasonable number of pole attachment requests to be received per year is 10,500. This number forms the basis for estimating

annual pole attachment-related expenses and revenues. Interrog. Resp. RSR-82. UI charges Attachers for application processing and survey fees as directed by the Authority in the 19-01-52RE01 Decision, which includes a per application fee of $150-$170 and a per pole fee of $125. Interrog. Resp. OCC-517. Applying these fees to the 10,500 pole forecast provides an annual revenue forecast of $1,360,500.

UI's allowable expenses, as determined above, include annual external contractor fees of $1.282 million and $768,000 for eight incremental FTEs for Rate Year 2023/2024. Late Filed Ex. 40, Att. 1; Interrog. Resp. RSR-116, Att. 1. This totals $2.050 million of anticipated expense, which leaves a deficit of $685,000 ($2,050,000-$1,360,000). The Authority finds that pole attachment applicants, not ratepayers, should cover the portion of the deficit that is attributable to the specific pole attachment application.

A portion of the external contractor fees and FTEs is not strictly attributable to costs to process applications but is instead attributable to UI's role as the single pole administrator (SPA). See Decision, Oct. 8, 2014, Docket No. 11-03-07, DPUC Investigation into the Appointment of a Third Party Statewide Utility Pole Administrator for the State of Connecticut, pp. 11-13. The Authority has reviewed UI's costs to determine the proportion of SPA work to total work since 2018. This information is presented in the following table.

Table 60: Percentage of SPA Costs Unrelated to Applications

Year	Total Costs Incurred	Costs Unrelated to Specific Applications	Percentage Unrelated Costs
2018	$563,987	$160,207	28%
2019	$2,603,199	$220,022	8%
2020	$1,651,387	$108,473	7%
2021	$1,907,735	$50,248	3%
Average	$1,681,577	$134,738	11.5%

Interrog. Resp. OCC-522, Atts. 2-5.

The Authority determined the unrelated costs by combining UI's costs attributable to its database management system (including licensing fees), with costs it incurs for regulatory compliance. Id. The Authority excluded from the table a large one-time $111,000 software enhancement cost incurred in 2018, which is not reflective of typical ongoing costs. Id., Att. 2. Based on the above, the Authority determines that 10% is a reasonable estimate of costs that UI incurs in the pole attachment process that are unrelated to specific applications from Attachers. Accordingly, of the $685,000 deficit, the Authority determines that 90%, or $616,500 (.90 x $685,000), is strictly due to specific pole application processing.

UI's customers should not have to pay the difference for pole attachment work, as they are not the cost-causer nor are they a direct beneficiary of the third-party attachment. Therefore, the Authority directs UI to charge applicants for any incremental charges above the initial application and per pole fee for all reasonable costs to process

applications. Accordingly, the Authority will increase UI's revenue by $616,500 for rent from electric property. Sch. WP C-3.01, line 5. This will require that UI directly invoice each Attacher and determine incremental costs. This also enables UI to scale FTEs or contractors as necessary without prior Authority approval since the pole attachment process now covers all costs. Lastly, this process will not burden the applicant since Attachers have the ability to complete the Engineering Phase on their own using the Self-Help Engineering Remedy, without relying on UI.[134] 19-01-52RE01 Decision, p. 24.

Accordingly, the Authority will reduce UI's proposed pole attachment contractor budget by $3 million as described above and increase its revenue from pole attachment applications and per pole fees by $616,500. The Authority adjusts the Company's projected revenue from "rent from electric property" to include $1,360,500 of baseline revenue from pole attachment applications and per pole fees for a projected 10,500 attachment requests and an additional $616,500 of revenue from direct charges to Attachers to cover incremental expenses to process applications. Interrog. Resp. RSR-82. Since the Company erroneously calculated revenue from pole attachment applications as $3.353 million based on unreasonable projections of 25,877 applications, the Authority's adjustment results in a revenue decrease of $1.376 million ($3.353 – $1.361 – $0.617) to the $7.012 million reflected in Schedule WP C-3.01, line 5. Late Filed Ex. 1, Att. 1.

b. Engineering and Delivery

The Authority disallows $706,500 of unsupported expense for "Engineering and Delivery" for Outside Services expense. Sch. WP C-3.09.

UI did not provide sufficient information justifying the increase in Test Year expense of $389,000 to the Rate Year 2023/2024 expense of $1.129 million. Id. The Company noted in footnote number 4 in Schedule WP C-3.09 that the "[p]ro forma adjustment reflects additional outside services required to support distributed generation, environmental permitting services, and Safety, Health, Environmental Quality." Id. When asked to provide the supporting contract, vendor quotes, and/or invoices justifying the "pro forma" increase, UI provided nothing, stating that there was no pro forma increase. Interrog. Resp. OCC-132.

A review of planned costs indicates that the increased costs are designed to support distributed generation, but not environmental permitting or Safety, Health, Environmental Quality. Id. Average annual historical costs in this item from 2018 through the Test Year are $359,750, which is very similar to the Test Year amount. As such, there is insufficient evidence to justify the proposed adjustment to the Test Year value.

Accordingly, the Authority reduces Outside Service – Engineering and Delivery costs to the Test Year amount plus an 8.61% increase for inflation, which equals $422,500

[134] NetSpeed requests that the Authority set a limit of $58.71 per pole incremental charge to each attacher to cover the $616,500 deficit since $616,500 divided by 10,500 projected attachment applications equals $58.71. NetSpeed Exceptions, p. 14. The Authority finds it unnecessary to impose such a limit at this time, since applicants have the ability to perform survey and engineering design as just described. Furthermore, this new process enables UI to charge applicants directly for all costs incremental to the initial application and per pole fee.

($389,000 x 1.0861). The adjustment reduces Rate Year 2023/2024 expense by $706,500 ($1,129,000 - $422,500).

c. Summary of Electric Distribution System Adjustments

The Authority disallows 17 FTEs for pole attachment work, reducing the request from 25 to 8 FTEs.

The total adjustments to the Outside Services schedule include the following:

1. A $3 million reduction in Outside Services - Electric Operations expense for pole attachment contractors;

2. A $706,500 reduction to Outside Services – Engineering and Delivery.

The adjustments above reflect a total reduction in Outside Services of $3.707 million.

15. UPZ and Vegetation Management Expense

The table below shows UI's proposed UPZ and other vegetation management expense, as well as the Authority's approved adjustments thereto.

Table 61: Approved Vegetation Management Expense

	UI Proposal	Approved
Utility Protection Zone Program	$14,840,000	
Utility Protection Zone Maintenance	$3,500,000	$14,000,000
Reliability Maintenance	$850,000	$850,000
Total	$19,190,000	$14,850,000

Interrog. Resp. OCC-136, Att. 1.

The Company's proposed vegetation management programs[135] consist of a UPZ program and Reliability Maintenance program. The UPZ program seeks to establish vegetation management clearance 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. CJE PFT, p. 47; Conn. Gen. Stat. § 16-234(a)(2). The UPZ program includes two sub-programs. The first is a continuation of the traditional UPZ program on single-phase and three-phase circuits that have not yet received full UPZ trimming. Interrog. Resp. RSR-78. The second, the UPZ Maintenance program, is to maintain the full UPZ specification on circuits that already conform to UPZ specification.

The Reliability Maintenance program is designed to address hazard conditions (such as hazard trees or direct tree contact with conductors) and customer requests. Hr'g Tr., 803:19-24.

The Company's Application seeks authorization for $7.791 million, $10.856 million, and $14.010 million for Rate Years 1, 2, and 3, respectively, for its proposed Utility UPZ

[135] Vegetation management means the retention of trees and shrubs that are compatible with the utility infrastructure and the pruning or removal of trees, shrubs or other vegetation that pose a risk to the reliability of the utility infrastructure. Conn. Gen. Stat. § 16-234(a)(4).

program. Sch. C-3.05. The Application includes a request to amortize UPZ costs and so includes deferrals of $4.338 million in Rate Year 1 (i.e., Rate Year 2023/2024), $12.059 million in Rate Year 2, and $17.843 million in Rate Year 3. RRP PFT, p. 49.

As discussed in Section IV.E.6., UPZ Deferral, the Authority is not approving amortization of any UPZ expenses, and, therefore, all allowable expenses will be directly expensed. All allowable UPZ expenses are discussed below.

The purpose of the UPZ program is to achieve a horizontal clearance of eight feet from outermost conductor and vertically from the ground to the sky across UI's entire system. Id., p. 54. Based on the UPZ work that has already been done (and described above), the Company requests an adjustment to the program to achieve the UPZ specification system-wide by 2029. Id. The modifications include the following:

1. an extension of the UPZ program from 12 years to 16 years, concluding in 2029;
2. an increase in total program cost from $162.5 million to $254 million;
3. completion of UPZ on remaining single-phase system;
4. second pass of UPZ on entire three-phase system; and
5. a new UPZ maintenance program designed to maintain the UPZ clearance on portions of the system that have already received full UPZ trimming and to begin the transition to four-year cycle maintenance trimming.

Id., pp. 58-59.

The Company requests an extension in years to the project to manage delays introduced by the customer consent process and traffic control, and to reflect limitations of securing qualified tree clearance contractors. Id., p. 59.

The Company also requests additional funds to (1) complete the UPZ clearance for the remaining 750 miles of single-phase system that has not received UPZ work; (2) perform a second pass of UPZ work on the 1140 miles of the three-phase system; and (3) implement the new UPZ Maintenance work to maintain the UPZ clearance on portions of the system that have already been addressed, but are in need of clearance work since more than four years have passed since the UPZ work. Id., p. 59; Interrog. Resp. RSR-78. The UPZ maintenance program will allow a transition by 2029 to a standard four-year cycle trimming program that would maintain the UPZ clearance on a going forward basis. Id.

The Company does not have a track record of properly executing vegetation management plans. UI's original proposal in 2013 was to spend $100 million over four years and to complete the program by 2018.[136] By the end of 2022, however, UI had spent approximately $109.5 million on UPZ to complete roughly half of the UPZ work (i.e., full UPZ on nearly half of the single-phase system and partial UPZ clearance on the entire three-phase system), meeting the goal of neither proposal. Interrog. Resp. OCC-527, Att. 1.

[136] The Authority approved the original program to be completed by 2021, in eight years rather than four, due to the high costs and the uncertainty of the benefits of the new program. 2013 Rate Case Decision, pp. 13-14.

Here, UI proposes to increase the annual UPZ spend once again, this time from $14 million to $18.340 million in Rate Year 2023/2024. Interrog. Resp. OCC-136, Att. 1. The table below shows that UI's annual UPZ and recurring maintenance spending has not achieved the level of spending that was authorized by the Authority in the 2016 Rate Case Decision.

Table 62: UPZ Actual vs. Authorized Spending ($ million)

	2017	2018	2019	2020	2021	2022	Total
Authorized	13.000	13.800	14.000	14.000	14.000	14.000	82.800
Actual	11.111	13.612	17.765	10.806	12.403	15.433	81.131
Difference	1.889	0.188	(3.765)	(3.194)	1.597	(1.433)	1.669

Interrog. Resp. RSR-85; RSR-84, Att. 1.

Considering the Company's inability to achieve consistent $13-14 million in annual spending, the Authority finds that the Company cannot realistically achieve upwards of $18 million of spending annually. This is further supported by the Company's experience that the customer consent process, town traffic control requirements, and competition for qualified crews introduce program delays. Interrog. Resp. RSR-85, p. 2; CJE PFT, pp. 56-58. Expanding the work plan increases the need for contractors, thus increasing the challenge. As such, allowing this level of spending in rates is not reasonable.

That said, the Authority concludes that the Company's cost estimates to complete the remaining work are reasonable, with one exception. The Company has used recent historical costs, cost trends, and its judgment to project costs on a per mile basis based on planned circuits topology and tree density, and costs from contractor bids. Interrog. Resp. RSR-81, p. 2. The Company's assumed costs for each program are presented in the following table.

Table 63: Estimated Costs Per Mile

Program	Composite Cost Per Mile
UPZ Standard	$57,519
UPZ Maintenance	$25,000
Four Year Cycle Trimming	$15,000

Interrog. Resp. RSR-81, p. 1; Hr'g Tr., 801:17-19.

The UPZ standard cost per mile is used to estimate full UPZ implementation costs for the remaining single-phase portions of the system and the second pass of the three-phase system, both of which involve significant trimming and removal of trees in the UPZ zone and the removal of hazardous trees outside the UPZ zone. Interrog. Resp. OCC-606; Hr'g Tr., 796:23-799:24. The UPZ Maintenance estimates are based on costs to maintain existing UPZ specification. The costs assume that incompatible trees have been already removed in prior UPZ work at that location, thus significantly reducing the costs from the UPZ standard estimate. Hr'g Tr., 1280:13-19. The four-year cycle trimming costs assumes all UPZ work has been done and the trimming is on a four-year cycle of growth, which is why it is significantly less than the UPZ Maintenance estimate, which anticipates eight years of growth. Hr'g Tr., 801:21-802:8. The Company's estimates for UPZ Maintenance are not reliable because the Company does not have direct historical

costs for this program, nor has the Company evaluated contractor bids for this type of work. Interrog. Resp. RSR-81, pp. 3-4.

In determining the annual UPZ program costs, the Company multiplies the above cost per mile estimates by the planned mileage and applies a 3% inflation adjustment for future years. Id., p. 2.

The Company designed this with the purpose of completing the UPZ clearance across its entire system by 2029. Hr'g Tr., 998:17-21. This plan relies on the assumption the Company should spend, at least, $254 million[137] to implement UPZ clearance across the entire service territory. While the original plan contemplated the whole system achieving UPZ specification, the continuing cost increases may require an adjustment to this goal.

There are a range of options for implementing vegetation management programs to protect the safety and reliability of the system. One end of the spectrum involves performing full UPZ clearance on the entire system. This involves a total cost of (at least) $254 million.

The other end of the spectrum would involve a complete transition away from UPZ implementation, toward a four-year cycle trimming program. This type of program would involve minimal trimming to maintain whatever the current clearances are along the Company's system. Doing this would result in an annual program cost of approximately $10.5 million, using the Company's estimate of $15,000 per mile. Hr'g Tr., 801:17-20. Doing this would forfeit much of the UPZ plan that has been established, since portions of the system had UPZ work 4-8 years ago, and thus significant growth has occurred. Hr'g Tr., 802:1-8. Due to the continued growth of these portions of the system, costs per mile may approach $25,000, though this estimate is untested. Id.; Interrog. Resp. RSR-81, pp. 3-4. While converting to a four-year trim cycle would be a drastic step, it is not an unreasonable one. Four-year cycle trimming is common in the industry, as all UI affiliate companies follow this practice because they do not have UPZ programs. Hr'g Tr., 1083:1-8.

The question before the Authority at this point is not how to implement UPZ across the system, but whether it is beneficial to customers and the public to do so. If it is deemed beneficial, then an optimal timeframe needs to be established. If it is not beneficial to subject the whole system to UPZ, the goal should be to identify where it is beneficial, and to prioritize those areas first. The Authority needs these questions answered prior to granting an increase in UPZ funding. While the Company did demonstrate the potential for some benefits to accrue, they are limited to comparisons of outage reductions and do not include a quantification of the value to customers. The Authority needs a more rigorous analysis to increase the budget for this program. UI has not done a cost-benefit analysis for this project, nor has it screened the UPZ program using the Resilience or Reliability Frameworks. Hr'g Tr., 1284:10-17.

[137] The Company's program now considers $229.5 million from 2014-2029 to finish the UPZ specification, plus an additional $24.5 million from 2023-2029 to maintain the UPZ specification with the UPZ Maintenance program, totaling $254 million. Interrog. Resp. OCC-136, Att. 1; OCC-319, Att. 1.

Accordingly, the Authority declines to expand the UPZ program as requested by UI. Instead, the Authority continues the funding allowance that was established in the 2016 Rate Case Decision for the UPZ program, where the Authority agreed to a $162.5 million program cost through 2025. 2016 Rate Case Decision, p. 9. The Authority finds no compelling reason to increase UPZ funding at this time.

Moving forward, a modification to the UPZ program to prioritize a transition to a four-year cycle, while taking a slower and more methodical approach to completing the UPZ program system-wide, appears to be a worthwhile pursuit. Doing so requires slowing the pace of the Company's timeline to perform full UPZ on the remaining single-phase and a second pass on the three-phase systems. Moving to a four-year cycle trimming sooner, however, enables the Company to better retain the UPZ clearances that currently exist, while implementing the full UPZ standard over a more achievable timeframe. Extending the timeframe to achieve a system-wide UPZ clearance also allows the Company to subject the UPZ plans to the RE08 Decision Reliability and Resilience Frameworks, which enable the Company to demonstrate quantifiable benefits (both in terms of avoided outage reductions, public safety benefits, and cost savings) to the Authority, Parties, and – most importantly – its customers.

Accordingly, the Authority provides the following direction for UI as it implements UPZ and other vegetation management work going forward:

1. Start the transition to four-year cycle trimming. The Company should use the UPZ Maintenance program to prioritize the transition to a four-year cycle. The Company need not transition immediately to a four-year cycle (i.e., UI is not required to trim 25% of its system in the first year), but UI must develop a plan to move to cycle trimming by 2027. The plan should be designed to optimally maintain full UPZ specification on the areas already treated.

2. Address first pass of remaining single-phase system. This next priority applies first to single-phase circuits that have not had UPZ trimming and are exposed to excessive tree growth. CJE PFT, p. 58. Full UPZ may be applied here where appropriate, but is not required (i.e., UI may perform standard maintenance trimming as opposed to UPZ if warranted). UI may, but is not required to, complete the planned single-phase miles according to the current plan outlined in the schedule in OCC-527, Attachment 1. It is acceptable to slow the pace of the remaining single-phase, so long as safety and reliability of the single-phase circuits are reasonably maintained.

3. Perform a second pass of full UPZ clearance of three-phase systems. This work is the lowest priority. When planning this work, the Company should attempt to maintain the existing UPZ specification on these circuits using UPZ Maintenance funds as appropriate. The Company should only apply a full UPZ clearance where it is cost effective to do so and as funds permit. This means the Company should develop plans to identify areas on the system that provide the most benefit as outlined in the Resilience and Reliability Frameworks.

To ensure that UI works diligently to execute the new UPZ program and follows the above priorities, the Authority directs UI to develop a plan for submission no later than

October 7, 2023, in Docket No. 23-08-09, Annual Electric Distribution Company Reliability and Resilience Framework Review. The plan will include a four-year work plan to implement the above priorities for years 2024 to 2027. The plan must demonstrate how UI will transition to four-year cycle trimming by 2027. The plan must demonstrate planned work for the three priorities above, including budget, mileage planned, and cost per mile. The plan must begin a first analysis on a long-term plan to finish UPZ work across the Company's system that fits within the Company's approved budget of $14 million per year. The plan must also begin to conform to the Reliability and Resilience Frameworks.

Based on the above findings, the Authority directs UI to make the following adjustments to the revenue requirement for the UPZ program. The Authority reduces the UPZ Deferral Regulatory Asset for Rate Year 2023/2024 by $4.338 million. Sch. WP B-1.0A and B-6.9. The Authority increases Rate Year 2023/2024 expenses by $7.532 million to include direct expensing of the total UPZ budget (which includes UPZ and UPZ Maintenance) of $14 million. Sch. C-3.05; Interrog. Resp. OCC-541. Therefore, the total allowed Outside Service – Line Clearance Expense is $15.334 million, which includes $14 million of allowable UPZ-related expenses, and $1.334 million of non-UPZ expenses for reliability maintenance trimming and other ongoing process and technology expenses. Sch. WPC-3.05; Interrog. Resp. OCC-542, Att. 1.

16. Advertising

The Company requests approval of annual advertising expense in the amount of $0.089 million, which is based on historical advertising expense costs. Late Filed Ex. 1, Sch. C-3.02. Annual advertising expense was calculated based on an initial Test Year amount of $0.130 million provided by the Company, then adjusted by $0.049 million to arrive at a figure of $0.080 million. Id., note 1. An inflation rate of 11.06% was then applied to the $0.080 million to arrive at the rate year request of $0.089 million of annual advertising expense. Advertising expense consists of customer bill inserts as well as phone book advertising. The Company claims that both activities are intended to educate customers. Late Filed Ex. 1, Sch. C-3.02.

The Authority is not persuaded that the proposed amounts for advertising provide value for customers as claimed by the Company. During the proceeding, the Company provided no support to quantify that this level of expense provided benefits to customers as purported by the Company or that the level of such expenditures is prudent and reasonable. Therefore, the Authority disallows the Company's proposed annual advertising expense of $0.089 million.

17. Central Facility Rent Credits

UI proposed rent credits of approximately $3.797 million, which consist of $0.866 million for 100 Marsh Hill Road (Operations Center) and $2.930 million for 180 Marsh Hill Road, Orange (Administrative Office, together Central Facility). These rent credits are for square footage utilized by Avangrid Service Company (Service Company) at the Central Facility. Late Filed Ex. 1, Att. 1, Sch. WPC-3.01. The rent credits are based on $33 per square foot beginning in 2012 and are subject to an annual escalation rate of 1.75%. Id. The Service Company currently leases 26,136 square feet of the Operations Center and 72,729 square feet of the Administrative Office. Id.; Interrog. Resp. RRU-70, Att. 1; Hr'g Tr. Mar. 21, 2022, 3418:13-20. The total square footage is 181,443 square feet for the Operation Center and 127,310 square feet for the Administrative Office. Id.

The total square footage for the Central Facility is 308,753 (181,443+127,310) and the Service Company currently leases a total of 98,805 (26,136+72,729) square feet or 32.02%.

The Authority increases the Company's proposed rent credits by $1.975 million for the square footage utilized by the Service Company at the Central Facility.

The Service Company provides administrative and management services to operating utilities of Avangrid Networks. Application, Sch. H-1.01, p. 42. The Company receives shared services from both the Service Company and Technical Services and these affiliates provide shared services to all operating companies. Application, Ex. UI-RRP-1, p. 14. Costs are directly charged to UI for goods and services utilized by or deemed to solely benefit the Company. Costs that are not directly attributable are indirectly allocated based on activities or metrics of the operating entity. For instance, costs for buildings are allocated based on the square footage utilized by the Company. Id., p. 15. The Massachusetts Formula is used to allocate costs that cannot be directly or indirectly allocated to a specific entity. Id., p. 15. Moreover, UI asserted that the crucial purpose of cost allocation, including the use of the Massachusetts Formula, is to realistically reflect cost causation. Id.

In exhibits filed in the 2013 and 2016 rate cases, the Company noted that UIL leased 69,263 square feet of the Operations Center and 43,219 square feet of the Administrative Office. Late Filed Ex. 29, Att. 3 Supplemental. UI did not explain why UIL previously leased 69,263 square feet of the Operations Center and the Service Company is currently only leasing 26,136 square feet. Also, the rent price of $33 per square foot when escalated at 1.75% annually from July 2012 through August 2024, resulted in $40.81 ($33*1.0175^12.25) per square foot. The Company reported that the distribution only revenue requirement for the Central Facility is $17.251 million. Late Filed Ex. 57, Att. 1. However, the Authority determines that the revenue requirement for the Central Facility before allocation to the transmission sector is $20.976 million.

The Authority finds that the rent credit amount reported by the Company does not accurately reflect the actual cost of the Central Facility attributable to the Service Company. Avangrid is based and headquartered in Orange, Connecticut. Based on the total revenue requirement for the Central Facility of $18.980 million and 308,753 square feet, the Authority determines that $61.472 ($18.980 million/308,753) is the appropriate amount for each square footage.

Table 64: Calculation of the Central Facility's Revenue Requirement ($000)

Description	Symbol	Amount
Gross Plant -Beginning	A	131,399
Gross Plant- Ending	B	150,608
Gross Plant –Average	C=(A+B)/2	141,153
Accumulated Depreciation - Beginning	D	34,655
Accumulated Depreciation – Ending	E	39,491
Accumulated Depreciation –Average	F=(D+E)/2	37,073
Average Net Plant	G=C-F	104,080
Interest Expense (LTD Rate 4.32%)	H=G*0.5*4.32%	2,248
Return on Equity (Allowed ROE -9.53%)	I=G*0.5*8.53%	4,439
Income Taxes on Equity Returns	J=I*26.925%	1,195
Total Returns, including Income Taxes	K=H+I+J	7,882
Maintenance Expenses(2021 escalated at 8.04%)	L	1,874
Land Lease -180 Marsh Hill Road	M	459
Property Taxes (Imputed at 3.325% x 70%)	N	2,422
Depreciation Expense	O=E-D	4,836
Subtotal Operating Expenses	P=L+M+N+O	9,591
Total Operating Expenses	Q=K+P	17,473
Uncollectible Rate	R	0.9000%
Revenue Requirement with Uncollectible Expense	S=R/(1-R)	17,632
Weighted GET Rate	T	7.1012%
Total Revenue Requirement with GET Expense	U=S/(1-T)	18,980

Late Filed Ex. 57, Att. 1.

To preclude the Company from subsidizing its affiliates, the Authority determines that the total rent credit from the Service Company to UI is therefore $6.078 million, which represents 32.02% of the total revenue requirement of $18.980 million for the Central Facility. Therefore, the Authority finds that the total rent credit from the Service Company is understated by $2.281 ($6.078-$3.797) million.

UI's Global 6 allocation factor is 16.33%. Interrog. Resp. RRU-201, Att. 4. The Authority uses the UI distribution wage allocator of 82.28% to determine $0.306 million ($2.281*16.33%*82.28%) as the additional rent credit that would be reallocated to UI distribution as a shared service rent expense. Therefore, the Authority determines that the Company's proposed rent credit for the Service Company's use of 32% of the Central Facility should be increased by $1.975 million ($2.281-$0.306). The table below summarizes the calculation of the additional rent credit from the Service Company.

Table 65: Additional Rent Credit for Use of Central Facility

Description	Amount ($000)
Central Facility Revenue Requirement	18,980
Percentage of Central Facility Square Footage Allocable to the Service Company (%)	32.02%
Central Facility's Revenue Requirement Allocable to the Service Company	6,078
Proposed Rent Credit Per WPC-3.01	3,797
Total Rent Credit Adjustment	2,281
Less Rent Credit Re-allocable to UI Distribution as CSC	(306)
Net Rent Credit Adjustment	**1,975**

18. Uncollectible Expense

The Authority disallows $1.087 million of the Company's proposed uncollectible expense for adjustments related to the use of an erroneous uncollectible rate, and reductions to both present rates and the requested incremental revenues.

Based on revenue at current rates, UI reported $3.120 million as the pro forma uncollectible expense for the rate year. Late Filed Ex. 1, Att. 1, Sch. WPC-3.0A. Moreover, the Company requested additional uncollectible expense of $1.221 million related to the $91.055 million additional revenue request. Late Filed Ex. 1, Att. 1, Sch. A-3.0A, p. 2. Therefore, the total uncollectible expense proposed for the rate year is $4.341 million ($3.120 + $1.221). UI proposed an uncollectible rate of 0.900% for the rate year. Late Filed Ex. 1, Att. 1, Sch. WPC-3.20.

The Authority finds that UI improperly used the originally proposed uncollectible rate of 1.36% to determine the $91.055 million incremental revenue for the rate year. Late Filed Ex. 1, Att. 1, Sch. A-3.0A, p. 2. The Authority determines that using the updated 0.900% uncollectible rate generates total additional revenue of $90.610 million. Thus, the correct incremental uncollectible expense is $0.808 million (90.610 x 0.900%). Therefore, the Authority reduces the additional uncollectible expense proposed for the rate year by $0.413 million ($1.221 - $0.808).

The Authority reduces the Company's present rate revenue by $6.751 million and disallows the associated uncollectible expense of $0.061 million. Additionally, the Authority reduces the incremental revenue requested for the rate year by $68.098 million and reduces the related uncollectible expense by $0.613 million. The table below summarizes the $1.087 million reduction to the Company's proposed uncollectible expense. Therefore, the Authority allows $3.254 million ($4.341 - $1.087) as the uncollectible expense for the rate year.

Table 66: Summary of Adjustments - Uncollectible Expense

Adjusted Items	Amount ($000)
Incorrect Uncollectible Rate	413
Present Rate Revenue	61
Total Disallowed Revenue	613
Total Uncollectible Expense Adjustment	**1,087**

19. Reconnect Service Fees

In Section VI.E.4., Reconnect Service Fees, the Authority directs the Company to include the $1.015 million RSF in other operating income instead of as an offsetting credit to O&M expenses.

20. Inflation Adjustment

The Company requested an 8.61% inflation factor. Application Ex. UI-RRP-1; UI Interrog. Resp. OCC-84. The Company is incorporating inflation projections based on projected consensus inflation forecasts from Blue Chip Economics. The Company is proposing to adjust those forecasts downward by 2% in each period. As part of this proposal, the Company is requesting that an inflation reconciliation be included, whereby the actual inflation rate experienced will be compared to Blue Chip Economic forecasts used in the revenue requirement calculations, and any difference in the inflation rate, multiplied by amounts affected by inflation, would be set up as a regulatory asset or liability, depending on whether the actual inflation rate is higher than or lower than the projected level. Application Ex. UI-RRP-1, pp. 12-13. The Company calculated an inflation factor of 10.61%, and when the inflation moderator is applied arrives at an inflation factor of 8.61%.

The Authority disallows the inflation factor as proposed by the Company. The Company provided updated inflation numbers in UI Interrog. Resp. RRU-542. The UI methodology spanned from Q1 2022 (i.e., from the end of the Test Year) to Q3 2024, including the mid-point of the Rate Year 2023/2024. The Company's methodology was essentially to sum up the changes in the aforementioned time span to arrive at the 10.61% proposal.

Instead, the Authority finds the simple percentage change methodology to be appropriate for ratemaking purposes. Using actual GDP Chained Price Index quarterly actuals and estimates for Q4 2021 to Q1 2022 (i.e., 121.3 and 124.2 for an average of 122.75) and GDP forecasted GDP chained price index estimates for Q1 2024 and Q2 2024 (i.e., 134 and 134.7 for an average of 134.35%). The percentage increase during the time frame of 9.45% (i.e., (134.35-122.75)/122.75) will be used for ratemaking purposes as the inflation factor. See UI Interrog. Resp. RRU-541 Att. 1, RRU-542 Att. 1 and UI Interrog. Resp OCC-84, Att. 14.

Table 67: O&M Expenses Subject to the Inflation Adjustment

	Inflation Adj. Rate Year Expense	Adj. at 9.45%	Exp. Adj.	Inflation Adj.
Advertising	89	86	(86)	0
Regulatory Assessments	3,649	3,597		52
Outside Services				
Line Clearance -Electric Ops.	297	292		4
Facilities Maintenance	2,826	2,786		40
Security and Safety-Electric Ops.	257	254		3
Electric Distribution System	1,459	1,438		21
Professional Services	1,720	1,695	277	29
Legal Expense	1,143	1,126		17
Computer Expense	661	651	(395)	3
Injuries & Damages	1,183	1,166	(550)	9
Telecommunications Expense	3,464	3,414	(1,075)	33
Transportation Expense	1,986	1,879		107
Other Employee Benefits Expense	951	937		14
Other O&M	5,210	5,134		76
Inflation Adjustment	**24,895**	**24,369**		**409**

Late Filed Ex. 1, Sch. C.

21. Water Heater Program

The Company began offering a water heater rental program to residential electric customers over 50 years ago. UI Interrog. Resp. CAE-75. The program allows customers to receive an electric water heater with no upfront cost, and instead customers pay for the cost of the heater, installation, maintenance, removal, and replacement of the water heater through a monthly on-bill lease payment under Rate WHR. Young & Crowley Prefiled Test., Sep. 9, 2022, pp. 3:5-13, 4:19. New customers also have the option to pay a one-time $350 installation fee and have a lower monthly on-bill lease payment as a result. Id., p. 4:14-18. The pricing established under Rate WHR has remained the same since 2005. Id., pp. 2:9, 6:4-5. The program is meant to offer electric customers efficient, load-controlled water heaters that primarily operate during off-peak hours, i.e., overnight. Id., p. 4:7-11; UI Interrog. Resp. CAE-75. Customers therefore gain the greatest benefit if they enroll in the Company's time-of-use rate, Rate RT, which offers electric rates below Rate R, the Company's flat rate, during off-peak hours. Young & Crowley PFT, p. 4:7-9. However, UI does not require program participants to enroll in Rate RT and instead educates new participants about the benefits of time-of-use rates. UI Interrog. Resp. CAE-75; Hr'g Tr. Mar. 8, 2023, 2869:1-24.

Additionally, UI meter services department staff provide any necessary repair services, while the program vendor, Hubbell, manufactures, installs, and removes heaters, as well as secures town permits and provides licensed electrician services for any electrical maintenance. Young & Crowley PFT, p. 3:8-14. The majority of participating customers receive an 80-gallon tank or, to a lesser extent, a 120-gallon tank.

Id., p. 4:2-5. However, the Company does provide 30-, 40-, 50-, and 65-gallon tanks to customers with space limitations. Id. The water heaters currently in use in the program have a useful life of 20 to 25 years. Hr'g Tr. Mar. 8, 2023, 2869:25 – 2870:4. New participating customers sign a water heater lease agreement for a minimum of one year. Young & Crowley, p. 5:5. Subsequently, customers can choose to continue with the program on a monthly basis, cease their participation and have the heater removed, or purchase the water heater from UI at its book value. Id., p. 5:6-7.

UI states that participation in the program is trending downward. Young & Crowley PFT, p. 5:10. Specifically, the number of participating water heater units has decreased by 16% between 2007 and 2021. Id., p. 5:10-13. Additionally, the number of new heater installations has also decreased, shifting from 214 new installs annually in 2008 to 65 new installs annually in 2021. Id., p. 5:14-19. The Company currently maintains a total of 10,699 water heater units as part of this program, of which over 30% have been in service for 20 years or more. Id., p. 3:7-8; Late Filed Ex. 131.

In response to new Department of Energy (DOE) water heater energy efficiency standards, the Company issued an RFP in 2015 seeking vendors offering DOE-compliant electric water heaters. Id., p. 6:5-8. The resulting new water heater offering was 23% more expensive than UI's previous standard water heater. Id. The Company did issue a new RFP in 2020, which sought to find a best-cost vendor for a two-year term. UI Interrog. Resp. CAE-75. However, out of the 11 potential vendors that UI solicited, only the incumbent vendor responded and was therefore awarded the RFP. Id. Given the lack of response in 2020, UI pursued a sole source acquisition in 2022 and negotiated pricing with the existing vendor for a new contract. Id. Further, in 2017, UI contracted with its program vendor to provide licensed electrical services and permitting, whereas prior to 2017, the Company's own Meter Services group provided such services. Young & Crowley PFT, p. 6:9-14. In 2022, the program vendor's costs for hardware, installation, removal, and servicing fees increased by 10% in comparison to the costs in 2017. Id., p. 6:15-17. The Company states that program costs have increased because of such increased vendor costs and updated efficiency requirements. Id., 6:2-3. Indeed, the Company reports that the costs of the program have increased significantly since 2015. Young & Crowley PFT, pp. 2:9-11, 6:2-8; Hr'g Tr. Mar. 8, 2023, 2881:3-8. Given that the tariff's pricing has not increased from its 2005 level, the Company alleges that the program is currently operating at a revenue deficiency and is recovering less than half the cost of the program. Young & Crowley PFT, p. 7:10-12.

In response to increasing program costs and declining customer participation, UI proposed to amend Rate WHR to increase monthly lease prices and to close the program to new customers by September 1, 2023. Young & Crowley PFT, p. 8:2-5, 8:11-13. Specifically, UI requested a rate increase of $6.00 per year for three years to be applied to all new installations requested by existing program participants. Id., p. 8:2-6. The Company states that this rate increase would "recover UI's revenue requirement over the 20-year depreciated life of newly installed water heater assets." Id., p. 8:2-3. The Company's proposed rate increases can be seen in the table below.

Table 68: UI's Proposed 2023/2024 Increase to Rate WHR

Rate Type	Current Monthly Rate	Proposed 2023/2024 Monthly Rate
80 Gallon Standard	$12.50	$18.50
120 Gallon Standard	$14.00	$20.00
80 Gallon Alternate[138]	$7.70	$13.70
120 Gallon Alternate	$9.00	$15.00

Young & Crowley PFT, p. 8:7.

Additionally, the Company opined that the water heater program is unsustainable over the long term and should therefore be closed to new customers and should phase out existing customers over time. Id., pp. 8:11-9:17. The Company alleges that Connecticut vendors in the competitive market currently offer similar, or even the same, services and equipment for 30% less per month than UI's proposed increased program rates, which reflect UI's true costs of providing the program. Id., p. 9:1-3; UI Interrog. Resp. CAE-77; Hr'g Tr. Mar. 8, 2023, 2872:8 – 2873:5. Indeed, UI confirmed that the Company's own contracted vendor, Hubbell, offers the same heater and electrical services to customers outside of UI's service territory for over 30% less than UI's proposed rates. UI Interrog. Resp. CAE-77; Hr'g Tr., 2872:25 – 2873:5. The Company theorized that because UI is currently acting as the "middleman," i.e., passing vendor services and costs and additional program administration costs through to customers, that vendors who provide the services directly to customers are able to offer lower rates. Hr'g Tr., 2872:20-24. Further, UI incurs additional costs above the price of equipment and services, such as the costs associated with having the lease payment on customer's electric bills, that vendors providing water heaters and associated services directly to customers do not have. Hr'g Tr., 2881:20-25.

Although UI proposed to close program participation to new customers, the Company is committed to serving existing customers until they choose to leave or until UI is "able to determine a fair and equitable process" for ceasing the program entirely. Young & Crowley PFT, p. 9:13-17. UI does expect that if the proposed increases to Rate WHR are implemented, customer attrition from the program will likely accelerate. Id., p. 9:20-21. For those customers who choose to continue in the program, UI proposed supporting such customers through program phase-out by providing alternative water heater rental suppliers and connecting customers with UI's internal C&LM team to discuss other efficient equipment, such as heat pump water heaters. Id., p. 10:1-3, 10:6-11. When prompted to propose a method that would phase out the program on a faster timeline, UI suggested that the Company could offer all participating customers a buy-out option. UI Interrog. Resp. CAE-78. Specifically, the Company suggested that customers could (1) purchase water heaters beyond their useful life at no cost; (2) purchase water heaters within their useful life at book value; (3) purchase water heaters within their useful

[138] "Alternate" here refers to the monthly lease fee for a customer that paid the $350 upfront installation fee. Such customers receive a lower monthly fee than those who opt not to pay this upfront fee. Young & Crowley PFT, pp. 8:7, 4:14-18.

life using low-interest financing options; and (4) low-income customers could purchase water heaters at a discount to book value. Id. Once the program ceases operations, UI proposed directing such customers to the C&LM team and program offerings. Id. However, UI cautioned that early program termination will still result in unrecovered costs for the Company that would then be included for recovery in its next rate case. Id.

The Department of Energy and Environmental Protection (DEEP) submitted to the Authority a summary of available water heater offerings and incentives under the C&LM program. DEEP Interrog. Resp. CAE-100, p. 1. Through the EnergizeCT website, customers can choose between electric heat pumps, gas condensing, or gas tankless water heater residential incentive offerings. Id. Electric heat pump water heaters are eligible for $750 in either instant discounts or instant rebates, and according to DEEP, result in $3,000 to $4,000 in lifetime savings. Id. Further, DEEP alleged that electric-resistance water heaters are "widely recognized as inefficient" and are therefore ineligible for incentives through EnergizeCT. DEEP Interrog. Resp. CAE-100, p. 1. DEEP supported closing program participation to new customers and recommended that UI quickly phase out the program so that customers transition from "low-efficiency electric-resistance units to high-efficiency heat pump water heaters[.]" Id., p. 2. Additionally, DEEP questioned the future viability of such a program if it were to be considered among other C&LM offerings, suggesting that the increasing program costs and inefficient equipment would render the program unviable in the competitive market. Id.

The Authority agrees that it is appropriate to phase out the Water Heater Rental Program and replace it with similar offerings from the C&LM program. The program's increasing costs, additional administrative cost of UI's management, declining customer participation, and low-efficiency equipment show that the existing program structure is an unnecessary use of ratepayer funds. Given that customers can receive the exact same equipment and services from the competitive market at lower prices, the Authority considers whether Company funds may be better used through marketing and educating customers about such external offerings instead. Additionally, the ages of water heaters currently operating in the program are predominantly heaters near the end of their useful life that will need to be replaced soon. Specifically, the average age of heaters in the program is 12.8 years, and according to the Authority's own calculations, the percentage of heaters that are over 10, 15, and 20 years is 65%, 46%, and 31%, respectively. See Late Filed Ex. 131. Accordingly, 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. The prompt phase-out will also reduce costs to customers, who will be able to purchase their end-of-life heater at no cost or a low book value. Furthermore, the Authority concurs with DEEP's argument that it is preferable for residential customers to utilize high-efficiency electric heat pump water heaters rather than low-efficiency electric-resistance water heaters. Finally, the Authority believes that because the C&LM program currently offers incentives and assistance for customers interested in efficient electric water heaters, utilizing UI's internal C&LM resources instead of an additional water heater rental program will be a more efficient use of ratepayer funds.

Accordingly, the Authority directs UI to close participation in the Water Heater Rental Program by new customers as soon as possible, but no later than, September 1, 2023. Additionally, the Authority directs UI to analyze current participating customers and

the status of participating equipment, and to utilize such analysis to develop a robust plan for phasing out all remaining equipment by September 1, 2025. This plan shall include an analysis of current FTEs supporting the program and how such internal resources can be adjusted to serve future customer needs. The Company shall submit such plan to the Authority for review and approval by June 1, 2024.

B. DEPRECIATION EXPENSES

1. Summary

A depreciation rate study proposes annual depreciation rates to be applied to plant-in-service balances. The product of the rate and plant balance is the annual depreciation expense, which is a charge to a company's operating expense to reflect the annual recovery or amortization of previously expended capital investment. The table below summarizes the Authority's adjustments to the Company's proposed depreciation expense. The justification for the adjustments is provided in the following subsections.

Table 69: Depreciation Expense ($000)

Company Proposed	82,576
Authority Adjustment	(10,040)
Total Allowed Depreciation Expense	**72,536**

2. Depreciation Study

UI filed a depreciation study related to the utility plant-in-service as of December 31, 2021 (Depreciation Study). The Company's Depreciation Study was performed by Larry Kennedy of Concentric Energy Advisors (Concentric). Kennedy Prefiled Test., Sep. 9, 2022. The Depreciation Study proposes depreciation rates that were calculated under a depreciation system using the straight-line method, average life procedure, and applied on a remaining life basis. Kennedy PFT, p. 19. This depreciation system is widely used by regulated utilities. However, the Depreciation Study in this case specifically used a refinement to the remaining life calculations that differs from methods previously adopted by the Authority. In this case, Concentric incorporates a "refinement" into the remaining life calculations based on a weighted investment by vintage approach. The vintage approach weighs the calculations of remaining life on an allocation of the actual book accumulated depreciation account by the Calculated Accumulated Depreciation factor determined for each vintage of plant in service. Kennedy PFT, p. 19.

The application of the present rates to the depreciable plant-in-service as of December 31, 2021, results in an annual depreciation accrual of $69,927,298. Interrog. Resp. RRU-211, Att. 1. In comparison, the application of the Company's proposed depreciation rates to the depreciable plant-in-service as of December 31, 2021, results in an annual depreciation accrual of $71,146,801. Ex. UI-LEK-2, p. 24. This represents an increase of $1,219,503 from current rates. The composite annual depreciation rate under present rates is 3.36%, while the Company-proposed December 31, 2021, composite depreciation rate is 3.42%. Ex. UI-LEK-2, p. 24. A significant cause of the Company-proposed change in depreciation rates is the proposed changes in average service life of many of the Company's accounts. Concentric proposed shortening the average service life in nine accounts, and lengthening the average service life in seven accounts. Kennedy PFT, pp. 7-8.

3. OCC's Position

The OCC disagrees with the Company's proposed refinement to the method used to calculate remaining life. The OCC also opposes the net salvage rates proposed in the depreciation study. The OCC does not, however, oppose any of the proposed service lives or Iowa Curves in the Depreciation Study for any account. Dunkel Prefiled Test., Dec. 13, 2022, p. 34.

The OCC contends that the Company did not use the accepted depreciation rate formula to calculate its proposed depreciation rates. Dunkel PFT, p. 8. The OCC states that the Company's refinement to the remaining life calculations results in higher annual depreciation rates and expenses. Dunkel PFT, p. 9. Further, the OCC claims that the Company's proposed depreciation rates violate the straight-line depreciation method. Dunkel PFT, p. 13.

Regarding net salvage, the OCC contends that the Company proposes to change the net salvage method previously adopted by the Authority. Dunkel PFT, p. 15. The OCC further argues that the Company's proposed net salvage rates are a step towards larger increases in the future. Dunkel PFT, p. 21.

The application of the OCC's proposed depreciation rates to the depreciable plant-in-service as of December 31, 2021, results in an annual depreciation accrual of $66,231,304. Dunkel PFT, p. 36. This is based on a composite depreciation rate of 3.19% for the total utility plant studied by the OCC. Ex. OCC-WWD-9, p. 1. Compared to the currently approved annual depreciation accrual applicable to plant-in-service as of December 31, 2021, the OCC's proposed depreciation rates would result in a decrease to the annual depreciation accrual in the amount of $4,915,497. Ex. OCC-WWD-9, p. 1.

4. Depreciation Rates

a. Remaining Life and Depreciation Rate Calculations

One of the major differences between the Company's and the OCC's proposed depreciation rates stems from the difference in calculating remaining life and the overall depreciation rate for each account. The method used by the OCC to calculate remaining life (the Traditional Method) has been accepted by the Authority in prior proceedings, including in the 2016 Rate Case Decision. Indeed, Mr. Kennedy acknowledges that his "reciprocally weighted" remaining life approach is also different than the approach used in UI's prior depreciation study (the Refined Method). Hr'g Tr. Feb. 16, 2023, 32:13-25. Under the Traditional Method, future depreciation accruals are divided by the composite remaining life for each account to calculate the depreciation accrual. Under Mr. Kennedy's Refined Method, however, the quotient obtained by dividing future accruals by the composite remaining life does not equate to the proposed annual accrual for each account. Ex. UI-LEK-2. At the hearing, Mr. Kennedy offered a detailed explanation of the Refined Method, and stated that future studies will make the calculation clearer with regard to presenting the composite remaining life calculation. Hr'g Tr., 38:1-9.

The Authority finds that continued reliance on the Traditional Method for the purposes of calculating remaining life and depreciation rates is reasonable. Compared with the Refined Method, depreciation rates calculated under the Traditional Method can be more clearly ascertained and replicated. Under the Traditional Method, estimated

future accruals can be divided by a stated remaining life to equate to the annual depreciation accrual for each account. Therefore, the Authority adopts the OCC's proposed depreciation rate calculations.

With regard to the Iowa curves and average service life estimates proposed by Mr. Kennedy for each account in the depreciation study, there was no evidence presented showing that such service life estimates were unreasonable. Therefore, the Authority accepts the Company's proposed service life estimates.

b. Net Salvage

The Company proposes a change to the method of determining net salvage rates previously adopted by the Authority. In the 2016 Rate Case Decision, the Authority adopted Mr. Dunkel's proposed net salvage method, which included a comparison showing the proposed net salvage accrual to the average amount actually spent for net salvage in the last five years. 2016 Rate Case Decision, p. 45. In this case, Mr. Dunkel proposes the continued use of this method of net salvage analysis. Dunkel PFT, p. 35. Mr. Dunkel argues that the net salvage method proposed by Mr. Kennedy results in higher negative net salvage rates compared with other methods. Dunkel PFT, p. 16. Mr. Dunkel refers to Mr. Kennedy's method in part to an "apples divided by oranges" method, in which the numerator and denominator are measured in different units. Dunkel PFT, p. 16. That is, the numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation. Given the nature of increasing material and labor costs associated with the removal of utility assets due to inflation, negative net salvage rates have tended to increase over time under this approach.

According to Mr. Kennedy, the salvage ratio should consist of the cost of retirements at the time of retirement, divided by the original cost of the investment. Kennedy Rebuttal Prefiled Testimony, p. 13. Based on his method of analysis, Mr. Kennedy believes there is a need for more negative net salvage percentages in certain accounts, which has resulted in an increase to the proposed depreciation rate. Kennedy PFT, p. 10. In response, Mr. Dunkel compares the net salvage accrual in the Company's proposed depreciation rates with the five-year average net salvage cost actually incurred. Dunkel PFT, p. 31, Table 6. According to Mr. Dunkel, the Company has actually incurred $3.425 million of net salvage cost (based on the prior five-year average), which is significantly less than the $9.737 million of net salvage included in the Company's proposed depreciation rates. Dunkel PFT, p. 31, Table 6. Accordingly, the Authority did not find compelling evidence to deviate from the approach adopted by PURA in prior cases with regard to net salvage. For these reasons, the Authority finds that the OCC's proposed net salvage rates are more reasonable than those proposed by the Company.

5. Adjustment to Depreciation Expense

Based on the above adjustments to the remaining life and net salvage calculations, the composite depreciation rate is 3.19%. Dunkel PFT, p. 37. Applying the composite depreciation rate to the allowed plant-in-service, as adjusted by the Authority in Section IV.B., Plant-in-Service, the Authority determines an approved depreciation expense of $72.535 million as shown in the table below.

Table 70: Adjustments to Depreciation Expense ($000)

Approved Plant-in Service Adjustment[139]	2,273,831
Composite Depreciation Rate	3.19%
Total Allowed Depreciation Expense	72,536
Company Proposed Expense	82,576
Authority Adjustment	(10,040)

Late Filed Ex. 1, Att. 1, Sch. B-1.0, C-3.29.

C. AMORTIZATION OF REGULATORY ASSETS

1. Summary

The Company proposed to recover annual amortization expense of $15.526 million in Rate Year 2023/2024, as summarized in the table below. Late Filed Ex. 1, Att. 1, Sch. WPC-3.30, p. 1. These amortization expenses are related to regulatory assets that UI proposed to include in rate base, as discussed in Section IV., Rate Base. All regulatory assets were removed from rate base and instead treated as an amortized expense with carrying charges calculated at the weighted cost of capital. The Authority applies this unique treatment as it is not approving a multi-year rate plan, see Section III.B., Multi-Year Rate Plan, and, as such, the calculation of regulatory asset carrying charges would have been significantly overstated if left in rate base.

Table 71: Summary of Approved Annual Amortization Expenses ($000)

Amortization Expense	Proposed	Adjustments	Approved
Loss on Sale of Bridgeport Ave	5,194	(5,194)	0
Environmental deferral	153	(153)	0
Pension deferral	2,965	(389)	2,576
OPEB deferral	(264)	0	(264)
Storm deferral	5,139	(1,856)	3,283
COVID deferral	2,792	(506)	2,286
CAM GET deferral	(945)	(315)	(1,260)
Isaias Penalty Over-Under	(16)	0	(16)
Rate Case Expense	508	(508)	0
Total Amortization Expense	**15,526**	**(8,921)**	**6,605**

Late Filed Ex. 1, Att. 1, Sch. WPC-3.30, p. 1.

[139] The Authority made an adjustment reducing the allowed Plant-in-Service by $222.402 million in Section IV.B., Plant-in-Service. Therefore, the approved Plant-in-Service for plant as of the end of Rate Year 2023/2024 (i.e., as of August 31, 2024) is $2,273,831,000 ($2,496,233,000 – $222,402,000). Late Filed Ex. 1, Att. 1, Sch. B-1.0.

2. Bridgeport Avenue Deferral

As discussed in Section IV.E.5., Bridgeport Avenue, the Authority disallows the $15.582 million regulatory asset. Therefore, the Authority also disallows $5.194 million annual amortization expense related to the regulatory asset. Late Filed Ex. 1, Sch. B-6.8 A and WPC-3.30.

3. Environmental Expenses

The Company proposes to amortize approximately $458,000 of past environmental costs related to the remediation of two sites: (1) a 19-acre industrial property located in New Haven (East Shore Project) used by UI for material storage and temporary staging and (2) the Bridgeport Avenue Project. Ex. UI-RRP-1, pp. 42-44. The result is a $153,000 expense. Late Filed Ex. 1, C-3.30 WP, p. 1.

The Company did not provide any evidence related to the prudency or reasonableness of the $458,000 expense. Further, the Company states that the East Shore Project is "currently entering the remedial planning, design, and remedial action phase," which indicates that the remediation activities have not commenced in earnest at that location. Notably, the two sites have been in the State of Connecticut's Voluntary Remediation Program (VRP) since 2004. Ex. UI-RRP-1, p. 43.[140] In addition, the Company does not appear (nor did it assert otherwise) to have been authorized to defer the accounting of these remediation costs. As such, allowing recovery of past costs would be impermissible retroactive ratemaking. Consequently, the Authority denies the deferred accounting of the $458,000 in past expenses and will exclude the $153,000 amortization from allowable expenses.

With respect to future remediation expenses for the East Shore Project incurred after the start of Rate Year 2023/2024, the Authority will allow deferred accounting treatment, with all deferred expenses subject to a prudency review in the Company's next rate proceeding. Any deferred remediation expenses are to be offset by the amounts included in the Company's allowed annual revenue requirement, and carrying charges will not be permitted on the deferred expenses.

The Authority will not permit deferred accounting for the Bridgeport Avenue project. The Company included $26,000 in Outside Professional Service Expenses for the Bridgeport Avenue project in its proposed annual revenue requirement. Late Filed Ex. 1, Sch. C-3.11 WP. This amount matches the annual costs projected by the Company over the next 5 years. Ex. UI-RRP-1, p. 43. According to the Company, the remediation of the Bridgeport Avenue project is limited to "post remedial groundwater monitoring and

[140] The East Shore Project has been in the VRP for almost 20 years, and DEEP expressed concern regarding the progress of remediation, stating there "should be a level of transparency surrounding the remediation to encourage accountability and to openly document UI's work on a project that impacts the public." DEEP Brief, p. 22. DEEP requests that the Authority order the Company to provide a remedial action plan by January 2024 and require annual progress reports. Id. Although DEEP has exclusive jurisdiction over the Company's remediation of the East Shore Project, the Authority is broadly responsible for ensuring that the Company is performing its public responsibilities with economy, efficiency, and care for public safety while also, in relevant part, reflecting prudent management of the natural environment. See Conn. Gen. Stat. § 16-19e(a)(3). Consequently, the Authority will order the Company to file a remedial action plan with DEEP by January 1, 2024, and provide annual progress reports until otherwise directed by the Authority.

reporting . . . ." Id., p. 42. Because ratepayers are already paying for the projected remediation costs through base rates, deferred accounting of the costs is not appropriate.

4. Pension Deferral

The Company requested the amortization of a $14.826 million pension cost regulatory asset over a five-year period, resulting in an annual expense of $2.965 million. Late Filed Ex. 1, Sch. B-6.2 A and WPC-3.30. The proposed pension deferral of $14.826 million is overstated by $3.599 million in carrying charges. Therefore, the Authority decreases the deferred expense by $3.599 million. In addition, the Authority removes the $13.344 million and the related deferred tax from the Company's proposed average rate base and instead amortizes the allowed $11.227 million outside of the rate base.

As discussed in Section IV.E.2., Pension Deferral, the Authority allows $11.227 million as the deferred pension costs subject to pre-tax WACC outside of rate base. Based on the allowed WACC, the pre-tax WACC is 8.0649%, which results in an $1.654 million total carrying charge on the approved pension cost deferral of $11.227 million over five years. The Authority amortizes the total pension deferral of $12.881 ($11.227 +$1.654) million over five years and derives an annual amortization expense of $2.576 ($12.881/5) million. As a result, the Authority reduces the Company's proposed annual amortization expense for the pension regulatory asset by $0.389 million ($2.965-$2.576 million).

5. Storm Deferral

The Company requested an annual amortization expense of $5.139 million based on a five-year amortization period. Late Filed Ex. 1, Sch. B-8.0 A and WPC-3.30.

As discussed in Section IV.E.7., Storm Reserve / Tropical Storm Isaias Deferral, the Authority allows $15.060 million as the deferred storm costs subject to pre-tax WACC outside of rate base. Based on the allowed WACC herein, the Authority determines that the pre-tax WACC is 8.0649%, and calculates $1.354 million as the total carrying charge on the approved storm cost deferral of $15.060 million over five years. The Authority amortizes the total allowed storm deferral of $16.414 ($15.060+$1.354) million over five years and derives an annual amortization expense of $3.283 ($16.414/5) million. As a result, the Authority reduces the Company's proposed annual amortization expense related to the storm deferral by $1.856 million ($5.139 - $3.283 million).

6. COVID Deferral

UI proposed a $2.792 million annual amortization expense for the proposed COVID regulatory asset based on a three-year amortization period. Late Filed Ex. 1, Sch. 6.3 A and WPC-3.30.

As discussed in Section IV.E.3., COVID Deferral, the Authority disallows $2.074 million of the COVID regulatory asset. Based on the allowed WACC herein, the Authority determines that the pre-tax WACC is 8.0649%, and calculates $0.557 million as the total carrying charge on the approved COVID-19 deferral of $6.301 million over three years. The Authority amortizes the total allowed COVID-19 deferral of $6.858 ($6.301+$0.557) million over three years and derives an annual amortization expense of $2.286 ($6.858/3) million. Therefore, the Authority reduces the Company's proposed annual amortization of the COVID deferral by approximately $0.506 million ($2.792-$2.286 million).

7. CAM GET Deferral

UI proposed $0.945 million as the annual amortized CAM GET deferral refundable to ratepayers based on a three-year amortization period. Late Filed Ex. 1, Sch. 6.6 A and WPC-3.30.

As discussed in Section IV.E.4., CAM GET Deferral, the Authority increases the CAM GET regulatory liability by $0.638 million to approximately $3.473 million. Based on the allowed WACC herein, the Authority determines that the pre-tax WACC is 8.0649%, and calculates that total interest refundable to customers over three years on the approved CAM GET is $0.307 million. The Authority amortizes the total CAM GET credit of $3.780 ($3.473+$0.307) million over three years and derives an annual amortized credit of $1.260 ($3.780/3) million. Therefore, the Authority increases the Company's proposed annual CAM GET credit by $0.315 million ($1.260-$0.945 million).

8. Non-Billable Make-Ready Work

In the 19-01-52RE01 Decision, the Authority established a regulatory asset to enable UI to perform make-ready work to accommodate the potential for a massive increase in pole attachment requests. 19-01-52RE01 Decision, pp. 44-45. The Authority enabled this to ensure that UI would be able to secure sufficient resources to perform the necessary make-ready work, including non-billable make-ready work,[141] meet the deadlines, and contribute to the timely realization of state public policy goals of broadband deployment. Id., p. 45.

The Authority established certain requirements for UI to utilize the regulatory asset. Id., p. 45. UI had to follow specific requirements to account for appropriate costs of performing non-billable make-ready work and request approval for them in its next general rate case. Id. The Authority set these requirements to ensure that costs were reasonably and prudently incurred. Id. The requirements include making the following information available in this case:

1. Detailed records of the underlying cause of any non-billable make-ready costs that have been booked to the regulatory asset. This requires separate accounting for (1) all pole capital and maintenance work required to be performed by UI in its ordinary course of business, even if performed at the time an attachment is made; and (2) all non-billable make-ready costs not

[141] Non-billable make-ready work is work to accommodate new attachments that is not charged to third parties. Id., p. 40. The Authority has adopted the FCC's distinction between billable and non-billable work. Id., p. 45. Specifically, 47 CFR § 1.1408(b) provides: "The costs of modifying a facility shall be borne by all parties that obtain access to the facility as a result of the modification and by all parties that directly benefit from the modification. Each party described in the preceding sentence shall share proportionately in the cost of the modification. A party with a preexisting attachment to the modified facility shall be deemed to directly benefit from a modification if, after receiving notification of such modification as provided in subpart J of this part, it adds to or modifies its attachment. Notwithstanding the foregoing, a party with a preexisting attachment to a pole, conduit, duct or right-of-way shall not be required to bear any of the costs of rearranging or replacing its attachment if such rearrangement or replacement is necessitated solely as a result of an additional attachment or the modification of an existing attachment sought by another party. If a party makes an attachment to the facility after the completion of the modification, such party shall share proportionately in the cost of the modification if such modification rendered possible the added attachment." 19-01-52RE01 Decision, p. 41.

performed during the normal course of business, but instead attributable to new third-party attachments.

2. All costs related to pole maintenance and capital work must indicate the specific FERC accounts to which such costs are booked, as well as the accounts to which any make-ready reimbursements are recorded.

Id.

In this case, UI requested recovery of $110,000 over a three-year amortization period. Sch. B-6.10. The Company provided the information shown in the table below in support of the costs and to meet the Authority's cost accounting requirements above.

Table 72: UI's Recorded Costs for Non-billable Make-Ready Work

Cost Description	Amount
Labor plus overheads	$ 63,664
Material	$ 44,037
Installation & Maintenance	$ 1,700
Interest	$ 425
Total	**$109,827**

Interrog. Resp. OCC-189, Att. 1.

UI also provided a description of the types of costs that might be included in the regulatory asset. Interrog. Resp. OCC-189. These costs may include work to correct existing National Electric Safety Code noncompliant conditions on a pole that are identified during the third-party attachment application process, such as raising conductors, correcting (or adding) guying, or replacing poles. Id. UI stated that it was still developing a process to track its non-billable make-ready costs. Id. UI did not associate any costs in the table above with specific causes. Id., Att. 1.

The Company subsequently stated that since its process for tracking non-billable make-ready costs is not complete, it is withdrawing the request for recovery in this proceeding. Late Filed Ex. 1, p. 2. The Company plans to seek recovery of these costs in its next base distribution rate case. Id.

The Authority finds that UI has not complied with the reporting requirements for seeking recovery of non-billable make-ready costs in the regulatory asset. The Company did not provide a separate accounting for non-billable and billable make-ready costs, nor did it provide records demonstrating the specific cause of those costs. Interrog. Resp. OCC-189. The Company did not indicate the appropriate FERC accounts to which it is recording the costs. Id. As such, the Authority is unable to determine whether these costs were appropriately classified as non-billable. Accordingly, the Authority disallows the entire $109,827 of costs booked to the regulatory asset.

The Authority also discontinues the use of a regulatory asset for the purposes of recording non-billable make-ready costs. UI has had an appropriate opportunity to recover its reasonably and prudently-incurred costs. Further, the regulatory asset was established as a stopgap to manage an anticipated large volume of attachments. 19-01-

52RE01 Decision, p. 45. According to UI's own testimony, anticipated large volumes of third-party pole attachment requests have not materialized. Hr'g Tr., 574:24-575:1. Moreover, the Authority authorizes eight new pole attachment FTEs in Section VI.A.2., Full Time Equivalent (FTE) Compensation, of this Decision. Thus, circumstances no longer warrant the use of a regulatory asset for recovery of non-billable make-ready costs and, therefore, the Company may not seek recovery of non-billable make-ready costs through a regulatory asset in the next rate case.

9. Rate Case Expense

The Company requests recovery of $1.523 million in expenses, amortized over three years in connection with the present rate case. Late Filed Ex. 1, Att. 1, Sch. WP C-3.30, p. 2. The expenses are labeled as outside labor expenses, which encompass legal and consulting expenses. Id. The Company further states that it is not proposing recovery of the expenses it incurred to attend and participate in the rate case. UI Brief, pp. 183-84. The Authority concludes that UI failed to sustain its burden that the outside labor expenses were reasonable and prudent; further, even if the Company had met its burden, the requested rate case expenses are barred from recovery under Conn. Gen. Stat. § 16-243p(b).

In its brief, the Company relies on its responses to several interrogatories to justify recovery for its rate case expenses. UI Brief, pp. 183-84; Interrog. Resp. EOE-98, Att. 1; Interrog. Resp. RRU-273 UI Att. 1. However, UI's responses contain no information explaining why such costs were reasonable and prudent, nor do they articulate any associated benefit to ratepayers. For example, UI asserts that each scope of work for external counsel and consultants was performed under a Company-approved purchase order and that it provided "details of each line item, including the parties [it hired]." UI Brief, p. 183; Interrog. Resp. EOE-98, Att. 1. However, the Company merely identifies the costs associated with each outside vendor and summarily asserts that, because it obtained a purchase order based on its own processes, the expenses must be reasonable and prudent. In another response, the Company compares its outside expenses approved in the 2016 Rate Case with its requested expenditures in this rate case but, despite asserting in its brief that its costs are "generally in line with the estimate included in the 2016 UI Rate Case," fails to justify several new line items added for the current rate case and an over $270,000 variance between its projected expenses in Docket No. 16-06-04 and the present case. UI Brief, p. 184; Interrog. Resp. RRU-0273 Att. 1.

The information discussed above provides no basis for the Authority to determine whether the expenses were reasonably and prudently incurred. For instance, the Authority cannot determine what the Company's justification was for selecting each vendor nor can it assess whether the staffing levels and hourly rates for the outside law firm and advisors is comparable to other vendors or is similar to what has recently been approved in similarly complex rate proceedings. Furthermore, the Company fails to provide any explanation for how the expenses benefit ratepayers. The lawyers and consultants retained for this matter advocated on behalf of the company, not ratepayers. Therefore, the Authority concludes UI failed to sustain its burden that its rate case expenses were reasonable and prudent.

Further, even if the Authority concluded that such expenses were reasonable and prudent, UI's rate case expenses are not recoverable from ratepayers under Conn. Gen.

Stat. § 16-243p(b). Whether Conn. Gen. Stat. § 16-243p(b) prohibits recovery for UI's rate case expenses is a matter of statutory interpretation; the Authority is bound by the plain meaning rule articulated in Conn. Gen. Stat. § 1-2z. "The meaning of a statute shall, in the first instance, be ascertained from the text of the statute itself and its relationship to other statutes. If, after examining such text and considering such relationship, the meaning of such text is plain and unambiguous and does not yield absurd or unworkable results, extratextual evidence of the meaning of the statute shall not be considered." Id. Additionally, the words and phrases in a statute must be construed according to the commonly approved usage of the language. Conn. Gen. Stat. § 1-1(a).

Conn. Gen. Stat. § 16-243p(b), as amended by Public Act 20-5 (P.A. 20-5) states that "[n]o electric distribution company shall recover its costs associated with attending or participating in a rate-making hearing before the Authority." The Authority requested pre-hearing briefs from Parties and Intervenors asking, in relevant part, whether P.A. 20-5 precludes UI from recovering from ratepayers all of its costs associated with this proceeding. All parties submitting briefs, in applying the plain meaning rule, concluded that the statute was clear and unambiguous, but reached drastically different conclusions.

EOE concluded that the statute's plain language precludes UI from recovering any rate case expenses under the statute, noting that the phrase "associated with" in the statute unambiguously applies broadly to the costs "related, connected, or combined together," with UI's participation and attendance at a rate case hearing. EOE Pre-Hr'g Brief, p. 2. OCC concurred with EOE's reasoning, concluding that the phrase "costs associated with. . . participation," includes the Company's preparation costs for the rate case hearing because UI would not be able to meaningfully participate in the hearings without preparation. OCC Brief, p. 37. Conversely, UI concluded that the plain and unambiguous language in the statute precludes recovery only for the Company's expense for attending and participating in the hearing and does not preclude recovery of "the balance of its rate case expense." UI Pre-Hr'g Brief, p. 10. The Company primarily focused on the definition of a "hearing" in its analysis, noting that a hearing is a distinct element of the adjudicatory process and that the Company may recover expenses other than those for attending and participating in a rate-making hearing." Id., pp. 9-10.

The Authority concludes that Conn. Gen. Stat. § 16-243p(b) is plain and unambiguous and precludes UI from recovering any rate case expenses under the statute. A "hearing" is not defined in either Title 16 or the Uniform Administrative Procedures Act (UAPA), but rather, as UI notes in its prehearing brief, the Connecticut Supreme Court has previously held that the term "hearing" has been "defined variously" as an "opportunity to be heard," a "session, as of an investigatory committee, at which testimony is taken from witnesses," or as "an instance or a session in which testimony and arguments are presented, [especially] before an official, [such] as a judge in a [legal action]." City of Meriden v. Freedom of Information Comm., 338 Conn. 310, 323 (2021). Further, Title 16 does not define the term "associated with,"[142] nor does it provide a list of

[142] UI's statutory analysis does not address the phrase "associated with" contained in Conn. Gen. Stat. § 16-243p(b), contrary to well-established cannons of statutory interpretation. "In construing statutes, we presume that there is a purpose behind every sentence, clause, or phrase used in an act and that no part of a statute is superfluous. . . . Because every word and phrase of a statute is presumed to have

what costs may be associated with rate-making hearings. The phrase, however, is commonly understood to mean "related, connected, or combined together."[143] Therefore, the Authority must consider what expenses are related to, connected to, or combined together with attending or participating in a rate-making hearing.

In the present case, the Authority held both public comment hearings and evidentiary hearings regarding UI's rate application. See Notice of Public Comment Hearing, Sep. 23, 2022; Revised Notice of Evidentiary Hearings, March 2, 2023. As the party with the burden of proof in this proceeding, the Company's Application contained documentary evidence, including testimony and models from internal UI staff, outside experts, and outside legal counsel. These materials were subject to scrutiny and subsequent discovery by the Authority and all Parties and Intervenors. In total, UI's Application and supporting materials, including discovery responses, were subject to cross examination at the evidentiary hearings in this matter and were germane to UI's participation in the rate-making hearings. Further, the Company's late filed exhibits were similarly subject to cross examination and the Company's briefs were utilized as a tool to summarize the Company's position on materials in the record emanating from the hearing. As such, the entirety of the Company's rate case expenses is barred from recovery under Conn. Gen. Stat. § 16-243p(b) because they are connected or related to the Company's participation or attendance at PURA's rate-making hearings.

Additionally, even if the language in Conn. Gen. Stat. § 16-243p(b) was ambiguous, the legislative record for P.A. 20-5 demonstrates that the General Assembly intended to disallow recovery for all rate case expenses, especially external legal and consulting fees. In response to a question regarding whether P.A. 20-5 prohibited the EDCs from recovering their costs from ratepayers for attending a ratemaking hearing, Representative Arconti stated:

> Currently their various attorneys, consultants, a utility would [hire] to participate in a rate making docket or proceeding. Those are currently cost recoverable that they can see cost recovery through utility bills so this, I look at it as [the] cost of doing business. I feel that should come from the utility shareholders or profits and that's what this Section would do if we were to pass it here tonight.

Rep. Arconti Test., Sept. 29. 2020 House of Reps. Special Session, p. 1405. Furthermore, Senator Needleman offered the following remarks when discussing P.A. 20-5:

> Section 8 [of P.A. 20-5] prohibits the electric distribution companies from recovery [of] costs associated with attending and participating in rate-making proceedings at PURA from ratepayers. Utilities employ all kinds of

meaning . . . a statute must be construed, if possible, such that no clause, sentence or word shall be void, or insignificant." (Brackets omitted), Lopa v. Brinker Intern, Inc., 296 Conn. 426, 433 (2010), quoting PJM & Associates, LC v. Bridgeport, 292 Conn. 125, 138 (2009).

[143] "Associated." Merriam-Webster.com (May 15, 2023). Courts ordinarily look to the dictionary definition of a word to ascertain its commonly approved usage. Redding Life Care, LLC v. Town of Redding, 331 Conn. 711, 718 (2019).

> costly experts to advocate for rate cases at PURA, including lawyers, accountants, engineers, rate specialists, and other highly paid consultants. Utilities currently recover these costs associated with proceedings in which they demand more money from ratepayers and presently, the only way PURA can disallow this is by a legal finding that the costs were unjustified, which can be challenged on appeal by the utilities.

Sen. Needleman Test., Oct. 1, 2020, Senate Special Session, p. 986. Additionally, on June 25, 2023, the General Assembly passed Senate Bill 7, An Act Strengthening Protections for Connecticut's Consumers of Energy (SB 7), which, in relevant part, amended Conn. Gen. Stat. § 16-243p(b) to clarify that all EDC rate case expenses are barred from recovery from ratepayers. Indeed, the State Senate, when discussing SB7 engaged in the following exchange:

> I'm looking at section 118, specifically the addition of the effective date of January 1, 2024, and I'm trying to understand if that is intended to do anything to disturb the underlying statute or PURA's inherent authority. As you know, we first codified this provision in the Take Back Our Grid Act for electric utilities, which is clarified and captures the original legislative intent in SB7. Also in SB7, we are expanding the existing provision to other utility sectors, which I gather is now effective January 1, 2024. However, PURA has the inherent authority to deny cost recovery for any cost that is not prudently or reasonably incurred, which has happened recently in rate cases. So my question is, does pushing the effective date to January 1, 2024 disturb the status quo in any way?
>
> No. Pushing the effective date to January 1, 2024, does not disturb PURA's existing authority.

(emphasis added) Sen. Needleman Test. June 6, 2023, Senate Session, p. 77.

The relevant portion of SB 7 was effective upon passage, which was after UI's Application was before the Authority; however, the above-cited legislative history makes clear that the General Assembly in considering the legislation merely sought to clarify its intent regarding Conn. Gen. Stat. § 16-243p(b) and to further expand the scope of the statute to all public service companies. As such, the Authority may retroactively apply the clarifications in SB 7 to the present case. See Town of Middlebury v. Dept. of Environmental Protection, 283 Conn. 156, 173 (2007), quoting Bhinder v. Sun Co., 263 Conn. 358, 368-69 (2003) ("an amendment that is intended to clarify the intent of an earlier act necessarily has retroactive effect.")

Therefore, even if Conn. Gen. Stat. § 16-243p(b) was ambiguous and required the Authority to consider extratextual evidence to discern the statute's meeting, PURA must still conclude that the statute bars recovery of UI's rate case expenses, particularly the outside legal, consultant, and other expenses it seeks recovery of in the present case.

Accordingly, the Authority denies the Company's request to recover $1.523 million in rate case expenses.[144]

D. TAXES

1. Payroll Taxes

The Authority disallows $0.502 million of the Company's proposed payroll tax expense to reflect reductions to compensation related expenses that are discussed in more detail in the applicable sections.

UI proposed $5.921 million for payroll tax expense for Rate Year 2023/2024. Late Filed Ex. 1, Att. 1, Sch. WPC-3.31. The table below summarizes the Authority's disallowances to payroll related expenses.

Table 73: Disallowed Payroll-Related Expenses

Payroll-Related Expenses	Amount Disallowed ($)
FTE Reductions	4,715,000
Incentive Compensations	1,495,000
Executive Compensations	349,645
Total Reductions	**6,559,645**

As a result of the approximately $6.560 million reductions to the payroll related expenses as shown above, the Authority reduces the Company's proposed payroll tax expense by $501,813 ($6,559,645 x 7.65%). Thus, the Authority allows payroll tax expense of $5.419 ($5.921-$0.502) million.

2. Gross Earnings Tax

The Authority disallows $6.375 million of the Company's proposed GET expense to reflect reductions to certain components of the Company's proposed revenue requirement as discussed in more detail in the applicable sections.

UI proposed $25.037 million for GET expense for Rate Year 2023/2024 based on current revenue. Late Filed Ex. 1, Att. 1, Sch. WPC-3.31. The Company increased the GET expense proposed for the rate year by $6.466 million based on the $91.055 million additional revenue requested for the rate year. Late Filed Ex. 1, Att. 1, Sch. A-1.0A and Sch. C-1.0A. Thus, UI proposed $31.503 million ($25.037 + $6.466) as the total GET expense for the rate year. The Company proposed GET expense based on a weighted GET expense rate of 7.1012%. Late Filed Ex. 1, Att. 1, Sch. A-3.0A. UI reported $368.660 million as the total revenue at current rates. Late Filed Ex. 1, Att. 1, Sch. WPC-3.0A. Thus, the Company proposed $459.715 million ($368.660 + $91.055) as the total revenue for the rate year.

As discussed in Section VI.A.18., Uncollectible Expense, the Authority finds that UI used the originally proposed uncollectible rate of 1.36% to determine the $91.055 million incremental revenue for the rate year. See Late Filed Ex. 1, Att. 1, Sch. A-3.0A, p. 2. The Authority determines that using the updated 0.900% uncollectible rate

[144] The Authority notes that the Company appears to have foregone a request to recover consultant expenses incurred by PURA and the OCC in this proceeding pursuant to Conn. Gen. Stat. § 16-18a(a).

generates total additional revenue of $90.610 million. Thus, the correct incremental GET expense is $6.434 million (90.610 x 7.1012%). Therefore, the Authority reduces the additional GET expense that the Company proposed for the rate year by $0.032 million ($6.466 - $6.434).

The Authority also reduces the Company's present rate revenue by $6.751 million and disallows the associated GET expense of $0.479 million. Additionally, the Authority reduces the incremental revenue requested for the rate year by $68.098 million and reduces the related GET expense by $4.836 million. The table below summarizes the $5.347 million reduction to the Company's proposed GET expense. Inclusive of these reductions, the Authority allows $26.156 million ($31.503 - $5.347) as the GET expense for Rate Year 2023/2024.

Table 74: Summary of Adjustments to GET Expense ($000)

Items Adjusted	**Amount**
Incorrect Uncollectible Rate	32
Present Rate Revenue	479
Total Allowed Revenue	4,836
Total GET Expense Adjustment	**5,347**

3. Municipal Property Taxes

The Company proposed in this proceeding a Rate Year 2023/2024 Distribution Property Tax Expense of $36.101 million. Late Filed Ex. 1, Att. 1., Sch. WPC-3.31. UI's proposed property tax expense of $36.101 million is significantly higher than the pro forma test period property tax expense of $29.739 million. Id. One reason for this increase is that UI is seeking recovery of $2.246 million related to projected additional property tax on net plant additions. Id., Sch. WPC-3.31a. Since the Authority is disallowing net plant additions after the Application date for the reasons discussed previously, any incremental property tax expense related to these net plant additions must also be removed from the calculation of rates.

In order to remove this activity from the property tax expense embedded in the Company's filing, the Authority began by reviewing and segmenting each line item on the applicable Company schedule (i.e., Late Filed Ex. 1, Att. 1, Sch. WPC-3.31a). Activity that occurred prior to the Application date was allowed, while activity that occurred after the Application date was disallowed. For any activity in which the date range included the month the Application was filed (i.e., September 2022), the Authority prorated this activity to include only 30% of this month (since the Application was made on the ninth day of September).

As illustrated in the table below, this calculation resulted in a downward adjustment to the property tax expense of $1.048 million.

Table 75: Property Tax Adjustment ($000s)

	Proposed	Allowed	Modification*
Additional Distribution Property Taxes on Net Additions	2,246	1,197	(1,048)

Late Filed Ex. 1, Sch. C-3.31a.
*Numbers do not sum due to rounding

Consequently, the Authority allows municipal property tax expense of $35.053 million ($36.101 - $1.048) for Rate Year 2023/2024.

4. State Income Tax

The Authority disallows $3.263 million of the Company's proposed State Income Tax (SIT) expense to reflect adjustments to both the current and proposed revenues and expenses as discussed in more detail in the applicable sections.

UI reported net SIT expense of negative $1.754 million based on the operating income at current rates. Late Filed Ex. 1 Att. Sch. WPC-3.32, p. 2. Based on the additional revenue proposed for the rate year, the Company requested $22.769 million as additional income tax expense for Rate Year 2023/2024. Late Filed Ex. 1, Att. Sch. C-1.0A. The composite income tax rate is 26.925% and the proposed SIT rate is 7.5%. Late Filed Ex. 1, Att. Sch. A-2.0A. Thus, the additional SIT expense proposed for the rate year is $6.342 million ($22.769 million x [7.5% / 26.925%]). Consequently, the total SIT expense proposed for the rate year is $4.588 million ($6.342 - $1.754).

The Authority makes tax-impacted adjustments to the Application in this Decision, which totaled $19.137 million. This amount is multiplied by 7.5% to increase SIT expense based on the adjusted current operating income by about $1.435 million. Moreover, the Authority reduces the Company's proposed additional revenue by $68.098 million, which is approximately equivalent to the $45.781 million disallowed operating income multiplied by the 1.48747 gross revenue conversion factor (GRCF). To remove the effect of uncollectible and GET expenses, the SIT rate is reduced to 6.8999%, which is 7.5% multiplied by 91.9988%, the inverse of the O&M conversion factor of 1.08697. As a result, the Authority reduces SIT expense related to the Company's proposed additional revenue by approximately $4.698 million ($68.098 x 6.8999%). Consequently, the Authority reduces the total SIT expense by $3.263 million ($4.698 - $1.435) for the rate year. As a result, the Authority allows SIT expense of approximately $1.325 million ($4.588- $3.263) for the rate year.

5. Federal Income Tax

The Authority disallows $8.453 million of the Company's proposed Federal Income Tax (FIT) expense to reflect adjustments to both the current and proposed revenues and expenses as discussed in more detail in the applicable sections.

UI reported net FIT expense of $2.912 million based on the operating income at current rates. Late Filed Ex. 1, Att. 1, Sch. WPC-3.32, p. 2. Based on the additional revenue proposed for the rate year, the Company requested $22.769 million as additional income tax expense for the rate year. Late Filed Ex. 1, Att. Sch. 1, C-1.0A. Thus, the

additional FIT expense proposed for the rate year is $16.427 million, which is $22.769 less $6.342 million, the proposed SIT expense discussed above. Accordingly, the total net FIT expense proposed for the rate year is approximately $19.338 million ($2.912 + $16.427).

The Authority makes tax-impacted adjustments in this Decision totaling $17.702 million ($19.139 - $1.435) to the Application, which is multiplied by 21% to increase the FIT expense based on the adjusted current operating income by $3.717 million. Moreover, the Authority reduces the Company's proposed additional revenue by $68.098 million, which equals the $45.781 million disallowed operating income multiplied by 1.48747 GRCF. To remove the effect of uncollectible, GET, and SIT expenses, the effective FIT rate is 17.8708%, which is 21% multiplied by 85.0989%, which itself is 91.9988% less 6.8999%. Both rates are discussed in the SIT section above. As a result, the Authority reduces FIT expense related to the Company's proposed additional revenue by $12.170 million ($68.098 x 17.8708%). Consequently, the Authority reduces the total FIT expense by approximately $8.453 million ($12.170 - $3.717 for the rate year. As a result, the Authority allows FIT expense of approximately $10.885 million ($19.338 - $8.453) for the rate year.

6. Interest Synchronization

The Authority makes $4.818 million interest synchronization adjustments in the calculation of the allowed income tax to reflect the allowed rate base and weighted cost of LTD as discussed herein.

As discussed in Section V.C.3., Capital Structure Analysis, due to the adjustments to the Company's proposed capital structure, UI's proposed weighted cost of LTD of 2.0736% is increased by 0.0864% to 2.16%. Based on the Company's proposed average rate base of $1.384 billion, the interest expense is increased by $1.196 million ($1.384 billion*0.0864%). Moreover, in Section IV., Rate Base, the Authority reduces the Company's proposed rate base by $278.412 million; thus, the allowed interest expense is reduced by $6.014 million ($278.412 million x 2.16%). Consequently, the Company's proposed interest expense for calculating income tax expense is reduced by approximately $4.818 ($6.014- $1.196) million.

7. Provision for Deferred Income Tax

The Authority increases the provision for deferred income tax by $2.703 million to reflect the reduction to depreciation expense. As discussed in Section VI.B., Depreciation Expense, the Authority reduces the Company's proposed depreciation expense by $10.040 million. Using the composite income tax rate of 26.925%, the Authority calculates the deferred tax effect of $2.703 million ($10.040 million x 26.925%).

8. Connecticut Investment Tax Credit

The Authority increases the allowed revenue requirement by Connecticut Investment Tax Credit (CT ITC) of approximately $1.762 million as a result of disallowance of the gross plant additions proposed for the Rate Year.

The Company reduced the CT income tax expense proposed for the Rate Year by $2.230 million CT ITC. Late Filed Ex. 1, Att. 1, Sch. WPC-3.32, p. 2. The $2.230 million

CT ITC was calculated based on the monthly capital expenditures proposed for the Rate Year. Late Filed Ex. 1, Att. 2, "DIT" Worksheet.

Based on the disallowance of the plant additions proposed for the Rate Year, Authority will remove the CT ITC credit of $1.762 [$2.230x(1-0.210)] million. The allowed amount is 79% of $2.230 million to reflect the removal of the 21% effect of FIT related to SIT deductions.

E. REVENUE DECOUPLING

In the instant Decision, the Authority: (1) denies UI's request to add carrying charges to the Revenue Decoupling Mechanism (RDM); (2) accepts a modified version of UI's proposed list of revenue elements to be included in the decoupling true-up; and (3) refers the allocation of RAM component costs among different rate classes for further consideration in the current RAM filing.

Under the approved RDM, UI is authorized to perform an annual "true up" to reconcile actual revenues to revenues authorized in the Company's previous rate case, collecting additional revenues as necessary to make up for any shortfalls in the previous year or conversely, crediting UI ratepayers if actual revenues exceed allowed revenues.

1. Carrying Costs

In its latest filing, UI proposed to include "carrying costs" (i.e., interest charged on under collections until they are trued-up) in its calculation of RDM over- or under-collection amounts. Application, Ex. MP-1, p. 18. The Authority declines UI's proposal since it has not articulated a compelling reason to include carrying charges in the RDM, which would constitute a departure from past precedent.

The Authority has previously declined to include carrying charges in the RDM. 22-01-04 Decision, pp. 16-17; Docket No. 16-06-04, Motion No. 53 Ruling, Apr. 1, 2020.[145]

Nonetheless, UI argues that because all other accounts included in the annual RAM filing include carrying charges, it is "reasonable for the RDM balances . . . to have carrying charges applied." UI Interrog. Resp. OCC-282A. The Company offers no further support to justify its request. OCC Brief, pp. 48-49.

The Authority denies UI's request to add carrying charges to the decoupling rider, as the Company failed to provide sufficient justification for why the RDM should include carrying charges, particularly as carrying charges were never intended as part of the structure of the rider. The mere fact that the decoupling rider is trued up in the same proceeding as a number of other charges for which carrying charges are permitted has no bearing on the appropriateness of carrying charges in the RDM and, thus, is not a justification for allowing such charges. Moreover, the RDM recovers fundamentally different costs than the other RAM components, which recover costs associated with generation, transmission, or public policy-related costs where such costs are not related

[145] The Authority allowed a narrow exception to its prohibition on carrying charges in the RDM when it directed a carrying cost credit to customers for an over-calculation related to a Company calculation error, but it reiterated that carrying charges should not otherwise be included in UI's RDM calculation. 22-01-04 Decision, pp. 16-17.

to the Company's core business and, thus, the Company is simply acting as a pass-through entity. The Authority allows carrying charges on under- and over-collections related to these charges due to the pass-through nature of the charges.

2. Other Revenues

The Authority accepts a revised version of the list of "other revenues" that may be excluded from the calculation of revenues for the purposes of the RDM true-up, as shown in the table below, noting that any revenues not specifically identified as being appropriate for exclusion should be included. The Authority approves the exclusion of only those revenues that can be shown to be reconciled in another true-up mechanism, to avoid double-counting revenues.

UI proposes a list of "other" revenues that will be included in calculating total revenues for purposes of the decoupling mechanism true-up and, by implication, certain sources of revenue that will not be included. Total revenues to be included are valued at approximately $18.4 million for 2021. Total revenues that would be excluded are estimated at an annual value of approximately $25 million.

UI proposes to include a number of sources of revenue that collectively were worth approximately $18.4 million in 2021 as "revenue" for the purposes of the RDM true up. These included sources are described in the following table below:

Table 76: UI Proposed Other Revenue Categories - Included in the RDM ($000)

Revenue Category:	**2021 Amount**
Late Payment Charges	(127)
Rent from Electric Property	2,124
Revenue Decoupling	10,350
Water Heater and Surge Protector Lease Programs	1,416
Demand Ratchet Waiver	226
Distributed Generation (DG) Programs	37
Miscellaneous Other Electric Rev	446
Company Use Revenue	2,579
Third Party Damages	258
Rent Credits	1,077
Total:	**$18,388**

UI Interrog. Resp. OCC 281, Att. 1.

UI proposes to exclude from the RDM reconciliation sources of revenue estimated collectively, by the Authority, at an annual value of approximately $24.9 million. These excluded sources are shown in the following table.

Table 77: UI Proposed Other Revenue Categories – Excluded from the RDM

Revenue Category:	Most Recent Amount where data provided ($000s)	Year	Description (UI-provided)
Intercompany	8,380	2020	Mutual Aid
Returned check fees	221	2021	
Interdepartmental revenues	541	2021	Included in base delivery
GenConn revenues	594	2021	GenConn revenues
Reconnection Fees	108	2021	Reflected as reduction to expense in C-3.21 Reconnection fees
CLM Revenues	1,002	2021	Reconciled through CLM
SBC Revenues	(3)	2021	Reconciled through SBC
Earnings Sharing Giveback	(5,045)	2021	Offset in regulatory amortizations
GSC Revenues	(38)	2021	Reconciled through GSC
Transmission revenues	(2)	2021	Reconciled through TAC
Regulatory amortizations	13,340	2021	
Regulatory deferrals	5,827	2021	
Total	**$24,925**		

UI Interrog. Resp. OCC-281, Att. 1.

The Company, however, submitted minimal evidence in the record to justify its proposal that the identified revenue sources should be excluded from the RDM reconciliation.[146] Notably, in Docket No. 22-01-04, the Authority explicitly denied UI's proposal to exclude income from certain accounts from consideration as part of actual distribution revenues, instead determining that any revenues not reconcilable in other true-up mechanisms should be included in the total actual distribution revenue for the RDM calculation. 22-01-04 Decision, p. 31. Given the sparse evidence in the record, the Authority must resort to its accounting expertise and, namely, several principles of utility accounting; specifically, that revenues should be recognized in the year in which they are received, that all revenues should be recognized, and that only revenues already included in a separate true-up mechanism[147] should be excluded from consideration as revenues for the purposes of the RDM true-up. Applying these principles, the Authority finds that the revenues proposed for exclusion by UI should be included or excluded as shown in the table below.

[146] For instance, in its Written Exceptions, besides citing to RRU-450 for the proposition that UI acted as a "pass-through" entity between UIL and GenConn, the Company relies on interrogatory responses submitted outside of the evidentiary record in this proceeding. UI Written Exceptions, p. 132 (citing to Interrogatory Responses in Docket No. 23-01-04).

[147] For RAM components, elements calculated as revenues should be actual revenues and not distribution expense offsets related to A&G and O&M expenses allocated to the RAM components.

Table 78: Inclusion / Exclusion of Other Revenue Categories in RDM

Category	Include / Exclude from Revenue for RDM	Note
Intercompany	Include	Mutual Aid revenues are revenues and should be counted.
Returned check fees	Include	These are revenues and should be counted.
Interdepartmental revenues	Include, with possible exceptions	These revenues should be counted, and any associated expenses should be so shown.
GenConn revenues	Include	Revenues.
Reconnection Fees	Include	Revenues.
CLM Revenues	Exclude	These are trued-up under a different mechanism.
SBC Revenues	Exclude	These are trued-up under a different mechanism
Earnings Sharing Giveback	Include	These revenues should be recognized and, if necessary, offsets should be recognized as expenses.
GSC Revenues	Exclude	These are trued-up under a different mechanism.
Transmission revenues	Exclude	These are trued-up under a different mechanism.
Regulatory amortizations	Include in year revenue is realized	Revenue should be recognized in the year received.
Regulatory deferrals	Include in year revenue is realized	Revenue should be recognized in the year received.

As discussed below, the Authority refers some questions about the allocation of RAM component costs among different rate classes for further consideration in its annual RAM proceedings.[148] The RDM is one of an array of revenue collection mechanisms collectively referred to as RAMs. An issue raised by CIEC witness Baudino pertains to how revenue adjustment mechanisms that are implemented through volumetric rate adders impact different classes of customers. Baudino asserts:

> *Because volumetric surcharges collect funds strictly based on usage, they impose an inordinate and unfair cost burden on high load factor customers, especially large commercial and industrial customers, even if they are using the system more efficiently than most customers. Moreover, while surcharges often are represented to be small their volumetric design means that individually they are large for high-usage customers and cumulatively can be devastating.*

[148] The Authority's annual UI RAM proceedings are docketed as XX-01-04, with the "XX" representing the year. For example, the 2024 UI RAM proceeding will be docketed as Docket No. 24-01-04.

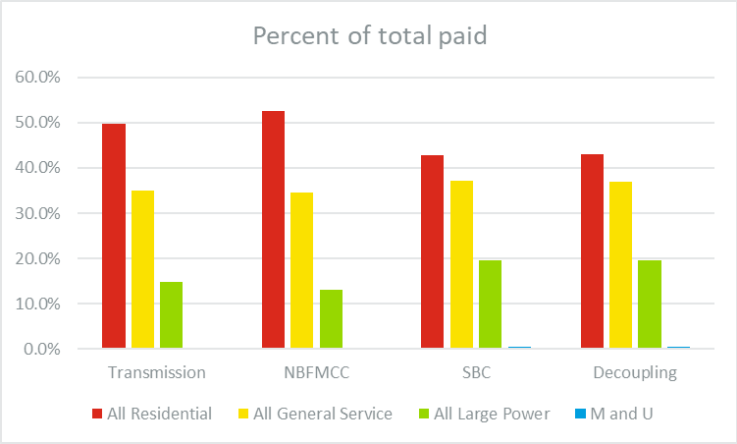
Baudino Prefiled Test., Dec. 13, 2022, p. 22. In light of this concern raised by CIEC, the Authority undertook an initial examination of how four RAM charges are allocated among different rate classes. (This analysis did not include Bypassable Federally Mandated Congestion Charges in this review, since, as stated in the 22-01-04 Decision, these are already limited to standard service and last resort services customers and are typically very small). 22-01-04 Decision, p. 31. The charges examined are summarized in the table below.

Table 79: Selected RAM Charges and Related Costs

Charge	Related costs	Assessment method
Non-Bypassable Federally Mandated Congestion Charge (NBFMCC)	ISO-NE ancillary services and support for renewable energy	Hybrid volumetric and demand
Transmission Adjustment Clause (TAC)	Network service costs, ISONE scheduling and dispatch, Hydro-Quebec, and Gross Earnings Tax	Hybrid volumetric and demand
Systems Benefits Charge (SBC)	Various program costs related to assistance for low-income customers	Straight volumetric
Revenue Decoupling Mechanism (RDC)	True-up to collect authorized revenue amount	Straight volumetric

The graph below shows the percentage of revenue requirement to be collected from each of three major customer categories (residential, general service, and large power) for the TAC, NBFMCC, SBC, and RDM. Large Power and General Service pay a larger share of costs for the two charges (SBC and RDM) collected on a flat per-kWh basis.

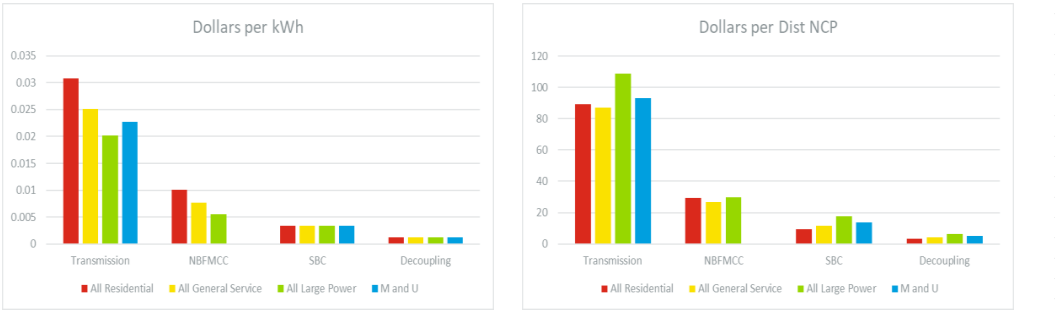
Figure 4: Comparison of share of revenue requirements allocated to the TAC, NBFMCC, SBC, and RDM[149]



[149] Analysis based on data referenced in UI Interrog. Resp. RRU-501.

The reason for the variance is the difference in load factor; on average, general service and large power customers use more kWh per unit of demand. The figure below shows a side-by-side comparison of how the distribution of costs among different rate groups compares, depending on whether these costs are considered on a per kWh usage basis or on a per kW, non-coincident peak (NCP) demand basis.

Figure 5: Comparison by Rate Group (kWh vs. NCP)[150]



The Authority takes no action on the issue raised by Baudino at this time; however, further examination of the appropriateness of flat volumetric charges for the collection of SBC and RDM revenues may be appropriate in Docket No. 24-01-04 or a subsequent RAM proceeding.

3. Late Payment Fees

The Company submitted other distribution revenues in Rate Year 2023/2024 for late payment fees of $4.318 million for the Test Year pro forma and $4.795 million proposed revenues, respectively. Application, Sch. WP C-3.01; see also Late Filed Ex. 1, Att. 1. The Authority determines that the revenues obtained from late payment fees are additional revenues that extend beyond the Company's allowed revenue requirement and should be removed from base rates. In terms of other proposed distribution revenues, the Authority directs UI to remove the proposed other revenues of $4.795 million for late payment fees. The reduction of the late payment fee reduces the pro forma other revenues for Rate Year 2023/2024 as follows: $21.891 million - $4.795 million = $17.096 million. Id. Furthermore, the Authority directs the Company to include the 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.

4. Reconnect Service Fees

The Authority determines that the Reconnect Service Fees (RSF) should be reported and included in "Other Operating" revenue and not as an offset to the O&M expense. Thus, the Company's proposed O&M expense for Rate Year 2023/2024 should be increased by $1.015 million.

The Company proposed a Reconnect Service Fee (RSF) expense of negative $1.015 million. Late Filed Ex. 1, Att. 1, Sch. C-3.21 WP. UI noted that the proposed RSF is based on a historical pre-pandemic three-year average of the number of disconnects for non-payment (DNPs) and the percentage of paid reconnections. Also, the Company

[150] Analysis based on data detailed in UI Interrog. Resp. RRU-501.

indicated that RSF is recorded on its books as an offset to O&M expense. Id. The Company asserts that its proposal to treat RSF as an offset to O&M expense, instead of reporting it in other revenues, is consistent with the approach approved by the Authority in the 2016 Rate Case Decision. Interrog. Resp. OCC-548.

The Authority has expressed its growing concern with certain distribution revenues that the Company included or excluded from actual annual revenues subject to the decoupling reconciliation in the years since the 2016 Rate Case Decision. More specifically, the Authority directed UI to adjust the actual 2021 distribution revenue to include other operating revenues that the Company had excluded. 22-01-04 Decision, pp. 21-27. In a response to inquiry in the instant proceeding, UI provided an exhibit where the RSF is reported as a component of "Other Operating Revenues" instead of as an offset to O&M expense. Interrog. Resp. RRU-68, Att. 1. To foster a more transparent presentation of revenues in the annual RDM reconciliation proceedings, the Authority directs UI to report RSF as part of other operating income instead of as an offset to operating expenses. Such a clear exhibit will distinctly enumerate revenue items that should be included in the annual RDM reconciliation. Also, it minimizes the confusion associated with revenue components that were previously used to reduce or offset O&M expenses. Revenues that the Company received for services provided or consumed should be clearly identified as such as part of the "Other Operating Revenues."

The Authority increases the Company's proposed O&M expense by $1.015 million to remove the RSF as an offsetting credit to the O&M expense and directs UI to record it as a component of other operating revenue.

VII. CLEAN ENERGY TRANSITION PROPOSALS

The Authority discusses the various proposals brought forward by the clean energy transition panel in the below section. Expenses associated with these proposals were not included by the Company in its requested Rate Year 2023/2024 revenue requirement. As such, any disallowances do not require an adjustment to the allowable expenses authorized by the Authority and summarized in Section VI.A.1., Summary. Such disallowances are also not authorized or intended to be included in the Rate Year 2023/2024 revenue requirement summarized in Section VIII., Approved Revenue Requirement.

A. MEDIUM- AND HEAVY-DUTY VEHICLE MAKE-READY PROGRAM

In the Application, UI proposed to establish a make-ready incentive program for MHD EV chargers. King, et al., Prefiled Test., Sept. 9, 2022 (King PFT), p. 10. The proposal was modeled off the existing light-duty (LD) EV Charging Program, as established in the EV Decision. See Decision, July 14, 2021, Docket No. 17-12-03RE04, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Zero Emission Vehicles. As in the LD EV Program, the Company proposed specific incentive levels for Level 2 EVSE and direct-current fast chargers (DCFCs). King PFT, p. 11:2-5. Specifically, UI proposed to provide, per plug, up to $6,000 in incentives toward Level 2 EVSEs and related electrical infrastructure and up to $55,000 in incentives toward DCFCs and related electrical infrastructure. Id. Further, the Company proposed to cover up to 100% of any make-ready costs for public fleets and up to 50% of make-

ready costs for private fleets. Id., p. 11:7-11. The Company aims to incentivize the construction of 408 Level 2 EVSEs and 374 DCFCs that will support approximately 1,000 MHD EVs. King PFT, p. 11:5-7; King PFT, Ex. UI-CETP-2, p. 1; UI Interrog. Resp. CAE-12, Att. 1.

The Company developed such goals and incentive levels using a variety of assumptions. UI Interrog. Resp. CAE-12. First, UI based the number of MHD EVs to support on Connecticut's commitment to the Multi-State MHD Zero Emission Vehicle Memorandum of Understanding, which aims to have 30% of all new MHD vehicle sales be zero emission by 2030. Id., p. 1; King PFT, p. 8:13-16; see Multi-State Medium- and Heavy-Duty Zero-Emission Vehicle Memorandum of Understanding, updated March 29, 2022, available at: https://www.nescaum.org/documents/mhdv-zev-mou-20220329.pdf/. Further, UI assumed that 75% of the EVs would be MD and 25% would be heavy-duty (HD), and that MD EVs would rely 50% on Level 2 EVSEs and 50% on DCFCs, and HD EVs would rely 100% on DCFCs. UI Interrog. Resp. CAE-12, p. 1. To calculate the number of chargers to incentivize, UI also assumed a charger to vehicle ratio of 1:1 for MD Level 2 EVSEs, 4:1 for MD DCFCs, and 1:1 for HD DCFCs. Id., pp. 1-2. UI stated that it based its proposed incentive levels on experience implementing the LD EV Charging Program and experience at affiliate companies with transit bus make-ready programs. Id., p. 2. Finally, the Company proposed per-plug incentives, rather than per-site incentives as used in the LD EV Charging Program, to reflect the flexibility needed with varied MHD vehicle use cases in contrast to LD vehicles. UI Interrog. Resp. CAE-12, p. 2.

To support these incentives, UI proposed a total budget of $16.4 million for a three-year program, with $3.4 million in capital expenditures for utility-owned equipment and $13 million for incentives to be deferred to a regulatory asset and amortized over a 15-year period, inclusive of carrying costs.[151] Hr'g Tr. Mar. 8, 2023, 2816:14-23; UI Supp. Interrog. Resp. CAE-12, Att. 1; see also King PFT, p. 11. Specifically, the proposed $13 million in regulatory asset expenses is comprised of $10.9 million in make-ready incentives for customer-owned infrastructure, $1.4 million in program administration expenses, and over $700,000 in program marketing and outreach expenses. UI Supp. Interrog. Resp. CAE-12, Att. 1. Additionally, the Company proposed adding four FTEs in order to support this new program. King PFT, p. 16; UI Interrog. Resp. CAE-13, pp. 1-2. The proposed FTE additions include three FTEs solely dedicated to the MHD EV Program and one FTE to support all EV programs. Id. UI stated that current FTEs dedicated to supporting EV initiatives do not currently perform the roles proposed for the MHD make-ready program, and that if the MHD program were to be launched, such additional FTEs would indeed be necessary above current staff capacity. Hr'g Tr. Mar. 7, 2023, 2721:11-2723:1.

The Authority notes that there is an ongoing proceeding investigating the establishment of an MHD EV charging program in Docket No. 21-09-17, PURA

[151] The Company originally proposed a total budget of $21.6 million for a three-year MHD make-ready program, where $4.6 million would be allocated toward capital expenses and $17 million would be deferred to a regulatory asset. King et al. PFT, p. 11:14-21. However, the Company identified that the original submitted numbers were incorrect and provided the correct numbers that are reflected herein. Hr'g Tr. Mar. 7, 2023, 2641:19-25, 2643:13-19; Hr'g Tr. Mar. 8, 2023, 2816:14-23.

Investigation into Medium and Heavy-Duty Electric Vehicle Charging (MHD Investigation). This proceeding has been ongoing since October 2021. See Notice of Proceeding, Oct. 4, 2021, MHD Investigation. As such, that proceeding has a number of involved stakeholders that have not been notified of UI's submission here regarding its MHD make-ready program proposal. Furthermore, as the Company states, MHD EV use cases are much more varied than LD EVs, and therefore require thoughtful discussion amongst stakeholders in order to create an effective program. As a result, Docket No. 21-09-17 is the appropriate arena in which to discuss any proposals related to MHD EV charging, including UI's proposal here.

Accordingly, the Authority denies UI's proposal for a MHD EV make-ready incentive program and directs the Company to submit any related proposals in Docket No. 21-09-17, PURA Investigation into Medium and Heavy-Duty Electric Vehicle Charging.

B. MUNICIPAL CURBSIDE EV CHARGING PILOT

UI proposed a municipal curbside EV charging pilot program in the instant proceeding. King PFT, pp. 12, 13:9. As proposed, the program would provide accessible EV charging infrastructure for EV owners that are "garage orphans," (i.e., do not have a designated location in which to charge their vehicle). Id. The Company opined that if a customer does not have a dedicated residential charging location, they will likely have to pay a premium for charging at public and retail charging stations that need to recoup a profit above the cost of energy. Id., p. 12; King PFT, Ex. UI-CETP-3, p. 1. In contrast, residential single-family home EV owners need only pay for the cost of energy consumed when charging their vehicles at home. Id. Therefore, this pilot program aims to target such customers by providing low-cost and accessible EV charging options. King PFT, p. 13:12-13, King PFT, Ex. UI-CETP-3, p. 1. Specifically, the program would aim to support 100 Level 2 curbside EV charging ports. Id. In order to reduce program costs and navigate siting feasibility, the EV chargers would likely be sited on "existing utility poles, streetlight poles, dedicated EV pedestals, or a combination." King PFT, p. 13:3-6.

UI also proposed that the pilot program would occur with two municipal partners. King PFT, Ex. UI-CETP-3, p. 1. When prompted, the Company shared that the two municipalities would likely be New Haven and Bridgeport, as they are the largest urban areas in UI's service territory. Hr'g Tr. Mar. 8, 2023, 2836:2-5. Indeed, according to UI, the idea for the pilot program began with discussions with the City of New Haven. Hr'g Tr., 2832:15-18. Additionally, UI stated that it intends to only conduct this pilot program in underserved communities. Hr'g Tr., 2835:18-21.

In its proposal, UI did not request any incremental program costs associated with implementing the municipal curbside EV charging pilot. King PFT, p. 13:14-16. Rather, the Company stated that all pilot-related costs would be fully funded through the existing LD EV Charging Program budget. Id. Therefore, the Company requested in its Application that the Authority approve adjustments to the LD EV Charging Program incentive eligibility to allow for the broader application of incentive funds, such as increased incentives toward equipment, signage, and other related construction and program costs. King PFT, Ex. UI-CETP-3, p. 1; Hr'g Tr. Mar. 8, 2023, 2772:9-23.

The Authority notes that it established the Innovative Energy Solutions (IES) Program in March 2022. Decision, March 30, 2022, Docket No. 17-12-03RE05, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Innovative Technology Application and Programs (Innovation Pilots) (IES Decision). The IES Program was established to allow companies and other stakeholders to develop innovative pilot projects and to receive initial funding support. IES Decision, p. 5; IES Decision, Att. B, p. 43. UI stated that staff were aware of the IES Program but nonetheless did not consider proposing the municipal curbside charging pilot in this year's application cycle. Hr'g Tr. Mar. 8, 2023, 2743:15-20. The Authority also notes that it conducts an annual review of the LD EV Charging Program to make strategic and other adjustments to the program. This year's annual review of the LD EV Charging Program is being conducted in Docket No. 23-08-06.

While the Authority agrees that "garage orphans" in economically distressed areas must be addressed to ensure that the transition to electric transportation is achieved equitably, the Authority finds that the IES Program and/or Docket No. 23-08-06 are more appropriate proceedings through which to submit and develop such a pilot program and to seek amendments to the current LD EV Charging Program than the current rate case proceeding. As stated previously, the Authority operates with the presumption that interested stakeholders must be provided ample notice of proposed program developments in order to provide feedback. Therefore, a rate case proceeding, which incorporates a large variety of topics and is tied to a statutory timeline, does not allow potentially interested EV charging-related stakeholders to truly participate and to discuss such a proposal. In addition, the Authority established the IES Program with the intent of supporting pilot programs such as this one. Accordingly, the Authority denies UI's requested proposal for a municipal curbside EV charging pilot and directs the Company to submit any future related proposals into the IES Program and future requests for modifications to the LD EV Charging program into the appropriate annual review proceeding.

C. EV CHARGING HUB

UI proposed an EV Charging Hub project in its Application. King PFT, pp. 13:17 – 14:2. The Company stated that the project is meant to address the fast-charging needs of future scaled-up EV market adoption. Id., p. 14:20-23. Furthermore, according to UI, the current approach for EV fast-charging deployment will not accommodate the needs of MHD EVs, as these sites are not designed to host such vehicles. Id., pp. 14:23 – 15:1; UI Interrog. Resp. CAE-14, p. 2. Therefore, UI opined that it is important to apply funding to charging infrastructure that will scale with the market, rather than continue to invest in infrastructure that will soon be a stranded asset due to shifting EV needs. Id., p. 15:1-5. As proposed, the EV Charging Hub would offer DCFCs to serve corridor fast-charging needs for light-, medium-, and heavy-duty EVs in one large-scale charging area. King PFT, p. 13:18-19; Hr'g Tr. Mar. 8, 2023, 2830:5-105-10. The Company does not currently have a targeted location in mind for the EV Charging Hub. Hr'g Tr. Mar. 8, 2023, 2808:19-22. However, the Company envisioned a charging hub that is close in proximity to a UI substation, due to the likely large amount of demand required by such a project. King PFT, 13:21-22. Specifically, the hub could serve a future load as high as 20 MW, and with an average charger power level of 250 kW, charge up to 80 vehicles simultaneously. Id., pp. 13:21 – 14:1.

In the proposal, UI suggested that the EV Charging Hub project would occur in four phases in partnership with third parties, who would ultimately own and operate the chargers and any driver amenities. King PFT, pp. 14:4, 13:19-21. The phases would include (1) site identification and evaluation, performed by both UI and third-party partners; (2) site acquisition, performed primarily by third-party partners; (3) design and engineering, where UI would perform electrical work and third-party partners would perform non-electrical work; and (4) construction, performed in a similar manner as phase 3. Id., p. 14:4-14.

To support the project, UI proposed a capital budget of $31.2 million to be incurred over four years. King PFT, p. 15:7-9. The Company stated that project planning would occur in 2023, and project expenditures would begin in 2024 and continue through 2026. Id. UI further stated that project funds would be provided by existing incentives in the LD EV Charging Program and any applicable federal grants. Id., p. 15:9-10. If UI is successful in receiving federal grants for the program, the Company alleged that the proposed capital requirement would decrease. Id., p. 15:10-11.

The Company is not aware of any existing large-scale fast-charging hubs meant to serve medium- and heavy-duty EVs. UI Interrog. Resp. CAE-14, p. 2. However, the Company did provide two examples of large-scale, light-duty fast-charging hubs. Id. Specifically, UI shared the Tesla Harris Ranch Supercharger, which offers 80 DCFC proprietary plugs to be used only by Tesla drivers, and the Revel superhub in Brooklyn, NY, which offers 25 DCFC universal access plugs. Id.

DEEP expressed strong support for further consideration of the EV Charging Hub concept in a more focused proceeding, such as the ongoing Medium- and Heavy-Duty EV Charging proceeding in Docket No. 21-09-17, or a new proceeding. DEEP Brief, p. 12. Specifically, DEEP opined that reviewing this proposal in a focused proceeding "would allow for greater stakeholder input and an opportunity for UI to receive valuable feedback from PURA and stakeholders." Id. Furthermore, DEEP expressed concern regarding the proposal's completeness as well as some project components, such as the proposed limitation of including only DCFCs at the Hub. Id. Therefore, there are many benefits to receiving further stakeholder feedback regarding the EV Charging Hub concept in a focused proceeding. Id., pp. 12-13.

The Authority notes the general lack of supporting evidence to establish the necessity of such a project's development, especially at this time. As the Company notes, there are currently no existing large-scale DCFC hubs that can serve both LD and MHD EVs. Furthermore, there is no record evidence to suggest that the market penetration of MHD EVs will reach such a high level within the next four-five years so as to require the proposed project. Finally, the Authority reiterates that there is an ongoing proceeding investigating MHD EV charging in Docket No. 21-09-17. This proceeding has been ongoing since October 2021. Notice of Proceeding, Oct. 4, 2021, MHD Investigation. Given that a primary goal of the EV Charging Hub is to support MHD fast-charging, the Authority finds that the existing MHD Investigation is the appropriate arena through which to discuss a proposal such as the EV Charging Hub pilot program. Moreover, the in-state build-out of DCFCs should not be done in a vacuum. Indeed, both the current LD EV Charging Program and the Connecticut Department of Transportation's (DOT) work on the NEVI Formula Program already envision deploying DCFC infrastructure. Any future

EV Charging Hub would need to take into account such work and proactively coordinate with DOT to ensure optimal use of federal and state financial and other resources.

Accordingly, the Authority denies UI's proposal for an EV Charging Hub and directs the Company to submit any future related proposals in Docket No. 21-09-17, PURA Investigation into Medium and Heavy-Duty Electric Vehicle Charging, and to coordinate any future DCFC build out initiatives with the LD EV Charging Program and DOT's NEVI work.

D. ENERGY STORAGE PILOTS

The Authority declines to approve the three energy storage pilots submitted by the Company in this proceeding but will review the projects for potential approval in Docket No. 22-06-05, PURA Implementation of Public Act 22-55. UI proposes three grid-scale front-of-the-meter energy storage pilots pursuant to Section 2 of Public Act 22-55, An Act Concerning Energy Storage Systems and Electric Distribution System Reliability, after engaging with Sound Grid Partners, LLC to perform a technical analysis to recommend an optimal portfolio of projects. Ex. UI-CETP-4, p. 2. Notably, each project includes "at least one critical facility or a municipally designated top-10 outage restoration priority facility and at least one source of renewable generation." Id. Each project was sized to be capable of serving an islanded load for a four-hour outage based on the historical maximum net load conditions. Id., p. 4. The threshold of four hours was selected as between 58% and 82% of historical outages on the analyzed circuits had a duration less than or equal to this value. Id. As part of the analysis, 14 demonstration objectives were identified. Ex. UI-CETP-4, p. 12. Each project in the proposed portfolio demonstrates either eight or nine of the objectives, and across the three proposed projects all 14 are demonstrated. Id. UI notes that the three proposed projects define a strong portfolio that will provide learnings for future program design while providing reliability benefits at a reasonable cost. Id. Additionally, the utility cost test (UCT) values for all three projects when comparing against a generator alternative range between 1.002 and 1.179, and the UCT values when comparing against a resiliency poles and wires alternative range between 1.107 and 1.490. Interrog. Resp. CAE-52, Att. 1, p. 1. Further, total resource cost tests were also completed for each of the three proposed projects comparing them to a generator alternative and a resiliency poles and wires alternative, where the total resource cost test (TRC) "includes all energy and non-energy benefits, such as water savings, non-embedded emissions, environmental attributes, and non-energy impacts." Id. The TRC value for each project when compared to a resiliency poles and wires alternative ranged from 1.084 to 1.468, while when compared to a generator alternative the TRC value ranged from 0.982 to 1.159. Id. Only one project, the North Haven project, had any cost test values below one, and it was the total resource cost test compared to a generator alternative, with a value of 0.982. Id. Lastly, each project avoids at least several million pounds of emissions for a single outage that utilizes the full battery storage solution capacity. Ex. UI-CETP-4, p. 11.

The Authority appreciates the work the Company has completed to date in developing and proposing these three grid-scale front-of-the-meter energy storage pilots pursuant to Section 2 of Public Act 22-55. Nevertheless, recognizing that additional stakeholder engagement and technical meetings have been held in Docket No. 22-06-05, the Authority declines to approve the three projects at this time but will continue to review the projects for potential approval in Docket No. 22-06-05.

E. INTEGRATED DISTRIBUTION SYSTEM PLAN & GRID MODERNIZATION ROADMAP

The Company has included two Integrated Distribution System Planning (IDSP) projects in the Application. The first is an advanced DER and load forecasting project ($335,000 of operating expense in Rate Year 3) and the second is a CYME Server project ($81,250 of capital expenditure in Rate Year 2023/2024). Ex. UI-CETP-1, pp. 30-31. UI Interrog. Resp. UPA-6. The Authority disallows the expenditures on both the advanced DER and load forecasting project and the CYME Server project.

In its description of the projects, the Company refers to PURA's October 2, 2019 Interim Decision in Docket No. 17-12-03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies, as the basis for developing its IDSP; however, no direction was given to the EDCs in that Interim Decision regarding the specific IDSP characteristics or the planning process necessary to implement an IDSP. Interim Decision, Oct. 2, 2019, Docket No. 17-12-03; Ex. UI-CETP-1, p. 30. Therefore, no guidance or orders governing an IDSP in Connecticut have been established on which to evaluate whether the Company's proposed IDSP projects are necessary or prudent. Instead, the Authority recently initiated Docket No. 21-05-15RE03, PURA Investigation into The Establishment of Integrated Distribution System Planning Within A Performance-Based Regulation Framework, which will establish the IDSP plan features and planning process necessary to evaluate such expenditures in the future. Until such decision has been issued, the Authority declines to approve cost recovery of IDSP-specific expenditures.

F. PLEASURE BEACH ISLAND

The Authority finds the Pleasure Beach Island (PBI) solar plus storage project to be a cost-effective solution to providing electricity to customers in a hard-to-reach area of UI's service territory, and consequently approves the proposed project subject to the conditions below.

UI proposes a solar plus storage system to serve two customers on PBI, a small "island/peninsula" located in the City of Bridgeport. Ex. UI-CETP-1, p. 22. PBI has two customers, a pavilion owned by the City of Bridgeport and two, 300-foot-tall radio transmission towers owned by WICC radio station. Id., p. 23. The customers on PBI are provided electric service via a "2,400-volt, three conductor, No. 1, rubber insulated, 6.9 kV submarine cable that was installed in 1940." Ex. UI-CETP-5, p. 2. UI states that while the useful life of the cable is difficult to predict, typical cable life is approximately 40 years, and consequently the longer a cable is in service after 40 years, the more likely the cable will fail. Hr'g Tr. Mar. 8, 2023, 2733:18-2734:6. Further, the cable, which is approximately 80 years old, has been damaged previously in 1984 and 2003. Ex. UI-CETP-5, p. 2. In those two instances, the failures were in locations where cable was accessible for repair, but UI notes that if failure occurred under the harbor, it is unlikely that UI will be able to make the necessary repair due to environmental and logistical considerations. Hr'g Tr. Mar. 7, 2023, 2703:8-2705:7, Clean Energy Transformation Panel Prefiled Test., Jan. 6, 2023, p. 10. Specifically, UI notes it is challenging to get permits for work in the area of the cable due to "a host of different oyster beds ... that are very environmentally sensitive," a nesting ground for birds, and other environmentally sensitive flora and fauna. Hr'g Tr. Mar. 7, 2023, 2704:14-2705:7.

Notably, if the WICC radio transmission towers were to lose power, the lighting for flight path safety as required by the U.S. Department of Transportation Federal Aviation Administration would be affected. Ex. UI-CETP-5, p. 2. The current plan to keep power available to the radio towers during an electrical outage is to use a back-up generator, which UI notes is "non-sustainable for a long period of time." Id. The generator, installed in 2017, is fueled by propane. Late Filed Ex. 125, p. 1. The current system configuration of keeping six to eight 100-pound bottles of propane on PBI would be able to fuel the generator for approximately four days, with replacement propane transported via ferry as a fire in 1996 destroyed part of the bridge between PBI and the mainland of Bridgeport, limiting access to the island. Id., Ex. UI-CETP-5, p. 2. Further, UI notes that sources estimate the useful life of a standby generator to be between 1,500 and 3,000 run hours and that a generator should be run a maximum of 500 hours continuously to maintain useful life. Late Filed Ex. 125, p. 1. Additionally, the operation manual for the generator on PBI recommends regular service every 250 hours. Id. Also, the generator only serves the WICC radio towers and not the other customer on PBI, the pavilion owned by the City of Bridgeport, which has no back-up power. Ex. UI-CETP-5, p. 2. Alternatively, if the cable were to be replaced to mitigate future electric service interruptions to PBI, the cost estimate ranges from $10 to $12 million dollars, in part because there is no available route for an overhead solution. Ex. UI-CETP-1, p. 25.

The proposed solar and storage project, which UI asserts is "the most cost-effective option," is estimated to cost $1.052 million, with $19.5 thousand in O&M costs in 2025. Ex. UI-CETP-5, pp. 1-3. The proposed project is a 210 kilowatt (kW) photovoltaic (PV) solar system paired with 315 kilowatt-hours (kWh) of battery storage. Id. The system is designed to replace the existing cable and provide reliable power at all hours to the two customers on PBI, which combined average approximately 11,000 kWh annually. Id., p. 1. The system is also designed to withstand a Category 3 hurricane. Id. Notably, UI states that the system size is approximate, but expects the final design to be similar to the proposed system, as the proposed system was preliminarily sized through discussions with a few third-party developers who provided similar system size estimates. UI-CETP-5, p. 1; Hr'g Tr. Mar. 7, 2023, 2699:2-2700:11. Additionally, the O&M costs for the system were calculated as 1.8% of the capital expenditure costs, which is a typical practice of the Company. Hr'g Tr., 2707:15-2708:7.

UI states that in the case of a storm where the system was not operating properly, personnel would be sent to maintain the system while the batteries provided interim power. Hr'g Tr., 2706:17-2707:14. Specifically, UI notes that the Company will not own the solar system but would have an agreement with the company who does own the solar system to ensure that the solar panels are maintained. Hr'g Tr., 2707:4-14.

The Company also states that the PBI solar and storage project was not submitted as a project in Connecticut's Energy Storage Solutions Program, or as a project pursuant to Public Act 22-55, An Act Concerning Energy Storage Systems and Electric Distribution System Reliability, as this system is "designed as an innovative project intended to replace existing, aged infrastructure past the end of its useful life to ensure reliable and safe 24 x 7 x 365 service to the customers on the island, not to provide back-up to customers nor reduce system peaks", and consequently does not meet either program's objectives. Interrog. Resp. CAE-17, p. 1. However, UI notes several benefits of the PBI project including: (1) that energy storage will be necessary to integrate renewable energy

sources to meet Connecticut's clean energy goals and this project will allow UI to gain knowledge about how such systems can be operated; (2) that this project provides operational resilience to customers in a hard to serve area of the company's territory; (3) that this project will help UI to assess opportunities to meet customer needs in unique ways and other potential locations and applications for battery storage; (4) that this project will provide greenhouse gas savings; and (5) that this project will assist Connecticut in reaching its goal of 650 MW of energy storage by 2027. Ex. UI-CETP-5, p. 2; Hr'g Tr. Mar. 7, 2023, 2708:8-2709:4. Lastly, the Company notes that the PBI project, and lessons learned from it, will benefit all UI customers due to the potential use of solar and storage projects in other locations, and consequently seeks to recover costs incurred for the PBI project through base distribution rates. Ex. UI-CETP-1, p. 24.

The Authority acknowledges the logistical and environmental difficulties in replacing the cable currently servicing PBI, as well as the substantially larger cost estimate to replace the cable relative to implementing a solar plus storage solution. Further, the Authority notes that using the generator back-up as a long-term solution is not feasible due to the required frequency of refueling and machine maintenance. The Authority finds the proposed project to likely be the most cost-effective available solution and one that provides broader benefits to the Company and ratepayers of Connecticut. Accordingly, the Authority approves the proposed PBI solar plus storage project, subject to the below conditions.

First, the Authority clarifies that UI is not currently statutorily authorized to be the owner of the solar system and directs UI to select a third-party with which to execute a PPA via a competitive RFP. Accordingly, the Company will be directed to file with the Authority the results of the RFP including the details of all bids, including the winning bid, with the Authority as compliance.

Second, the Authority notes that it has not identified where in base distribution rates that the PBI solar and storage project has been accounted for in the Company's Application. To the extent that the PBI project costs have been included in the Application, the Authority disallows cost recovery through the base distribution rates at this time as (1) insufficient evidence was provided to demonstrate that the final costs are prudent and (2) the project is not used and useful at this time, the former of which is required to allow for the recovery of expenses and both of which are required for rate base treatment as discussed in Section IV., Rate Base. Accordingly, any such costs should be removed from the approved revenue requirement.[152] The Authority does, however, authorize deferred accounting to allow the Company to track the costs of the PBI solar plus storage project. The tracked costs will be reviewed for the prudence and reasonableness of any incurred costs during the Company's next rate case proceeding. The 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.

Lastly, as directed in the July 12, 2021 Ruling to Motion No. 14 in Docket No. 10-10-12, Petition Filed by Cumulus Media, Inc. for an Investigation Pursuant to § 16-20 of

[152] The Authority did not identify any costs related to the PBI solar plus storage solution in the requested Rate Year 2023/2024 revenue requirement.

the General Statutes of Connecticut, the Company must file for the Authority's review and approval in the instant proceeding option(s) for a rate structure for the customers on the island pursuant to Conn. Gen. Stat. § 16-19e(a)(4) in order to allocate the cost of such service (Proposals) prior to the PBI solar plus storage project taking service. Such Proposals should be consistent with the Company's current terms and conditions, including the guarantee of a minimum annual payment for a term of years. The Proposals shall include a timeline of requested approvals, all partnerships and other contractual agreements that the Company has and plans to enter into for the project, and any other documents and legal parameters necessary to execute the Proposal. Any rate structure options considered and presented may take into account the non-energy benefits that this project may provide to the Company and its ratepayers as a whole, including environmental and societal benefits.

G. ELECTRIC POWER RESEARCH INSTITUTE EXPANDED MEMBERSHIP

The Company proposes to expand its membership to the Electric Power Research Institute (EPRI) to "facilitate research and industry collaboration around clean energy," including "program sets" related to energy storage, distributed generation, DER integration, electric transportation, and electrification. Ex. UI-CETP-1, p. 31. The Authority declines UI's request because there is insufficient evidence in the record explaining how the expanded membership will specifically benefit ratepayers. Additionally, there is conflicting and confusing testimony in the record regarding the actual costs for the expanded EPRI membership.

According to an interrogatory response, the Company requests that it recover a total of $565,900 over four years. Interrog. Resp. OCC-246. However, in a subsequent interrogatory response, the Company stated that its annual EPRI dues from 2017 through 2022 averaged $310,269. Interrog. Resp. OCC-387. Further, the Company testified at the hearing that it sought to increase its membership expense by "a little over $36,000" on an annual basis. Hr'g Tr. Mar. 8, 2023, 2805: 12-14. Finally, a schedule submitted by the Company indicated only a $17,00 increase in its membership expense. Sch. WP C-3.03. Therefore, the actual cost of the extended membership is unclear to the Authority.

Additionally, when asked about the program sets, the Company testified that it already belonged to two program sets it represented it wanted to join in the Application. Hr'g Tr. Mar. 8, 2023, 2806:1-4. Moreover, the Company only provided general and speculative remarks about potential benefits to its expanded membership and did not describe any quantifiable benefits to ratepayers. See Hr'g Tr. Mar. 8, 2023, 2806:1-25, 2807: 1-8.

Therefore, the record is unclear as to how much the expanded membership would cost, what program sets the Company belongs to, what the benefits of expanded membership in those program sets are, and how specifically the expanded membership would benefit ratepayers. Finally, P.A. 23-102 § 3 (a), effective from passage on June 6, 2023, and before Rate Year 2023/2024 commences on September 1, 2023, expressly prohibits a public service company such as UI from recovering through rates any direct or indirect costs associated with "membership, dues, sponsorships or contributions to a business or industry trade association or group or related entity incorporated 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." As such, the

Authority denies UI's request to recover its proposed expanded EPRI membership costs from ratepayers.

VIII. APPROVED REVENUE REQUIREMENT

The table 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 80: Approved Revenue Requirement

Section	Revenue Component	Amounts ($000)
IV.A.	Rate Base	1,105,196
V.A.	Weighted Cost of Capital	6.475%
	Allowed Cost of Capital	71,561
	Allowed Expenses:	
VI.A.	Operations & Maintenance	150,860
VI.B.	Depreciation	72,536
VI.C.	Amortization	6,605
VI.D.	Payroll Taxes	5,419
VI.D.	Gross Earnings Tax	26,156
VI.D.	Municipal Property Taxes	35,053
VI.D.	State Income Tax	1,325
VI.D.	Federal Income Tax	10,885
VI.D.	Provision for Deferred Taxes	2,703
VI.D.	CT ITC	1,762
	Total Allowed Revenue Requirement	**384,865**

IX. REVENUE ADJUSTMENT MECHANISMS

A. EARNINGS SHARING MECHANISM (ESM)

1. Summary

The Company proposed that its earnings sharing mechanism (ESM) continue as it is currently structured, with earnings above the allowed ROE measured on a calendar year basis shared 50/50 with customers. The Company is proposing to modify the structure so that the customers' 50% share, if any, would be first utilized to amortize and accelerate the recovery of UI's storm regulatory asset, if applicable, before being utilized as a cash credit. Application, Ex. UI-RRP-1, p. 9; Interrog. Resp. RRU 24. The Company indicated the mechanism returned approximately $15.66 million to customers, inclusive of carrying charges, due to earnings above the allowed ROE in 2017, 2018, and 2019. UI Interrog. Resp. RRU-26. In 2020, the customers' 50% share of earnings sharing was utilized to offset deferred major storm expenses. Id.

As shown in RRU-16, Attachment 1, the Company's calculation of its earned ROE for purposes of the ESM reflects its actual capital structure. Interrog. Resp. EOE-181. UI has utilized its actual capital structure when calculating earnings sharing for the last two decades. Id.

2. Positions of the Parties

EOE recommends that the Authority provide guidance to the Company requiring all future ESM reporting to calculate the ROE using the lesser of the (1) authorized or (2) carried equity position, and to apply ESM carrying costs as of January 1 of the subsequent year. Additionally, EOE asserts that the Company should be required to separately identify and exclude all disallowed costs from the ESM reporting going forward and provide an affirmation of the accuracy of their disallowed expenses. This guidance would still allow for the Company to achieve its authorized ROE based on its authorized capital structure and would then share excess earnings in accordance with the rate case decision. This approach would also ensure that customers are not negatively impacted in situations where the Company deviates from directives and orders outlined in a rate case decision. EOE Brief, p. 51.

EOE further argues that while deviations from a regulated entity's authorized capital structure would not result in changes to rates charged to customers (ratepayers), such deviations would, however, impact an entity's actual calculated ROE and WACC. When the actual equity percentage increases within the capital structure, the WACC would increase as there would be less debt charged at the lower cost. The inverse also holds true. Specific to ROE, a larger percentage of equity results in a lower calculated ROE as the utility income would be diluted within the calculation. This ultimately means that a regulated utility that exceeds its authorized equity percentage would derive a lower actual ROE, while still receiving the same amount of income (pre-ESM). Specific to the ESM, this means that a regulated utility could increase its carried equity percentages to derive a lower calculated ROE, which would negatively impact the customer's portion of the earnings sharing resulting in less money being returned to ratepayers or used to offset the Storm Regulatory Asset. EOE Brief, p. 51.

EOE highlighted how this would have benefited the ratepayers in past situations where the ESM was triggered. EOE indicated that the common equity level in the Company's capital structure has grown from 54.44% in 2017, to 59.15% in 2021, despite being set at 50% for ratemaking purposes. EOE Brief, p. 50. In 2017-2019, UI exceeded its allowed ROE and shared $16.46 million of overearnings, based upon the equity ratio shown in UI's actual capital structure. Interrog. Resp. EOE-181. However, had earnings been calculated using the 50% equity ratio allowed for ratemaking purposes, rather than the Company's actual capital structure, ratepayers would have seen an additional earnings sharing bill credit in 2020 of $2.07 million, as well as $5.83 million greater ESM payments over the 2017–2019 rate plan period. EOE Brief, p. 51.

Similarly, the OCC indicated that allowing UI to calculate earnings for ESM purposes using its actual capital structure defeats the rationale of the original rate case decision that set the authorized ROE, allowed ratemaking capital structure, and resulting weighted cost of capital. If a 50/50 capital structure was utilized for setting revenue requirements, an identical capital structure should be utilized to determine the level of earnings sharing in a given rate year. OCC Reply Brief, p. 22.

In addition to supporting EOE's recommended calculation of the ESM, OCC also proposed a modification to the ESM. Specifically, while the OCC does not necessarily oppose using ESM proceeds to pay off deferred storm costs, the OCC contends that the application of ESM funds to storm costs should be limited to storm costs that have been the subject of a review in a rate case or storm review case by PURA. As a result, only storm costs found to be prudent would be eligible to be funded by ESM proceeds. New storm costs should not automatically be charged against ESM until they are approved for recovery by PURA following a comprehensive and collaborative review in which the Company must meet its burden to demonstrate that incurred costs were necessary and prudent. OCC Brief, p. 249.

The OCC noted that if PURA does accept this modification, that the Authority should consider a sharing of one-quarter to storm deferred costs, one-quarter to shareholders, and one-half to ratepayers as a bill credit. The pay-down of deferred storm costs improves the financial matrix of the Company by reducing the level of deferred assets on the Company's balance sheet. Under the Company's proposal, OCC argues that shareholders would enjoy the full 50% benefit of the ESM mechanism, in addition to the benefit of this reduction in risk, while ratepayers would contribute their entire share of overearnings. Dividing overearnings between shareholders, ratepayers, and deferred costs would better reflect the balance intended in the ESM mechanism's design. Id., p. 250.

The OCC also petitioned the Authority to consider the reporting of the actual earned ROE. The OCC argues that UI accounted for costs that were not included in the revenue requirement as operating expenses, affecting the measurement of the Company's actual earned ROE. OCC Brief, p. 250. Specifically, the OCC states that UI has a long history of paying incentive compensation levels that exceed the amount allowed in rates and charging the excess amount above the line, thus reducing their earned ROE. Id. These actions cause the Company to earn below its allowed rate of return and experience a reduction in overearnings in years in which they in fact over earn. Id. The OCC requests that the Authority order UI to report its earned return based on a level of allowed expenses that does not include costs that were excluded for ratemaking purposes. Id.

3. Authority Analysis

The Authority orders UI to continue the ESM with a 50/50 split from the first dollar of over-earning above the allowed ROE calculated on a calendar year basis. In addition, the Authority agrees with the arguments presented by EOE and the OCC that the measurement of the ROE should use the lesser of the authorized or actual equity position when tabulating the ROE, as utilizing the Company's actual capital structure subverts the function of imbuing a capital structure for ratemaking purposes. The Authority also agrees with the OCC that the ESM revenue should only be applied to the storm regulatory asset after a prudence review by the Authority for two reasons: (1) consistent with the treatment of regulatory assets in this Decision and past PURA precedent, see Section IV.E.1., General, carrying charges do not accrue on regulatory assets prior to a prudence review; thus, there are no carrying cost benefits associated with applying ratepayers' share of the ESM to a storm regulatory asset prior to the prudence review; and (2) applying ratepayers' share of the ESM to a storm regulatory asset before a full review by the Authority introduces the risk that such costs are used to offset imprudent costs. The Authority will

determine the amount of ESM revenue to be applied to the current storm regulatory asset or any future storm regulatory assets for which the Authority has completed a prudency review on a case-by-case basis at the time the Company identifies ESM revenues. Lastly, the Authority also agrees with the OCC that incentive compensation (or indeed, any costs excluded for ratemaking purposes) above the levels authorized in the rate case should not be used to reduce the calculated ROE, as such incremental incentive payments are definitionally earnings; the Company is entitled to distribute such earnings how it sees fit, but only *after* the ratepayers' share of any overearnings is appropriately allocated. Accordingly, the Authority directs UI to incorporate the above changes into its ESM moving forward. The Authority further directs the Company to file a motion in the instant proceeding when ESM revenues are identified for a given calendar year outlining the amount of ESM revenues due to customers and a proposed plan for returning such revenues to customers.

B. PROPOSED ROE ADJUSTMENT MECHANISM

The Company proposed an ROE adjustment mechanism to adjust the ROE to reflect current conditions in each year of the multi-rate plan starting at the beginning of rate year two. Bulkley PFT, p. 70. The proposed mechanism would provide for symmetrical adjustment to the ROE upwards or downwards by 45% of the upcoming year's projected average spread between the one-year Treasury Bill and the two-year U.S. Treasury Note as estimated by the Blue Chip Financial Forecast. Id., p. 72.

The OCC is opposed to the proposed ROE adjustment mechanism for several reasons: (1) the Company recommendation would be formulaic and require an annual reopening proceeding before the Authority; (2) the methodology proposed is incorrect; and (3) the OCC does not support a multi-year rate plan; thus, an annual ROE reopening would be unnecessary. OCC Brief, p. 248; Interrog. Resp. RRU-247. Walmart also opposed the Company's proposed ROE adjustment mechanism indicating it deprives PURA of its authority to set an allowed ROE. Kronauer PFT, p. 11; Walmart Brief, p. 5.

The Authority disallows the Company's proposed annual ROE adjustment mechanism as such a proposal deprives PURA of the ability to fully examine the entire economic and financial conditions of the economy and Company. Instead, the proposed ROE adjustment mechanism reduces the ROE process to a one dimensional formulaic if-then analysis based on movements in short-term US Treasury rates. There are many errors centered on the use of short-term U.S. Treasury rates as the benchmark. First, as noted in Section V.E.3., Capital Asset Pricing Model, utility assets are long-lived assets and typically the 30-year U.S. Treasury rates are used in utility cost of capital analyses. Second, the Company's proposal is based solely on UI's expert witness' own analysis and reporting of a Virginia Commerce Commission's white paper. Interrog. Resp. RRU-245 and RRU-245, Att. 2. Third, the Company's request is based upon estimated movements to interest rates over the coming year, which would essentially require the Authority to link its ratemaking authority to Wall Street analysts' projections as the Blue Chip Financial Forecasts essentially compiles financial forecaster's projections related to various economic indicators. Fourth, the Company will not be operating under a multi-rate year plan, as outlined in Section III.B., Multi-Year Rate Plan, making the proposed ROE adjustment mechanism moot.

Finally, and most importantly, the Authority finds that an annual reopener to the ROE to address anticipated movements to U.S. short-term Treasury rates would result in increased customer rate uncertainty and is not in the public interest.

C. PROPOSED PBR METRICS

The Company proposed a demonstration program to test various performance-based metrics to develop useful information and data for future implementation of a PBR framework for the Company. Ex. UI-1, p. 25. The Company's proposed demonstration program anticipates the completion of the Authority's PBR proceedings in Docket Nos. 21-05-15, 21-05-15RE01, 21-05-15RE02, and 21-05-15RE03 (collectively, the PBR proceedings). The proposal includes five performance-based metrics that "would not have a financial incentive associated with them but would be tracked and analyzed for future rate cases. The five metrics are: (1) DER interconnection; (2) EV managed charging; (3) electric storage adoption; (4) Net Promoter Score ("NPS"); and (5) customer e-bill adoption." Ex. UI-1, p.27. UI proposed to use insights from tracking the metrics to make determinations about the continuation of metric tracking and the reasonableness of the proposed thresholds. Ex. UI-1, p. 32. The Authority declines to formally approve UI's PBR demonstration program.

The Authority appreciates the spirit of the demonstration program, which appears to be in preparation for the implementation of PBR; however, the identification, tracking, and reporting of a discreet set of metrics is not currently necessary. Tracking and reporting metrics is not a new business practice for UI. In complying with various existing Authority orders, compliance filings, and reporting requirements, UI is already well-practiced with the tracking, measurement, and reporting of metrics. Additionally, UI is currently responsible for tracking and reporting many other metrics and scorecards through the annual review of the Affordability Programs and Offerings, the state's clean energy programs, and the Reliability and Resilience Frameworks through Docket Nos. XX-05-01, XX-08-01 through XX-08-06, and XX-08-09,[153] respectively, among others. The Company's efforts to track and report a new set of PBR demonstration metrics would be better spent ensuring faithful and quality fulfillment of existing metric reporting requirements. Diligent data tracking and reporting within existing Authority requirements can serve the same intended purpose of the demonstration program, to further build the Company's experience with and capacity for rigorous data reporting. Many (if not all) of these existing metrics and reporting requirements are likely to be considered for inclusion or potential consolidation in Docket No. 21-05-15RE02, which focuses on reported metrics, scorecards, and Performance Incentive Mechanisms in the service of the regulatory goals and priority public outcomes adopted in the PBR Decision. Accordingly, the Authority encourages the Company to pursue the spirit of the proposed PBR demonstration program through existing reporting requirements and active participation in Docket No. 21-05-15RE02 but declines to formally approve the program at this time.

[153] "XX" represents the last two digits of the calendar year in which the proceeding is conducted.

X. RATE DESIGN

A. LEGAL FRAMEWORK

UI is a public service company within the meaning of Conn. Gen. Stat. § 16-1. The Authority is statutorily charged with regulating the rates of Connecticut's public service companies. Conn. Gen. Stat. § 16-19. Consequently, UI must "file any proposed amendment of its existing rates with the [A]uthority." Conn. Gen. Stat. § 16-19(a). Once a proposed amendment has been filed, the Authority "shall 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 such company is inadequate to or in excess of public necessity and convenience, . . ." Id.[154]

In striking this balance and making pragmatic adjustments, the Authority is guided by Conn. Gen. Stat. § 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 . . . ;
>
> (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 Electricity Regulation in the US: A Guide, Regulatory Assistance Project, p. 67.[155] Consistent with the philosophy of gradualism, the Authority typically requires rate class revenue reductions or increases to be within one and quarter times the overall distribution revenue increase. See 2016 Rate Case Decision, p. 108; see, also, 2013 Rate Case 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 Conn. Gen. Stat. § 16-19e(b).

The Authority weighs the above principles and considerations in determining appropriate cost and revenue allocation approaches and rate designs.

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[154] Conn. Gen. Stat. § 16-19(a) also permits the Authority to "evaluate the reasonableness and adequacy of the performance or service of the public service company using any applicable metrics or standards adopted by the authority pursuant to section 16-244aa."

[155] Available at: https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.

B. SALES FORECASTS AND REVENUE

The Authority approves UI's sales and revenues forecast for the Rate Year as the Authority finds the proposed sales and revenues forecast and the Company's out-of-model adjustments reasonable. The Company forecasted the monthly billed sales and the number of customers for calendar years 2022, 2023, and the 12-month period beginning September 1, 2023. The Company used calendar year 2021 (i.e., the 12-months ending December 31, 2021) as the historical test year. Ex. UI-MP-1, Executive Summary. The Company forecasts overall electric deliveries to decrease, on average, by 1.19% annualized[156] between the Test Year and Rate Year 2023/2024. Id., p. 17. The forecasted reduction in billed deliveries is driven by a forecasted reduction in deliveries to industrial and residential customers. However, commercial customer deliveries are forecasted to increase slightly between 2023 and 2026. Id. The reduction in billed deliveries to the industrial class is reflective of the trends in the economic variables the Company used to develop the sales and customer growth models. Specifically, industrial customer sales are highly correlated with manufacturing employment data in Connecticut. Interrog. Resp. CAE-27. The Company sourced economic data from an information services provider, IHS Markit. UI-MP-1 p. 7. IHS Markit projects manufacturing employment for Connecticut to decline, on average, by 2.28% per year from 2022 to 2026. Interrog. Resp. CAE-27. The table below summarizes the average annualized growth rates for the residential, commercial, industrial, and street lighting customer billed deliveries, as well as the annualized growth rates for the total billed deliveries.

Table 81: Billed Deliveries Annualized Growth Rates

Class	2023/2024 (%)	2024/2025 (%)	2025/2026 (%)
Residential	-2.13	-1.18	-0.63
Commercial	-0.07	+0.08	+0.17
Industrial	-2.34	-1.48	-1.16
Street Lighting	-4.27	-4.914	-5.28
Total	**-1.19**	**-0.63**	**-0.32**

Ex. UI-MP-1, pp. 9-12.

The Company forecasts that the overall number of customers will increase, on average, by 0.21% annually between the Test Year and Rate Year 2023/2024. Ex. UI-MP-1, p. 17. The forecasted increase in customers is driven by a forecasted increase in the number of commercial and residential customers, while the number of industrial and streetlight customers is forecast to decrease. Ex. UI-MP-2, Sch. B, p. 8. UI reports that residential customer growth is highly correlated with the number of households in Connecticut. Interrog. Resp. CAE-26. UI relied on IHS Markit projections that show an increase in the number of households in Connecticut beginning in 2023. Id.

The Company's forecasting methodology differs from methodologies used in previous rate cases. Historically, the Company used an Excel-based formulaic approach

[156] An annualized growth rate is a growth rate over a given time period adjusted to give the equivalent growth rate over one year. Specifically, the growth rate over the 32-month period between the end of the Test Year (i.e., December 31, 2021) and the end of Rate Year 2023/2024 (i.e., August 31, 2024) was annualized by dividing the rate by 32 and then multiplying by 12. Ex. UI-MP-2.

based on moving averages (i.e., a series of averages over subsets of the time-dependent dataset) and relevant out-of-model adjustments. Interrog. Resp. OCC-280. In the present case, the Company used an econometric modeling methodology to estimate the relationship between several independent variables and the dependent variable (i.e., the billed electric deliveries or the monthly customers). Ex. UI-MP-1 p. 4.

The Company stated that the Excel-based approach using moving averages is merely a projection of a past trend without any recognition of causal factors that drive electric consumption or customer growth. Interrog. Resp. CAE-21. Consequently, UI asserts that the Excel-based approach has many limitations and is slow to respond to any changes in underlying economic conditions. Id. In contrast, the econometric models incorporate causal factors that drive consumption and customer growth such as population, weather, and economic trends. Id. The econometric models perform significantly better than the Company's previous approach in terms of forecast accuracy, as demonstrated by ex-post testing. Interrog. Resp. CAE- 19. Ex-post testing involves withholding a portion of the sample data and generating the withheld portion of the data using the model. The generated data is then compared to the withheld data to assess the performance of the model. Ex. UI-MP-1, p. 16.

The Company used four categories of independent variables in the model: economic variables; price variables; weather variables; and binary variables. UI-MP-1 p. 6. The economic variables include data such as income and both Connecticut manufacturing and non-manufacturing GDP. UI-MP-1 p. 7. As stated above, the Company sourced the economic variables from IHS Markit. Id. The price variables were average retail sales prices for each customer class during the period 2006 through December 2021 adjusted by specific price indices or deflators. Id. p. 8. The Company sourced the weather variables from the National Weather Service for the Bridgeport, Connecticut weather station. Id. Binary variables are used to construct the model and take a value of 1 when a condition is present and a value of 0 when the condition is not present. Binary variables do not represent any underlying trends. Id.

The Company estimated the relationship by determining a best-fit curve between the independent variable(s) and the dependent variable, where "best-fit" refers to the curve that minimizes the sum of squared errors. Ex. UI-MP-1 p. 4. The Company tested various functional forms and selected the model results based on the best-fit criteria and the performance of the model in ex-post testing. Id., p. 3. Although the Company has not employed this methodology in previous rate cases, UI stated that other Avangrid Networks Operating Companies have used this methodology in their rate cases in Maine and in New York. Interrog. Resp. CAE-20.

The Company made out-of-model adjustments to account for the growth of distributed energy resources (DER), including solar PV and fuel cells, and beneficial electrification such as heat pumps (HP) and EVs. Ex. UI-MP-1, pp. 4-5. The Company developed the solar PV out-of-model adjustment by first estimating the actual (as opposed to nameplate) PV generation capacity as of December 2021, using the historical PV capacity factor for projects for which the Connecticut Green Bank has data of 13%, and applying the yearly growth rates provided by ISO New England's annual Capacity, Energy, Loads and Transmission (CELT) report. Ex. UI-MP-1, p. 5. The Company used estimates for Fuel Cell generation from the Avangrid Smart Grids Innovation Group from

2022 to 2031. Id. The Company used estimates for EV and HP penetration developed by the Smart Grids Innovation Programs group for the years 2022 to 2040. The EV forecast "assumes that 15% of vehicle sales in Connecticut will be EV by 2025 and 30% by 2030 with the annual number of EVs on the road equal to 80% of the assumed 10-year cumulative sales."[157] Interrog. Resp. CAE-23. The forecast assumes each vehicle will consume 9.7 kWh per day, which is based on the national daily mileage average and typical battery electric vehicle efficiency. The heat pump forecast is based on the 2021 ISO-NE heat pump forecast. Id. The Company expects these technologies to have a more significant impact in later years as the EV and HP markets mature. Id. Absent the out-of-model adjustments, the expected growth rates of billed deliveries to the residential class would have been positive and the expected growth rates of billed deliveries to the commercial class would also have been larger. Ex. UI-MP-1, pp. 9-11.

The Authority finds the Company's sales and revenues forecast, as well as the Company's out-of-model adjustments, to be reasonable. Since the Company has 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, the risk of misstating unit rates is minimized. Therefore, the Authority approves UI's sales and revenues forecast for Rate Year 2023/2024 without any adjustments.

C. Cost of Service Study

1. Summary

The Company filed an allocated cost of service study (ACOSS) based on the historical Test Year costs and revenues. Application, Ex. E 6.0. The ACOSS aims to functionalize costs into customer service and distribution-related services, classify them into customer, energy, and demand components, and subsequently allocate costs to customer classes as defined by the Company. In general, the resulting summary of costs by component and class serves as a guide for a utility when allocating revenue targets and subsequently designing specific rate structures for a rate application. Aside from using "replacement" costs in a Minimum System Study (MSS) approach to classify secondary distribution assets into customer and demand-related costs, the ACOSS is backwards-looking, assigning historical "embedded" costs already incurred by the Company.

The Company's proposed ACOSS utilized the MSS cost methodology to determine the classification of certain distribution accounts. Rimal Prefiled Test., Sep. 9, 2022, pp. 13-14. The MSS cost methodology classifies distribution system accounts such as poles, overhead conductors, and line transformers as being partially demand-driven and partially customer-driven costs. In UI's 2013 and 2016 rate cases, the Company utilized an alternative cost of service methodology, the Minimum Intercept Method (MIM), to derive customer and demand components of distribution system accounts. The Authority approved the MIM methodology in those decisions. 2013 Rate Case Decision, p. 147; 2016 Rate Case Decision, p. 93.

[157] The Authority interprets the Company's statement to mean that for a given year, the number of EVs assumed to be on the road is equal to 80% of the cumulative EV sales over the 10-year period ending prior to the given year (e.g., 80% of the 10-year cumulative EV sales ending December 31, 2023, would be used to estimate the number of EVs on the road for calendar year 2024).

While the Company has changed its cost methodology from the MIM to MSS, both approaches are used to determine the demand and customer-related costs of certain distribution accounts. The MSS methodology is described in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual. Hr'g Tr. Feb. 17, 2023, 329:24-330:7. According to the Company, other state jurisdictions that have approved the use of MSS include: New York; Maine; Indiana; and Eversource in Connecticut. Hr'g Tr., 318:21-319:9. Further, the Company opined that the MIM is more hypothetical in nature than the MSS methodology because it attempts to determine estimated costs for equipment such as conductors or transformers that carry no load and estimate a cost using data for other equipment sizes. Conversely, the MSS methodology attempts to determine costs based on a company's current system design. Hr'g Tr., 319:1-319:14.

The MSS approach, one of two methodologies discussed in the NARUC Electric Utility Cost Allocation Manual, is similarly meant to separate upstream-of meter drop secondary distribution into demand-classified and customer-classified plant, and is generally based on the same data, analyzed in a different manner. The data needed to conduct the MSS study is the same data that was used for the primary-secondary study to sub-functionalize poles and conductors between primary distribution and secondary distribution. Interrog. Resp. RRU-482.

The Company stated that to determine the costs of a minimum system size, the Company utilized the sizing and costs of replacement equipment currently being installed, rather than the embedded cost and size of equipment actually deployed in the field in the Test Year. Interrog. Resp. RRU-482. Finally, the Company proposed to allocate demand-based costs on the non-coincident peak (NCP) values for a given customer class, having not performed any alternative analysis. Interrog. Resp. RRU-486.

2. Position of the Parties

The OCC disagreed with several aspects of the Company's ACOSS. First, the OCC contended that the MSS approach is inappropriate, as costs in those distribution accounts should be classified purely on demand-drivers, not on a customer-basis. Chernick Prefiled Test., Dec. 13, 2022, p. 7. Second, the OCC opined that the costs associated with the MSS approach are "overpriced" by using current standards of replacement equipment and fail to capture the actual lower embedded costs incurred in serving the current system. Chernick PFT, pp. 7-12. Third, the OCC objected to the Company's use of class NCP as an appropriate demand allocator, arguing that nearly all distribution systems serve more than one class, and circuits are sized to serve all the classes in that area. Chernick PFT, pp. 17-19. Finally, the OCC recommends that the Authority require UI to improve its cost-of-service study before it is used for setting rates. Chernick PFT, p. 4.

In general, CIEC supported the use of the MSS methodology and the ACOSS as filed by the Company. CIEC argued that the ACOSS as filed "provides a reasonable starting point for cost and revenue allocation." Baudino Prefiled Test., Dec. 13, 2022, p. 10.

3. Authority Analysis

The Authority reviewed the Company's ACOSS and determines that the MSS cost methodology is generally acceptable. Specifically, the Authority finds the Company's testimony that the MSS cost methodology is less hypothetical than the MIM cost methodology compelling and, accordingly, accepts UI's use of the MSS ACOSS methodology. However, PURA is concerned with several aspects of UI's ACOSS, including the level of analytical rigor, and directs improvements to the Company's ACOSS below for future rate applications.

First, the Authority is troubled that the Company utilized the standards for currently installed plant and equipment in its MSS, rather than embedded plant and equipment as it does in the rest of the ACOSS. Hr'g Tr. Feb. 16, 2023, 176:9-178:5. Mixing currently installed costs under the MSS methodology appears to reflect costs that are less representative of and higher than the Company's embedded system costs. Therefore, for its next rate case, the Authority directs the Company to perform a MSS based upon the actual, incurred (i.e., average embedded) costs of the current system as constructed to the best of its ability and to demonstrate the resulting ACOSS summary values.

Second, the Authority recognizes the imperfect, but widely-accepted nature of the NCP allocator and accepts its usage in the ACOSS in the instant proceeding. Nevertheless, the Authority directs the Company to begin exploring alternatives to demand allocation, considering specific circuit information and sizing relating those to customer usage to be specifically discussed in testimony and filed as an alternative ACOSS in the Company's next rate case. In doing so, the Company must utilize all AMI data available to conduct relevant customer load research. Specifically, the alternative ACOSS must identify all of the circuit-specific data available to the Company, any additional data collected or load research performed, how the Company analyzed the collected data and research to determine customer class demand allocation factors, and the results of such analysis. The Authority encourages the Company to collaborate with the OCC ahead of filing its alternative ACOSS to ensure that the OCC's philosophical approach to the topic, as detailed in this proceeding, and specific input is incorporated.

Finally, the Authority is concerned about the applicability of the historically-based ACOSS as it relates to rates on a forward-looking basis. In an increasingly changing electric distribution landscape certain cost factors will change. For example, in the Company's response to interrogatory RRU-479, UI stated that the revenue requirement allocation in the Rate Year was performed based on Test Year results; while on cross-examination, the Company's witnesses admitted that future cost drivers, load patterns, and other factors may be distinctly different from the Test Year utilized in the ACOSS. Hr'g Tr., 194:16–195:15. Moreover, as demonstrated in Section X.A., Sales Forecasts and Revenue, the Company has the ability to reasonably anticipate and forecast near-term (within a few years) macroeconomic and service territory trends that, while still subject to uncertainty, provide a clearer picture of the likely actual costs over a forward period. Indeed, the Company's change to a more robust sales forecast model in this rate case serves to emphasize the point that such an approach is both feasible and preferable. Therefore, the Authority instructs the Company to also study a future Test Year equivalent to the third rate year of a hypothetical multi-year rate plan and to present it to the Authority in its initial filing in any subsequent rate cases. While the Company will also be required

to provide a future test year equivalent study in its next rate case, the Authority acknowledges and reaffirms the importance of a historical test year ACOSS to any utility rate case. The direction included in this Decision should not be construed as discarding the requirement to provide a historical test year ACOSS in the future, but rather an obligation for UI to provide supplemental analysis with its next rate application.

D. CLASS REVENUE ALLOCATION

1. Summary

In its Application, UI proposes to set its ACOSS aside as a guide for ratemaking purposes, preferring to adjust current rates on a present revenues relationship basis. The Company suggests that instead of allocating costs based on the ACOSS, a detailed rate design investigation can be conducted in either Docket No. 17-12-03RE02 or Docket No. 17-12-03RE11. Colca & Marini PFT, p. 5. The Company also suggests that a generic proceeding in which all relevant stakeholders could participate, yet to be opened, could resolve questions regarding the ACOSS. Hr'g. Tr. Feb. 17, 2023, 409:6-23.

UI proposes to allocate its rate increases in an across-the-board manner, apportioning the distribution revenue requirement increase request of 8.06% proportionally to all customer rate classes. Colca & Marini PFT, p. 5. Specifically, the Company proposes to allocate the rate increase among the classes by using a bundled approach whereby distribution and generation service revenues are combined.[158] UI Application, Sch. E-2.0-A-NL and E-2.1-A-NL; Application, Ex. UI-MC/MM-1, p. 5. Rates effective on September 1, 2022, were used for all generation service and delivery service components except for base distribution rates and the RDM. The RDM rate was set equal to zero to reflect that base distribution rates will be set to yield the retail revenue requirement. Colca & Marini PFT, p. 6.

As noted previously, the Authority generally attempts to equalize class rates of return when reviewing and approving customer class revenue allocation methodologies. The below tables provide a historical snapshot comparison of the rates of return and relative rates of return by customer class based on the Company's ACOSS in the 2016 Rate Case Decision and the instant proceeding.

Table 82: Rates of Return by Rate Class

Source	Total	R	RT	GS	GST	LPT	M	U
2015: (Docket No. 16-06-04 Colca PFT, MPC-2)	6.71%	6.92%	10.61%	11.16%	5.94%	2.02%	6.40%	11.14%
2017: (Docket No. 16-06-04, Order No. 2 – Comp. E 6.0A)	7.21%	6.95%	10.61%	8.27%	5.94%	3.99%	9.07%	15.75%
2021: (Docket No. 22-08-08 Ex. UI-BR-3)	7.25%	1.95%	8.77%	12.48%	16.85%	21.99%	0.10%	27.08%
2021: (Docket No. 22-08-08, Response to Late Filed Ex. 4)	7.25%	4.08%	4.08%	12.11%	15.34%	20.77%	0.04%	26.45%

[158] Stated another way, the Company calculated the percentage of the total, bundled revenues each customer class currently pays and distributed the requested distribution revenue increase across each customer class based on those percentages.

Table 83: Relative Rates of Return by Rate Class

Source	Total	R	RT	GS	GST	LPT	M	U
2015: (Docket No. 16-06-04 Colca PFT, MPC-2)	1.0	1.03	1.66	1.26	0.69	0.30	0.95	1.66
2017: (Docket No. 16-06-04, Order No. 2 – Comp. E 6.0A)	1.0	0.96	1.47	1.15	0.82	0.55	1.26	2.18
2021: (Docket No. 22-08-08, Ex. UI- BR-3)	1.0	0.27	1.21	1.72	2.32	3.03	0.01	3.74
2021: (Docket No. 22-08-08, Response to LFE-4)	1.0	0.56	0.56	1.67	2.12	2.87	0.01	3.65

The Company committed in its last rate case, Docket No. 16-06-04, to address the lower-than-average class rate of returns of residential customers and to move toward an equalized rate of return among customer classes over time. Hr'g Tr. Feb. 16, 2023, 213:18 – 214:2. However, the Company did not articulate how it has worked towards that commitment or how the residential customer class rate of return that results from a uniform increase for all rate classes furthers the objective of moving to class equalized rates of return. Hr'g Tr., 171:9-16. Instead, the Company simply stated that the ACOSS results should be used if actions were to be taken to differentiate any rate increases by customer class in order to move customer classes toward an equalized rate of return. Hr'g Tr., 205:13 – 206:9.

2. Position of the Parties

The OCC supported the Company's proposed bundled allocation strategy to uniformly increase the revenue requirements of all customer classes. Chernick Prefiled Test., Dec. 13, 2022, p. 19. The OCC clarified during cross examination that it is in support of a uniform increase for all customer classes but did not have a position on whether such increase should be calculated based on bundled or unbundled (i.e., distribution-only) revenue. Hr'g. Tr. Feb. 21, 2023, 636:13-24.

Similarly, Walmart did not disagree with the Company's revenue allocation approach if the full revenue requirement requested by the Company is approved. Kronauer PFT, p. 15. However, if the Company's requested revenue requirement is lowered, Walmart recommends that the Authority take significant steps to address the above-cost rates for distribution paid by the GS, GST, LPT, and U classes. Starting with the Company's proposed revenue allocation, Walmart recommends applying half of the difference between the approved revenue requirement and UI's proposed revenue requirement as a reduction to the RT, GS, GST, LPT, and U classes based on the proportional contribution of each class to the overall current revenue requirement per the ACOSS. Id., p. 16. Further, Walmart suggests that the remaining half of the difference between the approved revenue requirement and UI's proposed revenue requirement should be applied on an equal percentage basis to all customer classes, provided that no class moves from a subsidizing to a subsidized position, or vice versa. Kronauer PFT, pp. 15-16.

CIEC contends that the revenue allocation method proposed by the Company must be rejected for several reasons. CIEC states that the allocation of the distribution revenue increase proposed by the Company runs counter to the results of the ACOSS, rather than being guided by it. CIEC further suggests that the Company's ACOSS clearly

demonstrates that non-residential rates result in large subsidies to other customer classes. Baudino Prefiled Test, Dec. 13, 2022, p. 2. CIEC avers that these subsidies should be reduced to better align non-residential rates with the costs incurred to serve those customers and that the Company's proposed revenue allocation method further exacerbates the existing subsidies. CIEC asserts that there is no cost basis or other rationale that could justify continuing or worsening the inter-class subsidies currently embedded in commercial and industrial rates. Id., p. 3.

CIEC favors the class revenue allocation indicated by the ACOSS modeling. Baudino PFT, p. 15. CIEC provided an exhibit that shows that the Company's proposed bundled revenue allocation (i.e., distribution, transmission, and generation) results in a lower increase to the residential customer class in dollars than if spreading any increase equally based upon class distribution revenues. Id., p. 2. CIEC, however, recommends that the revenue increase be based on moving halfway toward the revenue level required to achieve equalized rates of return, as shown in the table below. Baudino PFT, pp. 15-16.

Table 84: CIEC Recommended Revenue Allocation

(1) Rate Class	(2) Present 9/1/23 Revenues $/year	(3) Equal Percentage Increase at UI Proposed	(4) Subsidy at Current Rates	(5) 50% of Subsidy	(6) CIEC Recommended Increase	(7) Percentage Increase
R	$147,269,025	$43,360,366	$ (32,881,264)	$ (16,440,632)	$59,800,997	40.6%
RT	$ 65,695,559	$ 19,342,719	$ 3,402,448	$ 1,701,224	$17,641,495	26.9%
GS	$ 38,324,949	$ 11,284,001	$ 5,878,403	$ 2,939,202	$ 8,344,799	21.8%
GST	$ 61,387,219	$ 18,074,217	$ 16,268,028	$ 8,134,014	$ 9,940,203	16.2%
LPT	$ 25,411,601	$ 7,481,928	$ 9,772,379	$ 4,886,190	$2,595,739	10.2%
M	$ 8,146,725	$ 2,398,637	$ (2,798,521)	$ (1,399,261)	$3,797,898	46.6%
U	$ 533,792	$ 157,164	$ 358,526	$ 179,263	$ (22,099)	-4.1%
Total	**$ 346,768,869**	**$ 102,099,032**	**$ (0)**	**$ (0)**	**$ 102,099,032**	**29.4%**

Application Sch. E-2.0-A-NL and E-2.1-A-NL; Baudino, PFT, Ex. RAB-3.

Lastly, CIEC advises that the Authority should not approve an indefensible class revenue allocation in this proceeding only to consider a more reasonable approach in a different docket, at an indeterminate time, without the benefits of the breadth of factors considered through a rate case. Baudino PFT, p. 15. CIEC recommends that the Authority approve a class revenue allocation that moves the rate classes closer to an equal rate of return, as indicated by the results of the ACOSS. Baudino PFT, p. 15.

3. Authority Analysis

As an initial matter, the Authority rejects the Company's proposed bundled class revenue allocation method, which incorporates generation, transmission, and distribution rates. While the Company admittedly did not take a "deep dive" to perform the necessary analytics of its ACOSS results, the Authority still finds the analysis informative in allocating revenue between classes. Hr'g Tr., 164:22-165:3. Moreover, the above tables demonstrate that the Company has moved significantly away from unity rate of return among the rate classes. In particular, the residential customer class and Class M Street and Security Lighting rates of return have lagged the commercial and industrial and Class U rate classes, imparting a de facto subsidy to residential and Class M customers.

Accordingly, the Authority adopts a class revenue allocation below that begins to address this subsidy.

The Company's explanation of the reasons for rejecting its filed ACOSS shifted over the course of the proceeding. Initially, in prefiled testimony, the Company cited the foregoing generic dockets as appropriate venues to examine allocated cost of service and rates. Colca & Marini PFT, p. 5. At the evidentiary hearings, the Company cited industry changes and open dockets in Connecticut, which were not modeled in its filed ACOSS. Hr'g. Tr. Feb. 16, 2023, 194:6 – 195:15. At other points in the hearings, the Company suggested that it did not have time to interpret the relative rates of return differentials that came out of its ACOSS. See, e.g., Hr'g Tr., 195:20 – 196:7. Separately, the Company cited as a primary concern that migration between Rates RT and R as a revenue recovery matter was responsible for setting the ACOSS results aside. Hr'g Tr., 417:3 – 419:14.

Regardless of the reasons the ACOSS was not relied on by the Company, UI ignored basic cost causation principles in proposing an equal percentage increase for each rate class using a bundled methodology. The proposal also violates the commonly accepted ratemaking principle of fairness since it ignores the results of the Company's ACOSS and imparts a revenue (and therefore rate) allocation scheme that is not tied to the distribution rate increases being sought. Moreover, relying on total revenues as opposed to distribution revenues to allocate a distribution revenue increase conflates the relationship between different energy products. Simply put, there is no logical basis for including transmission and generation costs in the allocation of distribution revenue.

The Company's dismissal of its ACOSS as a guide for cost allocation and rate design proposal is troubling, and the shifting justification even more so. Importantly, the Authority is unable to determine if a proposed cost and revenue allocation approach results in rates that are fair and not unreasonably discriminatory if the Company itself does not have reasonable confidence in the analytical underpinning of its proposal. The Company's assertion that it did not have time to analyze its ACOSS is particularly egregious as UI was not compelled to submit an Application on September 9, 2022, and had over 150 days after the submission of its Application to further understand and explain the ACOSS during the hearings in this proceeding. Ultimately, requesting an increase in distribution revenues without assurances that such increase will be fairly distributed amongst customers is irresponsible and constitutes a flagrant violation of the statutory imperative to ensure "appropriate protection to the relevant public interests." Conn. Gen. Stat. §16-19e(a)(4).

For the reasons noted above, the Authority rejects the currently proposed revenue allocation.[159] Instead, the Authority seeks to begin moving towards class equalized rate of return over time. Notwithstanding the above-stated concerns, the Authority recognizes

[159] The Authority also declines to adopt CIEC's suggested methodology for moving towards equalization of rate of return among the rate classes. While the Authority generally agrees with the intention of CIEC's proposal, the Authority finds that CIEC's proposed methodology violates the ratemaking principle of gradualism. Specifically, the Authority finds the proposed increase in revenues for the residential customer class of 40.6% to be in violation of these principles and outside of the Authority's general rule of not allowing the rate increase for any one customer class to exceed 125% of the overall average increase.

that the ACOSS may be used to provide relative guidance for the allocation of customer class revenue increases and as a first step towards equalized rates of return. Specifically, the Authority recognizes that the study's results show that residential customers and Rate M customers lag in their contributions to rate of return compared to the commercial and industrial and Rate U rate classes, which corresponds with the Authority's understanding that secondary distribution systems costs have and will likely continue to rise proportionally more than primary distribution system costs.

The revenue requirement approved in this Decision is $384.865 million, of which $369.726 million is annual operating revenues allocated to base distribution rates. $369.726 represents a 6.62% increase over the current $346.769 million incorporated into base distribution rates. As noted in Section X., Rate Design, the Authority typically requires rate class revenue reductions or increases to be within one and quarter times the overall distribution revenue increase. See 2016 Rate Case Decision, p. 108; see, also, 2013 Rate Case Decision, p. 153. Also as noted above, commercial and industrial customer and Rate U classes are currently disproportionately contributing to the overall rate of return. Accordingly, the Authority directs the Company to increase the distribution revenue requirements of all commercial and industrial customer classes and the Rate U rate class by the minimum amount allowable under the basic revenue increase formula (i.e., by 75% of the overall distribution revenue increase), or 4.965% (6.62%*0.75). This results in a total allocation of $6.239 million to customer classes GSU, GSN, GSD, GSTN, GST-SS, GST-LRS, LPT-SS, LPT-LRS, and U. The remaining $16.718 million shall be proportionately allocated to residential and Rate M customer classes, resulting in a 7.561% increase in the distribution revenue requirements of customer classes Rate R, RT, and M. The Authority finds the 7.561% increase acceptable as it falls below the maximum customer class increase of 8.275% (6.62%*1.25) allowable under the basic increase formula. The below figure provides the relevant customer class revenue requirements calculations based on the above direction.

Figure 6: Approved Class Revenue Allocation

Customer Class	Customer Count	Present Distribution Revenues	Multiplier % Increase	Distribution Revenues Increase	Adjusted Distribution Revenues
	#	$/year	%	$	$
R	234,868	147,269,025	7.561%	11,134,606	158,403,631
RT	71,902	65,695,559	7.561%	4,967,060	70,662,619
GSU	25,598	368,363	4.965%	18,290	386,653
GSN		5,296,516	4.965%	262,979	5,559,494
GSD		32,660,071	4.965%	1,621,613	34,281,683
GSTN	9,073	923,884	4.965%	45,872	969,756
GST-SS		44,224,882	4.965%	2,195,820	46,420,702
GST-LRS		16,238,453	4.965%	806,259	17,044,712
LPT-SS	369	7,965,881	4.965%	395,516	8,361,397
LPT-LRS		17,445,719	4.965%	866,202	18,311,921
U	3	533,792	4.965%	26,503	560,295
M	53	8,146,725	7.561%	615,951	8,762,676
Total		**346,768,869**	**6.620%**	**22,956,671**	**369,725,540**

This modest change will provide some movement towards rate equalization among all customer classes. However, the Authority acknowledges that full movement towards ACOSS will occur over time, with greater movement possible based upon the forward-looking ACOSS to be filed in the Company's next rate case.

Finally, as discussed further in Section X.D.1., Rate Design Proceeding, the Authority declines to open a proceeding to further discuss revenue and cost allocation and rate design at this time, as distribution rate cases, such as the instant proceeding, are the most effective venue for such determinations for a specific EDC.

E. RATE DESIGN

1. Rate Design Proceeding

The Company proposes that comprehensive rate redesign should await the outcome of, or be conducted in, one of two proceedings: Docket No. 17-12-03RE11, which was opened to address various rate design issues, or Docket No. 17-12-03RE02, which was designed to address Automated Metering Infrastructure (AMI) and related ratemaking. Docket No. 17-12-03RE11 has been concluded. Hr'g Tr. Feb. 16, 2023, 100:11. If the Company's proposal were accepted, that leaves only the AMI Docket as the forum for designing UI rates. The Company concedes it would then need to await

additional direction from PURA in order to craft specific rate designs. Hr'g Tr. Feb. 17, 2023, 425:3-5.

CIEC objects to the Company's revenue allocation approach and rejects the Company's suggestion that rate design issues be addressed in other generic dockets addressing AMI and rate design issues. CIEC avers that UI's current rate case is the appropriate venue to decide these issues and that delivery rate cases such as this docket are the traditional venue to resolve how a utility's revenue requirement is allocated to customer classes and the rate designs that are used to recover those costs.

The Authority agrees that a generic proceeding is not the appropriate venue for determining a specific regulated utility's rate design. More specifically, it is inappropriate for a regulated entity to request a distribution revenue increase without deep consideration of the most appropriate cost and revenue allocation methodologies and the most effective rate designs. Moreover, it is not appropriate (or logical) to ask for a rate increase, but to propose that the issues of cost allocation and rate design be tabled until *after* the increase is effective. Such an approach could be interpreted as absolving the Company of its responsibility to proactively make rate design proposals that are in its customers' and the public's interest, which PURA will not countenance.

The Authority may have been open to a generic docket to standardize cost and revenue allocation methodologies and rate designs, particularly if the objective was to leverage the Authority's, EDCs', and stakeholders' recent work related to the Equitable Modern Grid proceedings (i.e., Docket Nos. 17-12-03RE01 through 17-12-03RE11) and to standardize the relevant practices between the EDCs, to the extent desirable and practicable. However, such docket needed to be initiated and concluded well before the submission of any rate application to allow implementation of the direction from that proceeding to be addressed in the EDC's subsequent rate case, as distribution rate cases are the most effective venue in which to determine the application of cost allocation methodologies and rate design for a specific EDC as they allow for a comprehensive review of all relevant factors.[160] On a going forward basis, the Authority will not initiate a generic cost allocation and rate design proceeding until at least both Docket No. 17-12-03RE02 and Docket No. 21-05-15RE01 are substantially completed, given the priority of these, and other, dockets and as the outcome of both proceedings would impact a generic cost allocation and rate design proceeding.

Lastly, and most importantly, the existence of other proceedings and ongoing efforts that affect cost allocation and rate design does not alleviate a regulated entity from compiling a full and complete cost allocation and rate design proposal in a rate application. Indeed, there will always be unknown or uncertain factors when a company submits a rate application. The Company may not ignore these factors but must rather make a good faith effort to take them into account and to prepare for the most likely outcomes. Here, the Company should have taken any number of additional actions including, but not limited to, submitting its relevant testimony from Docket Nos. 17-12-03RE02 and 17-12-03RE11 into this proceeding and explicitly incorporating its

[160] However, some limited rate design changes may be appropriate outside of a rate case given sufficient cause shown, as was the case in the June 23, 2021 Interim Decision – Phase 1A (Eversource Rate 30) in Docket No. 17-12-03RE11.

recommendations from those investigations into its Application. Indeed, such an approach would likely have aided the Company in achieving its own objectives in those proceedings through this rate case.

2. Single-Year Rate Design

As described in Section III.B., Multi-Year Rate Plan, the Authority approves a revenue requirement for Rate Year 2023/2024 and rejects UI's Multi-Year Rate Plan. The Company is directed to file a revised single-year rate design plan consistent with the Authority's findings contained herein that will include revised tariffs and revenue proof.

3. Intraclass Cost Allocation

For the intraclass rate design, the Company proposes to increase only demand and energy rates for demand-metered rate schedules and only energy rates for non-residential energy-only metered customers. For demand-metered rate schedules, the Company proposes to increase demand and energy rates in the same proportion as the present revenues derived from those respective charges. Colca & Marini PFT, p. 6.

For the outdoor lighting customer class M rate schedules (Rates M, MC, MH, and LED), the Company proposed to increase the fixed monthly charge. Ex. UI-MC/MM-1, p. 7; Application, Sch. E-1.10A. For outdoor lighting schedule Rate U, the Company proposed to increase the fixed monthly charge and energy charge in the same proportion as the present revenue derived from those respective charges. Ex. UI-MC/MM-1, p. 7. The Company acknowledged that it had used an incorrect cost allocator in its ACOSS associated with service drops (FERC Account 369) to street lighting customers, and subsequently updated its cost of service to correct the cost allocation for street lighting customers. Interrog. Resp. OCC-352; CIEC-1 Att. 1. This correction had a minimal impact on the rate of return for street lighting.

Walmart objects to the use of per kWh energy charges to recover demand related costs, contending that such an approach violates cost causation principles. Kronauer PFT, p. 21. Walmart also addresses the Company's rate design for the GS and GST classes. While Walmart does not oppose the Company's proposed GS and GST rate designs at the Company's proposed revenue requirement, it suggests that if the Authority grants a lower revenue requirement for either classes GS or GST, the Authority should first set the demand and customer charges for those classes at the levels initially proposed by the Company and apply the reductions in revenue requirement to kWh-based rates on those schedules. Kronauer PFT, p. 24.

CIEC offers specific rate design recommendations for the LPT and GST classes; specifically, that the increase in revenue requirements to LPT customers be collected through an increased demand charge. For Rate GST, CIEC recommend that the kilowatt-hour and demand charges be increased at equal percentage increases. Baudino PFT, p. 16.

Other than the foregoing, no party addressed non-MRCC tariff rate design (i.e., non-residential customer charges, demand charges, or energy rates) directly in prefiled or rebuttal testimony. However, there was a significant level of interrogatories and cross-examination directed at the Company witnesses concerning various aspects of the Company's present rates and suggested reforms thereto, and the Company did offer

specific rate changes that would result from the application of its ACOSS in response to an interrogatory. UI Interrog. Resp. RRU-0494, Attachment 1, p. 3.

The Company's proposal to increase demand and energy rates in the same proportion as the present revenues derived from those respective charges for demand-metered rate schedules has no analytical basis. Specifically, such proposal is not consistent with either the intraclass cost allocation approved in the 2016 Rate Case Decision, as an approach consistent with that decision would require customer charges be increased proportionally along with energy and demand charges, or the ACOSS submitted in this proceeding. As outlined in the previous two sections, Sections X.B., Cost of Service Study, and X.C., Class Revenue Allocation, it is inappropriate to request a distribution revenue increase without an up-to-date analysis of a fair and equitable distribution of revenue and costs. As such, the Authority is left with little record evidence upon which to allocate intraclass costs. Moreover, the Authority is unable to assess the appropriateness of Walmart's and CIEC's recommendation to allocate the distribution revenue increases approved for demand-metered rate schedules in this Decision only to demand charges as there is no information in the record on how such an approach would impact smaller business customers on Rate GS.

Therefore, the Authority directs the Company to file as a compliance filing tariffs for the customer rate classes based upon the following direction, which incorporates the intraclass cost allocation approved in the 2016 Rate Case Decision, CIEC's recommendations, and the Maximum Residential Customer Charge:

> For residential rate classes Rate R and RT, the revenue increases approved in Section X.C., Class Revenue Allocation, and the reduction to the class revenue requirement for Rates R and RT due to the reduction in the customer charge shall be applied to usage rates. The Maximum Residential Customer Charge rate of $11.34 shall apply and is addressed in greater detail in Section X.D.4., Maximum Residential Customer Charge, below.
>
> For the commercial and industrial customer classes other than LPT, the revenue increases approved in Section X.C., Class Revenue Allocation, shall be proportionately spread over demand and energy rates.
>
> For the commercial and industrial customer class LPT, the revenue increases approved in Section X.C., Class Revenue Allocation, shall be applied to demand rates.
>
> For the outdoor lighting customer class M, the revenue increases approved in Section X.C., Class Revenue Allocation, shall be applied to the fixed monthly charge. For outdoor lighting schedule Rate U, the revenue increases approved in Section X.C., Class Revenue Allocation, shall be proportionately spread over the fixed monthly charge and energy charge.

4. Maximum Residential Customer Charge

The Authority accepts the Company's methodology to calculate its maximum residential customer charge (MRCC), which would reduce the MRCC for both Rates R

and RT. Based on the Company's calculation, MRCC residential customers would see a $1.50 reduction from the current value of $12.84 to $11.34 per month per bill. Ex. UI-MC/MM-2; UI Interrog. Resp. RRU-92.

Conn. Gen. Stat. §16-243bb, enacted in 2015, required the Authority to adjust each EDC's residential non-heating customer charge to recover only certain costs and O&M expenses associated with four specified functions: metering; billing; service connections; and the provision of customer service (statutory functions) for residential customers. The Authority contemplated the O&M costs directly related to the 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). As such, the Authority required 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.

The OCC did not oppose the Company's calculation of MRCC. Instead, the OCC opined that the costs included in the MRCC were associated with meters, services, meter reading, customer billing and accounting. Chernick Prefiled Test., Dec. 13, 2022, p. 19. Further, the OCC's witness opined that the proposed value is consistent with other estimates of customer-related costs that he has seen. Id.

The Authority reviewed UI's MRCC calculation and finds that it conforms with the MRCC Decision. Specifically, the Company calculated its proposed MRCC using only the FERC accounts allowed in the MRCC Decision. The Company did not include FERC Account 904 - Uncollectible Accounts in its calculation.

In the MRCC Decision, the Authority found that expenses in FERC Accounts 901, 902, 903, and 905 are directly related to billing, metering, or customer service. MRCC Decision, p. 31. As a result, the Authority deemed the costs in these accounts as eligible for inclusion in the MRCC calculation as identified through direct assignment. Id. However, the Authority found that there are no direct labor expenses incurred by the EDCs' credit and collection activity, which are recorded in Account 903 for the billing function. Id. In the instant case, no evidence was submitted that refuted or otherwise brought into question the Authority's findings in the MRCC Decision.

The Authority accepts UI's MRCC methodology and approves the reduced MRCC of $11.34. The Authority directs the Company to submit scored and unscored tariffs with the calculated MRCC.

5. Demand Charges for Small Business Customers

The Company's Rate GS offering is limited to customers with a monthly demand of less than 100 kW. Hr'g Tr. Feb. 17, 2023, 309:17-24. However, Eversource's electric rate for small businesses, Rate 30A, allows for customers with a monthly demand up to 200 kW. Hr'g Tr., 309:25-310:3. Additionally, the Company stated that it has not analyzed the distribution and range of demands in each of the GS and GST rate classes to ensure that smaller customers are generally covered by rate GS and that the cutoff point between the rates is appropriate. Hr'g Tr., 311:21-312:7. Further, when asked via interrogatory to "[p]rovide a breakdown of the GS and GST rate classes by 1) the number of accounts, 2) annual distribution revenues, and 3) annual kWh sales split into sections by customer

annual demand in 5 kW demand increments (i.e., number of accounts with monthly demand of 0-5 kW, 5- 10 kW, etc.)", the Company stated that it could not complete the analysis in the time allotted as it would take weeks. Interrog. Resp. RRU-491, pp. 1-2.

The Authority notes that changes to the threshold between rates GS and GST may be appropriate, as may be the creation of a new rate for small businesses, but that such a conclusion cannot be drawn from the information available in this proceeding. Accordingly, the Authority directs the Company to provide as a compliance filing in the instant proceeding by September 30, 2023, the following for both rates GS and GST: (1) the number of accounts associated with the rate; (2) the annual distribution revenues from the rate; (3) a histogram of the count of customers in groups divided by peak annual demand (e.g., number of accounts with peak annual demand of 0-5 kW, 5-10 kW, etc.); and (4) a histogram of annual kWh sales broken into groups divided by peak annual demand (e.g., annual kWh sales from accounts with peak annual demand of 0-5 kW, 5-10 kW, etc.).

Further, the Authority directs the Company to provide a recommendation for a threshold update between rates GS and GST in its next rate case application, as well as 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). The Company's recommendation much include the same histograms required of the compliance filing described above for each of the theoretical new rate classes. Further, the Company must provide an analysis of the hourly load profile of customers in the GS and GST rate classes for all four seasons and provide any recommendations on updating the distribution charges for each class based on daily and/or seasonal TOU. Lastly, the Company shall perform a demonstration of the per-kWh equivalent rate by demand tiers within all rate classes containing demand charges (this per-kWh equivalent is to be calculated as all distribution revenues collected both by kW or kWh [i.e., excluding customer charge revenues] by demand tier, divided by the sum of kWh served annually in that demand tier).

6. Time-of-Use (TOU) Rates

The Company did not provide any recommended changes to its existing Time-of-Use (TOU) rate structures or any related analysis in its Application. At present, the Company offers two non-generation-related TOU rates: Rate RT for residential customers; and Rate GST for commercial customers. Application, Sch. E-1.0-A , pp. 61 and 70. The Company has not adjusted its TOU rates since 2005, during which time the price differential rates were established in UI's last base rate case proceeding in the 2008 Rate Case Decision. Hr'g Tr. Feb. 17, 2023, 355:9-15; 2008 Rate Case Decision, pp. 17-22. Further, the Company stated that it does not study how its customers' behaviors change on TOU rates and what the price differentials might need to be in order to encourage behavior change to off-peak energy usage. Id. Currently, residential customers on Rates R and RT use about 26-27% and 24-25% of their energy during the on-peak times of 12:00 P.M. to 8:00 P.M., respectively. Hr'g Tr. Feb. 17, 2023, 353:24-354:11; Application, Sch. E-1.0-A, p. 62. The Company stated that this two-percentage point difference between the Rates R and RT customers has existed for several years. Hr'g Tr., 354:4-6. While UI opined that it would be open to examining and adjusting its existing TOU rates in the future, it proposed to maintain such rates in their current forms in this rate case proceeding. Hr'g Tr. Feb. 17, 2023, 293:5-14, 304:6-9, 306:25-307:1.

UI shared that adjusting its current TOU on-peak period to a shorter amount of time would sharpen the price signal for participating customers. Hr'g Tr., Feb. 17, 2023, 293:22- 294:2, 309:2-16. In addition, UI conceded that the on-peak periods for Rates RT and GST could each be shortened and still capture ISO-New England annual and UI distribution system peaks. Hr'g Tr., 305:16-23, 360:1-17. However, the Company did not provide data reporting on daily peak loads in order to better understand UI's year-round load distribution. Hr'g Tr., 359:10-19; Interrog. Resp. RRU-338, Att. 1.

Initially, UI claimed that adjusting its TOU on-/off-peak time periods would require a significant time and cost investment. Interrog. Resp. EOE-213; Hr'g Tr. Feb. 17, 2023, 357:13-19. Specifically, UI asserted that it would need to manually reprogram every meter in order to implement any changes to the on-peak time period for Rate RT customers. Id. However, subsequently, UI stated that it could remotely reprogram participating meters "en masse" over-the-air through a pilot program. Hr'g Tr. Feb. 17, 2023, 431:6-19; Hr'g Tr. Feb. 21, 2023, 595:17-19. UI also subsequently suggested a "more scalable solution," where UI could adjust the TOU period through modifications in the billing system rather than resort to manually reprogramming every meter. Hr'g Tr., Feb. 17, 2023, 436:2-13; Late Filed Ex. 9. When requested to provide additional detail regarding any required time or costs to adjust the TOU on-peak period, UI declined to do so; rather, the Company stated that further investigation would be required to provide such estimates. Late Filed Ex. 9.

The Authority is interested in further exploring the adjustment of TOU on-peak periods. As DEEP stated, the continued deployment of DERs and the likely increase in electric demand due to beneficial electrification could put additional strain on the electric grid. DEEP Brief, p. 16. Furthermore, such additional demand may increase ratepayer costs by requiring infrastructural upgrades that increase capacity. The Authority endeavors to support the deployment of clean energy projects throughout the state in an efficient, cost-effective manner that maximizes the benefits to ratepayers.

Additionally, the Authority is interested in further targeting the on-peak period to provide customers with a clear signal to avoid the greatest peak load times. As demonstrated by UI's data, the behavioral performance between Rates R and RT customers during the on-peak period is minimal. Therefore, the Authority questions whether there is currently any benefit to providing Rate RT under the existing rate design. Rate RT customers are not significantly incented to reduce their on-peak energy usage, which would provide additional benefits to ratepayers by reducing wear on the grid, reducing the likelihood of reliability events, and potentially avoiding future capacity upgrades. These benefits are currently lost, since customers have little motivation to adjust their behavior based on the large on-peak TOU period and the price differential between on- and off-peak energy usage. Accordingly, the Authority aims to not only study, but to implement through the Company's next rate case, adjustments to both the TOU on-peak time period and the price differential between on- and off-peak energy usage in order to optimize on- and off-peak energy use.

The Authority is disappointed with the lack of analysis and thoughtful proposals provided by UI in this rate case proceeding. First, the peak load data provided merely displays monthly load peaks. Interrog. Resp. RRU-338, Att. 1. Although the Company can provide and report in more granular detail, it declined to do so. As a result, the

Authority has little information on which it can modify, if appropriate, the current TOU on-peak period. While the Authority is interested in reducing the number of hours included in the TOU on-peak period, it is not interested in exposing distribution peak load hours to an off-peak period resulting in inefficient price signals during those times. Further, the Authority requested cost and timeline estimates from UI regarding adjusting the TOU peak periods multiple times in this proceeding. However, UI declined to provide such details. Therefore, the Authority is unable to authorize changes to the current TOU rates in this proceeding as the Company failed to provide, despite the Authority's repeated requests, sufficiently granular peak load data and cost and implementation timeline information to determine whether the changes the Authority intends to authorize are prudent and cost effective.

Accordingly, the Authority directs UI to provide further information as described below. Specifically, the Company shall, with its next rate case filing, utilize and refine its AMI data to conduct load research at the substation and feeder levels. Additionally, each existing or potential new customer class load research shall be robust enough to address the suggestions of the OCC in its testimony in this docket regarding classifications to demand and allocations of specific plant and equipment to customer classes. The load research shall also be made available to customers through appropriate portals accessible via the Company's website in order to determine how a customer's consumption compares to other customers and to determine how such customers' bills would be impacted by time-of-use and seasonal rates.

Accordingly, the Authority directs the Company to prepare specific rate redesign proposals in its next rate case application. Such rate redesign proposals shall address the following regarding TOU rates: (1) a shorter, more concentrated on-peak time period that is likely to capture ISO-NE and UI distribution system peaks and to incent the cost-effective shifting of load to off-peak periods; (2) the appropriate price differential between on- and off-peak TOU rates, reflecting and consistent with empirical research conducted by the Company and other utilities and rate design experts; (3) an alignment of TOU rates across utility functions that recover costs of generation, transmission, and distribution service (i.e., provide a TOU proposal for all retail electric rate components) with fixed demand-related costs primarily or exclusively recovered from customers in the on-peak rate period; and (4) a proposal to make TOU rates opt out, and the appropriate phase-in period over which time customers could adjust to opt-out time-of-use rates without severe rate and bill shock. Such rate redesign proposals shall also address the following regarding seasonal rates: (1) a proposal(s) for differentiation of generation, transmission, and distribution energy and demand rates into summer and non-summer periods at a minimum, and if cost differences are substantial, winter and shoulder month periods; and (2) the appropriate phase-in period over which time customers could adjust to seasonal rates without severe rate and bill shock.

7. Summary of Rate Design Direction

The Company is directed to file a revised rate design plan consistent with the Authority's findings contained herein that will include revised tariffs and revenue proof. The approved distribution revenue increase shall be allocated such that the revenue requirements of customer classes GSU, GSN, GSD, GSTN, GST-SS, GST-LRS, LPT-SS, LPT-LRS, and U are increased by 4.965% and the revenue requirements of customer classes R, RT, and M are increased by 7.561%. This modest adjustment to the customer

class revenue allocation will provide some movement towards rate equalization among all customer classes based on the ACOSS results.

Moreover, the Authority directs the Company to adhere to the following direction when allocating costs within a rate class:

> For residential rate classes Rate R and RT, the revenue increases approved in Section X.C., Class Revenue Allocation, and the reduction to the class revenue requirement for Rates R and RT due to the reduction in the customer charge shall be applied to usage rates. The Maximum Residential Customer Charge rate of $11.34 shall apply and is addressed in greater detail in Section X.D.4., Maximum Residential Customer Charge.
>
> For the commercial and industrial customer classes other than LPT, the revenue increases approved in Section X.C., Class Revenue Allocation, shall be proportionately spread over demand and energy rates.
>
> For the commercial and industrial customer class LPT, the revenue increases approved in Section X.C., Class Revenue Allocation, shall be applied to demand rates.
>
> For the outdoor lighting customer class M, the revenue increases approved in Section X.C., Class Revenue Allocation, shall be applied to the fixed monthly charge. For outdoor lighting schedule Rate U, the revenue increases approved in Section X.C., Class Revenue Allocation, shall be proportionately spread over the fixed monthly charge and energy charge.

8. Summary of ACOSS Direction

Considering the number and scope of rate design-related issues identified above, the Authority orders UI to prepare an ACOSS that can provide support for, and make explicit proposals concerning, the rate design options discussed herein (including demand charges for small business customers, TOUs, and seasonal cost analyses) with its next distribution rate case application. The direction included in this Decision should not be construed as discarding the requirement to provide a historical test year ACOSS in the future, but rather an obligation for UI to provide supplemental analysis with its next rate application. The Authority cautions the Company to be prepared to explain, support, and defend these analyses and proposals in a manner consistent with applicable statutory requirements and the rate design principles and considerations discussed above *before* filing any request for adjustments to its base distribution revenue requirements.

The Authority summarizes below the direction regarding changes to the ACOSS and the required supplemental analysis to be submitted in the Company's next rate case:

> ACOSS
> The Company must perform a MSS based upon the actual, incurred (i.e., average embedded) costs of the current system as constructed to the best of its ability and demonstrate the resulting ACOSS summary values.

The Company must begin exploring alternatives to demand allocation, considering specific circuit information and sizing relating those to customer usage to be specifically discussed in testimony and filed as an alternative ACOSS in the Company's next rate case. In doing so, the Company must utilize all AMI data available to conduct relevant customer load research. Specifically, the alternative ACOSS must identify all of the circuit-specific data available to the Company, any additional data collected or load research performed, how the Company analyzed the collected data and research to determine customer class demand allocation factors, and the results of such analysis.

The Company must study a future Test Year equivalent to the third rate year of a hypothetical multi-year rate plan and present it to the Authority in its initial filing in any subsequent rate cases.

Demand Charges

The Company must provide a recommendation for a threshold update between rates GS and GST, as well as 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). The Company's recommendation much include the same histograms required of the compliance filing described in Section X.D.5., Demand Charges for Small Business Customers, for each of the theoretical new rate classes.

The Company must provide an analysis of the hourly load profile of customers in the GS and GST rate classes for all four seasons and provide any recommendations on updating the distribution charges for each class based on daily and/or seasonal TOU.

The Company must perform a demonstration of the per-kWh equivalent rate by demand tiers within all rate classes containing demand charges (this per-kWh equivalent is to be calculated as all distribution revenues collected both by kW or kWh [i.e., excluding customer charge revenues] by demand tier, divided by the sum of kWh served annually in that demand tier).

Time-of-Use Rates

The Company's TOU rates proposal must recommend a shorter, more concentrated on-peak time period that is likely to capture ISO-NE and UI distribution system peaks and to incent the cost-effective shifting of load to off-peak periods.

The Company's TOU rates proposal must recommend the appropriate price differential between on- and off-peak time of use rates, reflecting and consistent with empirical research conducted by the Company and other utilities and rate design experts.

The Company's TOU rates proposal must recommend alignment of TOU rates across utility functions that recover costs of generation, transmission, and distribution service (i.e., provide a TOU proposal for all retail electric rate components). Such aligned rates shall recover fixed demand-related costs

primarily or exclusively in the on-peak rate period.

The Company must provide a proposal to make TOU rates opt out, and the appropriate phase-in period over which time customers could adjust to opt-out TOU rates without severe rate and bill shock.

Seasonal Rates

The Company must submit a proposal(s) for differentiation of generation, transmission, and distribution energy and demand rates into summer and non-summer periods at a minimum, and if cost differences are substantial, winter and shoulder month periods.

The Company's seasonal rates proposal must also include the appropriate phase-in period over which time customers could adjust to seasonal rates without severe rate and bill shock.

Lastly, the Company's rate proposals submitted in its next rate case provide a plan for moving existing and new customers classes closer to class-by-class rate of return parity, while balancing the rate design principles of gradualism and the Authority's rule that the rate increase for any one customer class should not exceed 125% or be less than 75% of the overall average increase.[161]

F. OTHER RATE-RELATED TOPICS

1. Economic Development Rates

a. Summary of Company Proposal

The Company proposes a new Economic Development Rate Rider (EDR Rider) as outlined in Exhibits E-1.0, A-C and E-1.1, A – C of the Application and discussed in Section V of the Direct Testimony of Mark P. Colca and Mark O. Marini. Ex. UI-MC/MM-1, p. 12. The proposed EDR rider was designed to attract new business customer accounts to the Company's service territory and to encourage business growth amongst existing customers. Ex. UI-MC/MM/GT-1, pp. 4-5. The Company notes that the rate can be made available as soon as September 1, 2023, if the Authority were to grant approval in this rate case. Ex. UI-MC/MM/GT-1, p. 3.

In developing the proposed EDR Rider, the Company claims to have reviewed numerous economic development rates from other jurisdictions. Interrog. Resp. CAE-1, Att. 1, pp. 1-5; Interrog. Resp. CAE-3, pp. 1-3. The Company notes that the Pacific Gas & Electric Corporation economic development rate implemented in California created or retained approximately 11,000 jobs through 2018 and added 119 MW of load to the electric grid. Hr'g Tr. Feb. 17, 2023, 465:9-21. Further, the Company notes that the number of industrial customers in UI's territory has been decreasing for at least 10 years, with a net loss of 30 to 40 customers a year for the last several years. Hr'g Tr., 283:12-

[161] Good cause may be shown for breaking the latter rule, particularly if there is shown to be significant disparity between the class rates of return. However, any proposal must adhere to the principle of gradualism, in order to avoid rate shock.

25, 285:16-286:2. Additionally, the Company has records of one inquiry over the last five years from a manufacturer of wind energy equipment relating to potential incentives for new businesses. Late Filed Ex. 11, p. 1.

The proposed EDR Rider provides a tiered discount to eligible Commercial and Industrial (C&I) customers (Subscribers) based on economic development commitment levels. The discount percentage applies to the total of the Subscribers' delivery portion of the bill (i.e., exclusive of generation charges) for incremental load charged under the otherwise applicable standard rate. Ex. UI-MC/MM/GT-1, pp. 2-3. The Company did not design the EDR Rider to discount generation services as generation services are subject to a competitive market in which the Company is not involved. Hr'g Tr. Feb. 17, 2023, 257:3-6.

Customers may subscribe to the proposed EDR Rider for up to 5 years (Term). Ex. UI-MC/MM/GT-1, pp. 2-3. The eligibility criteria for the EDR are based on either increased employment or capital investment, as shown below.

Table 85: Proposed Economic Development Incentives

Increased Employees	Discount	Term
10-25	5%	5 years
25-50	8%	5 years
50+	10%	5 years
Capital Investment	**Discount**	**Term**
$1M-$5M	5%	5 years
$5M-$10M	8%	5 years
$10M+	10%	5 years

Id., p. 3.

Additionally, to be eligible for the EDR rider, Subscribers must agree to the implementation of at least one energy efficiency, peak demand response, or grid modernization measure. Id., p. 4. Notably, the Company did consider negotiated discount rates versus providing set discount rates, and ultimately concluded that there needs to be a balance between administrative costs and overall economic benefit, and thus the EDR Rider was created with pre-determined discount rates. Hr'g Tr. Feb. 17, 2023, p. 254. The Company also considered discount percentages that reduce in value annually over the duration of the EDR Rider Term but selected fixed percentages as the least cost method of administering an economic development rate, further asserting that Subscribers can easily understand the single line-item discount. Ex. UI-MC/MM -1, p. 14.

The EDR Rider includes a proposed 2% additional discount over prescribed levels for new or expanding load located in distressed municipalities. Id., p. 4. Further, the Company indicated the adder could be expanded to include Environmental Justice Communities as defined per Conn. Gen. Stat. § 22a-20a. Hr'g Tr. Feb. 17, 2023, p. 347. Additionally, the Company notes that the revenue requirements in this proceeding remain unchanged whether the EDR is approved or not. Specifically, UI states that:

> The discount [provided by the EDR] is temporary in nature but will result in long-term sales that benefit all UI customers through increased economic activity in the Company's service territory. During the period of the discount, the Company proposes to recover all rate components subject to reconciliation processes (TAC, NBFMCC, SBC, RDM, and Conservation and Load Management) in the normal course of the corresponding dockets. For distribution, the Company proposes to establish a regulatory asset that will include the net distribution revenue derived from sales attributable to the discount. The net distribution revenue will be calculated as the total distribution revenue obtained through the Rate EDR program, less any incremental distribution capital recovery, operating and maintenance expenses, and general and administrative expenses incurred to serve the incremental load. The Company will then recover or return, as appropriate, the net revenue associated with the program in the next general rate proceeding. There were no revenues or expenses related to the proposed Rate EDR program in this filing.
>
> Ex. UI-MC/MM-1, pp. 15-16.

Finally, the Company notes that the offering could be made available to customers as soon as September 1, 2023, if approval from the Authority is received in this rate case. Ex. UI-MC/MM/GT-1, p. 3.

In response to the proposed EDR Rider, the OCC noted that "UI apparently relied entirely on mimicking the programs of other utilities, without any analysis of the value of an added job or million-dollar investment, or even the amount of added investment that is equally important as an additional employee (CAE-0003)." Chernick Prefiled Test., Dec. 13, 2022, p. 21. The OCC further pointed out four components of the EDR Rider that it identified as flaws. Id. Specifically, the OCC notes the following: (1) that adding an equivalent number of employees triggers the same benefit level for the smallest or largest companies; (2) that the Company had not explained why the magnitude of incentives were warranted; (3) that the Company had not explained the inequity in monetary investment value equivalents for the first ten jobs versus all others; and (4) that with the tiered discount for increased headcount, there is no incentive for adding more employees within a given tier (e.g., the discount level is the same for adding 49 employees as 26 employees). Id. The OCC proposes fixing the EDR Rider to have incentive levels increase by some set incremental value for each employee added or million dollars of investment, over some minimum threshold. Chernick PFT, Dec. 13, 2022, p. 22. The OCC also noted that UI should be required to justify the proposed magnitude of incentives and submit a full benefit-cost analysis (BCA). Id.

In response to the OCC testimony, the Company noted that the discount percentages proposed are similar in magnitude to other utility offerings in other jurisdictions with similar economic development provisions, and that the selection criteria were outlined in response to interrogatory CAE-3. Ex. UI-RP-REBUTTAL-1, p. 26. Further, the Company stated that a full BCA is unnecessary as a simple marginal cost approach can be used to ensure that discounts from the EDR Rider do not result in new loads that do not cover the incremental system costs to serve. Id., pp. 24-25.

In surrebuttal, the OCC stated that as the Company disagreed with the OCC proposal to improve the correlation between the discount levels and employment and investment, the Company should propose a new discount independent of jobs and investment to simplify the rate design. Chernick PFT, p. 5. The OCC states that the intent of the rate appears to be to increase sales, and there is no need to "be rational about" aligning the discounts with employment and investment as "any customer added at a rate higher than marginal costs would reduce rates to other customers." Id.

Also, in response to the proposed EDR Rider, CIEC stated that the proposal "represents a modest first step toward an effective EDR tariff, but [that] it has shortcomings", which the organization proposes to address. Baudino Prefiled Test., Dec. 13, 2022, p. 4. Specifically, CIEC proposes: (1) including a load retention provision to allow existing customers to engage in negotiations to retain loads that would otherwise be lost to UI and Connecticut; (2) increasing the discounts provided to better compensate for the current distribution rates; (3) increasing the term to seven years; (4) to suspend the system benefits charge and NBFMCC for incremental EDR load; and (5) to add a requirement that UI develop a promotional program for the EDR Rider. Id. CIEC notes that there is a current statutory barrier to waive or exempt customers from certain reconciliation components as a form of relief for economic development. Id., p. 22. CIEC also approves of linking the discount to employment and investment, and further recommends that program eligibility be dependent on several factors, including: (1) a commitment to retain or expand jobs in Connecticut; (2) a commitment to maintain or increase capital investment in Connecticut; (3) a commitment to maintain or expand electricity demand and/or consumption; (4) verification that the EDR Rider is a substantial factor in new customers' relocation to Connecticut; (5) and verification that the EDR Rider is necessary to preserve an average historical amount of capital investment of that the rate is a substantial factor in expanding electricity demand and/or employment. Baudino Prefiled Test., Dec. 13, 2022, pp. 25-26. CIEC also recommends that the economic development rate have a threshold value and agrees with the EDR Rider proposal that limiting eligibility to Rates GST and LPT effectively accomplishes this task. Id., p. 24. Additionally, CIEC proposes the consideration of a total MW capacity limit of 500 MW, with a limit established for both small and large businesses to recognize the unique challenges of each sector. Id., pp. 24-25. Further, CIEC argues that the discount prescribed by the EDR Rider should be applied to the entirety of customer bills as opposed to just incremental load from economic development. Id., p. 20. CIEC also contends that the discount in each tier of the EDR Rider should have the percentages doubled, to 10%, 16%, and 20%, respectively. Baudino Prefiled Test., Dec. 13, 2022, p. 33. CIEC states that the increased spending and investment from the EDR Rider discounts may have large multiplier effects, or spur spending and income in larger amounts than the investment through the EDR Rider. Id., p. 30. Finally, CIEC states that the Company should be required to file an implementation plan with the Authority indicating how it intends to promote the EDR, provide information on its website about the EDR Rider, and utilize multiple channels to publish contact personnel. Id., pp. 36-37.

The Company notes that the EDR Rider is instructed by rates in other jurisdictions and is a "reasonably conservative first step" in understanding the effectiveness of such an offering in attracting new customers and leading to growth. Hr'g Tr. Feb. 16, 2023, 239:25-240:20. The Company also notes a desire for a rate design that mitigates free-ridership. Hr'g Tr., 246:14-18. Additionally, with respect to the approval process for

Subscribers, the Company notes that even with set discount and eligibility requirements as in the proposed EDR Rider, potential Subscribers would be subject to demonstrating need of the EDR Rider to prevent free-ridership and personnel at UI would be responsible for approving or denying each applicant. Hr'g Tr., 250:14-251:20; 290:2-25. The Company also notes that it is not aware of any changes to current regulation that are needed to implement the proposed EDR Rider. Ex. UI-MC/MM/GT-1, p. 10.

Additionally, UI states that the CIEC proposal could potentially negatively impact non-participants, and that a retention tariff would result in greater risk of negatively impacting future utility rates through discounting existing billings. Ex. UI-RP-REBUTTAL-1, pp. 30-31. Further, UI states that "customers should not bear the risk of lost revenue as a result of discounts; nor should the discounts be subsidized by other customers." Id., p. 31. Moreover, the Company notes that the retention provision proposed by CIEC requires considerable judgement by the Company to evaluate the past and future capital investment trends of potential Subscribers, which is a task the Company is unable to do. Id., pp. 32-33. Consequently, the Company believes that the EDR Rider should exclusively be applicable to incremental or new load. Id., p. 31. The Company also notes that the special contracting process can be utilized as necessary to retain economically sensitive customers. Id., p. 32.

The Company states that it is important that the discounted rates recover the incremental cost of providing service at a minimum, and therefore proposes that UI can reject potential Subscribers EDR Rider applications if the incremental costs will not be recovered. Ex. UI-MC/MM/GT-1, p. 6. The Company notes that while a specific economic test has not been determined, one potentially useful test is a "hurdle rate calculation comparing the net present value of the future revenue stream against the cost of connection and any other electric-related infrastructure improvements required." Interrog. Resp. CAE-61, p. 1. UI also states that to measure the incremental load of each Subscriber for the purpose of calculating discounts, the Company may install metering equipment at an existing customer's premise at the expense of that Subscriber. Hr'g Tr. Feb. 16, 2023, 244:2-7. Further, in instances where it is not feasible or practical to separately measure incremental load, the incremental load will be considered any additional load over a baseline approximation agreed upon by the Subscriber and Company. Hr'g Tr., 244:7-11.

The Company notes that the benefits from the incremental load from customers covering at least marginal costs would range from zero, in the instance where no incremental load or customers are attracted by the EDR Rider, to some positive number, leading to benefits for all ratepayers. Hr'g Tr. Feb. 17, 2023, 466:4-25. Notably, the Company states an individual Subscriber is most likely to be unable to cover the marginal cost when the incremental load, and thus revenue, falls substantially short of projections assumed in the economic test conducted during the application process. Interrog. Resp. CAE-70, p. 1. However, the Company notes that in such an instance the discounts provided to the subscriber would fall proportionally to the revenue shortfall. Id.

The Company initially proposed an 18-month demonstration period for the EDR Rider and stated that customers would be charged back for the previous 12 months if they did not meet capital investments or employment requirements. Sch. E-1.0-A, p. 285. However, the Company later clarified that UI believes a 12-month demonstration period

and 12-month clawback period would be appropriate to provide better alignment. Hr'g Tr. Feb. 17, 2023, 335:9-11. Further, for customers who have not met the discount eligibility requirements at the end of the demonstration and clawback period, the repayment to the Company may be made using a payment arrangement, which are offered by the Company for a period up to six months, with customers allowed two arrangements in a 12-month period. Hr'g Tr., 335:24-336:9, 353:10-13.

As a part of the EDR Rider proposal, the Company proposes a regulatory asset, which will include the "total distribution revenue obtained through the Rate EDR program, less any incremental distribution capital recovery, operating and maintenance expenses, and general and administrative expenses incurred to serve the incremental load." Ex. UI-MC/MM-1, p. 16. The Company states that it will return or recover the net revenue associated with the EDR Rider in the next general rate proceeding, as appropriate. Id. Moreover, UI states that the Company does not want to enact an economic development rate at existing ratepayer expense and that over the long-term the EDR Rider is expected to have a contribution above fixed costs from the incremental revenue associated with the rate. Hr'g Tr. Feb. 17, 2023, 449:1-14. The Company notes that personnel specifically associated with the EDR Rider are not accounted for in the existing revenue requirement, and as such, if there is incremental labor due to a scope of work that cannot be handled by current employees, there may be incremental costs that the Company would seek to record through an avenue to be determined after consultation amongst UI accounting personnel. Hr'g Tr. Feb. 16, 2023, 259:22-261:1.

Notably, the EDR Rider does not propose any job quality requirements for the jobs leading to EDR Rider eligibility for potential Subscribers, whereas the Company stated that Central Maine Power did institute job quality requirements as part of its economic development rate offering. Interrog. Resp. CAE-8, pp. 2-3; Interrog. Resp. CAE-63, p. 1. The Company states that it did not think job quality requirements were appropriate now, but that job quality requirements may become more appropriate as the EDR Rider rate offering matures. Hr'g Tr. Feb. 17, 2023, 338:3-18.

Lastly, the Company proposes filing a report on the EDR Rider and Subscribers annually, including, "at a minimum, the name and city/town of each customer taking service under Rate EDR, the applicable percentage discount, revenues discounted over the most recent annual period and accumulated to-date, and the status of the employment and/or capital expenditures of current Subscribers." Ex. UI-MC/MM-1, p. 15. When considering tracking EDR Rider eligibility, the Company notes that with the tiered structure it may be very difficult in some situations to track small employee increases, such as a company with at least several thousand employees adding 10 incremental employees. Hr'g Tr. Feb. 16, 2023, 244:14-245:8.

b. Authority Analysis

The Authority approves the EDR Rider outlined herein. Specifically, the Authority approves an EDR Rider that provides a 15% base discount and a 20% discount for customers located in Distressed Municipalities and Environmental Justice Communities, with a total discount cap of 50% of the total incremental distribution revenue attributable to the incremental (i.e., new or expanded) load.[162] The Authority directs the Company to

[162] For clarity, the customer discount shall only be applied to the incremental customer load.

file an implementation plan by February 1, 2024, and to offer the EDR Rider starting no later than July 1, 2024. The first annual EDR Rider report shall be due December 31, 2024, and annually thereafter.

Commercial and industrial electric rates in Connecticut are high relative to the national average. CIEC uses current rates to support doubling the discount levels for each tier of the proposed EDR. Baudino Prefiled Test., Dec. 13, 2022, p. 18, 33. The Authority is sympathetic to CIEC's position and the need for Connecticut to remain competitive with its neighbors to attract and grow businesses in the state. However, the primary reason the Authority is approving an EDR is to attract incremental (i.e., new or expanded) load, while still receiving revenues from Subscribers in excess of the incremental cost to serve, which will drive down rates for all other customers, including existing commercial and industrial customers. The "multiplier effects" of the economic development resulting from an EDR, despite the real value that it may provide to the Connecticut economy, is a secondary objective of the Authority.

As an initial matter, the Authority accepts the assertion that a fixed rate discount over the Term of the EDR Rider is the least-cost method of administering the EDR Rider. Ex. UI-MC/MM -1, p. 14. Second, the Authority concurs that providing customers with a single line-item discount is an easily understandable way for Subscribers to both track and comprehend their discount. Id.

Thus, based on the hierarchy of objectives listed above and the Authority's conclusion regarding a fixed rate discount, the Authority approves a EDR Rider with a fixed amount for all Subscribers, as opposed to the Company's original proposal to vary the discount based on employment or investment. The Authority also makes this determination, in part, because the Company already proposed to evaluate each application for need and to ensure that the discount does not exceed the expected net revenue associated with the incremental load. Further, by implementing a fixed discount rate (i.e., percentage) for customers, small businesses are not disadvantaged relative to large businesses as may otherwise occur in the case where discount threshold requirements are tied directly to dollars of investment and headcount increase. Further, a set discount rate alleviates many of the issues outlined by the OCC with the proposed EDR Rider, including any inequity in monetary investment value equivalents for the first ten jobs versus all others and the lack of incentive for adding more employees within a given tier, while also addressing the fact that the proposed EDR Rider seems "unnecessarily complicated." Chernick Prefiled Test., Dec. 13, 2022, p. 21; Chernick Prefiled Test., Jan. 17, 2023, p. 5. The Authority also notes that while there is likely a correlation between employee headcount and capital investment, neither are directly tied to ratepayer benefits. Moreover, any increase in capital investment and employee headcount will be captured as part of the annual report discussed in detail below.

As the intention of the EDR is to spur incremental load growth in Connecticut, the Authority notes that the discount must not only provide substantial benefits to existing ratepayers, but sufficient incentive to attract incremental load as well. Thus, the Authority approves an EDR Rider that allows a 15% discount on UI's base distribution rate, consistent with the middle range of CIEC's proposed discounts. However, to ensure the objective of lowering customer rates is achieved, UI shall conduct a simple hurdle rate analysis of each application to ensure that the NPV of the future revenue stream over the

Term, inclusive of any EDR discount, is greater than the incremental cost to serve, inclusive of any connection and any other electric-related infrastructure improvements required. In the event that a 15% discount rate results in a negative NPV, the Company shall offer a discount up to 50% of any projected savings over the Term to the customer. In this way, the Authority can ensure that at least 50% of the benefit from the incremental or new load is allocated to existing ratepayers.

Additionally, the Authority authorizes an additional discount of 5% to new or incremental load located in Distressed Municipalities and Environmental Justice Communities (Underserved Communities). The Authority acknowledges that the proposed 2% additional discount on incremental load for new or expanding load in distressed municipalities is based on research by the Company, which found this value to be a consistent percentage applied for distressed municipalities. Hr'g Tr. Feb. 17, 2023, 345:12-346:7. The Authority notes, however, that the Federal Investment Tax Credit provides an additional 10% bonus for distressed municipalities. Id. Further, the Authority notes that the EDR Rider should broadly promote economic development in underserved locations. Accordingly, the Authority directs the Company to expand the locations available for the additional discount to include Environmental Justice Communities as defined by Conn. Gen. Stat. § 22a-20a. The Authority also approves an additional discount to Underserved Communities of 5% to ensure successful promotion of business growth in these areas. Moreover, the base 15% discount plus the 5% Underserved Communities adder result in a total discount of 20%, which represents the highest discount advocated for by CIEC. This discount will also be capped at 50% of any projected savings of the incremental load, as discussed herein.

The Term for the EDR Rider shall be five years. While CIEC recommended increasing the proposed EDR Rider term to seven years, the necessity of the increase to seven years is not clear based on the record evidence. The Authority also notes that a majority of the economic development rate offerings analyzed in creating the EDR Rider have terms where discounts are provided for five years or less. Interrog. Resp. CAE-1, pp. 1-5.

The EDR Rider shall also be limited to incremental load. The Authority notes that the intention of rate design is to incent new and expanding incremental load, and to use the incremental revenues to benefit all ratepayers. While retaining load that asserts an intention to leave UI's territory may be economically equivalent to attracting new or expanded load within the territory, it is significantly more difficult to assess whether and how an EDR Rider retained load in Connecticut than it is to assess whether it attracted a new business or load growth by existing Connecticut businesses. Ultimately, this difficulty bears itself out in additional risk of lost revenue and increased rates to UI customers as the result of potentially unjustified discounts. This risk adversely impacts the state's economic development, counter to the intention of the EDR Rider, through increased rates for business customers that result in lower revenues. Moreover, the Company has special contracting processes to retain economically sensitive customers. Given the inherent risks of including the retention of load within an EDR Rider, the Authority finds that it is more appropriate to utilize the special contracting process for such purposes. However, it is clear that the special contracting process is, at a minimum, not accessible enough to Connecticut businesses or appropriately well known by those business or

relevant government agencies, through no fault of their own. The Authority addresses the issue of accessibility and promotion of the special contracting process below.

The EDR Rider shall be available to all C&I customers, without any cap on participation, subject to the exceptions listed below. Namely, the Company shall disallow C&I customers directly participating in local commerce (e.g., a new restaurant) where EDR participation may provide a financial advantage against other existing local businesses.

Additionally, the Authority approves of the requirement for Subscribers to participate in at least one clean energy, grid modernization, or energy efficiency program.[163] The Authority also notes that while behind-the-meter (BTM) generation and the relevant solar and electric data should be analyzed during the application review process, BTM generation itself shall not impact EDR Rider eligibility.

The Authority directs the Company to require at least the following as part of the application from potential subscribers. First, the application must require three years, or the maximum duration available, of historical load and employee headcount data at an appropriate temporal resolution. If the headcount has decreased over the time period of the historical data, the application must include a narrative explanation of why the headcount has decreased. Further, the application must require data on any expected employment increase and capital investment being made in the Subscriber business, as well as projected load over the Term. Additionally, the application must include any other data as required by the Company for the hurdle rate calculation or other economic evaluations the Company chooses to perform. The application must also include an agreement between the Subscriber and the Company whereby the Subscriber agrees to provide relevant data on topics such as, but not limited to, load, headcount, capital investment, and salary information on incremental jobs. The Authority notes that this information can and should be provided confidentially, as appropriate. Additionally, the application should include an agreement between the Subscriber and Company whereby the Subscriber must meet some percentage (as agreed upon by the Company and the Subscriber, or set by the Company, e.g., 80% within the first three years and 90% thereafter) of the forecasted load increase over the Term, else be subject to a pro-rated repayment of discounts over a period of up to 24 months after the Term. The application should also include a narrative description of why the potential Subscriber's load is increasing or else, if new load, why the discount is a prerequisite for the business to locate in the UI service territory. Lastly, the application should specify a location to indicate whether a potential subscriber is in a Distressed Municipality or Environmental Justice Community. Information pertaining to whether the site is located within a distressed municipality or Environmental Justice Community should be checked by the Company in all instances.

The Authority approves the use of deferred accounting to be established for the EDR Rider that will be used as a true-up mechanism in the next general rate proceeding.

[163] Such programs include, but are not limited to: any program or measure included in the Conservation and Load Management Plan; the Energy Storage Solutions Program; the EV Charing Program; the Residential Renewable Energy Solutions Program; and the Non-Residential Renewable Energy Solutions Program.

Specifically, the Authority authorizes the Company to track the "total distribution revenue obtained through the Rate EDR program, less any incremental distribution capital recovery, operating and maintenance expenses, and general and administrative expenses incurred to serve the incremental load." Ex. UI-MC/MM-1, p. 16. The Authority acknowledges that, in the long term, the deferral is expected to have a credit balance owed to customers, but that early on there may be some start-up costs to the EDR Rider, which may be held as debits owed to the Company. Hr'g Tr. Feb. 17, 2023, 281:6-282:4. The Authority permits the Company to include the total contribution to fixed costs from the appropriate Subscriber load. Moreover, the Authority directs the Company to track capital costs and other upgrades incurred by Subscribers as part of the regulatory asset, and to count incremental Subscriber revenue against such costs. The Company shall not include (i.e., shall not accrue) any carrying costs on such capital expenses prior to seeking recovery, consistent with the treatment of regulatory assets in this Decision and PURA precedent. The Authority will scrutinize the costs included in such regulatory asset for reasonableness and prudence in the appropriate distribution rate case. When seeking recovery, the Company will also need to demonstrate how any deferred expenses, such as any incremental IT, marketing, and personnel costs, both reflect efficient management pursuant to Conn. Gen. Stat. § 16-19e and were necessary to achieve the Authority's direction and objectives regarding the EDR as outlined herein.

The Authority directs the Company to file with the Authority by December 31, 2024, and annually thereafter, a report regarding the implementation of the EDR Rider. The report is to include, but is not limited to, information on: (1) the name and city/town of each Subscriber; (2) the applicable percentage discount; (3) revenues discounted over the most recent annual period; (4) accumulated revenues discounted to date; (5) total load and total incremental load for each Subscriber, both in the most recent annual period and cumulative to date; (6) the total number of C&I customers in UI's service territory; (7) the number of Subscribers, broken down by new or expanding load, both added in the most recent annual period and cumulatively to-date; (8) the number of inquiries into the EDR Rider; (9) the number of applications for the EDR Rider; (10) the number of C&I customers that terminated their accounts annually since 2010; (11) the number of new C&I customers annually since 2010; (12) the number of Subscribers in Underserved Communities; (13) the MW of incremental load from Subscribers in Underserved Communities; (14) the percentage of all incremental load from Subscribers associated with those Subscribers in Underserved Communities; (15) a benefit-cost analysis of the program, inclusive of all costs included in the regulatory asset to-date; (16) the clean energy, grid modernization, or energy efficiency program(s) in which each Subscriber elected to enroll; (17) the capital investment of subscribers, including the investment in Underserved Communities; (18) the number of employees added by Subscribers, including the number of employees added in Underserved Communities; (19) and information on the salaries of jobs added, including but not limited to, the minimum, 25th percentile, mean, 75th percentile, maximum and median values, broken out by Subscribers located in Underserved Communities and any other location. The Company may also include any job-related information that it deems appropriate based on the experience of its affiliate, Central Maine Power, as well as a description of how job quality requirements were determined for Pine Tree Zones.

Additionally, for customers that inquire about or are otherwise accepted to the EDR Rider and ultimately elect not to bring new load or expand their load in Connecticut, the

Authority directs the Company to send out a survey on why such a decision was made by the potential Subscriber. The aggregated survey results should be included in the annual report. The information from the report will be used to inform any changes to the EDR Rider in the future.

The Authority further directs the Company to file an implementation plan for the EDR Rider with the Authority by February 1, 2024. The implementation plan shall include a draft application for the EDR Rider, inclusive of a detailed list of customer information that will be collected and presented in the annual report, along with a proposal regarding which data will be redacted or anonymized in said report. The implementation plan shall also include a marketing plan for the EDR Rider, including a budget and anticipated timeline. Further, the Authority notes that the special contracting process available to customers should be noted anywhere that the EDR Rider is marketed, as inquiries and uptake of special contracts are low, which may be in part due to lack of customer awareness.[164] The Authority notes that greater awareness may help reduce the number of C&I customers that close their accounts with the Company annually.

The Company noted that it plans to collaborate with the Department of Economic and Community Development (DECD), as well as Connecticut business organizations to promote the EDR Rider. Ex. UI-MC/MM/GT-1, p. 9. Accordingly, the Authority directs the Company to incorporate in all of its marketing materials, including website pages associated with the EDR Rider, point of contact information from the Company, as well CTNext, AdvanceCT, Connecticut Innovations, and DECD. Lastly, the Company shall contact DECD and the Office of the Governor (OTG) and provide in writing the details of both the EDR Rider and the special contracting process on or before the EDR Rider effective date. The Company shall file as compliance in this proceeding the written details provided to DECD and OTG within fourteen days of providing such details.

In summary, the Authority approves the EDR Rider, subject to the changes outlined herein. An overview of several key EDR Terms is depicted in the table below. The Authority directs the Company to make the rate available no later than June 1, 2024. Additionally, the Authority directs the Company to file as a part of its application in the next rate case the Company's special contracting policy. As part of the application, the Authority directs the Company to discuss the special contracting policy with DECD, and to file any recommendations from DECD along with the policy. Finally, the Authority reiterates that potential Subscribers may request a special contract if an economic development opportunity requires parameters outside of the terms approved herein.

[164] For clarity, the Authority does not require the Company to actively market the special contracting process, but rather to make sure that existing resources and contact information regarding the special contracting process are included with EDR Rider marketing materials and on relevant UI websites.

Table 86: Approved EDR Terms

Term	5 years
Discount	Base discount: 15% Plus: 5% for five years for being located in a Distressed Municipality or Environmental Justice community Discount Cap: 50% of the difference between the standard rate revenues over the Term for the additional load, less the incremental cost to serve[165]
Eligibility	C&I customers Incremental (i.e., new or expanded) load Participation in at least one clean energy/grid modernization/energy efficiency program Provide annual data to the Company for the annual report on the EDR Rider
Availability	Starting on or before June 1, 2024

2. Low-Income Discount Rate Cost Allocation

The Authority established a Low-Income Discount Rate (LIDR) in its October 19, 2022 Decision in Docket No. 17-12-03RE11, PURA Investigation Into Distribution System Planning of the Electric Distribution Companies- New Rate Designs and Rates Review (LIDR Decision). To recover costs related to the LIDR, the Authority directed the EDCs to reconcile all LIDR costs through the SBC. LIDR Decision, p. 29. However, the Authority did not establish a cost allocation methodology among rate classes through the SBC due to a lack of sufficient record evidence. Id., p. 30. As a result, the Authority stated that the consideration of LIDR cost allocation is more appropriate for a base rate case proceeding. Id. Furthermore, the Authority directed each EDC to propose "at least two potential cost allocation methodologies (e.g., based on a volumetric basis, number of customers in each class, or on write-offs in each class, etc.) of the LIDR among the different rate classes through the SBC in their next respective rate cases . . . for further discussion and evaluation among Parties and Intervenors." Id. Accordingly, the instant proceeding is the avenue through which to consider UI's allocation of LIDR costs through the SBC.

UI currently allocates costs through the SBC using a single kWh rate applied to all kWh sales. Interrog. Resp. CAE-79, p. 1; Interrog. Resp. RRU-501, Att. 1, p. 2. UI calculates this single kWh rate by dividing the annual energy kWh sales for each rate schedule by the total system annual sales. Id. The kWh rate is then adjusted for each rate schedule to include the Connecticut Gross Receipt Tax (GRT) at each rate schedule's statutory tax rate. Id. According to UI, this SBC cost allocation methodology has been used since 2004. Interrog. Resp. RRU-501, Att. 1. As a result of this

[165] The Company may offer a discount below 15% consistent with the discount cap calculation methodology.

methodology, UI's residential customers pay 43% of the SBC's total annual kWh through the kWh charge. Id.; Hr'g Tr. Feb. 17, 2023, 369:18-370:3.

In contrast to the Authority's directive, UI did not include two alternative LIDR cost allocation methodologies in its original Application. Colca & Marini Prefiled Test., Sep. 9, 2023, pp. 10:12 – 12:10. However, UI did provide two alternative cost allocation methodologies in response to Authority questioning. Interrog. Resp. CAE-79, pp. 2-3. In its response, UI stated that there are three potential allocation approaches for cost allocation: (1) customer-based; (2) revenue-based; or (3) demand-based. Id., p. 2. However, UI opined that a demand-based allocation would not be appropriate for the LIDR as there are little to no demand-related costs recovered through the SBC. Id. Therefore, the LIDR costs could be allocated either by customers or revenue, in addition to the existing energy-based allocation approach. Id.

Regarding a customer-based allocation, UI suggested that such an approach could be based on customer count. Interrog. Resp. CAE-79, p. 2. Customers could be calculated as of December of each year or as an average number over 12 months. Id. Further, UI would maintain converting the revenue allocated based on customer count to a per kWh, or energy, rate. Id. Alternatively, the LIDR cost could be collected as a monthly fixed charge that is equal for all customers and separate from the Basic Service Charge. Id. However, UI cautioned that a monthly fixed cost may not be compliant with the statute regarding the MRCC. Hr'g Tr. Feb. 17, 2023, 374:24-375:12. Additionally, the resulting rate, however it is structured, would still need to be adjusted to include the GRT at each rate schedule's statutory tax rate. Id.

Regarding a revenue-based allocation, UI suggested that LIDR costs be allocated through the SBC to rate schedules based on total delivery revenue. Interrog. Resp. CAE-79, p. 2. As proposed, this allocation would exclude generation service revenues. Id., pp. 2-3. Again, UI suggested that it would continue calculating an energy-based rate to recover the requisite revenues. Id., p. 3. However, as proposed under a customer-based allocation, UI suggested that it could instead collect LIDR costs through the SBC as a monthly fixed charge that allocates the revenue requirement to each rate schedule, divided by the number of bills rendered to each class, which would be calculated by dividing the revenue allocated to each class by the number of bills rendered to that class, and separate from the Basic Service Charge. Id. Again, UI would first need to confirm that the monthly fixed charge would not violate the MRCC-guiding statute. Hr'g Tr. Feb. 17, 2023, 374:24-375:12. Additionally, similar to the customer-based allocation, the rate would need to be adjusted to include the GRT based on statutory tax rates. Id.

UI further suggested organizing the SBC allocation of LIDR costs so that LIDR recipients are excluded from paying such costs. Interrog. Resp. CAE-79, pp. 2, 3. However, UI did not propose that arrangement in the Application in this rate case proceeding. Colca & Marini Prefiled Test., Sep. 9, 2023, pp. 10:12-12:10; Hr'g Tr. Feb. 17, 2023, 378:10-23. In response to Authority questioning, UI estimated a potential addition of $0.70 per monthly bill for LIDR recipients if they are not exempted from paying LIDR expenses. Hr'g Tr., 380:8-381:25. This estimate was based on assuming a total $5 million LIDR expense, 5 billion in kWh sales, and a LIDR recipient having a 700 kWh monthly bill. Id. Further, UI conceded that exempting LIDR recipients from paying related expenses would result in additional administrative costs. Hr'g Tr., 379:25-380:7.

UI shared that the cost of the New York low-income discount program is recovered through the distribution revenue requirement. Hr'g Tr., Mar. 21, 2023, 3236:14-23; Late Filed Ex. 12. Specifically, UI stated that costs are deferred and reconciled during the next rate case proceeding. Hr'g Tr., 3237:4-9, 3238:13-24. According to UI, the New York State Public Service Commission established a cost benchmark for the low-income rate of up to 2% of all electric utility revenues for the entire state, which is apportioned to the different utilities. Hr'g Tr. Mar. 21, 2023, 3237:10-3238:12.

Despite consideration of the alternatives, UI ultimately opined that its position is to maintain its existing SBC allocation for LIDR costs. Hr'g Tr. Feb. 17, 2023, 372:18-373:3. First, UI generally maintained that allocating the SBC using an energy allocator instead of a demand-based allocator is appropriate. Hr'g Tr., 370:25-371:12. UI further opined, "[the SBC] is a social program … so to that regard, I don't know what the most appropriate allocator would be … I don't know if there is a better one than energy." Hr'g Tr. Feb. 17, 2023, 371:13-17. However, UI ultimately shared that its position is to maintain the SBC's current allocation for LIDR implementation. Id., 372:18-373:3. UI opined that maintaining the current allocation method will provide customers with consistency and a similar, understandable bill, even with the larger change of LIDR implementation. Hr'g Tr., 373:4-22. Further, it will maintain the current customer allocation of costs, and so LIDR implementation will not cause certain customers to pay more than they currently pay and others to pay less than they currently pay. Hr'g Tr., 373:10-19. Notably, the Authority received no other comments regarding LIDR cost allocation from other Participants or interested stakeholders.

The Authority appreciates the proposals and discussion provided by UI in exploring LIDR cost allocation methods. The Authority concurs with UI's recommendation to maintain the current SBC allocation for LIDR expenses as an energy-based allocator is both an appropriate mechanism for allocating costs for the overall SBC rate and has been consistently relied upon to allocate public policy costs since it generally reflects the proportional contribution of each rate class to the overall revenue requirement. Hr'g Tr. Feb. 17, 2023, 298:21 – 299:3; 371:7-15. The Authority would also be open to a revenue-based allocator; however, there is no record evidence to suggest that a revenue-based allocator is preferrable or more aligned with cost causation principles than an energy-based allocator. Accordingly, the Authority concludes that there is no need or justification to adjust UI's current SBC allocation method for LIDR expenses at this time. Therefore, UI shall allocate LIDR expenses through its existing SBC allocation method.

Furthermore, the Authority does not believe that it is appropriate to exempt LIDR recipients from paying for LIDR program costs given the factors discussed in this proceeding. Again, UI did not propose such an exemption in its Application, nor did other Participants or stakeholders in this proceeding comment on whether such an exemption should be established. According to UI's own rough calculations, the potential monthly bill impact for LIDR recipients is $0.70, or $8.40 per year. However, this additional cost will be part of the customer's overall bill amount, which will be included in whatever discount they are eligible for resulting in a net monthly increase of $0.63 or $0.35 depending on the discount, i.e., 10% or 50%. Additionally, UI stated that it would incur additional administrative costs to exempt LIDR recipients from paying for LIDR program costs. Based on the foregoing, the Authority finds that the impact of not exempting LIDR

recipients from paying for LIDR program costs is ultimately marginal and, thus, does not warrant the additional cost or complexity required to effectuate such exemption. Therefore, the Authority does not in this proceeding exempt LIDR recipients from paying LIDR expenses.

Finally, the Authority confirms that any costs associated with LIDR implementation shall only be accounted for as expense item(s) under the SBC. Therefore, any potential lost recovery related to the LIDR shall not be accounted for as part of decoupling in the Revenue Decoupling Mechanism or Rate Adjustment Mechanism proceedings. Such an action would result in double counting of LIDR costs. Therefore, LIDR implementation expenses shall only be accounted for under the SBC rate.

Accordingly, UI shall maintain its current SBC allocation method and allocate future LIDR costs through the SBC's existing allocation method. Furthermore, LIDR recipients shall not be excluded from paying LIDR expenses. And finally, LIDR costs shall only be accounted for as expense item(s) under the SBC.

3. Pole Attachment Rates

UI proposed to modify the pole attachment rate for cable television (CATV) from $14.32 to $20.84 and the telecommunications service providers (Telecom) pole attachment rate from $14.96 to $22.57. MCMM PFT, pp. 16-17; Interrog. Resp. NECTA-1, Att. 1. The Authority finds that UI, in several instances, inappropriately calculated pole attachment rates using the FCC formula. Accordingly, the Authority modifies the pole attachment rates to $18.23 for the annual CATV rate and to $19.74 for the annual Telecom rate, as described in the following sections.

The Company's current pole attachment rates were approved by the Authority in the 2016 Rate Case. MCMM PFT, p. 16. In calculating the proposed rates, the Company followed the formulas established by the Federal Communications Commission (FCC)[166] and adopted by the Authority. Decision, Sep. 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), p. 8.

The Company stated that it attempted to follow the 2016 Rate Case Decision guidance when applying the FCC formula, so that the update for the proposed rates is based solely on the use of Test Year data. Interrog. Resp. NECTA-3.

[166] See Order In the Matter of Implementation of Section 224 of the Act (WC Docket No. 07-245) and National Broadband Plan for Our Future, Adopted and Released April 7, 2011 (FCC Pole Attachment Order, collectively FCC Orders). The FCC Orders established two methodologies for setting TELCO and CATV rates. FCC Pole Attachment Order, p. 58; 47 U.S.C. § 224(d). Notably, Appendix C of the FCC Orders specifies that Connecticut is one of 20 states that has opted to regulate rates, terms, and conditions for pole attachments; therefore, Connecticut is not subject to or bound by FCC rulings or policy pronouncements related to pole attachment matters, although the Authority may adopt FCC rulings or policy directives. See Fibertech Decision, p. 5.

a. Excess ADIT

UI's calculation for pole attachment rates does not include the unamortized excess ADIT[167] created by the Tax Act. In 2018, the TAX Act changed the federal corporate income tax from 35% to 21%. Hr'g. Tr. Feb. 21, 2023, 546:8-12. This change lowers UI's current and future income tax expense obligations, which creates excess ADIT for future tax obligations. Kravtin PFT, p. 17.

In accounting, excess ADIT (and ADIT in general) is subtracted from a company's rate base, and so serves to reduce the reflected value of a company's investment. Id. This accounting treatment affects pole attachment rates because the FCC formula seeks to proportionally allocate the costs of a bare pole to the attaching entity. The calculation, therefore, uses both pole investment data and ADIT data (as a reduction to investment) reported in FERC Form 1. Id.

Excess ADIT from the Tax Act changes is not, however, reported in FERC ADIT accounts (specifically, Accounts 190 and 281-283), but in a liability account (Account 254). Id., p. 18. ADIT Accounts 190 and 281-283 are included in the pole attachment formula as offsets to Account 364 investments. Hr'g Tr., 545:16-20. Account 254 is not in the pole attachment formula, whereas the other FERC ADIT accounts are. Kravtin PFT, p. 18. UI can identify its deferred tax liability from the Tax Act in Account 254. Hr'g Tr., 548:1-8.

When UI did not include the excess ADIT from the Tax Act, it technically followed the FCC formula calculation. However, it is more appropriate to include excess ADIT as an offset to pole investment data; doing otherwise would abuse an accounting artifact and not meet the spirit of the FCC formula. The Authority has likewise approved the inclusion of the Tax Act excess ADIT in Eversource pole attachment rates. Kravtin PFT, p. 18.

Accordingly, the Authority will modify the pole attachment formula to include excess ADIT as an offset to Account 364 investment data.

b. Appurtenance Factor

In the pole attachment calculations, UI applies the FCC's baseline appurtenance factor of 15%. MCMM PFT, Ex. 3. The appurtenance factor is used to identify and reduce FERC Account 364 by the percentage of investments of non-pole related investments in that account, such as cross-arms, braces, and transformer brackets. Kravtin PFT, p. 21. Since 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 uses the longstanding rebuttable presumption that 15% of FERC Account 364 investments are appurtenances and thus allows a 15% reduction to those investment figures. Id., p. 22; Interrog. Resp. NECTA-1, Att.1.

[167] ADIT is a tax liability account to record timing-related differences between the tax basis of the utility's fixed assets and their respective regulatory book valuation. These timing differences arise from the utility's ability to claim higher depreciation expense for tax purposes (in the early years of a new asset's life) as compared with regulatory depreciation (which is applied consistently across the asset's life using a straight-line method of depreciation, based on average total service or remaining life of the pole group). Kravtin PFT, p. 17.

NECTA asserts that UI did not sufficiently provide "readily obtainable continuing property records tracking its investment in appurtenances" in FERC Account 364, as required by the FERC Uniform System of Accounts and 18 § C.F.R. Part 101. NECTA Brief, p. 8. However, UI did furnish Account 364 investment data back to 2016 and specific work order detail sufficient to identify pole and appurtenance investments during 2022. Interrog. Resp. NECTA-4, Atts. 1-2. In this case, UI provided an appropriate level of detail that is common in the industry. Hr'g. Tr. Feb. 22, 2023, 703:16-18; 537:3-13.

NECTA states that an appurtenance factor of 25.1% is appropriate based on a one-year sample of utility pole and appurtenance work order data from 2021 provided by UI, showing that the appurtenance factor of total FERC Account 364 investments was 20.16% for a job-by-job basis, or 25.11% for total annual investment basis. Interrog. Resp. NECTA-4, Att. 2; Kravtin Surr., Ex. 1. However, rather than looking at a sample of data from approximately one year for Account 364, it is more appropriate and accurate to look at the sample of data on a work order basis to determine the costs of appurtenances as a percentage of total for each job and to use that to extrapolate across FERC Account 364. Hr'g Tr. Feb. 21, 2023, 612:24-613:25. Thus, the 20.16% appurtenance percentage is more reflective of the percentage of appurtenance costs for that year.

Extrapolating appurtenance percentage on a work order basis is not contrary to the FCC formula methodology as has been posited by NECTA.[168] Kravtin Surr., p. 6. NECTA argues that since the FCC formula uses total investment costs booked to FERC Account 364, then UI's appurtenance data should be considered on a total investment basis for the sample data. Id. NECTA argues that extrapolating appurtenance percentages on a project-by-project basis skews the result by giving small dollar projects equal weight to larger dollar projects. Id. NECTA's arguments are unconvincing. The representative sample of pole and appurtenance investment provided by UI ($7.908 million) accounts for only 3% of total FERC Account 364 plant-in-service for 2021 ($238.500 million). Interrog. Resp. NECTA-4, Att. 2; Interrog. Resp. NECTA-29, Att. 1. Since the sample data represents such a small portion of total FERC Account 364 investment, it is not necessarily more reflective to use total sample investment costs. Indeed, such an approach skews the importance of one year of investment data that reflects a mere 3% of total FERC Account 364 investment. In this case (i.e., considering a small sample of all pole and appurtenance investment), UI testified that it is more representative and precise to extrapolate the appurtenance factor on a project-by-project basis. Hr'g Tr. Feb. 21, 2023, 613:15-21. The Authority finds the Company's testimony convincing and, accordingly, the Authority approves the application of 20.16% appurtenance factor to determine rental rates.

c. Tax

The Authority finds that UI inappropriately used UIL tax information to calculate the tax carrying charge, which inflates the pole attachment rate.

The FCC formula points to the use of publicly filed operating company tax data (Account 408.1) reported on the FERC Form 1 annual report. Hr'g. Tr. Feb. 21, 2023, 549:4-10. Account 408.1 includes UI operating company tax data. Id. UI did not use the

[168] As previously stated, even if PURA did deviate from the FCC formula, which it did not, Connecticut has retained jurisdiction over pole attachment matters and is not bound by FCC determinations.

information from its FERC Form 1 report, but instead reported UIL tax data, which includes tax data from non-electric operating companies of UIL and which is not reported on the FERC Form 1. Hr'g Tr., 549:8-10, 549:11-21. UI should have applied the tax information from UI alone, as was the approved methodology in the 2016 Rate Case Decision. Hr'g Tr., 550:1-10; 2016 Rate Case Decision, p. 100.

Using UI's tax data as reported in the 2021 FERC Form 1 report reduces the tax carrying charge from 6.89% to 6.31%. Interrog. Resp. NECTA-29, Att. 1; Kravtin Surr., Ex. 2.

d. Maintenance Factor

The maintenance carrying charge is included in the pole attachment formula to ensure that Attachers pay the pole owner for a portion of the wide range of capital and operating costs associated with a pole. Hr'g Tr. Feb. 22, 2023, 701:2-17.

NECTA asserts that UI's calculated maintenance carrying charge is overstated. Kravtin PFT, p. 31. NECTA argues that the maintenance carrying charge percentage as derived using the FCC formula should be similar to UI's carrying charge approved in the 2016 Rate Case Decision. Id., p. 32. Specifically, NECTA asserts that one reason that the charge is overstated is that $5.99 million of deferred storm costs are inappropriately booked to FERC Account 598. Id., p. 32. NECTA argues that doing so inappropriately charges Attachers the full amount of deferred costs, where other ratepayers are receiving the benefit of amortized costs. Id. NECTA states that all storm deferred amounts that UI booked to Account 593 should be excluded from the FCC formula rate calculation; doing so would reduce the carrying percentage from 10.73% to 9%. Id.

The Authority declines to make NECTA's adjustment to the maintenance carrying charge. The maintenance carrying charge percentage in UI's proposal is reasonable when comparing 2015 Test Year data (i.e., data on which pole attachment rates were based in the 2016 Rate Case Decision) and 2021 Test Year data. In 2015, UI was amortizing significant UPZ vegetation management expense and had no major storms from 2013-2015. Interrog. Resp. NECTA-27, p. 2; Interrog. Resp. OCC-159. From 2016 through 2021, UI ceased amortizing UPZ vegetation management costs and experienced 11 storms. Id.; Interrog. Resp. NECTA-27, p. 2. Therefore, based on the accounting changes for UPZ (direct expense) and the increase in storm damage, it is reasonable that the maintenance carrying charge percentage has increased. Adopting NECTA's recommendation would decrease the maintenance carrying charge from the 2016 Rate Case Decision (9.27% to 9%), which does not align with the data presented. Kravtin PFT, p. 32.

Furthermore, there is no evidence demonstrating that UI has inappropriately recorded its deferred storm expenses in FERC Account 593. To the contrary, UI appropriately follows FERC accounting guidance, as deferred expenses can be assigned to Account 593. Interrog. Resp. NECTA-27, p. 1. UI's affiliate electric distribution companies in New York and Maine follow the same assignment and have done so for several years. Interrog. Resp. NECTA-35, pp. 3-4. The New York and Maine regulatory agencies have approved this accounting as appropriate for pole attachment rates. Hr'g Tr., 397:24-398:1.

Based on the above analysis, the Authority makes no adjustment to the maintenance carrying charge proposed by UI.

e. Different Rates for Telecom and CATV

NetSpeed and CCF request unified pole attachment rates for all Attachers using the CATV rate as proposed by NECTA. Id., p. 7; CCF Brief, p. 7. CCF and Netspeed both argue that the proposed rate for telecommunications Attachers is anti-competitive, discriminatory, and does not comply with the Fibertech Decision since the Telecom rates are 7.8% more than UI's proposed CATV rates. CCF Brief, pp. 2-3, 6; Netspeed Brief, pp. 2-3, 6.

The Authority finds that UI's proposed formula for pole attachment rates, while higher than the CATV rates, does not mean that they are anti-competitive or discriminatory. In the Fibertech Decision, the Authority adopted a definition implemented by the FCC for application to telecommunications companies. Fibertech Decision, p. 8. This telecommunication pole attachment rate was determined by the FCC to be just and reasonable. Id., p. 7. UI has followed the telecom pole attachment rate as approved by the FCC and the Authority. 47 CFR § 1.1406; Fibertech Decision, p. 8; Interrog. Resp. NECTA-1, Att. 1.

The reason the pole attachment rates differ is that the FCC-approved CATV and Telecom rates differ by design. Interrog. Resp. NECTA-1, Att. 1, pp. 1-2. When allocating costs to Attachers, the rate formula allocates pole costs (initial pole cost, ongoing maintenance costs, etc.) to Attachers based on the space that they use on poles. Id. The difference between the two rates arises because the CATV formula only includes the area within the 15-feet of usable space, whereas the Telecom formula includes 15 feet of usable space and part of 24 feet of unusable space. Id. This difference allocates more costs to Telecom Attachers than to CATV Attachers. Id.

As noted by NetSpeed in its written exceptions, the application of the CATV and Telcom rate formulas results in an 8.3% higher rental charge to Telecom attachers than to CATV attachers. NetSpeed Exceptions, p. 2. This differential increased from a 4.5% differential in the Fibertech Decision. Id., p. 3. The cause of the increase in the rate differential between Telcom and CATV providers is due to the increase in average pole height as derived in this case (39.19 ft.) from the last rate case (38.51 ft.). Interrog. Resp. OCC-473, Att. 1; Interrog. Resp. NECTA 1, Att. 1. This increase serves to both reduce the CATV-related usable space factor and to increase the Telcom-related space factor (which adds a percentage of the unusable space as a charge as just discussed) resulting in more than an 8% difference in rates.

This difference is inherent in the FCC-approved formulas and is what the Authority approved in the Fibertech Decision.[169] Indeed, in the Fibertech decision, the 2016 Rate Case Decision, and in the instant proceeding, the Authority recognizes that there would be a difference in the pole attachment rates between Telcom and CATV providers for the reasons detailed above. In the 2016 Rate Case Decision, the Authority did not find the

[169] The Authority stated in the Fibertech Decision that adopting the FCC-approved formulas would allow the State to *approach* rate parity, implying that the FCC formulas would not produce exact rate parity. Fibertech Decision, p. 1.

4.5% differential between the Telcom and CATV pole attachment rates to be unreasonably discriminatory. 2016 Rate Case Decision, pp. 98-101. Similarly, the Authority finds that the 8.2% differential between attacher rates in the instant case is also not unreasonably discriminatory.

Applying these rates to different Attachers is a straightforward and transparent process that is consistent with the Fibertech Decision and which uses the certification that each Attacher has received from the Authority. Hr'g Tr., 611:1-612:9. UI has appropriately reflected this information in its proposed tariff. Sch. E-1.0A. Therefore, the Authority finds that UI appropriately applied the Telecom formula.

f. Summary of Pole Attachment Rate Adjustments

Based on the adjustments made above to include excess ADIT as an offset to plant investment and to use of UI's tax figures rather than UIL's, both the CATV and Telecom rates are reduced.

Furthermore, in its written exceptions, NECTA identified that the pole attachment rate formulas applied UI's approved rate of return (ROR) from the 2016 Rate Case Decision. NECTA Written Exceptions, p. 16; Interrog. Resp. NECTA 30, Att. 1, p. 3. While the Authority approved pole attachment rates in the 2016 Rate Case Decision using a prior-approved ROR, the Authority will use the ROR as approved in this Decision. Interrog. Resp. *OCC*-483, Att. 1, p. 3. Accordingly, to be consistent with the approved ROR in this Decision, the Authority modifies the pole attachment rates using the Company's approved pre-ROE reduction ROR of 6.71%.

Applying these changes results in an annual CATV rate of $18.23 and an annual Telecom rate of $19.74. These modified rates reduce the Company's Rate Year 2023/2024 revenue by $579,602. Interrog. Resp. GoNetSpeed-3, Att. 1, p. 4. The Authority directs UI to recalculate its Telecom and CATV pole attachment rates and to file as compliance in the instant proceeding no later than September 15, 2023.

4. Electric Vehicle Supply Equipment (EVSE) Tariff

The Authority established EVSE tariffs for DCFCs and Level 2 chargers serving light-duty fleets in the EV Year 2 Decision and approved the final tariffs in its February 23, 2023 ruling on Motion Nos. 20 and 22 (Motion Nos. 20 and 22 Ruling). EV Year 2 Decision, pp. 47-50; Motion Nos. 20 and 22 Ruling. Specifically, UI created Rates GS-EVSE and GST-EVSE, which are predicated on UI's existing General Service (GS) and General Service TOU (GST) Rates. EV Year 2 Decision, p. 48; Motion Nos. 20 and 22 Ruling. The tariffs include a sliding scale of kWh distribution charges with kW demand charges for based on monthly load factor blocks of 5% increments (i.e., 0-5%, 5-10%, etc.) up to a 35% monthly load factor. Id. Pursuant to Authority directive, UI shall begin offering the Rates GS-EVSE and GST-EVSE no later than January 1, 2024. EV Year 2 Decision, p. 60; Motion Nos. 20 and 22 Ruling, pp. 2-3.

5. Annual Bill Analysis Comparison

The Authority denies the Company's request to terminate the mandated annual bill analysis comparison requirement for mandated Rate RT customers who request to switch to Rate R. The Company requested to terminate this provision based on the administrative effort to review the billing history for these customers. Application, Ex. UI-

MCMM-1, pp.18-19. The Company acknowledged in its Application that there are relatively few requests from mandated Rate RT customers. Id. The Company also stated that there are essentially no incremental costs at the current level of activity. UI Interrog. Resp. RRU-112. The Authority finds the Company has not provided sufficient evidence that reflects an exponential increase in requests or incremental costs to provide this service to its customers. Further, the Authority believes the bill analysis provides good customer service and enables customers to make an informed decision to choose rate RT or Rate R. For these reasons, the Company's request to terminate the bill analysis provision is denied. Should the Company again seek to terminate this provision in its next rate case, UI is instructed to contemporaneously propose an alternative, technology-based solution, including costs and implementation timeline details, for the Authority's consideration.

XI. TARIFF CHANGES

A. TERMS AND CONDITIONS

The Authority reviewed UI's Terms and Conditions and Explanation of Charge in its proposed tariff. Application, Sch. E 1.0-A, pp. 1-16. The Company made no revisions to the above cited tariff pages that were previously approved by the Authority, which are not rate-impacting. The Authority approves UI's proposed Terms and Conditions and Explanation of Charge.

B. MISCELLANEOUS FEES

1. Service Charges – Supplier Relations Fees

The Authority accepts UI's tariff revisions for Supplier Relations Fees proposed to go into effect on September 1, 2023. Application, Sch. E 1.0-A, Appendix A, pp. 17-23. The table below summarizes the supplier relations fees proposed modifications.

Table 87: Proposed Supplier Relations Fees

Supplier Fee	Proposed Modification (effective Sept. 1, 2023)
Cancel/Rebill (partial loader)	Decrease Labor fee from $91.17 hr. to $78.00 hr., increase per bill fee from $0.53 to $0.62.
Initialization (partial loader)	Increase set up and testing fee from $6,453.05 to $7,123.00 and rate configuration hourly rate from $124.48 to $137.40.
Change to Standard Rate Configuration (partial loader)	Decrease contractor rate from $107.10 hr. to $104.60 hr.
Meter Test (partial loader)	Increase single phase meter test from $88.75 to $104.13, increase three phase test from $112.67 to $132.56.
Cost to Provide Special or Expedited Meter Reads (partial loader)	Delete tariff Rate Element as there are no longer manual meter reads.
Interval Meter Data (partial loader) Load Pulse Output	Decrease installation fee from $795.44 to $759.04, increase monthly fee from $13.26 to $14.92.
Theft of Service (TOS) investigation (full loader), hourly rate	Decrease investigation fee from $94.78 to $75.81 hr., decrease supervisory fee from $108.69 to $95.23 hr., decrease billing support fee from $92.45 to $74.18 hr., and decrease standard field force from $88.88 to $81.81 hr.

The Company has not proposed rate changes to customer care center, web presentment, or customer-requested usage/data load analysis (partial loader) fees. Id. pp. 18 and 22.

Supplier Relations Fees recover the costs associated with performing the start-up initialization and various functions at the request of electric suppliers. Id. Supplier relations fees are cost based. Late Filed Ex. 1, p. 1. For example, the initialization fee recovers the costs for data testing, training, and to configure the supplier's initial set of rates. Id.

The Authority determines that the Company's proposed Supplier Relations Fees proposed in Schedule E 1.0A reflect reasonable, cost-based modifications that include some rate decreases from current rates. Consistent with Section III.B., Multi-Year Rate Plan, the Authority's acceptance of the Company's proposed supplier relations fee revisions is limited to those proposed in the initial rate year. The Authority declines to approve supplier relations fee increases proposed for subsequent rate years.

2. Standard Field Fees

The Authority accepts UI's proposed tariff revisions for certain Standard Field Fees. Application, Sch. E 1.0-A, Appendix A, pp. 24-25. UI's Water Heater proposed tariff revision is addressed separately in Section VI.A. 21., Water Heater Program.

3. Reconnection Charge

The Company proposes to increase the current reconnection charge to $19.35 from $15.66 for Rate Year 2023/2024. Sch. E-1.0A. This reconnection charge would apply to both hardship and non-hardship customers. Interrog. Resp. CAE-34. To waive reconnection charges, the Company's CSRs and other personnel review the circumstances of the assessed reconnection fee and the account history to understand the impact the fee has on the customer's ability to pay. Id. Unless the reconnection fee is a company error, the consideration for reconnection fee credits is made on a case-by-case basis. Id. Since the Company's last rate case, 642 reconnection fees were waived. Id. Of the 642 occurrences of waived fees, 130 were residential hardship customers. Late Filed Ex. 111. However, the Company states that it will update its training materials to include that CSRs are authorized to decide whether to waive a reconnection charge after reviewing the circumstances that resulted in the imposition of the fee. Interrog. Resp. CAE-34.

The Authority finds that the Company's current reconnection charge procedures are reasonable. However, the Authority anticipates an increase in service terminations after the current residential hardship shut-off moratorium ends.[170] As a result, the Company may have an increase in assessed reconnection charges, which will further hinder hardship residential and medically protected customers' ability to pay and reinstate their service. In response, the Authority reiterates that the Company must follow the minimum down payment guidance for disconnected hardship and non-hardship customers under the flexible payment arrangement offering parameters. Decision, Apr. 20, 2022, Docket No. 21-07-01, Application of The Connecticut Light and Power Company and Yankee Gas Services Company, each Individually d/b/a Eversource Energy, The United Illuminating Company, Connecticut Natural Gas Corporation, and The Southern Connecticut Gas Company for Approval of Arrearage Forgiveness Program 2021-2022, p. 20.[171]

Additionally, while the Authority acknowledges the Company's attempt to improve customer relations by revising its training materials to allow CSRs to decide when to waive a reconnection charge, the Authority emphasizes that there is room for improvement to evaluate a customer's circumstances. As such, the Authority intends to address this topic in the 2023-2024 Proposed AFP Plan proceeding (Docket No. 23-05-01) to develop a standardized approach to determining whether and when the reconnection fee may be waived (i.e., the number of times per year certain customers may receive a waived fee). Regardless of any additional measures developed, the Authority expects the Company to communicate with the customer both before and after the first disconnection to ensure enrollment in the most suitable affordability program to prevent service terminations.

The Standard Field fees are occurrence-based. The current fees and proposed Standard Field fees are summarized in the below table.

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[170] As directed in Motion No. 88 Ruling in Docket No. 20-03-15, the Company may resume service terminations no sooner than May 2, 2024.

[171] Disconnected residential customers that do not sign up for a payment arrangement with UI, including through the MPP, BFP, or another flexible payment arrangement, are subject to paying the Company's established reconnection fee as well as the customer's past due balance associated with the disconnection when they seek to reconnect their service. Sch. H-2.1.

Table 88: Proposed Standard Field Fees

Standard Field Fee	Proposed Rate Modification (effective September 1, 2023)
Reconnect Fees	Meter Reconnect Fee (straight time) increase from $16.46 to $19.35. Cut Tap Fee (straight time) increase from $156.96 to $170.00. Cut Tap Fee (overtime) increase from $200.49 to $217.59.
Lock Out – 2nd Field Visit (full loader)	1st Quarter hour (straight time) increase from $32.63 to $39.67. Additional Quarter hours (straight time) decrease from $22.53 to $19.83. 1st Quarter (overtime) increase from $43.74 to $50.77. Additional Quarters (overtime) decrease from $33.64 to $25.38.

The Reconnect Field visit fees are labor-based fees, with current rates in effect since January 1, 2019. Id. The straight time meter proposed reconnect fee of $19.35 reflects a $2.89 increase from the current rate. Annualized from January 1, 2019, the proposed increase represents an average annual change of 3.8%. The Cut Tap straight time proposed reconnect fee of $170.00 reflects a $13.04 increase from the current rate. Annualized from January 1, 2019, the proposed increase represents an average annual change of 1.8%. The proposed Cut Tap overtime reconnect fee increase of $217.59 reflects an increase of $17.10 from the current rate. Annualized from January 1, 2019, the percentage change equates to an average annual change of 2.0%.

The Lock Out 2nd Field Visit (full loader) fees include time (labor) and materials, with current rates in effect since January 1, 2019. The 1st quarter hour straight time proposed fee of $39.67 reflects a $7.04 increase from the current rate. Annualized from January 1, 2019, the change equates to an average annual change of 4.6%. The straight time additional quarter hours proposed fee of $19.83 reflects a $2.70 decrease from the current rate. Annualized from January 1, 2019, the change equates to an average annual change of 2.6%. The 1st quarter hour overtime proposed fee of $50.77 reflects an increase of $7.03 from the current fee. Annualized from January 1,2019, the change equates to an average annual change of 3.4%. The overtime additional quarter hours proposed fee of $25.38 reflects a rate reduction of $8.26 from the current rate. Annualized from January 1, 2019, the change equates to an average annual change of 5.3%.

The Authority reviewed the Company's Standard Field fees proposed rate revisions and finds the proposed changes for Rate Year 2023/2024 to be reasonable. Current rates have been in effect since January 1, 2019, a 4.67 year interval through the proposed implementation date of September 1, 2023. Consistent with Section III.B., Multi-Year Rate Plan, the Authority's acceptance of the Company's proposed supplier relations fee revisions is limited to the fees proposed in Rate Year 2023/2024. The Authority declines to approve fee increases proposed for subsequent rate years.

XII. CUSTOMER SERVICE ISSUES

A. BILLING, POLICIES, AND PRACTICE

1. Standard Bill

The Company's Standard Bill complies with the applicable regulations. Application, Sch. H.2.0 and Sch. H-2.1. The Authority notes that the standard bill was revised in Docket No. 14-07-19RE06 to modify UI's bill mock-up design. 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 Motion No. 13 Ruling, Oct. 21, 2022, Docket No. 14-07-19RE06.

2. Customer Rights and Termination Notices

The Company's Customer Rights and Termination Notices generally comply with the applicable regulations; however, in some instances such materials and policies warrant modification, as directed below. Application, Sch. H.2.0 and Sch. H-2.1.

Regarding the Company's Termination Notices, the Authority notes that such notices appropriately do not include any unregulated charges on the notice. Interrog. Resp. EOE-10. Currently, all UI termination notices are sent to customers via first class mail. Interrog. Resp. EOE-11. The Company states that the number of scheduled termination notices are matched daily via dunning jobs in the billing system against the number of notices mailed through UI's mailing services vendor. Id. Separately, the Company states it identified the opportunity to enhance its website features to allow customers to view termination notices online. Interrog. Resp. EOE-127. UI testified that, in September 2023, the Company will launch a feature for customers to view termination notices online. Hr'g Tr. Mar. 6, 2023, 2132: 11-25, 2133:16.

The Company resumed service terminations for non-hardship residential customers pursuant to Order No. 35 in Docket No. 20-03-15 in October 2021. Interrog. Resp. EOE-84. As a result, UI terminated 4,314 non-hardship residential customers from October through December of 2021, and 32,162 non-hardship customers from January through September 2022. Id. The Company states that prior to October 2021, customer terminations were not separated by customer type. Id.

Customers are contacted using various communication touchpoints prior to termination. Interrog. Resp. EOE-9. Below is a chronological order of all contacts made with a typical delinquent customer.

Action	Timing
Invoice with delinquent balance	Day 1
Shut off notice	Day 6
Text Alert (if registered)	Day 6
Final Reminder notice	Day 13
Reminder Call	Day 13

Interrog. Resp. EOE-9.

The Company provided sample communications it uses to alert residential and non-residential customers about their delinquent balances in response to interrogatories in this proceeding. Id.

The Authority acknowledges that the Company's current termination notice procedures (but not the notices themselves) comply with the minimum specifications outlined in Conn. Agencies Regs. §16-3-100. However, as discussed in the Decisions in Docket Nos. 21-07-01 and 22-05-01,[172] the Authority maintains that a variety of distribution methods of customer notices are critical to increasing customer knowledge, which, in turn, should help prevent terminations. Accordingly, the Authority directs UI to notify the Authority in Docket No. 23-05-01, Annual Review of Affordability Programs and Offerings (Energy Affordability Annual Review) when the Company implements the enhanced website feature for termination notices that UI witnesses referred to during the instant proceeding. In addition, the Company shall include an estimate of the one-time and recurring costs associated with including text messages as a medium to notify customers of an upcoming termination notice in such filing, as well as a potential implementation timeline for doing so.

Regarding the customer notices and accompanying materials, the Authority finds that the Company's sample termination communication materials for residential customers lack important, required information. As stated throughout the energy affordability dockets (i.e., Docket Nos. 21-07-01, 22-05-01, and 23-05-01), the Company is required to inform customers of their right to dispute a payment plan by contacting a review officer. However, the Company does not include the review officer information on the termination communication. The Authority will continue reviewing the Company's communication materials in the annual energy affordability review proceedings (i.e., Docket No. XX-05-01, where "XX" represents the last two digits of the calendar year in which the proceedings is conducted). In the interim, UI shall revise its termination materials to include this information regarding a customer's rights. The Company shall submit as compliance a copy of the revised termination materials no later than September 25, 2023, in the instant proceeding.

3. Estimated Bills

UI provided in this proceeding its policies and procedures for generating estimated bills, for which the Authority directs modifications herein to provide additional tools to affected customers.

According to the Company, if its system cannot provide an estimated bill, a clerical estimate may be required. Application, Sch. H-2.2, p. 5. An estimated bill is based on a "good billing history," meaning that estimated bills are based on actual usage and not forecasts. Id. Specifically, the Company uses the first actual reading after the estimated bills to find the kWh per day. Id. 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

[172] See Decision, April 20, 2021, Docket No. 21-07-01, Application of The Connecticut Light and Power Company and Yankee Gas Services Company, each individually d/b/a Eversource Energy, The United Illuminating Company, Connecticut Natural Gas Corporation, and The Southern Connecticut Gas Company for Approval of Arrearage Forgiveness Program 2021-2022; Decision, Oct. 12. 2022, Docket No. 22-05-01, 2022 Energy Affordability Annual Review.

estimated readings. Interrog. Resp. EOE-13. The Company infrequently issued estimated bills over the last three years. Interrog. Resp. EOE-17. Indeed, the percentage of estimated billing for calendar years 2019 through 2021 was less than one percent, except for August through November of 2020, during which time period the Company's estimated billing exceeded one percent for metered estimated bills for one to three months. Id.

EOE recommends that the Company include its telephone number on the first page of the bill to encourage the customer to rectify the reason(s) for receiving an estimated bill. EOE Brief, p. 37. EOE suggests that UI's telephone number appear in the same location as the messaging that informs the customer about the estimated bill (i.e., on the first page of the bill). Id. Specifically, the message should read "Please call UI at 800-722-5584." Id. In response to EOE's recommendation, the Company confirmed that it can accommodate the message to contact UI in the same location as the message about the estimated bill. Id.; Late Filed Ex. 94.

The Authority reviewed the policy and procedures associated with UI's estimated billing and finds that the Company's materials generally follow the applicable regulations. The Authority also finds that including the Company's telephone number is a useful tool to encourage customers to contact UI to prevent receipt of another estimated bill. Therefore, the Authority directs UI to include its telephone number on the first page of an estimated bill alongside the message about the estimated bill. The Company shall submit as compliance a copy of an estimated bill with its telephone number included no later than September 25, 2023, in the instant proceeding.

4. Security Deposit Policies

The Authority reviewed the current policies and procedures UI utilizes to administer customer security deposits. Application, Sch. H-2.3. Because the practice of requiring customer security deposits is currently suspended, and has been for several years, and because the Authority intends to examine more fully this topic in Docket No. 23-05-01 as previously announced, PURA declines to make a finding herein regarding whether such policies and procedures comply with Conn. Agencies Regs. §16-11-105 and §16-262j-1.

In March 2020, the Authority directed the Company to suspend the collection of security deposits until such a time as determined by the Authority. See Order No. 3, Motion No. 2 Ruling, March 18, 2020, Docket No. 20-03-15. At this time, the Company continues to forego requiring residential customers to submit a security deposit and does not intend to do so without the Authority's approval. Interrog. Resp. EOE-18; see also, Interrog. Resp. EOE-228.

The Authority intends to examine more fully in Docket No. 23-05-01 the electric and gas companies' security deposit procedures to ensure consistency and conformance to applicable statutes and regulations. To aid in this inquiry, the Authority directed UI to provide a detailed explanation of its security deposit practices in existence prior to the March 2020 cessation order.[173] See Compliance filing, March 1, 2023, Docket No.

[173] The Authority directed the electric and gas companies to submit into Docket No. 23-05-01 their respective security deposit practices that were in existence prior to the issuance of Order No. 3 in Docket No. 20-03-15. See Motion No. 83 Ruling, Dec. 29, 2022, Docket No. 20-03-15.

23-05-01. In its filing, UI proposed to reinstate security deposit procedures for non-residential accounts. Id. As such, the Authority will determine when UI may reinstate its security deposit procedures for non-residential accounts in the Docket No. 23-05-01 proceeding, as well as any further refinements thereto.

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, p. 26; see also Interrog. Resp. CAE-35. In accordance with this Decision, LPCs are not to be included in the Company's allowed revenue requirement and are to be removed from rate base; however, the revenues collected from late payment fees should be included in the Company's annual RAM filing as a "surplus" for RAM purposes that will serve to offset potential distribution revenue shortfalls, as discussed above in Section VI.E.3., Late Payment Fees.

In response to the Authority's directives pertaining to the COVID-19 pandemic, UI suspended the collection of LPCs in March 2020. PFT Customer Service Panel, Ex. UI-1-CSP-1, p. 23. On October 1, 2022, the Company resumed the collection of LPCs; however, UI temporarily halted the collection of LPCs again on October 27, 2022, because customers were being assessed the LPC in error. Interrog. Resp. EOE-211. According to UI, when LPCs were reinstated, a required programming change was missed. Id. Consequently, LPCs were being assessed against balances from charges prior to September 2022, transferred from other accounts and on accounts with payment arrangements; a total of 2,301 customers were impacted. Id. The Company's IT team corrected the programming issue and is in the process of testing to ensure the issue is fully addressed. Id. UI stated that it would notify the Authority when the Company begins to assess LPCs again.[174] Hr'g Tr. Mar. 7, 2023, 2460: 14-16.

The Company proposes to maintain the LPC of 1.25% and to waive LPCs on a case-by-case basis, unless the LPC is a result of a Company error. Interrog. Resp. CAE-35. To waive an LPC, the CSRs and other personnel will review the circumstances that caused the fee, the impact of the customer's ability to pay, and the account history. Id. The Company waived 399 LPCs from 2020 through 2021, prior to the suspension of LPCs during the COVID-19 pandemic.[175] Id. Regarding the Company's continued use of the criteria of a customer's ability to pay and account history to waive LPCs, the Authority reminds UI that customers should be informed of all their rights and available payment plans and screened for financial hardship eligibility.

Given the suspension of LPCs as a result of the COVID-19 pandemic, the most recent data on the Company's use of the LPC practice is limited. Furthermore, it is unclear from the record whether the LPCs are adequately serving their intended purpose. Therefore, additional information is necessary to evaluate the practice of utilizing late payment charges, including the magnitude of LPCs and any incremental prerequisites to

[174] By Correspondence dated April 28, 2023, in Docket No. 21-07-01, the Company notified the Authority it has completed the programming and additional testing and will reinstate late payment charges, to be assessed only on usage balances accrued after May 1, 2023, for non-hardship residential and non-residential customers.

[175] The Company testified that the waivers for 2021 (144) were credited in that year, but the charges were applied prior to the suspension. Tr., Mar. 7, 2023, 2449: 7-14.

imposition of an LPC for certain customer types. In Docket No. 23-05-01, the Authority intends to examine LPCs by analyzing: the type of customers who incur late payment charges; the average, maximum, and minimum late payment charges incurred by customers, by class, in a given year; and the impact LPCs have on uncollectibles for the electric distribution and gas companies. Accordingly, the Authority approves the Company's proposal to maintain the LPC of 1.25% and to waive LPCs on a case-by-case basis, unless and until modified by the Authority in Docket No. 23-05-01 or another future proceeding. In addition, on or before September 8, 2023, the Company is directed to submit as a compliance filing in Docket No. 23-05-01 an analysis of the type of customers who incur LPCs; the average, maximum, and minimum LPCs incurred by customers, by class, in a given year; and the impact LPCs have on uncollectibles. The Company's compliance filing shall also provide a fuller assessment of the instances in which it has historically waived LPCs, citing data for calendar years 2018 to date, as well as any recommendations pertaining to potential categories of customers who may benefit from an exemption to LPCs (e.g., financial hardship customers that are actively enrolled in a payment arrangement or affordability program).

6. Collections Practices

The Company's collections practices are the subject of scrutiny in several completed and ongoing proceedings, in addition to the instant docket. 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 (Collections Investigation); 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 (Collections 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). Concerns regarding the Company's practices remain following the instant inquiry, and in some cases were elevated by the investigation herein. As such, the Authority will require enhanced notifications and processes regarding RFP issuances for collections vendors, as well as the tracking of additional data to assist in inquiries regarding the efficacy of existing collections methods.

UI divides collections activities between accounts that can be finaled and those that cannot. UI Interrog. Resp. CAE-38; Hr'g Tr. Mar. 7, 2023, 2477:23 – 2478:2. Accounts that can be finaled, (i.e., disconnected from service) are referred to third-party collection agencies. Id. Accounts that cannot be finaled and must remain in an active status, such as those that are protected from disconnection under financial hardship status or medical protection, as well as accounts with difficult to access meters to perform a disconnection, are referred to a legal collection firm. Id.; Hr'g Tr., 2479:5-10.

UI residential customers receive a variety of Company touchpoints prior to a shutoff notice and eventual referral to collections. Hr'g Tr. Mar. 7, 2023, 2466:15-2467:23, 2469:2-10; Late Filed Ex. 114. These collection practices are consistent among UI, CNG, and SCG. Hr'g Tr. Mar. 7, 2023, 2468:16-23. According to UI, after the first unpaid bill, a residential customer will receive their next bill with a notification that their bill

is delinquent. Hr'g Tr., 2467:9-12. If the second bill is also not paid, the customer will receive a disconnection notice five days after receiving the second bill. Hr'g Tr., 2467:12-15. Residential customers will then receive a final reminder notice seven days after receiving the disconnection notice that encourages them to pay their arrearage. Hr'g Tr., 2467:15-18. Additionally, customers will receive a pre-recorded outbound call to remind customers they have a past due balance. Hr'g Tr., 2467:18-20. Seven days after the final disconnection notice, the account is eligible for disconnection. Late Filed Ex. 114. Finally, if the customer still does not reach out to the Company, the account will automatically be finaled seven days after disconnection. Hr'g Tr., 2472:1-4, 9-11. Once an account is finaled, if it (1) has a balance of over $25, and (2) is 44 days after being finaled, then the account is referred to a third-party collection agency. Application, Sch. H-2.10, Vol. 7, p. 136; Interrog. Resp. CAE-38, p. 2; Hr'g Tr. Mar. 7, 2023, 2467:20-23. Customers may pay their bill, to either UI or the third-party collection agency, during the 44 days between their account being finaled and the referral to collections. Hr'g Tr., 2479:20-2480:18.

Those accounts that must remain active are provided notifications of past due balances and encouragements to pay their bill instead of disconnection notices. Interrog. Resp. CAE-40, Att. 1. The Company recently changed its referral requirement for legal collections firms in June 2021. Interrog. Resp. CAE-39. Specifically, the Company now refers active accounts to legal collections firms that have an arrearage greater than $2,500 and are 90 days past due, whereas previously the active account referral threshold was 60 days past due with an arrearage of $1,000 or more. Id.

Commercial customers are also subject to service disconnections and collections activities. Interrog. Resp. CAE-86. Such customers are able to access commercial collections representatives. Interrog. Resp. CAE-86, p. 2; Hr'g Tr. Mar. 7, 2023, 2451:18-22. These representatives can help a commercial customer enter into a payment arrangement or renegotiate such an arrangement. Id. UI will refer commercial customers to either third-party collection agencies or the legal collections firm, but most commercial customers are referred to third-party collection agencies. Interrog. Resp. CAE-86, p. 2; Interrog. Resp. CAE-87. Similar to residential customers, commercial customers that have been disconnected are referred to a third-party collection agency after 44 days. Interrog. Resp. CAE-87. However, the threshold for referring commercial customer accounts to the legal collections firm does not follow the established threshold for residential customers. Hr'g Tr., 2471:2-4. Rather, UI will refer commercial accounts to legal collections "on an ad-hoc basis" if the Company has already exhausted all of its internal collections efforts and believes that the legal collections firm can provide additional assistance. Interrog. Resp. CAE-87; Hr'g Tr. Mar. 7, 2023, 2470:14-24. Overall, between 2018 and 2022, UI referred 104 commercial accounts to legal collections firms and 5,185 commercial accounts to third-party collection agencies, for a total of 1,160 commercial collections referrals. Interrog. Resp. CAE-87, Att. 1.

UI contracts with four third-party collection agencies comprised of two "primary" and two "secondary" agencies. Hr'g Tr., 2486:18-22. The Company's current primary collection agency vendors are Penn Credit Corp and Revco Solutions, Inc. and the secondary agency vendors are Eastern Account Systems of CT, Inc. and IC Systems, Inc. Hr'g Tr. Mar. 22, 2023, 3539:3-8; Late Filed Ex. 113. The Company utilizes the primary and secondary agencies in a competitive manner in order to encourage the best

performance and to receive the greatest amount of collections payments. Hr'g Tr., 2486:22 – 2487:3. Each primary and secondary agency is paid a fee on each collection payment received that ranges between 10-14% of the amount paid. Hr'g Tr., 2486:24 – 2487:3. Finaled accounts are first sent to the primary third-party collection agencies, and if that agency is unable to collect a payment for an account, it is then referred to the secondary third-party collection agencies. Hr'g Tr., 2487:7-12. If the secondary agency is also unable to receive a collection payment from an account, that account's arrearage is then deemed "uncollectible" and recovered through electric rates paid for by all ratepayers. Collections Investigation Decision, App. B, p. 5. Customers may also establish an affordable payment arrangement with the third-party collection agency if they are unable to pay the arrearage in full. Interrog. Resp. CAE-41.

UI currently contracts with one legal collections firm, Nair & Levin. Interrog. Resp. OCC-397; Late Filed Ex. 113. Active accounts are only referred to the legal collections firm if they meet the above requirements and have not contacted the Company to enroll in a payment arrangement or matching payment plan to reduce their arrearage. Interrog. Resp. CAE-38. Therefore, active customers can be referred to the legal collections firm at any time during the year, even during the winter moratorium season, if they have not entered into a payment arrangement with UI. Hr'g Tr., 2469:11- – 2470:7. The legal collections firm will then reach out to referred customers via letters and phone calls in order to request payments. Interrog. Resp. CAE-38, p. 1. The firm will also research the customer "to determine the best course of legal action to collect the overdue debt." Id. Active customers can set up a payment arrangement plan with the legal collections firm or reach out to UI to set up a payment arrangement. Interrog. Resp. CAE-41, p. 1. Further, if a customer is referred to the legal collections firm and is then deemed eligible for UI's Bill Forgiveness Program, the customer will be recalled back to UI and enrolled in the program. Id., p. 2. Between October 2019 and October 2022, UI referred 15,357 active accounts to the legal collections firm.[176] Interrog. Resp. OCC-394, Att. 1, Tab A.

UI's contracted legal collections firm previously pursued legal judgments and wage garnishments as a means of collecting past-due debt from active customers prior to the Authority's investigation into collections practices. Decision, Dec. 07, 2022, Collections Investigation, pp. 6-7. The legal collections firm was responsible for researching customers and determining whether legal judgments or wage garnishment were reasonable measures to pursue (i.e., does the customer have a job where wages can be garnished or assets to attach). Id., p. 6. However, the Authority directed the Company to "suspend the initiation of wage garnishments pending direction from the Authority" in its December 29, 2022 Ruling on Motion No. 1 in Docket No. 22-03-16RE01. Accordingly, UI does not currently have a plan for reinstating legal judgements and wage garnishments. Hr'g Tr., 2483:1-4. Furthermore, the Company is currently reevaluating its strategy of referring accounts to the legal collections firm in response to recent economic pressures and rising energy costs for customers. Hr'g Tr., 2483:14-20. Out of Avangrid's other subsidiaries, only the Berkshire Gas Company also refers active

[176] UI does not specify whether the 15,357 active accounts referred to the legal collections firm are residential, commercial, or a combination of both residential and commercial accounts. Interrog. Resp. OCC-394, Att. 1, Tab A. Given the small number of commercial accounts referred to legal collections, the Authority assumes that this number represents only the residential accounts referred to the legal collections firm.

accounts to a legal collections firm and pursues liens and wage garnishments. Interrog. Resp. CAE-38, p. 2. Neither Avangrid's New York Companies, New York State Energy and Gas and Rochester Gas & Electric, nor Central Maine Power use outside collections firms for active accounts. Id.

The Company establishes new contracts with legal collections firms and third-party collections agencies through an RFP process. Hr'g Tr. Mar. 22, 2023, 3540:2-9. The RFP process is not standardized, but rather, depends on UI's relationship with the collections vendors. Hr'g Tr., 3540:10-13. For example, UI has maintained its contract with legal firm Nair & Levin since 2012. Hr'g Tr., 3540:13-17. In contrast, UI issued a collective RFP with other Avangrid subsidiaries for a new three-year contract with third-party collections agencies in March 2021. Hr'g Tr., 3540:5-9, 3541:2-4. Therefore, UI's current contracts with the four third-party collection agencies all resulted from the same 2021 RFP process. Hr'g Tr. Mar. 22, 2023, 3541:8-14. The Company does not pursue sole source contracting for its collections vendors. Hr'g Tr., 3540:18-21.

The Company recovers legal and third-party collections expenses, as well as uncollected debt, through either the SBC or through base distribution and transmission rates. Late Filed Ex. 116; Collections Investigation, App. B, p. 5. Specifically, fees paid to legal firms for active hardship customer collections are accounted for as a legal expense and recovered through the SBC rate mechanism. Late Filed Ex. 116. Debt recovered from customers that were previously hardship write-offs are accounted for as credits and reduce the amount of hardship uncollectible write-off expenses that are recovered through the SBC. Id. Fees paid to legal firms for active non-hardship customer collections and to third-party collections firms for finaled accounts, regardless of hardship status, are recovered through base distribution and transmission rates. Id. Debt recovered from customers that were previously non-hardship write-offs are accounted for as credits and reduce the amount of non-hardship write-offs recovered through base distribution and transmission rates and through the Generation Service Charge rate mechanism. Id.

The Authority finds that greater transparency is needed regarding the Company's collections practices and contracted vendors. Indeed, the Authority is troubled with the level of discovery required in order to understand UI's current collections practices, which required myriad requests through interrogatories, late filed exhibits, and hearing examinations. Additionally, such discovery was required given that the Company's own standard operating procedure documents, which describe UI's corporate customer service procedures, are out of date and reference a vague revision timeline. Interrog. Resp. EOE-31, EOE-43, EOE-158, EOE-196; Hr'g Tr. Mar. 6, 2023, 2316:18 – 2317-22. Accordingly, the Authority directs UI to pursue open RFP processes in the future when seeking new collections vendors. Specifically, UI shall notify the Authority and stakeholders that such RFP is being issued by: (1) filing the notice and RFP as compliance with the Authority in the instant proceeding contemporaneously with the Company's release of such documents; and (2) posting the notice and RFP to the UI website for a period of time that comports at minimum with the Company's internal procedures.

Furthermore, the Authority finds that the lack of standardization for collections vendor management is concerning. Rather than ad hoc decisions regarding vendors

based on relationship status, UI shall establish a standard timeline for collections vendor contracts and regular RFP issuance. Accordingly, no later than December 1, 2023, UI shall submit as compliance in this proceeding an established policy and timeline for retention of a collections vendor that incorporates a 3-year contract length for collections' vendor(s) and includes a period of time to issue an RFP each time a new contract is needed.

Finally, the Authority remains interested in investigating the efficacy of the Company's collections efforts. UI currently incurs significant expense related to internal and external collections activities without any analysis pertaining to the efficacy of individual collection methods. The Authority acknowledges the ongoing working group and cost-benefit analysis effort regarding wage garnishments that is occurring in Docket No. 22-03-16RE02, through the Collections Working Group. In conjunction with the ongoing efforts of the working group led by the OCC, the Authority is interested in better understanding the connection between various collections efforts and actual collected debt, such as the relationship between disconnections, external collections vendors, and any declining arrearages. Accordingly, the Authority directs UI to begin tracking on a monthly basis the following, and to submit such data to the Authority as compliance on an annual basis, delineated by residential versus non-residential customers:

number of disconnection notices;
number of disconnections;
number of other Company notifications;
referrals to third-party collection agencies;
referrals to legal collection firms;
the number of referred customers that pay their arrearage;
the number of referred customers that enter a payment arrangement; and
the amount of collected payments per referred customer.

Specifically, UI shall begin collecting such monthly data by September 1, 2023, and shall submit the collected data to the Authority on an annual basis in that year's respective annual Arrearage Forgiveness Plan Docket, i.e., Docket No. XX-05-01. The first annual filing shall be submitted in the 2024 energy affordability proceeding in Docket No. 24-05-01.

B. CUSTOMER SERVICE TRAINING AND OPERATIONS

1. Customer Service Performance

The Company continues to misinform customers or to provide incomplete information, and as a result, the Authority directs remediation efforts herein to address at a minimum the individual ratepayers harmed or potentially harmed by the Company's actions in calls submitted as evidence in this proceeding.

According to EOE, UI had several violations from just the small sample of calls from July through October 2022 to which EOE listened. See Interrog. EOE-180; EOE Brief, pp. 19-20. In particular, EOE cited a call that occurred on June 13, 2022, in which the CSR did not use the hardship pre-qualifying questions provided to them, *even after* the customer explicitly expressed difficulty paying their bill. Id. As a result, the customer was placed on the COVID-19 payment arrangement, which was less favorable to the

customer than other options for which the customer likely qualified. In addition, EOE highlighted a call that occurred on October 10, 2022, in which a customer had an arrearage and a disconnection notice and was directed to pay $227.16 to avoid termination. EOE Brief, p. 21. According to EOE, the customer was not asked the hardship pre-qualifying questions or given any payment arrangement options. Id.

In addition, EOE opines that UI's unsatisfactory customer service interactions are caused by UI sending its most complex calls to an outside vendor. EOE Brief, p. 22. Instead of retaining credit and collections issues in house, UI routes these types of calls to its external vendor and fails to properly monitor, penalize, and provide accurate and understandable information to the vendor. Id.

In response to EOE, the Company stated that EOE focuses on only six of the 120 calls in Interrog. Resp. EOE-180. UI Reply Brief, p. 160. UI contends that the Company is customer-focused and proactively addresses issues as they occur, which is likely because of the large number of customer interactions in a year. Id. Nonetheless, the Company claims that it strives to provide the best possible customer service and monitors internal and external interactions. Id. Further, the Company argues that EOE's assertion that it does not properly handle complex credit and collections calls based on six out of 120 calls is inaccurate and not a fair measure of complexity. UI Reply Brief, pp. 161-162. The Company reiterates that since 2016, it has received an exponential growth in calls related to solar photovoltaic projects, other distributed energy resources, and other complicated matters requiring internal and specialized knowledge. Id.

Notwithstanding the Company's assertions, the severity of the EOE findings indicates that the Company needs to take more action to ensure that these occurrences are uncommon, and that violations of such foundational issues (i.e., screening for financial hardship) are virtually nonexistent. Therefore, the Authority will continue to provide directives in the energy affordability dockets to meet this objective and to assess penalties if the Company continues to fall short in educating and assisting customers based on their individual circumstances. The Authority intends to continue discussions on how to enhance quality customer interactions in Docket No. 23-05-01. The Authority will further examine ways to improve customer service interactions up to and including: (1) penalizing third-party vendors for violations; and (2) increasing the number of trainings, or training methods for external vendors. Moreover, as discussed in Section VI.A.4., Incremental FTEs, the Authority directs UI to adjust the percentage of credit and collections calls directed toward third-party call center vendors.

Lastly, UI shall contact each of the individuals that were harmed because of incomplete or inaccurate information in the sample of calls sent to EOE in the Company's response to Interrogatory EOE-180 in the instant proceeding. The Company shall ensure these customers are placed in the best 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. The Company shall submit as compliance in Docket No. 23-05-01, no later than December 15, 2023, 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. The Company shall also

include a similar report for customers whose service was terminated from July through October 2022.

2. Standard Operating Procedures Revision Lag

The corporate procedures documents presented in the Application were not updated with current Authority Decisions and Orders, which would help CSRs provide correct information to ratepayers. Interrog. Resp. CAE-29; Interrog. Resp. EOE-33; Interrog. Resp. EOE-34; Interrog. Resp. EOE-35. The Company testified it would complete a review of its Standard Operating Procedures (SOPs) in the early second quarter of this year. Interrog. Resp. EOE-196. In addition, the Company stated it provides timely revisions to CSRs regarding procedural changes through training, e-mail communications, team huddles, and communication meetings. Id. Typically, the SOPs are reviewed every one to two years, with periodic review outside of the planned schedule as required to meet business needs. Id.

The Authority finds the revision lag between training materials and SOPs disconcerting. Although the Company testified that the CSRs have the updated materials within the call center, the Authority finds the revision lag is an inefficient way to ensure staff are properly trained as it creates the potential for confusion, inconsistencies, and miscommunications. Based on the evidence in the instant proceeding, the Company still falls short of properly training its internal and external CSRs due to the continued provision of incomplete and misinformation to its ratepayers. As such, the Authority directs UI to prospectively revise all corporate procedure documents no later than 30 days after PURA directs any changes to programs or procedures. The Company shall submit as compliance in the applicable docket (i.e., the docket through which the Authority established the change) a redlined and clean version of the Company's revisions to its corporate procedures. Failure to comply with this directive may result in the Authority assessing civil penalties pursuant to Conn. Gen. Stat. § 16-41.

As for the corporate procedure documents submitted as part of the Application, the Company shall submit as compliance in the instant proceeding an updated version of all corporate procedure documents by January 31, 2024. The Authority expects that these documents shall reflect any and all policy changes authorized in the forthcoming decision in Docket No. 23-05-01.

3. Customer Service Study Results

The Authority concludes that, while UI uses a variety of surveys to measure customer satisfaction, the surveys fall short in their scope and size; thus, PURA directs certain changes to be observed on a prospective basis and cautions the Company on its further reliance on the Net Promoter Score concept detailed for the first time in this proceeding.

UI uses a variety of surveys to measure customer satisfaction. Application, Sched. H-2.7, UI Customer Contact Satisfaction; Application, Sch. H-2.8, UI Customer Satisfaction Perception Study; Interrog. Resp. EOE-87. These surveys include the Customer Contact Satisfaction Survey, Customer Satisfaction Study, and the Net Promoter Score, which are performed by Avangrid for all Avangrid subsidiaries, as well as the Electric Utility Residential Customer Satisfaction Study operated by JD Power and Associates. Id. The Customer Contact Satisfaction Survey and Customer Satisfaction

Study are conducted by the research group Great Blue Research based in Glastonbury, Connecticut. Application, Sch. H-2.7, p. 3; Application, Sch. H-2.8, p. 3; Interrog. Resp. CAE-49, p. 1.

The Customer Contact Satisfaction Survey measures the satisfaction of customers who have recently contacted UI. Application, Sch. H-2.7, p. 3. The moments of contact included in the survey are speaking with a CSR and using the website or automated phone IVR system. Id., p. 4. According to UI, the survey occurs via phone call and samples 125 UI customers on a quarterly basis for a total of 500 customers annually. Id., p. 3. UI reported an overall contact satisfaction result of 89% in 2021. Id., p. 5. The Company's current target for overall contact satisfaction is 90%. Interrog. Resp. CAE-47, p. 2. Additionally, customers reported their overall satisfaction with recent contacts with a CSR, the website, and IVR system at 87%, 92%, and 91%, respectively. Application, Sch. H-2.7, p. 10. While the reported satisfaction rates are higher for interactions with the website and automated phone IVR system, the sample number of interactions with CSRs is double the sample size of sampled web interactions. Id. Specifically, UI's reported CSR interaction sample size was 886 customers, whereas the reported website and IVR interaction sample sizes were 439 customers and 142 customers, respectively. Id. Therefore, although customers may be more satisfied with online and automated interaction offerings, it appears that many more customers are interacting with UI via contacting the Company's call centers. Id.

The second survey, the Customer Satisfaction Survey, randomly samples customers and measures their overall satisfaction with the Company. Application, Sch. H-2.8, p. 3. UI stated that it samples 170 customers on a quarterly basis for a total survey of 680 customers annually. Id. The Survey is operated via telephone calls and email. Id. According to UI, its customers reported an overall satisfaction result of 84% in 2021. Id., p. 4. The Company has not established a goal related to its customer satisfaction result. Interrog. Resp. CAE-49, p. 3. In comparison to the other Avangrid subsidiary companies, only Rochester Gas & Electric and Central Maine Power received lower satisfaction scores, whereas Berkshire Gas, Southern Connecticut Gas, Connecticut Natural Gas, and New York State Electric & Gas all received higher satisfaction scores. Application, Sch. H-2.8, p. 4.

Additionally, UI is utilizing a new survey metric called the Net Promoter Score (NPS). Interrog. Resp. CAE-47, pp. 1-2. The NPS metric is collected through a digital survey and asks customers how likely they are to recommend UI to others. Id., p. 2. The Company stated that the metric is collected on a 10-point scale and categorizes those who respond with 7 and 8 as "passives" and 9 and 10 as "promoters." Id. Those who respond 0 to 6 are categorized as "detractors." Id. According to UI, the NPS metric is calculated through subtracting the percentage of "promoters" from the percentage of "passives." Interrog. Resp. CAE-47, p. 2. Also according to UI, the use of the NPS metric is a common customer service practice used among various industries. Id. Furthermore, the Company shared that the NPS metric is easier to receive responses due to the digital format, as evidenced by the Company receiving 2,151 NPS surveys in its effort to begin collecting baseline data, in contrast to 456 Contact Satisfaction surveys. Id., pp. 1-2; Interrog. Resp. EOE-47.

The Authority finds that UI's current customer service surveys are lacking in ability to sufficiently measure customer satisfaction. First, the Company reports that it currently serves approximately 341,000 residential, commercial, and industrial customers. Notice of Intent, Aug. 1, 2022, p. 1. However, UI stated that its current survey sample quotas for the contact satisfaction and overall satisfaction surveys are set annually at 500 customers and 680, respectively. Application, Sch. H-2.7, p. 3; Application, Sch. H-2.8, p. 3. These surveys are therefore only capturing less than 0.2% of all UI customers. Such a survey cannot be used to satisfactorily understand current customer challenges nor to propose new customer service initiatives. Furthermore, the Authority is not persuaded that the NPS metric is a true measure of the full breadth of customer experiences and questions its relevance to a regulated monopoly. Thus, the Authority is concerned by the prospect that UI may choose to invest further in measuring the NPS metric rather than utilizing its existing surveys to measure customer satisfaction, given its reported success in receiving more NPS survey results. Indeed, while the collection of data via digital means is encouraging, the Authority reminds UI that not all of its customers may have access to digital options through which to answer such a survey.

Accordingly, the Authority directs UI to continue to utilize all existing surveys to measure customer experience and satisfaction. Specifically, UI shall not replace the contact satisfaction and overall satisfaction surveys with the NPS metric. Furthermore, the Authority directs UI to increase its survey sample quotas for the Contact Satisfaction Survey and Customer Satisfaction Study. The minimum survey quotas shall be at least 1% of all residential and commercial customers. UI shall incorporate this quota minimum in its customer satisfaction surveys to be submitted in its next base rate case proceeding.

Lastly, the Authority encourages the Company to actively engage in developing relevant customer satisfaction metrics in the recently established proceeding, No. 21-05-15RE02, PURA Investigation into Performance Mechanisms for a Performance-Based Regulation Framework, which will focus on reported metrics, scorecards, and Performance Incentive Mechanisms in the service of the goals and priority public outcomes adopted in the April 26, 2023 Decision in Docket No. 21-05-15.

4. Customer Experience Initiatives

In this proceeding, the Company detailed several initiatives that it is pursuing to enhance the customer experience for which the Authority provides guidance below.

UI is currently pursuing multiple initiatives that aim to improve their customers' experience with the Company. Pelella and Paterson PFT, pp. 11:10-15, 24:18-26:6, 27:8-12; Interrog. Resp. EOE-56. First, the Company has already embarked on its Voice of the Customer (VOC) Program, which utilizes various quantitative customer satisfaction studies as well as qualitative interviews to understand the customer experience. Interrog. Resp EOE-47.

UI used the VOC Program to develop initiatives for improving the customer experience. Pelella and Paterson PFT, pp. 4:20-5:2. Specifically, UI launched the Customer Journey Redesign Program, which aims to improve five journeys over the life cycle of a UI customer: (1) move-in/move-out; (2) outages; (3) billing and payments; (4) service requests; and (5) energy usage. Interrog. Resp. EOE-56, p. 1. Many of the planned improvements include additional capacities built into the Company's website and

mobile offerings that allow customers to self-service, gain more information regarding their usage and power outages, and generally increase transparency for customer empowerment and satisfaction. Id., pp. 1-2; Pelella and Paterson PFT, pp. 25:3-26:6. Indeed, two necessary new components to support this initiative include a Customer Orchestration Platform and a Digital Operations Center, both of which are concerned with improving customer experiences over the website, mobile app, email, and Short Message Service (SMS) contact channels. Pelella and Paterson PFT, pp. 27:14 – 28:11; Interrog. Resp. EOE-65.

The Authority appreciates UI's efforts to improve the Company's digital engagement offerings for customers. The Authority agrees that providing additional and more accessible information and interactive options to better understand energy usage will increase customer satisfaction and empowerment. However, the Authority is unconvinced by UI's justification for investing so heavily in primarily digital offerings. Specifically, UI stated that "customers are highly satisfied with digital options . . . to manage their account" and therefore embarked on further digital options to "[build] on that success." Pelella and Paterson PFT, p. 24:7-13. However, the Authority questions why the Company did not instead choose to invest in areas where customers were *unsatisfied* with their engagements with UI. Furthermore, while digital offerings are an important component of any successful modern company, there are still customers who may not have access to a computer and/or smartphone and will therefore be left out of such innovations. Indeed, improving the experience of such customers may be of even higher importance than those who do have access to computers and/or smartphones, since they have fewer engagement options at their disposal. And finally, the Authority questions why, after finding customer dissatisfaction with non-digital engagement options, as well as receiving multiple penalties from the Authority regarding CSR conversations with customers, that UI did not choose to further invest in improving the customer experience with its customer contact centers.

Accordingly, the Authority directs UI to develop a customer experience initiative under the Customer Journey Redesign Program that specifically aims to improve customers' experiences interacting with the Company's CSRs and contact centers, as well as those customers that do not have access to digital offerings. UI shall submit the proposal to the Authority for review and approval in the 2024 Energy Affordability Annual Review proceeding, i.e., Docket No. 24-05-01, no later than June 1, 2024.

5. EOE Recommendations for Customer Service

a. Budget Billing

The Authority concludes that certain recommendations made by EOE are appropriate for the Company to pursue regarding implementation of its budget billing program so as to provide adequate protections to those already enrolled against potential rate shock and to encourage additional enrolment as appropriate.

The Company's residential customers can enroll in the budget billing program to pay an equal amount each month for 12 months. Interrog. Resp. EOE-120. UI reevaluates the customer's budget billing amount once every six months to determine if the budget amount is adequate. Interrog. Resp. EOE-39. The Company's billing system compares the budget amount to the customer's actual usage for the previous 12 months

and adjusts the monthly budget amount accordingly. Id. Further, the system will perform another comparison at the end of the 12-month budget year, which may result in a refund, and will then automatically renew for another year. Id.

There were 16,662 customers who participated in budget billing in October 2022, an increase compared to the 12,071 in October 2021. Interrog. Resp. EOE-121, Att. 1. EOE notes there is a significant overall increase of 160% of the number of customers who participated in the program from 2017 to 2021. EOE Brief, p.39. The number of customers who participated in October 2022 compared to the same period in 2021 represents another significant increase. Id. Consequently, EOE recommends that UI continue its efforts to inform customers of this tool. Id.

EOE notes that UI does not consider price fluctuations in the retail market to determine the monthly budget billing amount. EOE Brief, p. 40. Given the recent increase in standard offer price, some customers' generation rate doubled during the winter period. Id. Although the recent standard service price is an unprecedented occurrence, EOE states that the Company's billing system should consider the increase in rates when determining or reevaluating appropriate budget payments. Id. Consequently, EOE recommends that UI propose a revision to its budget billing process to respond to an approved change in standard offer price, distribution, or transmission rates greater than 25%. Id.

The Authority concurs with EOE and appreciates the efforts directed toward encouraging and educating customers about the budget billing program. The significant increase in participation makes it evident that customers respond to a steady payment signal and are more likely and willing to enroll in the program. The Authority continues to seek methods to encourage customers to make affordable payments and to avoid service terminations and finds EOE's recommendation to be a reasonable improvement to the budget billing program in support of those objectives. The Authority recognizes that to include a change to rates when calculating the budget billing amount, billing system changes may be warranted. Therefore, the Authority directs UI to submit as compliance a proposal in the instant proceeding no later than 45 days after the date of this Decision; the proposal will be subject to stakeholder review and comment in the instant docket but will receive Authority review through Docket No. 23-05-01 as detailed below. The proposal, at a minimum, should include any one-time and/or recurring costs, an implementation timeline, and an explanation as to whether the identified costs have any bearing on the implementation timeline (e.g., one option may result in a reduction to the implementation timeline but is more expensive). Subsequent to review and consideration of any stakeholder comments, the Company shall submit its final proposal for Authority review and approval in Docket No. 23-05-01 no later than January 15, 2024.

b. High Bill Complaint Process

The Company developed a high bill complaint (HBC) procedure to assist its customers and CSRs. Application, Sch. H-2.10, Vol. 4. As part of the procedure, CSRs use the bill analyzer tool to provide customers with usage data. Interrog. Resp. EOE-40, Att. 1. Through this process, the CSR will analyze several factors which include, at minimum: billing days balance forwarded; weather condition; and estimated bills. Id. EOE notes that the bill analyzer tool is effective to examine customers' usage; however, on its own it does not provide customers with the reason for an increase in usage. EOE

Brief, p. 40. The bill analyzer tool also displays total charges for delivery charges, basic service charges, or other charges, but does not provide a specific line-item breakdown of the charges. Id. As such, EOE recommends that UI review the bill analyzer tool and determine the feasibility of including a display of individual line-item charges to help customers compare their bills. Id. The Company agreed with EOE that displaying individual line-item charges would be helpful to provide customers the opportunity to make a month-to-month or year-to-year comparison of charges. Hr'g Tr., 3468-3489.

The Authority concurs that the feature enhancement proposed by EOE could be helpful to customers when making usage comparisons, as it could, among other benefits, help customers with their conservation efforts. The Authority appreciates the Company's willingness to improve the bill analyzer tool to provide more information to its customers. However, before directing the implementation of such an enhancement, the Authority must examine the related costs to ensure the benefits outweigh any identified costs. Therefore, no later than November 30, 2023, the Company shall submit as compliance in the instant proceeding and in Docket No. 23-05-01 a proposal to implement this feature, which should include at a minimum any projected one-time or recurring costs and the implementation timeline.

XIII. CONCLUSION AND ORDERS

A. CONCLUSION

The Authority approves an annual revenue requirement for UI in the amount of $384.865 million for the rate year commencing on September 1, 2023. This represents an increase of $22.957 million from the Company's currently approved revenue requirement from which the Company had sought a $131 million increase over three years. In addition, the Authority makes determinations on a myriad of 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. In next year's RAM proceeding, Docket No. 24-01-04, UI shall provide in its RDM filing for calendar year 2023 an exhibit that true-ups the estimated CAM GET credit of $0.841 million if the variance is more than plus or minus 10% compared to the actual amount for the 11-month period ending August 2023.

2. In subsequent annual RDM filings, UI shall report RSF as a component of other operating income and not as an offset to operating expenses.

3. The Company shall not recognize deferred assets and liabilities under IFRS for regulatory reporting filed with the Authority. UI shall continue to record regulatory assets and liabilities under US GAAP. This Order does not preclude UI from reporting deferred assets and liabilities under IFRS in consolidated financial reports filed by its "ultimate" foreign parent company.

4. The Company shall pursue an open RFP process for the selection of all future collections' vendors, as discussed in Section XII.A.6., Collections Practices. Specifically, UI shall notify the Authority and stakeholders that such RFP is being issued by: (1) filing the notice and RFP as compliance with the Authority in the instant proceeding contemporaneously with the Company's release of such documents; and (2) posting the notice and RFP to the UI website for a period of time that comports at minimum with the Company's internal procedures.

5. No later than 10 days after the Company has executed a contract with its third-party payment processor for the Fee Free program, the Company shall submit as a compliance filing in this proceeding the executed contract between the Company and the third-party payment processor. The Company's filing must also include a timeline for implementing the Fee Free program.

6. No later than September 1, 2023, the Company shall close participation in the Water Heater Rental Program to new customers, as discussed in Section VI.A.21., Water Heater Program.

7. No later than September 1, 2023, and every month thereafter, the Company shall begin collecting residential and non-residential customer disconnection, collections, and arrearage data, as discussed in Section XII.A.6., Collections Practices. Further, the Company shall annually submit as compliance the collected data in each annual Arrearage Forgiveness Plan to be submitted in that year's energy affordability proceeding (i.e., Docket No. XX-05-01), with the first submission to be filed in the 2024 energy affordability proceeding in Docket No. 24-05-01.

8. No later than September 1, 2023, the Company shall submit as a compliance filing in this proceeding scored and unscored tariffs with revenue proof consistent with the Authority's Decision.

9. No later than September 8, 2023, the Company shall submit as a compliance filing in the 2023 energy affordability proceeding in Docket No. 23-05-01 an analysis of the following: (1) the type of customers that incur late payment charges; (2) the average, maximum, and minimum LPCs incurred by customers, by class, in a given year; and (3) the impact LPCs have on uncollectibles, as discussed in Section XII.A.5., Late Payment Charges. This filing shall also include an assessment of instances between calendar years 2018 to date in which the Company has historically waived LPCs and recommendations for potential categories of customers who may benefit from an LPC exemption.

10. No later than September 15, 2023, UI shall submit as a compliance filing in this proceeding an exhibit that quantifies the total accrued CAM GET regulatory liability amounts as of December 31, 2022, and August 31, 2023.

11. No later than February 15, 2024, and annually thereafter, UI shall submit as a compliance filing in this proceeding, the standard the Company applied over the preceding 12-month period to determine employee attendance at an event which causes the Company to incur travel, education, and training expense, as well as an explanation as to why such costs should be funded by ratepayers. Information provided shall include, at a minimum: how the standard considered whether and how such expense will help the Company meet its statutory obligations and provide benefits to ratepayers; a list and description of each event, including whether such event was hosted by an entity to whom the Company, an affiliate, or its parent company pay membership dues; a descriptive list of the individual(s) who attended any event, including the titles of the individual(s), years of service with the Company, years of service in the current job classification, and whether such expense was necessary for maintenance of a specialized certification; and an itemized list of costs for each event by individual, accompanied by receipts for all expenses.

12. No later than September 15, 2023, UI shall notify the Authority via a compliance filing in Docket No. 23-05-01, Annual Review of Affordability Programs and Offerings, when the Company implements the enhanced website feature for termination notices.

13. No later than September 15, 2023, UI shall calculate and submit as a compliance filing in this proceeding modified pole attachment rates as adjusted by the Authority in Section X.F.3., Pole Attachment Rates.

14. No later than September 25, 2023, the Company shall submit as a compliance filing in this proceeding a copy of an estimated bill that includes the Company's telephone number.

15. No later than September 25, 2023, the Company shall submit as a compliance filing in this proceeding revised customer termination materials that sufficiently inform customers of their right to dispute a payment plan by contacting a review officer, as discussed in Section XII.A.2., Customer Rights and Termination Notices.

16. No later than September 25, 2023, the Company shall submit as a compliance filing in this proceeding an updated version of all corporate document procedures the Company has previously submitted in this proceeding.

17. No later than September 30, 2023, the Company shall submit as a compliance filing in this proceeding a proposal to revise its budget billing process to respond to approved standard offer price, distribution, or transmission rates greater than 25%. The proposal, at a minimum, should include any one-time

and/or recurring cost, implementation timeline and identify whether costs have any bearing on the implementation timeline.

18. No later than September 30, 2023, the Company shall submit as a compliance filing in this proceeding the following for both rates GS and GST: (1) the number of accounts associated with the rate; (2) the annual distribution revenues from the rate; (3) a histogram of the count of customers in groups divided by peak annual demand (e.g., number of accounts with peak annual demand of 0-5 kW, 5-10 kW, etc.); and (4) a histogram of annual kWh sales broken into groups divided by peak annual demand (e.g., annual kWh sales from accounts with annual peak demand of 0-5 kW, 5-10 kW, etc.),

19. Beginning with the financial quarter ending September 30, 2023, and subsequently thereafter, the Company shall compute its actual earned ROE for ESM purposes using the lesser of the (1) actual carried common equity position, or (2) the authorized allowed rate making common equity portion. Furthermore, the Company shall identify and exclude all disallowed expenses from the earned ROE for sharing purposes. When ESM revenues are identified for a given calendar year, the Company shall submit for Authority review and approval a motion in the instant proceeding identifying the amount of ESM revenues due to customers and a proposed plan for returning such revenues to customers.

20. No later than October 1, 2023, in accordance with Section VI.A.3.b., Performance Metrics, the Company shall submit for Authority review and approval a baseline calculation for each of the performance metrics using the data for each year from 2017 through 2022.

21. No later than October 7, 2023, UI shall develop and submit for Authority review and approval in Docket No. 23-08-09, Annual Electric Distribution Company Reliability and Resilience Framework Review a four-year work plan to implement the UPZ priorities for years 2024 to 2027 and to transition to a four-year trimming cycle by 2027. The plan shall also demonstrate compliance with the priorities outlined in Section VI.A.15, UPZ and Vegetation Management Expense.

22. In its next RAM filing in Docket No. 24-01-04, the Company shall include the revenues collected from late payment fees in its annual RAM filing as a “surplus” for RAM purposes that will serve to offset potential revenue shortfalls.

23. No later than December 1, 2023, the Company shall submit as a compliance filing in this proceeding an established collections’ vendor timeline that incorporates a 3-year contract length for collections’ vendor(s) and includes a period of time to issue an RFP each time a new contracted is needed, as discussed in Section XII.A.6., Collection Practices.

24. No later than December 15, 2023, the Company shall submit as a compliance filing in the 2023-2024 Proposed AFP Plan proceeding, Docket No. 23-05-01,

a report of all improperly handled customer service calls identified in the Company's response to Interrogatory EOE-180 that, at minimum, includes: (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. The Company shall also file by December 15, 2023, an additional report using the above-identified criteria for customers whose service was terminated from July through October 2022.

25. Not later than January 1, 2024, the Company shall submit to DEEP, and contemporaneously as a compliance filing in this proceeding, a remedial action plan for the East Shore Project in accordance with DEEP's VRP. Until otherwise directed by the Authority, the Company shall provide subsequent annual progress reports on the remediation to DEEP and as a compliance filing in this proceeding.

26. Beginning on January 15, 2024, and annually thereafter, the Company shall submit a compliance filing in this proceeding with detailed information regarding whether UI met or exceeded each of its metrics the preceding year as described in Section VI.A.3.b., Performance Metrics. The compliance filing shall include an unlocked workable Excel spreadsheet providing the data on which the Company relied in making its determination.

27. Beginning on February 1, 2024, and annually thereafter, the Company shall submit as a compliance filing in its annual RAM proceeding the amount of UI, Avangrid Management Company, and Avangrid Service Company executive compensation customers paid in base rates and through the RAM or were credited in the RAM in the preceding year.

28. No later than 14 days after contacting the DECD and the OTG to provide in writing the details of both the EDR Rider and the special contracting process, the Company shall file as compliance in this proceeding the written details provided to DECD and OTG. The Authority notes that the DECD and OTG shall be contacted on or before the EDR Rider effective date.

29. No later than February 1, 2024, the Company shall file in this proceeding a motion for Authority review and approval of an implementation plan for the EDR Rider outlined in Section X.F.1., Economic Development Rates.[177] The implementation plan shall include a draft application for the EDR Rider, inclusive of a detailed list of customer information that will be collected and presented in the annual report, along with a proposal regarding which data will be redacted or anonymized in said report. The implementation plan shall also include a marketing plan for the EDR Rider, including a budget and anticipated timeline. Further, the Authority directs the Company to note the special contracting process in all of its marketing materials, including website pages

[177] Stakeholders will be afforded the opportunity to comment on the motion submitted in compliance with this Order, consistent with PURA practice and the Notice of Proceeding.

associated with the EDR Rider,[178] and to include contact information for the Company, as well CTNext, AdvanceCT, Connecticut Innovations, and DECD.

30. Not later than March 1, 2024, the Company shall submit as a compliance filing in this proceeding a summary of its discussion with Central Maine Power on how job quality requirements were determined for Pine Tree Zones, including how the final values and thresholds were determined, and any additional criteria considered but not included in the job quality requirements. For any criteria discussed but not included for Pine Tree Zones, the Company shall provide a narrative explanation of why Central Maine Power elected not to include the criteria in the final job quality definition.

31. No later than May 1, 2024, the Company shall submit for Authority review and approval in Docket No. 24-05-01 a proposed plan to: (1) transition credit and collections calls from the third-party call center to UI's internal call center; (2) identify which potential call types can be handled by the third-party call center that are currently handled by UI's internal call center; and (3) transition at least 35% of credit and collections calls directed toward third-party call center vendors to UI's internal call center by September 1, 2024, as discussed in Section VI.A.2.d.3., Customer Service Incremental FTEs.

32. No later than May 1, 2024, the Company shall submit for Authority review and approval in this proceeding confirmation that five (5) UIL-level customer service FTEs have been hired and a description of the capacity at which they are working for Connecticut ratepayers, as discussed in Section VI.A.2.d.3., Customer Service Incremental FTEs. The submission shall include a substantiated request for review and approval to seek incremental, prospective recovery for the five FTE salaries through an adjustment to distribution rates on September 1, 2024.

33. No later than June 1, 2024, the Company shall submit in this proceeding for Authority review and approval a comprehensive plan to phase out all remaining equipment in the Water Heater Rental Program by September 1, 2025, as discussed in Section VI.A.21., Water Heater Program.

34. No later than June 1, 2024, the Company shall submit for Authority review and approval in the 2024 energy affordability proceeding, Docket No. 24-05-01, a proposed customer experience initiative under the Customer Journey Redesign Program that specifically aims to improve the customer's experience with: (1) interacting with the Company's CSRs and contact centers; and (2) interacting with the Company as a customer without access to digital offerings, as discussed in Section XII.B.4., Customer Experience Initiatives.

[178] For clarity, the Authority does not require the Company to actively market the special contracting process, but rather to make sure that existing resources and contact information regarding the special contracting process are included with EDR Rider marketing materials and on relevant UI websites.

35. No later than June 1, 2024, in accordance with Section VII.F., Pleasure Beach Island, the Company shall submit as a compliance filing in this proceeding the results of the RFP including the details of all bids, including the winning bid.

36. Prior to the PBI solar plus storage project taking service, the Company must submit for the Authority's review and approval in the instant proceeding option(s) for a rate structure for the customers on PBI pursuant to Conn. Gen. Stat. § 16-19e(a)(4) in order to appropriately allocate the cost of such service. Such options should be consistent with the Company's current terms and conditions of service, including the guarantee of a minimum annual payment for a term of years. The filing shall also include a timeline of requested approvals, all partnerships, and other contractual agreements that the Company has and plans to enter into for the project, and any other documents and legal parameters necessary to execute the Proposal. Any rate structure options considered and presented may take into account the non-energy benefits that this project may provide to the Company and its ratepayers, as a whole, including environmental and societal benefits.

37. No later than December 31, 2024, and annually thereafter, the Company shall submit as a compliance filing in this proceeding a report regarding the implementation of the EDR Rider. The report shall comply with the requirements stated in Section X.F.1., Economic Development Rates.

38. In the Company's next rate case, UI shall file as a part of its application the Company's special contracting policy. As part of the application, the Authority directs the Company to discuss, in advance of filing, the special contracting policy with DECD and to submit any recommendations from DECD along with the policy.

39. In the Company's next rate case and in all future proceedings where UI requests recovery of catastrophic storm costs in the storm reserve, UI shall provide documentation demonstrating that all catastrophic storm costs meet the cost threshold as escalated twice each year according to the Handy-Whitman Index.

40. In the Company's next rate case proceeding, the Company shall incorporate an increase of its minimum survey quota to 1% of all residential and non-residential customers for the submitted Contact Satisfaction Survey and Customer Satisfaction Study, as discussed in Section XII.B.3., Customer Service Study Results.

41. In the Company's next rate case proceeding, the Company shall submit for Authority review and approval specific TOU rate redesign proposals. The rate redesign proposals shall address each of the issues identified in Section X.E.6., Time-of-Use (TOU) Rates, including issues related to seasonal rates.

42. UI shall record all net mutual aid revenue received by the Company resulting from sending mutual aid to other utilities to the storm reserve, as outlined in Section VI.A.11.d., Mutual Aid Revenue.

DOCKET NO. 22-08-08 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO AMEND ITS RATE SCHEDULE

This Decision is adopted by the following Commissioners:

Marissa P. Gillett

John W. Betkoski, III

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

August 25, 2023
Date