September 2, 2022

Ms. Tanowa Troupe, Secretary
Public Utilities Commission of Ohio
180 East Broad Street, 11th Floor
Columbus, Ohio 43215

RE: Duke Electric Consumers/*In the Matter of the Application of Duke Energy Ohio, Inc. for an Increase in its Electric Distribution Rates*, Case No. 21-887-EL-AIR, *et al*.

Dear Ms. Troupe:

On September 1, 2022, the Attorney Examiner in the above-referenced proceeding directed that intervenor testimony be filed on September 2, 2022, if parties have not filed a (partial) settlement. In accordance with the Attorney Examiner's directive and as there is not a settlement filed, OCC is filing the Direct Testimony of John Defever, C.P.A. today.

Very truly yours,

/s/ Angela D. O'Brien

Angela D. O'Brien (0097579)
Counsel of Record
Assistant Consumers' Counsel

cc: All Parties of Record & Attorney Examiners

OCC EXHIBIT NO._______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates.	)))	Case No. 21-887-EL-AIR
In the Matter of the Application of Duke Energy Ohio, Inc., for Tariff Approval.	)))	Case No. 21-888-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval To Change Accounting Methods.	)))	Case No. 21-889-EL-AAM

DIRECT TESTIMONY
OF
JOHN DEFEVER, C.P.A.

On Behalf of
Office of the Ohio Consumers' Counsel
65 East State Street, Suite 700
Columbus, Ohio 43215

September 2, 2022

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I. INTRODUCTION

Q1. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A1. My name is John Defever. I am a Certified Public Accountant, licensed in the State of Michigan. I am a senior regulatory consultant in the firm of Larkin & Associates, PLLC, with offices at 15728 Farmington Road, Livonia, Michigan.

Q2. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A2. Larkin & Associates, PLLC is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates, PLLC, has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings including numerous electric, gas, water/ sewer, and telephone utilities.

Q3. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A3. Yes. I have attached Exhibit OCC-JD-1, which summarizes my experience and qualifications.

Q4. ON WHOSE BEHALF ARE YOU APPEARING?

A4. Larkin & Associates, PLLC was retained by the Office of the Ohio Consumers' Counsel ("OCC") to conduct a review of Duke Energy Ohio's ("Duke" or "Utility") application for an increase in electric distribution rates.[1] Accordingly, I am appearing on behalf of the OCC.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A5. The purpose of my testimony is to present my recommendations, on behalf of OCC, regarding the total revenue requirement and revenue increase in base rates proposed by Duke to be charged to consumers. More specifically, I will address issues affecting the determination of rate base and adjusted operating income that will impact the total revenue requirement and revenue increase to be charged to consumers. My testimony explains and supports certain OCC Objections ("OCC Objections")[2] to the Staff Report of Investigation ("Staff Report")[3] related to the base rate revenue requirement of Duke. These Objections include OCC Objections No. 1 on overall revenue requirement and revenue increase, No. 3 through No. 6 on adjustments related to operating income and rate base.

[1] *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates*, Case No. 21-887-EL-AIR, et al. (October 1, 2021). (Application).

[2] Objections to the PUCO Staff's Report of Investigation by Office of the Ohio Consumers' Counsel (June 21, 2022). (OCC Objections).

[3] Staff Report of Investigation (May 19, 2022). (Staff Report).

II. ORGANIZATION OF TESTIMONY

Q6. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A6. The testimony is organized as follows: Introduction; Organization of Testimony, OCC Objections to Staff Report, and Conclusion.

Q7. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A7. Yes. I have prepared Exhibit OCC-JD-2 which contains an Overall Financial Summary (Schedule A-1) and supporting Schedules 1 through 9.

Q8. HAVE YOU INCORPORATED THE RECOMMENDATIONS OF OTHER OCC WITNESSES IN YOUR SUMMARY SCHEDULES?

A8. I have incorporated the recommended rate of return supported by OCC witness Dr. J. Randall Woolridge.

Q9. PLEASE DISCUSS SCHEDULE A-1 OF EXHIBIT OCC-JD-2, WHICH IS ENTITLED "OVERALL FINANCIAL SUMMARY."

A9. Schedule A-1 presents the overall financial summary (OCC's recommended revenue decrease and adjusted total revenue requirement) for the adjusted test year. This summary reflects the adjustments I am recommending in my testimony and rate of return sponsored by OCC witness Dr. Woolridge.

Q10. PLEASE DISCUSS SCHEDULES 1-9.

A10. My recommended adjustments to Duke's expenses for the test year and the rate base at date certain are provided on Schedules 1-9. They provide further support and calculations for the revenue decrease and the adjusted total revenue requirement I am recommending.

Q11. DOES OCC SUPPORT OR NOT OPPOSE CERTAIN STAFF REPORT RECOMMENDATIONS RELATED TO REVENUE REQUIREMENT, RATE BASE AND OPERATING INCOME?

A11. Yes. As listed and detailed in OCC Objections filed on June 21, 2022, OCC supports or does not oppose some of the recommendations in the Staff Report that benefit consumers. However, the Staff Report falls short of fully protecting consumers in many ways, as explained in the following OCC Objections.

Q12. PLEASE IDENTIFY SOME OF THOSE STAFF RECOMMENDATIONS THAT OCC CAN SUPPORT OR DOES NOT OPPOSE.

A12. OCC supports or does not oppose the following items, among others identified in OCC Objections, included in the Staff Report related to the revenue requirement, rate base and operating income. For example:

- The Staff Report correctly removed the $1,000,000 in expenses related to the proposed public service advertising and customer education campaign.[4]
- The PUCO Staff correctly removed labor and non-labor expenses associated with Demonstrating and Selling, a reduction of $2,706,172, and the related payroll tax expense of $101,481.[5]
- The PUCO Staff correctly reduced Duke's requested amortization of vegetation management from $2.33 million to $1.4 million annually and the recommendation of a five-year amortization period.[6]
- OCC does not oppose the PUCO Staff's removal of the portion of Silverhawk Electric System Operation facility ($13,184,293) attributable to distribution service outside of Ohio.[7]
- OCC does not oppose the PUCO Staff's removal of plant-in-service costs of $1,453,596 related to adjustments to plant-in-service ordered by the PUCO in Duke's previous rate case that had not been fully processed.[8]
- OCC does not oppose the PUCO Staff's exclusion of costs ($6,494) for meals and flowers that were improperly capitalized or excessive.[9]

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[4] Staff Report at 16.

[5] Staff Report at 16.

[6] Staff Report at 16.

[7] Staff Report at 9.

[8] Staff Report at 8.

[9] Staff Report at 9.

- OCC does not oppose the PUCO Staff's acceptance of Duke's reduction to plant-in-service of $30,967,410 as shown in Schedule B-2.2.[10]

III. OCC OBJECTIONS TO THE STAFF REPORT

OCC Objection No. 1: Overall Revenue Requirement

Q13. PLEASE SUMMARIZE THE REVENUE REQUIREMENTS PROPOSED BY OCC, STAFF REPORT, AND DUKE.

A13. Duke filed its application to increase rates to consumers on October 1, 2021, requesting a revenue increase of $54.7 million (for a total revenue requirement of $601.5 million with a rate of return of 7.26 percent. The test period utilized by Duke was [11] twelve months ending March 31, 2022, with a date certain of June 30, 2021.

The Staff Report proposed a range of revenue increase with a lower bound revenue increase of $1.9 million (with a rate of return of 6.52 percent) and an upper bound revenue increase of $15.3 million (with a rate of return of 7.03 percent).[12] The total revenue requirement ranges from $563.9 million to $577.4 million. The midpoint of the revenue increase is $8.6 million.

[10] Staff Report at 8.

[11] Staff Report at 48, Schedule A-1.

[12] Staff Report at 48, Schedule A-1.

OCC recommends a total revenue requirement of $560.6 million and a revenue decrease for consumers of $1.5 million (with a rate of return of 6.50 percent). *See* Schedule A-1.

Q14. WHY DO YOU OBJECT TO THE BASE RATE REVENUE REQUIREMENT PROPOSED IN THE STAFF REPORT?

A14. As discussed later in my testimony, the base rate revenue requirement proposed in the Staff Report is higher than needed to establish just and reasonable rates for Duke consumers to pay. Specifically, the proposed rate base in the Staff Report should be further reduced and the test year operating income should be increased based on my proposed adjustments. Additionally, the revenue requirement in the Staff Report is calculated from a rate of return of 6.52 percent to 7.03 percent. That rate of return is too high. OCC recommends instead a rate of return of 6.50 percent supported by another OCC witness, Dr. Woolridge.

<u>OCC Objection No. 2: Normalization of Storm Recovery Expenses</u>

Q15. DID THE STAFF REPORT MAKE AN ADJUSTMENT FOR NORMALIZATION OF MAJOR EVENT DAY ("MED") DISTRIBUTION STORM RECOVERY EXPENSES IN THE ADJUSTED TEST YEAR?

A15. The Staff report accepted Duke's methodology and adjustment establishing a baseline of $4,481,055 for MED distribution storm recovery expenses.[13] This causes the storm recovery expenses to be overstated, contributing to the need to unreasonably increase rates to Duke's consumers.

Q16. WHAT WAS DUKE'S METHOD FOR FORECASTING THIS EXPENSE?

A16. Duke's forecast was based on a five-year average of the costs from 2016 through 2020.[14] The 2016-2019 amounts are the amounts approved by the Commission in the annual Rider DSR cases and the 2020 amount is the amount requested by the Company in its application in the 2020 Rider DSR case (Case No. 21-0165-EL-RDR) as the order was not available.[15]

Q17. DO YOU AGREE WITH DUKE'S METHOD FOR FORECASTING THIS EXPENSE?

A17. No. I agree with the use of a five-year average but recommend the use of the years 2017-2021. The chart below shows the storm recovery expense for each of the years 2016 through 2021.[16]

Storm Recovery Expenses						
2016	2017	2018	2019	2020	2021	Avg 2016-2020
$5,084,274	$5,205,590	$7,652,378	$2,778,684	$1,684,350	$555,060	$4,481,055

[13] Staff Report at 14.

[14] WPC-3.8a.

[15] WPC-3.8a.

[16] WPC-3.8a, PUCO Application, Case No. 22-125-EL-RDR Att. 1 p.1.

Duke used the expenses from 2016 through 2020 for its calculation but the use of the most recent five years available is preferable as these amounts are more representative of current costs and costs expected to be incurred when rates established in this proceeding are in effect. As shown in the chart, the costs for this expense have declined over the past four years. As costs have been declining, Duke's forecast based on older data could result in an over-estimation of the projected storm recovery expenses and more than reasonable collection in rates from consumers.

Q18. DO YOU RECOMMEND ANY OTHER ADJUSTMENTS TO THE COMPANY'S FORECAST METHOD?

A18. Yes, as stated above, Duke used the amount requested in its 2020 Rider DSR application (Attachment JD-1), not the final approved amount for the 2020 storm recovery expenses. Since the PUCO order in that case has been issued, the authorized amount of $1,683,206 should be used for 2020 in calculating the average.[17] This is the amount approved by the PUCO to be reasonable and is consistent with the approved amounts used by Duke for 2016-2019.

Q19. WHAT IS YOUR RECOMMENDED ADJUSTMENT?

[17] Order dated September 23, 2021, Case No. 21-165-EL-RDR, et al. p.2 (Attachment JD-2).

A19. I calculated a five-year average for the years 2017-2021, using the 2020 approved amount and the 2021 as-filed amount, applying escalation factors provided by Duke in email dated 8-4-2022 (Attachment JD-3) which is illustrated below.[18]

Storm Recovery Expenses					
2017	2018	2019	2020	2021	Average
$5,571,851	$8,190,796	$2,974,197	$1,801,646	$555,060	$3,818,710

The result of using the most current five-year period for the average and the Final Order amount for 2020 expense results in an average of $3,818,710, a reduction of $662,345 to the MED distribution storm recovery expense proposed by Duke. This adjustment is shown on Exhibit OCC-JD-2, Schedule 2.

<u>OCC Objection No. 3: Gain on Disposition of Property</u>

Q20. DID THE STAFF REPORT MAKE AN ADJUSTMENT TO THE TEST YEAR OPERATING INCOME TO REFLECT HISTORICAL AMOUNTS OF GAINS ON DISPOSITION OF UTILITY PROPERTY?

A20. No.

Q21. DO YOU RECOMMEND AN ADJUSTMENT FOR GAINS ON THE DISPOSITION OF UTILITY PROPERTY?

[18] *See* WPC-3.8a, Order dated September 23, 2021, Case No. 21-165-EL-RDR p.2; Case No. 22-125-EL-RDR Att. 1 p.1.

A21. Yes. If Duke receives any gains on disposition of utility property in the years between rate cases, the gains are retained by Duke. As the ratepayers have been responsible for a return of and on utility property, the gains should be returned to consumers.

Q22. HAS DUKE REFLECTED ANY GAIN ON DISPOSITION OF UTILITY PROPERTY IN THE CURRENT CASE?

A22. No. Duke's response to OCC-INT-05-020 (Attachment JD-4) stated that no gains on the sale of utility property are included (or reflected) in the proposed revenue requirement.

Q23. DID DUKE HAVE ANY GAINS ON SALES OF PROPERTY SINCE THE LAST RATE CASE?

A23. Yes. According to Application Schedule C10.2, Duke recorded gains during the years 2016 – 2020 and the test year which are shown below.

Gains on Disposition of Property							
2016	2017	2018	2019	2020	Test Year	Total	5 Yr Amort
$843,392	$269,461	$25,165	$29,153	($24,224)	$297,903	$1,440,850	$288,170

As shown, Duke has received $1,440,850 of such gains since 2016. If the gains are not reflected in the operating income of the adjusted test year, Duke will unreasonably retain these gains to the detriment of consumers.

Q24. WHAT IS YOUR RECOMMENDED ADJUSTMENT?

A24. The adjustment is to amortize the total gains on sale of property from 2016 through the test year over five years, which results in a reduction to the adjusted test year expense of $288,170. This adjustment is shown on Exhibit OCC-JD-2 Schedule 3.

<u>OCC Objection No. 4: Board of Director Fees</u>

Q25. DID THE STAFF REPORT EXCLUDE FROM TEST YEAR EXPENSES FEES PAID TO DUKE'S BOARD OF DIRECTORS?

A25. No. However, an adjustment reducing part of the board of directors fees from the adjusted test year expenses is warranted.

Q26. HAS DUKE INCLUDED COSTS FOR BOARD OF DIRECTORS FEES IN THE ADJUSTED TEST YEAR?

A26. Yes. Duke has included $174,598 of costs related to the board of directors.[19]

Q27. SHOULD THESE COSTS BE COLLECTED THROUGH UTILITY RATES FROM CONSUMERS?

A27. It would not be appropriate or reasonable to collect all of these costs from consumers. The board of directors serves the interests of Duke's shareholders. As a result, consumers should not bear all of the costs for this expense.

[19] OCC-INT-05-004 Supplemental (Attachment JD-5).

Q28. WHO SHOULD BE RESPONSIBLE FOR THESE COSTS?

A28. As Duke and its shareholders are the primary beneficiaries of the board of directors, they should be responsible for the majority of the costs. A 75/25 sharing of board of director costs between shareholders and consumers, respectively, would be more appropriate.

Q29. WHAT IS YOUR RECOMMENDED ADJUSTMENT?

A29. The adjustment is a disallowance of 75% of board of director costs, a reduction of $130,949. (174,598 x 75%) This adjustment is shown on Exhibit OCC-JD-2, Schedule 4.

Q30. IS THIS ADJUSTMENT CONSISTENT WITH THE REGULATORY PRACTICES IN OTHER JURISDICTIONS?

A30. Yes. For example, the board of directors costs have been limited in Connecticut by the Public Utilities Regulatory Authority. The Decision in Docket No. 13-01-19 (Attachment JD-6) stated the following on page 73:

> The main objective of the BOD is to protect the interest of the Company's investors or shareowners. Ratepayers may tangentially garner benefits from the activities of the BOD; however, they are not the focus of the BOD decisions. Consistent with the determinations regarding public company costs discussed above, the Authority allows only 25% of BOD costs in rates.

<u>OCC Objection No. 5: Incentive Compensation Expense and Rate Base Adjustment</u>

Q31. PLEASE SUMMARIZE THE STAFF REPORT ADJUSTMENT TO INCENTIVE COMPENSATION.

A31. The Staff made a number of adjustments to incentive compensation. The Staff removed capitalized incentive compensation related to achieving certain financial goals of $2,352,669 from rate base[20] and reduced test year expenses by $6,696,448 by removing incentive compensation based on financial metrics, advertising for new business, and limited availability to a few highly compensated individuals.[21]

Q32. DO YOU AGREE WITH THE STAFF'S ADJUSTMENTS TO INCENTIVE COMPENSATION EXPENSE?

A32. No, because the Staff did not go far enough to remove these expenses from the test year, I support the removal of incentive compensation related to financial metrics but recommend additional reductions based on my review of the details of Duke's short-term incentive compensation plan.

Q33. WHY SHOULD THE COSTS RELATED TO FINANCIAL METRICS BE REMOVED?

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[20] Staff Report at 9.

[21] Staff Report at 15.

A33. Duke and its shareholders are the primary beneficiaries of any rewards based on financial metrics such as earnings per share. As Duke and its shareholders receive the benefits from such metrics, consumer should not be responsible for paying such costs.

Q34. PLEASE DISCUSS YOUR ADDITIONAL CONCERNS WITH DUKE'S SHORT-TERM INCENTIVE COMPENSATION PLAN.

A34. Duke's short-term incentive plan fails to provide sufficient incentive to employees. Because of this deficiency, the plan is more of a bonus plan than an incentive compensation plan and is simply providing additional pay to employees without clear benefits to consumers.

Q35. IN WHAT WAYS DOES THE SHORT-TERM INCENTIVE COMPENSATION PLAN FAIL TO PROVIDE AN INCENTIVE FOR BETTER EMPLOYEE PERFORMANCE THAT BENEFITS CONSUMERS?

A35. The first issue with Duke's short-term plan is that all employees receive a reward. For illustration, the charts below show the number of employees that were eligible for short-term incentive compensation and the number of employees that did not receive an award.[22]

[22] OCC-INT-05-023 Supplemental (Attachment JD-7).

Duke Energy Ohio, Inc. Short-Term Incentive Compensation		
Year	Eligible Employees	Did Not Receive
2019	633	0
2020	661	0
2021	639	0

Duke Energy Business Services LLC Short-Term Incentive Compensation		
Year	Eligible Employees	Did Not Receive
2019	8,306	0
2020	7,631	0
2021	7,811	0

As shown, every employee eligible for short-term incentive compensation over the past three years received an award.

Q36. WHY IS THIS AN ISSUE?

A36. Incentive compensation should provide a motivation for greater effort. An incentive program in which every employee receives a reward fails in this regard. When employees know they will be rewarded regardless of performance, the impact of the plan is diminished or non-existent.

Q37. ARE THERE ANY OTHER ISSUES WITH DUKE'S SHORT-TERM INCENTIVE PLAN?

A37. Yes. Duke's short-term incentive plan has a financial trigger. Unless an established Earnings Per Share (EPS) is reached, no incentive compensation will be received by the Company's employees.[23] Because the individual employee has little control over EPS, the connection between effort and reward is reduced. If employees know that regardless of how much effort they make, they may not receive a bonus, the incentive to work harder is diminished. It should also be noted that the plan's goals can be considered 100% financial based because whether or not payouts will be made hinges on achieving a financial goal.

Q38. WHAT IS ANOTHER DEFICIENCY OF THE SHORT-TERM INCENTIVE PLAN?

A38. Part of the award is based on team goals.[24] This further undermines the ability of an employee to directly determine the amount of incentive pay received. The plan's ability to provide incentive is reduced when the employee's own effort is not directly related to the reward received.

Q39. WHAT IS YOUR RECOMMENDED ADJUSTMENT TO THE TEST YEAR OPERATING EXPENSES ASSOCIATED WITH SHORT-TERM INCENTIVE COMPENSATION?

A39. The recommended adjustment is a disallowance of all short-term incentive compensation, a reduction of $5,035,189 to short-term incentive compensation expense. This is an incremental reduction of $1,234,006 to the recommended

[23] OCC-INT-05-026 (Attachment JD-8).

[24] Jacob J. Stewart Direct p.19.

reduction in the Staff Report. This adjustment is shown on Exhibit OCC-JD-2 Schedule 5.

Q40. PLEASE SUMMARIZE THE STAFF REPORT'S ADJUSTMENT TO INCENTIVE COMPENSATION IN RATE BASE.

A40. The Staff removed capitalized incentive compensation related to financial metrics capitalized from June 1, 2016, through the date certain, a reduction of $2,352,669 to distribution rate base.[25]

Q41. DO YOU AGREE WITH THE STAFF'S ADJUSTMENT?

A41. No, I do not think the Staff's adjustment goes far enough to rid consumers of these unnecessary costs. I support that incentive compensation related to financial metrics should be removed. However, I recommend an additional adjustment to rate base related to Duke's incentive compensation plan.

Q42. PLEASE EXPLAIN YOUR ADJUSTMENT.

A42. For the reasons I explained above, Duke's short-term incentive compensation plan fails to provide incentive to employees, therefore providing no benefit to consumers. As such, none of the costs related to the plan should be recoverable from consumers. I recommend the removal from rate base all capitalized short-term incentive compensation, a reduction to rate base of $4,220,420. This is an

[25] Staff Report at 9.

incremental adjustment of $1,867,750 to the Staff Report as shown on Exhibit OCC-JD-2, Schedule 6.

<u>O&M Expense Flow Through For Proposed OCC Adjustments</u>

Property Tax

Q43. PLEASE DISCUSS YOUR ADJUSTMENT TO PROPERTY TAX.

A43. The adjustment is a flowthrough from the OCC's rate base adjustment to capitalized incentive compensation. OCC's adjustment reduces property tax expense by $127,523, which is illustrated on Exhibit OCC-JD-2 Schedule 7.

Payroll Tax

Q44. PLEASE DISCUSS YOUR ADJUSTMENT TO PAYROLL TAX.

A44. The adjustment is a flowthrough from OCC's adjustment to incentive compensation expense. OCC's adjustment reduces payroll tax by $92,550, which is illustrated on Exhibit OCC-JD-2 Schedule 8.

Income Tax

Q45. PLEASE DISCUSS YOUR ADJUSTMENT TO INCOME TAXES.

A45. The adjustment is a flowthrough from the OCC's adjustments to O&M expenses. OCC's adjustments increase income taxes by $542,355, which is illustrated on Exhibit OCC-JD-2 Schedule 9.

IV. CONCLUSION

Q46. DOES THIS CONCLUDE YOUR TESTIMONY?

A46. Yes. However, I reserve the right to incorporate new information that may subsequently become available. I also reserve the right to supplement my testimony in the event Duke, the PUCO Staff or other parties submit new or corrected information in connection with this proceeding.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Direct Testimony of John Defever, C.P.A. on behalf of Office of the Ohio Consumers' Counsel has been served upon those persons listed below via electronic service this 2nd day of September 2022.

/s/ Angela D. O'Brien
Angela D. O'Brien
Assistant Consumers' Counsel

The PUCO's e-filing system will electronically serve notice of the filing of this document on the following parties:

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QUALIFICATIONS OF JOHN DEFEVER

John Defever, CPA is a regulatory consultant with Larkin & Associates. As such, Mr. Defever is responsible for the review and analysis of regulatory filings and the preparation of testimony, discovery requests, briefs, schedules, exhibits and reports. Mr. Defever also assists with the annual audit of a Michigan Railroad Company. Mr. Defever has been employed with the firm of Larkin and Associates since 2010.

Mr. Defever has performed work in the field of utility regulation on behalf of public service commission staffs, state attorney generals and consumer groups concerning regulatory matters before regulatory agencies in Alaska, California, Connecticut, District of Columbia, Florida, Hawaii, Iowa, Maine, Maryland, Massachusetts, Mississippi, Oregon, New Hampshire, and Vermont.

Mr. Defever received a Bachelor of Business Administration, Major: Accounting from Eastern Michigan University and an Associate in Applied Science at Schoolcraft College. Mr. Defever is a member of the Michigan Association of Certified Public Accountants and maintains continuing professional education in accounting, auditing, and taxation.

Partial list of utility cases participated in:

Docket No. 10-02-13	Aquarion Water Company of Connecticut Connecticut Department of Utility Control
Docket No. 10-70	Western Massachusetts Electric Company Massachusetts Department of Public Utilities
Docket No. 10-12-02	Yankee Gas Services Company Connecticut Department of Utility Control
Docket No. 11-01	Fitchburg Gas & Electric Light Company Massachusetts Department of Public Utilities
Case No. 9267	Washington Gas Light Company Maryland Public Service Commission
Case No. 9286	Potomac Electric Power Company Maryland Public Service Commission

QUALIFICATIONS OF JOHN DEFEVER

Docket No. 13-06-08	Connecticut Natural Gas Corporation Connecticut Public Utility Regulatory Authority
Docket No. 13-90	Fitchburg Gas & Electric Light Company Massachusetts Department of Public Utilities
Docket No. 8190	Green Mountain Power Company Before the Vermont Public Service Board
Docket No. 8191	Green Mountain Power Company Alternative Regulation Before the Vermont Public Service Board
Case No. 9354	Columbia Gas of Maryland, Inc. Maryland Public Service Commission
Docket No. 13-135	Western Massachusetts Electric Company Massachusetts Department of Public Utilities
Docket No. 14-05-06	Connecticut Light & Power Company Connecticut Public Utilities Regulatory Authority
Docket No. 13-85	Massachusetts Electric Company and Nantucket Electric Company D/B/A/ as National Grid Massachusetts Department of Public Utilities
Case No. 9390	Columbia Gas of Maryland, Inc. Maryland Public Service Commission
Docket No. 15-03-01	Connecticut Light & Power Company Connecticut Public Utilities Regulatory Authority
Docket No. 15-03-02	United Illuminating Company Connecticut Public Utilities Regulatory Authority
Docket No. 15-149	Western Massachusetts Electric Company Massachusetts Department of Public Utilities

QUALIFICATIONS OF JOHN DEFEVER

Docket No. 8710	Vermont Gas Systems Inc. Before the Vermont Public Service Board
Docket No. 8698	Vermont Gas Systems Inc. Alternative Regulation Before the Vermont Public Service Board
U-15-091 / U-15-092	College Utilities Corporation Golden Heart Utilities, Inc. Regulatory Commission of Alaska
Docket No.16-06-04	United Illuminating Company Connecticut Public Utilities Regulatory Authority
Docket No. 15-05-42	Southern Connecticut Gas Company Connecticut Public Utilities Regulatory Authority
Docket No. 20160251-EI	Florida Power & Light Company Florida Public Service Commission
Docket No. 20170141-SU	KW Resort Utilities Florida Public Service Commission
Application No. A.16-09-001	Southern California Edison California Public Utilities Commission
Case No. 18-0409-TF	Vermont Gas Systems, Inc. Vermont Public Utility Commission
Docket No. 17-10-46	Connecticut Light & Power Company Connecticut Public Utilities Regulatory Authority
Docket No. 2017-0105	Hawaii Gas Company Hawaii Public Utilities Commission
Docket No. 18-03-01	Connecticut Light & Power Company Connecticut Public Utilities Regulatory Authority
Docket No. 18-03-02	United Illuminating Company Connecticut Public Utilities Regulatory Authority

QUALIFICATIONS OF JOHN DEFEVER

Docket No. A.17-11-009	Pacific Gas & Electric California Public Utilities Commission
Docket No. 18-05-16	Connecticut Natural Gas Connecticut Public Utilities Regulatory Authority
Docket No. 18-05-10	Yankee Gas Connecticut Public Utilities Regulatory Authority
Docket No. 18-11-12	Connecticut Light & Power Company Connecticut Public Utilities Regulatory Authority
Docket No. 18-07-10	SJW Group and Connecticut Water Service Connecticut Public Utilities Regulatory Authority
Docket No. RPU-2019-0001	Interstate Power and Light Iowa Utilities Board
Docket No. 2018-0388	Kona Water Service Company Hawaii Public Utilities Commission
Docket No. DE 19-057	Public Service Company of New Hampshire New Hampshire Public Utilities Commission
Docket No. 20-03-01	Connecticut Light & Power Company Connecticut Public Utilities Regulatory Authority
Docket No. 20-03-02	United Illuminating Company Connecticut Public Utilities Regulatory Authority
Application No. A.19-08-013	Southern California Edison Public Utilities Commission
Docket No. D.P.U. 19-120	NSTAR Gas Company d/b/a Eversource Energy Massachusetts Department of Public Utilities
Docket No. 2019-00333	Maine Water Company – Skowhegan Division Public Utilities Commission
Docket No. 20-08-03	The Connecticut Light and Power Company & The United Illuminating Company

QUALIFICATIONS OF JOHN DEFEVER

	Connecticut Public Utilities Regulatory Authority
Docket No. D.P.U. 19-113	Massachusetts Electric Company & Nantucket Electric Company Each d/b/a National Grid
Docket No. D.P.U. 20-120	National Grid Massachusetts Department of Public Utilities
Docket No. 20-12-30	Connecticut Water Connecticut Public Utilities Regulatory Authority

Duke Energy Ohio, Inc.
PUCO Case No. 21-887-EL-AIR
Adjusted Test Year 12 Months Ended March 31, 2022
Exhibit OCC-JD-2
Accompanying the Direct Testimony of
John Defever, CPA

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Duke Energy Ohio, Inc.

PUCO Case No. 21-887-EL-AIR
Exhibit OCC-JD-2
Schedule A-1

Adjusted Test Year Ending March 31, 2022

Overall Financial Summary

LINE NO.	DESCRIPTION	JURISDICTIONAL PROPOSED TEST YEAR	OCC	STAFF LOWER BOUND	STAFF UPPER BOUND
1	Rate Base	$ 2,068,551,045	$ 2,034,275,176	$ 2,036,142,926	$ 2,036,142,926
2	Current Operating Income	$ 107,787,484	133,368,599	$ 131,375,412	$ 131,375,412
3	Earned Rate of Return (Line 2 / Line 1)	5.21%	6.56%	6.45%	6.45%
4	Requested Rate of Return	7.26%	6.50%	6.52%	7.03%
5	Required Operating Income (Line 1 x Line 4)	$ 150,176,806	$ 132,227,886	$ 132,820,968	$ 143,240,771
6	Operating Income Deficiency (Line 5 - Line 2)	$ 42,389,322	$ (1,140,713)	$ 1,445,556	$ 11,865,359
7	Gross Revenue Conversion Factor	1.2901147	1.2877569	1.2877569	1.2877569
8	Revenue Deficiency (Line 6 x Line 7)	$ 54,687,087	$ (1,468,961)	$ 1,861,525	$ 15,279,698
9	Revenue Increase Requested	$ 54,686,965	$ (1,468,961)	$ 1,861,525	$ 15,279,698
10	Adjusted Operating Revenues	$ 546,778,619	562,071,182	$ 562,071,182	$ 562,071,182
11	Revenue Requirements (Line 9 + Line 10)	$ 601,465,584	$ 560,602,221	$ 563,932,707	$ 577,350,880
12	Net Increase (%)	10.00%	-0.26%	0.33%	2.72%

Duke Energy Ohio, Inc. | **Case No. 21-887-EL-AIR**

Exhibit OCC-JD-2

Schedule 1

Adjusted Test Year Ending March 31, 2022 | **Page 1 of 1**

OCC Summary of Adjustments

Line No.				Source
	Rate Base			
1	Incentive Compensation - Rate Base		($1,867,750)	Schedule 6
	Operating Income			
2	Normalization of Major Event Day Distribution Storm Recovery	$	(662,345)	Schedule 2
3	Gain on Disposition of Utility Property	$	(288,170)	Schedule 3
4	Board of Directors Fees	$	(130,949)	Schedule 4
5	Incentive Compensation - Operating Income	$	(1,234,006)	Schedule 5
6	Total Operating Income Adjustments		($2,315,469)	
	Taxes			
7	Property Tax	$	(127,523)	Schedule 7
8	Payroll Taxes	$	(92,550)	Schedule 8
9	Income Taxes	$	542,355	Schedule 9
10	Total Taxes		$322,282	

Duke Energy Ohio, Inc. **PUCO Case No. 21-887-EL-AIR**

Exhibit OCC-JD-2

Schedule 2

Adjusted Test Year Ending March 31, 2022 **Page 1 of 1**

Normalization of Major Event Day Distribution Storm Recovery

Line No.	Description		Adjusted Test Year	Source
1	Company Amount	$	4,481,055	Staff Report p.14
2	OCC Recommended Amount	$	3,818,710	Line 10
3	OCC Adjustment	$	(662,345)	Line 2 - Line 1

		Storm Costs	Revised CPI (Duke email dated 8-4-2022)		Total
2017	$	4,926,798	0.88423	$	5,571,851
2018	$	7,380,890	0.90112	$	8,190,796
2019	$	2,741,347	0.92171	$	2,974,197
2020	$	1,683,206	0.93426	$	1,801,646
2021	$	555,060	1.0000	$	555,060
			Total	$	19,093,550
			Five Year Average	$	3,818,710

Duke Energy Ohio, Inc. | **PUCO Case No. 21-887-EL-AIR**
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Schedule 3
Adjusted Test Year Ending March 31, 2022 | **Page 1 of 1**

Gain on Disposition of Utility Property

Line No.	Description	Adjusted Test Year	Source
1	Company Amount	$ -	OCC-INT-05-020
2	OCC Recommended	($288,170)	Line 11
3	OCC Adjustment	$ (288,170)	Line 2 - Line 1
4	2016	$843,392	Company Schedule C-10.2
5	2017	$269,461	Company Schedule C-10.2
6	2018	$25,165	Company Schedule C-10.2
7	2019	$29,153	Company Schedule C-10.2
8	2020	($24,224)	Company Schedule C-10.2
9	Test Year	$297,903	Company Schedule C-10.2
10	Total	$1,440,850	Total Lines 4-9
11	5-Year Amortization	$288,170	Line 10/5

Duke Energy Ohio, Inc.

PUCO Case No. 21-887-EL-AIR
Exhibit OCC-JD-2
Schedule 4
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Adjusted Test Year Ending March 31, 2022

Board of Directors Fees

Line No.	Description	Adjusted Test Year		Source
1	Company Amount	$	174,598	OCC-INT-05-004 Supplemental
2	OCC Recommended Amount	$	43,650	Line 1 x 25%
3	OCC Adjustment	$	(130,949)	Line 2 - Line 1

Duke Energy Ohio, Inc. **PUCO Case No. 21-887-EL-AIR**

Exhibit OCC-JD-2

Schedule 5

Adjusted Test Year Ending March 31, 2022 **Page 1 of 1**

Short Term Incentive Compensation Expense

Line No.	Description	Adjusted Test Year	Source	Notes
1	Company Amount	$ 5,035,189	OCC-INT-09-010	
2	OCC Recommended Amount	$ -	Defever Testimony	
3	OCC Adjustment	$ (5,035,189)	Line 2 - Line 1	
4	Staff Adjustment to ST Incentive Comp	(3,801,183)	Staff Report WPC-3.14c1	
5	OCC Incremental Adj to Staff Adj	(1,234,006)	Line 3 - Line 4	

Duke Energy Ohio, Inc. | **PUCO Case No. 21-887-EL-AIR**

Exhibit OCC-JD-2

Schedule 6

Adjusted Test Year Ending March 31, 2022 | **Page 1 of 1**

Short Term Incentive Compensation Capitalized

Line No.	Description		Adjusted Test Year	Source
1	Company Amount	$	4,220,420	OCC-INT-09-014
2	OCC Recommended Amount	$	-	Defever Testimony
3	OCC Adjustment	$	(4,220,420)	Line 2 - Line 1
4	Staff Adjustment		(2,352,670)	Staff Report Schedule B-2.2, lines 20, 37, 52
5	OCC Incremental Adj to Staff Adj	$	(1,867,750)	Line 3 - Line 4

Adj TY Short Term Incentives Capitalized

		Portion of Capitalized Incentive Compensation Related to Financial Goals (50%)		Total Incentive Compensation Capitalized	Source
Distribution					
Incentives Allocated	$	711,377	$	1,422,754	OCC-INT-09-014
Incentives Allocated-Union	$	1,022,464	$	2,044,928	OCC-INT-09-014
Exec Short Term Incent	$	44,456	$	88,912	OCC-INT-09-014
Total Distribution	$	1,778,297	$	3,556,594	
General					
Incentives Allocated	$	207,410	$	414,820	OCC-INT-09-014
Incentives Allocated-Union	$	10,703	$	21,406	OCC-INT-09-014
Exec Short Term Incent	$	6,690	$	13,380	OCC-INT-09-014
Total General	$	224,803	$	449,606	
Common					
Incentives Allocated	$	98,822	$	197,644	OCC-INT-09-014
Incentives Allocated-Union	$	5,100	$	10,200	OCC-INT-09-014
Exec Short Term Incent	$	3,188	$	6,376	OCC-INT-09-014
Total Common	$	107,110	$	214,220	
Total	$	2,110,210	$	4,220,420	

Duke Energy Ohio, Inc.

Adjusted Test Year Ending March 31, 2022

Property Tax

Line No.	Description	Adjusted Test Year	Reference
1	OCC Adjustment to Rate Base	$ (1,867,750)	Schedule 6
2	Property Tax Percentage	6.83%	Property Tax Expense/Rate Base Staff WPC-3.6a, Schedule A-1
3	OCC Adjustment	$ (127,523)	

Adjusted Test Year Ending March 31, 2022

Payroll Tax

Line No.	Description	Adjusted Test Year	Reference
1	OCC Adjustment to Incentive Comp	$ (1,234,006)	Schedule 5
2	Payroll Tax Percentage	7.50%	STAFF WPC-3.14c
3	OCC Adjustment	$ (92,550)	

Duke Energy Ohio, Inc.

Adjusted Test Year Ending March 31, 2022

Income Tax Expense

Line No.	Description	Adjusted Test Year		Reference
	Federal Income Tax			
1	Jurisdictional Operating Income Adjustments	$	(2,535,543)	Schedule 1
2	Less Municipal Income Tax	$	12,521	Line 8
3	Total	$	(2,523,022)	
4	Federal Income Tax Rate		21.000%	Staff Schedule C-4
5	Adjustment to Federal Income Expense	$	529,835	Line 3 * Line 5
	Municipal Tax			
6	Jurisdictional Operating Income Adjustments	$	(2,535,543)	Line 1
7	Municipal Tax Rate		0.494%	Staff Schedule C-4
8	Adjustment to Municipal Tax	$	12,521	Line 6 * Line 7
9	Total Income Tax Adjustment	$	542,355	Line 5 + Line 8

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., to Adjust and Set Rider DSR.	)))	Case No. 22-0125-EL-RDR
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval of Tariff Amendments.	)))	Case No. 22-0126-EL-ATA

APPLICATION OF DUKE ENERGY OHIO, INC., TO ADJUST RIDER DSR FOR RECOVERY OF DISTRIBUTION MAJOR STORM EXPENSES

Duke Energy Ohio, Inc., (Duke Energy Ohio or Company) is an Ohio corporation engaged in the business of supplying electric transmission, distribution, and a standard service offer[1] to customers in southwestern Ohio, all of whom will be affected by this Application, and is a public utility as defined by R. C. 4905.02 and 4905.03. Duke Energy Ohio serves incorporated communities and unincorporated territory within its entire service area, which includes all or parts of Adams, Brown, Butler, Clinton, Clermont, Hamilton, Montgomery, and Warren Counties in Ohio.

In support of its Application, Duke Energy Ohio states as follows:

1. This Application is made pursuant to O.A.C. Chapter 4901:1-35 and the Opinion and Order of the Public Utilities Commission of Ohio (Commission), issued December 19, 2018, in Consolidated Case Nos. 17-32-EL-AIR, *et al.* (Opinion and Order).[2] In its Opinion and Order, the Commission approved a stipulation in which the signatory parties agreed, among other things,

[1] Duke Energy Ohio provides a standard generation service offer pursuant to an electric security plan, most recently approved in Consolidated Cases No. 17-1263-EL-SSO, *et al.*
[2] *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates* No. 17-32-EL-AIR, *et al.*, Opinion and Order (December 19, 2018).

that Duke Energy Ohio would extend its Distribution Storm (Rider DSR) to track annual incremental major storm expense, as compared to the amount recovered in base rates.[3] Rider DSR was originally approved by the Commission in the Company's ESP III Case No. 14-841-EL-SSO filing. In that proceeding, the Commission ordered the Company to track annual incremental major storm expense as compared to the amount recovered in base rates, but to not seek recovery under the rider until the balance of the asset or liability exceeded $5 million.[4] In the Commission's most recent order, the $5 million threshold was eliminated and the Company was instructed to file an application with the Commission to refund or recover the accumulated balance of the deferred storm cost deferral as of December 31, 2018, with annual rider filings thereafter.[5]

2. Rider DSR is a nonbypassable rider that is designed to either refund or collect amounts as compared to that which is recovered in base rates. The amount included in base rates is $4.3 million.[6]

3. Schedules supporting the calculation of the proposed rate for Rider DSR are provided as attachments hereto as Attachment 1. The schedules support the calculations for the various cost components that were approved for recovery through Rider DSR.

4. Attached hereto as Attachment 2 is the new tariff sheet No. 101.05, entitled 'Rider DSR – Distribution Storm Rider.'

5. Attached hereto as Attachment 3 is a summary of capital costs incurred for major storms.

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[3] *Id.*, pp. 42-43.
[4] *In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, Accounting Modifications, and Tariffs for Generation Service*, Case Nos. 14-841-EL-SSO, *et al.*, Opinion and Order, pp. 73-75 (April 2, 2015).
[5] *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates* No. 17-32-EL-AIR, *et al.*, Opinion and Order, pp. 42-43 (December 19, 2018).
[6] *Id.*, p. 43.

6. WHEREFORE, Duke Energy Ohio respectfully requests that the Commission approve this Application and the attached tariff and rates for Rider DSR and order rates to be effective first billing cycle of November 2022.

Respectfully submitted,

DUKE ENERGY OHIO, INC.

<u>/s/ Larisa M. Vaysman</u>
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Larisa M. Vaysman (0090290)
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Larisa.Vaysman@duke-energy

Duke Energy Ohio
Rider DSR
Case No. 22-0125-EL-RDR
Revenue Requirement

Schedule 1

Line No.	Description		Duke Energy Ohio	
1	Prior Year Regulatory Asset (Liability) [(1)]		$ (10,607)	
2	Total O&M for Major Storms		555,060	Schedule 2, Line 22
3	O&M for Major Storms in Base Rates[(2)]		(4,300,000)	
4	Total Incremental O&M for Major Storms Over (Under) Base Rates		(3,744,940)	Line 2 + Line 3
5	Regulatory Asset (Liability) as of December 31, 2021		(3,755,547)	Line 1 + Line 4
6	Calculation of Carrying Charges [(3)]	5.16%	(547)	
7	Revenue Requirement		$ (3,756,094)	Line 5 + Line 6

Notes:
[(1)] The prior year regulatory asset is the result of under-collections in Rider DSR in Case No. 20-0344-EL-RDR. Collection began with the November 2020 billing cycle and concluded with the October 2021 billing cycle.
[(2)] Commission Order on December 19, 2018, in the Company's Distribution Rate Case, Case No. 17-32-EL-AIR, pages 42-43.
[(3)] Accrual on ending balance from prior year at long term debt rate approved in the Company's Distribution Rate Case, Case No. 17-32-EL-AIR.

Duke Energy Ohio
Rider DSR
Case No. 22-0125-EL-RDR
Summary of 2021 O&M Expenses

Schedule 2

Line No.	Resource	Resource Description	2020 Storms [1] OSTM2002	2020 Storms [1] OSTM2006	2020 Storms [1] OSTM2009	2021 Storms [2] OSTM2104	Total
1	12000	Overtime	$ -	$ -	$ -	$ 12,075.46	12,075.46
2	12004	Overtime-Union	-	-	-	209,982.57	209,982.57
3	21000	Direct Material/Inventory Cost	-	-	-	1,795.24	1,795.24
4	28000	Material Allocations	-	-	-	44.73	44.73
5	28002	Stores Loading	-	-	-	202.40	202.40
6	30000	Direct Purchases	-	-	-	-	-
7	40000	Travel Expenses	-	-	-	122.84	122.84
8	41000	Meals and Entertainment (50%)	-	-	-	587.53	587.53
9	41001	Overtime Meals (Non Travel)	-	-	-	5,658.00	5,658.00
10	42000	Personal Vehicle Mileage Reimb	-	-	-	-	-
11	50000	Vehicle & Equip. Chargeback	-	-	-	10,514.55	10,514.55
12	69100	Baseload Contract Labor	-	-	2,605.50	252,914.15	255,519.65
13		Mutual Assistance Received	-	-	-	-	-
14		***TOTAL***	-	-	2,605.50	493,897.47	496,502.97
15	ALLOCATED AMOUNTS [3]						
16	5.46%	Payroll Taxes	-	-	-	12,124.37	12,124.37
17	27.31%	Fringe Benefits	-	-	-	60,644.05	60,644.05
18		***TOTAL***	-	-	-	72,768.42	72,768.42
19		***Fully Loaded O&M for Major Storms***	$ -	$ -	$ 2,605.50	$ 566,665.89	$ 569,271.39
20	MUTUAL ASSISTANCE CREDITS						
21		Mutual Assistance Provided					(14,211.33)
22		***TOTAL O&M FOR MAJOR STORMS***					$ 555,060.06

Notes:
[1] Represents costs recorded in 2021 for 2020 storms not present in filing for Case No. 21-0165-EL-RDR.
[2] Represents 2021 major storm expenses through February 2022.
[3] Payroll Taxes (5.46%) and Fringe Benefits (27.31%) are applied to "Overtime" and "Overtime-Union" labor costs (resource codes 12000 and 12004).

Duke Energy Ohio
Rider DSR
Case No. 22-0125-EL-RDR
Cost Allocation and Rate Calculation

Schedule 3

Line No.	Rate Class	Allocation Factor [1]	Allocated Deferral	Annual Bills 2021[3]	Projected Monthly Rider DSR Charge	Annual Billed kW 2021 [3]	Projected Monthly Rider DSR Charge Per kW
1	Residential (RS, RSLI, ORH, TD, CUR, RS3P)	49.23%	($1,849,200)	8,139,006	($0.23)	N/A	
2	Secondary Distribution (DS)	37.09%	(1,393,248)	N/A	N/A	17,933,697	($0.0777)
3	Electric Space Heating (EH)	0.45%	(17,053)	4,076	($4.18)	N/A	
4	Secondary Distribution (DM)	3.82%	(143,445)	549,966	($0.26)	N/A	
5	Unmetered Small Fixed Loads (GSFL, SFL-ADPL)	0.21%	(7,813)	1,273	($6.14)	N/A	
6	Primary Distribution (DP)	9.08%	(340,866)	N/A	N/A	4,381,053	($0.0777)
7	Transmission (TS)	0.00%	N/A	N/A	N/A	N/A	
8	Lighting (SL, TL, OL, NSU, NSP, SC, SE, UOLS, LED)	0.12%	(4,470)	1,710,537	$0.00	N/A	
9	Total	100.00%	($3,756,094) [2]	10,404,858			

Notes: [1] From Cost of Service Study in Case No. 17-032-EL-AIR, Schedule E-3.2, page 18, factor K205, "Weighted Distribution Line Allocation Factor."
[2] From Schedule 1 - Revenue Requirement.
[3] From CMS customer statistics for 12 months ended December 31, 2021

Duke Energy Ohio
139 East Fourth Street
Cincinnati, Ohio 45202

RIDER DSR

DISTRIBUTION STORM RIDER

APPLICABILITY

Applicable to all retail jurisdictional customers in the Company's electric service areas including those customers taking generation service from a Competitive Retail Electric Service Provider. This tariff does not apply to customers taking service under Rate TS, service at transmission voltage.

DESCRIPTION

All retail jurisdictional customers shall be assessed a charge/credit to recover/refund the costs incurred by the Company due to major storms above or below the amount in base rates. The rates for all customers are shown below.

CHARGES

Rate RS, RSLI & RS3P	$~~(0.10)~~(0.23) per month
Rate ORH	$~~(0.10)~~(0.23) per month
Rate TD	$~~(0.10)~~(0.23) per month
Rate CUR	$~~(0.10)~~(0.23) per month
Rate DS	$~~(0.03)~~(0.0777) per kW
Rate EH	$~~(1.91)~~(4.18) per month
Rate DM	$~~(0.12)~~(0.26) per month
Rate GS-FL, SFL-ADPL	$~~(2.81)~~(6.14) per month
Rate DP	$~~(0.03)~~(0.0777) per kW
Lighting (SL, TL, OL, NSU, NSP, SC, SE, UOLS, LED)	$0.00 per month

This Rider is subject to reconciliation, including, but not limited to, refunds or additional charges to customers, ordered by the Commission as the result of audits by the Commission in accordance with the December 19, 2018, Opinion and Order in Case No. 17-1263-EL-SSO, et al.

Duke Energy Ohio
Rider DSR
Case No. 22-0125-EL-RDR
Storms Capital Summary

		SOH2104DC			ALL STORMS TOTAL		
RESOURCE	**RESOURCE DESCRIPTION**	**107000 (cwip)**	**108620 (rwip)**	**Subtotal**	**107000 (cwip)**	**108620 (rwip)**	**Grand Total**
11000	Labor			0.00	0.00	0.00	0.00
11002	Labor-Union	5,898.61	48.65	5,947.26	5,898.61	48.65	5,947.26
12004	Overtime-Union	63,558.27	524.10	64,082.37	63,558.27	524.10	64,082.37
13000	Exempt Supplemental			0.00	0.00	0.00	0.00
18000	Labor Overhead Allocations	17,875.48	165.06	18,040.54	17,875.48	165.06	18,040.54
18001	Unproductive Labor Allocated			0.00	0.00	0.00	0.00
18005	Unproduct Labor Alloc-Union	1,708.18	16.54	1,724.72	1,708.18	16.54	1,724.72
18250	Allocated Payroll Tax	1,340.69	12.38	1,353.07	1,340.69	12.38	1,353.07
18251	Allocated Payroll Tax-Union	5,497.52	45.53	5,543.05	5,497.52	45.53	5,543.05
18350	Allocated Fringes & Non Union	5,516.03	51.31	5,567.34	5,516.03	51.31	5,567.34
18351	Allocated Fringes-Union	21,786.88	181.58	21,968.46	21,786.88	181.58	21,968.46
18400	Incentives Allocated			0.00	0.00	0.00	0.00
18401	Incentives Allocated-Union	2,134.95	17.71	2,152.66	2,134.95	17.71	2,152.66
19500	Service Company Overhead	4,142.79	34.16	4,176.95	4,142.79	34.16	4,176.95
21000	Direct Material/Inventory Cost	18,113.10		18,113.10	18,113.10	0.00	18,113.10
28000	Material Allocations	428.16		428.16	428.16	0.00	428.16
28002	Stores Loading	2,039.55		2,039.55	2,039.55	0.00	2,039.55
30000	Direct Purchases			0.00	0.00	0.00	0.00
35000	Direct Mat/Purchases Accrual	0.00		0.00	0.00	0.00	0.00
41001	Overtime Meals (Non Travel)	1,662.42	28.08	1,690.50	1,662.42	28.08	1,690.50
42000	Personal Vehicle Mileage Reimb			0.00	0.00	0.00	0.00
50000	Vehicle & Equip. Chargeback	5,296.32	89.50	5,385.82	5,296.32	89.50	5,385.82
50002	Vehicle & Equip Chrbk (Alloc)	21,044.30	355.68	21,399.98	21,044.30	355.68	21,399.98
60004	Outside Engineering			0.00	0.00	0.00	0.00
69100	Baseload Contract Labor	79,798.64	658.05	80,456.69	79,798.64	658.05	80,456.69
69400	Turnkey Service Contract Labor			0.00	0.00	0.00	0.00
78000	Allocated S&E (Non-Labor)	71,234.33	535.52	71,769.85	71,234.33	535.52	71,769.85
99970	AFUDC Debt	54.77		54.77	54.77	0.00	54.77
99971	AFUDC Equity	101.70		101.70	101.70	0.00	101.70
Grand Total		$329,232.69	$2,763.85	$331,996.54	$329,232.69	$2,763.85	$331,996.54

THE PUBLIC UTILITIES COMMISSION OF OHIO

IN THE MATTER OF THE REVIEW OF DUKE ENERGY OHIO, INC.'S DISTRIBUTION STORM RIDER.	**CASE NO. 21-165-EL-RDR**
IN THE MATTER OF THE APPLICATION OF DUKE ENERGY OHIO, INC., FOR APPROVAL OF TARIFF AMENDMENTS.	**CASE NO. 21-166-EL-ATA**

FINDING AND ORDER

Entered in the Journal on September 23, 2021

I. SUMMARY

{¶ 1} The Commission approves Duke Energy Ohio, Inc.'s application for recovery associated with the Distribution Storm Rider, subject to modifications.

II. DISCUSSION

{¶ 2} Duke Energy Ohio, Inc. (Duke) is an electric distribution utility (EDU) as defined by R.C. 4928.01(A)(6) and a public utility as defined in R.C. 4905.02, and, as such, is subject to the jurisdiction of this Commission.

{¶ 3} R.C. 4928.141 provides that an EDU shall provide consumers within its certified territory a standard service offer (SSO) of all competitive retail electric services necessary to maintain essential electric services to customers, including a firm supply of electric generation services. The SSO may be either a market rate offer in accordance with R.C. 4928.142 or an electric security plan (ESP) in accordance with R.C. 4928.143.

{¶ 4} On December 19, 2018, the Commission approved a stipulation and recommendation filed by Duke and other parties that, among other things, included an ESP for the period June 1, 2018, through May 31, 2024. *In re Duke Energy Ohio*, Case No. 17-1263-EL-SSO, et al., Opinion and Order (Dec. 19, 2018). In the Opinion and Order, the Commission continued Duke's Distribution Storm Rider (Rider DSR). In accordance with the stipulation, Rider DSR tracks annual incremental major storm expenses, as compared to the amount recovered in base rates. Duke is required to file an annual adjustment to recover or refund the accumulated balance of the deferred storm cost deferral as of December 31, 2018.

{¶ 5} On March 31, 2021, Duke filed an application regarding 2020 storm-related restoration costs. Duke explains that Rider DSR is a nonbypassable rider that is designed to either refund or collect amounts as compared to that which is recovered in base rates. Duke states that $4.3 million is included in base rates for Rider DSR and that the Company had $1,684,350 in Rider DSR expenses in 2020. Thus, Duke asserts that it seeks to refund $1,712,175, on a fixed monthly basis of $0.10 per residential customer.

{¶ 6} Staff filed its review and recommendation on September 1, 2021, and recommends an adjustment of $1,143.56. Staff asserts that it investigated whether Duke's application was reasonable and whether the application complied with sound ratemaking principles. Staff states that, generally, Duke appropriately included all major-storm related expenses. Staff recommends that a total of $618.95 related to meal expenses be disallowed, specifically for a meal purchased outside of the storm territory, for meals in which no receipts were provided, and for excessive meal delivery and service fees. Staff also recommends that a total of $312.33 be disallowed for an employee expense that fell outside of the storm dates. Further, Staff recommends disallowing a total of $212.28 related to personal vehicles, specifically for an expense in which no invoice/receipt was provided and for an expense where Staff could not verify the business purpose of travel, as the document submitted was redacted. After considering the $4.3 million already recovered in base rates for storm restoration, Staff's recommended revenue requirement is a refund of $1,713,318.44.

{¶ 7} Duke filed a letter on September 10, 2021, stating that it does not contest Staff's recommendations.

{¶ 8} Upon review, the Commission finds that Duke's application for recovery does not appear to be unjust or unreasonable and should be approved, subject to Staff's recommendations. Based on Duke's September 10, 2021 communication, no hearing in the matter is necessary.

III. ORDER

{¶ 9} It is, therefore,

{¶ 10} ORDERED, That Duke's application for recovery be approved, subject to Staff's recommended modifications. It is, further,

{¶ 11} ORDERED, That Duke be authorized to file in final form complete copies of the tariff pages consistent with this Finding and Order and to cancel and withdraw its superseded tariff pages. Duke shall file one copy in its TRF docket and one copy in this docket. It is, further,

{¶ 12} ORDERED, That the effective date of the new tariffs shall be a date not earlier than the date upon which the final tariffs are filed with the Commission. It is, further,

{¶ 13} ORDERED, That Duke shall notify all affected customers via a bill message or via a bill insert within 30 days of the effective date of the tariffs. A copy of the customer notice shall be submitted to the Commission's Service Monitoring and Enforcement Department, Reliability and Service Analysis Division, at least 10 days prior to its distribution to customers. It is, further,

{¶ 14} ORDERED, That nothing in this Finding and Order shall be binding upon this Commission in any future proceeding or investigation involving the justness or reasonableness of any rate, charge, rule or regulation. It is further,

{¶ 15} ORDERED, That a copy of this Finding and Order be served upon all parties of record.

COMMISSIONERS:

Approving:
Jenifer French, Chair
M. Beth Trombold
Lawrence K. Friedeman
Daniel R. Conway
Dennis P. Deters

MJS/kck

Fwd: FW: [EXTERNAL] Updated escalation Factor for Storm Costs

From: Tina Miller (tmlarkinassociates@gmail.com)

To: johndefever@yahoo.com

Date: Wednesday, August 10, 2022 at 03:18 PM EDT

---------- Forwarded message ---------
From: **Steinkuhl, Lisa D** <Lisa.Steinkuhl@duke-energy.com>
Date: Thu, Aug 4, 2022 at 2:57 PM
Subject: FW: [EXTERNAL] Updated escalation Factor for Storm Costs
To: Daniel.Duann@occ.ohio.gov <Daniel.Duann@occ.ohio.gov>, Angela.OBrien@occ.ohio.gov <Angela.OBrien@occ.ohio.gov>, tmlarkinassociates@gmail.com <tmlarkinassociates@gmail.com>
Cc: Lawler, Sarah E <Sarah.Lawler@duke-energy.com>, D'Ascenzo, Rocco <Rocco.D'Ascenzo@duke-energy.com>

The updated Consumer Price Index amounts are:

DUKE ENERGY OHIO, INC. — WPC-3.8b
ELECTRIC DEPARTMENT — WITNESS RESPONSIBLE:
CASE NO. 21-887-EL-AIR — L. D. STEINKUHL
CALCULATION OF CONSUMER PRICE INDEX — 09/13/21
FOR URBAN CONSUMERS
BASED ON THE PERIOD ENDED DECEMBER 31, 2021 = 100%

Line No.	Year	Consumer Price Index (A)	CPI 2021=100 Col. 2 / 278.80	
1	2017	246.52	0.88423	
2	2018	251.23	0.90112	
3	2019	256.97	0.92171	→ To WPC-3.8a
4	2020	260.47	0.93426	
5	2021	278.80	1.00000	

(A) Obtained from Bureau of Labor Statistics - Consumer Price Index - All Urban Consumers - Series IDCUUR0000SA0

Let me know if you have any further questions.

Thanks

Lisa

Duke Energy Ohio
Case No. 21-887-EL-AIR
OCC Fifth Set of Interrogatories
Date Received: February 25, 2022

OCC-INT-05-020

REQUEST:

Gains on sale of utility property. Identify all gains on sale of utility property for each year 2017, 2018, 2019, 2020 and 2021. State whether any gains have been reflected in the revenue requirement in the current case and identify the schedule where they are reflected.

RESPONSE:

Objection. This Interrogatory is overly broad and unduly burdensome, given that it seeks information that is neither relevant to this proceeding nor likely to lead to the discovery of admissible evidence in this proceeding with respect to dates outside of the test period. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, no gains of the sale of utility property are include in the revenue requirement.

PERSON RESPONSIBLE:

As to objection: Legal
As to response: Lisa D. Steinkuhl

Duke Energy Ohio
Case No. 21-887-EL-AIR
OCC Fifth Set of Interrogatories
Date Received: February 25, 2022

OCC-INT-05-004
SUPPLEMENTAL

SUPPLEMENTAL REQUEST:

What we are looking for is all costs related to any Board of Directors for which the Company is requesting recovery in the adjusted test year. This would include compensation paid to the Board of Directors and any transportation, lodging, meals/catering, meeting materials, etc. related to board of directors' meetings.

SUPPLEMENTAL RESPONSE:

Objection. This Interrogatory is overly broad and unduly burdensome, given that it seeks information that is neither relevant to this proceeding nor likely to lead to the discovery of admissible evidence in this proceeding with respect to dates outside of the test period. Objecting further, this Interrogatory fails to contain a definition of “fees” and thus forces Duke Energy Ohio to engage in impermissible speculation and guesswork regarding its intended meaning. Objecting further, this Interrogatory is ambiguous and vague as there is no mention of what company for which this information is being sought. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, see the table below for the costs related to Board of Directors for 2017 through 2021 and the adjusted test year.

Year	Total Electric Amount	Allocation	Distribution Adjusted Test Year
2017 Full Year Actuals	$ 164,300		
2018 Full Year Actuals	$ 166,701		
2019 Full Year Actuals	$ 173,528		
2020 Full Year Actuals	$ 158,758		
2021 Full Year Actuals	$ 156,251		
Adjusted Test Year	$ 211,416	82.585%	$ 174,598

PERSON RESPONSIBLE: Legal / Weatherston / Steinkuhl

REQUEST:

Board of Director Fees and Meeting Costs. Provide the total amount of BOD fees and meeting costs included in the adjusted test year and for each of the years 2017, 2018, 2019, 2020, 2021.

RESPONSE:

Objection. This Interrogatory is overly broad and unduly burdensome, given that it seeks information that is neither relevant to this proceeding nor likely to lead to the discovery of admissible evidence in this proceeding with respect to dates outside of the test period. Objecting further, this Interrogatory fails to contain a definition of “fees” and thus forces Duke Energy Ohio to engage in impermissible speculation and guesswork regarding its intended meaning. Objecting further, this Interrogatory is ambiguous and vague as there is no mention of what company for which this information is being sought. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, Duke Energy Ohio does not keep this information in the format requested.

PERSON RESPONSIBLE: Legal

STATE OF CONNECTICUT

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

DOCKET NO. 13-01-19 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE RATES AND CHARGES

August 14, 2013

By the following Commissioners:

John W. Betkoski, III
Michael A. Caron
Arthur H. House

<u>DECISION</u>

TABLE OF CONTENTS

DECISION

I. INTRODUCTION

A. SUMMARY

This rate setting proceeding was initiated by The United Illuminating Company by way of an application to the Public Utilities Regulatory Authority filed pursuant to §16-19 in the General Statutes of Connecticut on February 15, 2013. In its two-year application, as revised by Late Filed Exhibit No. 3, The United Illuminating Company requested an increase in distribution revenues of approximately $65 million or 23.8% in Rate Year 1 (July 2013 - June 2014) and an additional approximately $26 million or 7.7% in Rate Year 2 (July 2014 - June 2015). The rate application results in a cumulative increase of $91 million or approximately 33.6% above the revenue at current rates of $269.412 million. These additional revenues were requested to allow for recovery of capital investments to replace aging infrastructure, maintain reliability, harden its delivery system and meet its public service obligations. The United Illuminating Company proposed timing the rate changes to correspond with the expiring Competitive Transition Assessment, which was set to recover $81.5 million in 2013, by not implementing the new rates until January 1, 2014. For the first six months of the rate year, July 1 through December 31, 2013, The United Illuminating Company proposed to use other existing revenue sources to fund the increased revenue requirements (earnings sharing mechanism, excess Competitive Transition Assessment revenues) so as to defer any actual changes to the distribution retail schedules until January 1, 2014 when the Competitive Transition Assessment drops off and the new rate schedules commence.

This Decision allows The United Illuminating Company to increase its distribution revenues for Rate Year 1 by $19.979 million. This represents a reduction of $44.872 million from the proposed increase. Further, this Decision approves an additional increase of $25.802 million, which roughly maintains the reduction from that proposed by the company over two years. While this represents a total two-year increase in distribution rates of 16.5%, the reductions to the Competitive Transition Assessment and down trending generation service charges more than offset the distribution increase approved herein.

The Public Utilities Regulatory Authority denied The United Illuminating Company's request for an allowed return on equity of 10.25% and instead set rates herein to allow The United Illuminating Company a rate of return on equity of 9.15%. This Decision makes other downward revenue requirement adjustments in requested operations and maintenance expenses in categories such as advertising, membership dues, facilities maintenance, depreciation, travel, education and training, base payroll and overtime. This Decision also makes revenue requirement adjustments in claimed expenses for incentive compensation, stock ownership plan, medical expenses, directors' liability insurance, Board of Directors expenses, fringe benefits, and materials and supplies, and UIL Holdings Corporation corporate service charges. There also was a reduction in expenses for The United Illuminating Company's lease expenses at the Orange Central Facility.

With regard to the Central Facility, the final project costs came to $120.6 million. This compares with the original estimate in 2005 of $58.3 million and a more advanced and detailed final budget produced for the UIL Holdings Corporation Board of Directors in June 2010 of $93.7 million. The United Illuminating Company urged that the threshold to measure any cost overruns or imprudence should be the later budget. This Decision agrees with The United Illuminating Company's reference point and notes that the UIL Holdings Corporation Board, when presented with the proposed budget, actually reduced it by $8.2 million from $93.7 to $85.5. The Public Utilities Regulatory Authority asserts that The United Illuminating Company's ratepayers are not the default payer of last resort for all of the costs. Accordingly, this Decision disallows $8.2 million, which is the amount above the UIL Holdings Corporation Board's approved budget.

Other salient adjustments made herein include a partial denial of The United Illuminating Company's request to recover $53.3 million as a regulatory asset for extraordinary major storm expenses. In so doing, the Public Utilities Regulatory Authority established the definition for qualifying a major storm event for which The United Illuminating Company may seek recovery of extraordinary expenses incurred between rate cases. The definition eliminated claimed expenses for certain storms that are merely excused from calculations for reliability reporting but do not rise to the level of a catastrophic storm for which special treatment is provided. Utilizing the $5 million expense threshold for The Connecticut Light and Power Company, The United Illuminating Company at 20% the size of The Connecticut Light and Power Company, was provided with a comparable major storm expense of $1 million. Applying this standard, $7.2 million of the $53.3 million claimed expenses fall outside the scope to be considered a regulatory asset. Other downward adjustments were made to account for duplication of storm charges. This Decision does provide The United Illuminating Company with an annual $2 million for storm reserves to be used for major storm recovery costs and a mechanism for recovering approved storm regulatory asset costs through the customer's share of the earnings sharing mechanism and Competitive Transition Assessment overcollections.

In granting the revenue increases in 2013 and 2014, the Public Utilities Regulatory Authority is allowing The United Illuminating Company sufficient funds to engage in significant capital improvements to upgrade its distribution system and modernize its systems, processes and workforce. This Decision approved infrastructure replacement costs at a level of $45 million per year for years 2013 through 2018, an amount that is greater than spending for these costs in 2011 and 2012. In this manner, the Public Utilities Regulatory Authority seeks to ensure that The United Illuminating Company is financially equipped to provide efficient and reliable service to meet the growing demands and reliability level required by customers.

It has been stated in other rate setting discussions, but must be re-stated here again – the Public Utilities Regulatory Authority is firmly committed to allowing the distribution company to have the financial resources necessary to be able to maintain and operate its distribution system in a manner that provides safe and reliable electric service to approximately 325,000 customers in the State of Connecticut. In addition, The United Illuminating Company has the obligation to provide satisfactory customer service and also provide a fair return to its investors. Accordingly, the Public Utilities Regulatory Authority, as economic regulators, must also be sensitive to the overall business and economic environment in which The United Illuminating Company operates.[1] Public service companies cannot expect to be exempt from economic realities. Ratepayers are equally entitled to fair rates. Thus, the Public Utilities Regulatory Authority had to strike a delicate balance in considering all the relevant public interests and needs in this case. With these somewhat competing interests in mind, the Public Utilities Regulatory Authority has taken steps in this Decision to moderate the rate increases requested, while still adhering to the principles contained within the statutory ratemaking criteria.

B. BACKGROUND OF THE PROCEEDING

The United Illuminating Company (UI or Company) has been operating under distribution rates established in the June 3, 2009 Decision in Docket No. 08-07-04, Application of The United Illuminating Company to Increase Its Rates and Charges (2009 Decision). The 2009 Decision allowed UI a return on equity (ROE) of 8.75% for the two years covered in the Decision, 2009 through 2010. The Public Utilities Regulatory Authority (Authority or PURA) previously approved a $6.785 million distribution revenue increase in the 2009 Decision.

The Authority notes that for the 12 months ending December 31, 2009, UI reported an actual ROE of 8.89%; for the 12 months ending December 31, 2010, an actual ROE of 9.34%, for the 12 months ending December 31, 2011, an actual ROE of 8.74%, and for the 12 months ending December 31, 2012, an actual ROE of 10.34%. Woolridge PFT, Exhibit JRW-3.

C. CONDUCT OF THE PROCEEDING

By Notice of Audit dated March 5, 2013, the Authority conducted an audit of the books and records of the Company, at UI's offices, 157 Church Street, New Haven, Connecticut 06506, beginning on March 18, 2013.

By Notice of Hearing dated March 21, 2013, pursuant to §§16-19, 16-19b and 16-19e in the General Statutes of Connecticut (Conn. Gen. Stat.), the Authority held public hearings on this matter on April 22, 23, 25, 29, 30, 2013 and May 6, 7, 13, 15, 20, 23, 24, 2013 at the PURA's offices, Ten Franklin Square, New Britain, Connecticut, another on April 24, 2013, in the Kennedy Mitchell Hall of Records, New Haven, Connecticut and another on May 2, 2013, in the City Common Council Chambers in the City Hall, Bridgeport, Connecticut.

The Authority issued a draft Decision on this matter on July 29, 2013. All Parties and Intervenors were provided an opportunity to file written exceptions to and present oral arguments on the draft Decision.

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[1] According to the U.S. Energy Information Administration Electric Power Monthly, release date of June 21, 2013, Connecticut has the third highest electric rates in the continental United States, even before UI's proposed two-year increase of $95 million is taken into account. Connecticut's residential charge is more than 1.5 cents per Kilowatthour higher than the New England average.

D. PARTICIPANTS

The Authority designated The United Illuminating Company, 157 Church Street, New Haven, Connecticut 06506-0901, Connecticut Siting Council (CSC), Ten Franklin Square, New Britain, Connecticut 06051, Department of Energy and Environmental Protection (DEEP), 79 Elm Street, Hartford, Connecticut 06106-5127, Department of Economic and Community Development (DECD), 505 Hudson Street, Hartford, Connecticut 06106-7107, Office of Policy and Management (OPM), 450 Capitol Avenue, Hartford, Connecticut 06106-1308, and Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, Connecticut 06051, as Parties to this proceeding. Intervenor status was granted to the Office of Attorney General (AG), and Connecticut Industrial Energy Consumers (CIEC).

E. PUBLIC COMMENT

The Authority conducted evening public comment hearings within the UI service territory for the purpose of receiving comments from the general public concerning the Company's Application. UI's notice to customers regarding the hearings, submitted by the Company on February 22, 2013, was approved by the Authority on March 4, 2013. Two evening public hearings were held: April 24, 2013, at the Kennedy Mitchell Hall of Records, 200 Orange Street, New Haven, CT; and May 2, 2013, at the Bridgeport City Hall, 45 Lyon Terrace, Bridgeport, CT.

A total of 35 persons attended the two evening public hearings and 8 of those persons provided testimony to the Authority. Bridgeport Mayor Bill Finch commended the Company for its actions during Tropical Storm Irene (Irene), but noted that there was still room for improvement in the area of storm response. The Mayor also praised UI on its efforts as a corporate partner with Bridgeport, especially in the areas of green energy initiatives and the revitalization of the Steel Point project. Tr. 5/2/13, pp. 1351-1356. The other persons who provided testimony to the Authority were not in support of UI's Application for a rate increase. The commenters stated that their opposition to it was based upon the negative impact a rate increase would have upon customers, the current economic condition of the state, and a belief that a rate increase would cause increased burden to customers in financially stressed urban areas. Tr. 4/24/13, pp. 496-499 and 524-526; Tr. 5/2/13, pp. 1349, 1350 and 1358-1460.

The Authority also received 24 letters and emails regarding the Company's Application. Included among this total was a letter from State Representative Roland J. Lemar (96th). In his correspondence, he objected to UI's proposed rate increase and stated that the Authority has a responsibility to keep utility costs low and asserted that UI's request was unacceptable. Along with this correspondence, customers who wrote in were in opposition to UI's rate increase request, stating reasons similar to those offered at the evening public hearings.

II. AUTHORITY ANALYSIS

A. COMPANY'S PROPOSAL

As revised by Late Filed Exhibit No. 3, the Application seeks distribution rates designed to produce incremental revenues of $65 million in Rate Year 1 (July 2013 - June 2014) and an approximate additional $26 million in Rate Year 2 (July 2014 - June 2015) for a total requested increase in revenue requirements of approximately $91 million. For Rate Year 1 (RY1), the additional revenues represent an increase of approximately 23.8% over total revenues that would be expected under current rate schedules and projected sales on a total distribution bill basis. For Rate Year 2 (RY2), the additional revenues represent an increase of approximately 7.7% over the previous year's distribution revenues. Late Filed Exhibit No. 3, Schedule C-1 A-B. However, the Company's proposal is to utilize other revenue sources and defer any change in the distribution retail rate until January 1, 2014, coincident with the elimination of the Competitive Transition Assessment (CTA). The Company proposed to set a ROE of 10.25% for both rate years, an increase from the allowed rate of 8.75% currently in place. Nicholas PFT, p. 10.

The five basic elements of the Company's Application are as follows:

1. Rates are established for each rate year separately, in accordance with the ratemaking principles of Conn. Gen. Stat. §16-19e, based upon the costs, revenues and capital structure set forth in the Standard Filing Requirements (SFRs) for each rate year.

2. To mitigate the impact of the rate request on customers' bills, the Company proposed that there be no change in distribution rates during calendar year 2013. This would be accomplished by using existing revenue offsets to fund the increase in revenue requirements for July 1, 2013 through December 31, 2013. New distribution rates would be put in effect on January 1, 2014, coincident with the elimination of the CTA. On average, customers will not see an increase in their total electric bills when new rates are implemented on January 1, 2014.

3. Continuation of UI's full decoupling mechanism would true up actual revenues (up or down) to approved revenue requirements. The true up would assure that the revenue approved in a rate case by the Authority would actually be realized, no more and no less.

4. The Company proposed to maintain the existing earnings sharing mechanism, which shares on a 50/50 basis actual earnings (measured on a calendar year basis) above the authorized return. However, the Company also proposed to use the customers' 50% of earnings sharing, if any, to amortize and accelerate the recovery of UI's storm regulatory asset.

5. In accordance with past practice, the equity return and capital structure for the CTA would be adjusted to the approved distribution equity return and capital structure for the rate period prior to the projected full amortization of CTA rate base in the fourth quarter of 2013. UI has not included the revenue

requirements of any change to the CTA in this request, as the CTA rate component on customers' bills would be addressed in the annual CTA reconciliation proceeding. Nicholas PFT, p. 11.

B. TEST YEAR/RATE YEAR

It is the practice of the Authority in utility rate cases to establish rates prospectively upon the basis of a historical test year, adjusted for pro forma purposes. In this case, UI determined that the test year period is the 12 months ended June 30, 2012. RY1 and RY2 for the traditional rate request are the 12 months ended June 30, 2014 and June 30, 2015, respectively. Favuzza PFT, p. 7.

C. RATE BASE

1. Construction Program

UI proposed a $958 million, six-year construction program that would result in capital expenditures and plant additions during the term of the Rate Plan as stated below.

Proposed Capital Expenditures and Rate Base Additions
2013-2018
(Millions of Dollars)

	2013	2014	2015	2016	2017	2018	Total
Capacity and Reliability	35.1	30.2	22.2	23.6	25.1	24.6	160.8
Infrastructure Replacement	47.0	54.1	68.7	59.5	58.9	55.5	343.7
System and Business Ops.	25.9	16.5	15.5	18.2	17.6	18.6	112.3
Storm Preparedness	24.5	59.8	47.7	42.0	40.2	11.4	225.6
Other	18.0	16.6	20.5	18.9	21.0	20.8	115.8
Total Capital Expenditures	150.5	177.2	174.6	162.2	162.8	130.9	958.2

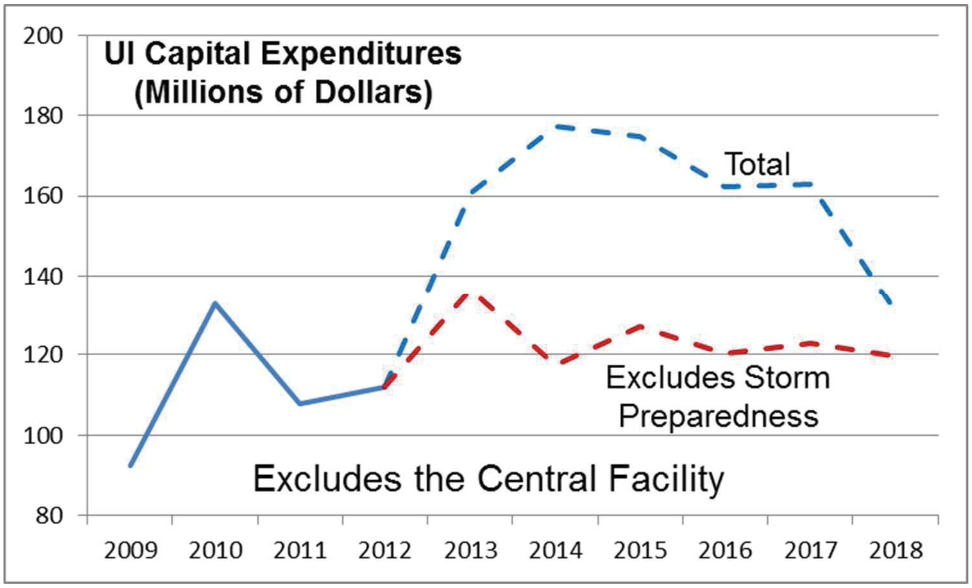
Schedule F-7.0.

The OCC suggested a phased approach to the capital spending challenge and recommended an initial spending level of $80 million per year plus full funding of the Enhanced Tree Trimming (ETT) Program. A proposed second phase of this proceeding would address other storm-related issues from outstanding storm-related dockets, including system hardening, storm preparation and response. The OCC stated that $80 million is the average historic spending for the most recent five years and is a reasonable baseline. Further, there is merit to such a concept in an environment in which sales and demand are not growing. OCC Brief, p. 53.

The AG focused on proposed capital spending for Storm Preparedness and questioned the extent to which the justification is sufficient, including the belief that a suitable analysis of costs and benefits has not been completed. The AG stated that a long-term plan including a detailed analysis of costs and benefits should be completed for consideration in a future rate proceeding. Similarly, a viable plan for the ETT initiative is lacking and hence no cost benefit analysis can be completed at this time. The AG did not oppose the notion of ETT, but recommended that the Authority require a more carefully considered plan before allowing UI to begin. AG Brief, pp. 13-16.

Based on information provided by the Company, the following chart indicates that the large increases proposed in capital expenditures are primarily due to the new category of Storm Preparedness. Reed PFT, p. 27.

UI Capital Expenditures
(Millions of Dollars)



Schedule F-7.0, Responses to Interrogatories AC-8, 9, 11 and 12.

The Authority finds that this comparison can be somewhat misleading, given that capital budgets are traditionally front-end loaded, since future requirements are not as well understood as near term requirements. Not including the Central Facility (CF) capital expenditures, the annual increase added to plant account is impacted disproportionately, having risen from $92.5 million in 2009 to a projected $177.2 million in 2014. Further, two of the more critical categories, Capacity and Reliability and Infrastructure Improvement, are projected to grow more than $22 million, or 36%, between 2012 and 2014.

Added to the growth of prior years, the Authority finds that this proposal represents a continuation of the trend of significantly higher spending, rate base and rates. Such increases require strong justification and the trend to higher and higher capital expenditures demands that long-term affordability, notwithstanding near-term justifications, be examined.

In evaluating the proposed capital programs, the Authority observes three characteristics of UI's proposals that have the potential to produce unnecessarily higher rates without corresponding benefits. These are:

1. **Justification.** UI included in its proposal a number of programs that appear to have a significant level of stakeholder support. However, there is the potential

that programs having a healthy level of stakeholder support can encourage unrestrained and excessive spending. Such programs, regardless of their attractiveness, cannot be allowed to become a blank check for a utility. Programs to: (a) improve declining reliability; (b) address the trend in aging infrastructure; and (c) improve emergency preparedness for major weather events have a broad level of support, and in some cases mandates, in the industry today. Utilities are nonetheless obligated to assure that the spending on such programs is proportionate to the benefits delivered.

2. **Affordability.** Regardless of the benefits to be derived from higher investments, it should also be obvious that at some point the resulting growth in rates becomes unsustainable, or in other words unaffordable. While it is appropriate to judge projects on their individual cost and benefit, it is also essential to consider the aggregate level of spending. Further, it is necessary to evaluate the trajectory of the aggregate in the long-term to understand the eventual sustainability of escalating spending trends.

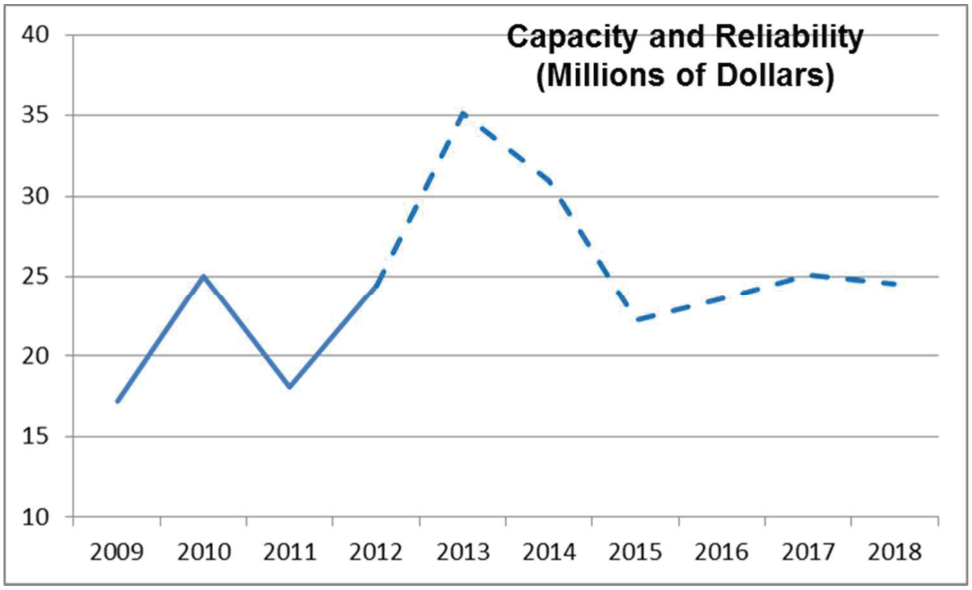
3. **Redefining the Paradigm.** The regulatory paradigm provides utilities the opportunity to earn a profit in the form of return on investment in rate base. That paradigm requires a careful definition of rate base, and such a definition has evolved through decades of consistent utility practices. Expanding the definition of rate base is obviously beneficial to a utility in that it increases earnings, and that is indeed the case in the UI proposal. Specifically, the proposed treatment of the ETT initiative as a capital investment, and the proposal to earn a full return on deferred storm expenses represent major shifts in utility practice. For the utility, such a shift is tantamount to turning an expense into a profit while the converse is true for customers. If a utility is allowed to change the definition of rate base, then fairness requires a corresponding adjustment to the allowed rate of return (ROR) to keep the long-established paradigm in balance.

Each of these concerns, to the extent applicable, will be discussed as part of the Authority's examination of the central issues regarding UI's construction program.

a. Capacity and Reliability

Based on information provided by the Company, the following chart indicates a large increase in the proposed Capacity and Reliability category, which the Authority finds to be primarily attributed to large substation expenditures. The reliability area also benefits greatly from many of the initiatives in the Storm Preparedness category.

Capacity and Reliability
(Millions of Dollars)



Schedule F-7.0, Response to Interrogatory AC-8.

There are two areas of concern that merit consideration by UI, and which are likely to take on greater significance in future proceedings. First, the Authority notes that the lack of any correlation between UI's demand forecasts and its forecasted capital needs is confusing. While there was ample testimony regarding the credibility of UI's forecast, the relevance of the forecast seemed far more in question and rendered the credibility question somewhat moot. This became apparent when UI introduced an extremely large decrease[2] in the forecast; but suggested no substantive change in the outlook for capital spending. Tr. 5/23/13, pp. 2643 and 2644. In the 2009 Decision, the Company claimed that an increase in the demand forecast was the primary reason cited for spending increases in Docket No. 08-07-04, Application of The United Illuminating Company to Increase Its Rates and Charges, and that peak demand today is actually lower than at that time. 2009 Decision, pp. 11 and 16.

UI's position that changes in peak demand forecast do not necessarily change the near-term outlook and needs for an individual substation seems valid. But the larger question relates to the incongruity of ever-increasing capital spending on a system where demand has declined. This clearly raises questions of long-term sustainability that have not been addressed by UI. Based on this fact, UI should prepare an analysis of its forecasted long-term investment needs (20 years) that includes the following:

1. The vision for the distribution system that the plan is intended to achieve.

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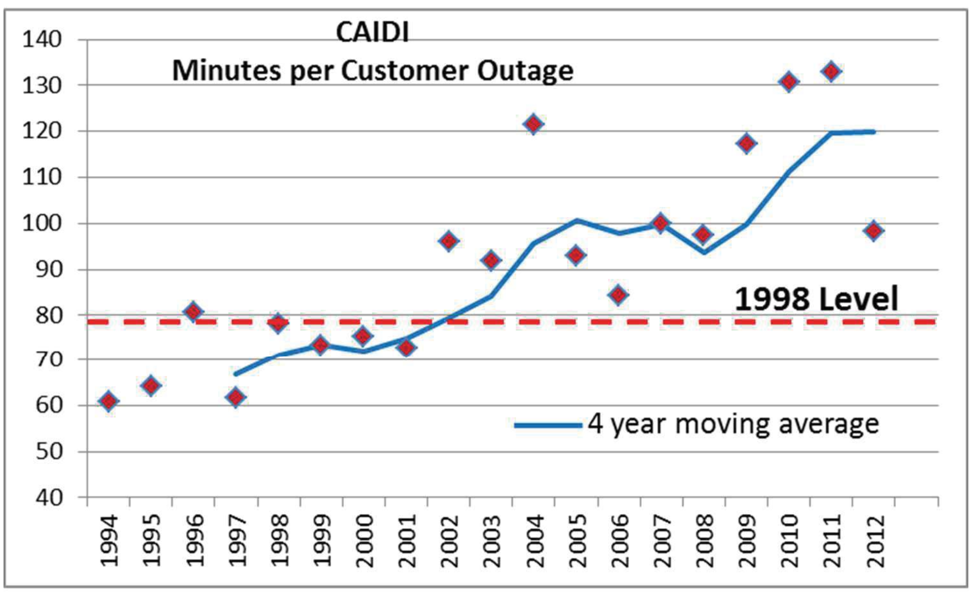
2 UI reduced its long-term forecast of peak demand significantly. For example, the forecast for 2014 has dropped to 1,408 MW from 1,486 MW (a decrease of 5.2%). Late Filed Exhibit No. 86, Revised, p. 7; Reed PFT, p. 8. This is the equivalent of three years of growth using UI's 1.7% annual forecast growth or nearly six years of growth using the Energy Information Agency's 0.9% annual forecast.

2. Assumptions and sensitivities regarding sales and demand growth, with specific conclusions regarding the relationship of future investment needs versus sales and demand growth.

3. Long-term rate impact of the forecasted level of growth.

Second, the Authority recognizes that stakeholders are rightly concerned about reliability as it relates to major storms. But there must also be attention to the day-to-day operations of the electric system. In fact, the legislated targets relate to day-to-day operations and specifically exclude major events. The designated measures are the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). The 1998 levels for these parameters represent the legislated performance targets. UI experienced a rise in SAIDI and a decline in SAIFI. An increase in the aggregate interruption time at the same time the number of outages is declining suggests something is amiss. Specifically, the average duration of a customer outage has been increasing significantly as evidenced by the Customer Average Interruption Duration Index (CAIDI) detailed below.

CAIDI
Minutes per Customer Outage



CAIDI = Customer Average Interruption Duration Index
= [SAIDI] / [SAIFI]
= Average restoration time

Reed PFT, pp. 14 and 16.

The level of performance in restoration times is out-of-synch with the 1998 legislative targets, and this is not a recent phenomenon.[3] This trend of extended outage restoration times has been in place for quite some time. While the aggressive storm programs in this capital budget proposal will surely benefit the non-storm CAIDIs, this

[3] Conn. Gen. Stat. §16-244i(d) requires that quality and reliability of service be the same or better than levels that existed on July 1, 1998.

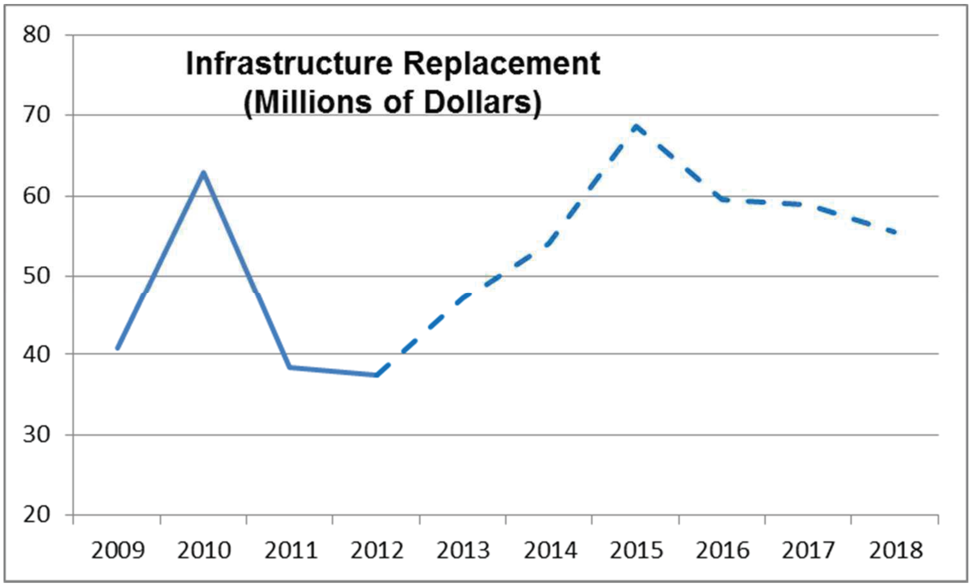
measure requires better focus in the future along with improved UI performance. Accordingly, in all future reliability reports to the Authority, UI will be directed to include an analysis of CAIDI performance as well as a plan for the improvement of CAIDI including year-by-year targets.

b. Aging Infrastructure

The issue of aging infrastructure, a component of Infrastructure Replacement, is a national problem; and the Authority has supported UI's efforts so that it is addressed. In fact, Connecticut began addressing the issue in 2003, before the topic became fashionable on a national scale. At that time, the Authority determined that the aging issue was attributable to assets that were installed during the high growth periods of the late 1960s and early 1970s. Since that equipment has an estimated useful life of about 40 years, much of the equipment is reaching the end of design life at about the same time. 2009 Decision, p. 20.

In the Authority's Decision dated January 27, 2006, in Docket No. 05-06-04, Application of The United Illuminating Company to Increase Its Rates and Charges (2006 Decision), UI proposed a program that was heavily weighted toward increasing its inspection and analysis activities. 2006 Decision, pp. 78-80. This was an effective first step in addressing the infrastructure issue and has since been followed by other utilities. Such programs allow utilities to better understand the age, condition and vulnerabilities of their infrastructure before investing large sums in modernization and replacement. In the 2008 rate proceeding, UI identified $82.5 million in proposed infrastructure replacement programs to be accomplished over the next two years. The Authority approved this level of spending after an adjustment for material costs. Id., pp. 20 and 23. UI reports that it has made significant progress in the execution of its infrastructure replacement projects. Reed PFT, p. 20. In the 2009-2012 timeframe, $179.6 million, or about $45 million per year, was expended on such projects. Response to Interrogatory AC-9. UI now proposes to spend an average $57.3 million per year in the 2013-2018 timeframe as detailed below. Application, Schedule F-7.0.

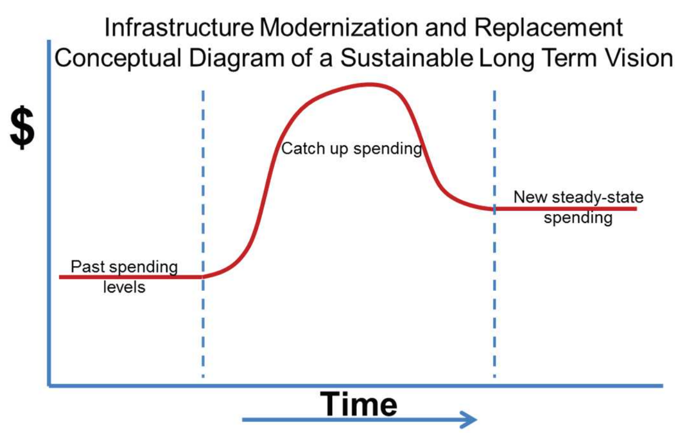
Infrastructure Replacement
(Millions of Dollars)



Schedule F-7.0; Response to Interrogatory AC-9.

Before embarking on this major expansion, the Authority finds it essential to re-visit the underlying reasons for the genesis of this program. As noted above, a great deal of distribution equipment is reaching end of design life at about the same time. It is therefore quite logical that a spending "bubble" proved to be necessary. Such heightened spending would, with time, return the system to some steady-state that could then be sustained in the long-term with a reasonable level of annual expenditures for modernization and replacement as diagramed below.

Infrastructure Modernization and Replacement
Conceptual Diagram of a Sustainable Long-term Vision



PURA Illustration.

In the immediate case of UI, this does not seem to be the plan. UI makes clear that it does not envision this program as catch-up or temporary or limited. It is a long-term program. Tr. 5/13/13, p. 2004.

The Authority finds such an approach to be inconsistent with an effective strategy for modernization and replacement. What began as a well-designed catch up initiative with a level of stakeholder support, has evolved into a permanent program of ever-increasing spending. As such, this illustrates the potential for well-intended and well-supported programs to grow beyond practical limits. At the present time, there does not appear to be a valid plan for the evolution of the infrastructure issue, nor is there a vision for the future distribution infrastructure and a corresponding level of steady-state spending.

The Authority finds that a valid plan and vision will demonstrate that the spending bubble was appropriate, and that it should continue for a limited period. But the bubble should not grow, nor should it continue indefinitely. Rather, it should give way to a reasonable and sustainable steady-state level of spending for infrastructure modernization and replacement. The amounts and duration of the bubble are subject to debate but the inappropriateness of ever increasing spending is not. In the absence of an acceptable long-term plan for the modernization and replacement of distribution infrastructure, the Authority limits its authorization in this category to $45 million per year for the years 2013 through 2018. This is the average spending level of 2009 through 2012 and more than the spending levels of both 2011 and 2012. This reduces the average plant-in-service in RY1 by $3.253 million and in RY2 by $14.955 million.

Such authorization will be reconsidered in a future rate proceeding provided a credible plan is presented by UI at that time. The expectation of the Authority for a future rate proceeding is that spending in this category should not necessarily increase but should reach a steady-state, subject to inflation, below the true up levels and that cost-benefit analysis of the program be provided. UI shall submit such a plan at the time of any future requests for spending on modernization or replacement of aging infrastructure.

c. Enhanced Tree Trimming Program

The notion of an Enhanced Tree Trimming (ETT) Program has firmly caught hold in Connecticut and has widespread support as evidenced by numerous independent reviews. While it may not be clear that such high levels of support will be sustained as the costs, rate impacts and environmental impacts of the proposed programs play out, the recommendation is nonetheless present. UI proposed to spend $99.7 million over four years under its ETT, a component of Storm Preparedness, for system hardening. Response to Interrogatory ODR-10.

The AG, while supporting the notion of an ETT Program, is troubled by a lack of focus for UI's proposed program. The AG further stated that UI had not sought to optimize the implementation of the program by considering a more targeted approach aimed at major lines and worst performing circuits. AG Brief, p. 15.

UI dismisses the AG concerns because the AG misunderstood the ETT Program. UI Reply Brief, p. 40. It appears, however, that the Company may have misunderstood the AG's concerns, which in the PURA's reading, simply asks that the approximately $100 million program be executed within the framework of a well-designed, optimum plan, and that it consider the sequencing and priority of the work. This is a reasonable requirement.

Although the affordability of ETT as proposed is an issue for the Authority, the opinions of many stakeholders lead the PURA to agree with the overall magnitude of the program, as defined by the proposed new clearance standards. These new standards will produce a ground-to-sky clear zone within eight feet of a distribution line. UI Brief, p. 54. Conversely, there are two major concerns that raise the potential issues of: (a) cost impact on customers and (b) cost effectiveness.

The addition of $100 million in added costs over the next four years represents a major perturbation. UI's proposal to fund this as a distribution asset, and hence spread cost recovery over more than 40 years, helps keep near-term rates lower but forces a relatively high cost long-term "mortgage" on customers at the same time. The Authority therefore seeks a balance between the perceived need to spend about $100 million and funding that cost in an optimal way.

Accordingly, the PURA concludes the following to mitigate the customer impact of the ETT initiative:

1. Treating ETT as a distribution asset is not appropriate.

2. The $100 million ETT program should be carried out over eight years (at $12.5 million per year), as opposed to the UI proposal of four years.

3. The recovery of each year's costs associated with the ETT program is to be via a five-year amoritization.

4. Carrying charges associated with the amortization will be UI's approved cost of capital.

With respect to cost effectiveness of the ETT program, the Authority notes that the Company's primary justification for ETT and other Storm Preparedness activities is its desire to respond to its customer wishes. The Authority finds such justification to be unacceptable. It is the utility's obligation, subject to the PURA's oversight, to balance various conflicting pressures to arrive at programs that best serve the customer and other stakeholders. Thus, to simply avoid this responsibility and consider only one variable is unacceptable.

Accordingly, the Company will be directed to develop and submit to the PURA for review, a more carefully considered, optimized plan for ETT before UI is allowed to begin the program that is now scheduled for 2014. The plan shall specifically address how the work is being packaged and prioritized for optimum effectiveness. In addition, the plan should contain reporting requirements to UI management and the PURA, the latter of which will include spending, miles trimmed, and impacts on reliability of the program on a circuit and annual system basis.

UI indicated that an added benefit of the ETT initiative is lower long-term operation and maintenance (O&M) costs for tree trimming. Tr. 5/13/13, p. 1978. UI will be directed to submit a supporting analysis to the Authority that includes quantification of those savings and a demonstration of how that commitment will become a reality in future years. The Authority disallows average plant-in-service related to the ETT program of $3.409 million in RY1 and $14.201 million in RY2.

d. Transmission & Distribution Operational Excellence Initiative

The Transmission and Distribution Operational Excellence Initiative (TDOEI) is a broad program that will cost $98.3 million over six years. It consists of a suite of products and tools associated with the analysis, planning, management and associated communications required for effective restoration of service in a major storm event. Each of the pieces of TDOEI represent a component or capability that should be, and indeed have been, considered essential. In that sense, there is little new here. UI emphasized that it is the integration of these various pieces that produces the primary benefits UI seeks. This includes timely and accurate estimated times to restoration (ETRs), reduction of restoration times, enhanced communications, improved work management and resulting future savings in capital and O&M expenses. Tr. 5/13/13, p. 1958; Reed PFT pp. 28-35.

The AG urged deferral of a decision on TDOEI until the next rate proceeding. The AG characterized TDOEI as vague and ill-defined. It recommended that UI prepare a more detailed plan that address costs and benefits after the Authority completes its review of UI's performance in Storm Sandy (Sandy) in Docket No. 12-11-07, PURA Investigation Into the Performance of Connecticut's Electric Distribution Companies and Gas Companies in Restoring Service Following Storm Sandy. AG Brief, p. 13.

The OCC also urged deferral of a decision on TDOEI to a second phase of this proceeding. The OCC cited several open dockets that should influence the scope of TDOEI. Until these decisions are reached, the associated cost impacts cannot be determined. OCC Brief, p. 57.

The Authority has seen ample evidence that the elements of the TDOEI, both individually and especially when tied together, produce value. The lingering question that the record does not answer is the extent to which that value justifies a capital expenditure of $98.3 million and a new revenue requirement of $139.7 million spread through 2026. Schedule F-7.0; Late Filed Exhibit No. 90, Attachment No. 2. UI noted that it received 127 recommendations from various organizations and the solutions to those recommendations lie largely in TDOEI, as well as some of UI's other storm preparedness initiatives.

As seen in the analysis of ETT and the associated testimony cited above, the primary and perhaps only justification offered by UI several times is its attempt to be responsive to the desires of stakeholders. While TDOEI was built from such recommendations, UI acknowledged that neither it, nor to its knowledge those making the recommendations, considered the associated costs. Tr. 5/23/13, pp. 2656-2658. The Authority supports the priority being given to preparedness for major storms. However, no program or series of initiatives is good enough to be implemented at any cost. The lack of any analysis of cost and benefits, and the use of such analysis to arrive at an optimum level of spending, is a serious flaw in the TDOEI proposal.

As noted earlier, the Authority sees each of the TDOEI elements as having a critical role in UI's management of outages. Improvement of these elements and their integration is a worthy objective. While the various open dockets may influence the extent of such improvements and integration, and the eventual level of required spending, this is not a reason to delay the start of UI's efforts. On the other hand, there is no basis at this time to conclude that the proposed $98.3 million will be well spent. In the absence of any cost benefit analysis, an evaluation by the Authority of the appropriateness of the proposed spending level is impossible.

Based on the aforementioned, the Authority determines that a temporizing measure is in order. This will allow UI to proceed with TDOEI, albeit it at a reduced level, until such time as the full program can be better defined in terms of a plan supported by cost benefit analysis and justification of aggregate spending. Recognizing that UI should attack the most important elements of TDOEI first, the Authority will approve most of the early funding with the provision that UI will subsequently demonstrate that the most important and cost effective elements were indeed addressed in the early years. On that basis, the Authority approves the following levels of TDOEI spending.

TDOEI Capital Expenditures
(Thousands of Dollars)

Calendar Year	Proposed Capital Expenditures	Approved Percentage	Approved Amount
2013	$23,361	80%	$18,689
2014	29,047	80%	23,238
2015	16,031	50%	8,016
2016	12,941	50%	6,471
2017	11,141	0%	
2018	5,767	0%	
Total	$98,288		$56,412

Response to Interrogatory AC-15, p. 2.

Based on the approved level of spending, the Authority decreases the average plant-in-service by $5.53 million in RY1 and $12.624 million in RY2. The Authority will consider expanded TDOEI funding if appropriate during the next rate proceeding. In the meantime, UI shall incorporate the results of pending storm-related dockets into a new, more detailed TDOEI plan that includes cost benefit analysis. That plan should also prioritize tasks such that the most important and effective improvements are addressed in the early years.

2. Working Capital Allowance

a. Introduction

It is a customary regulatory practice to allow an adjustment to rate base in recognition of the timing difference between when revenues are received and when expenses are paid out. For larger utilities, the Authority typically prefers that a lead/lag study be conducted to determine the appropriate working capital allowance rather than use some rule of thumb approach or the utility's balance sheet result. In this proceeding, UI conducted such a lead/lag study and requested that the results of that study be used when determining its rate base for each of its proposed rate years.

In conducting its study, the Company utilized test year ended June 30, 2012 data to determine the lead/lag factors and applied these factors to projected rate year revenues and expenses for the total UI company. Favuzza PFT, pp. 27 and 28. From this total company calculation, the Company subtracted its calculated transmission and energy supplier contracts related working capital to arrive at a 13-month average total distribution related working capital requirement of $27,356,000 for the rate year ending June 30, 2014, and $24,199,000 for the rate year ending June 30, 2015. Schedules H-1.5 A, p. 2 and H-1.5 B, p. 2; Late Filed Exhibit No. 3, UI Supplemental Attachment, pp. 6 and 7. The Authority reviewed UI's working capital request and finds it acceptable, except as discussed below.

b. Collection Lead Calculation

In calculating its collection lead, the Company used the 13-month average accounts receivable balance. This method of calculation is reasonable, but has implications on how uncollectible expense should be treated in the lead/lag study. Since accounts that are ultimately written off as uncollectible are part of the accounts receivable balance until they are written off, this method of calculating the collection lead grants the Company a return on uncollectible expense through the working capital adjustment until written off. Tr. 5/7/13, pp. 1829 and 1830. To account for this, the Authority adjusted the uncollectible expense lag as discussed below in Section II.C.2.c.ii. Uncollectible Expense.

c. Expense Lags

i. Payroll and Payroll Taxes

For payroll and payroll taxes, the Company proposed an expense lag of 47.2 days based on test year data. Schedule WP H-1.5 A–B, pp. 14 and 15. During the test year, the Company transitioned from weekly and monthly payrolls to a biweekly payroll. This transition is now complete and during both rate years the Company will be operating exclusively under a biweekly payroll. Tr. 5/7/13, pp. 1832 and 1833. The Company agreed that modifying the calculated payroll and payroll taxes expense lag to reflect exclusive use of a biweekly payroll is appropriate. Tr. 5/7/13, pp. 1833 and 1834. Making this change results in an expense lag of 49.2 days for payroll and payroll taxes.

ii. Uncollectible Expense

The Company proposed a 15.0 day lag for uncollectible expense. Schedules H-5 A, p. 1 and H-1.5 B, p. 1. As discussed in Section II.C.2.b. Collection Lead Calculation above, the lag for uncollectible expense should reflect the amount of time accounts sit in the receivable balance before they are written off. To determine the appropriate amount of lag days to use for uncollectible expense, the Authority reviewed the amount of time receivables, which are eventually written off as uncollectible, remain in the receivable balance. For regular (non-hardship) accounts, the Company's dunning process calls for UI to move to terminate a customer if their bill has not been paid after 33 days. Tr. 5/20/13, p. 2363. Once the termination process starts, the 4-step process takes about 21 days for the customer to be terminated. Response to Interrogatory CS-001. Seventy-five days after termination, the account is removed from the accounts receivable balance resulting in regular accounts remaining in the accounts receivable balance for 129 (33 + 21 + 75) days before they are written off as uncollectible. Late Filed Exhibit No. 81. For hardship accounts, the time frame is shorter; removed 90 days after having been billed if the receivable remains unpaid. Id. Since hardship accounts comprised 67.12% and non-hardship accounts 32.88% of the uncollectible expense during the test year, the Authority weighted the calculated lag to arrive at an expense lag of 102.8 [(90 x 0.6712) + (129 x 0.3288)] days for uncollectible expense. Schedule WP C-3.24 A–B.

In Written Exceptions, the Company claimed that the reserve allowance for doubtful accounts serves as a reduction to the receivable balance and, therefore, only a portion of the uncollectible receivable accounts (the hardship portion) are calculated as having been in the receivable balance prior to write off. Written Exceptions, p. 72. However, comparison of the receivable balances used in the Company's lead/lag study with the balance sheet show that the receivable balances used in the lead/lag study are gross of the reserve. Schedule WP H-1.5 A-B; LFE-001 Attachment, ADR-013 Attachment 7. As such, all uncollectible receivable accounts are included in the revenue lead calculation (i.e., granted rate base status until written off). Thus, the Authority's uncollectible expense lag adjustment detailed above is appropriate.

d. Adjustments to Expense Amounts

In addition to adjustments to the lag for the above expense categories, the Authority also made adjustments to: 1) the Connecticut Yankee (CY) Purchased Power amount used in the Company's lead/lag study; and 2) the amount of expenses or income allowed for ratemaking purposes. In the case of CY Purchased Power, the Company included $10,520,000 in RY1 for purposes of calculating that year's working capital requirement. Schedule H-1.5 A, line 14. Based on proposed settlement agreements filed by CY at the FERC on May 1, 2013, this $10,520,000 amount reduces to zero, eliminating $802,000 in rate base working capital in RY1. The adjustments made to expenses or income for ratemaking purposes are detailed throughout this Decision and impact the working capital the Company needs. The Authority adjusted the expense and income levels used to calculate the working capital needs of the Company to mirror the expense and income adjustments made by this Decision.[4] Tr. 5/7/13, pp. 1813-1815.

In Written Exceptions, the Company objected to the Authority's calculation of the working capital allowance based on the adjustments to expense and income for two

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4 This includes adjustments made when UI revised its overall proposal as reflected in Late Filed Exhibit No. 3. These adjustments are necessary since the working capital requirement piece of the proposal was not revised consistent with the overall proposal.

reasons: 1) changes to income tend to impact retained earnings, not dividends; and 2) changes also impact the Transmission Working Capital offset. Written Exceptions, p. 72. The Authority agrees in part with exception (1) and fully with exception (2). At least in the near term, companies tend to maintain dividends, while retained earnings fluctuate in the event income varies. Over the longer term, companies tend to adjust dividends for expected income levels to maintain an appropriate mix of dividends and retained earnings. Accordingly, the Authority has allocated the entire change to income to retained earnings for RY1, but maintained a proportionate mix for RY2. The Authority has also recalculated the Transmission Working Capital offset based on the 1.80% Transmission Working Capital allowance factor used in the Company's working capital proposal. Schedule H-1.5 A, p. 2; Schedule H-1.5 B, p. 2.

e. Conclusion on Working Capital

Based on the adjustments detailed above related to working capital, the Authority calculates a working capital requirement for the Company of $22,576,000 for RY1 and $19,000,000 for RY2. These amounts are $4,780,000 and $5,199,000, respectively, less than the $27,356,000 for RY1 and $24,199,000 for RY2 proposed by the Company. As such, the Authority reduces cash working capital $4,780,000 for RY1 and $5,199,000 for RY2.

3. Central Facility

The CF is UI's new headquarters located in Orange, Connecticut. Personnel transitioned to the new facility from a variety of other work locations starting in May of 2012. UI Brief, p. 66. The CF concept had the support of the Authority since it was originally conceptualized in the 2006 Decision. The proposal for the facility played a large role in both Docket Nos. 05-06-04 and 08-07-04. The eventual project cost was $120.6 million, including $90.9 million for construction costs, $22 million for land and $7.7 million for design, site demolition and permits. UI Brief, p. 68. The Company asserts that the project came in on time and under budget and that the CF project is projected to provide a levelized 20-year NPV revenue requirements benefit over its life of $31.8 million. Marone PFT, p. 9.

The OCC recommended that the portion of CF costs permitted in rates be limited to $83.5 million, which was the last amount approved by the Authority. The OCC also recommended an additional disallowance relating to the initial funds advanced for the project in the 2006 Decision. 2006 Decision, p. 19. A portion of that pre-funding previously was refunded in Docket No. 08-07-04. 2009 Decision, p. 82. The OCC then recommended that the balance of that pre-funding, amounting to $7.7 million, be disallowed. This would permit an addition to rate base of $75.8 million versus the requested $120.6 million. The OCC's basis for such a disallowance is imprudence associated with the overruns because they were neither approved nor disclosed to the Authority. OCC Brief, p. 6.

The OCC finds the Company's explanations for cost overruns to be unsatisfactory, citing as an example the escalation of land cost from $5.835 million to $22 million. UI testimony suggested that the Company went through an extended learning experience vis-à-vis commercial real estate and that ratepayers should not be funding the Company's learning curve. Further, ratepayers should not be held responsible for errors in estimation on the part of the Company, especially errors of the magnitude experienced in the CF project. Id., pp. 49 and 50.

The AG argued that UI should be held accountable to the project cost estimate used in Docket No. 08-07-04, except that the AG placed that estimate at $100.5 million, as opposed to the OCC's $83.5 million.[5] The AG observed that "the CF that UI chose to build is simply not the CF that the PURA approved. It is more costly and extravagant." In addition, the AG stated that the remaining balance of $7.7 million from the funds advanced from Docket No. 05-06-04 should be refunded, lowering the recommended addition to rate base to $92.8 million. AG Brief, pp. 10 and 11.

While the degree of incaution, if any, associated with the management of the CF project is subject to debate, there is no question that this proved to be a troubled project in the early years as the Company struggled with site-related issues. Phase 1 of the project, which was a 188,000 square foot office facility, was planned to be completed and occupied in 2008, but UI still had not located a suitable site at that time. Construction did not begin in earnest until 2010, five years after the initial concept was presented and initial funding was approved by the Authority. Most or all of this delay was attributable to locating and qualifying a suitable site.

The cost of the facility, as originally estimated in 2005, was $58.3 million and therefore it is appropriate for the Authority to examine the overruns in the context of the more than doubling of the cost. UI disagreed and characterized the 2005 estimate as not relevant in this regard. Tr. 5/13/13, p. 2147. The Company provided a reconciliation of the actual project costs to the 2005 estimate. Late Filed Exhibit No. 96.

UI believes a more appropriate starting point for examination of prudence is "when we identify a detailed budget." Tr. 5/13/13, p. 2146. That detailed budget was produced and presented to the UIL Board of Directors (UIL Board) in June 2010, at which time a project authorization of $85.5 million for construction costs was approved. It is noteworthy that UI management requested an authorization of $93.7 million, which the UIL Board declined to provide. Id., p. 2175. UI maintains that it is inappropriate to evaluate the prudence of overruns because there were no cost overruns with regard to the CF Budget. Response to Interrogatory ODR-020.

UI reported that, regardless of the increases in the project's costs, the intended cost savings to customers did materialize. UI indicated that such savings grew from the $26 million envisioned in 2005 to $31.8 million in 2012. UI's quoted savings are not net but are versus the "status quo" alternate. And those savings are presented as the reduction in the NPV of the 20-year revenue requirement. UI Brief, p. 71. UI claimed that it made prudent decisions at each point throughout the project and employed an internal team coupled with outside experts and consultants. UI asserted that it completed a facility that is appropriate in size and scope, supported the Company's public service obligations, and provided the benefits initially envisioned. Id., p. 69. UI attributed much of the cost

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[5] Various estimates were published at the time of Docket No. 08-07-04. The primary differences were a function of time during the period in which the docket was active. Specifically, the higher estimate reflected a new site that was chosen later in the proceeding. AG Brief, p. 10.

increases in the project to land and other site-related costs. Originally estimated at $5.835 million, the cost to acquire the final site was $22 million. In addition, there were many added costs for items related to a new site. Tr. 5/13/13, p. 2152.

Land acquisition costs rose from $5.835 million to $22 million, but the impact on project costs appears to be far more. In a reconciliation to the 2005 estimate, UI provided the following site-related added costs, which are over and above the added land acquisition cost:

- $0.9 million for quality assurance costs, site specific such as sub-surface and inspection services;
- $2.9 million for site prep costs due to specific sub-surface soil issues; and
- $5.0 million for construction costs for a parking structure due to buildable acreage limitations.

These three items, which appear to have been necessitated because of the change in site, total an additional $8.8 million. Response to Interrogatory LCG-15. When added to the land costs, the site-related cost growth is $25 million. UI provided details on all of its site acquisition activities in the 2005-2008 timeframe. While the Authority sympathizes with those frustrations, the explanations do not justify a four-year delay in Phase 1 and an overall increase in project costs of $25 million. As noted by the AG, UI acknowledges a learning curve in commercial real estate during the period. The Authority concludes that retention of experts early in the site selection and acquisition process would have likely precluded the need for such an extended and expensive learning curve.

UI suggested that it retained many consultants throughout the project, including experts in the category of "land appraisals / estimates." UI Reply Brief, p. 9. There was no evidence, however, of how such expertise was brought to bear on the site related issues that eventually led to $25 million in added costs. The UI comments regarding learning experiences suggested that such expertise was either not brought to bear or was ineffective.

With regard to other overruns, the AG claimed the CF that UI chose to build is simply not the CF that PURA approved. It is more costly and extravagant. The Authority believes that the more relevant point here is that the CF that UI chose to build is not the CF that the UIL Board approved. Management sought the UIL Board approval for the construction costs in June 2010. Response to Interrogatory ODR-20. But the Board denied management's request, directing instead that the proposed $93.7 million facility be revised and reduced by $8.2 million so as to be able to be constructed for $85.5 million. UI acknowledged the UIL Board action as a directive to cut $8.2 million from the project, but did not take any actions that might substantively produce such reductions. Tr. 5/23/13, pp. 2703 and 2704.

In any event, the unauthorized money was spent. In December 2011, 18 months after its direction to management, the UIL Board approved the overrun and a construction budget of $91.2 million. Response to Interrogatory ODR-020. The Authority concludes that this was perfunctory in that by that time the money had already been spent or committed, leaving the Board with no choice. It is this perfunctory and irrelevant approval that the Company then cites to prove “there were no cost overruns.”

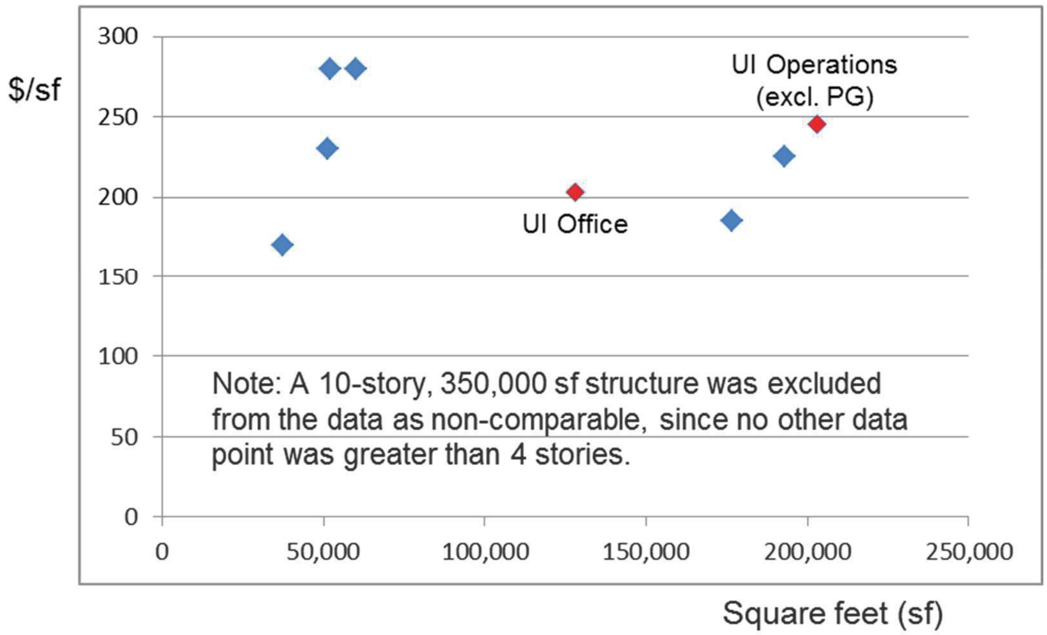
The Authority finds that despite clear direction from the UIL Board to change course, UI management proceeded on a path consistent with overspending the UIL Board authorization. Management does not seem to have accepted the directive, rather suggesting that “it was imposed on us.” Tr. 5/23/13, p. 2704. The Company stated that “[t]he UIL Board basically cut down on our contingencies that the project team felt we needed.” Tr. 5/13/13, p. 2175. No evidence was presented of what value was added by the overrun, why the overrun was unavoidable, why it was appropriate to spend the unauthorized funds, or whether any Board approvals were given for the added costs before they were already spent or committed. Accordingly, the Authority finds that the failure to execute the UIL Board’s direction is good cause for regulatory disallowance of the amount in excess of the Board’s authorization and that amount, $8.2 million, should be disallowed from rate base.

UI indicated that it did not fully spend the unapproved $8.2 million, rather under-running by several million dollars. This begs the question as to the appropriateness of reducing the disallowance to the amount actually spent. The key is whether the several million dollar under-run would have also occurred had the UIL Board’s reduced scope plan been adopted. If the under-run resulted from better construction performance or from a bad estimate, it is reasonable to assume that it would have happened under either plan. The full disallowance of $8.2 million is therefore appropriate.

UI defended the final project cost with the contention that “the building construction costs are lower than the industry average.” Marone PFT, p. 7. There are many ways to define and parse the data, but using UI’s own supporting data demonstrates that such a claim is not supportable. In response to a request for substantiation of this claim, UI submitted two sets of data. Response to Interrogatory LCG-10. The first was a report by R.S. Means that UI characterized as “the industry median for construction of comparable multiple story office buildings in the New Haven area.” The estimated cost for the standard structure was $233.80 per square foot. However, the chosen building size of 20,000 square feet was by no means comparable. The two facilities at Orange are 248,000 and 127,300 square feet, both far larger than the Means “standard” building. Hence, the Orange facilities should be much cheaper than the standard due to economies of scale. Id., Attachment 1.

The second set of data submitted by UI was similarly non-supporting. A study of “comparable” projects by the CF’s construction contractor, Whiting-Turner, is illustrated in the chart below. The chart suggests nothing remarkable, for better or worse, in the UI cost data.

Comparable Projects Review
by the Whiting-Turner Contracting Company



Response to Interrogatory LCG-10, Attachment 2.

The notion that any overruns are mitigated by the project's costs versus "comparable projects" is therefore not supportable. Id., Attachment 2.

UI also offered the project's benefits as a mitigating consideration in the evaluation of overruns. As noted above, the estimated NPV benefit versus a "status quo" alternate increased to $31.8 million compared to an initial estimated benefit of $26 million in 2005. This equates to an improvement in benefits of 22% which contrasts to an increase in project costs in that same period of 107%, $120.6 million versus $58.3 million. Increased benefits, therefore, do not justify or mitigate the impact of the overruns.

Both the OCC and the AG also recommended a disallowance of the un-refunded advances from Docket No. 05-06-04. The Authority approved the advanced funding in the 2006 Decision and then evaluated it again in the 2009 Decision. Since the project had not proceeded as contemplated in 2005, and the advanced funds were not expended for the tasks contemplated, both the OCC and the AG recommended in Docket No. 08-07-04, that those funds be returned to ratepayers. The Authority agreed in part. 2009 Decision, pp. 81 and 82.

The OCC's and the AG's current recommendation is to revisit their requests in the previous Decision and for the Authority to now refund that portion of the 2005 prefunding that was not previously refunded. The disputed amount is $7.689 million, consisting of the following:

Amounts Prefunded from 2005 and not Refunded in 2008
(Thousands of Dollars)

$6,783

Electric System Work Center Revenue Requirement	
Bridge project Operations & Maintenance Revenue Requirement	193
O&M at Existing Facilities Revenue Requirement	713
Un-refunded Total	$7,689

2009 Decision, p. 82.

The AG suggested that the failure to provide for a further refund will result in customers being charged twice for the above amounts. AG Brief, p. 10. It is not clear why any such duplication should result, since the three charges in question do not represent costs that have been accrued against the CF. Further, the Authority decided in 2008 that such costs were appropriate. Neither the OCC nor the AG provided evidence explaining why it is now proper to reduce rate base by the disputed amount. The Authority will therefore not order any additional refund of the 2005 prepayments beyond what was decided in Docket No. 08-07-04.

The net UI-Distribution capital cost for the CF is approximately 88.7% of the $120.6 million cost. Response to Interrogatory AC-80. The Authority limits the addition to distribution rate base associated with the CF to no more than $88.6 million as follows:

Central Facility Disallowances
(Millions of Dollars)

Project Cost	$120.6
Disallowed unauthorized costs	-8.2
Rate Base Addition	$112.4
Distribution Allocator	88.7%
Authorized Rate Base Addition	$99.7

Based on the aforementioned, the Authority disallows Central Facility capital expenditure of $7.304 million in each of the proposed rate years.

D. Storm Cost Recovery

UI addressed two major elements relating to the recovery of storm costs. First, the Company sought to recover the storm regulatory asset, which stands at $53.3 million as of April 30, 2013. From that amount, three storm events: Irene (August 2011), the October 2011 Snowstorm and Sandy (October/November 2012) came to approximately $42 million in costs. However, UI classified an additional 24 weather events as major storms. These additional 24 storms came to approximately $10.3 million for which it sought recovery. UI based its storm regulatory assets as being consistent with past practice and consistent with past regulatory definition of “major storm.” Second, UI proposed to establish a major storm reserve with annual funding of $2 million per year.

A review of past regulatory practice for the recovery of expenses related to a major storm is of value. The purpose of creating a regulatory asset of this nature is to allow a utility to seek recovery for an unplanned non-recurring expense between rate cases.

Generally, the company may keep commensurate profits if it is able to reduce expenses below those projected in its last rate case and absorbs those that may be greater. The creation of a regulatory asset is extraordinary ratemaking treatment, as rate recovery for these expense variances at the time of the next rate case (where current and future ratepayers pay for past expenses) would be retroactive ratemaking and improper regulatory practice. An exception to this retroactive ratemaking rule is for major expenses that are non-recurring and cannot be predicted but that could affect the financial health of a company. Even then, recovery is not guaranteed; rather, the company is allowed to claim it at the time of the next rate case rather than absorb it as is done with all other expenses between rate cases.

In Docket No. 08-07-04, the Authority allowed UI to create a regulatory asset for major storm expenses ". . . to be recovered in rates as determined in a subsequent proceeding." Decision, p. 66. UI assumed that the regulatory asset is applicable for major storms, with the definition of major being the same as has been traditionally used for reliability reporting in Connecticut. That definition examines the most recent four-year period and creates a frequency distribution of the number of locations requiring service restoration work per day. Whenever the frequency of restoration work locations exceeds the 98.5 percentile, the major storm criterion is met and data related to that event is exempt from reliability records. Response to Interrogatory OCC-82.

In its inclusion of a total of 27 storms as a regulatory asset, UI claimed the criteria it utilized was that used for being relieved from reliability reporting purposes. According to UI, the definition of major storms is related to the amount of "switching steps" and restoration work locations that exceed a certain technical percentile level. UI claimed that this major storm criteria test has been the same definition of a "major storm" that the PURA has used in the past. The Company suggested that if the Authority were to consider a new definition, it could do so on a prospective basis only, and then must increase allowed O&M costs for storms falling outside any new definition. Written Exceptions, p. 23; UI Reply Brief, p.16. UI proposed to collect the regulatory asset in rates over a 6-year period, which results in amortized payments of $8.9 million per year plus associated carrying charges consistent with the Company's authorized ROR. This produces a total revenue requirement of $68.9 million. Late Filed Exhibit No. 90, Attachment 3. UI emphasized that there has been no assertion that UI acted imprudently in the three recent major events: Irene, the October 2011 Snowstorm and Sandy.

UI also proposed to accelerate recovery of the regulatory asset if and to the extent that earnings sharing materializes for the benefit of customers. In that case, the customers' share of the benefits would be applied to reducing the regulatory asset, hence retiring it earlier and producing customer savings. UI Brief, pp. 56 and 57.

Citing an increasing number of major storms since 2009, UI also requested that it be permitted to establish a storm reserve fund that would require a customer contribution of $2 million per year. This fund would accumulate until major storm expenses were incurred, at which point the fund would be utilized. If and when the fund became fully depleted, additional major storm expenses would accrue to the regulatory asset. UI Brief, pp. 57 and 58. UI explained that, excluding the catastrophic storms of 2011 and 2012, major storm expenses averaged $2.9 million per year, such that a $2 million contribution to a reserve is deemed reasonable. Response to Interrogatory AC-38.

1. Positions of the Parties

The OCC objected to UI's proposed treatment of the regulatory asset because the definition of which storms are to be included is overly liberal, resulting in the inclusion of what the OCC characterizes as 20 no-name storms. In addition, the OCC argued that the costs UI included are not incremental storm costs but include continuing costs that are already accounted for in rates. OCC Brief, p. 5. Finally, the OCC cited a previous Decision in which the Authority decided that for CL&P, only storms having restoration expenses greater than $5 million should be funded from the storm reserve. Decision dated June 30, 2010, Docket No. 09-12-05, Application Of The Connecticut Light & Power Company To Amend Its Rate Schedules, p. 40 (2009 CL&P Rate Case Decision).

The OCC observed that the major storm criterion used by the Company should not influence how storm expenses are accounted for and collected. The 98.5% criterion was established for only one reason: to eliminate major storms from the day-to-day reliability data. As an alternate, the OCC suggested that CL&P's definition of major storms, which applied directly to what can be funded from the reserve, be applicable to UI. In UI's case, this would strip all of the costs now in the regulatory asset except those associated with Irene in 2011 and Sandy in 2012. In further support of this notion, the OCC offered citations to the 2006 Decision, which seem to tie the regulatory asset to catastrophic storms. The OCC did not object to UI's proposed $2 million accrual to the reserve, only to the use of the reserve for less-than-catastrophic storms. OCC Brief, pp. 60 and 61. The OCC also believed that UI's storm costs included base payroll, overhead and transportation costs that are regular operating expenses, not incremental expenses. The result is a recommendation by the OCC that the regulatory asset be reduced to $32.865 million. OCC Brief, p. 5.

The AG's position is similar to that of the OCC. The AG contended that UI's definition of a major storm is inappropriate and stressed that the UI definition was adopted by the Authority for reliability reporting purposes only. The AG recommended that the Authority apply a definition of major storms similar to that applied to CL&P, which is storms with an incremental cost that exceed $5 million. The OCC estimates this definition would reduce UI's regulatory asset by $9 million. The AG also objected to an additional $12.3 million in routine expenses that it believed are already in rates and hence are duplicate charges when also included as storm costs. Contrary to UI's position, the AG contended that such charges were not allowed in the 2009 Decision. The AG further argued that UI ratepayers already paid for the Company's regular labor, labor overtime, labor overhead and allocated overhead in rates. Accordingly, the AG suggested a total downward revision of $21 million to the Company's storm cost request. AG Brief, pp. 18 and 19.

2. Storm Costs Analysis

The Authority concurs with the OCC and the AG that the following issues should be examined: (a) the definition of major storm as applied to the use of the reserve fund and any storm regulatory asset; (b) the potential duplication of charges resulting from UI's definition of incremental storm costs; (c) the appropriateness of the requested $2 million annual reserve accrual; (d) the process for recovering the approved amounts in the regulatory asset; and (e) the Company's request to apply any earnings sharing to an accelerated pay down of the regulatory asset.

a. Definition of Major Storm

UI is correct that the Authority has used the switching steps percentile methodology in the past. However, it has been for the reporting of reliability statistics since 1996, not for the definition of a regulatory asset. This is the basis for measuring consistent day-to-day reliability performance by Connecticut's electric utilities. The desire to identify catastrophic storms for special treatment in terms of how associated costs should be recovered by utilities is a different and unrelated question. The Authority therefore concludes that UI's definition has never been given any status with respect to costs destined for the storm reserve.

UI's contention that such a definition has been firmly established and that the Authority has no right to change it retrospectively is incorrect. Such an argument is valid if the Authority previously had agreed to or otherwise established a definition for these purposes. But that is not the case. In this proceeding, the Authority will establish a definition, not change a previously approved definition.

The Authority clearly stated that with regard to future storm-related expenses, the Company is allowed to create a regulatory asset upon payment of such storm-related expenses, to be recovered in rates as determined by the PURA in a subsequent hearing. 2009 Decision, pp. 68 and 69. This obviously meant that if the Company suffered excessive storm-related costs, it could temporarily accumulate those in a regulatory asset, whose recovery would be determined by the Authority in a subsequent hearing. There was no guarantee as to how storm costs were to be defined, and no guarantee that they would all be recoverable regardless of how they were defined. The Company's belief that it was promised a definition of major storms, and that such definition would dictate the terms of recovery, is incorrect.

Critical to this discussion is that it was recognized by UI itself that the switching steps criteria was significantly flawed in terms of reflecting the magnitude of an actual weather event.[6] In the 2005 rate case, UI itself recognized the flaw in using the switching steps criteria and sought to re-cast the criteria in terms of extent of damage and number of customers involved. In Docket No 05-06-04, the Department discusses the storm reserve issue and recites that "[i]n 2003 and 2004 (continuing into 2005) the Company made no changes to the storm reserve account because of its new definition of major storm being predicated on the extent of damage and the number of customers involved."

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[6] Instructive here is testimony offered by Mr. Richard Reed of UI on October 11, 2005 in Docket No. 05-06-04, which was the UI rate case proceeding that allowed UI to create a regulatory asset for major storms, and where the changing definition of a major storm was discussed.

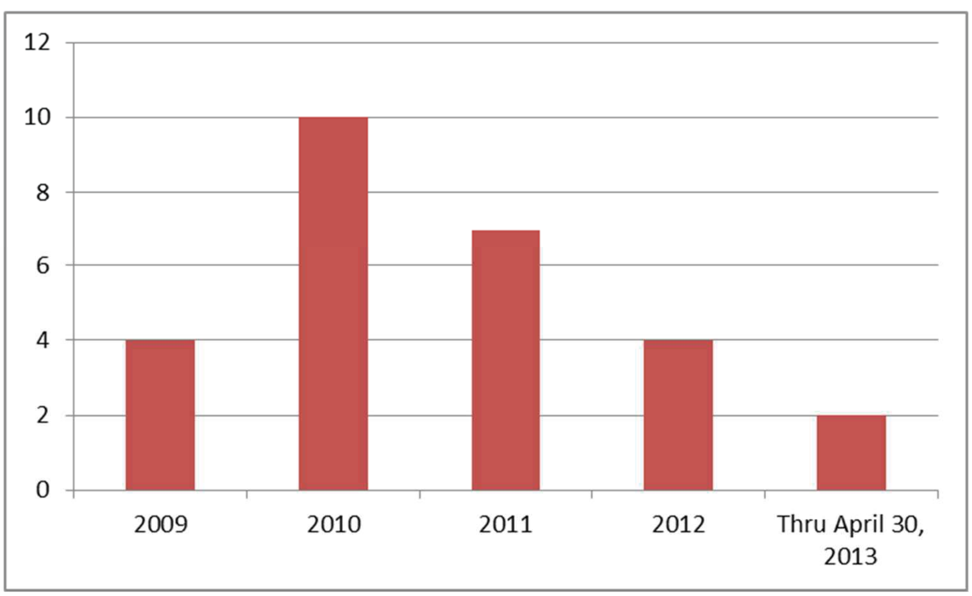
Reed: When the storm reserve was set up, the definition of a major storm was very much different from that it is today, and the definition of a major storm when the storm reserve was set up, which was right after Gloria, basically a major storm basically had to involve something like forty to fifty thousand customers, and that was the definition that as set up for a major storm. Back in the late 90's that definition was changed to basically be the number of switching steps. And, as Mr. Nicholas said, you can get some storms that are classified as major storms, and yet, not involve more than 800 customers. Tr, pp 774 and 775.

Decision, p. 40. Thus, the Company's contention that it has always used the switching criteria for the definition of a major storm is incorrect.

The Company's added contention was that the costs associated with storms falling outside any new major storm definition would need to be added as O&M expense. UI Reply Brief, p. 16. This contention assumes that: (1) an approved definition of major storms was in place; and (2) UI's storm-related O&M expenses, as reflected in rates, had been approved with that definition in mind. The Authority finds that both assumptions are wrong. It is logical that the two points in question, the major storm definition and allowable storm-related O&M expenses, are related; and it is appropriate to consider both. But no evidence has been provided in this proceeding on the latter. Also, there is no evidence presented indicating the extent to which the storm reserve is either consistent or inconsistent with any O&M level, or what that O&M level might be. As a result, the Authority is limited to defining major storms on a basis consistent with catastrophic events. Meanwhile, the degree to which this definition makes storm-related O&M expenses now in rates too high, too low or just right will have to be decided in a future proceeding.

The purpose of past Authority decisions on storm reserves and special treatments for storm costs was to provide utilities with protection in the event that extraordinary events required them to pay out large sums that could not be collected from customers in the near-term. This objective remains valid. But UI's concern that storms are becoming both more frequent and more severe, and that hence the necessary protections should be expanded, has not yet been proven. In fact, while the data shows an increase in storms in 2010 and 2011, the other years seem more normal, as illustrated on the accompanying chart.

Number of "Major" Storms per Year
(using the reliability definition of major storms)



Response to Interrogatory OCC-12, Revised Attachment 1;
Revised Response to Interrogatory AC-46.

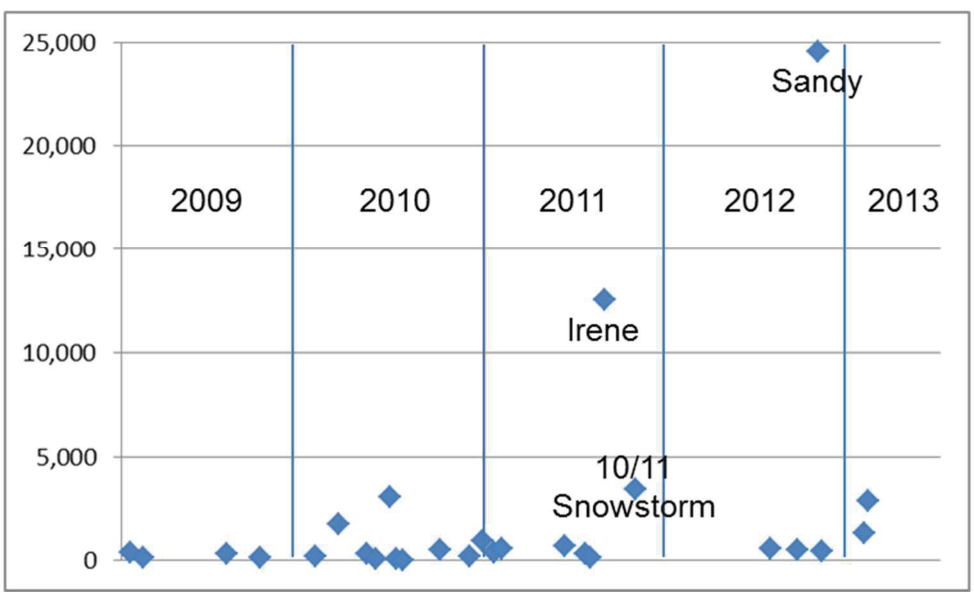
This suggests that if greater protection for normal storms is required, it is not yet demonstrated by the data. On the other hand, the experience regarding catastrophic storms has been quite clear, as illustrated below. Irene in 2011 and Sandy in 2012 were major events that no reserve could have been expected to handle. The Authority continues to believe that, unless a clear long-term trend towards many more storms becomes apparent, it is appropriate to focus protections in the form of reserves and regulatory assets on only the catastrophic events.

The Authority believes that a definition of major storms that eliminates the normal and focuses on the catastrophic is appropriate. As noted by the OCC and the AG, the definition employed at CL&P is $5 million. UI notes that it is perhaps one-fourth of the size of CL&P and that a $5 million definition would be neither comparable nor fair. The Authority agrees it is appropriate to scale this limit for application to a smaller company. As UI is about 20% as large as CL&P by number of customers, it is logical that a comparable major storm would be about $1 million.[7] Using that standard, 20 of the 27 storms now in the regulatory asset would no longer qualify for such treatment. The effect on the total storm costs is as follows:

Current requested balance - 27 storms	$53.3 million
Balance adjusted for new definition and 7 storms	$46.1 million
Reduction in the regulatory asset	$ 7.2 million

The distribution of the storm costs in the $53.3 million storm regulatory asset is shown in the following chart.

Storm Costs Currently in the Regulatory Asset
(Thousands of Dollars)



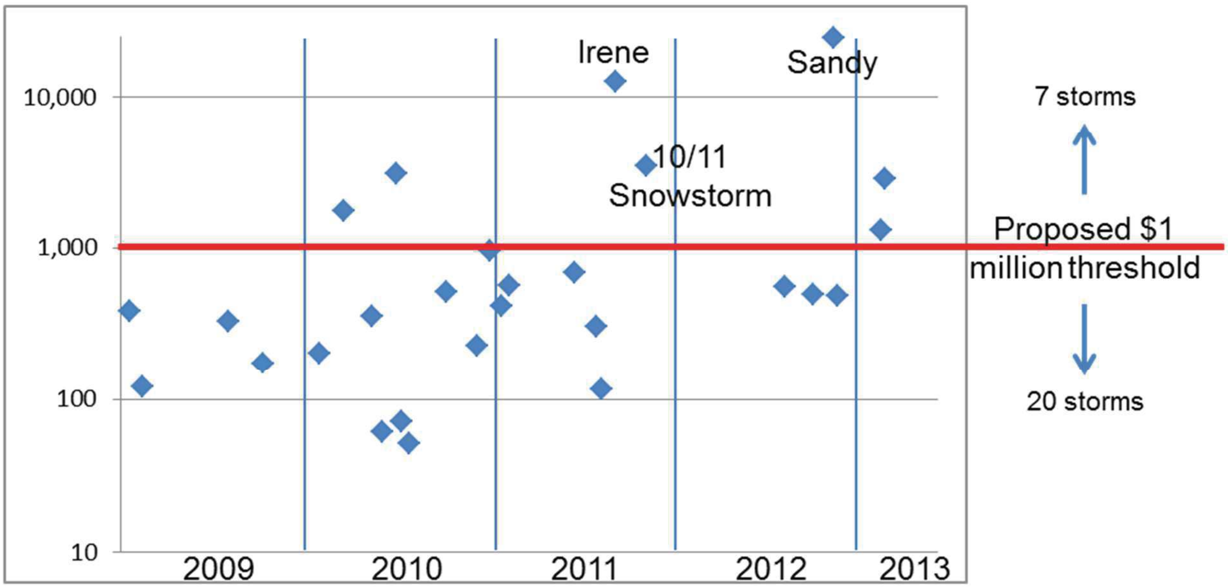
Response to Interrogatory OCC-12, Revised Attachment 1; Revised Response to

[7] A one-fourth scale would produce a limit of $1.25 million. As there were no storms between $1 million and $1.25 million, the amount to be excluded from the regulatory asset in this proceeding is the same.

Interrogatory AC-46; Late Filed Exhibit No. 28, Attachment 1.

The effect on the storm population is more apparent in the following diagram, which employs a log scale to better illustrate the spread of costs and the impact of selecting alternate values for the threshold.

Storm Costs Currently in the Regulatory Asset
(Thousands of Dollars – Log Scale)



Response to Interrogatory OCC-12, Revised Attachment 1; Revised Response to Interrogatory AC-46; Late Filed Exhibit No. 28, Attachment 1.

Therefore, the Authority sets $1 million as UI's major storm costs threshold. Based on the $1 million major storm costs threshold, the PURA recognizes $46.1 million for major storm costs for the period since the 2009 Decision through Storm Sandy in 2012, prior to the adjustments noted below.

b. Duplication of Storm Charges

As part of its request for storm expense recovery, UI included regular, rest time and non-productive time (base) labor as part of its requested regulatory asset storm cost recovery. For the seven events allowed for recovery in this Decision, UI included the following amounts for labor:

Event	Amount	Reference
02/07/13	$ 251,000	LFE-28
01/30/13	$ 141,000	LFE-28
10/29/12	$1,595,000	AC-46, Revised
10/29/11	$ 265,000	OCC-12
08/28/11	$ 959,000	OCC-12
06/24/10	$ 148,000	OCC-12
03/13/10	$ 119,000	OCC-12

Total Regular Labor	$3,478,000	

The OCC stated that base labor is included in normal O&M expenses when rates are established during rate proceedings. Recovery of base labor as part of the deferred storm request would allow for a double recovery of base pay. Only incremental costs should be included in storm costs that are eligible for recovery. As a result, storm costs are overstated by $3.288 million. OCC recommended that, at a minimum, the $3.288 million not be allowed for recovery.

The OCC continued that transportation costs and allocated overhead costs are also included in base O&M when rates are set. As with base labor, allowing recovery of transportation costs and allocated overhead as part of the deferred storm request would allow for a double recovery of costs already included in base rates. Based on the response to Interrogatory OCC-012, Revised, the deferred storm costs included transportation costs totaling $729,000 and allocated overheads of $3.197 million. The response to Interrogatory AC-046, Revised, identified another $1.342 million of transportation costs and the inclusion of $1.867 million of allocated overheads in its deferred storm cost request. As with base pay, only incremental costs should be included in storm costs that are eligible for recovery. As a result, the OCC argued that storm costs are overstated by $7.135 million ($2.071 million in transportation costs and $5.064 million in allocated overheads). The OCC recommended that the base rate costs of $7.135 million not be allowed for recovery. OCC Brief, pp. 81 and 82.

The AG is troubled by UI's inclusion in its storm cost recovery request of routine expenses that it would have incurred with or without a major storm. These routine costs amount to at least $12.3 million of the Company's storm cost recovery request: $1.6 million for labor – regular; $5.3 million for labor – overtime for salaried employees not normally paid overtime; $2.2 million for labor – overhead; and $3.2 million for allocated overhead. The Company included all costs that it incurred during storms that it considered "major" storm events, including regular payroll costs and regular meal reimbursement costs. AG Brief, pp. 18-20.

With respect to recovery of previously approved amounts in rates, the AG disputed UI's claim that the regulatory asset that had been approved by the PURA in Docket No. 08-07-04 allowed the inclusion of such (base rate) costs. The AG argued that the Company's cite to page 68 of the Decision in that case as well as Schedule B-6.3A, Note (1), from that proceeding does not support UI's claim. First, page 68 of that Decision relates to "Regulatory Assessment Expense" and discusses issues unrelated to storm cost recovery, such as the Company's generation service charge and its transmission allocations. The AG contented that this language does not support the Company's proposal to include routine expenses in its storm cost recovery request. Other parts of the Decision in Docket No. 08-07-04 also do not support UI's arguments. In that case, the PURA stated that, "[w]ith regards to future storm-related expenses above the $600 thousand provided for each of the rate years, the Company is allowed to create a regulatory asset upon payment of such storm-related expense, to be recovered in rates as determined by the Department in a subsequent rate proceeding." Decision, Docket No. 08-07-04, p. 66; AG Brief, pp. 18 and 19.

The AG continued that in the Company's previous rate proceeding, the PURA stated that if a major storm were to occur that exceeded the cost of its storm reserve fund, it "allows the Company to create a regulatory asset immediately upon the occurrence of the event and payment of the storm-related expense to be recovered, along with an amount to begin to restore the depleted reserve, in rates to be determined by the Department in a subsequent proceeding." Decision, Docket No. 05-06-04, 41. (Emphasis added). The AG stated that prior PURA Decisions only authorized UI to defer for future recovery storm-related expense and not those costs that the Company would have incurred. UI ratepayers have already paid for the Company's regular labor, labor overtime, labor overhead and allocated overhead in rates. The inclusion of these routine expenses in UI's storm cost recovery request would effectively require its customers to pay such costs twice, once in rates and a second time in a regulatory asset created for the recovery of extra-ordinary major storm costs. The AG recommended that PURA reject UI's proposal and only allow the Company to recover as major storms costs those costs that would not have been incurred "but for" the occurrence of the major storm. The Authority should also disallow any regulatory asset treatment of costs that are already covered in the Company's base revenue requirements. Id. 19 and 20.

UI stated that the inclusion of base labor is entirely appropriate and does not provide it with double recovery of costs. UI noted that when an individual performs storm work, work the individual would have otherwise performed is postponed until the cessation of the storm activities. Since the individual charges the storm time to the regulatory asset, the work that was deferred and later performed is not charged to the storm, but rather is expensed. Tr. 5/15/2013, pp. 2245 and 2246. Furthermore, there are many individuals who are not "distribution" employees who perform storm work (e.g., those whose work relates to, for example, the Generations Services Charge or Transmission). If these individuals do not charge their time to the storm, then the Company is not recovering the associated cost. UI Reply Brief, pp. 16 and 17.

The Authority is concerned with customers being charged for amounts that are already included in the current rates that they pay. This is essentially what the Company has done when establishing a regulatory asset that includes amounts which are part of the Company's normal business operations. The Authority does not require a true-up of UI's expense items between rate cases for amounts that are approved in base rates. The same can be said for expensed versus capitalized payroll. For the Company to isolate one area of its operations for deferral is selectively choosing expenses. The Company's interpretation regarding any express consent as a result of the 2008 Rate Case, to record costs already included in rates is without merit and the PURA finds no such consent.

The Company's claim that all work subsequent to a storm is all catch-up work equal to the same amount established in the regulatory asset is not credible. While there may be some increase to overtime following a storm, the Company provided no evidence to any particular amount and instead simply applied an amount equal to all regular labor charged during a storm period. As part of its base rate, the Company receives an amount for overtime, as with most other expenses, UI works within this amount which varies from year to year. The Authority also notes that significant overtime related to the seven storms, approximately $7,300,000, is being allowed for recovery.

Based on the above, the Authority disallows $3,478,000 in regular labor from the Company's regulatory storm asset request. Additionally, the Company includes benefits associated with this labor in its regulatory asset balance. This amount approximates 30% of the labor charged and is identified as labor-overheads in responses to Interrogatories AC-46, OCC-12 and UI Late Filed Exhibit No. 28; Tr. 5/15/13, p. 2248. Therefore, the Authority reduces the regulatory asset balance by $1,043,400 for the benefit amounts associated with regular labor in the regulatory storm asset request.

Other expense items where the Company requested regulatory asset treatment that would be considered base rate items include transportation and allocated overheads. The total amounts for the same seven storms equals $1,753,000 for transportation and $5,586,000 for allocated overheads. Responses to Interrogatories AC-46, OCC-12 and UI Late Filed Exhibit No. 28. The Authority will apply the percentage of regular labor to overtime labor or 47.7% ($3,478,000 / $7,298,000) for a determination of amounts for these two items to be deemed base amounts. Performing these calculations, the reductions to the regulatory asset for transportation and allocated overheads are $836,181 and $2,664,522, respectively. The balance for the storm regulatory asset approved in this Decision is as follows:

Company Request	$53,300,000
Reduction for non-qualifying storms	$ 7,200,000
Reduction for labor and benefits	$ 4,521,400
Reduction for alloc. Overheads and trans.	$ 3,500,703
Total allowed	$38,077,897

UI argued that non-distribution company employees' labor is charged to the distribution side of the Company in a storm recovery and, therefore, UI does not recover the transmission labor in future transmission or GSC filings. The Authority will allow UI to adjust its next Transmission Adjustment Clause (TAC) and GSC filing to reflect transmission and GSC labor that was previously charged to the storm regulatory asset. The Authority will require detail to justify this claim including but not limited to, employee name, title, dates worked, rate of pay and direct report during storm activities.

c. Recovery of Regulatory Storm Asset

The Company proposed to amortize the regulatory storm asset over a period of six years, earning rate base treatment on the unamortized portion. The ultimate cost of this treatment for a $53.3 million regulatory asset would be $68,885,000 at the end of six years, or $15,585,000 in excess of the asset for which the Company is seeking recovery.

Although the Authority has made adjustments to the regulatory storm asset, reducing the balance to $38,177,897, the cost of rate base treatment is still significant, approximately $11,200,000.

As part of its rate proposal and to mitigate the impact of the UI rate request on customers' bills, the Company proposed that there be no change in distribution rates during calendar year 2013. This would be accomplished by using existing revenue offsets to fund the increase in revenue requirements for July 1, 2013 through December 31, 2013.

New distribution rates would be put into effect on January 1, 2014, coincident with the elimination of the Competitive Transition Assessment (CTA). Under this proposal the average customers' total bill would not increase as a result of the change in distribution rates on January 1, 2014.

To accomplish this rate deferral, the Company proposed to utilize the 2010 earnings sharing regulatory liability, the 2012 earnings sharing regulatory liability, and the projected 2013 excess CTA revenues to fund the increase in distribution revenue requirements for July 1, 2013 through December 31, 2013. The Company stated that utilization of these revenue offsets provides for an alternative to having distribution retail rates increase ahead of when the CTA is set to expire.

The 2010 earnings sharing regulatory liability is $3,972,000, including carrying charges. The 2012 earnings sharing regulatory liability is $11,138,000, including carrying charges. The 2013 CTA excess revenue is currently projected to be approximately $11.9 million through the end of 2013, excluding any potential funds associated with the resolution of the spent fuel litigation with the US Department of Energy. UI Response to Interrogatory AC-073, Attachment 1. The Company and the US Department of Energy are in the process of finalizing a settlement whereby UI will be relieved of its obligation for spent fuel disposal at the Connecticut Yankee facility. UI is currently collecting funds for future spent fuel disposal obligations through the CTA. The estimated amount collected as of December 31, 2013 will be approximately $10 million.

The Authority finds that the best use of these funds would be to apply them to the storm cost regulatory asset, rather than defer to January 1, 2014, any rate increase, as a result of this Decision. Amounts related to customers' share of overearnings is equal to $15,110,000. UI Response to Interrogatory AC-73, Attachment 1. Together with projected CTA overcollections of $11,900,000 and an additional $10,000,000 for CY spent fuel disposal that customers will have funded through the CTA, but will no longer be obligated to fund, amounts to $37,010,000. The Authority finds that application of these funds to the storm cost regulatory asset is the most efficient use of funds for ratepayers in terms of overall costs, as well as for the Company in terms of expedited recovery of funds.

The Authority acknowledges that the customer overearnings portion of these funds are immediately available, while amounts related to CTA collections are subject to full reconciliation in 2014. To make the Company whole for this timing difference, the Authority will allow it to record carrying costs associated with the above CTA projected amounts and include such carrying costs in the 2013 CTA reconciliation which will occur in 2014.

E. Operations and Maintenance Expenses

UI originally proposed total O&M expenses of $152.044 million for RY1 and $151.384 million for RY2. The Company later decreased its proposed expenses by $3.392 million for RY1 and $3.401 million for RY2; resulting in total requested O&M expenses of $148.652 million for RY1 and $147.983 million for RY2. Late Filed Exhibit No. 3 Supplement; Schedules C-1.0 A and C-1.0 B. UI stated that it has been aggressive in cost control. The O&M costs in UI's application are comparable to the 2010 O&M

expense levels approved by the Authority in the 2009 Decision. In addition, the Company indicated that shared services costs are now allocated over four UIL Holdings Corporation (UIL) operating companies. As a result, UI now bears 45% of these shared services costs. UI Brief, p. 8. The Authority discusses adjustments and analysis to certain individual O&M expense components in the following sections.

1. Advertising

UI proposed advertising expenses of $672,000 in RY1 and $728,000 in RY2. The Company stated that increases in advertising expense are due to new programs that the Company is offering and the need to inform customers of such programs. Tr. 4/23/13, pp. 132 and 133. UI stated that advertising is not mandated by any government agency, but will generally serve to inform customers about the various products, programs and services offered by UI and the purpose, features and functionality of those offerings. UI Response to Interrogatory AC-2.

The AG stated that pursuant to Conn. Gen. Stat. §16-19d, certain types of advertising are not considered an operating expense of a regulated utility company; including political advertising, institutional advertising to create or enhance a company's public image and promotional advertising, unless authorized by the PURA. AG Brief, p. 29. The AG also stated that in the 2009 Decision, the Authority approved an advertising expense of $305,000, yet UI's actual advertising expense over the last five years has been far below its authorized amounts. Tr. 4/23/13, pp. 132 and 133. The Company has spent on average $200,600 for advertising from 2008 through 2012 [($224,000 + $173,000 + $241,000 + $222,000 + $143,000) / 5], which is consistently less than the previously allowed advertising expense of $305,000.

Given that the proposed new programs are not mandated but are discretionary in nature, the Authority agrees with the AG and disallows advertising expenses of $367,000 ($672,000 - $305,000) in RY1 and $423,000 ($728,000 - $305,000) in RY2. Therefore, the allowed advertising expense is $305,000.

2. Membership Dues

UI requested membership dues expense of $1.267 million for RY1 and RY2. Subsequently, UI reduced the membership dues expense for RY1 by $31,000 for dues related to the Northeast Gas Association. The Company stated that the expenses for both RY1 and RY2 represent a return to an appropriate level of investment in economic development. UI Response to Interrogatory AC-33.

The OCC recommended that membership dues be kept at the 2012 level of $849,000. OCC Brief, p. 72. During the test year and in 2012, UI made short-term reductions as part of UI's overall management of O&M budgets. The OCC cites Mr. Torgerson's Opening Statement:

> We looked at reducing our expenses overall, and that affected the holding company, United Illuminating, everywhere, so that we could meet our investors' expectations for the range we gave them on earnings. Now, we came in at the very low end of the range, but we managed to do that by

reducing a lot of our O&M expenses. The discretionary items just were eliminated from our overhead, and that was one of the ways we accomplished it.

Tr. 4/22/13, p. 10.

The OCC stated that if these discretionary items were eliminated for the benefit of shareholders they should also be eliminated for the benefit of ratepayers. OCC Brief, p. 72.

As with advertising and travel, education and training expenses, the Authority questions the benefit of the requested memberships. These memberships appear to be less important to the Company between rate cases and the establishment of those expenses in rates. The Authority calculates the average membership dues expense for the 3 most recent years to be $1.138 million [($1.527 + $1.037 + $0.849) / 3]. The test year expense of $1.112 million is comparable to the three-year average of $1.138 million. Both the test year and 3-year historical average membership dues expenses are less than the previously allowed expense of $1.155 million in the 2009 Decision. Therefore, the Authority allows membership dues expense of $1.112 million. This reduces the proposed membership dues expense for RY1 by $124,000 ($1.236 - $1.112) and $202,000 for RY2 ($1.314 - $1.112).

3. Outside Services

The total outside service costs for RY1 show an increase of $72,000 from the test year and a decrease of $1.11 million from RY1 to RY2. The table below summarizes the significant components of UI's outside service costs for RY1 and RY2.

Outside Service Costs
($ thousands)

	Test Year Ended 6/30/12	RY1 Ended 6/30/14	vs. Test Year Increase (Decrease)	RY2 Ended 6/30/15	vs. RY1 Increase (Decrease)
Electric Distribution System	$ 11,139	$ 12,621	$ 1,482	$13,340	$ 719
Facilities Maintenance	710	2,021	1,311	1,269	(752)
Line Clearance	4,593	2,485	(2,108)	911	(1,574)
Professional Services	3,862	2,902	(960)	3,021	119
Technology	9,963	8,508	(1,455)	8,754	246
Customer Services	2,369	2,660	291	2,763	103
Storm Reserve	-	2,000	2,000	2,000	-
Legal, Audit and Other	3,614	3,125	(489)	3,154	29
Total	$ 36,250	$ 36,322	$ 72	$ 35,212	$ (1,110)

Favuzza PFT, p. 20.

The above table summarizes the Company's SFR Schedules C-3.5 A-B through C-3.16 A-B; Late Filed Exhibit No. 3; Revised Schedule WPC-3.0 A-B.

a. Electric Distribution System

UI proposed $12.621 million for RY1 and $13.340 million for RY2 for outside services - electric distribution system expense. To adjust the test year expense of $11.139 million to RY1, the Company requested an increase of $1.483 million. To adjust the RY1 amount to RY2, UI requested an additional increase of $718,000. The expenses for the electric distribution system include inspection, wire shifting and other O&M costs associated with the transformer replacement project, streetlight maintenance and other non-capital costs. Favuzza PFT, p. 20.

As part of the Company's justification for the calculation of the RY1 and RY2 adjustment increases related to outside services of $1.483 million and $718,000, the Company presented an itemized outside services – electric distribution system table. UI also provided explanations as to why the RY1 and RY2 ending amounts are projected to increase above the test year level.

(in thousands)	Rate Year Ending 6/30/2014	Test Year Ended 6/30/2012	Variance
System & Business Operations	5,184	7,888	(2,704)
Infrastructure Replacement	6,331	3,012	3,319
Capacity & Reliability	590	126	464
Other Core Support	51	111	(60)
Preparedness	466	1	465
	12,622	11,138	1,484

(in thousands)	Rate Year Ending 6/30/2015	Rate Year Ending 6/30/2014	Variance
System & Business Operations	5,276	5,184	92
Infrastructure Replacement	7,024	6,331	693
Capacity & Reliability	670	590	80
Other Core Support	52	51	1
Preparedness	318	466	(148)
	13,340	12,622	718

UI Response to Interrogatory AC-40.

i. System & Business Operations

To adjust the test year expense of $7.888 million to RY1, the Company requested a decrease of $2.704 million. To adjust the RY1 amount to RY2, UI requested an increase of $92,000. The projects included in the System & Business Operations line item includes the transformer replacement program, minor maintenance, minor storms, vault inspection and maintenance, underground secondary network maintenance, third party pole attachments and pole data reconciliation. UI Response to Interrogatory AC-40.

Vault Inspection and Maintenance. Included within the System & Business Operations line item, the Company requested an increase of $540,000 for vault inspection and maintenance. The purpose of this project is to inspect all customer vaults for any potential environmental concerns and perform repairs as deemed necessary. The project began in 2013 and, therefore, did not have expenditures in 2012. UI Response to Interrogatory AC-40; Late Filed Exhibit No. 7.

The OCC claimed that these vault inspections are intended to protect UI personnel from potential environmental concerns, but if they are owned by customers, the customers should be charged for these inspections and repairs. The OCC recommended that in the case of customer-owned vaults, the customer should be charged for inspection and repair. Since UI did not know how many vaults were owned by customers, but described customer ownership as being typical, the OCC is recommending that 75% of the cost of $540,000, or $405,000, be removed from RY1 and RY2 O&M. OCC Brief, pp. 72 and 73.

UI countered the OCC claim, stating that expense levels reflect appropriate charges. The costs are for inspection of vaults that UI either owns or within which UI owns equipment (e.g., an environmental assessment). UI makes repairs to its own equipment within the vault. If it is a customer-owned vault, then the customer is responsible for any required remediation as well as the structural condition of the vault, and costs are not included. UI Reply Brief, p. 62.

The Authority reviewed UI's vault inspection and maintenance project. While the project began in 2013, the Company's 2012 test year indicates expenditures of $12,500. UI Response to Interrogatory OCC-132. UI stated that the costs are for inspection of vaults that UI either owns or within which UI owns equipment. According to the Company, it planned to inspect 100 vaults a year starting in 2013. The unit cost per vault is $5,400. Late Filed Exhibit No. 5. The Authority finds there is validity in the OCC's claim that UI did not know how many vaults were owned by customers.

The Company testified that the vault facility itself is on customer property and it contains UI equipment, so customers typically own the facility and sometimes it is owned by UI. UI further testified that customers may be responsible for remediation. Tr. 5/24/13, pp. 2823-2827.

The Authority questions the unit cost per vault inspection and/or repair maintenance. The Company also stated that the majority of the costs are for inspections and the repairs are for its equipment. The Authority does not believe the Company has quantified the cost of $5,400 per unit, considering the outside service job may entail an inspection the majority of the time. There is also concern relative to customer's responsibility for remediation of customer-owned vaults and UI's ability to pursue cost recovery of some vault repair work. The Authority agrees with the OCC in part. Therefore, the Authority decreases RY1 and RY2 by 50% to $270,000.

Pole Data Reconciliation. Also included within the System & Business Operations line item, the Company requested an increase of $252,000 for pole data reconciliation. This project is to implement a pole data management system. The project is done in conjunction with the Long-term Process and Technology Enhancement Program's Work Management and Field Mobile Enablement. This project began in 2013 and, therefore, did not have expenditures in 2012. UI Response to Interrogatory AC-40.

Because a technical meeting has been held concerning third-party pole administration and a Decision is yet to be issued regarding administration and the common technology to be used by all utilities, the OCC recommended deferral of the TDOEI for further work and study. No expenses were charged to the Pole Data Reconciliation project in System & Business Operations during the period 2008 through 2012 and the test year. Therefore, the OCC believed the pole data reconciliation also should be deferred pending resolution of the above items, and the $252,000 should be removed from RY1 and RY2. OCC Brief, p. 73.

UI countered the OCC claim, stating that pole data reconciliation is part of TDOEI. UI asserted that this program consolidates pole data information so that it can be shared in the field, and also supports TDOEI. UI Reply Brief, p. 63.

The Authority does not support the OCC's claim of deferral of the TDOEI based on a technical meeting relative to UI's request for an increase for pole data reconciliation. Therefore, the Authority will allow the Company's requested increase.

ii. Infrastructure Replacement

To adjust the test year expense of $3.012 million to RY1, the Company requested an increase of $3.319 million. To adjust the RY1 amount to RY2, UI requested an increase of $693,000. The projects included in the Infrastructure Replacement line item includes the street light relamping, transformer replacement program, construction outside contractors, pole management inspections, project management, ground level inspection and streetlight head repairs. UI Response to Interrogatory AC-40.

Streetlight Head Repair. Included within the Infrastructure Replacement line item, the Company requested an increase of $174,000 for streetlight head repair. The Company stated that similar to the street light relamping project, this project is the replacement of photocells and bulbs to municipal street lights and private area lights in response to SAP light repair notifications and calls. The additional request in the rate years over the test year is to provide for increased police protection requirements, civil contractor costs to repair and replace conduit and added costs for tree trimming. Additionally, the test year was lower than expected due to contractor use for the 2011 storm response. UI Response to Interrogatory AC-40.

The OCC claimed that UI completed a capital program to replace the entire light fixture on streetlights in 2010. UI then proposed a project to repair the same light fixtures, which had recently been replaced. In 2012, the Company spent $379,000 on this expense, but there was a timing accrual that pushed $239,000 into 2013. The OCC noted that the contractor was diverted to other priority projects in 2012. Late Filed Exhibit No. 7. Therefore, it seems that UI management did not consider this work to be a high priority. The actual amount spent in 2012 was $618,000 ($379,000 + $239,000). The Company requested an increase to $805,000 in each rate year. Because the fixtures are new, the OCC recommended that the amount be the same in RY1 and RY2 as it was in 2012, which would be a reduction of $187,000 per rate year. OCC Brief, pp. 73 and 74.

UI countered the OCC claim, stating that the Company is not proposing to replace the same light fixtures that it replaced in 2012 as part of its capital program. The lamp replacement program that replaced the fixtures is different from the current program that only replaces the bulb (and is an expense). The Company stated the lamp replacement project, a capital project, was started in 2006 and completed in 2010 and involved the replacement of all of the heads on the streetlights. Now the Company needs to relamp the new heads, which involves only the replacement of the bulb and photocell. The bulbs have a seven-year life expectancy, so those bulbs that were installed in 2006 when the lamp replacement project was initiated, need to be replaced. Execution of the replacement program before the bulbs burnout is critical. If the Company waited until individual bulbs burn out, the replacement of those bulbs becomes less efficient and consequently will result in increased costs due to single repair visits and damage to the street light head, resulting in reduced asset life. UI Reply Brief, p. 63.

The OCC's argument is not supported by the evidence, considering that UI requested to replace the bulbs and not the light fixtures. The Company testified that it previously performed the head replacements from 2006 to 2010, and the bulb and photocell are now approaching the end of their life expectancy. UI needs to relamp the bulbs before they fail. The light bulbs have a seven-year cycle. There was no requirement to redo the lights last year and during the test year because all the heads were replaced. Tr. 4/22/13, pp. 84-86. The Authority questions the OCC's use of the actual amount spent in 2012 through the end of the year for this line item. The test year ending June 30, 2012, is used for comparison purposes to determine the reasonableness of the forecasted rate year, absent analysis supporting an adjustment to the test year. The Authority rejects the OCC's claim.

Transformer Replacement Program. Included within the Infrastructure Replacement line item, the Company requested an increase of $615,000 for a transformer replacement program. UI stated that the transformer replacement program is a capital program that requires poles, at times, to be replaced to accommodate transformers being installed. The expense is associated with the shifting of the wires from the old pole to the new pole in accordance with the Company's depreciation policy. UI Response to Interrogatory AC-40.

The OCC claimed that in 2012, UI used both internal and external construction crews for distribution transformer replacement work. In the test year, the Company requested that the work be done solely by external construction crews. The use of internal and external crews in 2012 may have been a cost containment decision, similar to the Membership Dues. For the same reason, the OCC recommended that the amount stay the same for RY1 and RY2, at $384,000, which produces a reduction of $419,000 per rate year.

UI countered the OCC claim, stating that this project was for the systematic replacement of distribution transformers as described in Reed PFT at page 19 and UI's Late Filed Exhibit No. 7. The OCC provided no basis for its recommendation to include only $384,000 in the rate years stating only that it may have been a cost containment measure to use internal and external crews in 2012. The Company expected to use external crews for this program in RY1 and RY2, with internal crews working on other projects as opposed to calendar year 2012, when the work reflected the use of both internal and external construction crews. Additionally, the estimated number of transformers to be replaced in RY1 is greater than those replaced in 2012. UI Reply Brief, p. 63.

The Authority questions the OCC's use of the $384,000 actual amount spent in 2012 through the end of the year for this line item. The test year ending June 30, 2012, is used for comparison purposes to determine the reasonableness of the forecasted rate year, absent analysis supporting an adjustment to the test year. The Authority rejects the OCC's claim. Therefore, the Authority will allow the Company's requested increase.

iii. Preparedness

To adjust the test year expense of $1,000 to RY1, the Company requested an increase of $465,000. To adjust the RY1 amount to RY2, UI requested a decrease of $148,000. The projects included in the Preparedness line item include Long-term Process & Technology Enhancement and Short-term Tactical Enhancement. UI Late Filed Exhibit No. 5.

Long-term Process & Technology Enhancement. Included within the Preparedness line item, the Company requested an increase of $353,000 for Long-term Process & Technology Enhancement. The Company stated that this is a new capital program that began subsequent to the test year. Reed PFT, pp. 27-35. The O&M expenditures for outside services related to the suite of capital projects are for anticipated training and data conversion. These costs are considered O&M expenses in accordance with the Company's capitalization policy for education and training and data conversion. The variance reflects no expenditures in the test year. UI Late Filed Exhibit No. 5.

Short-term Tactical Enhancement. Also included within the Preparedness line item, the Company requested an increase of $101,000 for Short-term Tactical Enhancement. UI stated that this is a new initiative resulting from regulatory mandates on storm preparedness. The costs represent consultant services to improve preparation, execution and communication of the updated restoration plan to comply with said mandates. Since this project began subsequent to the test year, the variance seen is the result. UI Late Filed Exhibit No. 5.

The OCC claimed that UI has included $455,000 in RY1 and RY2 for O&M expenses, an increase of $444,000 above the test year actual expense, for two new projects associated with O&M expenses for training and data conversion. These projects are associated with a new capital expenditure program entitled Long-term Process & Technology Enhancement. The costs represent consultant services to improve preparation, execution and communication of the updated restoration plan to comply with said mandates. This project is connected to the TDOEI, similar to Pole Data Reconciliation. The OCC recommended removing $455,000 from the rate years for the same reasons as specified for Pole Data Reconciliation. OCC Brief, pp. 74 and 75.

The AG stated that the Authority should approve the costs of UI's Short-term Tactical Enhancement plan as a reasonable effort to improve the Company's ability to assess and respond to major service outages. The Authority should not, however, approve the cost of the Company's Long-term Process and Technology Enhancement Program. According to the AG, that program is vague and ill-defined and does not merit regulatory approval at this time. Instead, the Authority should complete its investigation into the Company's response to Sandy in Docket No. 12-11-07, and then allow UI to provide a more detailed long-term plan. AG Brief, pp. 12 and 13.

For clarification purposes, the Company is seeking O&M expenditures for outside services related to the suite of capital projects. The requested increases in expenses are in addition to UI's capital program requirements. The Authority has deferred analysis on the Company's request for its capital program requirements above.

The Authority examined UI's supporting cost documentation for the two main programs within the Preparedness category. The Long-term Process & Technology Enhancement and Short-term Tactical Enhancement are new rate year programs for anticipated training and data conversion and to update the restoration plan. UI determined the anticipated costs of the projects based on estimated outside services hourly cost per unit. According to UI, the cost for the Long-term Process & Technology Enhancement is $100 per hour for 3,535 units and cost for the Short-term Tactical Enhancement is $150 per hour for 670 units. UI Response to Late Filed Exhibit No. 5.

The Authority questioned the Company on what training would be necessary and how the hours were derived. The Authority is aware that these are new initiatives, whereas the Company is lacking historical data to back-up projects of this magnitude and the required number of hours needed for the task. The Company testified that it basically depends on the skill set of its workers and that the training hours might be less. Tr. 5/24/13, pp. 2752 and 2753. The Authority finds the concern of the OCC and the AG relative to the newness of the Long-term Process and Technology Enhancement Program has some merit. Therefore, the Authority decreases the Company's requested amount by one third in RY1 and RY2 by $155,000.

b. Facilities Maintenance

UI proposed $2.02 million for RY1 and $1.27 million for RY2 for outside services - facilities maintenance expense. To adjust the test year expense of $710,000 to RY1, the Company requested an increase of $1.31 million. These services are for administration, ground maintenance, building and structure, custodial services and substation building maintenance. The Company stated the RY1 increase is comprised of two key expense items, a one-time decommissioning cost of $746,000 primarily associated with exiting both owned and leased locations due to the move to the new CF, and ongoing building services costs associated with the new facilities of $546,000. Application, p. 21; Schedule WP C-3.9 A-B; UI Response to Interrogatory AC-39.

The OCC questioned UI as to how the respective increases in cost were determined and asked for supporting cost documentation for the amounts the Company requested. In response, UI referenced the Company's response to AC-39. UI Response to OCC-128.

The Authority questions why ongoing building service costs associated with the new facilities would increase regardless if the prior expenses were from owned or leased facilities. Tr. 4/22/13, pp. 128-132. The Authority finds that the Company should not incur additional expenses for items such as an on-site cafeteria, building equipment services, custodial services and snow removal. Late Filed Exhibit No. 8. Normally, the expectation upon the move from the older building facility work locations to a newer state-of-the-art CF would produce savings for these types of expenses. It is not the ratepayers' responsibility to bear the cost of an income-producing service such as an on-site food cafeteria. Also, the expectation would be that janitorial and building maintenance service expenses would not increase upon the move from older facilities to newer facilities. In addition, snow removal cost for cleaning parking lots and walk ways would not normally increase for essentially the same number of employees from other work sites. Recent years of extreme snow fall do not necessarily predicate an increase in the snow budget. An analysis of a comparative income statement for the five most recent years, including the test year revealed that the average for the past five years' facilities maintenance expense is significantly less than the rate year. UI Revised Response to Interrogatory AC-18.

The Authority notes that although the one-time decommissioning expense of $746,000 is not included in RY2, the Company should take some responsibility for the status of UI's compliance with the Order in the Decision dated November 16, 2011 in Docket No. 11-08-08, Application of The United Illuminating Company for Approval of the Sale of Improved Real Property Located at 801 Bridgeport Avenue, Shelton Connecticut. On December 19, 2012, the Company provided notice to the Authority that the Purchase and Sale Agreement had been terminated, effective November 26, 2012, and the Company would be marketing the property for sale. UI Response to Interrogatory AC-51. Consequently, the Authority decreases RY1 and RY2 expenses by $438,000.[8]

c. Storm Reserve

UI proposed $2 million for RY1 and RY2 outside services - storm reserve. To adjust the test year to the rate years, the Company requested an increase of $2 million. The Company maintained that given the frequency of major storms in recent years, the Authority should reinstate a major storm reserve, funded with $2 million per year to be included in rates. UI believed that, coupled with the storm reserve, any major costs in excess of the $2 million requested in rates should be deferred as a regulatory asset to be recovered in a subsequent rate proceeding. The Company stated that it fully extinguished its storm reserve account in 2007 and there was no funding for the storm reserve included in the 2009 Decision. Favuzza PFT, p. 23; Schedule WP C-3.7 A-B; UI Response to Interrogatory AC-38.

The OCC did not oppose the storm accrual, on the condition that only significant storms such as Irene, Sandy and the October 2011 Snowstorm are charged against the reserve. Normal wind, lightning, rain and ice storms should be charged directly to O&M and not the reserve. The storm reserve should be only for storms of a catastrophic nature, not storms determined to be major storms for SAIFA and SAIDA purposes. The OCC proposed that an individual storm cost threshold be set so that only storms that exceed $5 million be charged to the reserve. OCC Brief, pp. 59-61.

8 Site café $84,000 + building equipment services $122,000 + custodial services $124,000 + half of snow removal budget $108,000 = $438,000.

For clarification purposes, the Company sought storm expenses of $2 million per year to re-establish the funding of a storm reserve for future major storm expenses, plus the amortization of expenses to recover costs incurred from past major storms. UI Response to Interrogatory OCC-108. The Authority deferred analysis on the Company's request for annual amortization expenses to recover past incurred major storm costs contained within the storm regulatory asset to Section II.D. Storm Cost Recovery.

The Authority reviewed the analysis performed by the Company in determining the $2 million storm reserve request. According to UI, unfunded storm costs deferred for future recovery totaled $1.2 million in 2008 and $1.0 million in 2009, before jumping to $6.5 million in 2010 with an additional $2.9 million being incurred in the first 8 months of 2011, prior to Irene. The average of these four amounts, prior to the onset of Irene, the October 2011 Snowstorm and Sandy, is $2.9 million. UI Response to Interrogatories AC-38 and OCC-12.

The Authority is aware that continuing to defer major storm costs without establishing funding of an annual storm reserve can compromise the Company financially. UI believed the storm reserve to be a more appropriate method to address storm expenses when compared to specific storm insurance that is very costly and limited in availability. UI Brief, pp. 58-61. The Authority considers UI's determination of funding the reserve at $2 million annually to be reasonable. The Authority considered the OCC's concern relative to an individual threshold amount being set to be charged against the reserve. The storm cost threshold per occurrence is $1 million or greater to be charged to the reserve. To monitor funding, the Authority will direct UI to account for the storm reserve balance on an annual basis. The Authority approves the Company's request to reinstate a major storm reserve, funded at $2 million per year, to be included in RY1 and RY2.

4. Depreciation

The Company last submitted a depreciation study to the Authority in Docket No. 05-06-04, on the electric utility property and plant in-service as of December 31, 2003 (2003 Study). This study was prepared by its external consultant Management Application Consulting, Inc. (MAC). The Company submitted a new depreciation study prepared by MAC, for electric utility property and plant in-service as of December 31, 2008 (2008 Study). The study was in support of its overall depreciation expense claim in this proceeding. Application, Schedule H-1.9. The 2008 Study developed accrual rates based upon the straight-line method, remaining life (RL) technique and vintage/broad group method, or average life group, for compiling depreciation of each type of plant. This was the same basic approach and methods as used in the 2003 Study.

UI's Application reflected depreciation expense of $47.32 million and $54.08 million for the RY1 and RY2, respectively. Application, Schedules C-3.33 A-B. Depreciation expense was calculated by multiplying the annual average plant-in-service by the RL accrual rate. The accrual rate was determined by the Company's 2008 Study. The proposed service lives were also applied to new plant additions projected within the test years.

The 2008 Study used various statistical analyses to determine the estimated RL for each class of assets in service as well as salvage values and costs of asset removal. The estimated remaining lives determined within the 2008 Study were then used to set each class of asset's RL accrual rate. The 2008 Study recommended increasing or decreasing the remaining average service lives, net salvage rates and resultant depreciation accrual rate for a number of asset classes on which existing accrual rates are based (i.e., the 2003 Study). The following table provides a comparative analysis of the composite averages on a functional plant basis.

Composite Averages on a Functional Plant Basis
2008 vs. 2003 Depreciation Studies

	Yrs Service Life			% Net Salvage			% Depr. Rate	
	2008 Study	2003 Study		2008 Study	2003 Study		2008 Study	2003 Study
Transmission	45.5	43.3		(4.1)	(8.7)		2.34	2.31
Distribution	35.4	33.4		(17.2)	(8.8)		3.69	3.05
General	14.7	10.3		3.4	8.8		6.58	6.23
Total Electric	36.0	34.1		(11.0)	(8.6)		3.31	2.92

Application, Schedule H.1.9, p.10.

The total average service life (ASL) increased under the 2008 Study, which when considered on its own, would tend to reduce immediate revenue requirements. However, net negative salvage increased to 11%, a factor which increased revenue requirements. When considered collectively, the composite average annual depreciation rate increased from 2.92% under the 2003 Study to 3.31% under the 2008 Study as submitted. The Company sought to revise its annual depreciation rates and increase its annual depreciation expenses by approximately $4.6 million on a going forward basis based upon the 2008 Study. Application, Schedule H.1.9, p. 12. Approximately, $2.7 million of this amount was attributed to Account 370 Meters; the historical database includes electro-mechanical meters which have recently been replaced with Smart Meters (AMI), which accounts for 59% of the depreciation expense increase. Application, Schedule H.1.9, p. 30; Schedule H.1.9; Schedule B. Further, the proposed service lives were also applied to new plant additions projected within the test years resulting in pro forma additional depreciation expense claims of $8.770 million and $6.750 million for the RY1 and RY2, respectively. Response to Interrogatories AC-83 Revised; UI Attachment 2.

The Company stated that the analytical methods used in the 2008 Study were the same actuarial and semi-actuarial techniques used in the 2003 Study, and that those methodologies had been accepted by the Authority in the 2006 Decision. The Company summarized the increase in the 2008 Study depreciation expense claim as due primarily to the increase in depreciable assets from their capital program, increases in cost of removal and the retirement of old electro-mechanical meters. UI Brief, p. 83.

The OCC contended that the Company filed the 2008 Study without support of pre-filed testimony or a comprehensive report. Accordingly, there was no credible explanation and/or support for the depth of methodologies. Nor was there an interpretation of results using expert judgment to support conclusions and recommendations in the 2008 Study. OCC Brief, pp. 64 and 65. The OCC claimed that the ASLs or net salvage (NS) rates in several accounts appeared at odds with statistical results set forth. By way of example, the OCC opined that statistical data provided in the 2008 Study supports a 44-year ASL for Account 368 – Line Transformers, the second largest distribution account in terms of asset value. Without explanation, the 2008 Study recommended using 33 years. By way of further example, the 2008 Study results for Account 367 - Underground Conductors and Devices indicated negative NS ranging from negative 15% to negative 310%, yet the Company proposed to increase it from negative 10% to negative 20%. The OCC also pointed to UI Late Filed Exhibit No. 89, an account-by-account analysis setting forth ranges of NS results and averages, which in some cases show wide differences. The OCC noted that recommended study salvage rates were absent of any discussion or support for the rationale of the rate recommended. OCC Brief, pp. 65 and 66.

The OCC noted that UI is aware of the FERC USOA accounting regulations to keep retirements by vintage and did so with its fixed asset records. The OCC noted that the MAC did not have the vintage data and used a simulation methodology rather than actual data based on plant performance. OCC Brief, p. 67. Finally, the OCC noted that the 2008 Study was filed in February 2013 using data through year-end 2008, and that MAC concluded it was appropriate to do a depreciation study every five to seven years. This same firm performed the 2003 Study and recommended that a depreciation study should be performed every three to five years. Lastly, the OCC believed that the PURA should reasonably expect a depreciation study be prepared specifically for the February 2013 rate case, and that it should be based upon current data through year-end 2011. OCC Brief, p. 68. The OCC opined that for the above reasons, the 2008 Study and $4.6 million increase derived from said study should be rejected outright.

The AG concluded that the 2008 Study is not reliable and that the Authority should reject the Company's $4.6 million depreciation study adjustment. The AG referenced the OCC's testimony that the 2008 Study was not in compliance with the USOA and its recommendations were not supported by the 2008 Study itself. AG Brief, p. 29. The Authority reviewed the 2008 Study, the 2003 Study, Order No. 8 in the 2006 Decision, and the briefs and testimony related to the depreciation expense claim matter in this proceeding. The Authority's analysis, recommendations and adjustments pertaining to the issues at hand are discussed below.

a. Frequency of Depreciation Studies

In the 2006 Decision, the Authority found that it was normal practice to conduct a new depreciation study approximately every five years. In fact, as discussed earlier, the 2003 Study recommended that a depreciation study should be performed every three to five years. The Company suggested that whether depreciation studies should be updated every three to five years or every five to seven years is not of importance since the data used in the 2008 Study is less than five years old as of the close of the record. UI Reply Brief, p. 60. The Authority finds that it is important to provide for a normal practice as to when to conduct a new depreciation study. Thus, the Authority rejects the 2008 Study recommendation that depreciation studies be performed every five to seven years and finds that a depreciation study should be performed every three to five years, the same period of time as recommended in the 2003 Study.

Also in the 2006 Decision, the Authority ordered the Company to conduct a new depreciation study in the first rate proceeding that occurred after January 1, 2010. While the 2008 Study submitted as part of the instant proceeding may have met the minimum requirement, it did not preclude the Company from doing a study based upon more current data to support its overall depreciation expense claim in this proceeding. In fact, with regard to the general approach to conducting depreciation studies, the 2003 Study provided the following guidance:

> Regarding the procedure, MAC does not rely solely on the results of analyses of historical activity as the study objective is to develop accrual rates appropriate for the near-term future. To this end, we become familiar with the property via inspections and conferences. We also consider past and projected circumstances which have had or may yet influence average service lives, survivor pattern, removal costs and gross salvage.
>
> 2003 Study, p. 4.

It is intuitive that by the time the 2008 Study recommendations were submitted in this proceeding, to which said accrual rates would be applied in 2014 and 2015, they are based upon results that either reached the end of the range of expiration dates or are within the end of the near-term contemplated by the study approach. At best, the approach further indicated that one should at least consider past and projected circumstances, which have had or may yet influence accrual rates. The MAC depreciation consultant did not undertake or consider the impact of any new plant additions since the 2008 Study, and recommended against the need to update the 2008 Study for the purposes of the instant filing. Tr. 5/13/13, pp. 2087 and 2088.

The Authority will accept the 2008 Study based upon year-end 2008 data for purposes of determining accrual rates in this proceeding. The appropriate weight and consideration of the recommendations contained therein will be applied based upon the reliability of the information necessary to support the Company's burden of proof. Finally, the Authority will direct the Company to submit a copy of any future depreciation studies prepared on its behalf to the Authority upon completion of said study, and at the same time a copy of the report should be filed with the OCC.

b. Depreciation Study Methodologies

The OCC and the AG suggestion that the FERC USOA strictly requires a utility to perform an actuarial study based upon the actual physical plant performance is rejected. The Authority notes that the Company testified that it is aware of the USOA requirement to keep actual physical plant performance retirements by vintage and does so. OCC Brief, p. 67. The Company further argued that the FERC USOA only provided direction regarding accounting charges and did not provide specific methods in preparing depreciation studies. UI Reply Brief, pp. 59 and 60. The Authority agrees with the Company's interpretation. With regard to depreciation study methods, the FERC material referenced did not indicate that studies should be based solely upon the preferred method advanced by the OCC. Specifically, the FERC USOA provided that the accounting method described would serve as an estimating aid and allows for other appropriate methods.

> The utility shall keep such records of property and property retirements as will reflect the service life of property which has been retired and ***aid in estimating*** probable service life by mortality, turnover, ***or other appropriate methods*;** and also such records as will reflect the percentage of salvage and costs of removal for property retired from each account, or subdivision thereof, for depreciable electric plant. (emphasis added).

Late Filed Exhibit No. 91; Section 403 Depreciation Expense.

The Authority accepts the 2008 Study based upon the study methodology used, which was the same methodology used in the 2003 Study and relied upon in the 2006 Decision. The Authority applies the appropriate weight and consideration to the recommendations contained therein, based upon the reliability of the information necessary to support the Company's burden of proof.

c. Service Life, Net Salvage Rates, and Accrual Rates

In the majority of cases, the service life adjustments, NS rates and accrual rates are well reasoned and within the bounds of standard depreciation practices. In general, revisions to a longer service life, and/or reduced salvage rates reduce immediate revenue requirements. Conversely, a shorter service life and/or increased salvage rates will increase immediate revenue requirements. The Authority reviewed the Company's proposed depreciation accrual rate changes in the 2008 Study and compared them with the approved accrual rates in the 2003 Study, along with concerns raised by interested stakeholders. The Authority finds that the depreciation lives, methods and amounts recommended therein are acceptable, with the following exceptions.

d. Account 353 - Station Equipment

The Company proposed increasing the ASL in this account from 43 years to 45 years and recommended no change to the prior NS of -5%. The accrual rate would increase from 2.10% to 2.43%. The OCC and the AG recommended against any change in accrual rates, stating lack of evidence to support the analysis and recommendations. They both pointed to several representative examples in which the recommended average service lives or NS rates appeared at odds with the statistical results. OCC Brief,

p. 64; AG Brief, p. 29. The Company asserted that consideration of expert judgment sometimes produces results which diverge from the results of statistical analysis. UI Reply Brief, p. 61. The Company also explained that this account has a substantial volume of additions and retirements, and that a slight increase was warranted. However, the Company rationale for maintaining the same -5% salvage rate was merely a statement that it is still reasonable. 2008 Study, p 25.

The OCC pointed out that proposed NS rates in UI Late Filed Exhibit No. 89 differ considerably from those shown in the range of results and average results. OCC Brief, p. 66. A review of the referenced exhibit for this account shows a NS range of -0.4% to 1.1% and a 1999-2008 average result of zero. The 2003 Study similarly noted the 1999-2003 average result to be zero. 2003 Study, p. 9. The Company testified that it lacked good data for the historical years, and thus proposed no change in salvage rates to accounts 352 through 358. Tr. 5/25/13, pp. 2632 and 2633.

The Authority accepts the Company's recommendation for an increase in the ASL, but rejects the continuation of the -5% NS rate. The Authority's review of the evidence discussed above supports a change, and the PURA approves a NS rate of zero for this account. This change decreases negative NS by approximately $10.5 million over the Company's recommended RL, and reduces depreciation expense by approximately $258,446 each year. This yields an accrual rate of 2.31%.

e. Account 356 – Overhead Conductors and Devices

The Company proposed increasing the ASL in this account from 36 years to 40 years, and recommended no change to the prior NS in this account of -10%. The Company provided no detailed explanation to support the increase in ASL, other than it was based upon their analyses. The Company rationale for maintaining the same -10% salvage rate was that it was based upon their review. 2008 Study, p 26. The accrual rate would decrease from 3.32% to 2.46%. Id. For the same reasons discussed earlier, the OCC and the AG recommended against any change in accrual rates while UI recommended approval of the change.

The Authority accepts the Company's recommendation for an increase in the ASL, which reduces revenue requirements but rejects the continuation of the -10% NS rate. As discussed above, the OCC pointed to UI Late Filed Exhibit No. 89 and noted proposed NS rates which differ considerably from those shown in the range of results and average results. A review of the referenced exhibit for this account shows a NS range of -41.8% to 63.2% and the 1999-2008 average result of 3.1%. The 2003 Study rational for the -10% was that costs to remove are expected to exceed gross salvage by 10%. 2003 Study, p. 10. The Company testified that it lacked good data for the historical years, and thus proposed no change in salvage rates to accounts 352 through 358. Tr. 5/25/13, pp. 2632 and 2633.

The Authority's review of the evidence discussed above shows that the 2003 expected -10% salvage did not materialize and based upon 1999-2008 data reflects a positive 3.1% salvage rate. The Authority applies a conservative gradualism approach and approves a NS rate of zero for this account. This change decreases negative NS by approximately $1.7 million over the Company's recommended RL, and reduces depreciation expense by approximately $81,852 each year. This yields an accrual rate of 1.99%.

f. Account 367 – Underground Conductors and Devices

The Company proposed increasing the ASL in this account from 32 years to 34 years and recommended an increase to the prior NS in this account of -10% to -20%. The accrual rate would increase from 3.71% to 3.72%. The Company's explanation in support of the increase in ASL was that the plant balance in this account had increased almost 60% in the last five years. The Company's rationale for the increase to a -20% salvage rate was that it was based upon UI's review of historical data from 1999-2008. 2008 Study, p. 29. For the same reasons discussed earlier, the OCC and the AG recommended against any change in accrual rates while UI recommended approval of the change.

The Authority accepts the Company's recommendation for an increase in the ASL, but rejects the increased -20% NS rate. The OCC specifically addressed the request, indicating that the 2008 Study reflected a NS range from -15% to -310%, yet the Company proposed an increase of -10% to -20% without an explanation of its underlying logic and reasoning. In UI Late Filed Exhibit No. 89, the Company provided the same NS range and indicated a -50.8% average result for 1999-2008. The Authority finds the 2003 Study rationale for the -10% to be based upon a moderate request when compared to 35% salvage realized from 1999-2003. 2003 Study, p. 13.

The Authority's review of the above evidence shows that the 2003 Study applied a conservative approach by requesting only 30% of the realized -35% salvage rate experienced, or -10% salvage claim. The Authority concurs in part with the concerns raised by the OCC and will apply a conservative approach, similar to that in the prior study. The PURA accepts a salvage rate based upon 30% of the -50.8 salvage experienced in 1999-2008. This equates to a -15% salvage rate for this account. This change decreases negative NS by approximately $4.6 million over the Company's recommended RL for this account, and reduces depreciation expense by approximately $190,749 each year. This yields an accrual rate of 3.50%.

g. Account 368 – Line Transformers

The Company proposed increasing the ASL in this account from 33 years to 35 years and recommended a -15% NS rate in this account, a change from the current zero NS level. The accrual rate would increase from 2.59% to 3.11%. The Company provided no detailed explanation to support the increase in ASL other than the fact that it was based upon UI's analyses. Similarly, the Company rationale for increasing the current zero salvage rate to a -15% salvage rate was that it was based upon recent Company experience. 2008 Study, p. 29. For the same reasons discussed earlier, the OCC and the AG recommended against any change in accrual rates, while UI recommended approval of the change.

The Authority accepts the Company's recommendation for an increase in the ASL, which reduces revenue requirements, and accepts the -15% NS rate. The OCC specifically addressed the change in service life, indicating that the 2008 Study data supported a 44-year life. OCC Brief, p. 65. A review of the prior study analysis shows a somewhat steady and moderate trend to increase the ASL for this account. 2003 Study, p. 13. Thus, while the current study analysis might suggest a much greater life, the 44-year life, if applied, would be a 30% increase over the current 33-year life. The Authority accepts the recommend 35-year life as a gradual increase for this account.

A review of UI Late Filed Exhibit No. 89 reflected a NS range from -7.1% to -859.2% and an average result of -52.8% for the 1999-2008 period for this account. The Authority applied the same conservative approach discussed above in account 367 for the purposes of determining the NS rate for account 368. The Authority recognizes only 30% of the -52.8% actual salvage rate experienced during 1999-2008, which equates to a -15% salvage rate which is the same as UI claimed. Thus, the Authority accepts the Company's requested accrual rates as filed.

h. Account 370 – Meters

The Company proposed reducing the ASL in this account from 25 years to 20 years and recommended a -3% NS rate, a change from the current zero NS level. The accrual rate would increase from 4.62% to 14.97%. UI stated that the simulated plant record balance analysis (SPR-BAL) of the history of this account did not provide meaningful conformance index results.[9] The historical account base had electro-mechanical meters that recently have been replaced with AMI. UI further stated that the decision related to lives was based upon a review of the manufacturer's opinion, which indicated that electronic meters are not expected to realize long lives due to technological changes and the physical life of the electronic components. Thus, the 2008 Study recommends a 20-year ASL. The Company stated that its recommendation for a -3% NS rate is the same rate realized in the period 1999-2008. Finally, these changes, along with the recovery of $10,051,309 of reserve balance attributed to the retiring of prior meter investments, are the primary drivers for the overall increase in the accrual rate. 2008 Study, p. 30. For the same reasons discussed earlier, the OCC and the AG recommended against any change in accrual rates while UI recommended approval of the change.

The Authority accepts the Company's recommended ASL for this account. The change to an electronic-based network meter reading system offers a number of benefits including cost savings, which were reflected in revenue requirements. This type of meter is characterized by a somewhat shorter service life than the older mechanical meters, as is documented in industry literature and was noted in the prior proceeding. 2006 Decision, p. 82. However, the request for a -3% salvage rate based upon the 1999-2008 experience differs in approach from the 2003 Study, which indicated that a zero NS was used because meter removal is charged to an operation account and gross salvage is essentially zero. 2003 Study, p. 14.

The Authority notes that the 2003 Study rationale indicated no salvage costs for the 1999-2003 period; thus, the 1999-2008 ten-year experience is more accurately

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9 Conformance index (C.I.), is one of three key statistical reliability indications developed for each curve-life combination: C.I. is mathematically inter-related to the sum of the squared differences between the book and simulated balances, the retirement index, and the cycle index. 2008 Study, p. 19.

related to 2004-2008 five-year period and was the first time such costs were notably incurred. The Authority rejects the -3% claim and approves a zero salvage rate. This change decreases negative NS by approximately $0.8 million over the Company's recommended RL, and reduces depreciation expense by approximately $81,029 each year. Using the above Authority parameters results in an accrual rate of 14.65%.

i. Future Test Year Addition of Central Facility

UI's Application reflected a depreciation expense of $2.32 million and $2.33 million related to the addition of the new CF with associated rate base values of $104.54 million and $104.67 million in RY1 and RY2, respectively. The annual depreciation expense was based upon a 45-year life. Response to Interrogatory AC-83 Revised; UI Attachment 2. The 45-year life was determined by the Company based in-part upon consideration of the life rates in Account 390, where such assets would be recorded. UI did not seek advice or conformation as to reasonableness of the claim until late in the discovery process, and the new CF was not included as part of the 2008 Study. Tr. 5/13/13, pp. 2098-2100.

In an effort to support the 45-year life selected, the Company indicated that it considered the 2008 Study with a recommended life of 40 years. Consequently, UI based the 45-year life on the 2003 Study, which the Company stated was for newer assets. Tr. 5/13/13, p. 2100. A review of Account 390 in the 2008 Study noted a major increase of $12.3 million in plant balance since 2003. The recommended change in life from 45 years to 40 years was based upon the Company's analyses and judgment. 2008 Study, p. 31. The new CF reflected a depreciable cost of over $104 million, which is almost nine times greater than the $12.3 million increase referenced in 2003. UI testified that it did not solely rely upon MAC to determine the life of meters, rather additional outside experts were contacted to support its overall recommendation. Tr. 5/13/13, pp. 2101 and 2102. Company witnesses could not provide any information related to other depreciation study reports that would support its claim, nor did the Company dispute the possibility that other depreciation study reports for similar new facilities would use a 55-year life. Tr. 5/13/13, pp. 2104 and 2105.

UI did not provide specific justification for its choice of 45 years for CF depreciation. In the past, UI has provided such justification via experts when appropriate, including a prior study to determine depreciable lives for its new meters. Such an analysis would have been appropriate for a facility costing more than $100 million. UI's witness did not offer a suitable rationale behind the 45 year choice nor did he dispute the possibility that other depreciation study reports for new type facilities like this would use a 55-year life. Tr. 5/13/13, pp. 2104 and 2105. Therefore, the Authority also splits the difference between the two and assigns a 50-year life to the CF for purposes of developing the annual depreciation claim for this Application. This change decreases depreciation expense by approximately $232,311 and $232,598 in RY1 and RY2, respectively.

As discussed above and shown on the table below, the Authority decreases depreciation expense to certain accounts in UI's 2008 Study and the pro forma addition of the new CF for each of the rate years as follows:

		Rate Year 1	Rate Year 2
Account 353	Station Equipment	$(258,446)	$(258,446)

Account 356	Overhead Conductors and Devices	(81,852)	(81,852)
Account 367	Underground Conductors and Devices	(190,749)	(190,749)
Account 370	Meters	(81,029)	(81,029)
Subtotal 2008 Study Adj.		$(612,079)	$(612,079)
CF Addition	CF	(232,311)	(232,598)
Total Adjustments		$(844,387)	$(844,674)

j. Depreciation Expense

The Company proposed depreciation expenses of $47.321 million for RY1 and $54.070 million for RY2. Late Filed Exhibit No. 3; Supplemental Attachment, pp. 14 and 15. As discussed in detail above, the Authority disallows average plant-in-service of $19.496 million in RY1 and $49.084 million in RY2. Prorating the Authority's reductions to each of the adjusted capital items into equal quarterly amounts, using annual plant-in-service ratio of 66.7%, and applying the applicable approved depreciation accrual rates, the Authority calculates adjustments to the proposed depreciation expenses.

Based on the Authority's adjustments to the proposed average plant-in-service amounts for CF, infrastructure replacement program, TDOEI and ETT, the Authority determines depreciation expense reductions of $1.127 million in RY1 and $2.595 million in RY2. Therefore, inclusive of depreciation expense disallowance resulting from adjustments to accrual rates for certain plant accounts, the total disallowed depreciation expenses are $1.971 million ($1.127+ $0.844) in RY1 and $3.44 million ($2.595 + $0.845) in RY2.

5. Facility Rent Expense

a. Orange Central Facility

UIL occupies 69,263 square feet of space in the UI Operations Center in Orange (Operations Center). UIL also occupies 43,219 square feet of space in the UI Administrative Office (Administrative Office). UI charges UIL rent of $33 per square foot as of July 1, 2012, for the Operations Center and $33 per square foot as of April 1, 2012, for the Administrative Office. The rent received from UIL is recorded as a credit to UI's distribution facility rent expense account. For RY1, the Operations Center Rent Credit is $2.35 million and the Administrative Office Rent Credit is $1.46 million. Schedule WP C-3.21 A-B. UIL allocates approximately 45% of its shared services expenses, including facility rent expense, to UI based on the Massachusetts formula. For RY1, UI's distribution portion of UIL's Operations Center rent expense is $1.05 million and its portion of UIL's Administrative Office rent expense is $0.65 million. Id.

The cost per square foot of rent expense is determined by the CF's revenue requirement, which is a function of the cost of the CF. The Company's requested CF revenue requirement is based on its cost of $120.6 million. In this proceeding, the Authority disallowed CF costs of $20.7 million. The distribution portion of this disallowance is approximately 89% or $18.4 million. Using the allowed ROE and Cost of Debt in this rate case, the Authority calculates the CF revenue requirement for RY1 to be $15.17 million. This calculation results in a cost per square foot of $35.93 for the

Operations Center and a cost per square foot of $32.75 for the Administrative Office. UI's Operations Center Rent Credit for RY1 becomes $2.49 million and the Rent Credit for the Administrative Office is $1.42 million. UI's allocated portion of UIL's Operations Center rent expense is $1.12 million and its allocated portion of UIL's Administrative Office rent expense is $0.64 million. The net result is a decrease in UI's facility rent expense for RY1 of $37,000 ($1.338 - $1.301).

Orange Facilities	**RY1 per UI (000's)**	**RY1 per PURA (000's)**
Distribution Orange Administrative Bldg Property Lease	$809	$809
Distribution Orange Operations Center - Rent Credit	(2,346)	(2,489)
UI D portion of UIL Orange Operations Center Rent	1,047	1,120
Distribution Orange Administrative Office - Rent Credit	(1,464)	(1,415)
UI D portion of UIL Orange Administrative Office Rent	653	637
Total Orange Facilities	($1,301)	($1,338)

Schedule WP C-3.21 A-B.

For the calendar years beginning after July 1, 2012, the Company used a general escalation rate of 1.75% for the cost per square foot in calculating its Rent Credit. Schedule WP C-3.21 A-B. Therefore, the facility rent expense for RY2 is decreased by $38,000 [$37,000 x (1 + .175)]. Consequently, the Authority disallows total facility rent expenses of $37,000 in RY1 and $38,000 in RY2.

6. Travel, Education and Training

UI proposed travel, education and training expenses of $2.154 million for RY1 and $1.886 million for RY2, which represent increases of $1.064 million and $0.796 million, respectively, over the test year expense. Regarding the Company's fluctuation of expense levels in previous years compared to the current requested levels, Mr. Marone stated:

> But overall there were a lot of areas where, because of the weather and so forth, that we had to cut back. And we have cut back on many areas, things like travel and training and other sort of areas where we could do it on a short-term basis, but really isn't sustainable.

Tr. 4/22/13, p. 101.

The Company's travel, education and training expenses for years 2010 through 2012 were $1.399 million, $1.216 million and $0.726 million respectively. UI Response to Interrogatory OCC-148, Revised. The OCC noted that UI management reduced its travel, education and training expense to $726,000 in 2012 to a level that it believed was essential. The OCC stated that in this rate proceeding UI proposed an almost 200% increase in these expenses. The OCC recommended that this item be kept at the 2012 level of $726,000 for both RY1 and RY2. OCC Brief, p. 75.

The AG stated that an increase in UI's distribution travel, education and training expense amount may be justified, but not to the extent proposed by the Company. The AG determined that over the last five years, UI has averaged $1.1 million for these expenses. The AG recommended that the PURA approve a distribution travel, education and training expense of $1.6 million. AG Brief, p. 31.

The Authority finds that an increase in travel, education and training expenses may be justified, but not at the proposed levels. The Authority determines that the appropriate level of spending is the test year amount of $1.09 million. This amount is comparable to the average amount of travel, education and training expense for the past 3 years of $1.114 million [($1.399 + $1.216 + $0.726) / 3 = $1.114]. The allowed amount of $1.09 million is $364,000 greater than the 2012 calendar year expense of $726,000 and represents an increase over 2012 of approximately 50%. Therefore, the Authority reduces the travel, education and training expense by $1.064 million for RY1 ($2.154 - $1.090 = $1.064) and $0.796 million for RY2 ($1.886 - $1.090 = $0.796).

7. Compensation

UI reported total payroll expense of $57.61 million for the proforma test year and proposed approximately $57.86 million and $59.271 million for RY1 and RY2, respectively. Schedules C-3.27 A-B. In its updated filings, the Company proposed payroll expenses of approximately $57.68 million and $59.09 million for RY1 and RY2, respectively. Late Filed Exhibit No. 3, Supplemental Attachment, pp. 14 and 15.

a. Full Time Equivalents

UI noted that its base payrolls for RY1 and RY2 were developed based on 670.1 full time equivalents (FTEs), which was the base distribution O&M FTEs for the 12-month period ended June 30, 2012, the test year. The Company reported base distribution O&M FTEs of 630.8 for proforma test year, which are 39.3 fewer FTEs than in the test year. For base payroll calculations, UI proposed 16.5 new distribution O&M FTEs for the proforma period, 21.7 for RY1 and 22.9 for RY2. Thus, UI proposed 647.3 (630.8 + 16.5) base distribution O&M FTEs for the interim year, 652.4 (630.8 + 21.7) for RY1 and 653.6 (60.8 + 22.9) for RY2. Schedule WP C-3.27 A-B, p. 2. The Company reported 703.4 base distribution O&M FTEs for 2011 and 598.4 for 2012. UI noted that beginning in 2011, base FTEs reflect its distribution FTEs as well as its portion of FTEs allocated by UIL. The decrease in 2012 was due to the lower UIL allocation percentage following the integration of the gas companies. UI Response to Interrogatory OCC-8, Attachment Revised.

UI stated that the FTEs reported for 2008 to 2012 were actual FTEs at those points in time, and did not take into consideration any open positions. However, the rate year FTEs assume those open positions would be filled. Also, base FTE numbers are inclusive of amounts allocated by UIL to distribution, which can fluctuate over time and have actually lowered to UI distribution base payroll FTEs. Id. Furthermore, the Company testified that unlike 2012 FTEs that are based on an actual existing work mix, the FTE numbers proposed for the rate years assume take-away, vacancy and retirement positions were filled. In accordance with the nature of its business, UI stated that it always has a few positions that are not filled and areas that are not fully staffed. However, for the proposed rate years, the Company assumed its base distribution O&M FTEs are fully staffed and it included a payroll vacancy offset to the base payroll dollars. Tr. 04/22/13, pp. 191-195.

The Authority finds that the 630.8 base distribution O&M FTEs for the interim period is distortive and unsupported. The base FTEs for the interim period are 32.4 (630.8 - 598.4) more than total for calendar year 2012, which is six months prior to the beginning of RY1. Additionally, UI proposed to increase the interim period-base FTEs by 16.5 to 647.3, or 48.9 FTEs above the level as of December 31, 2012. On an annualized basis, this means adding 97.8 (48.9 x 2) new FTEs in a 12-month period. The historical FTE data provided in this proceeding does not support such a level of net increase to the base distribution O&M FTEs. UI Response to Interrogatory OCC-8. The Authority agrees with the Company that at any point in time there would be some unfilled positions; however, the actual FTE amount as of December 31, 2012, represents a better starting point for determining the appropriate FTE level for the proposed rate years beginning July 1, 2013.

The most up to date figures for existing FTEs are not as of June 30, 2012, but as of December 31, 2012. The actual distribution O&M FTEs and salary information are known and measurable as of December 31, 2012. Therefore, UI's proforma test year FTEs of 630.8 are overstated and do not represent the appropriate level of FTEs to develop base distribution O&M FTEs for the proposed rate years. As a result, 598.4 FTEs for 2012 is the suitable level to develop the base distribution O&M FTEs for the proposed rate years. Consequently, the appropriate base FTEs for the interim period is 614.9, which is the total calendar year 2012 level of 598.4 plus the requested additional 16.5 FTEs. For RY1, the Authority approves total FTEs of 620.1, which is the total of calendar year 2012 level of 598.4 plus the requested additional 21.7 FTEs. For RY2, the Authority approves total FTEs of 621.3, which is the total calendar year 2012 level of 598.4 plus the requested additional 22.9 FTEs. The Authority finds the FTE levels allowed herein are reasonable and will allow UI to efficiently and effectively run its operations.

b. Base Payroll

For the interim period, UI proposed total base distribution O&M payroll expense of approximately $49.854 million, which consists of $49.436 million for base payroll, $1.512 million for new FTEs, $0.330 million for escalation and negative $1.423 million for vacancy. For RY1, UI proposed total base distribution O&M payroll expense of approximately $53.565 million, which consists of $51.981 million for base payroll, $1.633 million for 21.7 new FTEs, $1.903 million for escalation and negative $1.951 million for vacancy. For RY2, UI proposed total base distribution O&M payroll expense of approximately $55.186 million, which consists of $51.989 million for base payroll, $1.589 million for 22.9 new FTEs, $3.577 million for escalation and negative $1.967 million for vacancy. Schedules WP C-3.27 A-B, p. 2; UI Response to Interrogatory OCC-8, Attachment Revised.

As discussed above, the Authority determines that the 2012 base distribution O&M FTEs is the appropriate level for developing the proposed rate years' FTE amounts. The Authority similarly concludes that the 2012 actual base payroll of $48.305 million is the appropriate amount for developing the base payroll amounts for RY1 and RY2.

Therefore, the Authority disallows base payroll expenses of $3.676 million ($51.981 - $48.305) in RY1 and $3.683 million ($51.988 - $48.305) in RY2.

i. Base Payroll Escalation

UI proposed combined composite escalation rates of 0.56% for the interim period, 3.62% for RY1 and 6.96% for RY2. Schedule WP C-3.27 A-B, p. 4. Based on its proposed base distribution payroll expenses for RY1 and RY2, the Company proposed escalation expenses of $1.903 million and $3.577 million, respectively.

The Authority accepts these base payroll escalation factors and calculates base payroll escalation expenses of $1.749 million ($48.305 x 0.0362) for RY1 and $3.662 million ($48.305 x 0.0696) for RY2. Therefore, the Authority reduces payroll escalation expense for RY1 by $154,000 ($1.903 - $1.749) and increases RY2 amount by $85,000 ($3.662 - $3.577).

ii. Net New Hires Payroll

UI proposed 16.5 new net FTEs for the interim period. The Company increased the proposed new FTEs to 21.7 for RY1 and to 22.9 for RY2. The Company proposed additional base payroll expenses associated with new FTEs of $1.512 million for the interim period, $1.633 million for RY1 and $1.589 for RY2. Schedule WP C-3.27 A-B, p. 2.

The Authority determines that average base payroll of $75,253 ($1.633 million / 21.7) for RY1 is significantly more than $69,389 ($1.589 million / 22.9) for RY2 given the fact that the base FTEs for both were held constant. The problem is further exacerbated by the fact that UI proposed an average base payroll of $91,636 ($1.512 million / 16.5) for the interim period. The amount is approximately $11,000 higher than the average base payroll of $80,724 ($48.305 million / 598.4) for calendar year 2012. Therefore, the Authority disallows $127,249 [($75,253 - $69,389) x 21.7] in base payroll for new hire FTEs in RY1.

iii. Vacancy Rate

UI applied a vacancy rate of 3.7% to determine base payroll offset for unfilled positions. Based on this rate, the Company calculated a base payroll vacancy offset of $1.951 million for RY1 and $1.967 million for RY2. Schedule WP C-3.27 A-B, p. 3.

The AG stated that the Authority should reject the 3.7% vacancy rate because it is less than the 5.1% the Company proposed and the 6.34% approved in the 2009 Decision. UI failed to demonstrate that it needed to adjust its proposed vacancy rate to maintain an adequate work force. UI customers should not fund positions that are not needed and that are unlikely to be filled. The AG recommended that the Authority maintain the vacancy rate at 6.34% and decrease the Company's proposed revenue requirement by $1.4 million in both RY1 and RY2. AG Brief, pp. 26 and 27.

The Authority finds that the AG recommendation is moot. The allowed base distribution O&M FTEs in this proceeding are the actual figures as of December 31, 2012, not the FTE figures as of June 30, 2012. As a result, the Authority is not calculating a vacancy offset to the allowed base payroll amounts.

c. Summary of Allowed Base O&M Payroll Expense

As discussed and detailed above, the Authority disallows total payroll expenses as summarized in the table below:

	RY1	RY2
Base FTE Payroll	$48.305	$48.305
Escalation	$ 1.749	$ 3.662
New FTEs Base Payroll	$ 1.506	$ 1.589
Total Allowed Base O&M Payroll	$51.560	$53.556

The Authority disallows base distribution O&M payroll expenses of $2.005 million ($53.565 - $51.560) in RY1 and $1.630 million ($55.186 - $53.556) in RY2.

d. Overtime

The Company requested payroll overtime expense of $7.032 million in RY1 and $7.178 million in RY2. Schedule WP C-3.27 A-B, p. 2.

According to the OCC, UI's base FTEs for both RY1 and RY2 are inclusive of new hires and are less than the test year level. The OCC cited UI's Response to Interrogatory ODR-8 in which the Company agreed that historical overtime expenses varied from year to year. The OCC stated that UI attempted to justify the increase in overtime by referring to added FTEs and a shift of work from storm restoration to O&M. The OCC concluded that the increase in overtime is not justified and recommended $6.256 million as the appropriate overtime expense for both RY1 and RY2. The amount was calculated based on the historical average of 2008 through 2012 overtime expenses. According to the OCC, UI ignored the fact that overall FTE levels for proposed rate years are less than that of the test year. Furthermore, the Company's attempt to justify increases to overtime expenses because of a shift from storm restoration is not supported by any evidence in the record. Hence, the OCC recommended that overtime expenses for RY1 and RY2 be reduced by $776,000 and $922,000, respectively. OCC Brief, pp. 69 and 70; Schedule A.

The Authority does not accept UI's justification that a shift of work from storm restoration to O&M would increase overtime. Tr. 04/25/13, pp. 732-734. The additional FTEs approved for both rate years should help mitigate the need for additional overtime expenditure, not exacerbate it. Also, overtime expenditures are within the Company's management control. The Authority finds that the FTEs for the test year were disproportionally skewed by the higher 2011 UIL allocation than in 2012. An overtime expense based on a five-year average helps smooth the anomalies created by unexpected events. The Authority agrees with the OCC recommendation and disallows overtime payroll expenses for RY1 and RY2 by $776,000 and $922,000, respectively.

e. Incentive Compensation

UI requested incentive compensation of $4.804 million for RY1 and $4.639 million for RY2. This compares to the actual test year O&M incentive compensation of $8.870 million. Schedule WP C-3.27 A-B. UI stated that its philosophy and practice with respect to employee compensation is simple and straightforward. The Company must compensate its employees 'at or near market' to attract and retain the individuals that it needed to perform its public service obligations. UI also stated that it sought recovery only for at risk pay at 'target' as the 'target' payout is part of the overall market compensation determination. UI Brief, pp. 75 and 76.

In its 2006 Decision, the Authority approved the annual incentive compensation of $3.994 million for inclusion in rates. This amount was the average of the Company's 2002-2004 incentive payments. In the 2009 Decision, the Authority reaffirmed its decision to limit the amount of incentive compensation to be included in rates at $3.994 million. 2009 Decision, pp. 37-41.

The OCC stated that the Company continued to pay incentive compensation at a level that was in excess of what was allowed in rates. Further, UI confirmed it had not performed any studies, nor was it in possession of any studies performed by others, that analyzed what had been allowed or disallowed in other jurisdictions when it came to incentive compensation. The Company had provided no new evidence to justify a change to the Authority's past practice of capping incentive compensation being charged to ratepayers. Moreover, per the Company's scorecard for triggering incentive payouts, specific customer goals are, at most, 25% of the incentive compensation paid and ratepayers should not be responsible for more than 25% of the incentive compensation paid. The OCC recommended that the incentive compensation requested should be reduced by 75% to reflect the 25% of customer specific goals; or as an alternative, the incentive compensation allowed in rates should remain capped at $3.994 million. OCC Brief, pp. 70 and 71.

The AG stated that UI's incentive compensation expense should be maintained at levels closer to $3.9 million per year. The AG maintained that the Company's incentive compensation is not effectively at risk because from 2008-2012 every executive and management employee that was eligible received incentive compensation. The AG stated that the goals that must be met to achieve incentive compensation are heavily weighted toward shareholder rather than customer benefits, such as the profitability of the Company. In addition, the Company failed to produce any studies comparing its proposed incentive compensation to that allowed in other jurisdictions. UI simply did not establish that it must pay higher incentive compensation to attract and maintain qualified employees. Therefore, the AG recommended a 3% increase to the $3.99 million incentive compensation expense allowed in the 2009 Decision, which resulted in an authorized incentive compensation expense of $4.1 million in RY1 and RY2. AG Brief, p. 26.

The Authority asserts that incentive compensation expenses should not be borne solely by the ratepayers. The PURA reaffirms its previous position of allocating costs between ratepayers and shareholders, maintaining the incentive compensation cap at $3.994 million to be adjusted for transmission and escalation. Accordingly, the Authority adjusts the test year incentive compensation of $3.994 million by $0.462 million which represents the transmission portion of 11.57% as calculated by the Company in Schedule H-1.6. This results in a starting point of $3.532 million for distribution incentive compensation. For RY1, the incentive compensation of $3.532 million is then escalated by 3.62%, which is the payroll escalation as presented in Schedule WP C-3.27 A-B, for an allowed incentive compensation expense of $3.660 million. For RY2, the allowed incentive compensation expense is $3.778 million, which is the base incentive compensation of $3.532 million escalated by the RY2 composite payroll increase of 6.96% as presented in Schedule WP C-3.27 A-B. The Authority reduces the requested incentive compensation expense for RY1 by $1.144 million ($4.804 - $3.660) and RY2 by $0.861 million ($4.639 - $3.778).

f. Summary of Adjustments to Total Compensation Expense

As discussed and detailed above, the Authority disallows total compensation expenses for RY2 and RY1 as summarized in the table below.

Summary of Compensation Expense Adjustments (Million)

Adjustments	RY1	RY2
Base Payroll	$2.005	$1.630
Overtime	$0.776	$0.922
Incentive Compensation	$1.144	$0.861
Total Payroll Adjustments	$3.925	$3.413

g. Other Compensation/Payroll Related Issue

The Authority is concerned that the Company mix of capitalized, base O&M, O&M overtime, regulatory storm base and overtime, and non-distribution payroll expenses may create potential for duplicative recovery of payroll expenses. The storm regulatory asset proposed in this proceeding included expenditures for both regular base and overtime payroll expenses. UI Reponses to Interrogatories AC-46, Revised Attachment, and OCC-12 Revised Attachment. UI testified that its base O&M payroll for 2011 and 2012 were less than amount the Authority allowed in the 2009 Decision. Tr. 04/25/13, pp. 747-751. The table below compares UI's accrued payroll expenses to the Company's Medicare wages.

	2011	2012	Test Year
UI Form 941s*	$88.459	$81.092	$84.225
LFE No. 16	$100.940	$90.351	$90.555
Differences	$12.481	$9.259	$6.330

*Annual totals (millions) include Distribution, Transmission, C&LM, GSC and System Benefits compensation.

ADR-13, Attachments 1 and 2.

Based on the analysis depicted in the table above, the Authority notes that the Company's reported accrued payroll expenses that are recovered in retail distribution rates were consistently and significantly higher than Medicare wages reported in the quarterly wage reports. The Authority acknowledges the fact that there is a difference between accrued compensation and paid compensation, but it questions the accuracy of the amounts reported by the Company in its Application. Given this concern, UI will be directed to provide reconciliations of Medicare wages reported in its quarterly wage returns to the total of accrued payroll amounts imbedded in capital projects, base O&M, O&M, overtime, incentive compensation, accrued regulatory assets and non-distribution operations' payroll expenses. Also, UI will be directed to provide schedules and exhibits detailing similar reconciliation for its proposed test year payroll expenses.

8. Pension/Other Post Retirement Employee Benefit

a. Background

UI has a qualified pension and other post-retirement employee benefit (OPEB) plan that covers the majority of its existing employees hired prior to 2005. Contributions to qualified pension plans are tax-deductible, and such plans are regulated by the Pension Benefit Guarantee Corporation (PBGC). The PBGC is a federal corporation created by the Employee Retirement Income Security Act of 1974 (ERISA) to encourage the continuation and maintenance of defined benefit pension plans, and to provide timely and uninterrupted payment of pension benefits to participants and beneficiaries in plans covered by the PBGC. The Company also has a non-qualified supplemental plan for certain executives and a non-qualified retiree-only plan for certain early retirement benefits. Contributions to non-qualified pension plans are not tax-deductible and such plan is not regulated by the PBGC.

Effective in 2005, UI implemented a defined contribution plan that replaces the existing qualified pension plan and retiree medical plan benefits/OPEB for new employees. The defined contribution plan consists of the current provisions of the 401(k) stock ownership plan (KSOP) for both pension and post-retirement medical benefits. New employees hired after the effective dates in 2005 are not part of the OPEB, essentially reducing OPEB costs with the passage of time as new employees are hired. In addition, as new employees replace existing employees who retire, the number of existing defined benefit pension plan participants will decrease each year. As a result, assuming no other changes in assumptions and that investment performance is as anticipated, pension and OPEB costs should decrease over time.

UI requested a total pension expense (Qualified and Non-Qualified) of $19.862 million and $15.820 million, and OPEB expense of $2.458 million and $2.567 million, for the 2014 and 2015 year rate plan period, respectively. Schedule WP C-3.28 Summary A-B; UI Response to Interrogatory FI-85. The data filed to develop the 2014 and 2015 rate year expenses was completed on November 21, 2012. Given that the rate year data was completed in November 2012, UI subsequently received its final update of 2012 liabilities for the year-end financial statement disclosures from its actuaries in February 2013. UI Response to Interrogatory FI-89, p. 2. As a result, UI subsequently revised its numbers based on more current assumptions as of April 30, 2013, and thus the Company's revised pension and OPEB expenses requested in rates are as follows: updated total pension expense of $16.872 million and $12.894 million, and revised total OPEB costs of $2.407 million and $2.499 million, for the rate plan years 2014 and 2015, respectively. UI Late Filed Exhibit No. 44. The Company noted that all of the updated data has been provided by the outside actuaries on a calendar year basis and UI submitted reconciliations for each plan to show how the actuarial calculations flow into the test year and rate years after UIL, capital and non-distribution O&M allocations. Id. The revised information as of April 30, 2013, represents a decrease in expenses from those originally filed mainly as a result of actual asset returns in excess of assumed amounts, the inclusion of updated 2012 census data for OPEB and normalization of overtime volatility resulting from the storms in 2012. Id.; UI Brief, p. 78.

Financial Accounting Standards (FAS) No. 87 expense, or pension expense, is based on the following elements which in total equal net periodic benefit cost.

Service cost
\+ Interest cost
\- Expected return on assets
\+ Amortization of Unrecognized
(Gain)/Loss
Prior service cost
Transition Obligation (Asset)
Net Periodic Pension Cost

Generally, service cost is the increase in projected benefit obligation due to the accrual of benefits that occurred in the current period. Interest cost reflects the growth in present value of projected accrued benefit obligations as they come one period closer to payment. These costs are offset by the expected return on assets, which equals the fair market value of plan assets times the expected long-term ROR on plan assets. To the extent these components deviate from actual or result from plan changes, the difference accumulates in asset or liability accounts and is amortized over a number of years into (gains)/losses, prior service cost, and transition obligation (asset). To the extent that actual and expected returns on plan assets are different, this is accumulated in unrecognized net (gains) or losses. Affecting each element of net periodic benefit cost are actuarial assumptions such as the discount rate, expected return on assets, and average wage increase. The underlying detail to these updated annual expense estimates is based on the data as of April 30, 2013 and is shown as follows:

UI Projected Net Periodic Benefit Cost
($ in thousands)

	Actual	Projected	
Qualified & Non-Qualified Pension	**2012**	**2014**	**2015**
Components:			
Service Cost	$ 6,663	$ 8,417	$ 8,754
Interest Cost	22,363	21,556	21,678
Expected Return on Plan Assets	(23,364)	(28,324)	(30,116)
Amortization of:			
Prior Service Costs	643	264	(5)
Transition Obligation (Asset)	-	-	-
Actuarial (gain) loss	14,365	16,950	15,710
Settlements / Curtailments	-	-	-
Net Periodic Benefit Cost	**$ 20,670**	**$ 18,863**	**$ 16,021**
Contributions (Qualified Pension Plan)	***$ 32,830***	***$ 18,000***	***$ 24,000***
OPEB			
Components:			
Service Cost	$ 1,023	$ 1,324	$ 1,393
Interest Cost	3,704	3,460	3,521
Expected Return on Plan Assets	(1,538)	(1,501)	(1,334)
Amortization of:			
Prior Service Costs	(69)	36	51
Transition Obligation (Asset)	392	-	-
Actuarial (gain) loss	1,362	1,825	1,690
Settlements / Curtailments	-	-	-
Net Periodic Benefit Cost	**$ 4,874**	**$ 5,144**	**$ 5,321**
Employer Contributions	***$ -***	***$ -***	***$ -***
Actuarial Assumptions:			
Discount Rate - Qualified Pension	5.30%	4.25%	4.25%
Discount Rate - Non-Qualified Pension	5.05%	4.00%	4.00%
Discount Rate - OPEB	5.30%	4.25%	4.25%
Average Wage Increase	3.80%	3.80%	3.80%
Return on Plan Assets - Pension	8.00%	8.00%	8.00%
Return on Plan Assets - OPEB	8.00%	7.00%	6.50%
Healthcare cost trend rate			
-Pre-65	8% grading 0.5% per yr to 5%	7% grading 0.5% per yr to 5%	6.5% grading 0.5% per yr to 5%
-Post-65	8% grading 0.5% per yr to 5%	7% grading 0.5% per yr to 5%	6.5% grading 0.5% per yr to 5%

UI Response to Late Filed Exhibit No. 44, Attachments 1, 4 and 6.

FAS No. 106, or OPEB expense, established accounting standards for post-retirement benefits other than pensions. This statement focuses principally on health care benefits, where the employer promises to provide health benefits after an employee retires. Such benefits are other post-retirement employee benefits and the expense is calculated with one additional assumption, the health care cost trend rate. This represents the expected annual rates of change in the cost of health care benefits currently provided by the post retirement benefit plan. As mentioned previously, employees hired after 2005, do not have this post retirement benefit. In lieu of the retiree medical coverage, new employees commencing employment with UI in 2005 are eligible to receive an additional cash contribution of $1,100 per year as a participant in the enhanced 401(k) plan (defined contribution pension plan). Tr. 4/29/13, pp. 906-908.

UI capitalizes a portion of its pensions, OPEB and 401(k) expenses into rate base. The amounts the Company requested in rates are adjusted for amounts allocated to capital and non-distribution O&M. UI Response to Interrogatory FI-113; Tr. 4/29/13, pp. 889 and 890. The percentage of pension and OPEB service costs allocated to capital and non-distribution O&M for the rate years is 53% to attain the UI distribution portion only. Compared to the normal benefits loader of approximately 30%, UI explained that this allocation is much higher because the schedules and workpapers presented for pensions show the gross amounts that include other business segments that are part of UIL. Tr. 4/29/13, pp. 920 and 921; UI Response to Late Filed Exhibit No. 44.

b. Actuarial Assumptions

The key actuarial assumptions used in determining the Company's pension expense are: discount rate, expected return on assets, and average wage increase. Discount rate is used to evaluate the present value of the plan liabilities. The higher the discount rate the lower the present value of the liabilities resulting in lower pension expense. Expected return is an assumption, not an actual return, and is a product of plan investment mix and the expected earnings on such mix. The higher the assumption the more the plan assumes it can earn resulting in lower pension expense. The average wage increase is the assumed increase in annual wages for all employees in the plan. The higher this assumption, the higher the pension expense.

Since UI's last rate proceeding, there has been a decline in discount rates due to the downward trend of interest rates nationwide over the periods. This trend can be illustrated by the Merrill Lynch 10+ High-Quality Corporate Bond Index. As of December 31, 2008, the index rate was 5.92% compared to 3.94% as of December 31, 2012. UI Response to Interrogatory FI-120. In addition to the decline in the general interest rate environment, UI changed the methodology of determining its discount rate based upon the settlement of pension and OPEB liabilities utilizing a hypothetical portfolio of actual, high quality corporate bonds which is different from the yield curve methodologies used in prior years. Favuzza PFT, pp. 15 and 16; UI Response to Interrogatory FI-91. The portfolio was built through a proprietary model developed by UI's outside actuarial consultants known as the BOND:Link methodology. The Company stated that this model results in an estimate of the discount rate that more accurately reflects the settlement value for plan obligations and was applied consistently throughout both rate years.

Based upon the 2012 Towers Watson Client Survey, there has been considerable movement towards BOND:Link away from the various yield curves and Citigroup. UI Response to Interrogatory FI-115. If the Company was still using the Citigroup Pension Discount Curve, this would have resulted in a discount rate of 3.75% for the qualified pension plan as of December 31, 2012. UI Response to Interrogatory FI-117. The Company's original filing used a discount rate of 4.30% for the qualified plan, 4.10% for the non-qualified plan and 4.30% for the OPEB in calculating expenses for the rate years. Given that the original rate year data was completed in November 2012, UI agreed to update the pension and OPEB plan expenses utilizing the latest available data as of April 30, 2013. Tr. 4/29/13, pp. 918 and 919; UI Response to Interrogatory FI-89. Utilizing the most recent available BOND:Link calculations as of April 30, 2013, the discount rates declined slightly to 4.25% for the qualified plan, 4.0% for the non-qualified plan and 4.25% for the OPEB for the 2014 and 2015 rate years. Although a lower discount rate would normally result in an increase to pension expense, the updates to discount rates were not significant enough to impact the actual decline in pension and OPEB expenses in this proceeding. UI Late Filed Exhibit No. 44.

The Company used an 8.0% expected return on assets assumption for both pension and OPEB for the 2014 and 2015 rate plan period. Favuzza PFT, p. 16; UI Response to Interrogatory FI-118. Effective January 1, 2012, UI engaged a new investment pension plan asset manager, State Street Global Advisors (SSGA), to replace Russell Investments. UI Response to Interrogatory FI-88. UI testified that the expected return on assets is based on the actual investment performance for the five-year period from 2008 through 2012 for the plan. Tr. 4/29/13, pp. 921-923; UI Response to Interrogatory FI-91. In developing its return forecast, SSGA made some changes to investment strategies and funds and moved UI's target asset allocation toward less equity from 60% to 50% and increased the fixed assets from 30% to 40%. UI Responses to Interrogatories FI-120 and FI-88. Given the current and prior five-year performance and the modeling supplied by SSGA, UI's approach in setting the 8% expected return on assets has been to consider the assumption in terms of longer-term perspective consistent with prior years. Since this rate assumes the amount one can earn on plan assets, the Authority finds that a higher expected return would lower pension expense. UI Response to Interrogatory FI-91.

In the Company's filing it has used an average wage increase assumption, which estimates the increase in pensionable wages, of 3.8% for the test year and both of the rate years. Favuzza PFT, pp. 16 and 17. The Company states that the actual increases in pensionable wages over the past two years have been higher than the estimated assumption due to storm overtime in both 2011 and 2012. The Company indicates the 3.80% being utilized reflects a more normalized long-term rate of increase and results in a more reasonable expense projection than using actual data. UI Response to Interrogatory FI-91. UI noted that this average wage assumption also reflected the amount approved in the last rate proceeding. A higher average wage increase would result in greater benefits earned by plan participants and thus would increase pension expense. UI Response to Interrogatory FI-119.

The same discount rate (4.25%) and expected return on plan assets (8.0%) are used to calculate OPEB expense. Application, Schedules WP C-3.28c, p. 4 and C-3.28g, p. 4; UI Response to Interrogatory FI-118. In addition, the Company used a healthcare trend rate assumption that is company specific and is based upon estimates from the carrier of the health insurance provided to retirees to project inflation in healthcare costs. UI also used an annual reduction or grading of 0.5% to determine the rate and terminal value of 5% to which the healthcare cost trend rate will eventually decrease. Favuzza PFT, p. 17. The Company's insurance carriers reported projected cost increases for UI's pre-65 and post-65 retirees and employee population of 10.3% for calendar year 2013. However, a survey of other companies indicated increases averaged 6.0% for 2013. According to UI, combining projected cost increases, survey data and the grading, indicate that the healthcare trend rate assumptions are in line with the industry and are reasonable. In determining the OPEB cost, UI imputed a healthcare cost trend rate of 8.0% for the test year, reducing 0.5% annually, to 7.0% and 6.5% for rate years 2014 and 2015, respectively. A higher healthcare cost trend rate would mean higher benefit costs and thus increased OPEB expense. Id.; UI Responses to Interrogatories FI-91 and FI-92; Tr. 4/29/13, pp. 926-931.

The detailed data and actuarial assumptions used to determine the pension and OPEB expenses included in UI's filing was originally prepared in November 2012. Subsequently, the Company revised all the pension and OPEB information as of April 30, 2013, representing a decline in the expenses for each rate year from those originally filed. As a result, pension expense decreased by $2.990 million to $16.872 million for rate year 2014 and by $2.926 million to $12.894 million for rate year 2015. OPEB expense also decreased by $311,000 to $2.407 million and by $339,000 to $2.499 million for rate years 2014 and 2015, respectively. UI Response to Late Filed Exhibit No. 44.

The primary reasons for the decreases in expenses relate to actual asset returns in excess of assumed amounts, updated 2012 consensus data and normalization data. Actual asset returns as of April 30, 2013, were in excess of assumed amounts resulting in reduced loss amortization and an increase in the expected return on plan assets for both pension and OPEB. Also, UI updated 2012 census data for OPEB which reported favorable experience compared to what was included in the original filing. Furthermore, UI updated the pay projection methodology which normalizes overtime volatility resulting from the storms in 2012 and this favorably impacted the qualified pension costs for 2013 through 2015. Although the update included a decrease in the discount rates from 4.30% to 4.25% for the qualified pension and OPEB and from 4.10% to 4.0% for the non-qualified pension plan, the decline was minimal, and therefore, had no significant impact or offset on the pension and OPEB expense in this case. All other actuarial assumptions (expected return on assets, average wage increase, healthcare cost trend rate) remained the same after the data was updated.

The Authority reviewed the Company's actuarial assumptions employed in the calculation of its requested pension expense for RY1 and RY2 and finds the discount rates of 4.0% for the qualified pension plan, 4.25% for qualified pension plan and OPEB, expected return on assets of 8.0% to be reasonable. For OPEB expense, the Authority also finds the average wage increase assumption of 3.8% and the initial healthcare cost trend of 7.0%, reducing 0.5% per year to an ultimate rate of 5.0% to be reasonable.

c. 401(k) Employee Stock Ownership Plan

UI is seeking full recovery of its matching contributions made by the Company to the 401(k) Employee Stock Ownership Plan (KSOP) along with incremental contributions for new employees in lieu of their participation in the pension and OPEB plans. UI Response to Interrogatory EL-122; Tr. 4/29/13, pp. 909-911. UI also provided an update to the 401(k) expense, which reduced the originally filed amounts by $42,000 for rate year 2014 and by $70,000 for rate year 2015. UI Response to Late Filed Exhibit No. 44. Before allocation to capital and non-distribution O&M, UI projects the full amount of KSOP contributions to be $6.052 million in rate year 2014 and $6.416 million in rate year 2015, which covers both the 401(k) matching and the benefit for new plan participants who are not eligible for the UI qualified plan. Id.; UI Response to Interrogatory FI-122; Schedule WP C-3.28f.

For union employees hired on or after April 1, 2005, and non-union employees hired after May 1, 2005 (new hires), the Company makes a contribution equal to 4% of compensation to the 401(k) in lieu of participation in the pension plan and an annual $1,100 contribution to the 401(k) in lieu of retiree medical or OPEB. UI Response to Interrogatory FI-124. In addition, UI offered a 401(k) to all employees with a maximum Company match of 4% for union and 3% for non-union employees. UI Response to Late Filed Exhibit No. 44. As discussed above, for new non-union employees (hired after May 1, 2005) and union employees (hired after April 1, 2005), an enhanced KSOP contribution has replaced pension plan coverage for these employees. Since these specific contributions are not KSOP matching contributions, they would be excluded from the total KSOP contributions disallowed in the Authority's calculation. The actual KSOP matching contributions would be $3.264 million in 2014 and $3.360 million in 2015. Id.

The Authority reviewed the issue of matching contributions as they relate to the Company's KSOP Plan. In its prior rate case Decisions, the Authority's Decision dated September 26, 2002 in Docket No. 01-10-10, DPUC Review of The United Illuminating Company Rate Filing and Rate Plan Proposal, the 2006 Decision and the 2009 Decision, the Authority found that matching provides a benefit to employees, but restricted the amount of matching recovery allowed. The Authority holds, consistently, this manner of treatment in this rate case. In this regard, keeping the matching formula intact, the Authority allows full recovery of matching contributions for all UI employees, except those who are entitled to benefit under the executive incentive compensation plan (EICP) and the management compensation program (MCP).

The Authority estimates conservatively that 50% of the employee matching expense is due to employees that do not receive any form of additional compensation beyond salary such as EICP and MCP. Accordingly, the Authority allows $1.632 million for the 2014 rate year ($3.264M x 50%), and $1.680 million for the 2015 rate year ($3.360M x 50%) or full recovery for this group. For the remainder, where it is estimated employees that already have significant potential of receiving additional compensation benefits through rates, the Authority finds that ratepayers should not be required to fully fund their matching contributions as well.

Accordingly, for those employees entitled to benefits under the EICP and MCP, matching expense will be borne 50% by shareholders and 50% by ratepayers. The Authority finds it reasonable to allow $0.816 million for the 2014 rate year ($1.632M x 50%), and $0.840 million for the 2015 rate year ($1.680M x 50%) to be borne by ratepayers. Therefore, including full recovery of the contributions in lieu of pension for new hires, the Authority allows $5.235 million for the 2014 rate year ($1.632M + $0.816M + $2.787M), and $5.576 million for the 2015 rate year ($1.680M + $0.840M + $3.056M) in total for KSOP expense. As such, the total disallowance for KSOP matching contributions is $0.817 million for the 2014 rate year and $0.840 million for the 2015 rate year. However, since these figures are based on gross amounts, allocation to capital and non-distribution O&M would be applied to calculate the actual KSOP expense allowed in rates. As discussed previously, the allocation to capital and non-distribution O&M expense of 53.1% for the 2014 rate year and 52.8% for the 2015 rate year should capture both the UIL portion and the portion of expense that follows payroll known as the benefits loader. Tr. 4/29/13, pp. 907-911. After allocation to capital and non-distribution O&M expense, the Authority computes the actual KSOP expenses allowed in rates of $2.455 million and $2.632 million for the 2014 and 2015 rate years, respectively. A summary table follows.

Summary of 401(k)/KSOP Expenses

	RY 2014	RY 2015
Before Allocation to Capital and Non-distribution O&M:		
UI Proposed as of 4/30/13 - KSOP Contributions	$6.052 M	$6.416 M
- Disallowance for KSOP	($0.817 M)	($0.840 M)
KSOP Expense Allowed	$5.235 M	$5.576 M
After Allocation to Capital and Non-distribution O&M:	*53.1%*	*52.8%*
UI Proposed as of 4/30/13 - KSOP Contributions	$2.837 M	$3.027 M
- Disallowance for KSOP	($0.382 M)	($0.395 M)
KSOP Expense Allowed	$2.455 M	$2.632 M

d. Medical Expense

Based on projected headcounts and a vacancy rate of 3.7%, the Company calculated total projected medical expenses of $11.817 million for the interim period, $13.059 million for RY1 and $7.745 million for RY2. The Company applied its projected and compounding premium escalation rates of 4.6% in the interim period, 9.6% in RY1 and 12.2% in RY2. After accounting for amounts allocated to capital and non-distribution O&M, UI proposed distribution O&M medical expenses of approximately $4.761 million, $6.127 million and $6.922 million for the interim period, RY1 and RY2, respectively. Schedules WP C-3.28a A-B.

The Company stated that its current health plans are self-insured programs and do not have any premiums. The Company pays an administrative fee per an enrolled eligible participant to the carrier to handle the claim payments to health provider and to negotiate on behalf of the Company reduced or discounted treatment fees. Also, the Company pays a stop loss fee to provide insurance against any single claim in excess of $300,000. These fees are paid on a monthly basis. Additionally, the Company pays all claim costs that have been incurred by all the covered participants and dependents. The claimed costs vary by week and month based on the treatments incurred by the total group. UI Response to Interrogatory OCC-18.

The Authority has several issues with UI's calculations of medical expenses proposed for RY1 and RY2. In Section II.E.7.b.iii. Vacancy Rate, the Authority agrees with the AG recommendation to increase the Company's vacancy rate to 6.34%, instead of the 3.7% applied by UI. Also, the Authority finds that the proposed medical cost premium escalation factors for RY1 and RY2 were overstated. The Company testified that subsequent to several rounds of negotiations with ConnectiCare, the insurer offered a 12.5% escalation rate as its final and best offer to renew for 2012. The Company made the decision to change to Cigna. For calendar year 2012, UI was able to negotiate an overall medical premium increase of 3.4% for active employees. This was accomplished through very aggressive marketing for the fully insured plan and changing medical vendors from ConnectiCare to Cigna. For calendar year 2013, UI initially estimated an overall medical escalation rate of 14.1%. This included an annual assumed medical trend rate of 10% and a prescription trend of 10%. However, the 2013 medical and prescription plans were converted to self-insurance and brought the overall administration costs down to 6.9% and stop loss to 4.2%. Had UI remained fully insured, Cigna would have required an increase of over 20%. For calendar year 2014, UI is estimating an increase of 11.7% for medical coverage. This includes a 10% expected trend plus 1.7% for Healthcare Reform transitional reinsurance fees and outcome research fees. UI Response to Interrogatory AC-67. In light of the above, the Authority believes the Company can effectively manage the escalation of medical costs. The actual premium escalation factors for 2012 and 2013 were significantly less than the projected amounts.

Furthermore, following the acquisition of the gas companies, several of UI personnel were transferred to UIL. Beginning in 2012 and under the new shared service approach, UIL share service costs are allocated to UI at 44.99%, which was calculated based on the Massachusetts formula. This allocation factor is also used for the proposed rate years. ADR-16 Attachment 1, p. 21. The Authority concludes that the medical costs allocated to UI distribution O&M in RY1 and RY2 are overstated. They do not take into account the decrease in UIL allocation factor following integration of the gas companies, nor reflect the transfer of UI personnel to UIL. The table below shows the calculation of percentages of the total projected medical expenses allocated to UI distribution O&M for the proforma periods.

Analysis of Projected Medical Expenses Allocated to UI Distribution O&M

	Interim Year	**RY1**	**RY2**
Total Medical Expense*	$ 11,246	$ 13,059	$ 14,667
Amount Allocated to UI Distribution O&M	4,761	6,127	6,922
UI Distribution O&M Allocation	42.34%	46.91%	47.19%

*Per Schedules WP C-3.28a A and WP C-3.28a B; **As determined by PURA.

The Company stated that its projected distribution O&M medical expenses should be viewed in conjunction with offset amounts to capital and non-distribution O&M. The combined amounts are the majority of the O&M amounts. The medical, dental, OPEB, 401(k) and pension amounts allocated from UIL are for the UIL employees that were previously Connecticut Natural Gas (CNG) and Southern Connecticut Gas Company (SCG) employees. UIL employees who were previously UI employees continue to have these same benefits originate at UI. The benefit costs associated with those employees are allocated out from UI to UIL via the offset to capital and non-distribution O&M. UI Response to Interrogatory AC-111.

Based on the UI distribution O&M allocation factors in the table above, the Authority determines non-distribution O&M and capital allocation factors of 57.66% (1 - 0.4234) for interim period, 52.81% (1 - 0.4691) for RY1 and 53.09% (1 - 0.4711) for RY2.

This illustrates that the non-distribution O&M and capital offset factors were less than that of the proforma interim period. This also indicates that significant amounts of the additional medical costs are being allocated to UI distribution O&M in RY1 and RY2. The Authority concludes that the 57.66% for the proforma interim period is the appropriate non-distribution O&M and capital factor for forecasting the offset amounts to the total medical expenses for RY1 and RY2. Therefore, the Authority calculates the allowed medical expenses using the interim period distribution O&M allocation factor of 42.34%.

In the table below, the Authority depicts its calculations of the allowed medical expenses for RY1 and RY2.

Calculations of Allowed Total Medical Expenses

	Interim Year	RY1	RY2
Employee Headcount Beginning Balance*	1,219	1,278	1,288
Incremental Net New Employee Headcount*	59	10	(7)
Employee Headcount Ending Balance*	1,278	1,288	1,281
Vacancy Rate Offset at 6.34%**	(81)	(82)	(81)
Adjusted Employee Headcount**	1,197	1,206	1,200
Percent with Medical*	85.8%	85.8%	85.8%
Subtotal Employees with Medical**	1,027	1,035	1,058
Average Employees with Medical**		1,031	1,047
Projected Average Annual Cost per Employee*		$10,752	$10,752
Projected Medical Expense Prior to Escalation**		$11,086	$11,252
Projected Annual Premium Increase**	4.6%	9.2%	9.2%
Projected Medical Expense (000)**		$12,655	$14,022
Allowed Distribution O&M allocation (000)**		42.34%	42.34%
Allowed Distribution O&M Medical Expense (000)**		$ 5,358	$ 5,936

*Per Schedule WPC-3-28a A-B; **As determined by PURA.

Based on the allowed distribution O&M medical expenses calculated in table above, the Authority disallows medical expenses of $0.769 ($6.127 - $5.358) million in RY1 and $0.986 ($6.922 - $5.936) million in RY2.

9. UIL Corporate Service Charges

UI proposed total allocated corporate service charges of $8.678 million for RY1 and $10.402 million for RY2. The RY1 amount consists of $0.750 million for public company costs, $0.888 million for Board of Directors (BOD), negative $1.016 million for UIL allocation to and Berkshire Gas Company (Berkshire Gas), and $8.056 million for corporate capital charge. Id. Also, the RY2 amount consists of $0.823 million for public company costs, $0.885 million for BOD, negative $0.998 million for UIL allocation to Berkshire Gas and $9.692 million for corporate capital charge. Schedule WP C-3.31 A-B.

a. Directors and Officers Liability Insurance

UI requested $347,000 for RY1 and $410,000 for RY2 for Directors and Officers Liability Insurance (DOL). Schedule WPC 3.31 A-B. The Company stated that as an investor-owned utility franchised by the State of Connecticut, DOL are prudent and reasonable costs. Tr. 4/25/13, pp. 659 and 660.

The OCC stated that in previous Decisions, the Authority allowed the Company to recover 25% of DOL costs from ratepayers. The OCC noted that despite the Authority's disallowance of 75% of the DOL cost, UI was attempting to recover 100% of the allocated electric distribution O&M portion of the DOL costs. The OCC recommended that no more than 25% of the DOL costs be borne by ratepayers. OCC Brief, pp. 68 and 69.

The AG indicated that the PURA should reject UI's request for ratepayer funding of DOL in total and allow UI the same 25% recovery of DOL recovery allowed in the Company's last two rate cases. AG Brief, p. 27.

The Authority finds no compelling reason to stray from the treatment applied in the 2006 and 2009 Decisions. The Authority agrees with the OCC and the AG and allows $87,000 of DOL expense to be funded by ratepayers in RY1 ($347,000 x 25%) and $102,000 in RY2 ($410,000 x 25%). This results in DOL insurance expense decreases of $260,000 and $308,000 in rate years 2014 and 2015, respectively.

b. Other Public Company Costs

Besides the DOL liability insurance expenses discussed above, the public company costs proposed for RY1 and RY2 included annual report, investor relations, Edgar filing SW maintenance, SEC reporting, shareowner services, and annual meeting expenses. These non-DOL public company costs are $0.403 ($0.750 - $0.347) million for RY1 and $0.413 ($0.823 - $0.410) million for RY2. Schedules WP C-3.31 A, p. 2 and WP C-3.31 B.

Consistent with determination regarding DOL insurance expenses discussed above, public company costs provide more benefits to the shareholders than to ratepayers. As such, a significant portion of these expenditures should be allocated below the line to equity owners. Hence, the Authority will similarly disallow 75% of the non-DOL public company costs from being recovered in rates. The Authority allows $0.101 ($0.403 x 25%) million in RY1 and $0.103 ($0.413 x 25%) million in RY2. Therefore, the Authority disallows non-DOL public company costs of $0.302 ($0.403 - $0.101) million in RY1 and $0.310 ($0.413 - $0.103) million in RY2.

c. Board of Directors

UI proposed total allocated BOD costs of $0.888 million for RY1 and $0.885 million for RY2. Schedule WP C-3.31 A- B. These costs included restricted stock expense for BOD, UIL legal and consulting matters, director stocks, director retirement pension and director expenses. Schedule WP C-3.31 A, p. 1.

The main objective of the BOD is to protect the interest of the Company's investors or shareowners. Ratepayers may tangentially garner benefits from the activities of the BOD; however, they are not the focus of the BOD decisions. Consistent with the determinations regarding public company costs discussed above, the Authority allows only 25% of BOD costs in rates. Hence, the allowed BOD costs are $0.222 ($0.888 x 25%) million for RY1 and $0.221 ($0.885 x 25%) million for RY2. As a result, the Authority disallow BOD costs of $0.666 ($0.888 – $0.222) million in RY1 and $0.664 ($0.885 x $0.221) million in RY2.

d. Corporate Capital Charges

The Company stated that UIL capital is primarily related to computer software systems, with the SAP enterprise resource planning system being the most significant. These computer software systems are recorded as UIL assets, as they benefit all of the UIL affiliates. A capital charge is developed based upon the annual depreciation incurred by UIL on these assets plus a return based upon the weighted-average allowed return for all of the UIL operating companies This total charge is then allocated to the operating companies based upon the three-factor Massachusetts formula. Favuzza PFT, p. 9. UI distribution's portion of the UIL capital charges are $8.056 million for RY1 and $9.692 million for RY2 in distribution rates. Schedule WP C-3.31a A-B; Tr. 4/23/13, pp. 273-275. The total allocated UIL capital charges are $0.733 million for the test year ending June 30, 2012, and $0.805 million proforma test year ending June 30, 2013. Schedule WP C-3.31a A-B. The average rate base amounts for determining the UIL capital charge to be allocated to operating companies are $5.807 million for proforma test year, $56.358 million for RY1 and $61.594 million for RY2. Schedule WP C-3.31a A-B. The total plant-in-service amounts used to calculate average rate base amounts are $11.240 million for the test year, $70.690 million for the proforma test year, $93.988 million for RY1 and $116.941 million for RY2. UI Response to Interrogatory AC-59 Attachment 2; UI Late Filed Exhibit No. 20 Supplemental Attachment.

All UIL corporate capital charges, including the corporate wide implementation of SAP, are allocated to business units based on each business unit's respective net plant plus construction work is in progress (CWIP), payroll, and revenues. The revenue portions do not include commodity revenues, which for UI are generation service charge (GSC) revenues, or purchased gas adjustment revenues in the case of gas companies. UIL business units include UI distribution, UI transmission, CNG, SCG and Berkshire Gas. UI Response to Interrogatory AC-59, p. 2.

UI testified that in 2003, it moved into the SAP environment for its customer information system and that the related costs are fully depreciated. Tr. 04/23/13, p. 284. The Company stated that the SAP enhancement projects are designed to implement the advanced functionality and features of new releases and applications available within the

SAP environment. The normal SAP enhancements do not necessarily encompass the full scope of the complex billing rates nor do they take into account the variability within those complex rates and the specific requirements for those complex rates. UI Response to Interrogatory AC-13. The first of the three phases of the SAP enhancement project was completed in August 2011. It involves transitioning UI's sister gas companies into the SAP environment and upgrading the SAP system up to current levels. The second phase of the SAP enhancement program to incorporate the call center activities for all companies into SAP was completed in May of 2012. The third piece of the program is to incorporate all the financials, human resources and payroll into one system. It is scheduled to go live in the third quarter of 2013. Then, all UIL companies will be on the SAP system. Tr. 04/23/13, pp. 277-281.

UI requested computer expenses of \$4.653 million in RY1 and \$5.137 million for RY2. Schedule WP C-3.17 A-B. The total computer expense for the proforma test year was \$5.431 million. The Company noted that the decrease in the amount proposed for RY1 in comparison to the test year is due to a decrease in the UIL allocation percentage following the integration of the gas companies. Id. Additionally, UI requested data security expense of \$0.381 million in RY1 and \$0.385 million for RY2. The data security expenses include security risk management and remediation costs of \$0.241 million in RY1 and \$0.245 million for RY2. The total security risk management and remediation expense for the proforma test year was \$0.043 million. The Company noted that the increase in the amount proposed for RY1 versus the amount for the proforma test year is due to increases to data security measures to protect its data system from becoming compromised and from unauthorized access. Schedule WP C-3.6 A-B.

Furthermore, as part of its estimated \$112.2 million for "System and Business Operations" capital expenditures for 2013 through 2018, UI proposed approximately \$17.5 million for other system and business operations. These projects include compliance, radio upgrade and such technology upgrades such as SAP enhancement and mobile data terminal refresh needed for daily electric operations. Reed PFT, pp. 22 and 23. Also, as part of its estimated \$115.8 million for "Other Core Support" capital expenditure for 2013 through 2018, UI proposed customer service technology investment of approximately \$14.3 million. The projects include the implementation of SAP hourly reads and complex billing upgrades that will allow the Company's CIS to collect and bill customers on real time pricing (RTP), critical peaking pricing (CPP) or variable peak pricing (VPP). Id., pp. 24 and 25.

The table below summarizes UIL's proposed SAP and CIS related capital expenditures by June 2015.

	Amount (millions)
SAP Projects	$ 39.734
Hardware	$ 4.857
Software - Customer Service	$ 16.998
Software - SAP Enhancement	$ 13.414
Software - Corporate Support	$ 39.358
Other -UIL CFC Renovations and AFUDC	$ 2.582
Total UIL Gross Plant as of June 2015	$116.941

Late Filed Exhibit No.20, Supplemental Attachment.

The Authority is concerned with the proposed capital charge to UI by UIL for several reasons. The amounts proposed for either rate year is more than 10 or 12 times the test year amount. As of December 31, 2012, UI has CIS related intangible gross plant of approximately $101.494 million, which is $5.121 million more than the $96.373 million as of December 31, 2011. ADR No. 13 Attachment 7, p. 1. As discussed above, UI's own proposed capital expenditures for system and business operations, and other core support, already included significant investments to upgrade and implement the SAP system. For recurring O&M expenses, including amounts allocated to it by UIL, the proposed computer expense is $4.653 million in RY1 and $5.137 million for RY2. The third and final phase of the SAP implementation project is to be completed by the interim year or as June 30, 2013. At that point, UIL gross plant is $70.690 million. UI Response to Interrogatory AC-58, Attachment. Subsequent to June 30, 2013, UIL is proposing to spend an additional $46.251 ($116.941 - $70.690) million.

Given the concerns discussed herein, the Authority determines that UIL average rate base of $28.520 million, which is calculated based on the gross plant of $70.690 million as of June 30, 2013, is the appropriate amount for calculating corporate capital charge to be allocated to UI. Response to Interrogatory AC-58 Attachment. The table below depicts the calculation of the allowed UIL capital charge for RY1 and RY2.

Calculation of Allowed UIL Capital Charges

	Rate Year 1	Rate Year 2
Allowed Average Rate Base (000)	$ 28,520	$ 28,520
Common Equity Ratio	50.00%	50.00%
Equity Rate Bas (000)	14,260	14,260
Weighted Equity Return	9.15%	9.15%
Equity Return (000)	1,305	1,305
Equity Gross-up Factor	1.6632	1.6632
Equity Return with Gross-up (000)	2,170	2,170
Weighted Debt Ratio	50.00%	50.00%
Debt Rate Base (000)	14,260	14,260
Average Cost of Debt	5.27%	5.32%
Debt Return (000)	752	759
Depreciation (000)	5,602	11,204
Property Taxes (000)	41	112
Total Costs to Recover (000)	5,643	11,316
Total Capital Charge (000)	8,565	14,245
Allocation % to UI-Distribution (000)	43.1%	43.1%
Charge to UI Distribution (000)	$ 3,690	$ 6,137

As shown above, the Authority utilizes the allowed cost of capital approved in this proceeding to calculate returns on average rate base. The allowed depreciation expense of $5.602 million for RY1 was determined by deducting the accumulated depreciation amount of $1.166 million as of June 30, 2012, from the $6.769 million as of June 30, 2013. UI Response to Interrogatory AC-58, Attachment. This amount was doubled to determine the allowed depreciation expense of $11.204 million for RY2. Based on the allowed corporate capital charges calculated in the table above, the Authority disallows $4.366 ($8.056 – $3.690) million in RY1 and $3.556 ($9.692 - $6.137) million in RY2. The Authority considers the allowed increases in corporate capital charges reasonable as they are 503% ($3.690 / $0.733) in RY1 and 837% ($6.137 / $0.733) in RY2 in comparison to the $0.733 million allocated in test year.

e. Summary of Corporate Service Charges Adjustments

The table below summarizes the Authority's adjustments to the proposed UIL corporate service charges in RY1 and RY2.

	RY1 (Millions)	RY2 (Millions)
DOL Liability Insurance	$0.260	$0.308
Other Public Company Costs	$0.302	$0.310
Board of Directors Costs	$0.666	$0.664
Corporate Capital Charges	$4.366	$3.556
Total Adjustments	$5.594	$4.838

10. Amortization Expense

In its Application, UI initially proposed a total amortization expense of $9.152 million for RY1 and $9.152 million for RY2. Each rate year amount consists of $0.417 million for rate case expenses and $8.734 million for storm related regulatory asset. Schedule WP C-3.34 A-B. In its updates to the SFR schedules, the Company proposed total amortization expense of $9.424 million for each rate year. The updated total amortization expense consists of $8.866 million for regulatory asset and $0.338 million for rate case costs. UI Late Filed Exhibit No. 3, pp. 3 and 4; UI Late Filed Exhibit No. 3 Supplemental Attachment, pp. 14 and 15. The Company stated that its storm regulatory asset is $53.314 million as of April 30, 2013, and rate case expense is reduced to $0.676 million. Therefore, the annual amortization expenses were increased by $0.217 million for the storm regulatory asset and reduced by $0.080 million for rate case costs. UI Late Filed Exhibit No. 3, pp. 3 and 4; Attachment 1.

a. Storm Regulatory Asset

In its Application, UI requested that its storm regulatory asset of $52.405 million be amortized over six years. This resulted in an annual amortization expense of approximately $8.734 million. Schedule WP C-3.34 A-B. In its updates to the SFR exhibits, UI increased the proposed storm regulatory asset amount to $53.314 million and the annual amortization expense to $8.887 million. UI Late Filed Exhibit No. 3, Attachment-1, pp. 6 and 11.

As discussed in the Section II.E.10.a. Storm Regulatory Asset, the Authority offsets the entire storm regulatory asset amount through disallowances and by offsetting the remaining balance via accrued Earnings Sharing Mechanism and accruing CTA regulatory liabilities. Therefore, the proposed storm regulatory asset amortization expense of $8.866 million is removed from each rate year's total operating expenses.

b. Rate Case

UI projected a total of $835,000 for rate case expenses to be amortized over two years. Response to Interrogatory OCC-56. Subsequently, the Company provided an updated total projection for rate case expenses of $676,000. Late Filed Exhibit No. 3, Attachment 1, p. 8. In addition, UI provided the total charges incurred for Rate Case expenses of $136,349 through April 2013. Id. The UI witnesses provided additional information as to whether projected rate case expenses were estimated amounts or whether they were determined by contractual agreements. Tr. 5/23/13, pp. 2759-2762.

The Company witnesses testified that the $20,000 projected for temporary help is a "place holder" for additional staff expense that had not been needed up to the point of the Late File Hearing. Id. Therefore, the Authority disallows the $20,000 of temporary help included in rate case expenses. Also, the Authority disallows the $45,000 for overtime and payroll overheads which should be accounted for in the Company's payroll expense. Therefore, the Authority allows total rate case expenses of $611,000 ($676,000 - $20,000 - $45,000).

UI proposed that the rate case expenses be amortized over a period of two years. This would result in an amortization expense of $338,000 for each rate year. ($676,000 / 2 years). The amortization permits the Company to fully recover its rate case costs in just two years. After two years, the Company, in effect, would continue to recover the expense in rates without a corresponding expense to offset the recovery. The Authority will direct UI to amortize rate case expenses over a period of three years, which more accurately reflects the length of time between the Company's rate case filings. The result is a rate case amortization expense of $204,000 ($611,000 / 3 years) per year. The Authority's adjustments reduce rate case expenses by $134,000 ($338,000 - $204,000) for RY1 and RY2.

c. Enhanced Tree Trimming

The Authority is concerned that UI's proposal to capitalize its ETT program costs in rate base would create additional financial burdens on ratepayers. While the ETT program is approved in this proceeding, the Authority finds that tree trimming costs are recurring costs that are normally expensed during the period they were incurred. However, given the magnitude of line clearance costs that the Company proposed for 2014 through 2018, the Authority determines that a hybrid capitalization maybe necessary. Therefore, UI will be allowed to capitalize its proposed ETT costs. However, carrying costs would not be calculated based on the Company's allowed ROR. Instead, the allowed carrying charges should be calculated on the net unamortized balances, that reflect the impact of deferred taxes, using 5.3%, the average of the cost of LTD allowed in RY1 and RY2 in this proceeding. The Authority will direct UI to file a worksheet exhibit showing the annual unamortized ETT cost balances along with the related accrued carrying charges.

UI claimed that the Authority changed the treatment of the $100 million the Company would incur for the ETT program. The assertion in the draft Decision that capitalizing the ETT costs would produce a large benefit for UI at the expense of customers is not correct. It is entirely appropriate and consistent with statutory and constitutional ratemaking principles for UI to receive its cost of capital in connection with making such a large long-term expenditure. UI stated that the ETT expenditure would be made so that the benefits of ETT can be realized by customers and stakeholders. The compensation should be UI's carrying cost or rate of return, which is based on its capital structure of 50% debt and 50% equity. This is the debt to equity mix that UI maintains through the issuance of debt and equity and is a mix that best positions UI to be able to fund capital programs and ETT as proposed. The Company stated that its 5.3% cost of long-term debt rather than its cost of capital is not acceptable to finance a $100 million capital project. Given UI's debt ceiling covenants and the impacts that such a large debt-funded expenditure would have on UI's credit rating and financial position, long-term capital expenditures cannot be made on a debt financing basis only. Written Exceptions, pp. 66 and 67.

Herein, the Authority reconsiders its determination from the draft Decision. UI will be allowed to earn its cost of capital on the ETT expenditures. However, given magnitude of the ETT proposal and the incremental impact it has on rates charged to UI's customers, the Authority determined that the ETT program should be done in a eight-year cycle instead of the four-year cycle the Company requested. Also, UI is directed to amortize each allowed annual $12.5 ($100 / 8) million ETT expenditure over five years. Based on above, the Authority calculates the allowed annual amortization and annual ETT balances as shown in the table below:

Annual Amortization Expenses for the Enhanced Tree Trimming Program

Key Assumptions:					
Amortization Period (Years)	5				
Income Tax Composite Rate	40.850%				
	Annual Amortization Expenses (000)				
	2013	2014	2015	2016	2017
	$0	$12,500	$12,500	$12,500	$12,500
	$0	$2,500	$2,500	$2,500	$2,500
	$0		$2,500	$2,500	$2,500
	$0			$2,500	$2,500
	$0				$2,500
Annual Amortization	$0	$2,500	$5,000	$7,500	$10,000
Cumulative Amortization	$0	$2,500	$7,500	$15,000	$25,000
	Deferred Taxes (000)				
	2013	2014	2015	2016	2017
ETT Expenditures	0	$12,500	$25,000	$37,500	$50,000
Amortized Amount	0	($2,500)	($7,500)	($15,000)	($25,000)
Balance	0	$10,000	$17,500	$22,500	$25,000
Deferred Taxes	0	($4,085)	($7,149)	($9,191)	($10,213)
Net Balance	0	$5,915	$10,351	$13,309	$14,788

For RY1, the Authority will allow ETT amortization expense of $1.25 million, which represents 50% of the 2014 amortization for six months that are in the rate year. For RY2, the Authority will allow UI to recover in rates total annual ongoing amortization expense of $7.5 million. This amount represents the three-year average of total annual amortization expense recoverable from 2015 through 2017. Based on the calculations in the table above, the Authority determines and allows in rate base a net ETT regulatory asset of $2.958 million in RY1 and $8.133 million in RY2. In the Company's next rate case, the allowed annual amount will be reconcilable to the actual amortization expenses recoverable based on UI's actual ETT expenditures to be incurred during the period indicated. Also, UI will maintain records such that its ETT costs are discernible from its normal line clearance expenses, which are also approved as part of the Company's O&M expenses. The Authority finds the total allowed annual amount for amortization and carrying costs to be reasonable. It and would allow the Company to effectively implement its proposed ETT program without encumbering ratepayers with unnecessary costs in rates.

11. Residual O&M Expense

UI proposed Company's residual O&M expenses of $4.438 million and $4 million for RY1 and RY2, respectively. The Company noted that residual O&M expenses include such item as material and supplies, meal, and publications. Schedules C-3.32 A and C-3.32 B.

The Authority notes that the proposed residual O&M expenses also included sales and use tax expenses of $298,000 for RY1 and $304,000 for RY2. UI Response to Interrogatory OCC-152, Attachment. The Company noted that the proposed amounts are UIL sales and use tax expenses charged to UI distribution O&M and that the test year amounts were embedded within the applicable individual O&M expenses listed in Schedule C-3.0. Id.

The Authority disallows the UIL sales and use tax expenses charge to UI distribution O&M. There is no basis for this allocation given the Company's testimony that its sales and use tax liability is determined under a special program by the Department of Revenue Services (DRS). UI's sales and use tax expenses are calculated based on its non-payroll O&M expenses, which included O&M expenses allocated to it by UIL. Consequently, the Authority disallows $298,000 and $304,000, which are the projected UIL allocated sales and use tax expenses for RY1 and RY2, respectively.

12. Distribution Offset for Transmission

a. Allocated A&G Expense

UI reduced proposed distribution O&M expenses by A&G expenses allocated to transmission operation of $6.4 million in RY1 and $6.364 million in RY2. The Company applied A&G expense allocation factor of 3.93% to the total distribution O&M expenses before allocation to calculate this transmission offset credit. Schedule WP C-3.29a A-B.

b. Allocated Customer Accounts Expense

UI reduced proposed distribution O&M expenses by customer account expenses allocated to transmission operation of $4.799 million in RY1 and $4.704 million in RY2. The Company applied a customer account expense allocation factor of 2.91% to the total distribution O&M expenses before allocation to calculate this transmission offset credit. Schedule WP C-3.29b A-B.

UI stated that the Authority did not address the distribution offsets for A&G and customer accounts expenses allocated to transmission operation in the draft Decision. The allocated transmission offsets result in reductions to the distribution revenue requirements. Therefore, adjustments to the proposed distribution O&M requires corresponding adjustment to the allocated transmission offsets amounts. Based on the total distribution O&M adjustments in the draft Decision and total transmission offset ratio of 6.84% (3.93% + 2.91%), UI calculated total allocated transmission offset reductions of $960,000 in RY1 and $880,000 in RY2. Written Exceptions, pp. 83 and 84

The Authority agrees with UI that the transmission offset credits should be similarly reduced for the total disallowed distribution O&M expenses. The total disallowed distribution O&M expenses before allocations are $13.379 million in RY1 and $12.191 million in RY2. As a result, the Authority determines that the total transmission offset credits for A&G and customer accounts expenses are $0.915 ($13.379 x 6.84%) million in RY1 and $0.834 ($12.191 x 6.84%) million in RY2.

F. OTHER TAXES

1. Payroll Tax Expense

UI proposed payroll tax expenses of $4.209 million for RY1 and $4.351 million for RY2. Schedule WP C-3.35c A-B. Based on adjustments to the Company's total proposed payroll expenses, the Authority calculated adjustments to the proposed payroll tax expenses using the combined effective rate for social security and Medicare taxes as detailed below.

Item	RY1	RY2
Payroll Expense Adjustment (million)	$3.925	$3.413
Employer's combined Payroll Tax Rate	7.65%	7.65%
Disallowed Payroll Tax Expense (million)	$0.300	$ 0.261

In light of the above, the Authority disallows payroll tax expenses of $300,000 in RY1 and $261,000 in RY2. Therefore, the Authority allows payroll tax expenses of approximately $3.909 ($4.209 - $0.300) million in RY1 and $4.090 ($4.351 - $0.261) million in RY2.

2. Gross Earnings Tax Expense

The Company proposed C&LM and renewables revenue of $41.109 million for RY1 and $40.442 million for RY2. Schedule WP C.3.35 A-B. To calculate the gross revenue conversion factor (GRCF), UI applied a weighted gross earnings tax (GET) rate of 7.0473%. The GET rate was determined by dividing the test year's total GET expense of $20.487 million by the total base revenue of approximately $290.703 million. Schedule A-3.0 A.

UI proposed current revenue GET expenses of $21.739 million for RY1 and $21.484 million for RY2. Schedule WP C-3.35 A-B. For the additional revenues requested for RY1 and RY2, the Company included GET expenses of $4.6 million and $6.403 million, respectively. Thus, UI proposed total GET expenses of $26.339 ($21.739 + $4.6) million for RY1 and $27.887 ($21.484 + $6.403) million for RY2. Schedule WP C-3.35 A-B; Late Filed Exhibit No. 3, pp. 2 and 3.

The RY1 current revenue GET expense of $21.739 million was determined by multiplying total revenue of $308.167 million by the weighted GET rate of 7.0544%. The RY1 total revenue of $308.167 million consisted of $267.057 million for distribution, $35.791 million for conservation and load management (C&LM) and $5.318 million for renewables. Schedule WP C-3.35d A. Similarly, The RY2 current revenue GET expense of $21.484 million was determined by multiplying total revenue of $304.551 million by the weighted GET rate of 7.0544%. The RY2 total revenues of $304.551 million consisted of $264.110 million for distribution, $35.210 million for C&LM and $5.232 million for renewables. Schedule WP C-3.35d B.

The Company provided the historical C&LM and renewable revenue for 2010, 2011, and 2012 as cited below.

	2010	2011	2012
C&LM Revenues (Lines 4 and 13)	$17.291	$16.818	$16.209
Renewables Revenues (Lines 5 and 14)	$ 5.764	$ 5.606	$ 5.402
Total	$23.055	$22.424	$21.611

Response to Interrogatory AC-85, UI Attachment 1.

Based on the above information, the Authority calculated the 3-year historical average for C&LM and renewables revenue to be $22.363 [($23.055+$22.424+$21.61) / 3] million. Consequently, the Authority determines that $22.363 million is the more appropriate figure and should be used in calculating GET expenses.

Calculation of Revenues for GET Expenses

	RY1 Revenues	RY2 Revenues
Distribution	$267.057	$264.110
C&LM and Renewables	$ 22.363	$ 22.363
Total	$289.420	$286.473

Schedule WP C-3.35d A.

Using the weighted average GET rate of 7.0544% calculated by the Company in Schedule A-3.0 A results in an allowed GET expense of $20.417 ($289.420 x .070544) million for RY1 and $20.209 ($286.473 x .070544) million for RY2. The Company requested GET expense of $21.739 million and $21.484 million for RY1 and RY2, respectively. The Authority reduces the RY1 GET expense by $1.322 million ($21.739 - $20.417) and the RY2 GET expense by $1.275 ($21.484 - $20.209) million.

To the extent that C&LM and renewables revenues are greater than $22.363 million allowed herein, the Authority directs the Company to create a regulatory asset for any shortfall of GET expense due to such differences. UI will be required to file exhibits supporting and explaining variances between actual C&LM and renewables revenues and the allowed amounts. The related compliance filings will include UI's actual quarterly Form UCT 212 EDC reports for each of the rate years and an analysis of C&LM, renewables and conservation adjustment mechanism (CAM) revenues.

3. Property Tax Expense

For the proforma test year, UI reported total property tax expense of approximately $12.255 million. In its Application and for its distribution operation, UI proposed property tax expenses of approximately $15.271 million for RY1 and $18.324 million for RY2. Schedules WP C-3.35 A-B. For the 2011 grand list year, which covers the 12-month period of July 1, 2012 through June 2013, the Company reported distribution tax expense of approximately $13.387 million. The amount was determined by subtracting the transmission operation total property tax expense of $12.752 from total property tax expense of approximately $26.139 million. Schedule WP C.3.35a A, p. 2. The distribution amount was also based on a total property assessment of approximately $410.916 million. Id. Hence, UI calculated 2011 grand list year composite mill rate of 32.578 [($13.387 / $410.916) * 1000). Id. The increase of $1.884 million ($15.271 - $13.387) is based on an additional property assessment of approximately $103.662 million and 70% abatement of the Orange CF assessment of approximately $68.352 million. Id., p. 4. The RY2 property tax expense increase of $3.053 million ($18.324 - $15.271) above the RY1 amount is due mostly to the additional property assessment of approximately $87.159 million and 60% abatement of the Orange CF assessment of approximately $68.352 million. Schedule WP C.3.35a B.

The Authority reviewed the proposed property tax expenses for RY1 and RY2 and determined that they were overstated. As discussed in detail above, the Authority disallows average plant-in-service of $19.496 million in RY1 and $49.084 million in RY2. Also, the Authority adjusted average depreciation reserves by $1.844 million in RY1 and $3.151 million in RY2. The tables below compare the growth in UI's gross plant to increases in its property tax expenses.

Growths in Gross Plants Versus Property Tax Expenses ($000)

	Test Year	Proforma	RY1	RY2
Gross Plants*	1,177,697	1,275,405	1,450,268	1,581,952
Increase over Test Year		8.30%	23.14%	34.33%
Property Tax**	12,255	13,387	15,271	18,324
Increase over Test Year		9.23%	24.61%	49.52%
Property Tax (No abatement)***	12,255	13,387	16,764	19,604
Increase over Test Year		9.23%	36.79%	59.97%

*Per Schedules B-1.0A and B-1.0B; **Per Schedule WP C-3.35A_B; ***Per Schedule WP C-3.35a, pp. 4 and 5.

Summary of Tax Expenses Per UI's Income Statement Trial Balance

	2010	**2011**	**2012**
Property Tax – Account 040816* ($000)	8,864	10,972	13,658
Percentage Increase over Prior Year		23.78%	24.48%

*Per OCC-72 Attachment, p. 28 and ADDR-13 Attachment 7, p. 28.

The Authority thoroughly reviewed the Company's testimony regarding proposed property tax expenses for RY1 and RY2. As the tables above indicates, UI's property tax expense increased by approximately $1.283 ($12.255 – $10.972) million for the six months between 2011 and the test year ending June 30, 2012. Between the test year and the 12-month interim period ending, June 30, 2013, the property tax expense is estimated to increase by $ ($13,387 - $12.255) million.

UI's gross plant is projected to increase by approximately $97.709 million between the test year and the end of the interim period. Schedule B-1.0 A. The Company noted that the distribution portion of the Central Facility capital costs was recorded in general already included in the total gross plant for the test year. Schedule B-2.1 A; Response to Interrogatory AC-117 Attachments 1 and 2. The Company proposed total gross plant additions included an increase to distribution plant additions of $44.39 ($130.666 - $86.276) million between RY1 and the interim period ended June 30, 2013. Schedule B-

2.0 A. Similarly, the distribution plant additions for grand list years 2013 and 2012 increased by $56.265 million ($147.525 - $91.260). Response to Interrogatory AC-94 Attachments 1 and 2. In addition to the Orange facility assessment, the Company testified that its assessment increased by $69.369 million between grand list years 2010 and 2011. Response to Interrogatory AC-94 Attachment 1. Net of the $15.933 million that UI stated was due to change in assessment method by the Town of Trumbull, the tax bill for the interim period ended June 30, 2012 includes projected distribution plant additions of approximately $76.337 million [($69.369 - $15.933) / 70%]. It is correct that the Company's property tax expenses are based on grand list year additions. However, the approximately $221.163 million plant-in-service additions for the 2012 grand list year consist mostly of the distribution portion of the Central Facility costs and the proforma year gross plant additions of $97.709 million. The property tax expense for RY1 is related to the 2012 grand list assessment. Similarly, the approximately $163.875 million plant-in-service additions for the 2013 grand list year consist mostly of the RY1 gross plant additions. Likewise, the property tax expense for RY2 is related to the 2013 grand list assessment. Regarding the Central Facility property tax adjustments for both RY1 and RY2, UI claimed that the Town of Orange will assess the Central Facility at its full value regardless of any adjustments to the gross plant amount for ratemaking purposes. Written Exceptions, p. 82.

To extent the Authority makes a determination that certain costs were not judiciously incurred, all associated costs are not recoverable in rates. The Company's argument that the Town of Orange will assess the Central Facility at its full value regardless of any adjustments to the gross plant amount for ratemaking purposes is unreasonable. This seems to suggest that ratepayers should incur related costs on amounts that the Authority finds the Company had unjustly incurred. Also, the construction of the Central Facility has been completed and its full cost has been recorded in UI's plant accounts. The 66.7% placed in service ratio is not applicable to completed project already placed in service and no longer in the construction phase. Based on updated plant and depreciation reserve adjustments herein, the Authority calculates adjustments to the Company's proposed property tax expenses are shown in the table below:

Calculations of Allowed Property Taxes (000)

	Rate Year 1	Rate Year 2
Plant in Service Adjustment (not Central Facility)	$12,192	$41,780
Depreciation Reserve Adjustment	$ 700	$ 1,434
Net Plant in Service Adjustment	$11,493	$40,347
Assessment Percentage	70%	70%
Assessment Amount	$ 8,045	$28,243
Composite Distribution Mill Rate	32.578	32.578
Property Tax Adjustment	$ 262	$ 920
Plant in Service Adjustment (Central Facility)	$ 7,304	$ 7,304
Depreciation Reserve Adjustment	$ 1,144	$ 1,717
Net Plant in Service Adjustment	$ 6,160	$ 5,587
Assessment Percentage	70%	70%
Assessment Amount	$ 4,312	$ 3,911
Less Rebate Adjustments (70% in RY1 and 60% in RY2	$ 3,018	$ 2,347
Net Assessment Amount	$ 1,294	$ 1,564
Orange Mill Rate	31.200	31.200
Central Facility Property Tax Adjustment	$ 40	$ 49
Total Property Tax Adjustment	$ 302	$ 969

As depicted in the table above, the Authority disallows property tax expenses of $0.302 million in RY1 and $0.969 million in RY2.

4. Sales and Use Tax Expense

UI proposed sales and use tax expenses of $1.204 million and $1.198 million for RY1 and RY2, respectively. The proposed expenses were determined by applying the test year sales and use tax effective rate of 1.88% to proposed distribution non-payroll O&M expenses of $64.059 million for RY1 and $63.706 million for RY2. Schedule WP C-3.35b A-B. The Company noted that based on its excellent audit history, it has been selected by the DRS to participate in a special sales tax program since October 1, 2003. The program determines UI's sales and use tax liability. Id.

In the instant proceeding, the Authority disallows non-payroll O&M expenses of $8.16 million for RY1 and $7.549 million for RY2. The Authority accepts the proposed sale and use tax effective rate of 1.88%. Therefore, the Authority disallows sales tax and use tax expenses of $153,000 ($8.16 million x 1.88%) in RY1 and $142,000 ($7.549 million x 1.88%) in RY2.

5. Connecticut Corporation Business Tax

UI stated that Public Act No. 13-184 extended the 20% surcharge on Connecticut Corporation Business Tax (CCBT) for calendar years 2014 and 2015. UI claimed that the extension of the CCBT surcharge will results in an estimated increase in state tax expense of $0.5 million in RY1 and $1.2 million in RY 2. The Company requested the establishment of a regulatory asset to recover the additional state tax expenses due to the impact of Public Act No. 13-184. Written Exceptions, p. 81.

The Authority disagrees with the Company's proposal to create a regulatory asset for state tax expense resulting from the extension of the 20% surcharge on the CCBT. Such a regulatory asset would need to be collected in future rate proceedings from ratepayers. The Company's proposal will simply create unnecessary inter-period inequity, which is peculiar to deferred recoveries of allowed costs incurred during period between rate cases. However, given the fact that the CCBT statutory rate applicable to 2014 and 2015 are now known and measurable, the Authority opines that it more proper to incorporate such rate into costs to be recovered from ratepayers in the instant proceeding. Therefore, the Authority will apply CCBT rate of 9% in this proceeding. The Authority changed the allowed GRCF to reflect 9% as the state tax rate. Also, the Authority increases UI's proposed state income tax expenses by $0.5 million in RY1 and $1.2 million in RY2.

6. Interest Synchronization

Interest synchronization adjustments are made to the income tax calculation to reflect the allowed rate base amounts for both rate years. The Authority made several adjustments to the Company's proposed total rate base amounts. These adjustments cause UI's interest expense deductions to be lowered for income tax purposes, which result in increases to the income tax expenses for RY1 and RY2.

7. OCC/AG IRS Rule Change Petition

On July 1, 2013, the OCC and the AG (together, Petitioners) filed a petition requesting that the Authority commence an investigation into the Connecticut public service companies' responses to certain changes in the Internal Revenue Service accounting regulations (IRS Rule Change Petition). In a ruling dated July 15, 2013, the Authority granted the Petitioners' request and opened Docket No. 13-07-06, Joint Petition of George Jepsen, Attorney General for the State of Connecticut, and Elin Swanson Katz, Consumer Counsel, for an Investigation into the Response of Connecticut's Public Service Companies to Certain Changes to IRS Accounting Regulations (IRS Rule Change Proceeding). The Petitioners also requested that the Authority reopen the evidentiary record and hold additional hearings in the instant proceeding to reflect the impact these rule changes will have on UI. Specifically, concerning the Company's tax refunds, future reduced liability, and recovery of costs associated with the 2011 and 2012 major storms.

In its response dated July 5, 2013 to the IRS Rule Change Petition, UI stated that it has taken repairs and maintenance' deductions for many years and has already prudently claimed both repair and maintenance and bonus depreciation deductions. Also, UI stated that it claimed a repairs and maintenance deduction on its 2009 federal and state income tax returns in advance of the issuances of the new regulations. Pursuant to the automatic consent rules, UI elected to make an accounting change and take a one-time tax deduction for repairs and maintenance. The deduction represented a cumulative tax accounting method change based on the Company's best interpretation of these new rules at that time. Furthermore, UI noted that in conjunction with its outside auditors, it conducted a repairs and maintenance study that resulted in the tax election to reclassify certain costs as expense versus capital. As a result, a $50,264,000 cumulative deferred tax liability shown in its response to Interrogatory AC-20 UI Attachment was created.

Additionally, the Company stated that the one-time deduction for tax purposes creates a deferred tax liability that will reverse itself over time as the assets capitalized on its books depreciate over time. Tr. 04/23/13, pp. 415-417. Based on the aforementioned, UI argued that the IRS Rule Change Petition is unnecessary and the Authority should deny it.

In the IRS Rule Change Proceeding, the Authority will review the responses of the public service companies to these new IRS tax regulations and make its determinations regarding each utility's interpretations and rate impacts.

G. Rate of Return

1. Introduction

In determining the appropriate cost of capital to allow the Company, Conn. Gen. Stat. §16-19e (a) requires that:

> [t]he level and structure of rates be sufficient, but no more than sufficient, to allow public service companies to cover their operating costs including, but not limited to, appropriate staffing levels, and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable . . .

To determine a ROR on rate base that is appropriate for the Company's overall cost of capital, the Authority identifies the components of its capital structure and estimates the cost of each component. The components are then weighted according to their proportion of total capitalization. These weighted costs are summed to determine the Company's overall cost of capital, which becomes the allowed ROR.

2. Capital Structure and Financial Condition

a. Capital Structure

The Company proposed rates that are based on a capital structure consisting of 50% long-term debt to 50% common equity for the RY1 and RY2. This ratemaking proposal differs slightly from the Company's actual capitalization mix of 49.65% long-term debt to 50.35% common equity projected as of RY1 and 49.60% long-term debt to 50.40% common equity projected as of RY2. The Authority's imposition of a 50/50 capitalization mix at the prior rate case in the 2006 Decision was the reason the Company proposed a ratemaking capitalization mix with a lower portion of common equity than actually exists. UI Late Filed Exhibit No. 3; UI Response to Interrogatory OCC-184 Attachment; Nicholas PFT, p.15; Tr. 4/29/13, pp. 834-836.

As of September 30, 2012, UI's end of period capitalization was 51.08% equity. The Company indicated that it plans to restore an approximate 50/50 capitalization mix on average during RY1 and to maintain this mix for RY2. UI intends to target this capitalization mix over the next five-year time period and will manage this capitalization mix with issuances of long-term debt to fund its operations and through capital contribution from its Parent Corporation. The Company suggested that the proposed 50/50 capitalization mix is in-line with industry practice for two reasons. First, the proposed 50/50 mix was in-line with the average capitalization mixes awarded to electric companies over the five-year period covering January 1, 2008 through December 31, 2012, as published by <u>Regulatory Research Associates</u> (RRA). UI Response to Interrogatory FI-58, Attachment; Tr. 4/29/13, p. 833. Second, the Company found its proposed capitalization consistent with the capitalization mix used by the firms included in the Company Utility Group. It had an average common equity component of 48.3% as of December 31, 2012, and was projected by <u>Value Line</u> to have 49.4% average common equity over the forecasted three-to-five year period. UI Response to Interrogatory FI-25; Tr. 4/30/13, pp. 1080-1083.

Over the last five years, the Company's equity component approximated 50% with 48.81% on December 31, 2008, 51.64% on December 31, 2009, 48.44% on December 31, 2010, 50.32% on December 31, 2011 and 51.67% on December 31, 2012. UI Response to Interrogatory FI-61. The UIL's most recent capital contribution to the Company was $100 million made in April 2012, and the purpose of this infusion was to rebalance the UI capital structure after the Company issued $100 million of new debt in April 2012. UI Response to Interrogatory FI-60.

By August 2013, the Company plans on achieving the 50/50 capitalization mix and will maintain this mix through issuances of long-term debt and common equity over the coming rate periods. The Company anticipates issuing approximately $75 million and $100 million of additional long-term debt in 2013 and 2014 and expects to have UIL make capital contributions as necessary to continue to target the 50% long-term debt to 50% common equity ratio. These estimated issuances of debt and equity were incorporated by the Company into its proposed ratemaking capital structures for RY1 and RY2. UI Responses to Interrogatories FI-59, FI-60 and FI-64; Tr. 4/29/13, p. 833.

The Company expressed the opinion that the 50/50 capitalization mix, or one with a higher percentage of common equity, best positions UI to be able to fund its capital program. Any capitalization mix less than 50% common equity is less than favorable to investors and therefore more likely to jeopardize the Company's access to capital and execute its capital program. Nicholas PFT, pp. 20-24; UI Response to Interrogatory FI-063; Tr. 4/29/13, pp. 840 and 841; UI Brief, p. 39.

UI's final capital structure proposal including components and corresponding costs are provided in the tables below.

Proposed 2014 Average Capitalization: Rate Year 1[10]

Class of Capital	Ratemaking Percentage	Cost	Ratemaking Weighted Cost
Long-term Debt	50%	5.32%	2.66%
Common Equity	50%	10.25%	5.13%
Total Capitalization	100%		7.79%

[10] For ratemaking purposes, UI proposed a 50% common equity to 50% long-term debt capitalization mix for both RY1 and RY2. UI Brief, p. 38.

Proposed 2015 Average Capitalization: Rate Year 2

Class of Capital	Ratemaking Percentage	Cost	Ratemaking Weighted Cost
Long-term Debt	50%	5.27%	2.64%
Common Equity	50%	10.25%	5.13%
Total Capitalization	100%		7.76%

UI Late Filed Exhibits Nos. 3 and 36; Schedule D-1.0 A; Schedule D-1.0B; UI Response to Interrogatory OCC-184; UI Brief, p. 38; Tr. 4/29/13, pp. 827-830.

Overall, UI stated that the above capitalization mix would be reasonable for ratemaking purposes because it needs to maintain, and/or strengthen, its credit standing and financial flexibility as it will need to raise capital over the rate period to fund significant systems. Avera PFT, p. 72; UI Brief, p. 39.

The OCC accepted UI's proposed capital structure and long-term debt cost rate, hence the primary issue in this case with respect to the cost of capital is the appropriate cost of common equity for UI. In its acceptance of the Company's proposed capitalization mix, the OCC argued that this showed fairness to the Company as UI's proposed capital structure contains a slightly higher common equity ratio (50.0% versus 46.5%) than the average of the OCC Proxy Group; and (2) UIL has a current common equity ratio of 38.0%. The OCC disagreed with the Company's request for a 10.25% ROE and an overall ROR of 7.78% as excessive and recommended a reduction to an ROE of 8.75% and overall ROR of 7.03%. Woolridge PFT, JRW-7; OCC Brief, pp. 5, 6 and 16; Tr. 5/15/13, pp. 2298-2301. The OCC's proposed weighted average cost of capital (WACC) is demonstrated by the tables below.

Class of Capital	**Capitalization Ratio**	**Cost**	**Weighted Cost Rate**
Long-Term Debt	50%	5.30%	2.65%
Common Equity	50%	8.75%	4.38%
Total	100%		7.03%

Woolridge PFT; Exhibit JRW-1; OCC Brief, pp. 5 and 6; 16, 37.

CIEC indicated its review of rating agency reports demonstrated that the operating subsidiaries bond ratings are tied to and/or constrained by the holding companies' financial ratios, policies and business profile. UIL reported a consolidated equity ratio ranging between 34% and 38%, yet UI proposed an equity ratio of 50% for ratemaking. According to CIEC, this represented a capitalization mix of higher debt leverage at the UIL level than proposed for ratemaking purposes at the UI operating level. In the absence of a ratemaking equity ceiling based upon the Parent Corporation debt level, operating companies have an incentive to place a higher proportion of equity at the operating level.

CIEC proposed that the Authority utilize the capital structure of UIL to set the equity ratios for ratemaking purposes. The rationale for this recommendation was based on CIEC's position that equity ratios of the Parent Corporation should serve as a ceiling for establishing ratemaking capitalization mix. In the absence of an adjustment to the authorized ratemaking capitalization to bring it more in-line with that of UIL, CIEC suggested that the ratemaking ROE be downwardly adjusted to reflect the lower financial risk of the Company as compared to UIL higher employed leverage. CIEC Brief, pp. 2 and 3.

b. Short-term Debt and Long-term Debt

The Company's primary use of short-term debt has been to fund capital expenditures while the construction work is in progress. The Company first funds CWIP with short-term debt. The Company indicated that CWIP is not included in rate base; therefore, short-term debt should not be included in the ratemaking capital structure. UI Responses to Interrogatories FI-026, FI-028 and FI-079; Tr. 4/29/13, 848-850; Tr. 4/30/12, pp. 1115-1120.

UI presently has 21 long-term debt issues. The interest rate on its current debt ranges from 1.25% to 7.13%. These current issues include a variety of debt financing vehicles including pollution control revenue refunding bonds to publicly underwritten notes to issue its debt. Its current embedded cost of debt is 5.39% date March 31, 2012. UI Response to Interrogatory OCC-184, UI Attachment; UI Late Filed Exhibit No. 45; Tr. 4/29/13, pp. 946-949.

Based upon its expected financing needs over the rate period, UI plans to issue debt financing. UI proposed that two anticipated new and replacement long-term debt issues are incorporated into the embedded cost of long-term debt for ratemaking purposes. The first is a 2013 Series Note for $75 million with an expected interest rate of 4.10% for RY1 and the second is a 2014 Series Note for $100 million with an expected interest rate of 4.70% for RY2. Incorporating these expected debt issues into the ratemaking capital structure is expected to reduce the current embedded cost of long-term debt to 5.32% for RY1 and to 5.27% for RY2. UI Response to Interrogatory FI-73; UI Late Filed Exhibits No. 3 and 36; Tr. 4/29/13, pp. 856-859 and pp. 951-954.

The Company indicated that it regularly seeks to refinance its outstanding debt when economically feasible. The Company has 11 series of taxable debt outstanding with requirements of a make-whole provision to redeem or refinance the debt. The make-whole provision renders redemption uneconomic irrespective of the interest rate environment. UI also has two tax-exempt notes outstanding. One was the 2003 Series with a variable rate presently at 0.407% and the other has a fixed 4.5% rate but non-callable until 2015. UI Response to Interrogatory FI-72.

As indicated above, the OCC accepted the Company's proposed debt to equity capitalization mix and its proposed weighted average cost of debt for RY1 and RY2. OCC Brief, p. 16.

3. Financial Condition

a. Credit Rating and Financial Metrics

The Company presently has a rating of Baa2 by Moody's Investor Service (Moody's) and BBB by Standard & Poor's Rating Services (S&P). UIL was rated Baa3 by Moody's and BBB by S&P. The Company stated that these rating agencies consider many quantitative and qualitative factors when determining ratings. The factors considered include credit metrics, regulatory framework, and ability to recover costs and earn returns. For Moody's, the recovery of costs and earning allowed returns approximates 50% of its ratings factors, while its evaluation financial ratios such as debt measurements and liquidity in earnings measurements account for approximately 25% of its ratings factors with the remaining 25% being qualitative factors. According to the Company, S&P also considers qualitative and quantitative factors such as business risk and financial risk without explicit weightings. Nicholas PFT, pp. 2-10; UI Responses to Interrogatories FI-1 and FI-3; Tr. 4/29/13, pp. 799-801.

The Company provided several financial ratios reviewed by credit rating agencies valued at December 31st, as compiled in the table below.

	2008	2009 (1)	2010 (1)	2011 (2)	2012 (3)
FFO to Interest Coverage	N/A	3.9x	4.6x	N/A	N/A
FFO to Total Debt	13.8%	17.9%	12.5%	12.1%	15.4%
Total Debt to Total Capital (4)	66.5%	61.4%	64.9%	65.5%	66.2%

(1) Calculated as of December 31, 2009 and December 31, 2010, respectively.
(2) FFO to Interest Coverage of 3.4x calculated as of September 30, 2011.
(3) FFO to Interest Coverage of 3.1x calculated as of March 31, 2012.
(4) S&P makes several adjustments to debt when calculating the total debt to total capital ratio, including a liability for underfunded pension and post-retirement benefit costs.

UI Response to Interrogatory FI-2; Tr. 4/29/13, pp. 802-805.

The ratios depicted in the table above each represent 7.5% of Moody's ratings factors. The Company indicated that even if the credit matrix ratios above were sustained at a strong level over a long time, there could be other factors that may prevent a rating upgrade. The Company opined that an increase in the allowed ROE from the present allowed 8.75% to its proposed 10.25% would further UIL's ability to attract equity capital that can be used to infuse equity to the Company. UI Response to Interrogatory FI-3. According to the Company, rating agencies consider many factors in evaluating the bond rating. The credit rating can only improve under the situation where the agencies have been convinced UI's quantitative and qualitative factors are moderated. The Company indicated that to obtain a ratings increase, it would have to show the ratings agencies its ability to recover costs, earn its allowed ROE, maintain a liquidity factor of 50% long-term debt, and hold strong performance on a number of financial ratios. The agencies would need to see consistent, sustained improvement above the levels presently maintained to upgrade its credit ratings. The Company could not specify how long this time period of consistent improvement would take as the rating agencies reserve the right to change the required level of improvement based upon changes to economic conditions, legislative changes or other events. UI Response to Interrogatory FI-27; Tr. 4/29/13, pp. 804 and 805. Evidence was also presented which indicated that the credit ratio of the Parent Corporation (i.e., UIL) can constrain the credit rating that the operating subsidiary (e.g., UI) can obtain. Based upon this constriction of the UI credit rating, the OCC indicated its proposed 8.75% ROE was fair. Tr. 5/15/13, pp. 2277 and 2278.

The Company's financial viability has remained stable since Docket No. 08-07-04 based upon UI's contention that it maintains an investment grade credit rating by maintaining a 50/50 equity to debt capitalization mix for ratemaking purposes. The primary determinants of the Company's cash flow are earnings, the capital expenditure program, taxes and pension costs. UI suggested that its capital expenditure program of approximately $950 million through 2018 requires extensive external financing and it must demonstrate strong financial viability to continue to have access to capital markets. UI Response to Interrogatory FI-69.

The Company supplied other key financial metrics valued at year end, December 31st, which are compiled in the table below. The forecasted figures for year-end 2013 through 2015 are computed based upon UI's revenue requirement as proposed in the Application.

Ratio	**2008**	**2009**	**2010**	**2011**
Total Asset Turnover (TAT)	N/A	N/A	N/A	N/A
Current Ratio (CR)	58.05%	74.12%	74.05%	52.30%
Cash Flow from Operations (CFO)	34.57%	81.13%	97.56%	39.65%
Total Debt to Total Capitalization	57.42%	52.78%	54.62%	56.61%
Times Interest Earned (TIE)	6.35x	4.80x	3.77x	3.42x
Fixed Coverage Ratio (FCR)	2.92x	2.63x	2.44x	2.31x
Cash Flow Coverage Ratio (CFC)	17.13x	25.19x	30.59%	14.23x
Operating Margin (OM)	11.00%	13.28%	12.68%	12.71%
Profit Margin (PM)	7.06%	8.63%	9.59%	11.38%
Contribution Margin (CM)	43.06%	45.49%	42.47%	42.63%
Return on Total Assets (ROA)	N/A	N/A	N/A	N/A
Return on Invested Capital (ROI)	N/A	N/A	N/A	N/A

Ratio	**2012**	**2013**	**2014**	**2015**
Total Asset Turnover (TAT)	N/A	N/A	N/A	N/A
Current Ratio (CR)	80.00%	122.85%	101.64%	86.80%
Cash Flow from Operations (CFO)	100.51%	98.79%	71.70%	64.13%
Total Debt to Total Capitalization	49.78%	50.15%	51.50%	50.74%
Times Interest Earned (TIE)	4.39x	3.05x	3.55x	3.52x
Fixed Coverage Ratio (FCR)	3.24x	3.02x	3.52x	3.50x
Cash Flow Coverage Ratio (CFC)	26.13x	22.70x	17.13x	17.33x
Operating Margin (OM)	18.57%	22.77%	26.21%	27.48%
Profit Margin (PM)	17.45%	12.94%	15.26%	15.43%
Contribution Margin (CM)	54.28%	52.45%	57.02%	59.42%
Return on Total Assets (ROA)	N/A	N/A	N/A	N/A
Return on Invested Capital (ROI)	N/A	N/A	N/A	N/A

UI Response to Interrogatory FI-071, Attachment; Tr. 4/29/13, pp. 810-813.

The Company also reported that its free cash flow has increased since 2008, which was negative $108.445M in December 31, 2008, to $9.858M on December 31, 2012. The Company anticipates positive free cash flow of $30.701M on December 31, 2013, but anticipates free cash flow to turn negative in year end 2014 and 2015. UI Response to Interrogatory FI-70; Tr. 4/29/13, pp. 806 and 807.

b. Capital Markets Access and Dividends

UI indicated that UIL had two equity issuances one in 2009 and one in 2010. The purpose of the 2009 issuance was for general corporate purposes including a $70 million equity contribution to UI, which was used by UI to repay $70 million in short-term debt outstanding. UI Response to Interrogatory FI-68. The 2010 equity offering was issued in order to fund the purchase of CNG, SCG and Berkshire Gas, and to pay for issuance costs and other corporate purposes. The size of the 2010 equity offering was $455.8 million and was oversubscribed. In total the 2010 equity offering including the oversubscription generated $524.1 million and net proceeds of $501.9 million after underwriting fees and other expenses.[11] The Company indicated that an oversubscribed equity offering was an indication that the offering was viewed positively and was well received by investors. UI Responses to Interrogatories FI-6, FI-9 and FI-10; Tr. 4/29/13, pp. 979-983.

With respect to the oversubscribed 2010 equity offering, UIL shareholders fared well as the UIL stock price increased from an offer price of $25.75 per share in September 2010 to $39.12 per share close of business on April 3, 2013. This increase represented approximately a 52% appreciation to the stock price over a two-year period exclusive of the dividend accruing to shareholders. UI Late Filed Exhibit No. 48; Tr. 4/29/13, pp. 993-995, 1001.

During the rate years from July 1, 2013 to June 30, 2015, UI indicated that its financing needs are projected to be approximately $400 million through a combination of long-term debt and equity to maintain its 50/50 capitalization mix. Nicholas PFT, p. 22; UI Response to Interrogatory FI-7.

The OCC disagreed with UI witnesses' (i.e., Nicholas and Avera) numerous statements, which characterized the present 8.75% allowed ROE as inadequate and UI's contention that the 8.75% restricted the Company's ability to attract capital. According to the OCC, UI presented no evidence that it had trouble with any issues in raising debt or equity capital in the past five years. To the contrary, the Company raised capital on two separate occasions since its last rate case. The OCC indicated that the market test for adequacy of the 8.75% allowed ROE was passed given that the Company successfully attracted large amounts of both debt and equity capital, as demonstrated by the investor's oversubscriptions to the capital, since the 2009 Decision. According to the OCC, the repeated contention that UI should be granted a higher ROE to attract capital was unsupported by the record, and had been directly contradicted by recent experience. The OCC urged the Authority to not be persuaded by unsupported talking points and scare tactics utilized by the Company in its attempt to get a higher authorized ROE in the current proceeding. UI Late Filed Exhibit No. 53; Tr. 4/30/13, pp. 1236-1241; OCC Brief, pp. 9 and 10.

The OCC also disagreed with UI's characterization that the allowed 8.75% damaged its stock price performance. Although UIL's stock plummeted below book value

[11] Proceeds to UIL were $436.4 million net of underwriting fees and other expenses. The portion that was oversubscribed generated proceeds of $68.4 million and net proceeds after underwriting fees were $65.5 million. UI Response to Interrogatory FI-6.

for a period, the OCC contended that the drop was only for a short time, during the worst point of the recession, and was consistent with what was going on in the market at that moment in time. The OCC examined the stock performance of UIL as a gauge of UI's authorized ROE of 8.75% relative to the performance of the Dow Jones Utilities Index (DJUI) and the S&P 500 over the past five years. According to the OCC, when UI's stock price dipped in 2009, both the S&P 500 and the DJU dipped even further. Lastly UIL's stock out performed DJUI and S&P 500 as the S&P 500 is about even over the past five years, the DJUI is up about 10%, and the stock of UIL has gained over 30%. Nicholas PFT, p. 9; Woolridge PFT, p. 2; Exhibit JRW-3, p. 2, Figure 3; OCC Brief, pp. 10 and 11. Further verifying UIL's strong stock performance was a graph provided in the UIL 2012 SEC 10-k report at p. 21 which showed the appreciation in the UIL stock price and how it outperformed the S&P500, S&P Public Utility Index, and S&P Electric Power Index. OCC Brief, pp. 12 and 13. Lastly, the OCC indicated that the UIL stock price's market-to-book ratio was 1.89 as compared to 1.56 for the companies included in the OCC's proxy group of electric companies. Therefore, the UIL stock price's market-to-book ratio increased from less than 1.0 at the time of the 2009 Decision to above the electric industry average at the present time. Woolridge PFT, Exhibit JRW-4, p.1; Tr. 4/30/13, pp. 1018, 1024, 1243 and 1244; OCC Brief, pp. 11 and 12.

The AG's review of UI's financial condition indicated that the Company has thrived since its last rate proceeding. UI consistently met its authorized ROE and enjoyed the benefits of full revenue decoupling.[12] UIL acquired the three natural gas companies and the UIL stock price appreciated and outperformed leading stock indices such as the S&P 500 and Dow Jones Industrial Utility Average (DJUIA). AG Brief, p. 5.

UI stated that it does not target a certain dividend payout ratio or dollar dividend amount to UIL; nor does UIL target a certain dividend payout ratio to its shareholders. According to UI, its objective in setting its dividend to UIL was to maintain its currently allowed 50% common equity and 50% long-term debt capital structure over time. UI detailed the dividend process as a review of the capital structure, calculated as a 13-month average, each quarter, as well as changes to earnings since the prior quarter, and any anticipated changes to earnings, current and projected debt, and the current and expected cash needs at UI and UIL. To maintain its capital structure, UI typically dividends its earnings to UIL and then UIL contributes capital to balance the capital structure when UI issues new debt. UI explained that the increased dividend payout was not an increased cost but a reduction to the ratepayer revenue requirement. This dividend review process was not changed due to the acquisitions of the LDC gas companies. UI Response to Interrogatory FI-65; Tr. 4/29/13, pp. 958-963. UI has only 100 shares of stock wholly owned by UIL.

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[12] Woolridge PFT, p. 10, Exhibit JRW-3 provided UI's earned ROE for the last ten years.

The following table summarizes past and future dividend payouts:

	Actual				
	2008	2009	2010	2011	2012
Earnings	$51,090	$56,973	$63,752	$68,860	$84,636
Dividends Paid	$28,746	$44,000	$57,800	$69,600	$53,100
Dividends/Earnings	56%	79%	91%	101%	63%

	Forecasted				
	2013	2014	2015	2016	2017
Earnings	$84,158	$92,764	$103,703	N/A	N/A
Dividends Paid	$109,350	$87,114	$97,613	N/A	N/A
Dividends/Earnings	130%	94%	94%	N/A	N/A

UI Response to Interrogatory FI-66; Tr. 4/29/13, pp. 958-963.

4. Authority Analysis of Capital Structure

Based upon its review of the evidence, the Authority adopts the Company's proposed ratemaking capital structure of 50% common equity to 50% long-term debt. The 50% proposed common equity is higher than the average common equity component of the OCC Proxy Group (46.5%) and of the Company Proxy Group (48.3%). Woolridge PFT, p. 15; OCC Brief, p. 16; Avera PFT, Exhibit WEA-15.[13] The Authority finds that the average common equity portion for electric and gas companies that were awarded allowed returns in 2012 was 50.83%. UI Response to Interrogatory FI-58, Attachment. In response to CIEC's recommendation to impose a cap on the ratemaking common equity portion to that of UIL (approximately 36%), the Authority sympathizes with CIEC's observation. . However, the Authority finds that imposing such an extreme change (approximately 14% downward adjustment to common equity) to the Company's ratemaking capitalization mix may be disruptive to its financial stability and credit rating. Despite the Authority's present reluctance to accept CIEC's proposal, the Authority will continue to monitor electric utility industry practices with regard to capitalization mix and will make changes to the ratemaking capital structure should industry standards change significantly.

Overall, the Authority finds a capital structure consisting of 50% common equity to 50% long-term debt adequate for ratemaking purposes and adopts the Company's proposed embedded cost of long-term debt as depicted in the tables below:

13 Avera PFT, Exhibit WEA-15 indicates that the Company Utility Group's common equity ratios at December 31, 2011, ranged between 30.5% and 60.9% and averaged 48.3% of long-term capital.

2014 Average Capitalization: Rate Year 1

Class of Capital	Ratemaking Percentage	Cost	Ratemaking Weighted Cost
Long-term Debt	50%	5.32%	2.66%
Common Equity	50%	--%	--%
Total Capitalization	100%		--%

2015 Average Capitalization: Rate Year 2

Class of Capital	Ratemaking Percentage	Cost	Ratemaking Weighted Cost
Long-term Debt	50%	5.27%	2.64%
Common Equity	50%	--%	--%
Total Capitalization	100%		--%

5. Cost of Common Equity

a. Introduction

The Company retained the services of a cost of capital expert (Dr. Avera) to review changes in financial and economic markets and to provide a recommended ROE, Dr. Avera recommended an ROE of 10.25%.[14] UI indicated that its present allowed 8.75% continues to be the lowest in the country. According to the Company, the recommended 10.25% is in-line with consensus positions and evidence gathered in Docket No. 09-10-06, Investigative Inquiry into the Desirability, Need and Feasibility of Establishing a Uniform Methodology for Determining Return on Equity (2009 Generic ROE Proceeding). The Company indicated that it is presently allowed 8.75%, which is below the level allowed other national electric and gas utilities. The Company stated that at the time of Docket No. 08-07-04, the national ROE average was 10.40%. Since that time, ROE rates have trended down and the 2012 average was 10.07% based upon Regulatory Research Associates' (RRA) reporting. Nicholas PFT, pp. 16 and 17.

The Company's requested 10.25% ROE was based upon the methodologies employed by its expert witness. The Company approach was to provide consistency with the consensus positions of the party participants in the 2009 Generic ROE Proceeding. Also, UI's approach was to include a summary of other analyses to serve as a test of reasonableness and ensure the resultant recommendation would be consistent with the *Hope and Bluefield* standards.[15] The Company's methods included the Discounted Cash Flow (DCF) Model and Capital Asset Pricing Model (CAPM) to a proxy group of companies which it declared were consistent with the 2009 Generic ROE Proceedings' consensus positions. The Company also included a Utility Risk Premium analysis based upon utility allowed returns by state regulatory commissions adjusted for current interest rates and UI's bond rating. Avera PFT, pp. 4 and 5. The Company enhanced its interpretation of the findings in Late Filed Exhibit No. 17 of the 2009 Generic ROE Proceeding by performing various methods as a test of reasonableness to the resultant ROE. The Company indicated that the 2009 Generic ROE Proceeding consensus

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[14] The work of Dr. Avera is referenced as Company testimony.

[15] The Company indicated that Late Filed Exhibit No. 17 from the 2009 Generic ROE Proceeding presented a summary of the final consensus position of the party participants. Late Field Exhibit No. 17 was included by Dr. Avera as Exhibit WEA-1.

position represented the utilities' compromise among themselves and the OCC. This compromise arrived at positions the participants could live with, but differed in material ways from the PURA's initial positions as posed in the Generic ROE Proceeding's strawman proposal. The Company indicated that uncertainty was something investors do not like, thus UI would prefer transparency in the Authority's Decision as to application of cost of capital methods and how they relate to the 2009 Generic ROE Proceeding. UI Responses to Interrogatories FI-19 and FI-20; Tr. 4/30/13, pp. 1085-1091.

Overall UI suggested that its proposed 10.25% ROE is supported by the record and should be approved so that the allowed ROE be competitive with comparable utilities around the nation. UI argued that investors have investment choices. In the event the allowed ROE is not competitive with other alternative investments, investors would prefer other investment options at a time when UIL would need to access the capital markets to finance over $400 million in anticipated capital needs. UI Brief, p. 5. In support of its claim that 10.25% is reasonable, UI highlighted a RRA report which indicated that during 2012 and first quarter of 2013, the most frequently authorized ROEs were in the 10% to 10.24% range. The median of authorized ROEs over the last 15 months was 9.95%. UI Brief, p. 17.

The OCC proposed an 8.75% allowed return should be implemented based on several significant points: (1) interest rates and capital costs are at historic low levels, and are about 200 basis points below the levels at the time of the 2009 Decision; (2) while the Company witnesses claimed that UI's authorized ROE of 8.75% has been an impediment in raising capital, the Company raised both debt and equity capital in recent years, including almost $1 Billion in 2010 to purchase CNG, SCG and Berkshire Gas; (3) over the past five years, UIL's stock price significantly outperformed both the S&P 500 and the DJUI, and currently sells at a market-to-book ratio well in excess of other electric utilities; and (4) authorized ROEs for electric utility companies have declined, reflecting the historically low interest rates and capital costs. OCC Brief, pp. 7 and 8.

The OCC advocated the fairness of the 8.75% allowed returns in light of its acceptance of UI's proposed debt costs and its proposed 50/50 capitalization mix. According to the OCC, the UIL capital structure used considerable more leverage with 34% common equity (reported by S&P) to 66% long-term debt; therefore, UIL's capital structure was less costly to manage than the 50% common equity held at the UI subsidiary. The OCC indicated that its acceptance of UI's proposal to extend decoupling should also factor into supporting the 8.75% allowed return as decoupling allowed the Company to earn and over-earn its allowed return since the last rate period. Lastly, the OCC pointed out that contrary to claims of inadequacy made by the Company, UIL had two oversubscribed equity offerings, and a large, but reasonably priced long-term debt placement. Lastly, rather than suffering extended stock market price losses, the UIL shareholder's value thrived as the stock price appreciated strongly during the inter-rate period and the UIL market-to-book ratio rose to above electric industry standards. OCC Brief, p. 15.

The OCC also found fault with the application of the methodologies employed by the Company. The primary issues included: (1) the proxy group to evaluate UI's cost of common equity capital; (2) an excessive DCF equity cost rate because of (a) asymmetric classification and elimination of DCF results, (b) excessive reliance on the EPS growth rate forecasts of Wall Street analysts and Value Line, and (c) a flawed and overstated br+sv growth rate; (3) the base interest rate and equity risk premium used in CAPM and RP approaches; (4) the validity of the Expected Earnings equity cost rate approach; and (5) the proposed adjustments for size and flotation costs. Woolridge PFT, p. 51; OCC Brief, p. 25.

The OCC's review of the 2009 Decision indicated that 8.75% was consistent with the ROE allowances set in past PURA Decisions in rate proceedings involving Connecticut's major energy utility companies shown below:

Company	Docket No.	PURA Allowed ROE (%)
UI	08-07-04	8.75%
Yankee Gas	10-12-02	8.83%
CNG	08-12-05	9.31%
SCG	08-12-06	9.26%
CL&P	09-12-05	9.40%

OCC Reply Brief, p. 2.

The AG recommended that the Authority reject UI's 10.25% ROE proposal and supported the OCC's recommended 8.75% ROE based on the OCC witness' review of prevailing economic conditions. The AG indicated that the 8.75% is in no way inadequate and suggested it was reasonable in light of UI's proposal to make full revenue decoupling a permanent mechanism. According to the AG, the present 8.75% ROE served the Company well, as it maintains all the necessary criteria to achieve solid investment grade ratings, a strong balance sheet, predictable cash flows with the decoupling mechanism. AG Brief, p. 20.

After an initial decline of the UIL stock price on February 4, 2009 (dropped to $17), the AG highlighted the strong stock price rebound and appreciation of UIL stock price since that time with a steady rise to approximately $40 on February 4, 2013. The AG noted that the stock price appreciation took place during a time period of record low interest rates, which made UIL's stock an attractive investment. UI Response to Interrogatory OCC-283; AG Brief, p. 21.

Another factor highlighted by the AG as a reason to maintain the current allowed return was the downward interest rate environment detailed by the OCC. Interest rates such as yields on long-term US Treasury Bonds and Public Utility Bonds are now approximately 2% lower than at the time of the 2009 Decision. Likewise, US economic conditions indicated a continued period of slow economic growth, unchanged unemployment levels and low inflation, which would serve to keep interest rates down. Woolridge PFT, pp. 10 and 11; Tr. 5/15/13, pp. 2283 and 2284; AG Brief, p. 22. Although the AG found ample evidence to reject UI's proposed 10.25% ROE, it suggested that UI's financial strength since the 2009 Decision was the strongest indicator of success with the 8.75%. UI over-earned its allowed return in five of the last ten years. Over the time period since the 2009 Decision (2009 to 2012), UI over-earned three out of four of those years. UI Response to Interrogatory OCC-192; AG Brief, p. 22. The AG urged the Authority to reject UI's proposed 10.25% ROE and maintain the present 8.75% ROE, thereby, saving ratepayers approximately $11.4 million in revenue requirement in RY1.[16] UI Response to Interrogatory CIEC-3; AG Brief, pp. 3 and 23.

The Company urged the Authority to reject the 8.75% ROE proposed by the OCC and supported by the AG and CIEC because the OCC's methods are faulty, unreliable and cannot be replicated. UI Brief, p. 28. The Company suggested it would be inappropriate for the Authority to pre-suppose that the claimed support of the past should determine the cost of equity today and going forward. UI Reply Brief, p. 21.

b. Proxy Groups

In selecting the Proxy Group companies, the Company used several criteria. These selected companies are classified by Value Line as electric utilities with: (1) an S&P corporate credit rating of "BBB+", "BBB", or "BBB-"; (2) regulated revenues of 70% or greater, as reported by AUS Utility Reports (AUS); (3) no significant ongoing merger activity impacting stock prices; and (4) consistent dividend payments over the last six months and over Value Line's forecast horizon. These criteria resulted in a proxy group of 27 utility companies, which were depicted in Exhibit WEA-3 and were referred to as the Company Utility Group. Avera PFT, pp. 9 and 16. The Company clarified that for the AUS companies classified as electric utilities, the percentage would refer to electric revenues, but for companies classified as combination electric and gas utilities, the percentage referred to the combined revenues of providing electric and gas service. UI Response to Interrogatory FI-39; Tr. 4/30/13, pp. 1093-1099.

The Company's ROE was measured by using company data for UI and for other firms in the Company Utility Group with risk as similar as possible to that of UI. The beta of the Company Utility Group was 0.73 while that of UI was 0.70. According to the Company, this represents a virtually identical risk profile between UI and the Company Utility Group. Avera PFT, pp. 16 and 17; Table WEA-2.

The 27 firms in the Company Utility Group consisted of: ALLETE, Alliant Energy, Ameren Corp., American Electric Power, Avista Corp., Black Hills Corp., CenterPoint Energy, Cleco Corp., CMS Energy Corp., DTE Energy Co., Edison International, El Paso Electric, Empire District Electric, Great Plains Energy, Hawaiian Electric, IDACORP, Inc., NorthWestern Corp., Pepco Holdings, PG&E Corp., Pinnacle West Capital, PNM Resources, Portland General Electric, SCANA Corp., Sempra Energy, TECO Energy, UIL and Westar Energy. Avera PFT, Exhibit WEA-3.

The Company screened out the following companies: ConEdison, Duke Energy, Northeast Utilities, Southern Company, NV Energy, UNS Energy, Xcel Energy, MGE Energy and Wisconsin Energy on the basis that their bond rates were either too high or too low. UI Response to Interrogatory FI-41; Tr. 4/30/13, pp. 1106-1110.

The OCC's proxy group consisted of 35 electric utility companies (OCC Utility Group). This group included companies that meet the following criteria: (1) at least 50%

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[16] A 1% change to the ROE translates to $7.634 million change to the revenue requirement. UI Response to Interrogatory CIEC-3. Therefore, linear interpolation indicated that a 1.5% reduction to the allowed ROE would result in an $11.451 million reduction to the revenue requirement. AG Brief, pp. 3 and 23.

of revenues from regulated electric operations as reported in AUS; (2) listed as Electric Utility by Value Line and listed as an Electric Utility or Combination Electric & Gas Company in AUS Utilities Report; (3) an investment grade corporate credit and bond rating; (4) has paid a cash dividend for the past three years, with no cuts or omissions; (5) not involved in an acquisition of another utility, and not the target of an acquisition, in the past six months; and (6) analysts' long-term EPS growth rate forecasts available from Yahoo, Reuters, and/or Zacks Investment Research (Zacks). The OCC indicated that UI's Corporate Credit Rating (CCR) was BBB and was in line with the average CCR of the OCC Utility Group. The riskiness of UI relative to the OCC Proxy Group using four different risk measures published by Value Line was found to be similar. These measures include Beta, Safety, Financial Strength, and Earnings Predictability. The OCC concluded that UIL and the OCC Utility Group are very similar in terms of risk. Woolridge PFT, pp. 13-15; Exhibit JRW-4, p. 2; OCC Brief, pp. 16 and 17.

The 35 firms in the OCC Utility Group consisted of: ALLETE, Alliant Energy, Ameren Corp., American Electric Power, Avista Corp., Black Hills Corp., CenterPoint Energy, Cleco Corp., CMS Energy Corp., Consolidated Edison, Inc., Dominion Resources, Inc., DTE Energy Co., Duke Energy Corporation; Edison International, First Energy Corporation, Great Plains Energy, Hawaiian Electric, IDACORP, Inc., MGE Energy, Inc., Nextera Energy, Northeast Utilities, NorthWestern Corp., NV Energy, Inc., Pepco Holdings, Inc., PG&E Corp., Pinnacle West Capital, PNM Resources, Portland General Electric, SCANA Corp., Southern Company, TECO Energy, UIL, UNS Energy Corp., Westar Energy, Wisconsin Energy Corporation and Xcel Energy, Inc. Woolridge PFT; Exhibit JRW-4. The OCC indicated that in selecting these companies, the 50% threshold of revenues from regulated electric operations was restricted to electric revenues for the combination electric and gas companies. This was in contrast to the Company approach which adds the percentage revenues of both electric and gas operations. Tr. 5/15/13, pp. 2287-2290.

The Company found the OCC Utility Group not reflective of the UI/UIL credit BBB corporate credit ratings. According to the Company, the OCC's proxy group included companies with stronger credit ratings given that the OCC credit quality criterion was merely that the peer group company be investment grade. Of the 35 companies in the OCC Utility Group, 23 companies had S&P bond ratings higher than UIL and only 6 companies had ratings lower than UIL. According to the Company, this application of proxy group selection slants the OCC Proxy Group to have lower risk (and conversely lower return) than UI. Tr. 5/23/13, pp. 2511-2515; UI Brief, pp. 29 and 30.

The OCC indicated that the Company Utility Group was comprised of similar companies that were selected for the OCC Utility Group, but excluded CenterPoint due to recent merger activity and El Paso and Empire District due to dividend payment past history as well as Sempra due to the fact it received a low percentage of revenues from electric operations. OCC Brief, p. 17; Woolridge PFT, pp. 51 and 52; Exhibit JRW-4; Tr. 4/30/13, pp. 1287-1290.

The OCC was critical of the Company's DCF test of reasonableness approach whereby UI applied the DCF approach to a proxy group of 13 non-utility companies, Abbott Labs, Coca-Cola, General Mills, Kellogg, Kimberly-Clark, McDonald's, PepsiCo, Procter & Gamble, and Wal-Mart. Avera PFT, Exhibit WEA-13. The OCC noted that the Authority has never used a DCF equity cost rate based on a non-utility proxy group in its ROE determination. In the 2009 Decision, the PURA determined that the non-utility proxy group, "was not comparable in the overall review of UI, therefore, the non-utility proxy group has been discarded from the cost of equity analysis." 2009 Decision, p. 95. The OCC indicated that just because the non-utility companies have the same beta as the companies in the Company Utility Group, does not mean that both should have a similar return. According to the OCC, the non-utility companies' growth expectations are overly optimistic. Tr. 4/3013, pp. 1291 and 1292. The OCC recommended that results of the non-utility group DCF are not an appropriate proxy for UI; therefore, the equity cost rate results for this group should be ignored. Woolridge PFT, p. 53; OCC Brief, pp. 17 and 18; Tr. 4/30/13, pp. 1290-1292.

c. Risk and Other Factors

i. Flotation Cost

According to the Company, an adjustment to the ROE to include flotation costs was appropriate to account for the impact of the real costs incurred in connection with raising capital. UI had incurred these costs in connection with past equity issuances and has plans to incur these costs in the rate years when UIL issues equity. UI stated that the Authority previously recognized that flotation costs are real and a precedent has been set in Decision dated June 29, 2011 in Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules (2010 Yankee Gas Decision) at page 134, which authorized 12 basis points as a flotation adder. Avera PFT, pp. 40-45; Tr. 4/3013, pp. 1056 and 1057; UI Brief, p. 27.

UI used the standard method for calculating a flotation adjustment by multiplying the dividend yield by a flotation cost percentage. Because UIL incurred issuance costs of approximately 4.3% of the gross proceeds from its 2010 equity issuance, the Company applied the 4.3% to UIL's dividend yield of 4.9% to arrive at a minimum flotation cost adjustment of 20 basis points. Therefore, UI requested the Authority incorporate a 20 basis points upward adjustment to its allowed ROE to account for flotation costs it has previously incurred and which it is expected to incur over the rate periods. UI Brief, pp. 20 and 27.

The Company agreed that flotation costs could be directly measured through an expense account to recover ongoing common stock flotation costs much in the way bond expenses are recognized in the utility revenue requirement, but this method would only apply to ongoing issuances not past ones. Overall, UI indicated that the purpose for the flotation cost allowance was to restore enough earnings to the investor and the Company so that it is in the same place it would have been without the equity offering. UI Response to Interrogatory FI-24; Tr. 4/30/13, pp. 1188-1196.

The OCC did not recommend including an adjustment for flotation costs. The Company argued that a flotation cost adjustment would be necessary to prevent the dilution of the existing shareholders, but provided no direct evidence that the UIL equity issue provided funds to UI. Avera PFT, pp. 44 and 45. The OCC suggested that these expenses could be recovered as O&M cost much like bond issuance costs. Tr. 4/30/13, pp. 1331-1334. The OCC indicated that the flotation argument was erroneous for several reasons. First, market-to-book ratios for the electric industry trades above 1.5x, which suggests a flotation cost reduction. Second, a flotation adjustment would be needed only in the event the market price of the stock was at/or below its book value. Third, flotation costs are primarily underwriting spreads or fees and not out-of-pocket expenses. It is the offering price, not the price the Company receives which matters to market; therefore, the Company should not get an adjustment to the allowed return. Fourth, flotation costs would be best viewed as a transaction expense to access the capital markets. Although, the Company wanted to be compensated for these transaction costs, UI had not accounted for other transaction costs in determining the cost of equity such as brokerage fees investors pay. Had the Company considered brokerage fees, then all else equal, the stock prices would be higher and the dividend yields would be lower (D/P). This would lower the effective cost of equity. OCC Brief, pp. 35-37.

The Company indicated that the OCC did not dispute the costs that UIL incurred when it issued more equity in the form of new common stock. The Company contended that flotation costs are reasonable to recoup through an upward adjustment to the allowed ROE. UI Brief, p. 36; Tr. 4/3013, pp. 1336 and 1337.

ii. Checks of Reasonableness

As checks on the reasonableness of the DCF, CAPM and utility risk premium cost of equity estimates, the Company looked at the cost of equity estimates resulting from additional methodologies used by other commissions or experts on behalf of utilities, commission staffs, and interveners in their consideration of cost of equity. Examples of the methods used to test reasonableness included an examination of authorized ROEs in other jurisdictions. In effect examining a proxy group of utilities and also the ROEs authorized in rate case Decisions in 2012. A method called Expected Earned Returns was also provided whereby an evaluation of the proposed ROE was made to expected RORs from available alternative investments; thereby, making use of the comparable earnings test. The Company indicated it was not aware of a Connecticut electric Decision that incorporated a comparable earnings type approach in estimating the cost of capital. Also, an Evidence-based CAPM was examined where projected bond yields were used (instead of the current 2013 bond yields used in main analysis). This Evidence-based CAPM included a size adjustment to take into account the small market capitalizations of utilities compared to the average S&P 500 companies. The Evidence-based CAPM formula expands the general CAPM formula to the following: $R_s = R_f + 0.25\ (R_m - R_f) + 0.75\ [b \times (R_m - R_f)]$. Another test of reasonableness involved a DCF analysis on low risk non-utility stocks (Non-Utility Group) was included to gauge comparable returns investors could obtain by selecting investment choices that are low risk but outside the realm of regulated utilities. Avera PFT, pp. 45-68; Exhibits WEA-9 through WEA-14; UI Responses to Interrogatories FI-49 through FI-54, FI-56; UI Brief, pp. 27 and 28; Tr. 4/30/13, pp. 1209-1211 and pp. 1216-1218.

Based upon these alternative methods, all but one of the testing methods yielded results that were higher than the proposed resulted weighted average (DCF/CAPM/utility risk premium) of 10.1%. Only the expected earnings approach resulted in a slightly lower result of 9.9%. Overall, the Company suggested that the checks on reasonableness demonstrated strong support for the proposed 10.25% weighted average cost of equity estimate that includes an upward adjustment of 20 basis points for UIL's actual flotation costs. UI Response to Interrogatory FI-49; Tr. 4/30/13, p. 1058; pp. 1209-1212; UI Brief, p. 28.

According to the Company, the OCC's recommendation of 8.75% was well below any authorized return by a state commission in the last year. Therefore, the Company criticized the work of the OCC because there were no checks of reasonableness performed using alternative methods to verify the proposed 8.75% recommendation was appropriate and in-line with alternative investment choices. UI Brief, pp. 29, 35 and 36.

iii. Decoupling: Risk and Return

The Company indicated that the OCC concurred with its assessment that there should be no reduction in ROE to reflect UI's decoupling mechanism. According to the Company, adjustment clauses and trackers are now common in the electric utility industry and they have been fully reflected in investors' expectations that form the basis for cost of equity estimates. Decoupling mechanisms, for example, are in place in 36 states. Since the prevalence of adjustment clauses have increased, the argument about the need for an explicit ROE adjustment has decreased. UI cited several jurisdictions such as Maryland and Hawaii, which previously incorporated downward basis point adjustments for decoupling but no longer applied these adjustments. The Company offered that downward adjustments to reflect the risk return trade-off to account for decoupling was no longer necessary and should not be explicitly applied in this instant docket. Avera PFT, pp. 64-66; UI Responses to Interrogatories FI-14, FI-48 and FI-57; Late Filed Exhibit No. 51; Tr., pp. 968, 978, 1020, 1198-1201, 2605-2008; UI Brief, pp. 36 and 37.

The OCC indicated that no specific adjustment was made for decoupling indicating that the 8.75% allowed return would be sufficient and fair at this time. Tr. 4/30/13, p. 1281. The OCC suggested there are many jurisdictions using trackers and it has become difficult to pull out what the particular tracker would be worth to the ROE. The OCC indicated that at present it is difficult to detach decoupling from the allowed return. Since UI has been granted decoupling, this is one of the reasons the OCC believes the 8.75% allowed return is reasonable. Tr. 4/30/13, pp. 1284 and 1286; Tr. 5/15/13, pp. 2276 and 2277.

The AG stated that the Company viewed full decoupling as revenue neutral and claimed that Moody's found it to be a significant credit positive as it provided for a level of cash flow stability and predictability. The Company did not propose a downward offset to the proposed ROE based on the contention that the decoupling is embedded within the expected market returns for equity investors. Avera PFT, pp. 11 and 12; UI Response to Interrogatory FI-04. The AG recommended that should the Authority approve decoupling, then the findings related to decoupling from the 2009 Decision must be reiterated. In particular that decoupling would be approved to solely provide UI with revenue and financial stability and reject the notion that decoupling would support or promote conservation and load management. Furthermore, the AG noted that UI's allowed ROE was downwardly adjusted to account for decoupling and should continue to be monitored for its impact to the allowed ROE. AG Brief, pp. 35 and 36.

iv. Weighting of Employed Methods

UI proposed that the results of the following cost of capital methodologies be weighted in accordance with 50% allocation to the Discounted Cash Flow Model, 25% to the Capital Asset Pricing Model and 25% to the Utility Risk Premium approach. The Company asserted that the Utility Risk Premium method was more reliable and relevant, but gave more weight to the DCF as that is what most analysts recommend. The Company indicated that its experience in past cases at the FERC, where the FERC does not utilize a CAPM or risk premium. UI Brief, p. 20; UI Response to Interrogatory FI-21; Tr. 4/30/13, pp. 1179-1181. The Company performed an exercise to revise its weighting scheme to 70% DCF, 15% CAPM and 15% Utility Risk Premium and the result was that the recommended ROE would drop to 10%. The Company agreed that the weighting of the cost of capital methodologies to develop the overall ROE recommendation was not a point of agreement in the 2009 Generic ROE Proceeding and also concurred that the weighting of the methodologies ultimately allowed in the ROE recommendation make a difference with regards to the outcome. UI Response to Interrogatory FI-21(C); Tr. 4/30/13, pp. 1181, 1183 and 1184.

The OCC recommended that only the DCF and simplified CAPM methods be considered. The OCC weighted the DCF model more heavily in its analysis. Although the OCC could not quantify a specified weighting criteria, the OCC offered that in its experience typically commissions weight the DCF at least 70% and typically more in the range of 80% to 90%. Tr. 4/30/13, pp. 1326-1328; Tr. 5/15/13, pp. 2304-2306.

d. Discounted Cash Flow Model

The Company and the OCC separately performed a DCF Model. The DCF model is a market based financial model which attempts to replicate the valuation process that sets the price investors are willing to pay for a share of stock.

The premise of the DCF model is that the intrinsic value of common stock can be estimated as the present value of future cash that flows to the investor plus the expected growth in selling the stock discounted to the present. In estimating the expected cash flows an investor expects in terms of dividends and capital gains, and given the current market price, an analyst can back-into the discount rate, or cost of common equity/ ROE. In its simplest form, the DCF consists of a current cash dividend cash yield (dividend) and a future price appreciation (growth) of the investment. Avera PFT, p. 17. Dr. Avera used the single-stage, constant growth DCF model as it is the most widely used version in public utility rate regulation. According to the Company, the constant growth DCF model is also consistent with the Parties' consensus position in the 2009 Generic ROE Proceeding and the most commonly used to evaluate the ROE for traditional regulated utilities. Avera PFT, pp. 18-21.

The single-stage, constant growth form of the DCF model is
K = D1 / Po + G, where:

K is the market-required return on equity;
D1 is the forecasted dividend paid one period into the future;
Po is an estimate to the current market price of the stock; and
G is investor's long-run growth expectations.

Avera PFT, p. 19.

The OCC also used the constant growth form of the DCF model using the traditional D/P + G formulation. Woolridge PFT, pp. 26 and 27; OCC Brief, p. 19.

i. Dividend Yield

For forecasted dividend yield component (D1), the Company used estimates of dividends to be paid over the next 12 months which were obtained from Value Line. This annual dividend forecast was divided by a 30-day average stock price to arrive at the expected dividend yield for each firm in the Company Utility Group. These expected dividend yields ranged from 2.8% to 5.6% and average 4.3%. UI indicated that the computation of the dividend yield was consistent with discussions in the 2009 Generic Rate Case Proceeding as the Company used a 30-day average for the stock price of each company included in the Company Utility Group and for the forecasted dividend portion, it used Value Line's forecasted dividend for each company in the proposed peer group.[17] Avera PFT, p. 20; Exhibit WEA-4; UI Responses to Interrogatories FI-32 and FI-34; UI Brief, p. 22; Tr. 4/30/12, pp. 1121-1123

The OCC employed the average of the six month and April 2013 dividend yields. For the group, the resulting average dividend yield was 3.95%. The OCC then adjusted this dividend yield by one-half the expected growth rate. Woolridge PFT, p. 28; OCC Brief, p. 19; Tr. 5/15/13, pp. 2307-2309.

The Company criticized the OCC's dividend yield estimation approach based upon its observation that spot dividend yields from AUS Utility Reports, and not a recent average of prices, were used to estimate the dividend yield portion of the DCF equation. This approach means that the OCC used the dividend yield calculated by AUS on one day approximately in the middle of the month. A 4% average of the AUS spot dividend yields for the months spanning October through March was averaged with a 3.9% median of spot dividend yields for one day in March; thus, obtaining the 3.95% dividend yield used for the entire proxy group. According to the Company, this approach rendered the OCC DCF computations unreliable. The Company suggests this approach be rejected based upon the Authority's prior finding that 30-day averages of prices and not spot yields should be used in computing the dividend yield component.[18] Tr. 5/23/13, pp. 2497-2505; UI Brief, pp. 28-31.

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[17] The Company verified that the forecasted dividend employed was Column (f), the estimated dividend for next 12-months from Value Line: Summary & Index. Tr. 4/30/13, pp. 1121-1123.

[18] 2010 Yankee Gas Decision, p. 127.

ii. Growth Rate

According to constant growth DCF theory, the long-term growth rate (G) indicates that earnings, dividends, book value and market price are all assumed to grow in lock-step and that the future growth horizon is infinite. The Company stated that theory does not always translate into practice. For utilities, structural and industrial changes resulted in declining dividends, earnings pressure and write-offs. As a result, historical growth measures do not meet the current requirements for the DCF. An example of this change has been the dividend response to more industry business risk as the dividend payout ratio for electric utilities has fallen from a historical approximate 80% on average to less than 60% in more recent years. UI claimed that the new focus of investors shifted from utility dividends to earnings per share (EPS). Likewise, the Company suggested that EPS is a widely accepted method in the investment community for estimating growth expectations. EPS was described as more influential than Dividends Per Share (DPS) by the investment community. Likewise, DPS growth estimates are only published by Value Line, investment research analysts do not typically publish DPS growth rates. Most security analysts focus on EPS growth.

To the Company, the EPS growth rates are a superior indicator of long-term future growth, given DPS growth rates have limited availability. Avera PFT, pp. 20-22. The Company used EPS growth projections from Value Line, Yahoo Finance/I/B/E/S, and Zacks.[19] Avera PFT, Exhibit WEA-4; UI Brief, p. 22. The Company does not believe that use of more growth rates is better than fewer growth rates. The Company argued that only relevant growth rates should be included and excluded in the Value Line projected DPS and book value per share (BVPS) growth rates based upon the contention that there was no evidence that they are useful in replicating investor expectations. UI Responses to Interrogatories FI-32 and FI-34; Tr. 4/30/13, p. 1121.

Although some analysts suggest EPS growth rates are biased, the Company indicated these are the only relevant growth rates as they reflect the forward expectations of investor's stock price expectation. The Company contended that ex-post accuracy of analyst's EPS estimates was not the crucial test of value of the estimates' ability to replicate investor behavior. UI supported this belief pointing to the continued success of investment series such as Thompson Reuters and Value Line that the projected EPS growth rates are widely quoted from these sources. Avera PFT, p. 24; UI Response to Interrogatory FI-35; Tr. 4/30/13, pp. 1131-1133.

The Company also included the sustainable growth approach to estimating a company's expected growth rate. This is calculated by the formula: $g = br+sv$ where b is the expected retention ratio, r is the earned return on equity, s is the percent of common equity to be issued annually as new common stock and v is the equity accretion rate. The Company stated that the sv portion of the sustainable growth equation is designed to capture the issuance of new common stock and incorporates an additional growth component with regard to issuing new stock. Avera PFT, pp. 25 and 26; Exhibit WEA-4, p.3; UI Response to Interrogatory FI-33; UI Brief, p. 23.

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[19] I/B/E/S International Inc. (IBES) growth rates are now compiled by and published by Thomson Reuters and can be found in Yahoo Finance. Avera PFT, p. 23; UI Brief, p. 22.

According to the constant-growth DCF model, EPS, DPS, and BVPS all grow at the same rate. To assess growth, investors have available a number of services that provide historic and projected financial information. The OCC evaluated the following growth rates (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 sustainable growth or 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 Yahoo, Zacks and Reuters. The OCC indicated that the relevant cash flows in applying the DCF are dividends. Likewise, dividends come from company earnings. Although earnings were the OCC's primary driver, the OCC indicated that it is important to incorporate the other growth measures to see what exactly investors are going to expect because over different periods, earnings are going to grow faster than dividends and then at other times dividends grow faster. The OCC also indicated that in the application of the sustainable growth model, it was understood that the bxr portion captured the lion's share of the expected growth and incorporating the sxv portion adds little to the computation. Woolridge PFT, pp. 26; 30 and 31; Exhibit JRW-10, at 6 of 6; Tr. 4/30/13, pp. 1303-1308; Tr. 5/15/13, pp. 2310-2315 and pp. 2322-2324.

The table below highlights the summary growth rates for the proxy group.

OCC DCF Growth Rate Indicator	OCC Utility Group
Historic Value Line Growth (EPS, DPS, and BVPS)	3.2%
Projected Value Line Growth (EPS, DPS, and BVPS)	4.3%
Sustainable Growth (ROE * Retention Rate)	3.9%
Projected EPS Growth from Yahoo, Zacks, and Reuters	5.1%
Average of Historic and Projected Growth Rates	4.1%
Average of Sustainable and Projected Growth Rates	4.4%

Woolridge PFT, Exhibit JRW-10, p. 6.

The OCC arrived at its recommended DCF growth rate by observing that historical growth rate indicators for the OCC Utility Group imply a baseline growth rate in the range of 3.2%, and the high end of the range set by analyst forecasts was 5.1%. From this review, the OCC recommended the midpoint of the range of 4.75% as the DCF indicated growth rate. Woolridge PFT, p. 38; OCC Brief, p. 21.

The Company found the OCC's growth rates to be unverifiable. The Company noted that the OCC's analysis cited a myriad of growth numbers but then a decision was made that a single growth estimate of 4.75% should be the growth component for the DCF analysis. UI Brief, p. 29. The Company indicated that the OCC's growth rates are derived from data ten or more years from this time period given historical growth rates are incorporated. The Company claimed that the concept put forward by the OCC that security analysts' long-term growth forecasts are unduly optimistic and upwardly biased is antiquated. UI argued that new rules have been enacted to assure transparency of financial information (i.e., Regulation FD, the Sarbanes-Oxley Act and the Dodd-Frank Act). Moreover essentially all financial data used in the analysis including the growth data can be obtained on-line. Therefore, the Company recommended that the analyst's long-term growth forecasts not be downwardly adjusted to reflect the past history. Tr. 5/23/13, pp. 2523-2530; UI Brief, pp. 31 and 32.

UI also took exception to the OCC's inclusion of long-run forecasted growth rates of DPS and BVPS. The Company noted that in the 2010 Yankee Gas Decision, the Authority stated that EPS growth is the primary growth rate to be considered and there can be no DPS or BVPS growth without EPS. 2010 Yankee Gas Decision, p. 129. The Company also noted that it had properly calculated the sustainable earnings growth rates as br (retention) plus sv (growth), while the OCC improperly omitted the sv growth portion. Woolridge PFT, WEA-4, p. 3; UI Brief, p. 32; Tr. 4/30/13, pp. 1310-1313. Overall, the Company suggested that historical rates of growth are incorporated into analyst's projections. Also, the Company suggested that the 4.75% growth rate in the OCC's DCF formula cannot be replicated or calculated from undelaying and was picked based on a best guess approach. Woolridge PFT, p. 38; Exhibit JRW-10; UI Brief, pp. 28; 32 and 33.

In contrast, the OCC took exception to the Company's excessive reliance on projected EPS growth rates from Value Line and Wall Street analysts. Overall, the OCC indicated that the appropriate growth rate in the DCF model was the dividend growth rate, not the earnings growth rate. Hence, consideration must be given to other indicators of growth, including historic growth perspective, dividend growth, internal growth and projected growth. With respect to analysts' long-term EPS growth rate forecasts, the OCC noted two issues that should sway one from exclusive reliance on these estimates. The first is that analysts are not accurate at all, and the second is that they are consistently overly optimistic. Id. On the first issue, the OCC cited a recently published study:

> . . . a recent 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.[20] Employing data over a twenty year period, these authors demonstrate that using the most recent year's EPS figure to forecast EPS in the next 3-5 years proved to be just as accurate as using the EPS estimates from analysts' long-term earnings growth rate forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth rate forecasts should be used with caution as inputs for valuation and cost of capital purposes.

Woolridge PFT, p. 35.

20 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.

On the second issue, the OCC observed that:

> 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. This has been demonstrated in a number of academic studies over the years. This issue is discussed at length in Appendix B of this testimony. Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. On this issue, a study by Easton and Sommers (2007) found that optimism in analysts' growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[21]

Woolridge PFT, pp. 35, 36 and 55; OCC Brief, pp. 26 and 27.

The OCC also found a flaw in the Company's sustainable growth calculation based upon the OCC's calculation that the average br+ sv growth rate was 4.2% for the Company Utility Group, but the median Value Line projected BVPS growth rate for the Company Utility Group was only 3.6%. Given the Company's sustainable growth rate figures were higher than those projected by Value Line, the OCC indicated that the methodology was flawed. Woolridge PFT, p. 56; OCC Brief, p. 28.

iii. DCF Results

In developing the overall DCF result, the Company eliminated implausibly low and high results. These outliers were identified as DCF estimates that were under 7% and over 17.7%, or were based on a growth forecast of more than 13.3%. The remaining approximately 90 individual DCF cost of equity estimates range from 7.0% to 15.2%. Avera PFT, p. 27; UI Brief, p. 23.

The basis for the Company's outlier elimination criteria rested with the approach taken by the FERC to identify illogical results. The FERC evaluated DCF results against observable yields on long-term public utility debt and recognized that it was reasonable to exclude any individual company result on the low end which falls below the average bond yield plus 100 basis points. According to the Company, the FERC had not applied a strict 100 basis point threshold as spreads of 110 and 122 basis points were considered low enough to exclude in the 2006 Decision. In establishing the low end elimination zone for indicated DCF cost of capital estimates, the Company indicated the implied BBB Utility Yield spread to be 6.81% and indicated that low end DCF estimates that ranged from 0.2% to 6.8% were eliminated based upon the FERC risk-return practice.[22] On the high end, the Company eliminated outliers on the basis of the FERC's extreme outlier principle which indicated that figures above 17.7% should be excluded. In this case, only one DCF estimate of 18.8% was excluded, and the high end of the DCF results for the Company Utility Group was set by a cost of equity rate of 15.2%. Avera PFT, p. 31. The Company

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21 Peter D. Easton & Gregory A. Sommers, Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts, 45 J. Acct. Res. 983–1015 (2007).

22 The Company's source for public utility bond yields was Moody's, which sold its financial information services to Mergent Bond Record in 1998. Thus, the two sources publish similar statistics. UI Response to Interrogatory FI-36(f); Tr. 4/30/12, pp. 1142-1144.

indicated that the DCF results from the four growth sources averaged 9.6% and the 9.6% was weighted 50% to the overall cost of capital recommendation. Avera PFT, pp. 28-30; Exhibit WEA-4; UI Responses to Interrogatories FI-36 and FI-38; UI Brief, p. 23; Tr. 4/30/13, pp. 1133-1140 and pp. 1151-1155. The results of the Company's DCF Results for the Company Utility Group are depicted in the table below:

Growth Rate	**Average**	**Midpoint**
Value Line	10.10%	10.70%
Yahoo/IBES	10.10%	11.10%
Zacks	9.70%	9.20%
Br +sv	8.60%	8.80%

Avera PFT, p. 23, Table WEA-4; UI Brief, p. 23.

The OCC's DCF approach developed composite inputs to the model based upon the companies selected for the OCC Utility Group. The OCC's DCF also used the median as a measure of central tendency; therefore, outliers were not given too much weight. These were the results of the OCC's DCF model and basis for its DCF recommendation.

	Dividend Yield	½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
OCC Utility Group	3.95%	1.02375	4.75%	8.8%

Woolridge PFT, p. 39; OCC Brief, pp. 21 and 25; Tr. 4/30/13, pp. 1307-1309.

The OCC indicated that the Company's selective elimination of DCF indicated results was a significant error to the application of the DCF model. Accordingly, the Company's DCF equity cost rate analyses relies on asymmetric elimination of DCF results. For example, equity cost rates below 6.81% and above 18.0% were deemed extreme outliers. These screens eliminate 16 of 108 indicated DCF results, or 15%. Interestingly, all but one of the eliminated DCF results was from the low end. Avera PFT, pp. 30 and 31; OCC Brief, p. 26. The Company's analysis biases the DCF equity cost rate study and reports a higher DCF equity cost rate than the data indicate due to the Company's elimination of primarily low-end outliers and by not eliminating the same number of high-end outliers. According to the OCC, the FERC uses a symmetric approach to eliminating outliers in contrast to the Company approach which eliminated results primarily on the low side. Woolridge PFT, p. 54; OCC Brief, p. 26; Tr. 4/30/13, pp. 1293-1301. In contrast, the OCC's analysis did not subjectively eliminate certain values, but used the median as a measure of central tendency so as to not give outlier results too much weight. The OCC recalculated the Company's DCF equity cost rate for the utility group without eliminating the so-called extreme outliers. The revised average of the mean and median DCF equity cost rates, including all observations, were 9.0% and 9.1%, respectively. Woolridge PFT, Exhibit JRW-13, p. 2; OCC Brief, p. 26; Tr. 4/30/13, pp.1300-1302.

e. Capital Asset Pricing Model

The Company also performed a CAPM review. CAPM is a forward looking theory of market equilibrium that measures risk using the beta coefficient. It is based upon the assumption that all non-market risk (unsystematic risk) can be eliminated through diversification. The risk that cannot be eliminated through diversification is called systematic risk. Systematic risk is the risk for which investors require compensation.

The CAPM is applied by adding a risk-free ROR to a market risk premium which is adjusted proportionately to reflect the systematic risk of the individual security relative to the market. The measure of relative risk of the security to the market is beta.

Mathematically, the following represents the simple CAPM:

$R_s = R_f + b \times (R_m - R_f)$, where:
R_s is the required return on stock;
b is the beta of the individual stock (i.e., measure of systematic risk);
R_m is the return on the market; and
R_f is the return on risk-free asset (i.e., treasury security).

Avera PFT, p. 33; UI Brief, p. 24.

The beta measure (systematic risk) was obtained from Value Line. The expected return on the market portfolio, the equity risk premium, is unobservable. It was estimated by taking a DCF approach to back into the market equity risk premium. The DCF analysis examined the dividend paying companies in the S&P 500. According to the Company, these 393 firms reasonably represent the market as a whole for purposes of answering the question "what do investors require today in the equity market?" The Company calculated DCF cost estimates using the earnings growth forecasts published by Value Line, Yahoo/IBES and Zacks, weighting them by the company's proportion of total market value. The Company added the implied average growth rate to a year-ahead dividend yield for these companies, to calculate a current DCF cost of common equity estimate for the market as a whole of 12.9%. Then the Company subtracted a risk free rate of 3.3%, and the resultant estimated forward looking market equity risk premium was 9.6%. Overall, these CAPM cost estimates ranged from 8.6% to 12.4%, and the Company used the mean CAPM cost estimate of 10.3%. The 10.3% CAPM indicated cost of capital estimate was weighted by 25% into the overall cost of equity recommendation. Avera PFT, pp. 33 and 34; Exhibit WEA-6; UI Responses to Interrogatories FI-17 and FI-29; UI Brief, pp. 24 and 25.

The OCC also employed a CAPM and used the standard three inputs: the risk-free rate of interest, beta (the systematic risk measure), and the equity or market risk premium. According to the OCC, the risk-free rate of interest is 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. Finally, the expected equity or market risk premium. Woolridge PFT, p. 40; OCC Brief, p. 22.

For the risk-free rate of interest, the OCC reviewed the recent trend in interest rates and determined the yield on 30-year Treasury bonds has been in the 2.5% to 4.0% range over 2011–2013 time period. To be conservative, the OCC recommended 4.0%, as the risk-free rate, or R_f. The OCC employed the average betas for the companies in the OCC Utility Group as provided in Value Line. The average beta for the group was 0.70. The equity risk premium is defined as 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. The OCC indicated this portion to be the most difficult part to estimate in the application of CAPM. Woolridge PFT, pp. 41 and 42; Exhibit JRW-11, p. 3; OCC Brief, pp. 22 and 23.

To determine an equity risk premium, the OCC reviewed the results of over 30 equity risk premium studies and surveys performed over the past decade. These were presented on page 5 of Exhibit JRW-11 and include the summary equity risk premium results of (1) the annual study of historic risk premiums as provided by Ibbotson Associates; (2) ex ante equity risk premium studies commissioned by the Social Security Administration (as well other similar studies labeled “Puzzle Research”); (3) equity risk premium surveys of CFOs, Financial Forecasters, and academics; and (4) Building Block approaches to the equity risk premium. The overall median equity risk premium of these studies is 4.97%. The OCC separately reviewed the results of the studies on page 5 of Exhibit JRW-11 that were published after January 2, 2010. The median figure is 4.83%. As a market risk premium in the OCC CAPM analysis, the following conclusion was made: “Much of the data indicates that the market risk premium is in the 4.5% to 5.5% range.” To determine an equity risk premium, the OCC reviewed the results of over 30 equity risk premium studies and surveys performed over the past decade. Woolridge PFT, pp. 47 and 48, 57; OCC Brief, pp. 22 and 23; Tr. 5/15/13, pp. 2337 and 2338. Based upon its analysis, the OCC indicated the CAPM derived cost of equity was 7.5% as:

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
OCC Utility Group	4.00%	0.70	5.00%	7.5%

Woolridge PFT, p. 57; OCC Brief, p. 24.

Dr. Wooldridge asserted that, as a whole, the 12.9% cost of equity estimate for the long-run return on market was too high. The Company stated that this assertion is unfounded. According to the Company, Dr. Woolridge’s agreement during cross-examination that in more than half the years from 1926 through 2012, the stock market earned more than the 12.9% is evidence that 12.9% was a reasonable figure. Tr. 5/15/13, p. 2583; UI Brief, p. 25.

The Company also had other issues with the OCC’s CAPM application, primarily in the estimation of the equity risk premium portion. According to the Company, the OCC’s proposed 5% equity risk premium reflects an opinion of what the number should be, and not any calculation. For example, the Company suggested that the OCC merely listed more than 40 equity risk premium numbers from a host of sources, identifying the numbers as mean averages; categorized these numbers into four categories; determined the median of the numbers in each category; and then showed the mean and the median of the medians from the four categories. A subset of the 40 plus numbers was developed and an estimation that most of the numbers are between 4.5% and 5.5%, and 5.0% was picked to use as the equity risk premium. Overall the Company's criticism was that despite the appearance of a thorough review, the OCC just picked a number to serve as proxy for the equity risk premium portion in the CAPM. Woolridge PFT, p. 47; Exhibit JRW-11, pp. 5 and 6; Tr. 5/23/13, pp. 2541 and 2542; UI Brief, p. 33.

The Company also pointed to an error in Exhibit JRW-11 as the OCC showed the Ibbotson arithmetic mean number to be 5.70% for the historical risk premium and 6.13% as the arithmetic mean number for the Ibbotson and Chen building block approach. The actual 2013 Ibbotson arithmetic mean number is 6.70%, applicable to both the historical risk premium and building block approach. This is 100 basis points higher than the number used for the historical risk premium and 57 basis points higher than the number he used for the building block. UI also provided its opinion as to the merits of using arithmetic as opposed to geometric mean in this estimation of equity risk premium. Overall, the Company opined that the OCC's 5.5% equity risk premium must be rejected along with the CAPM methodology employed. Woolridge in JRW-11, pp. 5 and 6; Tr. 5/23/13, p. 2543; UI Late Filed Exhibit No. 101; UI Brief, p. 34.

The OCC found fault with the Company's equity risk premium. The Company 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. The Company estimated market return of 12.9% for the S&P 500 equals the sum of the dividend yield of 2.6% and expected EPS growth rate of 10.3%. The expected EPS growth rate is the average of the expected EPS growth rates from Wall Street analysts as provided by I/B/E/S. The OCC found this equity risk premium excessive due to an inflated expected market return. The expected market return is excessive, in turn, due to the projected DCF growth rate of 10.3%. As the OCC noted in the DCF discussion, expected EPS growth rates of Wall Street analysts are highly inaccurate, overly optimistic, and upwardly biased, and a projected EPS growth rate of 10.3% was inconsistent with historic and prospective economic and earnings growth in the U.S. Woolridge PFT, p. 59; OCC Brief, pp. 28 and 29. The OCC evaluated growth in nominal Gross Domestic Product (GDP), S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960 and a summary is given in the table below.

Nominal GDP	6.80%
S&P 500 Stock Price	6.21%
S&P 500 EPS	6.98%
S&P 500 DPS	5.18%
Average	6.29%

Woolridge PFT, Exhibit JRW-14, p. 1.

These results suggest the historical long-term growth rates for GDP, S&P EPS, and S&P DPS to be in the 5% to 7% range and supported the OCC's position that the Company's proposed equity risk premium of 10.3% to be vastly overstated. To accept the Company's 10.3% equity risk premium would imply acceptance of the idea that the electric industry would grow at a pace greater than that of the nation as whole perpetually. Woolridge PFT, p. 60; OCC Brief, p. 29. Likewise, the OCC pointed out that recent economic trends showed a slowing down of the US economy as nominal GDP growth has slowed down to the 4% to 5% range, while economists were predicting projected long-term GDP growth rates in the 4.5% to 4.8% range. Typically one cannot expect a particular industry to grow faster than the economy it operated within over the long-run, therefore, the Company's figures appear to be unrealistic. According to the OCC, the Company's application of the DCF model to the S&P500 would not be an appropriate application of the financial theory as one stage DCF models would be used for industries that are in the mature growth phase and the US economy would be considered mature. A more appropriate application of the theory would be to use a two-stage or multistage growth model. Woolridge PFT, p. 62; OCC Brief, p. 30; Tr. 4/30/13, pp. 1313-1319; Tr. 5/15/13, pp. 2327-2334.

The OCC also clarified an issue brought to light during the Company's review of the numerous equity risk premium studies examined by the OCC. The OCC offered that the Company's cross-examination of the OCC would imply in the record that the Authority favored the equity risk premium to be calculated with the arithmetic mean. The OCC indicated this to be false and misleading because numerous PURA Decisions indicated that a combination of arithmetic and geometric mean had been used for the equity risk premium. A small sampling of these Decisions were: Decision dated June 30, 2010 in the 2009 CL&P Rate Case Decision at page 110; Decision dated September 8, 2010 in Docket No. 10-02-13, Application of the Aquarion Water Company to Amend Rate Schedules at pages 118 and 119, and Decision dated July 14, 2010 in Docket No. 09-12-11, Application of The Connecticut Light and Power Company to Amend Rate Schedules at page 113. The OCC indicated the Authority's past precedent to use both arithmetic and geometric estimates of equity risk premium; hence, the OCC recommendation would be in line with those Decisions. OCC Brief, pp. 32 and 33.

f. Utility Risk Premium

The Company incorporated the utility risk premium method. This method of calculating investors' required return builds from the observable risk-return tradeoff on bonds. The risk premium estimate of investors' required return is calculated by adding an equity risk premium to observable bond yields. The proxy for the utilities' cost of equity was to examine the returns authorized by state commissions. The data source was the RRA reports of ROEs authorized by utility commissions each year from 1974 through 2012 as reported by RRA. For each year, the Company subtracted the average utility bond yield from the average authorized ROE to estimate the equity risk premium – the amount that must be added to the return on a utility bond for a potential investor to invest in utility stock rather than utility bonds. Based upon this methodology, the average implied utility equity risk premium for utility cost of equity over utility bonds was 3.47%. Avera PFT, p. 36, Exhibit WEA-7; UI Brief, pp. 25 and 26.

The Company indicated that the historical nature of risk premium studies underestimated the cost of capital given utility firms now face greater risk than in the past. The results of a regression analysis confirms that in times of relatively low interest rates, equity risk premiums tend to be higher; conversely, in times of relatively high interest rates, equity risk premiums tend to be lower. The 3.47% equity risk premium was adjusted to 5.13% to reflect today's relatively low interest rates. Adding the 5.13% adjusted equity risk premium to the 5.45% yield on BBB utility bonds for 2013, resulted in a 10.58% (10.6% rounded) utility risk premium cost of equity. The 10.6% indicated cost of equity was weighted 25% into the Company's overall ROE recommendation. Avera PFT, pp. 37-39; Exhibit WEA-7; UI Response to Interrogatory FI-46; Tr. 4/30/12, pp. 1172-1176; Tr. 5/23/13, p. 2486; UI Brief, p. 26.

The Company utility risk premium 10.6% cost of equity rate included (1) a 2013 utility bond yield of 4.86%, (2) an interest rate adjustment of 1.66%, and (3) a risk premium of 5.13%. Avera PFT, p. 39. The OCC did not perform a utility risk premium method and did not believe it was a market-based method and should not be used of the cost of equity estimation process. The OCC indicated the base interest rate and the risk premium were excessive. The base interest rate was found in excess of investor return requirements because the base yield, the rate on A-rated utility bonds, was subjected to credit risk. The OCC finds the Company's risk premium to be inflated since the utilities have been selling at a market-to-book ratio in excess of 1.0 for many years and authorized rates of return have been greater than the return that investors require. Therefore, the risk premium produced from the 2008 Study is overstated as a measure of investor return requirements and produced an inflated equity cost rate. Woolridge PFT, p. 64; OCC Brief, p. 34; Tr. 4/30/13, pp. 1323-1326.

Lastly, the OCC pointed out that the portion of the risk premium approach that uses the allowed authorized returns as a proxy determining required returns in the stock market reflected utility commission behavior. Commission's authorized returns should not be relied upon as a proxy from a cost of capital approach that should be market based. The OCC indicated that the Company's own witness confirmed this:

> And, you know, if you look at the authorized returns, first of all, there tends to be a lag between when, say, capital costs and interest rates change and ROE decisions are made because in most states you have, you know, you have everything from discovery, testimony, hearings over a period of time, and eventually you have a decision, so that decision reflects what's in the record maybe six months to a year before, so there's usually a lag. But also over time if you look at, you know, the market to book ratios for gas companies, electric companies, it's been above -- significantly above one for the most part, which says these authorized returns over time have tended to be above what investors require.

OCC Brief, p. 34; Tr. 5/15/13, pp. 2334 and 2335.

g. Parties' Summary Results

The table below provides a summary of Dr. Avera's and Dr. Woolridge's various costs of capital method results with respect to the two proxy groups employed:

Method	Company Utility Group	OCC Utility Group
DCF	9.60%	8.80%
Equity Risk Premium Model	10.60%	NA
CAPM	10.30%	7.50%
Indicated ROE	10.10%	8.75%
Adjustment for Flotation Cost	0.20%	0.00%
Indicated ROE after Adjustment	10.30%	8.75%
Overall ROE Range	9.60% to 10.6%	7.50% to 8.80%

Avera PFT, pp. 32, 34, and 39, Exhibit WEA-2;
Woolridge PFT, Exhibits JRW-10 and JRW-11.

6. Authority Analysis of Cost of Equity

a. Overview: Economic Changes and Survey of Allowed Returns

The Company requested a 10.25% ROE based upon the review performed by Dr. Avera, while the OCC recommended an 8.75% ROE based upon Dr. Woolridge's analysis.

The Company provided the following financial and economic statistics related to GDP, Consumer Price Index (CPI), Unemployment, U.S. Treasury rates and other relevant information covering the changes in these indices from the time of its last rate case through most recent quarter or month, whichever is most relevant. This information is contained in Table A below:

TABLE A: Financial Indicators: 2008 to Present

Financial/Economic Indicator	2008	2012 (latest month or quarter)*	2013 (latest day, month or quarter)*	Change 2008 to 2012	Change 2008 to Present
Gross Domestic Product (Trillions)	14,291.5	15,684.80	N/A	2.35%	N/A
Consumer Price Index (CPI)	215.3	229.47	232.2	6.58%	7.85%
Unemployment Rate (National)	5.80%	8.80%	7.70%	3.00%	1.90%
Unemployment Rate (Connecticut)	5.64%	8.34%	8.00%	2.70%	2.36%
U.S. Treasury Bills (90-day)	1.37%	0.09%	0.09%	(1.28%)	(1.28%)
U.S. Treasury Bills (180-day)	1.62%	0.13%	0.11%	(1.49%)	(1.51%)
U.S. Treasury Bonds (10-year)	3.66%	1.80%	1.96%	(1.86%)	(1.70%)
U.S. Treasury Bonds (20-year)	4.36%	2.54%	2.78%	(1.82%)	(1.58%)
U.S. Treasury Bonds (30-year)	4.28%	2.92%	3.16%	(1.36%)	(1.12%)
State Allowed ROE's for utilities	10.46%	10.15%	----	(0.31%)	----
Market-to-book ratios for UI	1.68	1.61	----	(4.50%)	----
Market-to-book ratios for the Company Utility Group	1.32	1.41	----	6.82%	----
Dividend Yield UIL	----	4.70%	4.60%	----	----
Dividend Yield-Industry Average	----	----	3.84%	----	----

UI Response to Interrogatory FI-15.

The Company believed that interest rates on 10-year and 30-year US Treasury bonds were trending upward since July of 2012 based upon investor's speculation that the Federal Open Market Committee (FOMC) may slow down or discontinue the Federal Reserve Bank's accommodative monetary policy which would raise interest rates in near term. Tr. 5/23/13, pp. 2622-2624; UI Brief, p. 17. The Company also suggested that investor's growth expectations for UIL stock price has increased in recent months as a result of the state's new Comprehensive Energy Strategy, conversion of Connecticut customer's to natural gas heating, enhanced investment in transmission and a more favorable regulatory environment. Greater growth expectation for the UIL stock price would support a higher ROE for the Company. UI Response to Interrogatory FI-8; UI Late Filed Exhibit No. 100; UI Brief, p. 18.

Overall, the Company expressed the opinion that interest rates are expected to increase as the current low level of interest rates is the result of tepid economic growth and aggressive Federal Reserve policy to reduce unemployment and offset fiscal drag. The Company indicated the prospect of future Federal fiscal cuts was unclear, but the 2% increase to payroll tax in effect since January 2013 has had a negative impact on consumer confidence and spending. The Company suggested that the fiscal drag on the economy has been offset by Federal Reserve policy and other positive effects in the underlying economy. UI Response to Interrogatory FI-37; Tr. 4/30/13, pp. 1149-1151.

The OCC indicated that since the time of its last rate proceeding, UI operated in a time period of historically low interest rates. According to the OCC, the yields on A rated public utility bonds peaked in November 2008 at 7.75% during the financial crisis and have since declined to about 4.2% as of February 2013. These yields are at historically low levels. These interest values are shown in Figure 2 below. Since the time of UI's last rate case, the average yields for these bonds declined from 6.37% to 4.02% over the two time periods. These yields indicate a decline in utility capital costs of more than 200 basis points. The OCC maintained that since the time period surrounding the adjudication of this proceeding, interest rates have decreased and then they have bumped up. To the OCC, this was an indication of the maintenance of a low interest rate environment, not a definitive trend upwards as the Company suggested. Likewise, there was an indication from the OCC that the maintenance of a low interest rate environment would be aligned with the national unemployment rate. Thus, until unemployment reduces to 6.5% or less, it would be unlikely to see increases in US Treasury yields. Tr. 5/15/13, pp. 2279-2287. The figure below presents the OCC's summary of long-term 'A' rated public utility bond yields over 2008 and 2012-2013:

Apr-08	6.29		Sep-12	4.02
May-08	6.27		Oct-12	3.91
Jun-08	6.38		Nov-12	3.84
Jul-08	6.40		Dec-12	4.00
Aug-08	6.37		Jan-13	4.15
Sep-08	6.49		Feb-13	4.18
Average	6.37		Average	4.02

Data Source: Mergent Bond Record.

The decline in interest rates was acknowledged by the Company as the equity cost rate for UI declined since Dr. Avera presented testimony in Docket No. 08-07-04. Woolridge PFT, pp. 10 and 11; Exhibit JRW-3; Tr. 4/30/13, pp. 1222 and1223; OCC Brief, pp. 8 and 9. The downward trend in national interest rates has translated into lower authorized ROEs for electric utilities nationally since UI's last rate case. The OCC opined that in the past, many utility commissions were reluctant to set authorized ROEs at rates below 10%, which seems to have changed recently. This was shown by the fact that the average authorized ROE for electric utilities in the first quarter of 2013 was 9.75%.[23] Tr. 4/30/13, pp. 1231 and 1232; Tr. 5/15/13, p. 2481; OCC Brief, pp. 13 and 24.

The PURA focused on economic and financial changes since the Company's last rate case, the application of the cost of capital models proposed by UI and the OCC witnesses, the Authority's review of each witness' recommendations, and its own application of the cost of capital models as applied to the financial data in the record. The Authority did not rely on any one cost of capital method, but incorporated several methodologies accepted in the financial literature.

The Authority reviewed the changes to several financial and economic indicators to take account of the economic trends that have occurred since the Company's last rate case. Approximately four years have passed since the rates were approved in the 2009 Decision. There have been several noteworthy changes in this span of time. The first is the economic recession that began in the third quarter of 2008. It resulted in steep declines to the stock market, real estate market, and resulted in increased numbers of unemployed and underemployed workers. Unfortunately, the beginnings of this recession corresponded with the Company's last rate proceeding. In response, the Authority incorporated various financial mechanisms such as the debt tracker and pension tracker to assist the Company to mitigate its financial risk during that troubled economic period. In addition, a decoupling mechanism and earnings sharing mechanism were incorporated into rate polices, but these methods were approved separately and not related to the economic conditions. In response to the recession, the Federal government intervened to support the banking and auto sectors, as well as to provide injections of money to state governments. The accommodative, cheap money policies and resultant low interest rate environment of the Federal Reserve Bank (Fed) continue to the present, though there is discussion that these policies will likely gradually reverse should the national unemployment rate reach 6.5%. Tr. 5/15/13, p. 2285.

The poor economic conditions are evident in the table figures above. Since the 2009 Decision, U.S. economic growth has under-paced the increase in inflation. For instance, GDP increased by approximately 2.35% while inflation as measured by the CPI increased by 6.58%. Although there are some signs of improvement to the economy, such as unemployment easing off its highs during the height of the recession, unemployment still remains high at 7.7% nationally and 8.0% in Connecticut. Achieving a 6.5% national rate of unemployment, which would trigger the Fed's reversal to its accommodative monetary policy, would be highly desired but does not appear likely in the near future.

[23] The 9.75% excludes the authorized ROEs from Virginia, which include ROE adders for specific generation projects.

Short-term interest rates (90-day and 180-day U.S. Treasury Bills) have decreased almost to zero (0.09% and 0.11%). Ten-year U.S. Treasury Notes have decreased by approximately 196 basis points while longer term rates have also decreased on average, by 158 basis points for the 20-year U.S. Treasury bond to present and by 112 basis points for the 30-year U.S. Treasury bonds. Although the Company's observation is correct that US longer term bonds have increased slightly since the Application was filed, for example the 20-year US Treasury Note increased 24 basis points from 2.54% December 2012 to 2.78% at April 2013 and the 30-year US Treasury Note increased 24 basis points from 2.92% to 3.16% over the same time period, the Authority concurs with the OCC that these interest rates "have gone up and these have gone down." Tr. 5/15/13, pp. 2279-2287. Overall, a 24-basis point increase in the last five months does not appear to be indicative of a rapid upward trend in US government bonds as contended by the Company. Based upon the slow movement downward in the US unemployment rate, the Authority is not convinced that the US economy and US Treasury rates are ready to make a rapid upward spiral as the Company would want the PURA to believe. UI Response to Interrogatory FI-15; Tr. 5/15/13, pp. 2279-2287.

In its Written Exceptions, the Company was critical of the Authority's discussion of interest rate movements, citing to interest rate movements after the close of the hearing record and FED Chairman's Ben Bernanke's testimony on July 17, 2013. UI Written Exceptions, pp. 48-51. The Authority notes its analysis is reflective as of the close of the record on the last day of the hearing.

The trend in declining U.S. Treasury rates is reflected in the decline of state commission allowed ROEs. Over the time period since UI's last rate case, the average state-allowed ROE for electric utilities declined 31 basis points from 10.46% to 10.15%. UI Response to Interrogatory FI-15. Examining these allowed ROEs for electric utilities in the third quarter of 2013, the downward trend continues as the RRA report shows that of the 11 non-Virginia allowed ROEs which ranged between 9.30% to 10.20% and averaged 9.73%.[24] UI Late Filed Exhibit No. 52, p. 5; UI Reply Brief, p. 20.

Typically, the Authority would incorporate the downward trend in the long-term U.S. Treasury Bond rates of 112 basis points to the Company's last allowed ROE of 8.75% to get an updated ROE. In this case, the OCC concurred that the last allowed return was reasonable for the present time period. As such, the Authority finds the updated ROE to be acceptable at 8.75%. The Authority conducted a survey of Connecticut rate case Decisions since the 2009 Decision which allowed 8.75%. The Authority also notes that these lower allowed returns transcend other utilities as well. For example, the Decision dated September 8, 2010, in Docket No. 10-02-13, Application of the Aquarion Water Company to Amend Rate Schedules, the resulting ROE was 9.95%. In the Decision dated January 28, 2008, in Docket No. 07-07-01, Application of The Connecticut Light and Power Company to Amend Rate Schedules, the Authority allowed a 9.4% ROE. In the Decision dated July 30, 2009, in Docket No. 08-12-06, Application of Connecticut Natural Gas Corporation for a Rate Increase, a 9.31% ROE was granted. Likewise, in

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[24] Common Wealth of Virginia Commission allowed returns are excluded from the average as the Virginia legislature has included provisions for bonuses to allowed returns to granted. Tr. 4/30/13, pp. 1231 and 1232.

the Decision dated July 17, 2009, in Docket No. 08-12-07, Application of The Southern Connecticut Gas Company for a Rate Increase, a 9.26% ROE was granted. Given these awarded ROEs in Connecticut since the 2009 Decision, the range of reasonableness is 9.26% to 9.95%, with emphasis on the lower end of the range. The Authority used the survey to establish low-end parameters.

The Company and the OCC arrived at highly divergent results. The Authority will construct its own analysis and computations to determine which produced the more reliable results. The Authority relied on the record evidence, including raw data provided by the Company and the OCC to perform the various methods and computations and develop its own permitted range for each cost of capital method employed. The DCF, CAPM, Utility Risk Premium were analyzed based upon their submission in this proceeding in the attempt to incorporate different approaches to the estimation of the ROE. The methods included in UI's Test of Reasonableness were only included as benchmarking means for the Company. The Authority also examined these on a cursory level and provides comments. The Authority wants to be clear that a lack of explicit rejection as in past Decisions, should not be interpreted by the Company as implicit acceptance for later proceedings. The review of each witness position and comments, and the results of the Authority's analysis are detailed below.

b. Introduction and General Issues

i. Financial Condition and Risk

The Company's testimony presented a picture of financial peril due to the Authority's last allowed return of 8.75%. Examining the Company's financial performance shows a vastly different picture, indeed it is a picture of a company experiencing financial success in an incredibly difficult economic environment as depicted in Table A above. The Authority examined the Company's quantitative credit rating measures related to liquidity such as FFO to Interest Coverage and FFO to Total Debt. These are found to be within industry parameters and steady. Examining the other key financial ratios provided by the Company again shows a strong performance by UI. Results in 2012, show a company with strong coverage ratios with times interest earned at 4.39x and a fixed coverage ratio at 3.24x. Examining the profitability ratios shows operating margin at 18.57% and profit margin at 17.45%. The Company's estimates for 2013 through 2014 are somewhat lower than the 2012 year, but still very strong. UI Responses to Interrogatories FI-2 and FI-71. These quantitative credit rating financial ratios depict a strong financially sound company, not a company that was hampered due to 8.75% allowed ROE. By the Company's own admission, it has remained financially viable and stable since 2008 and holds on to its investment grade credit rating primarily as a result of it being authorized to maintain a 50/50 equity to debt capitalization mix. As noted above in Section II.G.4. Authority Analysis of Capital Structure, the Company was granted a revenue increase based upon its proposed 50/50 capitalization mix, thus, nothing should impact its financial viability and ability to hold on to it investment grade credit rating.

Another area cited by the Company where the 8.75% allowed ROE impacted its ability to do business was in accessing the equity markets. The Company claimed that after the 2009 Decision was released, its stock price decreased sharply. While that may have been the case, the reality is that all equities decreased in stock price after the recession began. The Company's connection between stock price decrease and the allowed ROE is misleading. The Company is not immune to the effects of the general economic environment. Likewise, the after effects of the Company's stock performance during the recession clearly shows a firm whose stock price has come back strong. UIL 2012 SEC 10-k, p. 21. In term of investor weariness of UI, the 2010 oversubscribed equity offers indications otherwise. In the two-year period since the oversubscribed 2010 equity offering, UIL shareholders have enjoyed a stock price appreciation of approximately 52% plus the dividends paid to them. UI Late Filed Exhibit No. 48; Tr. 4/29/13, pp. 993-993 and 1001.

Another means to examine market performance is to evaluate how a firms' debt and equity offerings are received by investors. The Authority concurs that the Company had no trouble raising equity or debt over the 2009 and 2010 offerings. Both its equity offerings were oversubscribed by investors. The Authority views this as positive re-enforcement that not only the Company has done well but that investors are not purely high-ROE focused. One area the Authority finds that the Company downplayed during this proceeding is the cash flow benefits it has enjoyed by the implementation of the decoupling mechanism. The Company admittedly agreed that decoupling ensures that the allowed revenue requirement is collected; therefore, it supports financial stability and steady cash flow. The fact that UI earned its allowed return since the 2009 Decision is supportive of the Authority's finding with regard to the decoupling mechanism's financial benefits. These benefits provide greater predictability in the collection of the Company's allowed revenue requirement. Therefore, these benefits have also accrued to UI's only shareholder (UIL) since the dividend payout ratio is expected to increase in 2013 (130%) and remain steady at 94% over RY1 and RY2 based upon the Company's Application. In contrast, the average dividend payout ratio from UI to UIL was 78% over the time period from 2008 through 2012. UI Response to Interrogatory FI-066; Tr. 4/29/13, pp. 958-963.

The Authority's review shows a company with strong financial ratios, which meet the criteria for its present credit rating. The Company had success accessing the credit markets as evidenced by the oversubscription of its equity offerings in 2009 and 2010. The Company's stock price also steadily appreciated since its last rate case providing its shareholders with strong investment return of over 50% price appreciation since 2010. The Company also enjoyed regulatory support as it has been consistently granted the 50/50 capital structure that it credits as a factor in being able to maintain an investment grade credit rating as well as the decoupling mechanism, which has allowed it to actually earn its allowed revenue requirement during the time period of the recession. Based upon the record, the Authority finds UI to be financially strong, stable and finds the Company's 8.75% ROE inadequacy argument to be poor.

Overall, the AG captured the argument best by identifying the following criteria all of which when taken together support the Authority's finding of strong financial condition and adequacy of the 8.75% ROE granted in the last rate proceeding. The argument is as follows:

1. interest rates and cost of capital are at historic low levels and are roughly 200 basis points below the levels at the time that UI's ROE of 8.75 percent was approved in Docket No. 08-07-04;

2. UI's currently authorized ROE of 8.75% has not in any way impeded the Company's ability to raise capital as UI has raised both debt and equity capital in recent years to purchase three natural gas distribution companies;
3. over the last five years, UIL stock has outperformed both the S&P 500 and the Dow Jones Industrials Utilities Index;
4. authorized ROEs for other regulated electric distribution companies are declining nationwide, reflecting the historically low interests rates and costs of capital; and
5. UI has earned above its authorized 8.75% ROE in five out of the last ten years and in three out of the last four years.

UI Response to Interrogatory OCC-192;
AG Reply Brief, p. 3.

The above argument provides a true picture of the Company's financial situation since its last rate case. Also in that proceeding, the Company stated it can obtain a ratings increase by showing the ratings agencies the ability to recover costs, earn its allowed ROE, maintain a liquidity factor of 50% long-term debt and hold strong performance on a number of financial ratios. Based upon the record evidence, UI has done all of this and more over the past four years such as showing successful access to debt and equity markets, obtaining regulatory support with the successful implementation of its revenue decoupling pilot program, thereby, reducing its downside risk as decoupling stabilizes cash flow as the risk of collecting the projected revenue requirement is reduced. With regards to the credit rating increase, the Authority finds that rating agencies' policy has been to impose a cap on the ratings of operating subsidiaries to that of the holding company. Therefore, UI is unlikely to be considered for a credit rating upgrade until UIL's financial condition improves so that it can obtain a credit rating upgrade. UI Responses to Interrogatories FI-1 and FI-3; Tr. 4/29/13, pp. 802-805.

Although the above analyses would lead one to conclude all is well for UI and simply grant UI the 8.75% allowed return as suggested by the other Parties to the proceeding, the Authority concurs with the Company that pre-supposition is inappropriate. The following analysis examines the cost of capital methodologies to estimate a forward looking allowed ROE.

ii. Proxy Group

The Authority considered the Company and the OCC witnesses' proxy groups. Both experts recommended using proxy groups consisting of publicly traded electric companies followed by Value Line. On the surface of the proxy group criteria selection, it appears both the Company and the OCC used very similar criteria such as the proxy company should be followed by Value Line, it should have paid consistent dividends, investment grade credit ratings, and a particular portion of revenues should come from the regulated business operations of the proxy company. The Authority finds these to be reasonable factors to consider in the selection of the proxy companies.

The Authority takes issue only with the percentage of regulated business criteria. It would appear that the only difference between the Company and the OCC is the percentage of regulated revenue considered. For example, the OCC recommended that proxy group companies have at least 50% of revenues from regulated electric revenues as reported by AUS Utility Reports. Alternatively, the Company cited that the basis for selecting its proxy electric companies was that 70% or greater of revenues be derived from regulated business operations as reported by AUS Utility Reports. The basis for this was the Company's interpretation of the record evidence in the 2009 Generic ROE Proceeding, which identified 70% as the threshold.

The Authority reviewed the summary of proxy group selection criteria, which were discussed by the parties in the 2009 Generic ROE Proceeding. The parties to that proceeding agreed in theory to the concept that one of the proxy company selection criteria would be the percent of regulated business. According to the consensus, that amount would be 70% of regulated revenues and/or assets should drive from the particular industry. Avera PFT, Exhibit WEA-1. Given the industry in question is the electric industry, one would expect the applicable criteria to be that 70% of revenues be derived from regulated electric revenues as reported in AUS Utility Reports. Examining the Company criteria, this is not the case. For the companies that are pure electric, it is clear that a 70% threshold is applied and those companies are selected for the proxy group. But for those companies identified as combination electric and gas, the Authority finds that the Company added both the percentage of regulated revenues from gas and electric operations and if the total added to 70%, then that company was added into the proxy group of companies. Therefore, hypothetically one could have a company in the proxy group that has 60% regulated gas revenues and 11% regulated electric revenues and pass the Company's test for inclusion.

The Authority does not find this approach to meet the spirit of the consensus position that 70% regulated revenues should derive from the particular utility business. In this case, the utility business is electric not a combination of electric and gas. In addition to the criteria previously described, the Authority revises the percentage of regulated revenue criteria to be 70% of regulated electric revenues as followed by AUS Utility Reports. Tr. 5/15/13, pp. 2290-2295. The Authority finds this appropriate as the valuation in question is for an electric utility and this allows the PURA to create a pure play electric proxy group. Furthermore, unlike the regulated water and gas industries, the regulated electric industry has many more publicly traded companies followed by Value Line; therefore, restricting to 70% the amount of regulated electric revenues still results in a large, robust proxy group. The Authority also accepts the OCC's recommendation to exclude CenterPoint due to recent merger activity and El Paso and Empire District due to dividend payment past history and Sempra due to the fact it received a low percentage of revenues from electric operations. These companies failed the Authority's criteria detailed below.

One final point with regard to the proxy group selection, for the most part, both the OCC and the Company recommended basically the same companies. Examining several of the proposed proxy companies that were from the combination of electric and gas utilities, there is some overlap between the Company and the OCC with regard to inclusion in the approved proxy group. It is clear that for those overlapping proxy companies that the Company's application of the 70% regulated revenues selection criteria basically breaks down to include companies with 50% or greater regulated electric revenues criteria as per the OCC's approach. As noted above, the Authority finds this approach unacceptable with respect to combination gas and electric companies.

The Authority's approved utility peer group (Authority Utility Group) represents the following selection criteria: (1) use applicable Value Line utility groups; (2) has consistently paid dividends; (3) not involved in merger or takeover activity; (4) 70% or more of revenues should be from regulated electric operations; (5) Value Line Projected EPS growth should be positive; and (6) credit ratings should be investment grade. In the case of the electric industry, the Authority implements more stringent screening criteria as there is a much larger universe of publicly traded electric utilities.

The table below provides a comparison of the proxy companies proposed by the Company and the OCC and also indicates those that passed the Authority's criteria. The Authority Utility Group consists of 23proxy companies and serves as the basis for its DCF and CAPM analyses.

Company Utility Group	**OCC Utility Group**	**Authority Utility Group**
ALLETE, Inc.	ALLETE, Inc.	ALLETE, Inc.
Alliant Energy Corp.	Alliant Energy Corp.	Alliant Energy Corp.
Ameren Corporation	Ameren Corporation	
American Electric Power Co.	American Electric Power Co.	American Electric Power Co.
Avista Corporation	Avista Corporation	
Black Hills Corporation	Black Hills Corporation	
CenterPoint Energy		
Cleco Corporation	Cleco Corporation	Cleco Corporation
CMS Energy Corporation	CMS Energy Corporation	
	Consolidated Edison, Inc.	Consolidated Edison, Inc.
	Dominion Resource, Inc.	
DTE Energy Company	DTE Energy Company	
	Duke Energy Company	Duke Energy Company
Edison International	Edison International	
ElPaso Electric		
	FirstEnergy Corporation	
Great Plains Energy Inc.	Great Plains Energy Inc.	Great Plains Energy Inc.
Hawaiian Electric Industries, Inc.	Hawaiian Electric Industries, Inc.	Hawaiian Electric Industries, Inc.
IDACORP, Inc.	IDACORP, Inc.	IDACORP, Inc.
	MGE Energy, Inc.	MGE Energy, Inc.
	Nextera Energy	
	Northeast Utilities	Northeast Utilities
NorthWestern Corporation	NorthWestern Corporation	NorthWestern Corporation
	NV Energy, Inc.	NV Energy, Inc.
Pepco Holdings, Inc.	Pepco Holdings, Inc.	Pepco Holdings, Inc.
PG&E Corporation	PG&E Corporation	PG&E Corporation
Pinnacle West Capital Corp.	Pinnacle West Capital Corp.	Pinnacle West Capital Corp.
PNM Resources, Inc.	PNM Resources, Inc.	PNM Resources, Inc.
Portland General Electric Co.	Portland General Electric Co.	Portland General Electric Co.
SCANA Corporation	SCANA Corporation	
SEMPRA		

	Southern Company	Southern Company
TECO Energy, Inc.	TECO Energy, Inc.	
UIL Holdings Corporation	UIL Holdings Corporation	
	UNS Energy Corp.	UNS Energy Corp.
Westar Energy, Inc.	Westar Energy, Inc.	Westar Energy, Inc.
Wisconsin Energy Corporation	Wisconsin Energy Corporation	Wisconsin Energy Corporation
	Xcel Energy, Inc.	Xcel Energy, Inc.

In its Written Exceptions, the Company suggested that the Authority Utility Group results in a proxy group with lower risk than the Company and that the resultant Authority Utility Group does not conform to the screening criteria identified by the Authority. The Authority Utility Group has less investment risk than UI and suggested an upward 25 basis point adjustment to the DCF result to adjust for the perceived risk differential between the Authority Utility Group and the Company. UI Written Exceptions, p. 36. Additionally, UI requested that UIL Holdings Corporation and First Energy Corporation be removed from the Authority Utility Group as these companies do not have 70% or more revenues from regulated electric utility operations. UI Written Exceptions, p. 42. The Authority examined the Companies' position and concurs. Regarding the inclusion of First Energy Corporation, the Authority reviewed its workpapers and determined that this company was not included in the DCF computations; therefore, no numerical computations are necessary to correct a typographical error. The table above is revised to correct the typographical error including First Energy Corporation. The Company also requested that UIL Holdings Corporation be removed from the Authority Utility Group. The Authority notes that UIL Holdings Corporation was included in the Authority Utility Group because it is the Company's parent corporation and was recommended by both the Company and the OCC as a proxy group company. The Authority should have clarified this inclusion in its narrative analysis. With this in mind, the Authority does concur with the Company that UIL Holdings Corporation does not have 70% or more regulated electric revenue operations and examined the impact of removing it from the Authority Utility Group. All else equal, the Authority's revision to exclude UIL Holding Corporation from the Authority Utility Group actually results in a 1 basis point reduction to its oveall ROE DCF range and the Authority finds this adjustment trivial and ignores this downward adjustment to its overall DCF result.

The Company's Written Exceptions also recommended that Ameren Corporation, Edison International and Nextera Energy meet the screening criteria and need to be included in the Authority Utility Group. UI Written Exceptions, p. 42. The Authority examined the Company's claim and disagrees for other reasons. Based upon the timeframe the Authority performed its analysis, Value Line's projected EPS growth for Ameren Corporation and Nextera Energy were both negative and Edison International had no EPS growth. The Authority also emphasizes the fact that Nextera Energy was not included by the Company in its proposed proxy group. Avera PFT, Exhibit WEA-3. Therefore, these companies were excluded. The Authority clarifies its screening criteria in this Decision to also include that Value Line's projected EPS growth should be positive. The Authority appreciates the Company's diligence in this matter regarding the clarification that positive projected Value Line EPS growth was a screening criteria used by the Authority's screening model that was not initially detailed in the narrative description. Based upon this clarification, the Authority makes no further adjustment to the Authority Utility Group.

Based upon the Authority's clarification regarding its selection criteria, the Authority finds no further changes are necessary to its resultant proxy group, the Authority Utility Group. The Authority is appreciative of the Company's diligence as it allowed for a more clear description of the process that the Authority took to establish the proxy companies. The Authority rejects the Company's claim that its proposed changes to the Authority Utility Group would require a 25 basis point upward adjustment raising the DCF result to 9.69% to reflect risk differential between the Authority original proxy group and those revisions proposed by the Company based upon the clarifications herein. UI Written Exceptions, p. 43.

iii. Decoupling

The record evidence overwhelmingly supports the conclusions that the decoupling mechanism has been supportive to UI from a cash flow perspective providing predictability and financial stability in an otherwise economically troubled climate. Financial theory would suggest that such a mechanism would tend to reduce risk and with less risk, there should be less return, all else equal. In reviewing the record evidence, the OCC's assessment basically concurred with the Company's position that the decoupling mechanisms have become more widespread in the electric utility industry with 36 States incorporating some type of decoupling mechanism for ratemaking purposes. Overall, the OCC indicated that decoupling better enables a company to earn its ROE. The OCC made no explicit adjustment to achieve its proposed 8.75% recommended ROE and indicated this figure was fair and that it accounted for decoupling without incorporating explicitly downward adjustment. Tr. 4/30/13, pp. 1280-1286. The AG noted that UI's allowed ROE was downwardly adjusted to account for decoupling and should continue to be monitored for its impact to the allowed ROE.

In this case, the Authority will not make an explicit downward adjustment to ROE, but notes that financial theory indicates a decoupling mechanism, which virtually guarantees the Company's ability to achieve its allowed revenues, eliminates some business risk that UI would otherwise face. Therefore, the Authority finds that an allowed return selected from low to midpoint of the range of reasonableness is appropriate and supported by the record evidence and financial theory.

c. Discounted Cash Flow Model

In reviewing the DCF approach, the Authority finds it necessary to address several differences between the Company and the OCC witnesses' applications of the model. They separately recommended different peer companies for inclusion in the proxy, and the Authority made revisions based upon the selection criteria it found appropriate and used these companies in both its DCF and CAPM analyses. Both witnesses used the constant growth form of the DCF which simplifies to $K=D1/P0 + G$. The Authority concurs with the suggested form of the DCF and incorporates it into the analysis.

i. Dividend Yield

In calculating the annual dividend yield, the Company used estimates of dividends to be paid over the next 12 months, which was obtained from Value Line. This annual dividend forecast was divided by a 30-day average stock price to arrive at the expected dividend yield for each firm in the Company Utility Group. These expected dividend yields ranged from 2.8% to 5.6% and average to 4.3%. The OCC employed the average of the six month of dividend yields and averaged that with the April, 2013 dividend yield from the AUS Monthly Utility Reports. For the group, the resulting average dividend yield was 3.95%. The OCC then adjusted this dividend yield by one half the expected growth rate.

The Company and the OCC differ over how to forecast dividend yield and the time period that they are calculated. Regarding the forecast of the dividend (D1), the Authority accepts the Company's proposal to use Value Line's estimate of dividends to be paid over the next 12 months (i.e., Value Line: Summary & Index, column (f)). This is based in part on the evidence in the 2009 Generic ROE proceeding and the fact that it is simply easier to utilize a number reported in Value Line than debate how much growth to be applied (full year or half year) to forecast the dividend portion. This debate can be lengthy in proceedings and the impact is *de minimum*. The Authority incorporates Value Line's estimate of dividends to be paid over the next 12 months [i.e., Value Line: Summary & Index, column (f)] as the D1 input to the DCF model.

Regarding the time period the data is collected, the Authority finds a 30-day average stock price long enough to capture changes in stock price movements and relatively simple to obtain from public sources online. The OCC's method of taking an average of dividend yields reported by AUS Monthly Utility Reports is one way to achieve the estimate, but it appears to be a roundabout way given these inputs are readily accessible given today's technology. The Authority incorporates a timeframe of 30 business days, or approximately 6 weeks, as reasonable for estimating the stock price portion for the dividend yield component of the DCF Model.

ii. Growth Rate

The growth element of the DCF application is the most complex and debated issue of all the DCF components. There were several areas of agreement and also several areas of debate. There was agreement from the Company and the OCC that professional stock analysts' five-year forecasts for EPS growth and Value Line's projections for EPS should be included in the estimation of the overall or composite growth component to apply in the DCF model. Regarding the professional analysts' five-year EPS forecasts, the Company proposes use of EPS growth projections from Value Line, Yahoo Finance/I/B/E/S, and Zacks; while the OCC recommended Value Line's projected growth rate estimates and the EPS growth rate forecasts as provided by Yahoo, Zacks and Reuters. The Authority sees little debate with regard to the incorporation of which professional analysts' EPS estimates to include and incorporates EPS growth projections from Value Line, Yahoo Finance/I/B/E/S, Zacks and Reuters.

One area of debate between the Company and the OCC is over the inclusion of Value Line's projections for DPS and BVPS. The Authority notes that in finance literature, there is general agreement that the DCF theory presumes that earnings, book value, market price and dividends all grow at the same rate. The Authority finds that under DCF theory and financial theory in general, all earnings will eventually accrue to investors through dividends and eventual sale of the stock. Even so, the cash stream an investor receives is a dividend and not the company's earnings. In reality, the investor only shares in those company earnings to the degree and timing the company wants the investor to participate in the company's performance (i.e., the dividend). A similar argument can be made for the inclusion of the BVPS growth rate into the DCF model since BVPS represents the underlying investment, which generates earnings and therefore dividends. Lastly from a more practical view point, the Authority finds that it is unlikely that an investor would examine the Value Line sheet for a company and look only for the EPS projections while those projections for DPS and BVPS are also there. Based upon its review, the Authority finds DPS and BVPS to be relevant growth rates. Therefore, the Authority's analysis also includes Value Line's projections for DPS and BVPS in its analysis. Tr. 4/3013, pp. 1305-1308.

The Company and the OCC have separately recommended inclusion of the sustainable growth rate (retention growth = br + sv) but there was some debate regarding the sv portion of the retention growth formula. As noted, the sv portion relates to future sale of stock above book value prices, which adds to external growth. The biggest factor, driving sustainable growth is the br figure, not the sv. Tr. 5/15/13, p. 2322. Clearly there is a presumption that Value Line's projections of BVPS take into account external growth. Likewise, the sv portion is only applicable when a company is in the process of issuing stock. The Authority agrees with the OCC's position that it is difficult to determine sv as one needs to know when a utility will undertake a stock offering and even more difficult to determine the market to book ratio of that stock offering at the time of its issuance. Under this circumstance, the sv inputs should be widely disseminated to the investment public and should be known and measurable. This is unlikely to happen as companies do not normally report to the media their plans to issue equity well in advance of the issue. It is clear that the greater portion of the sustainable growth rate does come from the br portion. Avera PFT, p. 27; Exhibit WEA-5, p. 1.

Examining the Company's assumption for estimating the sv portion, UI used the projected market-to-book ratio and the growth rate in common shares outstanding for the s portion while the v portion was computed as 1 minus the projected market-to-book. In this case, the Company made assumptions as to a stock offering being made and the amount issued. Exhibit WEA-5, page 1, shows that all the peer group companies are assumed to make a stock offering. The Authority finds this to be an unlikely assumption. Consequently, the Authority includes the sustainable growth formula, but puts little weight on the sv portion of the equation.

There was disagreement about including Value Line's five-year historic growth rates for EPS, DPS and BVPS in the estimation of the growth rate to be used in the DCF model. The Company strongly opposed inclusion of a historic growth rate in the calculation of an overall DCF growth rate. It argued that the historic growth rates have already been taken into account by stock analysts making EPS growth estimates. Avera PFT, pp. 20-24. Conversely, the OCC suggested historic rates, both the five- and ten-year, must be considered to provide a baseline of growth since investors have access to historic information, which provides the basis for investors' investment decisions. When asked how these historic growth rates were used to generate an overall DCF growth rate, the OCC merely stated that the projected figures carry more weight compared with the historic figures. Basically the projections are compared with the historic and inclusion of the historic figures depends on judgment. Tr. 5/15/13, p. 2325 and 2326. With this said, the Authority concurs that the five-year Value Line historic growth rates for EPS, DPS and BVPS should not be a separate input included in a composite growth rate for the DCF model. Although historic growth figures are excluded from the expected growth component of the DCF model, this does not suggest these historic growth figures have no place in the DCF analysis. Really these indicate the reasonableness of analyst forecasts. Therefore, the Authority used the Value Line's 5-year and 10-year historical growth rate figures for EPS, DPS and BVPS as a base line measurement means for evaluation of the forecasts.

iii. DCF Results

In its analysis, the Authority includes Value Line's five-year projected growth rate estimates for dividends, earnings and book value, as well as growth rates computed using the sustainable earnings/retention growth formula. The various Wall Street analysts' (Yahoo Finance, Zacks and Reuters) forecasts of EPS were also included in the analysis.

In applying the DCF model, the Authority reviewed the annual constant growth form and incorporated a screening mechanism, based upon the rationale that the cost of equity be greater than the cost of debt due to equity's greater risk. The Authority used the data in the record employing different measures of growth, including Value Line's projected growth rates for EPS, DPS and BVPS. Analyst EPS growth projections from Yahoo Finance/I/B/E/S, Zacks and Reuters were incorporated. The Sustainable Growth computation was also included. Overall, the Authority computed several scenarios using different estimates of growth. No one growth estimate was favored in place of another.[25]

Regarding the low side threshold, the Authority finds reasonable the concept that equity is more risky than debt. The Company suggested that it was reasonable to exclude any individual company result on the low end which falls below the average bond yield plus 100 basis points. The Authority finds this reasonable in theory. In establishing the low end elimination zone for indicated DCF cost of capital estimates, the Company used the implied BBB Utility Yield spread of 6.81% and excluded DCF results below 6.81%. The Authority's review finds that figure to be high. The latest Mergent Bond Record, May 2013 edition indicates that over the time period this rate proceeding commenced, the average BBB Public Utility Bond yield ranged from 4.49% to 4.74% and averaged approximately 4.64%. Therefore, it would appear the Company's downside screen is actually over 200 basis points above BBB Utility Bond yields. This fact is contrary to UI's testimony that it employed the FERC convention of 100 basis points added to prevailing public utility debt. The Authority's method is to add 100 basis points to the average Mergent BBB Public Utility Bond yield of 4.64% for 5.64%, and used 5.64% as its low end

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[25] The data (Value Line five-year Projected EPS, DPS and BVPS and EPS, DPS, and BVPS growth rates and Wall Street analyst's EPS estimates) used in the Authority's analysis was obtained from Late Filed Exhibit No. 55, Woolridge PFT, Exhibit JRW-10. Regarding the Authority's use of Value Line: Summary & Index's column (f) Estimated Dividend Next Year, the PURA used the most recent edition dated June 7, 2013. The Company agreed to take administrative notice of the latest Value Line: Summary & Index in its response to Interrogatory FI-16(d). The Authority notes that the use of the most recent edition served to increase the dividend yield portion in the DCF model and was a conservative assumption on the part of the Authority.

screen on individual DCF estimates.[26] None of the resultant DCF results were screened out on the low side.

On the high end, the Company eliminated outliers on the basis of the FERC's extreme outlier principle, which indicated that figures above 17.7% should be excluded. In this case, the Company excluded one DCF estimate of 18.8%. The resulting high end of the DCF results for the Company Utility Group was set by a cost of equity rate of 15.2%. Evidence was presented that the FERC extreme outlier or filter principles were established approximately 10 years ago and they have not been revised since, even though the financial markets have tumbled significantly as of a result of the 2008 recession. Tr. 4/30/13, pp. 1292-1295. The Authority examined historical US Treasury bond yields. Ten years ago, 20-year US Treasury rates were approximately 5%, while in 2013, the 20-year US Treasury rate is approximately 3%, for an approximate decline of 2% during these ten years.[27] The Authority incorporated a lower high end screen than the 17.7% DCF screen. There were only two indicated DCF results that met the Authority's filter, PNM Resources and Hawaiian Electric. The Authority elected to include these in the overall indicated DCF cost of capital range as these two companies only marginally violated the PURA's DCF filter by a couple of basis points each. The Authority finds this is a conservative approach to take.

Overall the Authority's indicated DCF range is 7.13% to 12.35% and averages to 9.24%. The Authority finds the average of 9.24% to be a reasonable estimate of the indicated DCF cost of capital methodology. As a final point, on the basis of the Authority's own DCF analysis, the Authority determines that its resulting tight DCF range is a strong indicator that its company peer group selection criteria in Section II.G.6.b.ii. Proxy Group, which utilizes a threshold that 70% or greater regulated revenues should be derived from the electric business, is a superior selection criteria as compared to both the Company's approach of adding the revenues of combination electric and gas and the OCC's 50% electric revenue threshold.

In its Written Exceptions, the Company indicated that the midpoint of the Authority's DCF range of 7.13% to 12.35% is 9.74%. UI Written Exceptions, p. 36. The Authority notes that its 9.24% is the average of the DCF results from the companies in the Authority Utility Group while the 7.13% and the 12.35% represent the minimum and the maximum DCF results used to establish a range of reasonableness. The average of a stream of over 20 results does not necessarily equal the average of the two endpoints of that same stream of figures. Therefore, the Authority finds that the Company's suggestion to revise the DCF result to 9.74% has no merit.

d. Capital Asset Pricing Model

The simple CAPM formula is widely accepted in cost of equity literature. As a result, the Authority will rely on the simple CAPM formula, and thus implemented a simple CAPM [$K = R_f + b \times (R_m - R_f)$]. There are several debates surrounding the application of

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26 The Company agreed to take administrative notice of the latest Mergent Bond Record in its response to Interrogatory FI-16(b).

27 The Company agreed to take administrative notice of recent and historical US Treasury Rates (90 day, 180 day, 10 year, 20 year and 30 year) from www.treasury.gov in its response to Interrogatory FI-16(a).

CAPM methodology such as the choice of the risk-free rate of interest, beta and risk premium.

i. Risk-Free Rate and Beta Estimate

The evidence regarding the selection of the risk-free rate of interest (R_f) does not show much controversy. The Company recommended using 3.3% from various sources including Value Line, which provided estimates for yields of 30-year U.S. Treasury Bond rates. Avera PFT, Exhibit WEA-6. The OCC also recommended the recent 30-year U.S. Treasury Bond yield of 4.0% based on its observation that 30-year US Treasury Bond yields have ranged between 2.5% and 4%, and recommended the 4% to be conservative. Woolridge PFT, pp. 41 and 42; Exhibit JRW-11. The Authority reviewed recent trends in 30-year US Treasury Bond yields and finds these have bounced up and down since January 2013, and in June 2013, reached 3.33%. Given current market conditions, the Authority finds it reasonable to use the average of the Company and the OCC proposals of 3.65% [i.e., (3.3% + 4%) / 2] as an acceptable proxy for the return on long-term risk-free rate of interest.

The measure of beta represents the volatility of a proxy group of companies to the aggregate market. Both the Company and the OCC recommended use of Value Line adjusted betas. Accordingly, the Authority incorporates Value Line adjusted betas into its analysis.[28] The beta of the Authority Utility Group is 0.68.

ii. Equity Risk Premium

A debate ensued regarding the estimation of the equity risk premium. The Company recommends 9.6% and the OCC recommended 5% based on their respective analyses. The Authority deliberated the Company's approach of using a DCF analysis on dividend paying companies in the S&P 500 to back into the equity risk premium and thought it to be an interesting approach to take. On the surface, the approach seemed plausible but the Authority took issue with the execution of the method, especially several of the assumptions made to estimate inputs. For instance, the Company stated that it selected 393 firms from the S&P 500 to represent the market as a whole. Likewise, the growth component of the market was estimated by weighting the expected market earnings growth forecasts from Value Line, Zacks, and Yahoo/IBES by the firm's proportion of the total market. These steps were taken to estimate the estimated return on the market (Rm) portion of the CAPM. The Authority examined the approach and found that a simple way to make this estimate is to use the Value Line's Summary & Index cover sheet. It provides many of the inputs the analyst could use directly without having to make assumptions to select a number of companies from the S&P 500. The Authority performed its own DCF analysis on the Value Line's 1700 companies using the data from the Value Line: Summary & Index and found the estimated return on the market to be lower than the Company's proposed 9.6%.

The Company proposal of applying the DCF model to measures of the market to back into the expected equity risk premium seems theoretically feasible. However, there

[28] The Authority used the most up to date adjusted Value Line betas dated March 22, 2013, February 22, 2013, and February 1, 2013, as provided by the OCC in Late Filed Exhibit No. 55.

are several complications brought to light by the OCC that the Authority supports. First, estimating the inputs to the DCF approach to generate an estimated return on the market requires using analyst estimates of growth. As noted by the OCC, expected EPS growth rates of Wall Street analysts are highly inaccurate, overly optimistic, and upwardly biased as compared to the historical performance. Woolridge PFT, p. 59; OCC Brief, pp. 28 and 29. Although it is difficult to evaluate the level of optimism, it is a factor that needs to be considered in the evaluation of cost of capital especially when expected growth rates are involved.

The OCC also raised another issue that questions the validity of a 9.6% estimate for the long-run equity risk premium. To accept this figure, one needs to believe that the long-run expected return on the stock market as a whole is 12.9% (9.6% plus the risk free rate of 3.3%). Given evidence that the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960 and a summary are much less than an average of 6.29%. Woolridge PFT, Exhibit JRW-14, p. 1. The Authority takes issue with the presumption that the return on the stock market can grow infinitely at a faster pace than the growth in the economy as a whole. It is reasonable to believe that at some point the growth in the overall US economy will serve as a cap to the growth in the stock market as a whole. The Authority concludes that the assumptions and implementation of the Company's DCF approach to estimating the long-run equity risk premium needs to be re-evaluated. The Authority believes one way to have mitigated the effects of optimistic growth inputs and the resultant expected equity risk premium that exceeded the growth rate of the overall economy can be to implement a two-stage or multi-stage DCF model considers various stages of growth in the US economy. Tr. 5/15/13, pp. 2332-2334. Although included in its overall computation of a reasonable estimate for the equity risk premium, the Authority places little weight on this approach.

Overall, the Company's criticism of the OCC's proposed 5% equity risk premium was that despite the appearance of thorough review, the OCC just picked a number to serve as proxy for the equity risk premium portion in the CAPM. UI Brief, p. 33. The Authority notes that the OCC's approach incorporates both the arithmetic mean approach and the geometric mean approach, and includes many academic studies examining the equity risk premium over the years. The OCC's approach is the most inclusive and has been included as an approach in numerous previous Decisions.[29] The OCC proposed 5% is included in the Authority's methodology to estimate the equity risk premium and the PURA placed greater weight on it than the Company's proposal.

The Authority review of equity risk premium determines that an investor should not expect a return much different than that produced by companies in the economy. In reviewing the methodologies presented, the Authority is drawn to the Ibbotson supply side model.[30] The Ibbotson supply side model suggests equity returns consist of inflation, the growth in real EPS, and income returns. One difference between the supply side model and the historical model is that the supply side excludes the growth in the price earnings (P/E) ratio. In Table C-1, Key Variables in Estimating the Cost of Capital

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[29] See for example the Decision dated July 14, 2010 in Docket No. 09-12-11, Application of Connecticut Water to Amend Rates, pp. 113 and 114.

[30] The Company agreed to take administrative notice of Morningstar's, Ibbotson Stocks, Bonds, Bills and Inflation (SBBI): 2013 Valuation Yearbook, 2013 edition, in its response to Interrogatory FI-16(h).

provides a comparison between the Ibbotson historical computation of the equity risk premium and the Ibbotson supply side equity risk premium. Both calculations use the arithmetic mean. In examining both figures, the difference is modest. For example, over the time period 1926-2012, the historical approach yields an equity risk premium of 6.70% while the supply side approach yields 6.11%. The Authority finds that the Ibbotson supply side approach is responsive to problems or biases contained in the historical data that are highlighted in the OCC's testimony. The Authority finds that it represents the best of both approaches in the sense that the building block approach is computed with an arithmetic mean. The Authority will use the Supply Side equity risk premium found in Table C-1 of the 2013 Ibbotson SBBI (6.11%) as one of the estimates to develop the equity risk premium.

Overall, the Authority incorporates the 6.11% from the Ibbotson Supply Side approach, the OCC's survey recommendation of 5% in approximate equal amounts and proportionately weighted to the Company's 9.6%. The Authority finds this reasonable especially in light of record evidence suggesting the equity risk premium can be as low as 3% based upon a recent CFA Institute article. Tr. 4/30/13, pp. 1177 and 1178, pp. 1217-1220 and pp.1276-1278; Tr. 5/15/13, pp. 2339-2343; OCC Late Filed Exhibits Nos. 54 and 97.

iii. Size Premium

A debate ensued regarding the inclusion or exclusion of a size premium. The Company asserted that it did not make a size adjustment for UIL's relatively small size compared to other utilities, either in his main DCF, CAPM and utility risk premium cost estimates or its check of reasonableness. The Company was aware that the Authority previously declined to take into account the difference in size among utilities in considering the cost of equity. The Company suggested that the size adjustment here reflects the documented difference between utilities and very large companies that dominate the S&P 500. Overall, the Company equated use of a size premium to an adjustment for size between utilities not between it and larger corporations. According to UIL, its approximate $2 billion capitalization is many times smaller than those in the S&P 500. UI Responses to Interrogatories FI-30, FI-31 and OCC-162 (Attachment 6); UI Brief, pp. 27 and 28 (footnote 16); Tr. 4/30/13, pp. 1059; 1157-1161 and pp. 1163-1166.

According to the OCC, the Company included a size adjustment in its CAPM approach for the size of the companies in the utility group. This adjustment is based on the historical stock market return studies as performed by Morningstar (formerly Ibbotson Associates). The OCC stated there are numerous errors in using historical market returns to compute risk premiums. Woolridge PFT, pp. 65 and 68; Tr. 4/30/13, pp. 1327-1330.

The OCC indicated that the Authority has rejected the inclusion of a size premium in a CAPM analysis in a number of rate proceedings. The Decisions for Birmingham Utilities, Inc., Valley Water Systems, Inc. and Aquarion Water of Connecticut reject the same type of adjustments recommended by the Company witness in the current proceeding.[31] Additionally, in The Connecticut Light & Power's last rate proceeding the Authority rejected the use of a size premium in its CAPM determination as follows:

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[31] See the Decision dated November 28, 2006 in Docket No. 06-05-10, Application of Birmingham Utilities, Inc. to Increase Rates, p. 74; Decision dated October 26, 2004 in Docket No. 04-02-14, Application For

> As stated in the past, the Department finds that incorporating a size adjustment in such a manner is not traditionally considered with the CAPM. In reality, the size premium is already considered in the Ibbotson Build-up Approach as noted in the 2009 Morningstar/Ibbotson Yearbook. Overall, in terms of regulation, government oversight, performance review, accounting standards, information disclosure, as monitored on an ongoing basis by commissions, state and federal agencies, utilities are different from industrials. The Department continues to find that size premiums are inappropriate for public utilities due to the effects of regulation and scrutiny these companies receive from regulators. Given the traditional form of CAPM does not include a size adjustment and the results of the empirical study reviewed, the Department rejects the incorporation of the proposed size adjustment to the CAPM.

Woolridge PFT, p. 68; 2009 CL& P Rate Case, p. 110.

As noted the Company equated use of a size premium to an adjustment for size between utilities not between it and larger corporations. The Authority finds this to be an improper comparison. The Authority reviewed the Company's contention that the adjustment made for size was somehow different from the size premium adjustments denied in past ratemaking Decisions. The Company witness testimony indicated that the size adjustment column is cited to Morningstar, 2012 SBBI Valuation Yearbook, Appendix C, Table C-1. Avera PFT, Exhibit WEA-12, p.1; UI Response to Interrogatory OCC-162 (Attachment 6). The Authority draws attention to this area of debate as the Company has gone out of its way to mask an area that has a long history with the Authority as something different. On the surface, if one reviewed only the Company Brief and its Reply Brief, then one would find some merit with the Company's argument that the adjustment is not for size. However, one must delve into the material to find the true nature of the proposed adjustment. The Authority concludes that the size adjustment included by the Company is no different from the size premium adjustments that have been rejected in the past. The Authority affirms its past precedent and rejects any type of size premium adjustment irrespective of how the description is couched by the Company.[32]

iv. CAPM Results

The computation below depicts the Authority's application of the simple CAPM. This yields 7.74% and is representative of the CAPM return in its overall analysis.

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate

an Increase in Rates For the Aquarion Water Company of Connecticut, p. 97. Decision dated March 30, 2007 in Docket No. 06-10-07, Application of Valley Water Systems, Inc. for Amendment of Rate Schedule, p. 50.

[32] The Authority draws attention to this area of debate as the Company has gone out of its way to mask an area that has a long history with the Authority as something different. On the surface, if one reviews only the Company Brief and its Reply Brief then one would find some merit with the Company's argument that the adjustment is not for size, but one must delve into the material in order to find the true nature of the proposed adjustment.

Authority Utility Group	3.65%	0.68	6.02%	7.74%

In its Written Exceptions, the Company found the Authority's application of the CAPM flawed based upon its objection that the weighting of the CAPM inputs used by the Authority was not transparent. The Company suggested that the equity risk premium be revised to 6.9% based upon the simple average of the Company's proposed 9.6%, the OCC's 5% recommendation and the 6.11% from Ibbotson Supply Side approach incorporated by the Authority. In support of its revision to use a simple average of the three methods, UI cited to the Decision dated June 29, 2011 in Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedule at page 133 (2010 Yankee Gas Rate Case). The Company also suggested that the OCC's 5% figure be revised to 5.2% based upon its belief that the OCC under reported the Ibbotson arithmetic risk premium in the computation that arrived at the OCC's overall 5% recommendation. Furthermore, the Company suggested that the Authority's incorporation of the Ibbotson Supply Side Equity Risk Premium of 6.11% be revised to reflect the 6.7% Ibbotson historic risk premium since the Ibbotson historic risk premium was used in the 2010 Yankee Gas Rate Case. Lastly, the Company suggested that its 9.6% estimate should be equally weighted given this was the approach taken in the 2010 Yankee Gas Rate Case. UI Written Exceptions, pp. 43-45.

The Authority does not dispute the Company's calculation that a simple average of 9.6%, 5% and 6.11% results in 6.9%. The Authority concurs with the Company's estimation that the weighting of the inputs was not equal, in fact, the Authority weighted the 6.11% Ibbotson Supply Side approach 50% and allocated the remaining 50% to the Company's and OCC's recommendations. The rationale for the unequal weighting is primarily based upon the Authority's finding that the Company's approach to apply the DCF model to measures of the market to estimate the equity risk premium is feasible but lacking in its execution given that the Company implemented the approach using a one-stage DCF growth approach instead of a two-stage or multi-stage growth DCF approach based upon the Authority's belief that at some point the growth in the overall US economy will serve as a cap to the growth in the stock market. Regarding the Company's contention that the OCC's recommendation should be raised to 5.2% based upon a perceived error in the OCC's summary table is also rejected as the Authority finds that the OCC's 5% figure was presented as an overall figure encompassing the OCC's review of various methodologies and academic studies. The Authority also notes that the effect of raising the 5% to 5.2% and applying a weighting factor to the 5.2% results in a minor upward adjustment of less than one basis point. Finally, the Company recommended that the Ibbotson historic equity risk premium (6.7%) be used in place of the Ibbotson Supply Side equity risk premium (6.11%). The Authority notes that both Ibbotson's estimates are arithmetic but the Supply Side approach is responsive to the issues and biases of using historical data and provides a building block approach using arithmetic mean estimation. Based upon the above discussion, the Authority rejects the Company's request to revise its 6.02% equity risk premium to the Company's proposal of 6.9%.

The Company also stated that if the Authority declined its proposal to raise the equity risk premium, then the Company suggested that the 7.74% CAPM result be given no weight in determining the overall ROE based up the Company's suggestion that the CAPM is subject to much controversy and the results of the model can substantially change based upon judgments as to one input. The Company indicated that the

Authority's weighting of the CAPM by 20% is an indicator that that little weight should be placed on it, and likewise the OCC's weighting of 5% to the CAPM and 95% to the DCF confirm the Company's belief that the CAPM should not be considered. UI Written Exceptions, p. 46. The Authority considered the Company's argument and concurs the CAPM approach is yielding low numbers in the current market environment. The question then becomes just because the model results in low returns, does this render the model inadequate in this environment? The Authority finds that the CAPM does have its place in the cost of capital estimation process and finds it has weighted it fairly given the Company itself had suggested its own CAPM approach be weighted 25% while the Company weighted its DCF 50% and 25% to its Utility Risk Premium method.

e. Utility Risk Premium Method

The Authority's review of the Company Utility Risk Premium method shows that the proxy for the utilities' cost of equity was the returns authorized by state commissions for the year from 1974 through 2012 as reported by RRA. The OCC did not perform a utility risk premium method and did not believe it was a market-based method and should not be used in the cost of equity estimation process. OCC Brief, p. 34; Tr. 5/15/13, pp. 2334 and 2335.

The Authority concurs with the OCC that using the allowed authorized returns as a proxy for the return on the stock market reflected utility commission behavior. Allowed returns should not be relied upon as a proxy from a cost of capital approach, this should be market based. The Authority finds that to allow utility state commissions' authorized ROEs to serve as a proxy for the stock return portion of a risk premium approach is to allow a non-market based estimate to serve as a proxy for the market's return. Cost of capital methods need to be market-based; therefore, the Authority rejects the Company's proposed Utility Risk Premium method in total.

f. Checks of Reasonableness

The Authority did not consider the results of UI's test of reasonableness. There are methodologies that have been proposed by the Company that have been rejected in the past and the Authority explicitly notes that those approaches are unacceptable.

As part of its analysis, the Company suggested that a check of reasonableness of its proposed 10.25% allowed ROE be based upon the DCF approach to a proxy group of 13 non-utility companies including Abbott Labs, Coca-Cola, General Mills, Kellogg, Kimberly-Clark, McDonald's, PepsiCo, Procter & Gamble, and Wal-Mart. Avera PFT, Exhibit WEA-13. The Authority concurs with the OCC's recommendation to ignore the results of the non-utility group DCF. The Authority reaffirms its finding in the 2009 Decision that the non-utility proxy group was not comparable in the overall review of UI, and therefore, was discarded. 2009 Decision, p. 95.

The Company also proposed an Evidence-based CAPM be examined which included a size adjustment to take into account the small market capitalizations of utilities compared to the average S&P 500 companies. The Evidence-based CAPM formula expands the general CAPM formula to the following: $R_s = R_f + 0.25\ (R_m - R_f) + 0.75$ [b x

$(R_m - R_f)]$. The Authority finds this Evidence-based CAPM is merely the Empirical CAPM, which the Authority has rejected in numerous proceedings.

As noted in the 2010 Aquarion Rate Case at pages 101, 102, 116 and 117, the Authority reiterates its conclusion that the Empirical-based CAPM, which takes the general form: $R_s = R_f + X (R_m - Rf) + (1\text{-}X) * [b \times (R_m - R_f)]$, is not acceptable for cost of capital estimation. This form of the equation is the same as the Company's Evidence-based CAPM. The only difference between the simple CAPM and the Empirical or Evidence based CAPM is the use of the X factor, which the Company set to 0.25. This X factor appears to be an arbitrary figure. The Authority believes that the X factor incorporates another level of conjecture that is unnecessary given that the simple CAPM formula is widely accepted in cost of equity literature. The Authority finds the simple CAPM appropriate as it avoids the need to incorporate the arbitrary X factor and rejects any use of a CAPM methodology that incorporates the X factor.

A method called Expected Earned Returns was also provided whereby an evaluation of the proposed ROE was made to expected RORs from available alternative investments, thereby making use of the comparable earnings test. The Authority finds this approach the same as the Comparable Earnings methodology rejected in previous Decisions. 2010 Aquarion Rate Case, p. 119. As noted in the 2010 Aquarion Rate Case:

> Lastly, this is an approach that the Department does not normally include in any of its analysis and hereby rejects it for this Decision. In the 2006 Birmingham Utilities Rate Case Decision, at pages 68 and 69, the Department explicitly rejected the Comparable Earnings approach.

2010 Aquarion Rate Case, p. 119.

Therefore, the Authority rejects the Company's proposed Expected Earned Returns approach based on its past precedent of excluding methodologies which compare regulated utility companies to non-regulated and/or non-utility companies for the estimation of the cost of capital.

g. Flotation Cost

According to the Company, an adjustment to the ROE to include flotation costs is appropriate to account for the costs incurred in connection with raising capital. The Company requested 20 basis points based upon its method of calculation. The OCC did not recommend including an adjustment for flotation costs as the Company provided no direct evidence that the UIL equity issue provided funds to UI.

The record indicated that since the 2009 Decision, UIL has made two equity issuances. The 2009 issuance was for general corporate purposes including $70 million equity contribution to UI. It was used by the Company to repay $70 million in short-term debt outstanding. Also, a 2010 equity offering was issued to fund the purchase of the three natural gas companies. In light of the fact that a portion of the 2009 equity issuance was made to repay $70 million of UI's short-term debt, the Authority will grant the Company's 20 basis point request. The Authority finds that UIL issuances have been used for UI purposes. The Authority reserves the right to review this allowance for flotation costs based upon future purposes of equity offerings.

h. Summary of Authority's ROE Analysis

The Authority accepted the OCC's recommendation that only the DCF and simplified CAPM methods be considered. Although the Company suggested a 50% weight to DCF, the Authority found a greater portion of the DCF methodology was reasonable based upon the revisions made to the Company's application of the CAPM and Utility Risk Premium approaches. The Authority weighed the DCF model more heavily in its analysis based upon the OCC's recommendation that commissions typically weight the DCF at least 70% and generally more in the range of 80% to 90%. Therefore, in establishing UI's allowed ROE, the Authority relied primarily upon the results of the cost of capital models. The Authority has not incorporated an explicit downward adjustment to ROE for decoupling, given the program has been approved again. The Authority shall monitor the effects of decoupling as it relates to issue of risk and return.

An ROE of 9.15% is indicated by the analysis and the cost of capital measures employed by the Authority and incorporates this into its weighted cost of capital analysis below. The Authority relied primarily on the results of the DCF. The Authority used its analysis that updated the last Company rate case and the survey of recent Decisions merely to establish benchmark parameters and to indicate in which direction the current allowed rate should trend. The table below represents a summary of the Authority's analyses and findings with respect to the ROE.

Method	**Authority Result**
Update Last Rate Case	8.75%
RAA 2013 Allowed ROE Range	9.30% to 10.20%
Survey Connecticut Allowed ROEs: 2008 to present	8.75% to 9.95%
DCF – Electric 70% Regulated Revenues	9.24%
CAPM	7.74%
Utility Risk Premium	Not Used
Size Premium	0%
Test of Reasonableness Methods	Not Used
Overall ROE Range	7.74% to 9.24%
Indicated ROE	8.94%
Adjustment for Flotation Cost	0.20%
Allowed ROE	**9.15%**

i. Authority's Allowed Weighted Cost of Capital

The Company's requested ROR of 7.79% in RY1 and 7.76% in RY2 (10.25% ROE with a 50% Common Equity and 50% Long-term Debt) is rejected as excessive given today's market environment. The OCC's ROR recommendations of 7.03% (8.75% ROE with 50% Common Equity to 50% Long-term Debt) is also rejected.

Consistent with the legal guidelines defined in Conn. Gen. Stat. §16-19e(a)(4), the Authority identified a ROR on the rate base that is deemed appropriate for the Company's overall capital structure. The Authority identified the key components of the Company's capital structure, estimated the cost of each component of capital, and then calculated its overall cost of capital by weighting each component cost by its proportionate share of the overall capital structure.

The table below summarizes the capital structure components and calculates the weighted cost of capital, including the 9.15% assigned ROR on common equity, determined by the Authority based upon the 50% common equity to 50% long-term debt capital structure.

2014 Average Capitalization: Rate Year 1

Class of Capital	Ratemaking Percentage	Cost	Ratemaking Weighted Cost
Long-term Debt	50%	5.32%	2.660%
Common Equity	50%	9.15%	4.575%
Total Capitalization	100%		7.235%

2015 Average Capitalization: Rate Year 2

Class of Capital	Ratemaking Percentage	Cost	Ratemaking Weighted Cost
Long-term Debt	50%	5.27%	2.635%
Common Equity	50%	9.15%	4.575%
Total Capitalization	100%		7.210%

Based on the above, the Authority has determined that a 7.23% return for RY1 and a 7.21% return for RY2 on the Company's rate base of $767,402,000 for RY1 and $840,395,000 for RY2 is reasonable. This results in an adjusted utility operating income of $$55,522,000 for RY1 and $60,593,000 for RY2. This amount is sufficient to service the Company's interest payments on its debt, fund its proposed capital construction projects and allow it to earn a fair ROR. The Authority finds that its downward 110 basis points (10.25% - 9.15%) adjustment to the Company's proposed 10.25% ROE results in an $8.3974 million downward adjustment to the UI's initially proposed revenue requirement, an annual cost reduction of approximately $22.00 per customer.[33] UI Response to Interrogatory CIEC-3.

H. Revenue Adjustments

In UI's original filing, it proposed total revenue at present rates of $262,470,783 for RY1 and $259,666,402 for RY2. Due to a subsequent revision to its sales forecasts, UI revised its RY1 and RY2 revenue at present rates. For RY1, UI proposed an increase of $412,664, for total revenue at present rates of $262,883,447. For RY2, UI proposed an increase of $206,165, for total revenue at present rates of $259,872,567. Late Filed Exhibit No. 69, Attachment 7.

Due to the Authority's adjustments to UI's proposed sales forecasts in Section II.J. Authority Adjusted Sales Forecast above, the Authority adjusts the revenue at present rates for each rate year accordingly. The Authority increases UI's RY1 proposed revenue at present rates by $5,522,782, for a total revenue at present rates of $268,406,229. See Attachment A for details. For RY2, the Authority increased UI's proposed revenue at present rates by $7,339,561, for a total revenue at present rates of $267,212,128. See Attachment B for details.

I. Proposed Sales Forecast

The primary purpose for the sales forecast is to project monthly sales by rate schedule and revenue class, which is converted to a short-term revenue forecast using existing or new electric service rates. UI used this forecast to estimate future revenues from sales and to set prices for sales. Response to Interrogatory LCG-25. According to UI, its projected sales at existing rates produce retail revenues that are insufficient to recover the Company's operating expenses, cover its debt service cost and provide an adequate return on invested capital in RY1 and beyond. Test year actual sales were down 3.6% from the 2010 level approved in current rates and UI projects the decline will grow further to 5.6% in RY1 and 7.1% in RY2. The projected decline in RY1 and RY2 sales is due to the state's proposed expanded Conservation and Load Management (C&LM) programs coupled with UI's existing C&LM efforts and the projected low economic growth. Nicholas PFT, p. 13.

Below is a discussion of how UI developed its RY1 and RY2 sales forecasts along with a description of the Authority's adjustments to those sales forecasts.

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[33] The Company indicated that a 1% change (100 basis point) to allowed ROE results in a $7.634 million dollar change to revenue requirement. The Authority interpolated the 110 basis points as $7.634 million plus $0.7634 for a total of $8.3974 million.

1. Forecast Development

UI created the sales forecasts using two distinct, sequential sub-processes that include: (1) estimation of future total system annual retail sales (high level forecast); and (2) allocation of those total system sales in detail among all rate elements by revenue class, rate schedule season, time-of-day and charge type. Late Filed Exhibit No. 77, Attachment 7, p. 2.

The first step was to develop high level sales forecasts for the years 2013, 2014 and 2015 to cover the RY1 and RY2 periods. For the 2013 forecast, the Company began with eight months of the 2012 actual sales which were weather normalized, and four months of forecasted sales. The 2012 sales were also adjusted for leap year. Lundrigan and Colca PFT, p. 19. Each of the calendar year forecasts began with the previous calendar year's adjusted forecasted sales. Each beginning year forecast was then adjusted for: (1) incremental sales activity; (2) conservation and load management impacts; (3) incremental distributed generation (DG) impacts; and (4) economic growth. Id., pp. 16-19. All adjustments were performed at the revenue class level and were allocated among the rate schedules by the proportion of quantity being adjusted that each rate schedule contributes to the total amount of that quantity. Response to Interrogatory OCC-253. This process resulted in a sales forecast at the system level, the outcome of which is a single energy value in units of GWh/year. Response to Interrogatory RA-44. For RY1, UI proposed a sales forecast of 5,319,130,068 kWh. For RY2, UI proposed a sales forecast of 5,232,756,858 kWh. Late Filed Exhibit No. 69, Attachment 7, pp. 1 and 2.

The second distinct process was the detailed forecast. This forecast extracted detailed billing data from UI's billing system and was adjusted through a number of steps to yield total annual sales equal to the system level forecast. Response to Interrogatory RA-44. The estimated total system sales were allocated among the rate elements by revenue class, rate schedule, season, time-of-day and charge type (demand, energy, unmetered and fixed monthly). Late Filed Exhibit No. 77, Attachment 7, pp. 2 and 3.

Regarding the adjustments, incremental sales activity comes from estimates made by UI's economic development team. Tr. 5/7/13, p. 1663. Its estimates came from two sources; (1) UI's Light the Night program, which is a turnkey outdoor lighting solution for businesses; and (2) changes to specific customer, or potential customer sales as determined by UI's economic development team. Incremental sales activities are proposed to decline in each forecast year 2013-2015. Economic growth was decided by UI's executive management team. Specifically, the team decided there would be no sales growth in 2013 and a 0.25% sales growth in 2014 and 2015. Lundrigan and Colca PFT, pp. 17 and 19. There were no specific forecasts or studies used by the UI executive management team in choosing the growth rates. Response to Interrogatory RA-10.

C&LM savings estimates were determined according to procedures used in the approved annual CL&M plan. The proposed sales reductions for C&LM were based on the impacts of the proposed expanded C&LM program[34] which: (1) has not yet been approved; and (2) according to UI, implementation is approximately one year behind what was included in its proposed sales forecast. Tr. 5/7/13, p. 1665. Furthermore, in the C&LM proceeding, UI testified that the proposed expanded CL&M plan goals would not be fully achievable absent new sources of oil funding, which sources do not currently exist. Tr. 5/1/13, pp. 727 and 728.

Estimated DG impacts were derived from information provided in the bids awarded in the first Low Emissions and Zero Emissions Renewable Energy Credit (LREC/ZREC) program solicitations approved by the Authority. Lundrigan and Colca PFT, pp. 17-19. More specifically, only medium and large ZREC and LRECs from the first solicitation period were included in the forecasts for RY1 and RY2 using the DG contracted delivery term start date (DTSD). Estimated small ZRECs were not included in the forecast because the small ZREC tariff was not available to customers at the time the forecast was developed. The DTSD for DG projects are as follows: 1 DG project on January 1, 2013, 7 DG projects on April 1, 2013, and 13 DG projects on October 1, 2013. While DG projects have one year from the DTSD to be on-line, the forecast is based on the DTSD date. According to UI, as of May 7, 2013, some customers have fallen behind the DTSD. Additionally, UI confirmed that that none of the LREC/ZREC projects have come on-line and that most had not even begun construction. Tr. 5/7/13, pp. 1737-1741.

The UI forecast team interpreted how all of these factors would likely impact monthly sales and revenues. UI Response to Interrogatory LCG-25. UI utilized this forecasting methodology for over 10 years and it was accepted by the Authority in each of the last three rate proceedings. UI Response to Interrogatory RA-58; UI Brief, p. 61.

In response to a request from the OCC to reevaluate the proposed sales forecast, UI revised the sales forecast methodology to begin with sales data rather than billed data. This eliminated the need for the billed to sales adjustment. Additionally, UI updated the monthly sales spread. The total annual sales did not change from the original filing. The proposed RY1 sales forecast is 5,319,130,068 kWh. The proposed RY2 sales forecast is 5,232,756,858 kWh. However, the revised sales spread resulted in a revised sales forecast for RY1, yielding an increase in present distribution revenue of $399,690 over the original forecast. In RY2, present distribution revenue was increased by $169,981 over the original forecast. Late Filed Exhibits No. 3 and 69.

2. OCC and AG Comments

The OCC stated that the proposed sales forecasts are not reliable and recommended that the 2012 actual sales be used for both RY1 and RY2. Additionally, the OCC initially had concerns with the methodology used by UI to spread the forecast among the classes particularly in the months of July and August for the residential rate classes. As stated above, that spread was reviewed and revised by UI in Late Filed Exhibit No. 69. The OCC reviewed the revised methodology to spread the sales forecast among customer classes and rate classes and accepted the results. However, the OCC

[34] Hearings to review the proposed expanded C&LM plan in Docket No. 13-03-02, PURA/BETP Consideration of 2013-2015 Conservation and Load Management Plan were being held concurrent with UI's rate proceeding in the instant docket.

disputed the reasonableness of the overall sales forecast. Even after reviewing UI's responses to Late Filed Exhibit Nos. 69 and 77, the OCC continues to believe that UI's overall sales forecast was primarily based on management judgment rather than statistical analysis of sales trends, economic growth, and other relevant factors. Therefore, the OCC does not support UI's proposed sales forecasts and recommends using 2012 sales data for both rate years. Rubin Supplemental Testimony, pp. 1 and 2.

The AG stated that UI's proposed sales forecasts and projected revenue levels are unreasonably low and unsupported and recommends that they be rejected by the PURA. The AG explained that while UI sales have declined moderately over the past few years, that decline coincided with a period of economic decline, which it believes is unlikely to continue. Instead, the AG agrees with the OCC that the Authority should approve the more reasonable 2013 sales forecast that is based on actual, weather-corrected 2012 sales. AG Brief, p 24.

J. AUTHORITY ADJUSTED SALES FORECASTS

1. Analysis of Proposed Adjustments

As discussed above, UI's forecasting methodology begins with a historical test period, which is typically the previous year, to which proforma adjustments are made to bring the sales forecast to each projected rate year. These adjustments included: adjustments for normal weather; economic growth; C&LM; and known large customer additions or changes. This type of sales forecasting methodology is common in the utility industries. And the Authority has approved in the past similar forecasting methodologies in numerous gas, water and electric rate proceedings. However, while perhaps not in recent UI rate proceedings, the Authority has made adjustments to the utility proposed sales forecast if in the PURA's opinion the specific adjustment amounts and/or the overall forecasts are not deemed reasonable and/or are not supported by record evidence. Regarding UI's proposed RY1 and RY2 forecasts in this proceeding, the Authority does not find them to be reasonable nor supported by the record. Therefore, the Authority made adjustments to the RY1 and RY2 sales. The reasons why the Authority came to this conclusion and the actual adjustments are discussed below.

First, the Authority finds that certain adjustments used in the proposed forecasts are unsupported by record evidence and are therefore, unreliable. For example, the fact that the proposed economic growth rate was decided by UI's executive management team and not based on specific forecasts or studies is of concern to the Authority. Therefore, the Authority finds that the proposed growth rates are not credible. Additionally, the Authority is unconvinced that the large negative adjustment to sales as a result of the CL&M program and the DG's from the LREC/ZREC program will come to pass during the two rate years.

More specifically, regarding the Company's proposed sales adjustments for the CL&M program, UI stated that the proposed expanded C&LM program is approximately one year behind what was included in its proposed sales forecast. Tr. 5/7/13, p. 1665. Furthermore, in the C&LM proceeding, UI testified that the proposed expanded CL&M plan goals would not be fully achievable absent new sources of oil funding, which sources do not currently exist. Yet the full amount of the lost sales from the expanded C&LM

program was included in the proposed sales forecasts. On that basis, the Authority finds UI's proposed lost sales adjustments for the expanded C&LM program to be overstated and are therefore unreliable.

Regarding the proposed sales adjustments for the DG projects, the Authority finds that UI over-estimated the sales reductions from DG projects and are therefore unreliable. This is due to the fact that UI based the DG sales reduction on the DTSD, yet some DG projects are behind the DTSD schedule, none of the DG projects were on-line, and most have not begun construction. Together, the sales adjustments performed by UI likely will result in an underestimated sales forecast, all other things being equal, and consequently, higher customer rates. Even though UI has a decoupling mechanism and, therefore, will be made whole regardless of whether the sales forecast is over- or under-estimated, which it undoubtedly will be one or the other, the Authority prefers to err on the higher side so that customer rates will be lower.

2. Reasonableness Test of Proposed Sales Forecast

In addition to the Authority's finding that the sales forecast adjustments discussed above are unreliable, the PURA also performed a test of reasonableness by looking at historical trending of recent annual weather normalized sales. Late Filed Exhibit No. 76. The trending is reviewed at the overall forecast level as well as at the customer and rate class level. While the Authority agrees that based on recent historic trends, UI's overall sales are likely to continue to decline for the foreseeable future, it disagrees with the extent to which the sales are reduced in the Company's proposed sales forecasts. The Authority also disagrees with the resulting allocations to the residential, General Service Rate (Rate GS), Large Power Time-of-Day (Rate LPT) and street lighting customer classes and finally to the rate classes. Under- or over-stated sales at each of these levels, particularly at the rate class level could have severe impacts on the resulting revenue. The table below shows the total normalized kWh sales for each year 2009-2012.

2008	2009	2010	2011	2012
5,709,357,877	5,592,519,500	5,587,127,018	5,484,802,899	5,410,918,136

Late Filed Exhibit No. 76, Attachment.

Based on the above figures, normalized annual sales decreased from year to year by the following percentages: 2009, 2.05% ((5,709,357,877 – 5,592,519,599) / 5,709,357,877) 2010, 0.10% ((5,592,519,500 - 5,587,127,018) / 5,592,519,500); 2011, 1.83% ((5,587,127,018 – 5,484,802,899) / 5,587,127,018); and 2012 1.35% ((5,484,802,899 – 5,410,918,136). Over the four year period, the average sales decrease was 1.33% ((2.05 +.10 + 1.83 + 1.35) / 4. Over the three year period, the average sales decrease was 1.09% ((0.10% + 1.83% + 1.35%) / 3).

Below is a comparison of the normalized 2012 kWh sales with UI's proposed sales forecast for 2013, 2014, and 2015 as shown in UI's Late Filed Exhibit No. 76.

2012	2013	2014	2015
5,410,918,136	5,337,165,891	5,274,999,999	5,186,000,000

Based on these figures, the 2013 proposed sales is a decrease of 1.36% from the 2012 normalized sales ((5,410,918,136 – 5,337,165,891) / 5,410,918,136). The proposed 2014 sales is 1.165% less than the proposed 2013 sales ((5,337,165,891 - 5,274,999,999) / 5,337,165,891). UI's proposed 2015 sales is 1.69% less than its proposed 2014 sales ((5,274,999,999 – 5,186,000,000) / 5,274,999,999). Over the three year forecasted period, the average proposed sales decrease was 1.40% ((1.36% + 1.165% + 1.69%) / 3). That is a 28% greater reduction in sales than in the historic period average of 1.09%.

The Authority finds that the additional 28% reduction to the three-year average historical sales reduction is too high and again, the record evidence does not support it. However, the Authority does not support using the 2012 normalized sales for each rate year as recommended by the OCC and the AG. Instead, the Authority concludes that absent any substantive data, the use of a three-year historical average overall change in sales is a reasonable approach for projecting net annual growth and shall be used in this proceeding. UI used a similar approach in forecasting its customer counts.[35] Therefore, for each of the forecasted years that derive the RY1 and RY2 sales forecasts, the Authority adjusted the prior year by -1.09% beginning with the 2012 normalized sales of 5,410,918,136 kWh.

<u>2013 kWh</u> (5,410,918,136 * -1.09%) + 5,410,918,136 = 3,351,939,128

<u>2014 kWh</u> (5,351,939,128 * -1.09%) + 5,351,939,128 = 5,293,602,992

<u>2015 kWh</u> (5,293,602,992 *-1.09%) + 5,293,602,992 = 5,235,902,719

Therefore, the overall adjusted sales forecast for 2013 – 2015 are as follows:

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[35] In its customer count forecast, UI used the average of the annual growth rates for the three years of 2009 through 2011. Late Filed Exhibit No. 75.

2013 kWh	2014 kWh	2015 kWh
5,351,939,128	5,293,602,992	5,235,902,719

For the rate year forecasts, the Authority took the average of the 2013 and 2014 for a RY1 adjusted sales forecast of 5,322,771,060 kWh and the average of 2014 and 2015 for an adjusted RY2 sales forecast of 5,264,752,856 kWh. For RY1, the Authority adjusted sales increases UI's proposed sales of 5,319,130,068 kWh by 3,640,992 kWh. For RY2, the Authority adjusted sales increases UI's proposed sales of 5,232,756,858 by 31,995,998 kWh.

3. Spread to Customer and Rate Classes

The Authority also modified the manner in which the RY1 and RY2 sales forecasts were spread to the customer classes (Residential, GS, LPT, and street lighting) and then to the individual rate classes. The Authority finds that the manner in which UI spread the sales to the customer class levels were not consistent with historical growth. For example, for the years 2010, 2011 and 2012, there was an increase in normalized sales for the residential customer class. Yet, UI projected a steady decrease for this class for the years 2013-2015. Similarly, the GS class was experiencing increases in sales for 2010-2012; however, UI proposed sales decreases for 2013-2015. And the LPT class was experiencing sales decreases, while UI proposed sales increases.

	Normalized Actual/Billions kWh			UI Forecast/Billions kWh		
Class	2010	2011	2012	2013	2014	2015
Res.	2.151	2.152	2.182	2.119	2.100	2.066
GS	1.462	1.612	1.850	1.742	1.671	1.643
LPT	1.920	1.667	1.324	1.424	1.451	1.426

Late Filed Exhibit No. 76.

As shown above, UI's proposed sales in many instances are the complete opposite of the recent historical trend. At the rate class level, the Authority finds similar anomalies in the sales spread. Therefore, the Authority reallocated the PURA adjusted RY1 and RY2 sales forecasts discussed above in Section II.J.2 Reasonableness Test of Proposed Sales Forecast among the customer and rate classes to be more reflective of recent sales trends. See Attachment A for RY1 Authority adjusted sales and spreads and Attachment B for RY2 Authority adjusted sales and spreads. The monthly allocation pattern of annual sales will be that as utilized by UI in Late Filed Exhibit No. 69.

K. Decoupling

In the instant case, the Company requested that its present Pilot Decoupling Program, established in the 2009 Decision, be made permanent. Lundrigan and Colca PFT, p. 19. Public Act No. 13-298 directed the PURA to decouple electric distribution companies distribution revenues from the volume of electricity sales. Further, in making its determination on this matter, the Authority shall consider the impact of decoupling on the electric distribution company's return on equity and make any necessary adjustments thereto. The Authority discussed this issue in Section II.G.6.b.iii. Decoupling. Based on the above, the Authority will accept the Company's existing pilot program as permanent.

L. COST OF SERVICE STUDY

In general, a cost of service study (COSS) is a mathematical business model that systematically assigns cost responsibility among customer classes for the assets and expenses incurred by a utility to serve customers. Since the COSS culminates in summarizing customer, demand and total costs by customer class, it is an invaluable tool for documenting equity and establishing revenue requirements and tariff charges by customer class.

The Company filed a COSS as part of their initial application. It followed the same design methodology used in its last COSS submission, which was approved by the Authority. The COSS test period is July 1, 2011 through June 30, 2012. Since all distribution costs are either customer related or demand related, the COSS used a number of customer allocators and two demand allocators. The Company believes that one of the demand allocators is improperly utilized. Tr. 5/6/13, p. 1497.

The demand allocator in question represents class non-coincident peak (NCP). It is used to allocate investment and expenses in secondary lines and transformers. The Authority ordered the Company to begin using this allocator in Docket No. 05-06-04. However, the Company stated that their earlier method, referred to as Sigma NCP (SIGNCP), is still the better allocator. SIGNCP sums individual maximum customer demands within each rate class resulting in a more precise aggregate allocator. Id. The Company submitted a new COSS that uses the SIGNCP. While the resultant class RORs are similar to what was obtained under the NCP, there are differences. For example, cost responsibility for residential rate classes increases slightly under SIGNCP. Late Filed Exhibit No. 62.

In Docket No. 05-06-04, the Authority changed the SIGNCP allocator to NCP in response to the OCC's argument that SIGNCP ignores diversity. The Authority today is not convinced of this assertion. Secondary lines may lack diversity because only a limited number of standard conduit sizes are ever installed to reduce inventory options and cost. Similarly, the Authority would expect that transformers servicing similar type customer groupings would be sized to satisfy the peak demand represented by SIGNCP. An example would be a transformer servicing a few homes with air conditioning load.

The Authority will not order adoption of SIGNCP in the instant case, but will direct the Company to make the case for SIGNCP in its next rate increase application. To say that it was used before will not be sufficient. The Authority will be looking for system design logic that speaks to the diversity issue. Also, the Authority is interested in developing this capacity allocator in a manner that will precisely pass costs through to customers by means of a demand rate. The Authority finds that the Company's current COSS methodology is acceptable for use in this and future applications. Nonetheless, the Authority invites the Company to offer accuracy improvement recommendations at any time.

M. REVENUE ALLOCATION

While class revenue assignment is normally predicated on improving relational class RORs as determined through a COSS, the Company chose to assign non-street lighting class revenues in RY1 based on CTA reductions. Effective January 1, 2014, the CTA charge presently on customer bills will be discontinued, resulting in an automatic bill reduction for all customers. To prevent bill increases as a result of the instant application, the Company proposed postponing the effective date of new rates to January 1, 2014, and increasing distribution average revenues for each rate class to closely match the CTA reduction for that class. In RY2, the Company increased non-street lighting rate class revenues by a similar overall revenue per kilowatt-hour increase. In RY1, the proposed street lighting revenues were significantly decreased and were further decreased in RY2. Lundrigan and Colca PFT, p. 12. The following table compares the ROR for each rate class.

Rate Class ROR

	Test Year	Proposed RY1	Proposed RY2
Rate R	4.36%	4.45%	4.17%
Rate RT	9.55%	9.86%	9.39%
Rate GS	6.31%	6.61%	7.06%
Rate GST	2.92%	6.34%	7.01%
Rate LPT	8.19%	15.28%	16.87%
Rate M	13.49%	5.51%	3.89%
Rate U	18.21%	1.96%	0.14%
System	5.84%	7.15%	7.28%

Response to Interrogatory RA-39.

The Authority finds that the Company's reliance on CTA reductions as justification for establishing new rate class revenues further exacerbates interclass subsidization as measured by ROR responsibility. Given the 24% proposed increase in RY1 revenue, a conventional rate increase proposal designed to trim interclass differences in RORs would have produced far greater equity among customer classes than that actually obtained by mathematically mimicking the CTA reduction. An example of this distortion is seen in the ROR increase from 8.19% at present rates to 15.28% under RY1 rates for Rate LPT. This increase is a direct result of following the CTA reduction for this class. The Company justified this increase by stating that: ". . . the Company had to slightly increase the ROR of Rate LPT even though they were already providing a ROR higher than the system average." UI Response to Interrogatory RA-54. An increase of this magnitude would never be proposed under a more conventional approach, and if it was, it would never be described as a slight increase. Further, the RY2 across-the-board revenue increase proposal is a second missed opportunity to improve equity. In Section II.N.2. Authority Rate Design, the Authority will provide revenue, unit rate and ROR guidelines for RY1 and RY2 to be followed when designing new rates.

N. Rate Design and Tariff Changes

1. UI's Proposed Rate Design

a. Overview

The Company submitted proposed tariffs for each year of its two-year rate plan. The revenue increase proposed for each tariff class in RY1 was designed to be less than the CTA reduction for the tariff in question. Effectively, customers would not receive a bill increase during the first one-half of RY1. In general, the revenue increase applied to tariff classes in RY2 was assigned such that all non-street lighting tariffs received approximately the same overall increase in average revenue per kilowatt-hour.

Additionally, the Company proposed new tariffs and introduced many new charges. All non-street lighting tariffs were modified to reflect a seasonal distinction in charges. Specifically, on-peak and off-peak charges were introduced for rates Residential Time-of-Day (Rate RT), General Service Time-of-Day (Rate GST) and Rate LPT and an inverted rate structure was introduced for the Residential Rate R. Tariffs were created to differentiate service based on voltage for Rate GS, Rate GST, and Rate LPT rate schedules. In general, the Company stated that all distribution costs are either customer or demand related and ideally should be recovered through a combination of customer and demand charges. Lundrigan and Colca, PFT, p. 12. Nonetheless, it chose to propose tariff structures that are heavily designed to convey price signals to customers. According to the Company, capacity and energy used only during the summer should be paid for during the summer. The Company described this practice as “capacity utilization cost recovery.” The Company is also proposing to introduce pricing signals that they consider missing under current pricing practices wherein independent generators sell electricity using daily flat rates. Tr. 5/6/13, pp. 1481-1485.

The Company had seasonal and inverted block rate structures until the Authority discontinued their use in the Decision dated September 29, 2008 in Docket No. 05-06-04RE04, Application of The United Illuminating Company to Increase Its Rates and Charges – Public Act 07-242, Seasonal Rates, Non Generation-Related Time-of-Use Pricing and Related Rate Design Issues. Lundrigan and Colca PFT, pp. 7 and 9. The Company has little expectation that their proposed price signals would actually reduce demand. While kWhs have steadily decreased over time, there has not been a corresponding reduction in coincident peak demand. Tr. 5/6/13, pp. 1481-1485. Finally, the Company does not believe that their proposed price signals would reduce kWh sales enough to warrant adjusting its sales forecast. Tr. 5/6/13, pp. 1517 and 1518. Because the Company’s rate proposals represent a dramatic change from present rate structures and affect multiple tariffs similarly, a summary discussion of the broader design issues is presented immediately followed by the Authority’s analysis before discussing each proposed rate structure in greater detail.

b. Service Voltage

The Company historically had applied a 3% reduction to metered kilowatt-hours for all Rate GS and Rate GST customers metered at the primary level. This adjustment is made to restate usage to a lower, or secondary, voltage level, consistent with each tariff’s service definition. To eliminate this adjustment, new primary and secondary tariffs were introduced to better accommodate ISO-NE’s energy market settlement process, among other reasons. For Rate LPT customers, the voltage adjustment consists of increasing metered kilowatt-hours by 3% for customers receiving secondary voltage service. Separate LPT tariffs were introduced for secondary and primary service customers. Lundrigan and Colca PFT, pp. 10 and 11.

Rather than create new tariffs to differentiate service voltage, the Authority asked UI if the differentiation could be made on one tariff per affected rate schedule by displaying both primary and secondary rates. The Company agreed that it could. Response to Interrogatory RA-38. Therefore, UI is directed to use a single tariff for each affected rate schedule that describes and displays the two service voltage rates.

c. Seasonal Rates

The Company reintroduced seasonal rates for all tariffs except street lighting rates. Winter rates as proposed are 25% less than summer rates. The Company chose 25% based upon a dated historical difference between summer and winter peak demands. The 25% distinction felt both appropriate and accurate to use according to the Company. Tr. 5/6/13, p. 1475. A recent comparison of the difference between summer and winter peaks for 2008 through 2012 showed differences that ranged from a one year high of 47% to a one year low of 27%. The five-year average difference was 34%. Response to Interrogatory RA-26. The Authority's discussion of seasonal rates in the 2009 Decision, which discontinued seasonal rates, recognized seasonal differences in the cost of procuring energy, not seasonal differences in distribution services costs.

Seasonal cost distinctions do not exist for a distribution company. The Company sizes each substation to reliably meet the annual one hour peak demand for that substation. The fact that lesser demands will also be serviced through the substation absolutely has no effect on the maximum capacity size requirements and costs of the substation. Further, setting unit rate differentials based on the difference between peak hour and any other lesser demand has no basis in cost. The Company chose a 25% cost differential because UI believed it was appropriate as a price signal, not because it reflected an underlying distinction in distribution costs. Mathematically, the Company needed to lower rates during the winter so they could increase rates during the summer and still satisfy class revenue targets. The arbitrary 25% choice was made to sound legitimate by justifying it as representing the difference in winter and summer peaks. The difficulty is that because lesser demands do not affect distribution costs, they are all irrelevant. Consequently, the Authority will disallow all proposed seasonal rates.

d. Peak and Off-Peak Rates

The Company introduced peak and off-peak rates, also referred to as time-of-day rates (TOD), within newly proposed winter and summer pricing periods for several rate classes. As with seasonal rates, TOD cost differences do not exist for a wire or distribution company. The hourly cost of generation does change during certain periods of the day as additional, less efficient and presumably more costly, generators are dispatched to satisfy demand. While hourly costs change for the generation portfolio, they are constant for single generators that do not switch or mix fuels inter-day. Distribution costs are incurred to satisfy the annual coincident peak hour demand at the substation and to meet individual customer maximum instantaneous demand at the customer node. While generation costs do vary by hour of service, distribution costs do not. Distribution costs are incurred to service customers or capacity. Consequently, the Authority will disallow all proposed on- and off-peak proposals for distribution rates..

e. Inverted Rate Structure

An inverted rate structure was introduced during the summer period only for Rate R. The Company proposed a summer rate structure wherein consumption over 500 kWh costs approximately 3 cents/kWh or approximately 60% more than consumption under 500 kWh. All winter consumption was priced at a single rate. The 3 cent distinction existed in earlier Rate R designs and the Company wanted to continue this distinction. Response to Interrogatory RA-33.

While the OCC agreed in theory that larger-usage customers increase summer costs for the Company,[36] it submitted an alternative proposal for Rate R. The OCC's proposal consisted of a summer inverted rate structure with a breakpoint at 1,000 kWh as opposed to the Company's proposed breakpoint of 500 kWh. The OCC argued that setting the summer first block level equal to the typical non-summer level of usage means that the second block better captures incremental summer usage. The OCC is concerned that a first block set as low as 500 kWh would require many thousands of customers to pay more during the summer for consumption that may vary little from what they consume through the non-summer period. The OCC stated that there is no basis for such a result. Rubin PFT, pp. 19 and 20.

The Authority finds fault with the analysis and Rate R design strategies expounded by both the Company and the OCC. At its core, the Company is a summer peaking electric distribution utility with less than 100% load factor. It consists of one distribution system shared by all customers and sized to meet peak period demands. Individual substations are sized to reliably meet the annual single hour peak demand experienced by that substation. All customers, not just larger-usage customers, share responsibility for the total cost of their substation based on their contribution to the critically important peak hour. The price signals proposed in Rate R are designed to replicate generation costs, not distribution-only costs. Further, because the rate structures proposed by both the Company and the OCC have no correlation with underlying distribution cost behavior, the resultant impact on customer bills would be discriminatory, arbitrarily established and easily susceptible to unintended consequences. For example, to satisfy Rate R's total revenue assignment and introduce the desired blocking price differential of 3 cents, smaller usage customers will receive bills that are smaller in the summer than winter for identical usage. In the name of proper price signaling, the Company would create a situation where summer bills decrease for some customers and increase for others when all customers share responsibility for peak hour costs. The OCC's proposal avoids this design trap, but it also assumes incorrectly that only larger-usage customers are responsible for an imaginary summer cost premium. Consequently, the Authority disallows the proposed Rate R inverted rate structure.

f. Street Lighting

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[36] As an example of increased summer costs, the OCC noted that hot temperatures negatively affect the carrying capacity of power lines. Rubin PFT, p. 19.

The test year distribution ROR for rate classes Street Lighting Municipal Company Owned Rate (Rate M) and Street Lighting Municipal Customer Owned Rate (Rate U), was 13.49% and 18.21%, respectively. JDL/MPC Exhibit 1. Those RORs are well above the test year system ROR. UI proposed to reduce the rates for Rate M and Rate U beginning January 1, 2014, to bring them close to the system ROR. Lundrigan and Colca PFT, p. 8. A comparison of the test year ROR and proposed rate year RORs with the system RORs is presented in the Section II.M. Revenue Allocation.

As indicated above, the system wide distribution ROR for the test year was 5.84%. UI's proposed RORs for Rate M and Rate U for both rate years are not set at or near the rate year system ROR, especially Rate U. And in RY2, UI proposed to move the rate class ROR even further from the system ROR. The Authority asked UI why it proposed to reduce the RORs to well below the rate year system RORs. The Company stated that street lighting rate classes provide somewhat of a different type of service than other rate classes in that they provide a benefit to all other rate classes through improved street lighting. Response to Interrogatory RA-55.

The Authority finds that distribution rates should not be based on societal benefits, or lack thereof, that some rate classes may or may not provide to others. The Authority's goal is to move toward cost based unity rates. On that basis, the Authority agrees to lower the ROR for Rate M and U; however, not to the extent proposed. UI is directed to change the streetlight RORs to no lower than the system ROR for each rate year.

g. Summary

The Authority supports moving toward equalized rate class RORs. For a distribution company, seasonal rates, inverted block structures and TOD are not capacity utilization cost recovery rates as the Company claims. They are inexact pricing schemes that inequitably discount bills for one subset of customers to create an opportunity to inequitably overcharge a different subset of customers in the name of price signaling. Under this method, neither subset of customers is treated equitably. Only a distribution demand charge that recognizes each customer's contribution to peak demand is capable of equitably billing customers for their specific contribution to overall capacity costs. For a distribution company like UI, demand charges alone provide true capacity utilization cost recovery.

Setting distribution rates based on distribution costs is the best course of action that the Authority can follow. This approach maximizes customer equity and completely eliminates the potential for discriminatory pricing, intentional or not. It also avoids the inevitable, unsound rate constructions demonstrated in the Company's Rate R proposal. While the discussion in this rate application has centered on Rate R, the other rate classes may also suffer from similar illogical billing signals. It is a fact that the Company has the highest electric rates in the continental United States, even before its proposed two-year increase of $95 million. AG Brief, p. 5. Consequently, the Authority is not worried that customers are indifferent to their electric bill or are unaware that generation costs more in the summer. Finally, the Company knows of no other electric distribution company (EDC) that offers summer and winter rates based on volume or on- off-peak periods. Response to Interrogatory RA-35.

The Authority will work with the Company to implement cost based customer and demand rates across all customer classes. Decoupling guarantees revenue stability for the Company, in part, by conceptually converting kWh charges into fixed charges. While full cost customer and demand charges cannot protect customers from a loss in customer count, it will insulate them from decoupling surcharges associated with conservation-based sales reduction. Under decoupling, full cost customer and demand charges take on a new significance. Until full cost customer and demand charges are reached, the new question of customer equity under decoupling depends on how the surcharges are structured. One overall company-wide kWh surcharge will surely disrupt inter-customer equity whereas a personalized, customer-specific surcharge would maintain the existing level of equity built into rates. The Authority will address these questions in its generic docket on decoupling, yet to be initiated.

The Authority will disallow all seasonal, TOD and inverted rate design proposals made by the Company. Nonetheless, in future rate applications, the Company is encouraged to submit alternative rate designs that provide voluntary customer choice. The only requirement is that distribution charges reflect distribution cost behavior as discussed herein.

2. Authority Rate Design

The Company will be directed to perform a new COSS for RY1 and RY2 reflecting the billing determinants and financial profile approved by the Authority herein. These studies will include the additional workpapers requested in Interrogatory RA-11. Relying on these studies, rates will be established as follows:

1. All proposed seasonal, TOD and inverted rate structures are disallowed. The following directives are to be made to existing rate structures.

2. The revenue assigned to Rate M and Rate U will be set to return class RORs that are no less than the overall system average ROR in both rate years.

3. Aside from Rates M and U, each rate class that contributed a Test Year class ROR in excess of the system average ROR of 5.84%, will have its revenue lowered while each class that contributed a Test Year ROR in excess of system average will have its revenue increased. Class revenue reductions and additions should not exceed one and one-quarter times the overall distribution revenue increase approved in the instant case. The Company should exercise its own discretion when assigning class revenues to balance to the overall distribution revenue requirement. Essentially, the Authority expects that every rate class will experience a change in revenue responsibility and have its ROR moved as close as possible to system average in both rate years.

4. For rate classes with demand charges, the demand charge originally proposed in Schedule E-2.2.A and Schedule E-2.2.B should still be implemented in each year, respectively. Revenue reductions should favor reducing kWh charges over service charges while revenue increases should follow the opposite approach.

5. For rate classes without demand charges, the service charge originally proposed in Schedule E-2.2.A and Schedule E-2.2.B should still be implemented in each year, respectively. Revenue reductions should favor reducing kWh charges over service charges while revenue increases should follow the opposite approach.

6. As with class revenue assignments, the Company will need to exercise its own discretion when adjusting unit charges. Unit charges should never exceed their full cost based level.

7. As part of its compliance filing, the Company will submit a Unity COSS for RY1 and RY2. Each study will also include the workpapers requested in Interrogatory RA-11.

8. In the RY2 compliance filing, the Company will comport with the directives and/or Orders in the final Decision in Docket No. 12-05-04, PURA Review of Electric Bill Charges and Costs.

The compliance filing for each rate year will consist of the following:

1. Testimony
2. Schedule E-1, Scored and Unscored Proposed Tariffs
3. Schedule E-2.0 Revenue Summary
4. Schedule E-2.1 Detailed Revenue Summary
5. Schedule E-2.2 Revenue Calculation
6. Schedule E-2.3 Typical Bill Comparisons
7. Schedule E-6.0 COSS
8. Schedule E-6.0 COSS – Unity
9. Standard Revenue Proof Exhibits

3. Tariff Changes

All of the tariff changes discussed below will become effective with the approved rates for RY1.

a. Bypassable Federally Mandated Congestion Charge

Currently, the bypassable federally mandated congestion charge (BFMCC) is embedded in UI's Standard Service Generation Charge (SSC) in the rate schedules, while CL&P displays them separately. UI agreed to make this change in its rate schedules. Tr. 5/7/13, p. 1788. The Authority prefers that the BFMCC be displayed separately in the rate schedules, consistent with CL&P. As part of its tariff compliance filing, UI is directed to break out the BFMCC from the SSC in the applicable rate schedules.

b. Explanation of Charges Section

UI's tariffs do not provide an explanation to customers as to the purpose of each charge. The Authority believes that such a section would be beneficial to customers by helping them better understand the many charges on their bills. The Company agreed to develop this new tariff section. Tr. 5/7/13, pp. 1790 and 1791. Therefore, as part of its tariff compliance filing, UI is directed to provide for Authority approval, a proposed explanation of charges section that lists each charge to which customers may be subject with an explanation of its purpose. The table must also list the full name of the rate schedules.

c. Other

UI submitted a revised version of its tariffs as part of Late Filed Exhibit No. 3. Clarifying language was added to the Terms and Conditions and other tariffs as recommended by the Authority and the OCC during the proceeding. Among the tariff changes is page numbering the tariffs and adding corresponding page numbering in the Table of Contents. Language was also added to the Availability section in Rate RT to correspond with the language in Rate R that specifies the regulatory requirement that customers on Rate R who exceed 2,000 kWh in a single billing cycle will be placed on Rate RT. Late Filed Exhibit No. 3, Attachments 2-5. The Authority approves these clarifying changes and as such, will be included as part of UI's tariff compliance filing.

4. Pole Attachment Revenue

In the Application, UI proposed to establish a telecommunications service provider (TELCO) pole attachment tariff in accordance with the Federal Communications Commission (FCC) order in WC Docket No. 07-245. The proposed TELCO tariff was filed in compliance to an order by the Authority in the Decision dated September 12, 2012 in Docket No. 11-11-02, Petition of Fiber Technologies Networks LLC for Authority Investigation of Rental Rates Charged to Telecommunications Providers by Pole Owners. Decision, Order No. 2. At the time the Application was filed, UI did not have the exact charge calculation, but indicated the intent of setting the rate equal to 66% of the fully embedded cost of owning and operating utility poles. The fully embedded cost is determined as part of UI's cable television (CATV) pole attachment rate. Therefore, the resulting revenue impact was not filed with the Application, nor was the proposed TELCO tariff.

In response to a request for the revenue impact of the proposal, UI proposed to set the TELCO rate at $17.40 per year per attachment, a decrease from the existing rate of $23.78. In preparing the response, UI determined that the CATV rate needed to be updated and was missing from the Application as well. UI Response to Interrogatory RA-1. The Company indicated that the CATV rate was last updated in its prior rate case. Tr. 5/6/13, p. 1415. UI proposed to increase the CATV rate from $10.56 per year per attachment to $20.46. UI will charge the full CATV and TELCO rates for attachments to poles that are solely-owned by UI, and 50% of the CATV and TELCO rates for attachments to poles that are jointly-owned by UI and another entity. The vast majority of the attachments are on jointly-owned utility poles. UI Response to Interrogatory RA-1.

Based on the proposed TELCO rate, UI anticipates a slight decrease in pole attachment revenue of $77,483 for RY1 and $80,727 for RY2. The increase in revenue from the originally proposed CATV rate of $604,343 for RY1 and $604,361 more than offsets this revenue decrease.

UI stated in the hearings that it informed the New England Cable Television Association (NECTA) of the proposal and also discussed its potential participation in the case. To allow more time for NECTA to participate, UI proposed to leave the CATV rate unchanged for the time being and file a limited reopener to examine the rate and have discussions as needed. The OCC stated it has no objection to this proposal. Tr. 5/23/13, pp. 2781 and 2782. UI then withdrew its proposal to revise the CATV rate, resulting in a net revenue requirement adjustment of ($77,483) for RY1 and ($80,727) for RY2. Revised Response to Interrogatory RA-1; Late Filed Exhibit No. 3.

The Authority accepts the Company's proposed CATV and TELCO rates, as shown in the Revised UI Response to Interrogatory RA-1, Attachment 2.

5. Make-ready Cost Recovery

Make-ready costs are the costs to make a pole ready for a third party to make their attachment. The costs are broken down in two ways, billable and non-billable. The billable costs are for work required by pole owners to make space on the pole or upgrades to the pole to allow new attachments to be installed to meet National Electrical Safety Code (NESC) standards. The non-billable costs are the costs for the pole owners or other attachers on the pole to correct any existing non-compliant NESC issues on the poles prior to the making a new attachment. Some examples of this work can include shifting wires, adjusting street lights and pole replacements. Late Filed Exhibit No. 103.

UI included approximately $500,000 in projected make-ready costs for inclusion in its O&M expenses for RY1 and $503,000 for RY2. Late Filed Exhibit No. 7. Of this amount, UI collects approximately $84,000 in revenues from the billable costs. Late Filed Exhibit No. 58.

The OCC argued that UI should look to the cost-causer for payment of the cost to bring attachments into NESC compliance, and that there is no PURA Decision that allows make-ready work to be charged as expenses to electric ratepayers. Brief, pp. 46 and 47.

UI stated that there is no additional revenue to offset its make-ready expenses, since each entity is responsible for its own costs to correct NESC compliance issues. UI Reply Brief, p. 65.

The Authority considered the arguments brought up by the OCC and the discussion of the underlying costs represented in Late Filed Exhibit No. 103. The PURA determined that an examination of the allocation of the remaining $416,000 in non-billable make-ready costs for RY1 and 419,000 for RY2 is warranted, and reallocation of the costs, if appropriate. When UI incurs O&M costs solely for the purpose of serving pole attachment customers, and the costs cannot be billed directly to a responsible party, those costs should be allocated to the collective group of attachers. As part of the required rate design required in Section II.N.2., Authority Rate Design, the Authority will direct UI to examine the current allocation of non-billable make-ready costs between the pole attachment rates and the general rates and ensure that the costs are allocated appropriately to the cost causers.

O. CUSTOMER SERVICE REVIEW

1. Standard Bill Form and Termination Notice

UI's standard bill form, termination notice and customer rights notice were reviewed and found to be in compliance with applicable regulations. Application, Schedule H-2.0 and H-2.1; UI Response to Interrogatory CS-12. Besides written notification of a pending termination, UI will call the delinquent customer seven days after the disconnect notice is mailed requesting that the customer contact the Company. UI Response to Interrogatory CS-1. UI also affirmed that unregulated charges are never included in a termination notice, in compliance with applicable regulations. Response to Interrogatory CS-2. UI noted that it continually has been making improvements to its processes and procedures to alleviate uncollectible risks.

The following are examples of the Company's improvement efforts: an account posting system for payments made at third-party or walk-in centers; sending accounts with balances greater than $2,500 and 90 days past due to a legal firm for collection or legal action; and a change in the dunning process where disconnection notices are issued when the customer's account is 33 days delinquent instead of 60 days delinquent. UI Response to Interrogatory CS-21.

2. Policies and Procedures for Estimated Billing

UI provided its policies and procedures for generating an estimated bill. UI's billing system produces an estimated bill that is based upon historical usage in the comparable month in the prior year. In certain cases, such as when the estimate needs to be based upon a time-of-day rate but the account was not on that time-of-day rate during the comparable month, a manual process to arrive at the estimate is utilized. All of these procedures have been reviewed and found to be in compliance with applicable regulations. Application, Exhibit H-2.2; UI Responses to Interrogatories CS-4 and CS-5.

UI's bill form and associated customer notices were also reviewed and found acceptable with one minor exception. Conn. Agencies Regs. §16-3-102 C 2 states:

> When a company is unable to obtain a company reading during any billing period for which such company reading was scheduled to be made, the company shall provide the residential customer with a card requesting an immediate customer reading, instructing the customer that he may provide such customer reading to the company, and warning the customer that if no customer reading is received by the company in time to be used in preparing the bill (such time limit to be specified on the notice), an estimated bill will be issued. The company shall provide the customer with instructions for furnishing the customer reading to the company. The company may provide for customer readings by mail or by telephone or by both methods.

UI provides its customers with the proper estimated bill form. The Company also provides customers with notification of an estimated bill (in both English and Spanish) as required by Conn. Agencies Regs. §16-3-102 C 3. However, UI does not provide to its customers a card that requests an immediate customer reading, instructions on how to read the meter, and a warning to the customer that if no reading is received by the Company in time to be used in the preparation of the bill, an estimated bill will be issued. UI Response to Interrogatory CS-3.

The Authority notes however, that the issuance of estimated bills by UI occurs very infrequently. The table below shows the percentage of estimated bills issued over time periods ranging from 1-3 months to as long as 13 or more months:

Year	1 to 3 Months	4 to 6 Months	7 to 12 Months	13+ Months
2010	0.316%	0.034%	0.014%	0.008%
2011	0.343%	0.039%	0.019%	0.008%
2012	0.399%	0.045%	0.011%	0.007%

UI Response to Interrogatory CS-6.

UI stated that it works very diligently to avoid issuing estimated bills and does everything it can to provide its customers an accurate meter reading on its bills. Tr. 4/22/13, p. 32. The extremely low percentage of estimated bills issued by the Company fully supports this statement. These factors notwithstanding, the Authority notes that the intent of Conn. Agencies Regs. §16-3-102 C 2 was to permit a customer the opportunity to provide an actual meter reading to the utility company in time to generate a bill based upon that actual meter reading and not an estimate. However, the Authority concedes the fact that the aforementioned regulation was originally promulgated in 1978, well before the functionality of UI's current metering infrastructure was considered. In its 2009 CL&P Rate Case Decision, the Authority cited this same area of non-compliance on pages 174 and 175. The Authority ruled that §16-3-102 C 2 was still applicable, and as such, CL&P was ordered to revise its estimated billing policies and procedures so as to comply with all of the provisions of Conn. Agencies Regs. §16-3-102. In response, the Authority approved CL&P's plan to institute an automated outbound calling procedure. Under this procedure, customers due to receive an estimated bill would be sent a pre-recorded message indicating that CL&P was unable to obtain an actual meter reading and provided the necessary procedures for a customer to undertake so as to avoid an estimated bill. Docket No. 09-12-05, Order No. 20 Compliance Filing, September 1, 2010.

Accordingly, the Authority also will direct UI to revise its estimated billing policies and procedures so as to comply with all of the provisions within Conn. Agencies Regs. §16-3-102.

3. Customer Security Deposits

The Authority reviewed the current policies and procedures UI utilizes to administer customer security deposits, and found them to be in compliance with Conn. Agencies Regs. §16-11-105 and §16-262-1. Application, Schedule H-2.3. At the present moment, UI does not intend to implement a requirement for residential security deposits. However, the Company has not ruled out this possibility in the future. UI Response to Interrogatory CS-7.

4. Service Appointments

UI schedules service appointments during normal hours of operation as well as during evenings and weekends. The service appointments are made Monday through Friday from 7:30 a.m. to 7:00 p.m., and Saturdays from 8:00 a.m. to 4:30 p.m. Application, Schedule H-2.4. On an as needed basis, service appointments can be scheduled outside of those previously mentioned times due to access issues or special request from the customer. Response to Interrogatory CS-9. In the event that UI is unable to keep a scheduled service appointment, the Company will attempt to either contact the customer to reschedule or complete the assignment by making a field visit on the scheduled day outside of the normal appointment window. UI Response to Interrogatory CS-10. Over the last three years, UI has been able to keep at least 97% of its scheduled service appointments. UI Response to Interrogatory CS-11; Tr. 4/22/13, p. 27.

5. Customer Care Center

UI maintains a Customer Care Center to address customer complaints and inquiries. The operating hours for this call center are 7:00 a.m. to 7:00 p.m. Monday through Friday, and 7:00 a.m. to 4:00 p.m. on Saturday. UI Response to Interrogatory CS-25. According to UI, it has established an internal goal for its Average Speed of Answer (ASA) of 90 seconds and an abandoned call rate of 5%. Tr. 4/22/13, pp. 55 and 56. Statistics below, submitted by UI for calendar years 2011 and 2012, indicate the call center's monthly performance against the Company's internal goals:

2011	ASA*	ACR**	2012	ASA	ACR
January	194	13.8%	January	80	6.8%
February	107	8.8%	February	28	3.6%
March	67	5.5%	March	51	4.3%
April	71	5.9%	April	26	2.4%
May	71	10.9%	May	56	4.6%
June	168	13.0%	June	77	7.0%
July	161	12.2%	July	179	14.2%
August	100	8.9%	August	100	11.1%
September	255	19.9%	September	194	14.7%
October	137	11.7%	October	52	6.6%
November	183	14.7%	November	206	16.5%
December	152	11.5%	December	218	17.7%

*ASA in seconds and **Abandoned Call Rate (ACR).

Response to Interrogatory CS-24.

The AG stated that UI has been unable to provide adequate levels of customer service. The AG noted that between January 2011 and February 2013, UI's call center did not meet the 90 second ASA threshold in 16 out of 26 months, and was unable to meet the abandoned call metric of 5% in 22 out of 26 months. The AG encouraged the Authority to re-impose and hold UI to the ASA and abandoned call metrics, and subject the Company to financial penalties and/or greater regulatory oversight for the failure to meet these goals. AG Brief, p. 36.

As for its current call center metrics, UI stated that it has no immediate plans to modify its goals, but its interest would be to improve the level of service that the Company provides to its customers. UI stated that it was on track to meet the 90-second ASA goal during 2012, but the effects of Sandy on the call center disrupted this path. According to the Company, up until October 2012, the call center's ASA was at 82 seconds, below the 90-second goal. Besides the impact of Sandy on the call center, UI also noted that it will be undertaking a number of technological initiatives such as the replacement of its telephone switch, improvements to the interactive voice response unit and additional self-service features that should all help to improve call center performance. Tr. 4/22/13, pp. 43-60.

The Authority's Consumer Services Unit (CSU) has continued to monitor the performance of UI's Customer Care Center pursuant to Order No. 6 in the 2009 Decision. Currently, there are no specific standards or benchmarks for EDC call center metrics set forth in Connecticut's statutes or regulations for such benchmarks. However, the Authority shares the AG's position that UI should provide adequate levels of customer service. Besides the technological initiatives that the Company is in the process of implementing, UI also noted its participation in monthly meetings with the Authority's CSU as a means to improve upon the level of service provided to customers. Tr. 4/22/13, p. 60. These monthly meetings were established in Order No. 19 in the 2006 Decision and continued in Order No. 5 in Docket No. 08-07-04. Accordingly, the Authority will direct UI to continue the monthly meetings with the CSU as well as to report on its call center performance statistics. These performance statistics will be reviewed based upon UI's self-imposed standards of a 90-second ASA and an abandoned call rate of no greater than 5% of calls.

6. Customer Service Summary

Overall, the Department found UI's customer service policies and procedures to be in compliance with applicable statutes and regulations, excluding those exceptions discussed previously in this section.

III. FINDINGS OF FACT

1. The test year period is the 12 months ended June 30, 2012.

2. Rate Year 1 (RY1) and Rate Year 2 (RY2) are the 12 months ended June 30, 2014 and June 30, 2015, respectively.

3. Not including the Central Facility (CF) capital expenditures, the annual increase added to plant account is impacted disproportionately, having risen from $92.5 million in 2009 to a projected $177.2 million in 2014.

4. The capital expenditures proposal represents a continuation of the trend of significantly higher spending, rate base and rates.

5. Stakeholders are rightly concerned about reliability as it relates to major storms.

6. While the aggressive storm programs in the Company's capital budget proposal will surely benefit the non-storm Customer Average Interruption Duration Index (CAIDI), this measure requires better focus in the future along with improved UI performance.

7. The aging infrastructure issue was attributable to assets that were installed during the high growth periods of the late 1960s and early 1970s.

8. A large amount of distribution equipment is reaching end of design life at about the same time.

9. The Company's approach for modernization and replacement of the infrastructure is inconsistent with an effective strategy for modernization and replacement.

10. A valid plan and vision will demonstrate that the spending bubble was appropriate, and that it should continue for some limited period.

11. Tree trimming costs are recurring costs normally expensed in the period they were incurred.

12. The notion of Enhanced Tree Trimming (ETT) has firmly caught hold in Connecticut and has widespread support as evidenced by numerous independent reviews.

13. The Company's primary justification for ETT and other Storm Preparedness activities is its desire to respond to customer wishes when used as the primary or only justification is unacceptable.

14. It is the utility's obligation, subject to the PURA's oversight, to balance various conflicting pressures to arrive at programs that best serve the customer and other stakeholders.

15. Most of the stakeholders that have lent their support to ETT did not understand or envision such a treatment of the program's costs and its impact on UI earnings and customer rates.

16. UI's argument that there is precedent for treating ETT program costs as capital citing a previous CL&P proceeding and FERC guidelines is not applicable.

17. Amortization of one-time major expenses is a common approach to minimize the effect on ratepayers, and there seems no reason why these ETT expenses cannot be treated accordingly.

18. A fair rate of interest needs to be established to make UI whole for the time value of the money they will advance.

19. There is ample evidence that the elements of the Transmission and Distribution Operational Excellence Initiative (TDOEI), both individually and especially when tied together, produce value.

20. No preparedness program or series of initiatives is good enough to be implemented at any cost.

21. The lack of any analysis of cost and benefits, and the use of such analysis to arrive at an optimum level of spending, is a serious flaw in the TDOEI proposal.

22. In the absence of any cost benefit analysis, an evaluation by the Authority of the appropriateness of the proposed ETT spending level is impossible.

23. In calculating its collection lead, the Company used the 13-month average accounts receivable balance.

24. Accounts that are ultimately written off as uncollectible are part of the accounts receivable balance until they are written off.

25. During the test year, the Company transitioned from weekly and monthly payrolls to a biweekly payroll.

26. The transition from weekly and monthly payrolls to a biweekly payroll is now complete and during both rate years the Company will be operating exclusively under a biweekly payroll.

27. A non-hardship account remains in the accounts receivable balance for 129 days before it is written off as uncollectible.

28. A hardship account is removed 90 days after having been billed if the receivable remains unpaid.

29. Hardship accounts comprised 67.12% and non-hardship accounts 32.88% of the uncollectible expense during the test year.

30. Comparison of the receivable balances used in the Company's lead/lag study with its balance sheet show that the receivable balances used in the lead/lag study are gross of the reserve for doubtful accounts.

31. The 98.5 percentile methodology for the reporting of reliability statistics is the basis for consistently measuring day-to-day reliability performance by Connecticut's electric utilities.

32. UI's definition of special treatment for catastrophic storms in terms of how associated costs should be recovered by utilities has never been given any status with respect to costs destined for the storm reserve.

33. UI's contention that a major storm definition has been firmly established and that the Authority has no right to change it retrospectively is incorrect.

34. The Company's belief that it was promised a definition of major storms and that such definition would dictate the terms of recovery, is incorrect.

35. The Company's assumptions that an approved definition of major storms was in place and that UI's storm-related operation and maintenance (O&M) expenses as reflected in rates, had been approved are wrong.

36. It is logical that the two points in question, the major storm definition and allowable storm-related O&M expenses, are related; and it is appropriate to consider both.

37. The Authority is limited to defining major storms on a basis consistent with catastrophic events and that eliminates the normal and focuses on the catastrophic is appropriate.

38. Certain types of advertising are not considered an operating expense of a regulated utility company; including political advertising, institutional advertising to create or enhance a company's public image and promotional advertising, unless authorized by the PURA.

39. The Company did not quantify the cost of $5,400 per vault inspection and/or repair maintenance.

40. The Long-term Process & Technology Enhancement and Short-term Tactical Enhancement are new rate year programs for anticipated training and data conversion and to update the restoration plan.

41. The Company is lacking historical data to back-up projects of this magnitude that are based on estimated outside services hourly cost per unit and the required number of hours needed for the task.

42. The Company should not incur additional expenses for items such as an on-site cafeteria, building equipment services, custodial services and snow removal for new facilities if the prior expenses were from owned or leased facilities.

43. It is not the ratepayers' responsibility to bear the cost of an income-producing service such as an on-site food cafeteria.

44. Continuing to defer major storm costs without establishing funding of an annual storm reserve can compromise the Company financially.

45. UI's determination of funding the storm reserve at $2 million annually is reasonable.

46. UI submitted two MAC depreciation studies on UI's depreciable electric utility property in service: a 2003 Study, as of December 31, 2003 in Docket No. 05-06-04 and a 2008 Study as of December 31, 2008.

47. Both the 2003 and 2008 Depreciation Studies used the straight-line method, technique and vintage/broad group method or average life group and actuarial data in which all retirements and surviving investments are aged for a large portion of property with the exception of several Distribution Plant accounts.

48. The total plant level average service life (ASL) in the 2008 Study was 36 years, while the ASL in the 2003 Study was 34.1 years.

49. The 2008 Study did not address the ASL of the new CF valued at $104.540 million and $104.669 million in the RY1 and RY2, respectively.

50. The CF is UI's new headquarters located in Orange, Connecticut and the cost was $120.6 million while the estimated cost in the 2006 Decision was $58.3 million.

51. In June 2010, the UIL Board authorized $85.5 million for construction costs for the CF and in December 2011, it approved $91.2 million.

52. Historically overtime expenses varied from year to year.

53. Overtime expenditure is within the Company's management control.

54. In the 2009 Decision, the Authority reaffirmed its decision to limit the amount of incentive compensation to be included in rates to $3.994 million.

55. UI continued to pay incentive compensation at a level in excess of what was allowed in rates.

56. UI has not performed any studies, nor availed itself to studies performed by others regarding incentive compensation allowed or disallowed in other jurisdictions.

57. From 2008 to 2012, every executive and management employee who was eligible received incentive compensation.

58. The Company's mix of capitalized, base O&M, O&M overtime, regulatory storm base and overtime, and non-distribution payroll expenses may create potential for duplicative recovery of payroll expenses.

59. The storm regulatory asset included expenditures for both regular base and overtime payroll expenses.

60. Base O&M payroll for 2011 and 2012 were less than amount the Authority allowed in the 2008 Rate Case.

61. The Company's reported accrued payroll expenses recovered in retail distribution rates were consistently and significantly higher than Medicare wages reported in the quarterly wage reports.

62. UI has a qualified pension and OPEB plan that covers the majority of its existing employees hired prior to 2005.

63. Contributions to qualified pension plans are tax-deductible and are regulated by the PBGC.

64. Effective in 2005, UI implemented a defined contribution plan that replaced the existing qualified pension plan and retiree medical plan benefits/OPEB for new employees.

65. Since UI's last rate proceeding, there has been a decline in discount rates due to the downward trend of interest rates nationwide over the periods.

66. The updates to discount rates were not significant enough to impact the actual decline in pension and OPEB expenses in this proceeding.

67. Matching contributions provide a benefit to employees, but restrict the amount of matching recovery allowed.

68. Where it is estimated employees that already have significant potential of receiving additional compensation benefits through rates, ratepayers should not be required to fully fund their matching contributions as well.

69. Since certain specific contributions are not KSOP matching contributions, they would be excluded from the total KSOP contributions.

70. In the 2006 Decision and the 2009 Decision, the Authority found that matching provides a benefit to employees, but restricted the amount of matching recovery allowed.

71. The Company's current health plans are self-insured programs and do not have any premiums.

72. UI pays an administrative fee per an enrolled eligible participant to the carrier to handle the claim payments to health provider and to negotiate on behalf of the Company reduced or discounted treatment fees.

73. UI pays a monthly stop loss fee to provide insurance against any single claim in excess of $300,000.

74. The Company pays all claim costs that have been incurred by all the covered participants and dependents.

75. The medical claimed costs vary from week to week and month to month based on the treatments incurred by the total group.

76. The proposed medical cost premium escalation factors for RY1 and RY2 were overstated.

77. The Company determined that 12.5% escalation rate offered by ConnectiCare to renew for 2012 was costly.

78. For 2013, UI converted its medical and prescription plans to self-insurance and brought the overall administration costs down to 6.9% and stop loss to 4.2%.

79. The total non-distribution O&M and capital offset factors for the proposed rate years were less than that of the proforma interim period.

80. The Authority previously allowed recovery of 25% of DOL insurance expense in rates.

81. Non-DOL public company expenses costs include annual report, investor relations, Edgar filing SW maintenance, SEC reporting, shareowner services, and annual meeting expenses.

82. Public company costs provide more benefits to the shareholders than to ratepayers.

83. BOD costs included restricted stock expense for BOD, UIL legal and consulting matters, director stocks, director retirement pension and director expenses.

84. The main objective of the BOD is to protect the interest of the Company's investors or shareowners.

85. Ratepayers are not the focus of the BOD decisions.

86. The Authority allows only 25% of BOD costs in rates.

87. UIL capital is primarily related to computer software systems, mostly SAP enterprise resource planning system.

88. Computer software systems are recorded as UIL assets as they benefit all of the UIL affiliates.

89. Capital charge is developed based upon the annual depreciation incurred by UIL on its assets plus a return based upon the weighted-average allowed return of its operating companies

90. This total capital charge is allocated to UIL's operating companies based upon the three-factor Massachusetts formula.

91. All UIL corporate capital charges are allocated to business units based on each business unit's respective net plant plus IP, payroll, and revenues.

92. UI moved into the SAP environment for its customer information system in 2003.

93. The decrease in the RY1 amount compared to the test year was due to a decrease in the UIL allocation percentage following the integration of the gas companies.

94. The Company has been selected by the DRS to participate in a special sales tax program since October 1, 2003, which will determine UI's sales and use tax liability.

95. Interest synchronization adjustments cause UI's interest expense deductions to be lowered for income tax purposes, resulting in increases to the income tax expenses

96. There is no question that the CF proved to be a challenging project in the early years as the Company struggled with site-related issues.

97. The Company's explanations do not justify a four-year delay in Phase 1 and an overall increase in the CF project costs of $25 million.

98. The retention of experts early in the site selection and acquisition process would have likely precluded the need for such an extended and expensive learning curve.

99. There are uncertainties associated with any large construction project, even of a less complex commercial structure.

100. While experts could have mitigated the cost impact, it conclusively cannot be determined that they could have fully eliminated it.

101. The CF that UI built is not the CF that the UIL Board approved.

102. By the time the money had already been spent or committed, left the Board with no choice but to approve it.

103. Despite clear direction from the UIL Board to change course, UI management proceeded on a path consistent with overspending the UIL Board authorization.

104. The Company proposed using a capital structure consisting of 50% long-term debt to 50% common equity for RY1 and RY2 to design rates.

105. As of September 30, 2012, UI's end of period capitalization was 51.08% equity.

106. The Company's primary use of short-term debt has been to fund capital expenditures while the construction work is in progress.

107. UI presently has 21 long-term debt issues with the interest rate on its current debt ranging from 1.25% to 7.13%.

108. UI is presently rated Baa2 by Moody's and BBB by S&P.

109. UIL is the Parent Corporation of UI.

110. UI manages to a 50% long-term debt to 50% common equity ratio capitalization mix with issuances of long-term debt to fund its operations and through capital contribution from its Parent Corporation.

111. UIL reported a consolidated equity ratio ranging between 34% and 38%.

112. The credit ratio of the parent company can constrain the credit rating that the operating subsidiary can obtain.

113. The Company financial viability remained stable since the 2009 Decision based upon the Company's contention that it maintains an investment grade credit rating by maintaining a 50/50 equity to debt capitalization mix for ratemaking purposes.

114. The primary determinants of the Company's cash flow are earnings, the capital expenditure program, taxes and pension costs.

115. UIL had two equity issuances one in 2009 and one in 2010.

116. The purpose of the 2009 UIL equity issuance was for general corporate purposes including $70 million equity contribution to UI, which was used by UI to repay $70 million in short-term debt outstanding.

117. The 2010 equity offering was issued to fund the purchase of three natural gas companies and to pay for issuance costs and other corporate purposes.

118. The size of the 2010 UIL equity offering was $455.8 million and was oversubscribed and generated $524.1 million with net proceeds of $501.9 million after underwriting fees and other expenses.

119. UI does not target a certain dividend payout ratio or dollar dividend amount to UIL; nor does UIL target a certain dividend payout ratio to its shareholders.

120. UI's objective in setting its dividend to UIL was to maintain its currently allowed 50% common equity and 50% long-term debt capital structure over time.

121. The beta of the Company Utility Group was 0.73 while that of UI was 0.70.

122. Decoupling mechanisms are in place in 36 states.

123. The UIL stock price outperformed the S&P 500, S&P Public Utility Index, and S&P Electric Power Index.

124. The UIL stock price's market-to-book ratio was 1.89 as compared to 1.56 for the companies included in the OCC's proxy group of electric companies.

125. Interest rates and capital costs are at historic low levels and are about 200 basis points below the levels at the time of the 2009 Decision.

126. The Company raised both debt and equity capital in recent years, including almost $1 Billion in 2010 to purchase CNG, SCG and Berkshire Gas.

127. Over the past five years, UIL's stock price significantly outperformed both the S&P 500 and the DJUI, and currently sells at a market-to-book ratio well in excess of other electric utilities.

128. Authorized ROEs for electric utility companies have declined, reflecting the historically low interest rates and capital costs.

129. The UIL capital structure used considerable more leverage with 34% common equity (reported by S&P) to 66% long-term debt.

130. In developing the overall DCF result, the Company eliminated implausibly low and high results and these outliers were identified as DCF estimates that were under 7% and over 17.7%, or were based on a growth forecast of more than 13.3%.

131. The proxy for the utilities' cost of equity was to examine the returns authorized by state commissions. The data source was the RRA reports of ROEs authorized by utility commissions each year from 1974 through 2012 as reported by RRA.

132. The Company utility risk premium 10.6% cost of equity rate included: (1) a 2013 utility bond yield of 4.86%; (2) an interest rate adjustment of 1.66%; and (3) a risk premium of 5.13%.

133. The system-wide distribution ROR for the test year was 5.84%.

134. UI created the sales forecasts using two distinct, sequential sub-processes that include a total system sales high level forecast and allocation of those total system sales in detail among all rate elements.

135. UI's forecasting methodology begins with a historical test period, which is typically the previous year, to which proforma adjustments are made to bring the sales forecast to each projected rate year.

136. The type of sales forecasting methodology used by UI is common in the utility industries and the Authority has approved similar forecasting methodologies in numerous gas, water and electric rate proceedings.

137. The Authority made adjustments to utility proposed sales forecasts in the past if in the PURA's opinion the specific adjustment amounts and/or the overall forecasts are not deemed reasonable and/or not supported by record evidence.

138. UI based the amount of lost sales from DG projects on the DTSD.

139. Some DG projects were behind the DTSD schedule, none of the DG projects were on-line, and most had not yet begun construction.

140. Over the three year period 2010-2012, the average sales decrease was 1.09%.

141. Normalized annual sales decreased by 2.05% in 2009, 0.10% in 2010, 1.83% in 2011, and 1.35% in 2012.

142. Over the four year period, the average sales decrease was 1.33%, and over the three year period, the average sales decrease was 1.09%.

143. The 2013 proposed sales is a decrease of 1.36% from the 2012 normalized sales.

144. The proposed 2014 sales is 1.165% less than the proposed 2013 sales and the proposed 2015 sales is 1.69% less than its proposed 2014 sales.

145. Over the three year forecasted period, the average proposed sales decrease was 1.40%.

146. The Company's COSS followed the same design methodology approved by the Authority in its last rate increase application.

147. The COSS test period is July 1, 2011 through June 30, 2012.

148. All distribution costs are either customer related or peak demand related.

149. The Company's reliance on CTA reductions as justification for establishing new rate class revenues further exacerbates interclass subsidization as measured by ROR responsibility.

150. Given the 24% proposed increase in RY1 revenue, a conventional rate increase proposal designed to trim interclass differences in RORs would have produced far greater equity among customer classes than that actually obtained by mathematically mimicking the CTA reduction.

151. The Company provides only distribution service.

152. The system wide distribution ROR for the test year was 5.84%.

153. UI's tariffs do not provide an explanation to customers as to the purpose of each charge.

154. The BFMCC is currently embedded in the SCC in the rate schedules.

155. UI's tariffs do not provide an explanation to customers as to the purpose of each charge.

156. The BFMCC is currently embedded in the SCC in the rate schedules.

157. UI determined that the CATV rate needed to be updated and was missing from the Application.

158. The proposed TELCO tariff was filed in compliance with an order by the Authority in the Decision dated September 12, 2012 in Docket No. 11-11-02.

159. UI withdrew its proposal to revise the CATV rate.

160. Make-ready costs are the costs to make a pole ready for a third party to make its attachment.

161. Non-billable make-ready costs are the costs for the pole owners or other attachers on the pole to correct any existing non-compliant NESC issues on the poles prior to the making a new attachment.

162. Of the total make ready costs included in the rate case, a small fraction is billable.

163. UI's standard bill form, termination notice and customer rights notice comply with applicable regulations.

164. UI's estimated bill form complies with applicable regulations.

165. UI does not provide customer receiving estimated bills with a means to provide the meter reading or instructions on how to read the meter, as required in Conn. Agencies Regs. §16-3-102.

166. From 2010 to 2012, less than 0.4% of bills issued were estimated.

167. UI's policies and procedures for the administration of customer security deposits comply with applicable regulations.

168. UI's Customer Care Center is available from 7:00 a.m. to 7:00 p.m. Monday through Friday, and from 7:00 a.m. to 4:00 p.m. on Saturday for customer complaints and inquiries.

169. UI maintains an internal goal for a 90-second Average of Speed of Answer and an abandoned call rate of no greater than 5% of calls at its Customer Care Center.

170. For the time period of January 2011 through February 2013, UI's Customer Care Center did not meet the 90-second Average Speed of Answer threshold in 16 out of 26 months, and did not meet the 5% abandoned call rate in 22 out of 26 months.

IV. CONCLUSION AND ORDERS

A. CONCLUSION

Based on the evidence presented in this proceeding, the Authority finds allowed revenues of $297,497,000 to be appropriate for UI in RY1 and $323,336,000 in RY2 as detailed in Appendix A and Appendix B, respectively. This is a reduction of $44.815 million from the Company's adjusted cumulative request of $90.595 million and a $45.781 million increase or 16.49% to present revenues. The Authority allows the Company an allowed rate base of $795,867,000 in RY1 and $886,878,000 in RY2. The Authority approves an allowed ROE for both rate years of 9.15%, for a weighted cost of capital of 7.235% in RY1 and 7.210% in RY2. This cost of capital is based on an allowed capital structure containing a 50% common equity component and a 50% debt capitalization component. The revenue requirement adjustments as authorized herein, will be sufficient to enable the Company to operate successfully, maintain its financial integrity, attract capital, compensate its investors for the use of their money and the risks assumed, and maintain high quality service. New rates will become effective for usage on and after August 14, 2013.

B. ORDERS

For the following Orders, submit one original of the required documentation to the Executive Secretary, 10 Franklin Square, New Britain, Connecticut 06051 <u>and</u> file an electronic version through the PURA's website at <u>www.ct.gov/pura</u>. Submissions filed in compliance with the PURA's Orders must be identified by all three of the following: Docket Number, Title and Order Number.

1. No later than August 28, 2013, UI shall file with the Authority for approval, five complete sets of tariffs, scored and unscored, that incorporate all tariff and RY1 rate changes approved herein. The Company shall include a supporting COSS and a unity COSS for RY1 reflecting the billing determinants and financial profile approved herein, that comports with the directives in Section II.N.2. UI shall also include a permanent Decoupling Rider DR reflecting the existing policies under the current Pilot Decoupling Program.

2. No later than August 28, 2013, as part of the required rate design discussed in Section II.N.2., <u>Authority Rate Design</u>, UI shall examine the current allocation of non-billable make-ready costs between the pole attachment rates and the general rates and ensure that the costs are allocated appropriately to the cost causers.

3. No later than August 30, 2013, UI shall acknowledge in writing that it will submit for the Authority's approval, any changes to its customer service practices,

procedures or policies in writing at least 15 business days prior to the effective date of such changes.

4. No later than August 30, 2013, and monthly thereafter until the Company's next rate case, UI shall submit a monthly report that contains the following Customer Care Center performance metrics including:

   a. the total number of calls received;
   b. the total number of calls handled by automated systems;
   c. the total number of calls handled by live customer service representatives;
   d. the total number of calls abandoned;
   e. the percent of calls abandoned;
   f. the average speed of answer, both live and automated;
   g. the number of full-time customer service representatives taking calls;
   h. the number of part-time customer service representatives taking calls;
   i. the ratio of total calls to representatives; and
   j. the total number of busy signals.

5. No later than August 30, 2013, UI shall resume its monthly meetings with the Authority's CSU until the Company's next rate case.

6. No later than October 31, 2013, UI shall submit to the Authority its revised estimated billing policies and procedures so as to comply with all of the provisions within Conn. Agencies Regs. §16-3-102.

7. No later than October 31, 2013, and quarterly thereafter, UI shall file with the Authority worksheets showing reconciliations of Medicare wages reported in its quarterly wage returns for the calendar quarters ended in the immediate prior months to the total itemized accrued payroll amounts that are imbedded in capital projects, base O&M, O&M, overtime, incentive compensation, accrued regulatory assets, and non-distribution operations' payroll expenses for the same three month periods. The total Medicare wages for the quarterly reconciliation shall include UI's own and amounts allocated to UI's distribution and transmission by UIL.

8. No later than November 1, 2013, and before the start of ETT work currently scheduled for January 2014, UI shall develop and submit to the Authority for review a more carefully considered, optimized plan for ETT, which shall:

   a. specifically address how the work is being packaged and prioritized for optimum effectiveness; and
   b. contain reporting requirements to UI management and the PURA, the latter of which shall include spending, miles trimmed and impacts on reliability of the program on a circuit and annual system basis.

9. No later than November 1, 2013, UI shall submit supporting analysis to the Authority that includes quantification of the long-term annual O&M savings to be realized from the ETT initiative, and a demonstration of how that commitment will become a reality in future years.

10. No later than March 1, 2014, UI shall file with the Authority for approval, five complete sets of tariffs, scored and unscored, that incorporate all RY2 rate changes approved herein. This compliance filing shall also comport with the directives and/or Orders in the final Decision in Docket No. 12-05-04, <u>PURA Review of Electric Bill Charges and Costs</u>. The Company shall include a supporting COSS and a unity COSS for RY2 reflecting the billing determinants and financial profile approved herein, that comports with the directives in Section II.N.2 and

11. No later than March 31, 2014, UI shall incorporate the results of pending storm-related dockets into a new, more detailed TDOEI plan that includes cost benefit analysis. That plan should also prioritize tasks such that the most important and effective improvements are addressed in the early years.

12. No later than August 15, 2014, UI shall file with the Authority exhibits reconciling actual C&LM and renewable revenues for the four calendar quarters ending June 30, 2014, to the $22.363 million allowed for RY1. This filing shall include signed copies of Form UCT 212 EDC and the supporting workpapers outlining the breakdown of C&LM, renewables and CAM revenues.

13. No later than August 15, 2015, UI shall file with the Authority, exhibits reconciling actual C&LM and renewable revenues for the 4 calendar quarters ending June 30, 2015, to the $22.363 million allowed for RY2. This filing shall include signed copies of Form UCT 212 EDC and the supporting workpapers outlining the breakdown of C&LM, renewables and CAM revenues.

14. No later than six months prior to the Company's next rate proceeding, UI shall prepare and submit to the Authority, an analysis of its forecasted long-term investment needs (20 years) that includes the following:

    a. The vision for the distribution system that the plan is intended to achieve.
    b. Assumptions and sensitivities regarding sales and demand growth, with specific conclusions regarding the relationship of future investment needs versus sales and demand.
    c. The long-term rate impact of the forecasted level of spending.

15. In its next rate case, UI shall provide a worksheet reconciling the allowed annual amortization expense to amounts recoverable under the Company's actual ETT expenditures incurred to date. UI shall include worksheet identifying expenditures for ETT and normal line clearance, as well as supporting records such as outside vendor invoices and related contracts specifying locations and terms for tree trimming activities for both the ETT and the normal line clearance expenditures.

16. In its next rate case, UI shall include exhibits and worksheet showing reconciliations of the total itemized accrued payroll amounts that are imbedded in capital projects, base O&M, O&M, overtime, incentive compensation, accrued regulatory assets, and non-distribution operations' payroll expenses to the total Medicare wages reported in its quarterly wage returns for the four calendar quarters in its proposed test year. The total Medicare wages for this reconciliation

shall include UI's own and amounts allocated to UI's distribution and transmission by UIL during four calendar quarters in the proposed test year.

17. The Company shall conduct a depreciation study review approximately every three to five years; or more frequently if deemed necessary by UI and include the following:

    a. The depreciation study shall be completed no later than nine months after the end of the selected depreciation study year (e.g., December 31 year-end to be completed no later than September 30). For future rate case proceedings, the Company shall utilize a Depreciation Study having a plant-in-service date that is within 12 months of the beginning of the proposed test year.
    b. Upon completion of the depreciation study, UI shall file a copy with the Authority and the OCC.
    c. If the Authority deems it necessary to conduct a formal review of any depreciation study prior to a pending base rate change application, the Company shall cooperate fully with the PURA.

18. At the time of any future requests for spending on modernization or replacement of aging infrastructure, UI shall submit a credible plan meeting the following criteria:

    a. Spending in this category should not indefinitely increase but should reach a sustainable steady-state (subject to inflation) below the catch up levels.
    b. The plan must be accompanied by suitable cost-benefit analysis of the program.

19. The Company will provide the necessary information to make its case for SIGNCP in its next rate application.

20. No later than April 30th annually, the Company shall account for the storm reserve balance. The report shall include additions and subtractions to the balance along with the date of the storm occurrences. The Company shall include an explanation of how it determined each storm charged to the account and an itemization of expenditures.

21. Beginning with the next submittal of required reliability reports to the Authority, UI shall include in all future reliability reports an analysis of CAIDI performance as well as a plan for the improvement of CAIDI including year-by-year targets.

22. UI shall amortize rate case expenses over a period of three years.

ATTACHMENT A

Rate Year 1
Authority Approved Sales Forecast and Distribution Revenue at Present Rates vs.
UI Proposed Sales Forecast (LFE-69) and Distribution Revenue at Present Rates

-	Authority Adjusted			UI Proposed			Authority Adjusted vs. UI Proposed		
		Present			Present			Present	
	1/1/2014	1/1/2014	1/1/2014	1/1/2014	1/1/2014	1/1/2014	1/1/2014	1/1/2014	1/1/2014
	Energy Sales	Revenues	Present Average	Energy Sales	Revenues	Present Average	Energy Sales	Revenues	Present Average
	kWh/year	$/year	Revenue ¢/kWh	kWh/year	$/year	Revenue ¢/kWh	kWh/year	$/year	Revenue ¢/kWh
R	1,454,086,315	$114,881,663	7.9006	1,421,974,411	$113,304,557	7.9681	32,111,904	**$1,577,106**	0.0675
RT	728,249,820	$46,362,137	6.3662	696,452,120	$44,804,205	6.4332	31,797,700	**$1,557,932**	0.0670
GSU Primary	834,346	$86,511	10.3687	813,015	$85,403	10.5045	21,331	**$1,108**	0.1358
GSU Secondary	2,500,370	$229,099	9.1626	2,436,422	$225,795	9.2675	63,948	**$3,304**	0.1049
GSN Primary	21,759	$2,162	9.9361	23,888	$2,272	9.5113	(2,129)	**-$110**	(0.4248)
GSN Secondary	54,376,961	$5,130,991	9.4360	54,027,099	$5,113,204	9.4641	349,862	**$17,787**	0.0282
GSD Primary	2,477,750	$127,467	5.1445	2,481,099	$127,547	5.1407	(3,349)	**-$80**	(0.0037)
GSD Secondary	351,486,525	$21,008,639	5.9771	349,680,602	$20,974,245	5.9981	1,805,923	**$34,394**	0.0210
GSTN Primary	20,958	$1,231	5.8737	19,772	$1,211	6.1235	1,186	**$20**	0.2499
GSTN Secondary	4,636,467	$306,795	6.6170	4,412,909	$303,148	6.8696	223,558	**$3,647**	0.2526
GST Primary - SS	75,223,967	$2,049,305	2.7243	66,777,672	$1,929,368	2.8892	8,446,295	**$119,937**	0.1650
GST Secondary - SS	1,151,649,990	$34,736,829	3.0163	1,021,774,496	$32,892,727	3.2192	129,875,494	**$1,844,102**	0.2029
GST Primary - LRS	101,263,031	$2,722,853	2.6889	89,880,919	$2,561,211	2.8496	11,382,112	**$161,642**	0.1607
GST Secondary - LRS	118,477,747	$2,952,790	2.4923	104,999,204	$2,761,379	2.6299	13,478,543	**$191,411**	0.1376
LPT Primary - SS	29,381,696	$1,088,070	3.7032	34,743,935	$1,088,147	3.1319	(5,362,239)	**-$77**	(0.5713)
LPT Secondary - SS	449,417,529	$11,133,666	2.4774	532,487,721	$11,133,688	2.0909	(83,070,192)	**-$22**	(0.3865)
LPT Transformer Owner - SS	6,488,458	$101,464	1.5638	7,680,222	$101,463	1.3211	(1,191,764)	**$1**	(0.2427)
LPT Primary - LRS	183,635,602	$3,468,081	1.8886	217,582,337	$3,468,155	1.5940	(33,946,735)	**-$74**	(0.2946)
LPT Secondary - LRS	177,636,838	$3,599,497	2.0263	210,508,339	$3,599,571	1.7099	(32,871,501)	**-$74**	(0.3164)
LPT Transformer Owner - LRS	377,677,221	$8,678,647	2.2979	447,476,149	$8,678,574	1.9394	(69,798,928)	**$73**	(0.3585)
M	45,775,831	$8,922,076	19.4908	46,073,469	$8,980,068	19.4908	(297,638)	**-$57,992**	(0.0000)
U	7,451,879	$816,256	10.9537	6,824,268	$747,509	10.9537	627,611	**$68,747**	0.0000
Total	5,322,771,060	$268,406,229	5.0426	5,319,130,068	$262,883,447	4.9422	3,640,992	**$5,522,782**	(0.1004)

ATTACHMENT B

Rate Year 2

Authority Approved Sales Forecast and Distribution Revenue at Present Rates vs.

UI Proposed Sales Forecast (LFE-69) and Distribution Revenue at Present Rates

-	Authority Adjusted			UI Proposed			Authority Adjusted vs. UI Proposed		
		Present			Present			Present	
	7/1/2014	7/1/2014	7/1/2014	7/1/2014	7/1/2014	7/1/2014	7/1/2014	7/1/2014	7/1/2014
	Energy Sales	Revenues	Present Average	Energy Sales	Revenues	Present Average	Energy Sales	Revenues	Present Average
	kWh/year	$/year	Revenue ¢/kWh	kWh/year	$/year	Revenue ¢/kWh	kWh/year	$/year	Revenue ¢/kWh
R	1,452,268,352	$114,892,521	7.9112	1,399,948,435	$112,322,933	8.0234	52,319,917	**$2,569,588**	0.1121
RT	727,339,330	$46,342,127	6.3715	685,634,260	$44,298,791	6.4610	41,705,070	**$2,043,336**	0.0895
GSU Primary	829,967	$86,379	10.4075	800,374	$84,843	10.6004	29,593	**$1,536**	0.1929
GSU Secondary	2,487,248	$228,645	9.1927	2,398,634	$224,055	9.3409	88,614	**$4,590**	0.1482
GSN Primary	21,645	$2,157	9.9653	23,517	$2,255	9.5911	(1,872)	**-$98**	(0.3742)
GSN Secondary	54,091,591	$5,121,622	9.4684	53,188,880	$5,075,737	9.5429	902,711	**$45,885**	0.0744
GSD Primary	2,464,747	$126,022	5.1130	2,442,426	$125,605	5.1426	22,321	**$417**	0.0297
GSD Secondary	349,641,924	$20,803,847	5.9500	344,254,745	$20,701,223	6.0133	5,387,179	**$102,624**	0.0633
GSTN Primary	20,848	$1,229	5.8950	19,465	$1,208	6.2044	1,383	**$21**	0.3093
GSTN Secondary	4,612,134	$306,916	6.6545	4,344,348	$302,530	6.9638	267,786	**$4,386**	0.3092
GST Primary - SS	74,973,093	$2,027,892	2.7048	65,669,066	$1,895,810	2.8869	9,304,027	**$132,082**	0.1821
GST Secondary - SS	1,145,606,132	$34,401,654	3.0029	1,004,793,189	$32,402,254	3.2248	140,812,943	**$1,999,400**	0.2218
GST Primary - LRS	100,731,603	$2,689,022	2.6695	88,388,766	$2,513,773	2.8440	12,342,837	**$175,249**	0.1745
GST Secondary - LRS	117,712,073	$2,915,956	2.4772	103,254,178	$2,710,700	2.6253	14,457,895	**$205,256**	0.1481
LPT Primary - SS	28,303,311	$1,077,435	3.8067	34,145,164	$1,077,438	3.1555	(5,841,853)	**-$3**	(0.6513)
LPT Secondary - SS	432,922,733	$11,008,878	2.5429	523,319,925	$11,008,859	2.1037	(90,397,192)	**$19**	(0.4393)
LPT Transformer Owner - SS	6,250,315	$98,994	1.5838	7,548,293	$99,002	1.3116	(1,297,978)	**-$8**	(0.2722)
LPT Primary - LRS	176,895,696	$3,431,290	1.9397	213,832,564	$3,431,296	1.6047	(36,936,868)	**-$6**	(0.3351)
LPT Secondary - LRS	171,117,103	$3,554,524	2.0772	206,884,035	$3,554,641	1.7182	(35,766,932)	**-$117**	(0.3591)
LPT Transformer Owner - LRS	363,815,482	$8,462,834	2.3261	439,789,531	$8,462,919	1.9243	(75,974,049)	**-$85**	(0.4018)
M	45,276,875	$8,824,825	19.4908	45,358,997	$8,840,821	19.4908	(82,122)	**-$15,996**	(0.0000)
U	7,370,654	$807,359	10.9537	6,718,067	$735,876	10.9537	652,587	**$71,483**	(0.0000)
Total	5,264,752,856	$267,212,128	5.0755	5,232,756,858	$259,872,567	4.9663	31,995,998	**$7,339,561**	(0.1092)

Appendix A

Rate Year 1 Income Statement

UNITED ILLUMINATING CO. - DN 13-01-19
INCOME STATEMENT
ELECTRIC - RATE YEAR ENDED JUNE 30, 2014
AS PER LFE No. 3, SUPPLEMENTAL ATTACHMENTS

August 14, 2013

PER CENT REVENUE INCREASE ALLOWED = 7.1991%

	REVISED PRO FORMA RATE YEAR	AUTHORITY ADJUSTMENTS	TABLE II	FINAL CHANGES	TABLE III
OPERATING REV. - SALES OF ELECTRICITY	$262,883	$5,305	$268,188		$268,188
OPER. REV. - WHOLE SALE AND OTHER	9,330	0	9,330		9,330
RATE REQUEST	64,851	0	64,851	(44,872)	19,979
TOTAL REVENUES	337,064	5,305	342,369	(44,872)	297,497
OPERATION& MAINTENNACE EXPENSE 1	$148,652	(12,464)	$136,188	(370)	135,818
OPERATION& MAINTENNACE EXPENSE 2	0	0	0		0
OPERATION& MAINTENNACE EXPENSE 3	0	0	0		0
DEPRECIATION EXPENSE	47,321	(1,971)	45,350		45,350
AMORTIZATION EXPENSE	9,224	(7,750)	1,474		1,474
OTHER AMORTIZATION EXPENSE	0	0	0		0
TAXES OTHER THAN GET OR INCOME TAXES	20,685	(453)	20,232		20,232
GROSS EARNINGS TAXES	26,339	(948)	25,391	(3,165)	22,226
INVESTMENT TAX CREDIT ADJUSTMENT	(2,211)	(302)	(2,513)		(2,513)
PROVISION FOR DEF. INCOME TAXES, NET	97	690	787	0	787
STATE TAXES (CURRENT)	3,420	3,012	6,432	(3,720)	2,711
FEDERAL TAXES (CURRENT)	18,108	8,889	26,997	(13,166)	13,831
LOSS (GAIN) - LAND SALE	0	0	0		0
TOTAL OPERATING EXPENSES	$271,635	(11,298)	$260,337	(20,421)	$239,916
OPERATING INCOME	$65,429	$16,603	$82,032	(24,451)	57,581

Rate Year 1 Rate Base

UNITED ILLUMINATING CO. - DN 13-01-19
RATE BASE LAST REVIEW DATE August 14, 2013
ELECTRIC - RATE YEAR ENDED JUNE 30, 2014

	REVISED PROFORMA	AUTHORITY ADJUSTMENTS	TABLE I
UTILITY PLANT IN SERVICE	$1,358,501	($19,496)	$1,339,005
PLANT 2	0	0	0
LESS: CONS. WORK IN PROGRESS	0	0	0
LESS: ACCUM DEP AND AMORT	385,914	(1,843)	384,072
NET PLANT	972,587	(17,654)	954,934
PLUS:			
WORKING CAPITAL	$27,356	(4,780)	22,576
PREPAYMENTS	1,377	0	1,377
SFAS 158 REGULATORY ASSET	165,554	0	165,554
IRS PENSION MORTALITY TABLE REG ASSET	0	0	0
STORM RESERVE REGULATORY ASSET	48,871	(48,871)	0
DEFERRED TAXES	1,736	3,875	5,611
OTHER REGULATORY ASSETS - ETT	0	5,000	5,000
LESS:			
DEFERRED INCOME TAXES	$207,940	345	208,285
STORM RESERVE	1,000	0	1,000
CUST. ADVANCES AND DEPOSITS	2,565	0	2,565
ALLOWANCE FOR BAD DEBT	3,400	0	3,400
REGULATORY PENSION LIABILITY	121,594	0	121,594
RESERVE FOR INJURIES AND DAMAGES	2,665	0	2,665
ACCRUED VACATION	5,486	0	5,486
STORM REGULATORY ASSET	20,237	(20,237)	0
DEFRRED TAXES - ETT		2,043	2,043
REGULATORY ASSET SFAS 158	12,148	0	12,148
RATE BASE	840,447	(44,580)	795,867
RETURN ON RATE BASE	7.78%	7.24%	7.24%
OPERATING INCOME	65,345	(7,764)	57,581

Rate Year 1 Expense Adjustment Detail

UNITED ILLUMINATING CO. - DN 13-01-19

TAX EFFECTED EXP.ADJ's
O & M

NO.	DESCRIPTION	ELECTRIC
	OPERATION& MAINTENNACE EXPENSE 1	
1	UNCOLLECTIBLE EXP.	44
2	Compensation	(3,925)
3	D&O Insurance	0
4	Travel, Education, and Tr	(1,064)
5	Advertising Expense	(367)
6	Membership Dues	(124)
7	Payroll Tax	0
	OPERATION EXPENSE 2	
1	Facilities Maintenance Ex	(438)
2	Electric Distribution Sys	(425)
3	Professional Services Exp	0
4	Line Clearance Expense	0
5	Legal Services Expense	0
6	Safety and Security Exper	0
7	Reconnect Service Fee Rev	0
8	Regulatory Assessment Exp	0
9	Transmission A&G Allocati	526
10	Transmission Customer Acc	389
11	Facility Rent Expense	(37)
12	Residual O&M Expense	(298)
13	Employee Benefit - Medica	(769)
14	401K/KSOP	(382)
15	Uncollectible Exp. - char	0
	MAINTENANCE EXPENSE	
1	Construction Program	0
2	Sales Tax	0
3	Corporate Service Charge	(5,594)
4	Rate Case Expense	0
5	Property Taxes	0
6	Transmission Offsets	0
7	MISC. EXPENSE	0
8	MISC. EXPENSE	0
9	MISC. EXPENSE	0
10	MISC. EXPENSE	0
	TOTAL O & M adjustments	(12,464)

OTHER TAX EFFECTED EXP. ADJ's

NO.	DESCRIPTION	AMOUNT
1	DEPRECIATION EXPENSE	(1,971)
2	DEPRECIATION EXPENSE	0
3	DEPRECIATION EXPENSE	0
4	DEPRECIATION EXPENSE	0
5	DEPRECIATION EXPENSE	0
6	AMORTIZATION EXPENSE	(8,866)
7	AMORTIZATION EXPENSE	(134)
8	AMORTIZATION EXPENSE- ETT	1,250
9	OTHER AMORTIZATION EXPENSE	0
10	LOSS (GAIN) - LAND SALE	0
11	LOSS (GAIN) - LAND SALE	0
12	LOSS (GAIN) - LAND SALE	0
13		
	Total	(9,721)

Appendix B

Rate Year 2 Income Statement

UNITED ILLUMINATING CO. - DN 13-01-19
INCOME STATEMENT
ELECTRIC - RATE YEAR ENDING JUNE 30, 2015
AS PER LFE No. 3, SUPPLEMENTAL ATTACHMENTS

August 14, 2013

PER CENT REVENUE INCREASE ALLOWED = 16.4944%

	REVISED PRO FORMA RATE YEAR	AUTHORITY ADJUSTMENTS	TABLE II	FINAL CHANGES	TABLE III
OPERATING REV. - SALES OF ELECTRICITY	$259,873	$8,143	$268,016		$268,016
OPER. REV. - WHOLE SALE AND OTHER	9,539	0	9,539		9,539
RATE REQUEST	90,595	0	90,595	(44,814)	45,781
TOTAL REVENUES	360,007	8,143	368,150	(44,814)	323,336
OPERATION& MAINTENNACE EXPENSE 1	$147,983	(11,357)	$136,626	(369)	136,257
OPERATION& MAINTENNACE EXPENSE 2	0	0	0		0
OPERATION& MAINTENNACE EXPENSE 3	0	0	0		0
DEPRECIATION EXPENSE	54,070	(3,440)	50,630		50,630
AMORTIZATION EXPENSE	9,224	(1,500)	7,724		7,724
OTHER AMORTIZATION EXPENSE	0	0	0		0
TAXES OTHER THAN GET OR INCOME TAXES	23,872	(403)	23,469		23,469
GROSS EARNINGS TAXES	27,887	(701)	27,186	(3,161)	24,025
INVESTMENT TAX CREDIT ADJUSTMENT	(2,525)	(969)	(3,494)		(3,494)
PROVISION FOR DEF. INCOME TAXES, NET	63	1,204	1,267	0	1,267
STATE TAXES (CURRENT)	3,605	3,323	6,928	(3,716)	3,213
FEDERAL TAXES (CURRENT)	21,935	7,515	29,450	(13,149)	16,301
LOSS (GAIN) - LAND SALE	0	0	0		0
TOTAL OPERATING EXPENSES	$286,114	(6,327)	$279,787	(20,395)	$259,392
OPERATING INCOME	$73,893	$14,470	$88,363	(24,419)	63,944

Rate Year 2 Rate Base

UNITED ILLUMINATING CO. - DN 13-01-19
RATE BASE LAST REVIEW DATE 14-Aug-13
ELECTRIC - RATE YEAR ENDING JUNE 30, 2015

	REVISED PROFORMA	AUTHORITY ADJUSTMENTS	TABLE I
UTILITY PLANT IN SERVICE	$1,506,288	($49,084)	$1,457,204
PLANT 2	0	0	0
LESS: CONS. WORK IN PROGRESS	0	0	0
LESS: ACCUM DEP AND AMORT	405,549	(3,151)	402,398
	-----------	-----------	-----------
NET PLANT	1,100,739	(45,933)	1,054,806
	-----------	-----------	-----------
PLUS:			
WORKING CAPITAL	$24,199	(5,199)	19,000
PREPAYMENTS	1,377	0	1,377
SFAS 158 REGULATORY ASSET	165,554	0	165,554
IRS PENSION MORTALITY TABLE REG ASSET	0	0	0
STORM RESERVE REGULATORY ASSET	39,986	(39,986)	0
DEFERRED TAXES	243	750	993
OTHER REGULATORY ASSETS - ETT	0	13,750	13,750
LESS:			
DEFERRED INCOME TAXES	$217,250	602	217,852
STORM RESERVE	3,000	0	3,000
CUST. ADVANCES AND DEPOSITS	2,565	0	2,565
ALLOWANCE FOR BAD DEBT	3,400	0	3,400
REGULATORY PENSION LIABILITY	115,871	0	115,871
RESERVE FOR INJURIES AND DAMAGES	2,665	0	2,665
ACCRUED VACATION	5,486	0	5,486
STORM REGULATORY ASSET	17,484	(17,484)	0
DEFRRED TAXES - ETT		5,617	5,617
REGULATORY ASSET SFAS 158	12,148	0	12,148
	-----------	-----------	-----------
RATE BASE	952,231	(65,353)	886,878
	===========	===========	===========
RETURN ON RATE BASE	7.75%	7.21%	7.21%
	-----------	===========	-----------
OPERATING INCOME	73,798	(9,854)	63,944
	===========	===========	===========

Rate Year 2 Expense Adjustment Detail

UNITED ILLUMINATING CO. - DN 13-01-19

TAX EFFECTED EXP.ADJ's
O & M

NO.	DESCRIPTION	ELECTRIC
	OPERATION EXPENSE 1	
1	UNCOLLECTIBLE EXP.	67
2	Compensation	(3,413)
3	D&O Insurance	0
4	Travel, Education, and Tr	(796)
5	Advertising Expense	(423)
6	Membership Dues	(202)
7	Payroll Tax	0
	OPERATION EXPENSE 2	
1	Facilities Maintenance Ex	(438)
2	Electric Distribution Sys	(425)
3	Professional Services Exp	0
4	Line Clearance Expense	0
5	Legal Services Expense	0
6	Safety and Security Exper	0
7	Reconnect Service Fee Rev	0
8	Regulatory Assessment Exp	0
9	Transmission A&G Allocati	479
10	Transmission Customer Acc	355
11	Facility Rent Expense	(38)
12	Residual O&M Expense	(304)
13	Employee Benefit - Medica	(986)
14	401K/KSOP	(395)
15	Uncollectible Exp. - char	0
	MAINTENANCE EXPENSE	
1	Construction Program	0
2	Sales Tax	0
3	Corporate Service Charge	(4,838)
4	Rate Case Expense	0
5	Property Taxes	0
6	MISC. EXPENSE	0
7	MISC. EXPENSE	0
8	MISC. EXPENSE	0
9	MISC. EXPENSE	0
10	MISC. EXPENSE	0
	TOTAL O & M adjustments	(11,357)

OTHER TAX EFFECTED EXP. ADJ's

1	DEPRECIATION EXPENSE	(3,440)
2	DEPRECIATION EXPENSE	
3	DEPRECIATION EXPENSE	0
4	DEPRECIATION EXPENSE	0
5	DEPRECIATION EXPENSE	0
6	AMORTIZATION EXPENSE	(8,866)
7	AMORTIZATION EXPENSE	(134)
8	AMORTIZATION EXPENSE- ETT	7,500
9	OTHER AMORTIZATION EXPENSE	0
10	LOSS (GAIN) - LAND SALE	0
11	LOSS (GAIN) - LAND SALE	0
12	LOSS (GAIN) - LAND SALE	0
13		
	Total	(4,940)

DOCKET NO. 13-01-19 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE RATES AND CHARGES

This Decision is adopted by the following Commissioners:

John W. Betkoski, III

Michael A. Caron

Arthur H. House

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Public Utilities Regulatory Authority, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

K. Santopietro

August 15, 2013

Kimberley J. Santopietro
Executive Secretary
Department of Energy and Environmental Protection
Public Utilities Regulatory Authority

Date

Duke Energy Ohio
Case No. 21-887-EL-AIR
OCC Fifth Set of Interrogatories
Date Received: February 25, 2022

OCC-INT-05-023
SUPPLEMENTAL

SUPPLEMENTAL REQUEST:

Incentive Compensation. For each plan, for each of the years 2019, 2020, and 2021, provide the number of employees eligible under the plan for incentive compensation payment and number of eligible employees that did not receive incentive compensation payment.

SUPPLEMENTAL RESPONSE:

Objection. This Interrogatory is overly broad and unduly burdensome, given that it seeks information that is neither relevant to this proceeding nor likely to lead to the discovery of admissible evidence in this proceeding with respect to dates outside of the test period. Objecting further, this Interrogatory fails to contain a definition or explanation to what "incentive program" refers and thus forces Duke Energy Ohio to engage in impermissible speculation and guesswork with regard to its intended meaning. Without waiving said objections, to the extent discoverable, and in the spirit of discovery, and assuming that the OCC meant the Company's short-term and long-term incentive programs, please see below for the number of employees eligible under the short-term and long-term incentive plans for incentive compensation and number of eligible employees that did not receive incentive compensation payment for plan years 2019 and 2020.

Duke Energy Ohio, Inc.

	2019		2020	
Incentive Plan	**Number Eligible Under Plan**	**Number Eligible, no Payment**	**Number Eligible Under Plan**	**Number Eligible, no Payment**
Short-Term Incentive	633	0	661	0
Long-Term Incentive Performance Shares [1]	0	0	0	*See footnote 1*
Long-Term Incentive RSUs [2]	2	1	2	1

Duke Energy Business Services LLC[3]

Incentive Plan	2019 Number Eligible Under Plan	2019 Number Eligible, no Payment	2020 Number Eligible Under Plan	2020 Number Eligible, no Payment
Short-Term Incentive	8306	0	7631	0
Long-Term Incentive Performance Shares [1]	49	4	50	*See footnote 1*
Long-Term Incentive RSUs [2]	421	93	400	69

[1] Performance shares do not vest until the end of the three-year performance period. For the performance shares granted in 2020, the end of the three-year performance period is 12/31/2022. Vesting is generally tied to the participants' continued employment through the three-year performance period.

[2] RSUs vest equally over three years. Vesting is generally tied to the participants' continued employment through the vesting dates.

[3] Not all employees of Duke Energy Business Services eligible for incentive have expenses charged to Duke Energy Ohio electric.

PERSON RESPONSIBLE:

As to objections: Legal
As to response: Jacob J. Stewart

REQUEST:

Incentive Compensation. For each plan, for each of the years 2019, 2020, and 2021, provide the number of employees eligible under the plan for incentive compensation payment and number of eligible employees that did not receive incentive compensation payment.

RESPONSE:

Objection. This Interrogatory is overly broad and unduly burdensome, given that it seeks information that is neither relevant to this proceeding nor likely to lead to the discovery of admissible evidence in this proceeding with respect to dates outside of the test period. Objecting further, this Interrogatory fails to contain a definition or explanation to what "incentive program" refers and thus forces Duke Energy Ohio to engage in impermissible speculation and guesswork with regard to its intended meaning. Without waiving said objections, to the extent discoverable, and in the spirit of discovery, and assuming that the OCC meant the Company's short-term and long-term incentive programs, see below.

Duke Energy Ohio, Inc.	**2021**	
Incentive Plan	**Number Eligible Under Plan**	**Number Eligible, no Payment**
Short-Term Incentive	639	0
Long-Term Incentive Performance Shares [1]	0	*See footnote 1*
Long-Term Incentive RSUs [2]	3	1

Duke Energy Business Services, LLC [3]	**2021**	
Incentive Plan	**Number Eligible Under Plan**	**Number Eligible, no Payment**
Short-Term Incentive	7811	0
Long-Term Incentive Performance Shares [1]	48	*See footnote 1*
Long-Term Incentive RSUs [2]	405	68

[1] Performance shares do not vest until the end of the three-year performance period, which for the performance shares granted in 2021 is 12/31/2023. Vesting is generally tied to the participants' continued employment through the three-year performance period.

[2] RSUs vest equally over three years. Vesting is generally tied to the participants' continued employment through the vesting dates.

[3] Not all employees of Duke Energy Business Services eligible for incentive have expenses charged to Duke Energy Ohio electric.

PERSON RESPONSIBLE:

As to objections: Legal
As to response: Jacob J. Stewart

Duke Energy Ohio
Case No. 21-887-EL-AIR
OCC Fifth Set of Interrogatories
Date Received: February 25, 2022

OCC-INT-05-026

REQUEST:

Incentive Compensation. Please explain if there is a financial earnings level which if not achieved, no incentive compensation payments will be made.

RESPONSE:

Yes, the Earnings Per Share (EPS) measure of the short-term incentive plan has a "circuit breaker" level that is set between the minimum and target EPS performance levels. The circuit breaker ensures the short-term incentive payout is affordable in the rare circumstances when financial performance is not in line with operational performance.

In general:

- If actual EPS is greater than the EPS circuit breaker, all measures will be paid out based on the scorecard.
- If actual EPS is equal to the EPS circuit breaker, payouts for all measures, including the team component, may be partially reduced.
- If EPS is less than the EPS circuit breaker, payouts for all measures, including the team component, will be reduced and capped at the EPS achievement.

PERSON RESPONSIBLE: Jacob J. Stewart