STATE OF CONNECTICUT

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

DOCKET NO. 16-06-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

December 14, 2016

By the following Commissioners:

John W. Betkoski, III
Michael A. Caron
Katherine S. Dykes

Lead Staff: **Error! Reference source not found.**
Legal Advisor: **Error! Reference source not found.**

DECISION

TABLE OF CONTENTS

I. INTRODUCTION 1
A. SUMMARY 1
B. BACKGROUND OF PROCEEDING 2
C. CONDUCT OF PROCEEDING 2
D. PARTIES AND INTERVENORS 3
E. PUBLIC COMMENT 3

II. AUTHORITY ANALYSIS 4
A. TEST YEAR / RATE YEAR 4
B. RATE BASE 4
1. Pension Liabilities-Deferred Taxes 4
2. Utility Protection Zone 4
3. Direct Contact Program 9
4. Regulatory Asset and Liability - Utility Protection Zone 10
5. Net General and Intangible Plant Allocated to Transmission 11
6. Capital Expenditures 14
a. General 14
b. Grid Modernization 20
c. Electric Distribution Infrastructure Capital Tracker 22
7. Working Capital Allowance 23
8. Rate Base Summary 24
C. OPERATIONS AND MAINTENANCE EXPENSES 25
1. Amortization Expense 25
a. Utility Protection Zone Expense 25
b. Rate Case Expense 25
2. Membership Dues Expense 26
3. Uncollectible Expense 26
4. Reconnect Service Fee Expense 28
5. UIL Corporate Service Charges 29
a. UIL Corporate Capital Charges 30
b. Directors and Officers Liability Insurance 35
c. Board of Directors 36
d. Other Public Company Costs 37
e. Donations 37
f. Summary of Corporate Service Charges Adjustments 38
6. Advertising 38
7. Incentive Compensation 38
8. Payroll 40
9. Travel, Education and Training 41
10. Depreciation 42
a. UI 2015 Study and the Company's Position 42
b. Positions of the OCC and AG 43
c. Authority Analysis 43
i. Average Service Life Calculation 43
ii. Net Salvage 45
iii. Account 390.45 – General Central Facility 46

11. Retirement Benefits 48
a. UI (401(k) Plan 48
b. Qualified Pension Plan 50
c. Directors Retirement Plan 52
d. Supplemental Employee Retirement Plan 53
e. Post Retirement Benefits Other than Pensions (OPEB) 54
12. Other Employee Benefits 55
13. Residual Operations and Maintenance 56
14. Income Taxes - Federal Corporate Tax Rate 57
15. Expenses Summary 58
D. COST OF CAPITAL 58
1. Rate of Return 58
2. Financial Condition 58
3. Capital Structure and Cost of Long-Term Debt 60
4. Authority Analysis of Capital Structure 62
5. Cost of Common Equity 63
a. Introduction 63
b. Financial Indicators, Interest Rates and Authorized ROEs 64
c. Proxy Groups 65
d. Other Factors 67
i. Flotation Cost 67
ii. Weighting of Employed Methods 67
e. Discounted Cash Flow Model 68
i. Dividend Yield 68
ii. Growth Rates 70
iii. DCF Results 71
f. Capital Asset Pricing Model 73
g. Risk Premium: Bond Yield plus Risk Premium 74
h. Parties' Summary Results 75
6. Discussion of Cost of Equity 77
a. Economic Changes and Survey of Allowed Returns 77
b. Proxy Group 77
c. Discounted Cash Flow Model 81
i. Dividend Yield 82
ii. Growth Rate 83
iii. DCF Results 83
d. CAPM Model 84
i. Risk-Free Rate and Beta Estimate 84
ii. Equity Risk Premium 85
iii. CAPM Results 85
e. Flotation Cost 86
f. BY + RP Model 86
g. Summary of Authority's ROE Analysis 86
h. Authority's Allowed Weighted Cost of Capital 86
E. EARNINGS SHARING MECHANISM 88
F. SALES FORECAST 89
G. LEVELIZATION PROPOSAL 91
H. REVENUE AND REVENUE ADJUSTMENTS 91
I. COST OF SERVICE STUDY 92

J. RATE DESIGN 93
1. Maximum Residential Customer Charge 93
a. Positions of Parties 94
b. Discussion 95
2. Pole Attachment Rates 96
3. Residential Service Rates 100
4. Tariff Changes 105
a. Terms and Conditions 105
b. Miscellaneous Fees 106
5. Summary 107
K. REVENUE INCREASE 108
L. GROSS RECEIPTS TAX 109
M. STORM RECOVERY COSTS 109
1. Lean-In Costs 109
2. Storm Reserve 110
N. CUSTOMER SERVICE REVIEW 112
1. Standard Bill Form and Termination Notice 112
2. Policies and Procedures for Estimated Billing 112
3. Customer Security Deposits 113
4. Service Appointments 113
5. Customer Call Center 113
6. Customer Service Summary 114
7. Full Credit Bureau Reporting 114

III. FINDINGS OF FACT 116

IV. CONCLUSION AND ORDERS 123
A. CONCLUSION 123
B. ORDERS 123

V. RATE MODEL 127
A. 2017 INCOME STATEMENT (000) 127
B. 2017 RATE BASE (000) 128
C. 2018 INCOME STATEMENT (000) 129
D. 2018 RATE BASE (000) 130
E. 2019 INCOME STATEMENT (000) 131
F. 2019 RATE BASE (000) 132

DECISION

I. INTRODUCTION

A. SUMMARY

In this Decision, the Public Utilities Regulatory Authority reviews The United Illuminating Company's request for a rate increase pursuant to an Application filed on July 1, 2016, requesting approval of a three-year rate plan commencing January 1, 2017, and extending through December 31, 2019. The application requests an increase in revenues to address a distribution operating deficiency of $66 million in 2017, an additional $20 million in 2018, and an additional $12.24 million in 2019 and a 9.92% return on equity. The United Illuminating Company seeks approval to collect these amounts consistent with its levelized rate plan, based on annual recoveries of $40.7 million in 2017, $47.4 million in 2018 and $39.1 million in 2019, followed by an offset of $25.6 million at the end of the three year rate plan. The United Illuminating Company also requests approval of its proposed rate design, which includes an earnings sharing mechanism and a continuation of its revenue decoupling mechanism.

In granting the revenue increases, the Public Utilities Regulatory Authority allows The United Illuminating Company sufficient funds to engage in significant capital improvements to upgrade its distribution system and modernize its systems, processes and workforce. The approved increase in revenues, the return on equity and the rate mechanisms described within this Decision, along with other determinations, will result in just and reasonable rates. It will provide The United Illuminating Company with sufficient revenue to maintain and operate an electric distribution system and provide a safe, adequate and reliable service to customers, while providing it an opportunity to earn a reasonable profit.

The United Illuminating Company must have the resources to be able to maintain and operate its distribution system in a manner that provides safe and reliable electric service to about 330,000 customers in the greater New Haven and Bridgeport areas. In addition, it must provide satisfactory customer service and provide a fair return to its investors.

The Public Utilities Regulatory Authority rejects The United Illuminating Company's request for an allowed return on equity of 9.92% and has determined that an allowed return on equity of 9.10% is fair and reasonable. For 2017, the Public Utilities Regulatory Authority approves total revenue of $363.034 million, which is an increase of $42.996 million above the current revenue level; for 2018, revenues of $374.529 million were approved, which is an additional increase of $11.495 million; and for 2019, revenues of $377.447 million were approved, which is an additional increase of $2.918 million. The estimated overall annual rate impact on a typical residential Rate R customer using 500 kWh per month will be an increase of approximately 3.2%.

B. BACKGROUND OF PROCEEDING

By letter dated June 7, 2016, The United Illuminating Company (UI or Company) provided notice of its intention to file an application for approval to amend its rate schedules to the Public Utilities Regulatory Authority (Authority or PURA), the Governor of the State of Connecticut, the Chief Executive Officer of every municipality located within its franchise area, the Office of Consumer Counsel (OCC) and the Office of the Attorney General (AG). UI is a public service company within the meaning of §16-1 of the General Statutes of Connecticut (Conn. Gen. Stat.). UI is a subsidiary of Avangrid, Inc. (Avangrid). The Company currently provides electric service in 17 municipalities in Connecticut. Application, p. 6.

The Company requested a waiver of certain provisions of the Standard Filing Requirements (SFRs). Letter dated June 1, 2016. By letter dated June 15, 2016, the Authority granted the Company's request for waiver of certain portions of the SFRs for large public utility companies.

By Application dated July 1, 2016, UI requested to amend its existing rate schedules pursuant to Conn. Gen. Stat. §§16-19 and 16-19e and §§16-1-46 and 16-1-53 *et seq.* of the Regulations of Connecticut State Agencies (Conn. Agencies Regs.) and the SFRs (Application). The Company indicated that this increase was necessary to address a distribution operating deficiency of $65.6 million. In total, the Company proposed rates designed to recover additional costs of $101.6 million during the period from January 1, 2017 through December 31, 2019. Application, p. 2.

C. CONDUCT OF PROCEEDING

By Notice of Audit dated July 11, 2016, the Authority conducted an audit of UI's books and records at the Company's offices located at 157 Church Street, New Haven, CT, beginning on August 1, 2016.

Pursuant to a Notice of Pre-Hearing Conference dated July 5, 2016, the Authority conducted a Pre-Hearing Conference on July 14, 2016, to discuss procedural issues with all admitted parties and intervenors at the Authority's offices located at Ten Franklin Square, New Britain, CT.

By Notice of Hearing dated July 21, 2016, pursuant to Conn. Gen. Stat. §§16-19 and 16-19e and Conn. Agencies. Regs. §§16-1-46 and 16-1-53 *et seq.,* the Authority conducted hearing sessions at its offices on September 12, 13, 14, 16, 19, 20, 21 and 22, 2016. In addition, the Authority held evening sessions solely for the purpose of receiving public comment. The hearings commenced at 6:30 p.m. on the following dates at the following locations: September 8, 2016, City Common Council Chambers, City Hall, 45 Lyon Terrace, Bridgeport, CT and September 12, 2016, Kennedy Mitchell Hall of Records, Hearing Room G2, 200 Orange Street, New Haven, CT.

The Authority issued its Proposed Final Decision in this matter on November 23, 2016. All Parties and intervenors were granted an opportunity to file Written Exceptions to the draft Decision and to present Oral Arguments.

D. PARTIES AND INTERVENORS

The Authority designated: The United Illuminating Company, P.O. Box 1564 New Haven, CT 06506; Office of Consumer Counsel, Ten Franklin Square, New Britain, CT 06051; and the Commissioner, Department of Energy and Environmental Protection, 79 Elm Street, Hartford, CT 06106-5127 as parties to this proceeding.

Intervenor status was granted to: Office of the Attorney General; Eversource Energy; New England Cable & Telecommunications Association, Inc.; Acadia Center; Fiber Technologies Networks, LLC, Lightower Fiber Networks I, LLC and Lightower Fiber Networks II, LLC (collectively, Lightower);, and Connecticut Industrial Energy Consumers.

E. PUBLIC COMMENT

The Authority conducted two evening public comment hearings within the UI service territory for the purpose of receiving comment from the general public concerning the Application. UI submitted a motion on July 11, 2016, for approval of its customer notice and permission to provide the notice to customers via bill insert. On July 14, 2016, the Authority approved the Company's request.

A total of 118 persons attended the hearings and of those, 33 persons provided testimony to the Authority. State Senator Joseph Crisco, representing the 17th District questioned the rate increase after UI's recent merger with Iberdrola, USA (Iberdrola). The Senator questioned promised cost savings that were supposed to be in effect due to the merger. Senator Crisco urged the Authority to reject the increase asserting that the state could not afford another rate increase. Tr. 9/12/16, pp. 189-193. State Representatives Yaccarino, Gentile, Hoydick, Devlin, Kupchik also expressed concerns regarding residential customers and businesses. The State Representatives requested that the Authority consider how a 30% increase in the residential customer service charge would affect the poor and elderly. Tr. 9/08/16, pp. 5-16. State Representative Lonnie Reed noted that UI's proposed rate increase seemed to be working at cross purposes to public policy, which supports a focus on conservation and renewable energy. Id., pp. 193-196.

Public comment mirrored those provided by the public officials. Overall, most Connecticut residents and businesses that spoke were not supportive of UI's Application. Many cited the state's current economic condition and the financial impact of a rate increase. Customers were particularly opposed to the 30% increase to the customer service charge. Tr. 9/08/16, pp. 20-28, 30-37 and. 40-48; Tr. 9/12/16, 203-205 and 225-235. A representative from the Connecticut Fund for the Environment discussed energy policies that are in place to conserve resources by avoiding unnecessary consumption and maximizing efficiency. The speaker contended that UI's policies penalize Connecticut residents for using energy more efficiently by raising the fixed customer service charge. Tr. 09/12/16, pp. 218 and 219.

The Authority also received 301 letters and emails regarding the Application. All of the people who wrote in were in opposition to UI's rate increase request, stating reasons similar to those offered at the evening public hearings. Written comments were

also submitted regarding UI's tree-trimming costs and practices. Customers expressed concern that the Company was removing non-threatening vegetation and ignoring those trees that required attention. Numerous members of the American Association of Retired Persons also wrote comments expressing their opposition to the 30% increase and demanding reasonable affordable rates for all Connecticut residents.

II. AUTHORITY ANALYSIS

A. TEST YEAR / RATE YEAR

It is the practice of the Authority in rate cases to establish rates prospectively on the basis of a historical test year, utilizing the most recent 12 months for which adequate records are available to reflect the actual operating results and experience during such period. Generally, the test year, adjusted for pro forma purposes, sets the boundaries within which the factors of ratemaking can be determined and used. The Authority may make certain prospective adjustments deemed necessary to ensure that a regulated utility has reasonable opportunity to achieve a fair rate of return (ROR). The Authority analyzed the operating experience of the Company for the 12 months ended December 31, 2015, and finds that this period is a reasonable test year period on which to predicate the Application. The rate years for the rate request are for the three years ending December 31, 2019.

B. RATE BASE

1. Pension Liabilities-Deferred Taxes

The Company cited deferred taxes on pension liabilities in Schedule B-9.2 of its Application, and provided a second revision in Late Filed Exhibit No. 3 due to changes discovered in Interrogatory FI-67 as stated below.

	Rate Year 2017	Rate Year 2018	Rate Year 2019
UI original filing pension liabilities deferred taxes	($17,977,000)	($15,413,000)	($13,521,000)
Change due to FI-67 on pension liabilities deferred taxes	($16,396,000)	($13,106,000)	($12,105,000)

Revised Late Filed Exhibit No. 3, Attachment 1.

UI calculated the change in pension liabilities because of lower deferred taxes on pension liabilities. A state tax rate of 9.0% was used in rate year 2017, 8.30% was used for rate year 2018, and 7.50% was used for the rate year 2019. A Federal tax rate of 35.0% was used for all three rate years. The Authority concurs with this change.

2. Utility Protection Zone

The Company's enhanced tree trimming (ETT) Program was originally approved in the Decision dated August 14, 2013 in Docket No. 13-01-19, Application of The United Illuminating Company to Increase Rates and Charges (2013 UI Rate Case Decision), as an eight-year program to occur from 2014 through 2021, with total expenditures of $100

million. The goal of the program was to establish a utility protection zone[1] (UPZ). The UPZ is defined as a rectangular area extending horizontally for a distance of eight feet from any outermost electrical conductor or wire installed from pole to pole and vertically from the ground to the sky. Reed and Thomas PFT, p. 32.

The Company stated that the costs to complete the current ETT Program as originally proposed are greater than anticipated due to the following factors:

- a higher tree density than projected;
- lengthening of the trimming cycle from four years to eight years to establish the UPZ on the three-phase sections of lines;
- increased costs for traffic control by local police departments; and
- a rigorous consent, objection and appeals process.

Id.

UI forecasted a total cost of $162.5 million for the proposed UPZ Program. It includes the $24.8 million spent in 2014 and 2015, the remaining $75.2 million allowed in the 2013 UI Rate Case Decision and $62.5 million for newly identified work that encompasses:

- $25 million related to work scope and second cycle trimming;
- $28 million for traffic control;
- $14 million to notify property owners and obtain consent; and
- $5.2 million reduction from savings associated with the Avangrid companies.

These factors will require an additional $27.3 million during the rate years comprised of increases of $5.5 million in 2017 and $10.9 million in each of 2018 and 2019. These budgets include procurement savings to be realized due to UI's merger with Avangrid. Id., p. 34; Responses to Interrogatories EN-67 and EN-73; Tr. 9/22/16, pp. 491-493. UI's proposed costs associated with the UPZ program for 2016 through 2023 are shown below:

UPZ Capital Forecast: 2016 – 2023 ($000)

	2016	2017	2018	2019	2020	2021	2022	2023
Approved UPZ Program	12,900	12,677	12,663	12,682	12,714	12,752		
Additional UPZ Requested		5,469	10,933	10,959	11,103	11,140	11,163	5,771
Integration Savings-UPZ Contractor		(544)	(991)	(993)	(1,000)	(1,003)	(469)	(242)
Total	12,900	17,601	22,604	22,648	22,817	22,889	10,694	5,529

Reed and Thomas PFT, p. 34.

[1] UPZ is defined in Conn. Gen. Stat. §16-234(a)(2). UI renamed the ETT program approved in the 2013 UI Rate Case Decision to the UPZ Program in this proceeding to conform with the definition in Conn. Gen. Stat. §16-234. Response to Interrogatory OCC-317.

When completed, this program is expected to reduce tree-related outages by up to 25% or greater in relation to day-to-day reliability with tangential benefits for withstanding damage in severe weather events. Since January 2014, UI's vegetation management team investigated and analyzed all storm and non-storm tree-caused outages. The investigation revealed that 60% of the tree-related outages during this period came from trees and tree parts within the eight-foot UPZ. In recent storms, this number was found to be higher, 68% or more, while only 8% of the trees that caused outages were found to be hazardous trees.[2] These results support the benefits that can be achieved by reducing the number of trees and limbs hanging over and in close proximity to the electric system. When there are no limbs hanging over the power lines, the potential for outages is reduced. Id., p. 35.

The OCC noted that in the 2013 UI rate case, the Authority was concerned with the impact of the $100 million of costs for the UPZ program and now UI has proposed that it be increased to $162.5 million. The 2013 UI Rate Case Decision stated that the addition of $100 million in added costs over the next four years represents a major perturbation. The OCC opined that if $100 million was considered to be a major perturbation, the proposed $162.5 should also be considered problematic. The OCC stated that danger trees, which are trees on or off the right-of-way with the potential to contact electric supply lines, appear not to be defined in the Company's vegetation management program. Danger trees can be healthy trees and should be included in the UPZ program. Also, the OCC argued that the UPZ program has reduced storm costs. However, the Company made no projections of future cost savings due to the UPZ program in its rate plan. Further, the OCC is troubled that UI's recent investigations of tree outages that occurred in three storm events in February, 2016 suggests a dramatic impact, but asserted that it is hard to reconcile this with the fact that no impact was reflected in storm costs in the filing. Additionally, the OCC claimed that the Company's statement that over 65% of the outages may have been avoided to justify the costs of the program ignores the possible impact on operations and maintenance (O&M) expense. The OCC asserted that an impact should occur almost immediately with such a program. OCC Schultz III/Defever PFT, pp. 63-66; Response to Interrogatory OCC-353.

The OCC recommended that the requested increases to the UPZ Program be denied. The fact that the Company expects no positive results and has not reflected any benefit during the first six years of the program is of concern. In addition, the significant increase in costs to amounts previously considered a major perturbation by the Authority and the fact that the program may be lacking a fundamental component as danger trees causes the increase to be questioned. Absent a quantifiable benefit, the OCC contended that the added cost be denied. Schultz III/ Defever PFT, p. 67.

The AG recommended that the Authority reject the Company's UPZ Program due to the cost impact on customers and the program's cost-effectiveness. During the rate years, the proposed UPZ Program will cost UI customers $27.5 million more than the approved ETT Program. The approved ETT Program funding levels represented an enormous commitment to tree trimming and a massive increase in those costs to

[2] Hazardous trees include any tree or part of a tree that is dead, extensively decayed, or structurally weak, which, if it falls, would endanger utility infrastructure, facilities or equipment.

ratepayers. UI's customers should not be required to pay for a more costly tree trimming program at this time. UI failed to demonstrate the cost-effectiveness of ETT or UPZ. Despite the $25 million that ratepayers have invested in ETT to date, UI was unable to show that its storm costs have declined or that its reliability has improved. Further, UI has not projected any storm cost savings for first six years of the UPZ program. The AG urged the Authority to reject UI's claims that the entire UPZ program should be completed before results of the program can be measured. Response to Interrogatory OCC-353. As UI trims trees to the ETT or UPZ standard, the incremental benefits of such trimming should be measurable in terms of storm cost savings and increased reliability, but UI has failed to demonstrate such benefits to date. Lastly, the AG recommended that the Authority reject the Company's assertion that a cause of the increased cost of UPZ is that its tree density turned out to be greater than it expected. It is not credible to believe that UI, which has provided electric distribution service in its 17-town service territory since 1899, is unaware of the tree density along its distribution line rights-of-way. Brief, pp. 27 and 28.

In the 2013 UI rate case, the Authority was concerned over the effect that the ETT program would have on rates. The Authority intended to fund the annual ETT expenditures in an optimal way by allowing UI to spend $12.5 million per year and to amortize the annual expenditures over five years, to hold rates at a reasonable level. 2013 UI Rate Case Decision, p. 14.

UI’s proposed increase of $62.5 million and the expansion of the program from eight to ten years compels the Authority to look closely at the near term and lifetime recovery of the UPZ costs and revenue requirements. In its consideration of the need to maintain the sustainability of the program and control rate impacts, cost recovery of the proposed increase would be more reasonable and affordable for customers by extending UI’s UPZ program to 12 years, and requiring that all new expenditures occurring after 2016 be expensed. The expenditures would be increased to $13 million in 2017, $13.8 million in 2018 and $14 million in 2019 to be continued through 2025. These allowances should fully fund the work intended in the new UPZ program.

During the phase out of the remaining amortized recovery period and the changeover to expensing UPZ costs, revenue requirements would increase $9.8million in 2017 and $4.8million in 2018 compared to UI’s proposal with a five-year amortization of annual expenditures. However, these increases will be offset by revenue reductions in the following 2.7 years and ratepayers will save an additional $16.6 million over the remaining life of the program compared to the UI proposal, as shown below. The results shown below were computed by the Authority through the use of UI’s UPZ revenue requirements model provided in its response to Late Filed Exhibit No. 28 using 50% equity, 50% debt and a ROE of 9.10% for years 2017 through 2027.

UPZ Program: Annual Expenditures and Revenue Requirements ($000)

Description		2013 Decision			Rate Years			Beyond Rate Years							
Program Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14
Expenditures/Revenue Requirements	Lifetime Total	2014	2015	2016	**2017**	**2018**	**2019**	2020	2021	2022	2023	2024	2025	2026	2027
UI 2013 Allowed Expenditures	$ 100,000	$12,500	$12,500	$12,500	$12,500	$12,500	$12,500	$12,500	$12,500						
RR-amortized 5 yrs	**$ 122,117**	$ 3,047	$ 6,343	$ 9,472	$12,466	$15,260	$15,268	$15,274	$15,274	$12,220	$ 8,914	$ 5,775	$ 2,804		
UI Proposed Expenditures	$ 162,467	**$10,339**	**14,446**	**12,900**	$17,601	$22,604	$22,648	$22,817	$22,889	$10,694	$ 5,529	-			
RR-amortized 5 yrs	**$ 198,443**	**$ 2,520**	**$ 6,247**	**$ 9,542**	$13,793	$19,153	$22,229	$24,319	$26,636	$24,850	$20,430	$14,706	$ 9,065	$3,713	$1,240
PURA Expenditures expensed aft 2016	$ 162,485	**$10,339**	**14,446**	**12,900**	$13,000	$13,800	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000		
PURA RR Amortized 2014-2016	45,984	2,520	6,247	9,542	9,493	8,984	6,305	2,894							
PURA RR Expensed 2017 &+	135,798				14,146	15,016	15,234	15,234	15,234	15,234	15,234	15,234	15,234		
RR-Amtzed to 2016 & expensed 2017 &+	**$ 181,783**	$ 2,520	$ 6,247	$ 9,542	$23,638	$24,000	$21,538	$18,127	$15,234	$15,234	$15,234	$15,234	$15,234		
RR Diff: UI Proposed - UI 100	$ 71,373	$ (527)	$ (96)	$ 70	$ 1,327	$ 3,893	$ 6,961	$ 9,044	$11,361	$12,630	$11,517	$ 8,931	$ 6,261	$3,713	$1,240
RR Diff: PURA -UI Proposed	$ (16,660)				9,845	4,847	(691)	(6,191)	(11,402)	(9,616)	(5,197)	528	6,169	(3,713)	(1,240)
CUM Savings: PURA-UI Proposed					(9,845)	(14,693)	(14,002)	(7,811)	3,591	13,207	18,403	17,876	11,707	15,420	16,660

Revenue Requirements Calculations using UI Late Filed Exhibit No. 28.

The Authority recognizes that hazard and danger trees are the same in the UPZ. The term danger tree is not defined in the UPZ plan or by the Authority in the Decision dated June 25, 2014, in Docket No. 12-01-10, PURA Investigation Into the Tree Trimming Practices of Connecticut's Utility Companies (2014 Tree Trimming Decision). The UPZ plan is reviewed annually by the Authority in the transmission and distribution maintenance dockets. See for example, Docket No. 15-12-20, PURA Review of Electric Companies' and Electric Distribution Companies' Plans for Maintenance of Transmission and Distribution Overhead and Underground Lines. Furthermore, in the Decision dated June 17, 2015, in Docket No. 14-07-18, PURA Report to the General Assembly Concerning Its Review of Each Electric Distribution Company's Vegetation Management Practices (2014 Report), the Authority concluded that the electric distribution companies' (EDCs) most current vegetation management plans meet the requirements of the Conn. Gen. Stat. §16-234 and the 2014 Tree Trimming Decision. 2014 Report, p. 16. The Authority observed the benefits of the ETT program as demonstrated in the Company's service reliability dockets since 2012 and expects improved annual reliability as the UPZ is implemented. The Company still projects at least a 25% reduction in day-to-day reliability with tangential benefits for withstanding damage in severe weather events. Reed and Thomas PFT, p. 35.

The Authority notes that less than half of the proposed $62.5 million increase is due to actual tree maintenance work. Approximately 15% of the proposed increase results from greater legislative and PURA requirements to obtain consent, make modifications and ensure that property owners understand the tree work to be performed before it occurs. The cost of traffic control has also been increasing at a high rate. In UI's 2013 ETT plan, traffic control was estimated to be $13 million or 13% of the vegetation management program costs. Through 2014 and 2015, the actual traffic control costs increased to 19% of program costs and now is projected to exceed $40 million or 24% of the UPZ program. Responses to Interrogatories EN-64, EN-68 and OCC-273. Although the Authority does not have jurisdiction over traffic control, it encourages the EDCs to work with legislators and town officials to allow flagmen to

direct traffic as much as possible. In the towns with high traffic control costs, the Company should request a wider UPZ where consent can be obtained from the property owner.

The Authority hereby approves expenditures for the UPZ Program of $13 million for 2017, $13.8 million for 2018 and $14 million for 2019 and annually thereafter, until the total cost reaches $162 million for the program life. All UPZ costs occurred in 2017 and thereafter will be expensed. The UPZ Program and funding will be re-evaluated in the Company's next rate proceeding.

3. Direct Contact Program

As a result of slower progress in establishing the UPZ, the amount of direct tree contact with energized primary lines has increased. A Direct Contact Program dedicated to clearing the direct tree contacts is necessary to ensure the safety and reliability of the electric system until the UPZ Program is completed and the normal routine maintenance cycle begins. Reed and Thomas PFT, pp. 35 and 36. The expected cost of this program is $839,000 in 2017, $836,000 in 2018 and $833,000 in 2019. Application, WP C-3.5 A-C.

The AG claimed that the Company collects more than an adequate amount from its ratepayers to fund vegetation management. UI proposed rates include $860,000, $876,000 and $901,000 for years 2017, 2018, and 2019 respectively, for its Reliability Line Clearance Program. Application, Schedule C-3.5. The Authority approved $100 million for vegetation management for the ETT Program. Thus, any costs associated with trees that are in direct contact with lines, should therefore come out of the Company's existing tree trimming budgets. AG Brief, p. 29.

The AG noted that UI spent less than authorized amounts on its routine tree trimming in 2014 and 2015. UI collected $1.9 million from ratepayers in 2014 and $0.9 million in 2015 for non-ETT vegetation management. Response to Interrogatory OCC-61. These dollars should have contributed to the prevention of direct contact of trees on UI's distribution lines during the Company's routine trim cycle. However, the Company only spent $1.4 million on vegetation management in 2014 and $0.6 million in 2015. Response to Interrogatory OCC-60. Therefore, the AG recommended that the Authority deny new tree trimming programs when the Company failed to spend the ratepayer funded vegetation management funds already in place. Also, the Authority should maintain the tree trimming and vegetation management dollars approved in the 2013 UI rate case, including ETT. Additionally, the Company should use those dollars more effectively rather than collect more from its ratepayers for the same purpose. Lastly, the AG recommended that the Authority reject UI's proposal for separate funding of the Direct Contact program. Id.

The OCC stated that direct contact is supposed to be controlled and/or eliminated by maintaining a proper trim cycle. A proper trim cycle addresses growth related contact by identifying the annual growth and trimming the entire system in segments. The OCC concurred with the AG and recommended that the entire amount proposed by UI for the Direct Contact Program be disallowed. Schultz III/Defever PFT, pp. 69 and 70.

The Authority recognizes that the progress of the UPZ Program has been hindered due to the consent process required by 2014 legislation and additional Authority requirements in the 2014 Tree Trimming Decision. It also recognizes the large amount of new funding allowed for ETT and requested for the UPZ Program. The Authority notes that the Company's annual Vegetation Management plan has never addressed the issue of excessive branch contact with its lines. A new Direct Contact Program with proposed expenditures of $839,000, $836,000 and $833,000 for years 2017 to 2019 should not be funded by ratepayers at this time especially with the large funding increase the Authority allowed for the UPZ program above. Therefore, the Authority disallows the proposed Direct Contact Program.

As the UPZ is established over the next nine years, tree clearance will decrease for trees trimmed prior to the 2014 ETT Program but not every tree branch will be too close to wires or make contact with energized wires. However, to ensure public safety and maintain reliability due to the time extension allowed in establishing the UPZ, the Authority will permit the requested Reliability Line Clearance Program expenditures to be increased by one half of the proposed rate year direct contact budgets for the removal of branches in direct contact with primary wires. Therefore, the Authority approves increased expenditures for the Reliability Line Clearance Program of $420,000, $418,000 and $417,000 for years 2017 to 2019. The total approved budgets for the line clearance expense are $1,280,000 for 2017, $1,294,000 for 2018 and $1,318,000 for 2019, which includes removal of all branches in direct contact with UI energized lines.

The Authority expects the unit costs of direct contact removals to be less than UPZ work. Conn. Gen. Stat. §16-234(e) does not require the EDCs to obtain a permit or provide notice to property owners to prune or remove a tree, as necessary, if any part of a tree is in direct contact with an energized electrical conductor or has visible signs of burning. The Authority expects UI to manage the direct contact condition with the line clearance funds, prioritizing high growth vegetation areas within the UPZ program and realize at least an 81% consent rate for full UPZ. The Company will be directed to include the management of this issue in its future vegetation management plans and it will be reviewed in the Company's next rate proceeding. The Company will be required to obtain data and file results of direct contact work and its management to justify the continuance of this funding.

4. Regulatory Asset and Liability - Utility Protection Zone

UI requested an UPZ regulatory asset, net of related accumulated amortization, of $23.123 million for 2016, $29.667 million for 2017, $36.693 million for 2018 and $41.301 million for 2019. The requested average UPZ regulatory asset, net of related accumulated amortization is $26.395 million for 2017, $33.183 million for 2018 and $38.997 million for 2019. The Company reported offsetting accumulated deferred income taxes (ADIT) of $9.446 million for 2016, $12.119 million for 2017, $14.810 million for 2018 and $16.469 million for 2019. The proposed average UPZ ADIT is $10.783 million for 2017, $13.465 million for 2018 and $15.640 million for 2019. Application, Schedules B-1.0 A, B and C; B-6.2 A, B and C.

Based on the Authority's determination, as described in Section II.B.2. Utility Protection Zone, directing the Company to expense UPZ expenditures for periods after

2016 and not treat them as regulatory assets, the Authority removes the rate base impacts of the proposed UPZ expenditures for periods subsequent to 2016 from the allowed rate base for each rate year. The table below summarizes the allowed net UPZ regulatory assets for 2016 through 2019:

Calculation of Net UPZ Regulatory Asset Net of Deferred Income Taxes ($000)

Descriptions	2016	2017	2018	2019
Net UPZ Regulatory Asset	$23,123	$15,586	$8,049	$2,580
ADIT	(9,446)	(6,367)	(3,249)	(1,029)
Net UPZ Regulatory Asset net of ADIT	$13,677	$9,219	$4,800	$1,551

As determined in the table above, the Authority finds that the allowed average UPZ regulatory assets, net of related accumulated amortization, are $19.355 million [($23.123 +$15.586) / 2)] for 2017, $11.818 million [($15.586 + $8.049) / 2] for 2018 and $5.315 million [($8.049 + $2.580) / 2] for 2019. Thus, the Company's proposed average UPZ regulatory assets are reduced by $7.041 million ($26.395 - $19.355) in 2017, $21.363 million ($33.183 - $11.818) in 2018 and $33.682 million ($38.997 - $5.315) in 2019. Similarly, the Authority finds that the average UPZ ADIT are $7.907 million [($9.446 +$6.367) / 2] for 2017, $4.808 million [($6.367 + $3.249) / 2] for 2018 and $2.139 million [($3.249 + $1.029) / 2] for 2019. Therefore, average UPZ ADIT are reduced by $2.876 million ($10.783 - $7.907) in 2017, $8.657 million ($13.465 - $4.808) in 2018 and $13.501 million ($15.640 - $2.139) in 2019. Thus, the average net UPZ regulatory assets in rate base are overstated as summarized in the table below:

Calculation of Net Average UPZ Regulatory Asset Disallowed ($000)

Description		2017	2018	2019
Net UPZ Regulatory Asset Requested	A	$26,395	$33,183	$38,997
Less Net UPZ Regulatory Asset Allowed	B	(19,355)	(11,818)	(5,315)
Net UPZ Regulatory Asset Reduction	C=A-B	7,041	21,363	33,683
UPZ ADIT Requested	D	10,783	13,465	15,640
Less UPZ ADIT Allowed	E	(7,907)	(4,808)	(2,139)
UPZ ADIT Reduction	F=D-E	2,876	8,657	13,501
Net UPZ Regulatory Asset Disallowed	G=C-F	$4,165	$12,706	$20,182

5. Net General and Intangible Plant Allocated to Transmission

The total distribution utility plant-in-service, which is comprised of intangible distribution and general balances, reported as of December 31, 2015, was $1,600.142 million. Application, Schedule B-1.0 A. The total plant-in-service balance for the three classes of utility plant reported in the Company's 2015 Federal Energy Regulatory Commission Form 1 (2015 FERC Form 1) was $1,656.328 million. Application, Schedule H-1.1, p. 207. UI reported total accumulated depreciation of $430.197 million for the three classes of distribution plant-in-service as of December 31, 2015. Application, Schedule B-1-0 A. The total accumulated depreciation balance for the three classes of utility plant reported in the 2015 FERC Form 1 was $462.325 million. Application, Schedule H-1.1, pp. 200 and 219. UI testified that the differences between the amount reported in its 2015 FERC Form 1 report and the SFR schedules are

associated with intangible and general plant amounts allocated to transmission plant. It used a wage allocation factor of 15.07% to allocate general and intangible plant, along with the related accumulated depreciation amounts to transmission. Application, Schedule H-1.6; Tr. 09/12/16, pp. 88-90; Tr. 10/06/16, pp. 1818 and 1819.

Based on its review of information provided in this proceeding, the Authority summarizes the differences between distribution plant and accumulated depreciation as reported in the table below:

	December 31, 2015 Ending Balances	
Description:	**Plant-in-Service**	**Accumulated Depreciation**
Distribution per 2015 FERC Form 1	$1,280,757,000	$294,622,000
Intangible per 2015 FERC Form 1	102,542,000	94,953,000
General per 2015 FERC Form 1	273,030,000	72,750,000
Total Distribution Plant per 2015 FERC Form 1	1,656,328,000	462,325,000
Total Distribution Plant per SFR Schedules	1,600,142,000	430,197,000
Differences	$ 56,186,000	$ 32,128,000

Application, Schedules B-1.0 A; H-1.1.

The $56.186 million difference between the 2015 total distribution plant amount reported in the Company's SFR schedules and in the 2015 FERC Form 1 equals the difference between the $805.988 million transmission plant-in-service reported in UI's response to Late Filed Exhibit No. 5 and the transmission plant ending balance of $749,802 million reported in the 2015 FERC Form 1. Application, Schedule H-1.1, p. 207; Late Filed Exhibit No. 5, p. 1. The $56.186 million difference also represents approximately 14.96% [($56.186 / ($102.542 + $273.030)] of the sum of the 2015 ending balances of the total intangible plant of $102.542 million and general plant of $273.030 million. However, the $32.128 million difference between the accumulated depreciation amounts via the SFR schedules and the 2015 FERC Form 1 is approximately 19.16% [($32.128 / ($94.953 + $72.750)] of the total amount of the ending balances of accumulated depreciation of intangible and general plant. This allocation factor is significantly higher than both the 14.96% calculated above and the 15.07% transmission wage factor that UI claimed was used to allocate intangible and general plant to transmission service.

By allocating the 2015 ending balances of the accumulated depreciation to transmission using a factor larger than the one applicable to distribution plant allocated to transmission service, the Authority finds that UI overstated the net distribution plant-in-service amount as of December 31, 2015. Using the 14.96% determined herein as the factor used to allocate intangible and general plant to transmission, the Authority finds that the total ending balances of accumulated depreciation for intangible and general plant that should be allocated to transmission plant is $25.089 [(94.953 + 72.750) x 14.96%] million. As a result, the Authority determines that the accumulated depreciation for intangible and general plant that the Company allocated to transmission is overstated by $7.039 million ($32.128 - $25.089).

The Company stated the proposed $7.039 million reduction to its rate base associated with the allocation of accumulated depreciation to transmission is erroneous. The Company indicated that the cost of removal (COR) is also allocated to transmission. UI specified that if the $7.013 million representing the transmission portion of UI's COR regulatory liability is included, the allocation factor for plant-in-service and accumulated depreciation are identical to the 14.96% determined by the Authority. UI Written Exceptions, pp. 22 and 23.

The Authority finds that the Company's claim that the referenced $32.128 million included COR of approximately $7.013 million to be in error. The table below illustrates activities in accumulated depreciation in 2015:

Item Descriptions	**Amounts ($)**
2015 Beginning Balance	469,090,446
2015 Depreciation Expense	66,373,476
Retirements	(21,112,226)
Cost of Removal	(8,253,282)
Salvage Value	870,888
Other Debits	638,687
2015 Ending Balance	507,607,989

2015 FERC Form 1, p. 219.

The total 2015 COR of $8,253,282 is related to accumulated depreciation in Account 108. Id. The Company testified that the distribution portion of this amount is $7,681,784 and the balance of $571,498 is associated with transmission. Tr. 10/06/16, pp. 1878 and 1879. As indicated in the table above, none of the $8,253,282 COR is associated with accumulated amortization related to the intangible plant. The 2015 accumulated depreciation ending balance of $294.622 million for distribution plant already reflected a reduction for the COR. Id., p. 219. Also, based on the negative salvage percentages associated with distribution plant accounts, the Authority concluded that the entire $7,681,784 is mainly related to accumulated depreciation for distribution plant-in-service and very little is associated with general plant-in-service. Id., 337.

There is no basis for UI to associate COR related to distribution plant-in-service with accumulated depreciation related to intangible and general plants. Therefore, none of the COR related to distribution plant-in-service should be used to gross-up the amount of accumulated depreciation allocated to transmission service. The Authority determines that the total net accumulated depreciation for intangible and general plants, after allocation to transmission is $142.431 million ($167.703 – $25.089). Therefore, the total accumulated depreciation for the three classes of distribution is $437.053 million ($294.622 + $142.431). This is approximately $6.856 million more than 2015 total distribution accumulated depreciation of $430.197 million reported by UI. Hence, the Authority reduces the proposed rate base in the rate years by $6.856 million.

6. Capital Expenditures

a. General

UI's proposed capital expenditures (Capital Program) disaggregated by category for the Rate Year is as follows:

Proposed Capital Program for Rate Years 2017 – 2019

	$ in thousands		
Categories	**2017**	**2018**	**2019**
Capacity	2,312	1,489	1,948
Customer	37,272	38,197	38,698
Reliability - Corrective	5,052	2,219	2,712
Infrastructure Replacement - Substations	18,882	8,550	8,416
Infrastructure Replacement - Distribution System	24,920	28,828	28,748
Modernization and Operational Excellence	(3,885)	2,021	3,720
System Resiliency	6,032	6,234	4,752
System Operations	10,525	11,974	9,298
Business Effectiveness	4,416	883	3,900
Total	**$105,526**	**$100,394**	**$102,191**

Note: Amounts may not add due to rounding.

Reed and Thomas PFT, p. 5.

The Capital Program consisted of expenditures for programs that address the needs of customers and system reliability and strengthens the system against major storms. Every year, the Company develops a ten-year capital forecasting plan that assesses system needs and potential solutions to system issues. From this process, the Company determines the investments required to meet distribution business objectives. Id. The Company outlined the key objectives for the Capital Program, which includes supporting the day to day functions of installing new services, responding to customer requests about service changes, responding to emergencies and numerous other projects to construct, and repair and replace distribution facilities to maintain reliability and meet customer needs. Id., p. 4.

The Capital Program is separate from the UI Storm Resiliency Plan (Resiliency Plan) which has been approved in the Decision dated October 26, 2016 in Docket No. 16-07-11, PURA Review of The United Illuminating Company's 2016 Storm Resiliency Plan (Resiliency Decision). The Resiliency Plan was filed pursuant to the merger settlement agreement approved in the Decision dated December 9, 2015 in Docket No. 15-07-38, Joint Application of Iberdrola, S.A, Iberdrola USA, Networks Inc., Green Merger Sub, Inc. and UIL Holdings Corporation for Approval of a Change of Control (2015 Iberdrola Change of Control Decision). The Resiliency Plan included programs costing an additional $50 million over four years. The programs are complimentary to the resiliency expenditures outlined above. The associated costs for the Resiliency Plan programs will be recovered through the non-bypassable Federally Mandated Congestion Charge (NBFMCC), which is outside of base distribution rates. Neither the OCC nor the AG opposed the Resiliency Plan. Resiliency Decision, p. 7.

The OCC and the AG contended that the Company's capital expenditures should be reduced by up to 20% of UI's proposed budget. They specified concerns with the Company's recent management of its capital budget and UI's lack of addressing the Authority's cost benefit analysis concerns outlined in the 2013 UI Rate Case Decision. The AG and OCC highlighted the variance in the Company's capital budget and actual expenditures for the years 2013-2015. AG Brief, pp. 7-12; OCC Brief, pp. 5-11. The table below illustrates that UI's actual capital expenditures from 2013 through 2015 were approximately 20% below that allowed by the 2013 UI Rate Case Decision.[3]

UI Allowed and Actual Capital Expenditures 2013-2015

	2013-2015 *($ in thousands)*			
Categories	**Actuals**	**Allowed DN 13-01-19**	**Variance**	**% Variance**
Capacity	31,302	45,439	(14,137)	-31.11%
Customer	102,389	102,702	(313)	-0.30%
Reliability - Corrective	6,260	10,328	(4,068)	-39.39%
Infrastructure Replacement - Substations	36,528	59,391	(22,863)	-38.50%
Infrastructure Replacement - Distribution System	50,442	50,019	423	0.85%
Modernization and Operational Excellence	23,763	45,874	(22,111)	-48.20%
System Resiliency	20,548	20,329	219	1.08%
System Operations	48,049	55,178	(7,129)	-12.92%
Business Effectiveness	862	9,847	(8,985)	-91.25%
Total	**$320,143**	**$399,108**	**$78,965**	**19.79%**

Note: Amounts may not add due to rounding.

Response to Interrogatory OCC-257.

The AG and the OCC also noted that as of the first two quarters of 2016, the Company underspent by 22% of its 2016 Capital Program budget. Late Filed Exhibit No. 23. The AG and OCC also argued that UI underspent by 16% from the years 2011-2015 in the resiliency category. Larkin PFT, p. 16; AG Brief, p. 7. Besides concerns with the Company's capital expenditure underspending, there are deeper concerns with UI's management that may be causing this trend. The OCC urged the Authority to place less emphasis on the Company's explanation for the project delays that contributed significantly to UI's recent underspending and instead focus on the distinct pattern of underspending and postponing projects. OCC Brief, p. 9.

The OCC's witness claimed that UIL had been facing financial pressure during 2014 and 2015 due to $60 million in costs of two attempted mergers. UI acknowledged that it was asked to reduce its budget to manage the entire UIL portfolio. Specifically, UIL asked the Company to shift money from the UI capital budget to support the growth of UIL's gas expansion program. UI stated that there have been times when the Company's capital budget was increased at the expense of other areas of the UIL portfolio. Tr. 9/14/16, pp. 585, 586 and 708.

Finally, the AG and the OCC argued that the Company's lack of a cost-benefit analysis further supported their argument to reduce UI's capital budget by 20%. AG

[3] In the 2013 UI rate case, the Authority approved the Company's capital plan for a two-year period beginning mid-2013 and ending mid-2015. Response to Interrogatory EN-41; Favuzza, Reed and Thomas Rebuttal Testimony, p. 6.

Brief, p. 12; OCC Brief, p. 10. The AG cited the 2013 UI rate case where the Authority outlined the three characteristics (justification, affordability, and redefining the paradigm) that it considered when evaluating UI's proposed capital plan. Brief, p. 8. The AG and the OCC argued that the Company's Capital Program does not satisfy the cost-benefit characteristic outlined in the 2013 UI Rate Case Decision and that any capital program at the levels proposed by UI requires a more exhaustive cost-benefit analysis process. AG Brief, p. 10; OCC Brief, p. 10. The Company argued that the Authority should consider the years 2004 to 2015 to assess UI's spending of its allowed budget where it has overspent by $37.77 million or 3.6%. Favuzza, Reed and Thomas Rebuttal Testimony, p. 5. The table below compares UI's spending for these years.

Allowed and Actual Capital Expenditures 2004-2015

	2004-2015 *($ in thousands)*			
Categories	**Actuals**	**Allowed/Filed**	**Variance**	**% Variance**
Capacity	100,385	122,834	(22,450)	-18%
Customer	353,146	260,371	92,775	36%
Reliability - Corrective	33,506	23,216	10,290	44%
Infrastructure Replacement - Substations	68,123	97,415	(29,293)	-30%
Infrastructure Replacement - Distribution System	244,994	207,051	37,943	18%
Modernization and Operational Excellence	28,045	46,030	(17,985)	-39%
System Resiliency	27,810	26,613	1,197	4%
System Operations	168,211	173,748	(5,537)	-3%
Business Effectiveness	63,239	92,402	(29,163)	-32%
Total	**$1,087,457**	**$1,049,681**	**$37,776**	**3.60%**

Note: Amounts may not add due to rounding.

Response to Interrogatory EN-41.

UI justified the underspending for each of the categories that contributed largely to the variance. In the capacity category, UI experienced a decrease in peak demand and forecasted only a modest load growth in the future. Specifically, substation load relief projects were 10% less than originally projected. . In the Reliability-Corrective Program, UI incurred $3 million less than originally projected since the need to rebalance feeders to address overloads did not materialize. Response to Interrogatory OCC-257. The Infrastructure Replacement - Substations category saw a $22 million reduction in spending due primarily to the reprioritization of substation rebuilds and removals. Most significantly, the Company began work to rebuild the Old Town substation as planned, when a new generator coming online required UI to shift work to rebuild the Baird substation to accommodate new generation into the system. This ultimately resulted in a shift of the Old Town substation rebuild to 2018. Tr. 9/14/16, pp. 466 and 467. The Authority notes that the above occurrences were largely outside of the Company's control. Additionally, a reprioritization of low voltage substation removals ultimately resulted in two lower cost removals moving ahead of a higher cost one that was originally planned. Id., p. 467. Finally, in the Modernization and Operational Excellence and Business Effectiveness categories, a bulk of the underspending was the result of an accounting treatment whereby the Company shifted the capital expenditure to UIL since the scope of these projects involved its gas companies. Much of these funds would ultimately be allocated back to UI as an O&M expense. Response to Interrogatory OCC-257; Favuzza, Reed and Thomas Rebuttal Testimony, p. 7.

Regarding its lack of a traditional cost-benefit analysis, the Company countered the OCC and AG's position stating that traditional cost-benefit analysis is not a primary means of justifying electric distribution system work and that the programs are necessary to maintain and improve service reliability levels and meet customer needs. UI further argued that it evaluates alternatives to determine the most cost-effective means to meet its obligations. While benefits may be difficult to quantify, the Company has presented adequate cost justification and shown the benefit of its programs. Id., pp. 8 and 9.

The Authority finds merit in both a long-term and short-term evaluation of the Company's historical spending. Capital spending is long-term in nature, as illustrated by the fact that UI forecasts its capital spending for ten years. A review of the Company's Capital Program for the rate year relative to recent years is further illustrative. The table below compares UI's approved capital plan in the 2013 UI rate case for the years 2013-2015 with its proposal for the rate years.

UI Allowed and Proposed Capital Expenditures

(2013 UI Rate Case Decision vs. Proposed Capital Program)

	($ in thousands)			
Categories	**Allowed DN 13-01-19**	**Proposed DN 16-06-04**	**Variance**	**% Variance**
Capacity	45,439	5,749	(39,690)	-87.35%
Customer	102,702	114,167	11,465	11.16%
Reliability - Corrective	10,328	9,983	(345)	-3.34%
Infrastructure Replacement - Substations	59,391	35,848	(23,543)	-39.64%
Infrastructure Replacement - Distribution System	50,019	82,496	32,477	64.93%
Modernization and Operational Excellence	45,874	1,856	(44,018)	-95.95%
System Resiliency	20,329	17,018	(3,311)	-16.29%
System Operations	55,178	31,797	(23,381)	-42.37%
Business Effectiveness	9,847	9,199	(648)	-6.58%
Total	**$399,108**	**$308,111**	**($90,997)**	**-22.80%**

Note: Amounts may not add due to rounding.

Response to Interrogatory OCC-257; Reed and Thomas PFT, p. 5.

UI's Capital Program for the rate years is nearly 23% below what was allowed from the 2013 UI rate case. Furthermore, the Company's proposal is 3.76% (1 - $308,111 / $320,143) less than UI's actual expenditures from 2013 to 2015. Id. The Authority finds that the Company's Capital Program has already accounted for the 20% reduction for which the AG and the OCC recommended. Consideration of the Company's accurate long-term track record for preparing and fulfilling its capital plan commitment since 2004 further supports this determination.

The Authority must also consider the 2015 Management Audit of The United Illuminating Company Final Report by Jacobs Consultancy dated November 9, 2015 (UI Management Audit Report). Relating to UI's Capital Program, the UI Management Audit Report evaluated the Company's use of the following:

1. project management tools;
2. construction methods;

3. job scheduling;
4. prioritization of work;
5. workforce management techniques; and
6. conformance with current industry, state and federal safety and work-related practices and standards.

UI Management Audit Report, p. 81.

The UI Management Audit Report concluded that the Company uses industry current practices in managing its projects and performs its construction activities in a consistent and controlled fashion that supports timely and quality construction program execution. Id., pp. 87 and 88.

The shifting and reprioritization of projects and programs is a reality that is well-understood. The potential for large annual and multi-year variances in capital budgets and plans exists due to a variety of external and internal forces. UI routinely tests and evaluates its system to help make informed engineering and business judgments so that it operates its system to meet its obligations to its customers and the Authority. UI revisits its Capital Plan annually to reprioritize projects every summer. Tr. 9/14/16, pp. 459, 460 and 535-538. The Authority finds that it must be more informed about the yearly reprioritization and realignment of UI's capital plans and will require annual filings as described below. These reporting requirements are identical to those that have been in place for The Connecticut Light and Power Company d/b/a Eversource Energy (CL&P) for many years.

The Authority acknowledges that while a traditional cost-benefit analysis would be helpful, capital programs by nature often are ill-suited for such a treatment. The Authority agrees with the Company that it can be difficult to quantify the full benefits of providing reliable service to customers and a safe work environment to its employees. Nevertheless, UI has shown in this case benefits of past programs, including the positive effect its Overhead Paper Insulated Lead Cable Program had on reliability metrics. Reed and Thomas PFT, pp. 20 and 21. Ultimately, the Authority agrees with the Company in realizing that construction programs should be analyzed based on the needs the programs are intended to address and the reasonableness of the solutions to those needs. This approach is consistent with the Authority's traditional methodology for analyzing electric utility construction programs.

While the recent underspending raises concerns about the UI and UIL's interaction (that is addressed below), based on the above analysis, the Authority determines that the Company has evaluated and adopted its Capital Program based on the current needs of the system. Accordingly, the Authority will not make any adjustments to the proposed capital spending level for the rate years based on the Company's underspending or a lack of a cost benefit analysis.

The Authority firmly supports the AG and the OCC premise that UI ratepayers should not subsidize UIL's gas subsidiaries. UI customers must be assured that they receive the full benefit of the capital programs for which they have paid in rates. Below, the Authority addresses whether the Company's ratepayers have received the full benefit for which they paid in rates since the 2013 UI Rate Case Decision.

First, Item 36 of the merger settlement agreement approved by the Authority in the 2015 Iberdrola Change of Control Decision, Appendix 1, to which both the AG and OCC were parties, allows for UIL to have the authority and responsibility to provide input into the development of the UIL Utilities' capital budgets and implement the approved budgets. Second, neither the AG nor the OCC have shown that UI customers did not receive full benefit of the amounts they paid in rates. To be clear, rates are established on rate base, not a comparison of budgeted and actual capital expenditures. The Company's August 6, 2015 filing in compliance with Order No. 1 for the Decision dated February 10, 1977 in Docket No. 76-03-07, Investigation to Consider Rate Adjustment Procedures and Mechanisms Appropriate to Charge or Reimburse the Consumer for Changes in the Cost of Fossil Fuel, shows that UI's actual average gross plant-in-service for the 12-month period ending June 30, 2015, was $1,481 million. When compared to the approved average plant-in-service of $1,457 million in the 2013 UI Rate Case Decision for the same 12-month period, it is clear that UI customers have not paid for assets that are not in service. 2013 UI Rate Case Decision, Appendix B.

The Company has not violated any of the Authority's statutes, regulations or orders by allocating capital away from these projects, but the fact that it has done so must be accounted for and made clear to the PURA. Ultimately, UI's approved Capital Program budget should not be reduced based on the needs of UIL or its subsidiaries. In order to keep fully informed on UI's Capital Program and its yearly reprioritization, the Authority will direct the Company to report on its capital spending as follows: by November 30 of 2017, 2018 and 2019, with a budget/forecast of spending by initiative or category for the following year; and by March 31 of each year 2018, 2019 and 2020 showing actual spending by initiative or category for the preceding year. The Authority recognizes that plans may change for good reason over the next three years. Accordingly, if the budgeted amount for any initiative or category changes by more than 10% from that represented in this proceeding and as modified by the Authority, the Company must provide an explanation in the annual budget report due each November 30. Further, if actual total spending varies from budgeted spending in any year, the Company must provide an explanation in the annual spending report due March 31 of each year. If the capital spending trend seen in recent years continues, the Authority will reopen the instant Decision and act accordingly.

No party or intervenor opposed any specific capital expenditure or project to be added to plant-in-service. The AG however, questioned the Company's wholesale replacement of specific types of equipment, particularly in UI's infrastructure replacement program. The AG requested that the Authority require the Company to submit a more strategic and optimized plan for review and approval prior to implementation. AG Brief, p. 13. The Authority finds however, that the Company has provided a capital plan that specifically addresses the concerns noted by the PURA in the 2013 UI Rate Case Decision and those reiterated by the AG. The Company has satisfied Order No. 14 of the 2013 UI Rate Case Decision by providing a 20-year plan that forecasts long-term system needs while addressing potential rate impact of the forecasted spending. Regarding infrastructure replacement, the Company provided its completed, active and future replacement programs. In that document, UI provided ample justification for need, cost and long-term management while attempting to manage spending at a steady-state level. Reed and Thomas PFT, Exhibit RJR/JDT. To the Authority, this approach is strategic and optimized while attempting to keep costs down and maintain a steady-state

level of spending to avoid future spending bubbles. The Authority reviewed the Company's proposed Capital Program and concludes that the expenditures are reasonable and necessary for safety, reliability and maintenance of the system.

b. Grid Modernization

The Grid Modernization Program includes expenditures related to modifying the electric distribution system to accommodate the proliferation of distributed energy resources (DER). The Company asserted that customers' desire for choice has resulted in a rapidly growing incorporation of DER on the electric distribution system. This has created a driving need for the grid to evolve from a central station model, where power flows predominantly in one direction, to a more dynamic model that accommodates bidirectional power flows and the ability to manage intermittent resources. The Company stated that it expects that over time, it is likely that pockets of high penetration will create areas where the system needs to be controlled, monitored and operated in a new way to maintain current performance standards and reliability in a more distributed and complex operating model. Reed and Thomas PFT, p. 23.

The Grid Modernization Program is comprised of three initiatives:

- Microgrid initiative, which consists of the costs and reimbursements from the Woodbridge Microgrid project.
- Distribution Management System (DMS) initiative, which will provide central monitoring and control functions and analytical capabilities for UI's distribution system, and potentially for DER. This initiative is intended to enable the Company to operate the system to accommodate increasing levels of DER and enable a new dynamic, bidirectional electric distribution system.
- Grid Analytics initiative, which will provide UI with the capability to gather data on voltage and load performance to better model the electric distribution system in preparation for increased DER penetration.

Id., pp. 23-25; Responses to Interrogatories EN-4 and EN-6.

DER interconnections have a significant impact on the electric distribution system that must be taken into account in system design and operation. When the Authority first approved its generator interconnection standards in 2004, it acknowledged these concerns when it stated: "[s]mall generators connected to lower voltage electric systems are electrically "weak" and less robust than large generators connected to high voltage systems, and are not subject to coordinated dispatch by a system operator. Large numbers of small generators may therefore weaken the integrity of the electric system." Decision dated April 24, 2004 in Docket No. 03-01-15, DPUC Investigation into the Need for Interconnection Standards for Distributed Generation (DG Decision), pp. 3 and 4. Furthermore, DER compromises the integrity of various protective devices and schemes in an electric distribution system if not properly accommodated, requiring further investment to accommodate the collateral impact of interconnections. DER does not benefit the reliability of the electric distribution system.

Since the DG Decision, DER interconnections have grown rapidly, posing a challenge to the EDCs, primarily due to solar photovoltaic installations. UI provided data demonstrating that DER interconnections increased from 59 in 2011 to 2,530 in 2015. The Company stated that, while it currently has sufficient margin to accommodate DER at a system level, it will lose this margin beginning as early as 2019. The Distribution Management System and Grid Analytics initiatives will prepare the Company's electric distribution system to safely manage and accommodate the influx of DER interconnections. Reed and Thomas PFT, pp. 24-26.

The Operational Excellence Initiative (OEI) consists of measures to modernize UI's Outage Management System, damage estimate capabilities, ability to more accurate estimate outage restoration times, and various other information technology (IT) projects and processes. The OEI will be fully implemented in 2016, and in years thereafter savings will accrue to the Company that are attributable to efficiency gains. Id., p. 22. The capital forecast for Grid Modernization and Operational Excellence is as follows:

Modernization and OEI Capital Forecast ($000)

	2016	2017	2018	2019
Modernization:				
-Microgrid	$2,087	$(2,670)	-	-
-DMS	-	-	$506	$5,745
-Grid Analytics	-	-	$3,540	-
OEI	$8,229	($1,215)	($2,025)	($2,025)
Total	$10,316	($3,885)	$2,021	$3,720

Id., p. 24.

No party or intervenor opposed the Grid Modernization or OEI Programs. The Bureau of Energy Technology and Policy (BETP) supported the Grid Modernization initiative. Specifically, it would improve data collection and analysis across the electric distribution system to prepare for the impact of DER on the system and improve planning for the considerable expansion of DER that is expected to occur. The BETP particularly endorsed deployment of the Grid Analytics and Distribution Management System initiatives, which form a foundation for grid-side system enhancement demonstration projects pursuant to Section 103 of Public Act 15-5, An Act Implementing Provisions of the State Budget for the Biennium ended June 13, 2017, Concerning General Government, Education, Health and Human Services and Bonds of the State. Finally, the BETP stated that it will require detailed information from the Company's implementation of DMS and Grid Analytics to coordinate with its demonstration projects and requested that the Authority order detailed reporting requirements in this proceeding. BETP Brief, pp. 14-16.

The Authority finds that the OEI will result in savings to ratepayers every year after 2016, and is therefore approved. The Grid Modernization initiatives have clearly been shown to be reasonable and necessary to accommodate the expanding DER penetration into areas of the electric distribution system, to prevent future negative effects from DER interconnections, more efficiently accommodate and operate DER in the system, and to thus facilitate energy policy, one of the goals of which is to promote the deployment of renewable resources. The Authority notes that some of the Grid

Modernization Initiatives are grid-side enhancement projects that are subject to both BETP and PURA approval per Section 103(b) of Public Act 15-5. Therefore, the Authority approves the Grid Modernization initiatives, subject to reporting requirements delineated in the Orders below, and any other modifications or reporting requirements that may result from final BETP or PURA approval of grid-side system enhancement projects under Public Act 15-5. Any reporting requirements established by BETP will also be utilized by the Authority in any reviews pursuant to this section. Finally, there is substantial uncertainty with regard to the schedule and quantification of the Grid Modernization initiatives, particularly since they are in the later years of the rate plan, as well as considerable variation in the expenditures. Consequently, the Authority will examine whether or not Grid Modernization capital expenditures should be included in the Electric Distribution Infrastructure Capital Tracking mechanism pursuant to Section II.B.6.c. Electric Distribution Infrastructure Capital Tracker.

c. Electric Distribution Infrastructure Capital Tracker

The OCC and the Company proposed that revenue requirements associated with infrastructure replacement and customer-related projects be removed from base rates and separately recovered through a tracking mechanism subject to adjustment either annually or semi-annually. The types of capital expenditures to be moved to such a charge would be those that are large, uncertain and are highly variable. The Company supports an annual mechanism whereby it would detail its actual capital expenditures from the previous year and allowed capital expenditure for the current year, to calculate a line item charge for customers. UI proposed that all capital expenditures in the Infrastructure Replacement category be included in this charge, which currently comprise approximately 41.5% of all capital expenditures. The Company also stated that capital expenditures in the customer category could be included, in which case the total capital expenditures to be moved to the new charge would comprise about 76.8% of all capital expenditures. The Company stated that its proposal is similar to the current Distribution Integrity Management Program (DIMP) tracker for Connecticut Natural Gas Corporation (CNG), which was approved by the Authority in its Decision dated January 22, 2014 in Docket No. 13-06-08, Application of Connecticut Natural Gas Corporation to Increase Its Rates and Charges (CNG 2013 Rate Case Decision). UI Response to Late Filed Exhibit No. 29.

The OCC's proposal is similar to UI's, except that its mechanism would adjust revenue requirements semi-annually, similar to the Water Infrastructure and Conservation Adjustment (WICA) that is in place for the water utilities pursuant to Conn. Gen. Stat. §16-262w. The OCC also proposed that the mechanism be limited to no more than 5% of total distribution revenues annually and 10% between rate proceedings. Such a mechanism will result in significant consumer protection and regulatory oversight similar to WICA, which has been a "win-win" for the utilities and customers alike. The OCC further asserted that a semi-annual proceeding will reduce regulatory lag and allow the Company to re-prioritize projects more easily. Finally the Authority should hold a generic proceeding in 2017 to establish a WICA-like process going forward. OCC Response to Late Filed Exhibit No. 29; Brief, p 138. The AG supported a mechanism similar to the one proposed by the OCC for the same reasons. Brief, pp. 13-16.

The BETP also supported implementation of a capital tracking mechanism similar to WICA. The BETP asserted that a WICA-like mechanism is preferable to a DIMP-like mechanism as it is a more thoughtful, strategic approach to address infrastructure issues than the WICA. The BETP asserted that a WICA-like program will allow for expedited recovery of costs by the Company and be of great benefit to the system and the customers it serves. Brief, pp. 18-22.

This issue has been raised too late in this proceeding to implement a capital tracking mechanism as part of the instant Decision. The parties in this proceeding have opposed other tracking mechanisms (for example, the DIMP), and it appears to the Authority that a more thoughtful, rational exploration of the topic is necessary given the shifting opinions on the matter. There are substantial differences in the parties' opinions on which costs should be included in an electric distribution infrastructure capital tracker (EDICT). The OCC and the AG asserted that an EDICT should also apply to CL&P, yet CL&P has not been given an opportunity to weigh in on this matter. The parties related such a tracker to the WICA; however, the issues that led to the implementation of WICA (generally, reluctance of water utilities to deploy the capital to remediate obsolete piping) are not similar to those of electric utilities, where there has been no reluctance to remediate aging infrastructure (see Section II.B.6. Capital Expenditures). There are compelling—if somewhat different—reasons to consider establishing an EDICT, given the substantial costs associated with infrastructure replacement, which vary widely year to year; the value provided by greater transparency around the utility's planning and prioritization of infrastructure projects and consideration of lower-cost alternatives thereto; as well as the fast-evolving need and technological options for grid modernization investments.

As noted by the parties, although the Authority has no explicit statutory authorization to implement an EDICT, it has broad jurisdiction over the amount that public utility companies collect in rates and the manner in which those rates are collected, which provides ample authority to adopt and approve such a mechanism. See, Conn. Gen. Stat. §16-19 et seq. Therefore, the Authority intends to open a proceeding in 2017 to consider whether an EDICT should be implemented for UI and CL&P, and if so, which costs would be included in it and how future proceedings would be conducted.

7. Working Capital Allowance

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 cash working capital (WC) allowance rather than using a 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 for determining its WC requirement for the term of the rate plan.

In developing its distribution WC requirement, the Company performed its lead/lag study utilizing its overall revenues and expenses. It then removed transmission and Generation Service Charge WC requirements to arrive at a distribution-only WC requirement. This is the same approach that was presented in the 2013 UI rate case

and accepted by the Authority. In reviewing the current lead/lag study, it became apparent that performing the total Company WC requirement and then making reductions required additional steps to verify a distribution-only WC requirement. This was further complicated by virtue of the fact that the transmission WC requirement, which is calculated differently by the FERC, required calculation of a separate factor to determine the transmission WC offset. Additionally, the accounts of the lead/lag study did not correspond to the applicable schedules of the Application itself (WP C-3.0 A, B and C) necessitating the need for an interrogatory to reconcile Application exhibits with the lead/lag study exhibits. Response to Interrogatory FI-137.

The Company provided a distribution-only WC exhibit in response to Late Filed Exhibit No. 31, providing a much more streamlined review. Providing this updated study during the hearing process did however have some shortcomings in that the original lead/lag study analyzed payments for total company expenses and did not acknowledge a distribution-only payment process. Timing prevented such a distribution-only study to be performed. Additionally, other programs such as Conservation and Load Management, Renewable Energy Investment Charge, System Benefits Charge and the NBFMCC are reflected in the total company but not distribution-only lead/lag studies. Response to Late Filed Exhibit No. 31.

The Authority will accept the total Company approach as proposed in this rate case. However, going forward and starting with its next rate case, the Company should file its WC request based on a distribution company-only basis with a lead/lag study that references the same specific accounts that are presented in the Company's rate application.

The Company made a reduction of $1,617,000 for prepaid insurance acknowledging that this was an item properly removed from the WC calculation. Late Filed Exhibit No. 3, Attachment 1, p. 17. The OCC acknowledged the Company's reduction of prepaid insurance from the lead/lag study and stated that this reduction should be from rate base. The OCC cited a previous precedent for this treatment by the Authority in the Decision dated July 17, 2009 in Docket No. 08-12-07, Application of The Southern Connecticut Gas Company for a Rate Increase (2008 SCG Rate Case Decision). Brief, p. 19.

The Authority finds that the adjustment made by the Company in Late Filed Exhibit No. 3 is for the full rate base reduction amount and accepts the Company prepaid insurance adjustment. 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. Based on these adjustments, the Authority calculated a WC requirement for the Company of $29,592,000 for rate year 1, $24,638,000 for rate year 2 and $20,185,000 for rate year 3.

8. Rate Base Summary

As shown in Section V. Rate Model, the rate base approved in this Decision is $981 million for 2017, $997.026 million for 2018 and $1,014.144 million for 2019.

C. OPERATIONS AND MAINTENANCE EXPENSES

UI originally proposed total O&M expenses of $158.231 million for 2017, $163.139 million for 2018 and $166.691 million for 2019. Including depreciation, amortization and taxes other than income tax expenses, the Company proposed total operating expenses of $281.557 million for 2017, $299.899 million for 2018 and $310.488 million for 2019. Application, Schedules WP C-3.0 A, WP C-3.0 B and WP C-3.0 C. The Company updated its requested total O&M expenses by increasing the 2017 amount by $0.547 million and decreasing the amounts in 2018 by $0.171 million and 2019 by $0.610 million. Late Filed Exhibit No. 3, Attachment 1, p. 1.

1. Amortization Expense

UI initially proposed a total amortization expense of $6.082 million for 2017, $16.041 million for 2018 and $18.502 million for 2019. Each year's total consists of rate case amortization expense of $0.417 million and UPZ regulatory asset amortization expense of $5.619 million for 2017, $15.578 million for 2018 and $18.040 million for 2019. Application, Schedule WP C-3.30 A-C. The Company subsequently updated its total amortization expense by reducing the proposed rate case amortization expense for each rate year by $0.066 million. Revised Late Filed Exhibit No. 3, Attachment 1, p. 1. Thus, UI's final proposed amortization expense is $6.016 million ($6.082 - $0.066) for 2017, $15.975 million ($16.041- $0.066) for 2018 and $18.436 million ($18.502- $0.066) for 2019. The difference is the result of the Company reducing the proposed rate case expense from $1.388 million to $1.190 million, which resulted in an annual rate case amortization expense of $0.397 million ($1.190 / 3). The approximately $198,000 decrease included reductions of $120,000 to legal costs, $95,000 to postage expense, $15,000 for costs associated with the return on equity (ROE) witness, and $10,000 for overtime and payroll overheads and an increase of $45,000 for the lead/lag study. Id., p. 11.

a. Utility Protection Zone Expense

Based on the Authority's determination, as described in Section II.B.2. Utility Protection Zone, directing the Company to expense UPZ expenditures for periods after 2016 and not treat them as regulatory asset, the PURA removes the related UPZ amortization expenses from the allowed amounts for the rate years. The allowed UPZ amortization expenses are $2.099 million for 2017, $7.537 million for 2018 and $5.469 million for 2019. Thus, the Authority disallows UPZ amortization expenses of $3.520 million ($5.619 - $2.099) in 2017, $8.041 million ($15.578 - $7.537) in 2018 and $12.571 million ($18.040 - $5.469) in 2019.

b. Rate Case Expense

The Company proposed outside legal expense of $500,000. The OCC argued that it should be reduced by 50% to $250,000. The OCC stated that the Company has in-house counsel and that outside legal expense invoiced through June 30, 2016, was only $18,301. Similarly, the OCC insisted that the Authority disallow overtime and payroll overheads of $30,000 from the rate case expense. According to the OCC, this would be consistent with the determination in the 2013 UI Rate Case Decision where the

Authority indicated that the overtime and payroll overheads should be accounted for in the Company's payroll expense. These recommended adjustments would reduce rate case amortization expense by $93,000 in each rate year. Schultz III/Defever PFT, pp. 71-73; Brief, pp. 44 and 45.

The Authority finds that the outside legal expense of $380,000 included in the total rate case expense is reasonable. Regarding the overtime and payroll overheads included in the total rate case expense, concurrent with the ruling in the 2013 UI Rate Case Decision, the Authority disallows the remaining $20,000 that UI included as a rate case expense as cited in Revised Late Filed Exhibit No. 3, Attachment 1, p. 11. Therefore, the Authority disallows $6,667 ($20,000 / 3) of the proposed rate case expense in each rate year. Consequently, for each rate year, the allowed rate case amortization expense is $0.390 million ($0.397 - $0.007).

2. Membership Dues Expense

UI proposed membership dues expense of $513,000 for 2017, $526,000 for 2018 and $541,000 for 2019. Application, Schedule WP C-3.3 A-C.

The OCC stated that UI included Plug-in Hybrid Electric Vehicle (PHEV) and Customer Contact Council as memberships in the rate years but not in the test year. The Company previously had memberships with both groups but had stopped paying dues. In the 2013 UI rate case, UI described costs related to these memberships as discretionary items that may be reduced to meet earnings goals. The OCC stated that ratepayers should not be responsible for these discretionary costs that UI has previously deemed non-essential. Also, the OCC indicated that Public Act 16-135, An Act Concerning Electric and Fuel Cell Electric Vehicles, did not require UI's membership in PHEV. Furthermore, the OCC stated that the Authority found in the 2013 UI Rate Case Decision that memberships in organizations are often for the benefit of shareholders and not ratepayers and that they are less important to the Company between rate cases. Thus, the OCC recommended reductions of $103,000 in 2017, $106,000 in 2018 and $107,000 in 2019 to remove the costs associated with these memberships. Schultz III/Defever PFT, pp. 33-36.

Consistent with the Authority's determination in the 2013 UI Rate Case Decision, UI's membership in certain groups is optional. The Company has the flexibility to eliminate the related costs to achieve earnings goals in the interim periods between rate cases. Thus, the Authority finds that the reductions in membership dues expense by $103,000 in 2017, $106,000 in 2018 and $107,000 in 2019, as recommended by the OCC, to be reasonable.

3. Uncollectible Expense

UI originally proposed uncollectible expenses of approximately $5.090 million for 2017, $5.051 million for 2018 and $5.044 million for 2019 based on its revenues at present rates. UI calculated a total debt factor of 3.93% for 2015 by averaging the four quarter factors for the year. Application, Schedule WP C-3.20 A-C. Additionally, UI's proposed revenue requirement increases included uncollectible expenses of approximately $0.669 million for 2017, $0.884 million 2018 and $1.021 million 2019.

Thus, the total requested uncollectible expenses are $5.759 million ($5.090 + $0.669) for 2017, $5.935 million ($5.051 + $0.884) for 2018 and $6.065 million ($5.044 + $1.021) for 2019. Application, Schedules A-1.0 A, A-1.0 B, A-1.0 C; WP C3.20 A, WP C-3.20 B and WP C-3.20 C. UI updated its filing by increasing 2017 uncollectible expense by $4,000 to $5.763 million and reduced the amounts for 2018 by $7,000 to $5.928 million and 2019 by $20,000 to $6.045 million. Revised Late Filed Exhibit No. 3, Attachment 1, p. 1.

The OCC asserted that the total debt factor of 3.93% proposed by UI is overstated and is not based on historical data. The OCC claimed that due to fluctuations in the bad debt expenses, a 5-year average is a more accurate method to "smooth out any unusually low or high years." The OCC calculated an uncollectible factor of 3.54%, which is based on the five-year average of uncollectible factors for 2011 through 2015. Thus, the OCC recommended reductions of $0.495 million in 2017, $0.492 million in 2018 and $0.491 million in 2019. Schultz III/Defever PFT, pp. 73-75; Exhibit L&A-1, Schedule C-2.

UI stated that the 3.54% uncollectible rate proposed by the OCC does not represent the level of uncollectible expense that the Company is currently experiencing. The uncollectible rates were 4.02% in 2014 and 3.995% in 2015. The Company stated that the five-year average of 3.54% proposed by the OCC is skewed by the 2.99% in 2013. UI Brief, p. 82.

A 3.54% bad debt factor calculated as an average of five-year historical bad debts is a better uncollectible factor for the proposed rate years. However, the Authority finds that the OCC was not consistent in its approach by using a non-hardship percentage of 26.27%, which was calculated based on the data for the same four quarters that the Company used to calculate its bad debt factor of 3.93%. Based on UI's Response to Interrogatory OCC-146, the Authority determines the five-year averages are $6.645 million for the total non-hardship write-off and $23.978 million for the total write-offs. Thus, the Authority finds that the five-year average percentage of the total non-hardship uncollectible to the total bad debt is 27.71% ($6.645 / $23.978).

Description	**2017**	**2018**	**2019**
Revenue @ Current Rates	$687,119	$ 681,326	$ 680,020
Uncollectible Factor	3.54%	3.54%	3.54%
Total Uncollectible Expense	24,324	24,119	24,080
Non-Hardship Percentage	27.71%	27.71%	27.71%
Non-Hardship Uncollectible Expense	6,740	6,683	6,673
GSC Non-Hardship Percentage	28.15%	28.10%	28.08%
GSC Non-Hardship Expense	1,897	1,878	1,874
Distribution Non-Hardship Expense	4,843	4,805	4,799

Based on the calculations shown in the table above, the Authority disallows distribution non-hardship uncollectible expenses at present rates of $0.247 million ($5.090 - $4.843) for 2017, $0.246 million ($5.051 - $4.805) for 2018 and $0.245 million ($5.044 - $4.799) for 2019.

The Company stated that the four quarter rolling average it used to calculate its requested uncollectible expense was used in the Decision dated February 4, 2009, in

Docket No. 08-07-04, Application of The United Illuminating Company to Increase Rates and Charges (2009 UI Rate Case Decision) and in the 2013 Rate Case. UI also argued that the Authority determined the uncollectible expense based on the test year's four quarter average in the Decisions dated December 17, 2014, in Docket No. 14-05-06, Application of The Connecticut Light and Power Company to Amend Rate Schedules (2014 CL&P Rate Case Decision), and dated June 30, 2010, in Docket No. 09-12-05, Application of The Connecticut Light and Power Company to Amend its Rate Schedules (2009 CL&P Rate Case Decision). UI stated that the Authority arbitrarily departed from the precedent of establishing uncollectible rates that are based on current economic conditions and recent history. UI Written Exceptions, pp. 23-25.

The Authority neither addressed the uncollectible expense factor nor discussed the use of a four quarter rolling average to determine such factor in four of the five Decisions referenced by the Company. The Authority maintains that the calculation of an uncollectible factor in rate proceeding is not a precedent setting event. The method allowed in each rate case proceeding is dependent upon, for instance, the overall review on the related uncollectible expense issues in such rate case application, impact on the additional revenue requests, and contemporaneous economic factors. The Authority concludes that uncollectible factors should be determined based on historical data, not on figures from one year. The historical multi-year uncollectible factor determined herein is concurrent with the multi-year rate plan being allowed in this proceeding. Thus, the Authority upholds its calculation of uncollectible factor based on the average of five-year historical data.

4. Reconnect Service Fee Expense

As offsets to the O&M expenses, UI proposed reconnection service fees of $0.721 million for 2017, $0.739 million for 2018 and $0.758 million for 2019. UI estimated disconnects for non-payment (DNPs) of 54,013 for the rate years based on the three-year average of the DNPs for 2013 to 2015. Based on a five-year average of 2011 to 2015 figures, the Company projected that 85% of DNPs would pay for reconnection during the rate years. UI stated that the 2015 reconnect service fee for a remote reconnect is currently set at $23.03. The reconnect fee was reduced in 2013 from a physical reconnect to a blended rate of 90% remote reconnect and 10% physical reconnect. It was further reduced in 2014 and 2015 to 100% remote reconnect. Due to automating the reconnect process for billing functions, UI proposed reducing the reconnect fee from the current $23.03 to $15.66 in 2017 and escalating it using the 3% labor rate increase per year. UI stated that due to system automation, reconnection activity only requires a customer care representative and only takes approximately 12 minutes per event. For the six months ended June 30, 2016, the total DNPs were 35,252 and the number of paid reconnections was 33,860. Application, Schedule WP C-3.21 A-C; Response to Interrogatory OCC-147; UI Brief, p. 90.

The Authority finds that the 54,013 DNPs that UI proposed for rate years failed to take into account that the Company implemented new distribution rates in 2014 and 2015. This is reflected in the increases in the number of DNPs from 49,539 in 2013 to 53,689 in 2014 and finally to 58,810 in 2015. The 2015 figures represents an approximately 19% increase in the DNPs since UI implemented its last distribution rate increase. Also, in the proposed rate years, reconnections would be performed 100%

remotely. In four years, the DNPs have increased by 30% from 45,205 in 2011 to 58,810 in 2015. The Authority concludes that the number of DNPs would similarly increase during the proposed rate years as a result of the distribution rate increases proposed in this proceeding. Thus, the Authority finds it reasonable to keep the DNPs at the 2015 level of 58,810 for the proposed rate years. By applying the 85% paid reconnection rate, the Authority estimates that the paid reconnections for the rate year is 50,133 (85% x 58,810).

The Authority also determines that the reconnect service fee should remain at the current rate of $23.03 for the rate years. Based on the Company's testimony, this is the reconnection fee since 2014 when UI began the 100% remote reconnections without any additional field visits. Therefore, the Authority concludes that the $23.03 is the correct cost associated with each automated reconnection for almost the past three years. Any further reduction to the reconnection fee removes and reduces any disincentive to mitigate the increases in DNPs and exacerbate the potential growth of the Company's uncollectible accounts. Additionally, it significantly reduces the amount of reconnection fees used to offset the O&M expenses. Therefore, the Authority finds that the appropriate annual reconnection service fees for the rate years is $1.155 million (50,133 x $23.03) for the rate years. As a result, the total O&M expenses are reduced by $0.434 million ($1.115 - $0.721 for 2017, $0.416 million ($1.115 - $0.739) for 2018 and $0.397 million ($1.115 - $0.758) for 2019.

5. UIL Corporate Service Charges

UI originally proposed total corporate service charges of $57.820 million for 2017, $61.023 million for 2018, and $64.177 million for 2019. The total corporate service charges allocated to UI distribution service are $47.865 million for 2015 and $48.303 million for the proforma test year. Application, Schedule WP C-3.27A-C. UI updated and reduced the total allocated corporate service charges to $56.680 million for 2017, $59.309 million for 2018, and $62.346 million for 2019. Revised Late Filed Exhibit No. 3, Attachment 1, p. 7. UI stated that the proposed increases to its shared service costs for the rate years are mainly due to an abnormally high vacancy rate of 6.2% in 2015. The merger-related activity in 2015 resulted in higher than normal levels of open positions and increased the time required to fill these positions. The Company claimed that the 4.60% vacancy rate projected for the rate years is more in line with historical rates. Therefore, the shared service cost increases are projected for both payroll and benefit costs. Favuzza PFT, p. 27. Additionally, the Company claimed that the increases to corporate service charges also reflect different methods of showing these charges in the SFR schedules.

In past proceedings, the corporate service charges were allocated and shown on the specific individual SFR schedules and workpapers. For this proceeding, the corporate service charges are shown on their own specific workpaper, Application, Schedule WP C-3.27 A-C, and were not included in UI's individual workpapers. UI stated that during 2011, it moved to a shared service model for IT, finance and related services, human resources, legal services and other administrative functions. Those functions were moved to the UIL level and the services are shared between UI-Distribution, UI-Transmission, CNG, The Southern Connecticut Gas Company (SCG) and Berkshire Gas Company (BGC). Response to Interrogatory OCC-387.

The OCC is concerned with the increases to the corporate service charges in the rate years because the UI allocation percentage is declining and, despite the significant increase in corporate charges, there are no corresponding decreases to O&M expenses. Despite the Company's claim that its 2015 merger with Iberdrola USA did not contemplate any synergistic savings, the level of merger-related credits included in the rate years are insufficient. According to the OCC, the merger was approved on December 9, 2015, and it will take some time to eliminate redundancies and realize cost savings. UI did not perform a full year analysis of costs incurred by the entities pre-and post-merger to evaluate if there are other efficiencies that are not currently apparent. Also, the OCC stated that based on the Company's own testimonies, from 2013 through the first quarter of 2016, the actual corporate service charges were significantly less than the budgeted amounts. Due to UI's pattern of over-budgeting and the uncertainty of the level of merger related efficiencies, it is reasonable to hold the Company's corporate services expense at the test year amount of $47.865 million. Therefore, the OCC recommended that the corporate service charges be reduced by $9.955 million in 2017, $13.158 million in 2018 and $16.312 million in 2019. Schultz III/ Defever PFT, pp. 36-46.

The AG stated that UIL's actual historic corporate service charge expenditures were less than the amounts approved by the Authority to cover these costs. The actual costs spent were 14% and 11% less than the approved amounts for 2013 and 2014, respectively. In 2015, UI spent 14% less than approved and in 2016 year-to-date, has spent 9% less than approved. Also, the UIL-Iberdrola merger should reduce the shared service charges and that UI's proposed O&M expenses do not reflect such savings. Thus, the AG urged the Authority to accept the OCC's recommendation and reduce UI's proposed corporate service charges by $9.6 million in 2017, $13.2 million in 2018 and $16.3 million in 2019. AG Brief, pp. 17 and 18.

a. UIL Corporate Capital Charges

The total UIL corporate service charges proposed for the rate years originally included corporate capital charges of $15.940 million for 2017, $18.424 million for 2018 and $20.609 million for 2019. The total corporate capital charge allocated to distribution service for 2015 was $11.023 million. Application, Schedule WP C-3.27 A-C. UI updated and reduced the total allocated corporate capital charges to $15.827 million for 2017, $18.295 million for 2018, and $20.473 million for 2019. Revised Late Filed Exhibit No. 3, Attachment 1, p. 7. UI stated that the corporate capital charge represents the calculated revenue requirement associated with the UIL capital expenditures which are mostly expenditures for IT software and hardware.

The revenue requirement for the corporate capital charge represents the return of and on the applicable rate base and is allocated to UI's distribution as an O&M expense using the Massachusetts formula (Massachusetts Formula). The corporate capital charge revenue requirement includes depreciation expense, interest expense, property taxes and an equity return. The allocation to UI's distribution via the Massachusetts Formula factor is based on UI-Distribution's portion of consolidated UIL net plant plus construction work in progress, payroll and revenues in the rate years. UI stated that the corporate capital charge revenue requirement increase from the test year level is primarily due to upgrades and improvements to SAP to provide better data and

efficiencies for customers and employees and for customer service projects to enhance the customer experience. Favuzza PFT, pp. 8, 9 and 28.

The Authority agrees that as UIL's operating companies are fully integrated into Avangrid during 2016 through 2019, there is the expectation that the scale of the merger would produce significant cost savings that is more than that achievable by UIL and its subsidiaries own their own. The Application shows noticeable increases in both UI's O&M costs and the amounts being allocated to it by UIL for shared service costs. Therefore, the Authority is similarly concerned with the growth of shared service charges allocated to UI-distribution. The total corporate service charges allocated to UI-distribution in 2011 was approximately $35.089 million and had increased to approximately $47.865 million in 2015. Despite this 36.41% increase in four years, the Company proposed to significantly increase the shared service cost allocated to UI-distribution to approximately $62.346 million by 2019. Response to Interrogatory OCC-158 Attachment; Revised Late Filed Exhibit No. 3, Attachment 1, p. 7. One of the major factors contributing to this rapid growth in the corporate service charges is the growth in the UIL gross plant year over year. The table below summarizes the growth in UIL's gross plant since 2012 and the level projected for 2016 through 2019.

Summary of UIL Gross Plant for Shared Service Capital Costs

Periods	UIL Gross Plant ($000)	Growth (%)
2012	$ 22,614	
2013	35,538	
2014	107,413	
2015	137,942	+28.42%
2016	183,601	+33.10%
2017	223,604	+21.79%
2018	263,824	+17.99%
2019	$302,579	+14.69%

Responses to Interrogatories AC-7 Attachment, p. 1;
OCC-340 Attachment and OCC-392 Attachment.

Subsequent to the responses cited above, UI reported that the UIL gross plant figures were $82.017 million for 2014 and $120.282 million for 2015. Response to Interrogatory OCC-392, Attachment. This response appears to indicate that the UIL gross plant amounts are overstated by $25.396 ($107.413 - $82.017) million in 2014 and $17.660 (137.942 -$120.282) million in 2015. For the five years from 2014 to 2019, the Company is proposing an increase to the UIL gross plant in the range of $195.166 million ($302.579 – $107.413) to $220.562 million ($302.579 – $82.017). The Authority finds the levels of growth proposed for the UIL gross plant are not sustainable and not in the best interest of UI's ratepayers. The proposed increases to the UIL gross plant are in addition to the significant increases proposed for the Company's distribution plant for the rate years. In the 2013 UI Rate Case Decision, UI 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 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.
>
> 2013 UI Rate Case Decision, pp. 73 and 74.

UI plans to spend approximately $11.2 million between 2016 and 2019 on IT and project management technology. The Company stated that its proposed IT investments include many "refreshes and upgrades" in distribution systems and computer equipment. Additionally, UI stated that its investments in project technology would integrate systems associated with "project performance, reporting and finance to ensure on-time and on-budget delivery of capital projects." Reed PFT, pp. 30 and 31. For the 2015 test year, the total IT O&M costs of approximately $11.534 million allocated to UI by UIL included approximately $7.79 million for recurring IT hardware and software maintenance costs, general communication and contractors/outside professional service expenses. These costs were similar to the approximately $11.473 million allocated to UI in 2014. Late Filed Exhibit No.1 - ADR-12, Attachment 1. For recurring O&M expenses, exclusive of amounts allocated to it by UIL, UI proposed computer expenses of $1.2 million in 2017, $1.215 million in 2018 and $1.288 million for 2019. Application, Schedule WP C-3.18 A-C. The Company also requested telecommunications expenses of $1.744 million in 2017, $1.769 million in 2018 and $1.778 million for 2019. Application, Schedule WP C-3.18 A-C. Similar to the concerns expressed in the 2013 UI Rate Case Decision, the Authority finds that the UIL proposed capital spending is excessive and not in the interest of UI's ratepayers. The Authority determines that the UIL proposed gross plant of $223.604 million, as of December 31, 2017, is the appropriate level of investment for calculating the corporate capital charge to be allocated to UI. This is approximately $103.322 million or 86% greater than UIL's 2015 gross plant amount of $120.282 million.

Due to the offsetting deferred tax assets created by the UIL net operating loss (NOL), starting in 2015, the UIL average rate base was not reduced by the related ADIT. Moreover, the Authority finds that for periods prior to 2015 when ADIT were used to calculate the average rate base amounts, the Company only applied the statutory Federal income tax (FIT) rate of 35% to determine the ADIT amounts. Response to Interrogatory OCC-392, Attachment. Costs allocated to a regulated utility by its unregulated affiliate should reflect an arms-length transaction. The temporary timing differences between the UIL book and tax depreciation deductions are not included in the calculation of UI's income tax expenses. Excluding the tax benefit of accelerated depreciation tax deductions for state income tax (SIT) purposes in the calculation of the UIL average rate base overstated costs to be allocated to UI. Also, regarding the UIL deferred tax asset that resulted from its tax basis NOL, there is no evidence that UI, by itself, would be in a NOL position if it incurred the related expenses on its own. A non-regulated holding company, such as UIL, can offset its NOL position with income from its affiliated companies, such as UI. It is disadvantageous to UI's ratepayers to incur increases in allocated O&M expenses for costs that do not exist. Therefore, ADIT should be calculated based on the combined statutory FIT and SIT rates applicable to

each period and the UIL average rate base for the proposed rate years should be calculated to reflect ADIT calculated as such. Accordingly, the Authority calculates the allowed average UIL rate base for determining the allowed capital charges as shown in the table below.

Calculation of the Average UIL Rate Base ($000)

	2016	2017	2018	2019
Gross Plant*	$183,601	$223,604	$223,604	$223,604
Accumulated Depreciation*	(50,784)	(73,288)	(98,202)	(123,117)
Annual Net Plant*	132,816	150,315	125,401	100,487
13-Month Average Net Plant*		141,784	137,858	112,944
Combined FIT and SIT Rate		40.850%	40.362%	39.875%
Accumulated Deferred Income Taxes		(57,919)	(55,642)	(45,036)
Average Rate Base*		$ 83,865	$ 82,216	$ 67,907

*2016 and 2017- Accumulated Depreciation per Response to Interrogatory AC-7 Attachment, p. 1.

The Authority utilizes the allowed capital structure of 50/50 equity-debt ratio and weighted costs of capital approved in this proceeding to calculate returns on average rate base. The allowed annual depreciation expenses are based on monthly rate of 0.93% for an average asset life of nine years. Response to Interrogatory AC-7, Attachment, p .3.

The Company stated the average rate base for UIL, which the Authority used to calculate the corporate capital charge allocated to UI distribution, is flawed. This is because the combined statutory tax rate of 40.85% was used to determine the appropriate level of ADIT instead of the actual differences between book and tax depreciation times the applicable state and federal tax rates. Also, the NOL should be incorporated into the calculation of the UIL average rate base. UI noted that the UIL average rate base should be increased by an average NOL asset of $37.4 million in 2017, $8.230 million in 2018 and $0 in 2019. Based on its proposed corrections, UI determined that the average rate base for UIL is $138.887 million for 2017, $103.091 million for 2018 and $70.606 million for 2019. UI Written Exceptions, pp. 4-6.

The Authority agrees that it is appropriate to add back the UIL NOL assets to each year is average rate base used to calculate the corporate capital charges allocated to UI. The application of the combined statutory income tax rate to calculate ADIT is consistent with the Company's own approach through its application. For example, all deferred taxes calculated as offsets to regulatory assets and liabilities were determined based on combined statutory income tax rates. Based on the average rate base amounts derived above, the Authority calculates the allowed UIL capital charges for 2017, 2018 and 2019 as shown below.

Calculation of the Allowed UIL Capital Charges (000, except percentages)

	2017	2018	2019
Allowed Average Rate Base	$ 83,865	$ 82,216	$ 67,907
Add back NOL Offset to Rate Base	37,440	8,230	0
Adjusted Average Rate Base	121,305	90,446	67,907
Common Equity Ratio	50.00%	50.00%	50.00%
Equity Rate Base	60,653	45,223	33,954
UI Equity Return	9.10%	9.10%	9.10%
Equity Return	5,519	4,115	3,090
Equity Gross-up Factor	1.6906	1.6768	1.6632
Equity Return with Gross-up	9,331	6,901	5,139
Weighted Debt Ratio	50.00%	50.00%	50.00%
Debt Rate Base	60,653	45,223	33,954
Average Cost of Debt	5.31%	5.14%	5.05%
Debt Return	3,221	2, 243	1,715
Total Return on Capital	12,552	9,225	6,854
Property Taxes	560	577	532
Depreciation	22,504	24,914	24,914
Total Costs to Recover	35,616	34,716	32,300
GSC Allocated System Charges	(105)	(144)	(186)
Total Capital Charge	35,511	34,572	32,114
Allocation % to UI-Distribution	40.26%	40.26%	40.26%
Charge to UI Distribution	$ 14,297	$ 13,919	$ 12,929

Based on the allowed corporate capital charges calculated in the table above, the Authority disallows $1.530 million ($15.827 – $14,297) in 2017, $4.376 million ($18.295 - $13.919) in 2018 and $7.544 million ($20.473 – $12.929) in 2019. The Authority considers the allowed increases to corporate capital charges to be reasonable as they represent a range of 15% to 23% over the $11.023 million for the test year.

The Company claimed that the Authority's use of only UI's ROE, average cost of debt, common equity ratio and weighted debt ratio to calculate corporate service charge allocated to UI is incorrect and inconsistent with past practice. UI professed that the investments are at the UIL level for the benefit of all of its operating companies and the proper values to calculate the allocated amount should be the weighted average of all of the UIL operating companies. According to the Company, this is the methodology allowed by the Authority in the 2013 UI Rate Case and in the Decision dated January 22, 2014, in Docket No. 13-06-08, Application of Connecticut Natural Gas Company to Increase Its Rates and Charges. Therefore, UI determined that the correct UIL corporate service charge disallowances are $0.316 million in 2017, $3.461 million in 2018, and $7.123 million in 2019. UI Written Exceptions, pp. 6-8.

The Authority determines that the level of costs to be allocated to UI should reflect UI's capital structure and weighted cost of capital. This avoids any potential for cross-subsidization to affiliates and assumes the same treatment for UIL investments that would have been applicable to UI if it had incurred such costs on its own. There is no basis for UIL to receive from UI's customers higher returns than authorized to UI. The Authority similarly used UI's allowed capital structure and weighted cost of capital in its

last rate case to calculate the allowed corporate capital charges allocated to UI. 2013 UI Rate Case Decision, p. 76.

The Company also argued that the draft Decision's determination to calculate the UIL corporate capital charge by keeping its gross plant at the 2017 year-end level denies cost recovery for any UIL capital investments in 2018 or 2019. The Company claimed the proposed investments are to replace and update/upgrade existing software systems, such as SAP to enhance and upgrade critical system for customer billing and call center technology; and for cyber security to protect its critical infrastructure. Id.

The Authority determines herein the appropriate level of UIL's investments considered prudent for UI's customers and that are in the public interest. The Authority's approach is also consistent with the determination in the 2013 UI Rate Case where it was determined that the gross plant of $70.69 million as of June 30, 2013, was the appropriate level of UIL's capital investment that should be funded by UI's ratepayers. 2013 UI Rate Case Decision, p. 75. The Authority herein determines that the proposed UIL investment of $223.604 million as of December 31, 2017, is an appropriate amount for UI to meet its obligations to ratepayers.

b. Directors and Officers Liability Insurance

UI requested $.422 million for rate year 1 $.432 million for rate year 2 and $.444 million for rate year 3 for the expenses associated with Directors and Officers Liability Insurance (DOL). Response to Interrogatory OCC-008 Attachment 1, Revised. The Company stated that these are necessary and non-discretionary business costs that the Company must expend and should be allowed to be recovered fully in UI's rates. UI Brief, p. 85.

The OCC stated that in previous Decisions, the Authority allowed the Company to recover 25% of DOL costs from ratepayers with the remaining 75% being borne by shareholders. While acknowledging the Company's statement that the costs are appropriate and necessary for running a business, the OCC asserted that not all appropriate costs are recoverable from ratepayers. In addition, despite the disallowance of 75% of these costs, the Company still provided DOL insurance in the years subsequent to the prior Decisions. The OCC recommended the disallowance of 75% of DOL costs consistent with previous Authority UI Rate Case Decisions. Brief, p. 29.

The AG recommended that the Authority reject UI's request for ratepayer funding of DOL because the proposed amount is improperly inflated. According to the AG, UI's test year amount for DOL was $786,000 and the Company did not adequately explain why this cost had increased so dramatically. The AG noted that the Authority has consistently rejected the Company's request that ratepayers pay 100% of this expense citing the Authority's 2008 and 2013 Decisions. In addition, the AG stated that DOL primarily protects the Company's directors and officers from lawsuits related to their employment and that the lawsuits are typically brought by the Company's shareholders. The AG recommended that the lion's share of the expense be funded by the shareholders and that the Authority should allow UI the same 25% recovery of DOL allowed in the Company's previous rate cases. The AG also recommended that the

Authority disallow $590,000 per rate year, which represents 75% of the test year DOL expense. Brief, pp. 18 and 19.

The Authority agrees with the AG and the OCC and will allow the Company to recover 25% of the test year DOL expense as it has the past three UI rate cases. Consequently, the Authority allows $105,500 ($422,000 x .25) of DOL expense for rate year 1, $108,000 ($432,000 x 25%) for rate year 2 and $111,000 ($444,000 x 25%) for rate year 3 and disallows $316,500 ($422,000 - $105,500) for rate year 1, $324,000 ($432,000 - $108,000) for rate year 2 and $333,000 ($444,000 - $111,000) for rate year 3.

c. Board of Directors

UI proposed total allocated Board of Directors (BOD) costs of $983,490 for rate year 1, $985,035 for rate year 2 and $987,571 for rate year 3. These are the UIL allocated costs to UI excluding DOL, D&O Energy Insurance, Side A D&O Liability and Audit and Accounting Service. The costs included are for restricted stock expense for BOD, UIL legal and consulting matters, director stocks, director retirement pension and director expenses. Responses to Interrogatories AC-11, OCC-91 and OCC-360.

The OCC cited the Authority's previous Decisions in which the PURA determined that these costs should be shared 75/25 between shareholders and ratepayers, respectively. The OCC recommended the disallowance of 75% of BOD costs, which is a reduction of $5.220 million in each of the rate years based on 75% of the 2015 test year amount of $6.960 million. Brief, p. 30.

The AG recommended that the Authority reject UI's proposal to recover 100% of its BOD costs from ratepayers as it did in the 2013 UI Rate Case Decision and assign no more than 25% of these costs to ratepayers. Brief, p. 19.

The main objective of the BOD is to protect the interests of the Company's investors or shareowners. Ratepayers may incidentally benefit from the activities of the BOD; however, they are not the focus of the BOD's decisions. Consistent with the determinations regarding DOL discussed above, the Authority allows only 25% of the BOD costs in rates. The Authority notes that the OCC's proposal for disallowance using the test year amount is not representative of the Company's typical BOD costs as shown in response to Interrogatory OCC-360. Therefore, the Authority makes its adjustments based on the UI distribution amounts as represented in response to Interrogatory OCC-91, and the UI distribution allocation percentages as represented in its response to Interrogatory AC-11. Hence, the allowed BOD costs are $245,873($983,490 x 25%) for rate year 1, $246,259 ($985,035 x 25%) for rate year 2 and $246,893 ($987,571 x 25%) for rate year 3. As a result, the Authority disallows BOD costs of 737,618($983,490-$245,783) in rate year 1, $738,776 ($985,035-$246,259) in rate year 2 and $740,678 ($987,571-$246,893) in rate year 3.

The Authority further determines that the Audit and Accounting Service cost included in the BOD expense should be allocated 50/50 between shareholders and ratepayers. Unlike other BOD expenses, Audit and Accounting costs benefit both the ratepayers and shareholders equally. Therefore, the Authority disallows $320,056

($640,112 x 50%) for rate year 1, $321,722 ($643,545 x 50%) for rate year 2 and $325,270 ($650,540 x 50%) for rate year 3.

d. Other Public Company Costs

Besides the DOL liability insurance and BOD expenses, the public company costs proposed for the rate years included investor relations expense of payroll and benefits, outside services, transportation, meals, travel and lodging, training, dues, postage, telephone, office supplies, other and SEC reporting. UI requested $287,000, $290,000 and $294,000 for non-DOL public company costs for rate years 1-3, respectively. Response to Interrogatory OCC-312.

Consistent with the determination regarding DOL insurance and BOD expenses, 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 $71,750 ($287,000 x 25%) in rate year 1, $72,500 ($290,000 x 25%) in rate year 2 and $73,500 ($294,000 x 25%) in rate year 3. Therefore, the Authority disallows non-DOL public company costs of $215,250 ($287,000 - $71,750) in rate year 1 $217,500, ($290,000 - $72,500) in rate year 2 and $220,500 ($294,000 - $73,500) in rate year 3.

e. Donations

The Company requested $137,334, $138,411 and $140,259 for donations for rate years 1-3, respectively. The Company stated that an itemized list of all donations included in each rate year is not available but the annual totals requested are the UI distribution portion of the total UIL amount. Response to Interrogatory OCC-164.

The OCC recommended the complete removal of donations resulting in a reduction of $137,334, $138,411 and $140,259 for donations in rate years 2017, 2018 and 2019, respectively. The OCC noted the Authority's Decision dated September 24, 2013, in Docket No. 13-02-20, Application of the Aquarion Water Company of Connecticut to Amend Its Rates (2013 Aquarion Rate Case Decision), which disallowed donation expenses and previous Aquarion Water Company rate cases. According to the Uniform System of Accounts for Electric Utilities, "donations for charitable, social or community welfare purposes" are to be recorded in Account 426, Miscellaneous Income Deductions, which is a below-the-line account for ratemaking purposes. Moreover, the OCC stated that the Company's donations for the test year are described as Economic Development Grants. This means that in exchange for providing money to these organizations, the Company received the benefits of creating and sustaining business relationships and image building, which are benefits to the Company, not ratepayers. Schultz III/Defever PFT, pp. 58 and 59.

Consistent with previous Authority Decisions, donations for charitable, social or community welfare purposes should be accounted for below-the-line. Therefore, the donations of $137,334, $138,411 and $140,259 for the rate years 2017, 2018 and 2019, respectively are disallowed.

f. Summary of Corporate Service Charges Adjustments

The table below summarizes the Authority's adjustments to the proposed UIL corporate service charges in 2017, 2018 and 2019.

	2017 (Millions)	2018 (Millions)	2019 (Millions)
DOL Liability Insurance	$0.317	$0.324	$ 0.333
Other Public Company Costs	$0.673	$0.678	$ 0.686
Board of Directors Costs	$0.738	$0.739	$ 0.741
Corporate Capital Charges	$1.530	$4.376	$ 7.544
Total Adjustments	$3.258	$6.117	$9.304

6. Advertising

UI proposed advertising expenses of $253,000 in rate year 1, $313,000 in rate year 2 and $319,000 in rate year 3. Application, Schedule C-3.2. The Company stated that increases in advertising expense are to support development of creative, media, direct mail production and event costs to support both existing and new customer programs. The requested budget increases are to develop informational brochures, bill inserts and direct mail to educate customers of the energy savings and safety benefits of programs. The information includes surge protection, private area lighting, water heater lease, residential distributed generation, plug-in hybrid electric vehicle, battery storage for renewable integration and customer education and phone book listings. UI stated that advertising will generally serve to educate customers of the energy savings and safety benefits of these programs and services. Responses to Interrogatories AC-28 and OCC-348.

The OCC noted that the Company failed to spend the money allowed for advertising expense in prior years. The Company was allowed $305,000 for each of the 2014 and 2015 rate years in the 2013 UI Rate Case Decision, yet the Company only spent $132,000 and $24,000 in 2014 and 2015, respectively. The OCC suggested that UI not be granted an increase when it has failed to spend what it had requested. Schultz III/ Defever PFT, p. 28.

The Company spent $211,000, $70,000, $41,000, $132,000 and $34,000 for the years 2011-2015 respectively, which is an average of $98,000 per year [($211,000 + $70,000 + $41,000 + $132,000 + $34,000) / 5]. Response to Interrogatory OCC-2. The Authority determines that the appropriate amount to allow for advertising is the average of the Company's actual advertising expense. Therefore, the Authority will allow $98,000 per year for rate years 1-3, which is a $64,000 increase over the test year amount of $34,000 ($98,000 - $34,000). Given that the proposed new programs are not mandated but are discretionary in nature and the appearance of this being less of a priority for the Company between rate cases, the Authority disallows advertising expenses of $155,000 ($253,000 - $98,000) in rate year 1; $215,000 ($313,000 - $98,000) in rate year 2; and $221,000 ($319,000 - $98,000) in rate year 3.

7. Incentive Compensation

UI requested incentive compensation of $1.436 million for rate year 1; $1.479 million for rate year 2; and $1.523 million for rate year 3. Application, Schedule WP

C-3.24A-C. This compares to the actual test year O&M incentive compensation of $1.214 million. The requested incentive compensation is for UI's distribution non-executive employees only. Incentive compensation for executives and management is a component of the corporate charge that is an allocation to UI from UIL. The executive and management incentive compensation included in the corporate charge for the pro forma 2015 year is $4.198 million. Incentive compensation included in the UIL corporate charges is $2.934 million, $2.868 million and $2.897 million for rate years 1- 3, respectively. Response to Interrogatory OCC-390 Revised. Total UI Distribution O&M incentive compensation for pro forma 2015 and rate years 1-3 are $5.412 million, $4.370 million, $4.347 million and $4.420 million, respectively.

UI stated that compensating its employees at market is critical to enable the Company to attract and retain the highly skilled and productive work-force that is essential to its mission of serving customers safely, reliably and at a high level. Also, its rate year incentive compensation should be allowed for recovery because it is a central part of its compensation structure. The market data that it relies on to set employee compensation levels demonstrates that they are reasonable based on consideration of the total pay package for its workforce. Brief, pp. 72 and 73.

The OCC took issue with the Company's approach to incentive compensation. It should be an extra amount that is offered based on the achievement of certain goals with the purpose of inspiring an exceptional effort from employees with the flipside of that being incentive pay is not received if goals are not met. Schultz III/Defever PFT, p. 55. In addition, the OCC stated that the Company scorecards for 2011-2016 show a breakdown of rewards based on categories such as financial goals and customer goals. Over the period of 2011-2015, the OCC determined that 25%-50% of the rewards were based on financial goals and that in 2016, 65% of the goals were financial-related. Further, the OCC argued that since the goals are focused on shareholder interests, shareholders should bear the greater portion of the costs. Therefore, the OCC recommended that 65% of the incentive compensation costs be assigned to shareholders and the remaining 35% shared between shareholders and ratepayers which results in a reduction of $1.185 million, $1.220 million and $1.256 million in rate years 2017, 2018 and 2019, respectively. Brief, p. 35

The Authority disagrees with the OCC that incentive compensation be allocated to shareholders and ratepayers based on the percentage of the scorecard goals, as that percentage can vary significantly (25%-65%) as demonstrated in the years 2011-2016. The Authority reaffirms its position that incentive compensation expenses should not be borne solely by the ratepayers and that costs be allocated between ratepayers and shareholders. In the Decision dated January 27, 2006 in Docket No. 05-06-04, Application of The United Illuminating Company to Increase Its Rates and Charges, (2005 UI Rate Case 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 Decision dated February 4, 2009 in Docket No. 08-07-04, Application of The United Illuminating Company To Increase Its Rates and Charges, (2008 UI Rate Case Decision) the Authority reaffirmed its Decision to limit the amount of incentive compensation to be included in rates at $3.994 million. 2008 UI Rate Case Decision, pp. 37-41. In the 2013 UI Rate Case Decision, the Authority

capped the distribution incentive compensation at $3.660 million for rate year 1 and $3.778 for rate year 2. 2013 UI Rate Case Decision, p. 60.

Accordingly, the Authority allows the starting point for incentive compensation as $3.778 million, which represents the previously allowed incentive compensation for rate year 2 in the 2013 UI Rate Case Decision at p. 60. The incentive compensation of $3.778 million is then escalated by 3%, for proforma 2015 for an allowed incentive compensation expense of $3.891 million. Application, Schedule WP 3.23 A-C, p. 4. For rate year 1, the allowed incentive compensation expense is $4.027 million, which is the pro forma 2015 incentive compensation of $3.891 million then escalated by 3.5% which is the weighted average of the base payroll escalation percentages for management and weekly/hourly employees. Responses to Interrogatories OCC-087 and OCC-390 Revised. Rate year 2 incentive compensation allowed is $4.152 million which is rate year 1 escalated by 3.1%, which is the weighted average of the base payroll escalation percentages for 2018. For rate year 3, the allowed incentive compensation is $4.280 million, which is the rate year 2 incentive compensation escalated by 3.1%, which is the weighted average of the base payroll escalation percentages for 2019. Therefore, the Authority reduces the requested incentive compensation expense for rate year 1 by $.343 million ($4.370 million - $4.027million); rate year 2 by $0.195 million ($4.347 - $4.132) and rate year 3 by $.140 million ($4.420 million-$4.280 million).

8. Payroll

The Company requested $42.859 million, $44.570 million and $46.335 million for payroll, for the rate years 2017, 2018 and 2019, respectively, excluding incentive compensation expense for 738.2 full time equivalent (FTE) employees. The requested amounts represent increases of $3.711 million, $1.711 million and $1.774 million over the pro forma 2015 payroll for each of the rate years. The Company requested an additional 45.6 equivalent FTE positions for UI distribution for the 2016 interim year through rate years 1-3 for a total of 738.2 FTEs. In addition, the Company used a 4.6% vacancy rate and an escalation rate in calculating the requested payroll. Application, Schedule WP C-3.23 A-C.

The OCC stated that the Company's request for 738.2 FTEs is not appropriate because the test year included 692.6 FTEs. Moreover, the OCC stated that the Company's requested vacancy rate is not sufficient and ignores historical vacancies and the historical decline in FTEs. In addition, the Company has repeatedly spent less on payroll than it projected. Based on the response to Interrogatory OCC-088, for years 2014 and 2015, the Company spent on average, 29% less on payroll than it was allowed. This means that the Company has collected substantially more than necessary from ratepayers for each of those years. Also, the OCC claimed that the appropriate vacancy rate is 6.6% based on the average 2015 vacancy of 46 FTEs. Consequently, the OCC recommended adjustments to remove vacancies from payroll based on its calculated vacancy rate resulting in reductions of $296,000, $303,000 and $309,000 to payroll in rate years 2017, 2018 and 2019, respectively. Schultz III/Defever PFT, pp. 76-78.

The Authority finds that UI's use of a 4.6% vacancy rate is appropriate as it more accurately reflects the Company's historical average vacancy rate rather than being

based on just one year. The OCC calculated its vacancy rate using only the 2015 test year, which was the year the merger between UIL and Iberdrola was proposed and eventually finalized. The Company's claim that the 2015 test year does not accurately represent typical staffing levels is valid. Rebuttal Testimony of Favuzza, Reed and Thomas, p. 30. The Company's historical average monthly vacancy for years 2011-2015 was 35.75 positions. Response to Interrogatory OCC-371. The Authority applied the proposed 4.6% vacancy rate to the requested 738.2 FTE positions resulting in 33.96 vacancies, which is in line with the Company's historical experience. The Company noted that there were 53 vacant positions in the 2015 pro forma year, of which, 23 had been filled to date. Some of the recently hired employees would count toward the 150 employees to be hired by UIL over the next three years per the settlement agreement in the 2015 Iberdrola Change of Control Decision. Tr. 09/13/16, pp. 269 and 418.

The Authority notes that the OCC's initial assertion that the Company has underspent by 29% in 2014 and 2015 is incorrect. The Company has underspent by 1% and 3% in years 2014 and 2015, respectively. Response to Interrogatory OCC-088 Revised. Therefore, the Authority accepts the Company's proposed payroll expense of $44.295 million, $46.049 million and $47.868 million for rate years 2017, 2018 and 2019, respectively.

9. Travel, Education and Training

UI proposed travel, education and training expense of $828,000, $843,000, and $851,000 for rate years 2017, 2018 and 2019, respectively. This represents an increase of $175,000, $190,000, and $198,000 in the rate years over the test year amount of $553,000. Application, Schedule WP C-3.22 A-C. The OCC stated that the Company provided the costs for programs that caused the increase but did not explain why such a significant increase was necessary at this time. The OCC recommended an adjustment to allow a five-year average of the 2011-2015 expenses, or $624,000, which equates to reductions of $204,000, $219,000, and $227,000 for the rate years 2017, 2018 and 2019, respectively. Schultz III/DeFever PFT, p. 33. The Company claimed that the increase is necessary due to the fact that training and travel expenditures were reduced during the test year, but that the reductions would not be sustainable over the long term if the Company is to have the employees and skills necessary to operate and maintain a reliable system. Rebuttal Testimony of Favuzza, Reed and Thomas, p. 40.

In the 2013 UI Rate Case Decision, the Authority found that an increase in travel, education and training expenses was justified, but not at the proposed levels. The Authority determined that the appropriate level of spending was the test year amount of $1.09 million. In this proceeding, the Company provided its travel, education and training expense for the years 2011-2015, which were $953,000, $561,000, $611,000, $440,000, and $553,000, respectively. Response to Interrogatory OCC-150. The Authority notes that the Company spent less in every year since the 2013 UI Rate Case and spent significantly less than what was allowed in the years 2014 and 2015. The decreased spending in the test year is not an aberration, but rather, a trend in decreased spending from what was allowed in the Company's last rate case.

The Company collected revenue from ratepayers at the allowed expense of $1.090 million but spent 59.63% [($1.090 - $.440) / $1.090] and 49.27% [($1.090 -$.553)

/ $1.090] less than allowed in 2014 and 2015. Therefore, the Authority determines that the appropriate allowed amount for travel, education and training expense is $624,000, which is the average of the expense for the years 2011-2015. [($953,000 + $561,000 + $611,000 + $440,000 + $553,000)/5]. The Authority's adjustments are reductions of $204,000 ($828,000 - $624,000) for rate year 1; $219,000 ($843,000 - $624,000) for rate year 2; and $227,000 ($851,000 - $624,000) for rate year 3.

10. Depreciation

A depreciation rate study calculates the annual depreciation rate that is then applied to the gross plant-in-service balance. The product of this calculation is the depreciation expense, which is a charge to a company's operating expense to reflect the annual recovery or amortization of previously expended capital investment.

a. UI 2015 Study and the Company's Position

UI filed a depreciation study related to the utility plant-in-service as of December 31, 2014. It updated depreciation rates based on the December 31, 2014 depreciation parameters applied to the Company's plant-in-service as of December 31, 2015 (UI 2015 Study). Three elements – method, procedure and technique – are needed to describe a depreciation system. UI's study employed a depreciation system composed of the Straight Line method for each depreciable property group, Broad Group procedure and the Average Remaining Life (ARL) technique. Robinson PFT, Exhibit EMR-1, p. 7. This is a system widely used by regulated utilities. Depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The Company's depreciation study was performed by Earl Robinson of AUS Consultants (AUS). Robinson PFT, p. 1.

The application of the present rates to the depreciable plant-in-service as of December 31, 2015, results in an annual depreciation expense of $72,414,786. In comparison, the application of the proposed rates to the depreciable plant-in-service as of December 31, 2015, results in an annual depreciation expense of $80,466,054, which represents an increase of $8,051,269 from current rates. Robinson PFT, Exhibit EMR-1, p. 2. The test year depreciation expense was $49.923 million and the projected rate year 2017 plant depreciation and amortization expense is $63.182 million. Application, Schedules C-3.29A-C. The composite annual depreciation rate under present rates is 3.23%, while the proposed December 31, 2015 composite depreciation rate is 3.59%. Robinson PFT, Exhibit EMR-1, p. 2.

In preparing the UI 2015 Study, AUS utilized actual Company data to investigate and analyze historical plant data to determine the remaining plant asset lives. The study applied the Retirement Rate method to analyze the Company's service life data sorted by age to develop a survivor curve for each account. Id., p. 7. For every account, a survivor curve served as the basis on which smooth curves (standard Iowa Curves) were fitted to determine the average service life (ASL) being experienced by the property account under study. Robinson PFT, pp. 2, 6, 7, 21 and 22. Mr. Robinson stated that the methods used in the UI 2015 Study produced results that are superior to other methods because it utilized more actual data and reduced the level of subjectivity. Tr. 9/22/16, pp. 1466 and 1467. The Company also contended that recent upgrades

installed in 2011 to UI's PowerPlan Software system, provided a more robust dataset to calculate depreciation rates. Response to Interrogatory EN-24. UI stated that irrespective of the depreciation study approach that was used and approved by the Authority in the past, the Company's current study is analytically sound in its use of the retirement rate method for every account. Brief, p. 119.

b. Positions of the OCC and AG

The OCC and AG contended that the Company's depreciation study tends to understate the ASL of its physical plant and also overestimates its future negative net salvage costs. The practical effect of these calculations is to accelerate the Company's recovery of its investment and to raise the overall annual expense to ratepayers. Acceptance of the UI 2015 Study as submitted would result in requiring customers to pay disproportionately for distribution infrastructure that will likely continue to provide service for years longer than the proposed ASL of the plant assets. AG Brief, pp. 30 and 31; OCC Brief, pp. 2, 50, 51 and 56. Further, the OCC opined that the UI 2015 Study contains math errors, is inconsistent with the method utilized in recent UI rate proceedings and violates regulatory accounting requirements. Thus, UI's request to increase its depreciation expense of $8 million should be rejected. OCC Brief, p. 2.

c. Authority Analysis

In this proceeding, the depreciation expense is the largest single expense in the UI proposed Total Operating Expenses as presented in UI's Application, Schedule WP C-3.0A, B, and C.

i. Average Service Life Calculation

The major difference between the Company and the OCC depreciation study findings is the ASL recommendations. To calculate ASL, AUS employed actuarial methods or Retirement Rate method using the Company's aged data for all accounts. However, the OCC witness, William W. Dunkel, identified specific accounts where the Simulated Plant Record Balances (SPR-BAL) method was used. SPR-BAL employs analytic methods when actual aged data is not available or detailed to the level that is appropriate for actuarial methods to be employed.

The Authority finds that the Company's approach of applying the Retirement Rate method to 8 of 19 distribution accounts is appropriate.[4] The aged data that exists for these accounts contained the level of detail necessary for a meaningful analysis. Those accounts are: 360.10-Distribution Land Easement, 361.00-Distribution Structures and Improvements, 361.11-Distribution Western Service Center, 361.12-Distribution Eastern Shore Metering Building, 362.00-Distribution Station Equipment, 370.10-Automated Meter Reading System, 371-Installs Customer Premises and 372.00-Distribution Leased Property Customer Premises.

[4] The Authority notes that it did not review the eight transmission accounts associated with transmission plant since the transmission system is not subject to its ratemaking jurisdiction.

.

The Authority finds that the SPR-BAL method should be used to calculate ASL for eight other accounts where the Company's plant accounting records utilized first-in-first-out (FIFO) accounting methods. The aged-data for these accounts does not incorporate the actual vintage details of certain assets such as poles, meters, conductors, conduits and transformers. The eight specific distribution accounts that utilize FIFO accounting methods are: 364-Poles & Towers, 365-Overhead Conductors, 366-Underground Conduit, 367-Underground Conductors, 368-Line Transformers, 369-Electric Distribution Services, 370-Meters and 373-Street Lighting. Tr. 9/22/16, p. 1436.

The Authority recognizes that the Company has improved the plant accounting data through the upgrade of its PowerPlan Software system in 2011. UI Response to Interrogatory EN-24. The 2011 software upgrade added functionality to retirement work in progress (RWIP) accounting classifications, which contribute to a more accurate depreciation analysis. Tr. 9/22/16, p. 1472. Improved RWIP and retirement values exist now for 2011 through 2016 in the Company's plant accounting system, but not for all accounts. While an improvement, five years of more accurate removal and salvage data is not sufficient to perform an actuarial analysis for ASL calculation on certain property classes that have a 20-49 year life span. The Authority recognizes that the Company has taken steps to improve its accounting records and more accurate retirement data is being collected. This results in improving quality of the aged data available for depreciation studies performed in the future.

For the eight account classes identified above, the FIFO values contained in aged data are closer to assumptions or estimates rather than absolute actual plant accounting that is tied to specific assets. Dunkel PFT, pp. 7 and 8; Tr. 9/22/16, pp. 1542 and 1543. The Authority finds that the ASL calculation using SPR-BAL method proposed by Mr. Dunkel in Schedule WWD-8 represents a more accurate ASL for the eight accounts as identified below. The Authority directs that the ASL values in Exhibit WWD-8 and the associated ASL-curves be incorporated into the Company's depreciation rates.

Existing, Proposed and Approved ASLs

Unified Account Number	Major Description Type	Existing ASL	UI Proposed ASL	PURA Approved ASL
364	Poles & Towers	37	32	41
365	Overhead Conductors	35	35	40
366	Underground Conduit	75	75	75
367	Underground Conductors	34	49	35
368	Line Transformers	35	35	45
369	Electric Distribution Services	42	42	52
370	Meters	20	15	20
373	Street Lighting	19	16	19

2013 UI Rate Case Decision: Robinson PFT, Exhibit EMR-1 and Dunkel Supplemental, Schedule WWD-8.

One of the examples of the Authority's review of the treatment of the SPR-BAL method as applied to FIFO accounts is account 370 - Meters. In this particular instance, Mr. Robinson proposed to shorten the existing ASL from 20 to 15 years. The annual depreciation expense would increase by $2,417,866 in this account under UI's proposal. Robinson PFT, p. 28; Exhibit EMR-1, p. 21. Mr. Dunkel proposed to maintain an ASL of 20 years. Dunkel Supplemental PFT, Schedule WWD-6.

On review of Account 370, the Authority finds that more accurate data on the vintage, original purchase value and salvage value of customer meters exists within the information system employed by the Company's metering department even though it is not contained in the aged data which serves as the basis for depreciation studies. Tr. 9/22/16, pp. 1483, 1485 and 1486. Within this particular accounting designation, during years when the Company was undertaking an automated metering program that featured large numbers of meter change-outs, the value of meter removal and salvage were not included in the specific aged data records for Account 370 - Meters. UI Responses to Interrogatories EN-27 and OCC-251; Tr. 9/22/16, p. 1436. This is an example where analysis of the aged data does not provide useful results because the data is incomplete. Also, in this instance, journal transfers between sub-accounts resulted in the loss of removal cost and salvage cost values that are necessary for a meaningful ASL calculation. UI Responses to Interrogatories EN-27 and OCC-251. The Authority observes that the life span of solid state metering in the industry today is closer to 20 years. This reinforces the analytic method and ASL values in Dunkel Supplemental PFT, Schedule WWD-8. Mr. Robinson and Mr. Dunkel separately stated that the aged data is typically the basis for their depreciation studies. Tr. 9/22/16, p. 1435. For studies in the future, the Authority finds that the Company should incorporate and utilize the most accurate and complete data available when conducting depreciation studies to provide the most meaningful results and recommendations.

ii. Net Salvage

Net salvage is the gross salvage less the cost of removal. In some general plant accounts, such as Account 392.00 - Passenger Cars, the gross salvage exceeds the cost of removal, which results in a positive net salvage. Robinson PFT, Exhibit EMR-1, p. 432. However, in the distribution plant accounts, the cost of removal generally exceeds the gross salvage, which results in a negative net salvage that is sometimes referred to as net salvage cost. The average annual amount the Company actually spent for negative net salvage in the distribution plant accounts during 2011-2015 is $3,040,869 per year. However, Mr. Dunkel stated that Mr. Robinson proposed to accrue $10,009,602 per year for net salvage in the distribution plant accounts. Dunkel Supplemental PFT, Schedule WWD-12.

Mr. Dunkel's testimony provided a comparison showing the proposed net salvage accrual to the average amount actually spent for negative net salvage in the last five years. He claimed that this is the same analysis that the Authority adopted in the 2013 CNG Rate Case Decision on p. 32[5] and in the 2014 CL&P Rate Case Decision. Similar to what the Authority approved in both the CNG Rate Case Decision and the CL&P Rate Case Decision, Mr. Dunkel claimed his treatment of net salvage gave significant weight

[5] UI has since acquired CNG.

to the net salvage costs the utility is actually incurring. Dunkel PFT, p. 23. In those Decisions, the Authority compared the accrual amount to the amount incurred. However, a distinction is that in the CNG Rate Case Decision, the Authority used the most recent five years incurred average, and in the CL&P Rate Case Decision, the Authority used the most recent three years incurred average. To balance the difference in the number of years used to calculate the incurred average, Mr. Dunkel claimed his approach was conservative in UI's favor. Dunkel Supplemental PFT, p. 20.

Mr. Dunkel also stated that his Schedule WWD-11 compared the annual accruals that result from the UI proposed net salvage depreciation rates and from the OCC proposed net salvage depreciation rates to the actual UI incurred net salvage cost. Id., pp. 19 and 20. The average annual incurred distribution net salvage costs are $4,615,136. Mr. Dunkel further proposed to accrue $5,380,491 per year. Overall, the OCC-proposed distribution plant net salvage depreciation rates produce an annual accrual that is 1.2 times the annual incurred distribution plant net salvage cost. The average annual incurred distribution net salvage costs are $4,615,136, but UI proposed to accrue $10,003,020 per year. Overall, the UI proposed distribution net salvage depreciation rates produce an annual accrual that is 2.2 times the average annual incurred net salvage cost. Dunkel Supplemental PFT, Schedule WWD-11. The OCC-proposed distribution net salvage depreciation rates produce an annual accrual that is approximately $4.6 million less than that produced by UI. However, the OCC's proposed distribution net salvage depreciation rates still comfortably cover the actual incurred net salvage costs. Dunkel Supplemental PFT, pp. 19 and 20.

Based on comparison to actual values and consistent with the CNG Rate Case Decision and the CL&P Rate Case Decision, the Authority adopts Mr. Dunkel's recommended net salvage rates and net salvage factors. Therefore, the adjustment of $4,622,529 is made to the UI's proposed total annual accrual-net salvage value of $10,003,020 as fully detailed in Dunkel's Schedule WWD-11.

iii. Account 390.45 – General Central Facility

This account was the subject of several differences between the positions of the Company and the OCC. The first is related to a math error. On the bottom of Schedule WWD-9, Mr. Dunkel noted two mathematical errors that Mr. Robinson made in calculating the weighted average life for Account 390.45 – General Central Facility. UI concurred and made the corrected calculation. Tr. 9/22/16, p. 1564; Dunkel Schedule WWD-9.

The Authority accepts the corrected calculation for the weighted average life of Account 390.45 as represented in the total class investment of $2,431,644 as cited in Dunkel Schedule WWD-9, p. 1.

The remainder of differences in this account involve the treatment of interim additions and the inclusion of future inflation. In the 2013 UI Rate Case Decision, the Authority approved a 50-year ASL for the newly constructed Central Facility on Marsh Hill Road, Orange. The FERC requires that depreciation be over the service life of the property and not before the service life starts. However, Mr. Robinson included in his depreciation rate calculation not only the current "Component" (e.g., the current roof), but

also the First Replacement Component (e.g., the future second roof). Robinson PFT, Exhibit EMR-1, pp. 133 and 134. The general Central Facility first went into service in 2012. Mr. Robinson expected that the First Replacement Component's (e.g., the future second roof) service life to start 21 years after the General Central Facility first went into service, this means that the future second roof would first go into service in 2033, and end 41 years after General Central Facility first went into service, which means the future second roof's service life would end in 2053. The Authority notes that Mr. Robinson is depreciating this investment years before the service life begins. Robinson PFT, Exhibit EMR-1, pp. 133 and 134; Dunkel Supplemental PFT, pp. 15 and 16; Schedule WWD-8, pp. 14-17.

The Authority hereby adopts Mr. Dunkel's proposed depreciation rates and parameters shown on Schedules WWD-6 and WWD-10. Mr. Dunkel recommended depreciation rates that produce an overall depreciation rate of 3.08%. Dunkel Schedule WWD-6, p. 4. The 3.08% composite depreciation rate is adjusted to account for transmission and non-depreciable plant-in-service to yield a 3.01355% composite depreciation rate utilized in the Authority Approved Depreciation Expense table below. The Authority disallows the Company's value of removed or reduced investment of $1,765,448 as stated in Robinson PFT, Exhibit EMR-1, pp. 133 and 134. Accordingly, the approved adjusted and corrected total investment of Account 390.45 – General Central Facility is $2,431,644 with weighted investment of $72,632,880 as fully detailed in Dunkel Schedule WWD-9 and Dunkel Supplemental PFT Schedule WWD-10.

In conclusion, in consideration of the discussions of ASL, net salvage and specific to Account 390.45 as each relates to depreciation expenses, the Authority disallows the Company's proposed depreciation expenses for rate year 2017 of $63,182,000, rate year 2018 of $65,423,000 and rate year 2019 of $68,688,000. Application, Schedules C-3.29A-C. The Authority adopts the depreciation expense of $51,237,000 for rate year 2017, $54,114,000 for rate year 2018 and $56,880,000 for rate year 2019, yielding reduced depreciation expense of $11.945 million in 2017, $11.309 million in 2018 and $11.808 million in 2019, respectively as detailed below.

Authority Approved Depreciation Expense

Description	Value (Thousands)
Rate Year 2017 Average Plant in Service	$ 1,700,236
RY Composite Depreciation Rate	3.01%
Allowed Depreciation Expense 2017	$ 51,237
Company Depreciation Expense	$ 63,182
PURA Adjustment to Depreciation Expense	$ (11,945)
Rate Year 2018 Average Plant in Service	$ 1,795,685
RY Composite Depreciation Rate	3.01%
Allowed Depreciation Expense 2018	$ 54,114
Company Depreciation Expense	$ 65,423
PURA Adjustment to Depreciation Expense	$ (11,309)
Rate Year 2018 Average Plant in Service	$ 1,887,470
RY Composite Depreciation Rate	3.01%
Allowed Depreciation Expense 2019	$ 56,880
Company Depreciation Expense	$ 68,688
PURA Adjustment to Depreciation Expense	$ (11,808)

UI Written Exceptions, Supplemental Exhibit 1, p. 1.

11. Retirement Benefits

a. UI (401(k) Plan

A 401(k) plan is a qualified retirement plan under the Internal Revenue Code (IRC) that allows employees to save a portion of their salary for retirement on a pre-tax basis. UI's 401(k) plan is designed to comply with Section 404c of the Employee Retirement Income Security Act (ERISA). Typically employers match a portion of each employee's contribution with the employee choosing the investment options for the contributions. UI does not bear any investment risk relative to the employee's investment choices. Response to Interrogatory FI-15.

Effective in 2005, UI implemented a defined contribution plan that replaced the existing qualified pension plan and retiree medical plan for new employees. Specifically, this defined contribution plan was implemented on April 1, 2005, for union employees and May 1, 2005, for non-union employees (collectively, New Hires). 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. Under the defined contribution plan, contributions are made on a pay period basis at 4% for each New Hire eligible salary plus a fixed amount per pay period with a $1,100 annual limit for post-retirement medical benefits. Application, Schedule WP C-3.24f A–C, p. 1. Total cost for the Company's 401(k) is $2,931,000 in the 2017 rate year, $3,019,000 in the 2018 rate year and $3,109,000 in the 2019 rate year. Favuzza PFT, p. 25.

The Company's position is that its 401(k) plan is an essential expense and, as such, appropriate for ratepayers to fund it. The 401(k) is necessary to ensure that UI

employees receive a competitive market based compensation package. Ratepayers benefit from the 401(k) since it allows the Company to attract and retain the highly skilled workforce needed to provide safe and reliable service. UI noted that, in past Decisions, the Authority adjusted a portion of the 401(k) matching contribution for employees who are also eligible for potential incentive compensation under the Company's Executive Incentive Compensation Plan (EICP) and Management Compensation Plan (MCP). UI continues to maintain that its entire 401(k) matching contributions is necessary to ensure that it provides competitive market-based compensation and benefits to its employees. Brief, pp. 73 and 74.

The OCC noted that the Authority has disallowed 50% of the 401(k) matching for employees that were entitled to benefit under the EICP and the MCP. The OCC argued that there should be no adjustment based on other compensation received. Even if an expense can be considered a legitimate business expense, it does not automatically make it appropriate to be recovered from ratepayers. Consistent with the 2013 UI Rate Case Decision, the OCC advocated the removal of 50% of 401(k) matching costs for employees receiving other compensation. This results in a reduction of $435,000, $448,000 and $462,000 in rate years 2017, 2018, and 2019, respectively. Late Filed Exhibit No. 60; Brief, pp. 32 and 33.

The AG advocated adjusting UI's recovery of its KSOP expense. This adjustment would limit recovery from ratepayers of matching contributions for Company employees who were entitled to executive incentive compensation and management compensation consistent with the 2013 UI Rate Case Decision. Brief, pp. 32 and 33.

The Authority adjusted the 401(k) based on its adjustments in past rate cases and also addressed matching contributions as they relate to the Company's KSOP Plan. While matching provides a benefit to employees, the amount of matching recovery allowed must be restricted. The Authority will allow recovery of matching contributions for all UI employees, except 50% of those who are entitled to benefit under the EICP and the MCP. Therefore, the Authority will follow its past practices and adjusted the 401(k) accordingly. The mechanics of this adjustment are as follows:

Description	2015 Test Year	2016 Interim Year	2017 Rate Year	2018 Rate Year	2019 Rate Year
Cost of employees receiving other compensation	$867,000	$845,000	$871,000	$897,000	$924,000
Adjustment for 50% of employees receiving other compensation.			($435,000)	($448,000)	($462,000)

The adjustment for the 401(k) is as follows:

	2017 Rate Year	2018 Rate Year	2019 Rate Year
UI's 401(k) request	$2,931,000	$3,019,000	$3,109,000
Adjustment for employees receiving other compensation	($435,000)	($448,000)	($462,000)
Adjusted 401(k) expense	$2,496,000	$2,571,000	$2,647,000

The above calculation of the 401(k) adjustment is in keeping with the OCC's adjustment methodology. Late Filed Exhibit No. 60. The Authority grants UI a 401(k) expense of $2,496,000, $2,571,000 and $2,647,000 for the rate years 2017, 2018, and 2019, respectively.

b. Qualified Pension Plan

UI sponsors a qualified pension plan for employees hired before 2005. This pension plan meets certain criteria under the IRC. Pension expense is accounted for under Accounting Standards Codification (ASC) 715. It provides the methodology to recognize employees' future retirement benefit costs as they accrue over their working career. Under ASC 715, yearly pension cost is calculated using the following formula:

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

The service cost is the value of benefits earned during the year for each employee. Interest cost is defined as the increase in plan liabilities resulting from the passage of the year. The expected return on assets is the projected return on market related value of UI invested assets for the year. Amortization refers to the cost for the year attributable to events from prior years such as plan amendments, gains and losses. 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 pension cost are actuarial assumptions such as the discount rate, expected return on assets and average wage increase. The Company's assumptions and expenses for the pension plan are the following:

	2017 Rate Year	**2018 Rate Year**	**2019 Rate Year**
Net Pension Expense	$12,555,000	$11,451,000	$10,341,000
Discount rate	3.24%	3.24%	3.24%
Salary increase assumption	3.8%	3.8%	3.8%
Expected return on asset assumption	7.75%	7.75%	7.75%

Late Filed Exhibit Nos. 3 and 14.

The above amounts included in UI's O&M expense have already been reduced by the amount allocated to capital, amounts for UIL employees included in the plan which have been allocated across the UIL utilities based on the Massachusetts Formula and

amounts allocated to transmission or other non-distribution cost components. There are no allocations from Avangrid, CNG, SCG, or any other Avangrid subsidiary embedded in the Company's pension expense for the test year or rate years. Responses to Interrogatories FI-55 and FI-79.

UI affirmed that its qualified pension plan costs were determined in accordance with ASC 715. Qualified pension costs were developed on a calendar year basis in consultation with the Company's outside actuaries. Calendar year 2016 is the first full year that UIL Holdings and its operating utilities, including UI, are part of a larger Avangrid organization. Therefore, when setting the actuarial assumptions for 2016 and forward, UIL strived for conformity with the other Avangrid companies. This approach is required by the accounting guidance in ASC 715, Compensation – Retirement Benefits, and ASC 805, Business Combinations. Further, consistency of accounting policies across affiliated companies is part of the overall principles of Generally Accepted Accounting Principles (GAAP). UI reported that pension costs have increased due to lower actual and projected financial returns and due to a decrease in the discount rate, partially offset by an increase in the asset values UI. Brief, pp. 64-66. The OCC and AG did not offer a position on the qualified pension plan expense.

UI's qualified pension expense is calculated using the above formula utilizing the actuarial assumptions of expected return on plan assets, discount rate and salary increase assumptions. The expected return is a long-term projection of the probable return on pension plan assets, which is influenced by the particular asset mix and expected returns on that asset mix. The higher the assumption for future returns on plan assets, the lower the pension expense. The discount rate is the rate at which projected benefits are discounted back to a present value. It is used to evaluate the present value of the pension plan liabilities. The higher the discount rate, the lower the present value of pension plan liabilities resulting in lower pension expense. The salary increase assumption is the long-term assumption of salary increase for all of the employees in the pension plan. The Company used a building block approach to determine the expected long term return on assets (ELTRA). This building block approach started with a base return expectation and adds other factors such as premiums for active management of pension investments. Other factors include the Towers Stochastic Capital Market Model, the Tactical Asset Allocation and Strategic Asset Allocation. This produced a 7.52% ELTRA actuarial assumption. Response to Interrogatory FI-26.

The Company stated that the discount rate of 3.24% for the rate years 2016 through 2019 was calculated through the development of yield curves derived from a portfolio of high grade, non-callable bonds with yields that closely match the duration of the expected cash flows of the pension benefit obligation. The broader nature of bonds utilized in this methodology produces less volatility in annual movements in the discount rate. The Company's outside auditors have determined that this methodology is in accordance with GAAP. This methodology was implemented in 2016 with the purpose of harmonizing pension accounting methodologies with the other Avangrid Networks utilities. Response to Interrogatory FI-56.

The Company calculated the salary assumption of 3.8% based on its payroll escalation assumption of 3.00% and promotion rate assumption of 1.00%. The salary increase assumption is based on a long-term perspective and includes not only payroll

merit increases, but also increases for promotions. Response to Interrogatory FI-58; Application, Schedule WP C-3.23, pp. 4 and 5.

UI's request for qualified pension expense is higher than what was approved in the 2013 UI rate case. This is attributable to a decline in expected asset values as a result of lower actual and projected financial returns. The Company stated that there are several factors that caused an increase in qualified pension expense. First, an increase in pension expense of approximately $6.5 million as a result of asset loss in 2015 from a negative 2% return versus the expected actuarially ROR assumption of 8.00%. Second, an increase in expense of approximately $1.0 million from a decrease in the discount rate and the expected long-term return on assets assumption. There was a decrease in expense of approximately $1.5 million due to demographic gains from 2015 to 2016. Favuzza PFT, p. 23. UI also decreased the discount rate due to movements in the portfolio of actual high quality bonds as determined by its actuaries to 3.24%. Tr. 10/6/16, pp. 1834 and 1835. In addition, the expected ROR was decreased from 8.00% to 7.75% based on the Company's review of the market. Late Filed Exhibit No. 3.

The Authority agrees with lowering the discount rate to 3.24% but disagrees with decreasing the expected return on asset assumption to 7.75%. For ratemaking purposes, the expected return on asset assumption, for pensions should be kept at 8.00% rather than 7.75%. The record supports this since the earned return on the pension assets was 10.4% as of August 2016 as stated in Supplemental Late Filed Exhibit No. 10. In addition, the historic year is more representative since the market is better in 2016 than what it was in 2015. Tr. 9/21/16, p. 1249. The following is the Authority's adjusted qualified pension plan expense:

	2017 Rate Year	**2018 Rate Year**	**2019 Rate Year**
Pension request	$12,555,000	$11,451,000	$10,341,000
25 basis point adjustment	($390,513)	($390,513)	($390,513)
Adjusted pension request	$12,164,487	$11,060,487	$9,950,487

c. Directors Retirement Plan

There are five retired directors that receive a total of $58,000 a year in retirement for their life-times. These directors served in the 1980s and 1990s. This is a direct expense of UI and is not associated with any identified C-schedule, which is why the Company included it in Residual O&M. Response to Interrogatory FI-212; Tr. 9/13/16, p. 295; Tr. 10/6/16, pp. 1841-1843; Late Filed Exhibit No. 18.

The $58,000 in retirement payments for retired directors is not a ratepayer expense; but more appropriately, a stockholder expense. Therefore, the Authority disallows the directors' retirement expense of $58,000 for all three of the rate years Current ratepayers do not receive benefit from the decisions made by the retired directors. This is because the electric utility industry is substantially different today from what it was in the 1980s and 1990s. In addition, current ratepayers are not necessarily the same that as when these directors held office. Consequently, the Authority reduces each year of the rate request by $58,000 for a total of $174,000 ($58,000 * 3).

d. Supplemental Employee Retirement Plan

The Company's non-qualified pension plan, Supplemental Employee Retirement Plan (SERP), is offered to participants of the UI qualified pension plan. It provides benefits under the same formula as the qualified plan but recognizes pay over the qualified plan pay cap. The plan was closed to new hires at the same time as the qualified pension plan on May 1, 2005, for non-collective bargained employees. In the 2013 UI rate case, the Authority allowed the SERP expense. In this proceeding, UI increased the SERP expense for two UI executives of UIL and allocated a share of this to UI. Late Filed Exhibit No. 3; Tr. 10/6/16, pp.1836-1838. A settlement was accepted for one executive in the amount of $400,000. Late Filed Exhibit No. 14. The expenses for the SERP are $933,000 in rate year 1, $525,000 in rate year 2 and $490,000 in rate year 3. Late Filed Exhibits No. 3 and 14.

UI reiterated its position that the SERP expense is beneficial to customers because it enables the Company to provide a compensation and benefits package that properly compensates employees with the experience, skills and qualifications necessary to serve customers. The executives under this plan have a range of employment opportunities due to their skill sets and these opportunities carry with them a certain level of compensation and benefits. Thus, it is necessary for UI to offer SERP benefits to attract and retain these highly qualified individuals. Brief, pp. 70 and 71.

The OCC asserted that the SERP expense should be disallowed for all three rate years. The OCC cited to the 2013 Aquarion Rate Case Decision and the 2008 SCG Rate Case Decision as examples of when the Authority has disallowed a SERP expense. The OCC took exception to UI's rebuttal testimony, which stated that the Authority allowed recovery of this expense in the 2013 UI rate case. Although the SERP was not disallowed in the 2013 UI rate case, it was not recommended for adjustment or discussed at all in the 2013 UI Rate Case Decision. The lack of disallowance in a case where the issue was not discussed by the Authority should not be considered as an explicit approval to allow that expense. The OCC disagreed that the SERP is necessary and argued that the recipients are already highly compensated without providing retirement benefits that are above limits set by the Internal Revenue Service (IRS) for qualified plans. Additionally, the OCC agreed with the 2013 Aquarion Rate Case Decision and the 2008 SCG Rate Case Decision that SERP benefits not be recovered from ratepayers. Brief, pp. 37 and 38.

The AG asserted that the SERP provides extra retirement benefits that go beyond the maximum level established by the IRS relative to traditional pension plans to UI's more highly compensated employees. At present, three current UI employees are eligible to receive SERP upon their retirement. It is currently paid to 19 former Company employees. The AG asserted that the Authority's treatment of SERP expense in the past has been inconsistent. The Authority did not allow recovery from ratepayers in the 2008 SCG Rate Case Decision or in the 2013 Aquarion Rate Case Decision. The AG recommended that the Authority reject recovery of SERP expenses from UI's customers in this case and going forward in other proceedings. While this may be an expense that UI chooses to incur to pay its executives, the costs of SERP should be borne by the Company's shareholders, not ratepayers. Brief, pp. 20 and 21.

Precedent in the 2013 Aquarion Water Rate Case and the 2008 SCG Rate Case Decisions can be found to disallow the SERP. Therefore, the Authority will eliminate the SERP expense. This expense is far above and beyond what ratepayers should be responsible for as the plan provides an extra layer of retirement benefits to highly compensated employees. The $400,000 one-time payment to one employee is excessive and should not be borne by ratepayers but rather, by stockholders. Tr. 10/6/16, pp. 1835-1837; Late Filed Exhibit No. 14, p. 2. Elimination of the SERP for rate making purposes should be phased-out over the three-year term of this rate case. In the Company's next rate case, the SERP will not be recognized for ratemaking purposes.

	Rate Year 2017	**Rate Year 2018**	**Rate Year 2019**
SERP	$933,000	$525,000	$490,000
Adjustment for Settlement	($400,000)		
Phase Out		($169,649)	($312,351)
Adjusted Total	$533,000	$355,351	$177,649

The Authority will phase out the SERP expense over the three-year period of this rate case by the adjusted total of the above SERP expense. This three-year phase-out is calculated as $533,000 for the 2017 rate year, $355,351 ($533,000 * 66.67%) for the 2018 rate year and $177,649 ($533,000 * 33.33%) for the 2019 rate year.

e. Post Retirement Benefits Other than Pensions (OPEB)

UI provides medical benefits to retirees as determined by ASC 715. UI is required to recognize these benefits during the working career of employees and not after they retire. Costs accrue from the date an employee is hired to the date of retirement when an employee is fully eligible to receive OPEB benefits. Response to Interrogatory FI-24.

In 2005, the Company closed its retiree medical plan to new entrants and replaced this coverage with a flat contribution of $1,100 per participant to the 401(k) plan. The contribution was provided to partially offset the elimination of retiree medical coverage, allowing the affected participants a savings vehicle for anticipated medical expenses. The $1,100 was set as a flat amount and does not automatically trend with medical inflation. Response to Interrogatory FI-7. As such, the OPEB expense is based on current retirees and those working at UI with an employment date before 2005. In 2015, UI offered a Medicare Exchange as an option to retirees who are Medicare-eligible and in 2016 made it the only option for non-union retirees. Response to Interrogatory FI-46.

The Authority finds that the present value of future benefits, under the OPEB, would be determined by employee retiree demographics. The rate years' expenses are based on the actuarial assumptions for a discount rate, expected return on plan assets and a medical trend rate. The discount rate, defined as the rate of interest under which the FAS 106 plan's obligations could be settled, is intended to reflect market interest rates at the time of valuation. The expected ROR is a long-term assumption used to calculate the expected investment income on the fair value of OPEB assets. These

assets are determined at the beginning of the year and adjusted for benefit payments and contributions expected to be made during the year. The health care cost trend rate is calculated using health care cost trends, which included estimates of health care inflation, changes in health care utilization or delivery patterns, technological advances, and changes in the health status of plan participants.

The Company stated that the OPEB plan amounts included in its O&M expense were reduced by the amount allocated to capital amounts for UIL employees included in the plan. This was allocated across the UIL utilities based on the Massachusetts Formula and the amounts allocated to transmission or other non-distribution cost components. Response to Interrogatory FI-47.

In 2016, the OPEB retiree medical plan was redesigned to a post-65 health retirement account such that retirees would receive a credit to purchase insurance in a private health care exchange. The effect of this change was to reduce OPEB expense by approximately $2.0 million. This reduction was partially offset by an increase in net OPEB expense of approximately $0.8 million due to normal changes in assumptions and the updated mortality scale. The Company stated that like pension costs, OPEB costs are determined in accordance through ASC 715. These costs are developed on a calendar year basis which aligns with the UI OPEB plan years. These costs are developed annually in consultation with the Company's outside actuaries. Favuzza PFT, pp. 22 and 23.

Like pensions, calendar year 2016 is the first full year that UIL Holdings and its operating utilities, including UI, are part of a larger Avangrid organization. As a result, in setting the actuarial assumptions for 2016 and forward, UIL worked to ensure conformity with the other Avangrid companies. This approach is required by the accounting guidance in ASC 715 and ASC 805. Further, consistency of accounting policies across affiliated companies is part of the overall principles of GAAP. This is the same approach that UIL applied when it acquired CNG, SCG and BGC in 2010. Brief, pp. 64-66. The OCC and AG did not offer a position on the OPEB expense. UI updated the OPEB rate year expenses to reflect more current discount rates and asset values. The increase in OPEB expense is a result of decreasing the discount rate to 3.24% and decreasing the expected return on asset assumption to 7.75%. Late Filed Exhibit No. 3. As with pensions, the OCC opined that the historic year was more representative, given the fact that the market was better in 2016 than in 2015. Tr. 9/21/16, p. 1249.

For ratemaking purposes, the Authority finds that the expected return on asset assumption should be kept at 8.00% rather than decreasing it to 7.75%. The Authority based this on an actual earned return on OPEB assets of 7.8% as of August 2016. Therefore, the increase in the expected return on OPEB plan assets from 7.75% to 8.00% decreases OPEB expense by $25,000 on an annual basis.

12. Other Employee Benefits

The Company requested other employee benefits expense in the amount of $630,000 in the 2015 test year $675,000 in the rate year ending 2017 $693,000 in the rate year ending 2018 and $712,000 in the rate year ending 2019. This account contains

the expenses of flex credits, service/recognition awards, group life insurance/long term disability, and education reimbursements. Application, Schedule WP C-3.24.

Flex credits are the dollar amounts paid to employees that waive their medical and or dental insurance coverage. Response to Interrogatory FI-225. The OCC advocated a reduction in the flex credit expense and argued the 3% escalation factor that the Company used in the rate years was too high. The OCC applied a 1.75% escalation factor to the flex credits from the consumer price index (CPI) which the Company utilized in its filing to escalate certain costs, rather than the 3%. The OCC recommended that flex credits be reduced by $7,000, $11,000 and $15,000 in the rate years 2017, 2018 and 2019, respectively. Brief, p. 48. The Company and AG did not address flex credits in their respective briefs.

The Authority finds that a better methodology for potential increases in the flex credits is adjusting for inflation as measured by CPI of 1.75%. This was used by the Company in its budgeting for the rate years 2017 through 2019 and is in keeping with the OCC's adjustment methodology. Late Filed Exhibit No. 62. This adjustment produced a reduction of $7,000 in the 2017 rate year, $11,000 in rate year 2018 and $15,000 in rate year 2019.

13. Residual Operations and Maintenance

The Company's residual O&M included meals, materials and supplies, office supplies, safety apparel, publications and similar accounts. Residual O&M is a portion of the other direct O&M costs of the SAP account grouping. Response to Interrogatory FI-84. The Authority examined the group of residual accounts starting with the test year and each of the three rate years. The Authority's analysis centered on what was included in each individual account, whether the expenses were adjusted elsewhere in the Application, and the probability that inflation in the general economy would affect that account.

UI explained that Residual O&M expense is in essence a "catch-all" expense category that is comprised of expense items that are not specifically associated with another identified C-Schedule. The Company gave as an example Account No. 590505 General-Safety Apparel, which was included in residual O&M because the costs in that account are not identified in a stand-alone category of the other C-Schedules. These costs include safety apparel required by union contract and for other employees who work in proximity to energized equipment. Tr. 9/13/16, pp. 297 and 298. Similarly, residual O&M includes costs for publications that include the purchase of up-to-date safety codes, manuals and distribution standards for the Company's operating personnel. Response to Interrogatory FI-210. The Company made the following reductions to Residual O&M:

Operating Expense Adjustment	Rate Year 2017 Adjustments	Rate Year 2018 Adjustments	Rate Year 2019 Adjustments
Utilities Update	($114,000)	($114,000)	($111,000)
Meals	($100,000)	($100,000)	($100,000)
Bank Fees	($133,000)	($133,000)	($133,000)
Remove Debt Issuance Amortization	($49,000)		
Total	($396,000)	($347,000)	($344,000)

Late Filed Exhibit No. 3, p. 1.

The Authority concurs with the Company and adopts its adjustments to Residual O&M expenses as stated.

The OCC took exception to some of the accounts that the Company included in its residual O&M expense and identified several accounts where rate year increases were a concern. The OCC made an adjustment of -5.76% to these accounts, which is the average of the budget to actual variance of the total O&M costs for 2013-2015. Brief, pp. 48 and 49.

The Authority also found other expenses that have unreasonable increases such as materials expense – stock, general uniforms, general office supplies and expenses and stores loader. To adjust these expenses, the Authority adopted the OCC's adjustment methodology for these accounts from 2013-2015. Late Filed Exhibit No. 61. In keeping with OCC's adjustment methodology, the Authority adjusted the expenses by lowering each expense by -5.76% each year. Total Authority adjustments are $185,000 ($98,000 + $19,000 + $15,000 + $53,000) for rate year 2017, $188,000 ($95,000 + $20,000 + $15,000 + $58,000) for rate year 2018 and $188,000 ($94,000 + $20,000 + $15,000 + $59,000) for rate year 2019. These adjustments produced the following adjusted total Residual O&M expense for each of the three rate years:

Late File 3 Revised Schedule 3.28 A	Residual O&M Expense	Authority Adjustments	Total Adjusted Residual O&M Expense
Rate Year 2017	$2,026,000	$185,000	$1,841,000
Rate Year 2018	$1,973,000	$188,000	$1,785,000
Rate Year 2019	$1,892,000	$188,000	$1,704,000

14. Income Taxes - Federal Corporate Tax Rate

The OCC requested that the Authority include in this Decision a directive to reopen the instant proceeding in the event that the newly elected administration reduces the corporate tax rate from 35% to 15%. OCC Written Exceptions, p. 31.

The Authority considers the OCC's recommendation to be speculative. The Authority employs currently effective income tax rates in this proceeding. If income tax rates change in the future, which materially impacts the revenue requirement allowed herein, the Authority may reopen this proceeding.

15. Expenses Summary

As discussed in the preceding sections, the table below summarizes adjustments to the Company's proposed expenses:

Summary of Expense Adjustments ($000)

Descriptions	2017	2018	2019
Advertising Expense	($ 155)	($ 215)	($ 221)
Membership Dues	(103)	(106)	(107)
Outside Service – Line Clearance	(420)	(418)	(417)
Uncollectible Expense	(247)	(246)	(245)
Reconnect Service Fees	(434)	(416)	(397)
Travel Education and Training Expense	(204)	(219)	(227)
Incentive Expense	(343)	(195)	(140)
Corporate Service Charges	(3,258)	(6,117)	(9,304)
Residual O&M	(185)	(188)	(188)
Amortization Expense	(3,527)	(8,048)	(12,578)
Depreciation Expense	(11,945)	(11,309)	(11,808)
Benefit Expense	(1,316)	(1,103)	(1,263)
Allowed UPZ O&M Expense	13,000	13,800	14,000
Total Expense Adjustments	**($ 9,317)**	**($14,780)**	**($22,895)**

D. COST OF CAPITAL

1. Rate of Return

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. Financial Condition

Moody's Investor Services (Moody's) upgraded the long-term issuer credit rating for UI in January 2014 from Baa2 to Baa1 (stable). In addition, in April 22, 2016, Standard & Poor's (S&P) upgraded UI's issuer credit rating from BBB to BBB+ / Stable. This upgrade was in conjunction with S&P's upgrade of Iberdrola S.A. (Iberdrola) and Iberdrola U.S. subsidiary, Avangrid, Inc. (Avangrid), which is the utility holding company

that now owns UI. Fitch IBCA (Fitch) rated the Company BBB+ / Stable. These rating actions indicate that UI's investment risk has declined. The ratings are strong for the electric utility services sector. Responses to Interrogatories FI-95, FI-96, FI-97, FI-119, FI-250, OCC-234 and OCC-235, Attachment 1 and Attachment 7; Woolridge PFT, pp. 8 and 9.

Iberdrola's senior unsecured credit rating is currently BBB+, Baa1 and BBB+ from S&P, Moody's and Fitch, respectively. Response to Interrogatory FI-101. The Company stated that as of December 31, 2015, the risk factors associated with UI are embedded in the risks associated with Avangrid. Responses to Interrogatories FI-245, FI-262 and OCC-229. As a general rule, a subsidiary company cannot earn a higher credit rating than its parent company. Given that the Company's credit ratings are equal to Iberdrola and are also embedded to the risks associated with Avangrid, it is unlikely that UI would obtain a credit rating upgrade without Avangrid being granted one.

The Company projected several financial ratios that are typically reviewed by credit rating agencies for 2017, 2018 and 2019 valued at December 31, under several scenarios including the Company's proposed 9.92% ROE, the current 9.15% ROE, an 8.92% ROE and the OCC's proposed 8.5% ROE. The Authority compiled in the tables below the effects of the Company's 9.92% ROE as compared to the OCC's 8.5% ROE to examine the implications for possible credit rating ramifications.

ROE: 9.92%, Company Proposal	**2017**	**2018**	**2019**
Funds from Operations (FFO) to Interest Coverage	4.9x	6.1x	5.1x
FFO to Total Debt	20.0%	26.4%	21.6%
Total Debt to Total Capital	49.3%	49.0%	48.6%

Response to Interrogatory FI-99, Attachment.

ROE: 8.50%, OCC Proposal	**2017**	**2018**	**2019**
FFO to Interest Coverage	4.8x	5.9x	4.9x
FFO to Total Debt	18.9%	25.0%	20.1%
Total Debt to Total Capital	49.8%	50.0%	50.0%

Late Filed Exhibit No. 36, Attachment.

Based on the above computations, the credit rating ramifications of the two ROE recommendations is small. Clearly, the 8.5% ROE shows some small deterioration to the financials, but the decline would not in and of itself result in a credit rating down-grade. On the other hand, the Company's proposed 9.92% ROE reflects modestly stronger financials but UI was unable to determine if a credit upgrade could be possible. Responses to Interrogatories FI-99 and FI-122; Late Filed Exhibit No. 36; Tr. 9/19/16, pp. 768-770. Subsequently, the Authority has confidence that an allowed ROE ranging from 8.5% to 9.92% would not likely change the credit ratings in any meaningful way, all else equal.

The Company suggested that higher credit ratings were correlated to a relatively lower cost of debt. Under the hypothetical of a one notch credit upgrade, the Company postulated that a reasonable expectation was a 2 to 5 basis point reduction to the cost of debt of a new issuance, possibly up to 25 basis points under the conditions of the 2008

financial crisis. Response to Interrogatory FI-100; Late Filed Exhibit No. 37; Tr. 9/19/16, p. 772; Tr. 10/5/16, pp. 272–274. The Authority concluded that even under the unlikely hypothetical scenario whereby the Company's proposed 9.92% ROE could bring in a one notch credit upgrade, the PURA does not find that a 2-5 basis point reduction to the cost of new debt warrants a reasonable trade-off to customers to bear a 9.92% proposed ROE, all else equal. The Company supplied other key financial metrics valued at year end, December 31. The forecasted figures for year-end 2017 through 2019 are computed based on UI's revenue requirement as proposed in the Application. Response to Interrogatory FI-123, Attachment.

Based on these data, it is clear that UI remained within the parameters of its credit ratings and based on the assumption of a 9.92% ROE, the forecasted years would for the most part, reflect even stronger results, all else equal. Irrespective of the strength of UI's individual financials, the Company's credit rating is tied to Avangrid and Iberdrola, thus UI's credit rating cannot rise above that of its parent companies respective ratings.

3. Capital Structure and Cost of Long-Term Debt

The Company proposed rates that are based on a capital structure consisting of a capitalization mix of 48% long-term debt to 52% common equity projected for December 31, 2016; forecasted long-term embedded cost of long-term debt rates of 5.31% in 2017, 5.14% in 2018 and 5.05% in 2019; a proposed ROE of 9.92% for the three rate years respectively; and a ROR on rate base (i.e., also referred to as weighted average cost of capital or WACC) of 7.72%, 7.69% and 7.71% for the three years, respectively. Late Filed Exhibit No. 40, Attachment 2; Company Brief, pp. 91 and 92.

Over the 2013 UI rate case years of 2013, 2014 and 2015, the Company's year-end common equity portion was 48.66%, 50.96% and 50.34%, respectively. Response to Interrogatory FI-106, Attachment. The Company stated its proposed common equity ratio of 52% was consistent with UI's current actual capital structure, as of June 30, 2016, which had 51.44% common equity. As UI does not have a formal process to review the target capital structure the Company relied on its expert witness' assessment of the capitalization mix to base its ratemaking capitalization mix proposal. Responses to Interrogatories FI-102 and FI-106; Tr. 9/19/16, pp. 776–779, 941. Subsequently, the Company's proposed capital structure comports with the equity-to-debt ratio of the proxy group developed by UI's witness, which is composed of 23 comparable EDCs (Company Utility Group). The mean of the Company Utility Group's capital structure is 53.46% common equity, slightly above UI's proposed common equity ratio of 52%. The Company opined that a common equity ratio of 52% will improve its credit metrics and its ability to access the capital markets at a reasonable cost. The Company also noted that the Authority has also accepted common equity ratios of 52% for UI's sister companies, CNG and SCG. Bulkley PFT, pp. 57 and 58; Responses to Interrogatories FI-102, FI-104, FI-105 and FI-246; Tr. 9/19/16, p. 941; Brief, pp. 92 and 93; Reply Brief, p. 55.

For the 2013 UI rate case, the Company proposed a ratio of 50% long-term debt to 50% common equity (50%-50% capitalization mix) for ratemaking purposes and indicated this mix would be its target capitalization mix. Response to Interrogatory FI-106; Tr. 9/19/16, pp. 775 and 776. The Authority adopted the 50%-50% capitalization

mix for ratemaking in the 2013 UI Rate Case Decision. The Company also indicated it could reduce its equity ratio to 50% by paying UIL that portion of its retained earnings that would reduce its equity ratio from the actual to 50%. Late Filed Exhibit No. 39; Tr. 9/19/16, pp. 784 and 785.

The OCC proposed rates that would be based on a 50%-50% capitalization mix, long-term embedded cost of long-term debt rates of 5.35% in 2017, 5.27% in 2018 and 5.32% in 2019, a proposed ROE 8.50%, and a resulting WACC of 6.90% in 2017, 6.79% in 2018 and 6.67% in 2019. According to the OCC, the Company's proposed capital structure has a higher common equity ratio and lower financial risk than other electric utilities. Brief, pp. 77 and 78. The OCC's rationale for the 50%-50% capitalization mix was finding that the average common equity ratios of the OCC's proxy group of 28 EDCs (OCC Utility Group) and Company Utility Groups were 47.1% and 47.4% equity respectively and the average common equity ratio approved by state regulatory commissions in electric utility rate cases was 49.54% (30 rate cases in 2015 and 47.74% in 2016 (16 rate cases).[6] The 50%-50% capitalization mix was proposed by the Company and adopted by the Authority in the 2013 UI Rate Case Decision. Woolridge PFT, p. 33; Brief, p. 85. The OCC stated that the relevant matter is financial risk. Since it is the holding companies that have common stock outstanding and not the operating companies, the financial risk is at the holding company level. Tr. 9/19/16, pp. 970 and 971. Overall, the OCC recommended that a combination of the industry averages and credit rating provide the appropriate benchmarks for the ratemaking capital structure and not the Company's managerial activities at the operating level. Response to Interrogatory FI-263.

The AG recommended that the Authority reject the Company's proposed 52% common equity for ratemaking as UI's current approved debt to equity ratio is the 50%-50% capitalization mix. The AG indicated that the proposed 52% common equity is economically inefficient and does not balance the interest of the Company and its customers. The 52% common equity proposal is also more costly for customers to support as the cost of equity is greater than the cost of debt. Additionally, the AG affirmed that the UI proposed capitalization ratio is higher than the median common equity ratios for the proxy companies in the OCC Utility Group and the Company Utility Group, which are 47.1% and 47.4%, respectively. Woolridge PFT, Exhibit JRW-4. Also, UI does not adequately explain why 52% is now appropriate as compared to the 50% common equity ratio that was approved in the 2013 UI Rate Case Decision. Lastly, the AG stated that it is not clear how a higher equity based capital structure could lower UI's external cost of debt since capital costs and credit ratings are ultimately dependent on the its parent companies, Avangrid and Iberdrola. Brief, pp. 43 and 44.

The Company argued that the OCC's proposed capital structure of 50% common equity to 50% long-term debt is flawed since the OCC is calculating the common equity ratio at the holding company level instead of the operating company level. Woolridge PFT, p. 35; Tr. 9/19/16, p. 951; Brief, p. 109. Since UI is a separate legal entity and has its own capital structure, that capital structure should serve the basis for review not UIL Holdings Corporation, Avangrid or other holding companies. Additionally, the Company

[6] Reported in Regulatory Research Associates (RRA), Regulatory Focus, January and July, 2016 editions.

indicated the ring-fencing provisions of the 2015 Iberdrola Change of Control Decision allows for UI's financial integrity to be protected and maintained as a stand-alone company. Response to Interrogatory FI-108; Brief, p. 110; Reply Brief, p. 55.

4. Authority Analysis of Capital Structure

The Authority accepts the Company's revised proposed long-term embedded cost of debt rate of 5.31% in 2017, 5.14% in 2018 and 5.05% in 2019 based on the incorporation of downward trending 10 Year US Treasury Rates (UST-10) and 30 Year US Treasury Rates (UST-30) used to forecast those years. Late Filed Exhibit No. 40, Attachment 2.

As stated previously, the Company received credit rating increases from Moody's, S&P and Fitch after the merger with Iberdrola. Typically higher credit ratings allow for greater and not less financial leverage, all else equal. Regarding the Company's proposal for a 52% common equity to 48% long-term debt ratemaking capitalization mix as opposed to maintaining the 50%-50% capitalization mix, the Authority examined several issues. The primary consideration is the allowed ratemaking capitalization mix used to compute the Authority's allowed ROR/WACC. When the Authority determines the cost of debt and the cost of equity, it looks to debt and equity markets. The cost of debt is directly measurable based on past actual debt issuances. In this proceeding, the Authority incorporated forecasted interest rates for the three issuances to be done over the proposed rate years. The cost of equity is much more difficult to estimate and involves a review of various cost of capital models to gauge investor behavior. Thus, in both cases the Authority is looking to capital markets for guidance.

The Company's organizational structure depicts UI as an operating company subsidiary of Avangrid, which is a subsidiary of the ultimate parent company, Iberdrola. UI is several organizational layers below Avangrid. Response to Interrogatory FI-132, Attachments. The Company claimed that the actual capitalization mix at the operating company matters for ratemaking purposes. According to UI, equity contributions to UI are made at the recommendation of UI management to Avangrid, and these recommendations would require the approval of the Avangrid BOD and approval of each intermediary subsidiary company's BOD. Response to Interrogatory FI-109.

The Authority recognizes that changes to the UI capitalization mix are based on decisions and approval at various management levels and reflect management choices and decisions related to the allocation of such items as common equity, dividend payments and retained earnings. The mathematics of the WACC calculation affirms that the greater the proportion of common equity, the greater the WACC, all else equal. The practice of balancing the interests of the Company in conjunction with fairness to the customers implies the Authority must broaden its review outside of the management decisions at the operating company level. The Authority finds that the same principal of looking to the capital markets for guidance for the cost of debt and ROE should also apply to establish the ratemaking capital structure. When establishing the proxy companies used to measure the cost of equity, the relevant companies are those that are publicly traded, not the operating companies. Therefore, the OCC is correct that it is the holding company level that matters since the cost of capital methods are relying on capital market data and not decisions made by individual company management.

The OCC Utility Group and Company Utility Group average common equity ratios are 47.1% and 47.4%, respectively. The PURA revised Woolridge PFT, Exhibit JRW-4.1 to reflect the companies discussed below in the Authority Proxy Group. The Authority Utility Group's mean and median common equity ratios are 46.3% and 47.1%, respectively. The Authority Proxy Group reflects slightly lower risk than the OCC Utility Group and Company Utility Group. The Authority accepts the OCC and the AG proposed 50%-50% capitalization mix for ratemaking purposes.

5. Cost of Common Equity

a. Introduction

The Company retained the services of a cost of capital expert, Ms. Bulkley to review changes in financial and economic markets and to provide a recommended ROE. The proposed 9.92% is based on a range of 9.92% to 10.35%. According to the Company, ROEs in litigated cases for electric utilities in 2016 ranged from 9.50% to 9.90% and the average return over that time period is 9.70%. Its proposal is 22 basis points within the 2016 average ROE. The Company's methods included the Discounted Cash Flow (DCF) Model, Capital Asset Pricing Model (CAPM) and a Risk Premium approach of the Bond Yield plus Risk Premium (BY + RP). Bulkley PFT, pp. 3 and 8; Supplemental Response to Interrogatory FI-261, Attachment; Brief, pp. 92; 94 and 95.

The OCC also retained the services of a cost of capital expert Dr. Woolridge, who proposed an 8.5% allowed return and overall RORs of 6.90% in rate year 1, 6.79% in rate year 2 and 6.67% rate year 3, respectively. The OCC's methods included the DCF model and CAPM, with significantly greater weight allocated to the DCF model. Brief, p. 2.

The AG did not retain the services of a cost of capital expert and generally supported the OCC's cost of capital testimony and its recommended ROE of 8.5%. Woolridge PFT, p 4. Based on the AG's review, capital costs for utilities remain at historically low levels. Moreover, utilities have been earning on average returns of 8% to 9%, and utility stock returns have outperformed the S&P 500. Tr. 9/19/19, pp. 961 and 62; Woolridge PFT, Exhibit JRW-7. Indeed, utility stock returns have outpaced the S&P 500 by a factor of three in 2016 to date. Tr. 9/19/16, p. 952. Simply put, returns in this range are more than adequate to attract investment capital and provide reasonable compensation to investors as required by Hope vs. Bluefield. In the event that the Authority incorporates a Capital Tracking Mechanism (CTM), the AG also recommended that the PURA explicitly reduce the Company's final authorized ROE explicitly to account for the CTM. This tracker would reduce risk and stabilize UI's revenue streams in years two and three of the rate plan. AG Brief, p. 42.

The Company criticized the OCC's proposed return, indicating it was too low and based on a flawed analysis. The Company also stated that the OCC's expert witness has a history of recommending ROEs below final authorized ROEs. Bulkley Rebuttal, pp. 4 and 31; Brief, p. 106. According to the Company, the OCC's ROE recommendations have consistently been in the 8.5% to 9% range. The OCC's 8.5% recommendation is below the range of allowed ROEs during the period of January 2013 to August 2016. In the opinion of the Company, ROE awards in other jurisdictions

provide benchmarks to assess the overall reasonableness and signals investors with respect to regulatory support for financial integrity, dividends, plant growth and fair compensation for business and financial risk. Finally, the DCF model is producing unreasonable results and the Authority should consider authorized returns in other jurisdictions. Tr. 9/20/16, p. 46; Reply Brief, pp. 45 and 46.

In response to that criticism, the OCC stated that authorized ROEs for electric utilities have declined to an average of 9.52% for the first half of 2016. The OCC suggested that the decline in authorized returns has lagged behind capital market cost rates. In other words, authorized ROEs have been slow to reflect low capital market costs especially in recent years where, some state commissions are reluctant to authorize ROEs below 10%. Furthermore, the OCC stated that the 2013 UI rate case, with the 9.15% allowed ROE, was cited as a credit positive decision by Moody's and the Company attracted a $4 billion acquisition premium in its merger with Iberdrola. Woolridge PFT, pp. 68 and 69; Reply Brief, pp. 17 and 18.

The OCC similarly criticized the Company's methods indicating that the 9.92% recommendation was too high due to a number of errors and flaws. The OCC cited the following errors and flaws for the DCF equity cost rate estimates: 1) the Company's asymmetric elimination of 50% of low-end DCF results; 2) the excessive use of the overly optimistic and upwardly biased EPS growth rate forecasts from Wall Street analysts; and 3) the use of a new DCF model, the projected constant-growth DCF model, where model inputs are projected into the future. For the Company's CAPM and RP approaches, the projected interest rates and market or equity risk premiums (ERP) are excessive and not reflective of current and prospective market fundamentals. Lastly, the Company erroneously included a flotation cost adjustment to the equity cost rate for UI. Woolridge PFT at 73; Brief, pp. 95 and 96.

The Authority notes that both recommendations have flaws. A review of each witness' ROE recommendation and corresponding allowed return for the period 2013-2016 indicates that there is a wide variation between their recommendations and the corresponding returns. Response to Interrogatory UI-006, Attachment 1; Bulkley Rebuttal Testimony, p. 31; Tr. 9/19/16, pp. 802, 803, 958 and 959; Response to Interrogatory OCC-241; Late Filed Exhibit No. 42; Tr. 9/19/16, p. 807.

The Authority's review indicates that the OCC's recommendations range between 8.5% and 9% over the 2013 to 2016 and appears to be between 50 and 75 basis points below authorized ROE on average. The Company's recommendations mostly range between 10.4% and 10.5% and are between 75 and 100 basis points above the authorized ROEs on average. Bulkley Rebuttal Testimony, p. 30; Late Field Exhibit No. 42; Tr. 10/5/16, pp. 1652-1660; Brief, p. 106. There is a wide disparity in proposals that the Authority must evaluate when determining an allowed ROE that is both just and reasonable to the Company and to customers.

b. Financial Indicators, Interest Rates and Authorized ROEs

The Company provided financial and economic statistics related to Gross Domestic Product, 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 the most recent quarter or month, whichever is most relevant. Response to Interrogatory FI-155, Attachment.

According to the OCC, interest rates and capital costs have decreased in reaction to Federal Reserve (FED) monetary policy and changes in the economy. In the second half of 2013, the 30-Year US Treasury Yield (UST-30) was in the 3.5% to 4.0% range. These rates declined to below 2.5% over the next year despite the Federal Open Market Committee (FOMC) announcement to wind down its Quantitative Easing III (QEIII) program. Interest rates increased in 2015 to above 3.0% in anticipation of an increase in the federal funds rate. In December 2015, the Federal Reserve increased its target rate for federal funds to 0.25% to 0.50% from 0% to 0.25%. Nonetheless, interest rates declined again to below 2.5% by the summer of 2016. According to the OCC, these yields have declined primarily due to continued slow economic growth and low inflation. Woolridge PFT, pp. 6 and 7, Figure 1; Responses to Interrogatories FI-264, FI-265, FI-266, FI-267, FI-268, FI-269 and FI-270; Brief, pp. 82 and 83; Tr. 9/19/16, pp. 963-969.

Based on the OCC's review, authorized ROEs for electric utilities have decreased since the 2013 UI rate case. Specifically, these authorized ROEs have declined from 9.80% in 2013, to 9.76% in 2014, to 9.58% in 2015, and to 9.52% in the first half of 2016. Woolridge PFT, pp. 7 and 8; Brief, pp. 83 and 84, Figure 2.

c. Proxy Groups

One hundred percent of UI's $888 million revenue was derived from electric utility services. Revised Response to Interrogatory FI-178. The Company stated that it applied screening criteria that it found consistent with the criteria applied by the Authority in the CL&P Rate Case Decision. Specifically, the Company began with a group of 45 companies that Value Line Investor Service (Value Line) classified as electric utilities and applied the following screening criteria to exclude companies that:

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

The Company's screening selection process yielded the following group of 23 companies: ALLETE, Inc.; Alliant Energy Corporation; Ameren Corporation; American Electric Power Company Inc.; Consolidated Edison, Inc.; DTE Energy Company; Edison International; El Paso Electric Company; Entergy Corporation; Eversource Energy; Great Plains Energy Inc.; IDACORP, Inc.; NorthWestern Corporation; OGE Energy Corporation; PG&E Corporation; Pinnacle West Capital Corporation; PNM Resources Inc.; Portland General Electric Company; PPL Corporation; SCANA Corporation; Westar

Energy, Inc.; Wisconsin Energy Corporation (i.e., WEC Energy Group); and Xcel Energy Inc. (collectively, Company Utility Group). Bulkley PFT, pp. 19-21; Brief, p. 95.

The OCC's screening selection process included the following criteria:

1. At least 50% of revenues from regulated electric operations as reported by AUS Utilities Report;
2. listed as an Electric Utility by Value Line and listed as an Electric Utility or Combination Electric & Gas Utility in AUS Utilities Report;
3. an investment grade issuer credit rating by Moody's and S&P;
4. has paid a cash dividend in the past six months, with no cuts or omissions;
5. not involved in an acquisition of another utility, the target of an acquisition, or in the sale or spin-off of utility assets, in the past six months; and
6. analysts' long-term EPS growth rate forecasts available from Yahoo, Reuters, and/or Zacks.

The OCC's analysis yielded the following group of 28 companies. ALLETE, Inc.; Alliant Energy Corporation; Ameren Corporation; American Electric Power Co.; Avista Corporation; Black Hills Corporation; Consolidated Edison, Inc.; CMS Energy Corporation; Dominion Resources, Inc.; Duke Energy Corporation; Edison International; El Paso Electric Company; Entergy Corporation; Eversource Energy; FirstEnergy Corporation, IDACORP, Inc.; MGE Energy, Inc.; NorthWestern Corporation; OGE Energy Corp.; Otter Tail Corporation; PG&E Corporation; Pinnacle West Capital Corp.; PNM Resources, Inc.; Portland General Electric Company; SCANA Corporation; Southern Company; WEC Energy Group, and Xcel Energy Inc. (collectively, OCC Utility Group). Woolridge PFT, pp. 31 and 32, Exhibit JRW-4; Brief, pp. 86 and 87. The OCC also performed its cost of capital methodology on the Company Utility Group as a means to provide an apple to apples comparison between the Company and OCC approaches. Woolridge PFT, pp. 75-93.

The OCC indicated that the median operating revenues and net plant among members of the OCC Utility Group are $5,153.6 million and $13,925.0 million, respectively. The OCC Utility Group receives 81% of its revenues from regulated electric operations, has BBB+ and A3/Baa1 issuer credit ratings from S&P and Moody's respectively, a current common equity ratio of 47.1%, and an earned return on common equity of 9.4%. The OCC also indicated that the Company Utility Group statistics were similar with median operating revenues and net plant among the members at $5,926.1 million and $17,867.0 million, respectively. The Company Utility Group receives 81% of revenues from regulated electric operations, has an average BBB+ issuer credit rating from S&P and an average A3/Baa1 long-term rating from Moody's, a current common equity ratio of 47.4%, and an earned return on common equity of 9.3%. The investment risk credit ratings provide a means to measure a company's risk. UI's issuer credit rating is BBB+ according to S&P and Baa1 according to Moody's. UI's S&P rating is equal to the average S&P rating for the OCC Utility Group and in line with the average S&P rating for the Company Utility Group (Baa1 vs. A3/Baa1). Subsequently, UI's investment risk is generally in line with the investment risk of the proxy groups. The OCC's risk analysis of the two proxy groups using five different risk measures (i.e., beta, financial strength, safety, earnings predictability and stock price stability) from Value Line shows that the

two proxy groups are similar in risk. Woolridge PFT, pp. 32 and 33; Exhibit JRW-4; Brief, pp. 87 and 88.

d. Other Factors

i. Flotation Cost

The Company stated that flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting and other issuance costs. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." A utility's flotation costs are incurred prior to the test year, but remain part of the cost structure that exists during the test year and beyond. These costs should be recognized for ratemaking purposes. Therefore, this cost is appropriate regardless of whether an issuance occurs during, or is planned for, the test year because failure to allow recovery of flotation costs may deny UI the opportunity to earn its required ROR in the future.

Prior to the merger with Avangrid, UIL closed on equity issuances of approximately $525 million and $214 million (for a total of 26 million shares of common stock) in September 2010 and September 2013, respectively. The Company proposed a 0.15% (i.e., 15 basis points) flotation cost adjustment. This was based on the costs of issuing equity that were incurred by UIL in its two most recent common equity issuances. Those issuance costs were applied to the Company Utility Group. The Company also noted that in the 2013 UI rate case, the Authority allowed an adjustment for flotation costs of 20 basis points. Response to Interrogatory FI-118; Bulkley PFT, pp. 38, 40 and 41; Exhibit AEB-2; Brief, pp. 95 and 101; Reply Brief, p. 52.

According to the OCC, the equity flotation cost adjustment is not necessary to prevent dilution to existing shareholders. The OCC contended that a flotation cost was not warranted and argued financial theory would suggest a flotation cost reduction. First, there are no identified current flotation costs for UI. The citation of equity issues in 2010 and 2013 means that UI was requesting annual revenues in the form of an adjustment to the ROE to account for past, and not future, flotation costs. Second, flotation costs associated with equity issuance costs are not recoverable like bond flotation costs where the amortization of bond flotation costs is included in annual financing costs. However, this concept of recovery is incorrect for several reasons. For example, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward. Woolridge PFT, pp. 88; 90-93; Brief, p. 104; Reply Brief, p. 18.

ii. Weighting of Employed Methods

The OCC relied primarily on the results of the DCF model. Woolridge PFT, pp. 67 and 68; Brief, p. 94. The Company proposed that more weight be given to the CAPM results in this case than have been given historically. At minimum the CAPM results should be considered in conjunction with the DCF results given current market conditions and the current low interest rate environment. The Company cited to two regulatory commissions that have done so in recent years. For example, the Surface

Transportation Board, which regulates the U.S. railroad industry, in January 2009 issued a decision including an equal weighting of the CAPM and the DCF results to harness the strengths of both models while minimizing their respective weaknesses. Furthermore, the Company indicated that in Opinion No. 531, the Federal Energy Regulatory Commission (FERC) recognized that the inputs to the DCF model have been underestimating the ROE. Although, the FERC had traditionally relied on the midpoint or median of the range of results from the DCF model, the FERC indicated that it would look to other ROE estimation methodologies to inform its judgment as to where, within the zone of reasonableness, the ROE should be set. In particular, the FERC found risk premium-based approaches informative, including the CAPM. Bulkley PFT, pp. 27-31.

e. Discounted Cash Flow Model

The Company and the OCC separately performed a DCF Model. The DCF model is a market-based financial model that 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 (i.e., ROE). In its simplest form, the DCF consists of a current cash dividend yield (dividend) and a future price appreciation (growth) of the investment. 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.

The constant growth DCF model requires the following assumptions: a constant growth rate for earnings and dividends; a stable dividend payout ratio; a constant price-to-earnings ratio; and a discount rate greater than the expected growth rate. The Company and the OCC used the constant growth from of the DCF model. Bulkley PFT, p. 33; Woolridge PFT, p. 47; OCC Brief, p. 88.

The OCC cautioned that one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and the expected growth rate). One must also consider recent firm performance, in conjunction with current economic developments and other information available to investors to accurately estimate investors' expectations. Woolridge PFT, pp. 45–48.

i. Dividend Yield

The Company's dividend yield was based on its proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended March 31, 2016. According to Company, the averaging period should also be reasonably representative of expected capital market conditions over the long-term. The Company use of the 30-, 90-, and 180-day averaging periods reasonably balances

those considerations. The Company's spot dividends (Do) were derived from Bloomberg Services as the last paid dividends. The Company then applied one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time. Bulkley PFT, pp. 33 and 34; Response to Interrogatory FI-165.

The Company indicated that dividend yields over 2015 have been historically low. The average dividend yield of the 30-day DCF model, which the Authority has typically relied on, was 3.4% as of March 16, 2016. This is below dividend yields of the Company Utility Group over the last 15 years. The Company stated that these dividend yield should be considered with caution. Bulkley PFT, p. 97; Brief, p. 97; Tr. 9/19/16, pp. 882 and 883. The Company suggested the primary driver of the low DCF results was the low dividend yields of the electric industry. Historically electric dividend yields were 3.5%, but the OCC's calculations used 3.2% dividend yields, 20 basis points below the historic average. Woolridge PFT, Exhibit JRW-10, p. 1; Reply Brief, p. 48.

The Company concurred that in the Application, the use of the 90-day and 180-day averaging stock price periods resulted in higher DCF results. The mean high of the Company's results would be reduced to 9.92% from 10.92% if the 90-day and 180-day averaging periods were removed. Response to Interrogatory FI-164. The Company criticized the OCC's DCF analysis as flawed indicating that the OCC's use of the average dividend yield and a selected growth rate does not reflect the risks of the proxy companies. The OCC's summary level analysis does not allow the Authority to consider the appropriate treatment of outliers. Since the OCC's growth rate is selected rather than relying on individual company growth rates, the Company claims that the OCC-indicated ROEs are influenced by stock market analyst judgment and not market expectations. Also, the OCC's current dividend yield is criticized as it is not reflective of current market conditions, which have bid up electric utility stock prices and driven dividend yields down. Bulkley Rebuttal, Exhibit AEB-Rebuttal-2; Woolridge PFT, Exhibit JRW-7, p. 2; Brief, pp. 106-108.

The OCC computed dividend yields for the companies in the OCC Utility Group and the Company Utility Group using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices ended July 29, 2016. Woolridge PFT, Exhibit JRW-10. The OCC adjusted the dividend yield by one-half of the expected growth so as to reflect growth over the coming year. The DCF equity cost rate (K) is computed as: $K = [(D/P) * (1 + 0.5g)] + g$. For the OCC Utility Group, the average of the median dividend yield of 3.30% was used. For the Company Utility Group, the average of the median dividend yields of 3.30% was used. Woolridge PFT, pp. 47-50; Exhibit JRW-10; Brief, p. 88. The OCC recommended using current and not projected stock prices in the DCF analysis as stock prices should reflect the risk and return preferences of investors and not an upward bias from a flight to quality as posed by the Company. Woolridge PFT, p. 55; Bulkley PFT, p. 7; Responses to Interrogatories FI-145 and FI-283.

The Company indicated that using consensus estimates of the forecasted dividend yield such as that available in Value Line: Summary & Index's column (f), Estimated Dividend Yield Next 12 Months (Value Line Column f) would be more

appropriate as a measure of market expectations. Response to Interrogatory FI-163; Tr. 9/19/16, p. 879. Since Value Line is aware of the timing of dividends, the OCC supported the use of Value Line Column f in place of adjusting the spot dividend yield by one-half the growth rate. Responses to Interrogatories FI-278 and FI-279.

ii. Growth Rates

According to the Company, the constant growth form of the DCF model assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share (EPS), dividends per share (DPS) and book value per share (BVPS) all grow at the same constant rate. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the Constant Growth DCF model. The Company used three sources of long-term earnings growth rates: Zacks Investment Research; Thomson First Call (provided by Yahoo! Finance or Yahoo); and Value Line. Buckley PFT, pp. 34-36; Response to Interrogatory FI-167.

The Company relied solely on stock market analysts' estimates of EPS growth as company earnings are the fundamental driver of a company's ability to pay dividends. Since dividends are based on management decisions, dividend growth rates are less likely than earnings growth rates to reflect accurately investor perceptions of a company's growth prospects. Dividend growth can only be sustained by earnings growth. Bulkley PFT, pp. 34 and 35; Response to Interrogatory FI-166. Although Value Line provides five-year growth estimates of EPS, DPS and BVPS, the Company did not use these growth estimates as EPS growth rates are the most relevant rates for stock price valuation. Since Reuters and Yahoo are both owned by Thompson, the Company recommended using only one of these growth rates to avoid double counting. Bulkley PFT, pp. 35-37; Responses to Interrogatories FI-162, FI-167 and FI-168; Late Filed Exhibit No. 44; Tr. 10/5/16, pp. 1664 and 1665; Brief, pp. 96 and 97.

The constant growth DCF model assumes that 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: Value Line's historic growth rates for EPS, DPS, and BVPS; Value Line's projected growth rate estimates for EPS, DPS, and BVPS; 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 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 primary driver, 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 reviewed averages of all historical growth rates to establish a base growth rate. Although the OCC did not eliminate any figures, historical growth rates were given very little weight, if any. Regarding the use of retention growth rates, the OCC did not use the terminal growth component as it would be reflected in the growth rates. Furthermore, the retention growth rates are implicitly considered by equity analysts. Although analyst projected EPS growth rates tend to be overly optimistic and upwardly biased, in this testimony, growth rates in the upper end of the range of growth

rate indicators were used. Woolridge PFT, pp. 56 and 57; Exhibit JRW-10, p. 6; Responses to Interrogatories FI-281, FI-282, FI-284, FI-285, FI-286, UI-005; Brief, p. 89.

Based on its analysis the OCC indicated that 5.0% was the appropriate growth rate for the OCC Utility Group and 5.1% for the Company Utility Group. Woolridge PFT, pp. 57 and 58; Brief, p. 90. The OCC suggested that the Company's DCF estimates are not credible because UI eliminated 50% of the constant-growth DCF indicated-results based on the its belief that the DCF estimates were too low and because it placed excessive reliance on the overly optimistic EPS growth rate forecasts of Wall Street analysts and Value Line. Woolridge PFT, p. 10.

iii. DCF Results

The Company recommended an ROE result of 9.92%. This recommendation was developed by excluding the results for certain proxy companies based on a 375 basis points threshold to develop a low end to screen individual DCF estimates. The basis for the 375 basis point threshold was the CL&P Rate Case Decision at p. 129. The effect of applying the 375 basis point screen was to eliminate ROEs below 8.22%. In the current case, the application of that screen eliminated ROEs below 9.02%. Bulkley PFT, p. 41; Responses to Interrogatories FI-171 and FI-172. The Company contended that the use of the 375 basis point factor to the DCF results would narrow potential areas of dispute. Bulkley PFT, p. 41; Responses to Interrogatories FI-171 and FI-172; Tr. 9/19/16, pp. 892-896.

The Company provided an exhibit to demonstrate that reducing the threshold from 375 basis points to 100 basis points resulted in a lower threshold of 5.16%, which is below the Company's cost of debt and lower than that provided for in the CL&P Rate Case Decision. Late Filed Exhibit No. 44, Attachment 1; Brief, p. 98; Response to Interrogatory FI-253. Contrary to the OCC's recommendation to totally eliminate DCF results screening and replace it with the use of the median, the Company supported the Authority's use of a DCF screening mechanism and reiterated use of the 375 basis point low end screen proposed. Reply Brief, p. 50.

The Company's constant growth DCF model produces a range of mean results from 8.95% to 11.26%, including the flotation cost adjustment. The table below summarizes the Company's results.

Company Constant Growth DCF Results:

	Mean Low	Mean	Mean High
30-Day Average Price	8.95%	9.92%	10.92%
90-Day Average Price	9.15%	10.12%	11.13%
180-Day Average Price	9.29%	10.26%	11.26%

Bulkley PFT, p. 42; Exhibit AEB-1; Brief, pp. 95 and 96.

The Company's range of results for the constant growth DCF model was calculated using the minimum growth rate (i.e., the lowest of the First Call, Zacks, and Value Line earnings growth rates) for each of the proxy group companies for the low end. The high results were calculated using the highest growth rate for each proxy

group company. The mean results were calculated using the average growth rates from all three sources. The Company also proposed a projected constant growth DCF model. This DCF analysis relies on Value Line's projected average prices and dividends for the period from 2019-2021 and the five-year projected EPS growth rates. The projected constant growth DCF model results increase the ROE by 99 basis points (i.e., 10.91% vs. 9.92% shown in Bulkley PFT, in the ROE for the Company Utility Group). Bulkley PFT, pp. 42 and 43; Exhibit AEB-3. According to the Company, the purpose of the projected DCF analysis was to demonstrate that if utility stock prices return to levels projected by stock analysts, then there would be a change to the DCF model results. Response to Interrogatory FI-170.

The OCC highlighted three errors with the Company's DCF equity cost rate analysis. The first is the asymmetric elimination of low-end DCF results based on reliance on the 375 basis point screen from the CL&P Rate Case. Instead the OCC used the median (as opposed to the mean or average) as a measure of central tendency. The median is a statistically valid approach to deal with data when potential outliers can lead to the average or mean producing a distorted measure of central tendency. By revising the Company's DCF results to use the median rather than the 375 basis point screen and eliminating the 0.15% adjustment for flotation costs, the OCC restated the Company's DCF ROE results to be 8.64%, 8.82%, and 9.05%, which are approximately 125 basis points below those proposed by the Company. Woolridge PFT, pp. 74, 76-77; Exhibit JRW-13; Brief, pp. 96 and 97; Tr. 9/19/16, pp. 980 and 981.

The OCC clarified that based on its experience, the FERC presently uses the median and a cost to debt plus a 100 basis point screen on the indicated DCF results. Tr. 9/19/16, pp. 983 and 984. Other than the CL&P Rate Case Decision, there is no empirical evidence supporting the 375 basis point low-end filter. The only result of this filter is to eliminate a greater amount of ROE results on the low end rather than the high end. Had a median approach been used by UI, the Company DCF results would be in the 8.64% to 9.05% range. This finding was supported by the Company's own calculations when it was asked to recast its DCF results with a 100 basis point low end screen. That produced an average DCF result of 8.49% without flotation costs. Woolridge PFT, p. 78; Tr. 9/19/16, pp. 948 and 949; Late Filed Exhibit No. 4, Attachment 2 Revised, p. 1; Reply Brief, p. 15.

The OCC stated that another problem with the Company's DCF analysis is the sole reliance on Wall Street analysts' and Value Line's EPS growth rate estimates. Woolridge PFT, pp. 53-55. In contrast, the OCC incorporated additional measures of growth such as Value Line's DPS and BVPS growth rates and the retention growth rates. Woolridge PFT, pp. 53 and 54; Brief, p. 97. Finally, the OCC stated that the Company's Projected DCF Model is problematic as it computes a dividend yield using Value Line's projected stock price and dividends for the proxy companies for the years 2019-2021 and the current forecasted EPS growth rates of Zacks, Yahoo, and Value Line. This is a new and untested approach and involved a mismatch of data and eliminated 50% of the Company's low-end DCF results based on the 375 basis point screens. Woolridge PFT, p. 79; Brief, pp. 97 and 98. The OCC indicated that it was unaware of a projected DCF model nor any regulatory commissions that have employed such a model. Response to Interrogatory FI-290.

The indicated DCF ROE results of the Company's proxy companies are almost the same as the results of the OCC when applying the OCC's methodology to the Company's proposed inputs. The table below summarized the OCC's DCF-derived equity cost rates for both groups.

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
OCC Utility Group	3.30%	1.0250	5.00%	8.40%
Company Utility Group	3.30%	1.0255	5.10%	8.50%

Wooldridge PFT, p. 59; Exhibit JRW-10; OCC Brief, p. 91

f. Capital Asset Pricing Model

Both the Company and the OCC performed a CAPM analysis. The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate. The CAPM formula is Ke = Rf + β (Rm-Rf).

Where:
Ke = the required market ROE;
β = Beta coefficient of an individual security;
Rf = the risk-free rate of return; and
Rm = the required return on the market as a whole.

In this specification, the term (Rm – Rf) represents the market risk premium or equity risk premium (ERP). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by beta, which represents the risk of the security relative to the general market. Bulkley PFT, pp. 43 and 44; Woolridge PFT, pp. 59 and 60; Company Brief, p. 100.

The Company estimated the ERP based on the expected return on S&P 500 Index less the yield on the US Treasury bonds with 30-year maturities (UST-30). The Company calculated the expected return on the S&P 500 Index companies for which dividend yields and long-term earnings projections are available using the constant growth DCF model. Based on an estimated market capitalization-weighted dividend yield of 2.17% and a weighted long-term growth rate of 11.03%, the estimated required market return for the S&P 500 Index is 13.32%. Therefore, the implied market risk premium over the current 30-day average of the UST-30, and projected yields on the UST-30, range from 8.99% to 10.66%. The Company stated this approach was consistent with the approach that was accepted by the FERC in Order 531. Bulkley PFT, pp. 45 and 46; Exhibit AEB-5; Tr. 9/19/16, pp. 915-919. The Company clarified that the FERC is performing and considering the CAPM but not explicitly weighting it in the final allowed ROE. Tr. 9/19/16, pp. 925 and 926. Overall, the Company's 8.99% to 10.66% ERP range reflects forward looking market data. As such, the Company's method should be considered by the Authority. Reply Brief, p. 52. The Company's CAPM analysis produces a range of returns from 10.59% to 11.02%. Bulkley PFT, p. 49; Brief, pp. 95 and 100.

The OCC had two concerns with the Company's CAPM analyses including the long-term projected UST-30 yield of 4.33% and primarily, the excessive ERP. According to the OCC, the basis of the Company's approach is not realistic as UI estimated a high expected stock market return of 13.19% for the S&P 500 based on a dividend yield of 2.17% and an expected DCF growth rate of 11.03% for the S&P 500. This 11.03% expected growth rate is not consistent with historic and projected earnings growth rates for the U.S. which historically has been in the 5% to 7% range. Current projections for the U.S. growth rates are below historic rates and have slowed to 4% to 5% since the 2008 recession. Woolridge PFT, pp. 81-83; Response to Interrogatory FI-292; Brief, pp. 98-101.

The OCC's CAPM analysis used the yield on long-term U.S. Treasury bonds specifically UST-30 as the proxy for the risk-free rate of interest in the CAPM. The yield on UST-30 has been in the 2.25% to 4.0% range over the 2013–2016 time periods, currently at the bottom of this range. Given the recent range of yields and the possibility of higher interest rates, the OCC used 4.0% as the risk-free rate, or Rf. The OCC used the betas for the OCC Utility Group and the Company Utility Group companies as provided in Value Line. The beta for both groups is 0.70. Bulkley PFT, pp. 59, 61 and 62; Exhibit JRW-11; Brief, p. 92.

The ERP is equal to the expected return on the stock market (e.g., the expected return on the S&P 500, E(Rm) minus the risk-free rate of interest (Rf). The ERP is difficult to measure because it requires an estimate of the expected return on the market - E(Rm). The OCC used various approaches to measure the expected return on the market. For example, the OCC indicated the oldest approach often called the "Ibbotson approach" consists of a historical evaluation of stock and bond returns. This historical approach suggests the ERP is in the range of 5% to 7%. This method was criticized by various academics and an entire study and debate has evolved over the correct estimation of the ERP. Therefore, the OCC stated it is important to look at the entire body of evidence and debate surrounding the ERP. Overall, the OCC's methods include the results of: 1) the various studies of the Historic Ex Post risk premium; 2) Ex Ante ERP studies; 3) ERP surveys of CFOs, financial forecasters, analysts, companies and academics; and 4) the Building Blocks approach to the market risk premium (MRP). There are results reported for over 30 studies and the median MRP is 4.63%. The OCC indicated that much of the research points to an ERP in the 4% to 6% range with recent studies suggesting an increase to ERP. Therefore, the OCC used the upper end of the range 5.5% as ERP.[7] Woolridge PFT, pp. 63-67; Exhibit JRW-11; Responses to Interrogatories FI-287 and FI-291; Brief, pp. 92 and 93; Tr. 9/19/16, 984-988. The results of the OCC's CAPM were performed for the OCC Utility Group and the Company Utility Group. The ROE indicated CAPM was 7.9% in both utility groups. Woolridge PFT, p. 69; Brief, p. 94.

g. Risk Premium: Bond Yield plus Risk Premium

The Company also performed a Bond Yield plus Risk Premium (BY+RP) approach. It is based on the risk principal that returns to equity holders are more risky

[7] Dr. Wooldridge's testimony references MRP studies. The Authority used the terms ERP and MRP synonymously.

than returns to bondholders and, as such, equity investors must be compensated to bear that risk. The Company used actual authorized returns for electric utilities as the historical measure of the cost of equity to determine the risk premium. As such, authorized ROEs for electric utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the relevant measure of interest rates. The risk premium is simply the difference between those two points. The purpose of the BY+RP was to corroborate the reasonableness of UI's DCF and CAPM results and to inform the Company's ultimate ROE recommendation. The results of the Company's BY+RP were an estimated ROE of 9.70% based on the current 30-day average of the UST-30 yield; an estimated ROE of 9.91% based on the near-term (2016-2017) projections of the UST-30 yield, and an estimated ROE of 10.44% based on longer-term (2017-2019) projections of the UST-30 yield. The results of the BY + RP range between 9.7% and 10.44%. According to the Company, this approach is consistent with the approach the FERC relied on in recent cases. Bulkley PFT, pp. 60-63, 66; Exhibit AEB-5; Brief, pp. 95, 100 and 101; Responses to Interrogatories FI-198 and FI-199; Tr. 9/16/16, pp. 908-912. The Company suggested that since authorized returns are public data, to some degree they are reflective of investor's required returns. Bulkley Rebuttal Testimony, pp. 53 and 54; Reply Brief, p. 52.

The OCC was critical of the Company's BY+RP approach, because there were several problems calculating a risk premium. For example, the methodology produces an inflated measure of the risk premium because it uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to project Treasury Yields. Since Treasury yields are always forecasted to increase, the resulting risk premium would be smaller if done correctly. According to the OCC, this BY+RP approach is a gauge of commission behavior and not investor behavior. Capital costs are determined in the market place through the financial decisions of investors. These costs are reflected in such fundamental factors as dividend yields, expected growth rates, interest rates, and investors' assessment of the risk and expected return of different investments. Regulatory commissions evaluate capital market data in setting authorized ROEs, but also take into account other utility and rate case-specific information in setting ROEs. As such, the Company's approach and results reflect factors such as capital structure, credit ratings and other risk measures, service territory, capital expenditures, energy supply issues, rate design, investment and expense trackers, and other factors used by utility commissions in determining an appropriate ROE in addition to capital costs. This especially may be true when the authorized ROE data includes the results of rate cases that are settled and not fully litigated. Overall, the OCC was not aware of any commissions that had explicitly adopted this risk premium approach. Given the issues posed by this approach, the OCC did not know if it would meet the Hope vs. Bluefield standard. Woolridge PFT, pp. 87-90; Brief, p. 103; Response to Interrogatory FI-295.

h. Parties' Summary Results

The Company's requested ROE of 9.92% is based on the application of its three approaches. The results of the Company Utility Group are depicted in the table below.

Constant Growth DCF			
	Mean Low	**Mean**	**Mean High**
30-Day Average Price	8.95%	9.92%	10.92%
90-Day Average Price	9.15%	10.12%	11.13%
180-Day Average Price	9.29%	10.26%	11.26%
Capital Asset Pricing Model			
	Current Rf (2.66%)	2016-2017 Projected Rf (3.15%)	2017-2019 Projected Rf (4.33%)
Value Line Beta	10.59%	10.71%	11.02%
Bond Yield Plus Risk Premium			
	Current Rf (2.66%)	2016-2017 Projected Rf (3.15%)	2017-2019 Projected Rf (4.33%)
Bond Yield Plus Risk Premium	9.70%	9.91%	10.44%

Buckley PFT, p. 66.

The OCC analyses for the OCC and Company Utility Groups indicated equity cost rates of 8.40% and 8.50%, respectively. These results are as follows**:**

	DCF	**CAPM**
OCC Utility Group	8.40%	7.90%
Company Utility Group	8.50%	7.90%

The OCC recommended that the appropriate equity cost rate to be in the 7.90% to 8.50% range. However, the OCC primarily relied on the DCF model, recommending the upper end of the range as the equity cost rate and that the appropriate equity cost rate for the groups is 8.50%. This recommendation gives primary weight to the DCF results for the two proxy groups. The OCC indicated that the 8.5% is reasonable as utility capital costs are still at historically low levels. The electric utility industry is one of the lowest risk industries in the U.S. as measured by beta, and authorized ROEs for electric utilities have declined from 10.01% to 9.8% in 2013, to 9.76% in 2015 and to 9.52% for the first half of 2016 based on RRA summary data. Additionally, the OCC opined that authorized ROEs have lagged behind capital market costs in recent years since some regulatory commissions have been reluctant to authorize ROEs below 10%. Woolridge PFT, pp. 68-70; Exhibits JRW-2, JRW-3 and JRW-8; Brief, pp. 94 and 95. Furthermore, the OCC indicated that its proposed ROE meets the Hope vs. Bluefield standard as it is comparable to returns investors expect to earn on similar risk investments, provides sufficient confidence in the Company's financial integrity, and is adequate to maintain the Company's credit and to attract capital. Tr. 9/19/16, p. 710; Brief, p. 106.

6. Discussion of Cost of Equity

a. Economic Changes and Survey of Allowed Returns

The AG argued that UI's proposal to increase its ROE to 9.92% from its currently authorized ROE of 9.15% during a time period where utility commission approved ROEs have been declining nationally for years. Tr. 9/19/16, pp. 947 and 959. Approval of the Company's proposed 9.92% ROE would result in the highest authorized return for any of the state's principal regulated public service companies over the last five years. The AG summarized the current allowed returns of Connecticut's public utilities. Brief, pp. 36-38.

The Authority finds a review of those allowed returns yield an allowed ROE range of 9.13% to 9.75% over the 2010 to 2014 time period and clearly depicts a downward trend. An examination of allowed returns for all electric utilities by RRA shows a decline in the average return from 10.03% in 2010 to 9.99% in first half of 2016. Examining specific allowed ROEs shows that for 2016, the range of allowed ROEs was 9.0% to 10.6% but it included several limited rider cases in the Commonwealth of Virginia (Virginia). Excluding the Virginia cases, the average allowed ROE is 9.52% for the first half of 2016. Response to Interrogatory FI-261, pp. 1, 4 and 8; Supplement to Response to Interrogatory FI-261; Tr. 9/19/16, pp. 960-964. Furthermore, during the course of this proceeding, long term U.S. Treasury rates have fallen on average, 70 basis points. Responses to Interrogatories FI-146 and FI-147; Late Filed Exhibits No. 40 and 43; Tr. 9/19/16, pp. 808.

An update to the Company's last allowed ROE of 9.15% for changes to the UST-30 shows those rates declined from an average of 3.45% in 2013 to an average of 2.38% in 2016 (September 2016) for a decline of 1.07%. Supplemental Response to Interrogatory FI-155, Attachment 1. Applying the 1.07% decline to the last allowed ROE of 9.15% results in 8.08% ROE, all else equal.

The OCC witness also testified in the 2013 UI rate case and had recommended an 8.75% ROE for a difference of 25 basis points from (8.75%-8.5%), the present OCC recommendation. In the 2013 UI rate case, the Company had proposed 10.25% and now proposes 9.92% for a 33 basis point reduction (10.25%-9.92%). Tr. 9/19/16, pp. 946-948; Reply Brief, p. 18. An analysis of these figures, applying the average of those reductions to the 2013 UI rate case 9.15% allowed ROE, results in an updated figure of 8.86% [(9.15%-0.29% where 29 is ½*(33+25)]. Although this does not take into account the complexities of the cost of capital models, it clearly indicates that both parties, are aware of and reflecting reductions to capital market conditions, all else equal, between 2013 and 2016.

b. Proxy Group

The Authority considered the Company and the OCC proxy groups. Both recommended using proxy groups consisting of publicly traded electric companies followed by Value Line. For the proxy group criteria selection, both the Company and the OCC used similar criteria such as the proxy that 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. For the most part, both the OCC and the Company recommended basically the same companies.

There are noteworthy differences with both parties that deviate from the Authority's past preferred practices to establish a utility proxy group. One difference is selection criteria of the percentage of regulated electric revenues to total revenues (i.e., 70% for the Company and 50% for the OCC); the inclusion of 70% regulated revenue to total revenue as separate criteria on the part of the Company; the direct use of SEC 10-K filings to determine the percentage of electric revenue to total revenue on the part of the Company instead of the AUS Monthly Utility Report (AUS) as used by the OCC, and with respect to merger activity, the exclusion of both the acquired and acquiring company from the recommended proxy group on the part of the Company. Responses to Interrogatories FI-178, FI-179, FI-181 and FI-252; Tr. 9/19/16, pp. 856-876.

The Authority proposed hypothetical revisions to the Company's proxy group to include Duke Energy Corporation (Duke), FirstEnergy, MGE Energy and Southern Company (Southern) and to exclude ALLETE, Inc. (ALLETE), DTE Energy Co. (DTE), PPL Corp. (PPL), SCANA Corp. (SCANA), WEC Energy Group and Westar. The hypothetical revisions resulted in downward adjustments to the Company's indicated DCF results including a 8.95% floatation adjusted 30-day constant growth DCF and indicated overall recommendation of 9.4%. Response to Interrogatory FI-184, Attachment-1; Exhibit AEB-1; Tr. 9/19/16, pp. 876-878.

The OCC was aware of the preference for AUS and used it in its analysis with the caveat that the percentage of regulated electric revenues was lower at 50%. The OCC indicated that its standard was 50% regulated electric revenues from AUS, and suggested that larger proxy groups reduce measurement error. By having larger proxy, groups, individual errors are averaged out. Tr. 9/19/16, pp. 976 and 977. The OCC did not suggest a minimum number of proxy companies to produce a reliable cost of capital results. Indeed, the reliability of the results depends on how comparable the companies in the proxy group are to the target company. Response to Interrogatory FI-273. According to the OCC, the 50% threshold results in a proxy group that is primarily electric utilities. Response to Interrogatory FI-272. The OCC indicated that the use of its proposed 50% versus the Authority's 70% electric revenue requirement would not impact the OCC's DCF or CAPM results in any significant way. Response to Interrogatory FI-274. With regard to the OCC's proposal to include Avista Corporation, Black Hills Corporation, CMS Energy Corporation, Dominion Resources, and Otter Tail Corporation, the Authority notes that the percentages of revenues derived from electric generation are 67%, 55%, 66%, 64% and 52%, respectively. Response to Interrogatory FI-271. Given these companies lack of significance to the OCC's final recommendation and to maintain consistency with past practices in the 2013 UI rate case, the Authority will exclude these companies from the final Authority Utility Group. The Authority finds that for the electric industry, 70% remains a good threshold percentage to derive the Authority Utility Group with the noted exceptions.

Although UI demonstrated an understanding of the Authority's proxy group criteria preference, the Company presented data related to the percentage of revenue derived from the business. The data included information demonstrating 70% of regulated

revenues from electric operations to total revenues and 70% of regulated operations to total revenues. The key difference is the electric revenues source versus regulated revenues. The AUS source shows there are companies called combination gas and electric. For these companies, it is important that the electric revenues be greater than 70% not just total regulated revenues are greater than 70%; otherwise gas revenues would be comingled. The Authority posed the Company a hypothetical combination electric and gas company that although had more than 70% regulated revenues (80%), only 20% was derived from its electric services. Based on the Company's 70% or more regulated revenue data, such a company would be included in its proposed proxy group. Responses to Interrogatories FI-158, FI-159, FI-179; Tr. 9/19/16, pp. 859 and 860. Consequently, the Authority rejects the Company's second 70% of regulated operations to total revenues.

The Company calculated its own percentage of electric revenues to total revenues directly from SEC Form 10-Ks (10-Ks) using its own algorithm while the OCC used the AUS figure reported in the percentage regulated electric revenue column. Response to Interrogatory FI-180; Tr. 9/19/16, pp. 974 and 975. The OCC was aware of the Authority's acceptance of this source for information. Response to Interrogatory FI-275. The Company indicated AUS was a subscription-only service, not available to it since UI did not subscribe. Response to Interrogatory FI-181. As such, the Company used business segment data provided in the proxy group companies' year end 10-Ks to perform the percentage to electric business revenue to total revenue calculation. The Company was aware of AUS and had reviewed it previous to the AUS example provided at the September 19, 2016 hearing. The Company stated its review of AUS in 2009 found several errors as the AUS material did not match the 10-Ks. Tr. 9/19/16, pp. 861-865. The OCC has occasionally noted errors in AUS over the years. The AUS is updated quarterly and it relies on quarterly financials while the 10-Ks are annual. Thus, it would not be unreasonable for the AUS data to not match the calculations made by the Company from the annual 10-Ks. Tr. 9/19/16, pp. 872-874.

The Authority concludes that much of the Company's perceived errors in the percentage of revenue calculations from the 10-Ks as compared to the AUS figures are likely attributable to the fact the AUS is quarterly and the 10-Ks are annual. AUS provides a simple, easy means to obtain the percentage electric to total revenue calculations. Reliance on AUS also eliminates the need to verify the accuracy of the Company's model. The Authority maintains that AUS is a reasonable source to obtain percentage electric to total revenue criteria to establish the Authority Utility Group.

The Authority's analysis finds another issue that led to differences in the proxy groups was the exclusion of companies on the basis of the timing of merger activities. Both the Company and the OCC felt that companies engaged in merger activity should be excluded from the final proxy group. There was a difference as to the timing of how far in the past merger activity is relevant. During the course of this proceeding, Great Plains Energy Inc. (Great Plains) and Westar Energy Inc. (Westar) announced a merger whereby Westar would be purchased by Great Plains. The OCC removed both companies from its proxy group and the Company indicated they would be removed from its final proxy recommendation. Response to Interrogatory FI-182; Tr. 9/19/16, pp. 874 and 875, 979.

Given this merger activity occurred during the course of the proceeding, the Authority finds that Great Plains and Westar will be left out of the Authority Proxy Group. The matter of merger activity timing also impacted the recommendation regarding the OCC's inclusion of Duke and Southern in its proxy group. Duke and Southern were both the acquiring companies with their respective mergers. The Company recommended excluding Duke and Southern suggesting that the stock price of both the acquirer and the acquired companies can be affected by the merger announcement. Responses to Interrogatories FI-184, FI-252 and OCC-221; Tr. 9/19/16, pp. 866-868. Although the OCC agreed that it is a common practice to exclude both the acquired and acquiring companies from the proxy group recommendation, it included Duke and Southern as their respective mergers had transpired approximately seven to nine months ago. According to the OCC, a good rule of thumb is a six-month cut-off period as used at the FERC. Since the merger activity in both cases occurred prior to six months, these companies were included. Tr. 9/19/16, pp. 977-979. Based on the distant timing of these acquisitions, the Authority will include Duke and Southern in its proxy group. Additionally, the Authority Utility Group gains the benefit of increasing the size of proxy group by the inclusion.

In applying the criteria that 70% or more of revenues should be from regulated electric operations, the Authority has primarily relied on this computation as provided by AUS.[8] The results of applying the 70% regulated electric criteria along with the other Authority criteria identified in the 2013 UI rate case[9] resulted in an Authority Utility Group of the following companies: Alliant Energy Corp.; Ameren Corporation; American Electric Power; Consolidated Edison, Inc.; Duke; Edison International; El Paso Electric, Entergy Corporation; Eversource Corporation; FirstEnergy Corporation; IDACORP, Inc.; MGE Energy; Northwestern Corporation; OGE Energy Corporation; PG&E Corporation; PNM Resources; Pinnacle West Capital; Portland General; Southern; and Xcel Energy. The Authority notes that the companies are included in the Authority Utility Group are recommended within both parties' groups.

There are three companies that both the Company and the OCC recommended. They are ALLETE, SCANA and WEC and AUS indicated that these companies have 67%, 58% and 68% revenues, respectively, generated from electric operations. Response to Interrogatory FI-271. Given both parties found these acceptable, the PURA will include them in the Authority Utility Group.

Further review of the Company's proxy group selection revealed that the Company excluded FirstEnergy Corporation (FirstEnergy) and MGE Energy, Inc. (MGE) and included DTE and PPL. The Company indicated FirstEnergy and MGE did not meet its 70% or greater regulated revenues of total revenues criteria and so were excluded. Responses to Interrogatories FI-156, Attachment 1; FI-183; and FI-184. Regarding the inclusion of DTE and PPL in the Company Utility Group, UI indicated that these companies only cleared the 70% electric revenue to regulated criteria and did not pass the Company's 70% regulated to total revenues. Response to Interrogatory FI-251.

---

8 Response to Interrogatory FI-154(g), specifically September 2016 edition AUS Monthly Utility Reports, pp. 4-10.

9 2013 UI Rate Case Decision, p. 123.

The Authority finds that based on the AUS report, FirstEnergy derives 71% of total revenues from electric services while MGE, DTE and PPL derive respectively 76%, 50% and 60% of their total revenues from electric services. Response to Interrogatory FI-154(g). Therefore, FirstEnergy and MGE should be included while DTE and PPL should be excluded. The AUS reports support including FirstEnergy and MGE in the proxy group. The Authority previously denied the Company's 70% of regulated revenues criteria and therefore excludes DTE and PPL. 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 23 proxy companies and will serve 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	Ameren Corporation
American Electric Power Co.	American Electric Power Co.	American Electric Power Co.
	Avista Corporation	
	Black Hills Corporation	
	CMS Energy Corporation	
Consolidated Edison, Inc.	Consolidated Edison, Inc.	Consolidated Edison, Inc.
	Dominion Resource, Inc.	
DTE Energy Company		
	Duke Energy Corporation	Duke Energy Corporation
Edison International	Edison International	Edison International
El Paso Electric	El Paso Electric	El Paso Electric
Entergy Corporation	Entergy Corporation	Entergy Corporation
Eversource Energy	Eversource Energy	Eversource Energy
	FirstEnergy Corporation	FirstEnergy Corporation
Great Plains Energy Inc.		
IDACORP, Inc.	IDACORP, Inc.	IDACORP, Inc.
	MGE Energy, Inc.	MGE Energy, Inc.
NorthWestern Corporation	NorthWestern Corporation	NorthWestern Corporation
OGE Energy Corporation	OGE Energy Corporation	OGE Energy Corporation
	Otter Tail Corporation	
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.
PPL Corporation		
SCANA Corporation	SCANA Corporation	SCANA Corporation
	Southern Company	Southern Company
Westar Energy, Inc.		
WEC Energy Group	WEC Energy Group	WEC Energy Group
Xcel Energy, Inc.	Xcel Energy, Inc.	Xcel Energy, Inc.

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. Both separately recommended different peer companies for inclusion in the proxy, and the Authority made revisions based on 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 used the simple constant growth form into the analysis.

i. Dividend Yield

The Company and the OCC dividend yield was based on their respective proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended March 31, 2016, for the Company and ended July 29, 2016, for the OCC. Both the Company and the OCC adjusted the dividend yield by one-half of the expected growth so as to reflect growth over the coming year. The OCC's analysis shows both the OCC Utility Group and the Company Utility Group average of the median dividend yields to be 3.30%.

The Authority finds there is no difference in the dividend yields proposed by both parties. The Authority also found both parties amenable to using Value Line Column f as a reasonable means to measure market expectations of the projected dividend for the next 12 months. In the 2013 UI Rate Case Decision, the Authority expressed preference for Value Line Column f. For consistency with that Decision, 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.

The Authority disagrees with the Company's claim that the primary driver of the low DCF results was the OCC's 3.2% dividend yields, which is 20 basis points below the 3.5% historic average. Company Reply Brief, pp. 48 and 49. First, a 20 basis points difference is not sufficient to bridge the gap between the OCC's 8.5% recommendation and the Company's 9.92% recommendation as 8.5% plus 0.20% is only 8.7%. Second, the Authority's incorporation of Value Line Column f incorporates estimates of the dividends to be paid over the next 12 months thus any time specific dividend under reporting would be alleviated. Additionally, the Authority notes that the mean dividend yield of the Authority Utility Group is 3.44% or 6 basis points below the Company's advocated historic 3.5% dividend yield.

Furthermore, regarding the time period the data is collected, the Authority in the 2013 UI rate case found a 30-business day average stock price long enough to capture changes in stock price movements as well as being relatively simple to obtain from public sources online. In this proceeding, the Authority maintains that the 30-business day time period is especially relevant as it is devoid of stock market price shocks or other anomalies. The Authority incorporates a timeframe of 30 business days, as reasonable for estimating the stock price portion for the dividend yield component of the DCF Model as stated in the 2013 UI rate case, p. 127.[10]

[10] By letter dated October 7, 2016, the Authority provided notice that this hearing and record in the docket cited above would close as of October 7, 2016, at 4:00 p.m. The sources used to compute the forecasted dividend yield are The Value Line: Summary and Index dated October 7, 2016, and adjusted stock prices from Yahoo. Finance.com for the 30 business days ended October 7, 2016. Reference Interrogatory FI-154(j); Tr. 10/6/16, pp. 1624-1630.

ii. Growth Rate

The growth element of the DCF application is the most complex and debated issue of all of the DCF components. The Company relied solely on analysts' EPS growth rates from Zacks, Yahoo and Value Line. The OCC advocated use of analyst EPS growth rate forecasts from Yahoo, Zacks, Reuters, and Value Line. The OCC also considered Value Line's historical growth rates (for EPS, DPS, and BVPS) Value Line's projected growth rates for DPS and BVPS and estimated retention growth. A significant amount of time was spent by both parties in debate over the incorporation of these growth rates in addition to those of stock market analysts. Based on the Company's estimations, the sole reliance on analyst EPS growth rates is a mean EPS growth rate of 5.13% as opposed to 5.10%. Bulkley Rebuttal Testimony, pp. 8, 9 and 36; Tr. 9/19/16, pp. 890 and 891; Reply Brief, p. 47. The Authority concurs that 3 basis points is not a meaningful difference. The Company recommended use of only Reuters or Yahoo growth rates to avoid double counting. Brief, p. 97. The Authority will use both as it is not clear if they are exactly the same as differences were found. Furthermore, the Authority estimates that investors will likely examine all the growth rate data available despite the fact that one company owns both data sources.

The Authority will incorporate the analyst's 5-year long-run EPS growth rates from Yahoo, Zacks and Reuters. Similar arguments were made by the Company and the OCC regarding the inclusion of Value Line's historical growth rates, projected DPS and BVPS growth rates and retention growth rates in the 2013 UI Rate Case Decision, pp. 127-129. For consistency with that Decision, the Authority incorporates Value Line's projected DPS and BVPS growth rates but not the historical growth rates. With respect to retention growth rates, the Authority computed these using the simple sustainable earnings/retention growth formula and respective data from Value Line's projections for 2019-2021.[11]

iii. DCF Results

In applying the DCF model, the Authority reviewed the annual constant growth form. In its analysis, the Authority includes Yahoo, Zacks and Reuters' forecasts of EPS in the analysis, Value Line's five-year projected growth rate per share estimates for earnings dividends, and book values, as well as, retention growth rates.

In developing the overall DCF result, the Company eliminated implausibly low and high results. The screening of potential outliers eliminated with the low end relied on the comparably rated Mergent Bond Record for comparably rated A and Baa Public Utility

[11] In response to the Company's request for details as to the source and calculations used in the Authority's analysis, the Company is directed to the following items. In reference to Interrogatory FI-154: All data used was dated no later than October 7, 2016. Tr. 9/19/16, p. 836. Analyst EPS estimates from Yahoo, Zacks and Reuter's growth rates dated September 28, 2016, were referenced and provided by the Authority at the October 6, 2016 hearing. Value Line-projected EPS, DPS and BVPS from Electric Utility (East) Issue 1 dated August 19, 2016; Electric Utility (West), Issue 11 dated July 29, 2016, and Electric Utility (Central), Issue 5 dated September 16, 2016; Tr. 9/19/16, pp. 815 and 816; Tr. 10/6/16, pp. 1624-1630; Company Brief, pp. 103 and 104.

Bond (PUB).[12] Screening out at the high end used a threshold of 750 basis points above the corresponding PUB rating. There were no results eliminated at the high end. The low end required more careful consideration. In the 2013 UI rate case, the Authority relied on the FERC risk-return practice of a 100 basis points threshold. This application resulted in an overall DCF range of 6.20% to 9.61% with a median of 8.40% and mean of 8.17%. In applying the 100 basis point criteria, two companies from the Authority Utility Group were eliminated as too low. The Authority also considered the Company's proposed a 375 basis point criteria which resulted in an overall DCF range of 7.96% to 9.61% with a median of 8.56% and mean of 8.60%. In applying the 375 basis point criteria, 9 of the 23 companies from the Authority Utility Group were eliminated as too low. The Authority does not find it reasonable to base the indicated DCF result decision on the basis of the remaining 14 companies from the high end.

The Authority performed a sensitivity analysis on the basis point spread over the corresponding Mergent PUB rating to eliminate results that were implausibly low ROEs while maintaining an Authority Utility Group that was reasonably robust. The Authority finds 325 basis points to be reasonable in this case as only six companies are eliminated, leaving a robust proxy group of 17 companies. Application of this criteria results in the elimination of approximately 50% of the companies initially identified as comparable. It also results in an overall DCF range of 7.06% to 9.61%.

The Company's proposed mean and mean-high DCF ROE results are above this range and thus are rejected. Although the OCC's recommended DCF ROE is within the range, it remains a significant change from the Company's current ROE. Moreover, using the OCC DCF ROE would result in either the lowest or among the lowest ROEs in the nation. Based on its experience, the Authority finds that 9% is reasonable, and it is reflective of the ROE derived from the DCF approach. The Authority notes that the Company's proposed mean-low DCF ROE range (i.e., 8.95% to 9.29%) supports this finding. Lastly, since the price input to the Company's projected DCF model is based on Value Line's projected stock prices, the Authority rejects UI's proposed projected DCF model as the PURA does not project the stock market.

d. CAPM 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 implement a simple CAPM [$K = R_f + b \times (R_m - R_f)$]. There are several debates surrounding the application of 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 used three sources to estimate the risk-free rate: 1) the current UST-30 average yield (i.e., 2.66%); 2) the projected UST-30 yield for 2016 through 2017 of 3.15%; and 3) the projected UST-30 yield for 2017 through 2019 of

[12] Reference FI-154(b), Mergent Bond Record, September 2016, edition, p. 14. The latest Mergent PUB ratings were A at 3.59% and Baa at 4.20 and were referenced and provided at October 6, 2016, hearing. Tr. 10/6/16, p. 1624.

4.33%. Bulkley PFT, pp. 44 and 45, Exhibit AEB4; Brief, p. 100. The OCC recommended a 4% as the average UST-30. Woolridge PFT, Exhibit JRW-11; Brief, p. 92.

The Authority reviewed recent trends in UST-30 yields and finds that they have hovered in the 2% range and reached 2.47% on October 7, 2016.[13] Given current market conditions, the Authority finds it conservative to use the OCC's 4% proposal. The measure of beta represents the volatility of a proxy group of companies to the aggregate market. The Company and the OCC recommended use of Value Line adjusted betas. Accordingly, the Authority incorporates Value Line adjusted betas into its analysis. After the 325 basis point criteria is applied, the beta of the Authority Utility Group is 0.7029.

ii. Equity Risk Premium

There was significant debate regarding the estimation of the equity risk premium. The Company recommended an ERP range from 8.99% to 10.66% based on its application of the constant growth DCF to the S&P 500 Index. The OCC recommended 5.5% based on their respective analyses.

The Authority considered 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. On the surface, the approach seemed plausible but the Authority took exception to such an approach in the 2013 UI Rate Case Decision, pp. 131-133. The PURA maintains its skepticism regarding the indicated CAPM results of this methodology, but shall provide equal weight to the Company's indicated ERP range of results with other Authority sources considered. The Authority also accepts the OCC's proposed 5.5% based on the 2013 UI Rate Case Decision, p. 133. In past analyses, the Authority incorporated the OCC's survey of methodologies (OCC ERP Survey). Woolridge PFT, Exhibit JRW-11. Since the OCC recommended 5.5%, the OCC ERP Survey is excluded.

The Authority also considered the findings of Duff & Phelps which suggested the long-term historical ERP to be 6.9%, the long-term supply side ERP to be 6.03% and Duff & Phelps's current recommendation to be 5.5% until further notice.[14] Based on the Authority's review, the indicated ERP is an average of the Company's range, the OCC and Duff & Phelps' recommendations for an average of 6.75%. Responses to Interrogatories FI-154(i), FI-255 and FI-256; Tr. 9/19/16, pp. 918-923.

iii. CAPM Results

The Authority's application of the simple CAPM yields an 8.75% equity cost rate that is representative of the CAPM return in its overall analysis.

---

[13] Reference Interrogatory FI-154(a). Source Yahoo.finance.com.

[14] Interrogatory FI-154 (i). Reference materials from September 19, 2016 hearing, Duff & Phelps, 2016 Valuation Handbook, Exhibits 3.12 and 3.15.

e. Flotation Cost

Although the OCC made reasonable arguments against including a flotation cost adjustment in this proceeding, the Authority accepts the Company's proposal of a 0.15% (i.e., 15 basis points) upward adjustment given UIL closed on equity issuances of approximately $525 million and $214 million (for a total of 26 million shares of common stock) in September 2010 and September 2013, respectively. With the merger into Avangrid, UI will no longer have a direct parent company making equity issuances on its behalf. It will be several layers below in the organizational structure of the entity that will actually issue future equity. The Authority will re-evaluate the acceptance of flotation costs on a case by case basis going forward.

f. BY + RP Model

The Authority concurs that authorized ROEs are merely a gauge of commission behavior and not investor behavior. The Authority cannot rely on authorized ROE decisions made in other jurisdictions as those decisions account for other utility and rate case-specific information when setting ROEs. The Authority must examine the specifics of the conditions of the companies it has jurisdiction over and compare that to capital costs as determined in the marketplace. The financial decisions of investors are reflected in such fundamental factors as dividend yields, expected growth rates, interest rates, and investors' assessment of the risk and expected return of different investments.

With respect to the Company's claim that this approach is consistent with the approach the FERC relied on in recent cases, the Authority carefully reviewed the cited FERC decision and found no language indicating that this approach was explicitly incorporated into the FERC's analysis. Late Filed Exhibit No. 41, Attachment 8, p. 212; Tr. 9/19/16, p. 840. The Authority considered and will reject the Company's BY+RP approach. No weight will be placed on this approach in the Authority's analysis.

g. Summary of Authority's ROE Analysis

Although the Company proposed more weight be allocated to the CAPM, based on the Authority revisions to UI's proposal, the PURA will rely on the DCF model. The Authority weighted the DCF model result more heavily than it weighted the CAPM result. The Authority also incorporated 0.15% as a flotation cost adjustment. The Authority's process is to use the cost of capital methodologies and assumptions in a consistent fashion over time and across the utility industries. The Authority finds it reasonable that the Company's allowed ROE be 9.10%.

h. Authority's Allowed Weighted Cost of Capital

The Company's requested ROR of 7.72% in rate year 1, 7.69% in rate year 2 and 7.71% in rate year 3 (9.92% ROE with a 52% Common Equity and 48% Long-term Debt) is rejected as excessive. The OCC's ROR recommendations of 6.79% in rate year 2 and 6.67% in rate year 3 (8.50% ROE with 50% Common Equity to 50% Long-term Debt) are also rejected.

Consistent with Conn. Gen. Stat. §16-19e(a)(4), the Authority identified an appropriate ROR on the rate base for the Company's overall capital structure. The Authority determined 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 tables below summarizes the capital structure components and calculates the weighted cost of capital, including the 9.10% assigned ROE on common equity, determined by the Authority based on the 50% common equity to 50% long-term debt capital structure.

2017 Average Capitalization: Rate Year 1

Class of Capital	Ratemaking Percentage	Cost	Ratemaking Weighted Cost
Long-term Debt	50%	5.31%	2.66%
Common Equity	50%	9.10%	4.55%
Total Capitalization	100%		7.21%[15]

2018 Average Capitalization: Rate Year 2

Class of Capital	Ratemaking Percentage	Cost	Ratemaking Weighted Cost
Long-term Debt	50%	5.14%	2.57%
Common Equity	50%	9.10%	4.55%
Total Capitalization	100%		7.12%

2019 Average Capitalization: Rate Year 3

Class of Capital	Ratemaking Percentage	Cost	Ratemaking Weighted Cost
Long-term Debt	50%	5.05%	2.53%
Common Equity	50%	9.10%	4.55%
Total Capitalization	100%		7.08%

Based on the above, the Authority determined that a 7.21% return for rate year 1, a 7.12% return for rate year 2 and a 7.08% return for rate year 3 on the Company's rate base of $981 million for rate year 1, of $997.026 million for rate year 2 and $1,014.144 million for rate year 3 is reasonable. 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 82 basis points (9.92% - 9.10%) downward adjustment to the Company's proposed 9.92% ROE results in a downward adjustment of $7.741, $7.848 and $7.772 million to UI's initially proposed revenue requirement for 2017, 2018 and 2019, respectively.[16]

---

[15] The WACC figures are subject to rounding.

[16] The Company indicated that a 1% change (100 basis points) to allowed ROE results in approximately a $9.441 million dollar increase/decrease to revenue prior to gross earnings tax and uncollectible for 2017 and $9.571 million for 2018 and $9.712 million for 2019. Application, Exhibits A-1.0 A, A-1.0B and A-1.0C. The Authority's 82 basis point reduction translates to reduction $7.741 million (0.82*$9.440), $7.848 million (0.82*$9.571) and $7.772 (0.82 *$9.478) for 2017, 2018 and 2019 respectively.

E. EARNINGS SHARING MECHANISM

The Company proposed an earning sharing mechanism (ESM) designed to share with customers 50% of UI's earnings above a set level over the Authority's allowed ROE plus a dead band that changes annually over the rate years. The proposed dead band of 20, 30 and 40 basis points would be applied in 2017, 2018 and 2019, respectively, and are intended to address several important factors. To illustrate, under the case where the allowed ROE is 9%, in 2017 the dead band would be 9.2% (9%+0.20%). The Company would retain all overearnings up to 9.2% and earnings above 9.2% would be shared 50%/50% with customers. The Company would continue to apply any dollars due customers to reduce the storm regulatory asset (if one exists at the time) or would provide the customer share through a bill credit. The Company suggested that its proposal better aligns the interests of customers and shareholders to achieve operating efficiencies and savings. Marone and Coretto PFT, p. 12.

The Company also suggested that a dead band incorporates an incentive that does not exist under UI's current ESM, which presently is a 50%/50% sharing with customers at the allowed ROE. According to the Company, the proposed ESM is designed to create the strong potential to identify cost saving opportunities. If achieved, the ESM would have the effect of increasing the earned ROE between rate cases and reducing the cost of service on a permanent basis in the next base rate case, which the Company claims is a substantial customer benefit. Responses to Interrogatories FI-116 and FI-117. The Company also stated that if its dead band ESM proposal was in place during the 2013 to 2016 rate years, it would have returned less money to customers. During 2014, UI returned $2,424,355 to customers, but if the ESM dead band proposal was in place and 2014 was specified as rate year 2, then the Company would have returned $1,191,632 to customers (or alternatively, reduced storm regulatory assets) for a difference of $1,232,723. Marone and Coretto PFT, p. 16. Response to Interrogatory FI-203; Tr. 9/13/16, pp. 429-441; Tr. 10/5/16, pp. 1631-1634.

The Company provided two alternatives to the ESM dead band approach. These were a graduated sharing percentage whereas the first 50 basis points above the allowed ROE would be shared 75% Company and 25% customer. For the next 50 basis points, the sharing would be 50% Company and 50% customer. All earnings that are more than 100 bps above the allowed return would be shared 25% Company and 75% customer. The other alternative was a multi-year measurement period where the earnings sharing calculation would be performed at the end of the rate period. Where in any cumulative earnings above the allowed amount would be shared 50% Company and 50% customer. Late Filed Exhibit No. 22. The Company stated it preferred no ESM to the one presently in place. Tr. 10/5/16, p. 1634.

The OCC recommended that the Authority reject the proposed dead band ESM and characterized it as regressive. The current equal sharing ESM should be maintained. According to the OCC, the Authority has a long-history of supporting proportionate (equal sharing) or progressive (a company retains less to start, but more as it saves more) ESMs in rate and ratemaking proceedings. UI's proposed dead band ESM would encourage further cost-shifting amongst sister utility companies shortly after a merger and immediately after a multi-year rate case have been completed. Setting an ESM with different dead bands from those at a sister utility could also lead to gaming and

provide further incentive for cost-shifting from one company to another. Brief, pp. 3, 140-144.

The AG recommended that the Authority reject UI's dead band ESM proposal and the alternative proposals provided in Late Filed Exhibit No. 22. The Authority should maintain the present ESM as is: 50%/50% sharing from dollar one above the Company's authorized ROE. The dead bands are unfair to customers in that they effectively raise the Company's authorized ROE beyond levels approved by the Authority. Moreover, graduated sharing percentages are unnecessarily complex and are likely to negatively impact ratepayers. The Company's request for a dead band under which it retains 100% of all excess earnings benefits shareholders at the expense of ratepayers. Lastly, the 30 basis point average dead band proposed by the Company represents approximately $2.8 million in revenue requirements. Brief, pp. 44-47.

CIEC also recommended rejection of the Company's proposal as the current ESM already provides sufficient incentive to maximize the efficiency of its operations. In fact, the record in this proceeding demonstrates that the current ROE has not acted as a disincentive to the Company. Brief, p. 14.

Additionally, BETP recommended rejection of the proposed ESM. It cited Conn. Gen. Stat. §16-19e where it is the Authority's responsibility to assure that the level of rates be sufficient, but no more than sufficient, to allow public service companies to cover their operating costs, capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection to ratepayers. BETP also stated that this mandate is not furthered by UI's ESM proposal. BETP Brief, p. 19.

The Authority considered the arguments made regarding the dead band ESM. Regarding the two alternatives proposed by UI, the Authority rejects these as being skewed towards the Company's interest (75% sharing), as well as being complicated to implement. The Authority also considered the Company's claim that the dead band ESM would give it more incentive to be more proactive seeking out cost saving measures. It is the Company's duty to seek out cost savings measures in any case. The Authority expects UI to perform this duty in a most cost conscious manner irrespective of the parameters of an ESM. UI did not present any evidence that suggests such a plan would create efficiencies or savings that would not exist absent of such a plan. For example, when asked what types of savings the Company had in mind, UI had little to specify. Tr. 9/13/16, p. 437. The Authority rejects the Company's proposed dead band ESM and will require it to continue the current 50%/50% sharing mechanism for the 2017 to 2019 rate years. The current method is equitable to customers, easy to implement and verify, and has served the function to provide customers some sharing and prevent costly rate proceedings in circumstances when the Company has over earned.

F. SALES FORECAST

The sales forecast in the present case is for January 1, 2017 through December 31, 2019. According to UI, the sales forecast is reviewed and revised at least annually as part of its budgeting process and for purposes of preparing the annual report on loads to the Connecticut Siting Council (CSC). The Company developed the sales forecast based on changes to sales from current levels using four adjustments. The four

adjustments were made to the previous year sales figure to yield the current year energy sales estimate. These adjustments are (a) economic growth, (b) incremental sales activities, (c) incremental conservation and load management activities (C&LM), and (d) incremental installations of distributed generation (DG). Additionally, UI added calendar year 2016 to illustrate the starting point of the 2017 forecast and the economic growth rate determined from the reconstituted sales analysis. The sales forecast included the energy savings impact from incremental C&LM and DG activities using line item adjustments to the previous year's energy sales. The incremental projected C&LM impacts were taken from the Company's 2016-2018 C&LM plan that was filed with the Department of Energy and Environmental Protection on October 1, 2015. The incremental DG impacts were taken from the Company's DG forecast submitted to the CSC. Colca PFT, pp. 19-22.

The starting energy sales value for each forecasted year was the energy sales from the previous year. The table below shows the proposed sales forecast for the rate years and 2016.

The United Illuminating Company
2016 through 2019 Sales Forecast [GWh]

	2016	2017	2018	2019
Prior year sales – 2015 using 6 month actual / 6	5,368	5,332	5,243	5,177
Incremental Sale Activities	1	1	1	1
CLM - Base and CAM Funded	(75)	(78)	(74)	(69)
DG from CEFIA Funded Projects and in Queue	(11)	(13)	(13)	-
DG from LREC/ZREC Projects	(10)	(29)	(30)	-
Economic Growth	43	46	49	52
Leap Year	16	(16)	-	-
Total	5,332	5,243	5,177	5,162
% Economic Growth	0.80%	0.85%	0.90%	0.95%
Overall Growth	-0.67%	-1.67%	-1.26%	-0.29%
Overall Growth (w/o leap year effect)	-0.97%	-1.37%	-1.26%	-0.29%

Id.

UI indicated that a component of the Company's sales forecast included changes to electricity sales as a result of economic growth for 2017 through 2019. As a result, UI projected overall growth in gigawatt hours of negative 1.675%, 1.26%, and negative 0.29% for rate years 2017 through 2019 respectively. In addition, the 2016 economic growth rates were calculated based on a reconstitution of sales to remove the effects of historic C&LM and DG activity.[17] The Company used historic DG impacts in its analysis based on the specific DG customer performance. The annual historic total impacts caused by C&LM and DG were added to the annual historic weather normalized sales to determine estimates of what annual sales would have been absent the Company's C&LM and DG incentive programs. The annual economic growth rates for sales to all customers and for each of the four revenue classes (residential, commercial, industrial

[17] The 2016 overall growth rate in gigawatt hours is negative 0.67%.

and street lighting) were calculated as the average change in reconstituted sales over the three year period of 2012 through 2014, which conforms to the forecast methodology prescribed by the PURA in its 2013 UI Rate Case Decision. Colca PFT, p. 21.

The Company's reasoning and methodology is consistent with the Authority's directives in the 2013 UI Rate Case Decision. The Authority finds the Company's sales forecast adjustments reliable and reasonable. Since the Company participates in decoupling, the risk of misstating unit rates is removed. Therefore, the Authority approves UI's sales forecast for the rate years without any adjustments.

G. LEVELIZATION PROPOSAL

The Company proposed to average or levelize the disparate three-year revenue increases to minimize year one bill impacts. The Company requested annual revenue increases of $65.6 million in 2017, $21.1 million in 2018 and an incremental $13.4 million in 2019. Under the Company's levelized plan, revenues would increase $40.7 million in 2017, $47.4 million in 2018 and $39.1 million in 2019. Revenues deferred in earlier years would accumulate carrying charges that would amount to $3.35 million over the three years. Year four would then require a rate reduction of $25.6 million to equate levelized revenues to the non-levelized, or normal, overall three-year revenue request. Favuzza PFT, pp. 4 and 5. The Company testified that a number of alternative three-year revenue increase plans were possible. Nonetheless, the Company preferred this one because it offered three years of similar rate increases. Tr. 9/16/16, pp. 736-743.

While the Authority appreciates the Company's concern over customer bill impacts absent levelization during rate year 1, the PURA does not see sufficient ratepayer value to warrant an additional $3.35 million in carrying charges. By rate year 2, ratepayers will experience $89 million of cumulative revenue increase under the proposed levelization plan and $86.7 under a normal standalone-year revenue increase approach. These amounts are essentially the same and the normal, standard one-year approach saves ratepayers $3.35 million in carrying costs. Based on the aforementioned, the Company's proposed levelization plan is denied.

H. REVENUE AND REVENUE ADJUSTMENTS

For rate year 1, the Company forecasted rate revenue at current rates of $311.675 million and other revenue of $8.051 million, resulting in a revenue deficiency of $65.596 million based on their proposed revenue requirement of $385.322 million. For rate year 2, the Company forecasted rate revenue at current rates of $309.780 million and other revenue of $8.360 million, resulting in a revenue deficiency of $86.706 million based on their proposed revenue requirement of $404.846 million. For rate year 3, the Company forecasted rate revenue at current rates of $309.560 million and other revenue of $8.704 million, resulting in a revenue deficiency of $100.154 million based on their proposed request of $418.417 million. Application, Schedules C-1.0A, C-1.0B and C-1.0C.

In the instant Decision, the Authority approved revenue requirement increases in the amount of $42.996 million, $13.087 million and $2.8 million for rate years 1-3,

respectively. Section V. Rate Model. The Authority denied the Company's rate levelization request as discussed in Section II.G. Levelization Proposal, necessitating an adjustment to rate revenue of $2.329 million, ($31.946) million and ($68.176) million for the rate years over the Company's proposed increases of $40.667 million, $88.029 million and $127.059 million for rate years 1-3, respectively as shown in the table below:

Net Change to Required Present Rate Revenues (Million)

	Company Proposal	Approved Increases	Net Adjustment
	(a)	(b)	(c=b-a)
Rate Year 1	$ 40.667	$42.996	$ 2.329
Rate Year 2	$ 88.029	$56.083	($31.946)
Rate Year 3	$127.059	$58.883	($68.176)

I. 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 company assets and expenses incurred by an EDC 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. In developing its COSS, the Company followed the detailed methodology consistently approved by the Authority in its 2013 UI Rate Case. The Company relied on its COSS results when designing rates. Effectively, the Company expects to move all rate schedules to equal rates of return in the next four years. Colca, PFT, p. 9.

The Company proposed allocating the demand component of line-transformers using a sum of all individual customers (SIGNCP) in a rate schedule. In the past, the Company utilized a non-coincident peak (NCP) allocator. UI argued that since this allocator offers greater specificity, it should be adopted and the use of the SIGNCP allocator should be extended to secondary lines. Colca, ADR-2, pp. 2-8. The OCC agreed with the Company's proposal to adopt the SIGNCP allocator for line transformers. Tr. 9/21/16, p. 1267. The Company also allocated uncollectible expense on the basis of customers. Previously, it utilized actual non-hardship write-offs to allocate uncollectible expense. Late Filed Exhibit No. 71.

The OCC made four recommendations concerning the COSS allocation methodology and presentation employed by the Company. These were:

1. Automatic meter reading infrastructure (AMI) costs should be allocated using a labor allocator as opposed to being allocated as part of the metering function as done by the Company.
2. Distribution system costs for poles, lines and transformers should be allocated fully on demand.
3. If the Authority rules against 2 above, then line transformer costs should be fully allocated on demand.
4. The COSS presentation under the equity model should be made clearer.

The OCC recommended that AMI be allocated using a generic labor allocator. The OCC asserted that AMI offers more customer benefits than just meter reading. For example, AMI is capable of capturing hourly interval data for all customers as well as offering a remote disconnect service. AMI also offers data analysis capabilities for theft detection. Rubin Supplemental PFT, pp. 4 and 5.

While AMI provides functionality that far surpasses basic meter reading, the Authority is not convinced that a labor-only allocator correctly captures the many benefits of AMI, which essentially offer improved functionality to all customer classes. The Company should continue using its proposed method of allocation. The OCC also proposed functionalizing the Company's investments in poles; overhead conductors and devices; underground conduits, conductors and devices; and line transformers as fully demand-related. Rubin Supplemental PFT, pp. 4-23. However, the Company proposed functionalizing these accounts as both customer and demand. The Company's proposal, which was also approved in its 2013 UI rate case, is approved again in this Decision. The Authority directs the Company to construct its compliance COSS utilizing the same methodology approved in its 2013 UI rate case with the single exception that the demand component of line transformers be allocated using the proposed SIGNCP, updated with the latest diversity factor. The SIGNCP will not be used to allocate secondary lines at this time. Also, the allocation of uncollectible expense will utilize actual non-hardship write-offs as done in the 2013 UI rate case. The proper allocation for SIGNCP, uncollectible expense and COSS presentation will be reconsidered in Docket No. 16-02-30, PURA Review of the Electric Distribution Companies Cost of Service Study Methodologies and Rate Design (Electric Generic).

J. RATE DESIGN

The Company proposed to hold all basic service charges constant, increase kWh charges for all tariffs with only kWh charges, and proportionally increase kWh and demand charges for tariffs with both types of charges. Additionally, the Company proposed to reinstate the 3% service voltage reduction for General Service Rate, Rate GS and General Service Time-of-Day, Rate GST customers receiving service from primary lines. The reduction adjusts for transformer losses so that these customers could be billed as if they received service from secondary lines. In the 2013 UI rate case application, the adjustment was removed to begin billing using actual metered energy. However, the cost of moving to actual metered energy proved to be too expensive. Consequently, the Company is proposing to return to its long established process of adjusting for transmission losses. Similarly, the Company proposed to return to the Large Power Time-of-Day, Rate LPT 3% service voltage increase adjustment that was removed in the 2013 UI rate case. Effectively, the tariffs will have separate rates for primary and secondary voltage as previously existed for many years. Colca PFT, pp. 10-13. The Authority reviewed the Company's proposal and approves it.

1. Maximum Residential Customer Charge

Conn. Gen. Stat. §16-243bb requires the Authority to establish a maximum residential customer charge for non-electric heating residential service in each utility company's next rate increase application following the passage of the new legislation.

The Company is the first EDC in the state to define the new maximum customer charge. Nonetheless, CL&P considered the initial interpretation of this legislation to be sufficiently important enough to request Intervenor status limited to this one issue. The new legislation requires the Authority to adjust the residential customer charge:

> . . . to recover only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service.

The Company included an additional worksheet to its COSS that calculated the new maximum residential customer charge (MRCC) according to its interpretation of the new legislation. The Company calculated a MRCC of $18.74 for Rate R and $22.66 for Rate RT. In comparison, the OCC calculated a MRCC of $7.50 for Residential Rate (Rate R) and $8.07 for Residential Rate Time of Use (Rate RT). The wide difference is due mainly to differing interpretations of "directly related" as discussed below. The following discussion demonstrates the differences. Aside from the OCC, a number of other parties showed interest in the MRCC.

a. Positions of Parties

The OCC offered its own calculation of the MRCC. The OCC argued that costs directly assigned to a function within a COSS model are includable in the MRCC, while costs allocated indirectly are not. As an example, the OCC accepted the inclusion of the investment in meters in the MRCC because it is a direct cost of metering. However, it faulted the Company's inclusion of miscellaneous intangible plant and general plant in the MRCC. Such costs are not part of the direct cost of metering customers and, therefore, should not be included in the customer charge. Rubin PFT, p. 13.

The OCC acknowledged that some cost allocations were needed to determine the appropriate level of cost to include in the MRCC. For example, determining the cost for maintenance of service lines required allocation because the Company accounts for the maintenance of all distribution lines in a single account. Similarly, since accumulated deferred tax is calculated at the Company level it must also be allocated among all includable plant accounts. The OCC provided its own recommended MRCC of $7.50 and $8.07 for Rate R and Rate RT, respectively. The OCC also provided a second calculation that assumed the Authority would include some level of overhead calculations. These rates were $8.56 and $9.36 for Rate R and Rate RT, respectively. Rubin PFT, pp. 14-17. During the hearing proceeding, the OCC indicated that it had found an error in its previous MRCC calculations. It inadvertently had omitted supervision and engineering costs for distribution, supervision costs for customer service, and deferred taxes on the allowance for bad debt. As a result, the OCC recommended a combined MRCC charge of $8.73 for Rate R and Rate RT. Late Filed Exhibit No. 64; Brief, p. 133.

The AG stated that the Company should include only directly related costs in the MRCC and provided an example using rate base. The cost of meters should be included because they are clearly directly related. However, indirect costs incurred for such items as buildings, furniture and other overhead costs should not. The AG also recommended to exclude such costs as taxes, amortization and regulatory commission expense. Once

established, the MRCC should remain constant throughout the three year rate plan. The AG asserted that unreasonably high customer charges are regressive and have a negative impact on lower income customers. AG Brief, pp. 34 and 35.

The BETP testified that only direct costs incurred for specific plant and equipment located on a customer's premise should be collected through the MRCC. Lower customer charges result in larger energy charges that provide a better price signal. Quinlan, PFT pp. 4-6. BETP also supported the OCC's recommendation for a lower residential charge and stated that the Company overstated the MRCC by including many costs that are not directly related. Only those fixed costs and operation and maintenance expenses that are immediately connected in a straightforward manner should qualify for inclusion in the MRCC. While the BETP recognized that the legislature provided the Authority with the discretion to define the new legislation, it anticipated a new, reduced customer charge would be the result. BETP Brief, pp. 6-11.

The Acadia Center (AC) also supported the OCC's recommendation for a lower residential customer charge. The AC claimed that the Company is attempting to include all related costs, as opposed to only directly related costs, in the MRCC. The AC argued that a "definitional cap" is appropriate and that there should be a reduction in the customer charge when the new law is applied. Finally, higher energy charges afford customers better control over their utility bills. Brief, pp. 2–6.

CL&P strongly urged the Authority to defer the ultimate definition of the MRCC to the Electric Generic. Deferment would afford CL&P full due process rights to advance its position concerning the definition of the new MRCC. CL&P also noted that the OCC commented that time constraints precluded a comprehensive analysis in the instant case and the OCC's definition of the MRCC is flawed. Lastly, UI's definition did not go far enough in defining service line costs. Brief, pp. 2-8.

b. Discussion

Various parties have offered definitions or examples of investments and operation and maintenance costs that should be considered "directly related" to metering, billing, service connections and the provision of customer service (allowable functions). All parties agree that direct costs i.e., costs that are solely attributable to individual customers, and/or located on customer premises are "directly related." The parties dispute whether, or to what extent indirect costs i.e., costs for items that are jointly attributable to residential and non-residential customers may be considered "directly related." If "directly related" were interpreted to exclude all indirect costs, as BETP contends, this could result in the exclusion of all costs associated with some of the eligible functions specified in Conn. Gen. Stat. §16-243bb, namely billing and provision of customer service. By contrast, including all indirect costs that are "necessary" for each of the eligible functions, as the Company appears to propose, could result in the inclusion of costs for overhead items that have only a de minimis relationship to residential customers such an interpretation of "directly related" is overly broad.

For the purposes of this Decision, and subject to further clarification in the Electric Generic, the Authority concludes that the term "directly related" as used in §16-243bb refers to direct costs as well as those indirect costs that are continuously or immediately

utilized to provide the four functions identified in Conn. Gen. Stat. §16-243bb for residential customers. This interpretation of "directly related" may include costs for items, such as the meter data management system (MDM) and the hardware that hosts the MDM that are jointly used for residential and non-residential customers. In which case, the pro-rata share of such costs should be included in the MRCC. Conversely, it may not include costs for items such as intangible plant, office furniture, and equipment that are only periodically, or minimally utilized for allowed residential customer functions. Proper application of this definition will require allocation of costs at a sub-account level, to ensure that the presence of a "directly related" cost within an account does not improperly subject the entire account to include MRCC. Applying this definition at the sub-account level is impossible to accomplish based on the incomplete evidentiary record in this proceeding. Therefore, in the instant case, to ensure basic compliance with Conn. Gen. Stat. §16-243bb, the Company will assume a test year MRCC of $8.50 and $9.50 for Rate R and Rate RT, respectively. Rate year 1 MRCCs will be adjusted upward by the rate year 1 overall revenue increase approved by the Authority. The Company will then design rates in conformity with other directives from this starting point.

The Company was afforded limited time to develop the MRCC in the instant case. However, its MRCC calculation as submitted is incomplete and cannot be relied on in this Docket. Although the Authority still has concerns with the MRCC definition submitted by the OCC, the OCC"s submission contains accounts that all parties agree are directly related. The Authority will expand the scope of the Electric Generic to include a complete vetting of the MRCC calculation. The expansion will afford both EDCs and all interested parties an equal opportunity to be heard.

Therefore, the Authority will reopen the instant case to re-examine the MRCC for rate years 2 and 3 if there are any significant changes with regard to the MRCC in the Electric Generic. Given the combination of the approved rate year 1 overall revenue increase discussed in Section II.F. Sales Forecast and introduction of the MRCC, the Authority estimates that the overall annual rate impact on a typical residential Rate R customer using 500 kWh per month will be an increase of approximately 3.2%.[18]

2. Pole Attachment Rates

UI proposed to modify the tariffed pole attachment rates for cable television (CATV) and telecommunications service providers (Telecom). Specifically, CATV pole attachment rates would increase from $10.55 to $24.43 per year and Telecom pole attachment rates would increase from $17.40 to $25.51 per year for UI solely owned poles. For jointly owned poles, UI bills half the proposed annual pole attachment rate. Tr. 9/21/16, p. 1135.

UI testified that the proposed CATV pole attachment rate increase is larger than the Telecom rate increase because the current CATV rates, last approved in the 2008 UI Rate Case, inadvertently applied a pole count that was nearly twice as large as the weighted value pole count utilized in UI's current application. The pole count is used as the denominator in the formulas used to calculate pole attachments rates and the higher

[18] The Authority applied the rate year 1 approved revenue requirement increase to Rate R on the same proportional basis relative to the overall revenue increase as the Company's proposal.

the pole count, the lower the pole attachment rate. UI claimed that current CATV pole attachment rates are understated because the Company inflated its pole count by counting all poles, regardless of ownership, as one pole in the 2008 UI rate case. For the Telecom Pole Attachment Rates approved in the 2013 UI rate case, the Company applied a weighted value or equivalent pole count in its calculation. The Company testified that an equivalent pole count, where jointly owned poles are counted as 0.5 or one half of a pole, is the correct method to count UI's poles. Colca PFT, pp.16 and 17.

The Company characterized its methodology for calculating the CATV and Telecom pole attachment rates as applying the Federal Communications Commission's (FCC) pole attachment formulas with some modifications. Tr. 9/20/16, p. 1141. Specifically, the Company identified two deviations from the FCC formula: the use of unbundled distribution quantities for investment and expenses and an allocation of general and intangible plant investment to the total cost of a bare pole. The Company cited UI's pole attachment rates approved in its 2008 and 2013 UI rate cases as justification for applying this methodology to calculate the proposed rates in the instant case. Response to Interrogatory RA-18.

UI determined that its net pole investment was $89.4 million using the unbundled methodology for net pole investment and expenses. To determine the total pole investment to recover per pole, UI applied an appurtenance factor of 15%, which reduced the net pole investment amount to $76.0 million. That amount was divided by 75,929 poles (a weighted value or equivalent pole total), which resulted in a total pole investment to recover per pole of $1,001. To determine the proposed pole attachment rates, UI multiplied the total investment per pole by a carrying charge component of 35.41% and a space ratio of 6.89% for CATV pole attachments. For Telecom pole attachments, a space factor of 10.91% and an additional cost adjustment factor of 66% was applied. Colca PFT, Exhibit MPC-4. The FCC pole attachment formulas for CATV and Telecom pole attachments vary slightly. UI's proposal yields revenues of $1.9 million in rate year 1 consisting of $1.5 million from CATV pole attachments and $0.4 million in Telecom pole attachments. Late Filed Exhibit No. 55, p. 3.

The New England Cable and Telecommunication Association Inc. (NECTA) determined that an annual pole attachment rate of $12.00 for CATV pole attachments and a $12.53 rate for Telecom pole attachments for solely owned poles was just and reasonable. NECTA's proposed pole attachment rates were based on a pole count of 140,595 and a "bottoms up" approach to the calculation of an average pole investment, which totaled $491.56 per joint pole. The bottoms up approach was calculated using UI's unit costing information for a bare pole. NECTA stated that UI's proposed pole attachment methodology is incorrect in that it deviated from the FCC formula in four material respects. First, UI's net pole investment amount per pole was too high, due to an incorrect pole count that UI applied in its rate calculations. Specifically, UI incorrectly applied a shared use pole count that reduced the number of poles from 140,595 poles to 75,929. NECTA's witness testified that jointly owned pole assets must generally be borne among two owners on a commensurate 50/50 basis. NECTA concluded that the reduced pole count was not economically appropriate and justified based on the information provided. Kravtin PFT, pp. 4 and 10. The witness also provided an exhibit which applied the FCC formula and utilized UI's full pole count of 140,595 poles. NECTA

derived a per pole investment figure of $531.28 and calculated a solely owned cable attachment rate of $12.55. Kravtin PFT, Exhibit PDK-5.

NECTA testified that UI's application of a Maintenance of Distribution wage allocator increased the Company's pole investment figure by $12.0 million ($8.8 million for general plant and $3.3 million for intangible plant). These inclusions are not sanctioned by the FCC pole attachment formula methodology, add additional costs to pole investment and do not conform to the Authority's orders governing pole attachment rates. NECTA asserted that the FCC formula is already a fully allocated formula and these additional costs should not be allowed. Additionally, the Company's use of a 15% appurtenance factor in its pole attachment rate calculation was not supported by UI. NECTA's analysis concluded that at least 30% of the investment booked to UI's FERC Account 364 is comprised of appurtenances. That percentage should be applied to any calculation that allocates net investment over a total number of poles. NECTA indicated that its bottoms up approach did not rely on a 15% reduction for appurtenances to produce just and reasonable rates. NECTA also pointed out that UI's methodology to calculate administrative and tax carrying charge factors varied from the FCC formula. Lastly, UI's use of non-FCC ratios to apply carrying charge factors complicates matters in that it strayed from the FCC formula. Kravtin PFT, pp. 13 and 14.

Lightower requested that the Authority reject UI's proposed pole attachment rates and adopt a rate of $12 to $13 for wholly owned poles. Lightower stated that such a rate would meet the requirements of 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 (Fibertech Decision), and would be consistent with the rates charged by the other pole owners in Connecticut. Brief, p. 2.

Lightower argued that during the 2013 UI Rate Case, UI violated its obligations under the Fibertech Decision. Specifically, the Company failed to submit a reopener to the Authority to examine pole rates and that no telecommunications provider was given an opportunity to challenge UI's calculations and methodology during the 2013 rate case hearings. Lightower stated that the Company had been collecting a disparate pole attachment rates in the past as UI's current Telecom pole attachment rates are 65% higher than CATV pole attachment rates. Finally, Lightower characterized the Company's notification of UI's proposed rate increase to pole attachers as legally defective. It stated that UI failed to comply with Order No. 2 of the Fibertech Decision and did not provide notice of proposed pole rate changes in accordance with existing Pole Attachment License Agreements. Brief, pp. 8 and 14.

This proceeding presents an opportunity to better align the pole attachment rates between Telecom and CATV pole attachers. UI's CATV pole attachment rates did not change in 2013 due to a notification issue. Tr. 9/21/16, p. 1142. The Company's current CATV attachment rate of $10.55 was approved in UI's 2008 Rate Case. It was based on a cost methodology that utilized UI's total pole count. Each pole was counted as one pole regardless of ownership status. UI's Telecom pole attachment rate of $17.40, approved in the 2013 Rate Case was based on an equivalent pole count where jointly owned poles were counted as 0.5 poles. UI charges CATV and Telecom pole attachers 50% of the pole attachment rate when a pole attachment is on a jointly owned pole even

though the CATV and Telecom pole attachment rates are based on different pole counts. Using data provided by UI, the Authority determined that approximately 91.8% of UI's poles are jointly owned. Response to Interrogatory RA-17. Although the Company and NECTA proposals sharply differ, both parties agree that the pole count is a major factor in determining net pole investment per pole and pole attachment rates. Colca PFT, p.17; Kravtin PFT, pp. 9 and 10.

UI calculated a total pole investment to recover per pole of $1,001. The Company testified that its capital accounts include the investment for UI's ownership of each pole. It includes the cost of installed poles where UI is the sole owner; the costs of installed poles where UI is the custodian of the pole, and the costs UI pays to Frontier for poles where Frontier is the pole custodian. UI's payment to Frontier is in accordance with the intercompany operational agreement between the two companies. UI testified that the balance of the installation and material costs for Frontier custodian poles are borne by the telephone company. UI also credits its investment account for monies received from Frontier for installed jointly owned poles when UI is the pole custodian. Tr. 9/21/16, pp. 1136 and 1137. UI attributed its increase in net pole investment from its last rate case to three variables: closing out multi-year work orders in recent years in its pole replacement program; inflationary pressures; and the financial impact to the rate base of changing out an old pole to a new one when the old pole may be partially or fully depreciated and the new pole is at current material and installation costs. Late Filed Exhibit No. 54.

NECTA performed a "bottoms up" calculation using UI's pole costing information and derived an estimated average investment cost of $491.56 per pole for joint use poles. It also provided an FCC rate calculation that determined a $531.28 cost per pole. Kravtin PFT, p 16. NECTA's FCC calculation is approximately half of UI's proposed investment per pole primarily because NECTA utilized a larger total pole count in its calculations.

The Authority finds that evidence indicates that there is not a 50/50 split in the custodial relationship nor in the Company's pole investment for joint shared poles between UI and Frontier. UI is the custodian for 74,592 or 57.7% of the jointly owned poles and Frontier is custodian for 54,471 or 42.3% of the poles. UI is also sole owner of an additional 11,262 poles. UI incurs all of the costs for solely owned poles and most of the costs for UI custodial jointly owned poles. Response to Interrogatory RA-17; Tr. 9/21/16, pp. 1136 and 1137. Under a reciprocal agreement with Frontier, UI pays $325 per installed pole, when Frontier is the custodian of the pole. Response to Interrogatory NECTA-5 Supplement. The Company did not provide evidence that quantifies the UI custodial poles impacted by the reciprocal agreement with Frontier.

The Authority finds that UI is assuming the majority of costs for 85,854 or 66.4% of the poles. The reciprocal agreement between UI and Frontier, regarding jointly owned installed poles, has an offsetting affect in terms of pole investment. Use of an equivalent pole count is not unprecedented when there is joint pole ownership and was approved by the Authority in the CL&P Rate Case Decision. However, because the Company assumes the majority of costs when it is the custodian of a jointly owned pole and a lesser cost when it is the non-custodian owner, the Authority approves a modified equivalent pole count based on sole ownership and the custodial relationship. Specifically, solely owned poles and UI custodial poles shall be counted as one pole and

Frontier custodial poles shall be counted as 0.5 poles. Applying this methodology yields an equivalent pole count of 113,225 poles and a net pole investment of $582.70 per pole. The Authority accepts UI's application of a 15% appurtenance factor as reasonable and historically based in FCC findings and in its pole attachment formulas.

UI charges half the pole attachment rate when a pole is jointly owned. The Authority reviewed UI's pole count data and estimates that approximately 91.8% of the poles in UI's territory are jointly owned. Response to Interrogatory RA-17. Additionally, the Authority analyzed UI's historical pole attachment data and determined that approximately 97% of pole attachments are on jointly owned poles and, therefore, are billed at 50% of the pole attachment rate. Late Filed Exhibit No. 55. UI will continue to charge half the annual rate for all jointly owned poles.

The Authority rejects the Company's proposed pole attachment rates and finds that UI's use of unbundled distribution quantities for investment and expenses are inconsistent with the FCC formulas. The Authority agrees with NECTA that the Company's inclusion of $8,754,040 for general plant and $3,287,749 for intangible plant should not be included in UI's calculations. The Authority also finds that UI should apply the FCC ratios for the carrying charge factors. These adjustments are consistent with the FCC pole attachment formulas.

The Authority will require UI to recalculate its Telecom and CATV pole attachment rates using the modified equivalent pole count stated above and apply the FCC pole attachment formulas as it did in its response to Interrogatory RA-17. Applying the above revisions, the Authority calculates the annual CATV pole attachment rates for solely owned poles to be $14.32 and the CATV annual rate for jointly owned poles to be $7.16. The annual Telecom pole attachment rates will be reduced to $14.96 for solely owned poles and $7.48 for jointly owned poles and overall, pole attachment rates will be priced closer to parity. This will result in a $767,074 revenue reduction for pole attachments from UI's final proposal in rate year 1, a $773,281 reduction in rate year 2 and a $779,487 reduction in rate year 3.

3. Residential Service Rates

Public Act 05-1, An Act Concerning Energy Independence, required the EDCs to implement time-of-use, interruptible and seasonal rates for all customers. Public Act 07-242, An Act Concerning Electricity and Energy Efficiency, directed the Authority to implement programs and measures to reduce peak electric demand. Combined, these legislative initiatives provided comprehensive, long-term energy policy directives. These laws significantly increased the financial benefit for net metering and directed the implementation of dynamic rate design strategies including time-of-use, seasonal or other rate designs. In addition, Public Act 07-242 directed the EDCs to submit a plan to deploy advanced meters. It required that such meters be capable of tracking hourly consumption to support net metering and proactive customer pricing signals through innovative rate design, such as time-of-day or real-time pricing of electric service for all customer classes. Licensed electric suppliers and aggregators were also required to offer dynamic rates.[19]

[19] See Conn. Gen. Stat. §§16-245(g), 16-243h, 16-243n, and 16-243w.

New and relocating customers are generally assigned to Rate R and can request information about Rate RT. The Company proposed to eliminate the requirement that Rate R customers whose energy consumption equals or exceeds 2,000 kWh in any one monthly billing period must be placed on UI's residential time-of-use tariff, Rate RT. UI also proposed that this policy be modified to allow any customer who was placed on Rate RT under the mandatory switch policy to return to UI's non time-of-use tariff, Rate R. In support of its request, UI stated that the mandatory time-of-use policy is unpopular with its residential customers, it causes additional administrative expense both to process the tariff change and to address complaints and appeals by customers seeking to avoid being switched or who request to be placed back on Rate R. In addition, UI notes that there is currently no statewide policy regarding mandatory residential time-of-use rates. Colca PFT, p. 10; Tr. 9/20/16, p. 1065; Late Filed Exhibit No. 51, Attachment 1, pp. 5 and 6.

UI reported that many customers do not have the flexibility to adjust usage to off-peak periods when the price advantage of Rate RT is assessed. While Rate RT is a valuable tool that should be available to address peak electric demand, service under that rate should be voluntary. UI would support the application of mandatory residential time-of-use rates if it were a statewide policy. Until that occurs, the current policy should be amended as proposed. Tr. 9/20/16, pp. 1229-1231; Brief, p. 138.

The AG asserted that time-of-use rates should remain available to customers but should be voluntary. Time-of-use rates are punitive to customers who are unable to shift their energy usage to lower cost times of day, such as the elderly, those caring for small children or the infirm and customers who work irregular hours. The AG noted that CL&P does not have mandatory time-of-use rates, which raises questions of continuing to apply this policy only in UI's service territory. The AG supported UI's proposal to eliminate the mandatory switch to Rate RT. Brief, p. 36.

The BETP recommended that the Authority deny UI's request to eliminate the mandatory assignment to Rate RT. The Company currently serves nearly 70,000 customers on the residential time-of-use rate. The BETP argued that since 2014, UI has only received 237 complaints or about 3% of the 7,340 customers that have been assigned to Rate RT during that time. The BETP challenged UI's assertion that customers who are allowed to return to Rate R will lower their electric cost. Under UI's proposed rates, a Rate RT customer with a typical residential load profile has the potential to annually save $127 in 2016, $329 in 2017 and $429 in 2019. The BETP also cited Connecticut's 2013 Comprehensive Energy Strategy to support its recommendation to maintain the Rate RT policy for UI, noting that time-of-use rates are a significant component of Connecticut's energy policies. The BETP asserted that the current policy does not allow a customer assigned to Rate RT to return to Rate R. Instead, the assignment is permanent. It is reasonable to allow a customer who has exceeded 2,000 kWh to return to Rate R if the customer does not exceed that level of consumption for 12 consecutive billing periods. However, UI should be required to provide bill comparisons to any such customer before they are allowed to return to Rate R. The Company should improve the educational material provided to all residential customers regarding the time-of-use rate to advance Connecticut's energy policy goals. Brief, pp. 11-14.

Pursuant to the 2006 Rate Case Decision, the Authority approved UI's proposal to merge the Company's two residential time-of-use rates, its residential time-of-use tariff Rates RT and residential heating and off-peak tariff, Rate A. UI proposed to combine its two residential time-of-use rates to simplify its tariffs and to provide expanded off-peak hours to customers being served under Rate A. Under its proposal, Rate A was eliminated and all customers served under that tariff were placed on Rate RT. 2006 Rate Case Decision, p. 118. UI served approximately 35,000 customers under Rate RT after the tariffs were merged.

Pursuant to the August 30, 2006 Supplemental Decision, in Docket No. 05-06-04, Application of The United Illuminating Company to Increase Its Rates and Charges, Supplemental Decision (Supplemental Decision), the Authority approved UI's request to implement the mandatory assignment of residential customers to Rate RT when a customer exceeded a pre-determined consumption threshold during UI's summer billing months of June through September. Under UI's proposal, once the threshold was breached, the customer's account would be transferred to Rate RT on January 1st of the following year. The customer could return to Rate R if the monthly consumption remained below the then current threshold for 12 consecutive months. Supplemental Decision, pp.11-15.

The mandatory assignment of residential customers to a time-of-use rate was also approved for CL&P as part of a statewide effort to increase the number of customers taking service under a time-based tariff. The number of peak hours under CL&P's residential time-of-use tariff was also reduced to align with the UI tariff. Decision dated December 21, 2006, in Docket No. 05-10-03, Application of The Connecticut Light and Power Company to Implement Time of Use, Interruptible or Load Response, and Seasonal Rates, pp. 11, 17-22, 36 and Order No.10. This policy was suspended for CL&P pursuant to the Decision dated December 19, 2007, in Docket No. 05-10-03RE01, Application of The Connecticut Light and Power Company to Implement Time of Use, Interruptible or Load Response, and Seasonal Rates – Review of Metering Plan, p. 26.

Although UI's 2006 proposal would have allowed customers to return to Rate R, the Company testified that over time all customers should be served under seasonal time-of-use rates and had planned to increasingly lower the monthly threshold until all customers were assigned to Rate RT. UI suggested that the transition to universal time-of-use rates occur over a six to seven year period and that it would educate its customers regarding this policy during that transition. UI concluded that it was necessary to require that all customers be billed under time-based rates to avoid free riders, increase awareness of the cost associated with using electricity during peak periods and provide a financial incentive to modify use. The Authority modified UI's proposal by expanding the thresholds to include consumption of more than 2,000 kWh in a billing cycle, requiring that customers not be allowed to return to Rate RT. The number of peak hours was reduced under Rate RT to provide customers with a greater opportunity to shift consumption. The time-of-use policy has not been implemented statewide. The Authority agrees with UI that the program should be suspended until such time as a statewide policy is reinstated, subject to the conditions discussed below.

The Authority reviewed UI's metering infrastructure to determine compliance with Public Act 07-242 and to evaluate whether to replace existing meters or to expand the

installation of existing, compliant meters. Advanced meters are necessary to gather the data needed to support time-of-use rates and other requirements of that Act. Pursuant to the March 19, 2008 Decision in Docket No. 07-07-02, Application of The United Illuminating Company for Approval of Metering Plan, the Authority approved UI's plan to install additional advanced meters to gradually achieve system-wide deployment and the investment in the communications and meter data management (MDM) technology platforms needed to support the information that the additional advanced meters would provide.

Dissatisfaction among some residential customers regarding the mandatory assignment to the time-of-use rate forms the basis for UI's proposal to modify the policy. The Authority also fields inquiries and complaints about this policy. UI's time-of-use policy began in 2006 and was later reviewed in 2011. See, Decision dated September 21, 2011, in Docket No. 05-06-04RE06, Application of The United Illuminating Company to Increase Its Rates and Charges – Review of VVP Pricing, Mandatory TOD and Seasonal Rates. In that docket, the Authority found that the phase-in of mandatory residential time-of-use rates had been completed, reaching the 2,000 kWh threshold, and that approximately 48,000 customers or 16% of UI's total of 285,000 residential customers were taking service under Rate RT. The Authority also noted that due to unusually hot weather during the summer of 2010, about 7,000 additional customers, those whose monthly consumption normally did not exceed 2,000 kWh, were assigned to Rate RT. Although many of these customers initially complained about the assignment to Rate RT, after being on the rate for several months customers realized that their costs were lower without modifying their consumption. As a result, UI reported that its experience with the policy has been positive. 2005 UI Rate Case Decision, p. 3.

The nature of recent complaints is similar to those reviewed in the past and demonstrates the long-standing misperception among customers that the time-of-use policy is punitive, over-reaching and that assignment to Rate RT will increase cost. The assignment to Rate RT is neither punitive nor over-reaching and was meant as part of a statewide effort to further Connecticut's energy policies. The policy was also intended to leverage UI's investment in advanced meters by providing more information to customers to target overall use and peak demand. UI continues to notify customers when they approach the 2,000 kWh threshold, warning of the potential assignment to Rate RT. UI also notifies the customer when the threshold is breached and permanently assigns them to Rate RT. Although the language and tone of UI's notification have changed somewhat over time, the content, and overall approach to effectuating this policy has not. As a result, the message and delivery irritates some UI customers. Tr. 10/6/16, p. 1897.

The evidence shows that customers assigned to Rate RT typically do not experience an increase to their annual electric cost and in most cases realize savings. However, these customers continue to believe that their electric bill will dramatically increase as a result of the assignment to Rate RT. As was the case in 2010, customers tend to understand the bill impact only after being placed on the time-of-use rate for several months and then realizing that their costs have not increased and are actually lower even without changing their lifestyle. Although UI's form letter provides general information about the impact to a customer's bill the Company does not provide specific information, (i.e., a proactive bill comparison, tailored to each customer's actual use as

part of the implementation strategy). UI stated that its meters are capable of gathering the data necessary to provide such a comparison and that it has considered this approach. However, UI has not modified its time-of-use program to provide this information due to the potential cost. Tr. 10/5/16, pp. 1681-1685.

UI's Rate R bill lists each of the unbundled components that comprise the total charges for delivery and supply. The Rate RT bill expands this list to show the peak and off-peak rate for most components. The Rate RT off-peak transmission rate is $0.000/kWh but UI does not display this line on the Rate RT bill because the total charge is zero. Tr. 10/5/16, p. 1685. However, the Rate RT bill does not summarize these costs or otherwise provide an at-a-glance comparison of the total peak and off-peak rates. As noted by UI, the customer must manually calculate these values. In addition, although the billing statement provides net metering customers with monthly peak and off-peak production, net usage and kWh bank balance, this information is very difficult to interpret, requiring the customer to seek assistance through the UI website or call center. UI has not made significant changes to its billing statement for some time and did not propose any changes to its bill or web presentation in this instant proceeding. Therefore, UI was unable to develop recommendations or cost estimates for updating its bills or website. Tr. 9/20/16, pp. 1097-1103; Tr. 10/16/16, pp. 1685-1683; Late Filed Exhibit No. 52.

UI has completed the installation of its MDM system, which collects time-of-use, demand and interval data for all residential customers served through an advanced two-way meter. Approximately 60% of all UI customers are served through an advanced two-way meter which includes many, but not all customers taking service under Rate R. As a result, UI has time-of-use data for many Rate R customers. Tr. 10/6/16, pp. 1887-1890.

In 2012, UI conducted a study to determine whether customers who were assigned to Rate RT had shifted their electric use to the off-peak period to benefit from the lower price (Usage Study). UI carefully screened participants to assure it only analyzed data for customers with an advanced meter who had not relocated during the study period and could demonstrate at least one year of data. UI testified that as a result, the study population was very limited. The Usage Study concluded that Rate RT customers did not shift any meaningful consumption to the off-peak period. UI has not conducted any additional studies since 2012. Response to Interrogatory RA-49; Tr. 10/6/16, pp. 1893-1897.

In addition to the tariffed medical exemption, UI has granted just cause waivers to the time-of-use policy. For example, repairing water or storm damage may require the use of fans or other construction equipment resulting in a one-time anomalous use of electricity. UI has been diligent in its review of these requests, requiring that customers produce contractor records or other evidence to support these claims. These reviews are time consuming and costly and at times have occupied significant senior UI staff resources. UI stated that its proposed modifications would eliminate customer complaints and reduce the administrative burden associated with reviewing these requests. Tr. 9/20/16, pp. 1059-1064, 1067. The Authority is aware of the practice to grant waivers and commends UI for its thorough review of these claims.

The Authority concludes that customer dissatisfaction has resulted from misperception fueled by the lack of clear and meaningful information about Rate RT and overall program delivery. Modifying the bill will also help Rate R customers in deciding whether to take service under the time-of-use tariff. UI did not propose any bill format modifications in this proceeding. However, the Authority finds that customers will benefit from changes to the way information is presented on UI's bill.

As discussed above, UI has made significant investments in equipment and resources to further the energy policies identified through Public Act Nos. 05-1 and 07-242, which policies remain in place. However, UI has not fully utilized its investment and resources in support of the time-of-use policy, but is well positioned to do so. While the Authority is suspending this policy due to the lack of a statewide implementation strategy for now, it will not abandon its effort to address these important energy policies. The evidence reveals the result of UI's efforts in administering the time-of-use program. Customers continue to complain when notified by UI believing they are being punished and that their electric bill will significantly increase. Further, customers assigned to Rate RT have not reduced demand or shifted any meaningful consumption to the off-peak. The Authority continues to support that customers should gradually transition to Rate RT and eliminate comparisons to Rate R. Instead of comparing overall cost to a flat rate, customers should be comparing overall cost based on their load profile.

The following actions will provide customers with additional tools necessary to reduce energy consumption and control peak demand in furtherance of Connecticut's energy policies. Based on the foregoing the following directives will provide customers with additional tools necessary to reduce energy consumption and control peak demand. The Authority concludes that these actions are required to further Connecticut's energy policies. Based on the foregoing, the following actions are required:

- On April 3, 2017, the Company will suspend the requirement to switch Rate R customers to Rate RT.
- The Authority will revisit the mandatory assignment to a time-of-use rate in the future.
- Customers that have been assigned to Rate RT under the mandate will be allowed to return to Rate R after UI provides information about time-of-use rates, which must include, but not be limited to, historical annual bill comparisons. One of the comparisons would use Rate R and the customer's actual consumption and the second would use Rate RT and show the cost if the customer were to improve their load profile by 10%.

4. Tariff Changes

a. Terms and Conditions

The Company proposed to update provisions in the Terms and Conditions to add greater specificity and clarity to those provisions. UI cited specific documents and dockets in the Terms and Conditions that are relevant to the provisions. The table below lists the proposed changes to the Terms and Conditions. Colca PFT, p. 18.

Section	Description
1.c	Added reference to a UI construction guideline document
2.c	Added provision to identify and seek legal recompense for unauthorized unmetered service
2.d	Added provision to include reasonable access to the Company' equipment in regard to disconnection
3.a	Added references to sections 3.f and 3.g
3.f	Added reference to a PURA docket number
4.a	Added language to include locking meters and tampering with locks
6.(iii)	Added provision regarding meter exchanges
8.b	Inserted provision to hold the Company harmless for unauthorized attachment of monitoring devices
8.c	Renumbered the exiting provision 8.b to 8.c
9.(v)	Inserted provision regarding customer provision of working space for the Company's equipment
13	Inserted section regarding scheduled outages

The Company's changes to the Terms and Conditions clarify, add to, and/or reinforce the current language in the specific sections. Responses to Interrogatories RA-30 through RA-37. The Authority finds that the new language is in keeping with that goal and there were no objections from the Parties. Therefore, the Authority approves the proposed tariff changes.

b. Miscellaneous Fees

The Company proposed to modify or eliminate certain provisions of the Supplier Relations Fees, Standard Field Fees and Billing Terms and Conditions. The table below lists the proposed changes to the provisions of Appendix A of the Terms and Conditions. Colca PFT, pp. 18 and 19. UI also proposed to adjust its return check fee from the current $23.28 to $25.89 in rate year 2017, $26.44 in rate year 2018, and $27.01 in rate year 2019. Response to Interrogatory RA-12, Attachment 1.

Proposed Revisions to Miscellaneous Fees

Section	Description
Supplier initialization	Added language to specify that the rates are based on average costs
Call to crc for a supplier	Updated the rates and updated the name of the UI customer service group
Provision of customer service for energy suppliers	Updated the rates and updated the term used to refer to an individual UI customer service representative
Meter test	Changed references from DPUC to PURA
Cost to provide special or expedited meter reads	Removed a specific vendor name from the section and added provision for customers to have meters read for off-cycle supplier switches
Cost to provide special or expedited meter reads amr/ami	Removed a specific vendor name from the section and added provision for customers to have a meter read off-cycle manually
Cost to provide interval meter data	Eliminated the availability of interval data files
Web presentment fees	Eliminated the availability of cellular and landline communication methods
Reconnect fees	Eliminated provisions for manual reconnections
Connect/disconnect for temporary service	Added a fee for the connection and disconnection of temporary basic single phase residential overhead services

The OCC stated that the proposed increase to the returned check fee is not consistent with the process costs incurred by UI. The proposed fee is significantly higher than similar charges imposed by UI's corporate affiliates that are also distribution utilities. The proposed charge also fails to recognize significant changes that are occurring in the utility and banking industries concerning the fees for, and cost of processing, returned electronic payments. Rubin PFT, p. 31.

UI asserted that the fees would be charged in the closest current year for returned checks and inflating the charge by 1.75% for each of the rate years. The total fees charged would be divided by the total number of checks and then added to UI's labor costs. Additionally, the returned check fee was cost-based only, with no mark-up or profit. Tr. 10/05/16, pp. 1583-1586, 1588. In proposing to update the fees, the Company assumed escalating rates based on the average increase in wages for the last two contracts of 3.0% or greater per year and a consistent rate of 1.75% utilized in the rate case for all escalations. Response to Interrogatory RA-30. The Authority finds these assumptions to be reasonable and approves the proposed changes to these fees.

5. Summary

The Authority will direct the Company to file a Rate Plan for the rate years incorporating the approved revenue requirement in Section V. Rate Model and Section II.H. Gross Receipts Tax and the guidelines established in Section II.F. Sales Forecast

Subsequent rate plans for rate year 2 and rate year 3 will be submitted to the Authority incorporated the directives herein and the directives ordered after the conclusion of the Electric Generic.

K. REVENUE INCREASE

The Company proposed the following class revenues for rate year 1.

	2017	2017		
	Present	Proposed	Change In	Percentage
Rates	Revenue	Revenue	Revenue	Change
R	$127,112,709	$144,041,376	$16,928,667	13.3
RT	61,170,152	67,594,901	6,424,749	10.5
GSU	342,740	378,901	36,161	10.6
GSN	5,936,434	6,562,260	625,826	10.5
GSD	27,574,687	30,476,015	2,901,328	10.5
GSTN	786,968	908,151	121,184	15.4
GST-SS	43,516,195	49,996,065	6,479,870	14.9
GST-LRS	7,164,052	8,431,933	1,267,881	17.7
LPT-SS	9,656,987	11,063,887	1,406,900	14.6
LPT-LRS	17,925,053	20,966,804	3,041,750	17.0
M	9,827,993	11,212,874	1,384,881	14.1
U	661,323	709,126	47,803	7.2
Total	$311,675,292	$352,342,292	$40,667,000	13.0

The rates of return from the COSS were used as a guide to allocate the proposed revenue requirement increase among the rate schedules. The Company proposed a rate design to move all rate schedules to the equal RORs in the next four years. Colca PFT, p. 9; Response to Interrogatory RA-1.

The proposed increases satisfy the Authority's basic revenue increase formula ordered in the Company's last rate increase application. Namely, no rate class revenue reduction or increase should exceed one and one-quarter times the overall distribution revenue increase. While the percentage increase for several classes exceeds the 16.25% maximum (13.0% x 1.25), the dollar and percentage error is still small enough as to be acceptable.

The OCC recommended that the Authority adopt a primary revenue adjustment policy wherein no class should receive a percentage increase that is more than 150% of the system average increase or less than 50% of the system average increase. The OCC stated that using these limits helps to move each class closer to the cost of service. It avoids unusually large rate increases or extremely small increases for classes that already are paying more than the cost of service. Rubin Supplemental PFT, p. 29.

The Authority finds the Company's proposed revenue allocation plan to be appropriate. A similar plan that stays within the Authority's 25% rule while improving RORs shall be utilized to develop compliance rates for all three rate years.

L. GROSS RECEIPTS TAX

During the proceeding in Docket No. 14-09-09, PURA Investigation of Utility Billing of Gross Receipts and Sales and Use Taxes (GRT Investigation), two issues arose that are relevant to the instant case. First, the question of whether nursing homes and other similar businesses offering residential-in-nature services should be classified as either commercial or residential for receiving electric and natural gas service. The Authority required additional information concerning existing practices before settling this issue. Decision dated August 3, 2016, in the GRT Investigation, p. 7. In UI's case, all nursing homes and similar residential-in-nature customers are classified as commercial electric service customers. Tr. 9/20/16, p. 1165. The Authority directs the Company to continue to follow this practice.

The second issue required all gas and electric utilities to file revenue and rate design calculation exhibits in a rate application absent any embedded GRT values. The GRT expense will be added as the last step when designing tariff rates. The Company stated that it will file final rates in this proceeding utilizing this technique. Response to Interrogatory RA-39. The Authority will direct the Company to comply with the above when designing rates.

M. STORM RECOVERY COSTS

1. Lean-In Costs

UI requested authorization to recover future incremental pre-staging or lean-in costs through the storm reserve. The types of costs to be recovered are those incurred for the purpose of deploying personnel and securing resources in advance of major storms, such as securing external line and tree crews, food and hotel support to accommodate such crews, travel time for those crews and incremental overtime. Because outside resources must be pre-arranged from locations that may be multiple days' travel time from Connecticut, financially significant decisions must be made in advance of storm impact. Whether the storm materializes or not, UI still incurs these costs. Reed and Thomas PFT, pp. 37, 39 and 43.

The Company proposed to track its incremental lean-in costs and charge them against the storm reserve. It did not propose to establish a separate reserve for lean-in costs. Id., p. 39. Rather, UI proposed a threshold for the recovery of lean-in costs. In those cases where the threshold is met, lean-in costs would be recorded to the storm reserve for review and collection similar to other costs charged to the reserve. According to UI, recovery of lean-in costs would be allowed where:

- UI's Incident Commander determines that circumstances warrant activation of the Emergency Response Plan (ERP);
- pre-staging of resources is appropriate as part of the ERP activation to facilitate the efficient restoration of service to potentially affected customers;
- pre-staging of resources will require UI to incur incremental cost due to the circumstances at hand; and
- UI provides written notice to the Authority informing the PURA of: (1) the

activation of the ERP; (2) the event classification declared; and (3) the decision to pre-stage resources with the potential to incur incremental cost.

Id., pp. 39 and 40.

UI demonstrated lean-in costs of $597,704 for the 2015 Winter Blizzard, $40,128 for Hurricane Joaquin (which was forecasted to possibly impact Connecticut, but turned out to sea), and an estimated $154,500 for the 2016 Tropical Storm Hermine that did not impact UI service. Late Filed Exhibit No. 25. Additionally, during the approach of Tropical Storm Hermine, two of UI's New York sister companies made resources available to the Company that it did not have to pay because of its merger with Avangrid. Tr. 9/12/16, p. 68.

The AG had no objection to allowing UI to use the storm accrual for legitimate pre-staging costs so long as the Authority has approved sufficient standards/guidelines governing such usages of the storm accrual fund. Brief, p. 25.

The Authority previously recognized the major benefits of pre-staging resources to storm restoration and public safety. For example, see the Decision dated August 1, 2012 in Docket No. 11-09-09, PURA Investigation of Public Service Companies' Response to 2011 Storms, pp. 50 and 51. The Authority also recognized that decisions on pre-staging must be made several days in advance of catastrophic storms, when the severity and timing of such storms may not be known; however, the PURA has encouraged the EDCs to make conservative decisions to ensure the state is adequately prepared for a catastrophic storm. Id. The Authority finds that since it has strongly encouraged both Connecticut EDCs to take actions that would require them to incur pre-staging costs, the PURA should also provide surety that the costs are recoverable to lessen any financial disincentive to take those actions. As these are preparation costs for storms that may never occur, the Authority will look for prudent decision-making as they are incurred. Therefore, the Authority will allow the Company to recover lean-in costs from the storm reserve for those storms that are forecasted to seriously impact electric service, but do not. The Company shall separately account for lean-in costs in the storm reserve. Detailed activity in these accounts will be subject to audit and review at the Company's next rate filing or any other period deemed necessary by the Authority.

2. Storm Reserve

UI requested that the Authority continue to allow it to fund its major storm reserve at $2 million per year and include the amount in distribution rates. The Company also proposed to continue treating major storm costs in excess of the cumulative amount in the reserve as a regulatory asset to be recovered in future rate proceedings. The reserve balance as of March 31, 2016, was $5.3 million. UI projected that the storm reserve would have ending balances of $6.763 million in 2016, $8.763 million in 2017, $10.763 million in 2018 and $12.763 million in 2019. UI has not incurred costs related to a major storm since the reserve was reinstated in the 2013 UI rate case. Additionally, UI proposed that the Authority allow it to continue to apply the customers' 50% share of earnings sharing to the deferred major storm costs. Finally, UI proposed that the Authority allow the Company to charge the major storm reserve for the costs incurred for pre-staging personnel and resources for expected major storms. The recovery of the

pre-staging costs would not be subject to the $1 million per occurrence major storm threshold established in the 2013 UI rate case. Favuzza PFT, pp. 33 and 34; Schedules B-1.0 A, B and C; B-8.0 A, B and C; C-3.6 A, B and C.

The OCC indicated there is no need for the Company to accrue and receive a return on $12.763 million of storm reserve balance as of 2019. The OCC disagreed with the Company's proposal to continue accruing $2 million per year into the storm reserve account and recommended a reduction of $2 million to the O&M expense in each of the rate years. The adjustment would increase rate base, net of deferred taxes, by $0.592 million in 2017, $1.819 million in 2018 and $3.068 million in 2019. The OCC stated that its recommendation is consistent with the 2005 UI Rate Case. In that Decision, the Authority determined that the storm reserve balance at of $3.7 million was sufficient to provide the Company protection against a potentially catastrophic event and disallowed the complete storm reserve expense. Moreover, if a catastrophe occurred and the associated costs exceeded the amounts in the reserve account, the Company could petition the Authority to seek recovery of the excess amounts. Schultz III/Defever PFT, pp. 29-32.

The OCC argued that maintaining the current annual storm reserve accrual and reserve balance based on the 2011 and 2012 storm costs is misleading. The OCC noted that based on The Liberty Consulting Group's findings, in Docket No. 11-09-09, PURA Investigation of Public Service Companies' Response to 2011 Storms, the costs of the 2011 and 2012 storms could have been substantially lower than the amounts incurred by UI. Also, the OCC stated that based on the findings herein, the UPZ program has the potential to cut storm costs significantly, as such, the damage from a similar future storm should be considerably smaller. Furthermore, the OCC stated that the storm reserve should not be seen as a means to fully fund the next catastrophic storm that hits UI's service territory and to subsidize the reserve to an unnecessary level. Hence, the OCC maintained its recommendation that the storm reserve accrual be suspended. OCC Written Exceptions, pp. 28 and 29. In the 2013 UI Rate Case, the OCC did not oppose the storm reserve accrual on the condition that only significant storms such as Irene, Sandy and the October 2011 snowstorm are charged against the reserve. The OCC had proposed that only catastrophic storms with costs exceeding $5 million be charged to the reserve. 2013 UI Rate Case Decision, p. 45.

In the 2013 UI Rate Case Decision, the three major storms including Irene (August 2011), the October 2011 Snowstorm and Sandy (October/November 2012) cost ratepayers approximately $42 million. 2013 UI Rate Case Decision, p. 24. The current storm reserve level was established in the 2013 UI rate case. The Authority considers the current reserve approach a useful tool to help mitigate rate shocks often associated with regulatory assets such as storm recovery costs. The current reserve balance of $6.763 million is not excessive when recent history is considered. The Authority does not consider it prudent to stop the storm reserve accrual just three years after it was implemented. The Authority will allow UI to continue to offset deferred major storm costs with the customers' 50% share of earnings sharing in the event that major storm costs exceeded the accumulated storm reserve balance. Customers will continue to receive a bill surcredit when there are no deferred major storm costs to reduce their shares of

earnings sharing amount. UI would incur such storm costs during periods between rate cases and the Authority has the right to review them for prudency.

N. 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. 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. Response to Interrogatory CA-2. UI has also affirmed that in compliance with applicable regulations unregulated charges are never included in a termination notice. Application, Schedule H-2.0 and H-2.1; Responses to Interrogatories CA-2 and CA-3, CA-4 and CA-14.

Currently, as required by regulation, the Company mails e-bill customers a termination notice through the United States Postal Service (USPS). The Company includes a message on the electronic bill statement displaying a message that a shut off is pending; however, the Company does not send a separate termination notice via email. Response to Interrogatory CA-5. While UI's current procedure of mailing the termination notice via USPS complies with the requirements of Conn. Agencies Regs. §16-3-100, a separate e-mailing of the same notice would be a welcome addition to e-bill customers. Accordingly, the Authority will require UI to explore the feasibility of providing a separate e-mailing of the termination notice to e-bill customers that coincides with the USPS mailing.

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 based on historical usage in the comparable month in the prior year. In certain cases, such as when the estimate needs to be based on 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; Response to Interrogatory CA-7.

UI's bill form and associated customer notices were also reviewed and found acceptable. UI provides its customers with the proper estimated bill form. The Company also provides customers with notification (in both English and Spanish) as required by Conn. Agencies Regs. §16-3-102(C)(3). UI began developing the programming for an outbound campaign that will notify customers of an estimated meter read. UI committed to completing the project to implement the remaining steps of Order No. 6 of the 2013 UI Rate Case Decision by first quarter in 2017. Response to Interrogatory CA-8.

The Authority notes 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
2013	0.051%	0.055%	0.014%	0.004%
2014	0.046%	0.047%	0.014%	0.006%
2015	0.059%	0.061%	0.016%	0.006%

Response to Interrogatory CA-9.

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 §16-262j-1. Application, Schedule H-2.3. At present, UI does not intend to implement a requirement for residential security deposits. However, the Company has not ruled out this possibility in the future. Response to Interrogatory CA-10.

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. On an as needed basis, service appointments can be scheduled outside of these times to address access issues or in response to a special request from the customer. Application, Schedule H-2.4. In the event that UI is unable to keep a scheduled service appointment, the Company attempts 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. Response to Interrogatory CA-12. Over the last three years, UI has kept at least 99% of its scheduled service appointments. Response to Interrogatory CA-13.

5. Customer Call 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. Response to Interrogatory CA-31. 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%. Statistics submitted by UI for calendar years 2014 and 2015 indicate the call center's monthly performance against the Company's internal goals:

2014	ASA[20]	ACR[21]	2015	ASA	ACR
January	1:02	4.7%	January	2:08	9.3%
February	1:17	5.4%	February	1:10	6.0%
March	1:38	6.8%	March	1:00	4.6%
April	:50	3.3%	April	1:19	5.8%
May	1:40	6.0%	May	2:44	13.2%
June	1:44	7.1%	June	2:36	11.6%
July	1:57	7.7%	July	2:05	9.8%
August	1:45	8.9%	August	1:26	6.1%
September	1:45	8.7%	September	1:37	7.0%
October	:47	3.8%	October	1:05	4.7%
November	1:17	5.9%	November	:57	3.7%
December	1:28	6.1%	December	:42	2.8%

Response to Interrogatory CA-30.

At present, there are no specific standards or benchmarks for EDC call center metrics set forth in Connecticut's statutes or regulations. The Authority has monitored UI's call center responsiveness since 2009. Along with the reporting of call center performance, UI has continued to meet monthly with the Authority's Consumer Affairs staff. These meetings have been valuable for both parties as a means to discuss complaint trends, ongoing issues, or anticipated issues. The Authority finds that there is value in continuing the call center reporting and the monthly compliance meetings. Accordingly, the Authority will direct UI to continue the monthly meetings with PURA staff as well as to report on call center performance statistics.

6. Customer Service Summary

Overall, the Authority found UI's customer service policies and procedures to be in compliance with applicable statutes and regulations.

7. Full Credit Bureau Reporting

Presently, UI reports positive and negative credit information to the three primary credit reporting agencies: Experian, Equifax and Transunion. UI Response to Interrogatory CA-20. This procedure has been in place since 1998. Tr. 9/16/16, p. 719. The procedure for reporting credit information is as follows:

- Files are transmitted on the second Monday of the month.
- Residential accounts with current balances are positively reported.
- Residential accounts with unpaid balances of 93 days or greater are negatively reported.
- Customers with current payment arrangements (forgiveness budgets, matching payments plan budgets and installment plans) are reported as current with a comment indicating that the customer is paying under a partial payment arrangement.

UI Response to Interrogatory CA-20.

[20] In minutes and seconds.
[21] Abandoned call rate.

UI asserted that its use of credit bureau reporting is one of a number of tools used to mitigate uncollectible risk. According to UI, credit bureau reporting is a means to impact customer behavior, helps customers prioritize monthly obligations and provides more leverage to a collector. The credit reporting agencies advised the Company that credit reporting can increase recoveries by as much as 15%. However, UI has not specifically quantified the benefits of credit bureau reporting on uncollectible balances. Information provided by UI indicated that its total accounts receivable increased from $38,990,935.18 in 2005 to $89,584,420.63 in 2016 (as of March 2016). In addition, the number of customer disputes filed with the Company regarding credit reporting has increased from 1,444 in 2008 to 8,092 in 2015. Responses to Interrogatories CA-22 and CA-23; Tr. 9/16/16, pp. 719-721.

UI noticed an increased awareness from its customers with derogatory Company credit postings. According to UI, these are customers that are typically pursuing financing for a home or an automobile. The Company contended that they are more motivated to contact UI and resolve the issue causing the derogatory credit information. Tr. 9/16/16, pp. 720 and 721.

The AG urged the Authority to reconsider the Company's authorization to engage in Full Credit Bureau Reporting (FCBR). The AG noted that UI already possesses a powerful incentive to encourage its customers to prioritize payment of the electric bill - termination of service for non-payment. According to the AG, as the Company can initiate a service termination a full 45 days before a derogatory credit posting is reported, customers are more likely to prioritize the payment of the utility bill. Also, UI has failed to show how FCBR has provided any benefits to ratepayers such as reducing the size of the Company's accounts receivables. Brief, pp. 47 and 48.

In response, the Company claimed that the AG's recommendation should be rejected. UI stated that the AG presented no evidence to link the increase in accounts receivable to credit bureau reporting or has the AG shown that the Company's reporting practices should have decreased receivables over time. UI also disputed the AG's observations regarding the increase in credit reporting complaints since 2008. UI asserted that the increase in disputes regarding credit reporting is not indicative of a problem with the Company's practice. Rather the increase in credit reporting disputes are due to increased customer awareness of personal credit scores and multiple, repeated attempts filed by customers seeking to redress posted information. UI Reply Brief, pp. 85 and 86.

UI also noted that the increase in receivables over the years has been largely driven by hardship accounts. According to the Company, hardship accounts in 2005 made up to 26% of arrearages and of those, 51% were related to medical protection. In 2015, hardship accounts accounted for 60% of delinquent balances and of those, 77% were related to medical protection. Id., p. 85. The issue of derogatory credit reporting and its impact on hardship customers was also discussed by the AG. The AG argued that many of UI's customers who struggle to pay their bills on time are economically vulnerable or disadvantaged. The threat of derogatory credit reporting is not likely to affect these customers' behavior nearly as much as the threat of service termination and the incursion of the costs associated with termination and reconnection. Brief, p. 48.

Presently, the Authority's jurisdiction over credit reporting is limited to Conn. Gen. Stat. §16-262d(g), which states:

> (g) No electric distribution, gas, telephone or water company, certified telecommunications provider, gas registrant or municipal utility furnishing electric, gas or water service shall submit to a credit rating agency, as defined in section 36a-695, any information about a residential customer's nonpayment for electric, gas, telephone, telecommunications or water service unless the customer is more than sixty days delinquent in paying for such service. In no event shall such a company, certified telecommunications provider, gas registrant or municipal utility submit to a credit rating agency any information about a residential customer's nonpayment for such service if the customer has initiated a complaint, investigation hearing or appeal with regard to such service under subsection (c) of this section that is pending before the authority. If such a company, certified telecommunications provider, gas registrant or municipal utility intends to submit to a credit rating agency information about a customer's nonpayment for service, it shall, at least thirty days before submitting such information, send the customer by first class mail notification that includes the statement, AS AUTHORIZED BY LAW, FOR RESIDENTIAL ACCOUNTS, WE SUPPLY PAYMENT INFORMATION TO CREDIT RATING AGENCIES. IF YOUR ACCOUNT IS MORE THAN SIXTY DAYS DELINQUENT, THE DELINQUENCY REPORT COULD HARM YOUR CREDIT RATING.

The legislature has provided clear statutory authority to report derogatory credit information to a credit rating agency. There is no denying the significant increase to the accounts receivable reported by UI in recent years. However, the Authority finds that the record is not clear whether the accounts receivable might have increased even further had FCBR not been introduced, thus leading to increased costs ultimately borne by the balance of the Company's ratepayers in the form of higher rates. Whether to exclude certain populations from FCBR is a matter of social policy within the statutory purview of the legislature.

III. FINDINGS OF FACT

1. UI does not bear any investment risk relative to the employee's investment choices.

2. 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. This defined contribution plan was implemented on April 1, 2005, for union employees and May 1, 2005, for non-union employees.

3. The defined contribution plan consists of the current provisions of the 401(k) KSOP for both pension and post-retirement medical benefits.

4. Total cost for the Company's 401(k) is $2,931,000 in the 2017 rate year, $3,019,000 in the 2018 rate year and $3,109,000 in the 2019 rate year.

5. The Authority adjusted the 401(k) based on Authority adjustments in past rate cases.

6. The Authority's adjustment allowed full recovery of matching contributions for all UI employees, except those who are entitled to benefit under the EICP and the MCP.

7. The Authority's 401(k) adjustment for employees receiving other compensation is $435,000 in the 2017 rate year, ($448,000) in the 2018 rate year and ($462,000) in the 2019 rate year.

8. UI sponsors a qualified pension plan for employees hired before 2005.

9. UI's qualified pension plan meets certain criteria under the Internal Revenue Code.

10. Pension expense is accounted for under ASC 715, which provides the methodology to recognize employees' future retirement benefit costs as they accrue over their working career.

11. The qualified pension expense was calculated using the assumptions of a discount rate of 3.24%, salary increase of 3.8% and the expected return on asset assumption of 7.75%.

12. The expected return is a long-term projection of the probable return on pension plan assets, which is influenced by the particular asset mix and expected returns on that asset mix.

13. The higher the assumption for future returns on plan assets, the lower the pension expense.

14. The discount rate is the rate at which projected benefits are discounted back to a present value.

15. The higher the discount rate, the lower the present value of pension plan liabilities resulting in lower pension expense.

16. There are no allocations from Avangrid, CNG, SCG or any other subsidiary of Avangrid embedded in the Company's pension expense for the test year or rate years.

17. There are five retired directors who served in 1980s and 1990s that receive a total of $58,000 a year in retirement for their life-times.

18. The Company's non-qualified pension plan, SERP, is offered to participants of the UI qualified pension plan.

19. The SERP provides benefits under the same formula as the qualified plan but recognizes pay, over the qualified plan pay cap designated by the IRS.

20. The Authority disallowed a SERP expense in the 2013 Aquarion Rate Case Decision, and the 2008 SCG Rate Case Decision.

21. UI provides retiree medical benefits for retirees as determined by ASC 715.

22. UI is required by the ASC 715 to recognize OPEB benefits during the working career of employees, not after they retire.

23. OPEB costs accrue from the date an employee is hired.

24. In 2005, the Company closed its retiree medical plan to new entrants and replaced this coverage with a flat contribution of $1,100 per participant to the 401(k) plan.

25. In 2015, UI offered a Medicare Exchange as an option to retirees who are Medicare-eligible and in 2016 made it the only option for non-union retirees.

26. The rate years of 2017, 2018, and 2019 OPEB expenses are based on the actuarial assumptions for a discount rate, expected return on assets, and a medical trend rate.

27. In 2016, the OPEB retiree medical plan was redesigned to a post 65 health retirement account such that retirees would receive a credit to purchase insurance in a private health care exchange.

28. The ultimate OPEB health care cost trend rate is 4.50% for rate year 2017, 4.50% for rate year 2018 and 4.50% for rate year 2019.

29. The Company requested other employee benefits expense in the amount of $630,000 in the 2015 test year; $675,000 in the rate year ending 2017; $693,000 in the rate year ending 2018 and $712,000 in the rate year ending 2019.

30. Other employee benefits consist of flex credits, service/recognition awards, group life insurance/long term disability and education reimbursements.

31. UI calculated deferred taxes on pension liabilities of $16,396,000 in rate year 2017, $13,106,000 in rate year 2018 and $12,105,000 in rate year 2019.

32. For deferred taxes on pension liabilities, a Federal tax rate of 35.0% was used for all three rate years.

33. For deferred taxes on pension liabilities a state tax rate of 9.0% was used in rate year 2017, 8.30% was used for rate year 2018, and 7.50% was used for the rate year 2019.

34. 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.

35. In developing its distribution WC requirement, the Company performed its lead/lag study utilizing UI's overall revenues and expenses and then removed transmission and Generation Service Charge WC requirements to arrive at a distribution-only WC requirement

36. The Company provided a distribution-only WC exhibit in response to Late Filed Exhibit No. 31

37. UI requested average UPZ regulatory asset, net of related accumulated amortization of $26.395 million for 2017, $33.183 million for 2018 and $38.997 million for 2019.

38. The Company reduced the proposed total rate case expense from $1.388 million to $1.190 million and requested an annual rate case amortization expense of $0.397 million.

39. The approximate $198,000 decrease to the proposed total rate case expense included reductions of $120,000 to legal costs, $95,000 to postage expense, $15,000 for costs associated with ROE witness, and $10,000 for overtime and payroll overheads, and an increase of $45,000 for lead/lag study.

40. The Company made changes to the tariff language for clarification.

41. The Company's changes made to miscellaneous fees are based on expected labor costs.

42. The Company's return check fee was cost-based.

43. The 2013 UI Rate Case Decision set out a methodology for calculating a sales forecast that was used in the instant case.

44. The Company reviews and revises its sales forecast at least annually as part of its budgeting process.

45. The Company's sales forecast covered January 1, 2017 through December 31, 2019.

46. UI began developing the programming for an outbound campaign which would notify customers of an estimated meter read.

47. The Company proposed earning sharing mechanism is designed to share with customers 50% of the Company's earnings above a set level above the Authority's allowed ROE plus a dead band that changes annually over the rate years.

48. The proposed dead band of 20, 30 and 40 basis points would be applied in rate years 2017, 2018 and 2019, respectively.

49. The Company claimed that, if its dead band ESM proposal was in place during the 2013 to 2016 rate years, it would have returned less money to customers.

50. In 2014, UI returned $2,424,355 to customers, but if the ESM dead band proposal were in place and 2014 was specified as rate year 2, then the Company would have returned $1,191,632 to customers (or alternatively, reduced storm regulatory assets) for a difference of $1,232,723.

51. Prior to implementing the time-of-use policy, UI served approximately 35,000 customers under Rate RT.

52. UI currently serves approximately 70,000 Rate RT through an advanced meter.

53. A customer assigned to Rate RT under the time-of-use policy is not allowed to return to Rate R per UI's tariff.

54. Some residential customers complain when they are assigned to Rate RT.

55. UI has completed the installation of its MDM system, which collects time-of-use, demand and interval data for all residential customers served through an advanced meter.

56. New and relocating customers are generally assigned to Rate R.

57. Moody's upgraded the long-term issuer credit rating for UI in January 2014 from Baa2 to Baa1 (stable).

58. S&P upgraded UI's issuer credit rating from BBB to BBB+ / Stable in April 22, 2016.

59. Fitch IBCA rated UI BBB+ / Stable.

60. S&P upgraded Iberdrola and Avangrid.

61. Avangrid is a utility holding company that now owns UI.

62. As of December 31, 2015, the risk factors associated with UI are embedded in the risks associated with Avangrid.

63. The Company proposed rates that are based on a capital structure consisting of a capitalization mix of 48% long-term debt to 52% common equity projected for December 31, 2016.

64. The Company proposed rates that are based on forecasted long-term embedded cost of long-term debt rates of 5.31% in 2017, 5.14% in 2018 and 5.05% in 2019.

65. The Company proposed rates that are based on a proposed ROE of 9.92% and corresponding WACC of 7.72%, 7.69% and 7.71% for the three years respectively.

66. Over the 2013 UI Rate Case years of 2013, 2014 and 2015, the Company's year-end common equity portion was 48.66%, 50.96% and 50.34%, respectively.

67. As of June 30, 2016, the Company had 51.44% common equity.

68. The Company Utility Group was composed of 23 comparable electric distribution companies.

69. The mean of the Company Utility Group's capital structure is 53.46% common equity.

70. For the 2013 UI rate case, the Company proposed a 50%-50% capitalization mix for ratemaking purposes, which was adopted by the Authority.

71. The OCC proposed rates that would be based on a 50%-50% capitalization mix.

72. The OCC proposed long-term embedded cost of long-term debt rates of 5.35% in 2017, 5.27% in 2018 and 5.32% in 2019.

73. The OCC proposed an ROE of 8.50%, and a resulting WACC of 6.90% in 2017, 6.79% in 2018 and 6.67% in 2019.

74. The Company retained the services of a cost of capital expert to review changes in financial and economic markets and to provide a recommended ROE.

75. The Company's methods included the DCF model, CAPM and a Risk Premium approach.

76. The OCC retained the services of a cost of capital expert who proposed an 8.5% allowed return.

77. The OCC observed that authorized ROEs for electric utilities have declined to an average of 9.52% for the first half of 2016.

78. The 9.15% allowed ROE from the 2013 UI Rate Case Decision was cited as a credit positive decision by Moody's.

79. The Company attracted a $4 billion acquisition premium with the merger with Iberdrola.

80. According to the OCC, interest rates and capital costs have decreased in reaction to FED monetary policy and changes in the economy.

81. In the second half of 2013, the UST-30 was in the 3.5% to 4.0% range. These rates declined to below 2.5% over the next year.

82. Interest rates declined to below 2.5% by the summer of 2016.

83. The authorized ROEs have declined from 9.80% in 2013, to 9.76% in 2014, to 9.58% in 2015, and to 9.52% in the first half of 2016,

84. One hundred percent of UI's $888 million revenue was derived from electric utility services.

85. UI's screening selection process yielded 23 proxy companies for the Company Utility Group proxy group.

86. The OCC analysis yielded a group of 28 proxy companies for the OCC Utility Group.

87. The median operating revenues and net plant among members of the OCC Proxy Group are $5,153.6 million and $13,925.0 million, respectively.

88. The OCC Utility Group receives 81% of its revenues from regulated electric operations.

89. The OCC Utility Group has a BBB+ and A3/Baa1 issuer credit ratings from S&P and Moody's respectively, a current common equity ratio of 47.1%, and an earned return on common equity of 9.4%.

90. UI's S&P rating is equal to the average S&P rating for the OCC Utility Group and is in line with the average S&P rating for the Company Utility Group (Baa1 vs. A3/Baa1).

91. Prior to the merger with Avangrid, UIL closed on equity issuances of approximately $525 million and $214 million (for a total of 26 million shares of common stock) in September 2010 and September 2013, respectively.

92. The OCC relied primarily on the results of the DCF model.

93. The Company's proposal gave more weight to the CAPM results in this proceeding than had been given historically based on current market conditions and the current low interest rate environment.

94. The Company and the OCC separately performed a DCF Model.

95. The Company and the OCC used the constant growth from of the DCF model.

96. Both the Company and the OCC performed a CAPM analysis.

97. The Company also performed a Bond Yield plus Risk Premium (BY+RP) approach.

IV. CONCLUSION AND ORDERS

A. CONCLUSION

Based on the evidence presented in this proceeding, the Authority finds allowed revenues of $363,034,000 to be appropriate for UI in rate year 1, $374,529,000 in rate year 2 and $377,447,000 in rate year 3 as detailed in Section V. Rate Model. This is a reduction of $39.369 million from the Company's adjusted cumulative request of $98.252 million and a $58.883 million increase or 18.84% to present revenues. The Authority allows the Company an allowed rate base of $981 million in rate year 1, $997.026 million in rate year 2, and $1,014.144 million in rate year 3. The Authority approves an allowed ROE for the rate years of 9.10%, for a weighted cost of capital of 7.21% in rate year 1, 7.12% in rate year 2 and 7.08% in rate year 3. 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 January 1, 2017.

B. ORDERS

For the following Orders, the Company shall submit one original of the required documentation to the Executive Secretary, 10 Franklin Square, New Britain, Connecticut 06051 and file an electronic version through the Authority's website at www.ct.gov/pura. Submissions filed in compliance with the Authority's Orders must be identified by all three of the following: Docket Number, Title and Order Number. Compliance with orders shall commence and continue as indicated in each specific Order or until the Company requests and the Authority approves that the Company's compliance is no longer required after a certain date.

1. As of December 14, 2016, the Company shall separately account for lean-in costs in the storm reserve as discussed in Section II.M.2. Storm Reserve.

2. No later than December 20, 2016, UI shall file with the Authority for approval, five complete sets of tariffs, scored and unscored, that incorporate all tariff and rate year 1 rate changes approved herein that comports with the directives in Section II.J. Rate Design to be effective January 1, 2017. The Company shall include a supporting COSS and a unity COSS for rate year 1 reflecting the billing determinants and financial profile approved herein, that comports with the directives in Section II.J. Rate Design.

3. No later than December 31, 2016, the Company shall cease the amortization of new ETT expenditures as discussed in Section II.B.2. Utility Protection Zone. JJ

4. As of January 1, 2017, the Company shall expense new UPZ expenditures as discussed in Section II.B.2. Utility Protection Zone.

5. No later than January 1, 2017, the Company shall collect data on the direct contact of branches with an energized line and its management of this work as discussed in Section II.B.3. Direct Contact Program.

6. No later than January 31, 2017, 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 30 business days prior to the effective date of such changes.

7. No later than January 31, 2017, and monthly thereafter, 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

8. No later than January 31, 2017, UI shall continue its monthly meetings with the Authority's Consumer Affairs Unit.

9. No later than March 31, 2017, the Company shall file with the Authority for its approval an education plan to inform customers about its time of use policy. AM

10. No later than April 3, 2017, the Company shall file with the Authority for its approval a plan with implementation dates for the cited actions to further Connecticut's energy policies as discussed in Section II.J.4. Residential Service Rates.

11. No later than April 3, 2017, UI shall submit for approval its plan including the cost to modify its electric billing statement as discussed in Section II.J.4. Residential Service Rates.

12. No later than November 30 of 2017, 2018 and 2019, the Company shall provide the Authority with a report of forecasted construction program capital spending by Initiative or category for the following year as discussed in Section II.B.6. Capital Expenditures. If forecasted spending varies from that represented in this proceeding by more than 10% in any initiative or category from that budgeted, or if the total aggregate forecasted capital spending varies by more than 10%, the Company shall provide an explanation of the reason for such variance.

13. No later than December 20, 2017, the Company shall file for Authority approval, a rate plan for rate year 2 incorporating the directives in Section II.J. Rate Design and any future directives ordered as part of the Electric Generic.

14. No later than March 31, 2018, 2019 and 2020, the Company shall provide the Authority with a report of actual construction program capital spending by Initiative or category for the preceding year as discussed in Section II.B.6. Capital Expenditures. If actual spending varies from budgeted spending by more than 10% in any initiative or category from that budgeted, or if the total aggregate capital spending varies by more than 10%, the Company shall provide an explanation of the reason for such variance.

15. No later than March 31, 2018 and each year thereafter, UI shall submit a report on its Grid Analytics and DMS initiatives as discussed Section II.B.6.b. Grid Modernization. The report shall include:

    a. All activities related to the Grid Analytics initiative deployment and utilization during the prior calendar year, including a summary of the implementation status of the Grid Analytics initiative, its current utilization by the Company, any lessons learned from its implementation, and its plans for implementing Grid Analytics or any changes to it during the upcoming calendar year.

    b. All activities related to the DMS deployment and utilization during the prior calendar year, including a summary of the implementation status of the DMS initiative, its current utilization by the Company, any lessons learned from its implementation, and its plans for implementing DMS or any changes to it during the upcoming calendar year. The report shall include the type of devices deployed by the Company, the locations in which they are deployed, the parameters that they monitor, the DER that they are monitoring, and a technical description of the value that they provide to the Company and its customers in monitoring and controlling the distribution system.

16. No later than December 20, 2018, the Company shall file for Authority approval, a rate plan for rate year 3 incorporating the directives in Section II.J. Rate Design and any future directives ordered as part of the Electric Generic.

17. In its next rate proceeding, the Company shall file data showing the cost of removal of branches making direct contact with energized lines and justify the continuance of this expense as discussed in Section II.B.3. Direct Contact Program.

18. In its next rate proceeding, the Company shall include the management of direct contact conditions with the line clearance funds, prioritizing high growth vegetation areas within the UPZ program and realize at least an 81% consent rate for full UPZ in its future vegetation management plans as discussed in Section II.B.3. Direct Contact Program.

19. In its next rate proceeding, the Company shall file its WC request based on a distribution company-only basis with a lead/lag study that references the same specific accounts that are presented in its rate application as discussed in Section II.B.7. Working Capital Allowance.

20. In its next rate proceeding, the Company shall file a depreciation study that 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) and shall have a plant-in-service date that is within 12 months of the beginning of the proposed test year as discussed in Section II.C.11. Depreciation.

V. RATE MODEL

A. 2017 INCOME STATEMENT (000)

THE UNITED ILLUMINATING COMPANY - DN 16-06-04
INCOME STATEMENT — 12-Dec-16 — PER CENT REVENUE INCREASE ALLOWED = 13.4346%
ELECTRIC - RATE YEAR STARTING JANUARY 1, 2017
FROM C SCHEDULED FILED 7/5/16 & LFE-003 FILED 9/30/16

	REVISED PRO FORMA RATE YEAR	AUTHORITY ADJUSTMENTS	21.178% TABLE II	FINAL CHANGES	TABLE III
OPERATING REVENUES	$311,675	$0	$311,675		$311,675
OPERATING REVENUES - OTHER	9,130	(767)	8,363		8,363
RATE REQUEST	66,005	0	66,005	(23,009)	42,996
TOTAL REVENUES	386,810	(767)	386,043	(23,009)	363,034
OPERATION & MAINTENANCE EXPENSE	$109,987	(4,162)	$105,825	(237)	105,588
OTHER O&M	50,000	10,491	60,491		60,491
MISC. EXPENSE	0	0	0		0
DEPRECIATION EXPENSE	63,208	(11,945)	51,263		51,263
AMORTIZATION EXPENSE	6,016	(3,527)	2,489		2,489
MISC. EXPENSE	0	0	0		0
TAXES, SALES & PAYROLL	21,180	0	21,180		21,180
GROSS EARNINGS TAXES	20,000	(54)	19,946	(1,629)	18,317
PROPERTY TAXES	15,000	0	15,000		15,000
PROVISION FOR DEF. INCOME TAXES, NET	2,000	4,181	6,181	0	6,181
STATE TAXES	7,500	(398)	7,102	(1,903)	5,199
FEDERAL TAXES (CURRENT)	14,740	(1,409)	13,331	(6,734)	6,597
INVESTMENT TAX CREDIT	0	0	0		0
TOTAL OPERATING EXPENSES	$309,631	(6,824)	$302,807	(10,503)	$292,304
INCOME FROM LEASE OF UTILITY PLANT	0	0	0		0
OPERATING INCOME	$77,179	$6,057	$83,236	(12,506)	70,730

B. 2017 RATE BASE (000)

THE UNITED ILLUMINATING COMPANY - DN 16-06-04 RATE BASE ELECTRIC - RATE YEAR STARTING JANUARY 1, 2017	REVISED PROFORMA	AUTHORITY ADJUSTMENTS 12-Dec-16	TABLE I
UTILITY PLANT IN SERVICE	$1,700,236	$0	$1,700,236
PLANT 2	0	0	0
LESS: CONS. WORK IN PROGRESS	0	0	0
LESS: ACCUM DEP AND AMORT	481,433	884	482,317
NET PLANT	1,218,803	(884)	1,217,920
PLUS:			
MISCELLANEOUS	$0	0	0
WORKING CAPITAL	30,866	(1,274)	29,592
PREPAYMENTS	0	0	0
DEFERRED TAXES	(9,740)	0	(9,740)
ETT REGULATORY ASSET	0	0	0
REGULATORY ASSET - FASB 158	181,030	1,764	182,794
UPZ REGULATORY ASSET	26,395	(7,041)	19,354
LESS:			
DEFERRED INCOME TAXES	$270,479	2,090	272,569
CUST. ADVANCES AND DEPOSITS	516	0	516
STORM RESERVES	7,763	0	7,763
UPZ REGULATORY LIABILITY	10,783	(2,876)	7,907
ALLOWANCE FOR BAD DEBT	3,500	0	3,500
PENSION LIABILITIES	160,445	0	160,445
RESERVE FOR INJURIES AND DAMAGES	3,650	0	3,650
ACCRUED VACATION	2,569	0	2,569
RATE BASE	987,649	(6,649)	981,000
RETURN ON RATE BASE	7.71%	7.21%	7.21%
OPERATING INCOME	76,148	(5,418)	70,730

C. 2018 INCOME STATEMENT (000)

THE UNITED ILLUMINATING COMPANY - DN 16-06-04					
INCOME STATEMENT		12-Dec-16		PER CENT REVENUE	
ELECTRIC - RATE YEAR STARTING JANUARY 1, 2018				INCREASE ALLOWED =	17.6113%
FROM C SCHEDULED FILED 7/5/16 & LFE-003 FILED 9/30/16			27.767%		
	REVISED PRO FORMA RATE YEAR	AUTHORITY ADJUSTMENTS	TABLE II	FINAL CHANGES	TABLE III
OPERATING REVENUES	$309,780	$0	$309,780		$309,780
OPERATING REVENUES - OTHER	9,439	(773)	8,666		8,666
RATE REQUEST	86,016	0	86,016	(29,933)	56,083
TOTAL REVENUES	405,235	(773)	404,462	(29,933)	374,529
OPERATION & MAINTENANCE EXPENSE	$114,386	(6,878)	$107,508	(309)	107,199
OTHER O&M	50,000	11,448	61,448		61,448
MISC. EXPENSE	0	0	0		0
DEPRECIATION EXPENSE	65,449	(11,309)	54,140		54,140
AMORTIZATION EXPENSE	15,975	(8,048)	7,927		7,927
MISC. EXPENSE	0	0	0		0
TAXES, SALES & PAYROLL	23,888	0	23,888		23,888
GROSS EARNINGS TAXES	20,000	(55)	19,945	(2,119)	17,826
PROPERTY TAXES	15,000	0	15,000		15,000
PROVISION FOR DEF. INCOME TAXES, NET	2,000	3,958	5,958	0	5,958
STATE TAXES	7,500	172	7,672	(2,269)	5,403
FEDERAL TAXES (CURRENT)	12,913	671	13,584	(8,833)	4,751
INVESTMENT TAX CREDIT	0	0	0		0
TOTAL OPERATING EXPENSES	$327,111	(10,041)	$317,070	(13,530)	$303,540
INCOME FROM LEASE OF UTILITY PLANT	0	0	0		0
OPERATING INCOME	$78,124	$9,268	$87,392	(16,404)	70,988

D. 2018 RATE BASE (000)

THE UNITED ILLUMINATING COMPANY - DN 16-06-04 RATE BASE ELECTRIC - RATE YEAR STARTING JANUARY 1, 2018	REVISED PROFORMA	AUTHORITY ADJUSTMENTS 12-Dec-16	TABLE I
UTILITY PLANT IN SERVICE	$1,795,685	$0	$1,795,685
PLANT 2	0	0	0
LESS: CONS. WORK IN PROGRESS	0	0	0
LESS: ACCUM DEP AND AMORT	529,654	1,202	530,856
NET PLANT	1,266,031	(1,202)	1,264,830
PLUS:			
MISCELLANEOUS	$0	0	0
WORKING CAPITAL	25,951	(1,313)	24,638
PREPAYMENTS	0	0	0
DEFERRED TAXES	(7,514)	0	(7,514)
ETT REGULATORY ASSET	0	0	0
REGULATORY ASSET - FASB 158	181,030	4,024	185,054
UPZ REGULATORY ASSET	33,183	(21,363)	11,820
LESS:			
DEFERRED INCOME TAXES	$287,051	1,979	289,030
CUST. ADVANCES AND DEPOSITS	516	0	516
STORM RESERVES	9,763	0	9,763
UPZ REGULATORY LIABILITY	13,465	(8,657)	4,808
ALLOWANCE FOR BAD DEBT	3,500	0	3,500
PENSION LIABILITIES	167,965	0	167,965
RESERVE FOR INJURIES AND DAMAGES	3,650	0	3,650
ACCRUED VACATION	2,569	0	2,569
RATE BASE	1,010,202	(13,176)	997,026
RETURN ON RATE BASE	7.63%	7.12%	7.12%
OPERATING INCOME	77,078	(6,090)	70,988

E. 2019 INCOME STATEMENT (000)

THE UNITED ILLUMINATING COMPANY - DN 16-06-04
INCOME STATEMENT 12-Dec-16 PER CENT REVENUE
ELECTRIC - RATE YEAR STARTING JANUARY 1, 2019 INCREASE ALLOWED = 18.4840%
FROM C SCHEDULED FILED 7/5/16 & LFE-003 FILED 9/30/16

	REVISED PRO FORMA RATE YEAR	AUTHORITY ADJUSTMENTS	31.739% TABLE II	FINAL CHANGES	TABLE III
OPERATING REVENUES	$309,560	$0	$309,560		$309,560
OPERATING REVENUES - OTHER	9,783	(779)	9,004		9,004
RATE REQUEST	98,252	0	98,252	(39,369)	58,883
TOTAL REVENUES	417,595	(779)	416,816	(39,369)	377,447
OPERATION & MAINTENANCE EXPENSE	$117,725	(10,008)	$107,717	(406)	107,311
OTHER O&M	50,000	11,491	61,491		61,491
MISC. EXPENSE	0	0	0		0
DEPRECIATION EXPENSE	68,714	(11,808)	56,906		56,906
AMORTIZATION EXPENSE	18,437	(12,578)	5,859		5,859
MISC. EXPENSE	0	0	0		0
TAXES, SALES & PAYROLL	26,106	0	26,106		26,106
GROSS EARNINGS TAXES	20,000	(55)	19,945	(2,787)	17,158
PROPERTY TAXES	15,000	0	15,000		15,000
PROVISION FOR DEF. INCOME TAXES, NET	2,000	4,133	6,133	0	6,133
STATE TAXES	7,500	728	8,228	(2,713)	5,515
FEDERAL TAXES (CURRENT)	12,738	3,141	15,879	(11,712)	4,167
INVESTMENT TAX CREDIT	0	0	0		0
TOTAL OPERATING EXPENSES	$338,220	(14,956)	$323,264	(17,618)	$305,646
INCOME FROM LEASE OF UTILITY PLANT	0	0	0		0
OPERATING INCOME	$79,375	$14,177	$93,552	(21,751)	71,801

F. 2019 RATE BASE (000)

THE UNITED ILLUMINATING COMPANY - DN 16-06-04
RATE BASE 12-Dec-16
ELECTRIC - RATE YEAR STARTING JANUARY 1, 2019

	REVISED PROFORMA	AUTHORITY ADJUSTMENTS	TABLE I
UTILITY PLANT IN SERVICE	$1,887,474	$0	$1,887,474
PLANT 2	0	0	0
LESS: CONS. WORK IN PROGRESS	0	0	0
LESS: ACCUM DEP AND AMORT	577,264	952	578,216
NET PLANT	1,310,210	(952)	1,309,258
PLUS:			
MISCELLANEOUS	$0	0	0
WORKING CAPITAL	21,770	(1,585)	20,185
PREPAYMENTS	0	0	0
DEFERRED TAXES	(4,871)	0	(4,871)
ETT REGULATORY ASSET	0	0	0
REGULATORY ASSET - FASB 158	181,030	6,289	187,319
UPZ REGULATORY ASSET	38,997	(33,682)	5,315
LESS:			
DEFERRED INCOME TAXES	$301,757	2,066	303,823
CUST. ADVANCES AND DEPOSITS	516	0	516
STORM RESERVES	11,763	0	11,763
UPZ REGULATORY LIABILITY	15,640	(13,501)	2,139
ALLOWANCE FOR BAD DEBT	3,500	0	3,500
PENSION LIABILITIES	175,102	0	175,102
RESERVE FOR INJURIES AND DAMAGES	3,650	0	3,650
ACCRUED VACATION	2,569	0	2,569
RATE BASE	1,032,639	(18,495)	1,014,144
RETURN ON RATE BASE	7.58%	7.08%	7.08%
OPERATING INCOME	78,274	(6,473)	71,801

DOCKET NO. 16-06-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

This Decision is adopted by the following Commissioners:

John W. Betkoski, III

Michael A. Caron

Katherine S. Dykes

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.



December 14, 2016

Jeffrey R. Gaudiosi, Esq.
Executive Secretary
Public Utilities Regulatory Authority

Date