STATE OF CONNECTICUT
PUBLIC UTILITIES REGULATORY AUTHORITY

RE:	**APPLICATION OF THE UNITED ILLUMINATING COMPANY TO AMEND ITS RATE SCHEDULE**	**:**	**DOCKET NO. 22-08-08**
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		:	**APRIL 27, 2023**

THE OFFICE OF CONSUMER COUNSEL'S BRIEF

Respectfully submitted,

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I. Table of Contents

II. Introduction

Pursuant to the schedule established by the Public Utilities Regulatory Authority ("Authority" or "PURA"), the Office of Consumer Counsel ("OCC") hereby respectfully submits its Brief in the above-captioned docket reviewing the distribution rate application ("Application") of The United Illuminating Company ("UI" or "Company"). For the many reasons set forth below, OCC urges the Authority to reject UI's unsound Application, which requests historic revenue increases from ratepayers without even adequate justification.

This is the core failing of UI's rate case. Lack of documentation and factual support is pervasive, and the overall sense from the proceeding – and especially from the hearings – was of an Application that was rushed and incomplete. It falls wells short of UI's evidentiary burden under our ratemaking standards. This brief seeks to identify as comprehensively as possible the many gaps present in UI's rate case.

It also seeks permanent reforms to help eliminate or reduce OCC's concerns around minimal justifications and documentation of capital expenditures, which will better protect ratepayers in future years as the Company's capital budget moves into rates. Specifically, OCC proposes the implementation of new filing standards for both capital expenditures and plant in service, that are intended to improve the current regulatory framework by providing PURA, OCC, and other stakeholders a more meaningful opportunity to understand the Company's intended investments, and to ensure that projects are executed efficiently and as originally authorized.

UI commenced its rate case on August 1, 2022, when it filed a notice of intent to file an application for an increase in distribution service rates with the Authority. On September 9, 2022, UI filed its Application for approval of amended rate schedules with the Authority. The

Application proposes amended rate schedules for three rate years that are designed to produce additional revenues of approximately $102.1 million in Rate Year 1 (September 1, 2023 – August 31, 2024), an incremental $17.2 million in Rate Year 2 (September 1, 2024 – August 31, 2015), and an additional $17.2 million in Rate Year 3, above current levels. Application, p. 2. While UI's rate increase request represents a total bill increase of approximately 9.2% over rates in place at the time of the filing in Rate Year 1, with additional bill increases of approximately 1.6 % in both Rate Year 2 and Rate Year 3 levels at current rates, UI's Application is designed to raise distribution rates by 25.0% on September 1, 2024, with additional step increases of 4.8% on September 1, 2024 and September 1, 2025. Exhibit UI-1, p. 9.

UI's Application also proposes to levelize rates to spread the proposed total rate increase over the three rate years, which would reduce the proposed revenue increase in Rate Year 1 to approximately $54.2 million, net of the current decoupling charge, and produce an average total bill increase of approximately 4.9% annually. The balance of the revenue deficiency in Rate Year 1 would be deferred for recovery in Rate Years 2 and 3, accumulating carrying charges of $3.9 million through the end of Rate Year 3. Application, p. 2.

If granted as proposed, the Application would result in the largest distribution rate increase ever granted to the Company by the Authority. If the Company's original Application were granted as requested without modification by PURA, during the proposed rate plan, ratepayers would pay a total of $357.9 million in distribution rates above current levels. UI's total rates are already among the highest in the continental United States, with the Company's distribution rates for its residential customers almost 2.91¢ per kWh above that of Connecticut's other electric distribution company, Eversource Energy.

UI's Application would only compound this unfortunate reality for Connecticut's beleaguered ratepayers. The Company's proposed rate plan would increase residential distribution rates, provided under Rate R, by approximately 2.93¢ per kWh in Rate Year 1, and by an additional 0.39 cents and 0.31 cents per kWh, in Rate Years 2 and 3. Approving a rate increase of this magnitude would provide no relief for the residents, businesses, and governmental entities who have been hammered by the drastic increase in electric generating supply rates in 2022-2023 and continue to struggle through tough economic times coming out of the COVID-19 pandemic.

UI has fared quite well financially in contrast. In the Final Decision for its last rate case, UI's approved rate plan set rates and revenue requirements for calendar years 2017-2019 and approved rate increases of approximately $43 million, $11.5 million, and $3 million, respectively. See Docket No. 16-06-04, *Application of The United Illuminating Company to Increase Its Rates and Charges*, Final Decision (Dec. 14, 2016) ("UI Rate Case Decision"), p. 1. That Decision also set the allowed return on equity ("ROE") at 9.10% and continued an earnings sharing mechanism that shared excess earnings 50/50 between ratepayers and shareholders with no deadband. As shown in the table below, since that Decision, UI has enjoyed much financial success, earning above its allowed ROE during each year of the rate plan and near the allowed levels after the plan's expiration in years 2020 and 2021.

(Rate Year) Calendar Year	**Actual ROE**	**Allowed ROE**	**Earnings Above Allowed ROE**
(Rate Year 1) 2017	9.34%	9.10%	0.24%
(Rate Year 2) 2018	9.59%	9.10%	0.49%
(Rate Year 3) 2019	10.12%%	9.10%	1.02%
2020	8.99%	9.10%	N/A

2021	8.23%	9.10%	N/A

See Response to AG-6, UI Attachment 1.

After an exhaustive review of the record evidence and testimony, OCC questions the Company's need for any significant rate relief and recommends that the Authority reject the Application as proposed. As discussed in detail later in this brief, given the uncertainty and lack of detail in the Company's proposed capital expenditure budget in Rate Years 2 and 3 and the upcoming establishment of performance-based ratemaking for Connecticut's electric distribution companies ("EDCs"), OCC recommends implementation of a single-year revenue requirement determination and rate plan instead of the three-year rate plan proposed by the Company.

While OCC advocates for a single-year rate award, OCC has also attempted to address many of the proposed capital expenditures, forecasted operations and maintenance expenses, and new program initiatives associated with Rate Years 2 and 3. Rather than the Application as proposed, the Authority should incorporate OCC's modifications to revenue requirements as detailed in this brief. Proper and reasoned adjustments based on record information will result in *pro forma* revenue requirements well below those sought by the Company. The adjustments offered by OCC are significant in number, but by no means an exhaustive or comprehensive list. Rather than the $102.1 million in rate increases initially proposed by UI in Rate Year 1, the result that should occur from this proceeding is a rate increase of no more than $49.2 million. A detailed listing of OCC's adjustments is shown on OCC Brief Exhibit, Schedule A.

OCC considers a single-year rate plan to be the best approach here not only because of the widespread evidentiary deficiencies in the Company's Application but also because it would align with the completion of the Authority's performance-based ratemaking framework, currently aiming for a conclusion in 2024. See Docket No. 21-05-15, *PURA Investigation into a*

Performance-Based Regulation Framework for the Electric Distribution Companies, ("PBR docket") Final Decision (April 26, 2023), pp. 31-32 and Appendices A, B, and C (discussing need to implement framework through EDC rate cases and the schedule for Phase 2 dockets). A single-year rate plan would make it possible to implement performance-based ratemaking with UI in 2025. The Application's three-year rate plan, however, would likely push implementation out to 2027 at the earliest. The transformative potential of performance-based ratemaking weighs strongly in favor of the most rapid timetable possible for implementation with UI. The Application, if granted as proposed, would thwart this objective.

More broadly, OCC desires utility and regulatory innovation – like the performance-based ratemaking framework – that empowers and benefits consumers. Rapid change is now possible in the utility sector. A modernized, equitable, and pro-consumer distribution grid is finally within realistic reach, but only if EDC rate cases – the primary regulatory mechanism for placing binding reforms on our utilities – are properly synchronized with, and informed by, key stakeholder interests, PURA's relevant initiatives and proceedings, and guiding public policy.

Here lies another major concern with UI's Application: it seeks to portray the Company as aligned with and supportive of this transformative moment in the energy space – through its clean energy proposals, for instance – yet it also seeks to arrogate to itself control over what that transformation will actually entail. Throughout the Company's Clean Energy Transformation panel, OCC discovered that UI had put forth clean energy concepts in this rate case, such as the Electric Vehicle Charging Hub, that had not been disclosed, vetted, or otherwise shared in the very PURA dockets that are currently tasked with handling such proposals (and in which UI already participates). This is concerning. The once-in-a-generation opportunity to remake the distribution grid so that it better helps and serves Connecticut's people and businesses is not UI's alone. That opportunity is for all.

OCC's strong concerns with the Application's clean energy proposals, as addressed in more detail below, must be understood in this context. It is not that OCC objects to any and all grid modernization and clean energy efforts, far from it. They are urgently needed in this crucial moment, but they must be done well – with appropriate and prudent planning, necessary and equitable stakeholder involvement, and an accurate assessment of their full benefits and costs. As proposed in UI's Application, they fall short of those requirements. Yet because of the importance of forward momentum on DER investments in the grid, OCC is not proposing that these proposals be rejected outright. Rather, we suggest that upon proper vetting and any final project approval within the correct docket, the Authority could design appropriate recovery avenues – such as an annual reconciling mechanism within the Company's RAM framework, or through a regulatory asset. Simply put, these proposals are premature to bake these costs into rates at this time.

III. Summary of Key Positions of the OCC

The following is a summary listing of OCC's positions on select key issues in this proceeding. Later sections of the brief address each in more detail.

a. Rather than the three-year rate plan proposed by UI, given the upcoming move to performance-based ratemaking, the uncertainty in the Company's forecast of plant additions, and OCC's recommendations regarding requiring additional documentation in support of rate applications, a single-year revenue requirement determination is appropriate for UI at this time.

b. UI initially proposed a rate increase of $102.1 million in Rate Year 1. Based on its review, OCC identified $52.9 million in decreases for the Authority's consideration, which if adopted would result in a $49.2 million distribution rate increase for a single rate year period. OCC anticipates other parties and intervenors will identify other reductions through briefing that OCC will likely support in addition to those identified within this initial brief.

c. The Company's proposal for a ROE of 10.20% and an overall rate of return of 7.38% for Rate Years 1 and 2, and 7.47% for Rate Year 3, is excessive, and should be rejected. OCC expert Dr. Randy Woolridge conducted a financial and economic forecast analysis that resulted in a recommendation that UI's allowed rate of return be reduced to an ROE of at least 9.0% and overall rates of return of 6.66% in Rate Year 1 and 2, and 6.76% in Rate Year 3, if a multi-year rate plan is approved by PURA. However, Dr. Woolridge's analysis of the cost of equity is conducted through the lens of market conditions directly impacting UI's parent company, Avangrid, and also the holding companies of other operating-level utilities within his proxy group. The Authority can make adjustments to the Company's allowed ROE based on factors beyond those considered in that analysis, such as the management issues identified throughout this proceeding and the actual operational risks incurred by UI. OCC supports imposing ROE reductions based on UI's performance in Tropical Storm Isaias, imprudent and inefficient management with respect to accounting standards, including but not limited to 15 years of improper recording of the TAC, and other accounting errors identified through the course of the rate case hearings.

d. The Company's proposed capital structure of 52% common equity and 48% long-term debt is equity rich and should be adjusted to 50% long-term debt and 50% common equity. This has the impact of ensuring that the Company maintains efficiency in accessing capital.

e. The Company's revised *pro forma* operating and maintenance and tax expenses are overstated and excessive and should be reduced for ratemaking purposes by at least $14.2 million annually.

f. The depreciation study performed by the Company's witness does not use the accepted depreciation rate formula and changes the service life formula from UI's prior rate case. UI's attempts to refine the remaining life calculation based on a weighted vintage approach should be rejected by the Authority. The Company's depreciation expense should be reduced by $4,915,497 based on a 0.24% reduction in overall proposed depreciation rates, which would lower current depreciation rates by 0.18%.

g. Approval of UI's Capital Plan should be deferred until the Company can provide improved documentation. OCC proposes the implementation of new filing standards for both capital expenditures and plant in service, that are intended to improve the current regulatory framework by providing PURA and stakeholders a more meaningful opportunity to understand the Company's intended investments, and to ensure that projects are executed efficiently and as originally authorized.

h. OCC recommends disallowances of all non-industry membership dues, incentive compensation and related employee perks like caregiving costs for pets and children, which can and should be paid for by Company shareholders instead of ratepayers.

i. UI has not sufficiently demonstrated that the loss incurred on the sale of the Bridgeport Avenue property was an integral part of the lowest cost option for consolidating operations. PURA should reject the Company's attempt to recover the loss on the sale plus carrying charges totaling $15.583 million over a three-year amortization period.

j. UI's cost of service study allocates an excessive share of distribution costs to the residential customer class because of how it classifies pole, line, and line-transformer costs and due to its splitting of pole costs between primary and secondary service.

k. The Company's Economic Development rate should be more thoroughly evaluated through further stakeholder-involved proceedings or required compliance filings for impacts to ratepayers, the state's energy efficiency and demand reduction goals, and economic development goals.

l. OCC supports the Company's completion of the enhanced vegetation management program, known as the Utility Protection Zone or "UPZ", as designed in its last rate case and thoroughly evaluated within subsequent storm dockets and the Authority's investigation into improving resiliency via Docket No. 17-12-03RE08. The budget already approved by the Authority allows adequate funding for the Company to complete the program, and the Company has not met its burden to establish a need for incremental funding at this time.

m. As stated above, OCC recommends that the project proposals included in the Clean Energy Transformation panel be evaluated within the underlying and ongoing docket intended to thoroughly vet, with stakeholder approval, the best way to move forward with critical DER investments like EV charging stations and energy storage. Upon any approval for the projects within the underlying docket, the Authority could design appropriate recovery avenues – such as an annual reconciling mechanism within the Company's RAM framework, or through a regulatory asset – thus OCC is not suggesting recovery is never appropriate, just that given the underlying docket is ongoing and these proposals have not been thoroughly justified or vetted by all stakeholders, it is premature to bake these costs into rates at this time.

IV. Applicable Legal Standards

General Statutes § 16-19(a) requires PURA to review proposed rate amendments of public service companies, including United Illuminating, to ensure that such proposed amendments will not result in rates that are "more or less than just, reasonable and adequate, or that the service furnished by such company is inadequate or in excess of public necessity or convenience." PURA must investigate the rate application using six principles laid out in General Statutes § 16-19e, including: (1) whether there is a clear public need for proposed services; (2) whether the company is managerially efficient and that the Company is competent to provide efficient and adequate service; (3) whether the Company performs its responsibilities with economy, efficiency and care and so as to promote economic development with consideration for energy conservation, energy efficiency, and the utilization of renewable energy and for the prudent management of the natural environment; (4) whether the level and structure of the rates being sought by the company are sufficient "but no more than sufficient" to allow the company to cover its operating costs and to attract capital and to maintain its financial integrity, while also providing appropriate protection to existing and foreseeable public interests; and (5) whether the rates charged reflect prudent and efficient management. General Statutes § 16-19e (laying out principles PURA must follow for assessing rates and utility management). PURA has 350 days to conduct its investigation and issue a decision. General Statutes § 16-19(b).

In addition to the general requirements for the assessment of rate amendments, General Statutes § 16-19mm requires that PURA "consider the external costs and benefits of all proposed resources, consistent with the state's energy and other policy, and integrated resource planning principles." General Statutes § 16-19yy also requires PURA to consider whether to link compensation of executives or officers, or any portion of incentive compensation for employees of any electric distribution company, to the achievement of performance targets established pursuant to Section 16-244aa.

Public utility companies are entitled to collect rates that will permit them to earn returns equal to similar entities in other undertakings that are attended by corresponding levels of risks and uncertainties. *Bluefield Waterworks & Imp. Co. v. Public Service Comm'n of W. Va*., 262 U.S. 679, 692 (1923). However, utility companies have "no constitutional right to such profits as are realized or anticipated in highly profitable or speculative ventures." *Id*. The proper rate of return cannot be standardized, and lower rates of return are appropriate where investments are "safe, returns certain, and risk reduced to almost a minimum." *Id*., 693. A utility company's constitutional guarantee is not the promise of the rate of return itself, but of the opportunity to earn it. *State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Comm'n of Missouri*, 262 U.S. 276, 290 (1923) (Brandeis J., concurring) ("[T]he federal Constitution guarantees to the utility the opportunity to earn a fair return."). In fact, utility companies enjoy no "guarantee of any level of revenues or return." *Southern New England Telephone Co. v. Department of Public Utility Control*, 274 Conn. 119, 125 (2005). The "authorized rate of return is in the nature of an opportunity rather than a guarantee." *Id*. The authorized rate of return can be envisioned as "a ceiling set by the department." *Id*.

The end results of a regulator's establishment of rates for a public utility should be the focal point, not the method or formula it used to get to that point. *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). The statutory standard of "just and reasonable" refers to the "result reached not the method employed" in reaching the rate itself. *Id.,* 602. "The rate-making process . . . i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests." *Id*., 603. As noted above, when reviewing the management decisions of a public utility company, General Statutes § 16-19e(a)(5) directs PURA to determine if "the level and structure of rates charged customers … reflect prudent and efficient management of the franchise operation . . ." This standard requires an assessment of the information available to management at the time the decision was made. *CL&P v. DPUC*, 216 Conn. 627, 645 (1990) ("The prudence of a management decision depends on good faith and reasonableness, judged at the time the decision is made."); *Violet v. FERC*, 800 F.2d 280, 282 (1st Cir., 1986) ("The prudence of the investment must be judged by what a utility's management knew, or could have known, at the time the costs were incurred.").

The Takings Clause of the Fifth Amendment of the United States Constitution entitles regulated utility companies to rates "sufficient to yield a reasonable rate of return upon the value of the property used, at the time it is being used, to render the services." *Denver Union Stock Yard Co. v. United States,* 304 U.S. 470, 475 (1938). However, utility companies are "not entitled to have included any property not used and useful for that purpose." *Id*. 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) (noting that "used and useful" was first enunciated in *Smyth v. Ames*, 169 U.S. 466 [1889]). The same standard is also the basis for the ratemaking prohibition against intergenerational inequity, or the concept that current ratepayers should not fund future system improvements, until those improvements actually provide benefits as in-service plant. *Id*.

When assessing the evidence that may be gleaned from a test year to establish rates, the results from that test year may be adjusted by "known and measurable" changes that could justify an alteration in rates for the public utility company. *Connecticut Natural Gas Corp.* v. *Department of Public Utility Control*, 51 Conn. Supp. 307, 322, 981 A.2d 1084, 1095 (2009) (discussing "known and measurable" changes to historic test year evidence). The application of the "known and measurable" standard is similar to an evidentiary standard, in that the Authority can conclude that proposed deviations from the test year evidence are not persuasive if they are not adequately demonstrable. *Id*. (noting that department was not persuaded by plaintiff's evidence regarding "known and measurable" changes).

The "legislature . . . has not imposed upon [PURA] any specific formula or policy to use in setting rates." *Town of Greenwich v. DPUC*, 219 Conn. 121, 126 (1991). PURA's "broad grant of regulatory authority carries with it the necessarily equally broad discretion, to be exercised within legal limits . . . to take into account such varying factors as economics, public policies, accounting principles, fairness to the parties, and the context and intent of any prior agreements entered into by the utility, and to balance those factors by a process of reasoned decision-making". *Office of Consumer Counsel v. Dept. of Public Utility Control*, 279 Conn. 584, 593-94 (2006). As the Supreme Court of the United States has recognized, "[t]he Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas. Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances." *Federal Power Commission v. Natural Gas Pipeline Co. of America*, supra, 315 U.S. 586.

Ultimately, the burden of proof to show that a proposed rate is just and reasonable is on the public service company. *See* General Statutes § 16-22 (placing burden of showing that proposed rate under consideration is "just and reasonable" on public service company). In the context of a rate case, the petitioning company bears the burden of proving not only the amounts of its operating costs and other expenses, but also the "basis for charging to its expense accounts and the propriety of including such charges for rate-making purposes." *Connecticut Natural Gas Corporation v. Public Utilities Commission*, 29 Conn. Supp. 379, 394 (1971). In order to establish the facts to justify a rate amendment, the company must present facts that exceed the preponderance of the evidence standard. *See Goldstar Medical Services Inc. v. Department of Social Services*, 288 Conn. 790, 821 (2008). "In the absence of state legislation prescribing an applicable standard of proof, . . . the preponderance of evidence standard is the appropriate standard of proof in administrative proceedings . . .." *Id*. The preponderance of the evidence standard requires evidence showing that facts are "more probable than not." *Id*. citing *Tianti* v. *William Raveis Real Estate, Inc.*, 231 Conn. 690, 702 (1995).

The Connecticut Supreme Court has held that "[t]he doctrine of judicial notice also applies to administrative agencies." *Benjamin F. et al. v. Dept of Developmental Services*, 208 Conn. App. 423, 450 (2021). General Statutes § 4-178(6) authorizes PURA to take notice of "judicially cognizable facts . . ." in a contested proceeding. A judicially cognizable fact is one "not subject to reasonable dispute in that it is either (1) within the knowledge of people generally in the ordinary course of human experience, or (2) generally accepted as true and capable of ready and unquestionable demonstration." *Connecticut Light & Power Co. v. Connecticut Dept. of Pub. Util. Control*, Superior Court, Tax Session, Docket Nos. CV094019951S & CV094019964S, (*Satter, JTR*, February 5, 2010).

Not all judicially cognizable facts require that notice be provided to the parties prior to a tribunal taking notice of such facts. *Moore v. Moore*, 173 Conn. 120, 121-122 (1977). Information that constitutes "matters of established fact, whose accuracy cannot be questioned . . . may be judicially noticed without affording a hearing." *Id*. at 122 (citing *Krawiec v. Kraft*, 163 Conn. 445, 451 (1972); *Guerriero v. Galasso*, 144 Conn. 600, 605 (1957)). The

Connecticut Code of Evidence provides that a tribunal "may take judicial notice without request of a party to do so. Parties are entitled to receive notice and have an opportunity to be heard for matters susceptible of explanation or contradiction, but not for matters of established fact, the accuracy of which cannot be questioned." Connecticut Code of Evidence § 2-2(b).

If the Authority finds any proposed amendment of rates to not conform to the principles and guidelines set forth in Section 16-19e, or to be unreasonably discriminatory or more than just, reasonable and adequate to enable the Company to provide properly for the public convenience, necessity and welfare, or the service to be inadequate or excessive, it is statutorily empowered to determine and prescribe, as appropriate, an adequate service to be furnished or just and reasonable maximum rates and charges to be made. General Statutes § 16-19(a).

V. Revenue Requirements

As stated above, OCC was disappointed in the lack of thoroughness in UI's initial application, and the inability of UI to provide more detailed planning and documentation for its proposed expenditures throughout discovery and the hearings. OCC's objections may be viewed as falling into two primary categories: those costs which should be entirely excluded from rates, and those for which there is insufficient documentation, justification, or explanation for the Authority to appropriately determine that the costs meet the legal standards necessary to be included in base rates at this time. With regard to costs in the latter category, UI bears the burden to justify these historically significant proposed increases in its revenue requirement; it has failed to meet that burden in the many areas outlined below. However, OCC does not necessarily take the position that these second-category costs should be outright rejected in the long term, and offers some suggestions within this brief for an appropriate review and evaluation process, as well as potential future recovery mechanisms, in order to achieve OCC's goal of increasing scrutiny of UI's revenue requests to better protect ratepayers while ensuring UI can move forward with investments in critical infrastructure projects that support resilience, reliability, and grid modernization upon proper substantiation.

a. Operation & Maintenance Costs

i. Board of Directors expense

For board of directors ("BOD") expense, the Company is requesting $347,090 for Rate Year 1, $347,610 for Rate Year 2, and $348,010 for Rate Year 3. Response to OCC-3 UI Attachment 1. As the purpose of the BOD is to serve the interests of the Company's shareholders, the shareholders are the primary beneficiaries of this expense. As such, the Company's customers should not be fully responsible for these costs. OCC recommends a 75/25 sharing of these costs between shareholders and ratepayers, respectively.

If our adjustment to remove corporate service charges inflation is accepted, as discussed below in Section V(a)(v), this adjustment should be based on the Test Year amount of $320,000 to avoid double counting. This is a reduction of $240,000 ($320,000 x .75) as shown on Exhibit LA-1, Schedule C-2.

ii. Other Public Company Costs

Similar to the BOD expense, other public company costs serve primarily the Company's shareholders. As the shareholders receive most of the benefit, OCC recommends a 75/25 sharing of these costs between shareholders and ratepayers, respectively.

If our adjustment to remove corporate service charges inflation is accepted, as discussed below in Section V(a)(v), this adjustment should be based on the Test Year amount of $161,000 to avoid double counting. This is a reduction of $121,000 ($161,000 x .75) as shown on Exhibit LA-1, Schedule C-3.

iii. Non-Industry Dues

The Company has included $69,000 in the Test Year for non-industry dues. Schedule G-2.8. This includes costs for memberships to chambers of commerce and business organizations such as the Bridgeport Regional Business Council and the Connecticut Business and Industry Association. Id. These types of memberships provide little or no benefit to ratepayers. As such, the costs should be the responsibility of the Company and its shareholders, not the ratepayers.

PURA recently disallowed all non-industry dues in its final decision in Docket No. 22-07-01, *Application of Aquarion Water Company of Connecticut to Amend its Rates Schedule* (March 15, 2023) ("Aquarion"), p.81. Consistent with that ruling, OCC recommends disallowance of all non-industry dues. If our adjustment to remove corporate service charges inflation is accepted, as discussed below in Section V(a)(v), the adjustment to non-industry dues should be based on the Test Year amount of $69,000 to avoid double counting. This is a reduction of $69,000 in each of the Rate Years as shown on Exhibit LA-1, Schedule C-4.

iv. Vacancies

The Company's request includes $36.985 million, $38.692 million, and $40.308 million for Rate Years 2023/2024, 2024/2025, and 2025/2026, respectively, based on 608 FTEs (519 Test Year plus 89 new hires). WP C-3.34, p. 2. The vacancy factor applied effectively reduces FTEs to 570 for the Rate Years.

Based on the historical record, the Company's request is excessive. In Docket No.16-06-04, the Company requested costs based on 738.2 FTEs for the years 2017-2019. In reality, head counts averaged 676.7 FTEs in 2018 and 663.1 in 2019. OCC-0064, OCC-0060. This disparity is actually even greater since Transmission FTEs were included in the response to OCC-0060 in addition to Distribution FTEs. As a result, the Company recovered $44.295 million, $46.09 million, and $47.868 million for 2017, 2018, and 2019, respectively, while only spending $17.921 million, $28.510 million, and $31.755 million for those years. Response to OCC-55 Attachment 1. The Company continued to recover $47.868 million through 2020 and 2021 while only spending $35.320 million in 2020 and $30.953 million in 2021. Id.

A further issue is that the capitalization rate in Docket No. 16-06-04 was 44.8%, but actual capitalization for 2017, 2018, and 2019 was 76.06%, 61.02 %, and 54.41%, respectively. Id. As a result, ratepayers not only paid excessive amounts, but they paid those amounts twice – first as an expense, and then later as depreciation.

In rebuttal, the Company claims that approved FTE levels in the prior case are irrelevant. Exh. UI-RRP-REBUTTAL-1, p.22. The fact that the Company's estimates regarding payroll are not credible and have resulted in year after year of overrecovery from ratepayers is not just relevant, but critical to assessing the Company's payroll request.

The Company also claims that its need for the requested FTEs is fully supported. Exh. UI-RRP-REBUTTAL-1, p.23. The Company misunderstands its burden. The Company has the burden of supporting costs that will actually be spent, not demonstrating a need for employees that, based on UI's track record, might never be hired.

Instead of allowing the Company to repeat this pattern of overrecovery in future rate years, the most known and measurable amount should be used as the basis for this expense. For the first nine months of 2023, the average FTE complement was 611. After applying the distribution allocator of 82.28%, the FTE count is lowered to 503, resulting in a reduction of 105

FTEs from the requested 608. Adjusting for the Company's vacancy rate of 38 FTEs, which is included in the calculation of payroll expense, OCC recommends a reduction of 67 FTEs.

This results in reductions to Rate Years 1, 2, and 3, of $3.601 million, $3.766 million, and $3.923 million, respectively, as shown on Exhibit LA-1, Schedule C-5. This adjustment should be considered conservative because as indicated in LFE-079, submitted March 13, 2023, the Company has even less employees now than at the end of the Test Year. The Company's Rate Year 1 payroll request was based on a headcount of 519 as of December 31, 2021, which decreased to 498 as of the time of the Application, and it was further reduced to 485 as of February 28, 2023. LFE-79. The fact that the Company's employee count has declined rather than increased further illustrates that its employee forecasts cannot be relied on.

Alternatively, it could be argued that this most recent employee count is the most known and measurable and should be used as the basis for this adjustment. If the employee count based on LFE-079 is used, this would result in further decreases to OCC's payroll adjustment of $429,640, $450,242, and $470,000 in Rate Years 1, 2 and 3, respectively.[1]

v. Corporate Service Charge

For Rate Years 1, 2, and 3, the Company is requesting $40.868 million, $40.929 million, and $40.976 million, respectively. C-3.27 A-C. The Company calculated these increases of over $3 million per year from the Test Year using projected inflation rates. Exh. UI-RRP-1, p. 28. However, the Company's approach is inconsistent with the historical record. As shown in the chart below, corporate service charges have been decreasing over the past five years.

[1] These amounts were derived by multiplying the average wage on Exhibit LA-1, Schedule C-5 by 8 additional vacancies, and multiplying the amounts by the O&M allocation factor.

($000)				
2017	2018	2019	2020	2021
$54,029	$46,406	$38,992	$38,296	$37,192

OCC-51 Attachment 1.

During the hearing, the Company confirmed the downward trend in corporate service charges, Tr. at 1544, as reflected in the response to OCC-51, Tr. 1545. As the charges decrease every year, it is clear that these costs have not been impacted by inflation, and an assumed increase is unwarranted.

Another concern is that the Company has significantly overrecovered over the prior five years as shown in the chart below.

	($000)				
	2017	2018	2019	2020	2021
Authorized	$53,022	$53,022	$52,729	$52,729	$52,729
Actual	$54,029	$46,406	$38,992	$38,296	$37,192
Difference	$1,007	($6,616)	($13,737)	($14,433)	($15,537)

(OCC-120, OCC-51 Att 1)

As shown, the Company has overrecovered more than $50 million from 2018-2021 from ratepayers. This further demonstrates that an increase due to inflation is unwarranted, since the costs were originally set higher than necessary.

The Company's rebuttal claims that our conclusions regarding the declining charges are incorrect because our calculations included corporate capital charges, which, as of 2018, are reflected on the Company's books in rate base. This point is irrelevant and misleading. With respect to recovery on a prospective basis, the issue is whether the cost in question is included in expense, and not what the paid overall cost was. The Company's change in accounting procedures did not change the amount authorized and collected or the actual amount charged by the Company.

Since, as explained above, it would be inappropriate to increase this charge for inflation, and OCC recommends the use of the Test Year amount, a reduction of $3.705 million, $3.766 million, and $3.813 million to Rate Years 1, 2, and 3, respectively. This adjustment is shown on Exhibit LA-1, Schedule C-1. As discussed elsewhere in this brief, this adjustment impacts OCC's adjustments to BOD expense, Other Public Company costs, and Non-Industry Dues.

OCC also submits that the Authority must adjust rate base downward to avoid a double recovery by the Company that would result from the above-noted change in its accounting methodology. The Company claims the decrease in expense is due to the Company's change in accounting, which shifted costs to plant. During the hearing, the Company explained that amounts previously charged to operating expense were pushed down to UI in the form of a higher rate base. Tr. 1549. The Company further explained that the costs are now a component of the revenue requirement in this proceeding as depreciation on the shared capital assets. Tr. 1550. LFE-024 requested that the Company provide a revised version of OCC-158 Att.1 reflecting only the plant in service as of the date of the phase-out of the corporate charge. According to LFE-024, the Company added to plant an amount in excess of the difference between the authorized expense collected from customers and the actual operating expense incurred. This demonstrates that there is an excess amount included in rate base as part of this proceeding for capital charges that customers have already paid for. The excess, as indicated above, is $6.617 million, $13.737 million, $14.433 million, and $15.537 million for the years 2018 through 2021, respectively. The total of $50.324 million is the amount of plant that is being sought for recovery as part of rate base in this proceeding that has already been paid for by ratepayers. Therefore, plant included in rate base should be reduced by $50.324 million and depreciation expense reduced by approximately $3 million, based on a 6% depreciation rate, to avoid a double recovery from customers. This recommendation is conservative and does not reflect an adjustment for any overrecovery of operating expenses in 2022 associated with the Company's change in accounting.

Additionally, under cross examination, the Company acknowledged that rates in 2022 reflected a recovery of the authorized amount for 2017-2019 amounts and that the authorized amount for 2019 going forward was essentially $53 million. Tr. 1547 – 1551. The pro forma operating expense according to the Company was $37.163 million, which is comparable to the 2022 operating expense. Tr. 1546. Therefore, it is recommended that since $15.837 million is included in the Company's rate base request that has already been paid for by customers, a further reduction of $15.837 million be made to rate base and depreciation expense be reduced by an additional $950,000.

UI is effectively trying not only to double recover costs allowed as O & M expenses in its last rate case, but to permanently include them in rate base and recover them multiple times over their respective useful lives. The Authority should not allow UI to re-categorize costs that were previously allowed as expenses so that they can be capitalized and recovered as part of rate base. PURA should reduce rate base to disallow any double recovery of these corporate service charges.

vi. Compensation and Benefits

1. Incentive Compensation

For Incentive Compensation, the Company is requesting $1,495,000, $1,555,000, and $1,618,000 for Rate Years 1, 2, and 3, respectively. OCC-23, Attachment 1. While OCC understands the principle behind incentive compensation as a tool to attract and retain talented employees, the fundamental issue with UI's incentive plan is that ratepayers receive little or no benefit from it. To the extent UI finds that shareholders receive a benefit, they should pay for it.

Part of the reason that ratepayers receive little to no benefit from the incentive plan is that it is poorly designed and managed. The incentive plan provides awards to every single employee. From 2017-2021, not a single eligible employee failed to receive an award. The Company testified that the only circumstances under which an employee has not received incentive compensation between 2017 and the Test Year was if the employee were terminated. Tr. 1868-1869. Since every employee can assume they will be awarded an annual bonus regardless of effort, it is hard to imagine that the plan provides any incentive whatsoever to employees. The claim that the Company makes in its rebuttal, that "the fact that eligible UI employees have consistently received incentive compensation payments in recent years indicates that the plan is working as it should", Exh. UI-CBP-REBUTTAL-1, p.5, is absurd. The negative impact on motivation of a plan that rewards every single participant is obvious.

Another flaw in the design of the incentive plan is that the connection between the individual employee's performance and the stated objective is unclear. It appears that individual employees can benefit from objectives that are achieved by others in an individual's "group." The Company witness testified that even where objectives can be individually tied to performance, they can make up only 40% of the incentive compensation package available to an employee. Tr. 1877. A specific example of this was revealed in the Company's rebuttal. The rebuttal states: "[f]or union employees, the incentives are designed so either all or none of the participants receive the payment." Exh. UI-CBP-REBUTTAL-1, p.8. As admitted by the Company's witness, because either all or none will receive the bonus, the plan will reward underperforming employees or fail to reward overperforming employees. Tr. 1905-1906. When asked whether there is "potential that a worker not deserving of the incentive compensation in the union could receive the benefit . . . because the group goal was met" the witness responded, "[a]ll of our union employees, the goals and the targets are all set by the collective bargaining agreement. So yes, the answer would be yes to that question." Tr. 1904. Tying a particular employee's reward to a group metric seems to dilute the already negligible (if any) amount of motivation that employees might have to perform better, which makes it all the more clear that ratepayers receive little, if any, benefit from this plan.

Even if this plan benefitted ratepayers to some degree, UI has not measured that benefit, and has thus failed to meet its burden in demonstrating the necessity of this plan. During the hearing, UI's witness admitted that the Company has not performed any analysis which demonstrates ratepayer benefits from the incentive compensation program. Tr. 1862. UI's witness admitted that the Company could not quantify the benefit received by ratepayers. Tr. 1863-1864. When asked how much of the variable portion of compensation benefits customers, and more specifically, for every dollar spent on incentive compensation what the dollar value benefit to ratepayers is, the witness responded, "we've never done a study on that." Tr. 1864.   Finally, the Company's witness had trouble identifying a means to determine whether the program provided any benefit to customers. Tr. 1864-1865. Instead, the Company's witness could offer only anecdotal support for providing the incentive. The Company's witness testified that the value to ratepayers of incentive compensation is "stability," noting that if the company "took that mechanism away . . . [t]hat would make us an outlier in terms of our peers and . . . we would struggle to attract, we would definitely struggle to retain because it is a key part of our compensation. The customer would then suffer in that moment because we wouldn't have, you know, we wouldn't have that ability." Tr. 1864.

Another concern is that the incentive plan is significantly weighted towards financial goals, which benefits primarily the Company's shareholders. This is discussed at length in Mr.

Schultz and Mr. Defever's prefiled testimony. In addition, the Company's rebuttal points out that if certain financial goals are not met, no incentive compensation payments will be paid. Exh. UI-CBP-REBUTTAL-1, p.9. Therefore, it could be argued that the entire plan is based 100% on financial goals. The point was further illustrated during the hearing, when the Company witness acknowledged that 70% of long-term incentives for UI executives are financially based and only 30% are based on performance or sustainability projects. Tr. 1766.

Despite the fact that the Company has failed to offer sufficient information to justify its incentive compensation in the first place, it requests an increase to incentive compensation over the Test Year amount. The Company does not have the data to demonstrate that the current level of incentive compensation is insufficient to meet established metrics. When asked whether the union performance metrics were achieved in the test year, the witness responded that the company "would need to check on that," and ultimately could not answer the question even after reviewing the record. Tr. 1870-1871. No witness on the panel could answer whether the union metrics were met in the Test Year. Tr. 1871. The Company cannot justify its request to increase incentive compensation if it cannot even demonstrate whether the existing metrics have been met using the current incentive compensation levels.

OCC recommends the disallowance of all incentive compensation costs and rejection of the Company's request for an increase in incentive compensation. This results in reductions to Rate Years 1, 2, and 3, of $1.495 million, $1.555 million, and $1.618 million, respectively, as shown on Exhibit LA-1, Schedule C-6. This adjustment is consistent with PURA's Decision in Docket No. 22-07-01, which disallowed 100% of incentive compensation costs. Aquarion, p. 64. Furthermore, all incentive compensation costs should be excluded from annual earned ROEs and earnings sharing reports that are contained in compliance reports filed by UI with PURA. If costs are specifically disallowed by the Authority, they should not be included as a means to reduce earnings and potential sharing under the Company's approved earnings sharing mechanism.

2. Caregiver Program

For Rate Years 1, 2, and 3, the Company is requesting $50,000, $54,000, and $60,000, respectively, for Caregiver Program costs. OCC-007. This program includes care for children, elder care, and house sitting and walking for cats, dogs, and domestic caged animals. OCC-007. OCC recommends disallowance for several reasons.

First, the Company has not demonstrated that ratepayers benefit from this expense due to reduced absenteeism. Under cross-examination, the UI witness attempted to make the claim that the program has resulted in $89,000 in absentee savings and 165 days saved. Tr. 1896. However, cross-examination revealed major flaws with this assertion. The amount purportedly saved was calculated by simply multiplying the amount of usage of the program benefit by average salary, which is an overly simplistic methodology. Tr. 1896. Further, the calculation was based on the unsupportable assumption that for every utilization of the program, the employee would have stayed home had they not used it. Tr. 1896. This is so illogical that it seems disingenuous. It ignores literally every other possible resource the employee may have utilized – such as family, friends, daycare, work from home, etc. This is the equivalent of offering free lunch on Fridays and assuming any employee that took part would not have eaten otherwise.

The Company has in no way connected usage of the program to reduced absenteeism. The Company revealed that it has not compared absenteeism rates at the UI level prior to implementation of the program to determine whether the program effectively reduces absenteeism. Tr. 1896. The Company, therefore, does not know how well the program works, and has failed to demonstrate usefulness. Further, the Company has not identified pet care as a contributor to absenteeism despite having incorporated pet care as part of the caregiver program benefit. The Company witness acknowledged that UI "never measured the problem [of absenteeism attributable to pet care] prior to implementing the benefit." Tr. 1907-1908. The Company, therefore, cannot, with any reasonable degree of certainty, know that pet care is relevant to the issue of absenteeism, and has failed to demonstrate necessity of this component of the program.

The Company also failed to substantiate its claim that this benefit is necessary to attract and retain employees. Exh. UI-CBP-REBUTTAL-1, p.11. The Company argues that the caregiver program "enhances the company's benefits and well-being package at a reasonable cost to differentiate itself in a competitive labor market." Exh. UI-CBP-Rebuttal, p. 11; Tr. 1897. The Company also testified, however, that "there are definitely other companies that use Bright Horizons for the same services," though it was unable to identify how many. Tr. 1898. The Company attempts to justify the program by claiming that it differentiates it from competitors, but the Company is not even aware of the extent to which competitors offer the same benefits. The Company's claim that the benefit is necessary to attract and retain employees is, thus, not supported by anything more than a feeling - without any sense of how many other employers offer similar benefits - that current and prospective employees would choose employment at UI over employment with another employer because UI offers the Caregiver Program. This is simply not enough to meet the Company's burden.

Finally, this benefit is not the norm and utility employees should not, absent a compelling reason, receive ratepayer-funded benefits beyond the rest of the workforce. The Company has not provided or substantiated any compelling reason that ratepayers, who may have their own children or animals to take care of, should pay for childcare and pet care for utility employees when they do not receive similar benefits. To be clear, OCC is not taking a position against pet care or childcare; we recognize that there are legitimate reasons to offer caregiver benefits. However, OCC submits that these benefits should be paid for by the Company's shareholders. Accordingly, OCC recommends complete disallowance of this cost, a reduction of $50,000, $54,000, and $60,000 for Rate Years 1, 2, and 3, respectively. The adjustment is shown on Exhibit LA-1, Schedule C-7.

3. Employee Recognition Awards

For employee recognition awards, the Company is requesting $92,000 in each of the Rate Years. The awards were described by the Company witness as follows:

> *There's a couple of components to it. One is service related. So if you reach certain service milestones, I think it's a year, five years, and then every five years after that there are certain awards you can get. Then the other one is is for, you know, to show gratitude for work that someone has done on a project like helping support our customer and so forth.*
>
> Tr. 1899.

However, when asked specifically about loyalty gifts, the Company witness responded, "it's a recognition of work that employees have done like supporting our customers or service anniversary related gifts." Tr. 1841. When asked to further clarify the difference between loyalty gifts and recognition awards, the witness responded "[i]t all falls under our broader gratitude program." Tr. 1842. Though the Company witness subsequently agreed that loyalty gifts and employee recognition awards could be bifurcated as relating to length of service and specific performance, respectively, the line between the two gifts remains blurry. A Company witness also testified, "we don't pay bonuses. We pay variable incentives." Tr. 1920. But the Company also describes its gratitude program as involving cash payments that are based upon whether employees are "either here for a certain amount of time or [the Company] want[s] to recognize for a certain task that was done." Tr. 1922. The Company testified that "loyalty gifts . . . could be items like retention . . . where we have at-risk employees, for instance, that we would look to pay retention." Tr. 1923. Any distinction between these programs and bonuses, which are universally paid to employees for either performance or retention, appears to be semantic. Because the Company has failed to make clear the difference between loyalty gifts and employee recognition gifts, and exactly what is covered in employee recognition awards, the Company has failed to satisfy its burden with respect to this program.

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 get employees more engaged. The Company's witness indicated that the point of the program is "[t]o increase engagement, to have people feel better about the work that they're doing." Tr. 1901. The Company fails to connect the point of the program to some measurable benefit to ratepayers.

Nor could UI justify the program on the basis of employee retention and/or the need to attract talent. The Company's witness indicated the following in response to 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." Tr. 1901. Thus, while it is a nice gesture for the Company to recognize the milestones of its employees' tenure, ratepayers do not benefit from these awards.

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 benefitting ratepayers and not necessary for the provision of service, OCC recommends removal of the full amount. This is a reduction of $92,000 in each of the Rate Years as shown on Exhibit LA-1, Schedule C-8.

vii. Storm costs

1. Paid Rest

In the current proceeding, the Company is attempting to recover Storm Isaias costs including $129,727 for "paid rest." UI Compliance Filing, Exh. UI-1, p. 2 (Nov. 9, 2020). "Paid rest" is essentially payment to workers for time that they are not working. The Company's rebuttal states the following:

> *There is a provision in UI's collective bargaining agreement that has been in place for many years that provides an employee with an 8-hour rest period after a 16 hour shift. If UI employees are required to work extended periods outside of their regular schedule in emergency conditions and the 8-hour rest period overlaps with the employee's regularly scheduled 8-hour shift, they will be paid at straight time for their regularly scheduled shift hours while they rest.*

Exhibit UI-CJE-Rebuttal-1, pp. 4-5.

The Company's rebuttal testimony argues that these types of provisions should be allowed because they were included in the collective bargaining agreement. Exhibit UI-CJE-Rebuttal-1, p. 4. This argument is unconvincing. The Company and union do not have the authority to override PURA when negotiating an agreement. The fact that certain payment is agreed to between the Company and a union does not mean that the payment is necessarily recoverable from ratepayers.

OCC recommends the disallowance of the entire amount of paid rest, a reduction of $129,727, as shown on Exhibit LA-1, Schedule C-9, line 6.

2. UPZ Overrecovery

For 2020, the Company was authorized to spend $14 million for UPZ, see Docket 20-08-03, LFE-010, but spent only $10,805,915, which resulted in an overrecovery of $3.1 million. OCC-152 Attachment 1. In its application, the Company ignores the overrecovery and requests the full amount of 2020 UPZ costs related to Storm Isaias. The request would clearly amount to a double recovery and it would be inappropriate for the Company to first overrecover $3.1 million for UPZ costs and then fail to credit customers with that amount when asking for UPZ storm cost recovery.

PURA's Decision in Docket No. 20-08-03 addresses this issue stating the following on page 126:

> *If the EDCs elect to pursue cost recovery of expenses related to Tropical Storm Isaias, such petition would be evaluated in the course of a future contested rate proceeding, at which time, the Authority will evaluate the final, audited cost data to verify that the storm costs are accurate, quantifiable, supported by documentation, and properly accounted. <u>The Authority will further confirm that costs have not been included in the rates and charges currently charged to customers.</u>*
>
> (Emphasis added.)

As explained above, $3.1 million of these costs have been included in the rates and charges currently charged to customers. To allow recovery in this case would constitute a double recovery.

The Company's rebuttal admits that it did underspend on the UPZ program in 2020 but argues that overspending in the prior year should be considered. This reasoning is flawed for the following two reasons: 1) UI mischaracterizes the issue, which is whether the UPZ storm costs were incremental to the UPZ expense for that year, and not whether a true up is in order; and 2) following the Company's logic that spending from other years should be included, the Company still underspent for UPZ over $3 million in total in the years 2017 – 2021. No matter how one applies it, following the Company's logic would result in collecting the same dollars that have already been collected from ratepayers.

OCC recommends disallowance of the non-incremental expense of $3,194,085 as shown on Exhibit LA-1, Schedule C-9, line 6.

viii. Rate Case Costs

The Company itemized the components of the Rate Case Expense in LFE 1. It requests $2,031,000, which is made up of a variety of outside labor costs and overtime and payroll overheads, amortized over 3 years.

Schedule WP C-3.30			
Distribution Other Amortization Expense			
(Thousands of Dollars)			
The United Illuminating Company			Page 2 of 2
Docket No. 22-08-08	Witness Responsible:		Revenue Requirements Panel
	Date Certain:		December 31, 2021
Rate Case Expenses:			
Outside Labor: [1]			
Legal	$	500	
ROE Witness	$	138	
Depreciation	$	175	
Financial, accounting and tax consulting	$	-	
Allocated Cost of Service	$	113	
Rate Design	$	81	
SFR Schedule	$	30	
Project Management	$	32	
Revenue Requirements	$	373	
Lead Lag Study	$	81	
Overtime & Payroll Overheads [2]	$	-	
Miscellaneous	$	-	

Total	$ 1,523	
Amortization over 3 years	$ 508	

Notes:

Amounts may not add due to rounding.

[1] Updated for post-filing work, excluding appearances at hearings.

[2] Removed per the response to EOE-0159 (the Company has not identified specific employees, hours of work, or tasks that are expected to be included within the referenced estimate.)

General Statutes §16-243p(b), as amended by Public Act No. 20-5, states: "No electric distribution company shall recover its costs associated with its attendance or participation in any rate-making hearing before the authority."

The Company explained that it seeks recovery of rate case expenses except for the cost of attendance and participation at hearings. Direct Testimony of the Revenue Requirements Panel, Exhibit UI-RRP-1, p. 34. Presumably, then, the requested rate case expense consists of costs expended in preparation for the hearings. It is clear, based on the requested expense, that the Company is drawing a distinction between *participation* in and *preparation* for the rate case hearings. OCC does not believe that Section 16-243p(b) creates such a distinction, and submits that the phrase "costs associated with . . . participation," as used in the statute, includes preparation costs, because the Company would not be able to meaningfully participate in the hearings without preparation. Accordingly, OCC submits that Section 16-243p(b) prohibits the recovery of hearing preparation costs, and that the Authority should disallow the rate case expense in its entirety.

In the alternative, should the Authority disagree with OCC's recommendation to disallow the entire rate case expense based on Section 16-243p(b), OCC proposes the following treatment of certain expenses.

Overtime and payroll overheads within the rate case expense should be excluded based on precedent. The Company initially included $332,000 of overtime and payroll overheads in its $1.661 million of rate case expense. Schedule WP C-3.30, p. 2, line 16. The inclusion of overtime and payroll overheads in rate case expense is in conflict with prior PURA decisions which disallowed this expense. For example, page 26 of the Decision in Docket No. 16-06-04 provided:

> *Regarding the overtime and payroll overheads included in the total rate case expense, concurrent with the ruling in the 2013 UI Rate Case Decision, the Authority disallows the remaining $20,000 that UI included as a rate case expense as cited in Revised Late Filed Exhibit No. 3, Attachment 1, p. 11.*

And page 76 of the 2013 UI Rate Case Decision provided:

> *Also, the Authority disallows the $45,000 for overtime and payroll overheads which should be accounted for in the Company's payroll expense.*

OCC recognizes that the Company's update in LFE-1 appears to remove overtime and payroll overheads, apparently because "the Company has not identified specific employees, hours of work, or tasks that are expected to be included within the referenced estimate." LFE-1. If the cost has been removed from the revenue requirement, OCC supports this exclusion, but seeks to emphasize that even if the Company had identified specific employees, hours or work, or tasks, it would still have been inappropriate to recover these costs. Consistent with these prior PURA Decisions, OCC recommends the disallowance of this expense which reduces annual rate case expense by $111,000. This adjustment is shown on Exhibit LA-1, Schedule C-9, Line 10.

As discussed with regard to Cash Working Capital (Section V(c)), an appeal to PURA precedent is not a sufficient proxy for a logical rationale for including or excluding depreciation and amortization. Based upon Schedule WP C-3.30, rate case costs should be reduced $55,000 reducing the Company's annual expense by $18,333.

In LFE-88, UI details the costs associated with its employees' attendance and participation in the evidentiary hearings. Based on hearing hours and fully loaded standard hourly labor rates, UI calculates that there were approximately $255,000 of in-house costs incurred to attend hearings. While these costs are not included in the revised rate case expense amortization contained in LFE-1 – see LFE-1, WPC-3.30, p.2 – the annual wages and salaries associated with these employees are included in pro forma payroll and benefit expenses. Effectively, the time spent by UI's employees on these rate case activities is being charged to ratepayers as normal payroll and benefit expenses. Consistent with the requirements of the revision to Section 16-243p(b), these costs should be removed from base payroll and benefit expenses to ensure that they are not being recovered from ratepayers.

Two items not included in the Company's rate case expense request are the costs with OCC's and PURA's consultants, which are deemed "as proper business expenses of the affected company" and recoverable pursuant to General Statutes § 16-18a(a). Based on the expenses billed to date, estimated remaining work to complete, and budgets, OCC estimates that its total consultant costs for this proceeding will total approximately $375,000 and that PURA's consultants will be at $200,000. OCC recommends adjusting UI's rate case expense to include OCC and PURA consultant costs of $575,000.

Based on the above, OCC recommends total rate case expenses of $320,000 ($375,000 + $200,000 - $255,000) that would be amortized over the three-year period requested by the Company, resulting in an annual expense amortization of $106,667 ($320,000 / 3).

ix. UPZ Program

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 Protected Zone ("UPZ") program. Exh. UI-CJE-1, pp. 47-63. The request also includes deferrals of $4.338 million in Rate Year 1, $12.059 million in Rate Year 2, and $17.843 million in Rate Year 3. Exh. UI-RRP-1, p. 49. The Company's proposed deferrals would reverse the Decision in UI's 2016 rate case, which instructed the Company to expense the UPZ program's annual costs. Docket No. 16-06-04, *Application of the United Illuminating Company to Increase Its Rates and Charges*, Final Decision (Dec. 14, 2016), p. 9 ("All UPZ costs occurred in 2017 and thereafter will be expensed"). Instead of following this approach, the Company requests deferral with amortization over 5 years.

Both time and costs for this program have grown far beyond the Company's initial request. The Company requested $100 million for an eight-year period in 2013. Docket No. 16-06-04, *supra*, p. 4 ("The Company's enhanced tree trimming (ETT) Program was originally approved in the Decision dated August 14, 2013 in Docket No. 13-01-19 . . . as an eight-year program to occur from 2014 through 2021, with total expenditures of $100 million"). In 2016, the Company received an additional 4-year extension for a total of $162.5 million. Docket No. 16-06-04, *supra*, p 7 ("In its consideration of the need to maintain the sustainability of the program and control rate impacts, cost recovery of the proposed increase would be more reasonable and affordable for customers by extending UI's UPZ program to 12 years, and requiring that all new expenditures occurring after 2016 be expensed"); p. 9 ("The Authority hereby approves expenditures for the UPZ Program of $13 million for 2017, $13.8 million for 2018 and $14 million for 2017 and annually thereafter, until the total cost reaches $162 million for the program life"). Now, the Company returns to request an increase, again, to the program's scope in both time and budget – this time more than doubling a program originally authorized for eight years at $100 million to 16 years at $228 million. Although the Company proposes doubling the timeframe and cost of the program, it proposes no comparable increase in system miles that the UPZ program would address. This was acknowledged during the hearing by the Company witness as follows:

> *Mr. Schultz: So the only real change we are looking at in the UPZ program, between when you initially set it up and what we are looking at today, is that you are now looking at it basically taking twice as long basically twice as much to cost, would you agree to that?*
>
> *Mr. Eves: Yes.*

The Company has suggested that contractors were not familiar with the tasks required for blue sky trimming. Exh. UI-CJE-1, p. 56 ("the personnel and equipment required for UPZ work is not typical of standard reliability-based line clearance."). As OCC has testified, this is inaccurate. Vegetation management contractors are familiar with aggressive tree trimming and removal. OCC Direct (Schultz/Defever), p. 62 ("Based on our more than 47 years of experience in reviewing vegetation management work and storm work, that suggestion strikes us as inaccurate. Contractors in this particular field have been dealing with aggressive trimming and tree removal for many years."). The Company overstates the impact that environmental issues, density of trees near lines, and traffic control have on the costs of the program – these issues are not new, particularly in Connecticut, so they should not be considered as the causes of the extension of the program's timeline. See OCC Direct (Schultz/Defever), p. 63. This issue was addressed in the hearing as follows:

> *Mr. Schultz: If you could refer to your, your rebuttal testimony - - just want to make sure I – page 7, lines 5 through 8, please. Do you, here identify the areas that have impacted the cost timeline of the UPZ program.*

Mr. Eves: *Yes.*

Mr. Schultz: Were the impacts identified as issues once the program began in 2014?

Mr. Eves: *They were. I guess our experience with them, as the program began, is not where it is today. We have had a significant amount of experience executing the program since that time frame.*

The Company's rebuttal states that the "UPZ program is delivering *exactly* the types of benefits to customers contemplated when it was chartered in 2014." Exh. UI-CJE-REBUTTAL, p. 6 (emphasis added). If the costs and time scope of the program have required adjustments in two separate rate cases – to the extent that costs and duration have now more than doubled – it is clear that the program is not going exactly as planned in 2014. The rebuttal also argues that the UPZ program was hindered by "customer consent, police protection, market constraints, and municipal disposal ordinances." Id. p. 7. However, these are common issues for tree trimming programs that should have been contemplated and should not result in a doubling of time and cost. See OCC Surrebuttal (Schultz/Defever), p. 30 ("This, as we discussed in our direct testimony, suggest[s] that these issues are novel to tree trimming programs when in fact other companies commonly incur the same issues").

In addition, as discussed below, the Company has not met the authorized UPZ spending amounts or performed the tree trimming work necessary to meet the program's approved time.

1. Detailed Objections to the UPZ Program

In addition to the general objections to the doubling of UPZ Program scope as raised above, OCC has specific operational concerns with the Company's proposed UPZ Program, as described below:

a. UPZ Costs Should Be Limited to First Pass, or Initial Clearing and Tree Removals

The Company's Maintenance Plan for Transmission and Distribution Overhead and Underground Lines discusses the UPZ program as a storm resiliency program "based on Enhanced Tree Trimming (ETT) practices as presented in the State's Vegetation Management Task Force (SVMTF) report" and further explains that "UPZ is UI's storm resiliency tree work specification, creating an eight-foot side clearance ground to sky, retaining desirable low height or ornamental trees within the zone or those that are planted under the Right Tree – Right Place program. Additionally, the Company will identify and remove whole or parts of hazardous trees from outside of the zone that could fall causing damage to utility infrastructure, facilities or equipment." OCC-429, Attachment 1. The Company has completed nearly 70% of the system to the UPZ specification and now proposes, among other items, to finish remaining single-phase work; complete a second pass of three-phase circuits; and begin recurring maintenance. See OCC-527, Attachment 1; Exh. UI-CJE-1, pp. 58-59.

The remaining single-phase work is clearing to UPZ specifications and should be expensed pursuant to the Authority's order as discussed above. The Company describes the second pass work as follows:

> *The second pass three-phase vegetation clearing activities involve UI's vegetation management professionals and contractors working closely with property owners and local tree wardens to identify, consent, and prune tree limbs encroaching on the UPZ due to growth since the first pass or previous customer objections. In addition, tree removals will be proposed for trees inside the UPZ that were intentionally pruned rather than removed on the first pass, and for trees that have become hazardous outside the UPZ. The anticipated costs per mile is approximately $58,600 and the remaining 1,140 second pass three phase miles will be completed in 2029.*

OCC-606. Second pass work includes pruning and tree removals on segments of circuits that have already been cleared to UPZ specifications, which is identical to work performed through

UI's standard vegetation management programs and practices once a line is cleared. Recurring maintenance is maintaining clearances on circuits conformed to UPZ specifications, which is also the same as UI's standard practices. The Company explains in its Maintenance Plan for Transmission and Distribution Overhead and Underground Lines that:

> *Beyond the Line Clearance planned circuit miles programs, the Company implements the following vegetation management programs to maintain or enhance the reliability of the electric distribution system:*
>
> - *Hazardous Trees: The Hazardous Tree program requires the complete removal to ground of all identified trees. Hazard trees are identified in several ways including; UI vegetation management resources, contractor permissions personnel, tree trim crews, town tree wardens and customers. The hazard tree removal program is designed to remove trees identified as dead, dying, diseased or structurally defective and located outside of the normal trim area, but pose a potential hazard to UI facilities. The process involves identification of hazardous trees through the circuit trimming program, reliability engineer, Vegetation Management Leads and Technicians followed by communications with customers, CDOT and/or municipalities to inform them of the hazard and to obtain their consent to remove.*
>
> - *Vine Management: Vine Management is the removal of various vines from poles and guy wires.*
>
> - *Distribution Rights-Of Way Line Clearance: Rights-of-Way Line Clearance is the removal of overgrowth on the distribution rights-of ways. Typically, such work is identified and generated through ROW inspections and maintenance trim cycles.*

OCC-429 Attachment 1, p. 34. Neither the second pass work nor recurring maintenance entail clearing to UPZ specification, but rather address ongoing maintenance and specific vegetation related issues. OCC does not see any discernible differences between recurring vegetation management work and what the Company proposes as second pass UPZ work. Hence, even absent the Authority's directive to expense UPZ costs after 2017, costs for both second pass work and recurring maintenance should not be capitalized, because that would diverge from standard utility practice – as evidenced by the standard applicable to Eversource. See Docket No. 17-12-03RE08, Eversource response to OCC-20 (indicating vegetation management as expense programs unless work is enhanced, which is then categorized as capital program). Therefore, it would be especially erroneous to allow for second pass work to be capitalized.

b. The Company Has Failed to Substantiate the Urgency to Complete UPZ Implementation and Benefits Accruing to Customers

In addition to the overall concerns expressed above with increasing program costs, the Company has still not offered sufficient data that accurately measures the benefits of UPZ in order to determine what cost levels are appropriate. UI touts the significant benefits of partial execution of the UPZ program but justifies remaining UPZ spending by stating that a significant portion of customers (140,000) are served by circuits without UPZ clearing. Exh. UI-CJE-1, p. 54. Conversely, UI's response to OCC-527 indicates that 81,123 customers remain on feeders without UPZ, which is roughly 27% of the system. The remaining customer exposure and urgency of program completion appears to be overstated. UI discusses benefits of UPZ but will not present a benefit-cost analysis, instead claiming that "the rationale and benefit-cost analysis are presented in the Direct Testimony of Charles J. Eves, Jr. on pages 47-63." OCC-529. The Company has not produced any supporting data for stakeholders to assess the claims made on benefits, which are discussed in general terms of overall system reductions in tree related outages as opposed to actual UPZ circuit performance. Exh. UI-CJE-1, p. 51, Chart CJE-7. The Company also provides a theoretical discussion on storm scenarios to support resiliency benefits, see Exh. UI-CJE-1, p. 58, but makes no attempt to quantify those benefits in a way similar to what is required in the RE08 Framework in Docket No. 17-12-03RE08. The Company has failed to meet its burden to identify the quantified resiliency benefits relative to the UPZ program cost. Given the above-discussed proposal to double program cost and delayed implementation, the Company should provide the Authority with an analysis prepared through the lens of the RE08 framework for the UPZ needed on the remaining portion of the system, which can be evaluated on an incremental basis. OCC recommends that the Authority require such an analysis prior to authorizing any incremental UPZ costs.

c. The Company Has Not Demonstrated a Need for Incremental UPZ Budget

UI's response to OCC-527 indicates that the Company has spent $109.5 million on UPZ to complete first pass work on 65% of the system that serves 73% of customers (2014 through partial 2022). As of September of 2022, the Company had spent $10.3 million, which constitutes an annualized 2022 total of $13.9 million. See OCC Direct (Schultz/Defever), p. 60. As noted by OCC's testimony, historical spending on this program has been *below* what is already authorized in rates. Id. Estimated spending as of December 31, 2022 totals $118 million, leaving a total of approximately $44.5 million in funding remaining from the previously approved amount of $162.5 million discussed above. Remaining first pass work is limited to approximately 750 miles[2] of single-phase line which, at an average of $57,519 per mile, see OCC-528, would cost approximately $43 million to complete. This figure aligns with OCC's recommendation of $44.5 million over the next three years. The Company has stated that it intends to prioritize the remaining single-phase work. Exh. UI-CJE-1, p. 60. Hence, the Company already has ample budget to complete first pass work plus additional budget to complete work in 2022 that has not been reported. Furthermore, second pass three-phase work

[2] This is higher than the 715 miles of remaining single phase line work indicated in OCC-528.

and incremental recurring maintenance, which as explained earlier are core expense items that align with UI's standard vegetation maintenance, should not be funded in the immediate rate year. Future funding should be contingent on the Company putting forth a comprehensive schedule and cost estimate that details how UI will transition from the UPZ program to an annual clearing cycle.

d. Proportional UPZ Costs Should Be Recovered From Communication Attachers.

UI's response to OCC-607 states that "The UPZ cost was amortized in 2014 – 2016 and has been captured in UI's operating cost since 2017. The cost is not included in the formula rate calculation for attaching entities paying a rental rate per pole. The UPZ cost is not currently recovered from joint owners."

However, communication attachers benefit significantly from the program. As a matter of basic logic, pole-mounted communications equipment and lines are just as vulnerable to vegetation hazards as electrical equipment and lines, so the same benefits of vegetation mitigation accruing to UI correspondingly accrue to pole attachers. OCC is not aware of legislation or regulation that would preclude recovery of these costs from attachers. To the extent that UPZ costs are not embedded in the pole attachment rates, OCC recommends the Authority endorse a methodology for UI to recover an appropriate portion of those costs from communication companies that benefit from the reliability enhancements brought forth by this program.

2. Summary of OCC's Recommendations for the UPZ Program

Consistent with PURA's Decision in Docket No. 16-06-04, OCC recommends that all UPZ costs be directly expensed. Additionally, OCC recommends disallowance of additional funding for second pass three-phase circuit work and recurring maintenance and denial of the request to defer costs and include the deferral in rate base. As discussed above, because the Company still has approximately $44.5 million in the UPZ budget based upon prior Authority authorizations, and because the next three years of UPZ program costs for initial clearing are expected to come to $14.8 million, or less, on an annual basis, there is no need for any incremental revenue for UPZ work. The second pass of three-phase circuits and recurring maintenance should be expensed and considered within a comprehensive program. Future funding should be contingent on the Company putting forth a comprehensive schedule and cost estimate that details how UI will transition from the UPZ program to an annual clearing cycle. Until that time, OCC submits that vegetation maintenance could be funded within the $44.5 million UPZ budget. The Authority should include no increase to the rate year. In addition, rate base should be reduced by $4.338 million in the rate year, and – again, should the Authority allow subsequent rate years – by $12.059 million in Rate Year 2 and $17.843 million in Rate Year 3, to exclude the Company's requested deferral, which is shown on Exhibit LA-1, Schedule B-5.

As discussed above, OCC also recommends that prior to authorizing any expense beyond OCC's recommended rate year, the Authority require UI to file a requisite benefit-cost analysis to support additional funding and that UI put forth a methodology to recover UPZ costs from pole attachers within pole attachment rates accompanied by corresponding revisions to any additional budget requests.

x. RDM Carrying Charges

The Company is attempting to apply carrying charges to the RDM over/under-collections. Exhibit UI-MP-1. However, the Authority has made it clear that carrying charges should not be applied. In the 2021 Decision, PURA twice stated that carrying charges should not be included in the RDM. The Order states:

> *Pursuant to the Decoupling Rider approved in Docket No. 16-06-04, "There will be no carrying costs assigned to either an over or under recovery or to any deferral under the decoupling mechanism."*
> …
>
> *The Authority thanks the Company for its careful consideration of the matter, and reiterates that carrying charges should not be included in UI's calculation of the Decoupling Rider, as required by the Authority's Decision in Docket No. 16-06-04.*

The Company's only justification for disregarding this ruling is based on the RDM reconciliation now being incorporated into the Annual RAM docket. Clearly, this has no bearing on the appropriateness of carrying charges in the RDM and should be ignored. Consistent with PURA's Decision, OCC recommends the disallowance of these carrying charges.

xi. Distribution Computer Expense

The Company has requested an increase of $395,000 for Rate Year 1 and an additional $1,000 for Rate Years 2 and 3. WP C-3.13. However, the Company has failed to provide sufficient support for the increases. When asked for support for the increases, the Companystated that the requested increases were based on "experience." OCC-129. The Company's rebuttal testimony also failed to provide any supporting documentation or calculations. As the increase is unsupported, it should not be recoverable from ratepayers. OCC recommends disallowance of the increases, a reduction of $395,000, $396,000, and $396,000 for Rate Years 1, 2, and 3, respectively. This adjustment is shown on Exhibit LA-1, Schedule C-10.

xii. ADIT

In its rebuttal testimony, the Company identified an error in the ADIT calculation in OCC's schedules. OCC has reflected this correction to rate base in its Summary of Adjustments Schedule filed with this brief.

xiii. Injuries and Damages Expense

As shown in the chart below, the Company's injuries and damages expense has had extreme fluctuations during the years 2017-2021. OCC-0041.

($000)				
2017	2018	2019	2020	2021
-19	1,483	-49	315	1,065

Despite these fluctuations, the requested level of injuries and damages expenses for the Rate Plan of $1.157 million, $1.158 million, and $1.160 million were determined by escalating the 2021 Test Year amount. Schedule WP C-3.14. Due to the significant fluctuations in the historical costs, the assumed increases from the Test Year are incorrect. The use of a five-year average would be more appropriate.

The Company's rebuttal states that the use of the negative amount in 2017 and 2019 in the average is not recommended because negative amounts are not reflective of the Company's typical costs for this expense. However, the fact that negative amounts occurred twice in the five-year period demonstrates just the opposite.

OCC recommends use of five-year average results in reductions of $598,000, $599,000, and $601,000 to Rate Years 1, 2, and 3, respectively. This adjustment is shown on Exhibit LA-1, Schedule C-11.

b. Plant-In-Service

The Company's request includes average Plant-In-Service of $2.515 billion, $2.658 billion, and $2.801 billion in Rate Years 1, 2, and 3, respectively. Sch. B-1.0 A-C. Based upon OCC's analysis that the increases in plant spending have declined each year since 2018, the Company's requested increases appear to be overstated.

i. The Company Has Failed to Provide Adequate Data to Support Its Request.

OCC's attempts to review the Company's request were hampered by the Company's failure to provide necessary information. The Company's response to OCC-158 failed to provide requested information such as rate year amounts, and the provided historical information was inconsistent with information already provided in the Company's filing. The Company also provided information regarding Accounts 368 - Line Transformers and 370 - Meters in discovery responses that contradicted information provided in the Company's Application. Finally, OCC-193 sought supporting documentation for capital additions during the interim period and the Company provided none. Although the Company's rebuttal describes information that was provided, it does not provide any of the requested supporting documentation. Exh. UI-CJE-REBUTTAL-1, p. 4.

As has been discussed throughout this brief, the Company bears the burden of proof, and through its failure to provide adequate documentation to support its Plant-In-Service calculations, it has not met its burden.

ii. The Information Provided by the Company Does Not Meet the Known and Measurable Standard.

During the hearing, the Company appeared to be unfamiliar with the known and measurable standard, which is described above in Section IV. See Tr. at 977 ("Well by definition a forecast cannot be known and measurable, right. It is a forecast. It is what we see in the future."). When specifically asked whether UI relies upon any document that defines the known and measurable standard, the Company's witness responded, "I am not aware of a document that explicitly defines the term, known and measurable." Tr. at 974.

As noted in Section IV, the costs for which the Company requests recovery should meet the known and measurable standard, but the witness's statement appears to imply that any forecasted cost cannot meet the standard. It is of particular concern that the Company does not appear to rely upon any internal policy to determine what is known and measurable when it projects its plant-in-service.

As OCC's witness testified during the hearing, "when you are looking at the costs that are put into the filing, the interim year and each of the three respective rate years for the capital additions are all projections. There is no actual numbers in there, except that they, according to the Company, some of the interim period has some actually that they used as a starting point and then just projected them through . . . .". Tr. 1324. Not only does this level of ambiguity place all of the risks associated with inaccuracies upon the ratepayers who are funding the plant as it enters service, but it also creates systemic issues that make it impossible for ratepayers, the Authority, or even the Company itself to obtain a universal understanding of what exactly is in rate base at any given time. For example, when asked whether the return earned on particular plant was included as part of the Company's last rate case, the Company's witness responded "I am not sure that the plant-in-service in each rate year was projected that specifically. Rather, I suspect that the revenue requirement in that proceeding was developed by taking the test year level of plant, and then assumed level of plant additions . . . proposed by the Company based on its spending needs and . . . discussed throughout that proceeding and then ultimately approved by the Authority." Tr. 1705. In other words, the Company's projections for Plant-In-Service have drifted so far from the known and measurable standard that the present status quo is entirely divorced from reality – to the extent that even the Company is unsure of whether a particular project is presently included in rate base. The Authority should take this into consideration in the context of OCC's recommendations for improved filing requirements and enhanced scrutiny of the Company's capital planning process – including the necessity for documentation and review of plant at the time it enters service – as discussed below in Section V(e)(i).

iii. The Information Provided by the Company Does Not Meet the Used and Useful Standard.

OCC requested a summary of Interim Period additions on Company Schedule B-2.1 A, including the status of each project. See OCC-157. The Company's response did not provide sufficient information for the Authority to determine whether the projects were used and useful, under the "bedrock principle of utility regulation" referenced in Section VI. Based upon the response, some of the projects have slipped and should be moved from the interim period to the rate year period, and those that will not be used and useful during the rate period should be excluded.

The OCC recommends adjustments based on the projects' current status. In addition, projects classified as "ongoing" should also be adjusted because the status was not provided. Conservatively, OCC recommends shifting at least 10% of interim period costs to Rate Year 1, which would reduce the interim period by $33.219 million. The Authority would be well-grounded in further reductions, because the costs lacked sufficient support, such that they could reasonably be entirely excluded from allowed revenue. For the Rate Years, the OCC recommends an increase of $131.618 million to plant additions based upon a five-year average of historical plant changes, with any increases to subsequent years based upon slippage from the interim year period. The Company's rebuttal claims that this proposed adjustment is arbitrary and unreasonable. Exh. UI-RRP-REBUTTAL-1, pp. 4, 11. OCC's approach is based upon actual known and measurable historical increases, whereas the Company failed to meet its burden to provide the necessary documentation to support its increases, despite receiving requests to do so.

iv. Proposed Plant-In-Service Adjustment

Based upon the foregoing, OCC recommends adjusting allowed Plant-In-Service from the Company's request, resulting in a reduction to Rate Year 1 of $23.567 million. Although we do not support the Company's multiyear rate plan proposal, as explained below in Section V(g), should the Authority allow additional rate years, OCC recommends reductions to Rate Years 2 and 3 of $44.579 million and $64.402 million, respectively, as shown on Exhibit LA-1, Schedule B-1, p. 1 of 2.

c. Cash Working capital

i. The Inclusion of Depreciation in Cash Working Capital is Inappropriate.

The Company has included depreciation in its proposed cash working capital ("CWC"). See Exh. UI-MJA-1, p. 12. Even by the Company's own definition of CWC, the inclusion of a non-cash item like depreciation is inappropriate. The Company describes cash working capital as follows:

> *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.*

OCC-198.As such, a non-cash item such as depreciation is inconsistent with the definition and purpose of CWC, as necessary when a cash outlay is needed to provide service before cash is received for that service. No such cash outlay is needed for depreciation, so it does not belong in the Company's calculation. See OCC Direct (Schultz, Defever), pp. 14-18; OCC Surrebuttal (Schultz, Defever), pp. 5-8.

A further concern is that the inclusion of depreciation in CWC could result in a double recovery from ratepayers. Because depreciation is part of the calculation of net income, and rate base includes the plant upon which depreciation is determined, the addition of depreciation to CWC could result in a double counting of that amount. See OCC Direct (Schultz, Defever), p. 16.

ii. The Company's Justifications for Inclusion of Depreciation in CWC Are Uncompelling.

The Company attempts to justify this inclusion by stating that non-cash items have been allowed in CWC in the Authority's prior rate case decisions. OCC-202. However, the Company's expert witness admitted during the hearing that he advocates for inclusion or exclusion of non-cash items based upon the applicable precedent in whichever jurisdiction he happens to testify, and appears to have recommended the disallowance as many times as allowance. The witness testified, "If the local precedent was that depreciation was not included in cash working capital, I did not include it. . . So I follow precedent, typically, of the jurisdictions that I am in." Tr. 460. The Authority should evaluate the veracity of the witness's testimony in light of this admission that he adjusts his position on this issue depending upon local precedent. The Authority is already aware of its own precedent, and as discussed in Section IV it is reasonable for the Authority to depart from precedent where it determines there is a good reason to do so.

This issue should not be decided on precedent alone, particularly as the precedent is inconsistent with the concept and necessity of CWC. As noted elsewhere in this brief, the Company has testified that it is reasonable for the Authority to make adjustments to prior approaches. See Tr. 1316 ("just because things were done, have always been done a way, or have been done a way for 25 years, we don't think for our customers or for the State of Connecticut or to promote clean energy, is always a good reason to keep doing them that way").

Other jurisdictions have acknowledged non-cash items should be removed from CWC, including Illinois, Maine, Missouri, Oklahoma, and Pennsylvania. LFE-013.

iii. Proposed Cash Working Capital Adjustment

OCC recommends the removal of non-cash items (depreciation and amortization) from the lead lag study used to calculate CWC. This results in a reduction to the Rate Year of $13.028 million. Although OCC does not support the Company's proposal for a multiyear rate plan, as discussed below in Section V(g), should the Authority authorize subsequent rate years, CWC should result in reductions to Rate Years2 and 3 of $13.641 million and $14.244 million, respectively, as shown on Exhibit LA-1, Schedule B-2.

d. Customer Service

The Company's application includes a description of UI's "customer service and customer experience vision," an explanation of some customer service-related organizational changes, and a request to add incremental FTEs for customer service. See Exh. UI-CSP-1. OCC filed responsive testimony expressing general concern with the Company's customer service priorities, and recommending metrics to measure customer service outcomes for the Company's low-income customers. See OCC Direct (Colton). The Company filed rebuttal testimony criticizing the OCC's recommendations and generally taking the position that the Company should be allowed to continue operating its customer service practices in accordance with the structure it has designed for itself. See Exh. UI-TAO/DRC-REBUTTAL-1. For the following reasons, the Authority should hold the Company accountable for its actions and their impacts by requiring that the Company employ better metrics to measure customer service generally and adopt OCC's proposed metrics to measure low-income customers specifically.

i. UI places More Emphasis Upon Ensuring That Customer Service is Provided Than Upon Improving the Quality of its Customer Interactions.

UI's direct testimony notes that it measures customer experience using "key performance indicators," which it identifies as "Average Speed of Answer," "Abandonment Rate," "Customer Contact Satisfaction," "Digital registrations," "Electronic bill adoption," and "Mobile Application Downloads." Exh. UI-CSP-1, p. 5. The Company views these indicators as "an overall target or goal for the Company and they are indicators, which are metrics that, an indicator of what you are trying to deliver." Tr. 2352. The six indictors were specifically chosen as the "top, you know, key performance indicators that . . . as a lead team, we track on a weekly basis. You know, and absolutely we have got operational metrics that sit below that . . . but in relation to our true north and ensuring that we are bettering our customer experience on a weekly basis, these are the, the things that we watch." Tr. 2354.

Two of these six indicators measure the speed and consistency with which UI answers the telephone, but are apparently entirely agnostic as to what is actually communicated to customers during phone calls and whether they are effectively communicating to achieve the purpose of the services. Three of the other six indicators merely measure the success in encouraging customers to adopt electronic billing tools. Only one of the metrics the company has identified as "key" is even relevant to the interactions between customers and the customer service team. The "Abandonment" metric only tracks how often a customer hangs up the phone before being connected with a customer service representative – the Company does not even track circumstances where the customer ends the call during an interaction with the Company. Tr. 2342.

Similarly, the metrics used to measure customer service representative performance for the Company's third-party vendors are based upon the amount of time a customer is on hold, the percentage of productive time, and the average quality assurance score. CAE-42; Tr. 2507. The two main indicators the Company looks at are "quality and call metrics," but according to the Company, "as far as rep performance, it's -- it's on the third-party vendor to manage their own folks." Tr. 2511.

When asked about the metrics used in other jurisdictions to measure customer service representative performance, the Company identified the "number of calls handled," "calls per hour," and "average handle time," which includes "talk time," "hold time," and "wrap-up time." Tr. 2524. The Company also identified "utilization," which means "the percentage of time that [a CSR is] . . . actually handling phone calls," [Tr. 2524] as well as "occupancy," which is "a measurement of the percentage of time when a . . . customer service representative is . . . actually speaking to a customer." Tr. 2524. The Company identified the metric of "adherence to schedule," meaning "how often and what percentage of the time are the representatives doing the things that they're scheduled to do." Tr. 2525. The Company witnesses added, nearly as an afterthought, "We also look at their quality assurance scores and post-call survey results." Tr. 2525.

When asked how the single identified metric that actually measures the quality of customer interactions is encouraged – specifically, whether there is an element of incentive compensation for customer service employees that is tied to the Company's goal to maintain a customer satisfaction score of 90% or better – the Company responded that the goal is just one of the additional goals that are in its performance reviews. "So we assess what goals we have for the . . . year, which includes those types of targets, as well as initiatives that we're implementing or projects that we should be working on. And then it all is compiled together as far as your overall performance rating. So that's the way we incorporate that target as well as other targets." Tr. 2517.

OCC is concerned by the Company's sole focus upon measuring whether customer service is provided, as opposed to how successful it is. The lack of internal resources devoted to measuring meaningful outcomes for customers is also concerning, and highlights the necessity for the Company to be measured by more relevant and impactful metrics, such as those recommended by OCC's witness in this proceeding, Roger Colton, as discussed below.

ii. A Planning Process that Utilizes More Meaningful Performance-Based Metrics is Key to Better Performance Outcomes in UI's Customer Service

To achieve any particular goal, prudent management involves a standard planning process, which is driven by results. As Mr. Colton explained, the process involves the following steps:

1. Identifying the outcome sought to be achieved;

2. Identifying the metrics by which to assess Company performance relative to that outcome (i.e., the extent to which, if at all, the outcome is being achieved);

3. Identifying the data by which to measure Company performance (i.e., the extent to which, if at all, the outcome is being achieved);

4. Using the data collection to determine what gaps, if any, exist between actual performance as revealed by the data and desired performance as established by the identified outcome; and

5. Determining what changes, if any, are necessary to improve the Company's performance relative to the outcomes it has established.

Tr. 03-07-23, at 2627 - 2629. Once this "feedback loop" has been exercised, the prudent manager begins the review process anew. In this fashion, the utility manager engages in a continuous improvement process by which to review whether they are engaging in effective and efficient management of resources and processes to serve customers. As Mr. Colton explained, this process has long been accepted as key to prudent management. Under the 30-year-old Government Performance and Results Act (GPRA), for example, "'[t]he key concepts of this performance-based management are the need to define clear agency missions, set results-oriented goals, measure progress toward achievement of those goals, and use performance information to help make decisions and strengthen accountability.'" OCC Direct (Colton), pp. 8-9.[3]

Mr. Colton noted that the GPRA identifies the use of performance metrics as integral to standard prudent behavior because: "[S]uccessful organizations recognize that it is not enough just to measure outcomes. . . By analyzing the gap between where they are and where they need to be to achieve desired outcomes, management can target those processes that are in most need of improvement, set realistic improvement goals, and select an appropriate process improvement technique." OCC Surrebuttal (Colton), p. 4.[4]

This standard planning process is already in use at UI as demonstrated by UI's use of measurable performance metrics, coupled with penalties applied when the identified performance is not achieved, in its standard business procedures regarding how the Company interacts with its customers.

UI explained in detail both its use of outcome-based performance metrics and its levying of "penalties" when identified performance goals have not been achieved:

1. UI establishes performance targets for its call center operations. According to UI witnesses, "historically. . . customer satisfaction, complaints, average speed of answer, in

[3] Citing Hinchman (June 1997). Managing for Results: The Statutory Framework for Improving Federal Management and Effectiveness, at 1, GAO /T-GGD/AIMD-97-144, available at https://www.govinfo.gov/content/pkg/GAOREPORTS-T-GGD-AIMD-97-144/pdf/GAOREPORTS-T-GGD-AIMD-97-144.pdf (last accessed June 15, 2022). This article was appended to OCC's Motion for Administrative Notice, dated February 15, 2023 as Exhibit I.

[4] Citing Johnny C. Finch (Assistant Comptroller General) and Christopher Hoenig (Director, Information Resource Management/Policies and Issues). (June 20, 1995). Managing for Results: Critical Actions for Measuring Performance, at 9, testimony before the U.S. House Subcommittee on Government Management, Information and Technology, Committee on Government Reform and Oversight. This article was appended to OCC's Motion for Administrative Notice, dated February 15, 2023 as Exhibit F.

some states service level percentage are all stipulated within the contract as targets for the vendor to achieve." Tr. 2178.

2. The Company, along with its call center contractor, discuss what actions need to be taken in order to achieve the desired performance. UI's witness testified: "Jeff's team has a very robust workforce management group that reviews that has basically a spreadsheet that they work with and they implement all the different variables that they believe are upcoming that would impact call volumes, answer, average handle times, shrinkage, all the different factors, what are they forecasting based on historical experience, and that's where they're assessing how many people do we need to bring on and when should we bring them on, and hence the most recent initiative to increase those training classes and supplement the resources so that we can get more people trained at the same time." Tr. 2183 – 2184.

3. The desired performance is measured and gaps in performance are identified. UI's witness testified: "on an ongoing basis we're meeting with the vendor every month, if not more than that. I believe Jeff's team meets with the vendor every week and discuss performance and review where the gaps are and the opportunities." Tr. 2180.

4. If the desired performance is ***not*** achieved, the Company undertakes to determine why it was not achieved and what actions should be taken in response. UI's witness testified: "I know it's been an ongoing discussion in reference to attracting and retaining employees. So we do get the new hire classes, they get on board. And, you know, in recent times they've had difficulty retaining those employees, so that's where Mr. Drahota is talking about we're trying some different strategies as far as doubling up on training classes to try to mitigate that risk." Tr. 2180 – 2181. UI's witness also testified: "we as well as our vendors have struggled with the recruiting and retaining of employees in such a competitive job market and that drives, you know, some of those results. The abandonment percentage, the average speed of answer metric, those are all indicators of staffing, you have the right people in the right place at the right time. And then that's what that indicates. *And we've done things to try to mitigate that*. They offer overtime, you know, incentives to their employees to maximize the amount of resources that they can have on the phones at any given time." (Emphasis added.) Tr. 2181 – 2182. UI's witness also testified: "So we've doubled up on some classes, which we normally haven't done in the past from what I understand, and my hope is that within a month or two we can see some stabilization in those metrics." Tr. 2179 – 2180.

This precisely tracks the planning process endorsed by Mr. Colton, which informs his recommendation on the Company's treatment of low-income customers, as was discussed under cross-examination; Tr. 2627 –2629; and further below in Section V(d)(iii).

In addition, however, under the Company's use of performance metrics with its call center, if the desired performance is still not achieved, the Company imposes a financial penalty. See Tr. 2186 ("We do not have the abandonment rate specifically tied into it. However, if they missed other metrics, we can penalize those."); Tr. 2177 ("[I]n the master services agreement with our contractors we do have metrics that the vendor is held accountable to which could result in penalty for the vendor, a penalty in terms of cost of the invoice, invoice to our company. So yes, those are in there.")

This, too, is consistent with what Mr. Colton recommended. OCC Direct (Colton), p.5.

OCC submits the Authority should order that the Company continue using this planning process to improve its customer service, but incorporate better metrics that are more sensitive to quality service for all of its customers. As discussed in Section (V)(d)(iii) below, OCC recommends specific metrics for customer service of low-income customers.

iii. OCC Recommends the Following Performance Metrics for United Illuminating Specific to Low-income Customers

In PURA's investigation into new rate designs and rates review, via Docket No. 17-12-03RE11, and its Review of Affordability Programs and Offerings via Docket Nos. 22-05-01 and 23-05-01, improving the treatment of low-income customers emerged as a key objective that PURA seeks to have electric utilities accomplish. OCC has consistently supported a more equitable regulatory framework that better addresses the needs of low-income customers, including the establishment of a low-income discount rate. The need to improve how UI addresses the needs of low-income customers should therefore come as no surprise to UI staff and management given that the Company has been engaged in these dockets. Throughout PURA's investigation into the viability of low-income discounts, PURA and multiple other parties (e.g., OCC, Authority Staff, EOE) have expressed deep-rooted concerns about how the appropriate treatment (or lack thereof) of low-income customers not only has an impact on the social and economic well-being of low-income customers, but also has an impact on the economic and financial well-being of the electric utilities themselves, and their ratepayers. Indeed, adopting measurable performance standards for low-income households is not simply a function of "properly" treating low-income customers due to the essential nature of electric service in today's world. It also is required so that UI can achieve fundamental operational outcomes such as billing and collecting revenue. As with any utility, UI would seek the following performance outcomes, all of which would be furthered by improving performance related to low-income households: (1) timely payment (if it issues a bill with a due date of 20 days later, it wants payment on or before Day 20); (2) complete payment (if it issues a bill for $100, it wants payment of $100); (3) regular payment (if it issues six bills, it wants six payments, one in response to each bill); and (4) receipt of payment without needing to chase it (e.g., sending disconnect notices, disconnecting service). See Tr. 2727 - 2729.

PURA has reason to be concerned about UI's treatment of its low-income customers. Despite UI's active involvement in the PURA investigation of low-income discount rates, UI reported in this proceeding that it developed no mechanism to identify its low-income customers. This failure to track low-income customers arises despite UI's implementation of means-tested programs such as Connecticut's Matching Payments Program required by PURA regulation, Tr. 2212, 2310 -2311; Connecticut's Hardship Program required by PURA regulation, Tr. 2257, 2315, 2316; or the receipt of means-tested federal LIHEAP or LIHEAP crisis funding.

Moreover, UI fails to track information that would give insight into how customers are experiencing programs and navigating resources. For example, while a customer may request the review of unreasonable payment plan terms, the Company does not track how frequently, if ever, payment plan terms are modified by a review officer. Tr. 2309. If this sort of data is not tracked, the Company cannot assess the reasonableness of the payment arrangements in which call center staff enroll customers and the accessibility of review officers to customers. Perhaps most concerning, UI does not acknowledge how its own behavior ***affects*** customer payment behavior. Indeed, in its rebuttal, UI argues that it would be inappropriate for it to use the percentage of low-income defaulted payment plans as a performance metric, because, "the Company cannot control a customer's payment behaviors." Exh. UI-TAP/DRC-Rebuttal-1, p. 9 – 10. In its rebuttal testimony, UI also asserts that "the COVID moratorium demonstrated that customers *were not motivated* *to enroll in or maintain* payment arrangements *when there was no threat of disconnection*," which was particularly disheartening after two years of active participation in the PURA investigation into the hardships faced by low-income customers. (Emphasis added.) Exh. UI-TAP/DRC-Rebuttal-1, p. 5. Attributing low-income payment patterns during COVID exclusively to the elimination of the "threat of disconnection" (and its corresponding assertion that low-income customers would have better "maintained" their payment arrangements if the Company could only have "motivated" them through the "threat of disconnection") is not only short-sighted, but clearly demonstrates UI's ill-based, and ungrounded, focus on activities rather than on the relationship between UI activities and payment outcomes. OCC Surrebuttal (Colton), p. 9.

Of course, UI's actions can affect payment behavior. The Company implicitly acknowledges this in the instant proceeding. For example, with payment arrangements, rather than incentivizing call center personnel to enter into the most reasonable and affordable payment plan, UI provides a financial incentive in its contract with its call center contractors to obtain bigger payments rather than smaller payments spread over a longer time period. See Tr. 2226 ("Q. . . .it looks to me like the vendor -- the vendor is rewarded for the average payment collected by dividing the total payment collected by the total number of payments collected. And in such a system, if I'm reading that correctly, if you get one large payment the vendor does better than if they get five small ones. A. (Daniels) I will say that I know that that was the intent of this particular metric." Tr. at 2226. Despite the Company's ability to impact payment behavior, the Company does not go out of its way to encourage customers to make those payments they are capable of making in order to avoid the disconnection of service. For example, based on testimony from UI, the Company's online payment system displays only "total amount due, and then gives the customer an option to select another payment." Tr. 2349. Thus, as of now, a customer using the online payment system who is facing a possible disconnection of service, would not see the minimum payment that could be made in order to avoid the disconnection and to retain service. Tr. 2349 – 2350.

Given the limitations in the Company's efforts to address customer payment behavior it would be appropriate for PURA to impose measurable performance metrics, along with financial incentives for accomplishing those metrics. This is precisely what PURA did in its recent Final Order with respect to Aquarion Water pursuant to the directive from the legislature in General Statutes § 16-19a(b), which provides that "the Authority shall consider the implementation of financial performance-based incentives and penalties and performance-based metrics." (Emphasis added.); see also Aquarion, p. 66. Thus, there is precedent for PURA to similarly adopt a reasonable set of performance metrics in the instant case. In furtherance of better customer service for low-income customers, Mr. Colton identified the following set of performance metrics to be applied to UI management performance:

- The critical first step toward providing adequate low-income assistance is to identify the low-income customer population of the utility. Accordingly, the Company should identify no fewer than 60% of its estimated number of low-income customers. If, hypothetically, UI has an estimated 1,000 low-income customers, it should be determined whether the Company has identified at least 600 of them. The 60% figure is a floor by which to measure adequate performance, not an absolute target.

- UI should also be evaluated on the extent to which it succeeds in enrolling those low-income customers in its low-income assistance programs (and maintaining that enrollment over time). The following metrics should be used to measure UI's performance with respect to this enrollment objective:

  - No fewer than 50% of UI's identified low-income customers in debt should be enrolled in reasonable amortization agreements leading to arrearage forgiveness.

  - No fewer than 50% of UI's identified low-income customers should be enrolled in UI's bill discount program.

  - No more than 20% of UI's identified low-income customers enrolled in its arrearage forgiveness and/or bill discount program(s) should be removed in any given year for a "default" involving a failure to recertify or reverify their income.

- The following outcome metrics should be used by which to measure UI performance with respect to its low-income programs:

  - The nonpayment disconnection rate (i.e., number of disconnections per 100 customers) for identified low-income customers should be no more than the nonpayment disconnection rate for residential customers as a whole.

  - The rate at which amortization agreements for identified low-income customers default should be no more than the rate of default for residential customers as a whole.

- The percentage of identified low-income customers in debt who have their arrears subject to a reasonable amortization agreement should be no less than the percentage of residential customers as a whole in debt who have their arrears subject to an amortization agreement.
- The average monthly arrears, measured in "Bills Behind," for identified low-income customers should be no more than the average monthly arrears (measured in "Bills Behind") for residential customers as a whole.

OCC Direct (Colton), pp. 5 - 7; 10 – 17.

The performance metrics that OCC has proposed to require of UI's management are not merely reasonable, but necessary. Mr. Colton recommended these metrics as part of a three-step process, which is critical to achieve the desired performance for low-income customers and customers in general: The first set of metrics recognizes that UI cannot adequately serve its low-income customers unless, until, and to the extent, that it actually identifies who its low-income customers are. The second set of metrics recognizes that identifying UI's low-income customers does not provide any value unless that identification is used to actually enroll those customers into available assistance programs and retain them in those programs once enrolled. The third set of metrics recognizes that an adequate and appropriate delivery of assistance to identified low-income customers will generate specific, measurable improvements in payment patterns. OCC Direct (Colton), p. 21.

The metrics proposed by Mr. Colton are in line with identified PURA objectives. They are squarely within two of the nine "priority outcomes" identified by Authority Staff in Docket No. 21-05-15, *PURA Investigation into a Performance-Based Regulation Framework for the Electric Distribution Companies* ("PBR" or "PBR Docket"), in Staff Concept Paper 3, dated October 7, 2022, namely, Social Equity and Affordable Service. OCC Direct (Colton), p. 23;

PBR Staff Concept Paper 3, p. 19. Moreover, if one accepts the principle, as OCC believes PURA has done, that “improving affordability is an essential element to effective and efficient bill collection,” the performance metrics recommended by Mr. Colton “are *also* reasonably within the scope of Efficient Business Operations, Customer Empowerment, and Quality Customer Service.” OCC Direct (Colton), p. at 23.

The metrics Mr. Colton recommended are also completely consistent with the “five principles” adopted in the PBR Docket. More specifically, each of the metrics Mr. Colton recommends “complies with all five of the Staff’s recommended principles” regarding PBR, namely, that performance metrics should: (1) reflect desired outcomes; (2) be clearly defined; (3) be quantifiable through reasonably available data; (4) be easily interpreted; and (5) be easily verified. OCC Direct (Colton), p. at 22 - 23; Docket No. 21-05-15, *supra*, Staff Concept Paper 3. 45.

Tying management compensation to low-income performance metrics is one reasonable way to better ensure such metrics are met. Such a system would “strengthen accountability,” which, as Mr. Colton explained in his Direct Testimony, is one purpose of the adoption of performance metrics. OCC Direct (Colton), pp. 8 - 9. Mr. Colton elaborated on this point during his cross examination when he testified that:

> *The purpose of having outcome metrics is to establish the goal, determine whether the goal is being achieved, determine what needs to be achieved in responding to an underachievement, but also in assigning accountability and responsibility. . . tying compensation to the achievement, or to the non-achievement of outcome measurements is exactly that, is assigning accountability and responsibility.*
>
> Tr. 2636 - 2637.

Using performance metrics in this way would also hold the right individuals to account. As Mr. Colton noted in his surrebuttal, it is management’s responsibility to “target those processes that are in most need of improvement," to "set realistic improvement goals," or to "select an appropriate process improvement technique." (Internal quotation marks omitted.) OCC Surrebuttal (Colton), p. 4.

Moreover, consistent with sound utility regulation, it would allow PURA to focus on an assessment of what UI is accomplishing (i.e., its outcomes or results), rather than on what UI is doing (i.e., its activities). OCC Direct (Colton), p. 8. For example, consider UI outreach to its low-income population:

> *Establishing an outcome performance metric allows UI to determine what barriers exist to enrollment. Rather than seeking to micro-manage the reasonableness of each action which UI decides to adopt to address the lack of information, or what GAO referred to as "program and access problems," the performance metric reviews the results of the UI activities. If those activities are not working, it remains within the province of the Company to determine what modifications need to be made in order to achieve the results (or outcomes) which PURA has deemed to be appropriate.*

(Emphasis omitted.) OCC Direct (Colton), p. 15-16.

Based on the foregoing, OCC submits that PURA should adopt the proposed metrics, which, as explained above, are consistent with previously identified metric parameters and regulatory goals. Further, OCC would support tying compensation to the proposed metrics, because doing so would be consistent with the sound regulatory principle of holding the regulated entity accountable for providing just and reasonable service to its customers.

iv. UI's Objections to OCC's Proposed Low-Income Metrics Are Baseless.

As noted above, the Company advanced a limited number of objections to employing performance metrics with respect to the service it provides to its low-income customers. None of these objections present a valid basis for deciding not to adopt the performance measurement recommended by Mr. Colton.

As already discussed above, the Company argued in its Rebuttal Testimony that UI should not be required to adopt outcome measurements because the Company does not have control over all of the factors that might influence outcomes. This objection is especially problematic. UI asserted that it should not adopt outcome metrics for whether customers enroll in UI programs and make required payments on time because the "Company does not have control over the customers' actions in this regard." UI Exh. UI-TAP/DRC-Rebuttal-1, p. 5. Moreover, it argued that the Company "cannot force customers to take action." Id., at 6. It finally argued that while UI "can take specific actions within its control to educate customers, conduct outreach, and communicate energy affordability programs to influence low-income customers to enroll in programs that will assist in improved payment patterns, the utility does not have sole responsibility in this regard." Id., at 9.

As Mr. Colton testified, "[a]dopting this argument, that no outcome metric should be used unless the Company has complete and total control over the outcome, would absolve the Company of *any* responsibility for the failure to achieve identified objectives. If this argument is adopted, UI is being given permission always to argue that the failure to achieve an objective is the fault of someone else." OCC Surrebuttal (Colton), p. 3. Tying management compensation to low-income performance metrics is one reasonable way to employ such metrics. Such a system would "strengthen accountability," which, as Mr. Colton explained in his Direct Testimony, is one purpose of the adoption of performance metrics. OCC Direct (Colton), at 8 - 9. Assume, hypothetically, that UI is engaging in outreach and education but customers are not taking action. UI would dismiss this outcome because "it cannot force customers to take [] actions." UI Exh.

UI-TAP/DRC-REBUTTAL-1, at 6. The failure to achieve the outcome would not trigger a review of the types of "outreach" and "education" in which UI was engaging, in order to determine whether such engagement could be improved. See id. UI would never be moved to consider whether its outreach could be better designed to communicate with certain groups of customers that require specific outreach types to optimize effective communication. For example, according to the National Regulatory Research Institute (NRRI) 2003 study of "where customers go for help paying bills," Hispanic customers turn to very different sources of information than do non-Hispanics." OCC Surrebuttal (Colton), pp. 4 –5. According to NRRI, "The results could suggest that utilities and commissions need to assess their outreach to Hispanic customers to inform them of programs like Lifeline and Link-Up. Nontraditional consumer education such as grass-roots campaigns might be more appropriate for hard-to-reach groups such as Hispanics." Id. (Citations omitted; internal quotation marks omitted.) In contrast, NRRI reported that the cohort of aging customers "relies much less on people close to them, compared to younger people and much more on the utility company." (Citations omitted; internal quotation marks omitted.) Id. UI's approach would attribute that failure to respond to a customer's *choice* not to respond. The Company would never consider whether it was perhaps providing culturally inappropriate outreach and education. OCC Surrebuttal (Colton), pp. 4 – 5, internal citations omitted.

It is also worth noting that despite its objection that it cannot be held accountable for customer behavior, the Company itself is proposing to apply metrics to customer activity that it cannot control. The Company has proposed its own performance-based metrics, in the form of the net promotor score and e-bill adoption. Exh. UI-CSP-1, pp. 27 - 28. As explained during the hearing, the net promotor score is driven by customer surveys taken "at the point of interaction."

Tr. 2372. The Company acknowledged that Company representatives do not control the outcome of the customer surveys – the Company offers customers options, and the customer can choose how the survey is filled out, or if it is completed at all. Tr. 2372-2373. The Company also acknowledged that "E-bill is absolutely optional," and that the Company's website has "the optionality to, you know, allow the customer to select e-bill or not." Tr. 2374-2375. Hence, the metrics proposed by the Company are measuring customer behavior over which the Company does not exert ultimate control. Ultimately, only the customer has control over their own survey and e-bill behavior. This highlights the disingenuity of UI's position with respect to low-income metrics. Using performance metrics in this way would also hold the right individuals to account. As Mr. Colton noted in his surrebuttal testimony, it is *management's* responsibility to "target those processes that are in most need of improvement, to set realistic improvement goals, or to select an appropriate process improvement technique." OCC Surrebuttal (Colton), p. 4.

The Company further opposed the use of performance metrics because, it argued, all that can be expected is for "the utility [to] take specific actions within its control to educate customers, conduct outreach, and communicate energy affordability programs to influence low-income customers to enroll in programs. . . ." Exh. UI-TAP/DRC-Rebuttal-1, at 9. What that statement does not acknowledge, however, is how decisions on what "specific actions within its control" are decided upon. UI asserts that it "supports a collective and collaborative approach to the success of existing and future programs while partnering with *all stakeholders*, which include the CAAs, DSS, other utilities, regulators and consumer advocates." (Emphasis added.) Id., at 9. Notice how UI defines "all stakeholders," to mean all stakeholders who are already involved in the utility regulatory process.[5] To the extent that UI fails to measure outcomes, however, it also fails to engage in a process where it might refine that definition of "all stakeholders" to include direct engagement with the people who are actually impacted by UI's decisions. Moreover, consistent with sound utility regulation, it would allow PURA to focus on an assessment of what UI is ***accomplishing*** (i.e., its outcomes or results), rather than on what UI is ***doing*** (*i.e.*, its activities). OCC Direct (Colton), at 8. For example, consider UI's outreach to its low-income population.

Moreover, as Mr. Colton noted, "in the absence of the measurement of outcomes, there is no step-in-the-process at which anyone might critique UI's outreach programs. UI's engagement in what it terms to be 'outreach' and 'education' is never assessed to determine whether UI is engaging in ***effective*** outreach and education."[6] Again, Mr. Colton noted with respect to performance measurements, "outcome metrics would be used to 'target those processes that are

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[5] The Connecticut LIDR decision documents how DSS is now involved with the PURA regulatory process. Docket 17-12-03RE11, *PURA Investigation into Distribution System Planning of the Electric Distribution Companies – New Rate Designs and Rates Review*, Decision (Oct. 19, 2022).

[6] The Company's argument that the effectiveness of its outreach should never be assessed through outcome measurement because customers simply "choose" not to respond ignores the available research on outreach. Mr. Colton noted, for example, "Relying on this argument, that the Company can only control what it does, not what the customer does, fails to acknowledge the impact of Company actions on influencing customer choices. One attribute of poverty populations, for example, is the constant set of life difficulties facing them on a daily basis. These difficulties not only create emotional barriers, but create physical and time-use barriers as well. One study reported that:

> Frequent and regular contact with service staff may also be difficult where families face daily stresses and have chaotic routines, especially for care givers in low-income families, sole parents, and those with children with disabilities, or where parents are experiencing complex problems like depression or postnatal depression, poor literacy, learning or community difficulties, mental health issues or substance abuse."

The study found that:

> many vulnerable families who refused were unable to understand information about service provision, while others felt too burdened by the complexity of their lives to be able to think about the possible benefits of a new service. [T]hey're disengaged from so much in their lives. To access a support service is so hard if you haven't slept properly or eaten that day. It's hard to step outside that cycle.

OCC Surrebuttal (Colton), pp. 8-9 (Citations omitted).

most in need of improvement,' to 'set realistic improvement goals,' and to 'select an appropriate process improvement technique.'" OCC Surrebuttal (Colton), p. 9. Establishing an outcome performance metric allows UI to determine what barriers exist to enrollment. Rather than seeking to micro-manage the reasonableness of each action which UI decides to adopt to address the lack of information, or what GAO referred to as "program and access problems," the performance metric reviews the *results* of the UI activities. If those activities are not working, it remains within the province of the Company to determine what modifications need to be made in order to achieve the results (or outcomes) which PURA has deemed to be appropriate.

UI additionally opposes not only the application of performance metrics in general, but opposes the specific metrics recommended by Mr. Colton. For example, UI does not want to track the percentage of estimated low-income customers which it has actually identified as low-income because, it asserts, the "Company does not have information currently about how to measure the denominator in Mr. Colton's equation" (i.e., the number of estimated low-income customers in UI's service territory)." Exh. UI-TAP/DRC-Rebuttal-1, at 6. As Mr. Colton testified, however, "UI's assertion that it 'does not have information currently' about how to estimate the number of low-income households in its service territory is a *very* different statement from an assertion that such information is not available. No reason exists that UI could not readily obtain and/or develop such an estimate." OCC Surrebuttal (Colton), p. 11. Colton provided examples of Connecticut-based instances where estimated numbers of low-income customers were developed. Id., pp. 11-12.

Finally, UI opposes Mr. Colton's proposed performance metrics on the grounds that it "does not track or possess all of the information that would be need to apply these metrics." Exh. UI-TAP/DRC-Rebuttal-1, p. 8. The Company did *not*, however, identify which information that it did not "track or possess." In contrast, Mr. Colton went through every piece of information that would be required to apply his recommended metrics and identified how and where the Company would, indeed, both "track and possess" each of the needed pieces of information. OCC Surrebuttal (Colton), p. at 11 – 12. Based on the foregoing, OCC submits that PURA should adopt the proposed metrics, which, as explained above, are consistent with previously identified metric parameters and regulatory goals. Further, as already discussed in Section V(d)(iii), OCC would support tying compensation to the proposed metrics, which will make it more likely that UI will improve performance in an area where historical performance has been unsatisfactory, one of the key rationales for deploying performance-based ratemaking. Doing so is also consistent with the long-standing regulatory principle of holding the regulated entity accountable for providing just and reasonable service to its customers.

In sum, OCC submits that PURA should not find any of UI's objections persuasive because UI should be held accountable, especially in determining solutions that can only be identified through implementation of metrics-centric processes, and have not provided sufficient justification as to why the Company does not or cannot obtain the necessary data to employ OCC's metrics.

v. Summary and Recommendation re: Customer Service

To summarize, OCC is concerned about the lack of attention to measuring customer outcomes through customer service. With respect to customers in general, OCC submits that the Authority should hold the Company accountable for its actions and their impacts by requiring that the Company employ better outcome-focused metrics to measure customer service. With respect to low-income customers more specifically, OCC submits that PURA should adopt Mr. Colton's proposed metrics, which are most likely to achieve better outcomes for its low-income customers. Further, for the reasons stated in Sections V(d)iii and V(d)iv above, OCC would support tying compensation to the proposed metrics consistent with the Final Decision in Aquarion.[7] Similarly, UI should be required to demonstrate how any additional FTEs that are allowed by the Authority to support customer service have impacted the ability to achieve the metrics established.

e. Capital Plan

i. The Authority Cannot Sufficiently Evaluate the Prudency of the Capital Plan.

As discussed above, it is the Company's burden to provide sufficient information for the Authority to evaluate whether its proposed costs are – or will be – prudently incurred. Without such information, the Authority cannot be expected to authorize costs, particularly under a system where the general approval of a capital expenditure plan sets in motion a series of actions that ensure that the Company maximizes its cost recovery and minimizes its own risk or accountability. As described below, the Company's proposal aligns with the status quo that has been developed and perpetuated over decades, and it is time for the Authority to rebalance the scale.

However, it is crucial to note that OCC's recommendations below should not be interpreted as sweeping and radical disallowances that call for the Company to cease its system planning process and corresponding investments in improving resiliency and reliability, or in transitioning into an improved and equitable modern grid. OCC's recommendation is <u>not</u> that

[7] OCC acknowledges that PURA has a pending investigation into the use of performance-based ratemaking (PBR). As Mr. Colton noted in his testimony, the fact that the PBR docket is, at present, on a different time track than the instant case does not detract from the benefits of adopting PBR in this docket. OCC Direct (Colton), p. 26. Nor does it prohibit the Authority from imposing performance based metrics in this proceeding.

these investments be wholly rejected, nor that the Company should not recover the prudently incurred costs of its appropriate investments. Rather, we suggest that in order to correct the below-described systemic problems with the Company's proposal, the Company's capital plan should be supported by reasonable documentation and data before capital expenditures are approved, and projects should also be evaluated before plant is allowed to enter service and be embedded in rate base. For longer term capital expenditures that will not even enter service for several years, the Company should have ample opportunity to implement OCC's recommendations herein, and obtain appropriate authorizations at a later time, without incurring financial harm from delayed cost recovery. For shorter term projects, OCC recommends that the Authority could design appropriate cost recovery mechanisms to allow for a reasonable transition to an improved capital planning scheme, such as reconciling mechanisms or regulatory assets. Generally, OCC's concerns with these proposals, as outlined below, demonstrate that it is premature to issue authorizations that will inevitably result in associated costs flowing into base rates without further meaningful review.

1. **The Capital Plan Was Developed Through a Complex Series of Decisions.**

As discussed above in Section IV, the Authority must ensure that "the level and structure of rates charged customers shall reflect prudent and efficient management of the franchise operation." Conn. Gen. Stat. § 16-19e(a)(5). The prudence of a management decision "depends on good faith and reasonableness, judged at the time the decision is made." C*onnecticut Light & Power Co. v. DPUC*, 216 Conn. 627, 645 (1990). The prudence of an investment must be judged by what a utility's management knew, or could have known, at the time the costs were incurred. *Id.; Violet v. FERC*, 800 F.2d 280, 282 (1st Cir., 1986). In order for the Authority to judge whether the decisions UI made in developing its capital plan were prudent, the Authority must consider the information available to the Company at the time the decisions were made.

The Company's witness panel testified at length about the many decisions the Company made throughout the capital planning process, and the information it considered in making each decision. The first step of the process is the identification of necessity. Tr. 1155; 1164. The analysis of need involves consideration of a broad array of data, from customer service requests [Tr. 1155, 23] to substation and circuit capacity analysis [Tr. 1156, 2], to the level to which infrastructure has deteriorated. Tr. 1156. When the company makes a decision as to whether a project is needed, it is looking at all kinds of data. Tr. 1156.

After a need is identified, the Company moves on to designing and engineering the project. Tr. 1157. This step is necessary in order to determine project cost. Tr. 1157. Some elements of project cost are procurement-based. Tr. 1157. The Company uses multiple different kinds of cost procurements, such as competitive bidding processes, as well as multiple material procurement processes, and these are subject to an internal process to determine what the appropriate cost should be. Tr. 1158. That internal process involves "open[ing] the door widely typically in the beginning of the procurement process," and the Company exercising the ability "to vet . . . the contractor's ability to do the work, or whether they have the staffing required for the volume of work . . ." Tr. 1158. The analysis of bids received is not "an absolute direct correlation that the lowest bid always get the -- the work . . . ." Tr. 1158. In analyzing project cost, the Company looks at all kinds of information and makes decisions based on its analysis of that information. Tr. 1159. The internal cost approval process also involves several layers of analysis. Estimates are developed "within the various business teams," which "follow the guidelines established by their departments for the type of work that they're doing." Tr. 1161.

The estimates are then vetted as part of "the individual business area's development of the project underneath the supervision of their management." Tr. 1161. The management is "involved within the committees that approve the projects to be included within the capital plan, and to move forward and authorize expenditure of company funds." Tr. 1161.

After costs are approved, the company moves on to the execution stage, which can involve further authorizations due to engineering changes or costs changes during construction. Tr. 1162. During the execution process, there are sometimes "unforeseen obstacles, underground obstacles, things of that nature that -- that cause you to divert from the original plan." Tr. 1162. For each potential diversion from the original plan, the Company again must look at data and make a decision about whether to divert, and the scope of any diversion. Tr. 1163. Those decisions may also be subject to an internal approval process, depending upon whether the level of change required exceeds certain thresholds. Tr. 1163.

2. The Information Upon Which the Company Relied In Making Its Capital Planning Decisions Is Not Available to the Authority.

In order to fulfill its statutory duty as to the level and structure of rates, the Authority must determine whether all of the decisions that led to the proposed capital plan were made reasonably and with good faith, given the information available to the decisionmakers at the time. When asked whether the company has filed the data it relied upon in making all of the decisions associated with developing its capital plan, the Company's witness responded, "That's not something that we would typically provide. It's not something that, honestly, we can provide in the timeframe that we're looking to be responsive towards all of the questions that are asked . . . of the company." Tr. 1171. However, the witness acknowledged the Company's burden and offered, “We’ve put forth what we believe is our best supporting information for the nature of our capital plan, our forecast, what we rely upon . . . .” Tr. 1171.

OCC disagrees that the supporting information filed in this docket is the best the Company could have put forward, and also disagrees that it is a reasonable representation of what the Company relied upon in forming its plan. As OCC’s expert witness, Helmuth Schultz, testified during the hearing, “. . . [O]ne of the issues we have here is we had a number of requests that asked for supporting documentation so we could do an evaluation of the projects on an any one project-by-project basis. And while in cross the Company’s witnesses said that the numbers are known and measurable, they aren’t, in fact really known and measurable because they don’t have, we weren’t provided any kind of supporting documentation to identify them as such.” Tr. 1329. OCC’s witness testified about this issue being mitigated in other jurisdictions where commissions now require companies to file verifiable data to support their capital projections. Specifically, the commission in Vermont now requires that companies file attachments with line items that would tell what is required for the company in the form of supporting documentation. “That would include estimates, quotes, and if estimate and quotes weren’t available . . . information from a similar project . . . and it had to be really similar . . . .” Tr. 1334-1335. “And in this case, for every project that was a specific project, there would be a file prepared that would have the reference to the . . . quotes or estimates, as well as the information from preceding projects that didn’t have estimates or quotes . . . [s]o we were even able to evaluate every one of the projects.” Tr. 1335; see LFE-44.

OCC filed copies of the standardized forms used in Vermont in response to Late File Exhibit Request 44. As demonstrated by LFE-44, Exh. A, the Vermont commission requires a project-level summary sheet with amounts tying to the total capital budget requested; work orders including project descriptions and rationale as well as start and end dates; cost/benefit analyses on a per-project basis; actual costs and estimates – supported by quotes, estimates, or invoices; materials lists; payroll breakouts; etc.

UI's capital plan as presented in its initial filing does not include anything resembling the level of minimum detail required in Vermont, and instead – as addressed in further detail below in Section V(e)(i)(3) – is supported by a few tables showing UI's unilateral determinations as to its capital budget, accompanied by narratives describing the basis for its determinations of need – without providing any of the actual data driving such determinations or budgets. See Exh. UI-CJE-1. Again, there simply is not enough data in the record for the Authority to determine whether the Company's decisions leading to the capital plan were reasonable at the time they were made.

3. Even if the Capital Plan Included Sufficient Detail for Evaluation, the Company's Proposal Does Not Allow For the Authority to Verify that Projects Are Completed Prudently and Efficiently.

During the hearing, the Company described the historic process for the Authority's approval of its capital plan, from its initial filing to the point when plant enters service. A witness noted, "there are three levels of review, currently, built into the Company's current rate plan and similar to what is contemplated in this plan." Tr. 1097.

First, the Company puts forward projections of both capital expenditures (i.e., the amount of the Company's capital it intends to invest in utility plant) and plant-in-service (i.e., the rate at which plant enters service and must be paid for by ratepayers). Tr. 1097. The Authority then examines the Company's application in the context of a rate case and does the best it can to determine whether the plan makes sense. Tr. 1098.

After the plan is approved, the Company submits compliance filings that demonstrate its progress in spending its budget. The compliance filings only indicate whether the Company has "completed [particular] elements and whether we are either 10 percent above or below those [allowed] costs, or where we stand." Tr. 1099. As the Company confirmed during the hearing, these compliance filings historically only indicate two things: how fast the Company is building, and how much money the Company is spending. Tr. 1099. The Company confirmed that no additional level of detail is historically provided in those filings, and contended that these two indicators provide sufficient information for the Authority to "have an understanding that . . . they got what they paid for." Tr. 1100.

The last and final opportunity for the Authority to evaluate the Company's capital plan progress is within the analysis of the next rate case. "The third level . . . is in the next case looking back over the amounts that are, that, have been put into service between cases . . . as the Company seeks to include those in rate base in the next case, as well, that the, that the intervenors, OCC and others in the Authority, have the ability to review those at that time, as well." Tr. 1097.

In summary, the historic prudency evaluation for the Company's capital plan has consisted of an initial authorization of a capital expenditure budget, based upon a similar level of data presented in this proceeding, as discussed above; the monitoring of the Company's budget progress filings; and then a retroactive review within the next rate case, after plant has already entered service and ratepayers have already begun paying for the Company's return of, and on, the investments.

During the hearing, the Company justified the legitimacy of this review standard by noting "that is the methodology that we use and have used as far back as I can recollect," [Tr.

744] and that the practice is "in accordance with what we have been doing for the last 100 years and in good faith." A witness similarly shared, "I've been involved in rate cases since 2005. We've been applying . . . this approach in . . . estimating and providing at a point in time . . . our best view of the future and filing . . . in the means that have been developed here." Tr. 1170. The Company's witnesses also confirmed in no uncertain terms that the Company's last rate case allowed a capital budget, and then projects were placed into service – and hence into base rates – without any further evaluation from the Authority. Tr. 745.

There are myriad problems with this system. As OCC's witness testified, the system allows for the Company to apply its approved budget towards projects that differ from those it presented in order to justify the budget in the first place. "[L]ets say the Company was supposedly going to put in $100 million in plant. And, in fact, they put in $85 million, so they had to explain the variants [sic] there as to what it is. Now the $100 million was based upon a different number of projects, some of which weren't even part of the rate request in this initially. And so that is where the problem, you know . . . [with the] lack of supporting documentation of when you presenting [sic] your rate filing." Tr. 1330-1331.

This is especially possible because the initial authorization is based upon projections, and expected outcomes are, by their nature, increasingly inaccurate the further out they are projected. The Company noted that the plan presented in this case includes projects that are not yet at the phase where costs have been fully internally authorized. Tr. 1165. In fact, the Company only authorizes and approves funds for a current budget year. Tr. 1166. Hence, some amount of costs in the proposed capital plan are estimated based upon historical data. Tr. 1166. Other projects are not ready for reality-based estimates because they are not yet ready to move forward into the execution phase. Tr. 1166. Those types of projects generate "a more general estimate that has more assumptions." Tr. 1167. When the Company does not yet have reliable cost data, it makes judgments about the expected costs based on "standard estimating practices," such as using "compatible units to determine the amount of – the work required . . . hours associated with that, what materials cost, those types of elements." Tr. 1168.

When the Company projects the plant it expects to be in service in a given rate year, in order to derive the revenue requirement for a particular rate year, it does so using projections for when particular projects are expected to enter service. Tr. 3299. However, some of its projects have projected in-service calendar years, rather than being targeted to particular months within the year. Tr. 3300 ("The forecasted plant additions they're done by calendar year, but for the out years 2024 through 2026 we do not have a monthly forecast for the plant in service additions"). So in order for the Company to project when exactly a particular project will enter service during a rate year – as measured from September 1st through August 31st, it uses historical Plant-In-Service rates to normalize its calendar year plan into a rate year plan. Tr. 3300. This adds an additional layer of ambiguity into the Company's already-ambiguous capital planning process.

In sum, regardless of whether it has been the historic practice for a century, the Company is requesting the Authority to authorize at least three years' worth of expenditures, amounting to hundreds of millions of dollars, using projections that the Company agrees are inaccurate, but with no practical way for the Authority to make meaningful adjustments or corrections when the impact of those inaccuracies eventually materializes. According to the Company's plan, by the time the plant actually enters service, the best we can do is to monitor the speed at which the Company has spent money – from which we are expected to be assured that we "got what [we] paid for," [Tr. 1100] – and then to try to make forward-looking adjustments in the next rate case.

This is precisely why the Authority must proactively take the initiative to make necessary adjustments now, to resolve this century-old problem and ensure that ratepayers are sufficiently protected from inefficiencies, waste, and fiscal carelessness. As a top Company executive testified during the hearing:

> *[J]ust because things were done, have always been done a way, or have been done a way for 25 years, we don't think for our customers or for the State of Connecticut or to promote clean energy, is always a good reason to keep doing them that way. So we sit here with an openness to think differently about how we are approaching plan design.. . . We have heard good questions and feedback and regulatory interest and guidance from the Commission and from other stakeholders on these issues, for example, the idea of protections for customers in the event that plant-in-service isn't closed to the same extent that it is reflected in rates in a multiyear plan. . . . And I just wanted the opportunity to say that we are committed to work, to hear what that feedback is and working them through. And just because the rules, as they existed, or the regulatory framework, as it existed coming into this case, contemplated a multiyear plan set up in a certain way and we proposed it that way, that we would be open to further adjustments to it reflective of new guidance or updated thinking on those topics." Tr. 1316.*

4. The Authority Should Require Detailed Documentation of the Capital Plan as Well As Plant-In-Service

UI's filing in essence demands that the Authority and its ratepayers rest assured that the Company has already done the work of determining what it needs to build, and what it will cost. During the hearing, the Company's witnesses emphasized that "everything that is in rates has to be in service before it can factor into the revenue requirement." Tr. 748. The Company attempts to justify the lack of specificity in its capital plan with the assurance that these are merely projections, and that ratepayers are not actually paying for anything until it actually exists. But as described above, the vague projections within the capital plan represent the entirety of information available to the Authority before capital expenditures become plant-in-service – a fact acknowledged by the same Company witness's statement that "every dollar of capital is assumed at some point to turn into plant." Tr. 747. Under this system of information asymmetry, the Company's incentive is to seek as large a capital budget as possible, supported by as little information as it can provide, so that it maximizes its flexibility and – most importantly – so that it offloads 100% of its capital risk onto ratepayers.

As discussed above, other jurisdictions have addressed this issue by mitigating the information asymmetry problem – via filing requirements that actually justify both projections and plant. The filing requirements in Vermont compel companies to file "supporting cost documentation for each capital project" within their base rate adjustment filings, see LFE-44 Exh. A, as well as "a cost summary reflecting the actual costs recorded . . . detailing labor, materials, contractor costs, invoices and overhead costs." See LFE-44 Exh. B. OCC recommends that the Authority impose similar requirements upon UI. Specifically, OCC recommends that the Authority require the Company to file supporting documentation for all capital expenditures for which the Company seeks preliminary authorization. That documentation should include, but not be limited to:

- A financial analysis or narrative describing the proposed investment;
- External quotes, estimates, invoices and/or contracts. To the extent the Company expects actual costs to ultimately differ from any such quotes, estimates, invoices or contracts, the Company should provide a narrative explaining such expectation;
- Recent similar invoices or projects with written detailed narrative explaining the similarities and differences between the prior project and the proposed investment;
- The applicable internal labor rates, supported by actual payroll information, for all internal personnel who will work on the proposed project, as well as projections for the time expected to be allocated to the project by all such personnel;
- Calculations of direct and indirect overhead costs.
  (the "Capex Documentation").

OCC also recommends that the Authority require the Company to file supporting documentation at the time that plant enters service, to show that actual costs correspond to the documentation provided in support of proposed capital expenditures. Such documentation should include, but not be limited to, invoices and corresponding receipts for all costs incurred – including labor, materials and overhead – and corresponding quotes, estimates, or contracts, along with a narrative describing all discrepancies between such quotes, estimates or contracts and such invoices and corresponding receipts (the "Plant Documentation").

OCC recommends that the Authority decline to approve any capital expenditure beyond the initial rate year unless and until the Company files appropriate Capex Documentation in compliance with the Final Decision issued in this case. OCC further recommends that the Authority review the Plant Documentation and conduct annual Plant-In-Service reviews. Plant-In-Service Reviews should take the form of contested proceedings before the Authority, and involve Authority Staff, OCC, and other stakeholders analyzing Plant Documentation as well as corresponding Capex Documentation to ensure that ratepayers are getting exactly what they are paying for. This level of review is necessary to ensure that rates are not unreasonable, nor discriminatory, nor more than just, reasonable, and adequate, nor in excess of public necessity and convenience, and that there is a clear public need for the services being provided, and that the Company is financially and managerially efficient, and that the Company is providing its public responsibilities with economy, efficiency, and care for public safety and energy security, and that rates promote adequate consideration for energy conservation, energy efficiency and the development and utilization of renewable sources of energy and for the prudent management of the natural environment, and that the level and structure of rates is sufficient, but no more than sufficient, to allow the Company to cover its operating costs, and yet provide appropriate protection to the public interests, both existing and foreseeable.

OCC recognizes that it would be impracticable to impose these recommended filing requirements immediately, because the Company has completed and ongoing near-term investments that must be accounted for before transitioning to a new standard. For this reason, OCC recommends that the Authority impose the above-described Capex Documentation requirement for all capital expenditures following the budgets approved within this rate case, which, as explained in Section V(g), should be limited to a single rate year. Similarly, OCC recommends that the Company be held accountable for the recommended Plant Documentation for all plant entering service within a reasonable time of the issuance of the Authority's Final Decision in this Docket, such that the Authority and stakeholders will have a reasonable window to review such filings, with as minimal a disruption to the Company's necessary operations as possible.

ii. Particular Elements of the Capital Plan Are Problematic.

In addition to the above-described concerns with the Company's proposed capital plan approval paradigm, and OCC's proposed solutions thereto, we identified specific concerns with the Company's application at the project level. We discuss these concerns below, as well as our recommendations for the Authority's consideration.

1. Incongruity With the Requirements of Docket No. 17-12-03RE08

OCC has reviewed UI's proposed reliability capital investments against the requirements set forth in the Authority's August 31, 2022 Final Decision in Docket No. 17-12-03RE08 (the "RE08 Decision").

In its initial filing [Exh. UI-CJE-1] the Company acknowledged that it failed to comply with the Reliably Framework requirements established in Docket No. 17-12-03RE08. The

Company's testimony stated, "(b)ecause the Authority's final decision in Docket No. 17-12-03RE08 was issued on August 31, 2022 and immediately prior to UI's rate application, it was not possible for this application to present UI's reliability and resilience programs based on the frameworks PURA intended for future rate cases. The Company will certainly work with the Authority within the rate case process to provide such information the Authority may require to evaluate the Company's reliability and resiliency investments as proposed." Exh. UI-CJE-1, p. 29. As an active participant in Docket 17-12-03RE08, UI was aware of pending requirements. Also, as noted elsewhere in this brief, UI exercised full discretion over the timing of its rate case application. This deficiency of the Company's filing could have been avoided at the outset if UI had put forth more effort in its analysis, project justification and presentation, and delayed the submittal of its rate case until it was actually ready to be reviewed. Instead, UI produced a minimally supported capital investment plan and attempted to substantiate investments and align elements with the RE08 Decision through interrogatory responses and subsequent reports - several of which were filed after the evidentiary hearings began.

The RE08 Decision established criteria to identify circuits for targeted reliability improvements, referenced as Tier 1 and Tier 2. See RE08 Decision, pp. 50-51. Under this Reliability Framework, UI was supposed to put forth feeder improvements for Tier 1 and Tier 2 circuits along with proposed system wide reliability programs (Tier 3) designed to achieve a 5% system reliability improvement. Order No. 1 of the RE08 Decision explicitly requires EDCs to identify and prioritize worst-performing circuits in accordance with the Framework.[8]

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[8] See RE08 Decision, pp. 50-51.
Tier 1: *EDCs are directed to turn first to the data collected by the newly required, customer-centric metrics established herein (i.e., CEMI, CELID, CEMSMI, and CEMM) for assistance in prioritizing the deployment of programs designed to enhance current blue-sky reliability performance. As described above, the new customer-centric metrics are required to be tracked and reported in tranches for customers experiencing*

a. Initial Filing

Regarding Tier 1 and Tier 2 circuits, UI's initial filing did not explicitly identify a worst performing feeder program or outline targeted feeders as directed by the Reliability Framework. The filing included a line item for "Corrective Reliability" in its capital investment proposal. The filing also included a Distribution Automation[9] ("DA") program intended to improve the performance of feeders with SAIFI above the target of 0.64, as set forth in Docket No. 15-07-38. This appeared to be an additional "worst-performing feeder" program targeted for 80 potential circuits. The Company initially provided no support for either program and did not explain how the feeder selection process aligned with the RE08 Reliability Framework (Tier 1 and Tier 2).

OCC-509 sought a list of Tier 1 and Tier 2 feeders and a comparison between those feeders and the list of 80 circuits discussed in in the DA program. This request was made to validate two key points. First, that UI would actually analyze its system and rely on criteria consistent with the RE08 Framework in developing a plan, and second, that proposed programs with similar objectives would be aligned. UI responded with a list of the DA feeders and stated that "UI has not historically calculated or filed CEMI. UI is developing the ability to provide this

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three or more, five or more, seven or more, and nine or more sustained interruptions. Feeders that map to customers in these tranches shall be prioritized as Tier 1 when crafting each EDC's enhanced reliability sub-plan.

Tier 2: *Re-imagining of previously approved worst performing circuit programs. Using criteria that utility would normally identify worst performing circuits, create a list and strike feeders duplicative of Tier 1. Then identify those having circuit reliability performance that is 250% or more above the EDC's blue-sky, system-wide SAIFI and SAIDI for the same reporting period. If a feeder is identified through this process as a poorest performing feeder during two of the four years covered by a plan approved in accordance with the Reliability Framework established herein, the feeder shall be reclassified as a Tier 1 priority in the subsequent four-year plan submitted pursuant to the Reliability Framework.*

Tier 3: *Other programs designed to achieve the 5% reliability-based planning parameter, or those mitigation measures designed to be more system-wide in nature.*

[9] The Distributed Automation program is further addressed in Section V(e)(ii)(2)(d).

calculation and file CEMI metrics by the 3/31/2023 filing of the TDRP."[10] OCC-509. This left the OCC and other stakeholders with no means to evaluate UI's targeted feeders and compliance with the Reliability Framework until the Transmission and Distribution Reliability Performance report ("TDRP") was filed on March 23, 2023, after all hearings were complete.

b. 2023 TDRP

In our evaluation of UI's 2023 Transmission and Distribution Reliability Performance report, which was filed in Docket 17-12-03RE08 on March 31, 2023, in compliance with Order No. 7 of the RE08 Decision, (the "TDRP"), OCC observes that the Company alludes to deriving targeted circuits using CEMI[11] and CELID[12] [TDRP, p. 24], but only actually uses CELID. The circuits are noted as the "Worst 4% Circuit CELID-9 Percentages – 2022" [TDRP Appendix 14] and presumably are Tier 1 in accordance with the RE08 Framework although UI never references the list as a "tier." UI provides no rationale as to why only CELID was utilized as opposed to additional metrics, such as CEMI. The Company relies on CELID data from 2022 which is a single year that does not reflect the performance that customers experience over time. The Authority should have expected UI to provide a more comprehensive set of data, given that UI has granular meter data for the majority of its system - one of the benefits of AMI. The company's criteria and analysis in developing Tier 1 circuits is non-existent, leaving stakeholders with no data to determine the reasonableness of UI's approach. The Company also developed a list called SAIDI/SAIFI Worst 4% of All Circuits [TDRP Appendix 13] which

[10] UI's Transmission and Distribution Reliability Performance report (TDRP) is intended, in part, to satisfy Order 2 in the RE08 Decision which requires certain reliability metric reporting described in Section II.B.3.d.ii of the Decision (pages 54-55). The OCC is unable to locate these requisite metrics including, for example, CEMI, CELID, CEMSMI, and CEMM, reported in tranches for customers experiencing three or more, five or more, seven or more, and nine or more sustained interruptions. While the OCC is not fully evaluating RE08 Decision compliance within this proceeding, the issue of continued reporting deficiencies must be emphasized since capital investment justification relies on this data.
[11] CEMI is defined as Customers Experiencing Multiple Interruptions
[12] CELID is defined as Customers Experiencing Long Interruption Duration.

presumably are Tier 2 circuits in accordance with the RE08 Framework. UI did not completely apply the 250% or higher criteria established in the RE08 Decision.

Next, UI prepared corrective actions for the fifteen worst 4% CELID-9 circuits, or fifteen in total. UI indicates that all circuits were included in UI's 2022 Reliability Corrective Action Plan, and provides discrete recommendations to be implemented in 2023. For each circuit, UI also identifies the event contributing to the CELID-9 outage and provides a separate recommendation to address the cause. For every circuit, UI's recommendation to address CELID-9 events is to "(w)ork with operations to identify potential solutions to help limit customer exposure to CELID9 events during blue sky days." [TDRP Appendix 13]. This is not a solution, but rather a deferral of corrective actions. It also implicates the question, as raised above in Section V(e)(i), of how UI can propose a long-term budget in this rate case based on unknown, future actions.

Overall, UI's plan is essentially an extension of its previous worst performing circuit program, augmented with CELID-9 data. The Company did not sufficiently follow the Reliability Framework. Although the Company's witness stated that the Company would be focusing on the CEMI/CELID circuits this year [Tr. 91] the plan only relies upon CELID data for a single year, or a snapshot in time. The TDRP includes no cost estimates and cannot be reconciled with UI's corrective reliability budget in the rate case. Furthermore, UI fails to forecast the expected reliability improvement should the corrective actions be implemented, leaving OCC to wonder how UI can meet the directive to submit a plan designed to achieve a 5% system reliability improvement.

c. Tier 3 Projects and Programs

Within the context of the Reliability Framework, Tier 3 is considered other programs or mitigation measures designed to be more system-wide in nature that, in conjunction with Tier 1 and Tier 2 circuits, are designed to achieve the 5% reliability-based planning parameter. In practicality, Tier 3 would be all other reliability related capital investments proposed in UI's rate case, although UI does not classify those programs or projects as Tier 3. The Reliability Framework requires UI to accompany proposed programs with metrics described in Table 19 on page 54 of the RE08 Decision, including items such as SAIDI, SAIFI, O&M expense, cost and revenue impact for each reliability program. The data is intended to provide stakeholders with a tool to evaluate the incremental costs and expected reliability benefits of projects and programs. UI's initial filing did not include the requisite information. UI eventually submitted LFE 35 on March 8, 2023, which includes a third-party report titled *Benefit-Cost Analysis of AVANGRID's 2023 Distribution Automation Plan for United Illuminating* (the "DA BCA"), and which was presented as a BCA for UI's proposed DA program and purportedly included reliability metrics and data as specified in Table 19 of the RE08 Decision. To OCC's knowledge, this was the single document provided by UI containing benefit-cost analysis to justify *any* the proposed reliability programs.

The DA BCA predominantly addressed the Distribution Automation program, which is discussed in more detail in Section V(e)(ii)(2)(d) below. It also provided Table 4-1, which was intended to recreate Table 19 of the RE08 Decision. See LFE-35, pp. 16-17. The table includes each of UI's historical reliability programs, costs for 2016-2022, and assigns storm and non-storm SAIFI and SAIDI. The table does not include system-level SAIFI and SAIDI improvements for each program or reliability driver. Instead, UI simply points to the calculation of SAIDI/cost and SAIFI/cost as a means to "contextualize the value of each reliability program." LFE-35, p. 15. OCC struggles to understand how the information provided by UI can be relied upon to analyze the costs and expected benefits of proposed reliability programs. The data is incomplete, and calculations cannot be validated and are questionable. For instance, UI calculates SAIDI/cost and SAIFI/cost using all-in reliability metrics, which includes storms. This is inexplicable given that these are reliability programs and designed for blue-sky system conditions. The most glaring omission is the expected reliability improvement for each program. This again highlights the fundamental issue of UI's failure to put forth a plan designed to achieve a 5% system reliability improvement, or at least explain how the proposed programs would maintain an acceptable level of performance.

d. RE08 Decision Resiliency Framework Requirements and the Company's Submittal

The RE08 Decision describes Resilience as ". . . the ability of the distribution system to withstand and reduce the magnitude and/or duration of disruptive events." RE08 Decision, p. 57. The Decision provides that "Resilience programs must deliver demonstrable and achievable benefits to ratepayers over time and must help EDCs in their mission to protect public safety. Accordingly, in seeking approval for resilience program expenditures, each EDC must design and submit a plan in accordance with the Resilience Framework outlined below." RE08 Decision, p. 58. The Decision sets forth criteria to guide the selection and prioritization of vulnerability zones, relying on all-in reliability metrics which include major storm outages and other factors such as system characteristics, environmental communities, critical facilities, life support customers, and customer classes. Mitigation measures are derived for each zone, with an alternative based on a reasonable set of future storm scenarios. The resulting Resiliency program must be accompanied by a benefit-cost analysis that includes estimated costs and a prediction of long-term benefits along with expected revenue requirements and bill impacts. Id.

The Company's initial filing did not include support for its proposed resiliency projects in compliance with the RE08 Decision, but in response to an interrogatory request, the Company later provided a third-party study titled *Benefit-Cost Analysis of AVANGRID's 2023-2027 Resiliency Proposals for United Illuminating*. RSR-011, Attachment 2. The Company filed the associated revenue requirement on January 18, 2023 as a supplement to the same interrogatory request. See RSR-0011, Supplement, Attachment 1. The analysis applied the RE08 Resiliency Framework to identify resiliency proposals for nine priority circuits.[13] The methodologies appeared to align with the Framework in that, among other items, multiple circuit selection variables were utilized, outages were predicated using various storm scenarios, mitigation alternatives were considered, benefits were quantified using avoided customer interruption costs, and BCAs were produced. Although UI prepared a thorough analysis, the study did not provide enough data to enable an effective evaluation of assumptions, modelling, and the benefit-cost analysis itself. In particular, the report raised questions as to the inputs on selecting circuits, the reasonableness of storm projections, how outages were modeled to reflect varying intensity of storms, and uncertainties with the ICE model used to quantify customer benefits. These are all complex components that require, in accordance with the Authority's directives in the RE08 Decision, a much deeper evaluation than provided in this proceeding – particularly because, as the first such methodology evaluated in a distribution rate case since the issuance of the RE08 Decision, the treatment in this proceeding should set a standard for future evaluations.

[13] The Company also proposed several additional projects in the resiliency category addressed in Section V(e)(ii)(2)(c).

The Company's Resiliency Plan cost is estimated at a present value of $19.9 million. Cost estimates have a tolerance of -50 to +200% and do not include contingency values, overheads, allocations, or reimbursements. OCC-612. The benefits do not exceed this cost until 30 years under conservative storm forecasts (benefits of $20.05 million, in present value), and for 20 years assuming a more severe storm forecast (benefits of $24.84 million, in present value). Under conservative storm assumptions, estimated SAIDI reduction is 0.65 hours per customer per year. Assuming more storms occur in future years, estimated SAIDI reduction is 0.98 hours per customer per year. RSR-011 UI Attachment 2, p. 35, Table 5-17. Analyzing only the information presented by the Company, however, the proposed resiliency projects are questionable given that projected costs exceed benefits for a long period of time and average reductions to outage durations are not substantial, given the level of necessary investment. UI already has excellent reliability metrics, so investments in improvement may quickly raise issues of diminishing returns. As previously expressed, however, the study should be assessed in far greater detail before the Authority can properly arrive at a final determination.

2. Analysis of Proposed Projects

Although as discussed above in Section V(e)(i), the Company's proposed capital plan does not provide sufficient detail for the Authority to properly assess the prudency of proposed investments, OCC has analyzed what data is available on a project-category basis and we highlight the following concerns. Our comments focus upon project need, timing, level of investment relative to expected benefits, and cost-effectiveness against alternatives. Deficiencies in any of these areas should call for potential project adjustments or exclusion altogether. In addition, OCC takes a more a holistic view of proposed investment levels relative to historic spend and system performance.[14]

a. Customer Projects

UI's proposed spend for customer projects includes new service connections, state and municipal work, metering, customer lighting, third-party pole attachments, customer service technology and other customer programs amounts to approximately $50 million in 2023. Exh. UI-CJE-1, p. 12. Expenditures are generally non-discretionary and driven by customer service requirements. Two areas of this program segment are concerning.

I. Pole Attachments

1. Increased Budget for Third-Party Pole Attachments

UI has "incorporated the potential level of attachment applications in its rate case filing from a cost and revenue perspective to ensure that UI is prepared to respond in the required time frames." Exh. UI-CJE-1, p. 14. The proposed annual investment level, which is approaching $14 million, has increased significantly from the $3 million expended in 2019. OCC-459. UI has explained that it is receiving more attachment requests and expects future increases but cannot validate that forecast – and testified during the hearings that the anticipated number of applications for the current year have not actually materialized so far. Tr. 573-574. OCC supports ensuring that both the EDCs and attachers are well equipped to facilitate expansion of broadband infrastructure and to remove barriers to entry of competitive providers, particularly as federal funds from the Infrastructure Investment in Jobs Act and the Capital Projects Fund of the 2021 American Recovery Plan Act are distributed in Connecticut. OCC is nonetheless

[14] The RE08 Decision is designed to facilitate similar reviews that rely on EDC provided data. However, as highlighted in this brief, UI has not provided requisite information including expected system reliability improvement that would be achieved if proposed investments were made, or how individual programs would contribute to that improvement.

concerned that UI may be incurring or plan to absorb incremental costs to process attachments driven by complex engineering that should be the responsibility of the attaching entity, and that UI is not being appropriately reimbursed for those costs and has not made an attempt to collect it from attaching entities. See Tr. 1025-26 (". . . the attachers are . . . providing attachment or application fees that cover, you know, *some* of the cost of executing that) (emphasis added); Tr. 1027 ("in all the work associated with the . . . entire universe of managing the pole attachments across the Company, I think there may be some shortfalls in recovering everything"). The hearing record reflects that attachers have the opportunity to provide engineering at the time of application but are not performing this work, instead relying on UI. The record also suggests that the Company has not succeeded in encouraging attaching entities to complete the work to facilitate a more efficient response time but instead has accepted the burden and expects ratepayers to fund that decision. See Tr. 1029 ("So that is an option that has been developed into Connecticut process to date. There has been very little adoption of that ability. And I guess let me clarify, very little as, no adoption to date."). For these fundamental reasons, UI's proposed budget increase for Third Party Pole Attachments/Replacement is not substantiated. Because the Company has not sufficiently justified an incremental cost over the test year amount of $8.56 million, which itself reflects excess costs that should have been borne by attachers rather than ratepayers, OCC recommends a reduction of $8 million for the rate year. OCC recommends that the Company be instructed that any future application for third-party pole attachment funding should include a detailed forecast with cost drivers, including identifying expected costs to process pole attachment applications that are in excess of application fees, consistent with the procedures set forth in Docket 10-01-52RE01, PURA Investigation of Developments in the Third-Party Pole Attachment Process.

2. The Company's Request for 25 FTEs to Process the Anticipated Increase in Pole Attachment Requests

In the testimony of Charles J. Eves, Jr. (UI-CJE-1) filed on September 9, 2022, on pages 38-43, Mr. Eves recommends that the Authority approve the addition of 25 FTEs to meet deadlines for the Company's anticipation of an increasing level of pole attachment applications in the near future. Mr. Eves claims that this increase in FTEs is driven in large part by the requirement that the Company meet Authority deadlines for processing applications as directed in the Authority's final decision dated May 11, 2022, in Docket No. 19-01-52RE01, *PURA Investigation of Developments in the Third-Party Pole Attachment Process – Make Ready*, which deadlines, when not met are subject to civil fines and penalties not recoverable in rates.

In response to OCC-305, the Company provided data on historical annual numbers of pole attachments requested by pole attachers. For the last four full years data prior to 2022 (for which there is only partial data provided) these averaged 10,511 (2018-2021). The Company provides estimates of anticipated pole attachments requested by pole attachers for 2023-2026. For 2023 and 2024, the Company estimates that the numbers will be 25,877 per year, a 146% increase over the prior period average. In 2025 and 2026, the Company anticipates this will drop back to the historical averages – 10,500 per year.

In his testimony on pages 573-574, Mr. Eves stated:

> *"…in preparation for this case, we went out and talked to the, to the attachers about their plans for this year and next year. That resulted in the numbers that we put forth around 25,000 attachments. To date, this year, those attachments have not materialized to that level." And further, "…the attachers that had given us a significant increase, have not, have not delivered those. We have actually got attachments from a, from an attacher that said that they weren't going to have any significant attachments this year, beginning to develop."*

The upshot of this is that the Company is requesting approval to employ 25 FTEs whose job is admittedly very specialized and specific to administering pole attachment applications in order to meet an anticipated increase that is 146% over historical trends, is admittedly subject to change, and is expected to revert back to trend after two years, potentially leaving Company employees trained in specialized tasks with limited applicability to their job descriptions.

Further, the Company recognizes that there is the potential for utilizing the resources of other Avangrid affiliated EDC organizations with similar responsibilities in other jurisdictions to augment some of the UI work and to balance out the work effort. Tr. 1033. Also, the Company recognizes that there is potential for sharing resources with Connecticut's other EDC, Eversource, which has similar responsibilities within the state of Connecticut. Tr. 1034.

OCC supports efficient and timely broadband deployment but also seeks to ensure that ratepayers are not getting saddled with costs that should more appropriately be attributed to attachers and protect ratepayers from funding FTEs that are not needed. With these goals in mind, OCC recommends that the Authority require UI to investigate options for sharing the anticipated increased workload and for shorter-term contract hiring, given the limited duration of the anticipated spike in need, as well as potential use of current unfilled vacancies, prior to any blanket approval of UI to build 25 additional permanent FTEs into its revenue requirement.

3. Survey and Application Fee Cost Recovery

In its Final Decision in Docket 19-01-52RE01, ("the SPA Decision") issued May 11, 2022, the Authority issued directives as to how the state's EDCs are allowed to process and make poles ready for pole attachments to the poles for which the EDC is the Single Point Administrator for poles in its service territory, and further what to charge for this process. The Authority set the application fee at $150 per application and survey fee at $50 per pole. In UI's response to Interrogatory OCC-552, the Company provided four years of data on the costs as required in the Decision. The UI response shows that over this four-year time period, the Company has fallen short of cost recovery by over $5 million. UI Response to OCC-522, Attachments 2-5. This cost shortfall is directly attributable to the pole attachers not paying the full cost incurred by the SPA on behalf of the pole attacher requesting the work of the making the pole ready for attachment.

The Authority has recognized that the level of the application and survey fees do not fully recover the cost of the engineering phase of the protocol for pole attachment. In the SPA Decision on page 39, the Authority states that it:

> *"…increased the fee as an initial step to achieve increased fairness for pole owners and electric ratepayers. This fee increase is a conservative, initial step toward lessening the gap between the costs the pole owners incur and the reimbursement received through application and survey fees. The Authority recognizes that it is unlikely that this per pole survey fee increase will cover all costs incurred by the pole owners, and thus intends to reevaluate the costs in future proceedings, including in the EDCs' next rate cases."*

OCC offers that there is nothing precluding an EDC from charging a communication company when engineering costs exceed the application fee. The Company is clearly incurring additional expenses to process applications, some of which require complex engineering. Those costs should be assigned to the communication company making the application. OCC submits that UI should be tracking and invoicing those costs and excluding them from its capital investment request in the Customer category. OCC requests that the Authority continue to recognize that the pole attachers are not paying their fair share of the Engineering Phase protocol in processing pole attachment requests and that the revenue under-recovery generally falls to the consumer in rate increases to the overall electric rates – a violation of the general principle of cost causation in rate-setting.

i. Municipal Hub

UI's newly established Municipal Dashboard falls under the Other Customer Program category. The Company proposes investing nearly $1 million per year to support this initiative. UI explains in response to OCC-611 that the dashboard:

> *allows UI's municipal stakeholders who require global situational awareness of the Company's response to an event, the ability to see the circuit topography involved in outages in near real time. UI's current outage map shows the isolating point but does not give the municipality situational awareness of the extent of the outage. This tool mines the outage topology every few minutes to provide municipalities a near real time view of what areas of their town are impacted. It also provides the ability to visualize the restoration plan day by day for a multi-day event, through a slider bar that allows the user to see the extent of the outages remaining looking ahead 1, 2 or more days.*

The response also notes that "UI identified a vendor that had created and hosted a similar outage map for a utility in Louisiana."

OCC recognizes the value of prompt and accurate outage information and that critical facilities, mostly located in municipalities, are particularly reliant upon this communication. However, the functionality of the tool appears to be little more than what can be gleaned from the Company's publicly available outage map. Based upon the information available to OCC, it is difficult to understand the nearly $1 million annual price for what appears to be additional GIS locational data and polling for outage updates on a more frequent basis. UI also confirmed that a competitive process was not followed to secure a vendor, which raises the concern of whether sole sourcing the initiative has resulted in an inflated cost. See Tr. 2053 ("we did not competitively bid this because we wanted to bias to speed"). Given these factors, and in keeping with OCC's recommendation against approving the Company's multiyear rate plan, OCC recommends that the Authority's approval of the Municipal Hub project be explicitly limited to a single rate year, and that approval of costs beyond one year be conditioned upon supplemental documentation demonstrating the benefits of this particular application and that there is no more cost-effective solution, and fully supporting the forecasted level for development and hosting – particularly absent a competitive bidding process.

b. Reliability Projects

UI generally characterizes reliability as preventative, corrective, or maintenance actions that are "key aspects of UI's planning process to maintain reliability performance at historical levels." Exh. UI-CJE-1, p. 15. The Company states that preventative maintenance, when coupled with infrastructure replacement and resiliency programs, provides ". . . the added benefits of reducing, and in some cases eliminating, the risk of future outages for certain failure modes." Exh. UI-CJE-1, p. 17. The Company states that it is fulfilling its commitments related to reliability performance that resulted from the Settlement Agreement in Docket No. 15-07-38 with systemwide targets, as follows:

Table CJE-5: Settlement Agreement Reliability Commitments

	2011-2014 Average
SAIDI	66 minutes
SAIFI	0.64

Exh. UI-CJE-1, p. 16. According to these comments, UI's underlying position on the need for reliability investments is that projects are required to *maintain* system reliability, and in some cases, are expected to *improve* system reliability. The Company's philosophy reflects the broader theme put forth in its application, which is that proposed investments are required for safety and reliability, and without those investments, performance would deteriorate to an unacceptable level. On the surface, this is a compelling rationale because quality of service, along with safety, is of paramount importance in the electric utility industry – and is certainly of paramount importance to Connecticut's ratepayers.

In its initial application[15] and throughout this proceeding, UI consistently and repeatedly claims that investments are needed to maintain safety and reliability but stops short of offering detailed justification beyond this broad policy statement. As crucial as safety and reliability are, projects are not *per se* reasonable, efficient, prudent, or necessary merely because they support these goals. UI ultimately bears the burden to prove that proposed investments will actually maintain or improve reliability. Although UI discusses the nexus between reliability investments and system performance, the Company fails to establish expected reliability benefits for any capital program in the Reliability project category, and furthermore, only provides support for a few select programs within the entire spending plan – such as resiliency or distribution automation – but even that support was not provided with the initial filing, and took the Company as long as six months after the initial application to produce for the review and consideration of the Authority.

The Company should have developed projects that provide the acceptable level of service via the most cost-effective investment levels necessary to achieve that level. OCC does not dispute that UI is expected to meet a system wide reliably target which determines an acceptable level of service, but as demonstrated by the chart below, UI has consistently met and exceeded its reliability targets since 2012.

[15] See Exh. UI-CJE-1, Mr. Eves references maintaining performance, maintaining reliable and resilient distribution system, and maintaining safe and reliable service as support for investments.

	SAIFI	SAIFI TARGET	CAIDI	CAIDI TARGET	SAIDI	SAIDI TARGET
2001	0.85		1.22		1.03	
2002	0.73		1.58		1.15	
2003	0.87		1.53		1.33	
2004	0.61		1.68		1.03	
2005	0.71		1.55		1.10	
2006	0.64		1.42		0.90	
2007	0.69		1.65		1.15	
2008	0.75		1.63		1.22	
2009	0.58		1.93		1.13	
2010	0.65		2.18		1.42	
2011	0.81	.64	2.10	1.72	1.70	1.1
2012	0.60	.64	1.62	1.72	0.97	1.1
2013	0.58	.64	1.47	1.72	0.85	1.1
2014	0.56	.64	1.57	1.72	0.88	1.1
2015	0.42	.64	1.47	1.72	0.62	1.1
2016	0.53	.64	1.38	1.72	0.73	1.1
2017	0.40	.64	1.37	1.72	0.55	1.1
2018	0.63	.64	1.57	1.72	0.98	1.1
2019	0.50	.64	1.28	1.72	0.63	1.1
2020	0.57	.64	1.33	1.72	0.77	1.1
2021	0.46	.64	1.44	1.72	0.66	1.1

OCC-418. The Company continued to achieve excellent reliability results in 2022, exceeding both the Settlement Commitments and most recent four-year average, see TDRP, p. 1, Table I.1.

	SAIFI	SAIDI	CAIDI	ASAI
2018	0.63	59	94	99.989
2019	0.50	39	77	99.993
2020	0.57	46	80	99.991
2021	0.46	40	86	99.993
Four-Year Average ('18 – '21)	0.54	46	84	99.992
2022	0.44	39	88	99.993

Given UI's outstanding system reliability performance,[16] the Authority must critically assess the need for, and level of, incremental investment in reliability projects. The remaining analysis in

[16] The 17-12-03RE08 Decision guides a reliability planning process aimed to target poor performing feeders followed by system-wide improvements. OCC has highlighted UI's deficiencies in meeting the RE08 Decision Reliability Framework. The preponderance of OCC's remaining analysis is focused on individual project justification.

this Section considers historical reliability performance, actual spend, and trending in contemplating the Company's request for future capital additions.

i. Corrective Reliability

The Company's initial filing includes a table proposing Corrective Reliability investments for years 2023-2027:

Table CJE-4: Corrective Reliability 2023 – 2027

Corrective Reliability (*$ in Thousands*)					
	2023	**2024**	**2025**	**2026**	**2027**
Reliability Improvement Projects	$3,040	$3,210	$3,281	$3,355	$3,559
Total Corrective Reliability	**$3,040**	**$3,210**	**$3,281**	**$3,355**	**$3,559**

Exh. UI-CJE-1, p. 16. The Company has stated that the Corrective Reliability category "has historically been targeted at the worst performing circuits in UI territory. Its main objective was to improve reliability performance to target levels for areas of the system that were under performing." OCC-584. In the same response, UI elaborated that "(a)s we move forward, these projects will be assessed based on the cost benefit provisions of the reliability and resiliency framework set forth in Docket 17-12-03 Re 08." Id. As discussed in Section V(e)(ii)(1), it is not clear that UI has adequately assessed its system to determine worst performing feeders in compliance with the RE08 Framework. The Company's methodology relies upon minimal data and uses a snapshot in time to create a list of targeted circuits. The Company's evaluation does not address costs or forecasted benefits. The Corrective Reliability budget was prepared before the circuits and potential corrective actions were identified, leaving a question as to how UI could accurately estimate the budget. Lastly, UI has minimally addressed the potential benefits of corrective actions, suggesting that its review of five selected circuits from 2011-2020 indicating an average improvement of 66% SAIFI and 65% SAIDI[11] should suffice. OCC-465.

However, although OCC's interrogatory explicitly requested that the Company provide workpapers, this response was not supported by any data.

While OCC supports UI's efforts to target the worst performing circuits, the data presented by the Company in this area of its application is insufficient to support the proposed level of capital investment – exceeding $3 million per year. OCC recommends that the Authority not approve the requested Corrective Reliability budget until UI prepares and presents an adequate worst performing feeder plan as guided by the RE08 Decision.

ii. Distribution System Replacement

The Company's initial filing includes a table proposing Distribution System Replacement investments for years 2023-2027:

Table CJE-6: Infrastructure Replacement – Distribution System

Infrastructure Replacement - Distribution System *($ in Thousands)*					
	2023	**2024**	**2025**	**2026**	**2027**
Splice Chambers	$7,047	$7,200	$7,630	$8,100	$8,376
Transformer Replacement	$5,013	$5,137	$5,210	$5,343	$5,467
Cable Replacement	$1,304	$0	$0	$0	$0
Network Inrastructure	$7,542	$6,974	$8,153	$8,217	$8,143
Ground Mounted Equipment	$2,994	$3,049	$3,105	$3,162	$3,276
Pole Replacement	$4,412	$4,491	$4,580	$5,310	$5,431
Other Infrastructure Replacement	$998	$1,003	$1,008	$1,013	$1,018
Total Infrastructure Replacement Distribution System	**$29,310**	**$27,853**	**$29,687**	**$31,145**	**$31,710**

Exh. UI-CJE-1, p. 18.

The distribution infrastructure replacement program is comprised of several sub-categories that group similar assets. However, UI does not provide insights as to how the Company determines the appropriate level of annual investment, nor what that investment will provide in terms of reliability. OCC attempted to explore this concept by issuing a discovery request seeking details of how the Company recognizes scope, benefits and cost when managing investment requirements, and for a description of how the Company determines costs and benefits for each program. OCC-472. The Company's response discussed the generalized benefits of proactive asset replacement – emphasizing safety and stating in one case that it ". . . is in society's interest to replace these assets before they degrade to the point of failure." OCC-472. The Company did not provide any of the requested information as to how assets are critically ranked and prioritized for replacement in each program,[17] or how the scope of replacement for targeted assets builds up to the proposed budget, and further did not quantify expected reliability benefits. The Company's support is a continuation of its repeated refrain that if the investments are not made, reliability deteriorates - or in this case, that reduced investment will cause serious (but identified or analyzed) harm to employees or the public.

To be clear, OCC fully agrees that the Company should be engaged in proactive maintenance to ensure continued safe and reliable service to ratepayers, but general appeals to safety and reliability do not relieve the Company of its burden to justify the necessity for, and level of, its proposed investments. There must be proper balance between maintaining reliable and safe service and ensuring that associated costs are not more than sufficient. Without further support, the Company's proposed budget levels appear arbitrary and possibly inflated, considering the system's already superior performance.

For example, UI spent an average of $6.4 million per year in pole replacements between 2017 and 2020. OCC-470. In 2021 and 2022, it reduced spending in the same category to $2.9 million per year. Id. UI now proposes to increase pole replacement spending up to $4.4 million

[17] In response to OCC-473, the Company provided spreadsheets with the results of maintenance inspections that UI relies upon to "isolate action items" for each of its asset replacement programs. The criticality and prioritization for replacement are not readily discernable from most of the data. In addition, pole attachment inspections in OCC-473 Attachment 5 and OCC-473 Attachment 6 indicate that less than 300 poles are labeled as "repair," "replace," or "treat," and further categorized from 1-4. The majority of poles appear to be jointly-owned and should therefore not be UI's sole cost responsibility. OCC again questions the rationale for a budget exceeding $4 million annually for this level of pole replacement, assuming that criticality requires action.

in 2023, with increasing amounts in later years. Id. The Company provided no justification for this increase over the 2021 and 2022 timeframe.

In the Transformer Replacement category, UI averaged $7.2 million per year between 2017 and 2021, but averaged nearly $2 million in 2021 and 2022. OCC-470. The Company now proposes to increase its levels of investment to $5 million to replace transformers in 2023, with continued increases over time. Again, UI provided no explanation for this increase over test year spending.

OCC recommends a reduction from the Company's proposed $29.3 million 2023 budget to $21 million in 2023, to align with the Company's 2022 forecasted spend. OCC-470. Without additional data to support the proposed investment levels in the Infrastructure Replacement project category, and correlate those investments with reliability performance, the Company has not met its burden to demonstrate that it cannot reasonably maintain system performance at or below targeted metrics without incremental investments. This recommended budget should allow the Company to appropriately prioritize safety issues and also address assets based on criticality rankings. If it does not, the Company should provide the Authority with the tools it needs to properly assess the necessity for increased investments.

iii. Substation Rebuilds

The Company's initial filing includes a table proposing Substation Replacement investments for years 2023-2027:

Table CJE-7: Infrastructure Replacement – Substations

Infrastructure Replacement - Substations (*$ in Thousands*)					
	2023	**2024**	**2025**	**2026**	**2027**
Substation Rebuilds	$7,512	$12,258	$9,981	$3,604	$0
Substation Removals	$2,100	$200	$0	$0	$0
Total Infrastructure Replacement Substations	**$9,612**	**$12,458**	**$9,981**	**$3,604**	**$0**

Exh. UI-CJE-1, p. 19. The Company's infrastructure replacement strategy for substations is similar to its distribution replacement program, in that it is intended to replace assets based upon condition before failure.

The Company is targeting three significant substation rebuild projects in this rate filing. First, UI plans to rebuild the Old Town Substation in Bridgeport, installed in 1968. Exh. UI-CJE-1, p. 19. The reliability concerns driving the rebuild include electrical clearance issues in the transmission yard, operational issues with switchgear, and inadequate lightning protection, among other concerns related to the age and condition of the equipment. Exh. UI-CJE-1, pp. 19-20. The new substation will replace and upgrade 115kV to 13.8kV components and include transmission line modifications. Exh. UI-CJE-1, p. 22. The Company notes that "[d]etailed engineering is currently in progress, with construction expected to commence in 2023 and an expected "in-service" date in 2026." Exh. UI-CJE-1, p. 20.

Because the engineering stage of the project is not yet complete, there is insufficient support to show that preliminary estimates are accurate. As discussed above in Section V(e)(i), the Company cannot have a realistic sense of how much a project will actually cost until the project is designed and costs are procured and internally approved. OCC recommends that the Company be ordered to resubmit its proposed investment based on the completion of final engineering for the project. The Company's submission should confirm investment timing, since the work must be coordinated with transmission work, which is another level of project management outside of distribution planning. OCC recommends that approval of future investment be contingent upon this subsequent submittal. As discussed during the hearing, the Company will not require revenue to recover its return of and on this investment until it enters service, which is not projected to occur until 2026. This should provide adequate opportunity for the Company to provide more reliable data to justify the cost.

The second major substation rebuild project proposed by the Company is to replace a 115 kV to 13.8 kV mobile substation originally purchased in 1962. Exh. UI-CJE-1, p. 20. The Company notes that "[t]he purchase of the replacement mobile substation is planned to take place after the completion of the Old Town Substation Rebuild project." Exh. UI-CJE-1, p. 20. Because this investment will not occur until after the Old Town project is complete, and because that project is not expected to be complete until 2025 [OCC-474] or enter service until 2026 [Exh. UI-CJE-1, p. 20], there is no need for the Authority to approve this project in the context of this rate proceeding. Again, the Company will not require revenue to recover its costs until this project enters service.

The third substation rebuild project is to replace the Ansonia Substation transformer. Exh. UI-CJE-1, p. 20. In response to OCC-480, the Company stated that the transformer experienced gassing issues in 2010 and repairs were made on site. In 2020, a dissolved gas analysis test again showed signs of increased gassing levels indicating continued deterioration. It is important to note that despite the Company's concerns stated within its initial filing that the Ansonia Substation "has been experiencing issues leading to high gas levels," and that "the issues have persisted and have reached unacceptable risk thresholds, in terms of potential for explosion," and that the transformer "requires emergency replacement to prevent catastrophic failure," Exh. UI-CJE-1, p. 20, the transformer has already been permanently removed from service and a mobile transformer has been deployed to replace it. OCC-480.

The Company has stated that it *plans* to replace the Ansonia Substation transformer. Exh. UI-CJE-1, p. 20. In one response, the Company estimates a replacement cost of $4.8

million and completion in the second or third quarter of 2024. OCC-480. This information provided by the Company implies that this is a prospective project. However, UI's proposed budget as filed for the Authority's approval includes only $975,000, which is only projected for 2023, with no future spend anticipated. OCC-474. The Company's response to OCC-157 indicated that $1,265,144 was invested in the project during the interim period, with an estimated completion in 2023. The disparity between these responses and testimony renders it impossible for the Authority to determine how the Ansonia Substation transformer replacement project will be funded, as well as the capital timeline. Due to this disparity, OCC recommends that the $975,000 be removed from any 2023 capital budget approval until such time as UI resubmit its proposal with more clarity around funding requirements.

c. Resiliency Projects

The Company's initial filing includes a table proposing System Resiliency investments for years 2023-2027:

Table CJE-8: System Resiliency

System Resiliency (*$ in Thousands*)					
	2023	**2024**	**2025**	**2026**	**2027**
Step Down Bank Removals	$2,301	$3,367	$3,468	$3,572	$3,679
Coastal Substations	$10,900	$7,340	$0	$0	$0
Substation Getaways	$0	$0	$1,800	$0	$0
Other System Resiliency	$4,622	$2,150	$1,570	$3,820	$2,401
Total System Resiliency	**$17,823**	**$12,856**	**$6,838**	**$7,392**	**$6,079**

Exh. UI-CJE-1, p. 26. UI proposes several projects in its resiliency category which are ". . . planned to harden UI's distribution system to mitigate damage inflicted by weather or to shorten the recovery time when damage to the system does occur. The projects in this category focus on reducing the system impacts of major storms." Exh. UI-CJE-1, p. 26.

These projects appear to be in addition to the RE08 Decision Resiliency Plan proposed by the Company in RSR-011 Attachment 2.

i. Step Down Bank Removals

The Company is proposing the removal of 13.8/4.16 kV step down banks and has noted that the ". . . elimination of the step down bank provides two resiliency benefits, one by replacing the remaining aged distribution assets and two by increasing the ability to backup." OCC-487. UI is thus classifying asset replacement projects as resiliency work, purportedly based upon asset condition but only apparently justified by the age of equipment. The Company also cited increased backup capability as its secondary justification, which is a general statement that does not indicate the load or customers that could benefit from such tie capability – which could be marginal. This approach does not recognize that the adjacent feeders may be compromised in a storm, thus adding little value for resiliency. The Company's justification for this work is limited to these few short statements and fails to meet the Authority's basic requirement that resilience programs ". . . must deliver *demonstrable* and *achievable* benefits to ratepayers over time and must help EDCs in their mission to protect public safety." RE08 Decision, p. 58 (emphasis added). Until such time as the Company can provide proper justification and a more robust analysis, including a BCA, OCC recommends that the proposed Step Down Bank Removal investments be excluded from approval in this rate case.

ii. Substation Getaways

The Company has proposed relocating overhead aerial cable feeders to underground at various distribution substations, citing that the purpose is to reduce "customer exposure to multiple feeder outages during major weather events." Exh. UI-CJE-1, p. 28. A more detailed evaluation of the integrity of existing assets revealed that the targeted feeder lines have experienced no known failures in the last approximately 20 years, which should indicate satisfactory asset condition. OCC-490. When questioned on the expected number of avoided outages, assumptions used in the analysis, and for an accompanying BCA, the Company simply referred back to its statement that “this project has been justified as a selective undergrounding project to minimize the exposure to thousands of customers for an outlier weather event.” OCC-491. The Company then attempted to justify the projects by stating “that there could be widespread failures of this type if a storm the intensity of the 1938 hurricane were to strike Connecticut.” OCC-491. However, a major hurricane could affect a significant number of UI’s facilities and the customers they serve, severely disrupting service across the system. UI has not provided an explanation for why the specific proposed portions of the electric system must be underground, to justify a specific benefit beyond the general potential for failure in a historic disaster. Until the Company can provide more specific justification and robust analysis on these specific undergrounding proposals, including a BCA, OCC recommends that the proposed Substation Getaways investments be excluded from approval in this rate case. This recommendation includes associated funding for the UI System Resiliency Cap project under the “Other Resiliency” category. See OCC-628.

i. Other System Resiliency

1. UI System Resiliency Program

These projects are related to the Resiliency Plan put forth by the Company as directed by the RE08 Decision and are addressed in Section V(e)(ii)(2)(c).

2. SIMS Metal Management

The Company stated that the SIMS Metal Management project “has a compound need. It is a customer project to support a significant load increase. To deliver this load increase undergrounding of a portion of the aerial cable run was necessary to avoid pole loading issues." OCC-628.

However, as noted for the other resilience category projects above, UI has not offered additional support to justify the expense associated with this project. In addition to that issue, this is a customer project that has been placed in the resiliency category, apparently solely because a portion of the project will entail underground cables. Finally, this project proposal appears inconsistent with UI's terms and conditions in providing service, in that the customer should bear direct responsibility for incremental costs associated with providing service to the customer. Approving this project would have implications for all customers if the policy is administered differently. Until such time as the Company can provide justification for the overall distribution system resiliency benefits of this project and can provide supported justification for its proposal to socialize the costs necessary to connect an individual customer across an entire rate class, OCC recommends that the SIMS Metal Management investment be excluded from approval in this rate case.

d. Grid Modernization – Distribution Automation

The Company's capital plan testimony also proposes Grid Modernization investments, which are summarized in a table:

Table CJE-11: Modernization

Modernization *($ in Thousands)*					
	2023	**2024**	**2025**	**2026**	**2027**
Electric Vehicle	$967	$1,885	$6,302	$16,044	$12,934
Distribution Automation	$3,836	$4,141	$4,614	$4,870	$5,141
Energy Storage	$0	$0	$1,190	$10,738	$3,683
Other Modernization	$552	$814	$1,735	$534	$0
Total Modernization	**$5,355**	**$6,840**	**$13,841**	**$32,186**	**$21,758**

The majority of these investments are explored in greater detail below in Section V(f) because they were also addressed within the Company's Clean Energy Transformation and Clean Earth Initiative testimonies. However, because the Distribution Automation investment is discussed at length within the Company's capital testimony, we address it within this Section.

i. DA Program Overview

Funding for the DA Program consists of capital for reclosers and required communication and infrastructure. Exh. UI-CJE-1, p. 37. The Company's initial filing provided no supporting documentation for the Program, and it was not until UI submitted a third-party report titled *Benefit-Cost Analysis of AVANGRID's 2023 Distribution Automation Plan for United Illuminating*, which was in response to a late filed exhibit request issued during the evidentiary hearing, that stakeholders and the Authority were provide any opportunity to evaluate the need and cost-effectiveness of the program. See LFE- 35, Attachment 1, filed on March 8, 2023. The study aims to "quantify the benefits associated with the Distribution Automation Program, compare historical blue-sky reliability programs, and recommend paths for future analysis of reliability programs within the UI service territory." LFE-35, Attachment 1, p. 3.

The Program aims to reduce the frequency of outages where feeder SAIFI exceeds a system target of 0.64, and UI suggests that implementation will bring significant benefits. See

LFE-35, Attachment 1, p. 2. The Company has excellent reliability performance, even achieving a system SAIFI of 0.44 in 2022. See TDRP, p. 1. During the hearing, a Company witness commented, ". . . there is financial benefit to society through increasing the electric bill to implement the automation, but deliver the outage savings that result from that. So, it will produce a, it will produce an improvement at the system level. If we bring the worst performing circuits in line with that target, and we do that for the 80 that are above it, then the performance will improve significantly. We had, the analysis that we did, though, was really focused on the financial benefit to society versus the cost of implementation. And it, was there a positive business case or not, and it showed that, in general, there was." Tr. 1071. Based upon its limited opportunity to review the analysis, OCC disagrees with this assertion.

Overall, it is important to point out that UI has saturated its system with reclosers in prior years, with over 400 currently installed. Tr. 3315. The basic function of reclosers is protective coordination, and according to the Company's witness as the hearing, "(c)urrently we have reclosers operating without communications, so they are protective devices that reclose, so if there is a branch that goes on a conductor, it will reclose several times to try to have a temporary outage, instead of a permanent outage, but they operate independently." Tr. 1073. The Company also confirmed that UI's three-phase reclosers ". . . have the capability for communications and remote control, but the communications systems have not been deployed, therefore the reclosers on UI's system operate as protection devices and are not remotely monitored to controlled." OCC-595. The next level of functionality is adding automation which would, as described by the Company's witness, "include the communications and telemetry necessary, and the cybersecurity elements necessary to bring it back to SCADA over, you know, routable communication network, and then protect the, you know, the core control system from any unintended access." Tr. 1073. Therefore, distribution automation is merely the process of adding communication infrastructure to enable automated sectionalizing and restoration schemes. The actual system benefits are provided by the function of the recloser alone; automation merely augments the benefits.

ii. Issues with the BCA Provided in LFE-35

The addition of reclosers, which are existing tools for reliability improvements that are currently incorporated in UI's distribution design criteria, should not be characterized as grid modernization investments. Rather, recloser additions are UI's core business. Justifications for adding a backbone communications network that will support field device visualization and automation – of which reclosers are a subset – should be evaluated within a holistic plan which UI has not produced.

UI has overstated the benefits of DA. Recloser installations are a standard practice that brings base reliability benefits when installed on feeders. Adding communications infrastructure that enables automation brings both incremental costs *and* benefits. The DA BCA identifies incremental costs of $2.18 million for the communications and infrastructure required to integrate the reclosers and related elements LFE-35 Attachment 1, p. 14, n. 1. The study evaluates total avoided outages due to recloser installations in order to measure benefits, but does not differentiate between the benefits achieved with basic recloser capabilities and those brought forth by automation. Hence, the study measures the benefits not of DA, but of reclosers. The incremental benefit of DA should be attributed to faster restoration time as compared to basic recloser protection and sectionalizing capabilities,[18] but this is not analyzed or presented in that

[18] The Company's witness confirmed this during the hearing. See Tr. 3329 *("…if we are going to implement it [the DA plan], there is benefit in putting it [reclosers] in without the communications.")

manner. UI has therefore failed to substantiate the statement that "(a)utomation can improve restoration times on virtually all mainline distribution outages and will reduce restoration costs and avoid interruption costs." LFE-35, Attachment 1, p. 1.

The DA Program relies upon blue-sky metrics to identify targeted feeders, but the provided BCA includes storms, except for Isaias. See LFE-35 Attachment 1, p. 2. It is not clear whether the DA Program is a reliability or resiliency program, which would inform the manner in which circuits are targeted and analysis is performed. At the hearing, the Company's witness stated ". . . at its foundation it is a reliability improvement program that it would have resilience benefits in moderate level events but not in -- I think resilience would lean more toward eliminating the cause of the outage." Tr. 3306. If the program is primarily for reliability, the BCA should be based upon blue-sky conditions. Although UI recognizes the limitations of distribution automation during severe weather events, UI relies on that very data to justify the program.

UI's BCA assumes that historical outages occurring over the last four years will occur at the same location and with the same frequency as future outages, see LFE-35 Attachment 1, p. 4, which appears statistically improbable. UI's assumptions regarding future storms are inconsistent with the methodologies used by the Company in its benefit-cost analysis of resiliency proposals, which establishes various storm scenarios to address uncertainties. RSR-0011 Attachment 2, p. 7. UI should maintain consistency in its methodologies for storm predictions within its resilience analyses.

The DA BCA report completed a BCA for a single year of installations, and UI has not defined the program for future years. Costs for an incomplete program should not be imbedded into rates.

iii. Potentially Duplicative Worst-Performing Circuit Programs

The Program aims to improve performance of worst performing feeders in addition to the Company's other efforts to address poor feeder performance. Tr. 3322. As discussed in Section V(e)(ii)(1), the RE08 Decision established criteria and methodologies for EDCs to identify worst performing feeders, classified as Tier 1 and Tier 2. The Company's effort identified 15 targeted circuits. In addition, the Company has proposed this DA program that relies on an entirely different screening process, and which identified 80 targeted circuits. The distinction between the two screening criteria is that Tier 1 and Tier 2 circuits are identified by applying reliability metric screens and then evaluating the most cost-effective solution to improve reliability, whereas the DA Program assumes that DA is the most cost-effective reliability improvement and seeks to identify candidate circuits where the solution can be applied. The Company has not provided sufficient rationale for the necessity of separate programs. With regard to resolving worst-performing circuits, the DA proposed program would also provide diminishing benefits with rising costs over time. Tr. 3333-3334. The initiatives should be collapsed, and DA should be considered an alternative to address worst performing feeders, rather than the singular solution.

iv. No Lessons Learned from Other Studies Have Been Provided

In its 2022 TDRP, which was filed in response to OCC-467 as Attachment 1, UI referenced a Distribution Automation Pilot Program that was initiated in 2019 with installations occurring in 2020 and 2021. That pilot was supposed to establish communications and control of 15 devices on two circuits to test signal coverage, latency, and bandwidth of the AMI communications system. OCC-467, Attachment 1, p. 26. The Company stated that "(f)ollowing this Pilot Project and in order not to over-burden the AMI network, the Company plans to use different technologies for communication in its large-scale deployment of Distribution Automation. Additional communication methods including private WiMAX broadband, radio, and Cellular are being considered." Id. UI has not provided any lessons learned, data generated, or even a description of the overall outcome of that pilot program in this rate case, in support of its request for a fully funded DA Program.

A system-wide communications study to determine technology feasibility should also be performed, before a DA Program can be implemented. To the OCC's knowledge, UI has not produced such a study and instead proposes to install reclosers and develop communications in parallel. This is an arbitrary approach and does not ensure that device connectivity will occur as proposed, casting doubt on program feasibility and the realization of expected benefits.

v. DA Program Recommendation

In summary, UI has not provided sufficient support to demonstrate that these multiple-million dollar investments are warranted at this time. UI should revisit its study and BCA, taking these comments into consideration. Ideally, a re-evaluation would occur in collaboration with all stakeholders to incorporate additional input. Until such time as the many issues with the DA Program proposal have been resolved, OCC recommends against approval of $3.836 million budget for Distribution Automation reclosers and communication infrastructure. Further, OCC seeks to better understand UI's grid modernization plan, proposed investments that are driven by that plan, and how the investments correlate with, or are required by, external initiatives such as components of Docket 17-12-03, which would be beneficial for all stakeholders in reviewing future requests for funding.

f. Clean Energy Transformation & Clean Earth Initiative

OCC fully recognizes that substantial ratepayer benefits will materialize from a full-scale transition to clean energy. We must transition from our collective reliance upon fossil fuels and other energy sources that are subject to price volatility out of our control and contribute towards the ever-worsening global climate crisis; that harm public health and the environment; and that exacerbate economic and social inequities. OCC also supports taking steps to bring us closer to a future where the widespread deployment of renewable, efficient, and more localized energy sources will substantially reduce the financial burden upon ratepayers. OCC is fully supportive of our state's initiatives to facilitate this transition, including but not limited to the state's electric vehicle, energy storage, and zero carbon generation goals. It is essential, however, that we design and implement the complex path to achieving those goals in the most cost-effective manner and in a collaborative and transparent manner, so that all stakeholder positions are given fair weight and consideration. OCC is concerned that UI's application is an attempt to control this crucial and delicate process in ways that feed the Company's capital bias and create benefits for Avangrid's shareholders, to the detriment of UI ratepayers. Additionally, as noted in OCC's direct testimony, the Clean Energy Transformation portion of the Company's application is problematic because "UI has not provided enough information to adequately assess its proposed cost recovery for clean energy transformation initiatives." OCC Direct (Stanton), p. 4. As discussed below, several of the Company's clean energy proposals would conflict or interfere with the collaborative stakeholder program designs developed or still pending within the Authority's broad grid modernization investigations. Many of the Company's proposals are underdeveloped, unsupported, or simply wholly unplanned. Some proposal elements appear duplicative of other ratepayer-funded initiatives proposed elsewhere in the Application, or already underway as part of the Company's current operations.

As explained below, the Authority should not authorize certain investments and plans proposed in this area of the application, and should instead direct the Company to advocate for its positions in the proper contexts, and with sufficient justification and support to meet its burden of proof. It is important to note that OCC's recommendation is <u>not</u> that these investments be wholly rejected, nor that the Company should not recover the prudently incurred costs of its appropriate clean energy investments. Rather, we suggest that many of these projects should be more thoroughly evaluated within targeted and focused proceedings – many of which are already underway – and that following those evaluations the Authority could design appropriate cost recovery mechanisms. OCC's concerns with these proposals, as outlined below, demonstrate that it is premature to embed their associated costs into base rates, or to alter programs already designed in separate investigations, until the proposals are more thoroughly evaluated.

i. The Application and the Company's Position

Actions taken by both of Connecticut's Electric Distribution Companies ("EDCs") are essential to achieving the State's climate and clean energy goals, including the elimination of greenhouse gas emissions from electric sales by 2040. While Connecticut's EDCs do not own electric generation (with a limited exception for storage resources), they nonetheless play a significant role in meeting the State's emission reduction targets through energy procurement, their participation in new clean energy transition programs, the Renewable Portfolio Standard, and energy efficiency programs. To this end, the Authority's regulation and decisions regarding approval of rate cases must continue to support and amplify the EDCs' role in decarbonization.

In its application, the Company states that one of its primary objectives in serving its customers is to "serve as a catalyst to cost-effectively advance Connecticut's clean energy policy." Application Filing Letter (Sept. 9, 2022), p.1. In its rebuttal testimony, the Company further noted that "[i]n presenting these proposals, the Company is requesting the Authority's approval to move forward with projects that will advance emerging technologies and the State of Connecticut's energy policy." Exh. UI-CETP-REBUTTAL-1, p. 3. As a part of its three-year rate plan, the Company is requesting a total of $48.1 million to support its proposed Clean Energy Transformation initiatives in the following categories: (1) Transportation Electrification; (2) Energy Storage; (3) Innovative Collaborations, Partnerships, and Pilots; and (4) Grid Modernization.

While OCC agrees with the importance of utility engagement in electrification and grid modernization, UI has not provided sufficient information to adequately assess its proposed cost recovery for its Clean Energy Transformation initiatives. OCC recommends that the Authority require EDCs – including UI – to support their program proposals for ratepayer funding with benefit-cost assessments (BCAs), comparative assessments to programs in other jurisdictions, public stakeholder engagement, and specific commitments to metrics and reporting. See OCC Direct (Stanton).

UI acknowledges that its Clean Energy Transformation initiatives do not align with OCC's recommendations, but states that the Company has been engaged in several PURA proceedings on related topics that have informed its proposals:

> *Although many of the Company's proposed clean energy transformation projects have not undergone the scope of stakeholder feedback, detailed BCAs or recommended metrics and measures as envisioned by OCC, the Company has been actively engaged in each of the topical reopeners (e.g., RE03 (energy storage), RE04 (ZEV), and RE05 (Innovation Framework)) and has used the topical discussions, experience, and lessons learned in other jurisdictions and industry research to inform the Company's CETP proposals.*

Exh. UI-CETP-REBUTTAL-1, p. 3. UI's involvement in other related PURA proceedings is not a substitute for providing adequate information in its rate application to demonstrate that its proposed Clean Energy Transformation initiatives are the most cost-effective – or the most beneficial to ratepayers – among programs that could achieve the same greenhouse gas emission reductions and clean energy outcomes.

As discussed below, UI also acknowledges that several of its proposed Clean Energy Transformation initiatives were not introduced in any other PURA proceedings prior to the inclusion of those proposals in this rate case filing, including the medium- and heavy-duty vehicle make-ready program, the municipal curbside charging pilot, and the EV charging hub initiative, among others. In general, the Company disagrees with OCC's recommendations that a BCA and stakeholder engagement process are necessary to make an accurate assessment of whether the funding in the best interest of ratepayers:

> *These are short duration projects intended to occur within the rate term to address a grid or customer need. The general goal of these projects supports the State's climate and energy policies, even though the specific scopes are not developed to a point to create a full BCA.*

Exh. UI-CETP-REBUTTAL-1, pp. 10-11. As noted above, clean energy projects are essential to meet Connecticut's goals. The existence of that imperative, however, does not justify approval of any and all projects proposed in the name of clean energy or emissions reduction. Clean energy measures must be subject to detailed quantitative assessment to determine which programs, structures, incentives, and other key choices will result in the best outcomes together with the lowest costs for ratepayers.

ii. MHD Make-Ready Program

The Company's application includes a proposed Medium and Heavy-Duty Vehicle Make-Ready Program (the "MHD Program"). The Company describes the MHD Program as "similarly structured to the existing Light-Duty EV Make-Ready Program, with customer incentives calculated on a per plug basis, rather than a per site basis, for up to $6,000 towards Level 2-related electrical infrastructure and up to $55,0000 for DCFC-related electrical infrastructure." Exh. UI-CETP-1, p. 11. The MHD Program is envisioned to support "approximately 1,000 MHD vehicles through installation of 400 Level 2 EV ports and 375 DCFC ports" and would "cover up to 100 percent of make-ready costs for public sector fleets". Id. The proposed budget for the MHD Program is $21.6 million, to be capitalized as utility plant, with $4.6 million projected for capital expenses and the remaining $17 million for customer incentives to be deferred as a regulatory asset. Id.

The Authority is currently developing a Medium and Heavy-Duty Electric Vehicle Charging Program via Docket No. 21-09-17. That proceeding is investigating "strategies to optimize the integration of MHD electric vehicles, and transit buses in particular, into the grid, including, but not limited to, potential rate design and infrastructure solutions." Docket No. 21-09-17, Notice of Proceeding (Oct. 4, 2021), p. 1. UI has participated in that docket, having filed Written Comments on May 27, 2022, and July 12, 2022; provided presentations for technical meetings on June 7, 2022 and August 11, 2022; responded to interrogatory requests, see CAE 1-10; and filed a Motion, see Mot. 004. See generally, Docket No. 21-09-17. As of the time of drafting this brief, the docket remains open with no decision yet issued. Despite the Company's articulated concern for the urgency of implementing its MHD Make-Ready Program, Docket No. 21-09-17 was opened on September 16, 2021[19] – over eighteen months ago – and yet the Company agrees that it has not filed its MHD Proposal in that docket. Tr. 2771. The Company has acknowledged that the Authority is already engaged in this proceeding, but explained that it

[19] *See* Docket No. 21-09-17, *PURA Investigation into Medium and Heavy-Duty Electric Vehicle Charging*, Time Schedule (last revised Aug. 26, 2022).

would "continue to engage in Docket No. 21-01-09-17 and ultimately will modify its program design as appropriate to align with any decisions made by the Authority in that proceeding." Exh. UI-CETP-1, p. 12. The Company stated that it included the MHD Program in its rate application as a way to "expedite the process" due to "the urgency of the State's goals." Tr. 2821. Although the State's goals are urgent, it is premature to propose a program asking for ratepayer funding in this proceeding without providing sufficient information to allow for a comprehensive assessment of the program compared to other alternatives that could achieve the same outcome.

None of the assumptions or determinations used by the Company to develop its proposed MHD Program have been tested by BCAs or comparative assessments or vetted by stakeholders, despite the existence of an ongoing docket specifically designed for that very purpose.

iii. Municipal Curbside Charging Pilot

The Company's application includes a proposal for a Municipal Curbside Charging Pilot (the "Curbside Pilot"). The Curbside Pilot would "assist and enable approximately two municipal partners in planning, developing, and installing EV charging infrastructure for residents that are considered 'garage orphans'" and would "support 100 L2 curbside charging ports by leveraging Make-Ready Program incentives." Exh. UI-CETP-3, p. 1. The Company's application claims there will be "No incremental cost [because the] Program will be funded through the existing EV Make-Ready Program". Id. However, the Company is seeking the Authority's approval to make an "adjustment to . . . what's available for incentives on the actual charging infrastructure, and the existing light-duty make-ready program it's eligible for 50 percent of the charging infrastructure on the actual charger itself, and we're requesting to have 100 percent of that cost covered." Tr. 2772. In other words, as the Company acknowledged in the hearing, the Company is seeking an order in this rate case that would adjust the make-ready parameters established in a different docket. Id.

The "existing EV Make-Ready Program" to which the Company refers was developed by the Authority as an element of a broad and lengthy stakeholder engagement process first conceived several years ago within the Authority's Equitable Modern Grid investigation within Docket No. 17-12-03. See Docket No. 17-12-03, *PURA Investigation Into Distribution System Planning of the Electric Distribution Companies*, Interim Decision (Oct. 2, 2019), pp. 14-16. The specific make-ready funding referenced by the Company was developed within Docket No. 17-12-03RE04, P*URA Investigation Into Distribution System Planning of the Electric Distribution Companies – Zero Emission Vehicles* (the "RE04 Docket"), again as the result of a robust and long stakeholder engagement process. See RE04 Docket, Final Decision (July 14, 2021), p. 12. In that proceeding, the Authority analyzed various stakeholder input and substantial external data to develop EVSE deployment targets for the entire state – which were founded upon statewide EV deployment goals – and developed apportionment of deployment targets for specific program parameters for the UI service territory. See Id., pp. 7-11; 18; 22; 28; 31.

The Electric Vehicle Charging Program developed in the RE04 docket is now subject to annual program review dockets, which are also structured around open and collaborative stakeholder engagement. *See* RE04 Docket, Final Decision (July 14, 2021), p. 42. To date, the Authority has completed two such review dockets,[20] and is presently engaged in the annual review of Program Year 3 within Docket No. 23-08-06.

[20] See Docket Nos. 21-08-06; 22-08-06.

The Company has acknowledged that although its Curbside Pilot would be included in the budget set forth in Docket No. 17-12-03RE04 and the subsequent annual review dockets, it has never proposed the Curbside Pilot in any of those dockets. Tr. 2772. The Company acknowledges that the Authority has not approved funding for the Curbside Pilot as part of the light duty make ready program conceived in, and adjusted within, those dockets. Tr. 2811. The Company also acknowledges that it has not yet selected the municipal partners who would engage in its proposed Curbside Pilot. Tr. 2813. The Company acknowledges that it has not consulted with or collaborated with Eversource – the other EDC who provides the programs and services under the currently operational light duty EV program – about its Curbside Pilot. Tr. 2832. The Company has suggested that the Municipal Curbside Pilot could involve utility-pole mounted EVSE, but has stressed that the proposed program wouldn't necessarily require that configuration. Tr. 2833 ("The other option could be mounted on other types of poles, like . . . light poles, there could be the option of having a standalone pedestal, like a typical EV charger that would sit on the side of the road"). When asked whether municipalities currently face some kind of obstacle that would prevent them from installing such EVSE solutions under the EV program already established by the Authority, the Company's witness responded, "if they had the clearance and right-of-way to put a charger in and use the existing program, anybody could do that – a municipality could do that and apply and get funding through the existing program." Tr. 2835.

The Company's Curbside Pilot proposal seeks for the Authority to adjust an incentive structure that was developed in the RE04 docket in consideration of input from multiple stakeholders over a period of years, and created as the result of a process that considered the needs of the entire state. The Curbside Pilot proposal also seeks for the Authority to approve a plan that would prioritize the deployment of the limited number of program-eligible EVSE to particular customers, without consideration of the impact upon other program elements. The Company has made no attempt to raise this notion in any of the dockets specifically designed for adjustments to the very program it seeks to adjust. The Company has provided no BCA or comparative assessment to justify its proposal, and there is no evidence in the record to suggest that municipalities currently face obstacles to install curbside charging equipment under the current light-duty program.

iv. EV Charging Hub

The Company's application includes a proposal for an EV Charging Hub. The project is described as "large scale, purpose-built infrastructure that will serve corridor charging needs for light-duty, medium-duty and heavy-duty EVs." Exh. UI-CETP-1, p. 13. The Company would partner with "one or more third parties" who would own and operate the chargers and driver amenities. Id. The hub would be located "in close proximity to a UI substation and *likely* would include a dedicated feeder to serve future expected load that *could be* as high as 20 MW." Id. (emphasis added). The Company speculated that "*Assuming* an average charger level of 250 kilowatts . . . the hub *could* charge up to 80 vehicles simultaneously" but adds, "[t]he exact number of vehicles served would depend on charger specification and the mixture of vehicle types served." Id. (emphasis added).

The Company proposed that the hub would be implemented in four phases: 1. site identification and evaluation; 2. site acquisition; 3. design and engineering; and 4. construction. Id. The EV Charging Hub would "apply existing make-ready incentives as applicable following the rules established in Docket No. 21-08-06." Id. The Company is proposing a capital budget for the EV Charging Hub of $31.2 million. Id., p. 15. The Company expects that the project will take four years to complete. Id.

To date, none of the four phases identified in the Company's testimony is complete. In fact, it seems that no phase has even begun, because the Company has not yet even identified a partner for the project. Tr. 2777. In fact, the Company has not yet issued an RFI to identify partners, but plans to do so "[w]ithin the next six months." Tr. 2808. The Company has not yet developed criteria for selecting a partner via that RFI process. Id. The Company testified that it would be within the purview of a third party partner, and not the Company, to select the appropriate site for the project. Tr. 2776. The Company immediately went on to testify that the Company, and not a third party partner, is currently evaluating a particular site. Tr. 2776. When asked how the Company will exert authority over the selection of a site, the Company responded, "we haven't defined that yet, whether we will have, you know, sign-off on an approval of the, you know, how sign-off or approval of the site would occur, that hasn't been defined yet." Tr. 2836. When asked whether the plan is for the third party partner to purchase a site that the company already owns, the Company responded, "We haven't planned that out." Tr. 2777. When asked whether the third party vendor would select a site on the basis of its capacity to equitably serve the ratepayers who would fund the project, the Company affirmed that "It is possible that they could make decisions that aren't using equity as their primary criteria." Tr. 2809.

The Company acknowledges that it has not performed a BCA to evaluate the costs and benefits of the proposed EV Charging Hub. Tr. 2767. The Company's cost estimate for the EV Charging Hub project of $31.2 million is "based on the typical costs for other services of that size." Tr. 2778. The Company acknowledged that costs can vary depending upon site location, site condition, and distance from existing infrastructure, noting, "the estimate received had a pretty big range, so there's a lot of variables that can impact the cost." Tr. 2778. The Company witness testified "I believe due to the timing of it that there's no impact on revenue requirements in this case," but acknowledged that the project is included in the portion of the Company's capital forecast labeled as "Modernization." Tr. 2779.

The Company also confirmed that the Charging Hub would be capable of powering up to 80 charging ports, despite the fact that the under the "current per-site limit we would only be able to incentivize a small percentage of those." Tr. 2773-2775. The Company has not proposed how the remainder of the proposed ports would be funded. The Company acknowledged that the EV Charging Hub has not been proposed in any of the Authority's electric vehicle dockets – or any docket at all, for that matter, prior to its filing in this rate case. Tr. 2772-2773.

The Company promises that it will attempt to secure federal funding to offset the ultimate impact upon ratepayers. Exh. UI-CETP-1, p. 15. When asked when the Company intends to apply for such funding, it responded, "It's hopefully in alignment with the release of NEVI discretionary funds. I believe they are anticipating to release those later this year, but they are not yet available." Tr. 2811. When asked if the Company has any sense of the level of federal funding that could be available, the Company responded that it does not. Tr. 2811.

This proposed project is a strong example of the serious issues with UI's capital planning process, as discussed at length in Section V(e)(i). The Company is proposing an idea – with no backing analysis beyond the basic, naked concept – and is seeking the Authority's approval to invest 31.2 million dollars in it. When directly asked to provide "supporting calculations and a narrative explanation for the proposed costs associated with the EV Charging Hub," the Company could only respond, "The EV Charging Hub is currently conceptual," and described its proposed $31.2 million budget as "a conceptual estimate," but promised that it is "currently working to refine these estimates." CAE-14. From the Company's perspective, ratepayers should not be concerned with this request because the project timeline does not anticipate that plant will enter service during its proposed rate plan, and therefore the $31.2 million is not in the revenue requirement in this case. But as discussed in Section V(e)(i), under the Company's proposed capital planning process, this case would be the Authority's only opportunity to evaluate the necessity, reasonableness, prudency, or usefulness of this project before it is already being built. And the Company has provided nothing here upon which the Authority could reasonably base such an evaluation. There is no BCA. There is no comparative assessment. There has been no stakeholder analysis. There is no partner, no site, no investigation of federal funding. The Company's EV Charging Hub proposal is so undeveloped, it does not even rise to the level of being a plan. There is only the vague phantom of an idea, and a multi-million-dollar budget request. Until such time as the Company can meet its burden to provide a plan that the Authority can actually analyze, OCC strongly recommends that the Authority decline to issue any authorization pertaining to the EV Charging Hub. CAE-14.

v. EV Research/Outreach Funding

The Company's Application also includes a bare-bones proposal for "dedicated funding to support studies, analysis, and working group related to EVs to help with program planning, assess future system impacts, and strategize how to integrate this new electrical load most efficiently." Exh. UI-CETP-1, p. 15. The Application speculates that studies will "help the Company analyze and prepare for future electrification," and that such analysis "*may include* gathering data," that working groups "*may include* EV Watts, CALSTART, and Alliance for Transportation Electrification, among others." Id. (emphasis added). The Application promises that the Company will – at some future point – "perform a full evaluation of active working groups and will assess the best combination of group participation in order to gain the most value within the allotted budget." Id. The requested funding would also cover "customer outreach and education," and "an Online EV Fleet Assessment Tool." *Id*., pp. 15-16. The Application includes no further details or plans as to the proposed analysis, working groups, outreach, or Fleet Assessment Tool. The Application proposes an annual budget of $350,000, or $1.05 million over a three-year period for these ideas. Exh. UI-CETP-1, p. 16.

Despite testifying that the location of the EV Charging Hub will be determined by the third-party partner, as discussed above in Section V(f)(iv), the Company also indicated that its proposed three-year EV Study program would impact the siting decision for the EV Charging Hub because "[o]ne of the things that we anticipate could be a topic of study is better understanding of the flow of traffic across corridors and identifying what the long-term charging needs are going to be for, for that traffic." Tr. 2814. However, the Company was unable to answer "what, exactly, related to EV's it would study in the first year." Tr. 2814-2815.

OCC notes that the Connecticut Department of Transportation already engages in rigorous traffic flow studies, which are publicly and readily available on the Department's website.[21] As the Company acknowledged during the hearing, the Department of Transportation is also already engaged in some analysis pertaining to EV charging needs. Tr. 2827. There is nothing in the record to explain why the Department of Transportation's data and analysis are insufficient to meet the Company's needs to understand traffic flow and EV charging demands, and therefore it is unclear whether some or all of the proposed EV Study expense is unnecessary as duplicative of research that has already been publicly funded.

As discussed with regard to the EV Charging Hub in Section V(f)(iv); the Curbside Pilot in Section V(f)(iii); the Storage Pilots in Section V(f)(vii); and elsewhere throughout this brief,

[21]Available at: https://portal.ct.gov/DOT/PP_SysInfo/Traffic-Monitoring/.

the Company has provided absolutely no detailed plan to justify this cost. The Company has not explained why its proposed working group will require incremental cost at all; what activities it intends to pursue in terms of outreach and education, and what costs are associated with such activities; or any further detail related to the EV Fleet Assessment Tool to explain or justify its necessity and reasonableness. The proposed budget of $1.05 million is not even apportioned among these elements – the Authority cannot even discern, for example, how much of the budget would be devoted to working groups as opposed to outreach.

Until such time as the Company can provide the information necessary for the Authority to evaluate the necessity, reasonableness, efficiency, and prudency of the proposed costs associated with EV Research and Outreach, and in keeping with OCC's recommendation against approving the Company's multiyear rate plan, OCC recommends that the Authority's approval of the EV Research/Outreach funding be explicitly limited to a single rate year, and that approval of costs beyond one year be conditioned upon supplemental documentation introduced in the underlying grid modernization dockets demonstrating the need for this additional budget (beyond current budget). OCC respectfully submits that a limitation to one year with a requirement to further substantiate the need in the context of the underlying EV dockets, as well as the PBR docket, allows UI ample resources to "prepare for future electrification" in the short term, but also allows OCC and the Authority to ensure that investments are effective and beneficial such that ratepayers will not incur longer-term unnecessary cost.

vi. Incremental EV FTEs

The Company's application includes a request for three additional full-time equivalent ("FTE") resources "to directly support the proposed MHD Make-Ready Program" as well as one additional FTE "to support ongoing planning and community and stakeholder engagement related to beneficial electrification." Exh. UI-CETP-1, p. 16. The application describes the "community and stakeholder engagement FTE" role as necessary to engage with stakeholders "on matters related to EVs and other beneficial electrification including the Municipal Curbside Charging Pilot," and notes that the role "will perform research to help inform the Company on technology, standards, state and federal policies, and market trends and developments related to EVs." Id., pp. 16-17.

While OCC supports the Company's efforts to understand the opportunities and challenges of EV deployment as related to the grid management, OCC believes the staffing needs should a) be addressed in the underlying EV dockets through which these programs are being finalized to ensure alignment of final program criteria with staffing needs, and b) utilize unfilled vacancy positions before adding incremental FTE costs. For example, as discussed above in Section V(f)(ii), the proposed MHD Make-Ready Program should not be authorized as part of this proceeding, and should instead be discussed in Docket No. 21-09-17. Until the Authority finalizes the development of the statewide MHD program in that proceeding, the Company cannot, and does not know the scope of incremental employees that will be necessary to staff the program. Ratepayers should not be expected to begin paying costs associated with three FTEs whose job functions have not yet been established or authorized. Therefore, the issue of staffing needs for the MHD program should be discussed and established within Docket No. 21-09-17, and the Company's request for three additional FTEs should not be approved in this case.

As discussed in Section V(f)(v), the company's proposal for outreach and research with regard to vehicle electrification does not provide sufficient information for the Authority to fully evaluate its scope or associated cost. The extent to which the proposed "community and stakeholder engagement FTE" will perform work associated with that proposed outreach or research described within that proposed budget is unclear. The application also notes that the proposed FTE will engage in outreach relating to the Municipal Curbside Pilot, but as discussed above in Section V(f)(iii), the proposed Curbside Pilot is also insufficiently supported by the Company's application and should not be authorized in this case.

It may be the case that the Company could make good use of incremental staffing to assist it with managing EV and other emerging technologies, but the Company also has unfilled positions that could be utilized to absorb the cost of the proposed "community and stakeholder engagement FTE." OCC recommends that the Company utilize existing vacancies to fill any immediate needs and raise additional staffing proposals to support grid modernization initiatives within the appropriate grid modernization dockets, and that the Company provide more detailed support with such proposals. OCC recommends that the Authority at most authorize one additional FTE for "community and stakeholder engagement" until these concerns are addressed.

vii. Storage Pilots

The Company's application includes proposals for three Battery Energy Storage System ("BESS") pilots – with proposed locations in Bridgeport; New Haven; and North Haven (the "BESS Projects") – and one solar-plus-BESS pilot – which is proposed to be located on Pleasure Beach Island in Bridgeport. Exh. UI-CETP-1, pp. 18-26 (the "PBI Project"). The proposed budget for the three BESS Projects is $15.61 million. Exh. UI-CETP-4, p. 5. The Company proposes to recover the costs of the BESS Projects in base rates. Exh. UI-CETP-1, p. 22. The proposed budget for the PBI Project is $1.052 million in capital expenditures, with $19,500 in O&M expense. Exh. UI-CETP-5, p. 1. The Company is proposing that it would own all three BESS Projects, as well as the BESS portion of the PBI Project. Exh. UI-CETP-1, pp. 21; 25.

1. **BESS Projects**

ii. Public Act 22-55 and Docket No. 22-06-05

On May 23, 2022, Governor Lamont signed Public Act 22-55, An Act Concerning Energy Storage Systems and Electric Distribution System Reliability – the relevant portion of which is now codified as Conn. Gen. Stat. § 16-244cc. The statute mandates that the Authority "direct each electric distribution company . . . to submit on or before January 1, 2023, no more than three proposals to the authority for a pilot program to build, own and operate energy storage systems." Conn. Gen. Stat. § 16-244cc(a). On June 8, 2022, the Authority issued a Notice of Proceeding in Docket No. 22-06-05, PURA Implementation of Public Act 22-55, which directly referenced the above statutory language and announced that Docket 22-06-05 was opened "specifically to: (1) develop requirements and other guidance by which the EDCs will develop proposals; (2) direct the EDCs to file proposals according to the Authority-developed requirements; and (3) review the proposals in accordance with P.A. 22-55." Docket No. 22-06-05, Notice of Proceeding (June 22, 2022), p. 1. One day later, the Authority issued within that docket a Notice of Request for Written Comments, which sought feedback from all stakeholders and participants as to the appropriate requirements for the EDCs' storage proposals, as well as recommendations for rules and policies for: measuring reasonableness and prudency, and a variety of other important topics. See Docket No. 22-06-05, Notice of Request for Written Comments (Jun. 9, 2022).

Following its receipt of comments responding to that notice from multiple stakeholders – including UI – the Authority issued a Proposed Decision in Docket 22-06-05 on September 6, 2022, and invited all docket participants to file written exceptions for the Authority's consideration. The Proposed Decision included detailed specifications for the EDCs' proposal requirements, and noted that "[o]nce the Authority receives proposal submissions, PURA will evaluate them for their adherence and consistency with the eligibility requirements described in Public Act 22-55 and herein." Docket 22-06-05, Proposed Decision (Sept. 6, 2022), p. 14. The Proposed Decision also provided all participants with notice that PURA would order the EDCs to submit proposals "no more than three proposals for ESSs that satisfy and comply with the requirements and framework outlined herein", by January 1, 2023, via "a motion for Authority review and approval". Id., p. 15. UI filed Written Exceptions to the Proposed Decision on September 12, 2022, which sought clarity as to the timing, form, and expectations of the Authority's project approval process, but which did not advocate that its BESS projects should be evaluated in this rate case, as opposed to within Docket 22-06-05. See Docket No. 22-06-05, Written Exceptions of the United Illuminating Company (Sept. 12, 2022).

The Authority issued an Interim Decision in Docket 22-06-05 on September 14, 2022, which included notice that:

> *The Authority will issue a tentative procedural schedule for the remainder of this docket after receipt of the EDCs' proposals. At this time, the Authority anticipates holding at least one Technical Meeting and requesting one set of written comments from stakeholders with a Final Decision issued sometime in calendar year 2024. The Authority will include in any Final Decision project cost caps and other cost containment measures to protect ratepayers, as necessary and appropriate.*

Docket No. 22-06-05, Interim Decision (Sept. 14, 2022), p. 15. UI submitted a motion in that docket on December 23, 2022, which sought the Authority's consideration of three pilot BESS projects located in Bridgeport; New Haven; and North Haven. See Docket No. 22-06-05, Mot. 003. The filing made no mention of the fact that UI had submitted the same three projects for approval in this rate case. The Procedural Schedule in Docket No. 22-06-05 currently anticipates that Technical Meetings will be held on April 25, 2023 and June 15, 2023; that Briefs will be due on July 6, 2023; that a Draft Decision will be distributed on September 6, 2023; that Written

Exceptions will be due on September 20, 2023; and that the Authority will issue a Final Decision on October 4, 2023. Docket No. 22-06-05, Time Schedule (last revised March 10, 2023).

b. The Company's BESS Projects Proposal in this Rate Case is Incompatible with the Proceedings Underway in Docket No. 22-06-05.

During the evidentiary hearing, the Company's witness acknowledged that the Interim Decision in Docket 22-06-05 ordered the Company to file BCAs pertaining to the proposed BESS projects in that docket, and that it is the Company's expectation that because "that was filed as part of that docket . . . it would be evaluated as part of that docket." Tr. 2766. The Company further acknowledged that Docket No. 22-06-06's Interim Decision notes that there will be continued stakeholder engagement in that docket, with a final decision potentially slated for 2024, and that the current schedule for that docket anticipates that two technical meetings will be held at future dates, as well as the filing of briefs. Tr. 2766.

The Final Decision in Docket No. 22-06-05 includes specific requirements for the form and content of the Company's BESS proposals, and the Authority developed those requirements with consideration of input from multiple stakeholders. The BESS Projects proposed in the Company's application in this proceeding do not adhere to those requirements.

As noted in Section V(f)(ii) above with regard to the MHD Make-Ready Proposal, the Authority has already opened a docket for specifically for stakeholders to collaboratively investigate and establish the most appropriate standards, specific costs, and goals for the very approval the Company is seeking in this rate case. Approval of these projects within this case would disrupt the process already underway in Docket No. 22-06-05.

c. OCC's BESS Projects Recommendation

OCC recommends that the project proposals already provided in Docket No. 22-06-05 be evaluated within that docket, in accordance with the carefully considered and specifically designed process the Authority has developed therein. Upon any approval for the projects under Docket No. 22-06-05, the Authority could design appropriate recovery avenues – such as an annual reconciling mechanism within the Company's RAM framework, or through a regulatory asset – thus OCC is not suggesting recovery is never appropriate, just that given the underlying docket it is premature to bake these costs into rates at this time.

2. PBI Project

iii. The Authority Provided Guidance as to How the Company Should Seek Approval for the PBI Project in Docket No. 10-10-12.

On October 28, 2020, the Company filed a Motion to Reopen in Docket No. 10-10-12, *Petition Filed by Cumulus Media, Inc. For an Investigation Pursuant to § 16-20 of the General Statutes of Connecticut,* which sought that the docket be reopened to consider a proposal "to construct an alternative delivery system consisting of an energy storage system, together with an off-grid photovoltaic solar system . . . on [Pleasure Beach Island] in order to provide safe, adequate, and reliable service to customers on the island." Docket No. 10-10-12, Mot. No. 14 (Oct. 28, 2020). On February 26, 2021, the Authority issued a request for all stakeholders to comment on UI's motion, and specifically to address the applicability of Conn. Gen. Stat. § 16-244e(a) to the Company's request, as well as "[w]hether the proposed facility could be developed under a special contract pursuant to Conn. Gen. Stat. § 16-19hh". Docket No. 10-10-12, Notice of Request for Written Comments (Feb. 26, 2021). UI filed responsive comments on April 1, 2021, taking the positions that: (1) Conn. Gen. Stat § 16-244e(a) would not prohibit the company from owning a solar-BESS asset and (2) that Conn. Gen. Stat. § 16-19hh would not prevent the proposed project from being developed under a special contract. Docket No. 10-10-12, UI's Written Comments (Apr. 1, 2021). The Authority issued a Notice of Request for Briefs on April 28, 2021, that sought stakeholder feedback and analysis of the issues of: (1) whether UI's proposal would entail the prohibited ownership by an EDC of a generation asset; (2) if so, whether a "lease, joint ownership agreement, partnership, or any other contractual agreement between UI and another party would affect, mitigate, or nullify" that issue. Docket 10-10-12, Notice of Request for Briefs (Apr. 28, 2021). Briefs responsive to the Authority's request were filed by Cumulus Media, Inc. (one of the PBI customers); the Authority's Office of Education, Outreach and Enforcement ("EOE"); UI; and OCC, and all stakeholders provided different perspectives on the issues.

On July 12, 2021, the Authority issued its ruling denying the Company's Motion without prejudice. Docket 10-10-12, Mot. No. 14 Ruling (July 12, 2021). The Ruling noted that although UI's motion to reopen was "not the appropriate procedural mechanism . . . [t]o the extent UI requires a determination as to the applicability of a general statute, a regulation, or final decision to UI's specific circumstance, UI should file a request for a declaratory ruling pursuant to Conn. Gen. Stat. § 4-176" and that "[s]uch petition should address the briefing topics articulated in the Authority's April 28, 2021 Request for Briefs in the instant docket." Id.

The Ruling directed that any future request for approval of the PBI Project should "present an 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." Id. The Ruling also specified:

> *UI may submit such rate structure proposal (Proposal) together with a future declaratory ruling or as a separate filing submitted for the Authority's review and approval after any necessary declaratory rulings are issued. Such Proposal 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 Proposal shall include a timeline of*

> *requested approvals, the statutory or regulatory basis for any such approvals, and a proposed set of parameters for any joint ownership agreements, partnerships or other contractual agreements that the Company may seek 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, as well as lessons-learned in operating a non-wires alternative.*

Id.

iv. The Company's PBI Project Application Does Not Align With the Authority's Guidance.

Indeed, the Company's application noted that the Authority's Ruling in Docket 10-10-12 "provided further guidance for a future submittal of the solar-plus-BESS project," and claimed that the PBI Project proposal in its application is "consistent with the Authority's ruling." Exh. UI-CETP-1, p. 24.

However, the Company offered testimony at the hearing that it is unaware of whether it ever filed a petition for a declaratory ruling prior to submitting its Pleasure Beach Island proposal in this rate case. Tr. 2783. Despite the above-cited requirements in the Authority's Ruling, the Company agreed during the hearing that its PBI Project proposal in this rate case does not include minimum annual payment terms; nor a timeline of approvals; nor a statutory and regulatory basis for approvals; nor a proposed set of parameters for joint ownership agreements. Tr. 2787-2788.

The Company's proposal includes an analysis indicating that if the full cost of the project were allocated between the two customers on the island in accordance with standard cost causation principles, each customer would pay more than $5 per kwh. Tr. 2788. However, the only alternative to this scenario offered by the Company is to socialize the entire project cost through base rates. Tr. 2788. The Company has apparently not analyzed, or even formally considered, seeking a contribution in aid of construction from the two customers. Tr. 2818. When asked why that option has not been explored, the Company's witness responded, "I am not sure. I haven't really thought through the recovery, that portion of the cost." Tr. 2818. The Company was asked to provide a late-filed exhibit that would "comment on whether a CIAC is applicable to the current proposal in the application for Pleasure Beach Island or replacing the cable." Tr. 2820. The resulting late-filed exhibit merely states, "The Company anticipates that CIAC would not be applicable to either customer on Pleasure Beach Island," and fails to offer any basis for that anticipation. LFE-128.

The Company has proposed that a third party would "design, construct, own and operate the solar PV system." Exh. UI-CETP-1, p. 25. However, as referenced by the Authority's April 28, 2021 Request for Briefs in Docket 10-10-12, the issue of "whether a lease, joint ownership agreement, partnership, or any other contractual agreement between UI and another party would affect, mitigate, or nullify the prohibition on an EDC's ownership of generation assets pursuant to Conn. Gen. Stat. § 16-244e" remains unresolved.

In sum, the Company has already received specific instructions from the Authority for how to seek approval of this very project, and has chosen to disregard those instructions.

v. The PBI Project Remains Insufficiently Planned.

Not only has the Company failed to adhere to the Authority's guidance for seeking approval of the PBI Project – it has also failed to develop a logical plan for the project, despite having first proposed it over two years ago. When asked what the relevant criteria for system sizing would be for both the solar and storage components of the PBI Project, noting that the system size proposed in the application is approximate and still needs to be finalized, the Company responded "[W]hat we did with those two projects is we actually spoke to a few third-party developers, you know, unofficially. Kind of, you know, hey. We're looking at these projects. What do you think for size-wise? We were given two sizes that were relatively similar. Then we did on our analysis and kind of compared what they gave us to what we thought it would be. And – and that's -- that's how we came down with that size of the system." Tr. 2699. The Company added, "Moving forward, if approved, we'll do a much more detailed analysis of sizing for both batteries and the PV system." Tr. 2700. The Company approached the Authority with a proposal to build this project as early as October 28, 2020, and to date has yet to perform a more detailed sizing analysis than the process to which it testified. See Docket No. 10-10-12, Mot. 14.

The Company also testified that the proposed operation and maintenance expense is based on "the trailing O&M for the capital cost," and is "kind of a placeholder." Tr. 2789. The actual O&M cost will be determined by "the contract that we enter into for supplying the power." Tr. 2789. The Company has not even yet determined whose responsibility the maintenance of the solar portion of the system would be. Tr. 2790.

vi. OCC's PBI Project Recommendation

In light of the concerns articulated above, OCC recommends that the Company file a petition for approval of the PBI Project in accordance with the Authority's clear instructions as issued in its Ruling as to Motion No. 14 in Docket No. 10-10-12. OCC recommends that such petition include an adequate analysis of necessary system size; a comparative analysis of all available cost recovery and cost allocation options; and adequate documentation to demonstrate the Company's cost estimates. Although we recognize that there are many reasons why a solar-plus-storage project could be an excellent solution for the specific issue of ensuring that the customers on Pleasure Beach Island continue to receive sufficient and reliable electrical service, OCC cannot recommend that the Authority authorize the PBI Project until such time as the Company has submitted a petition and documentation for the Authority's review.

viii. Expanded EPRI Membership

The Company's application includes a proposal to expand the Company's membership to the Electric Power Research Institute ("EPRI") "to facilitate research and industry collaboration around clean energy. The Company recommends an expansion of its membership to include program sets related to Energy Storage and Distributed Generation, DER Integration, Electric Transportation, and Electrification." Exh. UI-CETP-1, p. 31.

The Company appears to have provided conflicting information as to the proposed cost of this expanded membership. In its response to OCC-246, the Company indicated that its "Total Funding Request" is $565,900 over four years, with $135,300 requested for 2023; $139,300 requested for 2024; $143,500 requested for 2025; and $147,800 requested for 2026. OCC-246, Attachment 3. In its response to OCC-387, the Company provided the annual dues paid to EPRI from 2017 through 2022, with average annual dues in that timeframe amounting to $310,269.[22] Based upon these two interrogatory responses, one can only logically conclude that the "total funding request" amounts provided in response to OCC-246 represent only the proposed incremental expenses – rather than the total requested expense for EPRI dues – because on an annual basis they are only approximately slightly half of the current annual expense. However, during the hearing, the Company testified that it is proposing to increase its membership expense by "a little over $36,000" on an annual basis. Tr. 2805.

The C-Schedule provided in the Company's application also conflicts with its testimony and interrogatory response. Schedule C-3.03 includes an adjusted test year total of 285,000,

[22] Sum of $1,861,616 / 6.

increasing in Rate Year 1 to $302,000 (a $17,000 increase), and then increasing by only $1,000 in Rate Year 2, with no increase at all indicated for Rate Year 3. Sch. WP C-3.03.

The information offered in response to OCC-246; OCC-387; the information proposed in the Revenue Requirements schedules, and the testimony offered at the hearing are inconsistent. The interrogatory responses suggest that the Company is seeking annual incremental expenses of approximately $140,000; the testimony claimed the proposed increase is $36,000; and the Standard Filing Requirements schedule seems to show only $17,000 in Year 1 (and an annualized average increase of only $6,000[23]). It is not possible for OCC to determine exactly how much the Company is seeking to recover for this expense, or what percentage of what is sought is incremental to the amount already in base rates.

The Company's justification for expanding its membership is also confusing. As noted above, the Company's application explained that the expanded membership would "include program sets related to Energy Storage and Distributed Generation, DER Integration, Electric Transportation, and Electrification." Exh. UI-CETP-1, p. 31. However, during the hearing the Company's witness testified that the Company is actually already "in two of those programs sets, but we are looking to expand two additional ones and expand one that we are already in." Tr. 2806. Again, the information in the Company's Application appears incongruent with the information provided during the hearing. The Application indicates that the purpose of the incremental expense is to expand the Company's membership as to four program sets, but the Company's witness testified that the expense would include a total of three program sets.

The Company witness explained the value of the expanded membership would be to assist the Company "to understand some electro technologies that are being developed, you

[23] Total incremental increase of $18,000 across 3 rate years shown in Sch. WP C-3.03 (Yr 1 - $17,000; Yr 2 - $1,000; Yr 3 - $0) / 3.

know, that potentially could be an offering to some of our customers," and "on the electric transportation side, understanding the industry as a whole, whether it be the charger infrastructure development, of the electric vehicle industry, you know, class of vehicles that are being offered . . . ." Tr. 2806-2807.

OCC recognizes the value to the Company of improving its own understanding of emerging technologies, and we also recognize that some of that understanding can ultimately benefit ratepayers. However, the Company is seeking to increase its current EPRI membership by an amount that is frankly unclear – due to the confusing discrepancies between its Application, Interrogatory Response, and live testimony – and its initial application attempted to explain the necessity of this expense via a single sentence that merely identifies which "program sets" the Company would like to engage with. There is simply insufficient foundation in the record to justify the necessity, or direct distribution ratepayer benefit, of any increase to the Company's current EPRI membership dues.

OCC recommends that until such time as the Company can provide clear and simple explanations for exactly what program sets it seeks to expand; the incremental benefits that will accrue from such expansion; the costs associated with such expansion; and the degree to which those costs differ from costs already in base rates, the Authority should not approve the Company's request

ix. Clean Earth Initiative

The Company's application includes a proposal for funding to establish the "Co-Laboratory of Environmental Action, Net-zero-carbon And Renewable Technologies, to be known as the CLEAN EARTH Lab, for the purpose of facilitating essential research and development that will support and accelerate the achievement of the State's clean energy strategy, while improving UI's ability to continue to operate a safe, reliable, resilient and increasingly decarbonized power grid for its customers and communities." Exh. UI-JR-1, p. i. The Company seeks a total of $1.125 million in research funding across its proposed rate years, as well as an incremental FTE for an additional $110,000. Exh. UI-JR-1, pp. 13-14.

1. The Company Has Not Met Its Burden to Prove that the Clean Earth Initiative Investment Will Derive Corresponding Ratepayer Benefits

When asked for the timeframe under which the Company expects ratepayers to begin receiving the benefits of tools developed by the Clean Earth Lab, the Company witness responded "I guess the answer is I -- I don't know. And in terms of have we attempted to quantify [the benefits], it would really depend on what projects are selected at what time, the timeframe for those projects, the nature of those projects, and – and then the success of those projects." Tr. 2668. The witness continued by acknowledging that there may be no direct or tangible value to customers at all, and that the value may only accrue to the company itself. "[A]t this level of research there is a chance that the research performed gives us insight through learning something that does not have a direct, like, tangible value to customers, but has -- has a value for our institutional knowledge around a technology or a subject." Tr. 2668-2669. Although the Company takes the position that the Clean Earth Lab investment will "allow the company to avoid certain investments or expenditures altogether", OCC-259, when asked for details about which "certain investments or expenditures" will be avoided, the Company responded, "it's useful to say that no specific projects have been identified yet for this Clean Earth Lab as it's still a proposal. And there's a process to identify those projects that hasn't yet been conducted." Tr. 2648. When asked further questions about which particular investments or expenditures would be avoided, the Company responded, "the formal process of identifying or even calling for proposals for this research has -- has not yet been conducted." Tr. 2650.

The Company's proposal notes that the Clean Earth Lab's work would cover climate change impact, including outage and flooding forecasts. See UI-JR-1, p. 11. When asked whether this benefit would overlap with the Company's proposed investment in the UConn modeling program through the Eversource Energy Center as recommended by the Company's Storm Preparedness Panel, which OCC notes that it has not objected to, the Company clarified that "there's no current proposal for flooding prediction for Clean Earth, so there's no dollars earmarked in this proposal that would be referenced as incremental funding for flooding, flooding research that comes from Clean Earth." Tr. 2792. From OCC's perspective, this testimony conflicts with the justifications offered within the Company's prefiled testimony to support the Company's proposed investment in the Clean Earth Initiative, which includes a subsection entitled "Outage and Flooding Forecasting," and describes the proposed investment as necessary to "Develop and support operational models for weather outage and substation flooding forecasting across the United Illuminating service territory." Exh. UI-JR-1, p. 11. Moreover, the Company has offered no demonstration of the incremental benefits that would accrue from flooding forecasts as compared to what will be achieved via the UConn modeling budget proposed by the Storm Preparedness panel. UI has already invested $1,398,565 in ratepayer funds into the Eversource Energy Center's damage prediction model, which is $102,708 less than what was proposed in the project charter. CAE-55; CAE-55, Attachment 3; Tr. 2672-2673. The Company was unable to offer any information regarding the savings to ratepayers or improvement to operations resulting from this investment, aside from noting, "[J]ust in a general sense, I think the idea was to avoid a substation from flooding. And so when quantifying, like, benefits of something you avoid, I would just think of it in terms of that. Yeah. So how much would it cost if the substation flooded? I don't know." Tr. 2676.

2. The Clean Earth Initiative Proposal Would Derive Benefits to Areas Beyond UI's Distribution System, Despite Being Funded by UI Distribution Rates

The Company's prefiled testimony notes that the Clean Earth Initiative will "digitize and enhance tools and process for Transmission and Distribution Planning," including how DER and IBRs will impact "bulk transmission system dynamics." Exh. UI-JR-1, p. 11. The Company acknowledged that the benefits of the Clean Earth Initiative investment will ultimately include improving UI's ability to assess the system from both a transmission and distribution perspective, but when asked whether any portion of the Clean Earth Initiative costs would be allocated to Transmission, the Company responded that they would not. Tr. 2793. Distribution rates should not include funding for Transmission improvements.

The Company's prefiled testimony also notes that the Clean Earth Initiative will investigate "clean hydrogen & offshore wind power integrations including but not limited to: lower-cost *production of hydrogen* from regional offshore wind power." Exh. UI-JR-1, p. 12 (emphasis added). When asked about the connection between this research and UI's distribution system – which does not produce hydrogen – the Company responded, "in terms of the research and how it would affect distribution rates, I think it, that, itself, is a potentially good question to ask from a research standpoint." Tr. 2803. OCC does not disagree that these are important and worthwhile questions, and we support the Company's decision to begin to consider these important issues, but we are left wondering why exactly research that will improve Avangrid's green energy production initiatives should be funded by United Illuminating's distribution ratepayers, as opposed to a more appropriate source of capital, including shareholder contributions.

3. The Division Between the Eversource Energy Center and the Clean Earth Initiative is Unclear.

As acknowledged in the Company's testimony, "In 2015, PURA supported the establishment of the Eversource Energy Center at the University of Connecticut." Exh. UI-JR-1, p. 8. The Company proposes that the Clean Earth Initiative would "collaborate with the Eversource Energy Center." Exh. UI-JR-1, p. 10. During the hearing, Company witnesses testified that UI already interacts with the Eversource Energy Center. Tr. 2042 (". . . because of our past relationship, I can call them and basically ask a favor."); Tr. 2045 ("Sometimes they will do a special run of the UI model"). In fact, the Company's application is seeking $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. See Exh. UI-EPP-1, pp. 26-27; Tr. 2045 ("By virtue of using the Eversource Energy Center I think we are . . . leveraging the UConn resources that are engaged in this . . . research and are . . . basically paying our way to have our system evaluated."). OCC does not object to this $150,000 incremental investment. It strikes us as reasonable for the Company to invest in synergy with resources that are already available, and which the Company has already found valuable in providing service to its ratepayers, as opposed to a much larger investment that might unnecessarily duplicate the same resources. When asked for an example of work currently being performed by the Eversource Energy Center that would not be relevant to UI, or work to be performed by the Clean Earth Initiative that would not be relevant to Eversource, the Company's witness was unable to articulate any example. Tr. 2862-2863. To the extent that there is a clear distinction between the resources: (1) already available to UI via the Eversource Energy Center, or prospectively available via the company's proposed incremental $150,000 annual investment in Weather

Modeling; and (2) the proposed $1.125 million investment in the Clean Earth Initiative, the boundaries are impossible to identify.

4. OCC's Recommendation for the Clean Earth Initiative

OCC recommends that until such time as the Company can provide precise information as to what exactly will be researched by the Clean Earth Initiative; some indication of the benefits to UI's distribution ratepayers that will arise from such research; and the distinction between other proposed investments that appear to directly overlap with this proposal, the Authority should not approve the request for ratepayer funding for the Clean Earth Initiative. As discussed below, in the meantime OCC encourages UI to fund the Clean Earth Initiative with funding from its parent company's shareholders.

x. ESG Goals

1. The Company's Application Seeks Ratepayer Funding for Initiatives That Will Contribute to Avangrid's ESG Goals.

The record demonstrates that some of the clean energy proposals in the Company's application would support the Environmental, Social, and Governance ("ESG") goals set by Avangrid. *See* OCC-572. Specifically, the Company noted that the three BESS Projects would contribute to Avangrid's Storage Capacity Goal; and that the "number of EV charging plugs supported by incentives through the EV Make-Ready programs" contributes towards Avangrid's Network EV Charging Points Goal. *Id*. The Company reported that UI's contributions to storage capacity and eligible EV plugs would both be reported in Avangrid's annual Sustainability Report. *Id*.

During the hearing, the Company's witness also acknowledged that its proposed investment in the Clean Earth Lab aligns with Avangrid's ESG goals. Tr. 2663. The Company's proposed executive compensation plan will include incentives tied to ESG goals, and hence, ratepayers' contributions towards executive compensation will be used to drive UI towards meeting Avangrid's ESG targets. See OCC-571 Attachment 2, p. 49.

2. Avangrid's Shareholders Benefit From Positive ESG Performance.

OCC's witness testified that "Studies indicate correlations between a company's positive ESG performance and benefits to its shareholders," noting that "stock price volatility of companies with good ESG performance is lower than that of companies with poor performance," and that a study from NYU showed that "[t]he majority of companies studied indicate a positive correlation between ESG metrics and financial performance." OCC Direct (Stanton) p. 15, n. 46.

During the hearing, the Company's witness acknowledged that ESG "is aligned with our business model and has reputational benefit." Tr. 2849.

Avangrid is also able to improve its access to capital by maintaining positive ESG metrics. Avangrid's revolving line of credit includes an emissions intensity performance target. OCC-574. Iberdrola, Avangrid and UI have also issued green bonds, and although the Company was unable to provide "statistical evidence of a price advantage to the issuer as a result of green labeling," it acknowledged that "the green label has driven additional bids for the bonds," and that "there is some emerging evidence in the secondary market that green bonds trade at a premium." Id.

3. Shareholders Should Contribute to the Costs That Generate These Benefits.

During the hearing, the Company's witness panel was asked about whether UI's corporate parents ever contribute shareholder funds for research and development activities, and a Company witness testified that the SMART Grids innovation team at the corporate parent level is "devoted to promoting innovations," and collaborates with members of the Company's Clean Energy Transition witness panel. Tr. 2853-2854. When asked what percentage of Avangrid's budget is devoted to this area of research and development, in order for the Authority to compare Avangrid's shareholder funding towards ESG goals with the ratepayer-funded budgeting at the UI level, the Company declined to provide the information. Tr. 2856-2857.

As noted above, OCC wholeheartedly agrees that clean energy and climate resiliency initiatives do generate benefits for ratepayers – both in the form of immediate and long-term improvements to the environment, and consumer health and safety, as well as in their potential to ultimately reduce our dependence upon volatile and expensive global fossil fuel market forces and the related costly large-scale infrastructure investments necessary to distribute imported energy throughout our state. Although OCC has highlighted many concerns with the Company's clean energy proposals as presented in this case, we seek to emphasize that we do not question the overall value of EVs, storage, solar, or other clean energy transition technologies, and it makes sense that ratepayers should contribute towards the costs required to transition to a greener and more equitable grid. But shareholders should also contribute towards these costs from which they derive benefits.

xi. Overall Clean Energy Transformation Recommendations

As discussed above, OCC has strong concerns with the Authority issuing approvals for these projects absent further analysis. However, we seek to emphasize that our recommendation is not that these proposals be rejected outright, nor that the Company should not recover the prudently incurred costs of its appropriate clean energy investments. Rather, we suggest that upon final project approval within the correct docket, the Authority could design appropriate recovery avenues – such as an annual reconciling mechanism within the Company's RAM framework, or through a regulatory asset. Again, OCC's concern with these proposals is that it is premature to bake these costs into rates at this time.

We therefore recommend that the Authority require the Company to demonstrate and explain the benefits of these projects via the following categories of documentation and processes.

1. BCAs

OCC recommends that PURA require EDCs – including UI - to conduct and submit BCAs alongside program proposals for ratepayer funding, such as UI's proposed Clean Energy Transformation initiatives. BCAs would allow for a comprehensive assessment to determine which proposed programs are the most cost-effective or the most beneficial to ratepayers among alternative programs that meet the same goals.

The Company asserts that it is seeking approval (or, in UI's phrasing, "some interest from stakeholders and the Authority") of its proposed initiatives from PURA before conducting BCAs. See Tr. 2760 (". . . if UI saw that there was some interest from stakeholders and the Authority to move forward with those concepts, then yes, we would go ahead and put together the BCA analysis and that will be productive use of our resources."). If this practice were adopted, it would permit cost recovery via inclusion in rate base without a comprehensive assessment of the cost-effectiveness of each initiative.

The Company noted that "the State of Connecticut is still in the process of establishing formal BCA approaches for many of these types of initiatives" and, in the meantime, it would like to first obtain PURA's approval of its proposed "project concepts, after which UI would perform more detailed BCA to submit to the Authority as compliance prior to moving forward with execution and implementation." Exh. UI-CETP-REBUTTAL-1, p. 3-4. The Company's desire to run proposed project concepts by PURA prior to conducting detailed BCAs should not, however, be conflated with its seeking permission to charge ratepayers for projects that are still in the "concept" stage and have not undergone comprehensive assessments to determine their cost-effectiveness. UI appears to claim that its request to include its Clean Energy Transformation initiatives in rates can be interpreted instead as permission to spend resources on further assessment:

> *For some of the proposed pilots, a comprehensive BCA would require detailed engineering analysis with requests for proposals for firm pricing, which would take a considerable amount of time and resources to develop. The Company would undertake this work only after the Authority approves the proposed pilot concepts.*

Exh. UI-CETP-REBUTTAL-1, p. 4. OCC recommends that if UI seeks ratepayer funding to perform BCAs, the appropriate approach should be for the rate application to request funding for incremental costs for conducting BCA's, prior to seeking authorization to rate base projects that have not been justified or supported.

The Company has stated that it disagrees with OCC's recommendation that a BCA should be required to "accurately assess how each program provides benefits to customers" as well as the fact that "good project design should include a transparent stakeholder engagement process." Exh. UI-CETP-REBUTTAL-1, pp. 6-7. The Company points out that BCAs are not always accurate when assessing new, emerging technologies or business models:

> *While a BCA is an important decision-making tool, it is not the only consideration in determining whether a proposed project is reasonable to implement. For example, a project implemented to pilot a new technology or business model may not pass a BCA test initially but is needed to prove out that the technology or business model has the ability to provide intended benefits and the ability to sufficiently scale to produce a positive BCA in future applications.*

Exh. UI-CETP-REBUTTAL-1, p. 7. However, UI has not substantiated its claim that BCA is ineffective in the assessment of new and emerging technologies by providing evidence to that effect, or examples from other jurisdictions of alternative methods used to assess new and emerging technologies. Certainly, BCA – and any form of analysis – may have areas of strengths and weaknesses. That should not be, however, an excuse to perform no analysis at all. In effect, UI asserts a preference for PURA to rely on the opinions of the Company's experts without any evidence or analysis to back up those opinions.

OCC recommends that the Authority require the Company to submit BCAs or other acceptable forms of analysis to support the proposals identified in this Section V(f).

2. Comparative Assessments

OCC recommends that the Authority require EDCs – including UI – to present comparative assessments to analogous utility programs in other jurisdictions alongside program proposals for ratepayer funding, such as UI's proposed Clean Energy Transformation initiatives. Comparative assessments would allow EDCs to learn from the experiences of similar programs in other jurisdictions and avoid any unnecessary and costly investments.

The Company claims to have "been actively engaged and participating in the discussions related to comparing other utility programs, approaches in other states, as well as seeking to understand the extensive stakeholder feedback" in other regulatory proceedings. Exh. UI-CETP-REBUTTAL-1, p. 4. However, UI has not presented any further details regarding these "discussions" or its comparative assessment to support the proposed initiatives presented in the Company's rate application.

OCC recommends that the Authority required the Company to submit comparative assessments to support the proposals identified in this Section V(f).

3. Public Stakeholder Engagement

OCC recommends that PURA require EDCs – including UI – to engage in public stakeholder engagement processes in advance of program proposals for ratepayer funding, such as UI's proposed Clean Energy Transformation initiatives. Stakeholder engagement processes would ensure that important cost and benefit information are captured and incorporated into the program design to ensure that decision makers have access to all relevant information and perspectives.

When questioned about the timing of previous stakeholder engagement processes related to its energy storage initiatives, the Company confirmed that it did not hold separate stakeholder engagement processes specific to its proposed initiatives; instead, UI's proposals were "informed by" stakeholder processes in related proceedings. Exh. UI-CETP-REBUTTAL-1, p. 4. In place of a formal, docket-specific stakeholder process, the Company notes that it included letters of support from the three municipalities. See Exh. UI-CETP-REBUTTAL-2. UI's witness shared that from the Company's perspective, these municipalities are the "the largest key stakeholder," noting that "we've given the municipalities an opportunity to work with us and adjust and modify those projects, as needed, for their communities." Tr. 2770. Letters of support from municipal leaders, however, cannot replace a formal engagement process open to multiple stakeholders to ensure that all important information from the communities impacted by these projects is captured and incorporated into the design and implementation of the proposed projects. Although the perspectives, feedback, and knowledgebase of municipalities are crucial considerations for developing the best possible programs, input from three municipalities is not an appropriate proxy for the broad array of stakeholder engagement that has taken place via the Authorities Equitable Modern Grid initiatives, for example.

While the Company's proposals were informed by some limited (and indirect) stakeholder feedback, the proposals themselves were not subject to a formal stakeholder engagement process. Exh. UI-CETP-REBUTTAL-1, p. 4. Despite this, the Company asserts that it "welcome[s] feedback from all interested parties on ways to constructively tailor the proposals to maximize benefits for customers," id., without providing or even recommending avenues for that feedback to occur.

As noted above, the Company also explains that its proposals were "informed by" stakeholder engagement, and that upon PURA's approval it will continue to engage stakeholder at a more granular level:

> *To date, most, if not all, stakeholder engagement has been focused at the municipal and community stakeholder level in effort to understand overarching themes and develop a needs assessment from which to create conceptual design proposals. Upon project approval by the Authority, the Company, with its established municipal and community group partners, will then engage stakeholders at a more granular level as more resource intensive detailed design efforts take place.*

Stakeholder engagement should occur before new costs are authorized in rates, not after.

OCC recommends that the proposals identified in this Section V(f) be properly analyzed through an open, transparent, and collaborative stakeholder process.

4. Metrics and Reporting Commitments

OCC recommends that PURA require EDCs – including UI – to include specific commitments to metrics and reporting alongside program proposals for ratepayer funding, such as UI's proposed Clean Energy Transformation initiatives. Such metrics would allow for an evaluation of program performance relative to expectations, particularly as it relates to emission reductions and ratepayer impacts. These metrics should be developed through the stakeholder engagement processes described above.

g. Multiyear Rate Plan

The Company has proposed a Multiyear Rate Plan ("MYRP") in its application. See Exh. UI-RRP-1, p. 6. The Company argued that the MYRP is "necessary to recover an increase in revenue requirements of $102.1 million in Rate Year 1, an incremental $17.2 million in Rate Year 2, and an incremental $17.2 million in Rate Year 3, compared to total revenues that would otherwise be recovered under current rate schedules." Id. As shown in the Company's testimony, the cumulative impact of the MYRP would be an increase over current revenue requirements of $102.1 million in Rate Year 1, $119.3 million in Rate Year 2, and $136.5 million in Rate Year 3. *Id.*, see Table 1. The Company proposes to levelized the impact of this requested increase by evenly spreading that total incremental revenue requirement evenly over the three rate years, for a levelized revenue increase of $54.2 million in each rate year. Id. at p. 7. The proposal would involve the Company collecting additional carrying charges. Id. Pursuant to the proposed levelized approach, the Company would be collecting a cumulative $162.6 million more than its current rate structure by the end of proposed Rate Year 3. Id., Table 2.

The Company also proposed to increase Distribution Rate Base in each of the Rate Years – approximately $1.4 billion in Rate Year 1; $1.5 billion in Rate Year 2; and $1.5 billion in Rate Year 3. Id., p. 8, Table 3.

The Company also proposed that its proposed overall rate of return should increase across the MYRP – beginning Rate Year 1 at 7.38%; Rate Year 2 at 7.38%; and Rate Year 3 at 7.47%. Id. at p. 8, Table 4. As discussed below, the Company further proposes that its allowed Return on Equity be adjusted on an annual basis in each Rate Year, in accordance with a proposed mechanism. See Exh. UI-AEB-1, p. 70.

OCC recognizes that MYRPs generally can provide multiple substantial benefits, including "lower administrative costs associated with rate cases and containment of EDC costs," as recognized in the Authority's decision in Docket No. 21-05-15, *PURA Investigation Into a*

Performance-Based Regulation Framework for the Electric Distribution Companies, Final Decision (April 26, 2023), p. 22. As we noted in a filing in that docket, "Well-designed [MYRPs] can create strong cost control incentives, but currently Connecticut's [MYRPs] do not leverage this opportunity." See Docket No. 21-05-15, supra, OCC Comments (Feb. 16, 2023), p. 5. We further noted in those comments that it "can be challenging to evaluate the reasonableness of EDC cost forecasts in [MYRP] proceedings." Id., p. 6. It is precisely this challenge that prevents OCC from supporting the Company's proposed MYRP in this proceeding.

The Company has failed to meet its burden not only to demonstrate the basic building blocks through which it has derived its own near-term capital cost estimates, as discussed at length in Section V(e)(i), but also to provide the Authority with the confidence necessary to ensure that much of its purported incremental revenue requirements in subsequent rate years are reliable. As OCC's witness testified during the hearing, "[T]here is always those substituted projects that nobody ever got to evaluate in any way, shape or form for the projects that were supposedly to take place." Tr. 1343. As discussed further below, and addressed throughout all areas of this brief, the Company's filing in this proceeding is so broadly insufficient that OCC has serious concerns about setting rates beyond a single rate year, until such time as the Company can provide reasonable and organized documentation to enable the Authority can properly analyze its plan.

i. The Company Has Repeatedly Failed To Provide Information Necessary to Evaluate Its Projections

The Company offered testimony that it conducts "ongoing iterative reviews" of its rate application. Tr. 3279. When asked how the Authority can feel comfortable knowing that the Company has at some point identified all of the errors in its filing, the Company responded, "we want to make sure we get it right at the end of the day, and we do our very best before we file a rate case to do just that." Tr. 3284. However, despite the Company's testimony that it spent "many, many, many hours going through and scrubbing", Tr. 3284, its application, the Authority and the parties have found numerous substantial errors, exclusions, and unsupported assertions in the Application since it was initially filed. Throughout this proceeding, the Company has failed to provide the information necessary for the Authority or OCC to reasonably evaluate its rate increase request. Examples of these failures are referenced throughout this brief, including but not limited to Sections VII(a)(iii) and VII(a)(iv), as well as in this non-exhaustive list:

- Despite proposing a design for an economic development rate, the Company has performed no analysis whatsoever to determine the incremental cost of administering an economic development rate. Tr. 446.

- When asked how the Company would ensure that administrative costs booked to a regulatory asset are paired with corresponding reductions to operating costs already allowed in base rates, the Company responded, "we haven't worked that through yet" and "We would make sure, that the person's time is not double collected. How we would do that at this point, I don't know." Tr. 448-449.

- When the Company re-created the Cost of Service Study to combine the R and RT classes, it merely combined the non-coincident peaks of the two classes together, rather than running load research to calculate a non-coincident peak for the new combined class. Tr. 3541. When asked whether it would have been better to address the non-coincident peak issue differently for the combined class, the Company's witness responded, "potentially." Tr. 3241.

- LFE-92 requested that the Company file "a listing of all cloud-based software assets". Tr. 2106. The Company's response to LFE-92 indicated that "there are no cloud-based software assets on UI's books." The Company then filed a supplement that appeared to acknowledge that the Municipal Portal is a cloud-based asset. See LFE-92 Supplement (Mar. 29, 2023). OCC notes that this supplement was filed on the date the record closed and was not subject to cross examination. The Company testified that its initial response to LFE-92 was intended to represent that any cloud-based assets would be at the organizational level and used across all affiliated networks, and hence would not be on UI's books. Tr. 3452. However, another witness testified that the Company "is exploring opportunities to move our contact center telephony platform to a cloud-based solution." Tr. 3542. Even more confusingly, another witness testified that its EV managed charging program involves a "cloud platform." Tr. 3569. The Company witness then attempted to differentiate the EV platform by explaining that it is a system where "each individual connected device, whether it be an electric vehicle telematics in someone's . . . vehicle or a Level 2 charger, Smart charger, communicate data to the . . . platform via the internet. And we send signals to control load during demand-response events or in the case of active managed charging in this year, also through the internet." Tr. 3577. OCC has difficulty understanding how the described system, where apparently multiple users aggregate data in a single storage point via the internet, purportedly falls outside the scope of a "cloud-based software asset" as sought by LFE-92. OCC also cannot understand how a cloud platform specifically used for electric vehicle managed charging would be accounted for at the operational level and used across the Company's non-electric entities. This singular example raises concern about the extent to which other areas of the record are unclear or flatly incorrect.

- During the hearing, the Company was asked to provide information about its procurement practices, and specifically to identify the threshold dollar amount that triggers the requirement for a competitive bidding process. The Company provided LFE-46, which identifies a threshold amount for UI to seek higher level approval for an <u>expense, but</u> does not reference a competitive bidding process. When questioned about this during the late file hearing, the Company conceded that the identified threshold amount "typically" triggers a competitive bidding process. Tr. 3428. Expenditures above the identified threshold can be excused from a competitive bidding requirement if the Purchasing department at the Avangrid Service Company level decides the expense can be sole-sourced. Tr. 3428-3429. When asked whether Avangrid has standards guiding the appropriateness of a sole-sourced expense, the Company responded that the form used in the request process includes a list of potential justifications. Tr. 3429. However, when asked whether the Company had filed a copy of that form in the record, so that the Authority can properly evaluate whether those justifications are appropriate, the Company could "not recall if the sole source form was submitted in the final submittal." Tr. 3429-3430.

- A Company witness panel testified that a contractual provision incenting its customer service vendor to obtain the largest possible payment has not been enforced in the past. In fact, when asked whether that provision was currently being enforced, the witness responded, "Certainly not enforcing it, correct. That's correct." Tr. 2349. However, the Company later acknowledged that this was incorrect. See Tr. 2414 ("So we checked on that, and we verified that UI is paying that. It's in the contract for the iQor vendor and it's called collections effectiveness, I believe, and it is based on what is contractual.")

- A Company witness testified that communications from the Company's legal collections firm to customers include notifications that the customers can contact the Company directly. Tr. 2609. Specifically, the witness testified that such communications have "information about, you can still contact your utility." Tr. 2610. The Company was asked to produce a copy of this communication via LFE-121. The Company's response to that late file request notes that "upon further review, the Company determined that the letter sent by the legal collections firm does not specifically advise the customer to contact the Company." LFE-121. OCC was particularly surprised by this error because Avangrid made a strikingly similar error during the proceedings in Docket No. 22-03-16, where it provided an interrogatory response claiming that legal collections firm correspondence to customers included notifications about "COVID payment arrangements," but provided copies of correspondence into the record that contained no such information. See Docket No. 23-03-16, OCC-13; Tr. 82; OCC Brief at 24.

- The Company's Clean Energy witness panel was unable to explain whether there are any differences between the Pleasure Beach Island proposal within the rate case and the solution that was proposed in the context of Docket 10-10-12. Tr. 2785.

- A Company witness testified that the Company is "instigating a review, a strategic review of Workers' Comp to make sure we have the right cost level, the right technology, the right resources, et cetera. So that is something we are going to do as a proactive measure, something that we are sponsoring within the HR Department, but we have not done it yet. But that is something I would note that we are going to do." Tr. 1732-1733. When asked why the study wasn't complete prior to the Company seeking an escalator, the witness responded, "I can't answer that." Tr. 1733-1734.

- The Company has not yet issued an RFP to establish its credit card processing fee rates. At the time of the hearing, the RFP would not be issued for another month. Tr. 2369-2370. The term for the agreement sought by the RFP is three to five years. Tr. 2370. Until the agreement is established, the Company can only estimate "within a ballpark range" what the credit card fees will actually be. Tr. 2370.

- During the Company's cross examination of an OCC witness, Company counsel asked the witness whether he had performed any analysis to determine whether the increase in capital expenses caused by the corporate capital charge shift was offset by the reduction to expense. Tr. 1636. The witness responded that OCC was unable to perform any such analysis because the data showing "what dollars they did put into rate base" wasn't even available at the time of the hearing. Tr. 1636.

- The Company's Cost Benefit Analysis offered in support of its Distribution Automation proposal is only applicable to Rate Year 1. Tr. 3330. The Company is currently in the process of conducting a similar analysis for subsequent rate years, but as of the time of the hearing had not provided it to the Authority. Tr. 3330.

- The Company's application is seeking recovery of $1.4m in capital costs related to the light-duty EV program in this rate case, but to date the Company has incurred $0 in capital costs related to the light-duty program. Tr. 2711. The Company explained that although EV chargers have been installed through the current light-duty program, the Company has not yet incurred costs for those installations because either no new electrical service was required, or new service was required at no incremental cost to the Company. Tr. 2712. The Company agreed during the hearing that "it's reasonable to assume that those numbers may be lower based on the experience that we had to date." Tr. 2714. When asked whether the Company intends to amend its application to account for the lower-than-projected actual costs to date, the Company responded, "As of this time, that has not been determined if that is going to be amended." Tr. 2813.

- The Company offered testimony that its plan for the proposed DER Load Forecasting Pilot is to "perform the collaboration with the educational institution to . . . gain further insight and use that insight into informing a competitive RFP for an actual tool to be implemented." Tr. 2696. However, no terms had even been written up for an agreement with the educational institution as of the time of the hearing. Tr. 2696.

- Throughout the hearing, it was often difficult to determine whether witnesses were testifying from their own personal knowledge or offering hearsay testimony from their laptop screens or regurgitating answers that were directly whispered into their ears by other Company representatives. It was also often difficult to determine which witness was on which witness panel, and which witness should respond to questions about testimony or discovery responses that a different, now-unavailable witness sponsored. The Authority recognized this issue on the record. See Tr. 1775-1176. ("(A]t this point we are a week and a half into the proceedings, and I think the Authority's patience in terms of the constant consultations, especially with witnesses that are not on the panel, is really starting to try my patience. We are having difficulty assessing the credibility of individual witnesses when there are constant sidebars. And I think moving forward, we are just asking the witnesses, we are asking the questions to the witnesses on the panel to the best of their abilities. You know, we are happy to take read-ins and late files where appropriate, but I got to say that the constant sidebars are not only delaying the proceeding, but I am having trouble assessing what is coming from the individual witness, versus what is being whispered into their ear by somebody behind them. And at this point I feel the need to put that on the record. And I'll just advise you, you know, certainly it is your case to put on, but that is now on the record, and I just want the Company to be aware of that moving forward.").

During the late file hearing, months after the Company initially filed its application and mere days before the record would close, a Company representative promised, "as we continue to go through, if we find something through preparation, through an interrogatory response, through a Late-File response here today, we're going to want to get it right." Tr. 3284. Given the number of errors, last-minute corrections, and yet-to-be- finished elements in the record, OCC and other parties simply have not had a reasonable opportunity to analyze the Company's application in full before the close of the record.

OCC acknowledges that rate case filings are complex; that the Company is asked to produce voluminous information; and that like the Authority and OCC, there are competing pressures for the personnel resources the Company can devote to a rate case. However, as the

Company acknowledged, "there was nothing that required the company to file at the date in which it did submit [the rate application]." Tr. 1854-1855. To the extent that the record demonstrates that the Application was not yet ready to be presented to the Authority, this issue could have been mitigated by the Company, by simply devoting the time and resources necessary to finalize its application prior to filing it.

OCC also acknowledges and understands that mistakes happen, and we do not wish to suggest that the Company be held to an unrealistic standard of perfection in presenting its case. However, if the Company wishes to meet the burden of demonstrating the necessity for a rate increase, it must provide the information necessary for the Authority, OCC, and other stakeholders to analyze its application fully and exhaustively. Given the multitude of issues referenced in this section and throughout this brief, which may only be a small glimpse of the total portion of errors and discrepancies that might have been discoverable beyond the time-and-resource-limited window of review of this proceeding, the Company simply has not provided the Authority with sufficiently reliable information for the Authority to have any confidence in the accuracy of the Company's projected revenue needs.

ii. The Authority Should Not Approve an MYRP Until It Has Devised An Updated MYRP Framework Within Docket No. 21-05-15.

As noted above, the issue of MYRPs has arisen within the Authority's investigation of performance-based ratemaking ("PBR") via Docket No. 21-05-15. As of the filing of this brief, the PBR investigation has made substantial and important progress, and the Authority has very specific plans to further address many more critical issues – including the need to design an appropriate MYRP framework. The upcoming second phase of that investigation will "consider a revised MRP design, including an appropriate control period, and an Externally-Indexed Revenue Cap approach that allows for interim adjustments pursuant to a revenue cap index formula." Docket 21-05-15, supra, Final Decision (April 26, 2023), p. 20. The Authority's recent decision in that docket succinctly explained the necessity for a reevaluation of the current MYRP standard: "Though MRPs have been in effect in Connecticut for some time for electric utilities, the Authority finds it necessary to reevaluate the MRP mechanism for opportunities to improve its effectiveness in serving the outcomes of Efficient Business Operations and Affordable Service." Id. at 22.

The Company has already acknowledged that its MYRP proposal in this rate case is modeled after the current status quo:

> *Those three-year plans are based on forecasted capital spend and then other adjustments based on forecasts or other factors, such as inflation, where appropriate, on the expense side. You know, our understanding it the [Standard Filing Requirements], for example, are designed to solicit that. So they solicit capital forecasts information going out for three years, and that was the spirit and intent with which we prepared this plan. It was our understanding, at the time, that that is how multiyear rate plans worked in Connecticut.. . And just because the rules, as they existed, or the regulatory framework, as it existed coming into this case,* ***contemplated a multiyear plan set up in a certain way and we proposed it that way****, that we would be open to further adjustments to it reflective of new guidance or updated thinking on those topics.*

Tr. 1316 (emphasis added). Therefore, the MYRP proposed by the Company is precisely the model for which the Authority has already recognized a need for change. OCC submits that the Authority should not authorize any MYRP proposal – including and especially the proposal set forth in UI's application – until the open, transparent, and collaborative process within the Authority's performance-based regulation investigation derives an appropriate MYRP model that captures the value of MYRPs but addresses the many concerns raised herein.

h. Cost of Capital

The United Illuminating Company has proposed a capital structure consisting of 0.0 percent short-term debt, 48.0 percent long-term debt and 52.00 percent common equity for the three-years of the Company's proposed Multi-Year Rate Plan ("MYRP"). OCC Direct(Woolridge), p. 3. The Company has proposed a long-term debt cost rate of 4.32 percent for the first two years of the plan and 4.51 percent for year three. Id. The Company's witness, Ms. Anne Bulkley ("Bulkley") has recommended a common equity cost rate of 10.20 percent for the Company. Id. As shown in Table 1, UI has proposed an overall rate of return of 7.38 percent for the first two years of the MYRP. With the 4.51 percent debt cost rate in the third year, the overall rate of return is 7.47 percent in year three. Id.

Table 1

United Illuminating Company's Cost of Capital Recommendation

Rate Year 1 and 2

Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	48.00%	4.32%	2.07%
Common Equity	52.00%	10.20%	5.30%
Total	100.00%		7.38%

Rate Year 3

Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	48.00%	4.51%	2.16%
Common Equity	52.00%	10.20%	5.30%
Total	100.00%		7.47%

OCC's witness, Dr. J. Randall Woolridge, has provided an analysis that proposes a capital structure with a common equity ratio of 50.00 percent. OCC Direct (Woolridge), pp. 4-5. This common equity ratio is consistent with the Authority's past policies on UI's capitalization; and is more reflective of the capital structures of the proxy group. Id. Dr. Woolridge's analysis adopted UI's proposed long-term debt cost rates, and applied the Discounted Cash Flow ("DCF") Model and the ("Capital Asset Pricing Model ("CAPM") to a proxy group of publicly-held electric utility companies ("Electric Proxy Group"), and the group developed by Ms. Bulkley (the "Bulkley Proxy Group"). Id. Dr. Woolridge's analyses indicated a common equity cost rate in the range of 8.70 percent to 9.30 percent. Id. Because Dr. Woolridge relied primarily on the model, he employed an equity cost rate of 9.0 percent for the Company. Id. Given this proposed capital structure and the proposed senior capital cost rates for UI, Dr. Woolridge recommended an overall fair rate of return or cost of capital for the Company of 6.66 percent for the first two rate years and 6.76 percent for rate year 3.[24] This is summarized in Table 2 and Exhibit JRW-1.

Table 2
OCC's Proposed Cost of Capital

Rate Years 1 and 2

Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	4.32%	2.16%
Common Equity	50.00%	9.00%	4.50%
Total	100.00%		6.66%

Rate Year 3

Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	4.51%	2.26%
Common Equity	50.00%	9.00%	4.50%
Total	100.00%		6.76%

[24] It is important to note that Dr. Woolridge's recommendations are not an endorsement of the MYRP, and should not be interpreted as supportive of the MYRP. Dr. Woolridge's analysis is only offered to demonstrate an appropriate allowed cost of capital, and is formatted as responsive to the Company's analysis.

i. Issues Between Parties

As discussed in greater detail in Section V(h)(ii) below, there are a number of differing positions between the Company and OCC involving UI's cost of capital:

1. Capital Market Conditions

Ms. Bulkley's analyses, ROE results, and recommendations are based upon assumptions of higher interest rates and capital costs. Id., at 5-6. However, despite the 2022 increase in inflation and interest rates, there are several factors suggesting the equity cost rate for utilities has not risen significantly. First, despite the increase in year-over-year inflation, long-term inflation expectations are still below 2.50 percent. Id. Second, the yield curve is currently inverted, which suggests that investors expect yields to decline and that a recession in the next year is likely, which would also put downward pressure on interest rates. Id. Third, interest rates have fallen significantly since their peak in October of 2022. Id. Fourth, utility stock prices have held up very well in 2022 compared to the overall market. Id. Lastly, while authorized ROEs for utilities hit all-time lows in 2020 and 2021, these ROEs did not decline nearly as much as interest rates. Id.

2. Capital Structure

The Company has proposed a capital structure with a common equity ratio of 52.0 percent. However, UI's proposed capitalization includes a higher common equity ratio and lower financial risk than the common equity ratio maintained by the companies in the Proxy Group. Id., at 30-1. As a result, Dr. Woolridge adopted a capital structure that includes a common equity ratio of 50.00 percent for the three years of the proposed MYRP. This capitalization is consistent with UI's Company's last rate case, and it is more reflective of the capital structures of other publicly held companies. Id.

3. UI's Investment Risk is Slightly Below Other Electric Utility Companies

UI's Standard & Poor's issuer credit rating of A- is above the averages of the two Proxy Groups, which is BBB+. Id., at 6. This indicates that UI's investment risk is a little below that of other electric utilities. Id.

4. DCF Approach

Ms. Bulkley and Dr. Woolridge both employed the traditional constant-growth DCF model. Ms. Bulkley has overstated her reported DCF results in two ways: (1) by exclusively using the overly optimistic and upwardly biased earnings per share (EPS) growth rate forecasts of Wall Street analysts and *Value Line*; and (2) by claiming that the DCF results underestimate the market-determined cost of equity capital due to high utility stock valuations and low dividend yields. Id., at 6. On the other hand, in developing the DCF growth rate in his analysis, Dr. Woolridge reviewed thirteen growth rate measures – both historical and projected – and evaluated growth in dividends, book value, and earnings per share. Id.

5. CAPM Approach

Ms. Bulkley and Dr. Woolridge both also employed the Capital Asset Pricing Model ("CAPM"). The CAPM approach requires an estimate of the risk-free interest rate, beta, and the market or risk premium. There are two primary errors in Ms. Bulkley's CAPM analysis: 1) she employed the Empirical CAPM (ECAPM) version of the CAPM, which makes inappropriate adjustments to the risk-free rate and the market risk premium; and (2) more significantly, she computed a market risk premium of 9.78 percent. *Id.* As Dr. Woolridge noted, the 9.78 percent market risk premium is larger than: (1) indicated by historic stock and bond return data; and (2) well-above that found in the published studies and surveys of the market risk premium. Id., at 7. To compute her market risk premium, Ms. Bulkley applied the DCF to the S&P 500 and employed analysts' three-to-five-year earnings per share ("EPS") growth-rate projections as a growth rate to compute an expected market return and market risk premium. However, Dr. Woolridge demonstrated that the EPS growth-rate projection (11.14 percent) used for the S&P 500 and the resulting determinations – expected market return (12.94 percent) and market risk premium (9.78 percent) – both include unrealistic assumptions regarding future economic and earnings growth and stock returns. Id.

Dr. Woolridge noted that there are three commonly-used procedures for estimating a market risk premium: historic returns, surveys, and expected return models. Id. Dr. Woolridge used a market risk premium of 6.00 percent, which: (1) factors in all three approaches – historic returns, surveys, and expected return models – to estimate a market premium; and (2) employs the results of many studies of the market risk premium. Id. Dr. Woolridge also noted that the 6.00 percent figure reflects the market risk premiums: (1) determined in recent academic studies by leading finance scholars; (2) employed by leading investment banks and management consulting firms; and (3) found in surveys of companies, financial forecasters, financial analysts, and corporate CFOs. Id.

6. Alternative Risk Premium Model

Ms. Bulkley also estimated an equity cost rate using an alternative risk premium model, calling it the Bond Yield Risk Premium approach. Exh. UI-AEB-1, p. 41. Ms. Bulkley computed this risk premium using a regression of the historical relationship between the yields on long-term Treasury bonds and authorized ROEs for electric utility companies. Id., pp. 41-44. Ms. Bulkley computed the estimated ROE as the projected risk-free rate plus the risk premium. Id. There are several errors with this approach: (1) this particular risk premium approach is a gauge of *commission* behavior rather than *investor* behavior; and (2) this methodology produces an inflated measure of the risk premium because this approach relies on historically authorized ROEs and Treasury yields to calculate the risk premium, which is applied to projected Treasury yields. OCC Direct (Woolridge), p. 8. Finally, this risk premium of 9.78 percent is inflated as a measure of investors' required risk premium, since electric utility companies have been selling at market-to-book ratios in excess of 1.0. Id. This indicates that the authorized rates of return have been greater than the return investors require. Id.

7. Regulatory and Business Risks

Ms. Bulkley also considered UI's various regulatory and business risks in arriving at her 10.20 percent ROE recommendation. Exh. UI-AEB-1, p. 45. However, credit rating agencies already considered these factors when rating UI's bonds, so they are already accounted for in assessing UI's risk. OCC Direct (Woolridge), p. 8. As previously indicated, UI's S&P and Moody's issuer credit ratings of A and Baa1 are slightly above the averages of the two Proxy Groups, which are BBB+ and Baa1. Id. As such, Dr. Woolridge concluded that these risks are included in the credit rating process and UI is still slightly less risky than the proxy groups. Id.

8. UI's Financial Performance

Dr. Woolridge's analysis examined UI's financial performance over the past five years. OCC Direct (Woolridge), p. 9. The Company's financial highlights are provided in Table 3. Id. The Company's performance, in terms of revenues, net income, cash flow, coverage ratios, has been very consistent. Id. UI's cash flow from operations has covered the Company's capital expenditures, which tends to limit the need for external financing. Id. The Company's average earned return on common equity over the past five years, despite having declined, is 10.60 percent. Id. Overall, Dr. Woolridge concluded that the Company has delivered very consistent financial performance over time. Id.

Table 3
UI Financial Highlights
2017–2022

	2017 FY	2018 FY	2019 FY	2020 FY	2021 FY
Balance Sheet ($000)					
Total Debt / Total Capital (%)	49.03	43.39	42.68	41.82	41.54
Income Statement ($000)					
Total Revenue	921,181	970,052	988,798	1,046,846	1,070,905
Net Income	105,183	115,939	122,621	121,240	125,377
EBITDA / Interest Expense (x)	6.37	6.46	6.89	6.06	6.48
EBIT / Interest Expense (x)	4.44	4.54	4.42	3.99	4.05
Cash Flow ($000)					
Cash from Ops.	199,361	262,499	199,559	199,329	347,648
Capital Expenditure	(163,138)	(254,929)	(169,444)	(195,009)	(198,531)
Profitability (%)					
Return on Common Equity	11.15	11.41	10.76	9.97	9.93

Id.

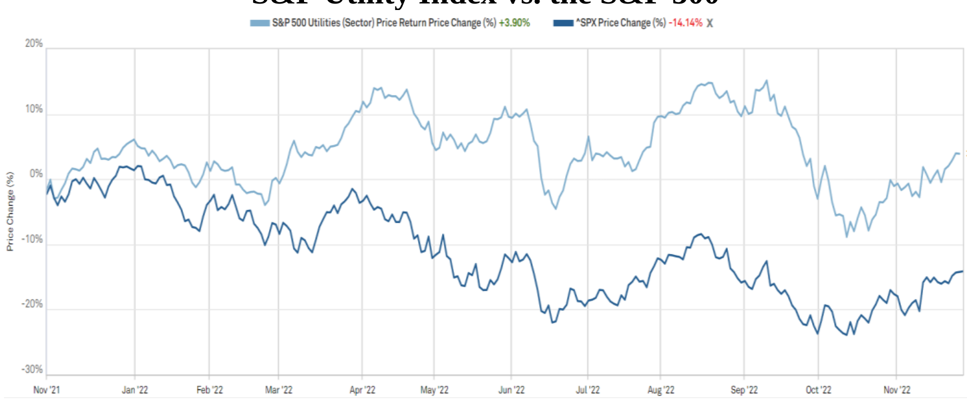
9. Capital Market Conditions and Authorized ROEs

a. Capital Market Conditions

Inflation and interest rates increased significantly in 2022 due primarily to: (1) the recovering economy, as discussed above; (2) the production shutdowns during the pandemic led to supply chain shortages as the global economy has recovered; and (3) the war in Ukraine has led to higher energy and gasoline prices worldwide. OCC Direct (Woolridge), pp. 10-12. Yields on 30-year Treasury bonds increased from the 2.0 percent range to over 4.50 percent in 2022, but subsequently declined. Id. In response the Federal Reserve increased the discount rate by 25 basis points in March of 2022; 50 basis points in May; and 75 basis points in June, July, September, and November – and may increase the discount rate again. Id.at 12. However, the Federal Reserve's actions on the discount rate only directly affect short-term rates. Id. Long-term rates are more a function of expected economic growth and expected inflation. Id. Whereas the government has reported annual year-over-year inflation rates as high as 9.20 percent in the past year, the 30-year Treasury yield is still only about 3.60 percent. Id.

Given the attention that the annual year-over-year inflation rates have received, Dr. Woolridge evaluated the inflation expectations by evaluating the breakeven inflationary expectations over the next 5-, 10-, and 30-year periods through an analysis of the yields on Treasuries and the yields on inflation-protected Treasuries, known as TIPS. Id., at 12-13. That analysis demonstrates that while inflationary expectations have risen, the expected inflation over the 5-, 10-, and 30-year periods are only 2.36 percent, 2.28 percent, and 2.40 percent. Id. at 13. These higher inflation and interest rates, combined with the potential for an economic recession, have hit the stock market in a negative way and the S&P 500 is down double digits. Id., at 14-15. Despite this, utility stocks have held up well relative to the overall market. Id. Figure 4 below compares the total returns on S&P 500 to the S&P Utilities Index.[25] Id. Although the S&P 500 is down approximately 14.14 percent over the past year, utility stocks have performed relatively well and are up 3.90 percent. Id.

Figure 4
S&P Utility Index vs. the S&P 500



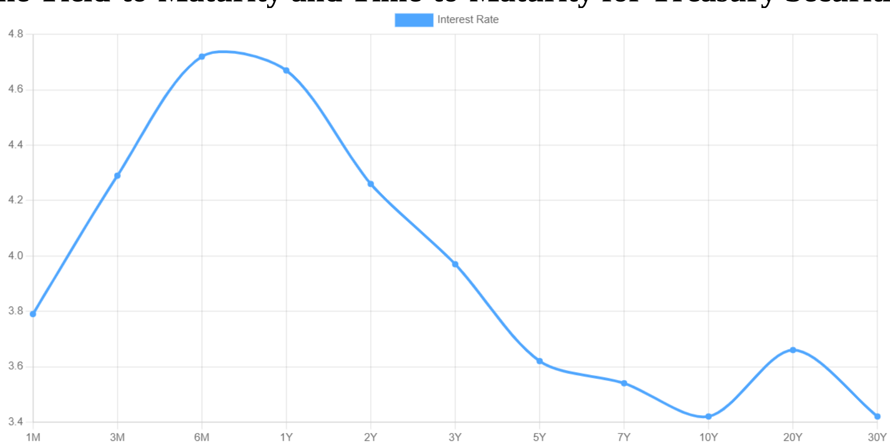
Source: S&P Cap IQ. Id.

Dr. Woolridge's analysis also addressed the prospect that interest rates will rise in the future. Id., at 15-16. To address this issue, the analysis provided Figure 5, which shows the

[25] The S&P Utilities Index is made up of the 29 utilities that are in the S&P 500. The index primarily is made up of electric utilities.

yield curve plotting yield-to-maturity and time-to-maturity for Treasury securities. Id. As Dr. Woolridge noted, the yield curve is usually upward-sloping because investors require higher returns to commit capital for longer periods of time. Id. However, as indicated in Figure 5, the yield curve is "inverted," which means that the yields on shorter-term maturity securities are higher than the yields on longer-term securities. Dr. Woolridge notes that this means that investors do not expect interest rates to remain where they are, and expect that they should decline. Id. Furthermore, Dr. Woolridge's analysis showed that every time the yield curve has inverted over the past fifty years, a recession has followed, and recessions result in decreases in interest rates. Id.

Figure 5
The Yield Curve
The Yield-to-Maturity and Time-to-Maturity for Treasury Securities



Source: https://www.ustreasuryyieldcurve.com/. *Id.*

Dr. Woolridge summarized his assessment of capital market conditions in the following way:

> *The U.S. economy, which declined nearly twenty percent in the first half of 2020, rebounded significantly in 2021 and has continued the rebound in 2022. This rebound has seen big increases in consumer and business spending, lower unemployment, and higher housing prices. The rebounding economy has put pressure on prices. This has been further exacerbated by the post-COVID supply chain issues and the higher energy prices brought on by the Russia-Ukraine conflict.*
>
> *Nonetheless, utilities took advantage of the low yields in 2020 and 2021 to raise record amounts of capital, and utility stocks have held up quite*

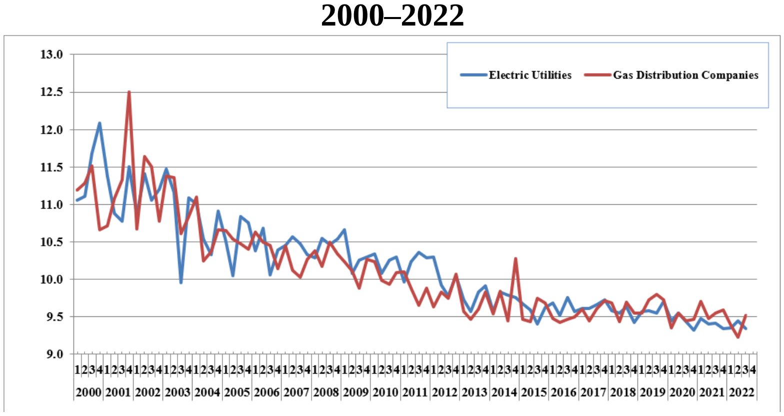
well in 2022 compared to the overall stock market, which is down about over 10 percent. The big economic issue is reported year-over-year inflation. However, while year-over-year inflation is expected to be high in the short-term, the yields on TIPS suggest that longer-term inflation expectations are still below 2.50 percent. However, as I noted above, with an inverted yield curve, the prospect of a recession is likely, which would lead to lower interest rates. Reflecting this environment, the yield on 30-year Treasury bonds has declined from 4.40 percent in October of this year to its current level, about 3.40 percent.

Id., at 16-7.

b. Authorized ROEs

Quarterly authorized ROEs for electric utility and gas distribution companies from 2000-2022 were provided in Figure 6 of Dr. Woolridge's analysis, which is repeated below. OCC Direct (Woolridge) pp. 17-22. As interest rates have come down, authorized ROEs for electric utility and gas distribution companies have slowly declined to reflect a low-capital-cost environment. Id. And in 2020 and 2021, with record low interest rates, authorized ROEs for utilities hit an all-time low. Id. Dr. Woolridge also provided the average annual authorized ROEs for electric utilities and gas distribution companies, shown below in Table 4. Id.

Figure 6
Authorized ROEs for Electric Utilities and Gas Distribution Companies
2000–2022



Id., at 18.

Table 4
Average Annual Authorized ROEs for Electric Utilities and Gas Distribution Companies
2010–2022

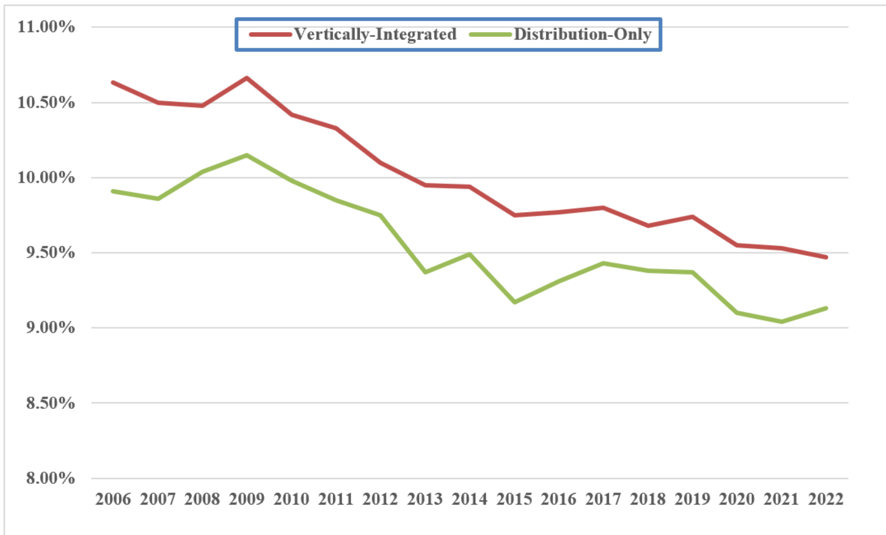
	Electric	Gas		Electric	Gas
2010	**10.37**	**10.15**	**2017**	**9.74**	**9.72**
2011	**10.29**	**9.92**	**2018**	**9.60**	**9.59**
2012	**10.17**	**9.94**	**2019**	**9.66**	**9.72**
2013	**10.03**	**9.68**	**2020**	**9.44**	**9.47**
2014	**9.91**	**9.78**	**2021**	**9.38**	**9.56**
2015	**9.78**	**9.60**	**2022**	**9.37**	**9.42**
2016	**9.77**	**9.54**			

Data Source: S&P Global Market Intelligence, RRA Regulatory Focus, 2022. Id., at 18.

One consistent factor in electric utility authorized ROEs is that the ROEs for delivery or distribution companies have consistently been below those of vertically integrated utilities. Id. at 19. Dr. Woolridge illustrated that relationship in Figure 7, repeated below. Id. Lower authorized ROEs are usually attributed to the fact that delivery or distribution companies like UI do not own and operate electric generation, which is perceived to be the riskier part of electric utility operations. Id. Authorized ROEs for electric delivery companies have been 30-50 basis points below those of vertically-integrated electric utilities in recent years. Id. The average authorized ROEs for electric delivery companies like UI were 9.10 percent in 2020, 9.04 percent in 2021, and 9.13 percent in the first three quarters of 2022.[26] Id.

[26] S&P Global Market Intelligence, RRA *Regulatory Focus*, 2022.

Figure 7
Authorized ROEs for Vertically Integrated versus
Delivery Only Electric Utilities
2006-2022



Dr. Woolridge also explained that the higher interest rates of 2022 do not necessarily require that authorized ROEs for utilities must increase. Id.at 20-1. Authorized ROEs for utilities did reach record low levels in 2020 and 2021 due to record low interest rates and capital costs. Id. However, utility ROEs did not decline to the extent interest rates did over these two years. Id. Dr. Woolridge performed a study of the relationship between the average daily 30-year Treasury yields and authorized ROEs for electric utilities and gas distribution companies, and provided the results in Table 5 – reproduced below. The average daily 30-year Treasury yield declined from 3.11 percent in 2018 to 1.56 percent in 2020, a decrease of 155 basis points. However, the average authorized ROE for electric utilities declined only from 9.60 percent in 2018 and 9.66 percent in 2019, to 9.44 percent in 2020 and 9.38 percent in 2021. Id. Hence, mean authorized electric ROEs declined by about 20 basis points, while the 30-year Treasury yield decreased by over 150 basis points. Id.

Table 5
Average Annual 30-Year Treasury Yields and Authorized ROEs for Electric Utility and Gas Distribution Companies
2018–2021

	2018	2019	2020	2021
30-Year Treasury Yield	3.11%	2.58%	1.56%	2.06%
Average Electric ROE	9.60%	9.66%	9.44%	9.38%
Average Gas ROE	9.59%	9.71%	9.46%	9.56%

Dr. Woolridge's analysis also presented the ROE rate case outcomes for electric and gas distribution companies in Connecticut over the 2010-22 time period via Table 6 – reproduced below – and noted that Connecticut authorized ROEs have been generally in line with the authorized ROEs for electric distribution companies across the country. Id. at 21-2.

Table 6
Connecticut Electric and Gas Rate Cases
2010—22

Company	Parent	Docket	Service Type	Date	Decision Type	Revenue Increase	Return on Equity (%)	CE Ratio
The CT Light & Power Co	ES	D-09-12-05	Electric	6/30/2010	Fully Litigated	101.9	9.40	49.20
Yankee Gas Services Co.	ES	D-10-12-02	Natural Gas	6/29/2011	Fully Litigated	6.2	8.83	52.20
The United Illuminating	IBE	D-13-01-19	Electric	8/14/2013	Fully Litigated	46.1	9.15	50.00
CT Natural Gas Corp.	IBE	D-13-06-08	Natural Gas	1/22/2014	Fully Litigated	7.3	9.18	52.52
The CT Light & Power Co	ES	D-14-05-06	Electric	12/17/2014	Fully Litigated	152.7	9.17	50.38
The United Illuminating	IBE	D-16-06-04	Electric	12/14/2016	Fully Litigated	57.4	9.10	50.00
The Sthrn CT Gas Co	IBE	D-17-05-42	Natural Gas	12/13/2017	Settled	11.2	9.25	52.19
The CT Light & Power Co	ES	D-17-10-46	Electric	4/18/2018	Settled	124.7	9.25	53.00
Yankee Gas Services Co.	ES	D-18-05-10	Natural Gas	12/12/2018	Settled	30.2	9.30	53.76
CT Natural Gas Corp.	IBE	D-18-05-16	Natural Gas	12/19/2018	Settled	19.7	9.30	55.00

Data Source: S&P Global Market Intelligence, RRA *Regulatory Focus*, 2022. Id.

Dr. Woolridge also highlighted the results of a recent *Wall Street Journal* article entitled "Utilities Have a High-Wire Act Ahead."[27] OCC Direct (Woolridge) pp. 23-4. The article discusses the issues utilities are facing today to meet the needs of its primary stakeholders – customers and investors. Id. In years past, utilities could invest and grow their rate bases without undue burden on ratepayers because low interest rates and gas prices moderated rate increases, but increased supply prices and interest rates in recent years have disrupted that

[27] Jinjoo Lee, "Utilities Have a High-Wire Act Ahead," *Wall Street Journal*, October 9, 2022, p. C1.

historical balance. Id. Moving forward, the greater financial burden on utility ratepayers associated with higher gas prices and interest rates may result in increased pressure upon regulatory commissions to look hard at utility rate increase requests. *Id.*

The *Wall Street Journal* article also highlighted the utility rate issue in the context of a recent study on rate of return regulation. Id., at 23-4. As noted in Dr. Woolridge's testimony, the 2022 study by Werner and Jarvis[28] evaluated authorized ROEs in 3,500 electric and gas rate case decisions in the U.S. from 1980-2021. Id. They compare the allowed rate of return on equity to a number of capital cost benchmarks – including government and corporate bonds; CAPM equity cost rate estimates; and U.K. authorized ROEs – and focused upon three questions: (1) To what extent are utilities being allowed to earn excess returns on equity by their regulators?; (2) How has this return on equity affected utilities' capital investment decisions?; and (3) What impact has this had on the costs paid by consumers?. Id.

Dr. Woolridge's testimony provided findings in the Werner and Jarvis study with respect to utility authorized ROEs, including:

- The real (inflation-adjusted) return regulators allow equity investors to earn has been pretty steady over the last 40 years, while the many different cost of capital measures have been declining;
- The gap between the authorized ROEs and the benchmarks suggest that regulators have been approving ROEs that are from 0.50 percent - 5.50 percent above the cost of equity estimates;
- One potential explanation is that utilities have become riskier. However, the authors find that utility credit ratings, on average, have not changed much over the past 40 years;
- An extra 1.0 percent of allowed return on equity causes a utility's capital rate base to expand by an extra 5 percent on average. This indicates that utilities have the incentive to overinvest in capital projects if they are earning an outsized return on those investments;

[28] Karl Dunkle Werner and Stephen Jarvis, "Rate of Return Regulation Revisited," Working Paper, Energy Institute, University of California at Berkeley, 2022.

- Both the return on equity requested by utilities and the return granted by regulators respond more quickly to rises in market measures of capital cost than to declines. The time adjustment for decreases is twice as long as for increases.

- Authorized ROEs tend to be approved at round numbers (1.0, 0.5, 0.25), with 10.0 percent being the most common authorized ROE;

- Overall, based on the gap, consumers may be paying $2-20 billion per year more than if authorized ROEs had fallen in line with other capital market indicators; and

- The authors also indicate that their results are similar to those found in a previous 2019 study by Rode and Fischback.[29]

Id., at 23-24.

Dr. Woolridge's testimony concluded that the Werner-Jarvis study demonstrates that authorized ROEs have not declined in line with capital costs over the past four decades, and therefore past authorized ROEs have overstated the actual cost of equity capital. Id., at 24. Hence, the Authority should not be concerned about allowing an ROE that is below other authorized ROEs. Id.

ii. Detailed Analysis of Cost of Capital

Dr. Woolridge's cost of capital analysis for the test year is presented in Exhibit JRW-1 and is summarized in Table 2 above. OCC Direct (Woolridge), pp. 4-5. As noted above, Dr. Woolridge's proposed capital structure includes 50.0 percent long-term debt and 50.00 percent common equity. Id. Dr. Woolridge has employed the Company's proposed long-term debt cost rates of 4.32 percent for years one and two of the MYRP and 4.51 percent for year three. Id. Dr. Woolridge's analyses indicated a common equity cost rate in the range of 8.70 percent to 9.30 percent. Since he relied primarily on the model, he employed an equity cost rate of 9.0 percent for UI. Id. With his proposed capital structure and debt cost rates, Dr. Woolridge is

[29] David C. Rode and Paul S. Fischbeck, "Regulated Equity Returns: A Puzzle." *Energy Policy*, October 2019.

recommending an overall fair rate of return or cost of capital of 7.38 percent for years one and two of the MYRP and 7.47 percent for year three. Id.

1. Capital Structure and Debt Cost Rates

UI has proposed a capital structure consisting of 0.0 percent short-term debt, 48.00 percent long-term debt and 52.00 percent common equity, with a long-term debt cost rates of 4.32 percent in the first two years of the MYRP and 4.51 percent for year 3. OCC Direct (Woolridge) pp. 26-30. Dr. Woolridge's proposed capital structure includes 50.00 percent long-term debt and 50.00 percent common equity. Id. at 34. Dr. Woolridge has used the Company's proposed long-term debt cost rates of 4.32 percent in the first two years of the MYRP and 4.51 percent for year 3.

In support of his capital structure adjustment, Dr. Woolridge cited several factors: The average common equity ratio for the Electric and Bulkley Proxy Groups are 41.70 percent and 42.48 percent. Id. at 27. The average common equity for water and gas companies in the Proxy Group is 46.8 percent. Id., at 20. For the proxies, these are the capital structure ratios for the holding companies that trade in the markets and are used to estimate an equity cost rate for UI. Id. They also include short-term debt because, like long-term debt, short-term debt has a priority to the earnings and assets of the company ahead of equity holders. Id. These ratios indicate that the companies in the Proxy Group have, on average, a lower common equity ratio than that proposed by UI. Id. As such, Dr. Woolridge notes UI has proposed a capital structure that has more common equity and less financial risk than the average capital structure of the companies in the Proxy Group. Id. Dr. Woolridge also notes that a capitalization with a common equity ratio of 50.0 percent is: (1) consistent with the Authority's past policies on UI's capitalization; and (2) more reflective of the capital structures of the proxy group. Id.

2. Cost of Equity

As noted above, Dr. Woolridge used DCF and CAPM approaches to estimate an equity cost rate for UI. Id., at 31-68. He applied these approaches to his Electric Proxy Group and Ms. Bulkley's proxy group and found that the appropriate equity cost rate for UI is in the 8.70 percent – 9.30 percent range. Id. at 4. Hence, Dr. Woolridge recommended a ROE of 9.0 percent for UI.

a. DCF Approach

vii. DCF Dividend Yield

For the DCF dividend yield for the Proxy Group, Dr. Woolridge employed the current annual dividend and the 30-day and 90-day average stock prices. Id., at 43. These dividend yields are provided on page 2 of Exhibit JRW-5. For the Proxy Group, the average of the mean and median dividend yields using the 30-day and 90-day average stock prices is in the range of 3.5 percent to 3.8 percent. Given this range, Dr. Woolridge used 3.65 percent as the dividend yield for the Proxy Group. Id. To account for the growth in the dividend in the coming year, he adjusted this dividend yield by ½ the projected DCG growth rate. Id. at 44.

viii. DCF Growth Rate

As Dr. Woolridge highlighted, the primary debate in applying the DCF model is the expected growth rate. OCC Direct (Woolridge), pp. 45-53. According to the constant-growth DCF model, earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS) all grow at the same rate. Id. To assess growth, investors have available a number of services that provide historic and projected financial information. For the companies in the two proxy groups, Dr Woolridge evaluated (1) *Value Line's* historic growth rates for EPS, DPS, and BVPS, (2) *Value Line's* projected growth rate estimates EPS, DPS, and BVPS, (3) prospective internal growth (the so-called b x r method) using *Value Line's* projected earnings retention rates and earned returns on common equity, and (4) the EPS growth rate forecasts as provided by Zacks, Yahoo, and S&P Capital IQ. Id.

Table 7 highlights the summary growth rates for the proxy group (Woolridge PFT, at 45-53 and page 6 of Exhibit JRW-5).

Table 7
DCF Growth Rate Indicators

Growth Rate Indicator	Electric Proxy Group	Bulkley Proxy Group
Historic *Value Line* Growth in EPS, DPS, and BVPS	4.8%	4.8%
Projected *Value Line* Growth in EPS, DPS, and BVPS	5.2%	5.5%
Sustainable Growth ROE * Retention Rate	4.0%	4.0%
Projected EPS Growth from Yahoo, Zacks, and S&P Cap IQ - Mean/Median	5.3%/5.6%	5.7%/5.8%

Exhibit JRW-5, page 6.

Dr. Woolridge made the following observation in arriving at his DCF growth rate:

> *The historical growth rate indicators for my Electric Proxy Group imply a baseline growth rate of 4.8 percent. The average of the projected EPS, DPS, and BVPS growth rates from Value Line is 5.2 percent, and Value Line's projected sustainable growth rate is 4.0 percent. The projected EPS growth rates of Wall Street analysts for the Electric Proxy Group are 5.3 percent and 5.6 percent as measured by the mean and median growth rates. The overall range for the projected growth-rate indicators (ignoring historical growth) is 4.0 percent to 5.6 percent. Giving primary weight to the projected EPS growth rate of Wall Street analysts, but recognizing the upward bias nature of these forecasts, I believe that the appropriate projected growth rate is in the 5.25 percent to 5.50 percent range. I will use the midpoint of this range, 5.375 percent, as my DCF growth rate for the Electric Proxy Group. This growth rate figure is in the upper end of the range of historic and projected growth rates for the Electric Proxy Group.*
>
> *For the Bulkley Proxy Group, the historical growth rate indicators suggest a growth rate of 4.8 percent. The average of the projected EPS, DPS, and BVPS growth rates from Value Line is 5.5 percent, and Value Line's projected sustainable growth rate is 4.0 percent. The projected EPS growth rates of Wall Street analysts are 5.7 percent and 5.8 percent as measured by the mean and median growth rates. The overall range for the*

projected growth rate indicators is 4.0 percent to 5.8 percent. Again, giving primary weight to the projected EPS growth rate of Wall Street analysts, but recognizing the upward bias nature of these forecasts, I believe that the appropriate projected growth rate is 5.50 percent, which I will use for the Bulkley Proxy Group. Similar to the Electric Proxy Group, this growth rate figure is in the upper end of the range of historic and projected growth rates for the Bulkley Proxy Group.

OCC Direct (Woolridge), pp. 53-4.

ix. DCF Equity Cost Rate

x.

Given the dividend yield and growth rate, Dr. Woolridge's DCF-derived equity cost rates for the proxy groups are:

$$\text{DCF Equity Cost Rate (k)} = \frac{D}{P} + g$$

Table 8
DCF Results

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Electric Proxy Group	**3.65%**	**1.026875**	**5.375%**	**9.10%**
Bulkley Proxy Group	**3.70%**	**1.027500**	**5.500%**	**9.30%**

Id. at 54.

b. CAPM Approach

Dr. Woolridge also employed the CAPM using the Proxy Group. OCC Direct (Woolridge), pp. 54-68. To determine an equity cost rate using the CAPM, there are three inputs: the risk-free rate of interest, the beta (the systematic risk measure), and the equity or market risk premium. Id. The risk-free rate of interest is the yield on the yield on long-term Treasury bonds and is readily observable in the markets. Beta, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historic betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium. Id.

xi. Risk-Free Interest Rate

The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. Woolridge PFT, at 56-7. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities. Id. As Dr. Woolridge observed, the yield on 30-year Treasury has been in the 1.3 percent to 4.75 percent over the past decade. Id. Treasury yields have increased with the increase in interest rates in 2022. In selecting a risk-free interest rate, Dr. Woolridge made the following observation:

> *Currently, Duff & Phelps is recommending a normalized risk-free interest rate of 3.50 percent or, if the spot 20-year Treasury yield is above 3.50 percent, Duff & Phelps recommends using the spot 20-year Treasury yield. As shown in Figure 5, the yield curve is currently inverted with 10- and 30-year Treasury yields in the 3.45 percent range and the 20-year yield in the 3.75 percent range. Given the recent range of yields, I am using 3.60 percent as the risk-free rate, or R_f, in my CAPM.*

OCC Direct (Woolridge), p. 56.

xii. Beta

Dr. Woolridge discussed a number of issues related to the calculation of betas in his testimony. OCC Direct (Woolridge), pp. 57-9. Despite some reservations, he elected to employ the betas for the companies in the proxy group as provided in the *Value Line Investment Survey*. Dr. Woolridge uses the median *Value Line* beta for the two Proxy Groups are 0.85 and 0.85. Id., at 58.

xiii. Market or Equity Risk Premium

The equity risk premium is the expected return on the stock market, minus the risk-free rate of interest. As such, it is the difference in the expected total return between investing in equities and investing in long-term Treasury bonds. OCC Direct (Woolridge), pp. 60-7.

Whereas the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market. Dr. Woolridge indicated that there are generally four ways to measure the equity risk premium:

- Historic Stock and Bond Returns: Historic stock and bond returns suggest a market risk premium in the 4.40 percent to 6.71 percent range, depending on whether one uses arithmetic or geometric mean returns.

- *Ex Ante* Models: Market risk-premium studies that use expected or *ex ante* return models indicate a market risk premium in the range of 3.47 percent to 6.00 percent.

- Surveys: Market risk premiums developed from surveys of analysts, companies, financial professionals, and academics are lower, with a range from 3.88 percent to 5.70 percent.

- Building Block: The mean reported market risk premiums reported in studies using the building blocks approach range from 3.00 percent to 5.21 percent.

Id., at 64.

To determine an equity risk premium, Dr. Woolridge reviewed the results of over thirty equity risk premium studies and surveys performed over the past two decades. These are presented on page 5 of Exhibit JRW-6 and include the summary equity risk premium results of: (1) the annual study of historic risk premiums as provided by Duff & Phelps (Formerly Morningstar and before that Ibbotson Associates); (2) ex ante equity risk premium studies commissioned by academics, consulting firms, and the Social Security Administration; (3) equity risk premium surveys of CFOs, Financial Forecasters, as well as academics; and (4) Building Block approaches to the equity risk premium. The overall average equity risk premium of these studies is 4.83 percent. Id., at 63-5.

Dr. Woolridge also observed the results of equity risk premium studies discussed above that were published since 2010, to eliminate those before the 2008 financial crisis. These results are presented on page 6 of Exhibit JRW-6. The average for the equity risk premium studies published since 2010 was 5.16 percent. Id., at 63.

Dr. Woolridge also highlighted the market risk premium estimates from a number of recent studies and surveys, including:

- An equity risk premium of 5.30 percent as of October 2022 as published by investment valuation guru Aswath Damodaran of New York University. Id. at 65;

- An annual survey conducted by Pablo Fernandez of analysts, academics, and companies. This survey is global and usually has more than 5,000 respondents. In 2022, the average market risk premium used in the U.S. was 5.60 percent. Id. at 65;

- Recommendations provided by Duff & Phelps, an investment advisory firm, for the normalized risk-free interest rate and market risk premiums to be used in calculating the cost of capital. Dr. Woolridge provided these recommendations over the 2008–2022 time periods on page 7 of Exhibit JRW-8. As of October 2022, Duff & Phelps' recommended normalized a market risk premium of 6.00 percent. Id. at 66;

- A quarterly market risk premium report provided by KPMG, the international accounting and consultancy firm. In its October, 2022 update, KPMG was recommending a market risk premium of 6.0 percent. Id. at 66.

Given the results presented on pages 5 and 6 of Exhibit JRW-6, and especially the studies and surveys highlighted above, Dr. Woolridge used a market risk premium of 6.00 percent for his CAPM. Id. at 66.

xiv. CAPM Equity Cost Rate

Using the inputs discussed above, Dr. Woolridge arrived at a CAPM equity cost rates of 8.70 percent for both proxy groups. Id. at 66.

$$K = (R_f) + ß_{ibm} * [E(R_m) - (R_f)]$$

Table 9
CAPM Results

	Risk-Free Rate	Beta	Market Risk Premium	Equity Cost Rate
Electric Proxy Group	3.60%	0.85	6.00%	8.70%
Bulkley Proxy Group	3.60%	0.90	6.00%	8.70%

Id. at 66.

3. Dr. Woolridge's Equity Cost Rate Conclusion

Dr. Woolridge's equity cost rate results are provided in Table 6. In arriving at his cost of equity recommendation, Dr. Woolridge made the following observations:

> *Given these results, I conclude that the appropriate equity cost rate for companies in the Electric and Bulkley Proxy Groups is in the 8.70 percent to 9.30 percent range. Given that I rely primarily on the DCF model and the Electric Proxy Group, I will use an equity cost rate of 9.00 percent for UI.*

OCC Direct (Woolridge), p. 68.

Table 10
Cost of Capital Results

	DCF	CAPM
Electric Proxy Group	9.10%	8.70%
Bulkley Proxy Group	9.30%	9.00%

Id. at 68.

Finally, Dr. Woolridge also argued that his recommended ROE of 9.00 percent is reasonable given the following:

- He employed a capital structure that has more equity and less financial risk than the average of the proxy groups;
- As Exhibit JRW-2 shows, capital costs for utilities, as indicated by long-term bond yields, are still at historically low levels, despite the 2022 increase in rates;
- As Table 7 shows, the electric utility industry is among the lowest risk industries in the U.S. as measured by beta. As such, according to CAPM, the cost of equity capital for this industry is among the lowest in the U.S.;

- While the overall stock market is down about 15 percent in 2022, public utility stocks have held up very well. Hence, utility stocks have performed well relative to the market in the face of higher inflation and interest rates.

Id. at 69.

Dr. Woolridge's ROE recommendation meets *Hope* and *Bluefield* standards. According to *Hope* and *Bluefield*, the return on equity capital should be: (1) comparable to returns investors expect to earn on other investments of similar risk;[30] (2) sufficient to assure confidence in the company's financial integrity;[31] and (3) adequate to maintain and support the company's credit and to attract capital.[32] Id.; see Section IV. Utility companies have been earning ROEs in the range of 8.0 percent to 10.0 percent in recent years. Exh. JRW-3, p. 3. With such ROEs, utilities such as those in the proxy group have strong investment grade credit ratings; their stocks have been selling at almost 2.0 times book value; and they have been raising abundant amounts of capital. While a 9.00 percent ROE recommendation is just barely below the average authorized ROEs for utility companies, it reflects the historically low levels of interest rates and capital costs.

4. Ms. Bulkley's Equity Cost Rate

Ms. Bulkley has also employed the DCF and CAPM approaches, and also used an alternative risk premium approach. Her ROE results are provided in Table 11. Based upon these results, she concluded that the appropriate equity cost rate is 10.20 percent for UI's distribution operations. Exh. AEB-1, at 3.

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[30] *See Bluefield*, 262 U.S. at 692 ("A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties").
[31] *Bluefield*, 262 U.S. at 692 ("The return should be reasonably sufficient to assure confidence in the financial soundness of the utility")
[32] Bluefield, 262 U.S. at 692 ("The return 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.")

Table 11
Summary of Ms. Bulkley's Equity Cost Rate Approaches

	Constant Growth DCF		
	Mean Low	*Mean*	*Mean High*
30-Day Average	8.27%	9.51%	10.96%
90-Day Average	8.15%	9.39%	10.83%
180-Day Average	8.19%	9.43%	10.88%
Constant Growth Average	8.21%	9.44%	10.89%
	Median Low	*Median*	*Median High*
30-Day Average	8.45%	9.39%	9.99%
90-Day Average	8.33%	9.29%	9.87%
180-Day Average	8.36%	9.37%	9.96%
Constant Growth Average	8.38%	9.35%	9.94%
	CAPM		
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.68%	11.72%	11.76%
Bloomberg Beta	11.11%	11.17%	11.23%
Long-term Avg. Beta	10.34%	10.43%	10.51%
	ECAPM		
Value Line Beta	11.99%	12.02%	12.06%
Bloomberg Beta	11.57%	11.61%	11.66%
Long-term Avg. Beta	10.99%	11.06%	11.12%
	Risk Premium		
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	9.89%	10.03%	10.18%

Exh. UI-AEB-1.

a. Inflated DCF Equity Cost Rate

Ms. Bulkley developed an equity cost rate by applying the DCF model to her proxy group. Exh. UI-AEB-1, pp. 31-35; Exh. AEB-2. In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. OCC Direct (Woolridge), pp. 73-77. Ms. Bulkley used three dividend yield measures (30, 90, and 180 days) in the DCF models she conducted. In the constant-growth DCF models, Ms. Bulkley has relied upon the forecasted EPS growth rates of Zacks, Yahoo Finance, and *Value Line*. Id.

Two errors in Ms. Bulkley DCF analysis which inflate the DCF equity cost rates: (1) she has exclusively used the overly optimistic and upwardly biased EPS growth rate forecasts of Wall Street analysts and *Value Line*; and (2) she has claimed that the DCF results underestimate the market-determined cost of equity capital due to high utility stock valuations and low dividend yields. Id., at 73.

xv. Analysts' EPS Growth Rate Forecasts

Dr. Woolridge's testimony provides an extensive discussion and analysis on the research regarding the forecasted EPS estimates and growth rates of Wall Street analysts. OCC Direct (Woolridge), p. 73. The testimony discusses the sources of analysts' forecasts, and distinguishes between short-term earnings estimates of quarterly and annual EPS and versus long-term (three-to-five year) projected EPS growth rates. Dr. Woolridge summarized his assessment of using the EPS growth rate forecasts of Wall Street Analysts in a DCF model:

> *It is highly unlikely that investors today would rely exclusively on the EPS growth rate forecasts of Wall Street analysts and ignore other growth rate measures in arriving at their expected growth rates for equity investments. As I previously indicated, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Hence, consideration must be given to other indicators of growth, including historical prospective dividend growth, internal growth, as well as projected earnings growth. In addition, a study by Lacina, Lee, and Xu (2011) has shown that analysts' long-term earnings growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[33] Accordingly, the weight given to analysts' projected EPS growth rates should be limited. And finally, and most significantly, it is well-known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.[34] Therefore, using these growth rates as a DCF growth rate produces an overstated equity cost rate.*
>
> *A study by Easton and Sommers (2007) found that optimism in analysts' earnings growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[35] Thus, exclusive reliance on these forecasts for a DCF growth rate results in failure of one the basic inputs in the equation. In addition, as noted above, a study by Szakmary, Conover, and Lancaster (2008) discovered that the three-to-five-year EPS growth rate forecasts of Value Line's to be significantly higher than the EPS growth rates that these companies subsequently achieved.[36]*

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[33] Michael Lacina, B. Brian Lee and Zhao Xu, *Advances in Business and Management Forecasting*, at 77–101 (Kenneth D. Lawrence, Ronald K. Klimberg eds., Emerald Grp. Publ'g Ltd. 2011).

[34] *See supra* note. 15 at 42.

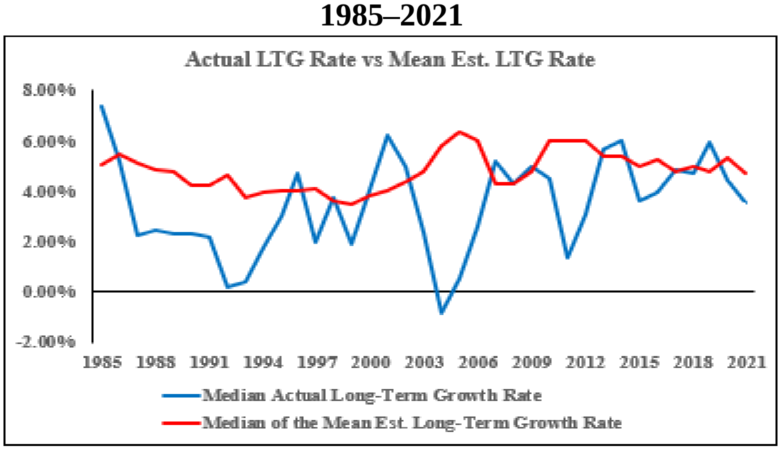
[35] Peter D. Easton, & Gregory A. Sommers, *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, J. of Accounting Research, 45, 983–1015 (2007).

[36] Andrew C. Szakmary, C. Michelle Conover, & Carol Lancaster, *An Examination of Value Line's Long-Term Projections*, 32 *J. of Banking & Fin.* 820–33 (2008).

Id., at 74-5.

Dr. Woolridge also presented the results of a study he conducted on the accuracy of analysts' EPS growth rates for electric utilities and gas distribution companies over the 1985 to 2021 time period. OCC Direct (Woolridge), pp. 49-50. In the study, Dr, Woolridge used the utilities listed as the electric utilities and gas distribution companies covered by *Value Line*. He collected the three-to-five-year projected EPS growth rate from I/B/E/S for each utility and compared that growth rate to the utility's actual subsequent three-to-five-year EPS growth rate. Id. The results of Dr. Woolridge's study are shown below in Figure 8. In this figure, the mean forecasted EPS growth rate (the red line) is consistently greater than the achieved actual EPS growth rate (the blue line) over the time period, with the exception of short periods in 1996, 2001, 2007, 2013, and 2019. Id. Over the entire period, Dr. Woolridge reports that the mean forecasted EPS growth rate is over 200 basis points above the actual EPS growth rate. Id. As such, Dr. Woolridge concluded that the projected EPS growth rates for electric and gas utilities are overly optimistic and upwardly based. Id.

Figure 8
Mean Forecasted vs. Actual Long-Term EPS Growth Rates
Electric Utilities and Gas Distribution Companies
1985–2021



Data Source: S&P Global Market Intelligence, Capital IQ, I/B/E/S, 2022. Id., at 49.

Dr. Woolridge also highlighted a 2008 study by Szakmary, Conover, and Lancaster which evaluated the accuracy of *Value Line*'s three-to-five-year EPS growth rate forecasts using companies in the Dow Jones Industrial Average over a thirty-year time period. Id., at 49-50. The authors found *Value Line*'s forecasted EPS growth rates to be significantly higher than the EPS growth rates that these companies subsequently achieved.[37] Id. The study evaluated the predicted versus projected stock returns, sales, profit margins, and earnings per share made by *Value Line* over the 1969 to 2001 time period.[38] Id. The study used the 65 stocks included in the Dow Jones Indexes (30 Industrials, 20 Transports and 15 Utilities), and found that the projected annual stock returns for the Dow Jones stocks were "incredibly overoptimistic" and of no predictive value. Id. The mean annual stock return of 20 percent for the Dow Jones stocks' *Value Line*'s forecasts was nearly double the realized annual stock return. The authors also found that *Value Line*'s forecasts of earnings per share and profit margins were "strikingly overoptimistic." Id. *Value Line*'s forecasts of annual sales were higher than achieved levels, but not statistically significant. The study concluded that the overly optimistic projected annual stock returns were attributable to *Value Line*'s upwardly biased forecasts of earnings per share and profit margins. Id.

Ms. Bulkley also errs by claiming that using current utility stock valuations and low dividend yields will underestimate the market-determined ROE using the DCF model. Id., at 76-7. This would mean that utility stocks are overvalued and that their stock prices will decline in the future (and therefore their dividend yield will increase). Id. Hence, Ms. Bulkley presumes to know more than investors in the stock market. But if Ms. Bulkley believed that utility stock

[37] Szakmary, A., Conover, C., & Lancaster, C., *An Examination of* Value Line*'s Long-Term Projections*, J. BANKING & FIN., May 2008, at 820–33.
[38] *Value Line* projects variables from a three-year base period (e.g., 2012 to 2014) to a future three-year projected period (e.g., 2016 to 2018)

prices will decline in the future, she should be forecasting negative utility stock returns, which is not what Ms. Bulkley presents. Id.

Dr. Woolridge also addressed how changes in regulations in the early 2000s timeframe have impacted the upward bias in analysts' EPS growth rate forecasts. Id., at 75-6. A number of studies demonstrate that the upward bias has continued despite changes in regulations and reporting requirements in the wake of the accounting scandals in the early 2000s. Id. Specifically, Dr. Woolridge cited a McKinsey study which shows that after a decade of stricter regulation, analysts' long-term earnings forecasts continue to be excessively optimistic. Id. A *Bloomberg Businessweek* article[39] also cited by Dr. Woolridge concluded, "Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects." Id., at 76.

b. Unrealistic CAPM Equity Cost Estimate

Ms. Bulkley developed an equity cost rate by applying the CAPM model to her proxy group. Exh. AEB-1, pp. 42–7; Exh. AEB- 5; OCC Direct (Woolridge), pp. 78-9. Ms. Bulkley used not only the traditional CAPM, but also the so-called Empirical CAPM (ECAPM) model for her proxy group. Id. The ECAPM is a variant of the traditional CAPM. Id. The CAPM approach requires an estimate of the risk-free interest rate, Beta, and the equity risk premium. Id. Ms. Bulkley used: (1) current (3.16 percent), near-term projected (3.48 percent), and long-term projected (3.80 percent) 30-year Treasury yields; (2) betas from *Value Line* and Bloomberg; and (3) a market risk premium of 9.78 percent. Id. Based upon these figures, she found CAPM mean and median equity cost rates ranging from 10.34 percent to 12.06 percent. Id.

[39] Roben Farzad, *For Analysts, Things Are Always Looking Up*, Bloomberg Businessweek, June 10, 2010, https://www.bloomberg.com/news/articles/2010-06-10/for-analysts-things-are-always-looking-up.

The primary errors with Ms. Bulkley's CAPM/ECAPM analyses are: (1) the use of the ECAPM version of the CAPM and (2) the expected market risk premium of 9.78 percent. OCC Direct (Woolridge), p. 78.

xvi. ECAPM

ECAPM, as popularized by rate of return consultant Dr. Roger Morin, attempts to model the well-known finding of tests of the CAPM that have indicated the Security Market Line (SML) is not as steep as predicted by CAPM. Id., at 78-9. As such, the ECAPM is an alternative version of the CAPM. Id. However, the ECAPM has not been theoretically or empirically validated in refereed journals. Id. The ECAPM provides for weights that are used to adjust the risk-free rate and market risk premium in applying ECAPM. Ms. Bulkley used 0.25 and 0.75 factors to boost the equity risk premium measure, but provided no empirical justification for those figures. Id.

Beyond the lack of any theoretical or empirical validation of ECAPM, there are two errors in Ms. Bulkley's version of ECAPM: (1) Dr. Woolridge is not aware of any tests of the CAPM that use adjusted betas such as those used by Bulkley; and (2) adjusted betas, which were previously discussed, address the empirical issues with CAPM. Id. Specifically, the beta adjustment (1) increases the beta and resulting expected return for low beta (beta,1.0) stocks, and (2) decreases the beta and resulting expected return for high beta (beta>1.0) stocks. Id. Hence, adjusting betas in this manner provides higher returns for stocks with betas less than 1.0, and lower returns for stocks with betas more than 1.0, which is consistent with the empirical studies of the CAPM. Id.

xvii. Market Risk Premium

Another error in Ms. Bulkley's CAPM analysis is the magnitude of the market (or equity) risk premium – which results in an inflated ROE result. OCC Direct (Woolridge), pp. 78-91. Ms. Bulkley developed an expected market risk premium by: (1) applying the DCF model to the S&P 500 to get an expected market return; and (2) subtracting the risk-free rate of interest. Id. As shown in Table 8, Ms. Bulkley's estimated market return of 12.94 percent for the S&P 500 equals the sum of the dividend yield of 1.71 percent and expected EPS growth rate of 11.14 percent. Id. Subtracting the current 30-year Treasury yield of 3.16 percent yields the market risk premium of 9.78 percent. Id. The expected EPS growth rate is the average of the expected EPS growth rates from S&P. Id.

Table 8
Bulkley CAPM Market Risk Premium

	S&P 500
Dividend Yield	1.71%
+ Expected EPS Growth	11.14%
= Expected Market Return	12.94%
+ Risk-Free Rate	3.16%
= Market Risk Premium	9.78%

Dr. Woolridge noted several errors in Ms. Bulkley's market risk premium calculation that results in a highly overstated CAPM equity cost rate. OCC Direct (Woolridge) pp. 80-82. First, the assumption of a 12.94 percent expected stock market return is excessive and unrealistic. Id., at 80. The compounded annual return in the U.S. stock market is about 10 percent (9.97 percent according to Damodaran between 1928-2021).[40] Id. As such, Ms. Bulkley's CAPM results assume that return on the U.S. stock market will be more than 30 percent higher in the future than it has been in the past. Id. Dr. Woolridge highlighted that this

[40] http://pages.stern.nyu.edu/~adamodar/.

extremely high expected stock market return, and the resulting market risk premium and equity cost rate results, are directly related to computing the expected stock market return as the sum of the adjusted dividend yield plus the expected EPS growth rate of 11.14 percent. Id.

Second, Ms. Bulkley's market risk premium of 9.78 percent is well in excess of market risk premiums: (1) found in studies of the market risk premiums by leading academic scholars; (2) produced by analyses of historic stock and bond returns; and (3) found in surveys of financial professionals. OCC Direct (Woolridge), pp. 81-2. Dr. Woolridge provided the results of over thirty market risk premiums studies from the past fifteen years. Exh. JRW-6, p. 6. Dr. Woolridge summarized the results: (1) Historic stock and bond returns suggest a market risk premium in the 4.40-6.71 percent range; (2) the market risk premium results for *ex ante* models vary from as low as 3.47 percent to as high as 6.00 percent; and (3) the market risk premiums developed from surveys of analysts, companies, financial professionals, and academics suggest even potentially lower market risk premiums, in a range from 3.88 percent to 5.70 percent. OCC Direct (Woolridge), pp. 81-82. As a result, there is no support in historic return data, surveys, academic studies, or reports for investment firms for a market risk premium as high as the 9.78 percent used by Ms. Bulkley. Id., at 82.

Third, the long-term EPS growth rate of 11.14 percent, which is used by Ms. Bulkley to compute her 9.78 percent market risk premium, is inconsistent with both historic and projected economic and earnings growth in the U.S. for several reasons: (1) long-term EPS and economic growth is about one-half of Ms. Bulkley's projected EPS growth rate of 11.14 percent; (2) long-term EPS and GDP growth are directly linked; and (3) more recent trends in GDP growth, as well as projections of GDP growth, suggest slower economic and earnings growth in the near future, during the period when the rates from this case will be effective. Id., at 83.

Dr. Woolridge provided an extensive analysis of EPS and GDP growth which demonstrates how overstated and unrealistic is Ms. Bulkley's projected EPS growth rate of 11.14 percent, which produces her 9.78 percent market risk premium. Id., at 83-92. Dr. Woolridge's analysis shows that:

- Ms. Bulkley's CAPM market-risk premium methodology is based entirely on the concept that analysts' projections of companies' three-to-five EPS growth rates reflect investors' expected long-term EPS growth for those companies. Id., at 80-1. Numerous studies have shown that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.[41] Moreover, a 2011 study showed that analysts' forecasts of EPS growth over the next three-to-five years earnings are no more accurate than their forecasts of the next single year's EPS growth.[42] Id. The overly-optimistic inaccuracy of analysts' growth rate forecasts leads to an upward bias in equity cost estimates that has been estimated at about 300 basis points.[43] Id.

- Changes in regulations and reporting requirements over the past two decades have not impacted the fact that analysts' long-term earnings forecasts continue to be excessively optimistic. Id., at 80-1.

- Over the long-term, there is a direct link between EPS and GDP growth rates, and historically they have grown in the 6 percent-7 percent range; Id., at 83-4.

- The trends and projections indicate slower GDP growth in the future, with the average projected GDP growth rates by such agencies as Social Security Administration, Energy Information Administration, and the Congressional Budget Office in the 4.0 percent to 4.4 percent range. Id., at 85-8. A major reason for the projected slower GDP growth in the future is the slowing growth of the population (and therefore workforce) in the U.S. Id.

- On a year-to-year basis, S&P 500 EPS growth rates are much more volatile than the GDP growth rates because the EPS growth for the S&P 500 companies can be influenced by factors like labor costs, interest rates, commodity prices, or the recovery of different sectors. Id., at 87-8.These short-term factors can make it appear that there is a disconnect

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[41] Such studies include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance,* pp. 643–684, (2003); M. Lacina, B. Lee, and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[42] M. Lacina, B. Lee, & Z. Xu, *Advances in Business and Management Forecasting,* Vol. 8, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[43] Peter D. Easton & Gregory A. Sommers, "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts," 45, *Journal of Accounting Research*, pp. 983–1015 (2007).

between the economy and corporate profits. But over time S&P 500 EPS growth rates tie to GDP growth rates. Id.

- Corporate profits are constrained by GDP. Id., at 88-9. Milton Friedman, the noted Nobel Laureate economist, warned investors and others not to expect corporate profit growth to sustainably exceed GDP growth, stating, "Beware of predictions that earnings can grow faster than the economy for long periods. When earnings are exceptionally high, they don't just keep booming."[44] Id. Friedman also noted in the Fortune interview that profits must move back down to their traditional share of GDP. Id., at 88. Likewise, Warren Buffett noted the following:

> *You know, someone once told me that New York has more lawyers than people. I think that's the same fellow who thinks profits will become larger than GDP. When you begin to expect the growth of a component factor to forever outpace that of the aggregate, you get into certain mathematical problems. In my opinion, you have to be wildly optimistic to believe that corporate profits as a percent of GDP can, for any sustained period, hold much above 6 percent.*[45]

Id., at 92. And Mr. Buffett goes on to explain what corporate profits will remain at about 6 percent of GDP:

> *One thing keeping the percentage down will be competition, which is alive and well. In addition, there's a public-policy point: If corporate investors, in aggregate, are going to eat an ever-growing portion of the American economic pie, some other group will have to settle for a smaller portion. That would justifiably raise political problems – and in my view a major reslicing of the pie just isn't going to happen.*

Id.

In summary, Ms. Bulkley's long-term S&P 500 EPS growth rate of 11.14 percent, which produces her market risk premium of 9.78 percent, is grossly overstated and is untethered in economic reality. Id., at 91-2. In the end, as Dr. Woolridge indicated, the issue is whether corporate profits can grow faster than GDP. Jeremy Siegel, the renowned finance professor at the Wharton School of the University of Pennsylvania, believes that going forward, earnings per share can grow about half a point faster than nominal GDP, or about 5.0 percent, due to the big

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[44] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," Fortune, (Dec. 7, 2017), http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

[45] Carol Loomis, "Mr. Buffet on the Stock Market," *Fortune*, (Nov. 22, 1999), https://money.cnn.com/magazines/fortune/fortune_archive/1999/11/22/269071/.

gains in the technology sector. OCC Direct (Woolridge), p. 92. However, he also believes that sustained EPS growth matching analysts' near-term projections is absurd: "The idea of 8 percent or 10 percent or 12 percent growth is ridiculous. It will not happen."[46] Id., at 92.

xviii. Bond Yield Plus Risk Premium Approach

Ms. Bulkley developed an equity cost rate by applying the CAPM model to her proxy group. Exh. AEB-1, pp. 41-44; Exh. AEB-5; OCC Direct (Woolridge), pp. 92-94. Ms. Bulkley developed the equity cost rate by: (1) regressing the authorized returns on equity for electric utility companies from the Q1 1992 to Q2 2022 time period on the thirty-year Treasury Yield; and (2) adding the appropriate risk premium established in (1) to two different thirty-year Treasury yields: (a) a current yield of 3.18 percent, a near-term projected yield of 3.40 percent, and a long-term projected yield of 3.80 percent. OCC Direct (Woolridge), pp. 92-94. Ms. Bulkley reported RP equity cost rates ranging from 9.89 percent to 10.18 percent. Id.

xix. Risk Premium

There are four primary errors with the risk premium proposed by Mr. Bulkley. First, Ms. Bulkley's methodology produces an inflated measure of the risk premium because the approach uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury Yields. Id. Because Treasury yields are always forecasted to increase, the resulting risk premium would be smaller if Ms. Bulkley used projected Treasury yields to estimate the risk premium and not historical Treasury yields. The net result is an overstatement of the risk premium. Id.

[46] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," *Fortune*, (Dec. 7, 2017), http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

Second, the overall approach is misguided in that it is a gauge of *commission* behavior and not *investor* behavior. Id. Dr. Woolridge testified that capital costs are determined in the marketplace through the financial decisions of investors, and are reflected in such fundamental factors as dividend yields, expected growth rates, interest rates, and investors' assessment of the risk and expected return of different investments. Id. Regulatory commissions, on the other hand, evaluate capital market data in setting authorized ROEs, but also take into account other utility- and rate case-specific information in setting ROEs. Id. As such, Ms. Bulkley's approach and results reflect other factors such as capital structure, credit ratings and other risk measures, service territory, capital expenditures, energy supply issues, rate design, investment and expense trackers, and other factors used by utility commissions in determining an appropriate ROE in addition to capital costs. Id. This may be especially true when the authorized ROE data includes the results of rate cases that are settled and not fully litigated. Id.

Third, the errors of Ms. Bulkley's approach are exemplified by the risk premium results relative to the actual authorized ROEs for electric companies. Id. Ms. Bulkley's risk premium equity cost rate estimates range from 9.89 percent to 10.18 percent. Id. These figures overstate actual state-level authorized ROEs. Id.

Finally, Ms. Bulkley's methodology produces an inflated required rate of return since utilities have been selling at market-to-book ratios well in excess of 1.0 for many years. Id. This indicates that the authorized and earned rates of return on equity have been greater than the return that investors require. Id. Therefore, the risk premium produced from Ms. Bulkley's study is overstated as a measure of investor return requirements, and produced an inflated equity cost rate. Id., p. 94.

xx. Regulatory and Business Risks

Ms. Bulkley also considered UI's various regulatory and business risks in arriving at her 10.20 percent ROE recommendation. OCC Direct (Woolridge), p. 8. As Dr. Woolridge explained, credit rating agencies consider these factors when rating UI's bonds, so they are already accounted for in assessing UI's risk. Id. And as previously indicated, UI's S&P and Moody's issuer credit ratings of A and Baa1 are slightly above the averages of the two Proxy Groups, which are BBB+ and Baa1. As such, Dr. Woolridge concluded that these risks are included in the credit rating process and UI is still slightly less risky than the proxy groups. Id.

iii. Summary of Dr. Woolridge's Recommendations

For the reasons explained above, Dr. J. Randall Woolridge has proposed a capital structure with a common equity ratio of 52.0 percent, an equity cost rate of 9.00 percent, and an overall fair rate of return – or cost of capital – of 6.69 percent for the first two rate years, and 6.76 percent for Rate Year 3.

Dr. Woolridge's recommendation does not consider any potential adjustment to ROE contemplated by the Authority in its Revised Notice of Proceeding relating to its Tropical Storm Isaias Response and Transmission Expense Reporting, nor any further adjustment the Authority may seek to apply based upon other specific facts under its consideration in this case, as discussed below.

iv. There is Appropriate Justification for the Authority to Authorize a Lower ROE

As noted above, the Authority can make adjustments to the Company's allowed ROE in consideration of factors beyond those considered by Dr. Woolridge's analysis. As Dr. Woolridge observed, there is not a guaranteed or automatic relationship between the ROE authorized by a regulatory commission and the market performance of a corresponding holding company. There is evidence in the record that authorized ROEs nationwide have reached levels exceeding the true cost of equity by as much as 5.5% -- despite utility credit ratings remaining flat -- resulting in consumers overpaying by billions of dollars on an annual basis. See OCC Direct (Woolridge), pp. 23-24. As noted by Dr. Woolridge,[47] whereas inflated returns may not have been unduly burdensome upon ratepayers in the past, times have changed – the ever-increasing household energy burden fueled by extreme supply volatility and general economic turmoil has brought us to a critical inflection point, and it is necessary for the Authority to ensure that the returns earned by companies like UI are sufficient, but no more than sufficient, for those companies to recover the cost of capital.

The Court in *Bluefield* recognized this a century ago, when it noted that "[w]hat annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts," and that, "[a] rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." *Bluefield*, 262 U.S. at 692-93. Indeed, the Court acknowledged that "no proper rate can be established for all cases," and that a rate of return on equity as low as 6% could be appropriate where "investment [is] . . . safe, returns certain and risk reduced almost to a minimum." *Id*. at 693. In setting the ROE for UI, the Authority should consider all "circumstances, locality and risk,"[48] including the fact that Connecticut's revenue decoupling paradigm provides UI with shelter from risk that is even significant among regulated utilities in

[47] See OCC Direct (Woolridge), pp. 23-24.
[48] Bluefield, 262 U.S. at 693.

general. Tr. 3199-3200 (when asked whether every regulatory jurisdiction has a revenue decoupling mechanism like Connecticut's, EOE's witness responded, "I don't know of any others that have that exact, that level of guarantee," and adding that the mechanism would "certainly be risk reducing").

1. The Company Overstates Its Argument That Regulatory ROE Reductions Cause Long-Term Financial Distress

As identified by EOE's witness during the hearing, in setting an appropriate ROE in this case, the Authority is supposed to determine the market return that investors will require in order to provide UI access to capital, but in practice the ROE set by the Authority, which is applied against rate base, is essentially a book return. Tr. 3194. In other words, the return on equity as allowed by PURA may impact the market return, but is not equivalent to the return on equity that will be actually earned by shareholders. Tr. 3194 (". . . if you buy a stock . . . it would only be the return on the market price you purchased.").

This is because there are elements beyond a company's earnings that impact the attractiveness of its market value. Tr. 3207. And here, the Authority is setting the earnings of a subsidiary as a mechanism to influence the market value of its parent entity,[1] so there are also elements beyond UI's earnings that impact the market value of Avangrid's stock, including but not limited to the unregulated operations in which Avangrid engages. Tr. 3208-3209. Thus, establishing an allowed rate of return on equity for an operating entity like UI, as measured by a percentage or rate base, is at best an imprecise tool for influencing the market value of a publicly traded parent like Avangrid. A company's book value, as measured by rate base, is "not necessarily the same" as the market value of the company's shares. Tr. 3195 ("I think the electric [companies] are about two, the market price is about twice the book on average"). It is for this reason that lowering an operating company's authorized ROE does not guarantee a reduction in a parent company's ability to attract capital from its investors. Tr. 3209-3210. A company's allowed ROE can be lower than the authorized ROEs for comparable companies, and the company should still have no trouble raising capital so long as the authorized ROE is equal to or greater than the market-based cost of equity. Tr. 3210.

The goal is for PURA to set an ROE for UI that is sufficient, but no more than sufficient, for UI to attract the necessary capital for the provision of service. Tr. 3205. PURA's target ROE should be the numerical equivalent of "enough, but not too much." Tr. 3205

a. Pinnacle West Capital Corporation

The Company has repeatedly hypothesized that an allowed ROE below its recommended 10.2% "can negatively affect the Company's access to capital and the overall cost of capital." Exh. UI-AEB-1, p. 51. The example the Company repeatedly provides in support of this hypothesis, in every context in which the hypothesis has been offered, is the case of Pinnacle West Capital Corporation ("PNW"), for whom "a below average authorized ROE . . . resulted in a 24 percent decline in the share price." Id.; also see Exh. UI-AEB-REBUTTAL-1B, p. 11 ("In the case of PNW, the market had a strong negative response to the 8.70 percent ROE determination for its operating subsidiary, Arizona Public Service Company."); Tr. 2982-2983 (PNW excluded from Company's proxy group because of "a significant change in the company's stock price that occurred after its APS subsidiaries rate determination where the company lost about 24 percent of its value . . . "); Tr. 2996 (when asked whether a commission's ratemaking decisions are a proxy for the return actually required by investors, the Company's witness responded, "I think the Pinnacle West example is precisely why not, actually. That commission authorized an ROE of 8.7 and the investment community, they were downgraded, the stock price lost 24 percent of its value."); Tr. 3590 ("Pinnacle West, we talked about to a great extent when I was here a few weeks ago and the risks associated with bad regulatory outcomes in that particular jurisdiction, and how it affected their stock price and it affected the risk associated with those companies."). The Company's witness testified that following the 24% decline in PNW's share price, "the stock prices still remained low, it has been very volatile and low". Tr. 2984.

Because PNW is the only specific example the Company has provided to support its theory of the relationship between allowed ROEs and market response, it is useful for the Authority to examine the timeline of what exactly occurred to PNW, via the publicly accessible documentation of which the Authority may take administrative notice.[49] As discussed above in Section IV, the Authority may take administrative notice of judicially cognizable facts, and not all such facts require that notice be provided to the parties prior to the Authority's taking of such notice. *See Moore v. Moore*, supra, 173 Conn. at 122 ("matters of established fact, whose accuracy cannot be questioned . . . may be judicially noticed without affording a hearing."). The Connecticut Code of Evidence also permits a tribunal to "take judicial notice without request of a party to do so," and notes that parties are not entitled to receive notice and have an opportunity to be heard for "matters of established fact, the accuracy of which cannot be questions." Connecticut Code of Evidence, Sec. 2-2(b).

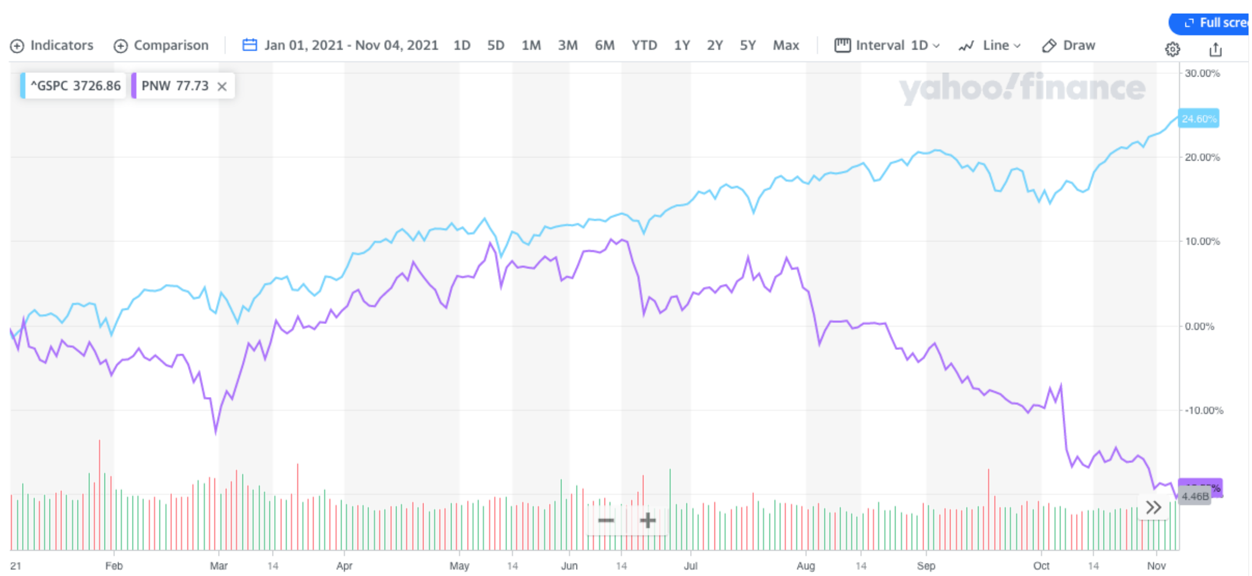
[49] Although, as noted herein, PURA is free to take notice of the historic stock prices of PNW and Eversource without providing the parties to this proceeding notice or an opportunity to be heard, it should be noted that all parties to this proceeding – particularly the Company – were in fact provided notice that such stock prices are at issue in this proceeding, because the Company itself raised the issue of those companies' stock performance in support of its theory that there is a direct connection between the ROE of an operating utility as set by its regulator and the price of its parent company's stock.

Connecticut courts have traditionally acknowledged that a trier of fact may take notice of publicly observable economic conditions, including pricing data, and that such facts are so inarguable that they do not require that other parties be afforded the opportunity to be heard. *See Moore v. Moore*, 173 Conn. 120, 123 (1977) ("Whether there has been inflation between 1969 and 1974 is not open to argument. . . . The mere fact of inflation, . . . may be judicially noticed without affording an opportunity to be heard . . . ."); *New Haven Trust Co. v. Doherty*, 74 Conn. 468, 468 (1902) (Supreme Court took "judicial notice that in 1895 the current rate of interest on moneyed securities exceeded 1¾ per cent."); *Mognol-Martin v. Martin*, 2002 Conn. Super. Ct. 14011, No. FST-FA-0184537-S, 2002 WL 31561808 at *2 (Conn. Super. Ct. Nov. 1, 2002) (Superior Court took judicial notice of then-current **prices of publicly traded stocks**) (emphasis added); *Murphy v. Murphy*, No. NNH-FA-000439011-S, 2001 WL 497077 at *1, n. 1 (Conn. Super. Ct. Apr. 25, 2001) (Superior Court took judicial notice of the **market value of public-traded stock on a particular date**) (emphasis added); *Layman v. Layman*, No. FST-FA-010186011-S, 2003 WL 21675904 at *3 (Conn. Super. Ct. Jun. 26, 2003) (Superior Court took judicial notice of **closing price of a particular publicly traded stock on a date certain**, as published in an issue of the Wall Street Journal) (emphasis added).

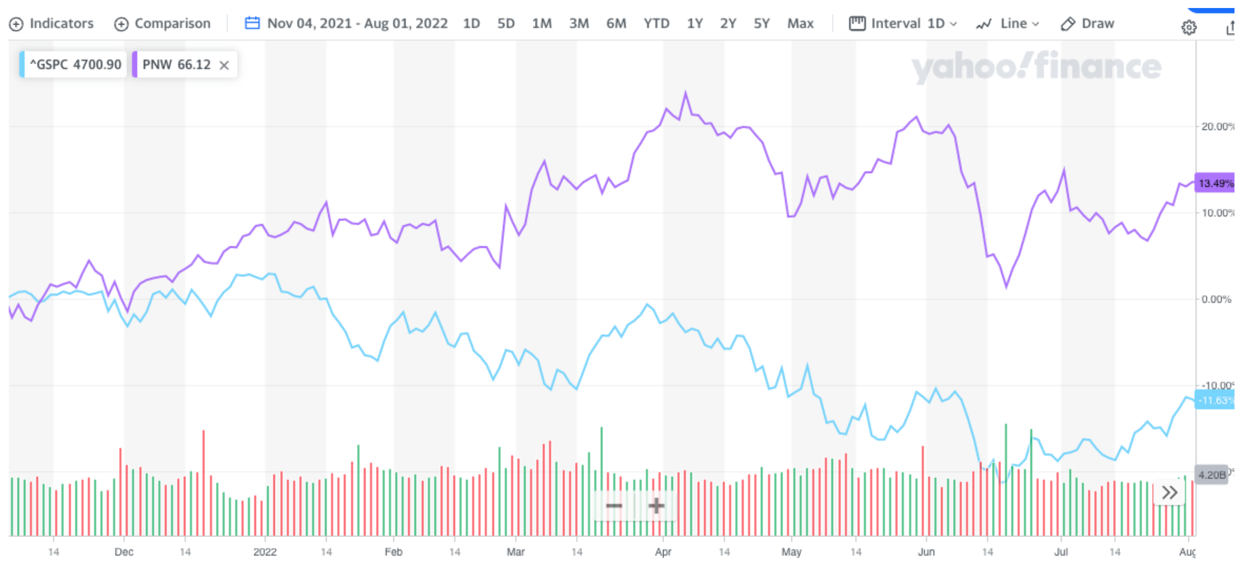
As noted in the Company's direct testimony, the Arizona Corporation Commission issued a "Recommended Opinion and Order" on August 21, 2021, recommending an ROE of 9.16%. Exh. UI-AEB-1, p. 54. The Commission then amended that recommendation to 8.70% on October 4, 2021. Id.

The Company provided an analysis showing PNW's stock price performance between January 1, 2021 and November 4, 2021, comparing it to the performance of the S&P 500 Index. Id. at 56. The analysis shows that PNW's price generally exceeded the Index (with the exception of a dip around March of 2021) up until August of 2021, at which time it began to steadily decline below the Index until November of 2021, which is where the analysis ends. Id. The Company's witness described the Company's chart as indicating that "there was a drop after the first [decision], and a drop after the second one. So the market responded, actually, prior to any credit rating downgrades, the market response was, was swift." Tr. 3625.

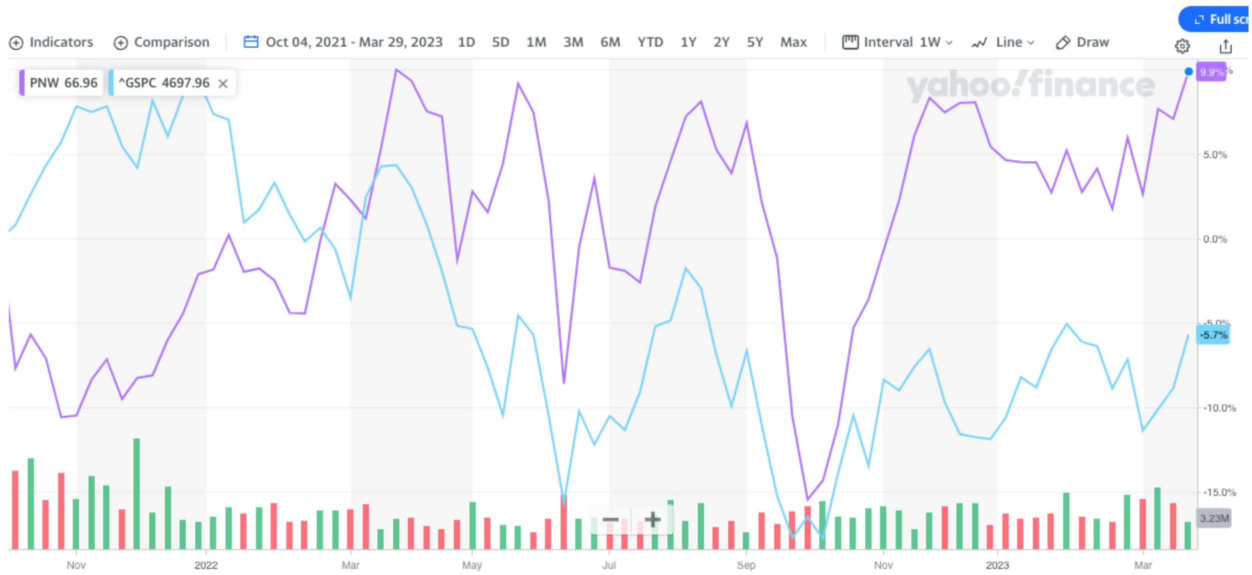
OCC was able to replicate this analysis, using the same inputs,[3] and the overall picture is the same as shown below. PNW's market performance noticeably declined in August of 2021, and again in October of 2021. It is important to note, however, that the historical stock price data does not support the Company's testimony that PNW's "stock price lost about 25% of its value over the course of the two decisions that were issued. There was sort of an interim decision and a final decision." Tr. 2983. PNW closed at $80.16 on August 20, 2021 – the day prior to the issuance of the Arizona Commission's Recommended Opinion and Order – and closed at $72.73 on October 5, 2021 – the day after the Commission's final Decision. The reduction in stock value between those two dates is less than 10%.



Like the Company's chart as shown in its testimony, this chart only shows approximately 10 months of data. When OCC adjusted the date inputs to reveal the data for the 10 months that followed this snapshot – from November 4, 2021 to August 1, 2022 -- we noted that the trend appeared to reverse itself quite dramatically, with PNW growing 13.49% over the time period, while the S&P 500 shrank 11.63%.



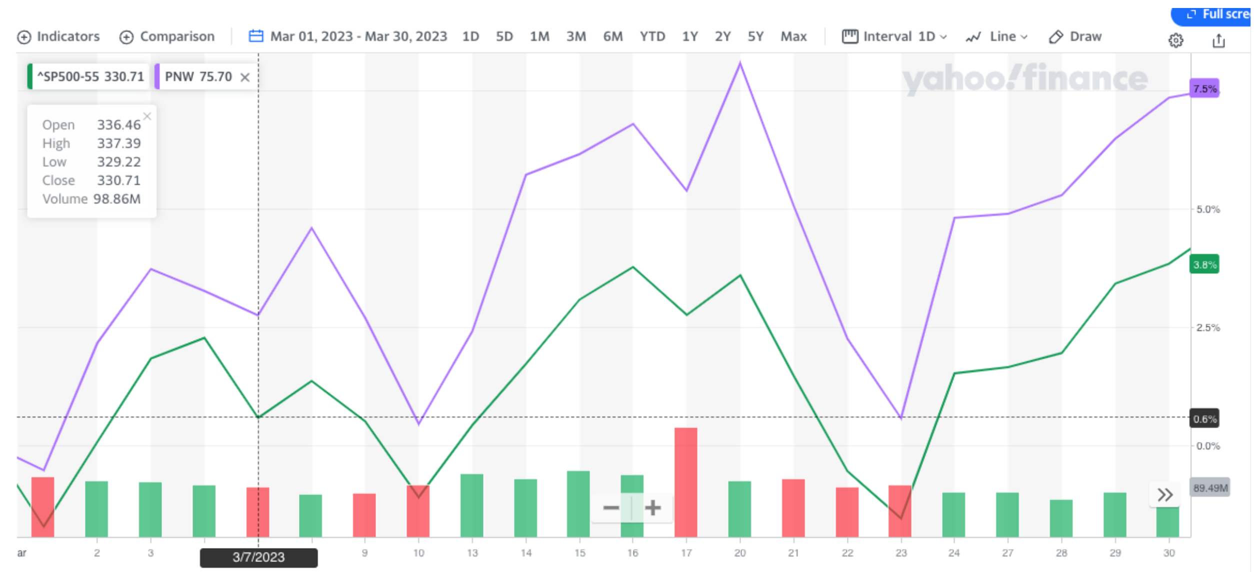
OCC adjusted the date range for the same analysis to show the overall picture from October 4, 2021 – the date when the Arizona Corporation Commission set PNW's ROE to 8.70% -- until March 29, 2023, the date of the close of evidence in the instant proceeding. This chart captures the whole picture of market activity subsequent to the reduction to PNW's allowed ROE, and hence is the clearest demonstration of the ultimate impact upon the operating company's access to capital while operating under the 8.70% restriction. The data appears to show that PNW has consistently performed better than the overall S&P 500 since early 2022.



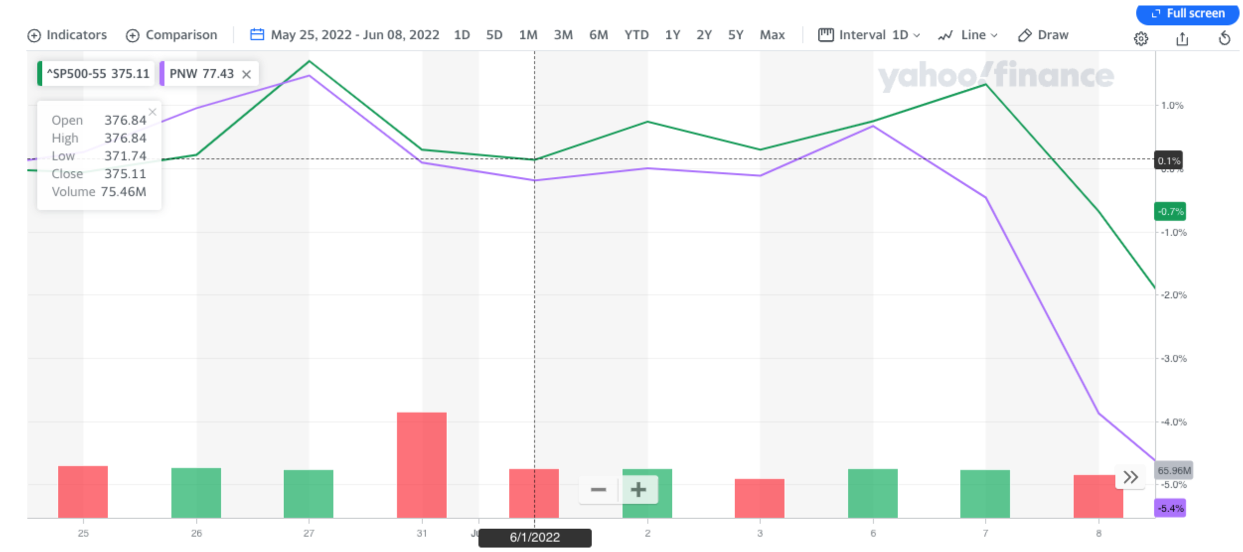
When the Company's witness testified on redirect during the Late File Hearing regarding this apparent improvement in PNW's market performance, she testified, "we just talked about how the price of Pinnacle West stock has come back some, they did file an appeal with the Supreme Court and they were successful on certain portions of that appeal. And they have also, subsequently, filed another rate proceeding. And so those factors are likely to be contributors to the change in price that we have seen since that time." Tr. 3628.

The Authority can measure the veracity of that testimony by comparing the timeline of events referenced against PNW's historical stock performance. The Arizona Court of Appeals issued a decision on March 7, 2023 in *Arizona Public Service Company* v. *Arizona Corporation Commission*, No. 1-CA-CC21-0002 (Ariz. App. Div. 1, Mar. 7, 2023) (2023 WL 2377024). The decision "affirm[ed] the Commission's discretionary base return on equity determination but vacate[d] the 0.2% reduction because the Commission's use of customer-service metrics exceeded its rate-making authority." *Id.*

If the Authority reviews PNW's stock performance across a time frame spanning across the month of March, 2023, there is no immediately apparent impact attributable to March 7, 2023 – particularly when compared against the S&P 500 Utilities Index (SP500-55). PNW's pricing appears to track the industry-wide trends, as opposed to being impacted in any way by the March, 7, 2023 court decision:



Arizona Public Service Company filed a new rate application with the Arizona Corporation Commission on June 1, 2022 in Docket No. E-01345A-22-0144, which remains pending. If the Authority observes the two-week window surrounding June 1, 2022, again tracked against the S&P 500 Utilities Index, it is similarly difficult to discern any market impact whatsoever from this new rate case filing:



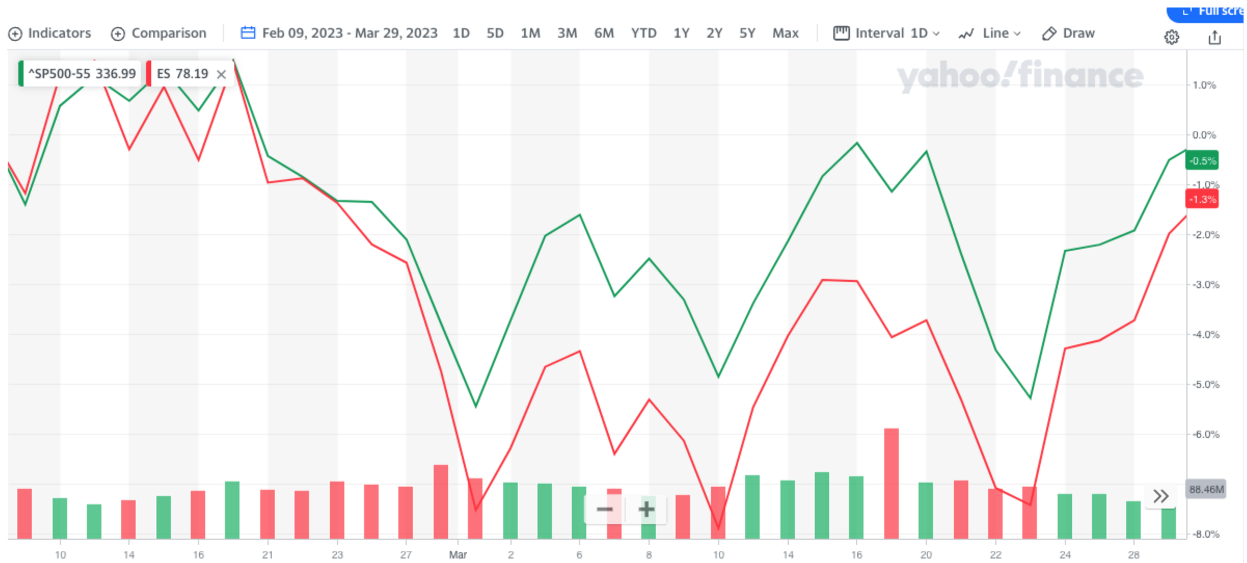
b. The Authority's Recent Aquarion Water Decision

In support of its theory that a regulatory body reducing a company's ROE has direct and serious consequences for its parent company's financial performance, the Company also raised the alleged impact of the Authority's recent Final Decision in PURA Docket No. 22-07-01, *Application of Aquarion Water Company of Connecticut to Amend Its Rate Schedule*, issued on March 15, 2023, which reduced Aquarion Water Company's allowed ROE to 8.70%. Tr. 3610-3611. The Company testified that "there have been, several analysts who have demonstrated concerns, significant concerns, about that decision and how that affects the Company," Tr. 3590-3591, and "based on that one regulatory decision, RRA reduced the regulatory ranking for the State of Connecticut two notched based on that one decision. The . . . in the Bank of America report, the expectation is a 3 percent earnings hit for Eversource as an overall company . . . ." Tr. 3610-3611.

However, the Company has not provided the Authority with any analysis of the actual market performance of the Aquarion Water Company's parent, Eversource Energy, which trades on the New York Stock Exchange under the symbol "ES". OCC has conducted a similar analysis for Eversource as the Company's analysis of PNW. We have compared Eversource's market growth against the S&P 500, from the week prior to the Authority's issuance of the Proposed Final Decision in Docket No. 22-07-01 – which was the first public announcement of the prospect of a reduced ROE – until the close of evidence in the instant proceeding:

The data appears to indicate that although Eversource underperformed the market at some points during the studied time period, the points do not necessarily align with the issuance of the Proposed Final Decision (February 16, 2023) or the issuance of the Final Decision (March 15, 2023). In fact, the data indicates that Eversource's stock declined 0.68% as of close on February 16, and then grew 2.66% the following day. The price fell from $76.80 at close on March 15 to a lowest point of $73.25 at close on March 23 (a 4.6% reduction) but as of March 29, 2023, the stock closed at $77.55 - an increase over the price at opening on the date the Final Decision was issued.

Furthermore, if you compare Eversource's performance over the same timeframe against the S&P 500 Utilities Index, which measures the performance of the utility sector rather than the overall market, the data appears to indicate that Eversource's price trends map closely to those of utilities overall. To whatever extent Eversource's price dropped following the issuance of the Proposed or Final Decisions in Docket No. 22-07-01, the performance of the entire utility sector appears to have behaved similarly.



Hence, not only has the Company failed to even attempt to demonstrate a measurable market impact from the Authority's Final Decision in Docket No. 22-07-01, but the uncontestable market pricing data directly conflicts with the Company's theory that reducing a company's allowed ROE has a substantial impact upon its access to capital.

i. Depreciation

i. The Authority Should Adopt OCC's Recommended Depreciation Rates

UI presented depreciation rates prepared by Larry E. Kennedy, who proposed an increase in depreciation rates for distribution plant from 3.10% to 3.14%. and a decrease for general plant from 5.03% to 4.90%. Exh. UI-LEK-1, p. 7. In contrast, OCC recommends a decrease in depreciation rates for distribution plant from 3.10% to 2.83% and an increase for general plant from 5.03% to 5.24%. OCC Direct (Dunkel), p. 36-37. For the reasons that follow, the

Authority should reject the Company's proposed depreciation rates and adopt those recommended by OCC.

The Authority should accept OCC's proposed depreciation rates because they are designed to be appropriate. OCC's recommendation uses the same remaining life formula and the same net salvage method used to derive the depreciation rates currently in effect for the Company. Also, OCC's proposed depreciation rates are not designed as a first step in a plan designed to drive up depreciation rates over time, as is the case with the rates proposed by the Company, as explained in Section V(i)(iv) below.

The Authority should reject the Company's proposal to increase depreciation rates as fundamentally illogical. As OCC's witness summarized during the hearing, it doesn't make any sense for depreciation rates to increase:

> *I'll also point out, in this case, the lives, average lives right now are five years longer than when they were in the prior case. The longer lives reduces the depreciation rate. The ratepayers should be getting about a $4 million reduction in this case because of the lives are longer. And this is not me saying that, that's the Company filed lives are five years longer than they were before. That should have been a multimillion dollar reduction for the ratepayers.*
>
> Tr. 151; see also Exh. OCC-WWD-1, p. 6 - 7.

The Authority should further reject the Company's proposal for the reasons that follow.

ii. The Company's Proposal Incorporates a Refinement into the Remaining Life Calculation that Would Lead to Perpetual Overrecovery

The Company's proposal "incorporates a refinement into the remaining life calculations," Exh. UI-LEK-1, p. 19, which would result in charging ratepayers at least three times as much as would be appropriate.

To understand this, it must first be recognized that the depreciation rates established in this proceeding are expected to be in effect for at least three years, which the Company's witness acknowledged in the following exchange:

> *Q: ... the company is proposing a three-year rate plan which means your depreciation rates, if accepted, would be in effect for at least three years?*
>
> *A: That's my understanding."*
>
> Tr. 41.

The effect of the Company's refinement is illustrated by Account 360.00. The Company calculated the Net Book amount, which is the amount "that remains to be properly recovered from ratepayers" for the year 1926 vintage in Account 360.00 to be $36,337.[50] Exhibit UI-LEK-2, p. 141. The **Annual** Accrual the Company proposes be charged to ratepayers **is the exact same number -** $36,337.[51] Exh. UI-LEK-2, p.141. Since the depreciation rates are reasonably expected to remain in effect for at least three years, the problem with this proposal is that the unrecovered amount of $36,337 would be fully recovered from the ratepayers after the first year. UI would continue to recover the $36.337 in the second year and the third year, which would constitute an overrecovery. Hence, this example clearly demonstrates that the Company's "refinement" to the remaining life calculations includes charging ratepayers at least three times more than the value of the applicable remaining life. Exh. OCC-WWD-Surrebuttal-1, p. 9. In fact, the overrecovery would continue until rates are reset by the Authority, which could exceed the proposed multiyear rate plan. As the Company's own witness acknowledged, the proposed

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[50] This is in the Net Book Column. Mr. Kennedy agreed that the amount in the net book column is, "the total amount that remains to be properly recovered from ratepayers." (Tr. At 42.)

[51] The 1926 Vintage shows the unrecovered amount (Net Book Value) is $36,337 and that the Company proposes an Annual Accrual of $36,337.

Rate Year 3 rates would be in effect for "the rest of time until the next rate case." Tr. 453. Therefore, the overrecovery is theoretically perpetual.

The above is just one example of the perpetual overrecovery issue. The Company's depreciation rates would result in repeatedly overcharging ratepayers for Account 370.10 as well, which can be seen on page 171 of Exhibit UI-LEK-2. For every row where the "ALG Remaining Life" column is blank, the Annual Accrual proposed is the same dollar amount as the unrecovered amount, i.e., the Net Book Value. Since UI would receive the Annual Accrual in each of the three proposed rate years, and because the rates in effect for proposed Rate Year 3 would remain in effect until UI's next rate case, this too would constitute perpetual overrecovery, totaling more than $4 million in over recovery within the proposed rate plan for this one account alone. Exh. UI-LEK-2, p. 171[52].[53]

1. The "Refinement" The Company Made to the Remaining Life Formula is Unsupported By Any Depreciation Textbooks or Sound Depreciation Methodologies

Consistent with the derivation of the current UI depreciation rates, OCC's proposal used the remaining life formula from Public Utilities Depreciation Practices published by the National Association of Regulatory Commissioners (NARUC) to calculate the proposed depreciation rates. Exh. OCC-WWD-1, pp. 1, 3.

UI's proposed depreciation rates, however, incorporate a refinement that deviates from the methodology approved in UI's last rate case. As part of this "refinement," the Company changed to a different remaining life formula located in a book named Depreciation Systems.

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[53] The Net Book Value totals over $2 million for the vintages for which the proposed Annual Accrual is the same dollar amount as the unrecovered investment (Net Book Value) [these vintages also show blank in the Remaining Life column]. The Annual Accrual for these same vintages also totals over $2 million. In three years $6 million would be recovered, when the unrecovered amount was $2 million.

Mot. 60, Exh. A, p. 143; Exh. UI-LEK-1, p. 19. Not only did the Company deviate from the methodology previously approved by the Authority, it also made adjustments to the Depreciation System formula because, in the opinion of the Company's witness, the Depreciation Systems remaining life formula was not reasonable:

> *Q: Did you just say that in fact you made modifications to the Depreciation System calculation?*
>
> *A: I said precisely that I think in these two specific circumstances that is not reasonable. I did in fact intentionally and knowingly make changes based on my many years of doing these calculations to make a fair and reasonable assumption.*
>
> Tr. 60.

2. The Company Inappropriately Altered the Required Remaining Life Values

The Authority should further reject the Company's proposal because it inappropriately altered remaining life values. As investments get older, they have a shorter remaining life. Depreciation tables, called Iowa Curves, show how many years of remaining life are to be used in the depreciation calculations for various ages. In the Company's calculations, there were some vintages which were so old that the remaining life was 0 years according to the Iowa Curve, which, in theory, means the Company should no longer be collecting depreciation on those vintages. Mot. 60, Exh. A, p. 338; Tr. 62; see also Tr. 66-67. When an asset no longer has a remaining life, it has been fully depreciated; meaning ratepayers have already fully compensated the Company for its investment. However, instead of putting 0 in the remaining life column for the vintages that were so old that the Iowa Curve remaining life was 0 years, the Company left the column blank.

During the hearing, the Company's witness initially offered reassurances that these blank spaces were actually equivalent to attributing 0 years remaining life to these old vintages, consistent with the Iowa Curve. Tr. 63; see also Tr. 65-67.

> *Q: So, isn't it correct all the blanks are actually zero remaining life?*
>
> *A: Okay. I'm sorry, I misunderstood your question. Yes.*
>
> Tr. 61.

However, the witness subsequently changed his testimony, and admitted that the Company had not used 0 years to calculate the depreciation amount of the vintages for which he left the remaining life column blank:

> *... So just to be clear, and I want the record to be clear as to what we've done, is we would assign that a remaining life of one.*
>
> Tr. 63-64.
>
> *... One is I would recover that whole amount of net book value in one year, ...*
>
> Tr. 60; see also Tr. 58.

This utilization of an inaccurate remaining life value, which would result in recovering the "whole amount of net book value in one year," for a depreciation accrual that would be collected from ratepayers for at least three years, created the perpetual overrecovery issue previously discussed.

The Company's highly modified remaining life formula uses the incorrect remaining life, violates the accepted remaining life formula, violates the definition of remaining life, violates the definition of straight-line depreciation, and overcalculates the depreciation rates. Exh. OCC-WWD-1, pp. 10-14. Accordingly, the Authority should reject the Company's proposed depreciation rates that result from this highly modified remaining life formula.

3. The Company's Inaccurate Claims Regarding Remaining Life Should Be Unpersuasive to the Authority

The Company has made three inaccurate claims with respect to remaining life, which the Authority should set aside in its analysis.

a. The Company's Proposed Remaining Life Calculation Is Not Widely Used.

First, the Company's witness incorrectly claimed that the remaining life calculation he proposed in the instant proceeding is widely used:

> *... It's been recognized in a number of jurisdictions specifically recently adopted in Idaho, Illinois, Montana. I'm missing a few, but off the top of my head. It's been very widely adopted as simply being a refinement to the widely used depreciation method.*
>
> Tr. at 34.

This assertion is unpersuasive given that two different discovery requests sought documents from cases in other jurisdictions in which the remaining life calculations were the same calculations the Company proposed; OCC-0632 and RRU-00476; and, as the Company's witness acknowledged during the hearing, none of the documents the Company provided from other jurisdictions show the same remaining life calculations proposed in the Company's application. In other words, none of the documents showed that other jurisdictions have approved a calculation that shows a blank in the Remaining Life column, but a dollar amount in the Annual Accrual column.[54]

During the hearing, the Company's witness confirmed this:

> *Q. Okay. And you provide several documents. I would represent I have looked through the documents you were provided, and I would represent I never found a case where the remaining life was either zero or blank and*

[54] For example, see the 1926 vintage on Exhibit UI-LEK-2 p. 141.

> *they had any amount in the annual accrual column that was anything other than zero or blank. Can you now disprove what I just said?* Tr. at 67. A. *(Kennedy) There's none in this set of examples that we filed here.*
>
> Tr. 66-71.

The second discovery request sought documents from cases in other jurisdictions where the remaining life calculations were the same as the calculations the Company used in this proceeding. The Company provided 2,000 pages from other jurisdictions in response.

During the hearing, the Company's witness acknowledged that despite the Company's volume of the company's response, it did not include an example of another jurisdiction using the Company's proposed methodology:

> *Q: I will again represent to you that I went through the 2,000 pages of documents which you provided looking for the same calculation I have seen you do in this case which is when there is a remaining life of zero or blank, and I would represent in no case where there was a remaining life of zero or blank did I find a dollar amount in the annual accrual column that was any number other than zero or blank. Can you demonstrate from the documents you provided that I just made an incorrect statement?*
>
> *A. You did not make an incorrect statement, sir.*
>
> Tr. 71-72.

b. The OCC's Methodology Does Not Use the Same Remaining Life for All Vintages.

The Company's second inaccurate claim with respect to remaining life is that "[o]ne feature of the remaining life method used by Mr. Dunkel is that all vintages are assigned the same remaining life."[55] Exh. UI-LEK/AN-REBUTTAL-1, p. 8.

This is false. If the Authority reviews Exhibit OCC-WWD-SURREBUTTAL-2, it is clear that the remaining lives are different for different vintages. For example, Mr. Dunkel used a 74.83 year Remaining Life for the 2021 vintage, and an 8.83 year Remaining Life for the 1955

[55] The Company's witness was addressing Account 360.00.

vintage. During the hearing, the Company's witness was asked to support the claim that the OCC assigned all vintages the same remaining life, and the witness could not. Tr. 84 – 89; Exh. OCC-WWD-SURREBUTTAL-2.

c. The Proposed Perpetual Overrecoveries Would Not Be Offset By Underrecoveries Elsewhere

The Company's third inaccurate claim with respect to remaining life is that the above-described overrecovery issue is cured by corresponding underrecoveries as to other assets. After acknowledging that the Company would overrecover by approximately a million dollars in a particular vintage, the Company's witness claimed that such over-recovery would be offset by an underrecovery in other vintages:

> *Q: And as we previously discussed, your rates will be in effect at least three years, so isn't it true you would overrecover by approximately a million dollars in that one vintage, in that one account?*
>
> *A: In that one vintage. I will point out vintages later, 2017, for example, that has $21 million of original cost and 2015 that has $22 million of original cost, again, has the same phenomenon going the other way as compared to the more composite level of calculation.*
>
> Tr. 46.

However, these vintages are not "going the other way," or underrecovering. In the 2015 vintage, the amount in the Net Book Value column is $19,054,251, which is the amount "that remains to be properly recovered from ratepayers." Exh. UI-LEK-2, p. 171.[56] The Annual Accrual shown is $1,570,161 which would be charged to ratepayers each of the 12.14 years of the remaining life, which totals a $19,061,754 recovery from ratepayers.[57] That slightly exceeds

[56] Mr. Kennedy agreed that the amount in the net book column is, "the total amount that remains to be properly recovered from ratepayers." (Tr. at 42.)
[57] $1,570,161 per year charged to ratepayers * 12.14 years = $19,061,754.

the $19,054,251 amount which remained to be recovered. The slight difference is due to rounding. There is also no underrecovery in the 2017 vintage. Exh. UI-LEK-2, p. 171.[58]

In the vintage rows in which the Company has placed a number in the Remaining Life column, the Company has used the correct remaining life.[59] However, in the vintage rows in which the Remaining Life column has been left blank, the Company has used an incorrect remaining life. As explained above, the Company would overrecover in vintage rows where the incorrect remaining life has been used. There are no vintage rows where UI would underrecover.[60]

iii. The Company Proposed to Change the Net Salvage Method That Has Previously Been Adopted by the Authority

Similar to the "refinement" the Company made to the remaining life calculations, UI also proposes to change the net salvage method which was approved by PURA in UI's last rate case. Exh. OCC-WWD-1, pp. 15-19. Not surprisingly, of the four "widely accepted methods of accounting for the collection of net salvage" that the Company considered, see Exh. UI-LEK-2, page 12, the Company proposed to change to the "the one that produces the highest net salvages." Exh. OCC-WWD-1, p. 16. During the hearing, the Company's witness acknowledged, "I would definitely say those, most analysis that we have done, it is the one that produces the highest net salvage rate." Tr. 105.

In the net salvage method recommended by the Company, the net salvage dollar amount in the numerator is stated in recent dollars, and the original cost dollar amounts in the

[58] In the 2017 vintage, the amount in the Net Book Value column is $19,859,697, which is the amount "that remains to be properly recovered from ratepayers." The Annual Accrual shown is $1,432,133 which would be charged to ratepayers each of the 13.87 years of the remaining life, which totals $19,863,684 recovery from ratepayers. That slightly exceeds the $19,859,697 amount which should be recovered.
[59] Plus or minus a tiny amount due to rounding.
[60] Plus or minus a tiny amount due to rounding.

denominator are stated in dollars from years or decades earlier. This is the equivalent of dividing apples by oranges. The Authority did not accept this in the prior UI case and should not accept it in this case. See OCC Direct (Dunkel), pp. 17-18; Exh. OCC-WWD-1, pp. 17-18. For example, one of the largest investments that retired in Account 365 in the year 2017 had gone into service in the year 1974. Therefore, its original cost is stated in year-1974 dollars, which is included in the $271,434 denominator of the Company's calculation. However, the Company divides these old dollars into the amount in the numerator which is stated in year-2017 dollars. A year-1974 dollar is worth approximately 5 times a year-2017 dollar. The Authority should reject this methodology as it is obviously flawed. Exh. OCC-WWD-1, pp. 16-19.

As discussed in OCC's direct testimony at pages 20 through 21 of Exhibit OCC-WWD-1, the outdated net salvage method the Company proposes does not properly collect future net Cost of Removal from current ratepayers, because it was not developed for that purpose. The net salvage method the Company proposes was developed in the early days of regulation when net salvage was generally "positive." When Net Salvage was positive, that meant the Gross Salvage the utility would receive at the time of retirement would fully cover the Cost of Removal. This meant no Cost of Removal would generally have to be collected from the ratepayers. This outdated net salvage method was not designed to apply to situations in which the net salvage is negative. In this proceeding the net salvage for the majority of the large accounts is "negative". Exh. OCC-WWD-1, pp. 20-21. Accordingly, the outdated net salvage method the Company proposes does not properly collect future net Cost of Removal from current ratepayers, because it was not developed for that purpose, and was not developed to apply to the current conditions.

The Company's witness claimed, with no supporting evidence, that its proposed net salvage method is the most widely accepted in "North America". Exh. UI-LEK-2, p. 12. This claim should be given very little weight by the Authority for several reasons.

First, under cross-examination, when asked to clarify his statement, the Company's witness indicated that he was including Canada in "North America," but he was not sure if he was including Mexico in "North America." Tr. 105. Therefore, not even the Company can be certain of the veracity of this claim.

Second, the claim is not supported by data, such as a multijurisdictional survey. In a discovery request, OCC named five different east coast state jurisdictions in the United States, and asked the Company which net salvage methods were accepted in those jurisdictions. The Company did not know, and was not able to determine, the acceptable methods in four of the five jurisdictions.[43.] If the claim is based upon the personal knowledge and experience of the Company's expert witness, the Authority should consider that the bulk of Mr. Kennedy's experience is in Canada, rather than the United States, as demonstrated by his resume. Exh. UI-LEK-1A; Tr. at 106.

Third, the record demonstrates that the Company's proposed net salvage method is not used in Pennsylvania, New Jersey, or Connecticut. When presented with the net salvage calculations which are used in Pennsylvania, the Company's witness acknowledged that its proposed calculations are not accepted there:

> *Q: Is it correct that this calculation in the Pennsylvania case, which you selected for perhaps other reasons, is much closer to Mr. Dunkel's calculation in this Connecticut case, than it is to your net salvage calculation in this Connecticut case?*
>
> *A: I would agree, seeing this, yes.*
>
> Tr. 114-15; see also RRU-0467 UI Att. 4, p. 1.

The record also contains evidence that the Net Salvage method utilized in New Jersey does not follow the Company's proposed method. Mot. 60, Exh. C; Tr. at 108-109. In New Jersey the net salvage dollar amounts are not divided by the original cost that retired that year. As discussed above, UI's current rate structure here in Connecticut, as set forth in its last rate case, also does not use the Company's proposed net salvage method.

For these three reasons, the Company has failed to support its claim that its proposed net salvage method is the most widely accepted in North America, and the Authority should not be persuaded by this claim.

iv. The Company is Asking the Authority to Adopt an Inappropriate Net Salvage Method

For Account 365, the Company stated that under its net salvage method it,

> ***believes that a net salvage rate of up to negative 100 percent may be warranted****, in the interest of* ***gradualism and moderation****, Concentric recommends a* ***stepped in increase*** *be utilized for this account. At this time, Concentric recommends that a negative 20 percent net salvage estimate to be used in the depreciation calculations within this study.*
>
> (Emphasis added.) Exh. UI-LEK-2, p. 16.

The negative 100 percent net salvage, which is effectively what the Commission would approve if the Company's net salvage method were adopted, produces an additional $7 million annual increase in depreciation expense over what the Company has filed in the current proceeding. That is just in one account. Exh. OCC-WWD-1, p. 23. The Company has made similar statements for other accounts. Exh. OCC-WWD-1, p. 24, 25.

The Company subsequently noted that under its proposed net salvage method,

> *There are some accounts for which the data indicated that a* ***far more negative*** *net salvage rate* ***would be appropriate****.* ***In future studies****, if the historical data continues to show that a more negative net salvage amount is correct,* ***we may recommend a further increase****.*

(Emphasis added.) Exh. UI-LEK/AN-REBUTTAL-1, p. 21.

Thus, it is clear that if the Authority were to accept the Company's proposed net salvage method now, it would create a foothold for the Company to seek continuously expansive increases in future filings.

As OCC's witness summarized during the hearing:

> *The real issue in this case is not what they filed in this case, the real issue is to have, whether you have an order that essentially says, here is the foundation for a huge future increase in the next case. So I would recommend you adopt my net salvage rates, even if they were the same dollars as they had. Because my net salvage rates do not assume any future increase or decrease, they are fair. Their net salvage method assumes that this is step 1 to huge future increases. So even if the dollar amounts were the same, I would not recommend you accept their method, because you are laying the foundation for future huge increases, undeserved huge increases. My method, like I said, I am putting two and a half, 2.2 times average money from the current ratepayers into the reserve, 2.2 times what the Company actually spends in recent years, taking out of the reserve. I am definitely growing the reserve rapidly, and no more should be taken from the ratepayers than that.*
>
> Tr. 150.

The Authority should not sanction these future increases through adoption of the Company's methodology.

v. OCC's Depreciation Recommendation

Based on the foregoing, the Authority should reject the Company's depreciation proposal, and instead adopt the methodology proposed by OCC, which mirrors the methodology adopted by the Authority in the Company's last rate case.

VI. Rate Design

xxi. Cost of Service Study
xxii.

The Company proposes to "increase distribution rates to all rate schedules such that the percent increase in bundled revenues to each rate schedule is equal to the" overall company-wide increase in revenues. Exh. UI-MC/MM-1 at 6.

Thus, the Company presented its cost-of-service study, see Exhibit UI-BR-1, WP 7.0, primarily for informational purposes. However, other parties have suggested that the results should be used in determining the revenue allocation for each class. As a result, OCC must address the shortcoming of the cost-of-service study.

i. The Company's COSS

OCC's expert witness Paul Chernick identified two major groups of problems that allocate the residential class with an excessive share of the distribution costs:

- Classification of pole, line and line-transformer costs between customer and demand drivers; and
- Sub-functionalization of pole costs between primary and secondary service.

Exhibit OCC-PLC-1. In addition, as explained by Mr. Chernick, the Company's use of the class non-coincident peak (NCP) is outdated and should be revised as the Company's load data improves.

ii. Classification of Pole, Line, and Line-Transformer Costs

The Company classifies distribution pole, line, and line-transformer costs between customer-related and demand-related components, based on the so-called minimum-system method. See Exh. UI-BR-1, p. 13. This classification is very important, since classes with small customers (especially the residential class) have a much larger portion of the total customer count than they do of system demand, while the large-customer classes (such as LPT) have a much larger share of system demand than they do of customer number. Thus, costs classified as customer-related will fall heavily on residential customers. See Exh. OCC-PLC-1, p. 12.

The minimum system study assumes that the length of primary and secondary lines and the number of poles and transformers are determined by the number of customers. See id., pp. 13-17. It also assumes that, no matter how little load the customers might have, the minimum system would be built of the smallest equipment currently being installed. Id. Finally, even though the imaginary minimum system would be made of these actual load-carrying components, the Company assumed that the minimum system would carry no demand. Id.

After the cost of the minimum system is estimated, that portion of the system cost is classified as customer-related and allocated in proportion to customer number. The remaining cost is treated as demand-related.

The imaginary minimum system overstates the costs attributed to customer number in seven ways:

- The Company acknowledges that any decision to increase the number of poles would be dependent on the load to be served, not the number of customers. Exhibit OCC-PLC-1 at 8. Just adding a customer does not increase the number of poles.
- The Company assumes that the poles of the minimum would be taller (and hence more expensive) than some existing poles, so the real 20' poles are replaced by 40' poles in the supposedly minimum system. Exhibit OCC-PLC-1 at 8.
- The Company provides inconsistent costs for conductors and uses "minimum" conductor sizes and costs that are higher than the costs of the least expensive conductors used on the system. Exhibit OCC-PLC-1, Table 1.
- Where there are multiple phases of conductor on a length of line, or even multiple feeders following similar routes to provide adequate capacity to meet load, the Company did not reduce the number of conductors to the number required by a minimum system. Exhibit OCC-PLC-1, at 9–10, 13. This error was apparently motivated by the Company's decision to follow the text of the 1990 NARUC Cost-of-Service Manual and include load-related

conductors, rather than to think through the meaning of a "minimum" system. Exhibit UI-RP-REBUTTAL-1, at 11.

- The Company recognizes that it provided incomplete workpapers for the conductor analysis Exhibit UI-RP-REBUTTAL-1, at 11–12.
- The Company used a 25-kVA transformer in the minimum-system study, even though 10-kVA transformers would be sufficient for any reasonable definition of a "minimum" system. Exhibit OCC-PLC-1, at 11.
- The Company ignored the effect of customer load on the number of transformers. Exhibit OCC-PLC-1, at 11–12.

In addition, the Company's "minimum" system, with its relatively large conductors and transformers, could carry a significant share of the load of the classes with low load per customer. The portion of the class load that could be served by the "minimum" system should be netted out of the class demand before it is used to allocate the demand-related costs. Exh. OCC-PLC-1, at 12. That would be a large share of the residential load, and a small part of the GST and LPT load. The Company does not recognize this factor, see id., and acknowledges that it ignored the load carrying capacity of the minimum system, see Exhibit UI-RP-REBUTTAL-1, at 15. As Mr. Chernick computes, the minimum system may carry 42% of residential load, but less than a percent of LPT load. Chernick Rebuttal at 3. Reflecting that benefit would dramatically reduce the allocation to the residential class.

iii. Splitting Costs Between Primary and Secondary Loads

The Company properly subfunctionalizes most categories of distribution costs between the primary system, which serves all distribution customers, and the secondary system, which connects residential and some GS customers to the primary system. All distribution customers are charged for the primary system, but only customers served at lower secondary voltages are charged for the secondary system. See Exh. OCC-PLC-1, pp. 13-14.

The Company properly divides the costs of most of the distribution system between primary and secondary, with the exception of poles.

As demonstrated by Mr. Chernick, the cost of "combined" poles, which carry both primary and secondary line, is essentially the same as the cost of primary-only lines. At most, only about 2.4% of the cost of the combined poles can be attributed to adding secondary to a pole required for primary. Exhibit OCC-PLC-1, at 16. However, the Company assigned a much higher share of the cost to secondary.

As with the minimum system, the Company created an imaginary distribution system for the pole functionalization. In this imaginary system, the Company assumes that primary lines would be on one pole, and the secondary lines would be on a second pole, right next to the primary pole. Exhibit OCC-PLC-1, at 16. In reality, this system would be extremely expensive and inefficient, and the company does not demonstrate that it actually uses this twin-pole system anywhere. A more appropriate approach would be to compare the cost of the actual system (including combined poles) to the costs of an all-primary system, to determine the incremental cost of providing secondary service. Id., at 15.

The Company also errs in charging secondary customers extra for the poles that carry only secondary. Those secondary poles are less expensive than primary or combined poles; secondary customers save the Company money by allowing the use of some secondary-only poles rather than the more expensive poles that the Company would have to install if those customers opted to be served at primary. See Exh. OCC-PLC-1, at 16.

On a related point, the Company classifies the fixtures, most of which are required for the primary lines, using the fictional twin-pole computation, as if the imaginary secondary poles required the same fixtures as the actual primary and combined poles. Exhibit OCC-PLC-1, at 17.

b. Residential Rate Design

During the hearing, the Company's witness panel acknowledged that the cost of service and rate design proposal was rushed. See Tr. 163 (claiming the Company "had a fairly short window to look at" rate design options). The Company initially proposed that because it had not taken the time to fully design its rate proposal, unresolved rate design issues should be spun off into a separate docket – either Docket No. 17-12-03RE11; 17-12-03RE02; or a generic docket. See Tr. 420 (noting "those dockets would allow for a more robust view from a lot of different points here. . . when it gets to the time to make revenue allocations, by that time we don't have a chance to rerun the study to try different things."); Tr. 491 (discussing possibility of generic docket). The Company succinctly acknowledged its plan during the hearing:

> *Q:* *So you are putting forward a cost of service study in this case that you concede is not representative of what the likely future is, and you are asking us to allocate revenues based on a cost of service study that is going to be almost immediately outdated, and then you want us to come back and have a separate cost of service docket that is going to be multi years long?*
>
> *A:* *Exactly.*

Tr. 195-196. The concerning failures of the Company to meet its burden of proof as referenced throughout the many pages of this brief also apply to the issue of rate design – the Company has provided the Authority with hastily prepared and inadequate documentation, and now expects the Authority to take the initiative to resolve its own preparation shortfalls. From OCC's perspective, the record is bereft of the most basic information necessary to allocate costs in accordance with the applicable standards.

As noted in OCC's direct testimony, the Company has proposed an equal percentage impact in revenues to be collected from all customer classes. Exh. OCC-PLC-1, at 19. We noted that it would be particularly burdensome to impose increased distribution revenue burden upon any particular class of ratepayer, due to recent historically high generation costs and the potential for extreme supply market volatility in the future. Id. Given the above-referenced failure of the Company to provide a reliable basis upon which to more specifically allocate costs, OCC recommends that the Company's equal percentage impact is the only allocation option in the short term. However, OCC recommends that the Company be ordered to file thorough and reliable data such that a reasoned and evidence-based rate design may be implemented after its single rate year, as discussed in Section V(g).

c. Economic Development Rate

Economic Development Rates can and should be structured so that they both meet economic development goals and also benefit all ratepayers, or at a minimum do not make ratepayers worse off by reducing revenues. An economic development rate should also balance the state's objectives for increased energy efficiency and demand reduction measures with the ratepayer benefits of spreading costs over increased usage.

The Company proposes a complex system of discounts for GST and LPT customers with eligibility criteria based upon employee headcount or capital investment. Exhibit UI-MC/MM-1, p. 13. OCC is concerned that there is not enough evidence to determine if this is the best structure to use the ratepayer subsidies to encourage either increased employment or capital investment in the state. Exhibit OCC-PLC-1, at 21–22. Nor it is clear that the proposed rate would increase revenues and benefit other ratepayers, since a customer may install new equipment, receive an economic development discount, and reduce usage on existing equipment, resulting in higher usage and lower revenues.

On rebuttal, the Company largely agreed with Mr. Chernick's analysis that as structured, the subsidy is unlikely to encourage employment or capital investment, but indicated that the increased employment and/or investment was not really the point of the discounts. Exhibit UI-RP-REBUTTAL-1 at 25–26. Instead, UI argued that the real purpose of the discount is to increase sales, with the hope that all ratepayers will benefit from the increase in revenues, net of the increase in regulated distribution and transmission costs and the effect of higher loads on wholesale energy prices and line losses. UI has not, however, quantified the anticipated economic benefits or the impacts to load. Tr. 277, 439. With no sense of the incremental load – and hence, no sense of the associated dilution of the overall revenue burden – the Company has not been able to quantify the "benefit to all other existing ratepayers." Tr. 252. OCC would be happy to see increased employment, increased investment, and increased revenues, but the proposed tariff does not guarantee that the participating customers would increase revenues.

Having clearly defined goals of the Economic Development Rate and a more thorough benefit-cost-analysis of the most cost-effective way to meet those goals would be beneficial prior to implementation of an Economic Development Rate. For example, it is not clear that rate discounts correlated with increased energy use are consistent with the State's objectives for increasing energy efficiency and demand reduction, but it is also still unclear that the proposed employment/investment incentives would be effective, as acknowledged by the Company. Designing an economic development rate requires careful and detailed analysis, and would benefit from more input from stakeholders and a thorough cost benefit analysis to determine the most cost-effective way to meet the established policy goals. The Company should be required to engage in that process and file an improved EDR proposal.

If the Authority were to decide to allow the Company to proceed with its flawed EDR, the Company should be required, at a minimum, to file a cost benefit analysis after the first year of implementation of the proposed EDR to enable the Authority and stakeholders to evaluate the impacts of the program and any need for reforms after Rate Year 1.

VII. Distinct Issues

a. The Authority's January 18, 2023 Notice of Request for Briefs

On January 18, 2023, the Authority issued a Notice of Request for Briefs in this docket, seeking briefs from OCC and other parties responding to five individual prompts, and instructing that such briefs were due to be filed in this docket by February 6, 2023 (the "Notice"). OCC filed a response on February 6, 2023 that acknowledged the Notice and addressed the five prompts. OCC noted, however, that it would respond more fully to several prompts within its legal brief, scheduled to be filed after the close of the record. As promised, OCC offers its full response to those briefing prompts below.

i. Prompt No. 1

The Notice's first briefing prompt asked whether Section 8(b) of Public Act 20-05 "precludes [UI] from recovering from ratepayers all of its cost associated with its rate application in the current proceeding," and requests that responses be supported with statutory analysis and legislative history.

Section 8(b) of Public Act 20-05 – commonly known as the "Take Back Our Grid Act" – amended Conn. Gen. Stat. § 16-243p, effective November 1, 2020, to add subsection (b), which provides: “No electric distribution company shall recover its costs associated with attendance or participation in any rate-making hearing before the authority.”

As noted in OCC’s February 6, 2023 response to the Notice, the plain language of the statute prohibiting recovery of all costs associated with a rate application clearly applies to UI – as an electric distribution company – and to this case – as it involves a “rate-making hearing before the authority.” See Conn. Gen. Stat. § 1-2z. OCC notes that UI has apparently also acknowledged the general applicability of the statute, via reference, in its application. Exh. UI-RRP-1, p. 34, Line 7; n. 7.

Nevertheless, the Company has sought recovery of costs associated with its attendance or participation in this proceeding, as discussed above in Section V(a)(viii). As argued above, OCC recommends that the Authority disallow portions of the Rate Case expense, based on the application of General Statutes § 16-243p (b).

ii. Prompt No. 2

The Notice’s second briefing prompt asked for a description of “metrics or standards that the Authority should consider in imposing the fifteen (15) basis point reduction in return on equity (ROE) levied in the April 28, 2021 Decision in Docket 20-08-03 . . . including how to determine if and when the ROE reduction is no longer necessary to ‘properly incentivize improved storm response performance by UI.’”

As noted in OCC’s February 6, 2023 response, the issue of the ROE adjustment imposed in Docket No. 20-08-03 is presently on appeal, and is now before the Supreme Court, within *United Illuminating Company v. Public Utilities Regulatory Authority*, Docket No. S.C. 20795, in which OCC is an Intervenor-Appellee.

The Company has taken the position that it would be "inappropriate to impose PBR metrics with financial . . . penalties in this docket prior to full consideration of a PBR framework and a final decision in Phase 2 of the PBR docket." UI-TAP/DRC-REBUTTAL-1, p. 3. However, the Company has acknowledged that there is precedent for the Authority imposing financial penalties relating to company performance in rate cases, prior to the existence of the PBR docket. See Tr. 2371 (noting the Company is "aware of situations where . . . the Authority has" imposed a financial penalty relating to company performance in a rate case, and specifically identifying "the Eversource ROE from 2007 to 2012 storms, and their subsequent rate case"). OCC notes that the Authority also reduced the Southern Connecticut Gas Company's ROE by 10 basis points due to a determination of imprudent management. See Docket No. 08-12-07, *Application of the Southern Connecticut Gas Company for a Rate Increase*, Final Decision (July 17, 2009), pp. 116-117.

From OCC's perspective, the issue of the imposition of an ROE penalty is distinct from the issue of determining appropriate performance metrics to determine when an ROE penalty is no longer necessary. It would therefore be appropriate for the Authority to impose a penalty prior to determining such metrics, and for such penalty to remain in place until such metrics are determined and corresponding goals are appropriately achieved.

OCC notes that the Company's February 6, 2023 brief did not propose any metrics or mechanisms to measure a point at which an ROE reduction is no longer necessary, and instead argued that no ROE reduction should be implemented at all because "UI has made substantial process improvements and ERP enhancements subsequent to the Storm Decision . . . that address all of PURA's underlying concerns." UI's Brief (Feb. 6, 2023), p. 22.

This argument fundamentally ignores the purpose of performance-based regulation, which is to create incentives for Company performance via evidence-based mechanisms. In other words, the mechanisms should be tools to drive performance, *as measured by appropriate metrics*. The Company should demonstrate that its purported solutions – the "mitigating factors that demonstrate that the Company has taken seriously PURA's findings"[61] – have actually improved the Company's performance deficiencies. It has not done so. Therefore, it would be appropriate for the Authority to impose an ROE penalty until such time as the Company can demonstrate improvements via appropriate and reasonable indicators.

iii. Prompt No. 3

The Notice's third briefing prompts seeks an explanation for whether evidence supports a finding that UI's failure to revise its TAC accounting constitutes imprudent and inefficient management.

In the Authority's August 17, 2022 Decision in Docket No. 22-01-04, it found 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." Docket No. 22-01-04, *PURA Annual Review of the Rate Adjustment Mechanisms of The United Illuminating Company*, Final Decision (Aug. 17, 2022), p. 15.

As noted in OCC's February 6, 2023 response, this issue is also presently on appeal, and OCC is an active participant in that proceeding. *See The United Illuminating Company v. Public Utilities Regulatory Authority*, Docket No. HHB-CV22-6075751-S.

[61] UI's Brief (Feb. 6, 2023), p. 21.

OCC notes that the Company's accounting standards have raised concern in multiple contexts within this rate case as well. The record is full of examples:

- The Company booked its cloud computing platform for its Municipal Hub in a FERC account designated for "overhead lines," and conceded during the late file hearing that this was incorrect. Tr. 3445.
- As discussed below, the Company booked costs associated with remediation of English Station in above-the-line accounts. LFE-60 Supplement; See Section VII(f).
- The Company's initial filing included approximately $300,000 in internal expenses relating to the remediation of English Station, which had to be subsequently removed. Tr. 3338.
- When asked why costs associated with transporting employees to remediation sites was included in the schedule labeled "Professional Services," a Company witness responded, "We had to put this adjustment somewhere, we put it here." Tr. 1573.
- The Company acknowledged that it had inadvertently recovered approximately $10,000 from distribution ratepayers that should have been allocated to Transmission. Sch. C-3.03, n. 4; Tr. 1570-71.
- A Company witness testified that they could not be entirely sure whether costs of incentive compensation tied to legislative engagement had been properly scrubbed from the test year. Tr. 1882-1884.
- The Company's initial filing included an error amounting to $5.2 million because "the spreadsheet that was used to identify the cost, there was a cell error that was pointing to a wrong percentage." Tr. 2817.
- The company was unable to provide historical plant additions prior to 2018 because "data prior to 2018 is not readily available," Tr. 731, and could not even provide a response to indicate the exact date of when an internal change caused this data problem. Tr. 735.
- The Company had to refile its calculations for executive compensation allocations because it made an incorrect assumption about its own allocation standards. See Tr. 1979 (" . . . when the schedule was prepared, it just assumed everyone used the Mass Formula . . . so this isn't what is in the test year. Because a bit could have been direct charged and a bit could have actually been capitalized and not actually be in the expense for the revenue requirement, so we are going to redo this for you").

As discussed above in Section V(g), OCC is generally concerned with the sheer volume of errors, missing data, insufficient information, and unilateral process changes that have become evident over the course of this proceeding. The record in this case would appear to support a finding of managerial imprudence with regard to the state of the Company's accounting procedures in general. This is not the first time that UI's accounting procedures in RAM-related dockets have been called into question. The Company has created a pattern of sloppy accounting, in which UI continues to operate with imprudence and appears to believe that it is exempt from being penalized for negligent accounting procedures and for failing to seek recovery of expenses in a timely matter. See Docket No. 14-02-01, Final Decision (Nov. 12, 2014) pp. 9-15; and Docket No. 18-03-02, Final Decision (Jan. 2, 2019) pp. 8-12. PURA has warned the Company about this imprudent behavior and improper accounting practices. While OCC continues to believe that the Authority would have been justified to disallow expenses in the above referenced proceedings, PURA should take action now as the Company has dragged its feet in correcting out-of-period items and reconciling costs from prior years. The Company appears to be operating with an unreasonable degree of imprecision in its accounting, in ways that present measurable financial risk to ratepayers. OCC would support the development and implementation of metrics designed to incent the Company to exercise an appropriate level of care for the financial impacts of its accounting procedures.

iv. Prompt No. 4

The fourth briefing prompt in the Notice asks whether the evidence supports a finding that UI's "'repeated occurrences of untimely submissions of reconcilable expenses and credits' identified in the . . . Decision in Docket No. 18-03-02 . . . constitutes imprudent and inefficient management." In that Decision, the Authority discussed its concern with UI's late discovery that approximately $1.5 million had not been recovered through the TAC. See Docket No. 18-03-02, PURA Annual Review of the Rate Adjustment Mechanisms of the United Illuminating Company, Final Decision (Jan. 2, 2019), p. 11 ("the time period between when an incurred cost should be recovered in rates and when the Company actually requests recovery is an important element in evaluating whether UI overcomes the presumption of imprudence.").

As OCC advocated within that docket, the Company failed to overcome the presumption of imprudence because of its failure to request cost recovery in a timely fashion. The Authority properly found that "good business practices and generally accepted accounting principles require timely reporting of revenues and expenses," and that the Company's accounting error was "inconsistent with good business and accounting practices," because the "Company should have controls in place to ensure that its reconciliation exhibits captures all accounts necessary for the RAM proceedings." Id. at 12.

As noted above, OCC's concerns about the Company's lack of attention to detail have flowed through to the instant docket. In addition to the specific accounting errors listed above in Section VII(a)(iii), and the many concerns discussed in Section V(g), the record in this case demonstrates a lack precision, and a general lack of organization and preparedness, similar to the TAC recovery error raised in Docket No. 18-03-02:

- The Company took the position that its Rate Design testimony and initial Cost of Service Study were impacted by a "fairly short window," but acknowledged that the Company chose to file its rate application at the time that it did, and could have re-run its study and waited to file its rate application after it had developed a more complete rate design model. Tr. 421. The Company's witness acknowledged that there was nothing preventing the Company from correcting the study other than the competing pressure to file a rate case in order to meet the company's financial needs. Tr. 421.

- The Company's rate design testimony recommends that rate design be finalized within the proceedings in Docket No. 17-12-03RE11, and the Company did not appear to be aware that that proceeding has closed until alerted to this fact during the hearing. Tr. 193. This is especially concerning given that the Company appeared and participated in that proceeding.

- The Company's rate design panel acknowledged that its plan is for the Authority to allocate revenues based upon a cost of service study that is "not representative of what the likely future is," and is "going to be almost immediately outdated," and that the Authority would then have to "come back and have a separate cost of service docket that is going to be multi years long." Tr. 195-196.

- The Company's rate design panel proposed that there would be an opportunity to adjust rates each year at "each annual setting of the new revenue requirement," but then immediately testified that any adjustments would be revenue neutral. Tr. 433; 434. The Company's application also does not propose any mechanism to set a new revenue requirement on an annual basis.

- The Company's response to RSR-2 includes a list labeled "UI Capital Expenditure - In Rates". See RSR-2, Attachment 1, p. 3. During the hearing, the company offered testimony that capital expenditures are not in rates, and that capital investments only actually roll into rates when they are put into service. See Tr. 748. However, when asked why its response includes a listing of "UI Capital Expenditure – In Rates," the Company's witness panel was unable to provide an explanation. Tr. 748.

- Similarly, the Company's witness panel was unable to confirm whether the current rate structure as approved in the Company's last rate case includes forecasted capital expenditures or plant-in-service. Tr. 749.

- When asked why the Company's supplemental response to OCC-139 indicated that the Company did not have relevant information dating prior to 2012 the Company responded that it only retains such documents for a seven year period – even if the Company does not come in for a rate review within the applicable seven year period. Tr. 936-940. The Company witness explained that "that level of granularity for a plan, a budget, a forecast back at that point in time, which developed into a revenue requirement, which then became actual . . . was not readily available." Tr. 1128. The Company could not confirm whether the relevant information was actually filed in the Company's last rate case. Tr. 1131-1133.

- The Company testified that it would have to manually reprogram individual meters in order to adjust the applicable peak time for a given rate class. Tr. 357; EOE-213. The Company later testified that it actually has the technological capability to reprogram meters remotely, and that it would use that capability for something on the scale of implementing a peaking period change for an entire rate class. Tr. 430-431. The Company then testified that in fact it could make such adjustments on the back end, without having to reprogram individual meters at all. Tr. 436.

- The Company's direct testimony proposed that its free-free credit card proposal would be trued up on an annual basis, but during the hearing the Company clarified that it is actually seeking to defer the costs of the program as a regulatory asset or liability until its next rate case. Tr. 2367-2368.

This disturbing volume of errors and discrepancies, coupled with the multiple instances where the Company could not – or in some cases would not – explain them, should be analyzed in the Authority's consideration of whether the Company's cost recovery filings with PURA reflect prudent and efficient management. In the context of a contested distribution rate case, where all parties must examine and analyze substantial quantities of data in a limited time period, the ability of the Authority, OCC, and other stakeholders to conduct a thorough and fair analysis is substantially prejudiced by this level of imprecision. As discussed above in Section V(g), OCC remains concerned by the potential that the Company's filing in this case includes even more errors and discrepancies than were identified within the limited case review window, and the degree to which those issues may ultimately harm ratepayers. OCC would support the development and implementation of metrics designed to incent the Company to exercise an appropriate level of care and responsibility in its cost recovery requests.

v. Prompt No. 5

The fifth briefing prompt in the Notice seeks an explanation of whether UI's recovery of executive and officer compensation packages through rates "should be correlated with prudent and efficient management, particularly with respect to any finding of prudent or inefficient management related to the Storm Decision, the 22-01-04 Decision, or the 18-03-02 Decision." The prompt also asks for input as to metrics or standards the Authority should consider in determining the allowable executive or officer compensation necessary to adequately incentivize prudent and efficient management.

As to the question of whether the recovery of executive and officer compensation should correlate with a consideration of prudency, the answer is inarguably yes. The Company is only entitled to recover "its costs . . . that have been prudently incurred". Conn. Gen. Stat. § 16-243p. Therefore, the Company's costs of executive and officer compensation are only recoverable to the extent to which the Company prudently incurred them. It is also appropriate for the Authority to consider whether such compensation costs reflect "service furnished by [the] company [that] is inadequate to or in excess of public necessity and convenience". Conn. Gen. Stat. § 16-19(a)(4). Therefore, it would be appropriate for the Authority to consider whether the levels of the Company's executive and officer compensation are excessive based upon a determination that such costs were imprudently incurred.

The Authority is also statutorily empowered to "evaluate the reasonableness and adequacy of the performance or service of the [Company] using any applicable metrics or standards adopted by the Authority," and to "determine the reasonableness of the allowed rate of return of the [Company] based on such performance evaluation." Id., § 16-19(a)(4)(A);(B). The Authority is specifically empowered to "establish standards and metrics for measuring [the Company's] performance of objectives that are in the interest of ratepayers . . . [including] emergency response, cost efficiency, affordability . . . customer satisfaction, municipal engagement . . . and resilience." Conn. Gen. Stat. § 16-244aa. In light of this mandate, it would be entirely appropriate for the Authority to design metrics to incentivize managerial performance that improve the concerns arising from the decisions referenced in the Notice.

OCC recommends that the Authority formulate such metrics or standards in alignment with the process and framework set forth within Docket No. 21-05-15. For example, it would be appropriate for the Authority to identify a reasonable outcome for the Company to achieve; and then to identify the metrics that would measure the Company's success at such outcome; and then to design mechanisms that would drive such metrics. The Authority could design these elements within the still-pending phases of Docket 21-05-15 and reopen this proceeding to impose them, if appropriate.

b. ROE Adjustment Mechanism

Via RRU-247 and RRU-248, the Authority asked OCC to opine upon whether the Company's proposed ROE adjustment mechanism would constitute single-issue ratemaking and would result in an annual mini-rate case proceeding. See Exh. UI-AEB-1, p. 70. OCC filed responses to those interrogatories indicating that we would address the Authority's questions in the context of this brief.

OCC is opposed to the proposed ROE adjustment mechanism for several reasons. First, the Company's proposal would entail a formulaic and presumably automatic adjustment, and therefore would not entail any procedural process for the Authority to analyze the contextual appropriateness of the adjustment, in light of other considerations that may be relevant at the time the adjustments would go into effect. As suggested by the Authority's question in RRU-248, adjustments to the ROE should involve, at the very minimum, a proceeding before the Authority.

Secondly, the ROE adjustment mechanism proposal suggests, in and of itself, that the Company's entire ROE analysis is incorrect. If it were sufficient to set ROE solely based upon "the projected change in interest rates over the period that rates will be in effect," then it would be inappropriate for the Company's analysis supporting its proposed 10.2% allowed ROE to consider inflation; general monetary policy; allowed ROEs in other jurisdictions; regulatory risks; etc. Hence, if the proposed ROE adjustment mechanism is an appropriate tool to set an allowed ROE, the vast majority of the Company's ROE analysis is invalid.

Third, for the reasons discussed above in Section V(g), OCC does not support the Company's proposed multiyear rate plan. The ROE adjustment mechanism is proposed to be used "for each year of the rate plan," but if the Authority approves only a single rate year there will be no need for an automatic adjustment mechanism following that year.

c. Earnings Sharing Mechanism

Issues and concerns surrounding the Company's Earnings Sharing Mechanism ("ESM") have arisen throughout this proceeding.

i. Proposal to Pay Down Storm Costs With the ESM

UI proposes a modification to the sharing of potential overearnings, if the Company earns above its allowed ROE during one of the twelve-month rate year periods. See Exh. UI-RRP-1, p. 9. Rather than the 50/50 sharing with no deadband in place for UI, whereby ratepayers receive 50% of overearnings as a bill credit, UI has proposed that the Company utilize ratepayers' share of overearnings be "first utilized to amortize and accelerate the recovery of UI's storm recovery asset, if applicable, before being utilized as a cash credit." Id. OCC notes that this proposal is similar to what has been in place for UI previously, and is also similar in nature to earlier in the 2000s when a portion of overearnings were utilized to pay down stranded cost balances that were the result of restructuring.

While OCC does not necessarily oppose using ESM proceeds to pay off deferred storm costs, 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 notes that if PURA does accept this modification, that the Authority should consider a sharing of 1/4 to storm deferred costs, 1/4 to shareholders, and 1/2 to ratepayers as a bill credit. OCC sees the pay-down of deferred storm costs as a financial benefit to both ratepayers and shareholders, as it 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, 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.

ii. Reporting of Actual Earned ROE

In this rate proceeding, it has become clear that in periods between rate cases, UIbooks costs that were not included in revenue requirements as operating expenses that affect the Company's operating results as measured by its actual earned ROE (i.e., English Station costs as discussed in Section VII(f); Tr. 3423). Items disallowed or only partially allowed for ratemaking purposes should not be included in earnings reports or the annual ESM filing.

UI has a long history, dating back to the early 2000s, of continually paying incentive compensation levels that exceed the amount allowed in rates and charging the excess amount above-the-line, thus reducing their earned ROE. See, e.g., Docket No. 08-07-04, *Application of the United Illuminating Company to Increase Its Rates and Charges*, Final Decision (Feb. 4, 2009), p. 35. These actions caused the Company to earn below its allowed rate of return and resulted in UI experiencing a reduction in overearnings and the amount of money paid back to ratepayers through the earnings sharing mechanism in years in which they overearned. Id., p. 37 ("the excess amount paid by UI were recorded above the line and reduced their earned ROE below its allowed rate of return in 2006 and resulted in a reduction in earnings sharing with ratepayers."); p. 40 ("The Department agrees with the OCC and the AG that there are large, unsupported increases . . . the Company will be ordered to report only the Department-authorized amount of incentive compensation in any future ROE report to the Department"). While theoretically, in between rate cases, UI can incur costs to compensate employees at whatever rate they choose; donate to charitable organizations; or provide other employee benefits not allowed in its rate case. That does not mean that the Company should be allowed to effectively pass those costs on to ratepayers by decreasing their earned return and potentially reducing overearnings that would result in a bill credit through the ESM. As a result, 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 disallowed for ratemaking purposes. In the event that UI continues to incur expenses that are specifically disallowed by PURA's decision in this rate proceeding, UI should be required to record the disallowed expenses in expense accounts considered below-the-line, and should not be allowed to include them in calculating the actual earned ROE. OCC notes that this recommendation is consistent with the Authority's treatment of incentive compensation expenses in UI's 2008 rate case decision. See Id.

d. Accounting Changes

As discussed above in Section VII(a)(iii), in this rate proceeding it has become evident that UI has altered its accounting treatment of various expense items from the manner that they were treated in the Company's last rate case. UI should not be allowed to change the manner in which it treats and record costs for ratemaking or earnings reporting purposes without prior PURA approval. UI should not be capitalizing costs that were treated as expenses or expensing items that were capitalized per a rate case finding. These accounting changes may not only potentially impact revenue requirements for decades, but may also impact the Company's, financial condition and rating matrices. Before making such changes in accounting treatment, the Company should be required to file notice with the Authority, seeking approval to change accounting methods from those allowed in an applicable rate proceeding. This filing should be required to provide PURA at least 60 days notice, prior to implementing such changes. The compliance filing should explain the rationale for the proposed accounting methodology change and the impact on the Company's, revenue requirements, financial statements, and credit rating matrices. The Authority could then review the proposed changes with input from docket participants, holding a hearing if necessary, prior to approving such accounting changes.

e. Bridgeport Ave Property

The Company's Application seeks to recover $15.583 million for the loss incurred on the sale of a property located at 801 Bridgeport Avenue in Shelton (the "Bridgeport Ave Property"). See Exh. UI-RRP-1, p. 46; Sch. B-6.8A; EOE-99. The Company proposed to recover approximately $14 million held as a regulatory asset due to the loss, amortized with carrying costs over a three-year period. Exh. UI-RRP-1, p. 46. In 2003, the Company determined that it would sell the property as part of the Central Facility Consolidation Project. OCC-163. As noted within the application, the Authority authorized the sale of the Bridgeport Ave Property in its January 10, 2018 Final Decision issued in Docket No. 17-10-40, where the Authority held that "the property is no longer an essential part of the franchise, plant, equipment or other property of The United Illuminating Company and will be neither necessary nor useful in its performance of its public service obligations." Docket No. 17-10-40, *The United Illuminating Company Application for Approval to Sell Improved Land at 801 Bridgeport Ave., Shelton, CT*, Final Decision (Jan. 10, 2018), p. 1. Importantly, the Authority ruled that the Company could "establish a regulatory asset associated with the loss on the sale of this property," and that "[t]he recovery of the regulatory asset will be determined in a future rate proceeding upon a comprehensive review of the lowest cost option for consolidating operations." Id., p. 6. The

Authority specified that "if UI is able to show in the future that the sale . . . 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." Id., pp. 2-3.

However, the Company has not sufficiently demonstrated that this was the lowest cost option – particularly in light of the fact that the sale has resulted in a cost to customers. In fact, the evidence reveals that the loss was the result of imprudent managerial decisions.

The Company initially occupied the property as a tenant, subject to a lease beginning in 1983, which was amended and restated on January 19, 1994. OCC-175 Attachment 1; Tr. 1242. The Company first became aware that the property was environmentally contaminated in 1997. LFE-36. The Company purchased the property in 2004 for $16.2 million. Id. That purchase price was not negotiated at the time of purchase, but rather had been established within the 1994 lease terms. OCC-175 Attachment 1; LFE-36 ("The purchase of 801 Bridgeport Ave for $16.2M occurred per the conditions of the 1994 lease agreement that provided the Company the opportunity to purchase 801 Bridgeport Ave after 10 years for the stated $16.2M or continue under the 20-year lease agreement . . ."). The Company has claimed that it obtained an appraisal at the time it purchased the property, but that "due to the passage of time, the Company was not able to locate a copy of the document." OCC-170. However, as part of that acquisition transaction, the Company agreed to assume the responsibility to remediate the environmental contamination and to maintain ongoing liability for post-remediation obligations pursuant to the Connecticut Property Transfer Act. Id. In other words, despite knowing that the property became contaminated subsequent to executing the 1994 lease, the Company chose to purchase the property for a price negotiated years prior to the contamination, and also agreed to assume ongoing environmental liability. The Company acknowledged that the issue of environmental liability "could be part of the negotiating process" in real estate transactions involving contaminated property. Tr. 1145.

A further concern is that the Company has continued to recover expenses relating to the Bridgeport Ave Property in rates after the property was no longer being used. According to the response to OCC-173, the Company stopped using the Bridgeport property in May of 2012. However, according to the Company's supplemental response to OCC-174, the Property was not removed from rate base until January 1, 2015. Ratepayers continued to pay property tax on the Property through the 2017 Rate Year – five years after the property ceased being used or useful. OCC-174 supp.

Another concern is that despite not receiving any approval from the Authority, the Company is seeking to recover $5,428,036 in carrying charges from June 30, 2016 through August 31, 2023. EOE-99, EOE-165 Attachment 1. As the Company had no approval and this would be considered retroactive ratemaking, OCC recommends the disallowance of carrying charges.

Because the Company has failed to meet its burden to demonstrate that the loss incurred from the sale of the Bridgeport Ave Property was "an integral part of the lowest cost option for consolidating its operations," OCC recommends disallowance of the entire loss, including carrying charges, which results in reductions to Rate Years 1, 2, and 3, rate base of $12.986 million, $7.792 million, and $2.597 million, respectively, as shown on Exhibit LA-1, Schedule B-6. The annual amortization expense of $5.194 million is also recommended for exclusion as shown on Exhibit LA-1, Schedule C-9.

f. English Station

Pursuant to General Statutes §16-244f, UI was required to fully divest or functionally separate from its non-nuclear generating facilities by January 1, 2000. PURA's predecessor, the Department of Public Utility Control, approved UI's divestiture plan, in its June 9, 1999 Decision in Docket No. 98-10-07, *DPUC Review of The United Illuminating Company's Divestiture Plan – Phase II*. The Department found that UI satisfied the divestiture requirement with regard to English Station and determined that the units should be retired and decommissioned.

In an application dated April 4, 2000, UI requested to sell the English Station generating site to Quinnipiac Energy, LLC., who planned to operate the generating units to sell power in the wholesale market. See Docket No. 00-04-05, *Petition of The United Illuminating Company for Approval to Sell English Station*. UI paid the purchaser $4.25 million, who assumed the responsibility to decommission the facility. The DPUC approved the transaction finding that the sale of the English Station units would result in substantially lower cost to customers than if United Illuminating were to decommission/dismantle English Station according to its original plan. Docket No. 00-04-05, ***Error! Reference source not found.****supra*, Final Decision (June 29, 2000) p.1. In approving the sale to Quinnipiac Energy, the Department specifically noted:

> *The Department is approving this transaction based on the Application as presented, including the presumption that decommissioning/dismantling responsibility will be assumed by QE. Therefore, the Department will not permit any future costs for any reasons other than costs related to bulkhead repair to revert to ratepayers.*

Id., p. 5. As a condition of the Authority's decision approving the Settlement Agreement that authorized Iberdrola's acquisition of UIL in Docket No. 15-07-38, UI committed to spending $30 million for remediation of the English Station site. See 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, Final Decision (Dec. 9, 2015), Appendix 1, p. 3. UI also entered into a partial consent order ("PCO") with the Department of Energy and Environmental Protection (DEEP) regarding the investigation and remediation of the former generating units at English Station. Id.

In this rate proceeding, there were several sets of discovery from several docket participants surrounding the status of the English Station site's remediation and amount of costs incurred for remediation including legal expenses. Through the review of legal expenses while on audit at UI offices, OCC discovered evidence showing that expenses associated with English Station were incurred in the test year and charged above-the-line for ratemaking purposes. The response to OCC-610 showed that the Company's original Application failed to remove $299,992 in test year legal expenses contained in WPC-3.12 that were associated with the remediation of English Station. These expenses were subsequently removed in the update to legal expenses contained in LFE-1, revised WPC-3.12. Tr. p. 3338.

Given the Authority's directive that "the Department will not permit any future costs for any reasons other than costs related to bulkhead repair to revert to ratepayers", Docket No. 00-04-05, supra, Final Decision (June 29, 2000), p. 5, OCC attempted to obtain from the Company a detailed breakdown of English Station costs incurred by UI to ensure that ratepayers were not being charged for costs relating to English Station. Unfortunately, UI's responses to OCC Interrogatories numbered 610 and 641 and LFE-60 failed to provide appropriate documentation to illustrate whether UI has followed the Department's above-referenced directive. It was not until March 16, 2023 – nine business days prior to the close of the evidentiary record – that UI provided a detailed accounting of English Station expenses including FERC accounts. See LFE-

60 Supplement. UI was not transparent on its disclosure of the level of English Station costs incurred and whether those expenses were charged above-the-line as operating expenses.

The supplement to LFE-60, shows that in the fourth quarter of 2015, UI set up a reserve account for English Station's environmental remediation. From that time in 2015 until during 2020, the Company charged all its costs related to the English Station environmental remediation efforts – including its legal and internal labor costs – against the reserve. SeeLFE-60 Supplement. However, in 2020, UI determined that its legal and internal labor costs were ineligible to be charged against the $30 million reserve based on the PCO, which states that UI shall pay "$30 million minus any costs incurred or accrued for remediation and investigation (not including attorney's fees and any direct time charges of Respondent's [UI's] employees, managers or officers)." OCC-0609 UI Attachment 1, p.37. From that point going forward, UI removed internal labor and legal costs that had already been booked to the reserve and on a going forward basis, stopped recording such costs to the reserve. At that time, however, the Company began to charge those costs above-the-line as operating expenses. UI claims that this change did not impact UI's base distribution rates, because such rates were established in Docket No. 16-06-04 and no costs related to English Station environmental remediation were reflected in the revenue requirement approved by the Authority in the Company's last rate case at proceeding. See Tr. 3437.

UI's witnesses acknowledge that these charges were not associated with bulkhead repair at the English Station site. Tr. 3420-3423. LFE-60 UI Supplement Attachment 1 shows that in 2021,$299,992 of legal expenses were charged to Account No. 923, Outside Service and that $108,339 were charged in the first three quarters of 2022. In 2021 $343,172, and through September 30, 2022, $1,382,719 was charged to Account No. 582, Station Expenses, with an additional $3,023 charged to Account 589, Rents, in the first three quarters of 2022. While costs associated with English Station may not have been allowed in setting revenue requirements in UI's last rate case, the Company's accounting treatment of these costs violate the spirit of the 2000 Decision that allowed the sale of English Station. The intent of the 2000 Decision was clearly spelled out in Commissioner Caron's dissent in Docket No. 00-04-05, where he stated that "environmental remediation costs incurred by UI were already the responsibility of shareholders." Docket No. 15-07-38, supra, Final Decision (Dec. 9, 2015) 12/9/Commissioner Caron Dissent, p. 2.

While it may seem logical that expenses not specifically included in the Company's revenue requirement would ultimately not be recovered from ratepayers, this perspective is directly inconsistent with the Company's position as to overrecovery in general. In the context of the English Station line of questioning, the Company agreed that any expense the company incurs that isn't within the applicable revenue requirement should negatively impact net income, and ultimately be borne by shareholders. Tr. 3437. However, in the context of overrecovery in general, when OCC has identified areas where the Company will incur *less* on a particular cost than what is allocated in the revenue requirement - the Company has taken the reverse position and argued that it is unfair to carve out and examine particular costs from the context of the overall revenue requirement. For example, in defense of the Company's Depreciation proposal in this proceeding (See Section V(i) above), the Company has taken the position that it is justifiable for the Company to continue to recover depreciation expense as to fully-depreciated assets because the issue is offset by underrecoveries in other areas, and therefore in the end ratepayers are ultimately unharmed. See Tr. 43 ("So there is [sic] puts and takes on some of these accounts. There is an overrecovery perhaps . . . but on other larger accounts . . . it goes the other way"). The Company acknowledged that there are "circumstances in which a depreciation on a Company's investments might stop," but argued, "the company is not going to stop investing in its system either." Tr. 3372-73. The Company's messaging, as OCC understands it, is that the overrecovery caused by the continuous accrual of depreciation expense for fully depreciated assets is somehow excused by the fact that the company continues to invest in new assets (ever-growing the rate base upon which it earns its return). The Company seeks to assure us that it all, essentially, comes out in the wash.

But the Company cannot have it both ways – the Company must either strictly tie revenue to specific expenditures authorized in its revenue requirement (as is the Company's position in the English Station context), or be able to ignore the need to apply revenues to particular accounts so long as overall costs are balanced (as is the Company's position in the Depreciation context). The logic here does not hold. In OCC's view, the Company should book above-the-line costs only to authorized expenditures, and authorized revenue should reflect actual costs.

Expenses that are shareholders' responsibility should not be charged above-the-line to operating expenses. Furthermore, these expenses relate to UI's former generation assets - assets from which UI divested in 2000. Stranded cost recovery ended in 2016. Costs from UI's past generation activities have long been removed from its revenue requirements. The Company's attempts to book these expenses against operating results of the distribution business reduces UI's earned ROE, and therefore booking these costs above-the-line reduces the potential for ratepayers to benefit from the Company's earning sharing mechanism. These actions fly in the face of the original English Station Sale Decision, as well as the Decision approving Iberdrola's application to acquire UI's parent company, UIL. PURA should not allow these actions to continue.

In this rate proceeding, PURA should order UI to stop charging any English Station costs above-the-line to operating expenses. The Authority should also order the Company to restate 2021-2023 earnings and earned ROEs with all English Station expenses removed from its net income calculations. While UI removed the legal expenses from the pro forma expenses in LFE-1, PURA should ensure that other expenses charged to Account No. 582 in the Test Year are not carried forward into rate year expenses.

VIII. Conclusion

OCC thanks the Authority for the opportunity to provide input in this case of great importance to the Company's ratepayers. For the reasons addressed above, OCC recommends that the Authority reject the rate application of The United Illuminating Company and, more appropriately, limit the requested increase to the Company's current rates and revenues as recommended herein.

Respectfully submitted,

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Supervisor of Technical Analysis

CERTIFICATE OF SERVICE

I do hereby certify that on this day the foregoing document was filed with the Public Utilities Regulatory Authority, and copies thereof were served upon each person designated on the official service list in this proceeding in accordance with R.C.S.A. § 16-1-15.

Dated at New Britain, Connecticut this 27th day of April, 2023.

/s/ William E. Dornbos
William E. Dornbos, Esq.
Commissioner of the Superior Court